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London

Project TransmiT: Updated Comparison of the WACM 2 and Status Quo Charging Models

Prepared for RWE npower

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Executive Summary

NERA Economic Consulting and Imperial College London have been commissioned by RWE npower to model the welfare impacts of a proposal from Ofgem to reform the British Transmission Network Use of System (TNUoS) charging methodology.[1] The current proposal would see the "status quo" transmission charging methodology replaced by an alternative known as the "WACM 2" methodology.

Methodology

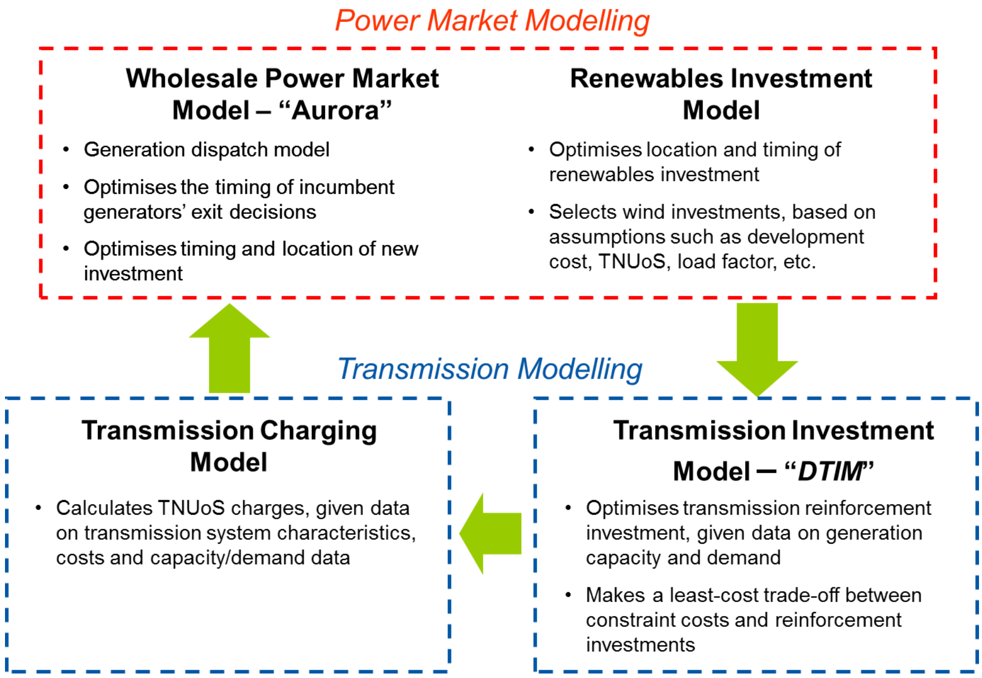
To compare the status quo and WACM 2 charging models, we used a modelling framework that combines wholesale market models, a load flow and investment model of the British transmission system, and a charging model based on the National Grid Tariff and Transport Model used to calculate ICRP tariffs. We iterate between these models in order to obtain an equilibrium set of TNUoS charges, generation investment, and transmission investment. This framework is illustrated in Figure 1.[2] However, for this assignment, we have made two key changes to our approach:

- Firstly, we have changed the way in which we account for the Capacity Payment Mechanism (CPM) that is currently being implemented in the British wholesale electricity market. This changes slightly the method we use to forecast generators' entry and exit decisions, as well as wholesale power prices.
- Secondly, we have developed a new version of our renewables optimisation tool to reflect recent developments in government policy on renewables subsidies, such as the introduction of the Contract for Different (CfD) Feed-in Tariff (FIT) scheme, and the Levy Control Framework (LCF). We have also simplified the renewables investment modelling process, which facilitates the interpretation of results.

[1] Project TransmiT: Further consultation on proposals to change the electricity transmission charging methodology, Ofgem, 25 April 2014.

[2] We provide more details on this framework in a report submitted to Ofgem earlier in the Project TransmiT process. See: Project TransmiT: Impact of Uniform Generation TNUoS, Prepared for RWE npower, NERA Economic Consulting and Imperial College London, 31 March 2011, Chapter 2 and Appendix A.

Figure 1
Overview of Modelling Framework



Source: NERA/Imperial

Key Findings

Following a process of iteration between our market and transmission system models, which resulted in a high degree of convergence, the main results we obtained are as follows:

- The WACM 2 charging methodology significantly reduces TNUoS charges for low load factor plants, e.g. wind farms, in Scotland as compared to the status quo, and significantly increases charges for low load factor thermal generators in England and Wales. Plants that run at higher load factors are affected less;
- As a result, a higher proportion of new onshore wind generation and new thermal generation capacity locates in Scotland. Our analysis shows that locating more generation capacity towards the north of the country increases transmission system costs;
- The TNUoS costs that new CCGT plants face under WACM 2 are higher. Because wholesale energy and capacity prices need to rise to a level that remunerates investment in new CCGTs, WACM 2 causes higher capacity prices, which materially increases consumers' bills;
- Overall, we estimate that WACM 2 would increase consumers' bills by around £2.8 billion in NPV terms over the period to 2030, which is materially more than Ofgem's recent consultation estimates. We also estimate that power sector costs would increase due to WACM 2 by around £300 million. Our estimated welfare impacts are materially greater than those estimated by Ofgem's consultants (Baringa), suggesting Ofgem has underestimated the negative effect of WACM 2 on consumers; and
- We find no difference in the environmental performance of the two charging models. Renewables deployment and CO_2 emissions are similar across the runs, and in any case,

whatever the level or structure of TNUoS paid by generators, government environmental policy (e.g. subsidies) can adjust to ensure targets can be met.

Implications

The role of locational TNUoS charges is to promote the efficient use of the transmission system. If changes to the transmission charging regime improve the efficiency of network usage, we would expect total power sector costs to fall as a result, and thus increase social welfare. In practice, our market and transmission system modelling suggests that the WACM 2 charging model would reduce social welfare, which suggests it does not promote a more efficient use of the transmission system. Our analysis also suggests that introducing WACM 2 would increase costs to the consumer due to its effect on wholesale energy and capacity prices. It also suggests that the Baringa modelling commissioned by Ofgem understates the impact of WACM 2 on consumers' bills.

By implementing changes to the current transmission charging regime that do not deliver demonstrable improvements in economic efficiency and consumer benefits, Ofgem may increase investors' perception that the new regime will have a limited lifespan. Generators cannot predict these changes and they cannot protect themselves against the effects of such changes, except by maintaining a diversified portfolio of generation. Removing the current charging model may therefore undermine the incentives provided by the transmission charging regime.

Additionally, although we have not estimated these effects in this report, the distributional effects of introducing the WACM 2 charging model may be significant. Regulatory decisions that redistribute value amongst industry participants, especially without any resulting and demonstrable improvement in efficiency, will add to investors' perception of regulatory risk and increase the costs of financing for the British energy industry, and thus further increase consumer bills.

Overall, therefore, the modelling presented in this report does not support the introduction of the WACM 2 model as currently proposed. Finally, in addition to the evidence presented in this report, we see fundamental problems with the design of the WACM 2 charging model, and the evidence presented to support the hypothesis that it is more cost reflective than the status quo. We discuss these issues further in an accompanying report.[3]

3 Project TransmiT: Critical Review of Ofgem's April 2014 Further Consultation, Prepared for RWE npower, 27 May 2014.

1. Introduction

NERA Economic Consulting and Imperial College London have been commissioned by RWE npower to review the recent consultation document published by Ofgem relating to proposals to reform the British Transmission Network Use of System (TNUoS) Charging Methodology, and to prepare modelling analysis for submission in response to this consultation.[4]

1.1. Background on Project TransmiT

In 2010, Ofgem announced a fundamental review of current electricity charging arrangements, called "Project TransmiT". Through this process, Ofgem originally proposed three possible scenarios for charging going forward:

- The "status quo", whereby the current model would continue with minor modifications;
- A "socialised" charging model, whereby generation TNUoS charges would be paid through a uniform charge per MWh of energy output; and
- An "improved ICRP" charging model, which seeks to alter the existing charging model in an attempt to, amongst other things, better reflect how different types of generator impose different costs on the transmission system.

Ofgem considered the introduction of the "improved ICRP" and "socialised" charging models in the "options for change" document it published during the Project TransmiT process. In this paper, Ofgem ruled out the socialised charging model on the grounds that removing the economic signals conveyed to users through locational transmission charges would cause a "disproportionate" increase in power sector costs and customer bills. At the same time, it suggested that "*improved ICRP is the right direction for transmission charging arrangements*".[5] However, following this consultation, it published a decision that suggested that the "*the choice between Improved ICRP and the Status Quo is not clear cut*".[6]

It therefore initiated a Significant Code Review (SCR). Ofgem directed National Grid to organise an industry Workgroup to draft a modification to the Connection and Use of System Code (CUSC), referred to as modification CMP213, to develop the "improved ICRP" methodology.[7] The Workgroup considered a range of variants on the original "improved ICRP" methodology. At a meeting of the CUSC Modifications Panel on 31 May 2013, the Panel voted by majority that 8 out of the 27 options better facilitate the "Applicable CUSC Objectives". The result of this majority vote formed the Panel's recommendation to Ofgem.

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4 Project TransmiT: Further consultation on proposals to change the electricity transmission charging methodology, Ofgem, 25 April 2014. Unless otherwise stated, all references in this paper to Ofgem (April 2014) refer to this consultation document.

5 Project TransmiT: Electricity transmission charging: assessment of options for change, Ofgem (188/11), 20 December 2011, para 6.16.

6 Electricity transmission charging arrangements: Significant Code Review conclusions, Ofgem (65/12), 4 May 2012, page 5.

7 Stage 02: Workgroup Consultation, Connection and Use of System Code (CUSC), CMP213 Project TransmiT TNUoS Developments, National Grid, 7 December 2012, para 1.7-1.10.

On 14 June 2013 the CUSC Panel submitted its Final Modification Report (FMR) to Ofgem for its consideration.[8]

On 1 August 2013, Ofgem announced that it was "minded to" implement one of the variants of "improved ICRP," in favour of which the CUSC Modification Panel had voted, known as "Workgroup Alternative CUSC Modification 2" (WACM 2).[9] WACM 2 is similar to the original "improved ICRP" model, but assumes that plants in regions with high concentrations of low-carbon generation impose higher costs on the transmission network than those in regions with a diverse mix of generation sources (or those dominated by thermal generation).

1.2. Ofgem's "Minded to" Decision

Ofgem's August 2013 Impact Assessment compared the various charging options submitted by the Industry Workgroup against the following 'relevant objectives' for changes to the Use of System charging methodology, as set out in Section C5 of National Grid's transmission licence:

- **The methodology facilitates competition in the generation and supply of electricity**

  Ofgem's initial view was that "*all of the CPM213 proposals are more cost reflective than the status quo*" and would therefore *"promote competition more effectively*".[10]

- **The methodology yields charges which reflect, as far as is reasonably practicable, the costs incurred by the transmission operator**

  Ofgem's expressed the view that alternatives featuring the proposed methodology Diversity 1 (including WACM 2) "*most appropriately reflect the TOs' investment decisions for "year round" conditions, and therefore are the most cost reflective options*".[11]

- **The methodology, as far as is reasonably practicable, properly takes account of the developments in the transmission licensees' transmission business**

  Ofgem expressed the view that, of the options considered, the WACM 2 charging model "*best incorporates the developments of HVDC and island links as well as best taking into account the changing generation mix*".[12]

Ofgem has also compared the charging options against the Authority's principal objective to protect the interests of existing and future consumers, wherever appropriate through the promotion of effective competition. These interests include:

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8 Project TransmiT : Impact Assessment of industry's proposals (CMP213) to change the electricity transmission charging methodology, Ofgem (137/13), 1 August 2013, para 2.12. Unless otherwise specified, all other citations of Ofgem (August 2013) in this report refer to this document.

9 Ofgem (August 2013), page 5

10 Ofgem (August 2013), para 6.9

11 Ofgem (August 2013), para 6.47

12 Ofgem (August 2013), para 6.62

- **Reduction of greenhouse gas emissions**: Ofgem believes that "*All CMP213 proposals should further promote sustainable development relative to the Status Quo*" and that the modelling "*suggests that Diversity 1 options present the lowest risk to targets associated with reducing greenhouse gas emissions*".[13]
- **Security of supply**: Ofgem did not "*consider security of supply to be materially affected by any of the CMP213 options*".[14]
- **Consumer bill impacts:** Ofgem believed that the long term benefits of the new methodology "*are likely to outweigh considerably the short term disbenefits as regards consumer bills*".[15]

Hence, as the above summary shows, Ofgem's August 2013 consultation document expressed Ofgem's belief that WACM 2 best facilitated all the "relevant objectives" for the Use of System charging methodology, as well as meeting the Authority's principal objective.

1.3. Evidence Submitted Since the "Minded to" Decision

Ofgem's April 2014 consultation re-opens the consultation on the August 2013 minded-to decision to implement WACM 2, following receipt of additional evidence on (1) the cost reflectivity of WACM 2, and (2) evidence on the impact of the proposed change on the sector and on consumers.

In October 2013, following the August 2013 Impact Assessment, NERA and Imperial prepared two reports that were submitted alongside RWE's response to Ofgem's consultation:

- In one report submitted in October 2013, NERA and Imperial reviewed the Ofgem Impact Assessment that led to Ofgem's August 2013 "minded-to" decision to implement WACM 2. The report highlights that Ofgem failed to check whether the proposed methodology reflects the costs that different generators impose on the system better than the existing methodology. Analysis presented in this report suggests that WACM 2 reflects costs less closely than the status quo methodology; and[16]
- NERA and Imperial also performed a modelling exercise to assess the economic case for introducing the WACM 2 charging model. The electricity market and transmission system modelling conducted for this assignment suggests that WACM 2 would lead to higher transmission system costs, higher generation costs, and higher consumer bills over the period to 2030. Therefore, the modelling does not support the introduction of the WACM 2 model.[17]

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13 Ofgem (August 2013), para 6.69.

14 Ofgem (August 2013), para 6.76

15 Ofgem (August 2013), para 6.81

16 Project TransmiT: Review of Ofgem Impact Assessment of Industry Proposals CMP213, NERA Economic Consulting and Imperial College London, Prepared for RWE npower, 9 October 2013.

17 Project TransmiT: Modelling the Impact of the WACM 2 Charging Model, NERA Economic Consulting and Imperial College London, Prepared for RWE npower, 9 October 2013.

During early 2014, Ofgem then engaged with us through bilateral discussions and a Q&A process to better understand the analysis and arguments presented in these reports. As part of this process, we prepared a third report, submitted to Ofgem in February 2014, in which we updated and expanded the analysis of whether the WACM 2 charging methodology is more cost reflective than the status quo methodology. Across a range of scenarios, the analysis showed that the WACM 2 methodology does not constitute an improvement on the existing methodology in terms of cost reflectivity.[18]

1.4. Scope of this Report

In this report, we provide an update to the modelling presented in the report we prepared in October 2013 that compares the welfare impacts of the status quo and WACM 2 charging methodologies. As part of this update, we also respond to the various comments made by Ofgem in its April consultation paper, and in the accompanying Baringa report, on our modelling approach and results.

However, the modelling presented in limited to showing results for a "base case". It would have been desirable to perform sensitivity analysis to evaluate the robustness of our conclusions to changes in fundamental assumptions about the evolution of the power sector. However, the relatively short consultation window did not allow sufficient time to complete any extra sensitivity analysis.

The remainder of this report is structured as follows:

- In Chapter 2 we describe our modelling approach, and set out the changes we have implemented since preparing our October 2013 modelling report;
- Chapter 3 presents the results of our updated comparison between WACM 2 and status quo;
- Chapter 0 presents our updated estimates of the welfare effects arising from the introduction of the WACM 2 methodology; and
- Chapter 5 concludes.

18 Assessing the Cost Reflectivity of Alternative TNUoS Methodologies, NERA Economic Consulting and Imperial College London, Prepared for RWE npower, 21 February 2014.

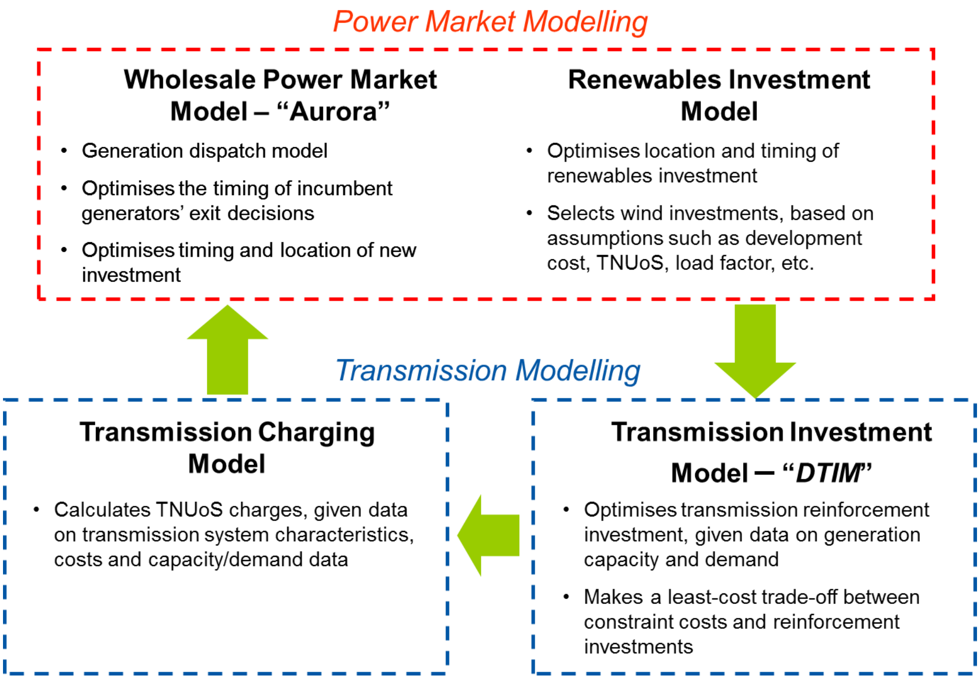
2. Our Modelling Approach

2.1. Overview of Our Framework

This report presents a comparison between the status quo and WACM 2 charging models. To make this comparison, we use the modelling framework we developed to compare the status quo charging model to the socialised and "improved ICRP" models in previous assignments. Albeit with minor modifications (see below), this framework is also the same as the one we use to compare the WACM 2 and status quo charging models in the report submitted to Ofgem in October 2013.[19]

This framework combines wholesale market models, a load flow and investment model of the British transmission system, and a charging model based on the National Grid Tariff and Transport Model used to calculate ICRP tariffs. As before, we iterate between these models in order to obtain an equilibrium set of TNUoS charges, generation investment, and transmission investment. This framework is illustrated in Figure 2.1, and is described in more detail in our previous reports.[20]

Figure 2.1
Overview of Modelling Framework



Source: NERA/Imperial

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[19] Project TransmiT: Modelling the Impact of the WACM 2 Charging Model, NERA Economic Consulting and Imperial College London, Prepared for RWE npower, 9 October 2013.

[20] Project TransmiT: Impact of Uniform Generation TNUoS, Prepared for RWE npower, NERA Economic Consulting and Imperial College London, 31 March 2011, Chapter 2 and Appendix A.

2.2. Changes to Our Generation Modelling Approach

2.2.1. Accounting for the capacity mechanism

Our modelling framework explicitly accounts for the Capacity Payment Mechanism (CPM), which is in the process of being implemented in the British market by National Grid and DECC. In line with government plans, we assume that:

- The auctions for the CPM will begin from late this year, with the first capacity contracts delivered from 2018 onwards;
- We define each generator's capability to supply capacity contracts based on our assumption on their expected availability at peak time. Also, as per the arrangements currently proposed, subsidised low carbon generators are not eligible for support under the CPM;
  - Typically, a generator's expected availability at peak reflects a its net installed capacity, derated by an assumed forced outage rate that varies by technology;[21]
- We assume, following the assumptions in the DECC Impact Assessment for the proposed CPM, that the CPM delivers a derated reserve margin of 8% throughout the period to 2030. [22]However, we do not allow the model to adjust the volume of capacity procured in response to changes in the capacity price, as will occur in reality through the price elasticity expected to be built into the capacity demand curve, on the basis that we do not yet know how this price elasticity of demand parameter will be set;
- Existing generators, refurbishment projects and new entrants can all set the price in the capacity market, as per the proposed CPM; and
- Our approach assumes that generators bid into the capacity mechanism in a competitive way, such that they seek to recover no more than their fixed costs (levelised over the life of the plant) through the capacity mechanism, net of any margins earned from the energy and ancillary services markets. Hence, the marginal generator should recover its total costs in net present value terms through the margins earned from the energy, ancillary service and capacity markets.

In practice, we model the CPM within our setup of the Aurora model. Aurora contains a range of functionality for the modelling of capacity mechanisms, reflecting its origins in the US where many markets have had capacity mechanisms in place for many years. Aurora models the CPM by first building the capacity required to serve the energy market in the most efficient way, and then optimising the additional investment required to meet the assumed demand for capacity. Hence, in high-level terms, the capacity price emerging from Aurora reflects the marginal capacity cost of the most expensive unit required to meet the assumed capacity requirement, after netting off any energy market margins that marginal unit earns.

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[21] In the particular case of wind, we assume 8% availability at peak, which is based on the de-rating assumption used by National Grid in its 10 Year Statement. Source: National Grid 2012, *10 Year Statement 2012*, Table 2.5.1, page 30. Note, wind farms are not eligible to provide capacity to the CPM, but their availability to provide capacity is an important determinant of the demand for capacity from other sources in the capacity auctions.

[22] DECC 2013, *Electricity Market Reform – Capacity Market*, page 25

We also allow Aurora to use its “capacity price smoothing” algorithm, which smoothes out the volatility in capacity prices that occurs over time in models of this sort.[23] We consider that this approach is justified on the basis that our modelling approach does not explicitly account for some factors that will tend to cause smoothing of capacity prices over time, such as the following:

- We assume a perfectly inelastic capacity demand curve, whereas the real demand curve used in the capacity auction will contain some elasticity that will tend to smooth out the volatility of prices in response to small changes in fundamentals;
- In reality, experience of US capacity mechanisms suggests that, where price volatility is observed in reality, regulatory bodies take steps to smooth out capacity prices over time, with the intention of providing stable costs to consumers and stable revenues to investors. Such interventions might include, floors on the capacity price, increasing the price elasticity of demand for capacity, etc; and
- Our modelling approach does not necessarily capture the opportunities that generators have to arbitrage capacity prices from year-to-year. For instance, generators could withhold relatively cheap (i.e. infra-marginal) refurbishment projects from one year’s auction if the price is expected to be low, in anticipation of obtaining a multi-year contract in a subsequent year when prices may be higher. Such behaviour would tend to equalise prices over time.

2.2.2. Basic data and assumptions

Aside from the way in which we account for the CPM, all other features of our approach to simulating the wholesale market are unchanged from the analysis we published in October 2013. However, we have made a range of changes to basic data and assumptions, which we summarise in Table 2.1 below.

[23] The algorithm works by first calculating capacity prices, based on the money needed to make the marginal unit whole. Aurora then smoothes these prices to decrease drastic jumps between years. This minimises large swings in capacity prices but may result in marginal resources over-earning or under-earning slightly in any given year

Table 2.1
Summary of Key Changes to Assumptions

Assumption	Details of Our Approach
Nuclear Penetration	• Our previous report assumed considerable development of new nuclear power generation capacity starting in 2020, with capacity ramping up to around 15GW by 2030. • Given recent developments in the UK nuclear programme, this assumption is no longer plausible. Hence, we now assume new nuclear comes online from 2023 (earliest feasible online date for the first new unit at Hinkley Point). Thereafter, we assume that one new EPR comes online every other year, such that 4 new EPRs are online by 2030 - one at Hinkley Point, one at Sizewell and one at Sellafield, in that order. This equates to around 6 GW of capacity by 2030. This is in line with the expected expansion rate reported in the government's 2013 updated energy and emissions projections – 10 GW of new nuclear capacity between 2020 and 2030 – delayed a few years to reflect a more realistic time frame, based on recent developments. • In this modelling exercise, we have not modelled the timing of deployment for each new nuclear site in response to changes in TNUoS, reflecting the numerous project-specific constraints that will influence the timing of each new nuclear site coming online.
Renewables Penetration	• Given the lower assumed nuclear penetration, power sector emissions would, all else equal, increase in our framework. Hence, in this updated analysis, we assume renewables penetration increases during the 2020s. Previously, we assumed renewables penetration of 30% of generation throughout the 2020s. We now assume growth from 30% to 40% during the 2020s. • We assume a mix of renewable technologies that is broadly in line with government aspirations, as set out in more detail in Appendix A. One key change from our previous assumption is that we assume a higher penetration of small scale PV is likely. • We then let the renewables investment model choose the location of wind investments to provide the volume of energy we assume needs to be delivered from onshore and offshore wind.
CCS	• Broadly, we have not changed our approach to modelling the deployment of CCS. We allow Aurora to optimise the timing, volume and location of deployment, and we allow investment patterns to change in response to changes in TNUoS and other factors such as CO_2 prices.
Electricity Demand	• For baseline demand, excluding electric vehicles and heat pumps, we take the average of the "central" and "baseline policies" scenarios from DECC's 2013 updated energy and emissions projections. Our electric vehicles and heat pump projections are an average of the "Gone Green" and "Slow Progression" scenarios from National Grid's *Future Energy Scenarios.*
Fuel Pricing	• Our gas, crude oil and coal price forecasts are based on forward prices as of 31st March 2014 followed by interpolation to the IEA "New Policies" scenario from the 2013 World Energy Outlook (WEO). These assumptions are therefore derived using a similar approach as for our October 2013 modelling report, though previously we adopted the IEA's "Current Policies" scenario.

Assumption	Details of Our Approach
CO_2 Pricing	• As before, and as for fuel prices, our EU ETS price forecasts are based on forward prices as of 31st March 2014, followed by interpolation to the IEA "New Policies" scenario forecast from the 2013 WEO. • We also account for the recent announcements made during the 2014 Budget regarding the reduction in Carbon Price Support (CPS) rates. We assume that CPS rates remain constant at £18/tonne throughout the modelling horizon, such that UK power generators face a constant premium on the EU ETS price.
Generator Opex and Capex	• We have updated our generator cost assumptions using PB power's *Electricity Generation Cost Model 2013 Update of Non-Renewable Technologies*, prepared for DECC

Source: NERA/Imperial

2.3. Changes to Our Renewables Modelling Approach

2.3.1. Reform of RES subsidy arrangements - allocation of CFDs

In order to initiate the CfD FIT scheme, DECC began a process in March 2013 to help renewable developers make firm investment decisions ahead of the enduring regime going live. This process, known as the Final Investment Decision Enabling for Renewables (FIDER), has selected eight wind and biomass projects for development and agreed contracts for their support.[24] These projects will receive support at the level of the maximum strike prices published in December 2013 by DECC.[25]

However, various details of the enduring CfD regime are still to be clarified and certain features are currently under consultation, pending a final decision. DECC is expected to award contracts to applicants on an annual basis, starting in the final quarter of 2014. The allocation of contracts will be constrained by the budget available to support renewable investments. This is set out in the Levy Control Framework (LCF), which places a cap on total spending in each year on levy funded schemes, currently covering small-scale FIT payments, the Warm Home Discount and RO and CfD FIT payments; the latter making up the most significant share of the total budget.

Given an available budget trajectory, DECC has proposed that renewable technologies will be divided into two groups – *mature* and *immature* technologies - with separate budget pots for each group. The mature technologies, which are expected to include biomass, onshore wind and solar PV, will be subject to competitive allocation with contracts awarded via an auction process in which projects bid in the strike price that they are willing to accept and receive the auction clearing price, determined for each commissioning year. Initially DECC does not expect the projects applying within the immature group, including offshore wind, to exceed the available budget, but in time also intends to introduce competition to this group as well.

[24] The award of investment contracts was formerly announced by DECC on 23 April 2014.

[25] DECC. Investing in renewable technologies – CfD contract terms ansd strike prices. December 2013.

DECC has not released information on the relative size of the available budget that will be allocated to the different technology groupings. This will be set out prior to each allocation round.[26] DECC therefore retains a significant degree of flexibility to control how much of each technology is awarded a CfD contract.

2.3.2. Implications for modelling

At the time of writing, there therefore remains some uncertainty regarding the operation of the enduring CfD FIT regime, specifically with respect to the allocation of funds across the range of renewable technologies. We have therefore set up our renewables investment model in such a way as to reflect the flexibility DECC retains to control which technologies receive support under the expectation that the government will aim to meet its renewables targets at least cost. DECC has stated that:[27]

> *"Government will set budget allocations that it considers best meets its policy objectives including achieving the renewables target, keeping consumers' costs low, the total costs within the LCF and achieving value for money"*

Hence, we do not impose fixed constraints on the split between onshore and offshore wind used to achieve the target levels, either in terms of budgetary allocation, capacity or output that comes online, as this approach best reflects recent policy statements by DECC. Our approach allows the government flexibility to implement the optimal mix of onshore and offshore wind as it learns about changes in cost (including TNUoS costs) as well as capacity constraints. We also expect that, over the modelling horizon, offshore wind will develop into an increasingly mature technology, at which point it is likely that offshore projects will be required to directly compete for government support – via auction – with onshore wind projects.[28]

2.3.3. Development of a new modelling tool

To reflect these latest changes in RES subsidy arrangements, we have developed a new version of our renewables investment model. As well as reflecting recent policy developments, this new tool uses a simpler algorithm than the model we applied for the modelling work published in October 2014. This added simplicity means that the results we

[26] For the first allocation round, due to take place in 2014, DECC intends to publish the final budget in September 2014, with the first auction expected in October 2014. (DECC. Electricity Market Reform: allocation of Contracts for Difference. Consultation on Competitive Allocation. January 2013; and subsequent government response on competitive allocation (May 2014).

[27] DECC. Electricity Market Reform: Allocation of Contracts for Difference – A Government response on Competitive Allocation. May 2014

[28] The government has stated its ambition to "move to competitive price discovery processes for all technologies as soon as practicable". (DECC. Electricity Market Reform: Allocation of Contracts for Difference – A Government response on Competitive Allocation. May 2014.) Hence, whilst DECC proposals do not explicitly set out direct competition between onshore and offshore wind projects (as they have been allocated to the separate mature and immature technology groupings, respectively) by retaining control of the share of the budget to be allocated to each technology group we expect there to remain implicit competition amongst all wind project types. The wind project selection tool that we have developed therefore projects both onshore and offshore wind deployment based on a cost minimisation algorithm, subject to various capacity constraints.

obtain may be easier to explain with reference to changes in TNUoS than in our previous model, in which results were sometimes difficult to interpret due to the interactions of the various resource constraints with the algorithm to determine the lowest possible subsidy levels and optimise investors' response to those signals.

As under our previous approach, the new model deploys additional wind capacity to meet the required RES output not provided by existing wind farms or from other renewable generation sources. To do so, it selects investments from a list of 143 potential offshore and onshore projects, which differ in terms of their geographic location, water depth (for offshore wind) and load factor. Deployment is selected by the model to minimise wind development and operating costs over the horizon to 2030. This approach is informed by DECC's stated intention to introduce competition in the allocation of CfD contracts and to minimise the impact of renewables subsidies on consumer bills.

The model adopts the following approach:

- It takes data on onshore and offshore wind farm costs (e.g. construction and operating costs, including TNUoS), load factors of potential wind generation projects by region, the availability of generation sites by region, earliest available online dates, etc;
- It then runs a linear program that selects the lowest cost wind investment projects (per MWh of output over the lifetime of the asset) available, subject to assumed constraints on the timing and rate of project development;
- In each year new wind capacity is added to meet the increasing target levels of RES (we assume a linear increase in the RES share between 2014 and the 2020 target of 30%, and again between 2020 and the 2030 target of 40%);
- The optimised deployment of wind projects is then reintegrated into the overall RES forecast to provide the generation mix in each year from renewable sources; and
- The budget implications of these projects are then assessed, using projections of baseload and captured wholesale energy prices, added to the projected net cost of all other RES generation, and compared against the Levy Control Framework budget.

Our modelling assumptions are set out in more detail in Appendix A.

2.4. Changes to Our Transmission Modelling Approach

Since our last modelling exercise, we have not materially changed our approach to modelling the transmission system using DTIM. We have, however, made some relatively minor changes in our assumptions:

- We have changed slightly the approach we use to calculate WACM 2 and status quo charges, as a result of discussions held between NERA, Imperial and National Grid following the closure of the last consultation window. We have altered the approach we use to calculate equivalent impedances on the HVDC bootstraps to align precisely with the approach adopted by National Grid in its modelling work that fed into the August 2013 Impact Assessment. The reason for this change is to more accurately reflect the mechanics of the two charging methodologies in this welfare analysis, as proposed by National Grid and Ofgem;[29]

- Because the western HVDC bootstrap now appears to be entering the final stages of development,[30] we have assumed that in both the WACM 2 and status quo scenarios, DTIM has no discretion to alter the online date (we assume 1 January 2017) in response to changes in generation mix; and
- We assume that the G:D split remains at 27:73 indefinitely, reflecting the recent Acer opinion that covers the appropriate level of TNUoS charges to be recovered from generation and load.[31]

2.5. Framework for Modelling Investment Decisions

Our modelling approach assumes that generators take decisions regarding the timing, type and location of new entry decisions (and exit decisions) by comparing the revenues earned by each project to the costs it incurs over the whole modelling horizon. New investments will come online only if the expected net present value (NPV) of revenues exceeds the expected NPV of costs, where NPVs are calculated using a market-based discount rate specific to each generation technology.

Baringa has described this method as a “perfect foresight” approach, and suggests that this approach implies investors have “full knowledge” of the conditions they will face in the future. This description is extremely misleading. We do not assume investors have perfect foresight. We assume that investors account for all information available at the time of making their investment decisions, by forming forecasts of the *expected* conditions that are most likely to prevail in the future. However, because expected cash flows are risky (i.e. there is some uncertainty around expected outcomes in the future), we discount the future expected cash flows with a discount rate that appropriately reflects the riskiness of those cash flows (i.e. the investors’ opportunity cost of capital). This modelling approach is consistent with financial and economic theory regarding investment decision making. In contrast, Bargina’s approach assumes that investors only account for expected costs and revenues over the following five years when making investment decisions. Hence, Baringa assumes that investors adopt systematically naive and irrational behaviour. There is no basis for this approach in financial or economic theory.

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29 Note, this approach should not be seen as an endorsement of National Grid’s method for calculating HVDC equivalent impedances. As we have discussed in previous reports, the definition of rules to apportion flows across the HVDC and AC networks is arbitrary and unrelated to the long-run marginal cost that generators impose on the transmission system.

See: Assessing the Cost Reflectivity of Alternative TNUoS Methodologies, NERA Economic Consulting and Imperial College London, Prepared for RWE npower, 21 February 2014, Section 5.2.3.

30 National Grid and Scottish Power plan to install the first sections of undersea cable this year: http://www.westernhvdclink.co.uk/marine-cable.aspx

31 Agency for the Cooperation of Energy Regulators (ACER) April 2014, *Opinion on the Appropriate Range of Transmission Charges Faced by Electricity Producers,* Annex A

Appendix B of the accompanying NERA/Imperial report provides a more detailed discussion of the justification for our approach and of the fundamental conceptual problem with Baringa's "imperfect foresight" approach.[32]

32 Project TransmiT: Critical Review of Ofgem's April 2014 Further Consultation, Prepared for RWE npower, 27 May 2014, Appendix B.

3. Modelling Results

This chapter summarises the results that emerge from the process of iteration between our wholesale market and transmission system models, covering the projected evolution of the wholesale market, forecasts of TNUoS charges, a description of our models' predicted locational investment decisions, forecasts of transmission system costs, and a discussion of the extent to which the model's iterative algorithm produced a converged result.

3.1. Market Modelling Results

3.1.1. Generation investment decisions

Figure 3.1 and Figure 3.2 show our projections of peak demand and installed generation capacity in the status quo and WACM 2 scenarios. Both scenarios show similar projections of installed capacity, with the LCPD opted-out coal plants closing over the period to 2015, and most existing CCGT plants remain online until towards the end of the modelling horizon as they tend to be used as peaking plant in the meantime. As noted, in Appendix B, we assume that all plants that have opted into the Limited Life Derogation (LLD) will opt out of the IED and therefore close by 2023, whilst plants that have not signed up to the LLD opt-in to the IED and can continue running beyond 2023 if it is profitable for them to do so.[33]

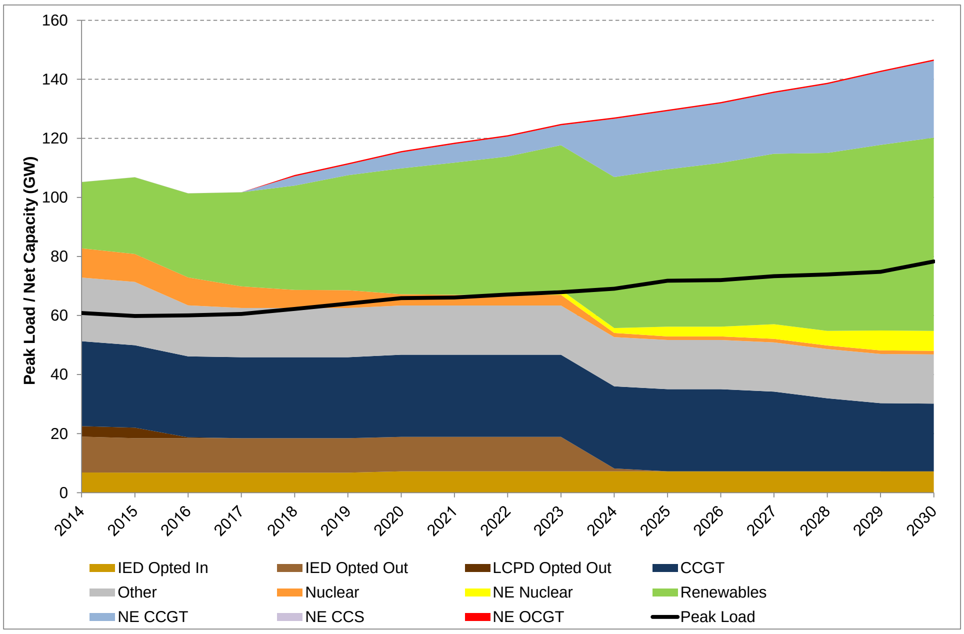
Over time, the model develops new gas-fired capacity, primarily CCGTs and a very small amount of OCGT capacity, to meet the capacity margin target and replace retired capacity. In both cases, we assume that sufficient new renewable generation capacity comes online to meet 30% of energy demand by 2020 and 40% by 2030, although as discussed in Section 3.2.3, the location of the wind capacity varies across the scenarios. We also assume that around 7GW of new nuclear capacity is phased in gradually from 2023 in both cases.

In contrast to our previous results, the model does not choose to build any new CCS capacity in addition to two demonstration projects that we assume come online in both scenarios. This change can be explained by the downward revision of our CO_2 price forecasts, which means that savings on emissions costs are no longer large enough to make CCS plants competitive with new entrant CCGTs, given their higher fixed costs.

[33] DEFRA has indicated that generators choosing the LLD option will still have the opportunity to fully comply with the IED by 2016. Thus it is possible that some of the plants in the LLD could eventually opt-in, by installing the necessary equipment and continue running beyond 2023. However an LLD plant that decides to change its status would have to close first and reopen as a new plant.

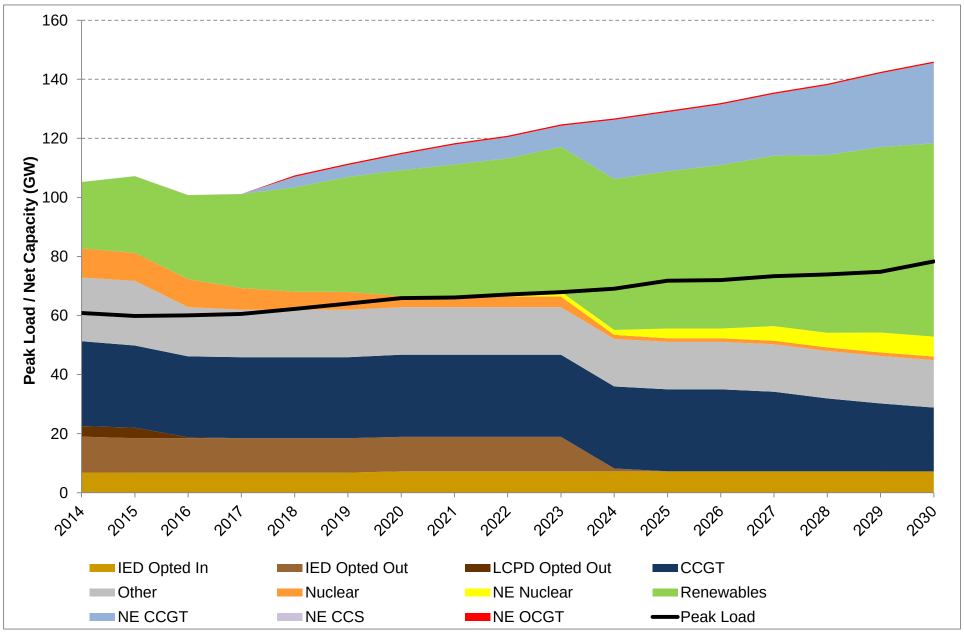
Source: The Environment Agency April 2013, *The Industrial Emissions Directive*, Chapter III, Page 5. https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/296461/LIT_8298_c8fd64.pdf

Figure 3.1
Projected Supply-Demand Balance – Status Quo



Source: NERA/Imperial. Note, the "other" category (in this chart and those that follow), includes technologies such as CHP, pumped storage, oil-fired peakers, etc.

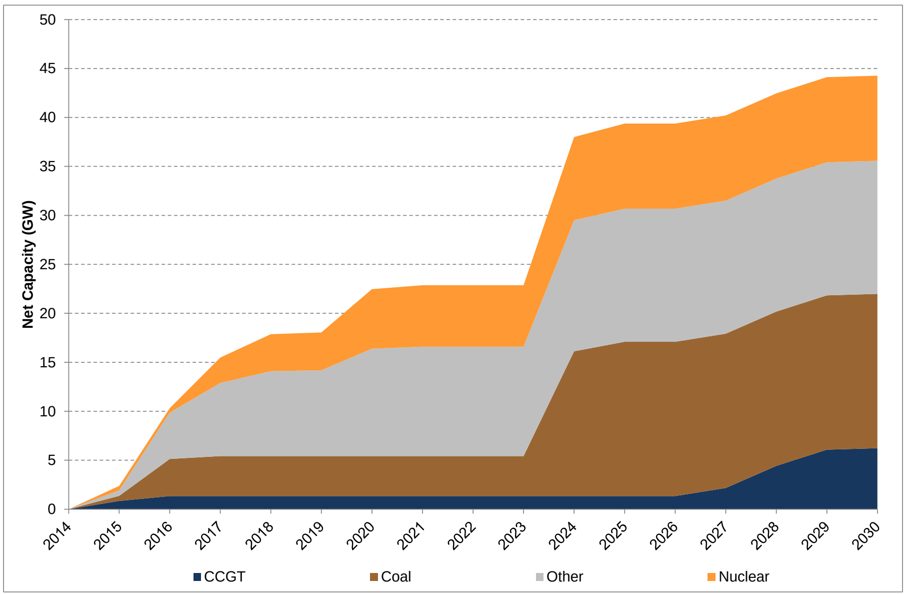
Figure 3.2
Projected Supply-Demand Balance – WACM 2



Source: NERA/Imperial

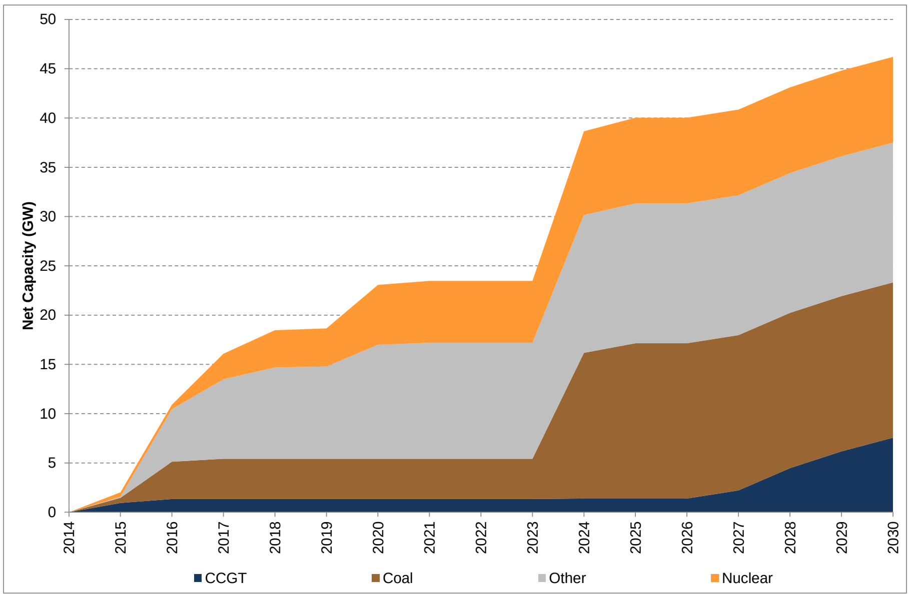
Figure 3.3 and Figure 3.4 show our projected retirements of existing thermal plants across the two scenarios. Comparison of these two figures shows that, save for some minor differences in the timing of CCGT retirements, the two cases are similar in terms of the retirement profiles.

Figure 3.3
Projected Cumulative Retirements – Status Quo



Source: NERA/Imperial

Figure 3.4
Projected Cumulative Retirements– WACM 2

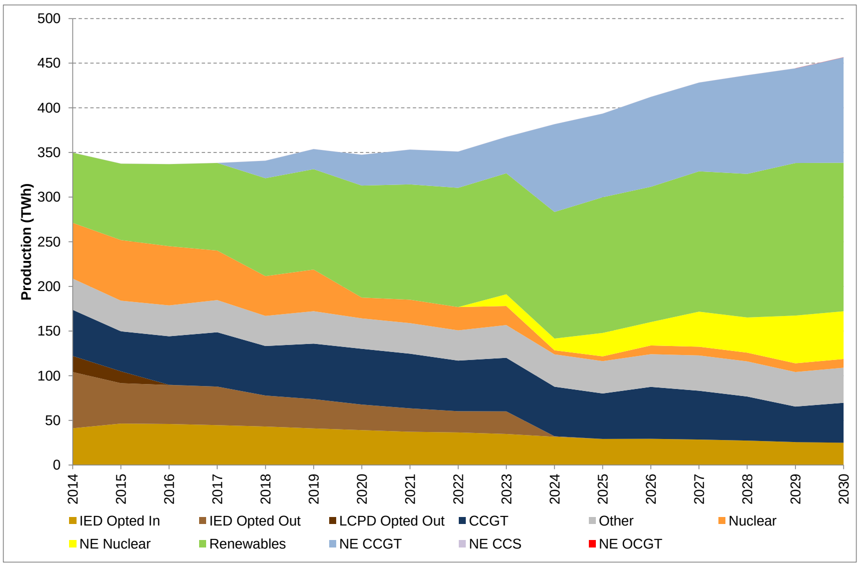


Source: NERA/Imperial

3.1.2. The generation mix

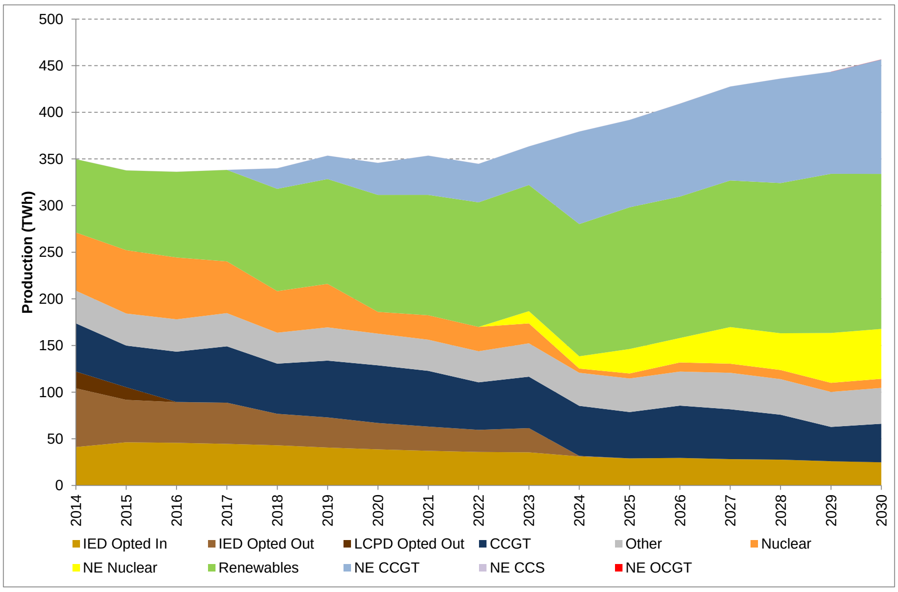
Figure 3.5 and Figure 3.6 show that the modelled production mix is extremely similar across the two scenarios. In both cases, production from existing coal, gas and nuclear plants is replaced by output from renewables, new nuclear and new gas-fired CCGT capacity. Some coal-fired generation remains on the system throughout the period to 2030.

Figure 3.5
Projected Production Mix – Status Quo



Source: NERA/Imperial

Figure 3.6
Projected Production Mix – WACM 2



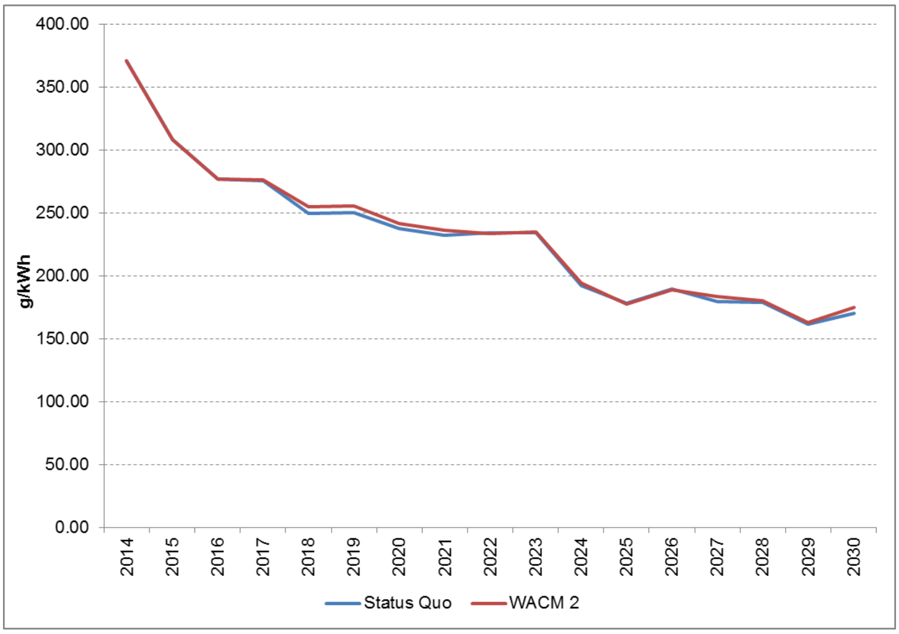
Source: NERA/Imperial

3.1.3. CO_2 emissions intensity

As Figure 3.7 shows, CO_2 emissions from the power sector fall in both scenarios from around 360g/kWh to around 160g/kWh by 2030, i.e. a smaller reduction than we obtained in our previous runs of the model. As yet, no formal target for CO_2 emissions intensity from the power sector has been set by government, although DECC and other organisations like the Committee on Climate Change (CCC) have mooted tighter targets than we achieve for 2030, in the region of 50-100g/kWh.

This change in result occurs because of (1) the delays seen in the UK new nuclear programme, (2) the reduction in CO_2 prices following the cap on CPS rates, and (3) the higher proportion of the existing coal fleet that remains on the system as a result. Offsetting these effects, we also see some reduction in emissions intensity out to 2030 as a result of renewables penetration rising gradually over time.

Figure 3.7
CO2 Emissions Intensity (WACM 2 vs Status Quo)



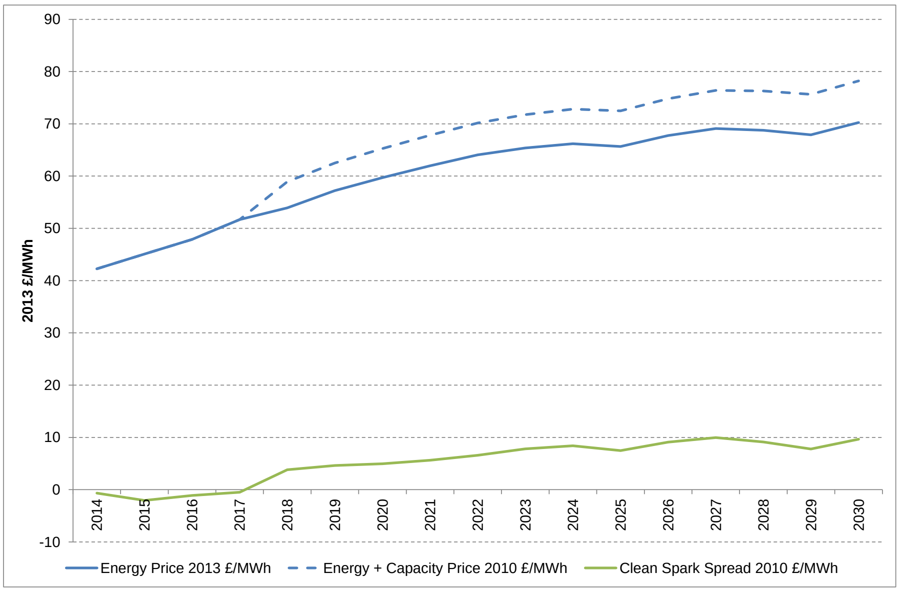
Source: NERA/Imperial

3.1.4. Wholesale energy prices

Figure 3.8 and Figure 3.9 show our projections of baseload prices and baseload clean spark spreads across the two scenarios. As the figures show, our price forecasts are broken down into an energy price and a capacity price from 2018 onwards, following the introduction of the capacity market. In both cases, prices rise over time in line with our assumed growth in commodity prices.

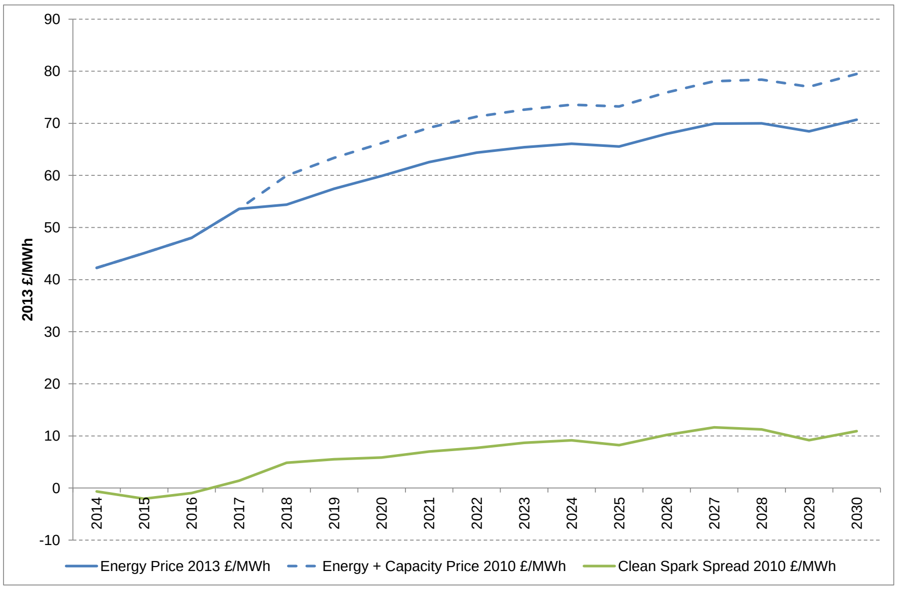
Clean spark spreads recover from their current low levels over the period to 2024 as the need for new investment emerges. Spreads remain relatively stable from around 2025 onwards, at around £10/MWh. Figure 3.8 and Figure 3.9 show that the general trends in prices and spreads are similar in the two cases. However, as discussed further in Section 3.1.5, capacity prices are somewhat higher in the WACM 2 scenario, reflecting the higher marginal cost of new entry caused by higher TNUoS for southern thermal generators in this case.

Figure 3.8
Baseload Prices and Clean Spark Spreads – Status Quo



Source: NERA/Imperial

Figure 3.9
Baseload Prices and Clean Spark Spreads – WACM 2



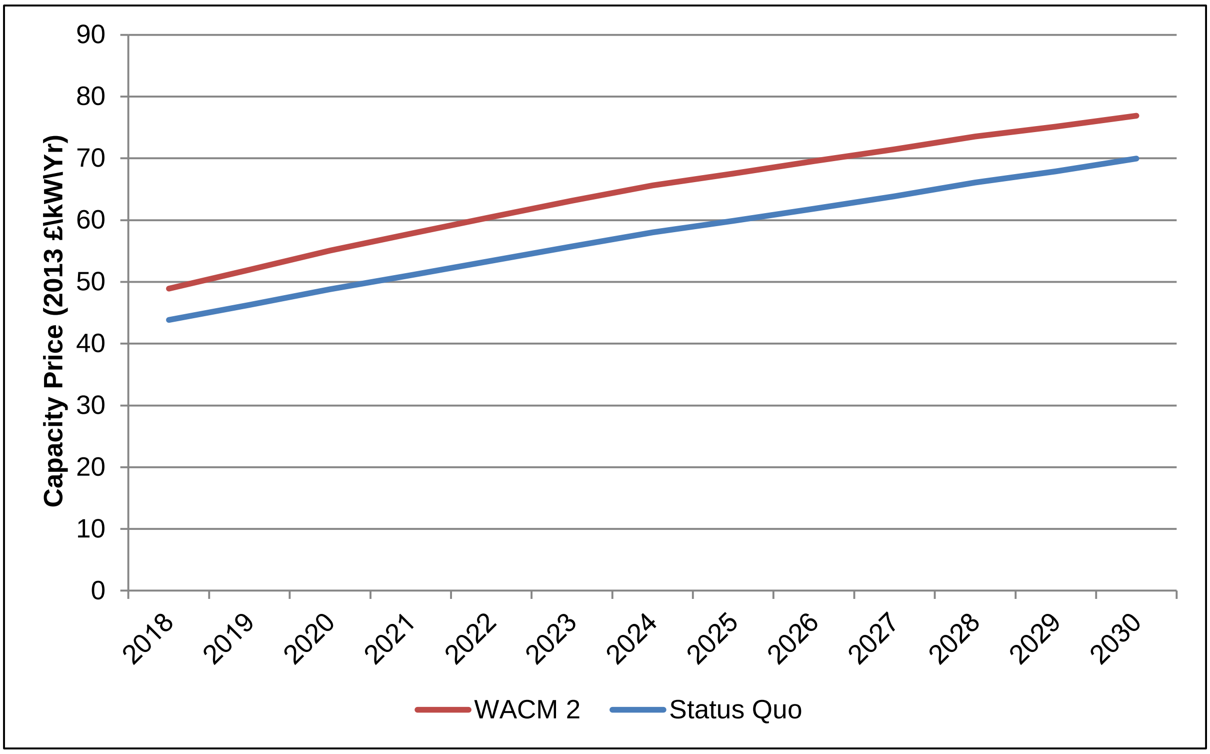
Source: NERA/Imperial

3.1.5. Capacity prices

Figure 3.10 sets out our modelled capacity price projections. As noted in Section 2.2.1, the capacity prices which come out of our Aurora model reflect the marginal capacity cost of the most expensive unit required to meet the assumed capacity requirement, after netting off any energy market margins that marginal unit earns. Under both scenarios, we find that the marginal resource is new build CCGT in every year of the capacity mechanism. Thus, the capacity prices reflect the net marginal capacity cost of a new build CCGT.

As discussed in Section 2.2.1, these capacity prices are “smoothed” over time, which is an approach we consider to be appropriate, given the features of this modelling approach, and the specific characteristics of the proposed British CPM.

Figure 3.10
Capacity Price Forecasts (2013 £/kW)



Source: NERA/Imperial

Under the Status Quo, we find that the capacity price rises from around £43 per kW in 2018 to around £70 per kW in 2030. Capacity prices under WACM2 follow a similar trend, but are around £7 kW higher, reflecting the higher TNUoS charges faced by marginal CCGTs under WACM 2. Indeed, as Table 3.1 illustrates, we find that the differences between the fixed costs of the marginal resource under WACM 2 and under the Status Quo in each year of the capacity market, are of a similar magnitude to the differences in capacity price, rising from £4.40 per kW in 2018 to around £8.50 per kW by 2030.

As in the Baringa modelling,[34] there are differences between the change in the marginal new entrant's fixed costs due to WACM 2, as compared to the change in capacity price. This difference is caused by a number of factors, including differences in the margins earned by the marginal plant in the energy market across the cases, and the fact that the table shows only a "snapshot" of the marginal generator's TNUoS costs in the year shown on the left-hand-side of the table. In practice, the model will also consider changes in TNUoS over time when selecting optimal investments. Hence, the comparison shown below is only approximate, and in practice, the model ensures that the CPM price remunerates investment in the marginal new entrants required to serve demand and meet the target reserve margin assumed for the CPM.

Table 3.1
Comparison of The Fixed Costs of the Marginal Resource under WACM 2 and the Status Quo

	Fixed Costs of the Marginal Resource (£/kW/Year)			Capacity Price (£/kW/Year)
Year	**Status Quo**	**WACM 2**	**Impact of WACM 2**	**Impact of WACM 2**
2018	106.2	110.7	4.4	5.1
2019	106.7	108.3	1.6	5.7
2020	107.0	109.3	2.3	6.2
2021	107.3	114.0	6.7	6.7
2022	105.4	106.0	0.6	7.1
2023	102.9	106.9	4.0	7.4
2024	114.7	109.5	-5.2	7.6
2025	105.5	108.8	3.3	7.7
2026	110.5	119.6	9.1	7.7
2027	108.4	117.0	8.6	7.6
2028	110.5	116.9	6.4	7.5
2029	108.1	116.5	8.4	7.2
2030	107.4	115.8	8.5	6.9
Avg 2018-30	**107.7**	**112.2**	**4.5**	**7.0**

Source: NERA/Imperial

3.2. Modelled TNUoS Charges

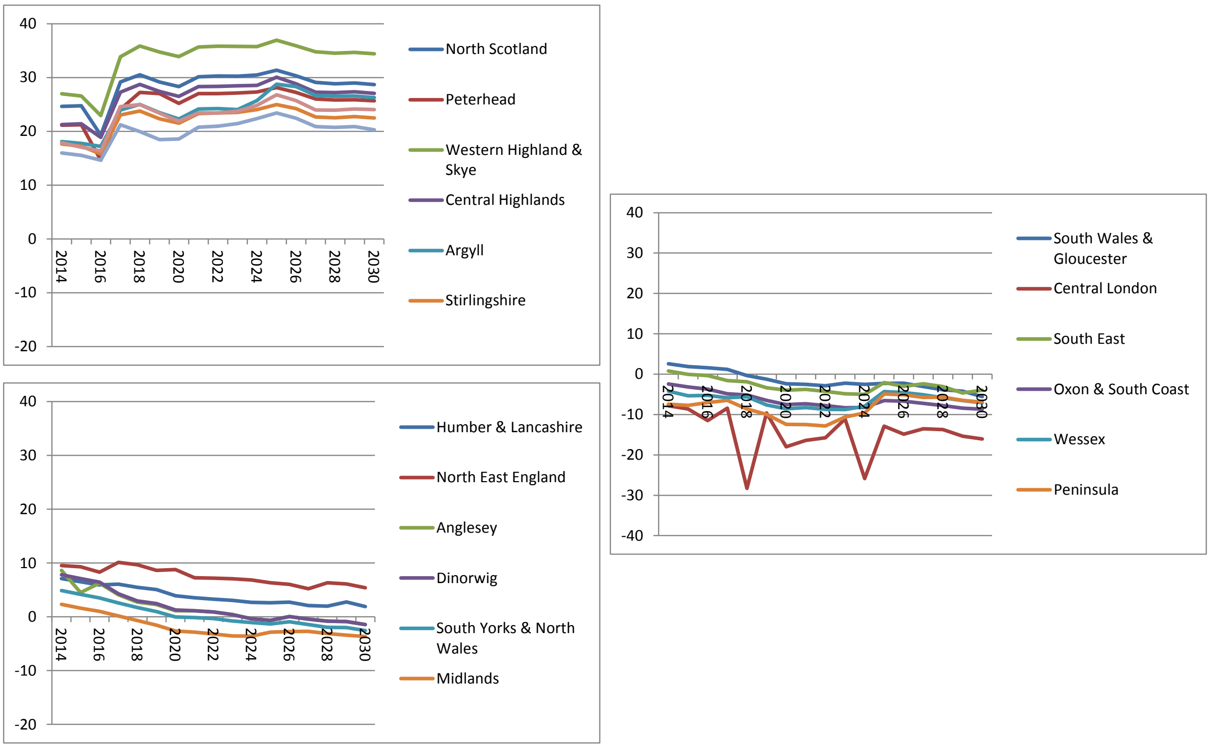
3.2.1. Status quo

Figure 3.11 presents the TNUoS charges emerging from the final iteration of the status quo scenario. Charges in the Scottish TNUoS zones increase over time, with a step up around 2017 due to the construction of the western HVDC bootstraps. Charges in most zones in

[34] CMP213: further analysis and review of consultation responses, Baringa, 25 April 2014, page 63.

England and Wales trend downward over time, although charges in Central London exhibit volatility from year-to-year.[35]

Figure 3.11
Status Quo TNUoS Charges (2013£/kW)



Source: NERA/Imperial

3.2.2. WACM 2

The WACM 2 charging model links TNUoS charges to plant load factor and technology. Hence, Figure 3.12, Figure 3.13 and Figure 3.14 show the charges that CCGTs, nuclear plants and intermittent plants respectively would face across the 20 TNUoS zones:[36]

- Figure 3.12 illustrates that, for CCGT plants, TNUoS charges follow a similar trend to the status quo run, with charges rising in Scotland as HVDC bootstraps come online, and generally falling or remaining stable in England and Wales. Towards the end of the modelling horizon, TNUoS charges for CCGTs in Scotland start to trend downwards as the peak security component of the charge starts to signal a slight shortage of thermal generation in Scotland in the “peak security” background. However, high “year round” charges for CCGTs mean the overall TNUoS charges faced by generators in Scotland

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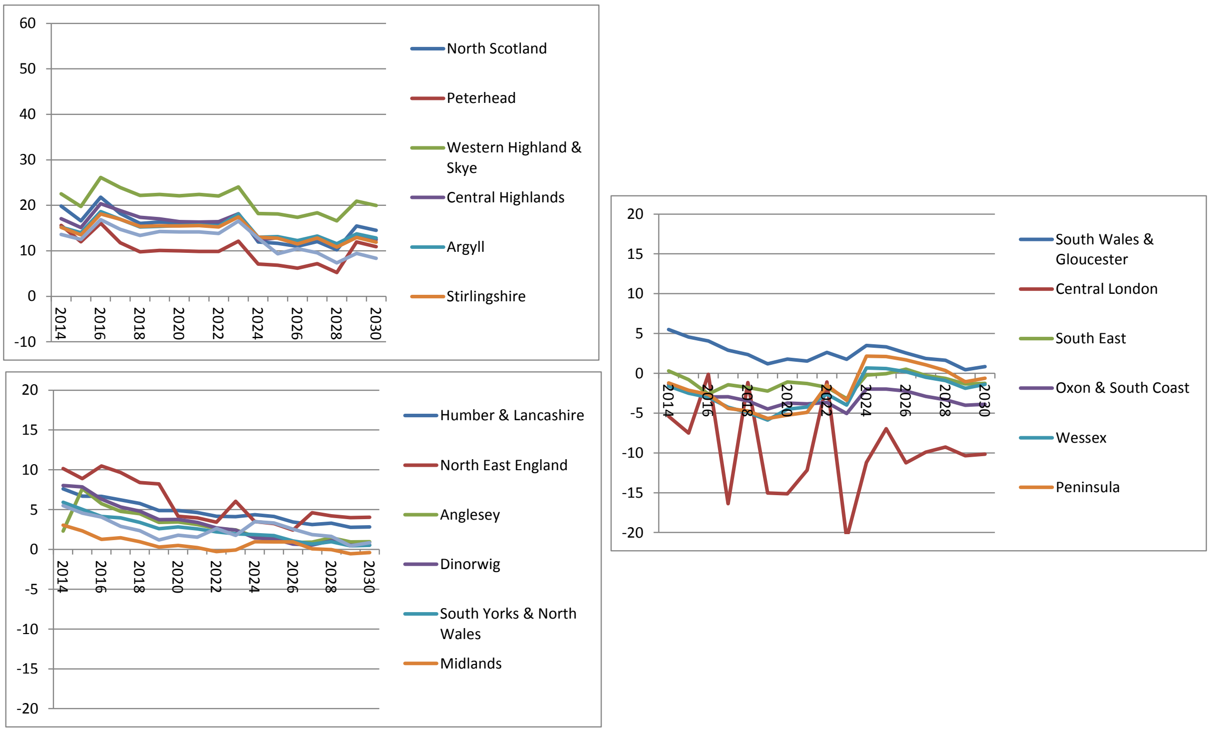
35 Note, this volatility has little impact on modelling results, as the scope to develop new transmission connected generators in London is negligible, as we assume it is not possible at all.

36 WACM 2 tariffs are calculated using the average load factors projected for each year from the Aurora model for the relevant technology.

remains higher than in England and Wales. The charges faced by English and Welsh CCGTs tend to be slightly higher in the WACM 2 case, but follow a similar trend overall.

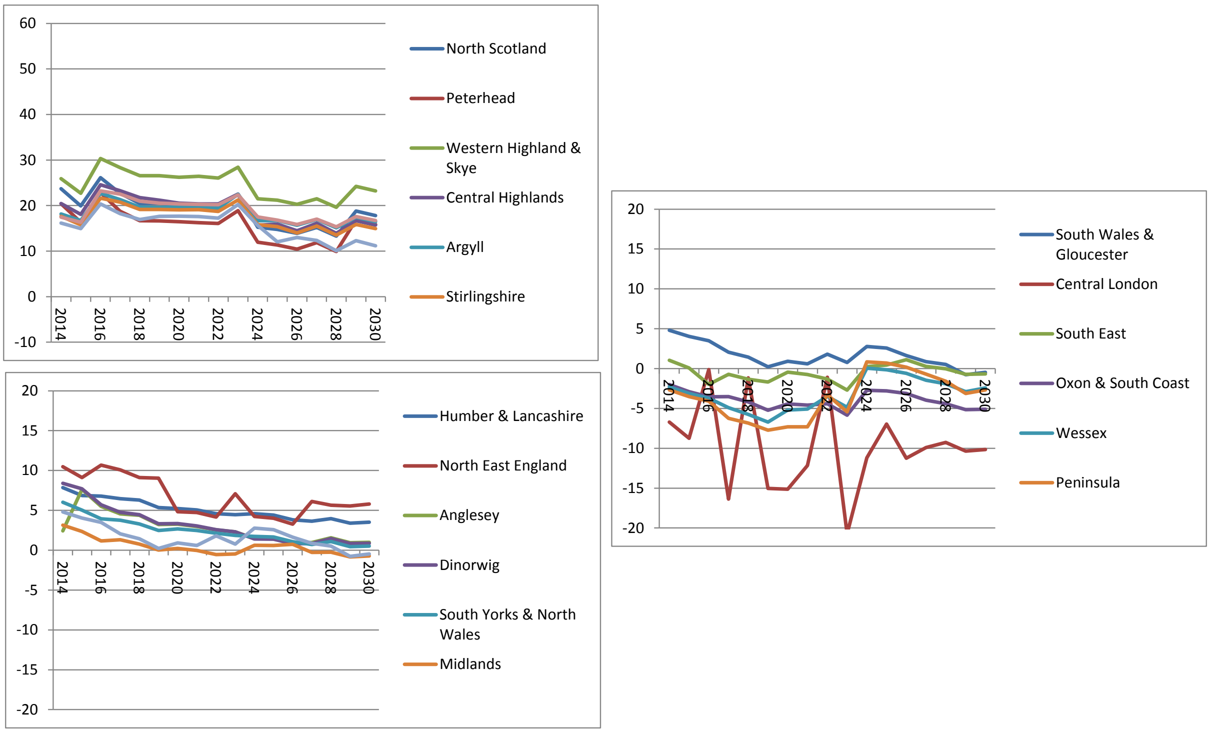
- The charges faced by nuclear plants, shown in Figure 3.13, are similar to those charged to CCGTs, with differences relating to differences in load factor that scale liability to pay year-round charges.
- For intermittent plants, however, the impacts on TNUoS charges are larger, as Figure 3.14 shows. Scaling generators' liability to pay the shared component of the year-round charge by load factor materially reduces (increases) the charges faced by intermittent plants in positive (negative) TNUoS zones, and thus blunts the locational incentive conveyed through TNUoS charges.

Figure 3.12
WACM 2 TNUoS Charges for CCGTs (2013£/kW)



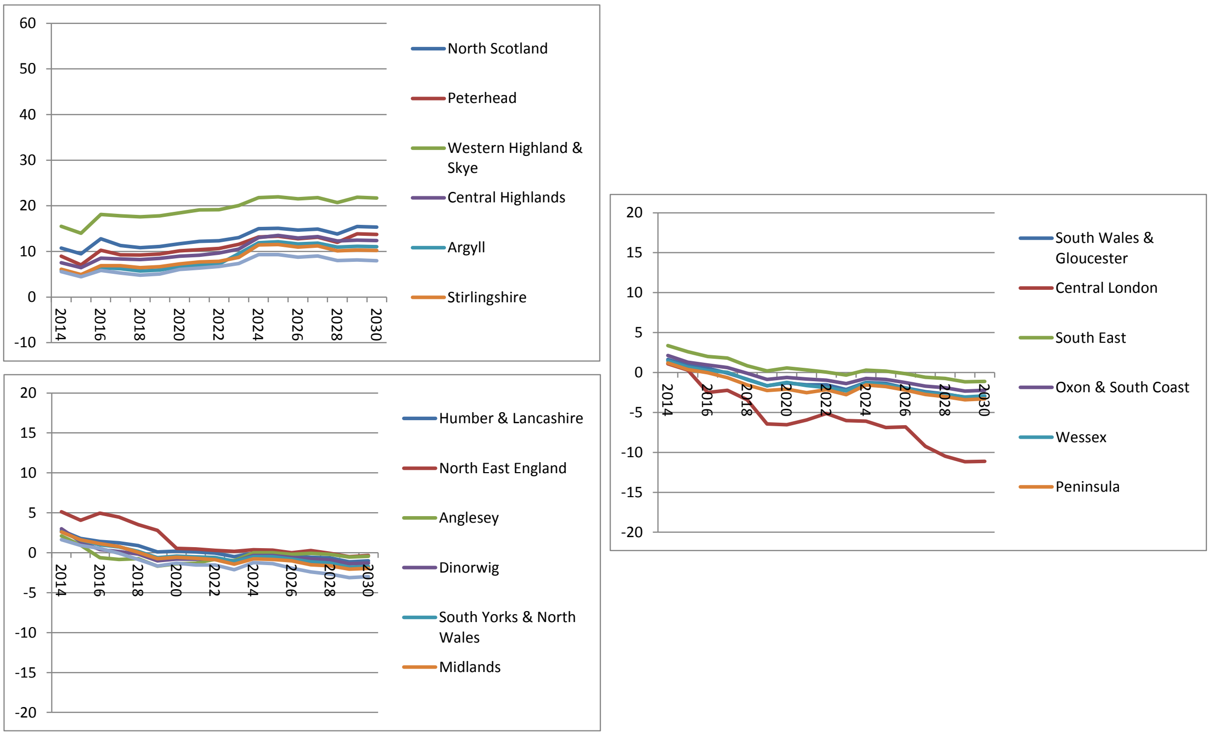
Source: NERA/Imperial

Figure 3.13
WACM 2 TNUoS Charges for Nuclear Plants (2013£/kW)



Source: NERA/Imperial

Figure 3.14
WACM 2 TNUoS Charges for Wind Plants (2013£/kW)



Source: NERA/Imperial

3.2.3. Comparison of WACM 2 and status quo charges

Generators' liability to pay the year-round component of WACM 2 TNUoS charges depends on load factor, so the impact of the proposed reform depends both on location and load factor. Although the effects can vary from year-to-year, Table 3.2 and Table 3.3 show the impact of WACM 2 on non-intermittent generators' TNUoS charges by load factor in 2014 and 2025 by zone. They show that generators in most Scottish zones (1 to 8), especially those with a low load factor, benefit. In contrast, generators in most southern zones, especially those with a low load factor, see their TNUoS charges rise.

As intermittent generators are not liable to pay the peak security charge under the WACM 2 model, Table 3.4 and Table 3.5 show the impact for intermittent plants separately. However, the effects are similar; low load factor plants in the north benefit most.

Table 3.2
Impact of WACM 2 on Non-Intermittent Generators' TNUoS Costs by Zone and Load Factor in 2015 (2012£/kW)

	TNUoS Zone																			
Load Factor (%)	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
0%	-17	-14	-15	-15	-12	-11	-10	-13	0	-1	-3	-1	1	1	6	7	-2	4	6	10
10%	-16	-13	-14	-14	-11	-10	-9	-11	0	-1	-3	0	1	1	6	7	-2	3	6	10
20%	-14	-11	-12	-12	-10	-9	-8	-10	0	0	-3	0	1	1	5	6	-1	3	6	9
30%	-13	-10	-11	-11	-8	-8	-7	-9	0	0	-3	0	1	1	5	6	-1	3	5	9
40%	-11	-9	-10	-10	-7	-7	-6	-7	0	0	-3	0	1	1	5	5	-1	3	5	8
50%	-9	-7	-8	-8	-6	-5	-5	-6	0	0	-3	0	1	1	4	5	0	2	5	8
60%	-8	-6	-7	-7	-5	-4	-4	-5	1	0	-3	0	1	1	4	4	0	2	4	7
70%	-6	-5	-5	-5	-3	-3	-3	-3	1	0	-2	1	1	1	4	4	0	2	4	7
80%	-4	-4	-4	-4	-2	-2	-2	-2	1	0	-2	1	2	1	3	3	1	2	4	6
90%	-3	-2	-3	-2	-1	-1	0	-1	1	1	-2	1	2	1	3	2	1	1	3	6
100%	-1	-1	-1	-1	0	0	1	0	1	1	-2	1	2	1	2	2	1	1	3	5

Source: NERA/Imperial

Table 3.3
Impact of WACM 2 on Non-Intermittent Generators' TNUoS Costs by Zone and Load Factor in 2025 (2012£/kW)

	TNUoS Zone																			
Load Factor (%)	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
0%	-31	-30	-31	-29	-28	-23	-20	-26	1	-5	3	2	4	5	9	3	0	7	7	10
10%	-30	-29	-29	-28	-27	-21	-19	-24	1	-5	3	2	4	5	8	3	1	7	7	10
20%	-28	-28	-28	-26	-25	-20	-18	-23	1	-5	3	2	4	5	8	3	1	7	7	9
30%	-27	-26	-26	-25	-23	-19	-17	-21	1	-4	3	2	3	5	7	3	1	6	7	9
40%	-25	-25	-25	-23	-22	-17	-15	-19	1	-4	2	2	3	5	7	3	1	6	6	8
50%	-24	-23	-24	-22	-20	-16	-14	-18	1	-4	2	2	3	4	7	3	2	6	6	8
60%	-22	-22	-22	-21	-19	-15	-13	-16	1	-3	2	2	3	4	6	3	2	5	6	8
70%	-21	-21	-21	-19	-17	-14	-12	-14	2	-3	2	2	3	4	6	3	2	5	5	7
80%	-20	-19	-19	-18	-16	-12	-11	-13	2	-3	2	2	3	4	6	3	2	5	5	7
90%	-18	-18	-18	-16	-14	-11	-9	-11	2	-3	2	2	3	4	5	3	2	4	5	6
100%	-17	-17	-17	-15	-13	-10	-8	-10	2	-2	2	2	3	4	5	3	3	4	4	6

Source: NERA/Imperial

Table 3.4
Impact of WACM 2 on Intermittent Generators' TNUoS Costs by Zone and Load Factor in 2015 (2012£/kW)

	TNUoS Zone																			
Load Factor (%)	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
0%	-16	-14	-13	-15	-13	-12	-11	-10	-4	-5	-3	-5	-2	1	0	10	3	5	7	9
10%	-14	-12	-11	-14	-12	-11	-10	-9	-4	-5	-3	-4	-2	1	-1	10	4	5	7	9
20%	-12	-11	-10	-12	-10	-10	-9	-8	-4	-5	-3	-4	-2	1	-1	9	4	5	7	8
30%	-11	-10	-9	-11	-9	-9	-8	-6	-4	-4	-3	-4	-2	1	-1	9	4	5	6	8
40%	-9	-9	-7	-10	-8	-8	-7	-5	-4	-4	-2	-4	-2	1	-2	8	5	4	6	7
50%	-7	-7	-6	-8	-7	-7	-6	-4	-4	-4	-2	-4	-2	1	-2	8	5	4	6	7
60%	-6	-6	-4	-7	-5	-5	-5	-2	-3	-4	-2	-4	-2	1	-2	7	5	4	5	6
70%	-4	-5	-3	-5	-4	-4	-3	-1	-3	-4	-2	-4	-1	1	-3	6	6	4	5	6
80%	-3	-3	-1	-4	-3	-3	-2	0	-3	-4	-2	-3	-1	1	-3	6	6	3	5	5
90%	-1	-2	0	-2	-2	-2	-1	2	-3	-4	-2	-3	-1	1	-3	5	6	3	4	5
100%	1	-1	1	-1	0	-1	0	3	-3	-3	-2	-3	-1	1	-4	5	7	3	4	4

Source: NERA/Imperial

Table 3.5
Impact of WACM 2 on <u>Intermittent</u> Generators' TNUoS Costs by Zone and Load Factor in 2025 (2012£/kW)

Load Factor (%)	TNUoS Zone 1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
0%	-18	-17	-18	-19	-19	-15	-16	-16	-3	-6	1	0	1	2	1	8	3	6	3	4
10%	-17	-16	-16	-18	-17	-14	-14	-15	-3	-6	1	0	1	2	1	8	3	6	3	3
20%	-16	-14	-15	-16	-16	-13	-13	-13	-3	-6	1	0	1	2	0	8	3	6	3	3
30%	-14	-13	-13	-15	-14	-11	-12	-11	-3	-6	1	0	1	2	0	8	3	5	2	2
40%	-13	-12	-12	-13	-13	-10	-11	-10	-2	-5	0	0	1	2	0	8	3	5	2	2
50%	-11	-10	-11	-12	-11	-9	-10	-8	-2	-5	0	0	1	1	-1	8	4	5	2	1
60%	-10	-9	-9	-11	-9	-7	-8	-6	-2	-5	0	0	1	1	-1	8	4	4	1	1
70%	-9	-8	-8	-9	-8	-6	-7	-5	-2	-4	0	0	1	1	-1	8	4	4	1	0
80%	-7	-6	-6	-8	-6	-5	-6	-3	-2	-4	0	0	0	1	-2	8	4	4	1	0
90%	-6	-5	-5	-6	-5	-3	-5	-2	-2	-4	0	0	0	1	-2	8	5	3	1	-1
100%	-4	-3	-4	-5	-3	-2	-3	0	-2	-4	0	0	0	1	-2	8	5	3	0	-1

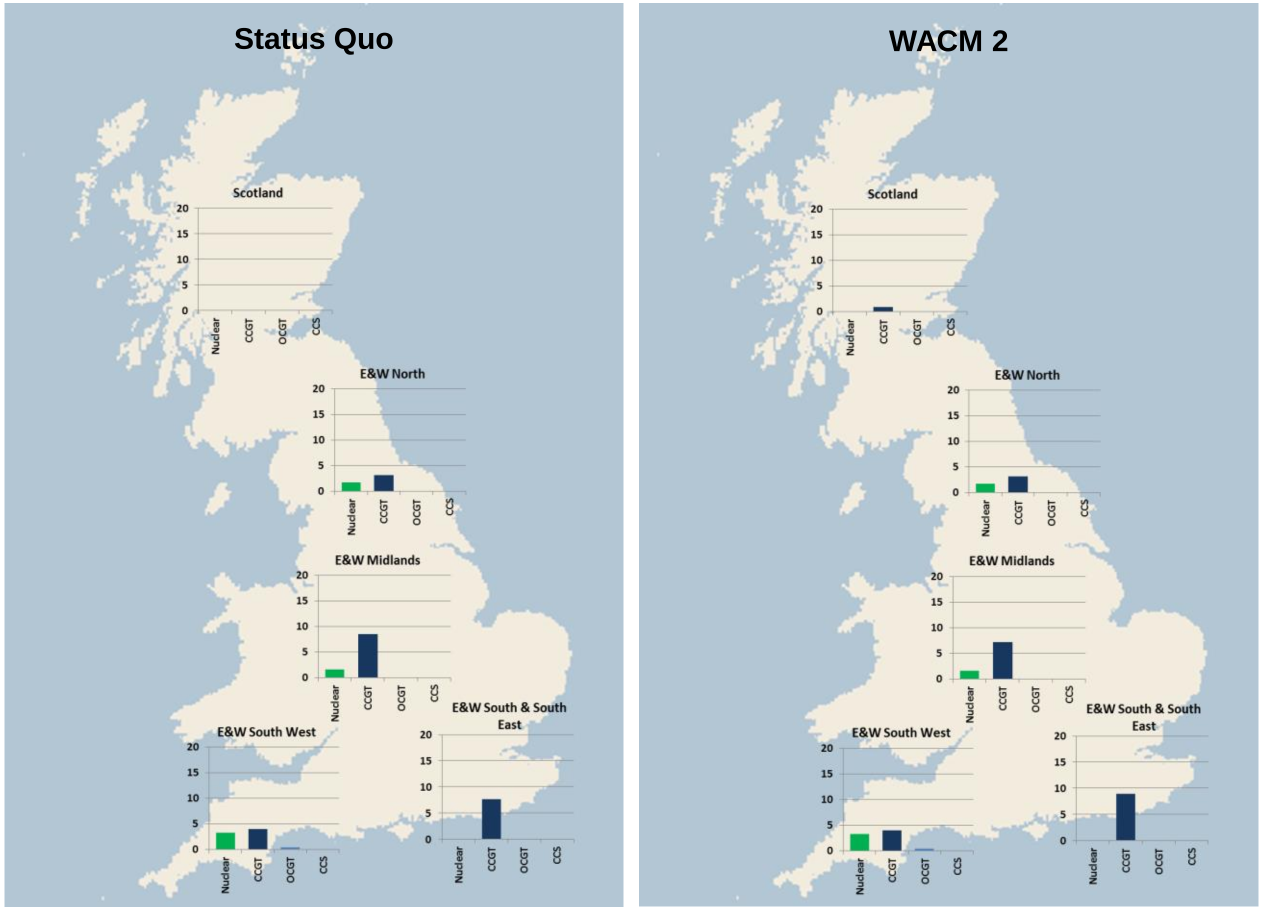
Source: NERA/Imperial

3.3. Locational Investment Decisions

3.3.1. Impact of WACM 2 on the location of conventional generation investments

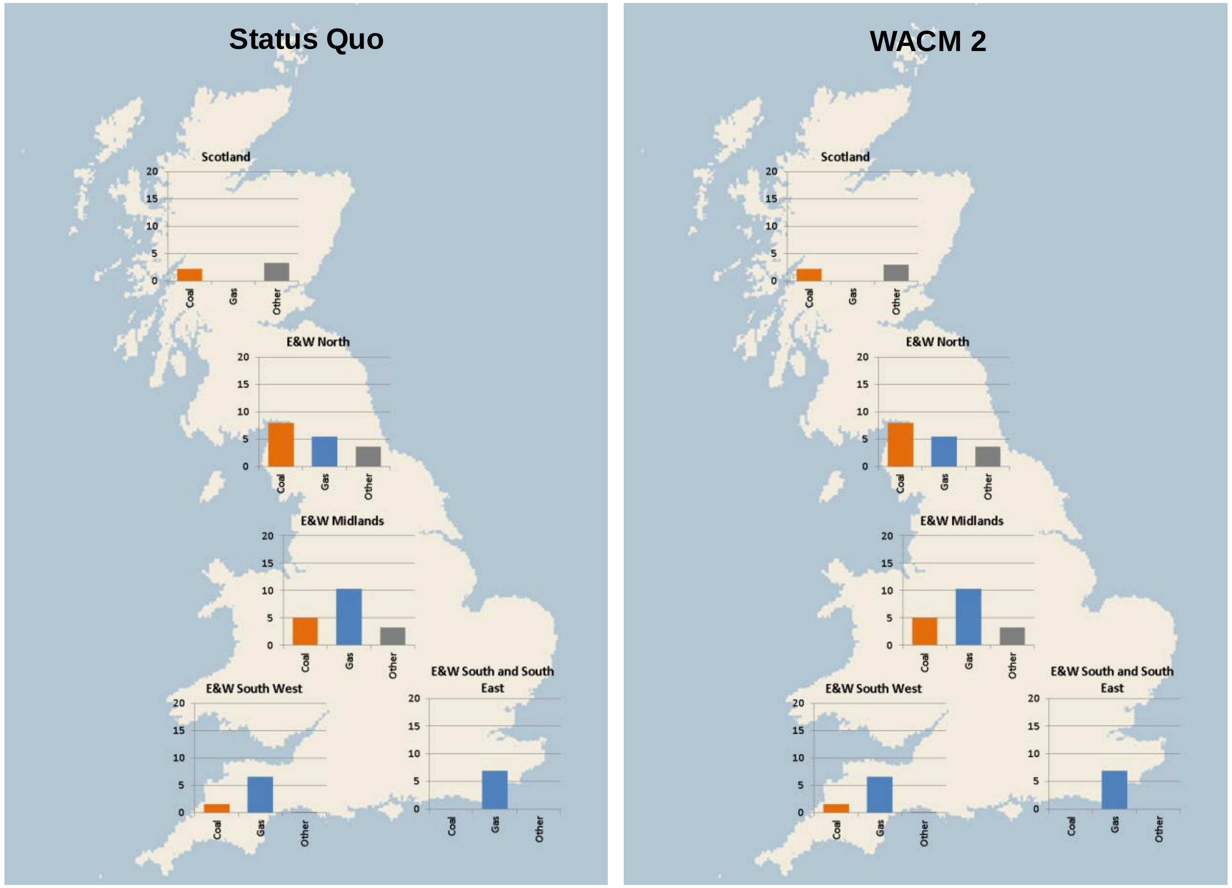
As Figure 3.15 shows, the patterns of non-wind generation investment are similar across the two scenarios by 2030. Investments in gas-fired CCGTs are spread around England and Wales in both scenarios, with slightly more investment in new CCGT capacity by 2030 in the WACM 2 case, due to small differences in the profile of retirements for existing CCGTs (see Figure 3.16, Figure 3.3 and Figure 3.4).

Figure 3.15
Location of New Generation Investments by 2030 (Excl. Wind) - Status Quo vs. WACM 2



Source: NERA/Imperial

Figure 3.16
Location of Existing Thermal Generation in 2020



Source: NERA/Imperial

However, a notable difference between the two scenarios is that the model projects a small amount of new thermal investment in Scotland under WACM 2, whereas under the status quo there is no new thermal investment in Scotland, and slightly higher investment in the midlands. The slight shift in the location of new capacity towards the north of GB is in line with WACM 2's long run impact on generators' TNUoS costs. As Table 3.5 shows, WACM 2 results in increased TNUoS costs for CCGTs located in the south of Britain and a decrease for CCGTs in the North, increasing the incentive to locate in Scotland where CCGTs face lower gas exit charges and land costs.[37]

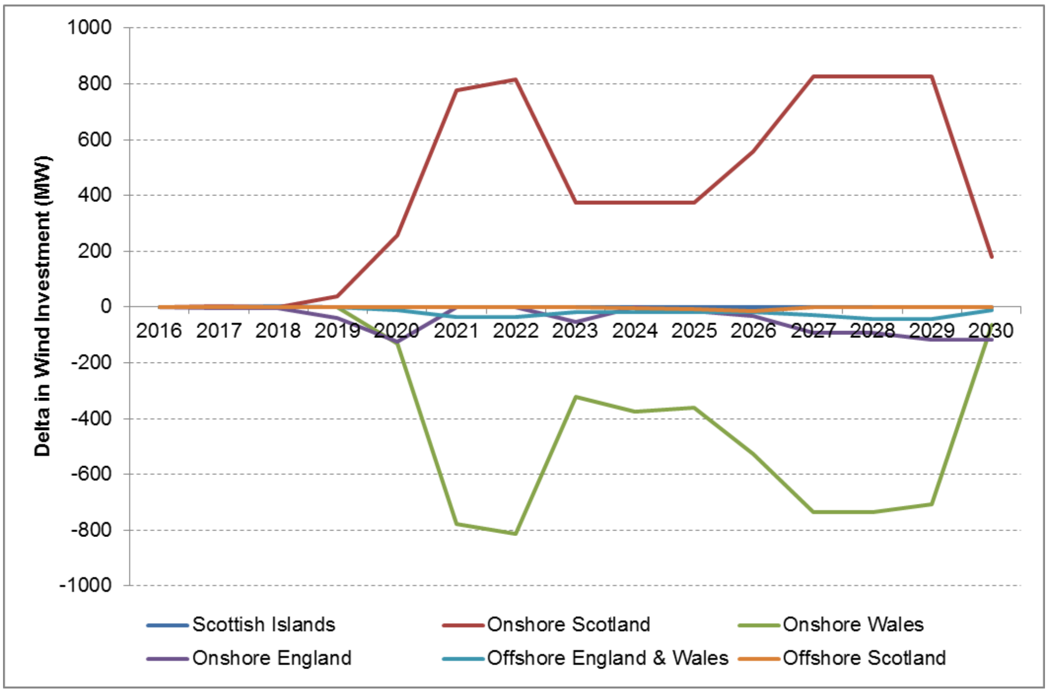
In contrast to our previous study, there is very little difference in the distribution of existing generation capacity around the system in 2020 as coal retirements are the same across scenarios and the introduction of the capacity mechanism means that the majority of existing CCGTs stay online until close to their assumed maximum lifetime, as Figure 3.3 and Figure 3.4 showed.

3.3.2. Impact of WACM 2 on the location of wind investments

Figure 3.17, Figure 3.18 and Table 3.6 show that patterns of wind generation investment are similar across the two scenarios. However, WACM 2 causes a small shift in onshore wind investment from Wales to Scotland. As Figure 3.17 shows, this difference amounts to around 600MW on average between 2020 and 2030. There is virtually no change in offshore investment patterns.

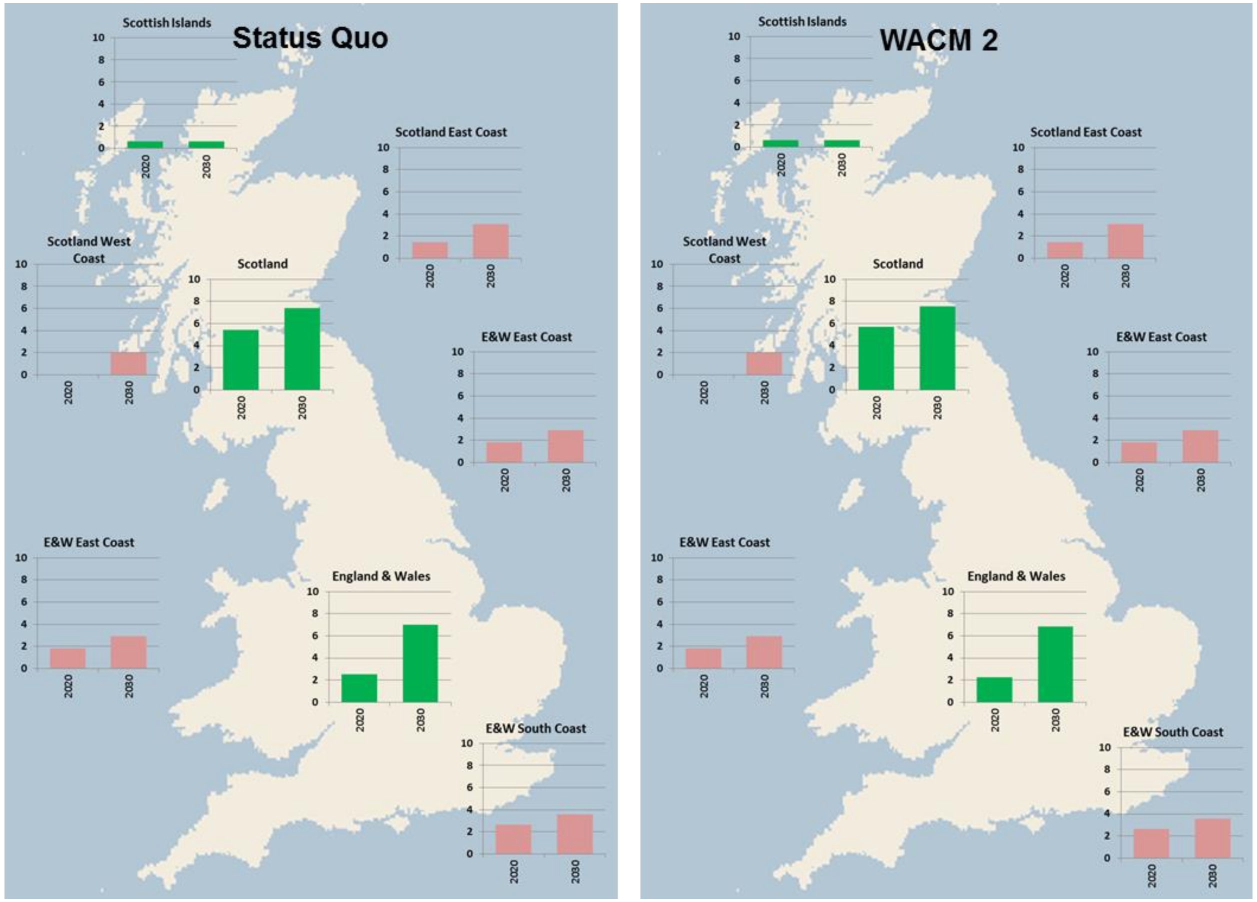
[37] Our model projects that new CCGTs will achieve load factors of around 70%, although this varies from year-to-year.

Figure 3.17
Difference in Locational Decisions for Wind Investment by Year
(Investment in WACM 2 Case, less Investment in Status Quo Case)



Source: NERA/Imperial

Figure 3.18
Locational of Wind Generation in 2030 - Status Quo vs. WACM 2



Source: NERA/Imperial

Table 3.6
Breakdown of Wind Capacity by Region – Status Quo vs WACM 2

Status Quo

Renewables (GW)	2020	2030
Offshore E&W East Coast	1.83	2.94
Offshore E&W South Coast	2.64	3.59
Offshore E&W West Coast	4.05	5.72
Offshore Scotland East Coast	1.43	3.10
Offshore Scotland West Coast	0.00	1.99
Scottish Islands	0.62	0.62
Onshore E&W	2.52	7.04
Onshore Scotland	5.44	7.38
Scotland	7.49	13.09
E&W	11.04	19.29

WACM 2

Renewables (GW)	2020	2030
Offshore E&W East Coast	1.83	2.94
Offshore E&W South Coast	2.64	3.58
Offshore E&W West Coast	4.05	5.72
Offshore Scotland East Coast	1.42	3.10
Offshore Scotland West Coast	0.00	1.99
Scottish Islands	0.62	0.62
Onshore E&W	2.27	6.86
Onshore Scotland	5.70	7.56
Scotland	7.74	13.27
E&W	10.79	19.10

Source: NERA/Imperial

3.3.3. Wind capacity savings under WACM 2

As shown in Table 3.6, total investment in new wind capacity is very slightly lower under WACM 2. However, this difference is relatively small over the modelling horizon. During the period between 2020 and 2030, we estimate that around 30MW less offshore capacity is developed under WACM 2 than under status quo, although this figure varies from year-to-year. The model develops slightly less capacity, as the model develops slightly higher load factor for those onshore sites it selects under WACM 2, and thus needs fewer MW of wind capacity to meet the total wind energy production target. The model reduces investment in offshore capacity under WACM 2 rather than onshore capacity because we assume the development of new onshore capacity is constrained (see Appendix A, Section A.3.3.3), and offshore sites are generally more expensive than onshore sites.

3.3.4. Comparison to Baringa results

The result presented above, that the movement in wind capacity from south to north under WACM 2 is relatively modest, contrasts with the findings of recent modelling work commissioned by Ofgem from Baringa, which finds that a substantial quantity of wind investment shifts from England and Wales into Scotland as a result of WACM 2. For instance, in Baringa's Original Case, "*approximately 1,400MW of new onshore wind capacity shifts from South Scotland, Midlands and North Wales to North Scotland under WACM2*".[38]

Without full access to the Baringa model, we cannot conclusivly state what is driving this difference in results, but we consider it likely that the difference is caused by differences in our load factor assumptions. As far as we understand, Baringa assumes flat load factors in each of Scotland, England and Wales, such that the load factors of wind farms in Scotland are higher for all sites than the load factors of wind farms in England and Wales. This assumption is incorrect and overly simplistic, as many sites in England and Wales have higher load factors than competing sites in Scotland, as demonstrated by the analyses presented in Appendix A of this report (Section A.3.4.2) and the accompanying NERA/Imperial report.[39] As a result, the Baringa modelling probably overstates the movement of wind investment from England and Wales to Scotland under WACM 2.

3.3.5. Impact on the renewables supply curve from WACM 2

Overall, our analysis suggests that the impact of WACM 2 TNUoS charges on the wind supply curve is limited, as shown below in Figure 3.19 and Figure 3.20. The charts take the average levelised cost of generation for each potential wind development site over the period from 2016 to 2030.[40] The minimal difference observed between the two sets of charges is a reflection of the fact that, for the most part, TNUoS charges make up a relatively small element of the total system costs of a wind generator, and that as well as reducing TNUoS at

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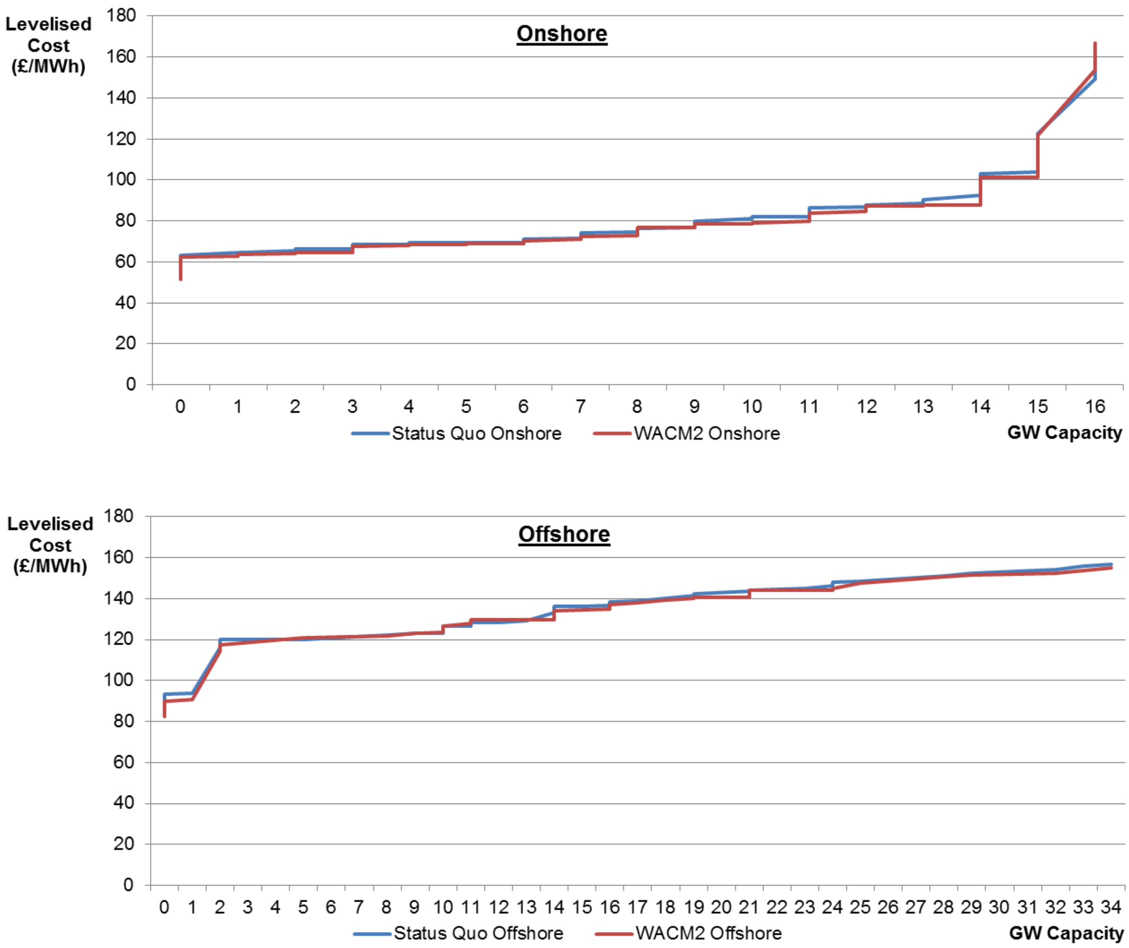
38 CMP213: further analysis and review of consultation responses, Baringa, 25 April 2014, page 50.

39 Project TransmiT: Critical Review of Ofgem's April 2014 Further Consultation, Prepared for RWE npower, 27 May 2014, Appendix D.

40 Note that this simplification is required because capital costs are assumed to decrease over time, dependent upon the commissioning year, and because TNUoS costs also vary over time.

some sites, WACM 2 also increases the costs for other sites, such as those in England and Wales. Hence, the impact of WACM 2 is also to "shuffle the deck" of available wind sites in the merit order.

Figure 3.19
Comparison of Wind Supply Curve under Status Quo and WACM2 TNUoS Charges



Source: NERA/Imperial

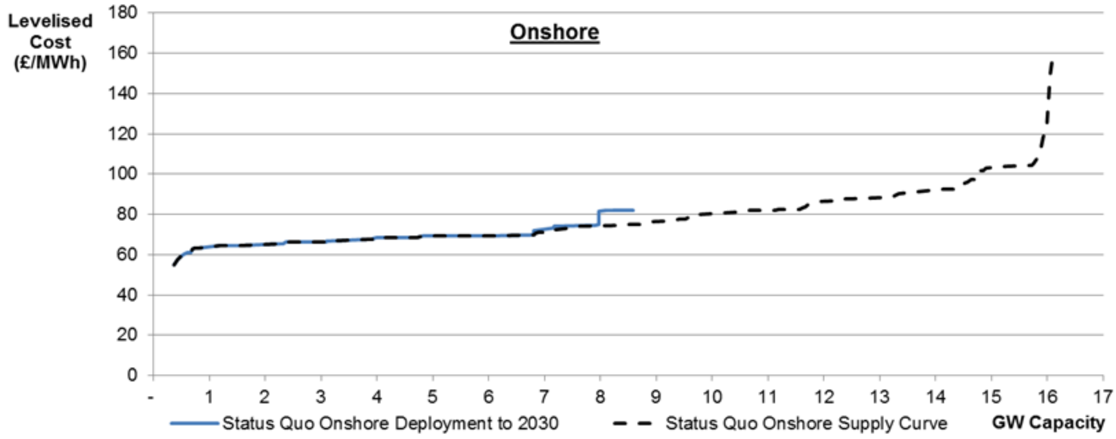
3.3.6. For given TNUoS charges, the model selects the most efficient wind sites

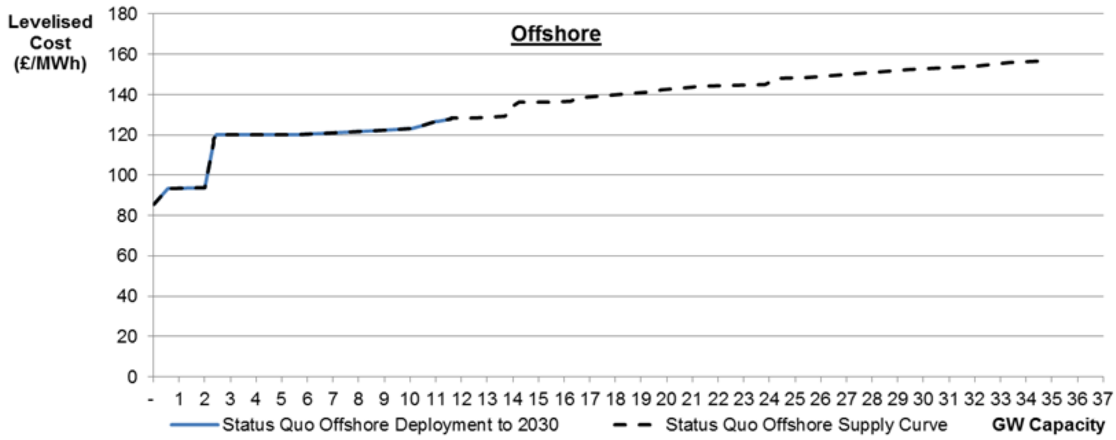
Given TNUoS charges and all other fixed and operational costs, the model selects, subject to various constraints, the most efficient deployment of wind farms in order to provide the required volume of wind generation at least cost, as described in greater detail in Appendix A.

Figure 3.20 shows the wind supply curve under the status quo and the actual deployment of wind projects by 2030, separately for both onshore and offshore projects. It shows that the model selects the lowest cost wind sites available (including TNUoS) under both the

WACM 2 and status quo scenarios.[41] Hence, the change in renewables investment patterns we identify are readily explicable, and the remarks made by Baringa and Ofgem regarding the difficulty in interpreting our previous set of modelling results no longer apply to these results.[42]

Figure 3.20
Deployment of Onshore and Offshore Wind Projects to 2030 (Status Quo)





Source: NERA/Imperial.

41 The only exception is one onshore wind project that is developed "out of merit", with a cost of just over £80/MWh, as the top half of Figure 3.20 illustrates. The model develops this project because, despite its relatively high cost, it has a particularly high load factor. Because the model has a constraint on the rate of onshore projects it can develop (in MW per annum), it uses this relatively high load factor site to meet the energy production target as an alternative to more expensive offshore sites, even though it is slightly more expensive than some alternative onshore sites with lower load factors.

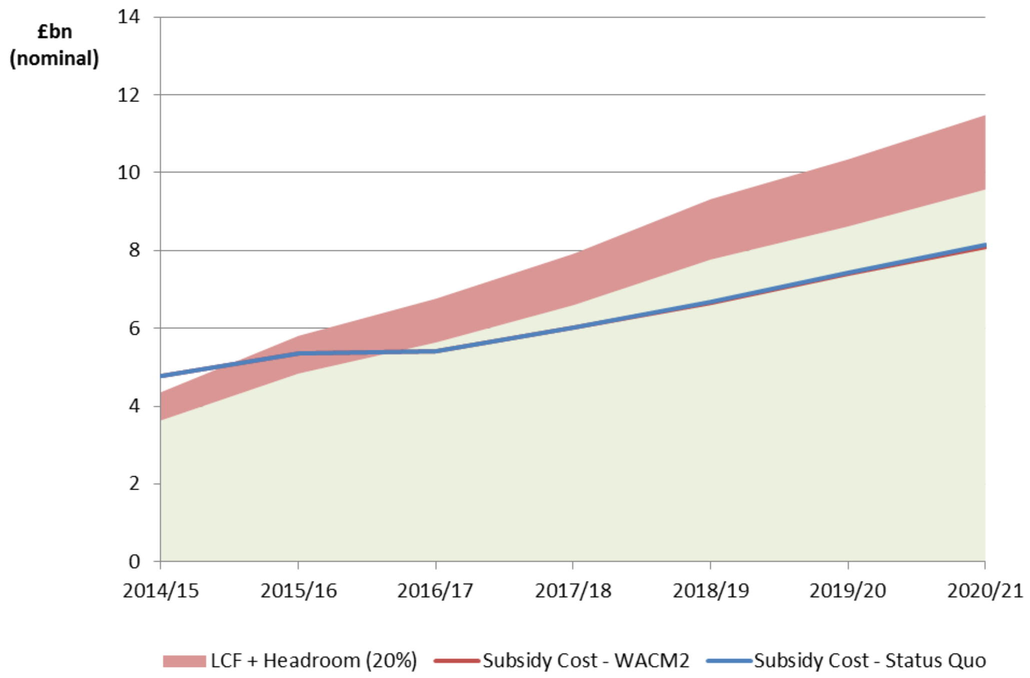
42 See, for instance: Ofgem (April 2014), Appendix 2 para 1.53.

3.4. Renewables Subsidies

As Figure 3.21 shows, renewables subsidy costs[43] generally increases as new capacity is added. This trend is halted towards the end of the 2020s as some existing capacity reaches the end of its life and is replaced by new, lower cost wind farms. The total cost of subsidising renewable energy under both the status quo and WACM2 cases are similar, and support costs are marginally lower under WACM 2.

The LCF budget agreed between HM Treasury and DECC includes the provision of headroom of 20% to allow some degree of flexibility to stretch the budget. Such flexibility is particularly important as more generators move onto CfD FIT contracts, where subsidy payments are dependent upon the prevailing wholesale power price. The LCF budget and headroom are shaded in red in Figure 3.21, which is set until the end of the 2020/21 financial year.

Figure 3.21
RES Support Cost and LCF



Source: NERA Analysis
Note: LCF projection is purely illustrative as no budget has been established for this period

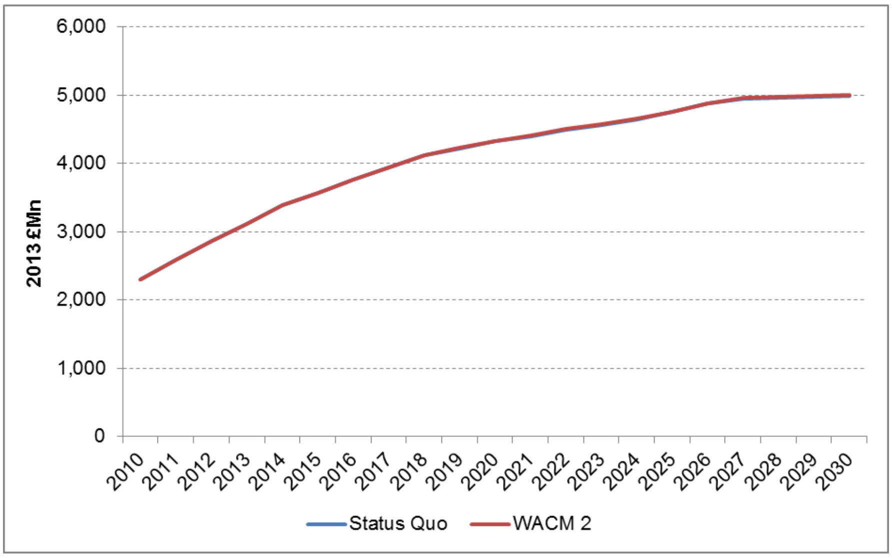
43 The total subsidy cost, as shown by the red and blue lines in Figure 3.21, includes estimated support for renewable generation under the RO, CfD FITs and small-scale FITs. It also includes an estimate of payments made under the Warm Home Discount as this is currently allocated from within the Levy Control Framework (LCF) budget.

The cost estimates shown in Figure 3.21 indicate that the LCF is likely to be breached in 2014/15 and 2015/16.[44] However, costs then fall back within the budget envelope. The LCF budget therefore does not constrain the deployment of renewable generation over the modelling horizon. As the LCF budget has only been set out to 2020/21, we make no assessment of whether increasing subsidy costs will breach any budgetary limits during the remainder of the modelling horizon to 2030.

3.5. Transmission System Costs

As shown in Figure 3.22, TNUoS revenue is very similar across scenarios, reflecting our finding that there is virtually no difference between modelled transmission investment requirements across the two scenarios. This is not surprising given the similarity in both thermal and renewables investment patterns across scenarios. In particular, offshore investment and hence offshore grid costs are almost identical across scenarios.

Figure 3.22
TNUoS Revenue (2012 £Mn) – Status Quo vs. WACM 2

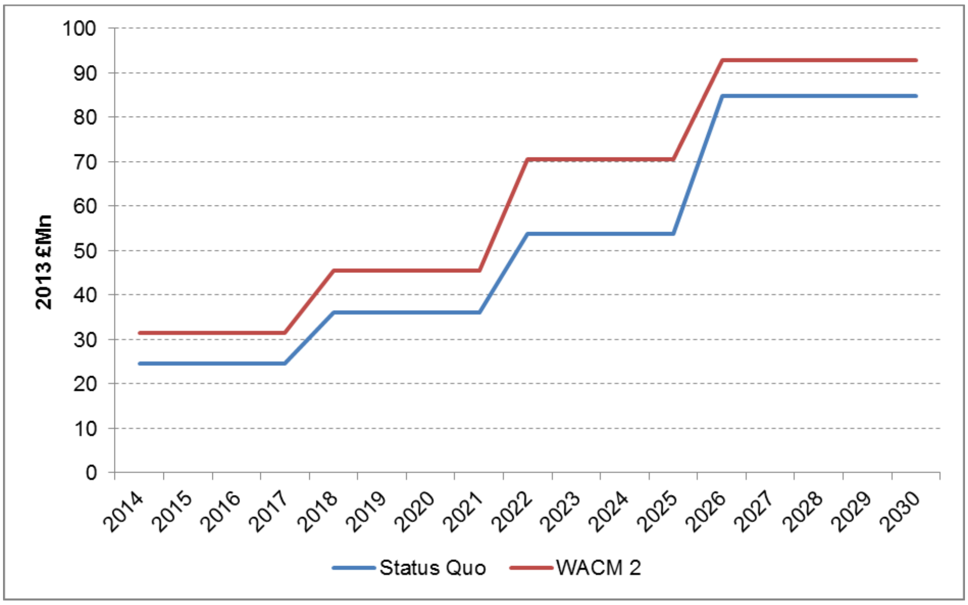


Source: NERA/Imperial

However, as Figure 3.23 shows, our modelling suggests that constraint costs are higher under WACM 2. Hence, while the changes in the generation mix resulting from introducing WACM 2 are insufficient to trigger additional reinforcements under our assumptions, transmission system costs do increase through higher constraint costs. Transmission losses, as shown in Figure 3.24, are also generally higher under WACM2, as more power is transported from north to south under WACM 2, as more wind and CCGT capacity is located in Scotland. Thus, the results of our model suggest that whilst transmission investment costs are almost identical across scenarios, transmission system costs are higher under WACM 2.

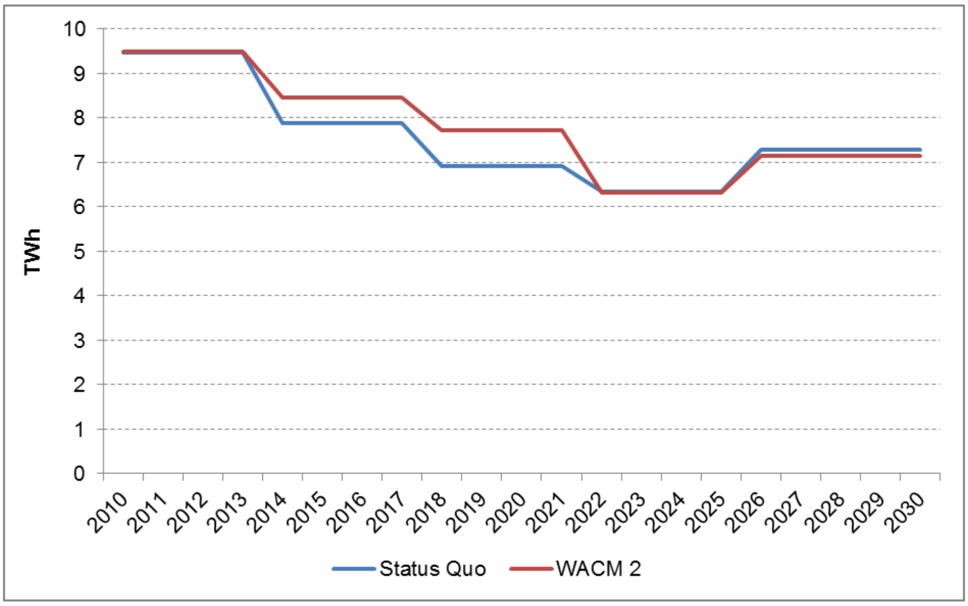
[44] This temporary breach of the budget is expected by DECC and highlighted in a recent review of the LCF by the National Audit Office (NAO). The Levy Control Framework. 27 November 2013.

Figure 3.23
Constraint Costs (2012 £Mn) – Status Quo vs. WACM 2



Source: NERA/Imperial

Figure 3.24
Transmission Losses (TWh) – Status Quo vs. WACM 2



Source: NERA/Imperial[45]

45 Although more generation capacity locates towards the north of GB under WACM 2, we find a very small reduction in losses towards the end of the modelling horizon as a larger share of conventional generation capacity is located in the

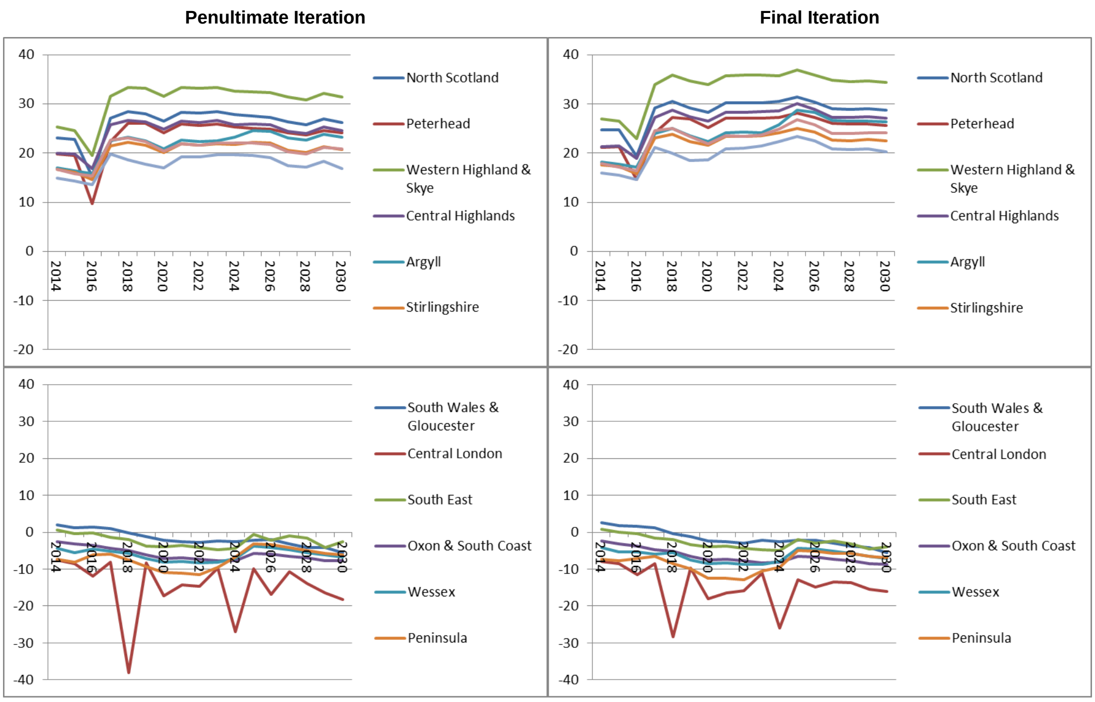
3.6. Convergence

The sections below describe the extent to which the iterative process between the market and transmission system models has converged. We note that the Baringa modelling presented in the April 2014 consultation appears not to show equivalent information on the extent to which its model reaches a converged solution.

3.6.1. Convergence in tariffs

As Figure 3.25, Figure 3.26, Figure 3.27 and Figure 3.28 illustrate, we obtained a high degree of convergence in TNUoS tariffs in the penultimate and final iterations of both the Status Quo and WACM 2 scenarios. We note, that the peak security charge under WACM 2 becomes more widely dispersed in Scotland between the penultimate and final iterations though the general trend is similar, and as discussed below, this difference does not create instability in generation investment decisions across the final and penultimate iterations of the WACM 2 case.

Figure 3.25
TNUoS Tariffs (2013 £/kW) – Status Quo, Final and Penultimate Iteration

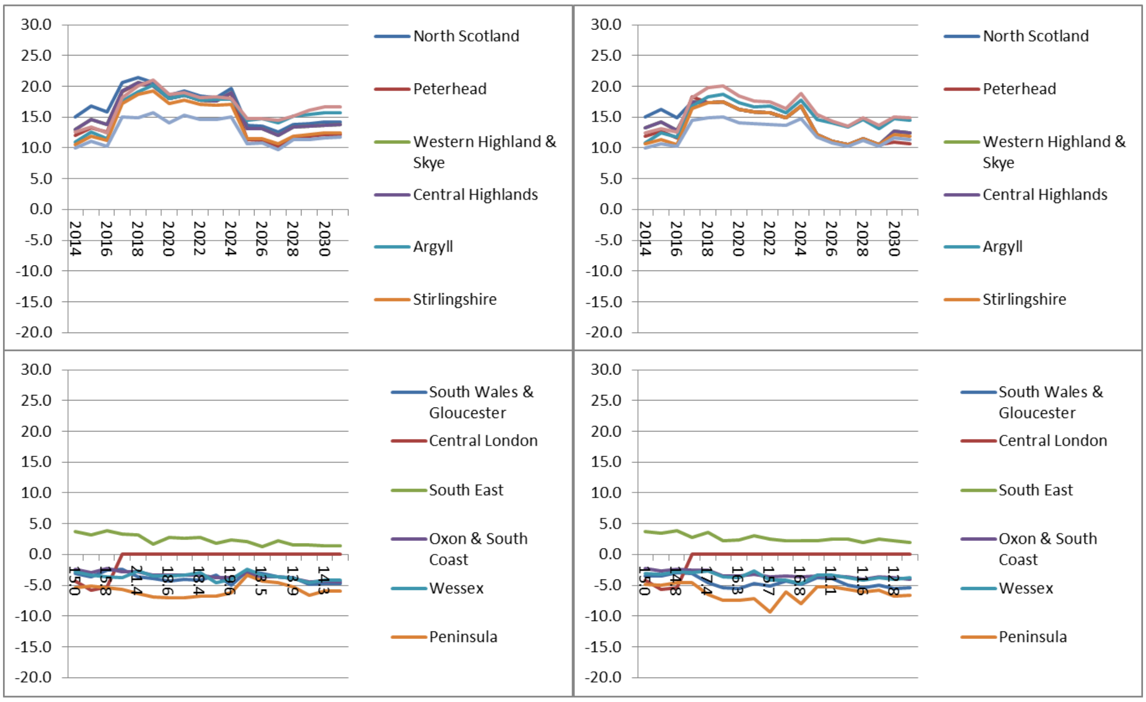


Source: NERA/Imperial Analysis

south west of England and Wales than under status quo, which slightly increases losses. However, the difference between the cases is small.

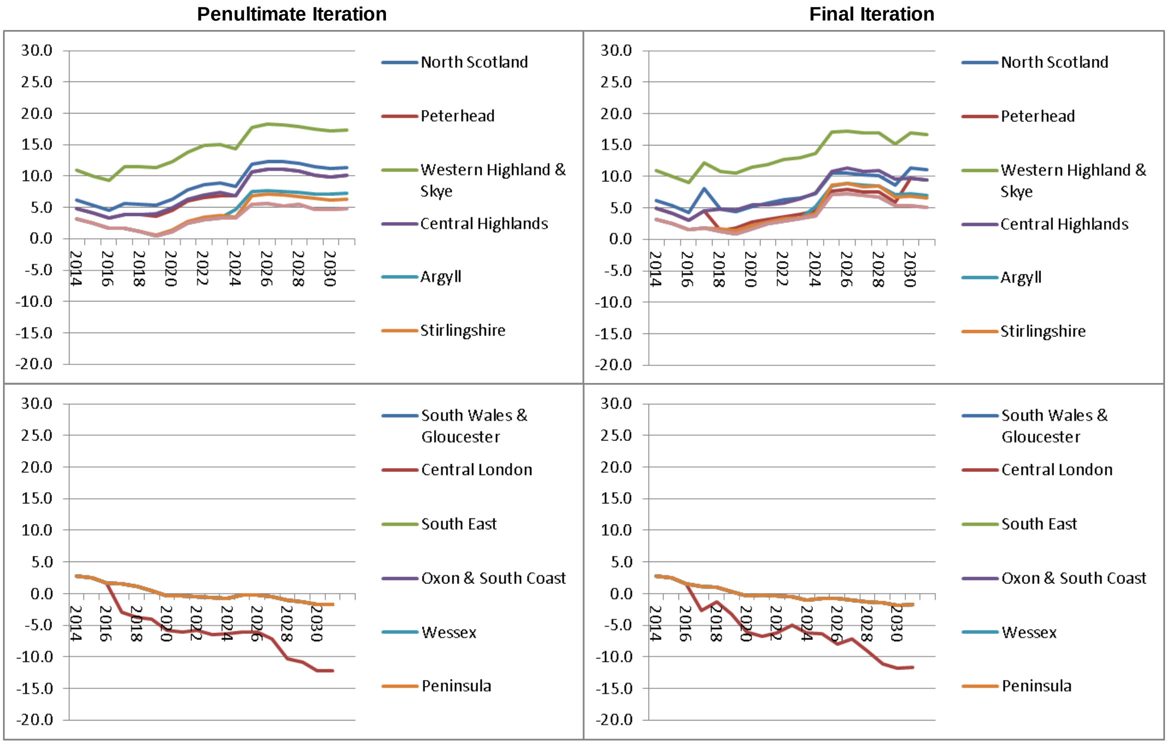
Figure 3.26
TNUoS Tariffs (2013 £/kW) – WACM 2 Year Round (Shared), Final and Penultimate Iteration

Penultimate Iteration **Final Iteration**



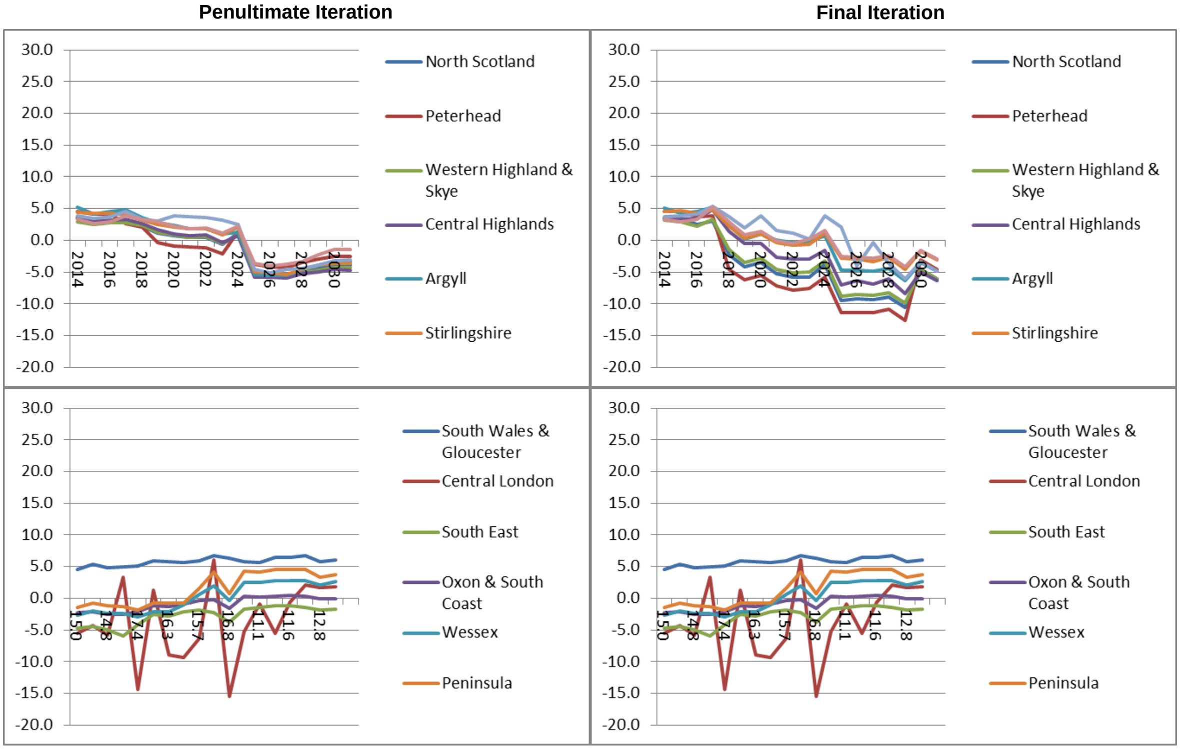
Source: NERA/Imperial Analysis

Figure 3.27
TNUoS Tariffs (2013 £/kW) – WACM 2 Year Round (Non-Shared) Plus Residual, Final and Penultimate Iteration



Source: NERA/Imperial Analysis

Figure 3.28
TNUoS Tariffs (2013 £/kW) – WACM 2 Peak Security Final and Penultimate Iteration

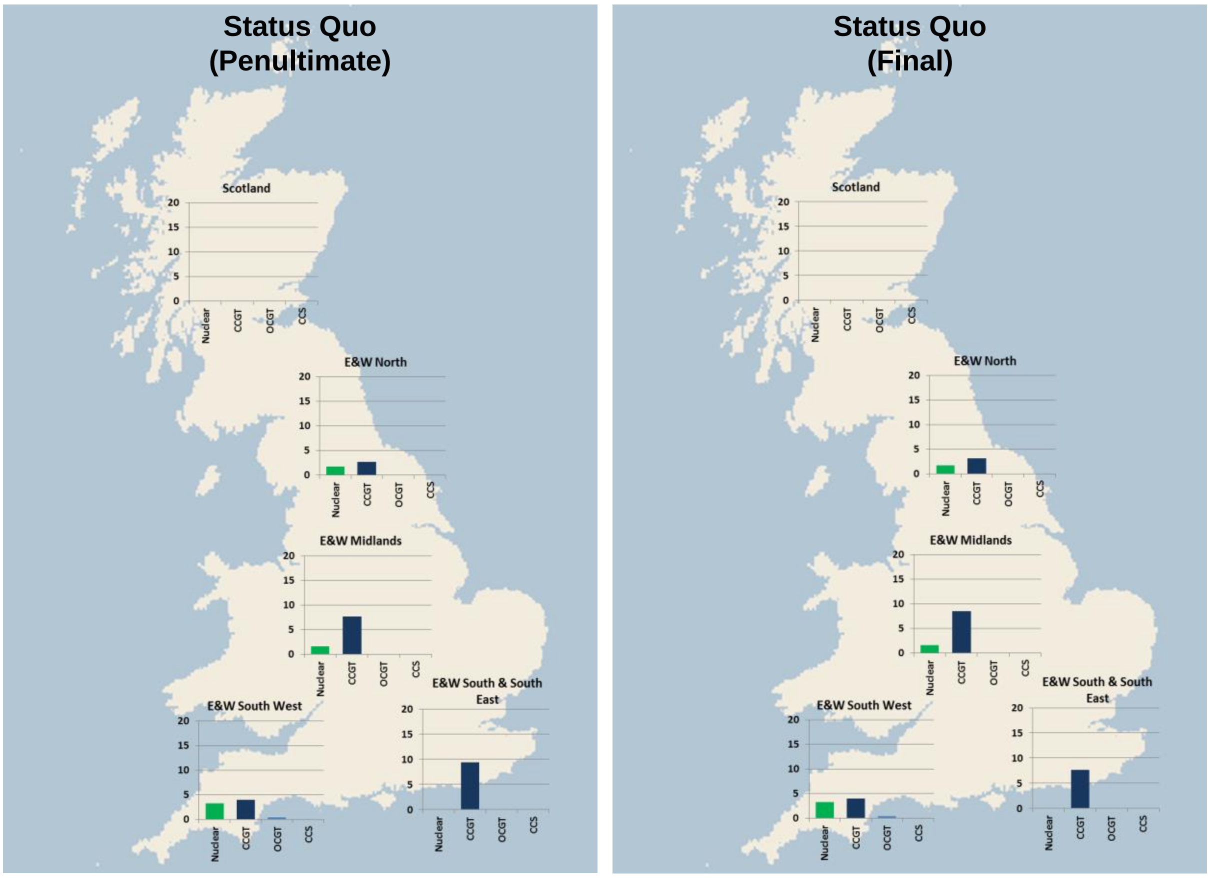


Source: NERA/Imperial Analysis

3.6.2. Convergence in the location of thermal investment decisions

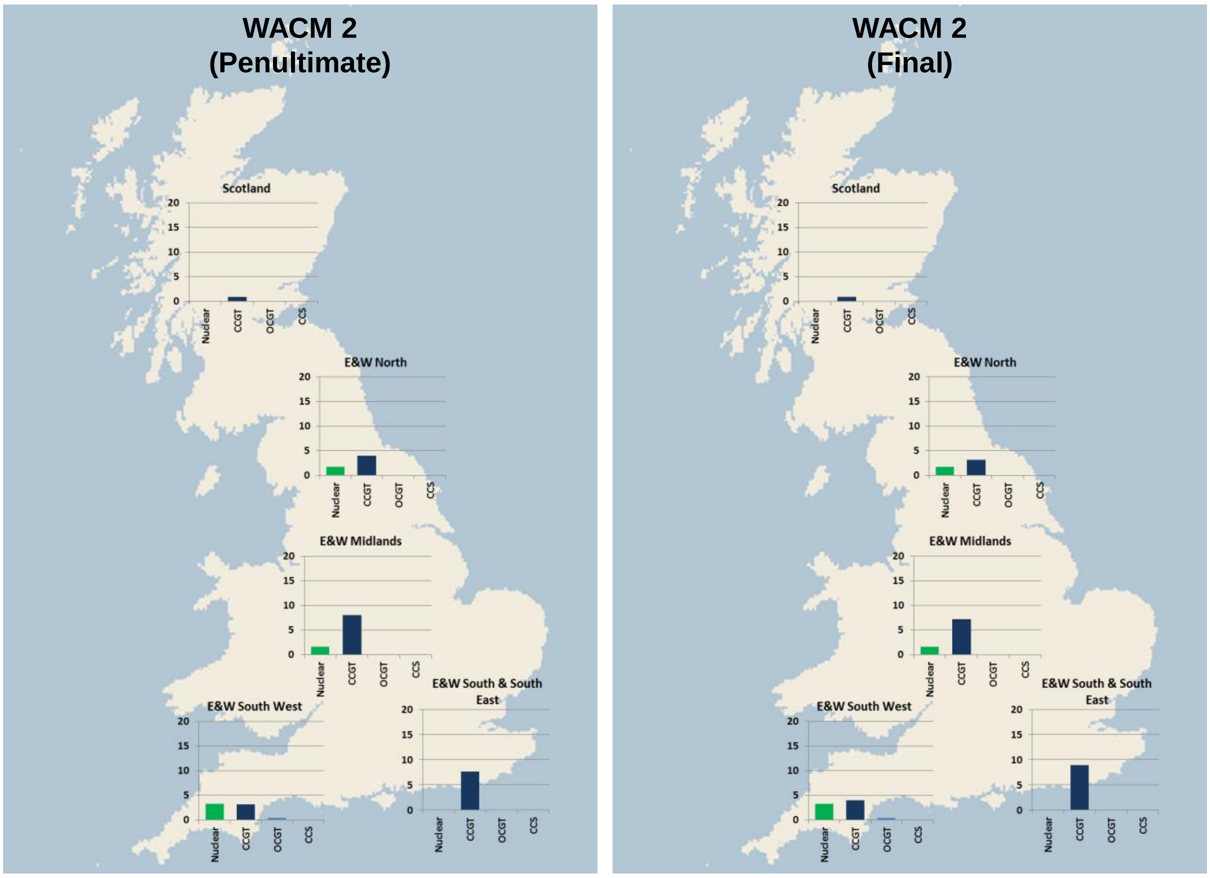
As Figure 3.29 and Figure 3.30, illustrate, in the final and penultimate runs of our status quo and WACM 2 scenarios, we obtained a high degree of convergence in the location of generation investments, with relatively stable investment patterns across the two cases

Figure 3.29
Location of New Generation Investments by 2030 (Excl. Wind) – Status Quo, Final vs. Penultimate Iteration



Source: NERA/Imperial Analysis

Figure 3.30
Location of New Generation Investments by 2030 (Excl. Wind) – WACM 2, Final vs. Penultimate Iteration

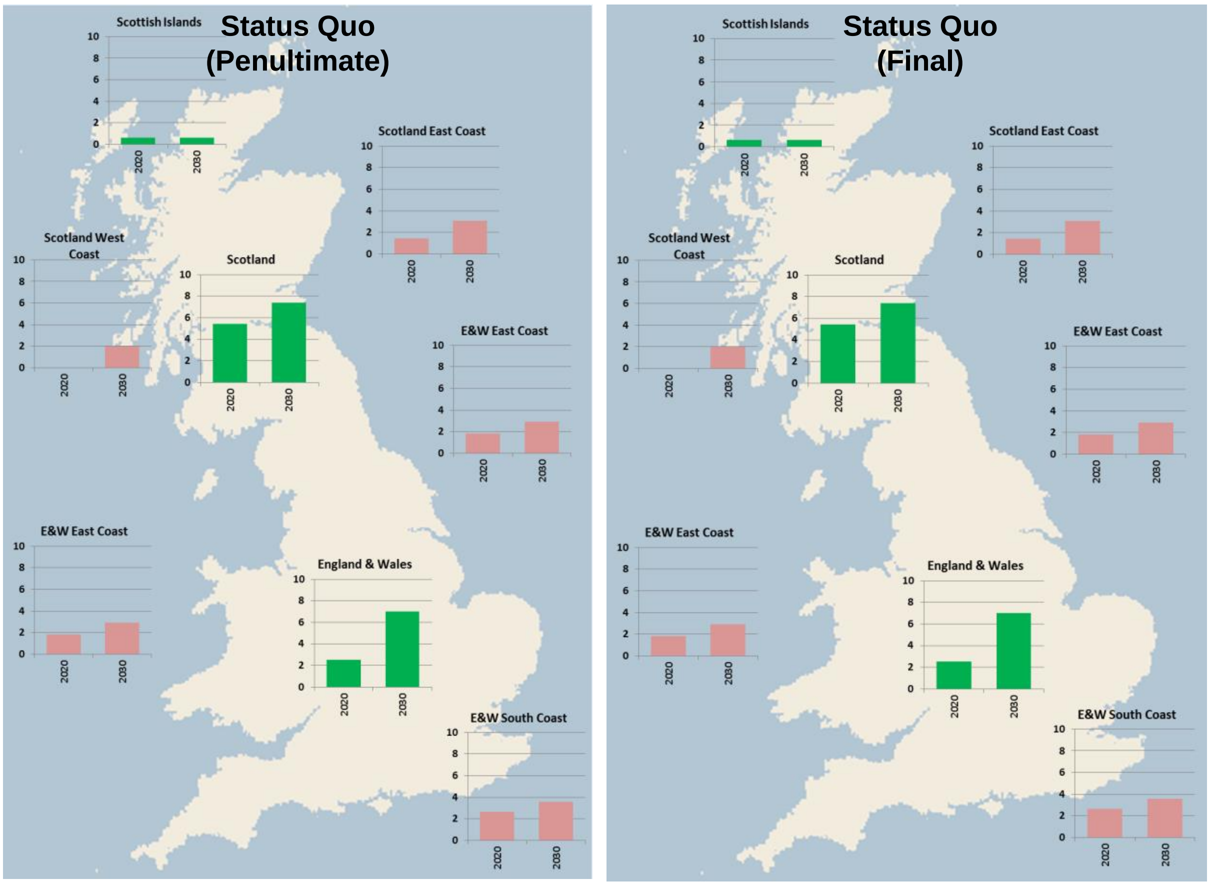


Source: NERA/Imperial Analysis

3.6.3. Convergence in the location of wind investment decisions

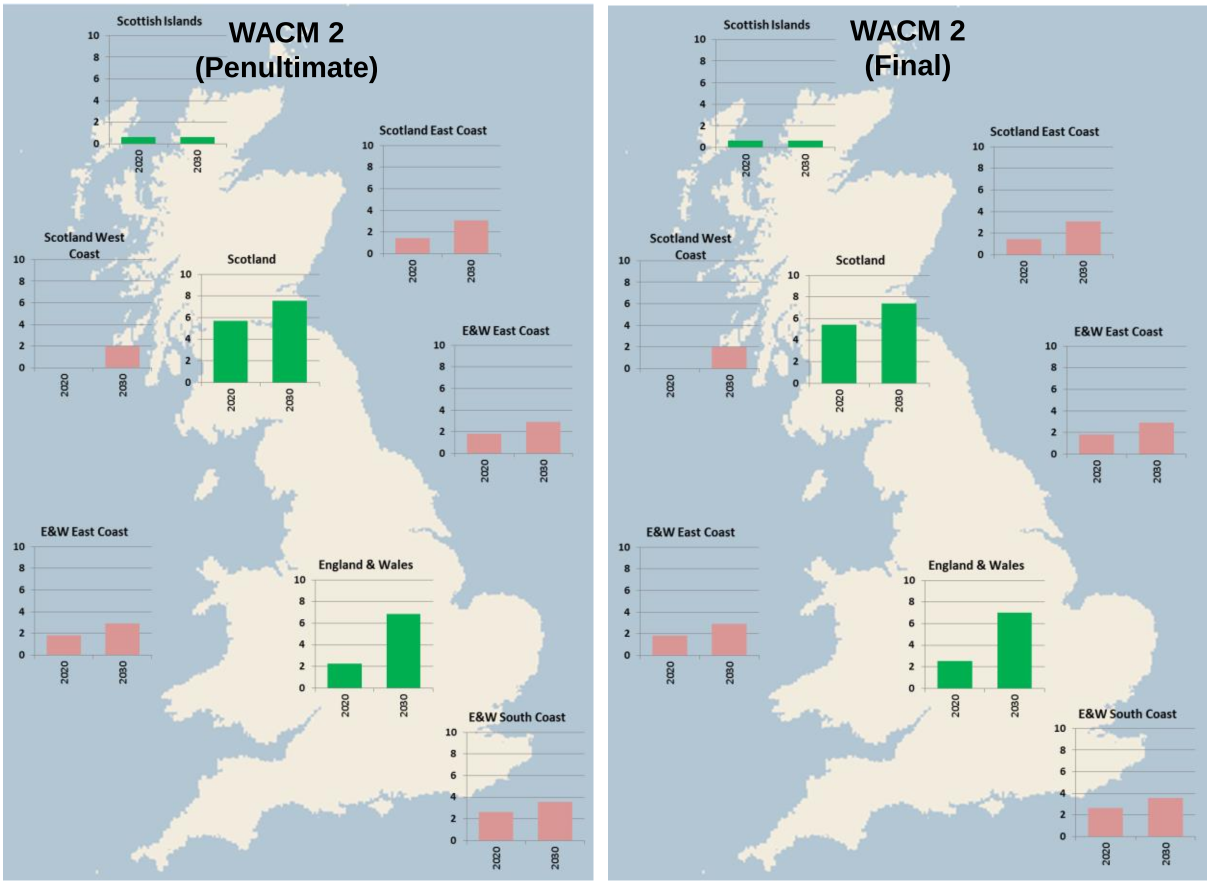
We also achieved a very high degree of convergence in the investment decisions of onshore and offshore wind under both scenarios, as Figure 3.31 and Figure 3.32 show.

Figure 3.31
Location of New Wind Investments by 2020 and 2030– Status Quo, Final vs. Penultimate Iteration



Source: NERA/Imperial Analysis

Figure 3.32
Location of New Wind Investments by 2020 and 2030– WACM 2, Final vs. Penultimate Iteration



Source: NERA/Imperial Analysis

3.7. Conclusions

The results set out above show that the WACM 2 charging methodology significantly reduces TNUoS charges for low load factor plants in Scotland as compared to the status quo, and significantly increases charges for low load factor thermal generators in England and Wales. Plants that run at higher load factors are affected less. We estimate that the impact of the WACM 2 charging model will as follows:

- A higher proportion of new onshore wind generation and new thermal generation capacity locates in Scotland. Our analysis shows that locating more generation capacity towards the north of the country increases transmission system costs.
- Because English and Welsh CCGT plants typically determine the marginal cost of new entry into the power market, and WACM 2 increases TNUoS for this category of generation, the costs that these marginal new entrants need to recover from the energy and capacity markets rises. Hence, our model forecasts that higher prices will emerge from the CPM under WACM 2.

- We find no difference in the environmental performance of the two charging models, as we assume that renewables subsidies adjust to achieve a target of 30% of renewables in total power generation by 2020 and 40% by 2030. Both scenarios have similar levels of CO_2 emissions.

4. Welfare Impacts

Table 4.1 shows the welfare effects we estimate from our comparison of the status quo and WACM 2 charging models. The table shows that introducing the WACM 2 model would increase transmission system costs by £390 million over the period to 2030 and cause a slight decrease in generation costs (i.e. the costs of developing and operating generation assets) of around £100 million. Hence, WACM 2 causes a net increase in power sector costs of £292 million. This total increase in power sector costs proxies the reduction in overall social welfare caused by WACM 2.

Transmission system costs (investment, plus constraints, plus losses) increase, as described in Section 3.5 above, because generation tends to locate further north within GB. The decrease in generation costs under WACM 2 is primarily due to a small reduction in wind costs of around £70 million, due to less capacity being developed (see Section 3.3.3 above). There is also a reduction in import costs under WACM 2 of £255 million, which is largely offset by an increase in GB thermal generation costs of £225 million.[46] Thus, the overall impact on generation costs is small.

Table 4.1
Effects of Introducing the WACM 2 Charging Model

	NERA/ICL			Baringa	
	2014-2020	2021-2030	Total	Total (Original Case)	Total (Alternative Case)
Impact on Consumers					
Power Purchase Costs (inc. capacity payments)	525	2,463	2,987	1,103	503
Low Carbon Subsidies	-69	-510	-579	-488	-514
D-TNUoS	5	34	39	28	10
Constraints	48	78	126	219	-7
Losses	215	-4	212	169	73
Total	724	2,061	2,785	1,031	65
Power Sector Costs					
Generation Costs (excluding TNUoS)	10	-109	-99	-625	-122
Transmission Investment	-11	65	53	168	-12
Constraints	48	78	126	219	-7
Losses	215	-4	212	169	73
Total	262	30	292	-69	-68

Source: NERA and Imperial Analysis; Redpoint Analysis. Note, a positive number indicates an increasing cost following the introduction of WACM 2. NERA/Imperial NPVs calculated between 2014-20 and 2021-30, using a real discount rate of 3.5%. Baringa's NPVs are calculated between 2011 and 2030.

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[46] Hence, WACM 2 is changing the share of imports in the generation mix, but because import costs are closely balanced with the costs of running thermal generators within Great Britain, this change has little effect on the total costs of the system.

We also estimate that the introduction of WACM 2 would materially increase consumers' bills by around £2.8 billion in NPV terms over the period to 2030. Consumer bills rise by around £3 billion due to higher wholesale procurement costs (see Section 3.1.5). Bills rise by a further £0.4 billion due to increases in D-TNUoS, constraint costs and losses, which we assume are passed through directly to consumers. There is, however, an offsetting decrease in low carbon subsidy costs of around £0.6 billion due to the lower strike prices for onshore wind under WACM 2, which result from lower TNUoS charges for wind farms.

Overall, we note that the increase in consumers' bills we identify as a result of WACM 2 is materially larger than the impact identified by the Baringa modelling, which, depending on the scenario examined, was between a £65 million increase and a £1,031 million increase.[47] This suggests that Baringa's modelling may be understating the impact of WACM 2 on consumers' bills.

As noted in our previous modelling report,[48] although the welfare loss from WACM 2 indicated by our modelling is significant, it is subject to a range of uncertainty and further work would be required to compare the WACM 2 and status quo charging models robustly in advance of any decision to alter the existing TNUoS charging methodology. The consultation window allowed by Ofgem did not allow sufficient time to perform a range of sensitivity analysis.

[47] Source: NERA calculations using: CMP213: further analysis and review of consultation responses, Baringa, 25 April 2014, Tables 19 and 20, page 67.

[48] Project TransmiT: Modelling the Impact of the WACM 2 Charging Model, NERA Economic Consulting and Imperial College London, Prepared for RWE npower, 9 October 2013.

5. Conclusions

The role of locational TNUoS charges is to promote the efficient use of the transmission system. If changes to the transmission charging regime improve the efficiency of network usage, we would expect total power sector costs to fall as a result, and thus increase social welfare. In practice, our market and transmission system modelling suggests that the WACM 2 charging model would reduce social welfare, which suggests it does not promote a more efficient use of the transmission system. Our analysis also suggests that introducing WACM 2 would increase costs to the consumer due to its effect on wholesale energy and capacity prices. It also suggests that the Baringa modelling commissioned by Ofgem understates the impact of WACM 2 on consumers' bills.

By implementing changes to the current transmission charging regime that do not deliver demonstrable improvements in economic efficiency and consumer benefits, Ofgem may increase investors' perception that the new regime will have a limited lifespan. Generators cannot predict these changes and they cannot protect themselves against the effects of such changes, except by maintaining a diversified portfolio of generation. Removing the current charging model may therefore undermine the incentives provided by the transmission charging regime.

Additionally, although we have not estimated these effects in this report, the distributional effects of introducing the WACM 2 charging model may be significant. Regulatory decisions that redistribute value amongst industry participants, especially without any resulting and demonstrable improvement in efficiency, will add to investors' perception of regulatory risk and increase the costs of financing for the British energy industry, and thus further increase consumer bills.

Overall, therefore, the modelling presented in this report does not support the introduction of the WACM 2 model as currently proposed. Finally, in addition to the evidence presented in this report, we see fundamental problems with the design of the WACM 2 charging model, and the evidence presented to support the hypothesis that it is more cost reflective than the status quo. We discuss these issues further in an accompanying report.[49]

[49] Project TransmiT: Critical Review of Ofgem's April 2014 Further Consultation, Prepared for RWE npower, 27 May 2014.

Appendix A. Renewables Modelling Assumptions

A.1. Algorithm

As noted above in Section 2.3.3, the updated version of our renewables investment model selects investments in the lowest cost wind generation sites. Hence, the objective function that the model seeks to minimise calculates the net present value of the lifetime costs of those wind farms deployed by the model. The model takes data on the costs of developing new wind farms (see Sections A.3.3.2 and A.3.4.1 below), including TNUoS charges (see Sections A.3.4.1.2 and A.5 below), and load factors (see Sections A.3.3.1 and A.3.4.3). It then minimises total cost, subject to the following constraints:

- A set of development constraints for new onshore and offshore projects, as set out in Sections A.3.3.3 and A.3.4.2:
  - Separate constraints on the rate of deployment of new onshore and offshore capacity both in the period to 2020 and between 2021 and 2030;
  - Caps on the total quantity of new capacity at each development; and
  - No development before specified dates at each site, which reflect our assumptions on the earliest date at which the various potential projects could come online;
- Capacity at each site is non-zero and non-decreasing over time; and
- Wind capacity is developed at the rate required to meet the assumed target. We impose this constraint to reflect an assumption that the government will not provide more renewables subsidies than are required to meet its obligations under the EU Renewables Directive up to 2020, which we assume requires 30% of generation from renewables. Beyond 2020 we assume a target share of renewable electricity generation that grows to 40% by 2030.

A.2. Model Outputs

The model identifies the combination of wind investments that meet the assumed renewables target at the lowest cost to the consumer and forecasts:

- Investment in wind capacity, at project level, in each year up to 2030. This deployment is then aggregated into each project’s corresponding transmission zone. The forecasts feed into the DTIM transmission investment model, the transmission charging model and the Aurora model as input assumptions; and
- Forecasts of the subsidy costs required to remunerate new investments in wind capacity built to meet the target, which is used for the CBA calculations. The subsidy cost is calculated by estimating the minimum support required under the CfD scheme for the marginal wind project in each year, taking into account upfront and operational costs, TNUoS charges as well as the assumed weighted average cost of capital based on NERA analysis. This calculation is carried out for both onshore and offshore wind projects separately as they will receive different support levels. The forecast power price captured by intermittent generators (calculated separately in Aurora) is then subtracted from this level.

A.3. Model Inputs

To provide inputs into our renewables investment model, we defined assumptions on the costs of developing and operating onshore and offshore wind farms, which we summarise in Sections A.3.3.2 and A.3.4.1 as well as data on subsidy levels and power prices.

A.3.1. Non-Wind RES forecasts and existing wind capacity

The starting point for our RES forecast out to 2030 is the existing capacity of different technology types as at the end of 2013, based on Energy Trends data, published by DECC.[50] To the existing capacity we add NERA's forecast for the deployment of solar PV, bioenergy, hydro and other RES technologies (including tidal, wave and geothermal, but excluding wind) between 2014 and 2030. These forecasts are based on detailed pipeline information for each technology, DECC's Renewable Energy Roadmap (including annual updates) and National Grid modelling as part of the EMR delivery plan, as well as supplementary technology specific sources and NERA analysis.[51]

- **Bioenergy**: The significant majority of biomass capacity expansion is expected to be delivered by coal plants that convert to run on biomass. We assume that the three biomass plants granted early CfD FITs under the 'Final Investment Decision Enabling for Renewables' process are all built (conversion of a second unit at the Drax power plant, conversion of Lynemouth power station and the Teeside Renewable Energy biomass plant with CHP).

  We assume that 95 percent of the capacity of new dedicated biomass plants under construction are built, remaining within the cap of 400 MW on further Renewables obligation support. We also forecast almost 900 MW of new energy from waste capacity to 2020, reflecting DECC's development pipeline, with a reduced annual rate of deployment between 2021 and 2030.[52]

- **Solar**: We assume that capacity expands at approximately 1 GW a year to reach approximately 10 GW by 2020, which is at the conservative end of the projected range in DECC's renewable energy roadmap. Whilst there has been a significant increase in deployment in the first quarter of 2014, the government has made recent proposals to curb support for new solar under the Renewables Obligation scheme from 2015, and it is likely to struggle to compete effectively with onshore wind developments under the proposed CfD allocation of contracts via auctioning.[53] Capacity then expands at roughly half this rate between 2021 and 2030.

- **Other RES**: Our forecast assumes limited additional capacity from other RES types including established technologies such as hydro, landfill gas and sewage gas as well as

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50 DECC. Energy Trends. Table 5.1. April 2014.

51 Primary sources for NERA's renewables forecast include: DECC Renewable Energy Roadmap (July 2011) and subsequent updates in December 2012 and November 2013; DECC EMR Consultation (July 2013); and National Grid EMR Analytical Report (July 2013).

52 DECC's development pipeline is available via the RESTATS online portal.

53 DECC. Consultation on changes to financial support for Solar PV. 13 May 2014.

relatively immature technologies such as geothermal, anaerobic digestion, advanced conversion technologies and tidal and wave power.

We calculate the renewable electricity output from all technologies, with the exception of new wind projects, by applying technology specific load factors to both existing capacity and our capacity projections. Then, using our demand forecast to 2030 we calculate the additional renewable output required from new wind projects to meet the target RES shares of 30% in 2020, rising to 40% in 2030. Our wind project selection tool is set up to deliver this RES *deficit* in each year from a selection of potential onshore and offshore wind farms that differ in terms of both their location as well as their load factor. The tool is programmed to achieve the target level of RES at least cost, as described in the following paragraphs.

A.3.2. The range of wind development zones

In the wind project selection tool, we define 143 different wind development opportunities, covering both onshore and offshore locations. The model deploys capacity from amongst these 143 potential projects based on their differing characteristics.

We include 19 onshore zones, plus two on the Scottish Islands (Western Islands and Shetlands/Orkney), with five different types of sites available within each of these zones. Hence, in total, we define (19+2) x 5 = 105 onshore development zones. The five types of site differ according to their assumed load factor, such that in each zone we assume that a range from high to low load factor sites are available, with the distribution of sites informed by the range of load factors achieved by existing onshore wind farms (see below).[54]

In addition, we also define 26 offshore development zones, including Round 2 sites, Round 3 sites, and sites in Scottish Territorial Waters. Because there is some variation in seabed depth within some of these offshore development zones, we have split some offshore zones based on seabed depths (deeper sites are more expensive – see below). Including those offshore development zones that we split according to seabed depth, we define 38 offshore development zones in total.

A.3.3. Onshore wind assumptions

A.3.3.1. Load factors

A.3.3.1.1. Importance of load factor assumptions

Given the range of available sites for wind farm development, decisions over where in the country investors develop wind farms depend largely on a trade-off between:

- Locational variation in wider and local TNUoS costs;
- Locational variation in load factors, and

[54] The exception to this approach is capacity on the Scottish Islands. As there are no wind projects in these locations at present, we have assumed no variation in load factors in these development zones.

- Locational variation in other generation costs, i.e. the costs of constructing, operating and maintaining the generation assets.

The trade-off between these factors is the reason why detailed load factor assumptions are essential to ensuring the robustness of the modelling work conducted, an important dimension of which is ensuring an accurate degree of regional variation in wind load factors. For instance, if we assumed less variation in load factors than is seen in reality, changes in TNUoS charges would tend to have a larger impact on investment decisions in the model than in reality (and vice versa).

A.3.3.1.2. Our approach to estimating regional load factors

For onshore wind projects, we estimate the distribution of load factors in each development zone by the following method:

1. We estimate the load factors of existing wind projects in the UK by taking historic monthly Ofgem data on the number of ROCs awarded to each project over the course of a year, from April 2011 to March 2012;
2. Based on the above load factor estimates we calculate the 10^{th}, 30^{th}, 50^{th}, 70^{th} and 90^{th} percentile load factors for each of 19 onshore development zones. These percentiles represent the five different types of site available for development within each zone, refered to in Section A.3.1 above. Table A.1 below sets out the load factor distribution for each potential development zone; and
3. We then "shape" these load factors over the year using a representative wind production profile, which is based on data obtained from the Irish Single Electricity Market, shifting the profiles up or down to achieve the annual load factors shown in the table below for each of the 105 wind development zones.

Table A.1
Onshore Load Factor Distribution

	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%

As no historic wind production data currently exists for the Scottish Islands, we assume a load factor of 35% on the Western Isles, and 49% on Shetland/Orkney, consistent with the Redpoint modelling assumptions (see below). On the Scottish Islands, unlike other onshore development zones, we assume no further variation in load factors within these two development zones.

A.3.3.1.3. Comparison with National Grid/Redpoint

Table A.2 shows the distribution of onshore load factors we observe in the Ofgem dataset (on which we base our modelling assumptions), as compared to the National Grid/Redpoint modelling assumptions shown in Table A.2, which have no within-region variation. The tables show that the National Grid/Redpoint approach materially understates the variation in load factors seen in reality.[55] This shortcoming, sometimes referred to as "aggregation bias", is likely to bias the sensitivity of wind investment decisions identified by National Grid/Redpoint. The NERA/Imperial modelling work does not suffer from this shortcoming.

[55] The same problem applies to offshore wind, where our analysis of wind intensity data suggests substantially more variation in wind load factors is likely than National Grid/Redpoint assume.

Table A.2
National Grid/Redpoint Load Factor Assumptions

NG/Redpoint Assumed Onshore Load Factors

Type	*Location*	*Load Factor*
Onshore Wind	Orkney and Shetland Isles	45.0%
Onshore Wind	Western Isles	35.0%
Onshore Wind	North Scotland	29.0%
Onshore Wind	South Scotland	28.0%
Onshore Wind	England	26.0%
Onshore Wind	Wales	27.0%
Offshore Wind	All Zones	37.6%

Source: Redpoint. Modelling the Impact of Transmission Charging Options. December 2011.

We note that the LCP report "Quality Assurance of CMP213 Modelling", did not pick up this problem. With reference to the assumed wind load factors, it simply states, that "Assumptions appear reasonable".[56] However, LCP does not elaborate on the standard by which it considers the assumptions to be reasonable, or present any evidence to support this conclusion.

A.3.3.2. Costs

We take cost estimates for onshore wind construction and operating costs from DECC's electricity generation costs report (December 2013).[57] DECC differentiates between onshore, offshore Round 2 and offshore Round 3 technology types and reports the costs associated with pre-development, construction and operational (split between fixed and variable) stages of a project as well as insurance costs. We use DECC's "medium" cost scenario. For onshore wind farms commissioning in 2016, this means we use a capital cost of £1,600/kW, and an annual O&M cost of £40.1/kW. To this we add a variable operational cost of £5/MWh.[58] In line with DECC's projections we assume that costs decrease over time, in real terms. Projects commissioning in 2020 – the last year for which DECC reports costs – have a levelised cost 5% below that of projects commissioning in 2016. Beyond 2020 we assume no further decrease in the levelised cost of onshore wind farms that come online.

We annualise upfront construction costs using an assumed weighted average cost of capital (WACC), which is based on NERA's analysis for DECC on the required hurdle rates under the new CfD FIT regime. DECC sets out its assumptions on the WACC for each technology in its recent report on electricity generation costs.[59] This results in a real pre-tax WACC for onshore wind of 7.1%. NERA's analysis for DECC was specifically focused on the cost of

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56 Quality Assurance of CMP213 Modelling 2014, LCP, page 31.

57 DECC. Electricity Generation Costs Report December 2013. p54

58 All cost estimates are in 2012 prices.

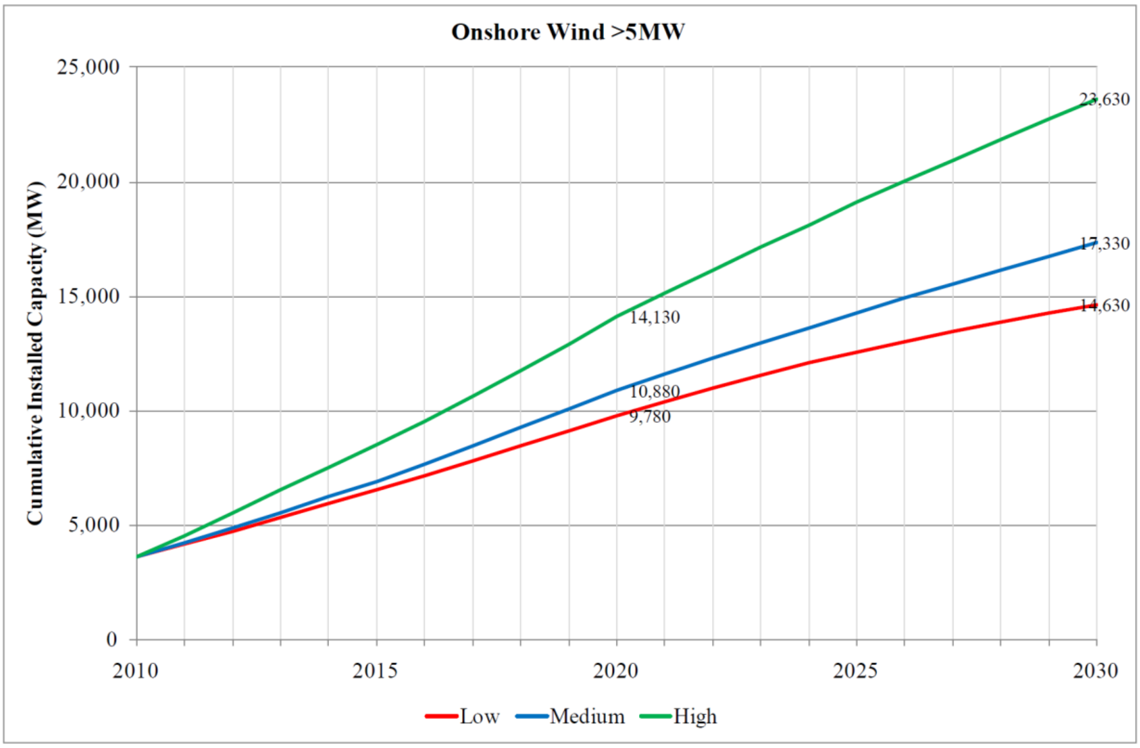
59 DECC. Electricity Generation Costs Report December 2013. p45

capital under the new CfD FIT payments and is therefore directly applicable to new wind projects that will be subsidised under this regime.[60]

A.3.3.3. National build rates and resource potential

The Arup report for DECC also provides estimates of the UK's onshore wind resource potential out to 2030. We adopt Arup's medium scenario to define caps on the total onshore wind resource in our modelling. Hence, by 2020 our model is able to develop up to 10,880 MW of onshore wind capacity, which rises to 17,330 MW by 2030, as Figure A.1 illustrates.

Figure A.1
Arup Onshore Resource Potential Estimates



Source: Arup (2011), Figure 9.

We split this total UK onshore resource potential between England, Scotland, Wales and Northern Ireland, based on Arup's projections. Within each of these regions, our division of resource potential between transmission zones is based on the data from SKM (2008) shown in Figure A.2. In order to allow sufficient flexibility for the model to choose projects in the different regions we calibrate regional caps to Arup's high onshore wind scenario, although we maintain the medium scenario resource cap for the aggregated deployment of onshore wind across Great Britain.

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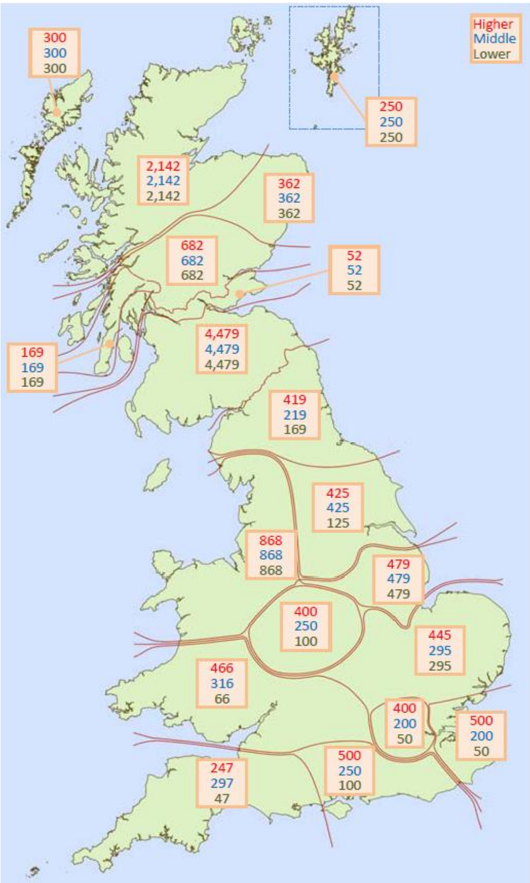
60 NERA. Changes in Hurdle Rates for Low Carbon Generation Technologies due to the Shift from the UK Renewables Obligation to a Contracts for Difference Regime. December 2013.

Figure A.2
Wind Resource by Region



Source: SKM (2008)[61]

In addition to applying a cap on the total level of investment in each transmission zone we also impose constraints on the earliest build date for new projects. For capacity on the mainland we assume that new projects come online from the start of 2016. For the Westland Isles we assume an earliest available online date of 2017 and for the Shetlands the earliest online date is set as 2018.[62]

[61] Growth Scenarios For UK Renewables Generation And Implications For Future Developments And Operation Of Electricity Networks, BERR Publication URN 08/1021, SKM, June 2008. Figure 4.2.

[62] Based on National Grid 2013 Electricity 10 Year Statement. November 2013.

A.3.4. Offshore Wind

A.3.4.1. Costs

A.3.4.1.1. Turbine, tower and foundations costs

The costs of developing offshore wind turbines fall into the following main categories:

- Infrastructure and grid connection costs;
- The cost of turbines and towers;
- Foundations costs; and
- Licensing and planning costs.

Having conducted a review of published literature on the costs of developing new wind generation capacity and through our discussions with RWE, we understand that the costs of turbines and towers and licensing and planning do not differ significantly with the distance from shore or the depth of the seabed. However, foundations costs depend mainly on seabed depth, and infrastructure and grid connection costs depend largely on distance from shore.

As per the treatment of onshore wind, we take cost information from DECC (2013), based on its "medium" cost estimates. We use different cost estimates for Round 2 and Round 3 offshore wind farms. Offshore wind developments in Scottish Territorial Waters are assumed to have similar costs to Round 2 sites. For Round 2 offshore wind farms commissioning in 2016, this means we use a capital cost of £2,570/kW, and an annual O&M cost of £74.3/kW. To this we add a variable operational cost of £2/MWh. For Round 3 offshore wind farms commissioning in 2016, we use a capital cost of £2,705/kW, an annual O&M cost of £103.7/kW and no additional variable operational cost.[63] In line with DECC's projections we assume that costs decrease over time, in real terms. Round 2 (3) projects commissioning in 2020 – the last year for which DECC reports costs – have a levelised cost 9 (10)% below that of projects commissioning in 2016. Beyond 2020 we assume that the levelised cost of offshore wind farms coming online (both Round 2 and 3, as well as those in Scottish Territorial Waters) decreases by 1% per year to 2025 and then by 0.5% per year between 2026 and 2030.

Because the Round 1 and Round 2 sites are all relatively close to shore, and hence we assumed they are all in areas with a relatively shallow seabed, we do not make any further adjustments to DECC's cost estimates of turbine, tower and foundations costs. However, the depth and distance from shore of the Round 3 sites differ considerably across the various proposed developments.

Therefore, we adjust construction costs by £9/kW/metre of seabed depth either above or below this level, corresponding to the slopes of the lines in Figure A.3.[64]

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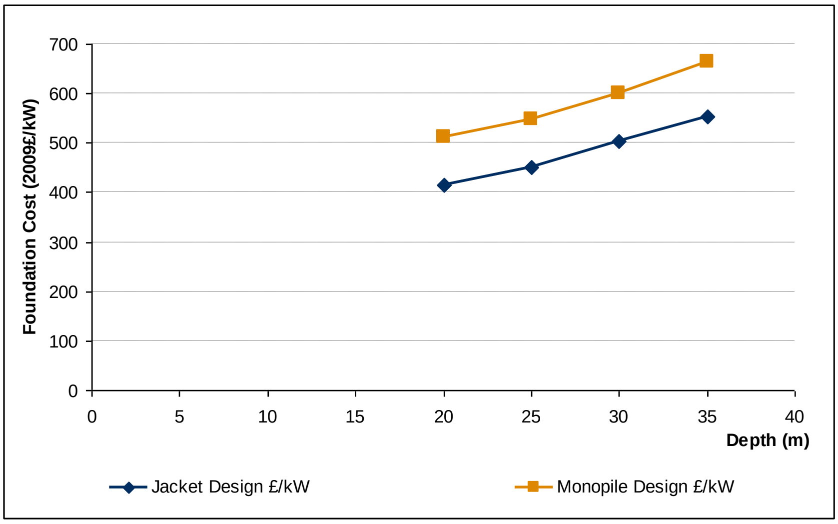
[63] All cost estimates are in 2012 prices.

[64] Calculated on the basis of foundation costs by Ramboll (2009) for "jacket and monopole" foundations.

Figure A.3
Seabed Depth vs. Foundation Cost



Source: NERA/Imperial Analysis of data from Ramboll[65]

We recognise some statements from the wind generation industry that indicate costs may increase substantially when developing offshore wind sites in water depths beyond 30 metres, and that beyond a certain water depth, it may become more efficient to build floating wind turbines, rather than turbines with fixed foundations. For instance, the British Wind Energy Association states on its website that:[66]

> *"Although it is possible to build structures in water deeper than 30 m (for example the oil platforms in the North Sea), it is very expensive and is not economically viable at present for offshore wind turbines.*
>
> *Wind speeds tend to increase as you move offshore. This means that turbines built further offshore should capture more wind energy. Unfortunately, as the distance to land increases, the cost of building and maintaining the turbines and transmitting the power back to shore also increase sharply, limiting the distance out to sea at which offshore wind projects will be built."*

However, at present we do not have any firm evidence regarding the scale of the cost increase that occurs beyond 30 metres, and in particular, we have no firm evidence that the cost increase (as a function of water depth) is more than the £9/kW/metre we use for our modelling. For example, a study by the "SEAWIND – Altener project" assumes that the cost increase per metre of incremental water depth is 2%, both in waters shallower than or deeper

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65 Kriegers Flak Offshore Wind Farm, Jacket and Monopile Foundation Study 2008-2009, March 2009.

66 http://www.bwea.com/offshore/faqs.html#limit

than 30 metres.[67] Hence, this study does not contradict our assumption that there is no step-change in costs beyond 30 metres of depth.

A.3.4.1.2. Infrastructure costs

Our infrastructure investment cost assumptions for offshore wind projects, which define the local asset charges each offshore wind site pays, are set out in Table A.3 below. These are based on Redpoint estimates from its December 2011 modelling report.

Table A.3
Offshore Transmission Investment Costs

Site	Tariff (£/kW/year)	Site	Tariff (£/kW/year)
Docking Shoal	43	Moray Firth	61
Race Bank	101	Norfolk Bank	62
Humber Gateway	88	West of Isle of Wight	36.34
Triton Knoll	54	Argyll Array	29.05
Westermost Rough	33	Beatrice	37.1
Dudgeon	34	Forth Array	42.1
London Array II	59	Inch Cape	37.91
Gwynt y Mor	64	Islay	16.1
West of Duddon Sands	80	Kintyre	4
Bristol Channel	38.84	Neart na Gaoithe	61
Dogger Bank	166	Solway Firth	11.3
Firth of Forth	61		
Hastings	35.24		
Hornsea	95		
Irish Sea	61		

Source: Redpoint. Modelling the Impact of Transmission Charging Options. December 2011. (Table 27)

A.3.4.1.3. Financing costs

As for onshore wind, we annualise upfront construction costs using an assumed weighted average cost of capital, which is based on NERA's analysis for DECC on the required hurdle rates under the new CfD FIT regime. For Round 2 and Scottish Territorial Waters offshore wind projects we apply a real pre-tax WACC of 9.7%. For Round 3 projects, the WACC is slightly higher at 10.1%.[68]

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67 Offshore Wind Energy Projects Feasibility Study Guidelines, SEAWIND - Altener Project 4.1030/Z/01-103/2001, Per Nielsen, EMD Ver. 3.0 June 2003, page 10.

68 DECC. Electricity Generation Costs Report December 2013. p45

A.3.4.2. Build rates and resource potential

For each potential offshore wind project we take the earliest available online date from a report by Renewable UK on offshore wind project timelines.[69] We have verified these dates, and supplemented them in certain instances, with additional information from the relevant websites of project developers.

We also use information in the Renewable UK report to inform our cap on capacity at each of the different offshore wind locations. We do not apply a specific additional constraint on the rate of deployment of offshore wind projects, although in practice staggered deployment is effectively achieved through the different earliest available online dates, with some projects not expected to be fully operational until the early 2020s.

A.3.4.3. Load Factors

Our approach to defining locational load factor assumptions for offshore wind farms uses wind speed data from the "wind atlas" and a mathematical relationship between average wind speed and expected load factors:

- We estimated a mathematical relationship between the average load factor of offshore wind sites and the "wind intensity" of a site using data from the Carbon Trust (2008);[70]
- To estimate the average annual load factors of offshore sites throughout the UK, we take wind speed data from the "wind atlas", convert these into "wind intensity", and use the above relationship to estimate average annual load factors by site; and
- We calibrated the function we use to convert wind speed to load factor to ensure that on average, wind sites achieve a load factor of 37.7%, based on the Arup (2011) assumption.[71]

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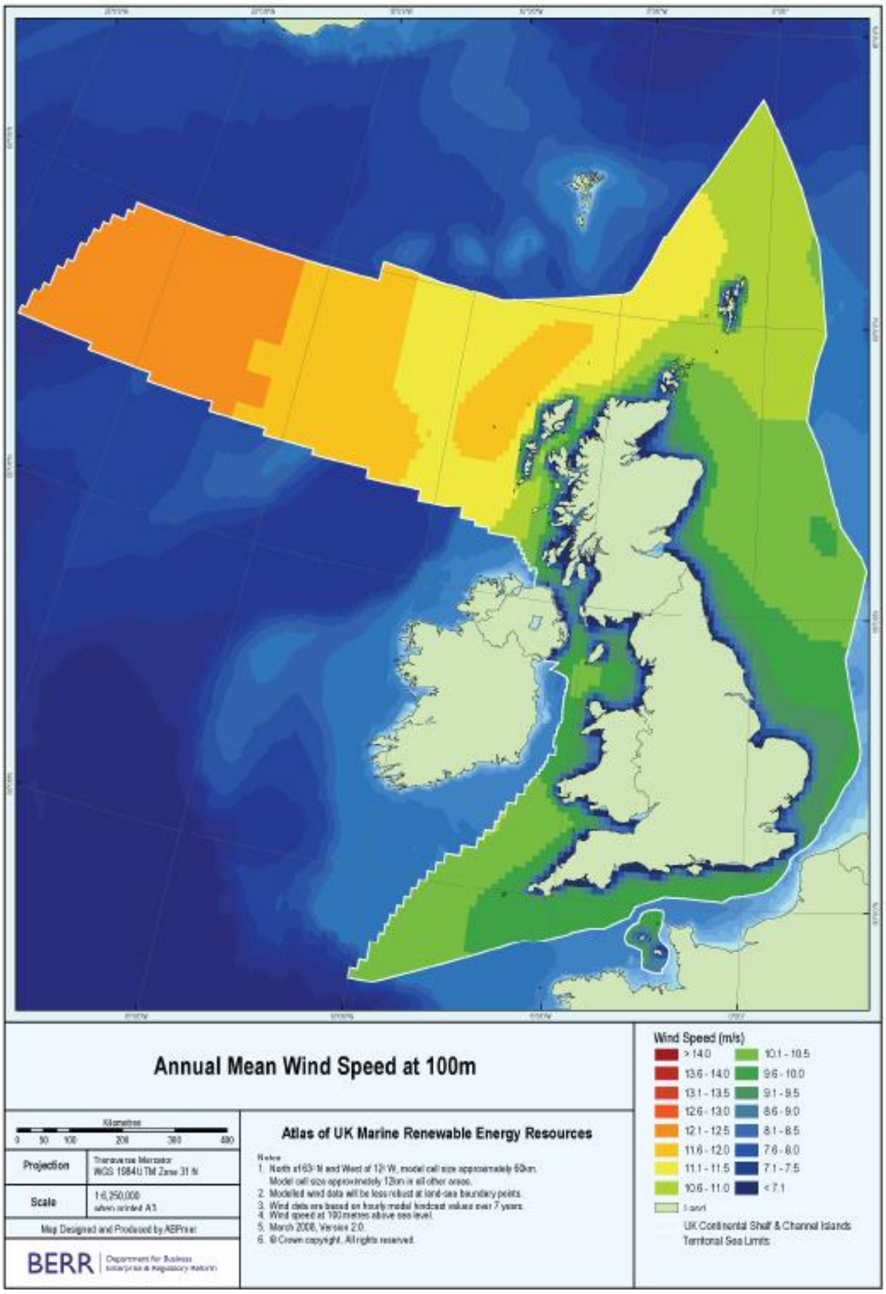
[69] Renewable UK. Offshore Wind Project Timelines 2013. June 2013.

[70] Offshore wind power: big challenge, big opportunity - Maximising the environmental, economic and security benefits, the Carbon Trust, 2008, Chart A1.

[71] Arup (2011), Appendix F.

Figure A.4
GB Wind Speed Atlas



Source: The Renewables Atlas (2008)[72]

72 http://www.renewables-atlas.info/downloads/documents/Renewable_Atlas_Pages_A4_April08.pdf

Table A.4
Median Load Factors for Offshore Development Zones

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 Analysis

A.4. Renewables Subsidies

Existing renewable capacity is supported under the Renewables Obligation (RO) scheme. We have developed a renewables model that is broken down by technology as well as the year in which capacity comes online; its *vintage*. We forecast the value of a ROC in each year by taking the current ROC buyout price – the price an energy supplier is required to pay per MWh as a penalty if it submits an insufficient number of ROCs relative to its obligation – and uplifting it by 10%. This value increases each year in line with the RPI measure of inflation, which we have projected forward based on the existing trend in this index. By applying the ROC banding awarded to each vintage of each technology we estimate the total subsidy cost of existing generation, assuming RO support continues for 20 years, as set out in current policy.

In the period between April 2014 and March 2017 renewable generators have the option of electing to receive support via the RO scheme or under the new CfD FIT scheme. We assume that all new capacity coming online in 2014 and 2015 elects to receive support under the existing RO regime. In 2016 and the first quarter of 2017, half of new capacity elects to receive support under the RO and the other half under the CfD FIT regime. From April 2017 onwards all support is assumed to be provided through CfD FITs.

Our estimates of support under the CfD FIT scheme are calculated by assuming that all technologies, with the exception of new wind projects which are selected via the wind project selection tool, receive the maximum CfD strike price published by DECC in December 2013.[73] These strike prices are either maintained or decrease over time. For the horizon beyond which DECC has published maximum strike prices, we forecast the levels of support that will be provided by continuing the observed trend forward. The total support is then calculated by subtracting either the projected baseload or intermittent power price (dependent on the technology) from the assumed strike price. Support for projects under the CfD regime is provided for 15 years, after which the project receives the prevailing market price and no additional government support.

The estimated support provided to new wind projects, whose deployment is modelled in the wind project selection tool, is then added to this to provide a forecast for the total cost of renewable electricity support in each year. This total cost is compared relative to the budget set out in the Levy Control Framework. It is also fed into the cost benefit analysis, which assesses the overall welfare impact of the different TNUoS charging scenarios.

A.5. TNUoS Charges

Our wind investment model takes TNUoS charges from the most recent iteration of our transmission system model. These charges are updated with every iteration of our power market and transmission system models. Our final wind investment forecasts are those which result from the set of converged TNUoS charges, which are set out in Appendix C.

A.6. Wholesale Power Prices

We assume that each new wind farm in the model receives a subsidy payment as a top-up to the power price received by intermittent generators. New non-intermittent renewable technologies, such as biomass, receive a subsidy payment as a top-up to the prevailing baseload power price. This replicates how support will be provided to new capacity under the CfD FIT regime. Power prices are taken from our Aurora model.

[73] DECC. Investing in renewable technologies – CfD contract terms ansd strike prices. December 2013.

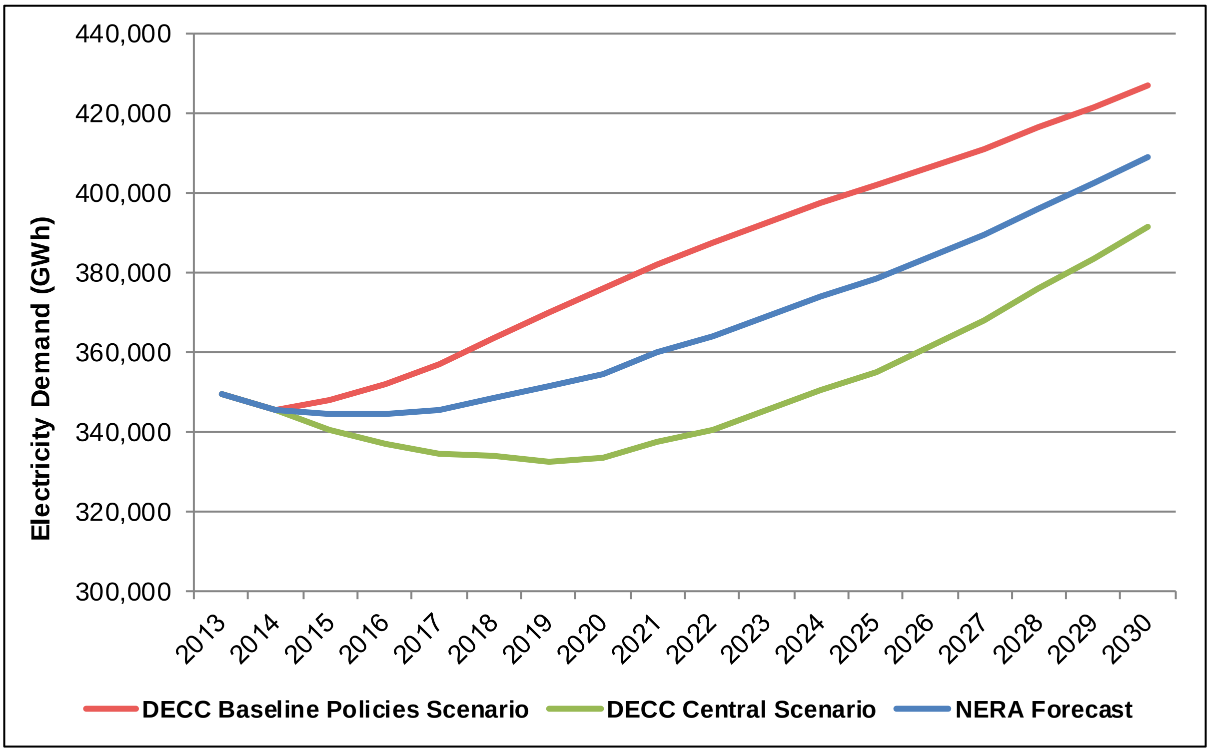
Appendix B. Other Generation Modelling Assumptions

B.1. Demand Assumptions

Figure B.1 sets out our demand forecast. As noted in Section 2.2.2, we adopt the average of DECC's "Baseline Policies" and "Central" scenarios for our baseline domestic consumption forecast (excluding electric vehicles and heat pumps), and add to this the average of the heat pump and electric vehicles projections from "Gone Green" and "Slow Progression" scenarios from National Grid's Future Energy Scenarios.

Our baseline peak demand forecast is constructed by applying the growth rates of our annual demand forecast to the National Grid's 2013 ACS peak demand estimate of 60GW, from its 2013 Winter Outlook report.

Figure B.1
GB Demand Forecast (GWh)

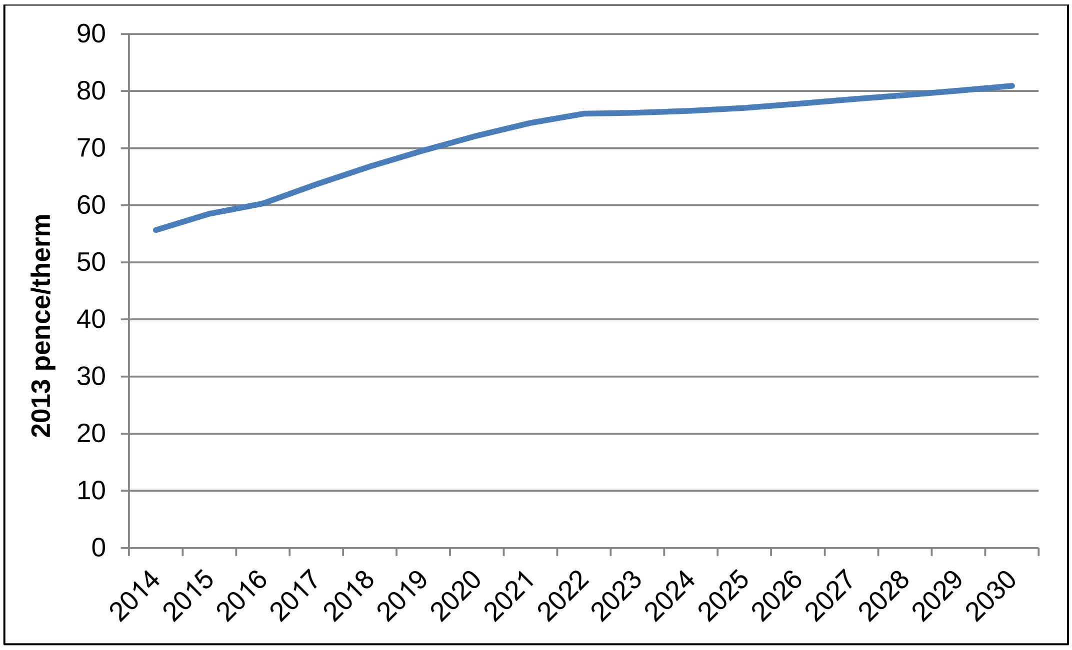


Source: NERA/Imperial

B.2. Fuel Price Forecasts

This section sets our fuel price projections. As noted in Section 2.2.2, our our gas, oil, coal and EU ETS carbon price forecasts are based on forward prices as of 31st March 2014 followed by interpolation to the IEA "New Policies" scenario from the 2013 World Energy Outlook (WEO). We derive our HFO and gasoil prices from our oil price forecasts, using a regression technique. We construct our UK carbon price forecast up to 2017 by adding the confirmed Carbon Price Support (CPS) rates to EU ETS price forecasts. From 2018 onwards, we assume that the CPS rate remains capped at £18 per tonne, in line with recent government announcements.[74]

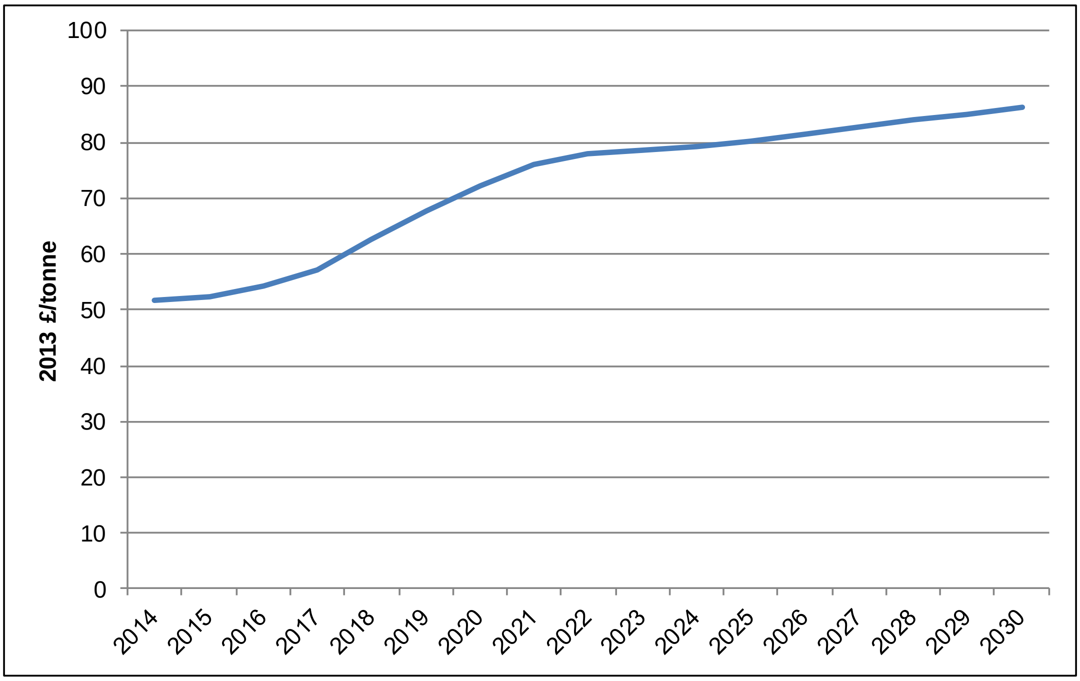
Figure B.2
Gas Price Forecast (Real 2013 pence/therm)



Source: NERA/Imperial

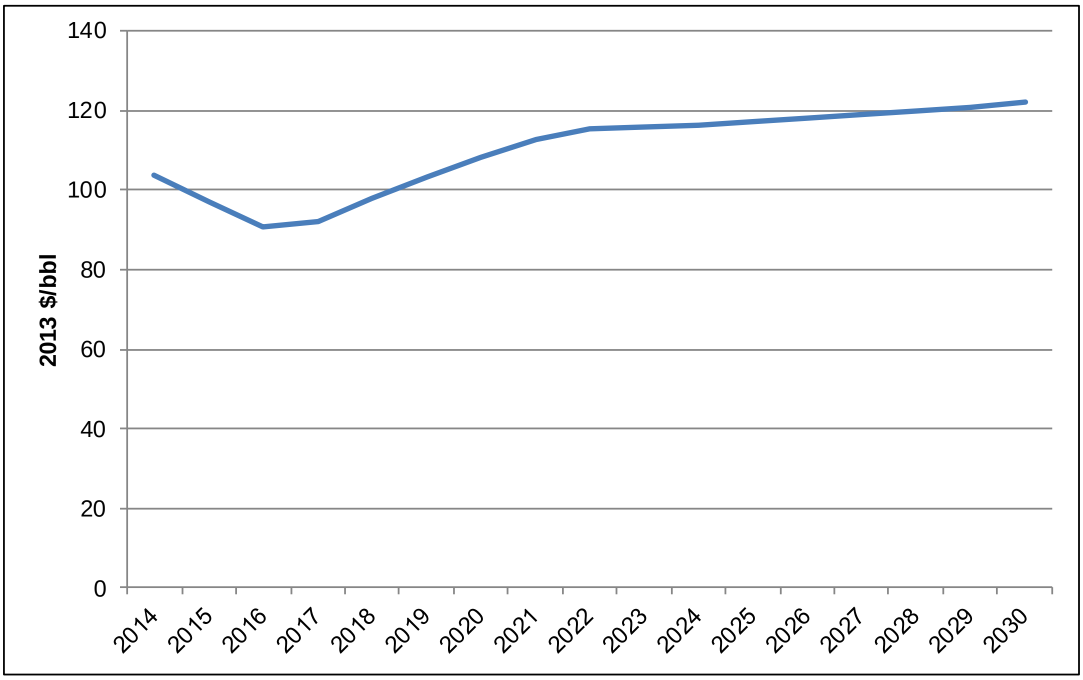
[74] The government announced as part of its 2014 budget that the CPS rate would be capped at £18 per tonne until 2020. As the government has given no clear indication of what will happen after 2020, we assume that the cap remains in place for the remainder of the modelling horizon.

Figure B.3
Coal Price Forecast (Real 2013 £/tonne)



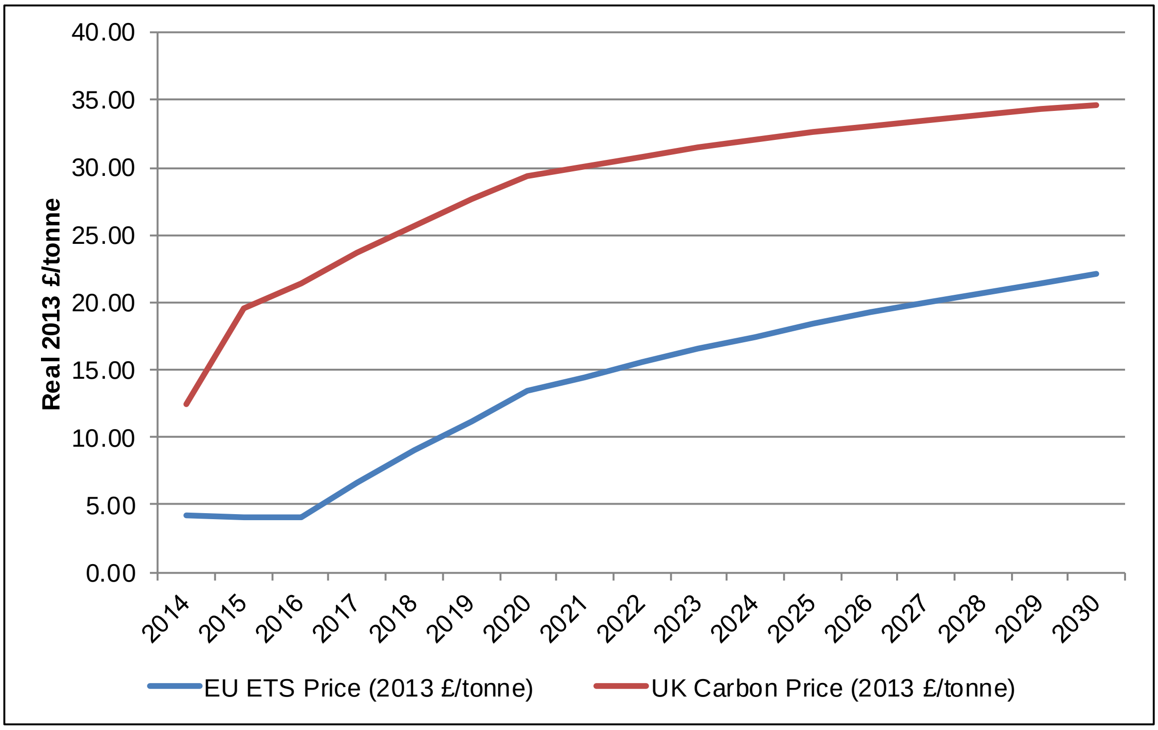
Source: NERA/Imperial

Figure B.4
Brent Crude Forecast (Real 2013 $/bbl)



Source: NERA/Imperial

Figure B.5
Carbon Price Forecast (Real 2013 £/tonne)



Source: NERA/Imperial

Appendix C. Modelled TNUoS Charges

Table C.1
WACM 2 TNUoS Charge - Year-Round Shared Component (2010 £/kW/yr)

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
North Scotland	14.10	15.26	13.92	16.43	16.31	16.36	15.28	14.83	14.74	13.99	15.73	11.37	10.42	9.90	10.84	9.89	11.98
Peterhead	11.11	11.98	10.89	17.15	16.31	16.36	15.28	14.83	14.74	13.99	15.73	11.37	10.42	9.90	10.84	9.89	10.30
Western Highland & Skye	12.42	13.33	12.11	16.43	16.31	16.36	15.28	14.83	14.74	13.99	15.73	11.37	10.42	9.90	10.84	9.89	11.98
Central Highlands	12.42	13.33	12.11	16.43	16.31	16.36	15.28	14.83	14.74	13.99	15.73	11.37	10.42	9.90	10.84	9.89	11.98
Argyll	10.12	11.67	10.97	15.78	17.20	17.53	16.22	15.65	15.79	14.79	16.62	13.67	13.16	12.58	13.67	12.36	13.82
Stirlingshire	9.98	10.67	9.88	15.39	16.31	16.36	15.28	14.83	14.74	13.99	15.73	11.37	10.42	9.90	10.84	9.89	11.43
South Scotland	9.39	10.06	9.63	13.55	13.95	14.09	13.25	13.11	12.91	12.79	13.89	11.04	10.12	9.65	10.52	9.64	10.88
Auchencrosh	11.69	12.29	11.82	16.99	18.57	18.76	17.27	16.55	16.38	15.34	17.65	14.43	13.40	12.74	14.00	12.77	14.05
Humber & Lancashire	0.74	0.98	0.69	0.30	0.97	2.38	2.17	1.69	2.10	1.88	1.52	1.00	0.97	1.42	2.32	2.79	2.35
North East England	2.08	1.21	0.91	0.64	1.31	2.66	2.52	1.93	2.57	2.32	4.25	3.67	3.62	3.88	6.11	5.38	5.15
Anglesey	0.08	0.41	0.01	-1.22	-0.97	-0.38	-0.45	-0.46	-0.13	-0.03	-0.61	-0.60	-0.47	-0.06	0.25	0.50	0.09
Dinorwig	0.38	1.47	-0.31	-3.05	-2.64	-1.47	-1.71	-1.77	-1.24	-0.82	-0.95	-0.43	-0.28	0.22	1.26	1.45	1.21
South Yorks & North Wales	0.08	0.41	0.01	-1.22	-0.97	-0.38	-0.45	-0.46	-0.13	-0.03	-0.61	-0.60	-0.47	-0.06	0.25	0.50	0.09
Midlands	-0.33	0.50	0.10	-0.47	-0.66	-0.87	-1.11	-1.11	-0.86	-1.02	-1.90	-1.71	-1.62	-0.92	-1.40	-0.95	-1.11
South Wales & Gloucester	-3.22	-3.25	-2.70	-2.90	-4.31	-5.11	-5.14	-4.35	-4.79	-4.04	-4.55	-3.57	-3.60	-4.70	-5.00	-4.68	-5.22
Central London	-3.88	-5.28	-5.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
South East	3.55	3.19	3.66	2.58	3.42	2.04	2.22	2.89	2.39	2.07	2.12	2.07	2.37	2.40	1.87	2.30	2.12
Oxon & South Coast	-2.09	-2.54	-2.24	-2.38	-2.41	-3.26	-3.31	-2.96	-3.41	-3.23	-3.45	-3.27	-3.27	-3.36	-3.76	-3.41	-3.55
Wessex	-2.83	-3.02	-2.61	-2.77	-2.53	-3.45	-3.56	-2.48	-3.94	-3.86	-4.42	-3.17	-3.18	-3.51	-3.90	-3.57	-3.75
Peninsula	-4.52	-4.68	-4.25	-4.25	-6.01	-6.93	-7.01	-6.70	-8.76	-5.69	-7.53	-4.95	-4.97	-5.33	-5.70	-5.42	-6.38

Table C.2
WACM 2 TNUoS Charge - Year-Round Non-Shared Component (2010 £/kW/yr)

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
	3.16	2.71	2.59	6.47	3.58	3.73	5.29	5.57	6.26	6.68	7.78	10.50	10.63	10.60	10.75	9.37	12.44
North Scotland	2.05	1.58	1.41	3.14	0.32	1.33	2.90	3.19	3.70	4.24	5.29	7.86	8.12	8.03	8.26	6.89	10.92
Peterhead	7.63	7.04	6.98	10.28	9.15	9.48	11.07	11.30	12.24	12.63	13.81	16.71	16.88	16.86	17.07	15.59	17.63
Western Highland & Skye	2.05	1.58	1.41	3.14	3.52	3.99	5.58	5.33	5.71	6.50	7.99	10.79	11.39	11.06	11.53	10.33	10.92
Central Highlands	0.36	0.04	0.00	0.66	0.25	0.47	1.98	2.51	3.05	3.53	5.96	8.70	9.06	9.04	9.12	7.98	8.57
Argyll	0.36	0.04	0.00	0.66	0.61	0.95	2.45	2.72	3.37	3.74	4.88	8.75	9.00	8.86	9.14	7.67	8.16
Stirlingshire	0.36	0.04	0.00	0.66	0.25	0.47	1.98	2.51	3.05	3.53	4.54	7.33	7.49	7.52	7.49	6.37	6.82
South Scotland	0.36	0.04	0.00	0.66	0.25	0.47	1.98	2.51	3.05	3.53	4.54	7.33	7.49	7.52	7.49	6.37	6.82
Auchencrosh	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Humber & Lancashire	1.02	2.24	2.13	3.40	3.40	2.74	3.46	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
North East England	1.04	-0.41	-0.32	-1.83	-1.68	-1.09	-1.25	-1.32	-1.11	-0.79	-0.34	0.17	0.19	0.28	1.01	0.95	1.12
Anglesey	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Dinorwig	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
South Yorks & North Wales	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Midlands	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
South Wales & Gloucester	0.00	0.00	0.00	-3.59	-2.22	-3.38	-5.35	-6.17	-5.53	-4.28	-4.81	-5.31	-6.73	-5.68	-7.35	-9.06	-9.22
Central London	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
South East	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Oxon & South Coast	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Wessex	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Table C.3
WACM 2 TNUoS Charge – Peak Security Component (2010 £/kW/yr)

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
North Scotland	3.24	3.26	2.41	2.87	-2.10	-3.96	-3.24	-4.96	-5.50	-5.46	-3.56	-8.94	-8.68	-8.81	-8.41	-9.94	-4.32
Peterhead	4.28	4.26	3.47	3.56	-4.28	-5.81	-5.12	-6.69	-7.33	-7.14	-5.47	-10.67	-10.63	-10.67	-10.14	-11.78	-2.95
Western Highland & Skye	3.04	2.75	2.15	3.10	-1.31	-3.20	-2.58	-4.32	-4.83	-4.68	-2.98	-8.22	-7.96	-8.07	-7.80	-9.23	-4.31
Central Highlands	3.30	3.13	3.27	4.47	1.38	-0.48	-0.43	-2.56	-2.81	-2.72	-1.44	-6.53	-6.00	-6.41	-5.73	-7.80	-4.72
Argyll	4.73	4.04	4.31	4.95	2.27	0.23	0.90	0.11	-0.35	-0.16	0.70	-4.43	-4.43	-4.52	-4.15	-5.92	-3.22
Stirlingshire	4.29	4.37	3.96	4.53	2.08	0.26	0.93	-0.30	-0.73	-0.60	1.13	-2.59	-2.79	-3.09	-2.51	-4.29	-1.56
South Scotland	3.56	3.67	3.94	5.09	3.47	1.88	3.56	1.47	1.06	0.15	3.59	1.98	-3.78	-0.33	-3.35	-5.75	-3.09
Auchencrosh	3.09	2.79	3.06	4.92	2.76	0.86	1.29	-0.04	-0.42	0.17	1.42	-2.37	-2.49	-2.57	-2.20	-3.89	-1.52
Humber & Lancashire	4.34	4.16	4.40	4.95	4.35	3.62	3.51	3.75	3.35	3.16	3.94	4.27	4.27	3.82	3.25	3.23	3.26
North East England	4.04	4.21	4.15	5.05	4.06	2.83	3.37	0.61	0.20	-0.05	4.35	3.31	3.28	2.93	3.04	3.12	3.23
Anglesey	5.15	0.00	6.06	6.93	5.77	5.20	4.97	4.78	4.26	3.62	3.92	1.86	1.80	1.47	1.19	2.00	1.79
Dinorwig	5.15	4.13	6.07	6.93	5.77	5.20	4.98	4.78	4.26	3.62	3.92	1.87	1.80	1.47	1.19	2.00	1.79
South Yorks & North Wales	3.30	2.96	3.26	3.54	3.62	3.29	3.22	3.46	3.13	2.80	3.32	2.81	2.79	2.36	2.20	2.64	2.65
Midlands	1.09	0.25	0.73	0.31	1.00	1.33	1.33	1.52	1.22	0.99	2.32	2.63	2.65	2.16	1.82	1.91	1.69
South Wales & Gloucester	4.32	5.01	4.47	4.66	4.84	5.57	5.36	5.23	5.56	6.35	5.87	5.45	5.34	6.01	5.99	6.31	5.45
Central London	-5.24	-4.02	-5.42	3.12	-13.53	1.14	-8.39	-8.73	-5.90	5.72	-14.49	-4.97	-0.87	-5.16	-0.58	1.91	1.57
South East	-4.36	-4.12	-4.63	-5.60	-3.90	-2.37	-2.57	-1.97	-1.74	-2.10	-3.51	-1.65	-1.37	-1.13	-1.16	-1.41	-1.74
Oxon & South Coast	-2.14	-1.96	-2.31	-2.43	-1.97	-1.15	-1.26	-0.78	-0.31	-0.16	-1.43	0.29	0.24	0.31	0.37	0.32	-0.05
Wessex	-2.46	-1.82	-2.23	-2.20	-2.81	-1.93	-2.00	-0.97	0.51	1.83	-0.28	2.41	2.30	2.66	2.66	2.61	2.02
Peninsula	-1.41	-0.70	-1.13	-1.25	-1.69	-0.67	-0.74	-0.69	1.43	3.84	0.69	3.99	3.88	4.26	4.26	4.31	3.09

Table C.4
WACM 2 TNUoS Charge – Residual Component (2010 £/kW/yr)

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Residual	2.62	2.33	1.47	1.10	0.96	0.36	-0.36	-0.16	-0.29	-0.45	-1.02	-0.68	-0.70	-0.98	-1.21	-1.34	-1.77

Table C.5
Status Quo TNUoS Charge (2010 £/kW/yr)

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
North Scotland	23.12	23.59	20.93	27.52	28.76	26.67	26.55	28.18	28.57	28.36	29.27	31.27	29.60	28.21	28.33	27.35	27.54
Peterhead	19.86	20.34	17.70	22.81	25.09	24.66	23.16	24.77	25.05	24.95	25.91	27.71	26.21	24.58	24.83	23.87	24.05
Western Highland & Skye	25.26	25.19	23.48	31.91	33.95	32.01	31.89	33.52	33.92	33.70	34.38	36.75	34.95	33.79	33.92	32.92	33.10
Central Highlands	19.87	20.28	18.47	25.43	27.18	25.14	24.91	26.56	26.91	26.80	27.68	30.39	28.36	26.71	27.03	25.98	26.12
Argyll	16.98	16.84	16.51	22.42	23.66	21.52	20.94	22.71	23.13	22.65	24.97	29.42	28.57	26.92	27.13	25.92	26.01
Stirlingshire	16.42	16.18	14.99	21.70	22.42	20.31	20.28	21.83	22.24	22.14	23.33	24.67	23.44	21.97	22.13	21.28	21.46
South Scotland	15.03	14.81	13.86	19.96	18.87	16.83	17.83	19.80	20.05	20.55	22.28	24.36	22.93	21.66	21.65	20.85	21.20
Auchencrosh	16.81	16.20	15.38	23.41	23.74	21.49	20.67	22.10	22.31	22.54	24.57	28.18	26.48	24.72	24.99	24.08	24.27
Humber & Lancashire	6.80	6.39	5.60	5.43	5.01	4.83	3.69	3.32	3.07	2.88	2.52	2.89	2.71	2.49	2.36	3.11	2.35
North East England	9.00	8.83	7.75	9.40	8.93	7.72	8.58	6.93	6.86	6.85	6.91	7.16	6.49	6.07	7.35	6.79	6.74
Anglesey	8.23	4.64	5.96	3.61	2.38	2.20	1.04	1.15	0.92	0.53	-0.54	-0.93	-0.28	-0.17	-0.55	-1.02	-1.24
Dinorwig	7.49	6.91	6.17	3.82	2.58	2.40	1.25	1.17	0.92	0.53	-0.53	-0.93	-0.28	-0.17	-0.55	-1.02	-1.24
South Yorks & North Wales	4.81	4.27	3.53	2.31	1.67	1.09	0.05	0.04	-0.22	-0.61	-1.12	-1.10	-0.81	-0.79	-1.34	-1.67	-1.90
Midlands	2.39	1.85	1.09	0.09	-0.57	-1.23	-2.40	-2.54	-2.89	-3.22	-3.03	-2.69	-2.60	-2.66	-3.15	-3.35	-3.57
South Wales & Gloucester	2.85	2.39	1.64	1.19	-0.39	-1.05	-2.29	-2.22	-2.65	-1.87	-2.16	-2.08	-2.12	-2.56	-3.14	-3.71	-4.78
Central London	-7.11	-7.73	-9.76	-7.70	-14.96	-9.64	-16.49	-16.48	-14.88	-11.02	-21.46	-14.23	-11.04	-14.66	-11.78	-12.32	-11.87
South East	1.00	0.29	-0.46	-1.57	-1.48	-2.50	-3.44	-3.38	-3.83	-4.36	-4.98	-3.34	-3.40	-3.51	-4.19	-4.54	-4.86
Oxon & South Coast	-2.05	-2.63	-3.43	-4.72	-4.80	-6.00	-7.02	-6.77	-7.20	-7.85	-7.74	-6.54	-6.62	-7.13	-7.70	-8.13	-8.42
Wessex	-3.47	-4.54	-5.30	-5.85	-4.79	-7.20	-8.00	-7.65	-8.06	-8.24	-7.68	-4.26	-4.41	-4.78	-5.36	-6.02	-6.60
Peninsula	-6.68	-6.38	-7.13	-6.22	-8.66	-9.39	-12.51	-12.28	-12.67	-10.36	-11.24	-6.08	-6.23	-6.59	-5.69	-6.39	-6.92

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