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Assessing the Cost Reflectivity of Alternative TNUoS Methodologies

Prepared for RWE npower

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Executive Summary

Background

In the context of Project TransmiT, RWE npower commissioned NERA Economic Consulting and Imperial College London to review the recent Impact Assessment published by Ofgem relating to proposals to reform the Transmission Network Use of System (TNUoS) Charging Methodology.[1] The review found that, despite Ofgem's claims to the contrary, the proposed charging model does not reflect the recent reforms to the transmission investment planning procedures set out in the National Electricity Transmission System (NETS) Security and Quality of Supply Standards (SQSS).

The review also highlighted the fact that Ofgem has failed to compare the costs generators impose on the transmission system to WACM 2 TNUoS charges. Hence, Ofgem did not have sufficient evidence to robustly conclude on whether or not the proposed charging model is more cost reflective than the status quo. In light of this, we carried out our own preliminary analysis to compare WACM 2 and status quo charges to the long-run marginal cost (LRMC) of transmission associated with different types of generators in a range of locations on the system. The results suggest that charges resulting from the WACM 2 methodology reflect the LRMC of transmission less closely than the status quo methodology.

The purpose of this report is to provide further information on the LRMC analysis we presented in our review of the CMP213 Impact Assessment. We also present the results of a number of sensitivities which test the robustness of our conclusions.

Methodology

The analysis presented in this report uses Imperial College's Dynamic Transmission Investment Model (DTIM). DTIM optimises generation dispatch and transmission network investment by balancing the costs of network constraints with the costs of network reinforcement, minimising the overall cost of power system operation and expansion over the period to 2030.

We use the DTIM model to estimate the LRMCs of transmission associated with generation technologies of different types in different parts of the system. We then compare these estimates of LRMC to the WACM 2 and status quo TNUoS charges that generators would face under the DTIM network configuration.

For our reference case, we adopt generation and demand backgrounds from National Grid's "gone green" scenario using data from 2013 to 2030. We also conduct a sensitivity which uses National Grid's "slow progress" generation scenario, to show the extent to which the outcomes of our analysis vary with the generation mix. We also conducted a series of sensitivities regarding the generation background, the assumed bid/offer spreads applied by

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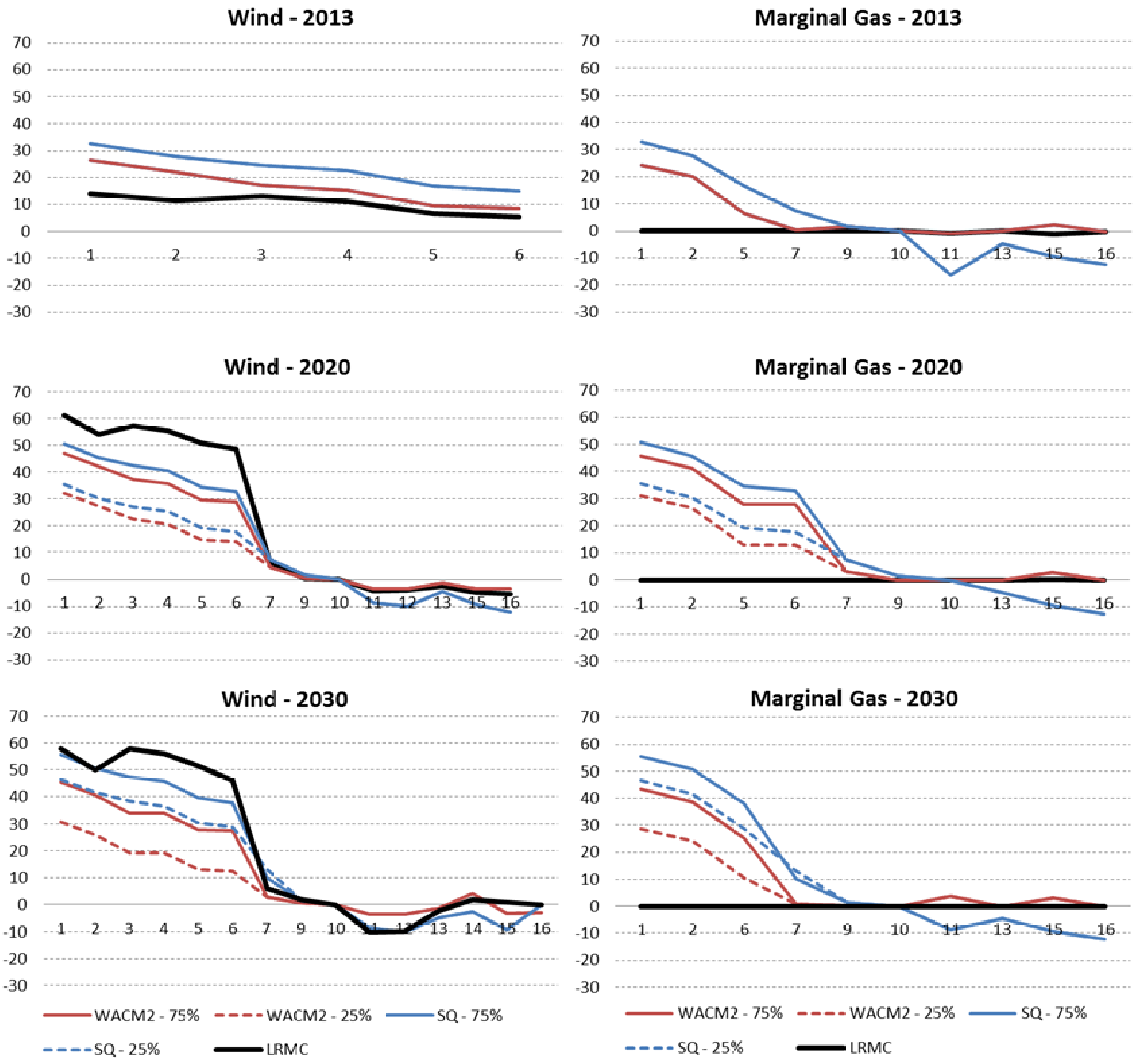
[1] Project TransmiT : Impact Assessment of industry's proposals (CMP213) to change the electricity transmission charging methodology, Ofgem (137/13), 1 August 2013.

generators when they offer capacity into the market, transmission investment cost assumptions, and alternative assumptions on HVDC utilisation in the charging methodology.

Key Results

Our analysis shows that, as the left hand side of Figure 1 illustrates, both the WACM 2 and status quo methodologies send locational signals to wind farms that understate the LRMC of transmission caused when they connect in Scotland relative to the LRMC of connecting in England and Wales. Because WACM 2 compresses the locational spread between tariffs in the north and tariffs in the south compared to the status quo, this analysis suggests that WACM 2 is less cost reflective for wind farms than the status quo.

Figure 1
TNUoS vs. LRMC for Wind and Marginal Gas Capacity in Reference Case (£/kW/yr, by DTIM Zone)



Source: NERA and Imperial analysis

Hence, WACM 2 will distort the trade-offs investors in wind farms make between regional variation in wind speeds and locational network access charges, causing more investment in wind farms in Scotland, and less in England and Wales, than is economically efficient. As a result, more transmission investments will be required than is economically efficient to transport output from Scottish wind farms to load centres towards the south of GB, which will inflate the costs of developing and operating the transmission system.

A significant cause of this result is the method used to set assumed utilisations on the HVDC bootstraps, which results in generators in Scotland, and wind farms in particular, paying less than the marginal cost that their presence imposes on the transmission system. Specifically, the need for the offshore HVDC bootstraps to reinforce the transmission system between Scotland and England/Wales is driven largely by significant volume of wind generation connecting to the system in Scotland.[2] Setting charges to Scottish generators below the marginal cost of providing capacity on these bootstraps sends inefficient signals to users regarding the costs their presence imposes on the transmission system.

As the right hand side of Figure 1 illustrates, WACM 2 and the status quo methodologies also set locational tariffs for peaking plants in Scotland in excess of the LRMC of transmission that their presence imposes on the system relative to the LRMC of connecting in other parts of the country. Because WACM 2 compresses the spread between tariffs in the north and tariffs in the south more than the status quo, this suggests that WACM 2 is more cost reflective for this category of generation. However, under both WACM 2 and status quo methodologies, TNUoS charges are lower for peaking plants in England and Wales than in Scotland. Hence, setting TNUoS for peaking plants in Scotland that are above the efficient level is unlikely to change locational decisions, and thus will have no impact on transmission system costs.

We also find material differences between estimated TNUoS tariffs and the LRMC of transmission caused by baseload gas and nuclear plants, suggesting neither model is cost reflective for these categories of generation. However, the difference between the two charging methodologies is negligible, suggesting that WACM 2 is no more or less cost reflective than the status quo for these technologies.

We have tested the sensitivity of these conclusions to changes in our fundamental modelling assumptions, and found that they do not change materially following changes in our assumed generation background, changes in transmission costs, and changes in our assumed bid/offer spreads applied by generators (a key driver of constraint costs).

Overall, therefore, our analysis shows that WACM 2 does not constitute an improvement on the existing methodology in terms of cost reflectivity. Furthermore, WACM 2 is probably less transparent, stable and predictable, than the status quo. Thus, whilst there may be a case for reforming the existing TNUoS charging methodology, we do not find any evidence to suggest that WACM 2 will better facilitate the relevant objectives for the use of system

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[2] According to National Grid, "*The main driver of the Western HVDC Link project is the large volume of renewable generation that is expected to connect in Scotland and Northern England over the next ten years.*" Source: National Grid Electricity Transmission, RIIO-T1 Detailed Business Plan, July 2011, page 34.

charging methodology, namely to promote competition and encourage efficient investment decisions through the application of cost reflective charges. Moreover, regulatory decisions that reform transmission charges that are not well justified on the grounds of improving efficiency will undermine the credibility of the new methodology, may reduce generators' responsiveness to the locational signals conveyed through TNUoS, and may reduce the efficiency of any locational decisions they take.

1. Introduction

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. At the same time, it suggested that "*improved ICRP is the right direction for transmission charging arrangements*".[3] However, following this consultation, it published a decision that suggested that "*the choice between Improved ICRP and the Status quo is not clear cut*".[4]

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.[5] 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. On 14 June 2013 the CUSC Panel submitted its Final Modification Report (FMR) to Ofgem for its consideration.[6]

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

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

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

5 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.

6 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.

"Workgroup Alternative CUSC Modification 2" (WACM 2).[7] 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).

In December 2013, Ofgem decided to postpone implementation of any new TNUoS methodology beyond the charging year 2014/15. It also committed to continue to engage with industry participants regarding the evidence received in response to its consultation on the CMP213 Impact Assessment before reaching a final decision on the candidate TNUoS methodologies. Ofgem is currently "*working towards making a decision in March 2014*".[8]

1.2. Our Previous Assessment of the WACM 2 Methodology

In response to Ofgem's recent consultation process, NERA and Imperial prepared a review of Ofgem's Impact Assessment and "minded to" decision paper, which RWE submitted alongside its consultation response.[9] Chapter 2 of this review considered whether the proposed WACM 2 charging methodology reflects the transmission investment costs that TOs are obliged to incur under the NETS SQSS to accommodate incremental generation capacity, and whether it does so better than the status quo methodology.

Our previous report concluded that, although the WACM 2 charging model reflects the costs of complying with the "demand security" standards imposed by the SQSS, it does not reflect the costs of adhering to the other two transmission network planning requirements specified in the new SQSS:

- We identified that none of the analysis performed by the CMP213 Workgroup or Ofgem had explicitly identified whether the binding driver of transmission investment (and hence the costs that should be reflected in TNUoS charges) is the SQSS "economic criterion" or the investments prescribed by full CBA;
- Some illustrative examples we prepared using a simple schematic transmission system (see Appendix B of our October 2013 report) showed that the proposed charging model does not reflect the costs imposed on the TOs by the need to comply with the "economic criterion" in the SQSS. Hence, if adherence to the SQSS "economic criterion" is the binding driver of investment, then the WACM 2 charging model is not cost reflective;
- We identified that neither the Workgroup nor Ofgem had performed any assessment of whether WACM 2 tariffs reflect transmission system costs prescribed by a CBA model better than those under the status quo or the alternative charging models Ofgem considered. We therefore concluded that, if the obligation to perform additional transmission investments that are justified on the basis of a CBA is the binding driver of

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7 Project TransmiT : Impact Assessment of industry's proposals (CMP213) to change the electricity transmission charging methodology, Ofgem (137/13), 1 August 2013., page 5

8 Project TransmiT: update on progress and next steps, Ofgem Letter, 16 December 2013.

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

investment, then the analysis considered by Ofgem in its Impact Assessment was inadequate for evaluating whether the WACM 2 model is cost reflective; and

- Our review of the analysis performed by the Workgroup and Ofgem that aimed to assess whether the proposed charging models reflect the costs of investment to accommodate generation prescribed by a CBA model showed that this analysis was flawed and incomplete. Our own comparison between incremental transmission costs (estimated using a CBA model) and WACM 2 suggested that the WACM 2 charging model is no more cost reflective than the status quo methodology.[10]

Overall, our analysis therefore showed there was no objective basis for Ofgem's claim that the WACM 2 charging model would improve the cost reflectivity of transmission charging, and hence does not achieve the objective set out in Ofgem's direction to NGET to develop a methodology that *"better reflects the transmission investment framework set out in the NETS SQSS"*.[11] Also, we concluded it does not better achieve the objectives of the Use of System Charging Methodology, set out in Condition C5 of National Grid's Licence, that charges should "*reflect, as far as is reasonably practicable, the costs incurred by the transmission operator*" because the methodology does not reflect the costs of providing the investments prescribed by the SQSS.

1.3. Scope of this Report

The purpose of this report is to provide further information on the analysis we presented in our review of the CMP213 Impact Assessment to compare WACM 2 and status quo charges to the long-run marginal cost (LRMC) of transmission (estimated using a CBA model).

The remainder of this report is structured as follows:

- Chapter 2 describes the importance of assessing how closely the charges resulting from alternative TNUoS methodologies reflect the LRMC of transmission;
- Chapter 3 provides a summary of our modelling assumptions;
- Chapter 4 sets out in detail the method we use to estimate both the LRMC of transmission expansion using a CBA model, and calculate the WACM 2 and status quo charges that are consistent with these estimates of LRMC;
- Chapter 5 presents our modelling results; and
- Chapter 6 concludes.

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[10] See Chapter 5. We found that WACM 2 tariffs were further from LRMC than status quo tariffs for wind plants in Scotland, but closer to LRMC for thermal peaking plants in Scotland. The differences between the two charging models were smaller for baseload plants.

[11] Project TransmiT : Impact Assessment of industry's proposals (CMP213) to change the electricity transmission charging methodology, Ofgem (137/13), 1 August 2013, para 2.10

2. The Role of Long Run Marginal Cost in Transmission Pricing

In this chapter, we set out the basis for benchmarking alternative TNUoS methodologies against estimates of the LRMC of transmission reinforcement.

2.1. The Importance of Locational Signals

Electricity is a homogenous product at the points of production and consumption. This characteristic means that all electricity is the same from the perspective of consumers, whatever technology is used to generate it or wherever it was produced. However, electricity is characterised by significant transport costs. As a result, the location of generation capacity relative to the location of consumption within an electricity grid can significantly affect the overall costs of supplying end-users.

The costs of transporting electricity fall into two broad categories: fixed infrastructure costs and short-run marginal costs (congestion and losses), as defined below:

- **Infrastructure and Operating Costs:** In order to move power from one location to another, transmission infrastructure, including power lines, cables, transformers and other equipment, is required. The cost of building and maintaining these assets depends on their capacity to transport electricity from one area to another and the distance over which this capacity is provided, regardless of any flow of energy over those assets.
- **Short-Run Marginal Costs:** Once energy starts to flow over the infrastructure assets, it imposes additional costs of two kinds:
  - **Constraint Costs:** When insufficient transport capacity is available to accommodate power flows, instead of transporting power from one area to another, expensive generators that would not be dispatched in an uncongested system have to be dispatched to ensure supply exactly equals demand in all areas.
  - **Losses:** The further energy travels along a transmission line, the higher the proportion of the energy that is lost. This lost energy has to be replaced, at a cost, by increasing total generation output.

The mechanisms used to allocate these transport costs to generators can materially affect the value of a generator and the value of its output. Hence, they can also affect generators' locational decisions. In theory, signalling electricity transport costs to generators through energy and/or infrastructure prices can give them an incentive to make an efficient (i.e. cost minimising) trade-off between all the factors that vary by location. For instance:

- The choice of where to locate wind farms entails a trade-off between regional variation in wind speeds and the costs they impose on the transmission system; and
- The choice of where to locate gas-fired generators entails a trade-off between regional variation in gas and electricity transmission system costs, along with other factors such as the availability of cooling water, etc.

The signals conveyed to investors through the charges that recover the costs of infrastructure, constraints and losses therefore provide a means of ensuring that generation investors make a least cost trade-off between their own generation costs and the transmission costs their presence imposes on the system, and hence promotes economic efficiency.

2.2. Locational Marginal Pricing

2.2.1. A market design that uses Locational Marginal Pricing (LMP) of energy sends efficient locational signals

One means of sending efficient locational signals to generators is through a system of Locational Marginal Pricing (LMP) of energy, whereby energy prices reflect the short-run marginal costs (SRMCs) of generation and transmission at each node on the network. The costs of losses and congestion then show up as differences between energy prices at different nodes on the network.

LMP is efficient in the short-run as prices reflect the impact of losses and constraint costs and therefore promote the optimal use of the existing network. SRMCs also provide efficient locational signals for new generation capacity, incentivising investors to build in areas where constraint costs are high, thereby serving to relieve constraints on the system.

As such, LMP "*is the electricity spot pricing model that serves as the benchmark for market design – the textbook ideal that should be the target for policy makers. A trading arrangement based on LMP takes all relevant generation and transmission costs appropriately into account and hence supports optimal investments*".[12] Indeed, the efficiency benefits of LMP were recognised during the policy debate that led to the development of the Investment Cost Related Pricing (ICRP) charging model. National Grid noted in its 1992 review of transmission charging methodology that "*real time SRMC (LMP) provides precisely correct economic signals, and hence provides appropriate locational incentives to National Grid's customers*."

2.2.2. In the absence of locational energy pricing, efficient signals can only be conveyed through infrastructure charges

Although the efficiency advantages of LMP are well-established in academic literature on electricity market design, at present there is no locational pricing of energy in the British electricity market:[13]

- The British wholesale market is characterised by a single national wholesale price which reflects the marginal cost that would prevail in an unconstrained system;
- Transmission constraints are resolved through the Balancing Mechanism (BM), whereby generators 'bid' or 'offer' to either increase or decrease generation. Therefore, although the presence of transmission constraints may allow generators to capture additional value compared to the national wholesale price through the BM, there is limited locational pricing of energy. National Grid socialises the cost of the actions it takes through the BM to manage transmission constraints through the Balancing Services Use of System

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[12] International Energy Agency, Tackling Investment Challenges in Power Generation in IEA Countries: Energy Market Experience, Paris, 2007, page 16.

[13] National Grid considered introducing a form of LMP in a 1992 review UK transmission charging but decided against it, due to foreseen practical difficulties associated with implementing such a scheme and potential lack of transparency. LMP is not currently being considered as one of the options for change within Ofgem's on-going review of UK transmission charging, Project Transmit.

(BSUoS) charge, which is a flat (i.e. non-locational) charge per MWh of generation levied on all generation output; and

- The costs of losses are paid by generators and consumers through small reductions or uplifts to the volume of power production or consumption accredited to them under the settlement system. These adjustments do not vary by location.

Hence, in the absence of locational energy pricing, the only means of sending efficient locational signals regarding electricity transmission system costs to users is through the TNUoS charges levied on generators to access the transmission system.

2.2.3. Transmission tariffs reflecting the LRMC of infrastructure can proxy the efficient signals conveyed by LMP through locational SRMCs

In the absence of LMP (or any other form of zonal energy pricing) in the wholesale market, efficient signals regarding the SRMC of energy can still be conveyed to users through transmission infrastructure charges. If the transmission system is planned optimally, then the SRMC of energy can be approximated by the long-run marginal cost of transmission infrastructure. As a team from Strathclyde University and Birmingham University (2011) noted in their recent report for Ofgem:[14]

> "*LMPs and the associated transmission prices are the most efficient system of charging for transmission, reflecting the actual state of the electricity system and its associated short-run marginal costs. If the transmission companies undertake the appropriate investments, these short-run marginal costs should also be a good approximation of the long-run marginal costs of transmission, at least when the former are averaged over time.*"

Hence, the efficient signals conveyed to users under LMP can be approximated through infrastructure charges set equal to the LRMC of transmission.[15]

2.3. LRMC as a Benchmark for Cost Reflective TNUoS

2.3.1. The original ICRP methodology was intended to reflect the LRMC of transmission reinforcement

Despite the absence of locational energy pricing in the British wholesale market, sending the same efficient locational signals to users that would result from LMP can be achieved by setting TNUoS charges equal to the LRMC of transmission required to accommodate users of different types at each node on the network.[16]

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[14] Keith Bell et al. Birmingham and Strathclyde Universities February 2011, Academic Review of Transmission Charging Arrangements, page 48.

[15] Accordingly, our method for estimating an access charge that is fully consistent with LRMC (see Chapter 4) effectively derives LRMC by averaging nodal SRMCs over the year.

[16] For the avoidance of doubt, note that an LRMC-based charging methodology does not seek to recover or reflect constraint costs through infrastructure charges. Instead it aims to reflect the through charges the LRMC of

National Grid recognised the importance of LRMC as a standard for efficient transmission tariff design in its original 1992 review of transmission access charges, noting that "*the valuation of long run marginal costs is a natural starting point for tariff design in a capital intensive, regulated industry*".[17] National Grid therefore developed the original ICRP methodology as a means of approximating the LRMC of transmission.[18] However, National Grid and the Director General of Electricity Supply both recognised that the ICRP was only a proxy for LRMC, and further improvements to better reflect LRMC were possible:

- National Grid considered another LRMC-based charging methodology as part of its 1992 review, referred to as "scenario based LRMC", which aims to provide a more accurate estimate of LRMC than the ICRP approach by taking into account the likely level and location of demand and generation on the UK transmission network over a thirty year period at three or five year intervals. However, National Grid doubted whether such a method could be accurately applied. [19]
- The Director General of Electricity Supply accepted National Grid's ICRP charging methodology in a statement of 27 November 1992. However during a price control review of National Grid in 1996, the Director General stated that National Grid should "*consider taking greater account of the short term costs and opportunities reflecting the extent of spare capacity on the system at any time and place*".[20] In other words, the Director General recognised that the ICRP methodology was (and remains) an imperfect approximation of LRMC, because it does not reflect the extent to which scarcity or surpluses of capacity at certain points on the network affect future investment costs.

2.3.2. Even if proposed transmission tariffs differ from LRMC, it is possible to assess how closely they approximate LRMC

While it is technically possible to set tariffs equal to LRMC, the process surrounding the development of the ICRP methodology illustrates there may be some practical difficulties associated with doing so. However, it is possible, when designing a TNUoS methodology, to estimate how closely the proposed tariffs approximate the LRMC of transmission.

For example, although National Grid rejected the "scenario based LRMC" methods that it considered would more accurately reflect LRMC than the ICRP method, it used the results

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infrastructure costs TOs incur to efficiently accommodate additional generation capacity. However, in an optimally planned transmission system, there is no difference between the charges that would result from these alternatives.

17 National Grid, 30 June 1992, *Transmission Use of system Charges Review*, Proposed Investment Cost Related Pricing for use of System, page 41. Emphasis added.

18 We conclude that National Grid intended that the ICRP methodology should approximate LRMC because it notes that the optimisation problem required to implement these calculations "*solves for the LRMCs of each node".* Source: National Grid, 30 June 1992, *Transmission Use of system Charges Review*, Proposed Investment Cost Related Pricing for use of System, page 52.

19 National Grid, 30 June 1992, Transmission Use of system Charges Review, Proposed Investment Cost Related Pricing for use of System, page 43

20 Offer 1996, *The Transmission Price Control Review of The National Grid Company*: *Third Consultation, page14*

from modelling of the "scenario based LRMC" method to investigate the extent to which ICRP is a good approximation of true LRMC: [21]

> "*In fact, in 1992, the National Grid Company did estimate long-run marginal costs properly, by comparing the differences in investment costs between two scenarios and a base case with the differences in revenue yielded by the Investment Cost Related Prices for transport in the imaginary system. Under a high demand growth scenario, with new generation mainly in the North and with closures concentrated in the South, incremental revenue would fall significantly short of incremental investment cost. Under low demand growth and with new generation concentrated in the South, revenue would follow capital expenditure closely.*"

Thus, whilst the 1992 review decided not to implement a transmission charging methodology based on detailed calculations of LRMCs for a range of generation and demand scenarios, this evidence suggests that National Grid used estimates of LRMC as a benchmark against which to assess the cost-reflectivity of the proposed transmission charging methodology.

2.3.3. Setting charges close to LRMC is consistent with the investment costs imposed on TOs under the SQSS

Historically, transmission network investment has been driven by the need to provide a secure network at times of peak load. The philosophy of the existing TNUoS charging methodology was clearly aligned with this historical network investment driver and the investment process that was specified in the original NETS SQSS "peak demand" condition.

However, recent reforms of the NETS SQSS have changed this situation, and investment is now driven by both the need to provide peak security, and the need to make an economic trade-off between constraint and investment costs, as we describe in detail in Section 2.2 of our review of the CMP213 Impact Assessment.

Assuming the transmission system is planned optimally, as described above in Section 2.2, the costs that TOs incur to make an optimal trade-off between investment costs and constraint costs are reflected through tariffs set equal to the LRMC of transmission required to accommodate incremental generation capacity.

2.3.4. Neither Ofgem nor National Grid has compared the charges resulting from any of the proposed charging methodologies to LRMC

A number of statements made by National Grid and Ofgem throughout the Project TransmiT and CMP213 processes seem consistent with the aim of adjusting the TNUoS methodology to reflect the LRMC of transmission incurred by TOs under the new NETS SQSS. For example:

> "*…the defects that CMP213 seeks to address is focused only on improving the long run TNUoS signal which is to recover long term costs of transmission system build as opposed to short term constraint costs on the system. We do not consider the efficient*

[21] Ralph Turvey 2000, *What Are Marginal Costs and How to Estimate Them,* page 25.

> *recovery or signalling of short run SO costs (via BSUoS) to be part of the scope of TNUoS charging and therefore is not integral to our CMP213 assessment*".[22]
>
> "*the majority of transmission investment is no longer planned on a deterministic basis for peak demand conditions and is increasingly planned using cost benefit analysis techniques for conditions expected to occur across all times of the year".*[23]
>
> *"it is the CBA method of transmission network planning and the relationship between the SRMC and LRMC of transmission that allows for an investigation of the impact that an additional 1 Megawatt (MW) of generation plant has on constraint costs in order to quantify its incremental network requirements on a network where transmission network capacity is shared*".[24]

As noted above, setting transmission tariffs equal to the LRMC of transmission investment (at least in the absence of LMP) sends the most efficient locational signals to users, and we have surveyed precedents of National Grid benchmarking ICRP tariffs to LRMC. Hence, we conclude that the only credible means of assessing whether the alternative charging methodologies emerging from the CMP213 process are "cost reflective" (or more cost reflective than the status quo) is to compare proposed tariffs to LRMC.

As discussed in Section 2.3 of our review of the CMP213 Impact Assessment, in the recent Project TransmiT and CMP213 processes, neither Ofgem nor National Grid has compared the charges resulting from any of the proposed charging methodologies to LRMC.

2.4. Conclusions

Efficient locational signals are important in competitive power markets for ensuring that investors make an efficient trade-off between their own costs and the costs of transmission infrastructure, constraints and losses that their presence imposes on the system. One means of sending efficient locational signals to generators is through LMP, whereby energy prices reflect the SRMC of generation and transmission at each node on the network.

However, while the efficiency advantages of LMP are well-established in academic literature on electricity market design, at present there is no locational pricing of energy in the British electricity market. In the absence of LMP (or any other form of zonal energy pricing) efficient signals regarding the SRMC of energy can still be conveyed to users through transmission infrastructure charges. If the transmission system is planned optimally, then the SRMC of energy can be approximated by the LRMC of transmission, and signalled through infrastructure charges set to reflect LRMC.

The notion that transmission tariffs should reflect LRMC was considered during the 1992 review of transmission access charges, when National Grid developed the original ICRP

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[22] Ofgem 2013, *Project TransmiT: Impact Assessment of industry's proposals (CMP213) to change the electricity transmission charging methodology*, page 52

[23] CMP213 Project TransmiT TNUoS Developments, Stage 05: Draft CUSC Modification Report – Volume 1, para 3.14.

[24] CMP213 Project TransmiT TNUoS Developments, Final Modification Report, June 2013, Annex 4, Para 4.19.

methodology as a means of approximating the LRMC of transmission. Whilst the 1992 review decided not to set TNUoS equal to a precise calculation of LRMC, National Grid did use calculations of LRMC as a benchmark against which to assess the cost-reflectivity of the then-proposed ICRP transmission charging methodology.

Based on this evidence, we conclude that the only credible means of assessing whether any of the charging methodologies proposed following the CMP213 process are "cost reflective" is to compare proposed tariffs to LRMC. As discussed in Section 2.3 of our review of the CMP213 Impact Assessment, in the recent Project TransmiT and CMP213 processes, neither Ofgem nor National Grid has compared the charges resulting from any of the proposed charging methodologies to LRMC.

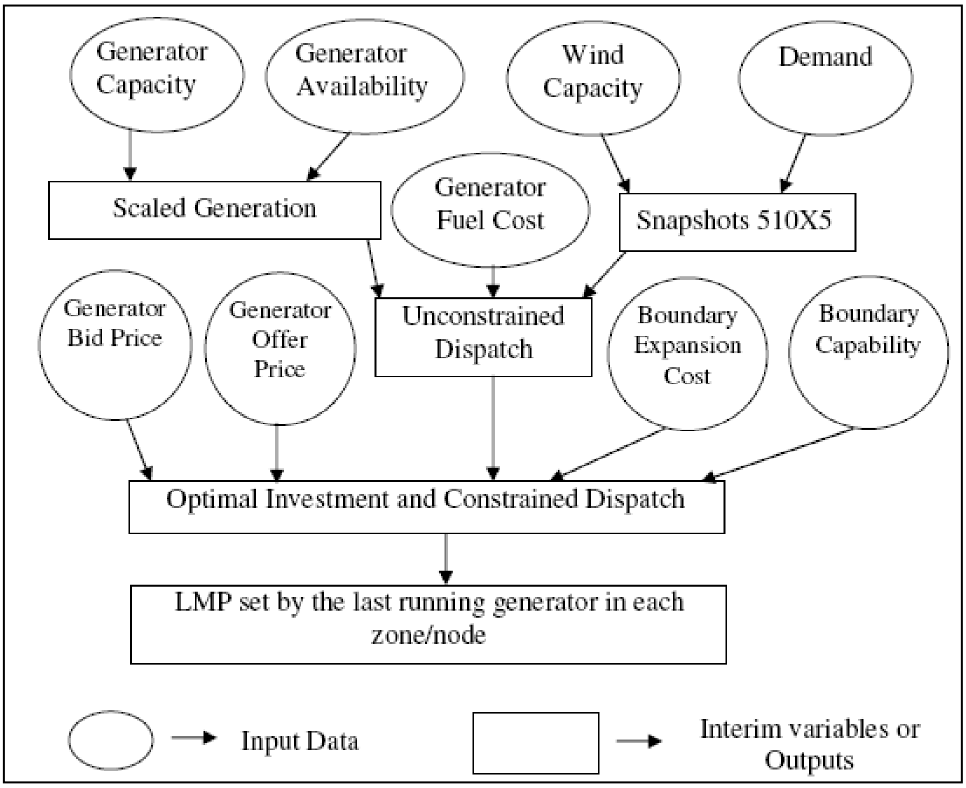
3. Modelling Assumptions

As described further in Chapter 4, we have used the Imperial DTIM model to estimate LRMCs of transmission reinforcement associated with generation technologies of different types in different parts of the system. This chapter describes the modelling assumptions used to calibrate DTIM.

3.1. Overview of DTIM

DTIM is a model developed by Imperial College/SEDG for the purpose of supporting optimal transmission investment decisions on the transmission system in Great Britain. DTIM balances the costs of network constraints with the costs of network reinforcement, minimising the overall cost of power system operation and expansion over a given duration (e.g. the next twenty years), as described in Section 4.1 below. Throughout the optimization period the model determines when, where and how much to invest using data inputs including a demand forecast, current and future fuel costs, bids and offer prices, evolution of installed generation capacity, the location and quantity of new wind capacity, transmission and generation maintenance plans, etc. Figure 3.1 summarises the inputs and outputs required by DTIM.

Figure 3.1
DTIM Inputs and Outputs



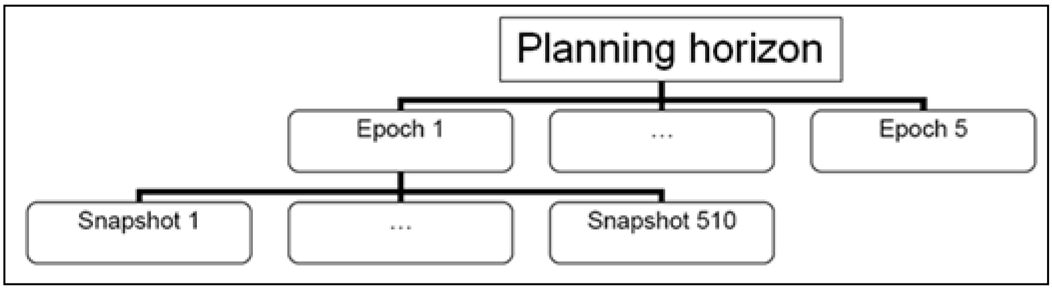
Source: Source Imperial College/National Grid

3.2. Definitions of Epochs and Planning Scenarios

For this assignment, we divided the 2010-2030 modelling horizon into five "epochs" of four-five years. Investment in transmission capacity can take place at the beginning of each epoch.

Throughout an epoch, generation capacity is assumed to be static, whereas generation fuel costs and availabilities can be varied seasonally. Each epoch consists of a number of representative snapshots, designed to represent a range of fundamental demand and supply conditions.

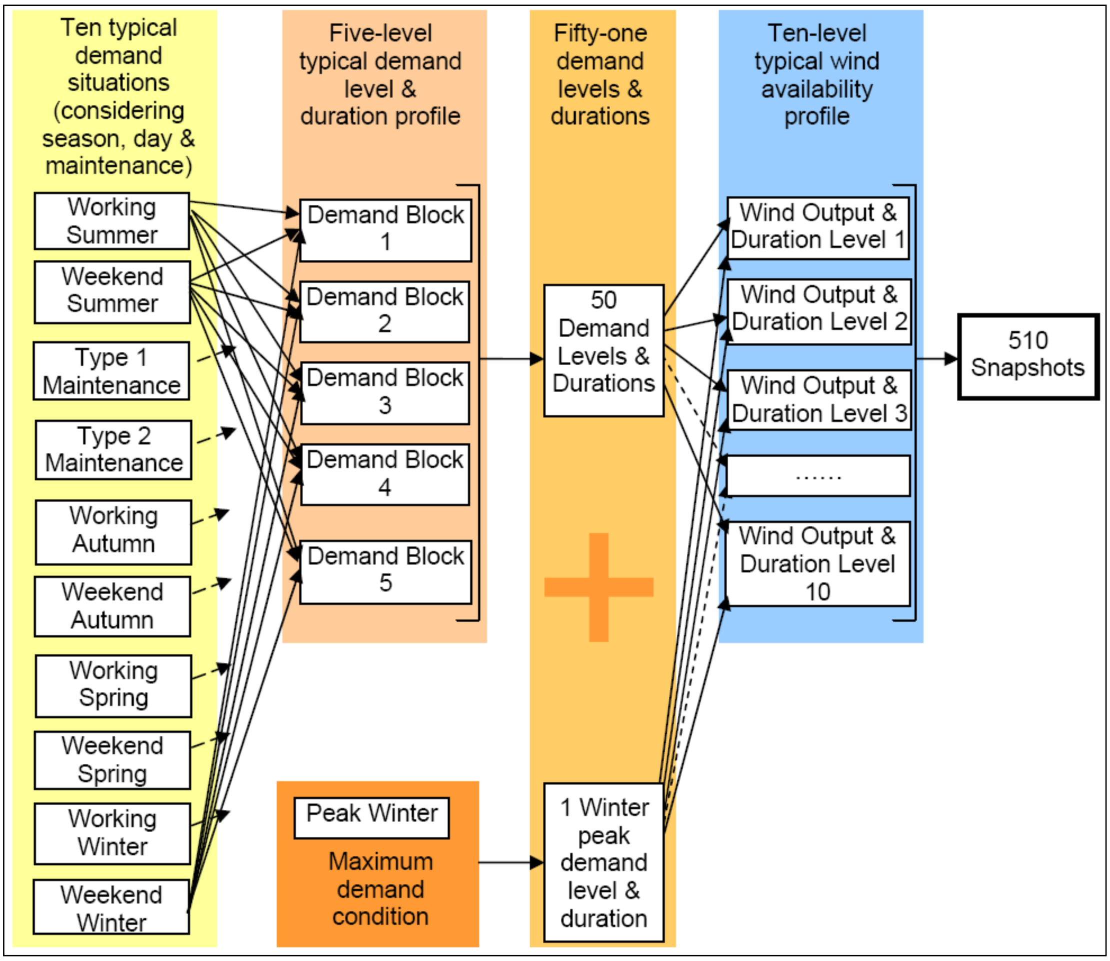
Figure 3.2
DTIM Epochs



Source: Imperial College

The 510 snapshots are obtained by combining 51 demand levels with 10 wind output levels. Of the 51 demand levels (each with a duration specified within the model), one of them represents the level of winter peak demand, and the other 50 are derived from 5 daily demand blocks that apply on 10 typical days. The 10 typical days are working days and weekends for winter, spring, summer, autumn and boundary maintenance seasons respectively. In addition, the boundary maintenance days can represent the demand levels of any season specified by the user. The demand levels are adjusted to take into account any intermittent embedded generation including PV and hydro. Figure 3.3 summarises this process.

Figure 3.3
DTIM Snapshot Definitions



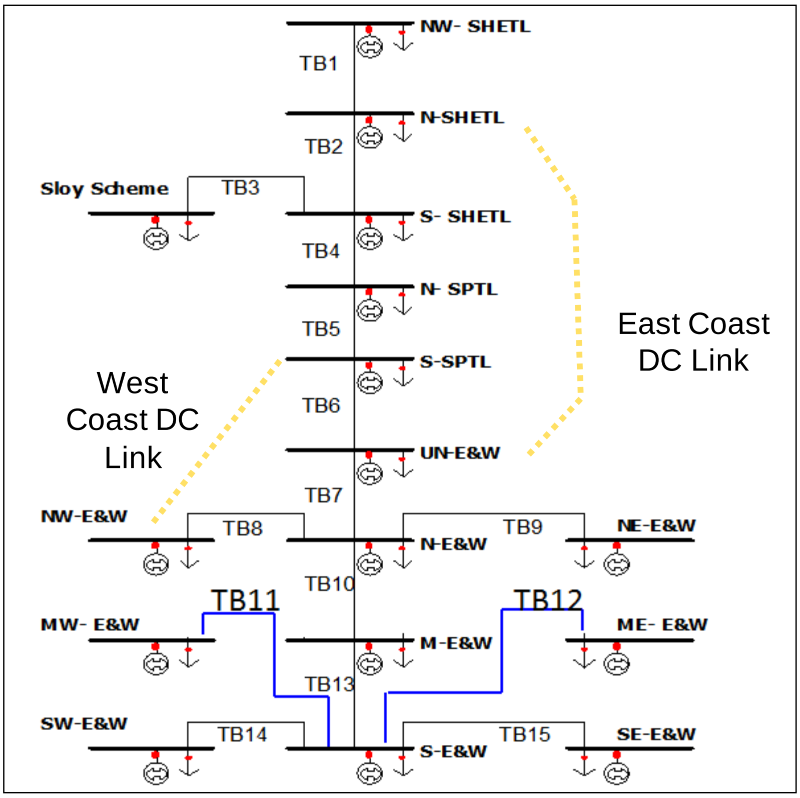
Source: Imperial College

3.3. Network Topography

DTIM uses a 16-zone, 15-boundary radial network to represent the GB transmission network, as shown in Figure 3.4. Each node represents a GB zone, and each branch represents a boundary. The network was developed by Imperial College and has been used extensively in the past for supporting the Transmission Access Review (TAR), the fundamental review of the SQSS, and by National Grid to validate a CBA exercise performed for the ENSG. We have also included the Western and Eastern DC links in the model, and allowed DTIM to optimise the timing and capacity of these "bootstrap" investments.

In order to reflect the need for the HVDC bootstraps, we include constraints on maximum boundary capacities, the most important of which is the maximum capacity of 4.4GW on the Cheviot boundary (any further increase in Scotland –England transmission capacity can be delivered only through the HVDC links).

Figure 3.4
DTIM Radial Network



Source: Imperial Analysis

The transmission boundaries shown above in Figure 3.4 can be mapped onto those boundaries identified in the SYS, as follows:

- DTIM boundaries TB1 to TB6 equate to SYS boundaries 1-6;
- DTIM boundary TB7 is mapped to a non-SYS boundary, known as B7a, which runs South-of-Penwortham rather than South-of-Harker;
- DTIM boundary TB8 is a non-SYS boundary to North Wales, namely West of Deeside and West of Treuddyn;
- DTIM boundary TB9 is mapped to the Humber Estuary boundary, namely East-of-Keadby and cuts across Thorton--Creyke Beck circuit;
- DTIM boundary TB10, TB13 and TB15 are SYS boundaries B8, B9 and B15 respectively;
- DTIM boundary TB11 is south Wales boundary, namely West-of-Walham plus West-of-Melksham;
- DTIM boundary TB12 can be mapped to East Anglia., ie. transmission zones Norwich Main, Sizewell and Bramford; and
- DTIM boundary TB14 maps to the boundary to Cornwall, Devon and Somerset (NGET FLOP zones F and E). that's SYS boundary B13, SYS zone Z13.

The initial capacities and thickness of each transmission boundary are shown in Table 3.1 below, although as noted above, these boundaries can be expanded by the model.

Table 3.1
DTIM Transmission Boundary Characteristics

Transmission corridor	2010 Transfer Capability (MW)	Boundary Thickness (Distance, km)
SHETL- North West	400	60
SHETL- North to South	1600	100
SHETL- Sloy Export	210	50
SHETL – SPT	1550	120
SPT- North to South	2618	35
SPT – NGET	2200	150
NGET - Upper North – North	3573	150
NGET - North Wales	3000	79
NGET- Humber	5500	40
NGET- North to Midlands	10000	93
NGET- South Wales	3500	75
NGET- East Anglia	2800	80
NGET- Midlands to South	10000	155
NGET- South West	3477	195
NGET- Estuary	5000	60
HVDC East Coast	0	300
HVDC West Coast	0	250

Source: Imperial College

For each boundary, the model requires data on the thickness, seasonal rating, initial capacity and transmission expansion costs. The expansion cost is a piece-wise linear function which consists of up to 5 sections. The ratings of boundaries are scaled by different factors corresponding to five seasons (Summer, Autumn, Winter, Spring and Maintenance) and windy/non-windy conditions.

3.4. Generation Backgrounds

As described in Chapter 5, we have estimated the LRMC of transmission investment and associated WACM 2 and status quo tariffs under two scenarios on the future GB generation mix. We use National Grid’s latest “gone green” and “slow progress” scenarios to show the extent to which the outcomes of our analysis vary with the generation mix. As the tables show:

- The “gone green” case has materially more wind capacity than the “slow progress” case (57GW in GG vs. 34GW in SP by 2030);
- The “gone green” case has more nuclear capacity (13GW in GG vs. 9GW in SP by 2030);
- The “gone green” case has more other renewables (26GW in GG vs. 11GW in SP by 2030); and

- Both cases have around the same level of fossil-fuel fired thermal capacity (49GW in GG vs. 47GW in SP by 2030).

The generation and demand inputs that we used are shown in Table 3.2 and Table 3.3. We distribute the capacity shown in the table around the system using the same locational assumptions as Imperial developed in discussion with National Grid during a previous assignment.[25]

Table 3.2
Gone Green Generation Inputs

	2013	2015	2020	2025	2030
Wind	10,354	12,713	26,349	47,040	56,941
Nuclear	9,470	8,980	8,980	12,121	12,710
Marine	12	16	55	241	854
Base_Gas	19,804	20,094	16,659	24,451	25,803
Base_Coal	11,450	9,785	10,801	3,255	5,423
France	4,200	4,200	6,200	7,600	7,600
Other Renew	5,943	8,026	13,659	18,586	22,549
Water	1,708	1,752	1,856	1,985	2,176
Marg_Gas	15,328	14,836	18,555	16,244	14,227
Marg_Coal	8,993	8,393	4,798	952	1,152
Pump_Stor	2,744	2,744	2,744	3,356	3,356
Peakers	2,294	991	991	782	782
Total	92,300	92,530	111,647	136,613	153,573
Peak Demand	61,863	61,395	59,667	60,548	62,717

Source: National Grid

25 DTIM User Report, National Grid (Qiong Zhou and Paul Plumptre), 30 September 2009.

Table 3.3
Slow Progress Generation Inputs

	2013	2015	2020	2025	2030
Wind	10,182	12,429	17,674	28,579	34,422
Nuclear	9,470	8,980	8,980	9,991	9,251
Marine	12	14	40	40	40
Base_Gas	20,015	20,005	17,349	27,984	31,275
Base_Coal	11,450	9,785	9,453	1,537	0
France	4,200	4,200	5,200	6,200	7,200
Other Renew	5,551	6,082	8,549	10,068	10,912
Water	1,699	1,724	1,790	1,866	1,951
Marg_Gas	15,491	14,771	19,325	18,592	17,243
Marg_Coal	8,993	8,393	4,199	450	0
Pump_Stor	2,744	2,744	2,744	2,744	2,744
Peakers	2,294	991	917	782	748
Total	92,101	90,118	96,220	108,833	115,786
Peak Demand	61,513	60,417	57,550	57,114	56,736

Source: National Grid

3.5. Transmission Cost Assumptions

As noted in Section 3.3 above, DTIM is designed to represent conditions on the British transmission system as closely as possible, using a simplified boundary approach. Given this simplified network topography, DTIM dispatches generation, and selects transmission investments to make a least-cost trade-off between the costs of constraints and reinforcements.

3.5.1. Assumptions on transmission reinforcement costs

Given the simplified boundary structure of the model, the cost of reinforcing each boundary depends on the assumed unit cost of transmission (in £/MW/km/yr), which is multiplied by the assumed thickness of each boundary (in km).

We therefore assume a uniform cost of reinforcement across the AC network of £60/MW/km/yr for all onshore circuits. In reality, we recognise that a diverse range of reinforcement options exists (e.g. overhead lines vs. underground cables, reinforcements at different voltage levels, building new substations), the cost of which will vary. However, we assumed a uniform reinforcement cost of £60/MW/km/yr on the basis that it is a reasonable approximation of the average cost of adding boundary capacity to the onshore network. This is in line with National Grid estimates, set out in the recent review into the NETS SQSS, which use three alternative methods to derive a high-level generic cost of reinforcement: [26]

[26] National Grid April 2011, *NETS SQSS Amendment Report GSR009 Review of Required Boundary Transfer Capability with Significant Volumes of Intermittent Generation*, Appendix 5, pages 58-59

- *'Ideal' pricing, based on idealised reinforcements of overhead line.* This method yielded a reinforcement cost of £58 /MW/km/yr;
- *Actual pricing, based on actual planned examples of network expansion outlined in a 2009 Electricity Network Strategy Group (ENSG) report.* National Grid converted ENSG estimates of total project costs into £/MW/km/yr reinforcement costs, which ranged from £100 to £240/MW/km/yr; and
- *Average pricing, based on TO revenues and installed capacity.* This method yielded reinforcement prices of £32, £58 and £41/MW/km/yr, for SHETL, SPT and NGET respectively.

In our modelling, the only type of investment to which we apply a different cost assumption is the offshore HVDC bootstraps, on the basis that these technologies are more expensive than conventional AC reinforcements. For the offshore bootstraps, we assume a reinforcement cost of £160/MW/km/yr.[27]

As described further in Chapter 5, the assumed spread between the costs of onshore (AC) reinforcement and offshore HVDC reinforcement is an important driver of our conclusions on the extent to which the proposed charging methodologies produce charges that reflect LRMC. With this in mind, we consider that the assumed spread between the two reinforcement costs we have assumed (a ratio of AC to HVDC reinforcement costs of less than 3:1) is relatively conservative. [28]

Because DTIM applies a cost minimisation algorithm, new transmission infrastructure comes online as soon as our modelling suggests it is required. In reality, delays in commissioning new transmission lines (e.g. due to planning delays) may cause actual investment patterns to deviate from this optimised solution. But for the purposes of modelling and appraising the cost reflectivity of alternative TNUoS methodologies, we abstract from this constraint.

3.5.2. Transmission constraint assumptions

DTIM performs both a constrained and unconstrained dispatch of generation capacity that we assume is installed on the transmission system. By re-dispatching generation to reflect the impact of constraints, DTIM is able to make a least-cost trade-off between reinforcements and constraints.

The costs of constraining generators down in one part of the country and constraining them up in another part of the country depends on the bids and offers they submit to the balancing

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[27] The assumptions used by National Grid regarding the cost of the western HVDC link in the Transport and Tariff Model (£113/MW/km/yr and length of 370km = £41,810/MW/yr) results in a similar overall cost to our assumption (£160/MW/km/yr and a length of 250km = £40,000/MW/yr).

[28] The costs of onshore boundary reinforcements are dominated by overhead lines and the assumed overhead line units costs in the National Grid Transport and Tariff Model are between £11.1/MW/km/yr for 400kV and £30£/MW/km/yr for 132kV. In contrast, the assumed unit cost for offshore HVDC is £113.1/MW/km/yr. This implies a ratio between the costs of the reinforcement options of between 3:1 and 10:1, and our assumptions imply a ratio of less than 3:1.

Source: Project TransmiT: Theme 4 – Reflecting new transmission technology: HVDC, National Grid. URL: https://www.ofgem.gov.uk/ofgem-publications/54314/transmit-wg-3-treatment-hvdc.pdf.

mechanism. For our modelling, we have considered two alternative assumptions regarding generators' bids and offers into the balancing mechanism, the results of which are presented in Chapter 5:

- Our basic assumption is that generators offer their capacity into the balancing mechanism at short-run marginal cost (see Section 3.6 below), and there is no spread between their bid and offer prices. Hence, the marginal (avoided) cost of constraining down a generator is the same as the marginal cost of constraining up a generator up. However, we recognise this approach ignores a range of factors that might cause generators to apply a spread between their bid and offer prices, such as unit commitment costs, dynamic constraints and the impact of market power.
- We therefore conduct a sensitivity in which we apply the bid/offer prices assumed in the Redpoint/National Grid modelling conducted as part of the Project TransmiT process. These are set out in Table 30 of the Redpoint modelling report.[29] Applying these spreads increases the cost of constraining generators down and constraining others up to compensate. All else equal, we would expect the application of these bid/offer spreads to increase the quantity of transmission capacity provided by the model, by altering the trade-off between transmission investment and constraints.

3.6. Generation Marginal Cost Assumptions

As noted above, in our reference case, we assume that generators are dispatched on the basis of their marginal costs, and do not apply any spread between the bid and offer prices. We also consider a sensitivity in which generators' bid/offer prices differ from marginal cost.

In both runs, we set marginal costs for fossil fuel fired units based on the same fuel and CO_2 prices used in our modeling of the welfare impacts of WACM 2.[30] However, unlike our previous welfare modeling,[31] the analysis in this report uses the simpler approach of taking a generic marginal cost by fuel type. To derive these generic marginal costs by fuel, we assumed thermal efficiencies (HHV, sent-out) of 49% for gas-fired plants and 35% for coal and oil-fired plants.

The resulting marginal costs are shown in Figure 3.5 below. As the figure shows, our assumed marginal costs for fossil fuel-fired generators' rise over time, in line with assumed growth in both fuel and CO_2 prices.

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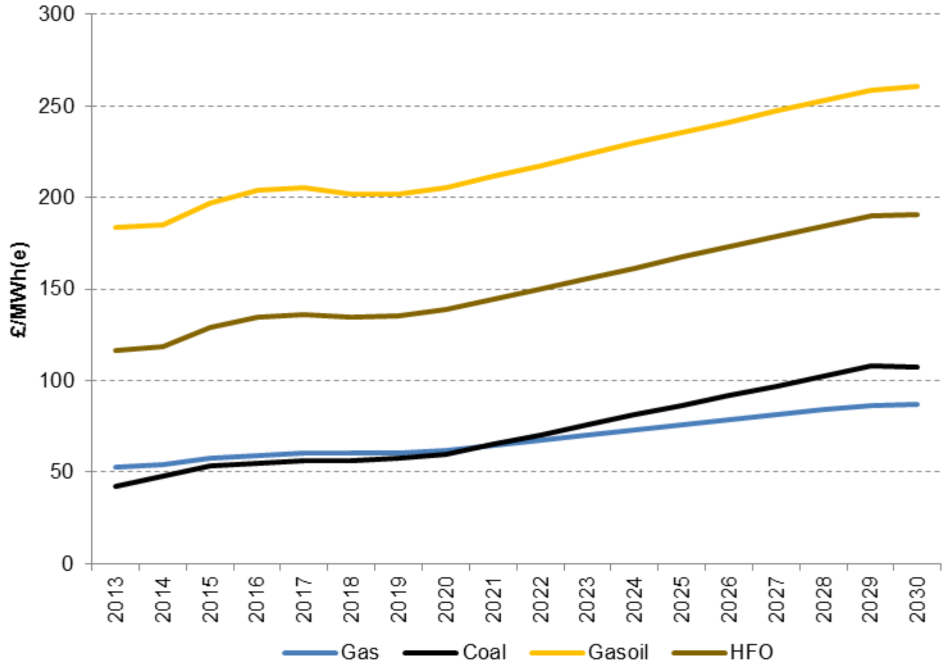
[29] Modelling the Impact of Transmission Charging Options, Redpoint Energy, December 2011.

[30] Our commodity price forecasts are described in: Project TransmiT: Modelling the Impact of "Improved ICRP": Prepared for RWE npower, NERA Economic Consulting and Imperial College London, 12 October 2012, Section B.1.

[31] In our study that estimates the welfare impacts of the WACM 2 charging methodology, we define detailed assumptions on the marginal costs of each thermal unit on the system, based on estimates of how thermal units' thermal efficiencies differ.

Figure 3.5
Generation Marginal Costs for Fossil-Fuel Fired Units (£/MWh(e))



Source: NERA/Imperial analysis of data from Bloomberg and the IEA

We assume marginal costs for wind and nuclear plants of £0/MWh. In both cases, however, we set offer prices for nuclear and wind at high levels because these technologies cannot be constrained up. Similarly, nuclear generation bid prices were set to a large negative number to deter the model from constraining them down, which reflects the inflexibility of these plants. For marine capacity, we assume a marginal cost of £10/MWh, and for other renewable technologies, such as biomass, we assume a marginal cost of £60/MWh.

4. Method for Estimating LRMC

This chapter sets out in detail the methods we have employed to estimate the LRMC of transmission triggered by the presence of a generator of a particular type in each part of the transmission system.

4.1. Overview of Procedure

Using the Imperial Dynamic Transmission Investment Model (DTIM), we estimate the LRMC of transmission associated with particular types of generation at different points in the network using the following two-step approach.

1. We perform one run of DTIM so that, taking the mix of installed generation capacity as given, both generation dispatch and network investment is optimised, making a least-cost trade-off between constraints and investment. We use this run of the model to calculate net power injection at each node (for both generation and demand customers) under an efficient pattern of dispatch and transmission investment; and
2. In a second step, we then perform another run of DTIM, which takes these net injections (across the whole planning horizon) as given. Hence, in this second run, the model does not optimise dispatch, as the net injections already reflect an optimal dispatch. However, we do allow DTIM to build the least-cost transmission network to accommodate these flows. This procedure allows us to obtain the duals on the power flow constraints at each node, for every hour. These duals represent the marginal transmission reinforcement cost that the model incurs if generation at a particular node increases slightly. By identifying which hours in the year a particular generation technology runs, we can then identify the extent to which a particular generation technology at a particular node is contributing to (or reducing) total transmission reinforcement costs, and thus impute the LRMC of transmission investment triggered by a marginal increase in generation capacity of each technology present at each node.

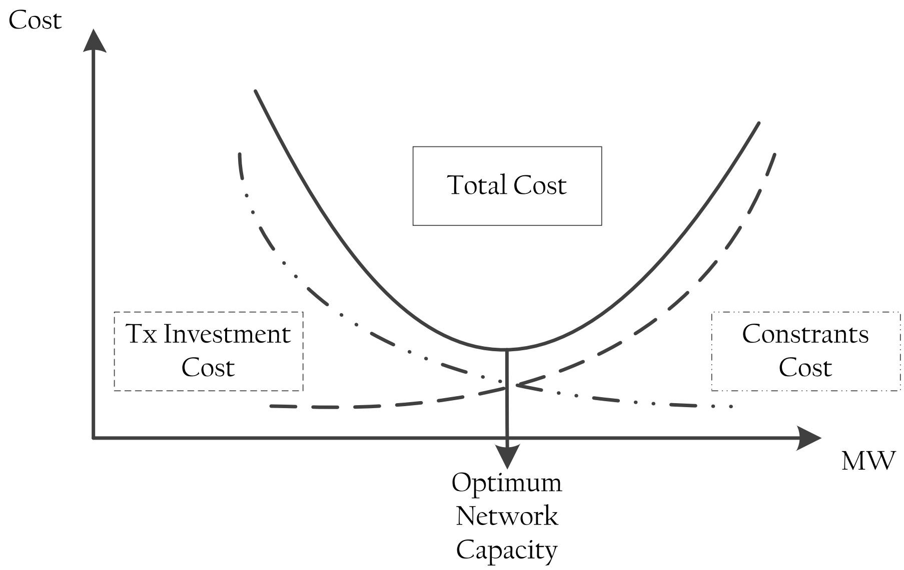
Finally, in a third step, we compare the estimated LRMC of transmission investment triggered by a marginal increase in generation capacity of each technology present at each node to an estimate of the tariffs that would be charged under the WACM 2 and status quo charging methodologies.

4.2. Step 1: Optimising Network Investment

4.2.1. The Imperial DTIM model

As described above, we applied the Imperial DTIM model, which performs a Cost-Benefit Analysis (CBA) to balance the cost of network constraints against and the cost of network reinforcement to determine the optimal network investment strategy over the modelling horizon (here, 20 years). The modelled patterns of investment minimise total systems costs, including generation operation costs and network expansion costs, as presented in Figure 4.1.

Figure 4.1
Illustration of DTIM Cost-Benefit Analysis Framework



Key input data in this optimisation include network topology, the demand profile forecast for each zone (node), current and future fuel costs, bid and offer prices, the assumed evolution of installed generation capacity, the location and quantity of new wind capacity and transmission and generation maintenance plans. We describe our assumptions on these key variables in Chapter 3. Throughout the optimization period considered (e.g. 20 years) the model determines when, where and how much to invest in network reinforcements.

In its simplest form, the model is formulated as a linear programming problem that minimizes the sum of the Net Present Values (NPVs) of transmission investment cost and the cost of congestion in the system across a given multi-year period. As described in Chapter 3, DTIM divides the whole time horizon of the study into a number of stages (time blocks), referred to as "epochs" in the model. Yearly variations in operating scenario (conditions) driven by seasonal and daily changes in demand and wind, including consideration of transmission maintenance windows, are represented by 550 operating scenarios. These scenarios include one with no (or very low) wind output during peak demand, which is used to reflect the fact that wind has low capacity value and hence cannot displace network assets.

4.2.2. Algorithm for selecting optimal investment and dispatch

In a simplified form, the objective function of the network planning problem in DTIM is formulated as follows:

$$\min \sum_{t=1}^{T} \sum_{l=1}^{Nl} (k_{l,t} \cdot F_{l,t}^{inv}) + \sum_{t=1}^{T} \sum_{s=1}^{Ns} \sum_{g=1}^{Ng} (dur_{s,t} \cdot c_{g,t} \cdot P_{g,s,t}) \tag{1}$$

Where:

- t denotes each of the T time blocks in the modelling horizon;
- l denotes each of the Nl transmission boundaries represented in the model;

- $k_{l,t}$ is the unit cost of transmission investment for boundary *l* at time *t*;
- $F_{l,t}^{inv}$ is the additional transfer capacity for boundary *l* proposed to be implemented in epoch t, which is selected endogenously by the model;
- *s* represents each of the *Ns* operating scenarios within a year;
- g represents each of the Ng generators on the system;
- $dur_{s,t}$ is the duration (in hours) of operating scenario *s* at each epoch *t*;
- $c_{g,t}$ represents the marginal generation cost of unit g at each epoch *t*; and
- $P_{g,s,t}$ is the production (in MW) of generator g, in operating scenario *s* at each epoch *t*, which is selected endogenously by the model.

The optimization is also subject to several constraints, as summarised below.

First, supply and demand must be balanced at all times (for all operating scenarios in all epochs):

$$\sum_{g}^{Ng} P_{g,s,t} - \sum_{d}^{Nd} P_{d,s,t} = 0 \; \forall \; (s,t) \tag{2}$$

Where $P_{d,s,t}$ is demand at node *d* in operating scenario *s* in epoch *t*.

Second, power flows must respect transfer capacity of each transmission boundary, after accounting for the model’s decisions to expand transmission capacity, at the assumed costs that feature in the objective function. The following equation (3) demonstrates that the capacity of transmission boundary *l* in epoch *t* is the total of existing maximum capacity and all investment selected by the model for boundary *l* up to epoch *t*.

$$\left|F_{l,s,t}(\mathbf{P}_{g,s,t}, \mathbf{P}_{d,s,t}, \mathbf{Y})\right| \leq \bar{F}_l + \sum_{p=1}^{t} F_{l,p}^{inv} \; \forall \; (l,s,t) \tag{3}$$

Where:

- $F_{l,s,t}$ is the power flows across transmission boundary *l* in operating scenario *s* in epoch *t*;
- $F_{l,s,t}$ is a function of all power injections, $\mathbf{P}_{g,s,t}$ (supply) and $\mathbf{P}_{d,s,t}$ (demand), and **Y** the “network admittance” matrix in the respective operating scenario; and
- $\bar{F}_l$ is the existing maximum transfer capacity of transmission boundary *l*.

Additionally, we constrain all generation and transmission capacity to operate within feasible and stable operating regions.

4.3. Step 2: Estimating LRMC

4.3.1. Overview of calculation

Although step one allows us to optimise generation dispatch and transmission investment, it does not provide the outputs required to calculate the LRMC of transmission investment imposed by individual generation technologies at different points on the grid. We require a second run of DTIM to calculate LRMCs.

Specifically, from the first run we take optimised net injections (optimised generation dispatch, less assumed demand) at each node, and impose the constraint on DTIM that flows in the second run are precisely equal to the optimised level from the first run. We then let DTIM build the least-cost transmission network required to accommodate these net injections. The resulting transmission build patterns from this run are (by definition) identical to the result from the first run. The only difference is that, by imposing a pattern of nodal net injections on the model as a constraint, we can calculate the shadow cost of marginally tightening these constraints on total transmission reinforcement costs.

From the shadow prices on the constraints on net injections by node, DTIM epoch and DTIM operating scenario, combined with information about the running regime of individual generators produced in the first run, we can compute the LRMC of transmission expansion caused by different types of generators at different points on the system, and analyse how these LRMCs vary over time.

4.3.2. Computation of LRMCs

The following detailed formulae describe precisely how we calculate the LRMCs of transmission infrastructure associated with different types of generation at different points on the system.

First, we formulate and solve an optimisation problem with the objective to minimise only the cost of transmission investment, with power injections across the system being fixed according to the results from the first step (see Section 4.2.2). The problem is formulated as a linear optimization model with the following objective function:

$$Min\ CF_{l,s} = \sum_{s=1}^{Ns} F_{l,s} * k_l * d_l * c_{l,s} \tag{4}$$

Where:

- $CF_{l,s}$ is the power flow cost for boundary l in operating scenario s in £;
- $F_{l,s}$ is the power flow of boundary l in scenario s (in MW);
- k_l is the unit transmission investment cost of boundary l (in £/MW), which (in broad terms) represents the annualised upfront development cost of transmission expansion, multiplied by the length of boundary l;
- $c_{l,s}$ is a constraint flag for boundary l in scenario s, which is equal to one if the boundary is constrained in a particular operating scenario and zero if not;
- d_l is defined as follows, and is intended to represent the inverse proportion of the year that boundary l is constrained; and

$$d_l = 1/\{[\sum_{s=1}^{Ns}(c_{l,s} * dur_s)]/\sum_{s=1}^{Ns} dur_s\} \tag{5}$$

- dur_s is the duration of a particular scenario in hours.

Hence, the objective function in equation (4) is effectively defined such that the total capital cost of transmission infrastructure on a particular boundary in a particular hour is obtained by multiplying the unit cost of reinforcing that boundary, by the flow on that boundary, but only if that boundary is constrained during the hour in question. The equation also spreads the costs of reinforcing the boundary uniformly across those hours in the year when the boundary is constrained.

In addition to the constraint that the net injections at each node are identical to those emerging from step one, the constraints of this problem are the same as those applied in the first run (given by equations 2 and 3). As noted above, the results from this run produce exactly the same results in terms of transmission investment patterns as the run performed at the first stage. However, optimisation problem (4) enables us to calculate the Lagrange multipliers associated with nodal power balance equations, measure the marginal impact of each power injection at each node and each scenario on network investment costs.

From these Lagrange multipliers, we can compute an annual access charge for each generator that imposes on it the LRMC of transmission investment that would be caused by adding a MW of generation capacity. This calculation is performed on a nodal basis, and accounts for differences in generators' running regimes and how this impacts LRMC. The Annual Access Charge (for generator g at node n, in £ per annum) that reflects the LRMC of transmission investment is equal to:

$$Annual\ Access\ Charge_{g \in n} = [\sum_{s=1}^{Ns} (L_{ref,s} - L_{n,s}) * P_{g,s} * dur_s] / \sum_{s=1}^{Ns} dur_s \qquad (6)$$

Where

- $L_{n,s}$ represents the Lagrange Multiplier on the constraint on power injections at node n in operating scenario s;
- Node *ref* is the reference node and corresponds to DTIM node 10;[32] and
- $P_{g,s}$ is the generation output of generator g in scenario s.

Note that equation 6 uses the difference between the Lagrange Multipliers at a given node (n) as compared to those at a reference node. The final step is to convert this annual access charge, which reflects LRMC, into a charge per kW of Transmission Entry Capacity (TEC). This ensures comparability with the modelled Status quo and WACM 2 tariffs (see Section 4.4 below):

$$Annual\ Transmission\ Tariff \left(\frac{£}{kW}\ p.a.\right) = LRMC_g = Annual\ Access\ Charge_{g \in n} / TEC_g \qquad (7)$$

[32] The definition of the reference node was selected to be consistent with the WACM 2 and status quo charging models. Selecting a different reference node would shift estimated LRMCs and transmission tariffs under both methodologies up or down, but would not change the regional spread in tariffs (e.g. the delta between Scottish and English/Welsh tariffs).

Where TEC_g is the Transmission Entry Capacity of generator g.

4.4. Step 3: Calculating WACM2 and Status Quo Tariffs

4.4.1. Ensuring consistency between estimated LRMCs and tariffs

For the purpose of comparing the LRMC estimates (derived as above) to WACM 2 and status quo charges, we developed Transport and Tariff Models to compute charges under each of the methodologies. These Transport and Tariff Models entail the following simplifications:

- The first simplification is that the Transport and Tariff Models we developed use the DTIM network topography (see Section 3.3 above) that represents the main GB transmission network boundaries. It is therefore a simplified version of the network topography implemented in the Transport and Tariff model that National Grid uses to compute charges. Specifically, it does not account for flows within each network "zone".[33]
- When the National Grid Tariff and Transport Model calculates the incremental cost associated with increasing injections at each node, incremental flows on each circuit are multiplied by an "expansion constant", a "security factor", and series of different "expansion factors" that vary for each types of transmission asset.[34] In contrast, our simplified Transport and Tariff model assumes a single £60/MW/km/yr expansion cost for the whole onshore network, and a separate £160/MW/km/yr expansion cost for the HVDC bootstraps.[35] These assumptions are consistent with the assumed costs of adding transmission capacity within the model.

Although the DTIM network topography is a simplified version of the real GB transmission network, by using precisely the same network topography and investment costs to select transmission investments, compute LRMC, and compute tariffs, we ensure complete consistency between the estimated TNUoS charges and network investment costs.

In principle, there is no reason why one could not develop a model of the GB transmission system like DTIM that selects optimal transmission investments, but with the same (more complex) network topography as is used in the National Grid Transport and Tariff model. Of course, given the added complexity of the model, developing such a model might be time

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33 Note, this approach differs from that adopted in earlier analyses conducted by NERA and Imperial College that assessed the welfare effects of introducing WACM 2. For these studies, although we still used DTIM to select optimal transmission investment, we used the National Grid Tariff and Transport Model to compute status quo and WACM 2 TNUoS charges.

34 The expansion constant is based on the cost of investing in standard 400kV overhead lines, which account for the highest proportion of capacity on the network. The expansion factor is designed to account for the higher costs associated with other circuit types (namely cables and 132kV and 275kV overhead lines). See National Grid, April 2010, *The Statement of the Use of System Charging Methodology*, pages 17 – 20 for a detailed explanation of how National Grid estimates these expansion constant and expansion factors.

35 As described in Section 3.5.1, we differentiate between the costs of the HVDC bootstraps and the costs of upgrading the onshore network because the costs of adding transmission capacity through offshore HVDC cables is markedly higher than the costs of reinforcing the onshore transmission grid.

consuming, but it would enable a more precise comparison between LRMC and status quo and WACM 2 tariffs than we have been able to perform using our simplified framework.

4.4.2. Implementing status quo and WACM 2 charging methodologies

Using the Transport Model developed using the DTIM network, we computed tariffs in accordance with the status quo and WACM 2 methodologies as follows:

a. We ran the Transport Model using three generation backgrounds per year (status quo peak security background, and the WACM 2 year-round and peak-security backgrounds), calculating the marginal MW/km per node resulting from each methodology;

b. In the WACM 2 case:
   - We allocated transmission assets between the year-round and peak-security backgrounds depending on which background produced the higher flows on each circuit, as per the proposed methodology; and
   - We split the year-round marginal MW/km between shared and non-shared components by implementing the proposed NGET “diversity 1” methodology, as we did in our earlier study to compare status quo and WACM 2; and

c. We then calculated two sets of status quo and WACM 2 charges. We performed a range of sensitivities associated with the assumed levels of utilisation of the HVDC lines (and, in turn, the assumed flow of marginal MW between the HVDC and AC networks). Our analysis assumed utilisations on the bootstraps of between 25% and 75%.

At step (c), we conducted sensitivities associated with the assumed levels of utilisation of the HVDC lines to assess the impact of this assumption on TNUoS charges. Under both the status quo and WACM 2 methodologies, the level of HVDC utilisation depends on the method used to calculate equivalent impendences. A number of different approaches have been suggested for setting equivalent impendences through the Project TransmiT and CMP213 processes, and depending on the assumption used, utilisation can vary between 10% and 80% of line capacity.[36]

Although our earlier modelling to estimate the welfare effects associated with the WACM 2 charging methodology applied National Grid’s method “4a” for setting equivalent impendences,[37] at present we are not aware that any firm decision has been taken on which of the alternative methods will be implemented. For this analysis of the cost reflectivity of the alternative charging methodologies, we therefore considered the range of assumptions between 25% and 75% on the utilisation of the bootstraps.

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36 Source: Theme 4 – Reflecting New Technology: HVDC, Assessment of options for setting of HVDC in Transport model, National Grid Presentation, Andy Wainwright and Ivo Spreeuwenberg, slide 10.

37 HVDC desired flow (relative loading) = Average [Flow across boundaries (before HVDC) that HVDC crosses/Average boundary secured capacities]* HVDC capacity

Source: Theme 4 – Reflecting New Technology: HVDC, Assessment of options for setting of HVDC in Transport model, National Grid Presentation, Andy Wainwright and Ivo Spreeuwenberg.

In practice, as discussed further in Chapter 5, this assumption materially affects TNUoS charges in Scotland, and so also influences the assessment of whether any particular charging methodology is cost reflective.

5. Modelling Results

5.1. Overview

This chapter summarises the modelling results we obtain for a range of scenarios, using the procedure set out in Chapter 4 and the data and assumptions described in Chapter 3. As noted above, the purpose of this analysis is to examine the extent to which the WACM 2 and status quo charging methodologies reflect the LRMC of transmission caused by generators of different technologies in different parts of the system.

We also consider a range of sensitivities to the "reference case" to evaluate the sensitivity of our conclusions to changes in our assumptions compared to those outlined in Section 3. The results of these sensitivities are summarised in this chapter, and presented in more detail in Appendix A:[38]

- The generation and demand background for the reference case is based on the National Grid "gone green" scenario described in Table 3.2. However, as noted in Section 3.4, because there is considerable uncertainty regarding the future generation mix in GB, we have also considered a sensitivity regarding the types of generation capacity installed on the system by re-running using National Grid's "slow progress" background;
- In the reference case, we assume generators are dispatched at their marginal fuel and CO_2 cost, without any bid/offer spreads or adders. As described in Section 3.5.2 above, we conduct a sensitivity in which we assume generators apply bid-offer spreads. The effect is to increase the costs of constraining generators up/down, which affects the LRMC of transmission capacity required to accommodate them optimally; and
- In the reference case, we assume transmission investment costs of £60/MW/km/yr for onshore circuits and £160/MW/km/yr for the HVDC bootstraps. As described in Section 3.5.1 above, and as the results below show, the assumed spread between HVDC and AC reinforcement costs is an important driver of the differences between LRMC and estimated WACM 2 and status quo tariffs. Hence, we consider a sensitivity where we increase HVDC reinforcement costs by 20% and reduce AC reinforcement costs by 20%.

5.2. Reference Case Results

5.2.1. Estimating LRMC

Figure 5.1 and Figure 5.2 show our estimated LRMCs of transmission required to accommodate incremental generation capacity in each of the DTIM network zones (see Section 3.3 above). The LRMC estimates presented in Figure 5.1 and Figure 5.2 have the following features:

- For wind farms, the estimated LRMCs tend to be highest in the Scottish zones (1-6), and LRMCs for all generation technologies in the English and Welsh zones are relatively low

[38] Note, the reference case is defined solely as a model run against which the results of sensitivities can be compared. We do not necessarily consider our reference case assumptions to be the most likely or plausible set of assumptions.

(often negative). This difference reflects the extra costs that northern generators impose on the system, as transmission capacity is required to transport their output to southern load centres;

  - The high LRMCs for wind in the Scottish zones reflect the fact that, on the margin, additional wind generators in Scotland trigger the need for more reinforcement of the key north-south transmission lines, in particular the HVDC bootstraps, and so the cost of these bootstraps is reflected in the LRMC estimated for Scottish wind farms in 2020 and 2030;

- Our estimated LRMCs for nuclear generators in the Scottish zones also increase materially in the 2020 and 2030 cases, as they also rise to reflect the cost of reinforcing the Scotland-England/Wales boundaries using the HVDC bootstraps. By 2030, the "gone-green" generation background does not assume any nuclear capacity will be located in Scotland (see Table 3.2). LRMCs for nuclear plants in England and Wales are relatively low and (in all cases but zone 12 in 2020) positive;
- In contrast to wind and nuclear, our LRMC estimates for Scottish peaking ("marginal gas") plants do not rise to a level that reflects the capacity cost of the bootstraps. This reflects the fact that peakers tend to generate in low wind conditions, when the capacity built to transport output from Scottish wind farms to southern load centres (i.e. on the HVDC bootstraps) is not constrained, and thus these plants are not adding to transmission capacity costs on these boundaries. In fact, as the north-south transmission lines are reinforced to accommodate growth in generation capacity (especially wind) in Scotland, the LRMCs of Scottish peakers fall as there is more spare transmission capacity in high demand, low wind periods when those peakers are most likely to generate. The LRMC of accommodating incremental peaking plants in English and Welsh zones is also close to zero, suggesting that peaking plants add very little to transmission reinforcement requirements, irrespective of their location;
- We find a similar result for gas plants operating at higher load factors ("baseload gas"). These plants add very little to transmission reinforcement costs if they are located in England or Wales, but also impose a much lower LRMC of transmission than wind farms or nuclear plants in Scotland. This is because, at times when north-south transmission lines are likely to be constrained (high wind conditions), our modelling suggests these plants are likely to be out of merit. In some cases, it is possible that the model is choosing to constrain down thermal plants in Scotland before curtailing wind output when north-south transmission lines are becoming constrained. However, the effect is the same; they are not running when the lines are constrained, so are not adding to the infrastructure costs incurred to accommodate them. In other words, because it is cheaper to constrain them down than to build additional capacity to accommodate their output, their presence on the system in Scotland is not adding to transmission investment costs, and is not reflected in LRMC.[39]

In interpreting these estimates of LRMC, it is important to consider the following:

[39] In these circumstances, a "baseload gas" plant's decision to locate in Scotland would be adding to constraint costs, but under current GB market arrangements, these costs are socialised. TNUoS charges are only intended to recover the incremental infrastructure costs incurred to accommodate generators, not the incremental constraint costs.

- The charts in Figure 5.1 and Figure 5.2 all present LRMCs relative to a reference node (node 10), as the formulae in Section 4.3 set out. In reality, if one were to set a transmission charge that precisely reflected the LRMCs shown in the figures, it may be necessary to levy an additional "residual" charge on generators to ensure recovery of the Maximum Allowed Revenue (MAR).[40] However, because any residual charge is levied as a non-locational £/kW/yr charge, the locational signals conveyed to generators would be the same as the locational signals conveyed to generators if they paid the LRMC-based charges shown in the figures below, but without any residual charge. Moreover, as the data in Appendix B shows, the residual charges are small, and do not vary materially across scenarios, so adding a residual to the charts below would not materially affect our conclusions.
- Although the choice of the reference node is somewhat arbitrary, we selected node 10 because it is in approximately the same location as the reference node used in the current TNUoS Transport and Tariff Model. Selecting a different reference node would shift the lines shown in Figure 5.1 and Figure 5.2 up or down by a flat £/kW/yr amount, common to all zones and technologies, such that the LRMC curves intersect with the horizontal axis at a different node. Changing the reference node would therefore not change the *relative* LRMCs imposed (or charges faced) by generators at different locations,[41] or the locational signal conveyed to generators. In the context of transmission charging, changing the reference node only changes the revenue recovered from the locational element of the charge, and thus changes the size of the residual charge.
- The charts only show LRMC estimates for those technologies that are transmission-connected in each zone.[42] Hence, for example, we only show LRMC estimates for nuclear plants in 2020 in zones 6, 7 and 12, as these are the only zones in which nuclear plants are present in that year in the "gone green" background, and in 2013 (transmission connected) wind plants are only present in zones 1-6.

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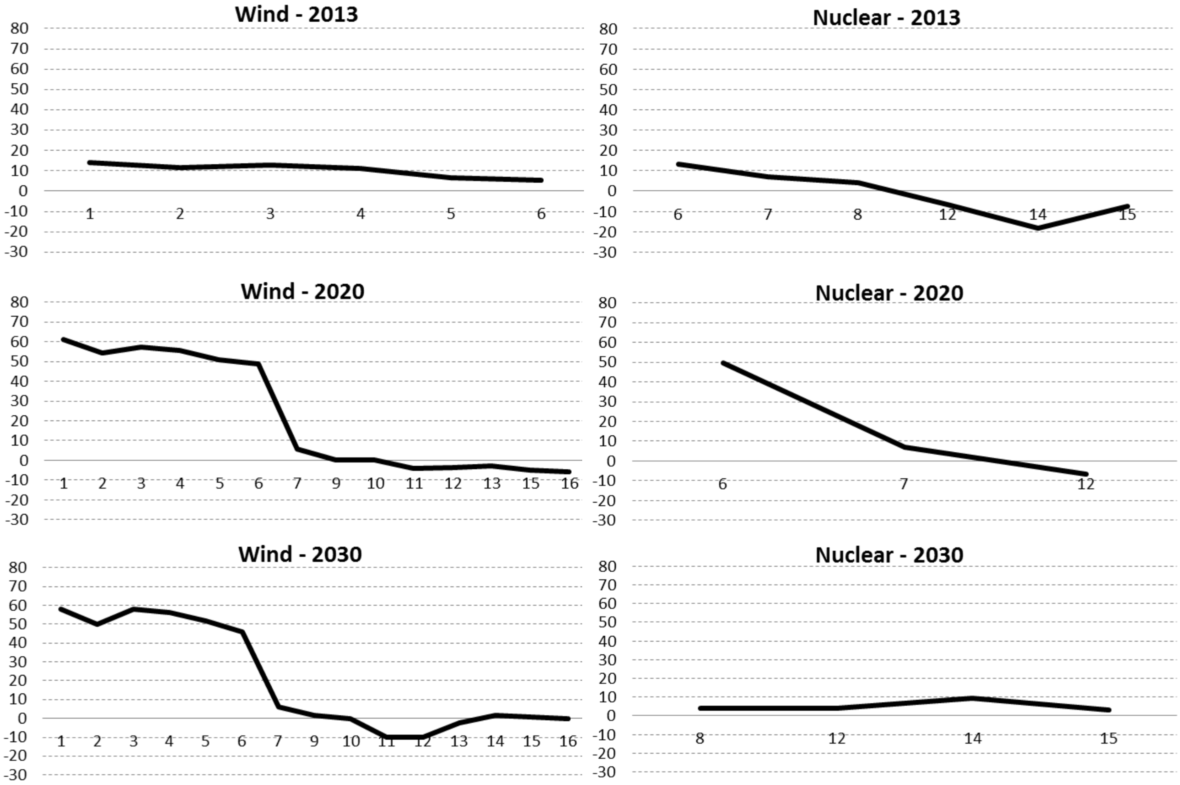
[40] In reality, this residual charge could be positive or negative.

[41] For example, the difference in LRMC from accommodating a generator of a particular technology in zone 1 relative to zone 8 would remain the same, irrespective of the choice of reference node (and so on).

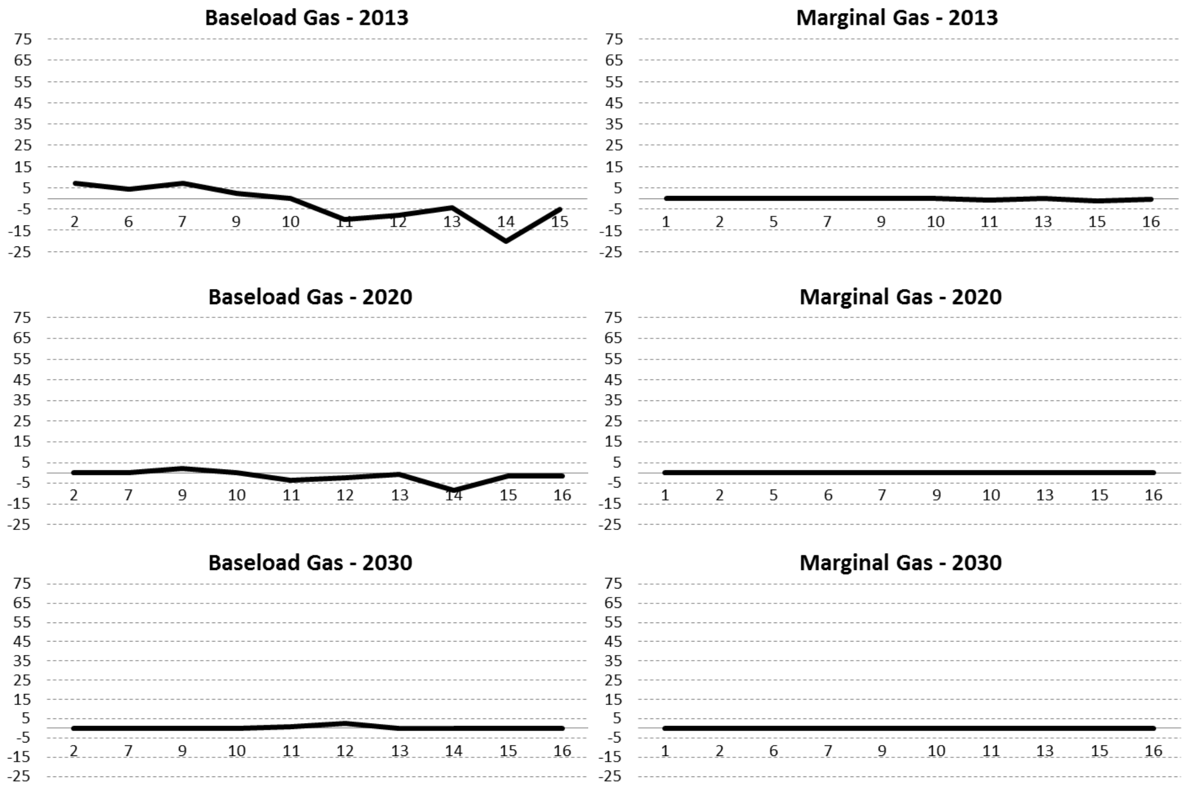
[42] For reference, zones 1-6 are in Scotland and zones 7-16 are in England and Wales.

Figure 5.1
LRMC Estimates for Wind and Nuclear Capacity (£/kW/yr, by DTIM Zone)



Source: NERA/Imperial

Figure 5.2
LRMC Estimates for Gas Capacity (£/kW/yr, by DTIM Zone)



Source: NERA/Imperial

5.2.2. Comparison to WACM 2 and status quo TNUoS charges

Figure 5.3 and Figure 5.4 compare the same LRMC estimates shown above to the WACM 2 and status quo charges we have computed following the methodology set out above in Section 4.4. The figures show the following:

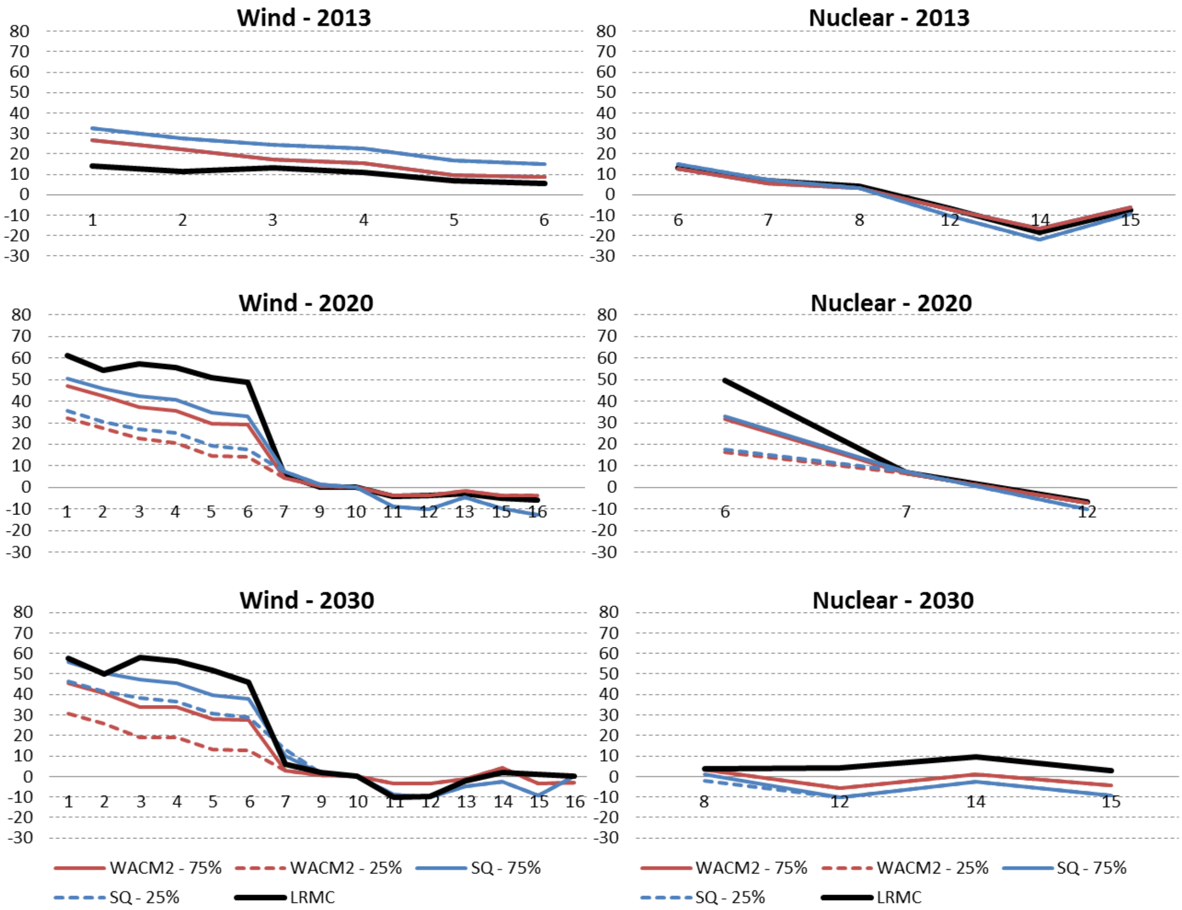
- Relative to charges at the reference node, WACM 2 and status quo charges for wind generation are higher than LRMC in zones 1 to 6 in 2013.[43] However, this finding changes materially in 2020 and 2030 once the HVDC bootstraps come onto the system. In the Scottish zones, WACM 2 and status quo charges for wind generators are both materially lower than LRMC. Status quo charges in 2020 and 2030 in Scottish zones are higher than WACM 2 charges, and thus are closer to LRMC. In England and Wales, WACM 2 charges in 2020 and (in some zones) in 2030 are slightly above LRMC, and status quo charges are slightly below LRMC by about the same amount.
- Therefore, in the case of wind generation, the locational spreads between the LRMCs in the north of the country and the south are much larger than the locational spreads under

[43] There is no sensitivity to the assumed level of impendences in this year, as the bootstraps are not yet in operation.

status quo and WACM 2. Because WACM 2 compresses the locational (i.e. north-south) spread in TNUoS charges faced by wind farms, it reduces the efficiency of the locational signals conveyed to them compared to the signals conveyed under the status quo methodology. In other words, the WACM 2 methodology sets charges to wind farms that reflect LRMC less closely than status quo.

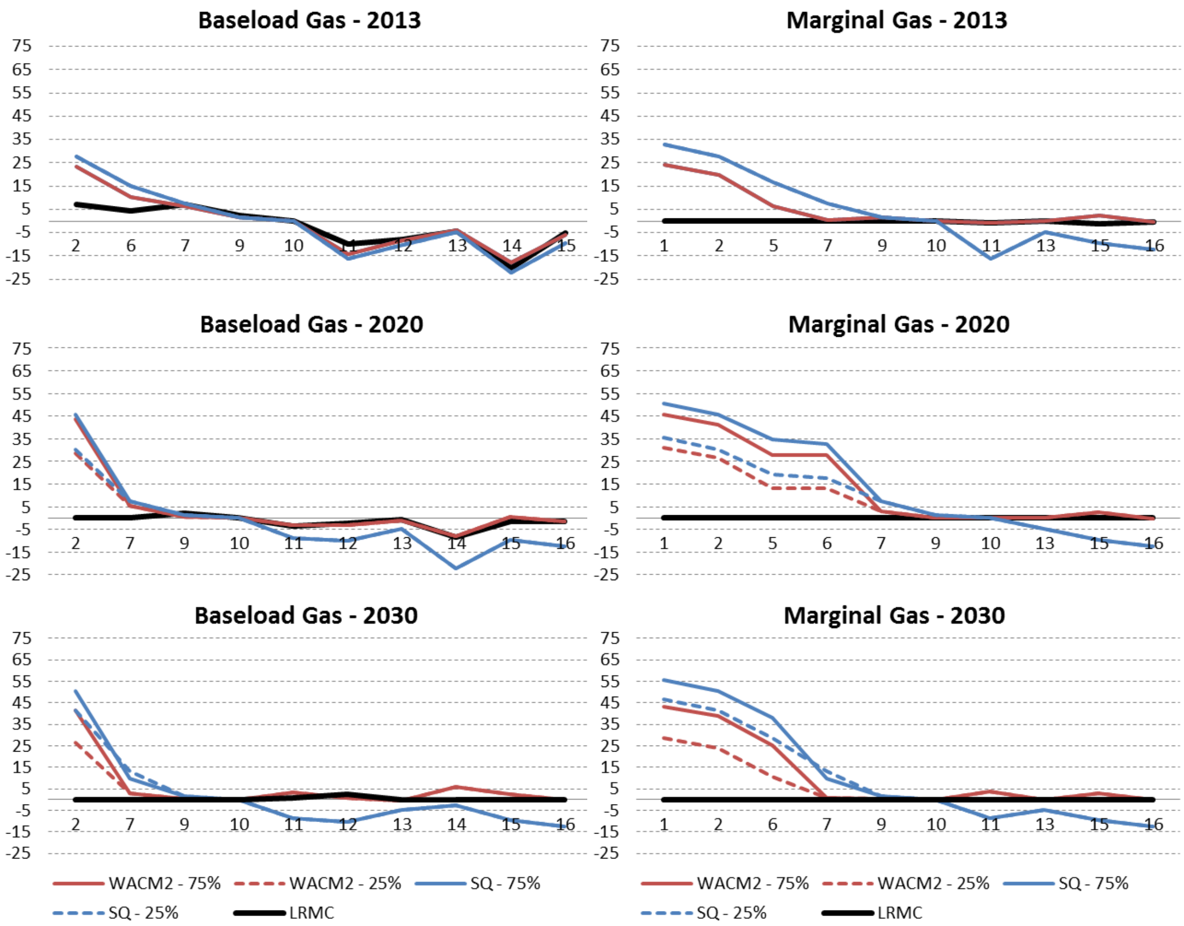
- In 2013, both charging models result in charges to nuclear plants and baseload gas-fired generators that are extremely close to LRMC, except in Scotland where baseload gas generators pay slightly more than LRMC. In 2020 and 2030, there are a number of differences between LRMC and the charges we compute for both methodologies across a number of zones. However, both WACM 2 and status quo tariffs are extremely close together, which suggests that the introduction of WACM 2 does not materially improve or worsen the extent to which tariffs reflect LRMC for nuclear and baseload gas plants.
- As noted above, LRMCs for peaking gas-fired generators are low in all zones, often close to zero. Both the WACM 2 and status quo methodologies charge this type of generator tariffs well-above LRMC in the Scottish zones in 2013, 2020 and 2030. WACM 2 tariffs for this type of generator tend to be lower in Scotland, and so are marginally closer to LRMC. In other words, both status quo and WACM 2 exaggerate the locational signal conveyed through TNUoS as compared to LRMC. Because the WACM 2 charging methodology reduces the locational spread in tariffs, it produces tariffs that are closer to LRMC.

Figure 5.3
TNUoS vs. LRMC for Wind and Nuclear Capacity (£/kW/yr, by DTIM Zone)



Source: NERA/Imperial

Figure 5.4
TNUoS vs. LRMC for Gas Capacity (£/kW/yr, by DTIM Zone)



Source: NERA/Imperial

5.2.3. The impact of alternative HVDC utilisation assumptions

An important feature of HVDC circuits, which differentiates them from the interconnected AC transmission circuits that make up the existing transmission network, is that they are despatchable. Hence, in the Transport Model used to set WACM 2 tariffs, the amount of power which flows across them is effectively set manually. National Grid has proposed a range of alternative methods for determining the incremental flows across HVDC circuits in the Transport Model through a range of alternative rules for setting equivalent impendences.

Ultimately, the choice between such rules is arbitrary. National Grid acknowledged the arbitrary selection of its approach for setting equivalent impendences on the HVDC bootstraps in its Technical Working Group Report:

> "*Of all the above methods proposed, **none will represent how the HVDC link is actually operated** (although in principle the optimal power flow should come close) as this is up to the conditions on the transmission network and System Operator actions at a given point in time. Therefore, whilst based on some underlying*

> *assumptions and representing an approach based on logic,* ***none of the above methodologies is inherently more 'correct' than another***".[44]

In practice, to assess which of the alternative methods proposed by National Grid for setting equivalent impendences on the bootstraps is most cost reflective is to compare the tariffs resulting from the alternative methods to the LRMC of transmission. Our reference case results illustrate the sensitivity of TNUoS charges (under both methodologies) to this assumption, and thus highlights the importance of checking, before any change in the TNUoS methodology is implemented, whether alternative methods of setting equivalent impendences result in cost reflective charges.

To show the sensitivity of WACM 2 and status quo charges to the assumed impendences on the HVDC bootstraps, the results shown above in Figure 5.3 and Figure 5.4 show that status quo and WACM 2 tariffs are both highly sensitive to this assumption, especially tariffs in Scottish zones.

In contrast to the wide variation in TNUoS charges that results from varying the assumptions on HVDC utilisation, the LRMC is completely independent of this assumption. It depends only on the incremental transmission capital cost incurred when an additional MW of generation capacity (of a particular type and location) connects to the system. One reason why the treatment of the bootstraps causes WACM 2 and status quo charges to differ from LRMC, is that this treatment introduces an element of average cost pricing into the charging methodology, which reduces the efficiency of signals compared to a marginal cost based charge.

The effect of these rules is that TNUoS charges in Scotland reflect some average of the assumed LRMC of expanding the AC system assumed in the WACM 2 methodology (i.e. through the expansion constant), and the assumed LRMC of expanding the HVDC bootstraps. In contrast, the LRMC of reinforcement incurred by the TOs to accommodate incremental units of generation capacity in Scotland depends only on the LRMC of expanding the HVDC bootstraps, as their ability to reinforce the AC system is constrained. Hence, the WACM 2 procedure of averaging the LRMCs of (relatively low cost) AC and (relatively high cost) HVDC reinforcements means that tariffs depart from LRMC. As a result, the WACM 2 charging methodology is unlikely to set tariffs close to LRMC.

This apparent introduction of some elements of average cost pricing run contrary to the original intention of the ICRP charging model, and the conditions for efficient transmission pricing described in Chapters 2 and 4. For instance, in its 1992 review of UK transmission charging methodology, National Grid states that it:[45]

> "*…takes the view that given its objectives of charging, it is appropriate to charge on a basis of marginal costs. In other words, each user on the system should pay charges*

[44] National Grid, *Project TransmiT: Electricity Transmission Chargin Significant Code Review; Initial Report of the Technical Working Group, Annex 4*, page 88. Emphasis added.

[45] National Grid, 30 June 1992, *Transmission Use of system Charges Review*, Proposed Investment Cost Related Pricing for use of System, page 13

which reflect the cost of an increment of usage of the system rather than the average cost of the total use made of the system".

5.2.4. Overall assessment of cost reflectivity

Overall, therefore, these reference case results suggest that:

1. WACM 2 sends less efficient locational signals to wind farm developers than status quo, albeit both understate the additional costs that this type of generator imposes on the network when it connects in the north of the country rather than the south of the country. This distortion would tend to cause too much investment in wind generation in Scotland compared to the level that is economically efficient, and thus drive up transmission system costs;
2. WACM 2 sends more efficient locational signals to developers of peaking plants than status quo, albeit both methodologies overstate the relative costs that this type of generator imposes on the network when it connects in the north of the country rather than the south of the country. Under both methodologies, however, TNUoS charges are lower for peaking plants in England and Wales than in Scotland.[46] Hence, setting TNUoS for peaking plants in Scotland that are above the efficient level is unlikely to change locational decisions, so the introduction of WACM 2 will not materially affect the efficiency of peaking plants' locational decisions; and
3. The WACM 2 and status quo methodologies send extremely similar locational signals to developers of baseload technologies (i.e. nuclear and baseload gas), but these signals differ materially from LRMC in some zones/years.

As noted above, the charges shown in the figures above include only the locational element of the TNUoS charge. If these alternative methodologies (including LRMC-based pricing) were implemented as charging methodologies, each would provide a different amount of revenue recovery through the locational component and thus require a different residual to equate revenue with the TOs' MAR, as we describe in Section 4.3.2 above. However, irrespective of the uplift applied using the residual, the locational spread in tariffs would remain the same, and so the conclusions above regarding the efficiency of the locational signals conveyed to network users under the alternative methodologies are robust to changing the level of the residual.

5.3. Summary of Sensitivity Results

As noted above, to test the sensitivity of the conclusions we draw from our reference case results, we have conducted three sensitivities. The key results from these sensitivities are shown in Figure 5.5 and Figure 5.6. More detailed results are shown in Appendix A.

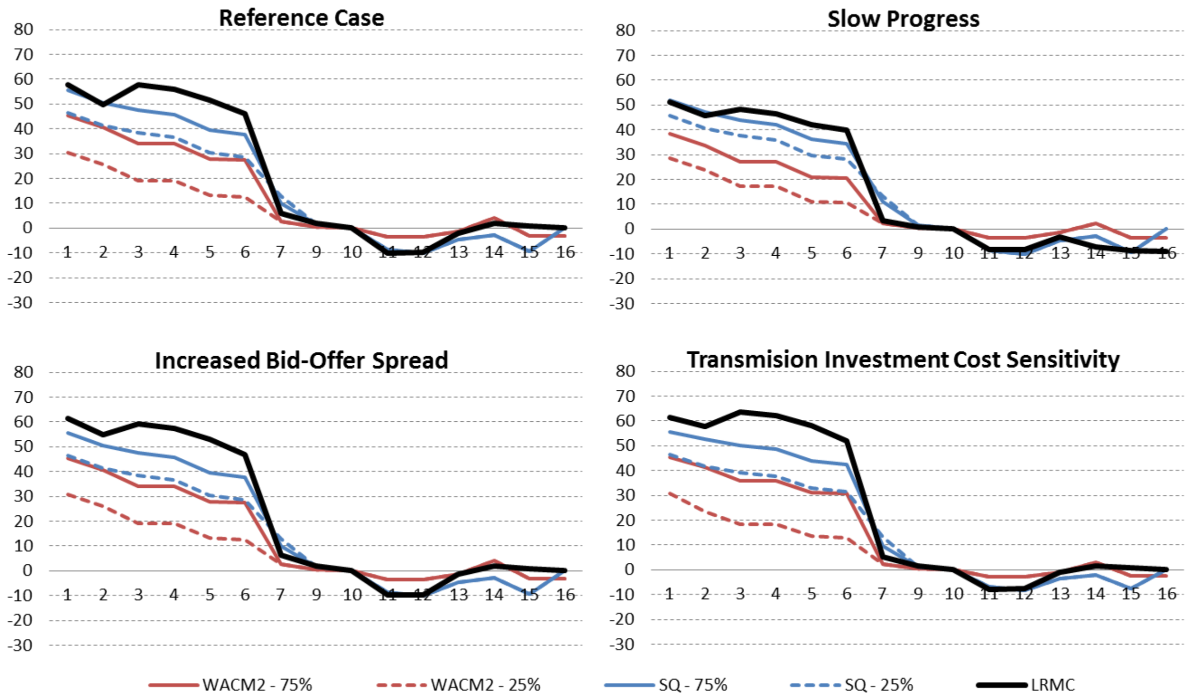
- Figure 5.5 shows that, across a range of scenarios, we still find the same result as in the reference case that both WACM 2 and status quo understate the additional costs that wind farms impose on the network when they connect in the north of the country rather than

[46] As the charts in Figure 5.4 show, marginal gas plants (i.e. peakers) pay lower TNUoS charges in English and Welsh zones under both WACM 2 and status quo than their would pay in Scottish zones.

the south of the country. Because WACM 2 "compresses" the regional spread in tariffs compared to status quo, it sends less efficient locational signals to wind farm developers than status quo. This distortion would tend to cause too much investment in wind generation in Scotland compared to the level that is economically efficient, and thus drive up transmission system costs.

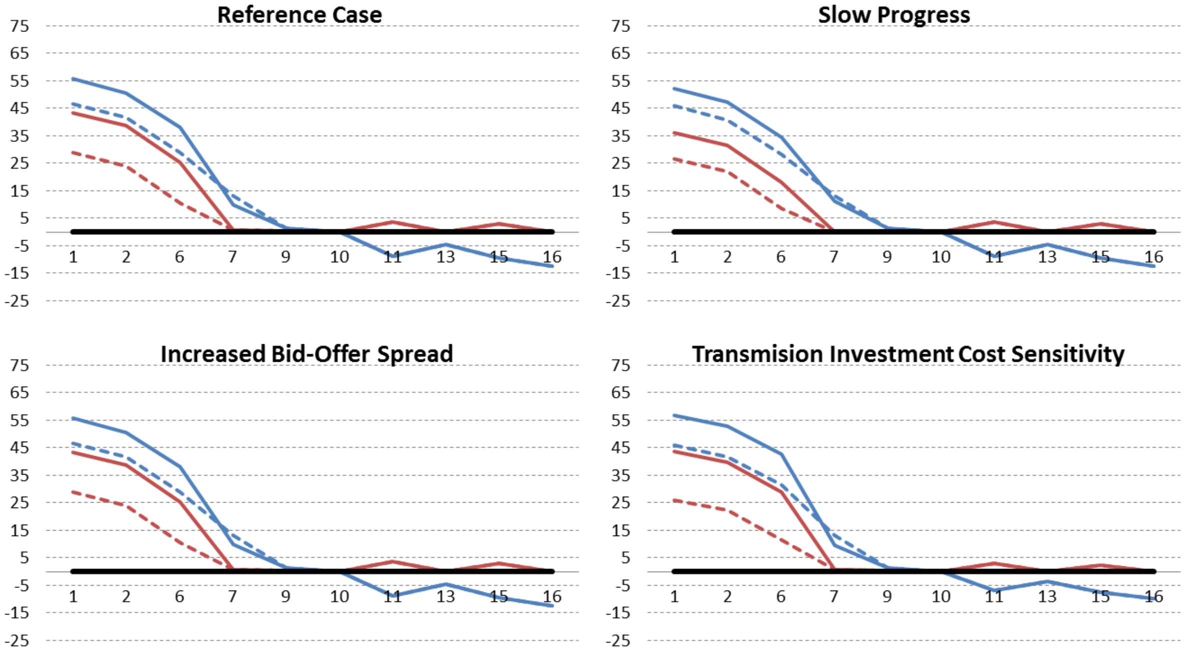
- Figure 5.6 shows that, across a range of scenarios, we still find the same result as in the reference case that both WACM 2 and status quo overstate the additional costs that peaking plants impose on the network when they connect in the north of the country rather than the south of the country. Because WACM 2 "compresses" the regional spread in tariffs compared to status quo, it sends more efficient locational signals to wind farm developers than status quo. However, for the reasons noted above, it is unlikely that this improvement in cost reflectivity under WACM 2 will materially affect generators' locational decisions.
- As in the reference case, we find across the range of scenarios that WACM 2 and status quo send extremely similar locational signals to developers of baseload technologies (i.e. nuclear and baseload gas), but these signals differ materially from LRMC in some zones/years.

Figure 5.5
TNUoS vs. LRMC for Wind Capacity in 2030 by Scenario (£/kW/yr, by DTIM Zone)



Source: NERA/Imperial

Figure 5.6
TNUoS vs. LRMC for Peaking Gas Capacity in 2030 by Scenario
(£/kW/yr, by DTIM Zone)



Source: NERA/Imperial

5.4. Conclusions

The results of the modelling presented in this chapter show that, across a range of scenarios:

- Both the WACM 2 and status quo methodologies send locational signals to wind farms that understate the LRMC of transmission caused when they connect in Scotland relative to the LRMC of connecting in England and Wales. However, because WACM 2 compresses the locational spread between tariffs in the north and tariffs in the south compared to the status quo, this analysis suggests that WACM 2 is less cost reflective for Scottish wind farms than the status quo. This finding means that WACM 2 will tend to result in more investment in wind farms in Scotland (and less in England and Wales) than is economically efficient, and thus drive up transmission system costs.
  - A significant cause of this result is the method used to set assumed utilisations on the HVDC bootstraps, which as we describe, introduces an element of average cost pricing and so causes tariffs to deviates from the efficient locational signals that would be conveyed through a marginal cost-based charge.
- WACM 2 and the status quo methodologies set locational tariffs to peaking plants in Scotland in excess of the LRMC of transmission that their presence imposes on the system relative to the LRMC of connecting in other parts of the country. Because WACM 2 compresses the spread between tariffs in the north and tariffs in the south more than the status quo, this suggests that WACM 2 is more cost reflective for this category of generation. However, under both WACM 2 and status quo methodologies, TNUoS charges are lower for peaking plants in England and Wales than in Scotland. Hence, setting TNUoS for peaking plants in Scotland that are above the efficient level is unlikely

to change locational decisions materially, and thus will have no impact on transmission system costs.[47]

- We also find material differences between estimated TNUoS tariffs and the LRMC of transmission caused by baseload gas and nuclear plants, suggesting neither model is cost reflective for these categories of generation. However, the difference between the two charging methodologies is negligible, suggesting that WACM 2 is no more or less cost reflective than the status quo for these technologies.

Overall, therefore, we conclude that the WACM 2 charging methodology is less cost reflective than the status quo methodology. While the WACM 2 charging methodology does make changes to TNUoS charges that (on the face of it) recognise the dual drivers of transmission reinforcement (peak security and "year-round" investment requirements), these changes are applied through a series of heuristic and approximate calculations. Our analysis shows that the combination of these approximations used in the WACM 2 methodology produces locational charging signals that reflect the LRMC of transmission less accurately than the status quo.

[47] For thermal peaking plants, our previous modelling of the welfare impacts of alternative TNUoS methodologies compared to the status quo has shown that TNUoS charges are the main driver of locational signals for thermal plants. While other costs may vary by location, such as fuel supply costs, the resulting regional variation in costs is small in comparison to the regional variation in TNUoS costs. In contrast, wind farms face a trade-off between regional variation in wind speeds and regional variation in load factors, and both factors have a material impact on locational investment decisions.

6. Conclusions

As we described in our review of Ofgem's CMP213 Impact Assessment, neither Ofgem nor the CMP213 Workgroup has compared the tariffs emerging from the alternative charging methodologies to any estimate of the transmission costs that TOs incur to accommodate generators on the transmission system. Without such a comparison it is not possible for Ofgem to substantiate its claim that the proposed WACM 2 charging model is more cost reflective than the status quo.

This report compares estimates of WACM 2 and status quo tariffs to estimates of the LRMC of transmission associated with different generation technologies in different parts of the system, using analysis conducted with the Imperial College DTIM model. The standard that a cost reflective TNUoS methodology should reflect the LRMC of transmission is consistent with (1) ensuring economically efficient outcomes by signalling to generators the marginal cost they impose on the transmission system, and (2) the original intentions of the ICRP methodology, that aimed to set charges to approximate LRMC.

- Both the WACM 2 and status quo methodologies send locational signals to wind farms that understate the LRMC of transmission caused when they connect in Scotland relative to the LRMC of connecting in England and Wales. However, because WACM 2 compresses the locational spread between tariffs in the north and tariffs in the south compared to the status quo, this analysis suggests that WACM 2 is less cost reflective for Scottish wind farms than the status quo. This finding means that WACM 2 will tend to result in more investment in wind farms in Scotland (and less in England and Wales) than is economically efficient, and thus drive up transmission system costs.
- WACM 2 and the status quo methodologies set locational tariffs to peaking plants in Scotland in excess of the LRMC of transmission that their presence imposes on the system relative to the LRMC of connecting in other parts of the country. Because WACM 2 compresses the spread between tariffs in the north and tariffs in the south more than the status quo, this suggests that WACM 2 is more cost reflective for this category of generation. However, under both WACM 2 and status quo methodologies, TNUoS charges are lower for peaking plants in England and Wales than in Scotland. Hence, setting TNUoS for peaking plants in Scotland that are above the efficient level is unlikely to change locational decisions, and thus will have no impact on transmission system costs.
- We also find material differences between estimated TNUoS tariffs and the LRMC of transmission caused by baseload gas and nuclear plants, suggesting neither model is cost reflective for these categories of generation. However, the difference between the two charging methodologies is negligible, suggesting that WACM 2 is no more or less cost reflective than the status quo for these technologies.

Overall, therefore, we conclude that the WACM 2 charging methodology is less cost reflective than the status quo methodology. While the WACM 2 charging methodology does make changes to TNUoS charges that (on the face of it) recognise the dual drivers of transmission reinforcement (peak security and “year-round” investment requirements), these changes are applied through a series of heuristic and approximate calculations. Our analysis shows that the combination of these approximations used in the WACM 2 methodology produces locational charging signals that reflect the LRMC of transmission less accurately than the status quo.

Besides cost reflectivity, we recognise that there may be other criteria that National Grid and Ofgem need to consider when developing the TNUoS charging methodology, such as predictability, stability and transparency. With reference to these considerations, the status quo methodology performs at least as well as WACM 2:

- Following the CMP213 Workgroup process, a range of alternative charging methodologies were developed, and the CUSC Panel voted (by majority) in favour of several of them. On this basis, it seems that all the methodologies under consideration are sufficiently transparent, predictable and stable to constitute viable approaches for use in GB transmission charging. If this is the case, then the only other factor to choose between them is the extent to which they are cost reflective;
- On the basis that WACM 2 would introduce a number of new complex calculations to the charging methodology that are not present in the status quo (diversity factors, etc), it appears less transparent than the status quo; and
- On the basis that WACM 2 makes generators' TNUoS charges conditional on their Annual Load Factor, which is itself unpredictable from year-to-year, WACM 2 tariffs will also be unpredictable from year-to-year due to load factor uncertainty.

Overall, therefore, against the range of criteria against which the charging methodology should be appraised, WACM 2 performs less well than the status quo, and there is therefore no case for its introduction. However, we recognise that the status quo methodology does not signal the dual drivers of transmission investment, and, as our analysis shows, both the status quo and WACM 2 methodologies send locational signals that differ from LRMC. There may therefore be a case for reforming the existing TNUoS charging methodology, but as our analysis shows, WACM 2 does not constitute an improvement on the existing methodology, as it is less cost reflective, and is probably less transparent, stable and predictable, than the status quo.

In addition to these findings, which show there is no case for introducing WACM 2, any decision to reform transmission charging arrangements will result in material distributional effects, adding to the perception of regulatory risk in the UK energy market, thus increasing the rates of return required by investors and increasing the costs faced by customers. Moreover, regulatory decisions that reform transmission charges that are not well justified on the grounds of improving efficiency will undermine the credibility of the new methodology, creating the perception that any locational signals it conveys will be temporary. This will tend to reduce generators' responsiveness to the locational signals conveyed through TNUoS, which may reduce the efficiency of any locational decisions they take. These additional considerations reinforce our conclusion that there is no case for introducing the WACM 2 charging model.

Appendix A. Full Sensitivity Results

This appendix presents more detailed results for the sensitivity analysis summarised in Section 5.3.

A.1. "Slow Progress" Scenario

We see very similar results as in the reference case if we switch to using the National Grid "slow progress" generation background rather than "gone green", save for a few minor differences that reduce both TNUoS charges and estimated LRMCs:

- The LRMCs for nuclear and baseload gas in 2020 and 2030 are generally slightly lower compared to the reference case and are more closely aligned with both WACM 2 and status quo TNUoS charges;
- Both the LRMCs and TNUoS charges for wind in 2020 and 2030 are slightly lower compared to the reference case; and
- The WACM2 and status quo TNUoS charges for peaking plants ("marginal gas") in 2020 and 2030 are slightly lower than in the reference case, so are both closer to LRMC.

Because this scenario reduces slightly TNUoS charges under both methodologies and reduces LRMC too, the conclusions we draw based on our reference case do not change when we adopt the "slow progress" generation background. Primarily, WACM 2 results in tariffs that are less cost reflective for wind plants, and more cost reflective for peakers. There is little difference between the two methodologies for baseload gas and nuclear.

Figure A.1
TNUoS vs. LRMC for Wind and Nuclear Capacity – "Slow Progress"
(£/kW/yr, by DTIM Zone)

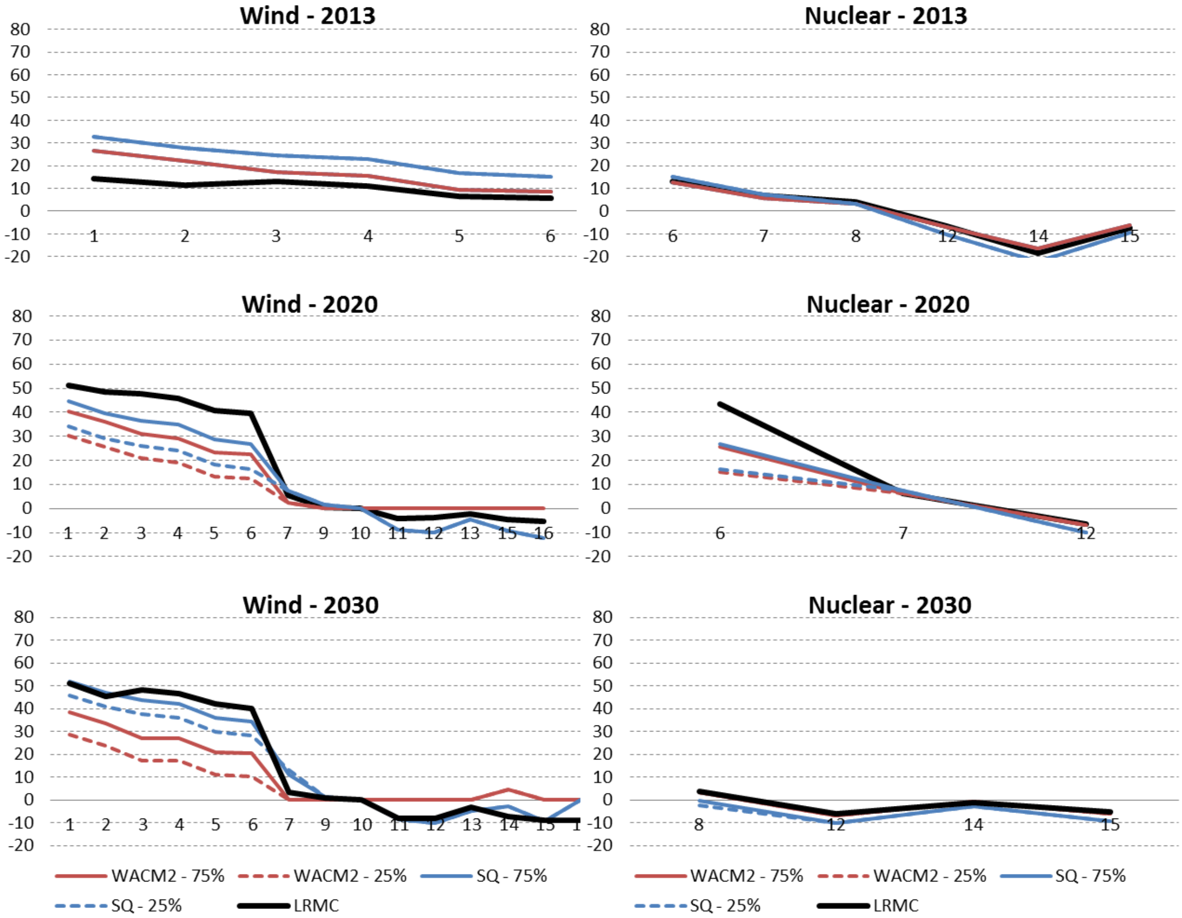
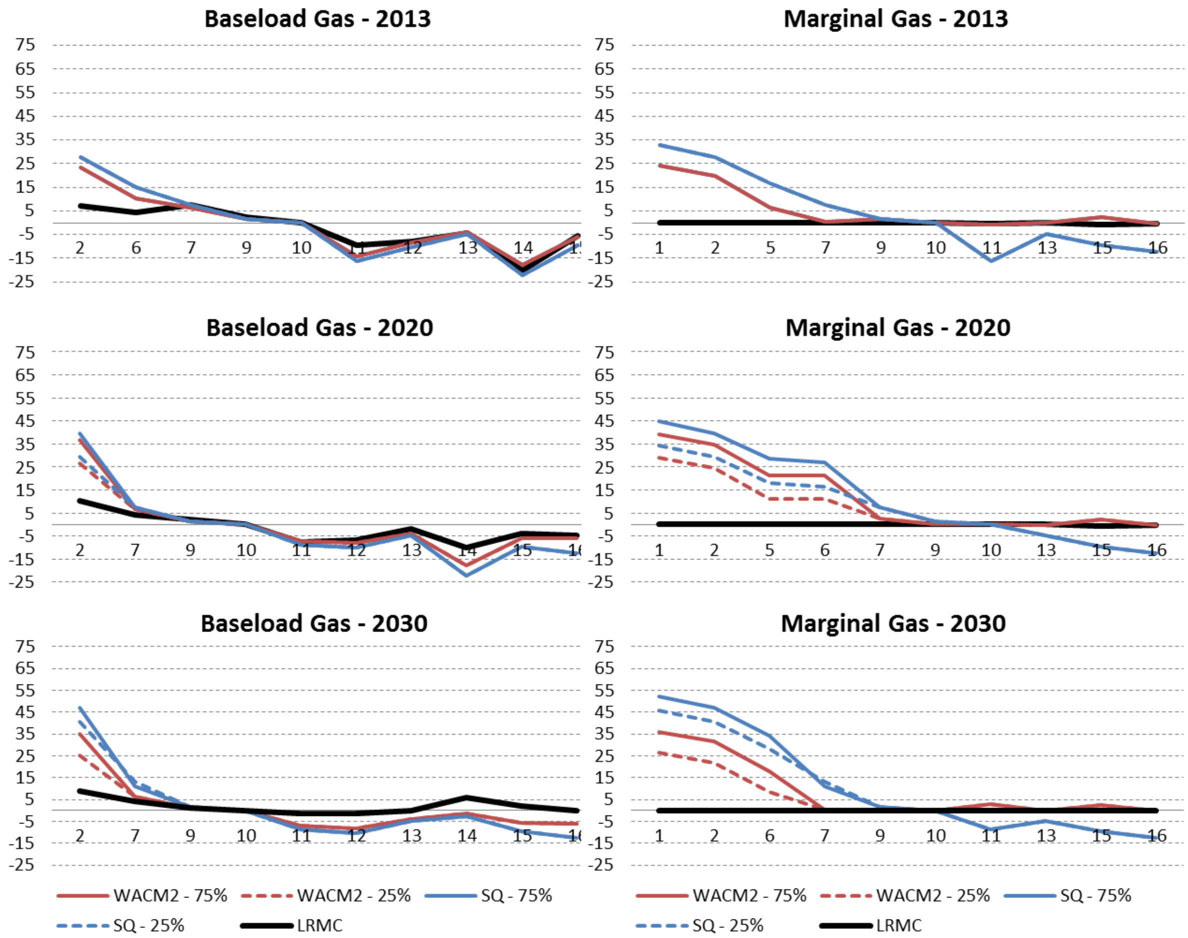


Figure A.2
TNUoS vs. LRMC for Gas Capacity – "Slow Progress"
(£/kW/yr, by DTIM Zone)



A.2. Increased Bid-Offer Spread Scenario

In this scenario, the estimated LRMCs increase slightly in absolute terms compared to the reference case, particularly for wind and baseload gas. This is because we assume that generators are more expensive to constrain off in this scenario. Higher constraint costs drive higher LRMCs, as the optimal level of investment in network infrastructure increases. Since TNUoS charges are independent of the bid-offer spread under both the WACM 2 and status quo charging methodologies, our tariff forecasts are the same as in the reference case.

Hence, altering our assumptions on generators' bid-offer spreads does not change our conclusions regarding the relative performance of the two charging methodologies in terms of the extent to which they reflect LRMC. In fact, it reinforces the conclusion that both methodologies understate the LRMC of transmission caused by wind farms in Scotland relative to those in England and Wales.

Figure A.3
TNUoS vs. LRMC for Wind and Nuclear Capacity – Increased Bid-Offer Spread (£/kW/yr, by DTIM Zone)

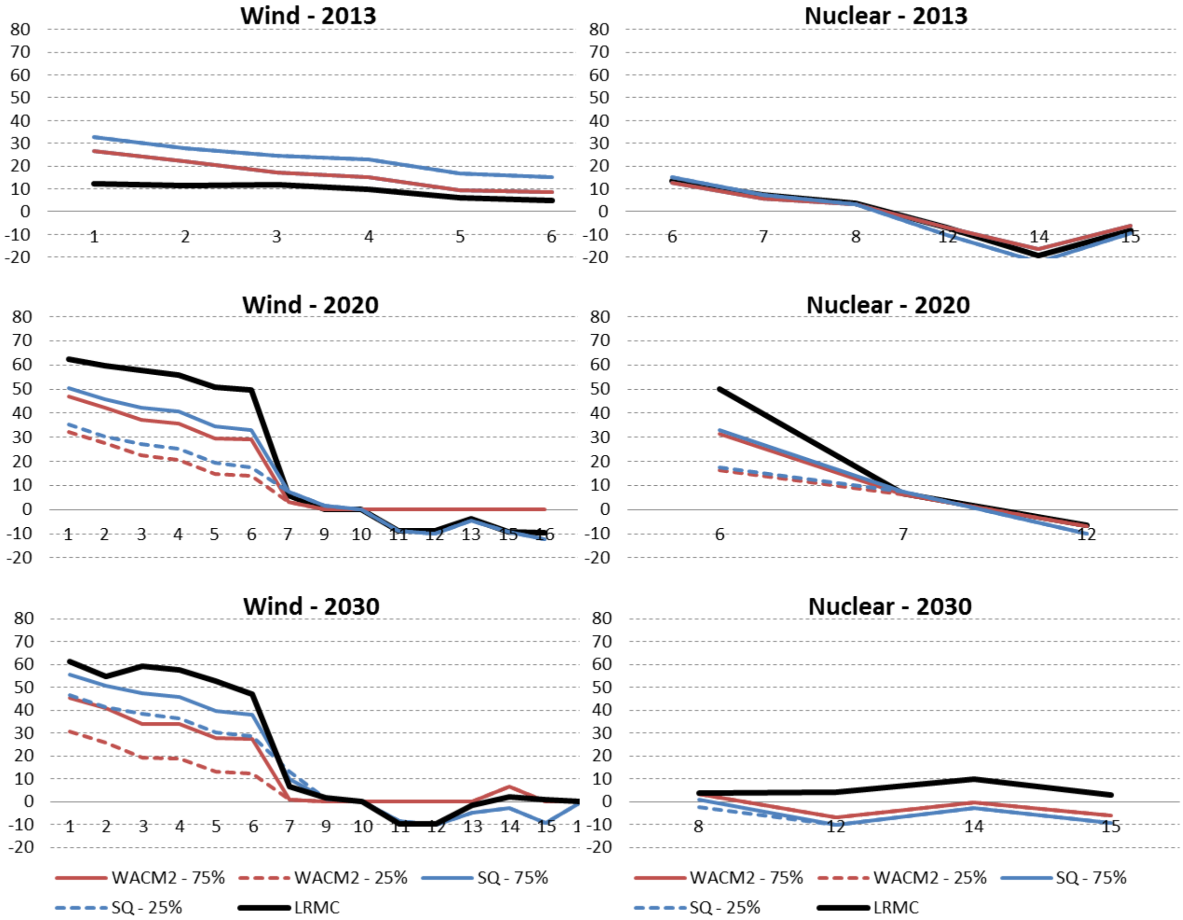
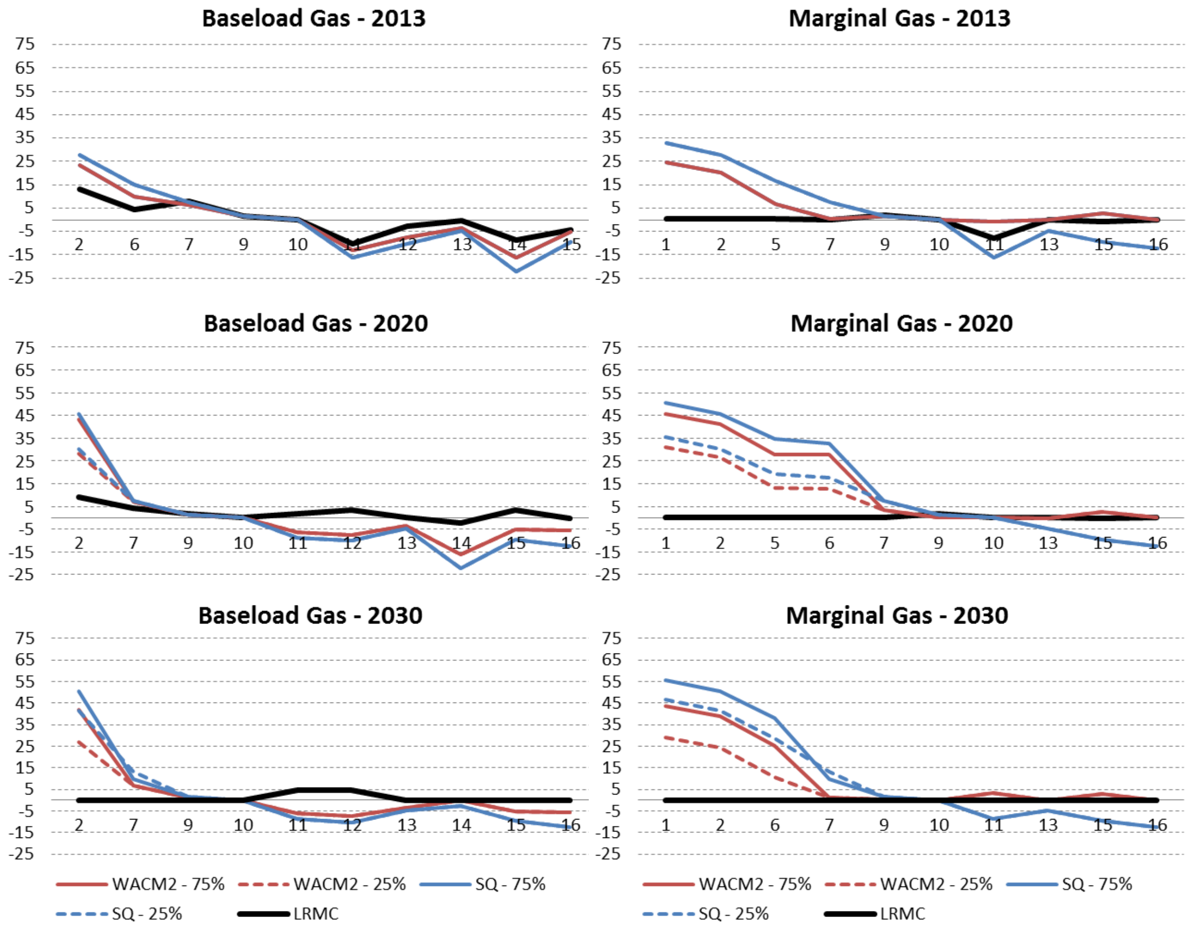


Figure A.4
TNUoS vs. LRMC for Gas Capacity – Increased Bid-Offer Spread
(£/kW/yr, by DTIM Zone)



A.3. Transmission Investment Cost Scenario

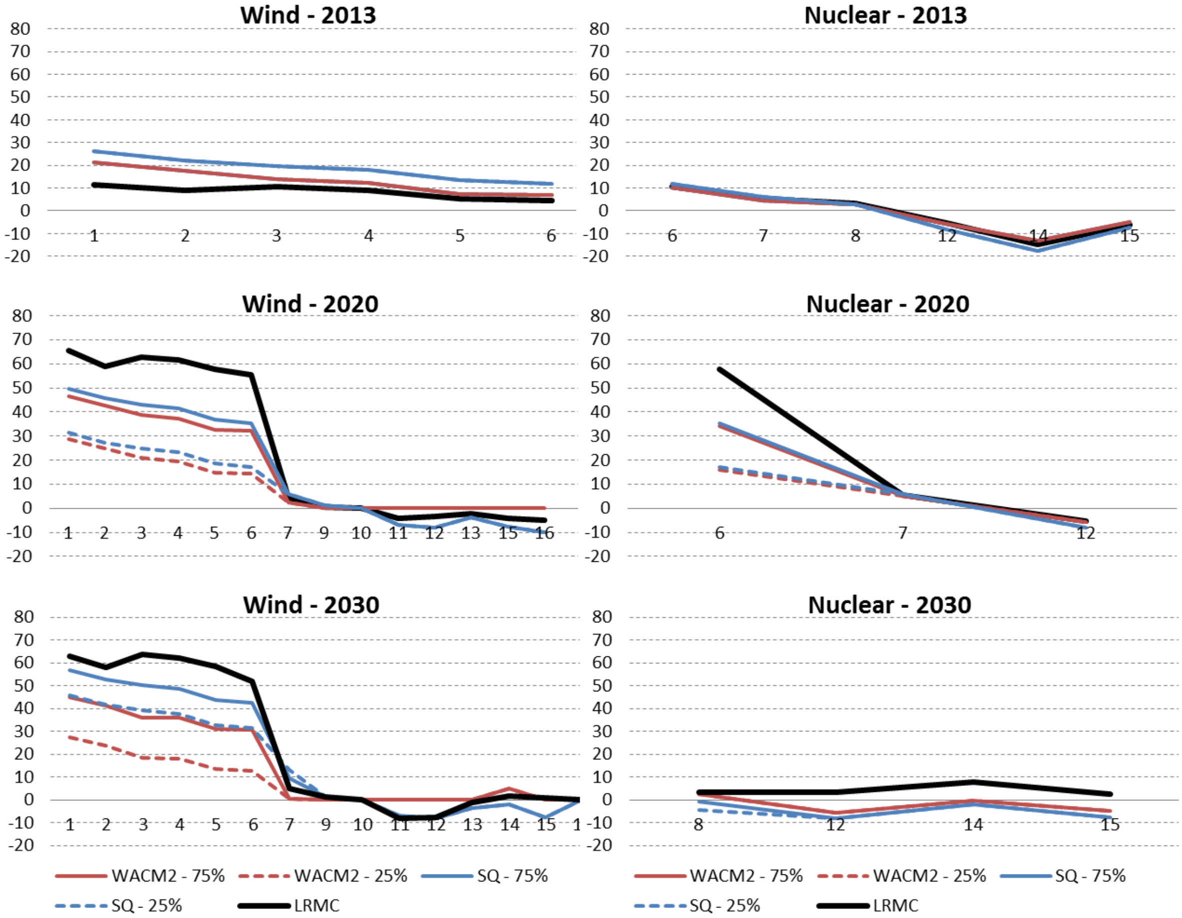
In this scenario, we assume the annualised capital cost of the HVDC links increases by 20%, and the cost of AC lines falls by 20%. The rationale for this sensitivity is that, as discussed in Section 5.2.3, one reason for the large differences we observe between tariffs and LRMCs is the difference in the assumed costs of reinforcing the HVDC bootstraps compared to reinforcing the onshore AC system. Both tariff methodologies set Scottish tariffs using an average of the two reinforcement costs (with the weighting determined by the assumed utilisation on the bootstraps), whereas LRMC depends solely on the cost of reinforcing the bootstraps, due to the constraint on expanding the Cheviot boundary beyond 4.4GW.

As the figures below show, increasing the spread between the assumed costs of AC and HVDC reinforcements increases the spread between LRMC and charges for both methodologies. For example, the locational element of WACM 2 tariffs for wind plants in

DTIM zone 2 in 2030 are 81% of LRMC in the reference case, which falls to 71% in this case.[48]

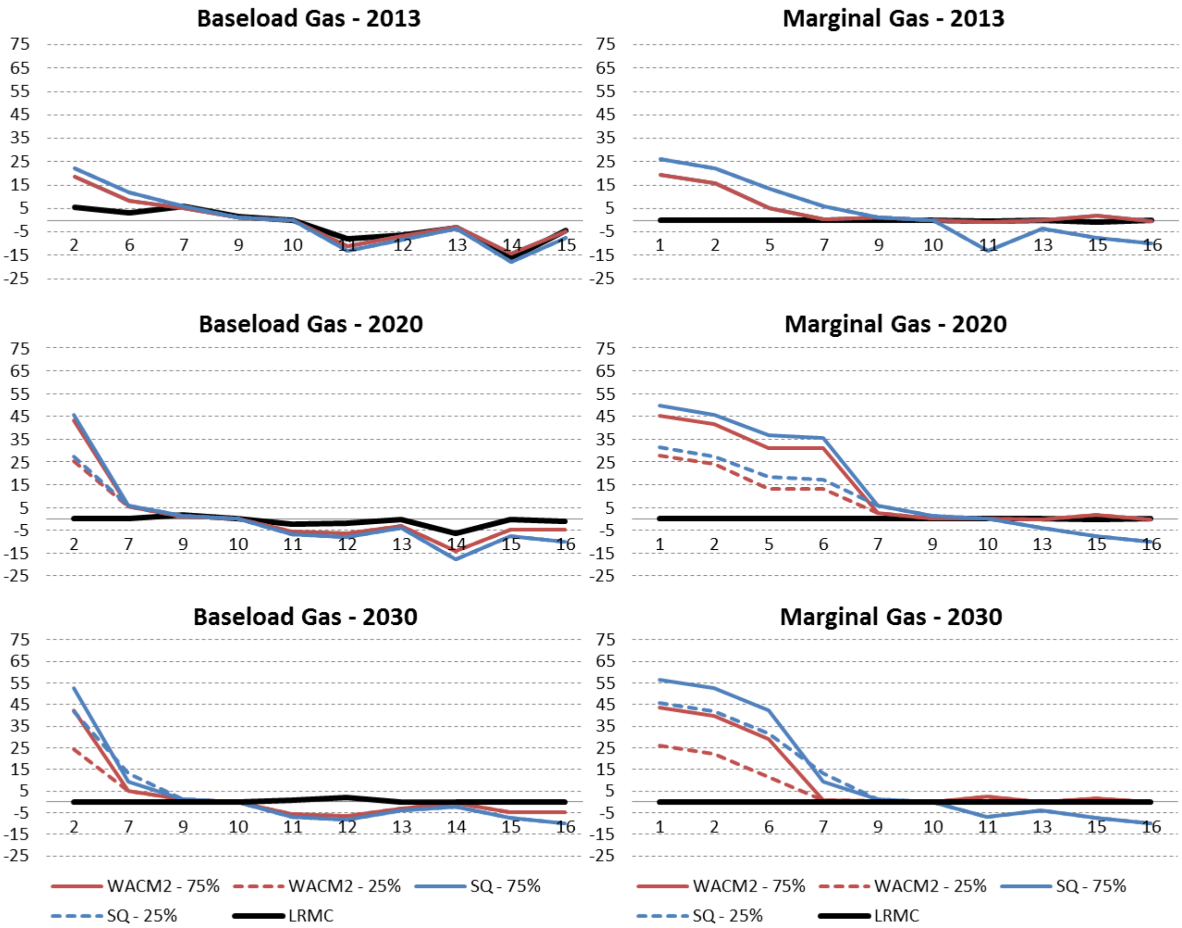
Otherwise, the LRMCs and TNUoS charges follow broadly the same pattern observed in the reference case, so the conclusions we draw above are robust to changing the assumed spread between HVDC and AC reinforcements.

Figure A.5
TNUoS vs. LRMC for Wind and Nuclear Capacity – Transmission Investment Cost Sensitivity (£/kW/yr, by DTIM Zone)



[48] If we were to reduce the spread assumed between the cost of reinforcing the HVDC and AC networks, we would expect to see the reverse effect, with LRMC moving closer to the two sets of charges.

Figure A.6
TNUoS vs. LRMC for Gas Capacity – Transmission Investment Cost Sensitivity (£/kW/yr, by DTIM Zone)



Appendix B. Residual Charges

Table B. 1 shows our estimates of the residual charges under WACM 2, the status quo and the LRMC-based methodology. As noted in Section 5.2.1 above, the residual charge does not vary across zones or technology. Thus, incorporating the residual into the locational charge curves shown in Section 5.2 would simply shift the lines up or down by a flat £/kW amount and so would not affect locational signals. As Table B. 1 shows, there is also little variation in residuals across charging methodologies, so including them in the charge estimates would not affect our conclusions.

Table B. 1
Residual Charges (£/kW)

Year	Status Quo	WACM 2	LRMC
2013	3.16	2.81	5.45
2020	5.16	3.18	0.98
2030	2.14	2.72	-0.95

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