NERA
ECONOMIC CONSULTING

Imperial College
London

Project TransmiT: Modelling the Impact of the WACM 2 Charging Model

Prepared for RWE npower

9 October 2013

NERA Project Team

Sean Gammons
Richard Druce
Vakhtang Kvekvetsia
Robin Brejnholt
Peter Davies

Imperial College Project Team

Professor Goran Strbac
Christos Konstantinidis
Danny Pudjianto
Rodrigo Moreno

NERA Economic Consulting
15 Stratford Place
London W1C 1BE
United Kingdom
Tel: 44 20 7659 8500 Fax: 44 20 7659 8501
www.nera.com

Contents

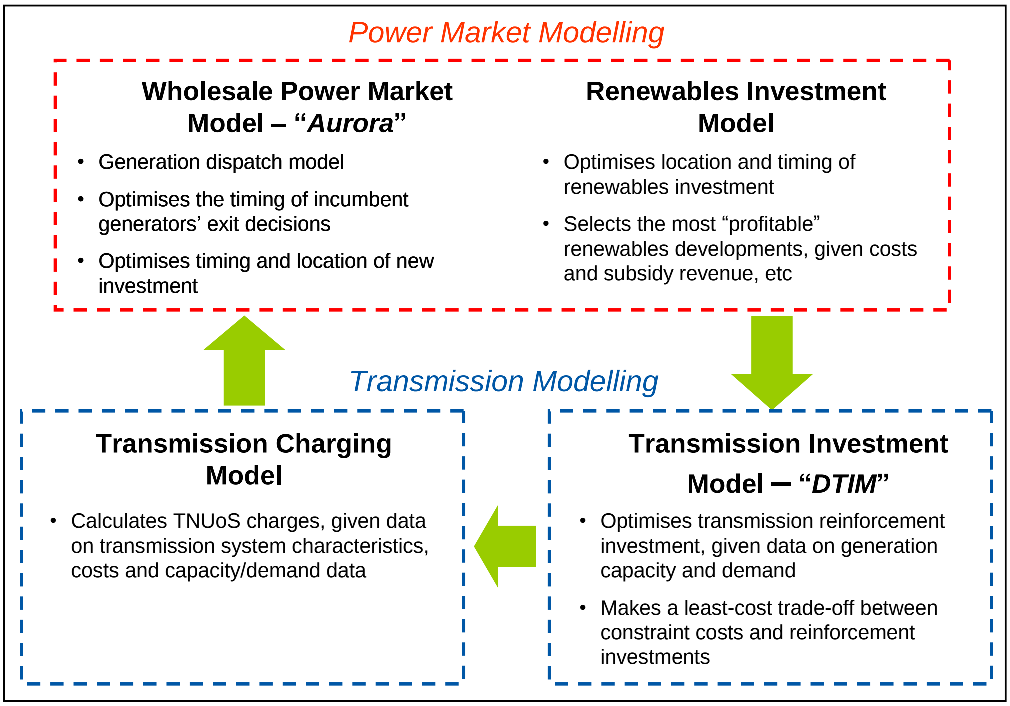
Executive Summary

Our Assignment

NERA Economic Consulting and Imperial College London have been commissioned by RWE npower to model the impact of Ofgem's recent "minded to" decision to reform the British Transmission Network Use of System (TNUoS) Charging Methodology. Specifically, we have been commissioned to compare the "status quo" methodology, with the proposed "WACM 2" methodology that Ofgem indicated it is "minded to" implement in its recent Impact Assessment.[1]

To make this comparison, we have used the same power market and transmission system modelling framework, as summarised in Figure 1, that we developed for studies performed in 2011 and 2012 comparing the "status quo" charging model with a uniform transmission charging model and the "improved ICRP" charging model.[2]

Figure 1
Overview of Modelling Framework



Source: NERA/Imperial Analysis

---

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

2 (1) Project TransmiT: Impact of Uniform Generation TNUoS: Prepared for RWE npower, NERA Economic Consulting and Imperial College London, 31 March 2011. (2) Project TransmiT: Modelling the Impact of "Improved ICRP", Prepared for RWE npower, NERA Economic Consulting and Imperial College London, 12 October 2012.

Key Findings

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 (losses, constraints and investment) by £1.7 billion over the period to 2030 and increase other power sector costs (e.g. the costs of developing and operating generation assets) by around £4 billion. Hence, we estimate that WACM 2 would cause a net increase in power sector costs of £5.7 billion. This increase in power sector costs proxies the reduction in overall social welfare caused by WACM 2.

Table 1.1
Effects of Introducing the WACM 2 Charging Model

	2014-2020	2021-2030	Total
Impact on Consumers			
Power Purchase Costs	1,484	233	1,717
Low Carbon Subsidies	821	1,935	2,755
D-TNUoS	412	331	743
Constraints	-49	165	116
Losses	268	422	690
Total	2,936	3,086	6,022
Power Sector Costs			
Generation Costs	1,157	2,890	4,047
Transmission Investment	501	389	890
Constraints	-49	165	116
Losses	268	422	690
Total	1,877	3,866	5,743

Note, a positive number indicates an increasing cost following the introduction of WACM 2. NPVs calculated between 2014 and 2030, using a real discount rate of 3.5%. Source: NERA/Imperial.

We also estimate that the introduction of WACM 2 would materially increase consumers' bills by around £6 billion in NPV terms over the period to 2030. Around £1.5 billion of this impact is due to increases in D-TNUoS, as well as constraint costs and losses, which we assume are passed through directly to consumers. Another £1.7 billion of the effect is down to the increase in power prices resulting from a higher long-run marginal cost of new entry into the wholesale power market. Low carbon subsidy payments also increase by around £2.7 billion.

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 power prices.

By implementing changes to the current transmission charging regime that do not deliver demonstrable improvements in economic efficiency, 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 their effects, 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, thus further increasing consumer bills.

Overall, therefore, the modelling presented in this report does not support the introduction of the WACM 2 model. 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.[3]

[3] See: Project TransmiT: Review of Ofgem Impact Assessment of Industry Proposals CMP213, Prepared for RWE npower, NERA Economic Consulting and Imperial College London, 25 September 2013, Section 2.

1. Introduction

NERA Economic Consulting and Imperial College London have been commissioned by RWE npower to model the impact of Ofgem's recent "minded to" decision to reform the British Transmission Network Use of System (TNUoS) Charging Methodology.[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 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. This finding was consistent with previous modelling work conducted by NERA and Imperial, which found that the socialised charging model would materially reduce social welfare and increase costs to the consumer.[5]

At the same time as rejecting the socialised charging model, Ofgem suggested that "*improved ICRP is the right direction for transmission charging arrangements*".[6] 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*".[7] It therefore initiated a Significant Code Review (SCR). Ofgem directed National Grid to organise an industry Workgroup to draft a

---

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

5 Project TransmiT: Impact of Uniform Generation TNUoS, Prepared for RWE npower, NERA Economic Consulting and Imperial College London, 31 March 2011.

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

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

modification to the Connection and Use of System Code (CUSC), referred to as modification CMP213, to develop the "improved ICRP" methodology.[8]

Following this decision document, NERA and Imperial conducted further modelling work in October 2012 to compare the performance of the status quo and "improved ICRP" charging models. We found that replacing the existing charging model with "improved ICRP" would have little effect on social welfare, but would materially increase wholesale power prices by raising the TNUoS costs incurred by new entrants into the power market that have to be recovered through wholesale prices.[9]

The Workgroup established for the SCR process 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. On 14 June 2013 the CUSC Panel submitted its Final Modification Report (FMR) to Ofgem for its consideration.[10]

On 1st August 2013, Ofgem announced that it is 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).[11] 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).

A stakeholder consultation on the latest proposals is currently underway, following which Ofgem plans to publish a final decision towards the end of this year. This report is intended to feed into this consultation process.

1.2. Report Overview

The remainder of this report is structured as follows:

- Chapter 2 describes our approach to comparing the status quo and WACM 2 charging models;
- Chapter 3 sets out the results of our modelling in terms of generation investment impacts, changes in TNUoS charges, and changes in transmission system costs;
- Chapter 4 presents the results of our cost benefit analysis; and
- Chapter 5 concludes.

---

8 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.

9 Project TransmiT: Modelling the Impact of "Improved ICRP", Prepared for RWE npower, NERA Economic Consulting and Imperial College London, 12 October 2012.

10 Ofgem, para 2.12.

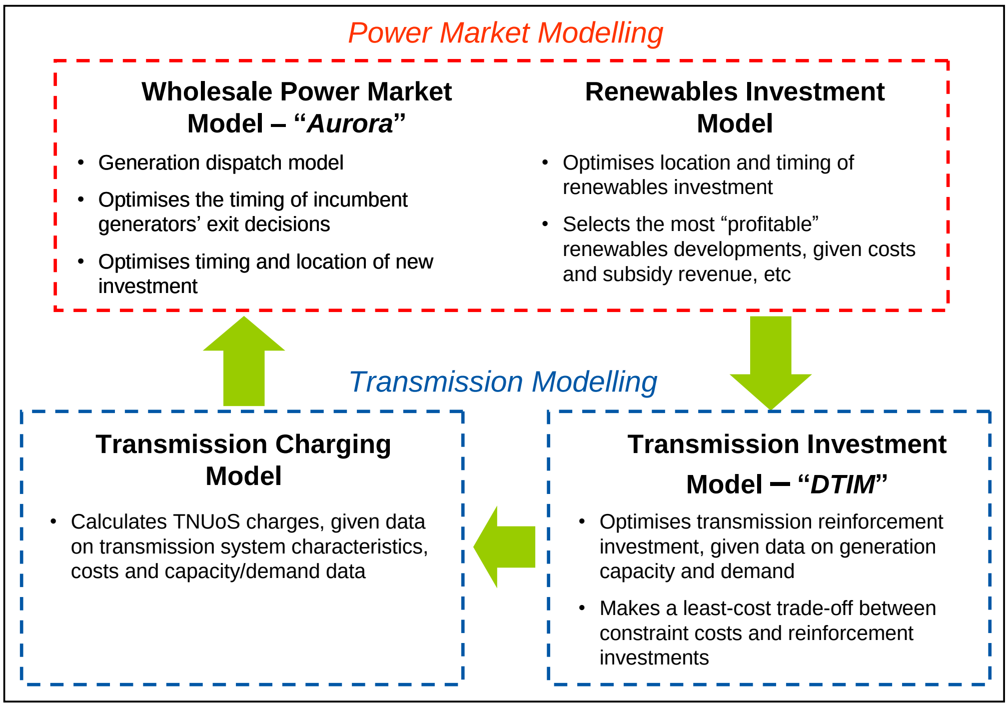
11 Ofgem, page 5

2. Our Approach

2.1. 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. This framework combines wholesale market models, a load flow and investment model of the British transmission system, and a charging model. 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.[12]

Figure 2.1
Overview of Modelling Framework



Source: NERA/Imperial

2.2. Assumptions

Given the demanding timetable imposed by the Ofgem consultation window, we have not had sufficient time to update our models to reflect changes in market conditions since our October 2012 modelling report.

---

12 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.

We have therefore re-run the model setup we developed to evaluate the "improved ICRP" charging methodology, having adjusted the charging model to account for the differences between this charging model and the WACM 2 model. In particular, we needed to account for the proposed "diversity" adjustments that split the "year round" charge into two components, and are intended to better reflect the extent to which transmission assets are shared. We developed this charging model by reviewing the published descriptions of the WACM 2 charging model from Ofgem and the CMP213 Workgroup, as well as the charging model produced by National Grid and provided to CMP213 Workgroup members.

All other modelling assumptions (generation backgrounds, new entrant cost assumptions, fuel and CO_2 prices, demand growth, etc) remain unchanged compared to our October 2012 report. In particular, we have not updated our assumed network configuration and definition of TNUoS zones to reflect recent changes to the status quo methodology, which now includes 27 rather than the 20 zones represented in our models.[13]

The only change to modelling assumptions we made was to make a correction to the assumed retirement dates for the three LCPD opted-out oil-fired units (Fawley, Littlebrook and Grain), which were incorrect in our previous model runs. We ran the status quo scenario forward a further two iterations to ensure that this relatively minor change to assumptions did not affect results. The results presented in this report therefore use this updated run of the status quo case, and compare it to our run of the WACM 2 case.

---

[13] The Statement of Use of System Charges: Effective from 1 April 2013, Version 9, Revision 1, National Grid.

3. Modelling Results

As set out above, our modelling results emerge from a process of iteration between models that simulate investment decisions in generation capacity, investments in transmission capacity, and future TNUoS charges.

In this chapter, we start by presenting our projections of how the wholesale market will evolve in the period to 2030. We then present our forecasts of TNUoS charges, the associated locations of new generation investment, and the associated transmission system costs (investment costs, constraints, losses). We also describe the extent of convergence achieved through the iterative modelling exercise.

3.1. Market Modelling Results

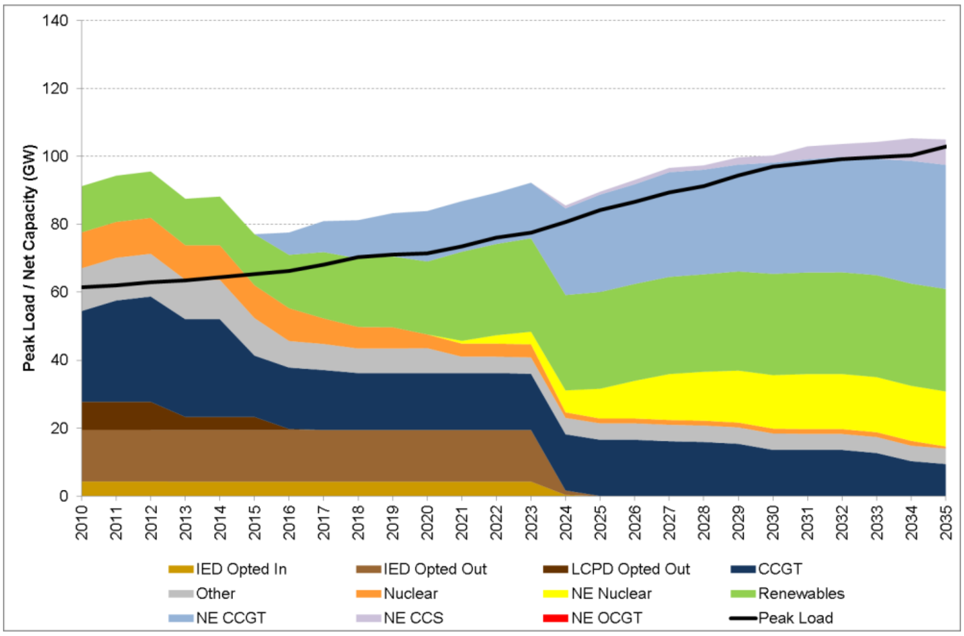
3.1.1. Generation investment decisions

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,[14] and existing CCGT plants retiring gradually in the coming years. The model also makes a choice regarding how much coal-fired capacity opts into the IED. As the figures show, in both cases, the majority of coal-fired capacity opts out, accepts limited running hours between 2016 and 2023, and then closes.

Over time, the model develops new CCGT capacity to meet demand growth and replace the units that retire. As CO_2 prices rise, the most economic form of new capacity switches from unabated CCGT capacity to CCGT+CCS, which the model starts to develop from the mid-2020s. The model also develops all the new nuclear projects available to it (around 15GW) by the end of the modelling horizon. In both cases, we assume that sufficient new renewable generation capacity comes online to meet 30% of energy demand by 2020, although as discussed in Section 3.2.4, the location of the wind capacity, and the mix of onshore and offshore development, varies across the scenarios.

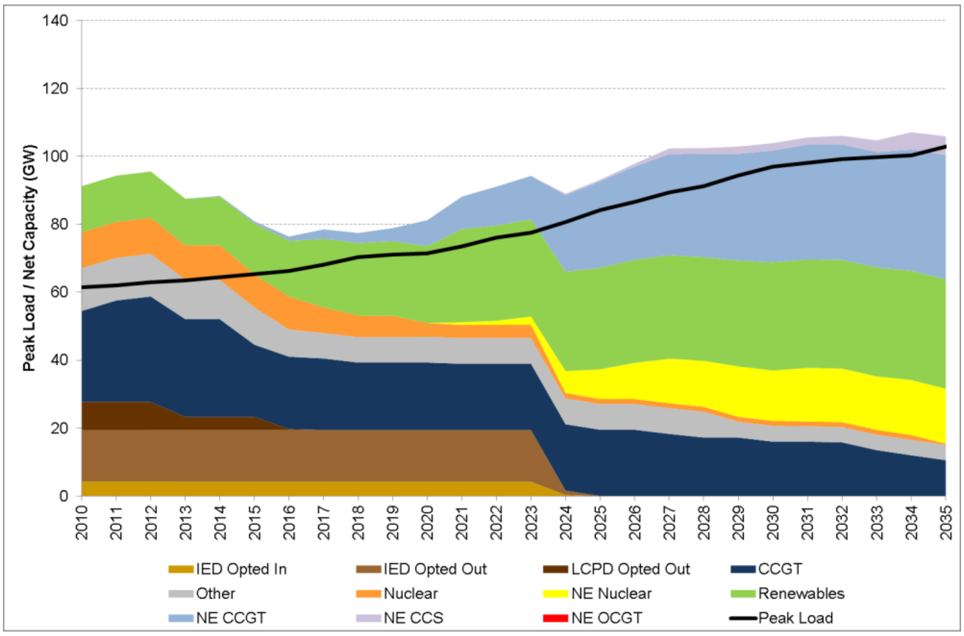
14 Note, although the precise closure dates for some opted out coal plants have been announced recently, these announcements post-dated our 2012 information date. Hence, we model most opted out coal plants by compelling the model to close them no later than end-2015, although the precise closure date is determined endogenously by the model, with limited operating hours in the meantime.

Figure 3.1
Projected Supply-Demand Balance – Status Quo



Source: NERA/Imperial

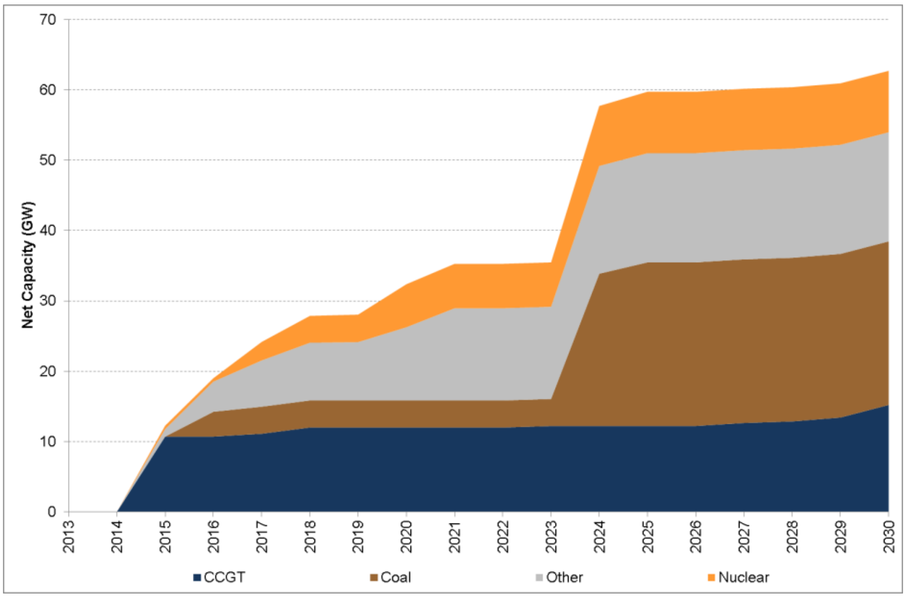
Figure 3.2
Projected Supply-Demand Balance – WACM 2



Source: NERA/Imperial

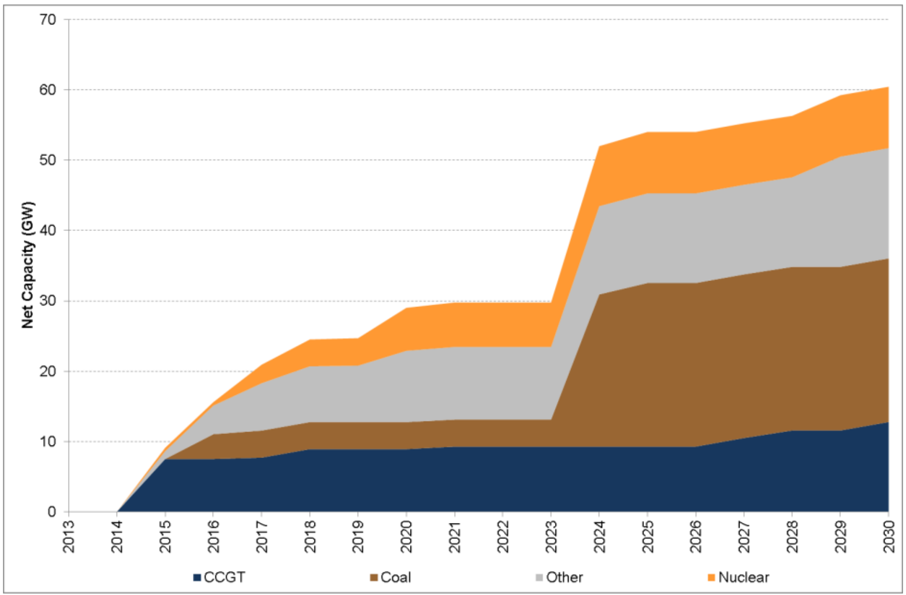
Figure 3.3 and Figure 3.4 show our projections of retirements across the two scenarios. Comparison of these two figures shows that around the same quantity of gas-fired CCGT capacity retires across the two cases, although in the status quo case slightly more existing CCGT capacity comes online, crowding out some existing CCGTs. In the long-run 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

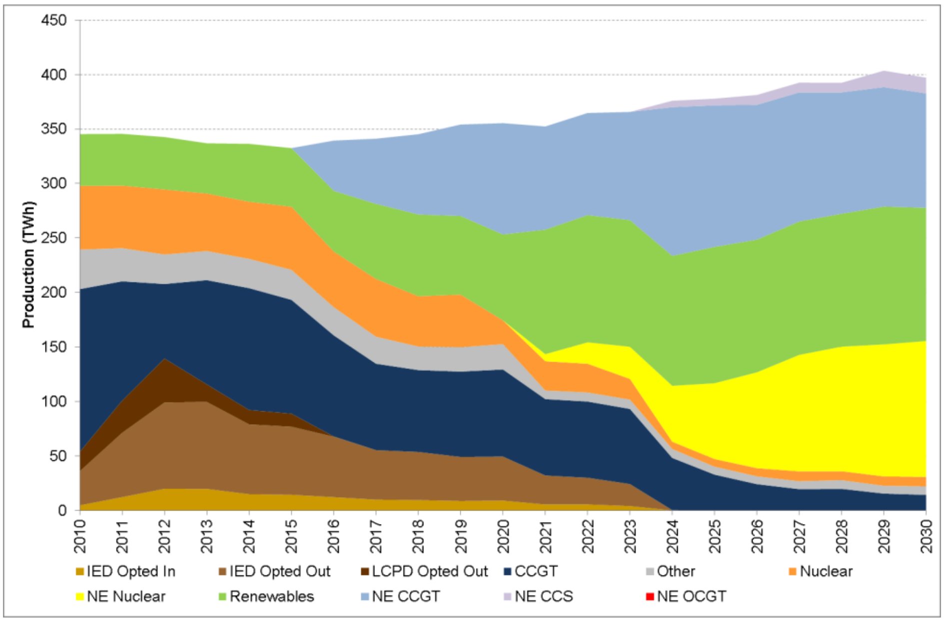


Source: NERA/Imperial

3.1.2. The generation mix

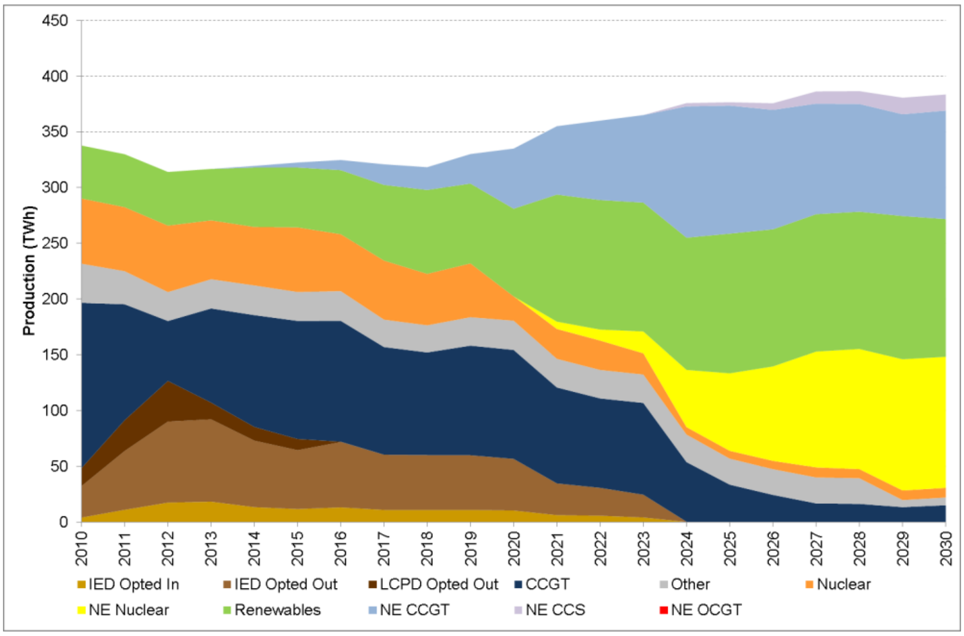
Figure 3.5 and Figure 3.6 show the modelled production mix across the two scenarios. In both cases, production from existing coal, gas and nuclear plants is replaced by the output from renewables, new nuclear and new gas-fired CCGT capacity.

Figure 3.5
Projected Production Mix – Status Quo



Source: NERA/Imperial

Figure 3.6
Projected Production Mix – WACM 2



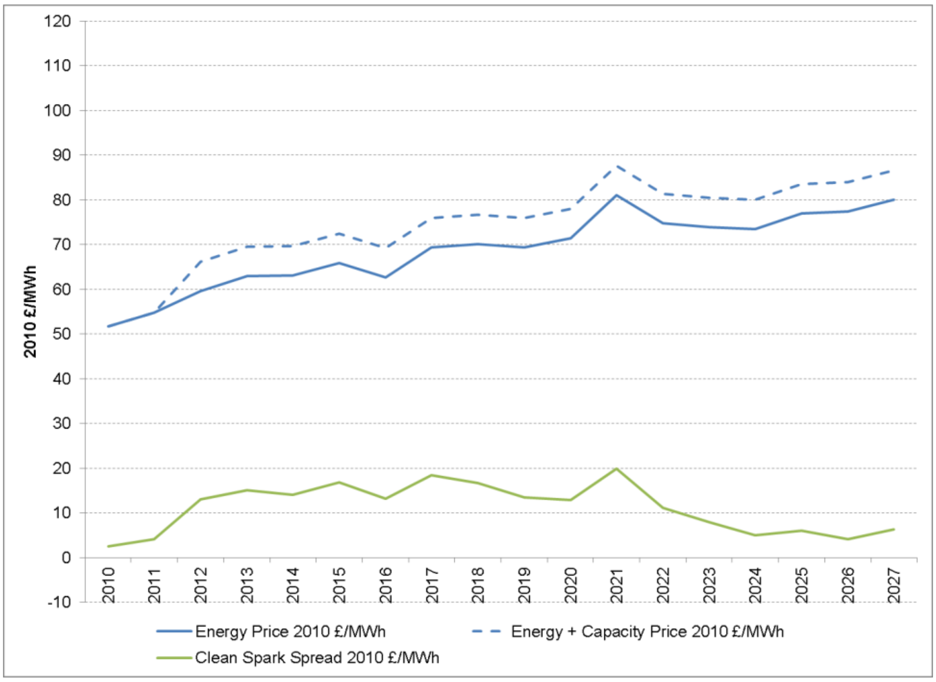
Source: NERA/Imperial

3.1.3. Market price trends

Figure 3.7 and Figure 3.8 show our projections of baseload prices and 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. In both cases, prices rise over time in line with our assumed growth in commodity prices. Also, the figures show that the CPM begins in 2015 when the model suggests that new investment in gas-fired CCGTs is required.[15]

Clean spark spreads recover from their current low levels over the period to 2016 as the need for new investment emerges. Spreads remain relatively stable until around 2025, when they fall to less than £5/MWh. This trend of falling baseload spreads reflects the falling load factors achieved by new entrant CCGTs, as they are increasingly displaced in the merit order by new nuclear, renewables and CCS. Figure 3.7 and Figure 3.8 show that the general trends in prices and spreads are similar in the two cases.

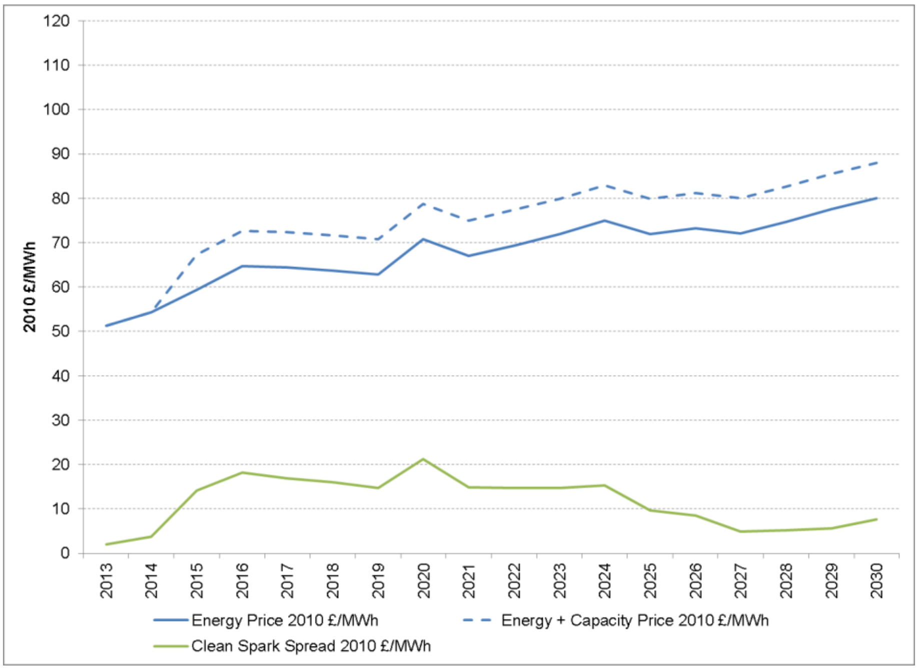
Figure 3.7
Baseload Prices and Clean Spark Spreads – Status Quo



Source: NERA/Imperial

15 Our approach to modelling the capacity mechanism reflected the lack of details published in October 2012 of how the scheme would operate. We therefore adopted a fundamental approach to modelling the CPM, as follows. We assumed that the first contracts would be delivered from the point in time at which our market modelling suggests that new investment in generation capacity is required, i.e. 2015. We modelled the CPM on the assumption that it is successful in correcting the market failure created by a (real or perceived) cap on wholesale energy prices. Hence, we run our market models on the assumption that prices cap spike to VOLL, which we assume is €10,000/MWh, to generate an efficient capacity mix. We then apply a price cap of €1,000/MWh to generate a series of energy prices, and calculate the loss in revenue to generators, which represents the "missing money" created by the price cap. We assume the "missing money" is returned to generators through a market-wide capacity payment. We calculate the capacity payment by annuitising this missing money over the modelling horizon. Hence, whereas the missing money may be volatile form year-to-year, we assume the CPM smoothes out the scarcity rents required to pay for peaking plants over the modelling horizon.

Figure 3.8
Baseload Prices and Clean Spark Spreads – WACM 2



Source: NERA/Imperial

As noted above, the prices emerging from the two model runs are extremely close, and the delta between them is therefore extremely small on average. Given the potential for some instability between model runs (see Section 3.5), and the "noise" that can show up in market price forecasts, we do not, therefore, draw firm conclusions from the model itself regarding the direction of the price effect resulting from implementing the WACM 2 charging model. Instead, we assume that prices will need to converge on the long-run marginal cost of new entry, and that long-term differences between market prices will result only from differences in the costs of new entry. This condition is necessary for achieving an economic equilibrium, as new entrants will need to earn sufficient revenues to cover their fixed upfront and ongoing costs in order to enter the market.

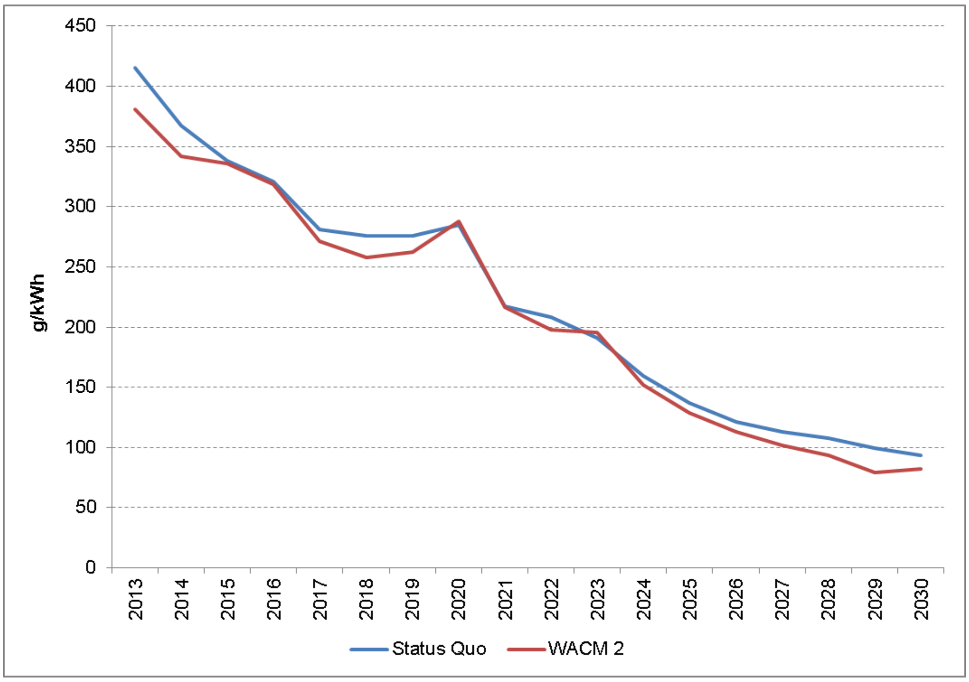
Our approach to estimating the price effect is therefore to (1) identify which generation technologies are the "marginal" source of new entry into the market in each scenario using the results from our market model, (2) estimate the change in TNUoS costs faced by the marginal new entrant in each case, and (3) calculate the change in prices required to ensure that in both cases prices cover the long-run marginal cost of entry. We describe the results of this analysis in Section 3.2.4 below.

This approach ensures our price impacts follow directly from changes in the cost of new entry, which was not the case in the modelling performed for Ofgem by National Grid. We note in our report critiquing the Ofgem Impact Assessment and "minded to" decision that the modelled changes in market prices did not correspond to the changes in the marginal cost of new entry indicated by changes in TNUoS charges.[16]

3.1.4. CO_2 emissions intensity

As Figure 3.9 shows, CO_2 emissions from the power sector fall in both scenarios from around 400g/kWh to between the 50 and 100g/kWh targets that government and other organisations like the Committee on Climate Change have mooted for 2030. Both scenarios assume CO_2 prices rise to £70/tonne by 2030 in line with the government's projections for the Carbon Price Floor.

Figure 3.9
Projected CO2 Emissions Intensity – Status Quo vs. WACM 2



Source: NERA/Imperial

3.2. Modelled TNUoS Charges

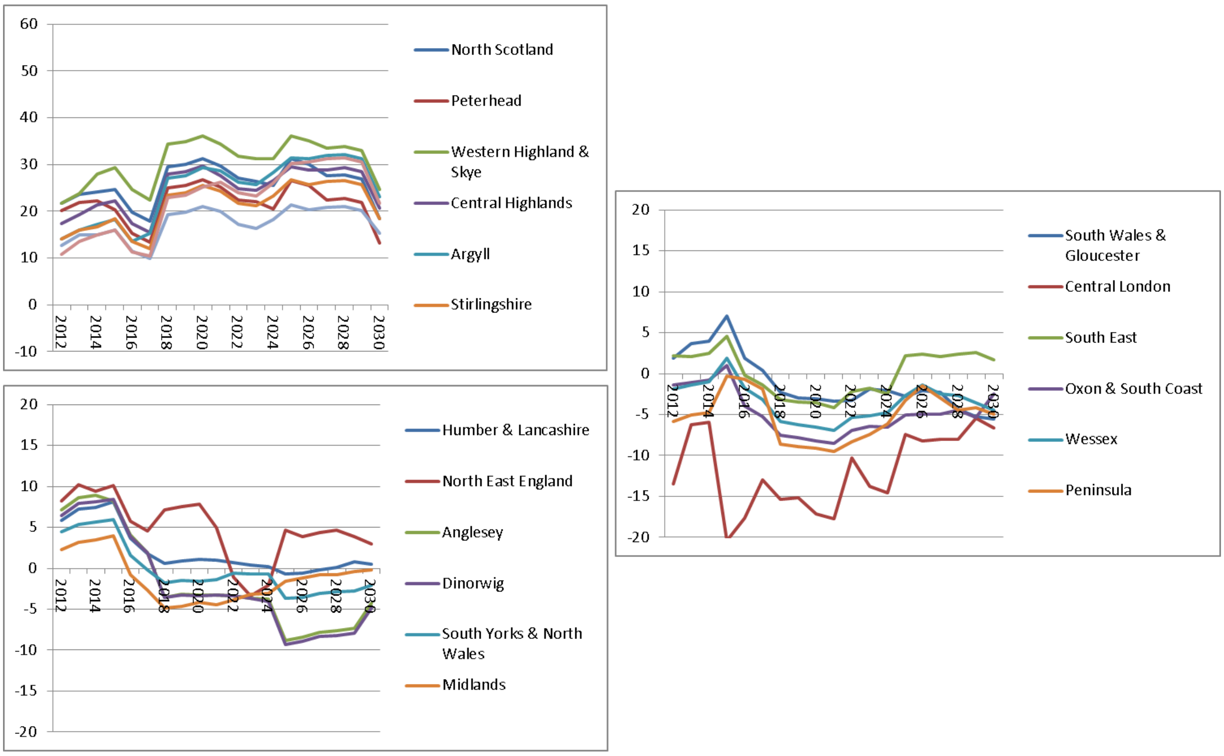
3.2.1. Status quo

Figure 3.10 presents the TNUoS charges emerging from the final iteration of the "status quo" scenario. Charges in the Scottish TNUoS zones increase over time, with steps up around 2018 and 2022 due to the construction of HVDC bootstraps to accommodate increased north-south power flows resulting from the construction of new wind generation capacity in Scotland. Charges in most zones in England and Wales trend downward over time, although

[16] Project TransmiT: Review of Ofgem Impact Assessment of Industry Proposals CMP213, Prepared for RWE npower, NERA Economic Consulting and Imperial College London, 25 September 2013, Section 4.2.

some zones, in particular Central London, exhibit relatively volatile charges from year-to-year.

Figure 3.10
Status Quo TNUoS Charges (2012£/kW)



Source: NERA/Imperial

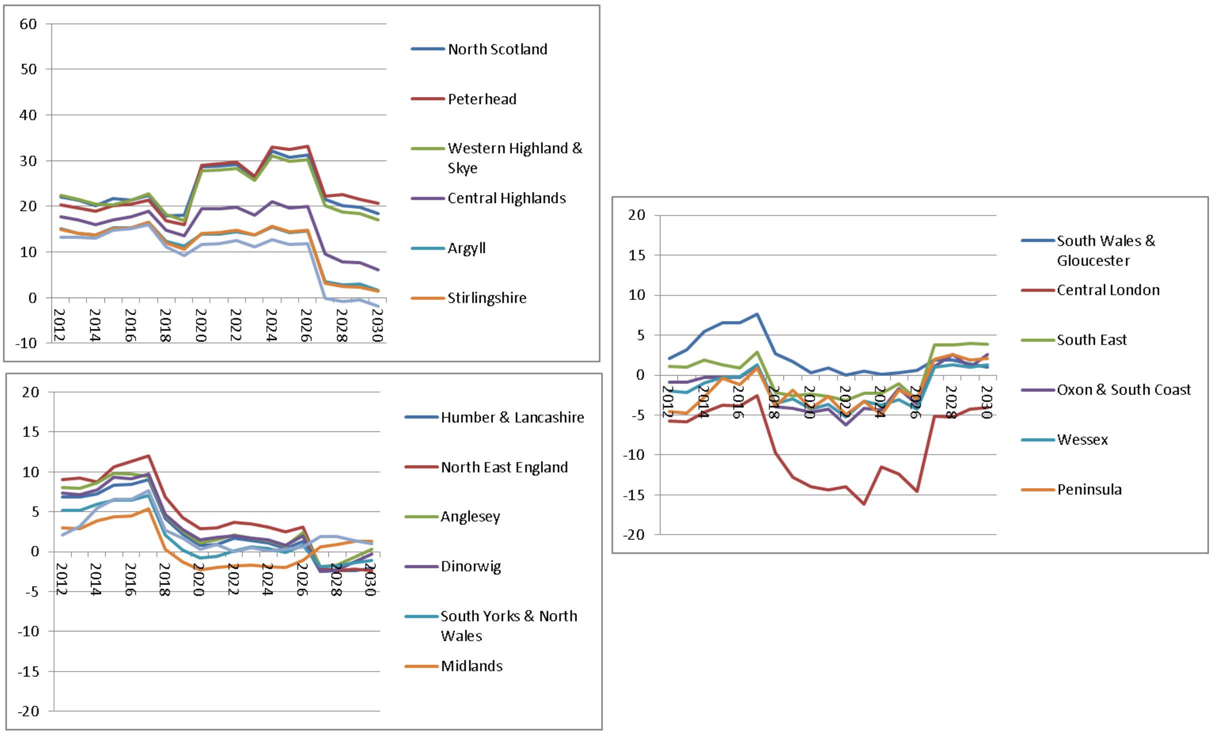
3.2.2. WACM 2

The WACM 2 charging model links TNUoS charges to plant load factor and technology. Hence, Figure 3.11, Figure 3.12 and Figure 3.13 show the charges that CCGTs, nuclear plants and intermittent plants respectively would face across the 20 TNUoS zones. Figure 3.11 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 low wind, high demand conditions. However, high “year round” charges for CCGTs mean the overall TNUoS charges faced by generators in Scotland remain high. 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 3.12, are similar to those charged to CCGTs, with differences relating to differences in load factor that scale liability to pay year-round charges.

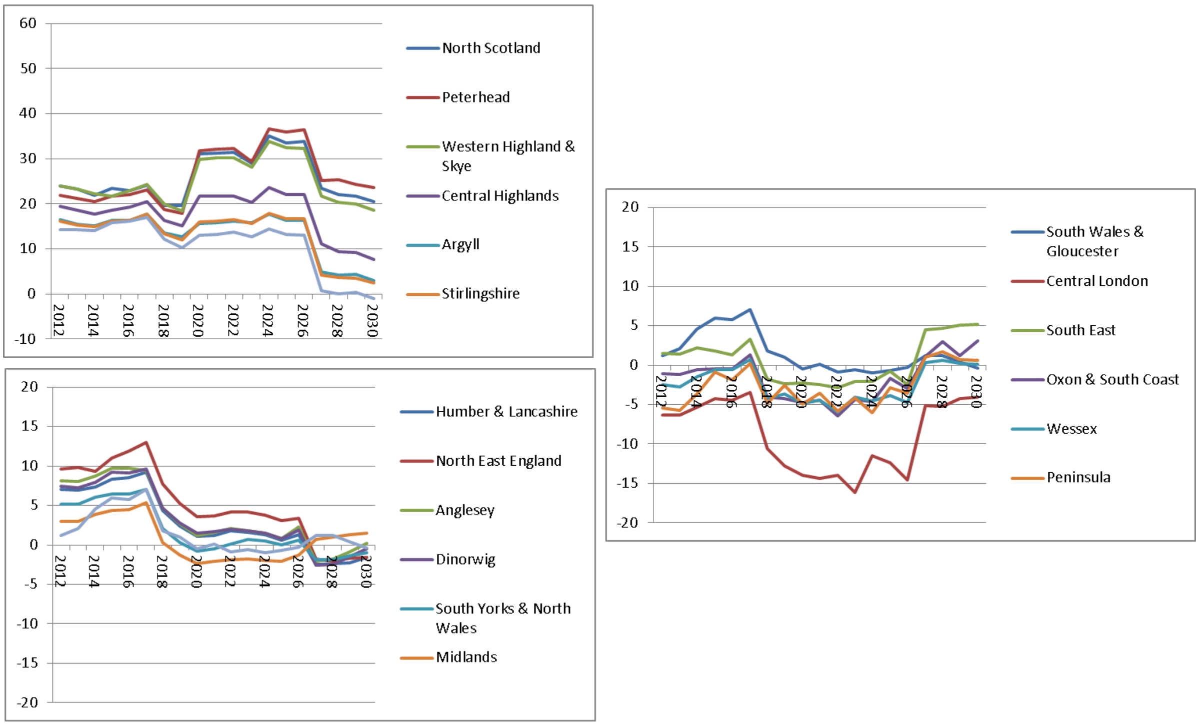
For intermittent plants, however, the impacts on TNUoS charges are larger, as Figure 3.13 shows. Scaling generators' liability to pay year-round charges by load factor materially reduces (increases) the charges faced by intermittent plants in positive (negative) TNUoS zones, and thus blunts the locational incentive conveyed through TNUoS charges.

Figure 3.11
WACM 2 TNUoS Charges for CCGTs (2012£/kW)



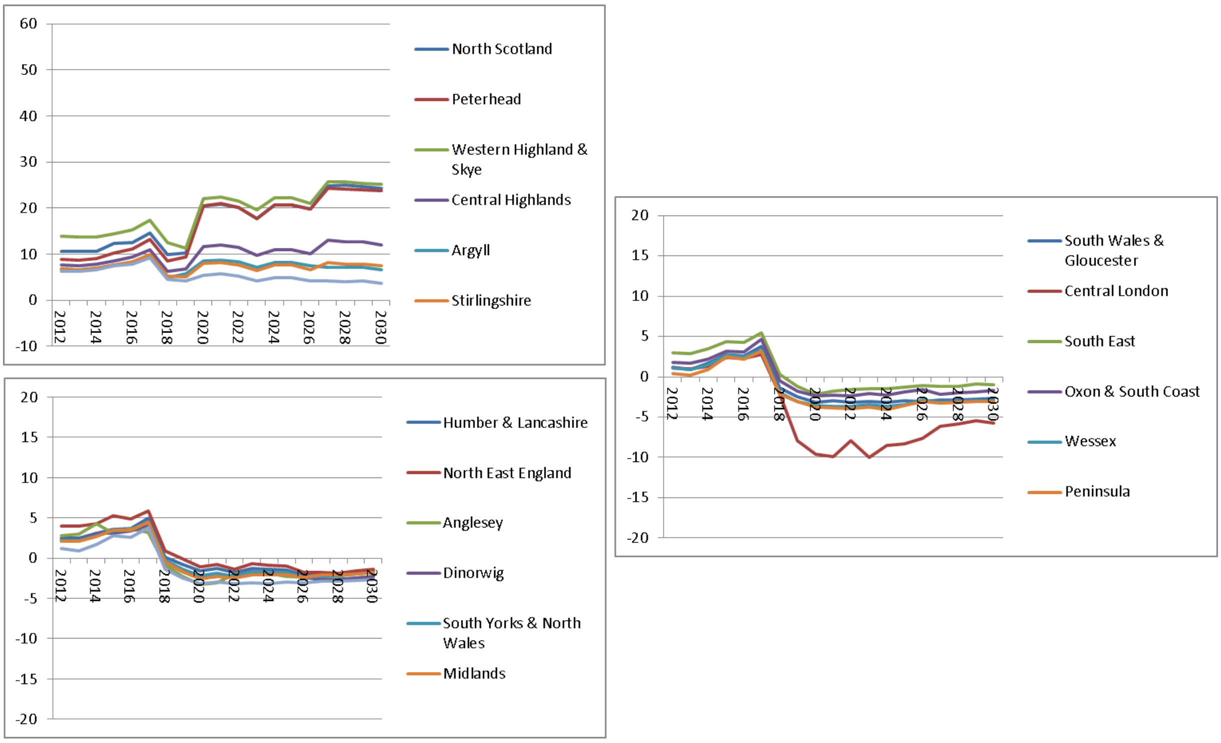
Source: NERA/Imperial

Figure 3.12
WACM 2 TNUoS Charges for Nuclear Plants (2012£/kW)



Source: NERA/Imperial

Figure 3.13
WACM 2 TNUoS Charges for Wind Plants (2012£/kW)



Source: NERA/Imperial

3.2.3. Comparison of TNUoS costs

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 3.1 and Table 3.2 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 3.3 and Table 3.4 show the impact for intermittent plants separately. However, the effects are similar; low load factor plants in the north benefit most, but intermittent plants in most zones see their charges fall.

Table 3.1
Impact of WACM 2 on <u>Non-Intermittent</u> Generators' TNUoS Costs by Zone and Load Factor in 2014 (2012£/kW)

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

Source: NERA/Imperial

Table 3.2
Impact of WACM 2 on Non-Intermittent 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%	-37	-37	-38	-37	-42	-36	-30	-38	-1	-7	8	8	3	4	11	3	1	8	6	10
10%	-36	-36	-37	-37	-41	-35	-30	-37	-1	-7	8	7	3	3	10	3	1	8	6	9
20%	-35	-35	-36	-36	-40	-35	-29	-36	-1	-7	7	7	3	3	10	3	1	8	6	9
30%	-34	-34	-36	-35	-39	-34	-29	-36	-1	-7	7	7	3	3	10	3	2	8	5	9
40%	-33	-34	-35	-34	-38	-34	-28	-35	-1	-6	7	7	3	3	9	3	2	8	5	8
50%	-32	-33	-34	-34	-37	-33	-28	-34	-1	-6	7	7	3	3	9	3	2	8	5	8
60%	-31	-32	-33	-33	-36	-32	-27	-34	-1	-6	7	7	3	3	9	3	3	8	5	7
70%	-30	-32	-33	-32	-35	-32	-27	-33	-1	-6	7	7	3	3	8	3	3	8	4	7
80%	-29	-31	-32	-32	-34	-31	-26	-32	-1	-6	7	7	3	3	8	3	3	8	4	6
90%	-28	-30	-31	-31	-33	-31	-26	-32	-1	-6	7	7	3	3	8	3	4	8	4	6
100%	-27	-29	-31	-30	-32	-30	-25	-31	-1	-6	7	7	3	3	7	3	4	8	3	5

Source: NERA/Imperial

Table 3.3
Impact of WACM 2 on Intermittent Generators' TNUoS Costs by Zone and Load Factor in 2014 (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%	-15	-15	-17	-15	-12	-11	-9	-8	-4	-5	-6	-5	-2	0	-1	9	1	4	4	8
10%	-14	-14	-16	-13	-11	-10	-9	-7	-4	-5	-6	-5	-2	0	-1	9	1	4	4	8
20%	-13	-13	-15	-12	-10	-9	-8	-6	-4	-4	-6	-5	-2	0	-1	8	2	4	4	7
30%	-12	-11	-14	-11	-9	-9	-7	-6	-4	-4	-6	-5	-2	0	-2	8	2	3	4	7
40%	-10	-10	-12	-10	-8	-8	-6	-5	-4	-4	-6	-5	-2	0	-2	8	2	3	3	7
50%	-9	-9	-11	-9	-7	-7	-6	-4	-4	-3	-6	-5	-2	0	-2	7	3	3	3	6
60%	-8	-8	-10	-8	-7	-6	-5	-3	-4	-3	-6	-5	-2	0	-3	7	3	3	3	6
70%	-7	-6	-9	-6	-6	-5	-4	-3	-3	-3	-6	-5	-2	0	-3	6	3	3	3	5
80%	-5	-5	-8	-5	-5	-4	-4	-2	-3	-3	-6	-5	-2	0	-3	6	4	2	3	5
90%	-4	-4	-7	-4	-4	-3	-3	-1	-3	-2	-6	-6	-2	0	-3	5	4	2	2	5
100%	-3	-2	-5	-3	-3	-3	-2	0	-3	-2	-6	-6	-2	0	-4	5	4	2	2	4

Source: NERA/Imperial

Table 3.4
Impact of WACM 2 on Intermittent Generators' TNUoS Costs by Zone and Load Factor in 2025 (2012£/kW)

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

Source: NERA/Imperial

3.2.4. Impact on new entrant costs

As noted above in Section 3.1.3, we tie our estimates of the impact on costs to consumers on to our estimates of the cost of new entry into the power market. Throughout the modelling horizon, the marginal source of new entry into the market is either conventional gas-fired CCGT or CCGT + CCS. Therefore, in order to gauge the likely impact of WACM 2 on the cost of new entry, and hence long run power prices, we have calculated the change in levelised fixed costs following the implementation of WACM 2 faced by both types of new entrant plants in £/MWh, and compared them with TNUoS costs under the status quo. Table 3.5 shows the impact of WACM 2, relative to the status quo on the levelised fixed costs faced by new entrant CCGTs and (CCGT+CCS plants) in the locations in which our market model builds new capacity.

Table 3.5
Impact of WACM 2 on New Entrant CCGT TNUoS Costs (£/MWh)

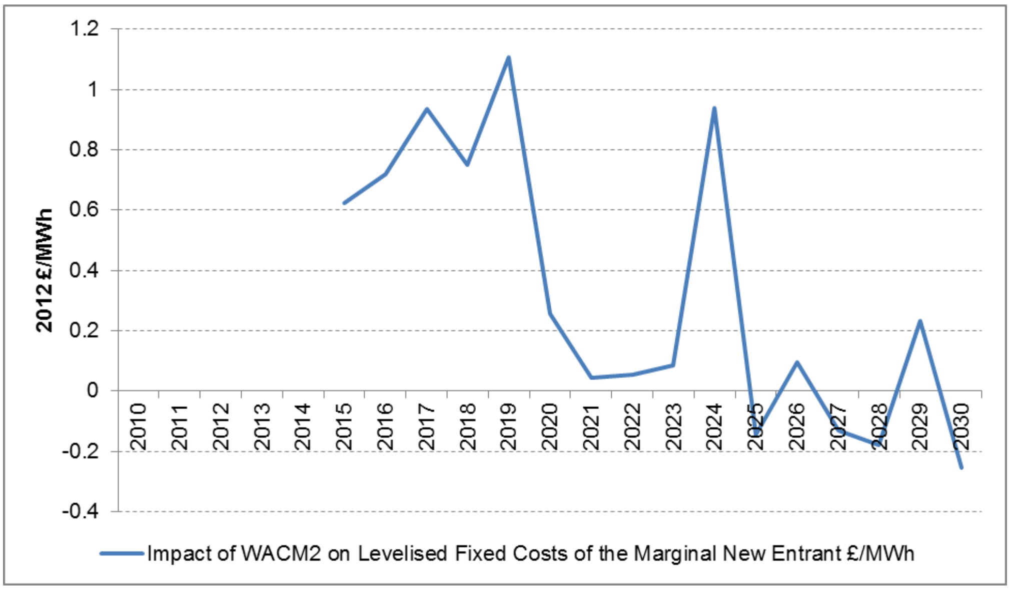
		Impact of WACM 2 on New Entrant CCGT TNUoS Costs (£/MWh)		
	Zone	**2014**	**2020**	**2030**
CCGT	**9**	0.6	0.2	-0.3
CCGT	**10**	0.9	0.0	-0.9
CCGT	**13**	0.5	0.2	0.3
CCGT	**14**	0.4	0.0	0.6
CCGT	**15**	0.6	0.4	1.8
CCGT	**17**	0.0	-0.5	0.6
CCGT	**18**	0.0	-0.3	0.4
CCGT	**19**	0.0	-0.3	1.1
CCGT	**20**	0.1	0.0	1.7
CCGT + CCS	**9**	0.7	0.2	-0.1
CCGT + CCS	**13**	1.2	0.8	0.6

Source: NERA/Imperial

The WACM 2 charging model changes the fixed costs of new entrant CCGTs and CCGT+CCS plants by between negative £0.90/MWh and positive £1.80/MWh, depending on their precise load factor and the zone in which they connect to the system.

To convert this into an equivalent price effect, we have also identified which type of new entrant generator provides the marginal source of new entry in each year, and then estimated the change in price that would be required to preserve the equilibrium condition that the marginal new entrant precisely recovers its costs, and estimated the difference in required prices across the status quo and WACM 2 scenarios. As Figure 3.14 shows, in the period to 2020, the long-run marginal cost of new entry is around £1/MWh higher under WACM 2 than the status quo. This effect is smaller towards the end of the modelling horizon, falling to around zero on average from around 2025.

Figure 3.14
Impact as a Result of WACM 2 on the Power Prices Required to Ensure Generator Revenues Cover the Long Run Marginal Cost of New Entry



Source: NERA/Imperial

3.3. Locational Investment Decisions

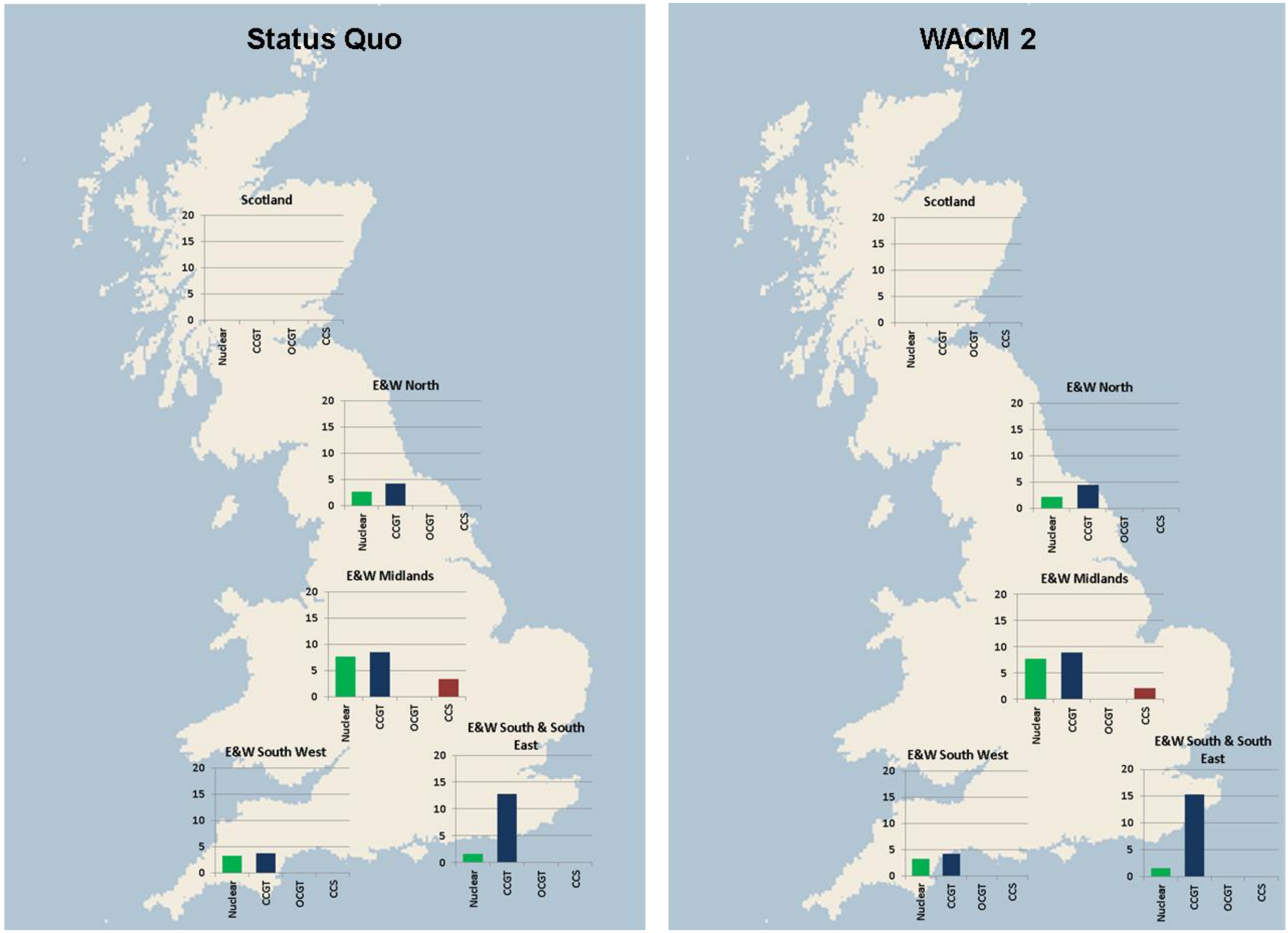
As Figure 3.15 shows, the patterns of non-wind generation investment are similar across the two scenarios. The model develops plants at all the new nuclear sites in both cases. Investments in gas-fired CCGTs are spread around England and Wales in both scenarios, with slightly more investment in new capacity in the WACM 2 case and slightly less investment in CCGT+CCS capacity. Our modelling results do not project any new thermal investment in Scotland.

Over the modelling horizon, the distribution of existing generation capacity around the system also changes slightly because of differences in retirement decisions. Figure 3.16 shows the locations of existing generators (i.e. those that are already online today) for the year 2020. It shows some small differences in the location of CCGT closures, with slightly more retirement in the south west in WACM 2 and slightly more retirement in the south east in the status quo, but overall the differences are small.

Figure 3.17 and Table 3.6 show that WACM 2 causes around 900MW more wind investment to take place both in Scotland and in England and Wales. This overall growth in wind investment is caused by a reduction in investment at relatively high load factor sites, and the improved profitability of wind sites as TNUoS charges fall.

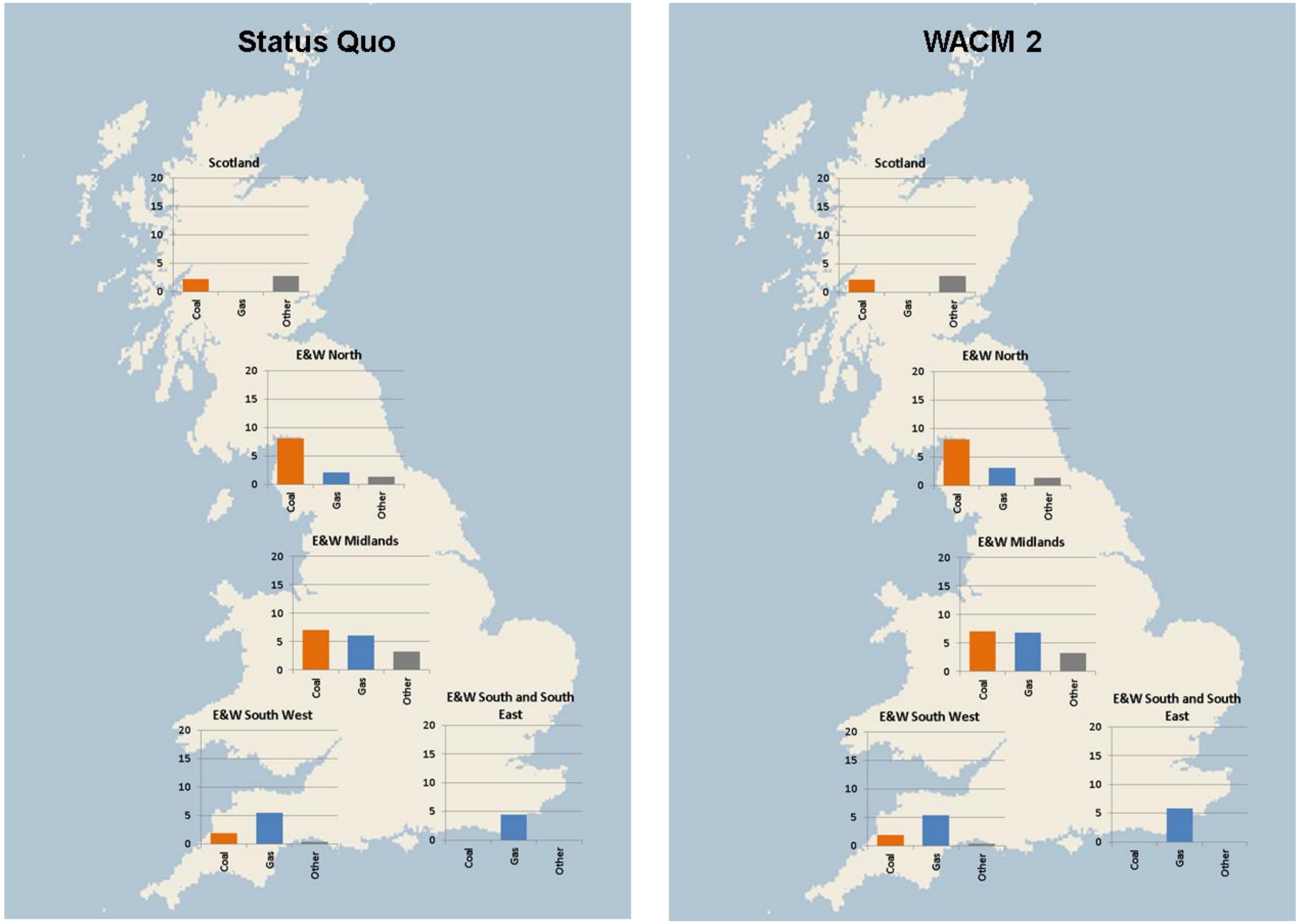
Despite these relatively modest changes in the split of investment between England and Wales and Scotland, the WACM 2 scenario has a number of differences in the location of investment within these regions. For instance, under the WACM 2 model wind developments take place on the Scottish Islands, whereas they do not in the status quo. In England and Wales, the WACM 2 case also results in more wind capacity offshore and less onshore. In Scotland the reverse is true, with capacity moving onshore in the WACM 2 case. These movements in wind capacity are caused both by changes in TNUoS charges and the changes in subsidy payments to wind farms in response to changes in TNUoS.

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



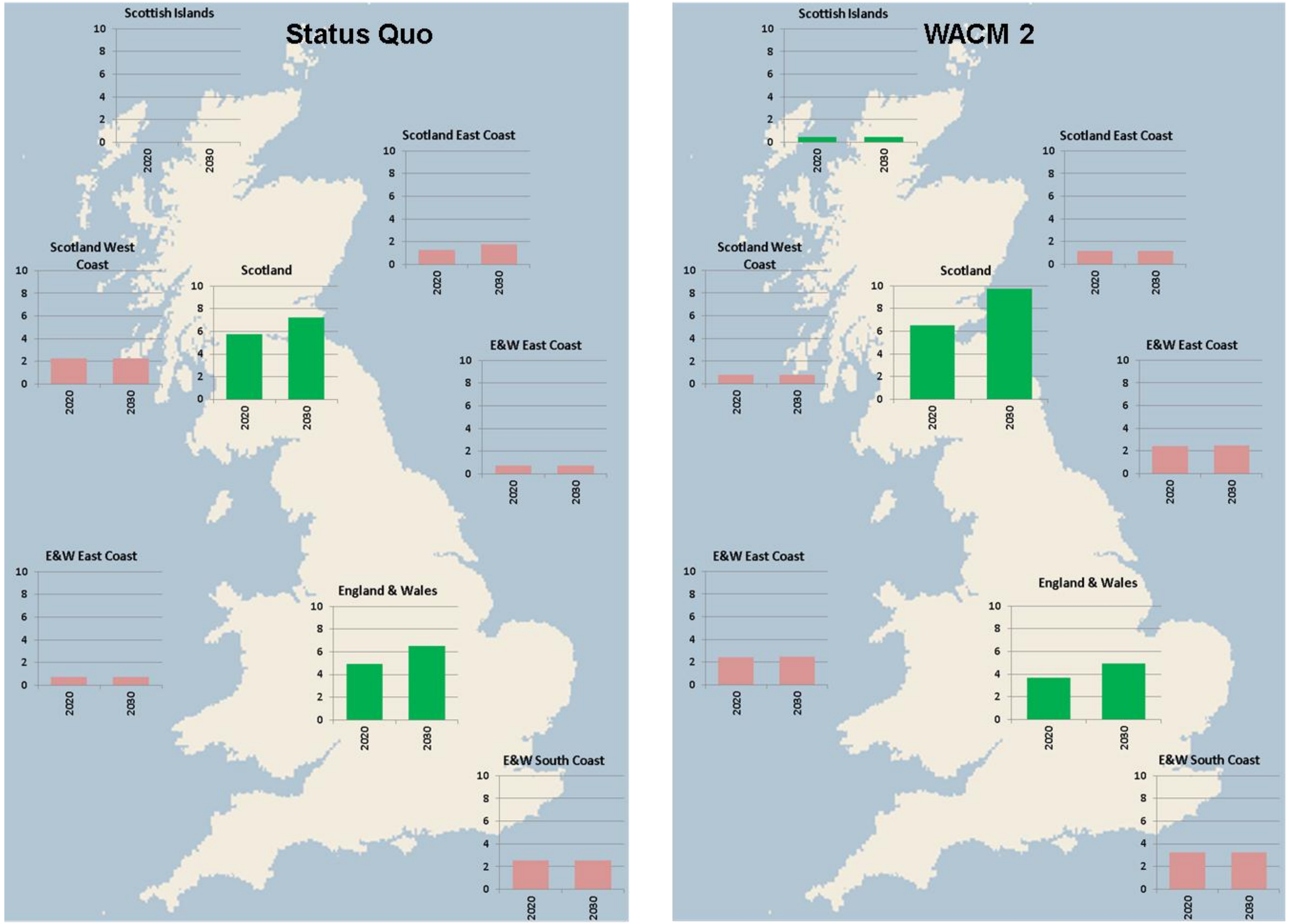
Source: NERA/Imperial

Figure 3.16
Location of Existing Generation Capacity in 2020 (Excl. Wind) - Status Quo vs. WACM 2



Source: NERA/Imperial

Figure 3.17
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	0.73	0.73
Offshore E&W South Coast	2.55	2.55
Offshore E&W West Coast	1.22	1.22
Offshore Scotland East Coast	1.30	1.79
Offshore Scotland West Coast	2.29	2.29
Scottish Islands	0.00	0.00
Onshore E&W	4.92	6.52
Onshore Scotland	5.75	7.22
Scotland		11.29
E&W		11.02

WACM 2

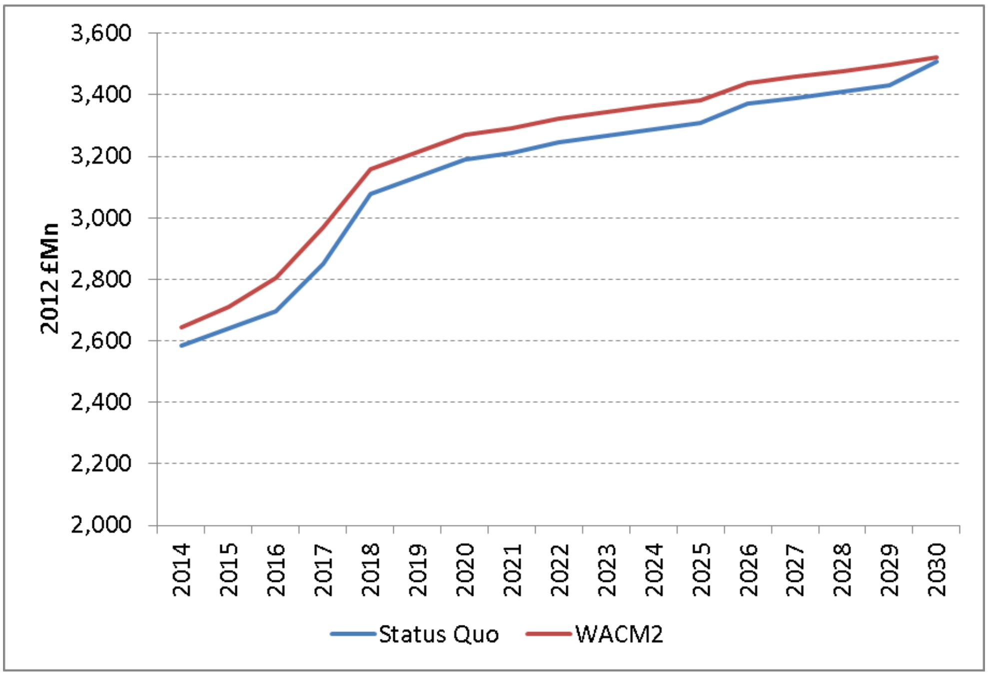
Renewables (GW)	2020	2030
Offshore E&W East Coast	2.43	2.48
Offshore E&W South Coast	3.27	3.27
Offshore E&W West Coast	1.22	1.22
Offshore Scotland East Coast	1.18	1.18
Offshore Scotland West Coast	0.78	0.78
Scottish Islands	0.47	0.47
Onshore E&W	3.69	4.92
Onshore Scotland	6.51	9.76
Scotland		12.19
E&W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

Source: NERA/Imperial

3.4. Transmission System Costs

Because the WACM 2 charging model results in slightly more renewable generation capacity that is also located further north, it tends to increase transmission system costs, as well as transmission losses due to increased north-to-south power flows. As shown in Figure 3.18, transmission investments costs increase over the period by around £1bn, resulting in annualised transmission system costs that are around £100m higher.

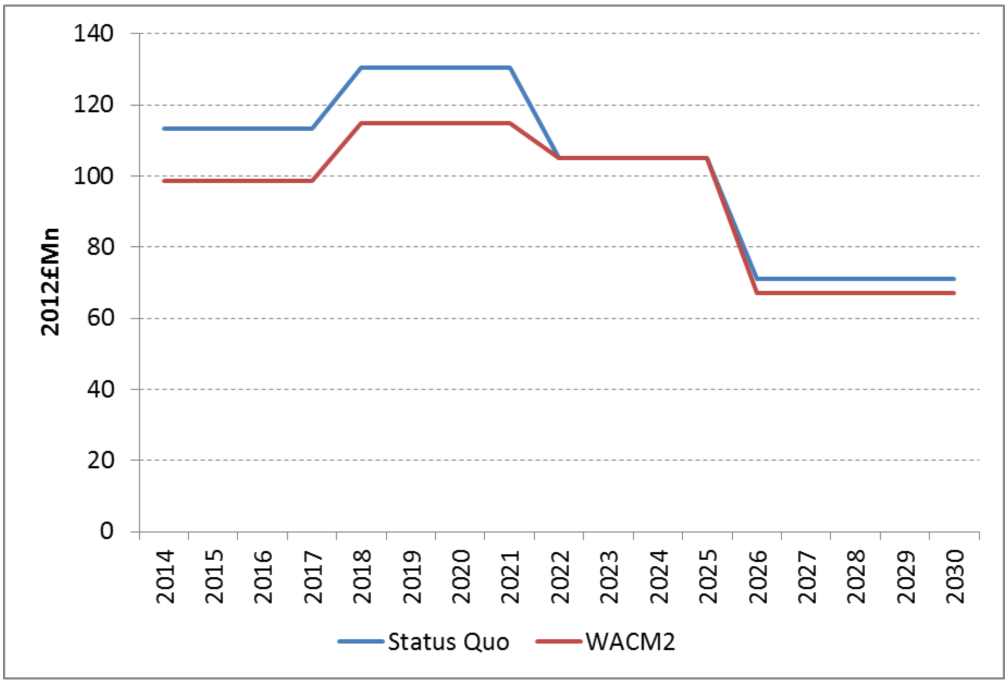
Figure 3.18
TNUoS Revenue (2012 £Mn) – Status Quo vs. WACM 2



Source: NERA/Imperial

Constraint costs, as shown in Figure 3.19, are broadly similar across the two cases, although slightly higher in the status quo in the early years. This variation occurs because, in our modelling framework, the level of constraint costs is determined by the marginal costs of reinforcing the network, rather than the volume of reinforcement required. This is the case because DTIM builds transmission investment capacity optimally, up to the point where the marginal cost of constraints is equal to the marginal cost of reinforcement. If we assumed sub-optimal transmission investment, e.g. due to planning delays, we would expect to see larger differences in total transmission system costs (constraints plus investment) as a result of WACM 2.

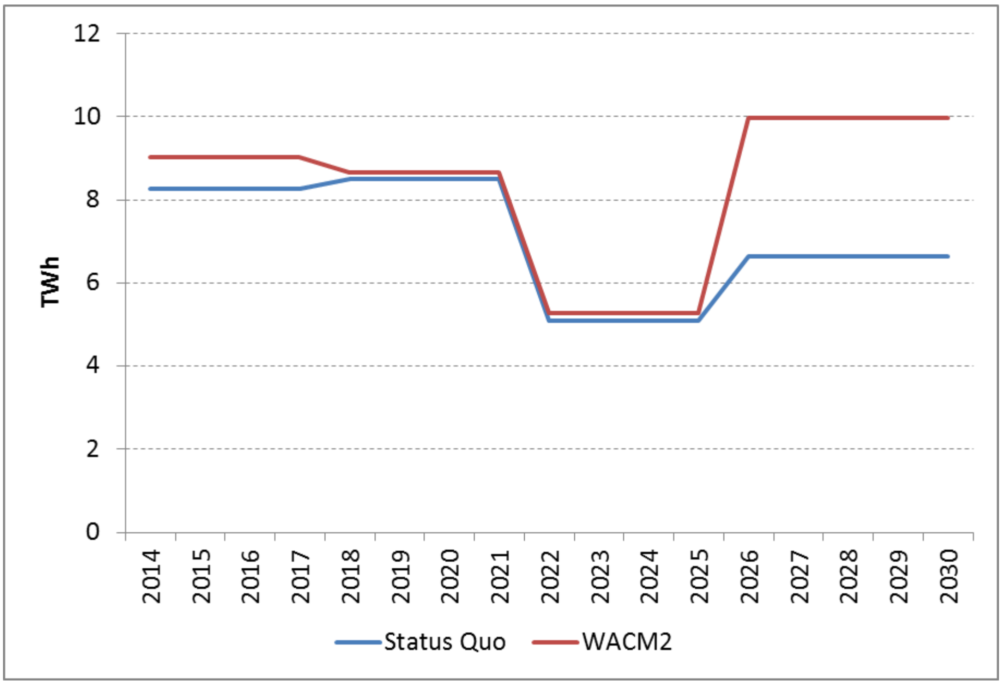
Figure 3.19
Constraint Costs (2012 £Mn) – Status Quo vs. WACM 2



Source: NERA/Imperial

Transmission losses, as shown in Figure 3.20, increase because more power is transported from north to south under WACM 2, as more wind generation is located in Scotland.

Figure 3.20
Transmission Losses (TWh) – Status Quo vs. WACM 2



Source: NERA/Imperial

3.5. Convergence

3.5.1. Status Quo

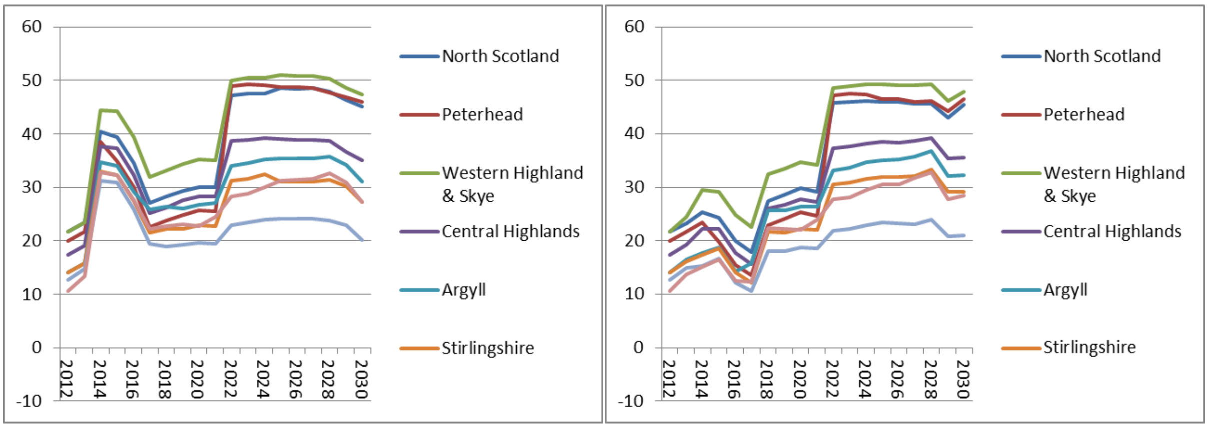
As Figure 3.22 and Figure 3.23 illustrate, in the final and penultimate runs of our status quo scenario, we obtained a high degree of convergence in the location of generation investments, with relatively stable investment patterns across the two cases. However, we did observe some instability in the speed with which existing thermal plants retire between the final and penultimate runs of the model, as Figure 3.24 illustrates. Given this instability, we have based the results presented in this report on the average effects across the final and penultimate runs of the model.

However, in earlier iterations of the model, we did observe some “flipping” of generation between Scotland and England. As Figure 3.21 illustrates, modelled TNUoS charges after 2020 were relatively stable, but charges between 2015 and 2018 showed instability from run-to-run, which drove some instability in investment patterns with a small amount of CCGT capacity and some wind capacity moving between Scotland and England and Wales from run-to-run.[17] The small amount of generation capacity that moved north in response to reductions in TNUoS charges was small, and it had the effect of significantly increasing TNUoS charges in response. This increase in TNUoS made these generation investments unprofitable, so we imposed the assumption in the final runs of the status quo case that these generators would anticipate the increase in TNUoS their presence would cause, and thus would choose not to locate there in the first place.

---

[17] These results are illustrated in our report that compares the status quo and “improved ICRP” cases. Note, as described in Section 2.2, we have rolled forward the status quo case by two iterations since this report. Source: Project TransmiT: Modelling the Impact of "Improved ICRP", Prepared for RWE npower, NERA Economic Consulting and Imperial College London, 12 October 2012, Section 3.5.

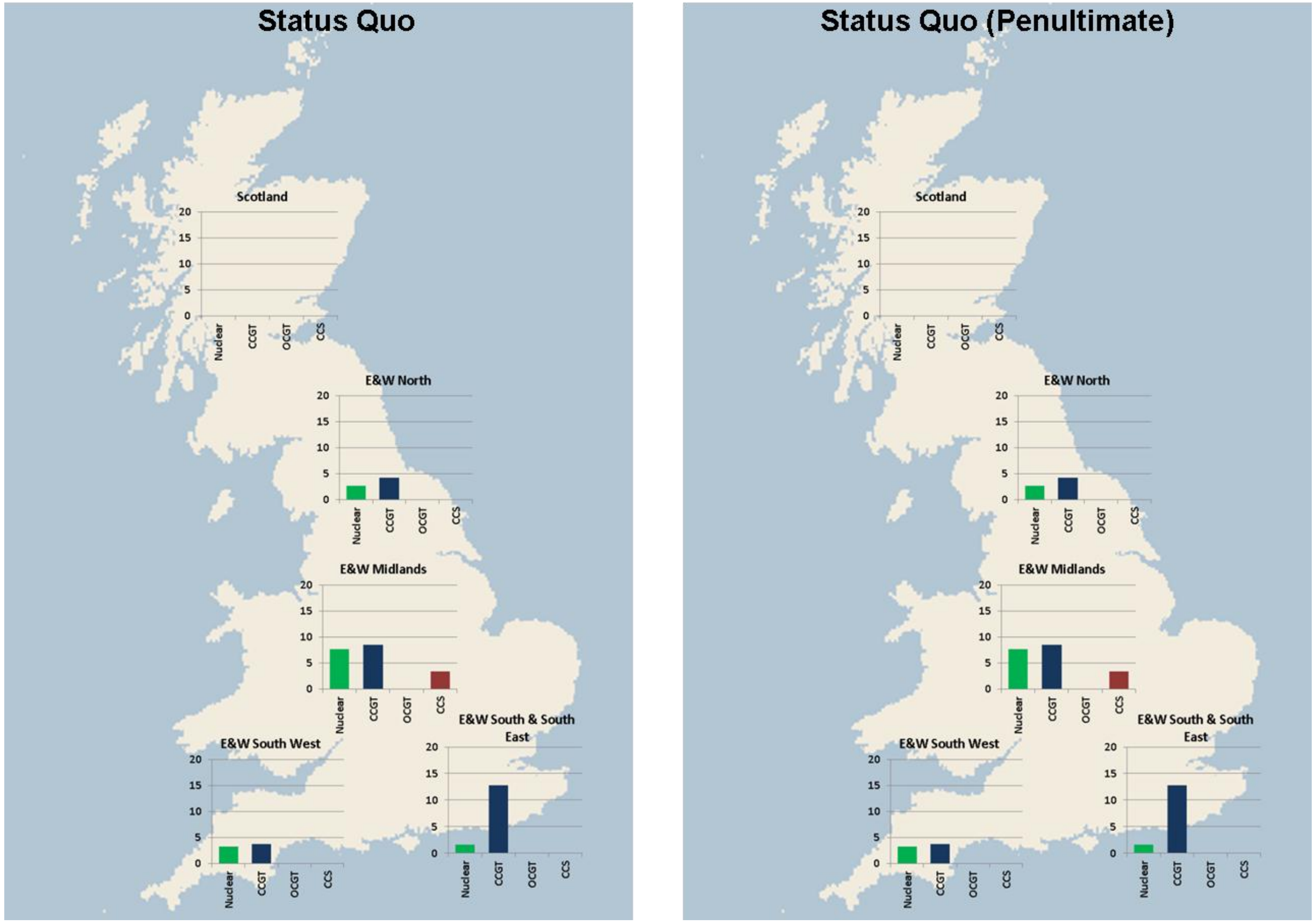
Figure 3.21
Instability in Status Quo TNUoS Charges in Scottish Zones During Model Iteration



Note, the figure shows TNUoS charges emerging from subsequent runs of the model.
Source: NERA/Imperial [18]

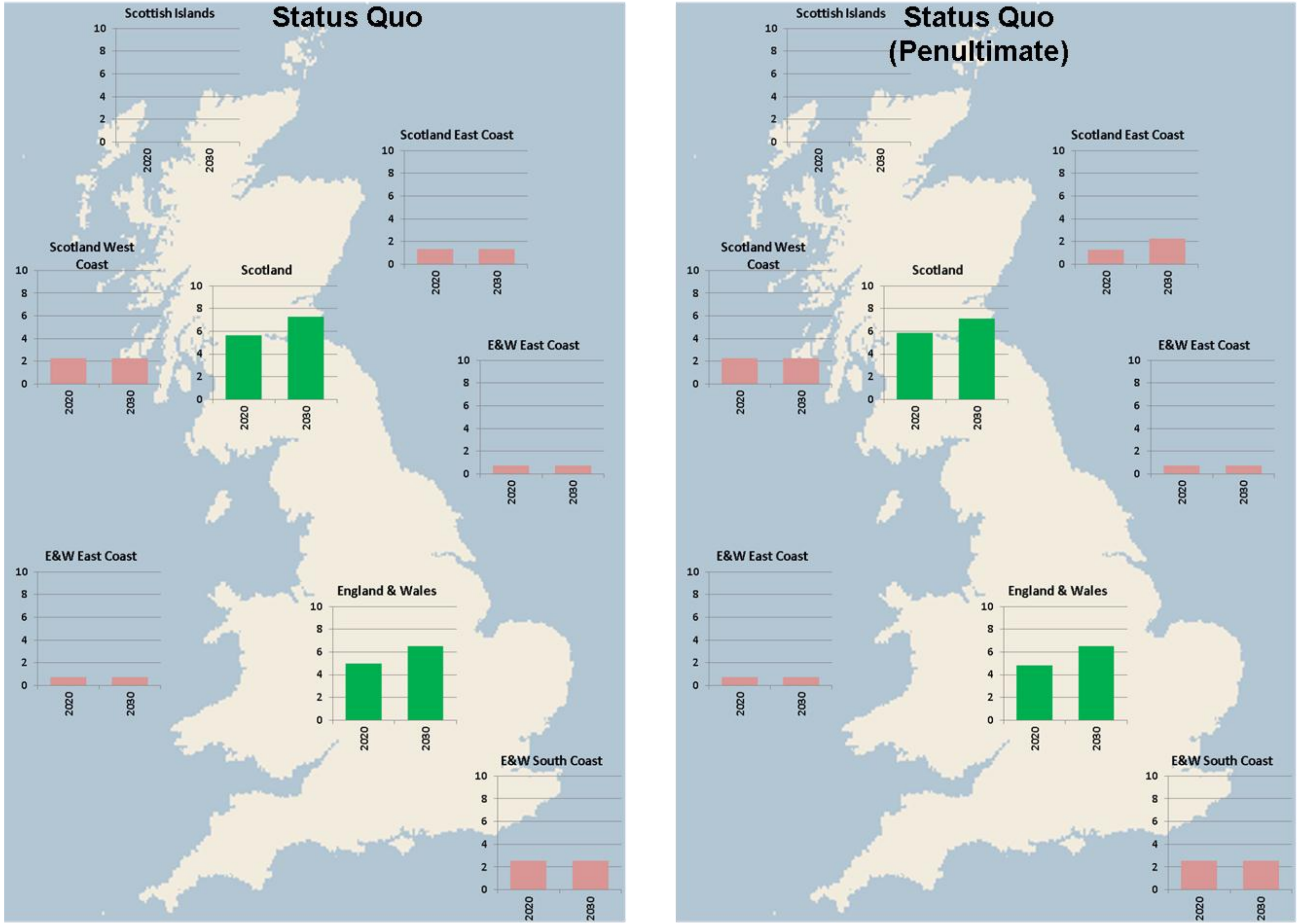
[18] Project TransmiT: Modelling the Impact of "Improved ICRP", Prepared for RWE npower, NERA Economic Consulting and Imperial College London, 12 October 2012, Figure 3.25

Figure 3.22
Locational of New Generation Investments by 2030 (Excl. Wind) – Status Quo, Final vs. Penultimate Iteration



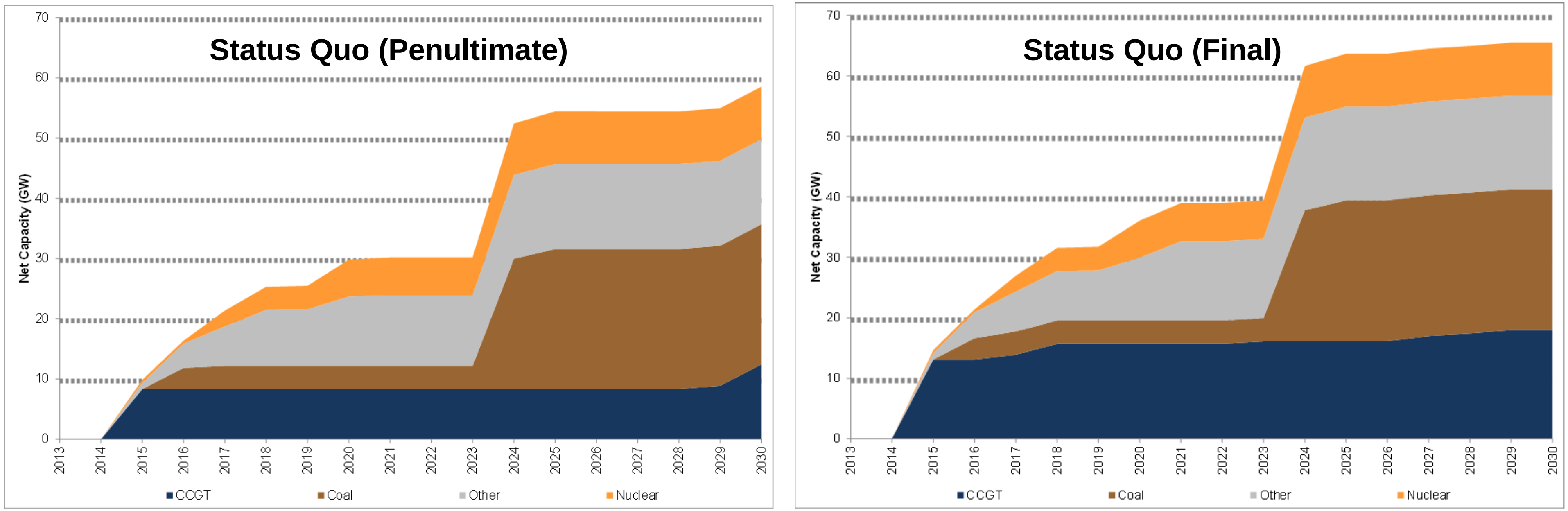
Source: NERA/Imperial

Figure 3.23
Locational of Wind Generation by 2030 – Status Quo, Final vs. Penultimate Iteration



Source: NERA/Imperial

Figure 3.24
Modelled Retirement Decisions – Status Quo, Final vs. Penultimate Iteration

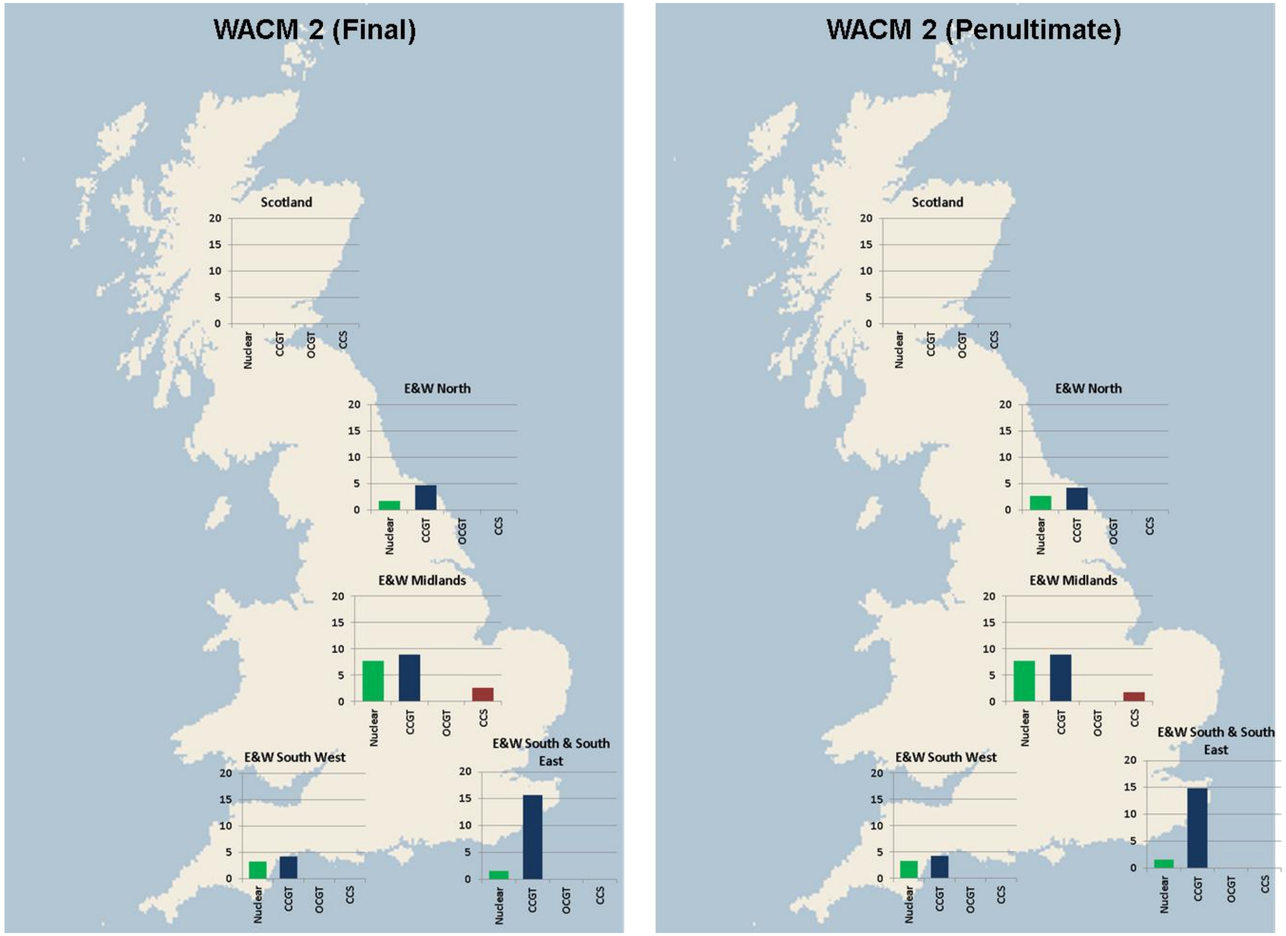


Source: NERA/Imperial

3.5.2. WACM 2

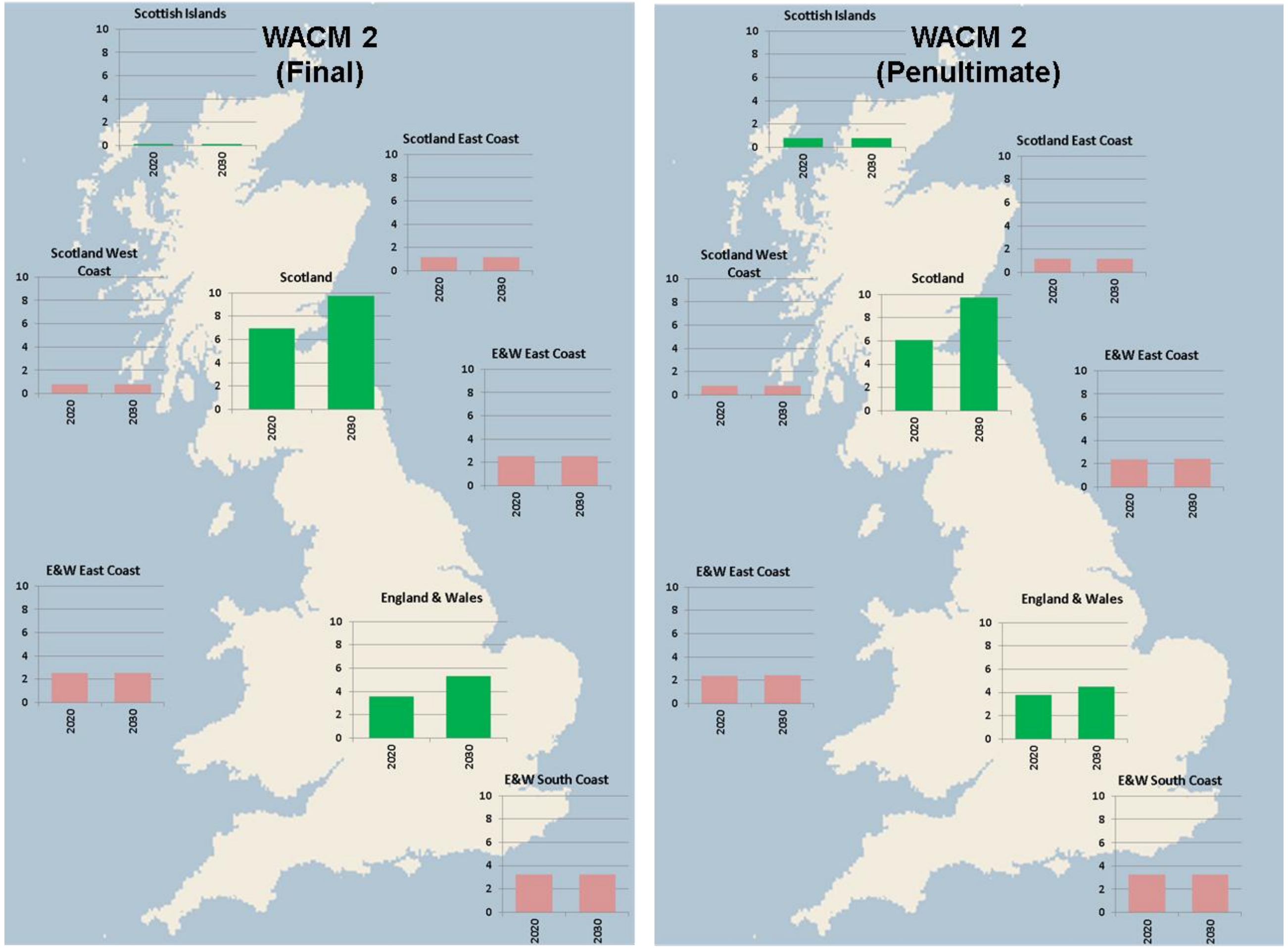
In the WACM 2 case, as Figure 3.25 illustrates, we see some instability in new CCGT and CCS investment patterns between the final and penultimate iterations, with some small differences in the location of that investment within England and Wales. The change in the amount of investment required is associated with variation between the final and penultimate iterations in how quickly existing generators retire, as Figure 3.27 illustrates. Given this instability in investment patterns, for the cost benefit analysis summarised in Chapter 4 below, and in presenting the results for the wholesale market modelling results shown in Section 3.1, our approach is to take the average effect of the WACM 2 charging methodology across the final and penultimate iterations of the model. As Figure 3.26 illustrates, we also see some small changes in wind investment between the final and penultimate iterations of the WACM 2 scenario, with some variation in the wind capacity developed on the Scottish islands.

Figure 3.25
Locational of New Generation Investments by 2030 (Excl. Wind) – WACM 2, Final vs. Penultimate Iteration



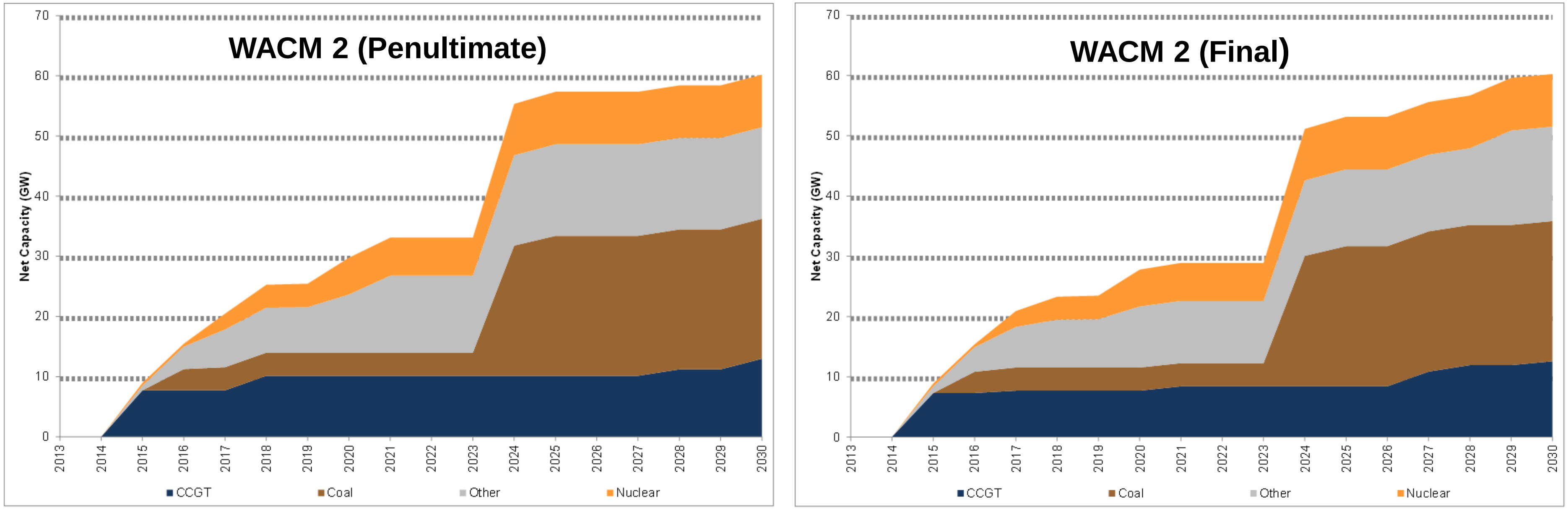
Source: NERA/Imperial

Figure 3.26
Cumulative Retirements of Existing Thermal Assets – WACM 2 Final vs. Penultimate Iteration



Source: NERA/Imperial

Figure 3.27
Modelled Retirement Decisions – WACM 2, Final vs. Penultimate Iteration



Source: NERA/Imperial

3.6. 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 be to increase the amount of new wind generation capacity that locates in the north of GB. Our analysis shows that locating more generation capacity towards the north of the country increases transmission system costs.

We find no difference in the environmental performance of the two charging models, as (1) we assume that renewables subsidies adjust to achieve a target of 30% of renewables in total power generation, and (2) both scenarios have similar levels of CO_2 emissions between 50g/kWh and 100g/kWh by 2030.

Finally, because WACM 2 increases the costs incurred by new entrant thermal generators in England and Wales, which determines the level to which wholesale power (energy+capacity) prices will need to rise to remunerate new investments will be higher under WACM 2. This effect will increase the costs consumers incur to purchase power on the wholesale market, as discussed further in the following chapter.

4. Welfare Effects

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 £1.7 billion over the period to 2030 and increase other power sector costs (e.g. the costs of developing and operating generation assets) by around £4 billion. Hence, WACM 2 causes a net increase in power sector costs of £5.7 billion. This increase in power sector costs proxies the reduction in overall social welfare caused by WACM 2.

Table 4.1
Effects of Introducing the WACM 2 Charging Model

	2014-2020	2021-2030	Total
Impact on Consumers			
Power Purchase Costs	1,484	233	1,717
Low Carbon Subsidies	821	1,935	2,755
D-TNUoS	412	331	743
Constraints	-49	165	116
Losses	268	422	690
Total	2,936	3,086	6,022
Power Sector Costs			
Generation Costs	1,157	2,890	4,047
Transmission Investment	501	389	890
Constraints	-49	165	116
Losses	268	422	690
Total	1,877	3,866	5,743

Source: NERA/Imperial. Note, a positive number indicates an increasing cost following the introduction of W. NPVs calculated between 2014 and 2030, using a real discount rate of 3.5%.

We also estimate that the introduction of WACM 2 would materially increase consumers' bills by around £6 billion in NPV terms over the period to 2030. Around £1.5 billion of this impact is due to increases in D-TNUoS, as well as constraint costs and losses, which we assume are passed through directly to consumers. Another £1.7 billion of the effect is down to the increase in power prices resulting from an increase in the long-run marginal cost of new entry into the wholesale power market. Low carbon subsidy payments also increase by around £2.7 billion.

Finally, although this welfare loss 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. For example:

- Although the increase in power sector costs is large, it is small as a proportion of total costs, and will be subject to a degree of "noise" as a result of the process of iteration between a series of market and transmission system models that we perform for this analysis. For instance, although these models have largely reached a converged solution, some instability remains from run-to run; and

- Our analysis is based on a single set of assumptions including regarding, amongst other things, generation and transmission costs, government policy regarding future subsidies, and demand growth. To reach more definitive conclusions regarding the impact of WACM 2, it would be necessary to run a number of sensitivities to identify whether the result is sensitive to any of these underlying drivers.

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 power prices.

By implementing changes to the current transmission charging regime that do not deliver demonstrable improvements in economic efficiency, 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.[19]

[19] See: Project TransmiT: Review of Ofgem Impact Assessment of Industry Proposals CMP213, Prepared for RWE npower, NERA Economic Consulting and Imperial College London, 25 September 2013, Section 2.

Appendix A. Modelled TNUoS Charges

Table A.1
Generation TNUoS Charges (2012 £/kW/yr) – Status Quo

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
North Scotland	24.06	24.66	19.87	17.88	29.58	30.05	31.31	29.68	27.08	26.45	25.45	31.19	30.02	27.65	27.83	26.97	18.33
Peterhead	22.24	20.28	15.37	13.43	25.03	25.50	26.76	25.18	22.42	22.00	20.51	26.48	25.47	22.41	22.80	21.94	13.16
Western Highland & Skye	28.03	29.32	24.60	22.47	34.41	34.89	36.16	34.40	31.81	31.22	31.24	36.06	35.01	33.57	33.78	32.92	24.62
Central Highlands	21.31	22.21	17.41	15.41	27.94	28.44	29.70	27.55	24.90	24.49	26.50	29.43	28.73	28.89	29.35	28.50	20.71
Argyll	17.22	18.32	13.63	15.36	27.09	27.58	29.39	28.72	26.21	25.74	28.30	31.48	31.30	31.86	32.07	31.24	23.13
Stirlingshire	16.72	18.38	13.61	12.07	23.51	23.99	25.58	24.35	21.76	21.19	23.29	26.67	25.71	26.33	26.60	25.72	18.46
South Scotland	14.99	15.91	11.42	9.85	19.35	19.81	21.04	19.93	17.23	16.38	18.29	21.36	20.27	20.80	21.03	20.12	15.29
Auchencrosh	14.86	15.92	11.36	10.37	22.92	23.44	25.21	26.26	23.90	23.32	26.11	30.20	30.60	31.16	31.39	30.49	21.73
Humber & Lancashire	7.40	8.12	3.66	1.79	0.60	0.92	1.07	0.95	0.66	0.37	0.24	-0.70	-0.55	-0.22	0.14	0.80	0.45
North East England	9.44	10.15	5.72	4.57	7.15	7.49	7.82	4.94	-1.13	-3.35	-2.13	4.63	3.89	4.36	4.64	3.90	2.97
Anglesey	8.88	8.22	4.09	1.85	-3.55	-3.22	-3.32	-3.26	-3.33	-3.69	-3.72	-8.86	-8.41	-7.78	-7.60	-7.36	-4.27
Dinorwig	8.13	8.43	3.87	1.84	-3.55	-3.22	-3.32	-3.26	-3.33	-3.69	-4.06	-9.33	-8.94	-8.36	-8.18	-7.94	-4.85
South Yorks & North Wales	5.70	5.94	1.57	-0.24	-1.76	-1.46	-1.61	-1.37	-0.61	-0.71	-0.65	-3.62	-3.61	-3.12	-2.91	-2.79	-2.10
Midlands	3.49	3.95	-0.78	-2.66	-4.90	-4.61	-4.18	-4.43	-3.87	-3.13	-3.07	-1.62	-1.21	-0.82	-0.76	-0.41	-0.23
South Wales & Gloucester	4.00	7.02	1.84	0.38	-2.30	-2.93	-3.07	-3.38	-3.23	-1.93	-2.13	-2.78	-2.11	-2.27	-4.34	-5.29	-5.53
Central London	-5.95	-20.44	-17.62	-13.01	-15.32	-15.15	-17.19	-17.69	-10.35	-13.73	-14.57	-7.45	-8.20	-8.03	-8.04	-5.42	-6.62
South East	2.43	4.53	-0.15	-1.38	-3.18	-3.42	-3.57	-4.15	-2.22	-1.82	-2.44	2.18	2.42	2.11	2.38	2.62	1.72
Oxon & South Coast	-0.77	0.95	-3.92	-5.28	-7.51	-7.80	-8.19	-8.54	-6.93	-6.40	-6.56	-5.03	-4.95	-4.93	-4.43	-5.38	-2.51
Wessex	-1.01	1.86	-1.83	-3.20	-5.89	-6.26	-6.57	-6.96	-5.38	-5.15	-4.74	-2.69	-1.43	-2.45	-2.67	-3.52	-4.49
Peninsula	-4.74	-0.28	-0.67	-1.85	-8.59	-8.92	-9.14	-9.49	-8.32	-7.47	-6.15	-3.23	-1.50	-2.94	-4.49	-4.14	-4.92

Source: NERA/Imperial

Table A.2
Generation (Peak) TNUoS Charges (2012 £/kW/yr) – WACM 2

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
North Scotland	2.55	1.93	1.37	3.27	-5.90	-6.04	-4.22	-5.27	-5.01	-6.57	-3.62	-16.27	-16.33	-15.25	-15.86	-14.59	-16.79
Peterhead	3.00	2.38	1.90	1.18	-6.97	-7.13	-5.27	-6.37	-7.57	-7.64	-4.60	-22.66	-17.85	-18.94	-17.39	-16.13	-18.32
Western Highland & Skye	0.80	0.23	0.68	2.43	-5.13	-5.28	-3.51	-4.57	-4.34	-5.90	-3.12	-14.19	-14.28	-13.20	-13.88	-12.60	-14.78
Central Highlands	1.90	1.12	1.29	0.90	-3.68	-3.81	-2.56	-3.40	-3.24	-4.62	-2.03	-13.64	-13.80	-12.65	-13.09	-11.93	-13.95
Argyll	2.91	2.27	1.85	0.93	-3.17	-3.32	-1.48	-1.80	-1.61	-3.06	-0.27	-11.43	-11.50	-10.21	-10.72	-9.46	-11.51
Stirlingshire	2.76	2.13	1.65	1.64	-1.79	-1.93	-0.00	-1.09	-0.80	-2.38	0.71	-11.55	-11.04	-10.41	-10.27	-9.07	-11.19
South Scotland	3.67	2.87	2.42	1.48	0.71	0.61	2.52	1.57	1.64	0.28	2.80	-9.61	-10.03	-8.82	-9.60	-8.71	-10.84
Auchencrosh	1.63	0.90	0.49	1.14	-2.27	-2.36	-0.81	-1.31	-1.26	-2.54	-0.07	-10.24	-10.31	-9.10	-9.64	-7.99	-10.07
Humber & Lancashire	4.17	3.27	2.82	1.83	0.56	0.41	2.75	1.52	1.60	0.76	3.88	-0.77	-0.71	-0.28	-1.20	-0.60	-1.57
North East England	3.93	3.77	3.40	1.91	1.21	1.08	3.43	2.02	2.10	1.17	4.08	-1.83	-1.84	-1.00	-1.76	-1.17	-4.57
Anglesey	6.84	5.69	4.79	4.89	4.24	4.06	4.27	3.16	3.19	2.31	5.78	0.91	1.09	2.80	2.68	3.14	2.70
Dinorwig	6.47	5.69	4.79	4.89	4.24	4.05	4.26	3.16	3.19	2.31	5.33	0.35	0.48	2.16	2.05	2.51	2.06
South Yorks & North Wales	3.10	2.42	2.07	1.53	0.86	0.79	2.68	1.66	1.81	1.13	3.64	-0.07	-0.01	1.04	0.47	1.01	0.54
Midlands	1.00	0.72	0.57	0.30	-0.07	0.20	1.29	0.60	0.57	0.27	2.12	3.47	3.71	4.15	3.60	3.44	3.66
South Wales & Gloucester	5.41	5.55	5.85	6.55	7.35	6.66	6.19	6.28	6.14	6.20	5.28	5.66	5.33	5.12	3.59	4.13	4.15
Central London	-3.86	-1.54	-3.54	-5.58	-5.54	-5.05	-3.01	-5.98	-3.15	-2.61	-6.85	2.40	3.51	1.44	3.16	1.04	3.22
South East	-4.99	-4.16	-3.68	-4.05	-1.97	-1.79	-2.96	-1.53	-1.12	0.86	-3.32	5.86	5.92	3.90	5.54	3.91	5.57
Oxon & South Coast	-1.74	-3.49	-3.02	-3.25	-0.62	0.05	-3.57	-1.96	-0.39	1.19	-4.79	4.35	4.95	2.34	4.70	2.26	3.66
Wessex	-1.34	0.67	0.93	2.47	3.98	4.50	1.56	2.74	2.44	3.10	-0.95	5.55	5.66	4.48	5.17	4.48	4.88
Peninsula	-0.33	1.79	2.11	6.56	8.50	8.61	4.70	6.42	4.35	6.24	1.25	7.10	7.03	5.83	6.17	5.83	6.20

Source: NERA/Imperial

Table A.3
Generation (Year Round - Shared) TNUoS Charges (2012 £/kW/yr) – WACM 2

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
North Scotland	12.40	12.73	12.71	11.82	18.22	18.52	17.06	19.75	19.42	18.27	15.53	9.98	9.89	9.99	11.08	10.67	10.34
Peterhead	13.21	13.59	13.98	13.90	15.75	16.02	14.59	17.57	17.24	16.02	13.29	7.19	7.05	7.18	8.21	7.90	7.53
Western Highland & Skye	11.55	12.00	11.81	11.35	15.75	16.02	14.59	17.57	17.24	16.02	13.29	7.19	7.05	7.18	8.21	7.90	7.53
Central Highlands	11.55	12.00	11.81	11.35	15.75	16.02	14.59	17.57	17.24	16.02	13.29	7.19	7.05	7.18	8.21	7.90	7.53
Argyll	8.39	8.97	9.12	9.40	14.22	14.56	13.46	16.97	16.72	15.45	12.78	9.39	9.30	9.39	10.40	10.33	9.94
Stirlingshire	8.55	9.18	9.48	9.10	14.59	14.86	13.48	16.53	16.16	14.99	12.25	6.02	5.91	6.04	7.10	6.80	6.45
South Scotland	7.28	7.72	8.00	7.48	9.16	9.37	8.33	11.87	11.69	10.27	8.03	5.23	5.12	5.22	6.28	5.97	5.62
Auchencrosh	7.61	8.10	8.32	7.75	9.60	9.88	8.94	14.77	14.63	13.05	10.78	6.65	6.51	6.59	7.68	7.74	7.38
Humber & Lancashire	0.77	1.63	2.12	2.45	2.20	2.32	1.18	1.88	1.92	1.03	-0.49	-0.15	-0.12	0.13	1.30	1.14	1.27
North East England	2.67	5.19	5.56	5.36	3.58	3.69	2.05	3.72	3.74	2.81	0.49	0.55	0.52	0.43	1.43	0.58	-0.86
Anglesey	-0.11	0.11	0.62	0.30	-0.21	-0.16	-0.54	0.60	0.66	0.01	-1.40	-1.00	-0.95	-1.04	-0.77	-1.17	-1.38
Dinorwig	-0.89	-0.49	0.41	-0.36	-1.16	-0.96	-0.14	0.52	0.56	-0.24	-1.40	-1.00	-0.95	-1.04	-0.77	-1.17	-1.38
South Yorks & North Wales	-0.11	0.11	0.62	0.30	-0.21	-0.16	-0.54	0.60	0.66	0.01	-0.86	-0.39	-0.37	-0.56	0.16	-0.49	0.37
Midlands	-0.05	0.10	0.30	-0.16	-0.84	-1.18	-1.47	-1.04	-0.96	-1.12	-0.90	-0.07	0.13	-0.62	0.07	-0.04	0.18
South Wales & Gloucester	-3.24	-3.79	-4.13	-3.22	-4.25	-3.51	-4.66	-5.23	-5.37	-5.26	-3.65	-3.29	-3.54	-4.84	-5.21	-5.97	-3.60
Central London	-4.48	-7.27	-7.17	-	-	-	-	-	-	-	-	-	-	-	-	-	-
South East	3.31	3.32	2.85	2.38	1.12	0.69	1.79	1.09	1.22	2.90	3.79	3.07	2.97	4.55	2.92	4.42	3.18
Oxon & South Coast	-2.32	1.18	0.08	-0.25	-1.16	-1.27	-1.82	-2.07	-2.56	1.60	5.81	0.15	2.20	1.35	1.90	4.22	3.04
Wessex	-2.35	-4.67	-4.93	-3.23	-4.17	-4.43	-4.73	-5.07	-5.57	-5.04	-1.69	-3.13	-3.08	-2.93	-3.51	-3.04	-2.74
Peninsula	-3.97	-6.46	-6.77	-4.12	-5.10	-5.12	-6.32	-5.86	-7.97	-6.17	-2.84	-4.51	-3.94	-4.46	-4.77	-4.58	-4.14

Source: NERA/Imperial

Table A.4
Generation (Year Round – Not Shared) TNUoS Charges (2012 £/kW/yr) – WACM 2

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
North Scotland	5.32	5.84	6.39	7.36	26.00	26.15	25.55	20.83	21.30	21.53	21.37	28.47	28.51	28.31	28.12	27.80	27.24
Peterhead	3.37	3.98	4.06	5.69	30.96	31.21	30.42	24.73	25.27	25.60	25.54	35.43	35.53	35.31	35.21	34.67	34.13
Western Highland & Skye	7.61	8.13	7.88	7.40	27.93	28.07	27.37	23.01	23.38	23.66	23.17	28.60	28.65	28.41	28.21	27.93	27.38
Central Highlands	3.37	3.98	4.06	5.69	16.54	16.56	16.09	12.48	12.94	12.93	12.81	17.80	17.62	17.57	17.10	17.16	16.49
Argyll	2.21	2.59	2.85	4.78	9.86	9.79	9.63	6.53	6.78	6.97	6.78	7.72	7.79	7.50	7.24	7.38	6.76
Stirlingshire	2.21	2.59	2.78	3.81	9.15	9.15	9.01	5.84	6.08	6.30	6.13	10.33	10.38	10.25	10.03	10.15	9.57
South Scotland	2.21	2.59	2.78	3.67	7.06	7.05	7.03	4.06	4.37	4.50	4.51	5.62	5.70	5.42	5.21	5.23	4.65
Auchencrosh	3.43	3.60	3.77	4.94	8.84	8.78	8.86	4.06	4.37	4.71	5.00	5.99	6.15	5.85	5.63	5.88	5.27
Humber & Lancashire	-	-	-	-	-	-	-	-	-	-	-	0.01	0.02	0.02	-	-	-
North East England	1.23	-	-	-	-	-	-	-	-	-	-	0.01	0.02	0.02	-	-	-
Anglesey	-0.78	-0.60	-0.21	-0.66	-1.15	-0.80	0.40	-0.07	-0.10	-0.25	-	-	-	-	-	-	-
Dinorwig	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
South Yorks & North Wales	-	-	-	-	-	-	-	-	-	-0.00	-	-	-	-	-	-	-
Midlands	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
South Wales & Gloucester	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Central London	-	-	-	-4.31	-7.82	-7.92	-3.74	-8.78	-6.82	-5.32	-5.44	-2.92	-3.49	-2.36	-3.47	-1.53	-3.31
South East	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Oxon & South Coast	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Wessex	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Peninsula	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Source: NERA/Imperial

Report qualifications/assumptions and limiting conditions

NERA shall not have any liability to any third party in respect of this report or any actions taken or decisions made as a consequence of the results, advice or recommendations set forth herein.

This report does not represent investment advice or provide an opinion regarding the fairness of any transaction to any and all parties. This report does not represent legal advice, which can only be provided by legal counsel and for which you should seek advice of counsel.

The opinions expressed herein are valid only for the purpose stated herein and as of the date hereof. Information furnished by others, upon which all or portions of this report are based, is believed to be reliable but has not been verified. No warranty is given as to the accuracy of such information. Public information and industry and statistical data are from sources NERA deems to be reliable; however, NERA makes no representation as to the accuracy or completeness of such information and has accepted the information without further verification. No responsibility is taken for changes in market conditions or laws or regulations and no obligation is assumed to revise this report to reflect changes, events or conditions, which occur subsequent to the date hereof.

NERA
ECONOMIC CONSULTING

NERA Economic Consulting
15 Stratford Place
London W1C 1BE
United Kingdom
Tel: 44 20 7659 8500 Fax: 44 20 7659 8501
www.nera.com