RWE

Follow up to RWE's response to the CMA's working paper on locational pricing in the electricity market in Great Britain

RWE has responded to the CMA's working paper on locational pricing (March 27th 2015). In that response RWE noted that the impact assessment undertaken in 2010 for Modification proposal P229 identified significant efficiency gains and social welfare benefits from introduction of a seasonal zonal transmission losses scheme and that the analysis would need to be updated to take account of a number of new factors. In addition a question was raised at the Hearing regarding whether RWE could comment on potential direction of change in the magnitude of these benefits since the original analysis was undertaken.

As a consequence RWE has commissioned additional modelling from NERA Economic Consulting (NERA) and Imperial College London (Imperial) to provide an updated estimate of the benefits of introducing locational zonal losses. We would note that this work is a preliminary estimate as a consequence of the time available but does provide some additional information that should be taken into account in the CMA consideration of locational pricing.

The analysis undertaken by NERA and Imperial has focused on the impact on dispatch decisions that would arise following the introduction of locational losses in the wholesale power market. As such, the further effects that might arise with respect to future power station location has not been modelled, which it may be expected would give rise to additional efficiencies for consumers.

This simplification is a result of the time constraints placed on NERA / Imperial in order to be able to provide the CMA with updated estimates prior to the publication of the CMA's initial findings.

The analysis that has been done considers two alternative methodologies for the implementation of zonal losses. The first is aligned with the seasonal average approach that was considered in P229 and the second approach is an hourly calculation, providing a real-time calculation of the impact of losses.

The findings of the analysis are that there would be a material benefit to consumers arising from a zonal losses scheme being implemented. The work suggests that consumers would benefit by a total of between £880M and £1,600M (NPV) in the period 2016 to 2030, depending on the method used for implementation, through reduced energy prices, lower losses and lower constraint costs.

As stated above, the work is preliminary and any implementation would require further work to determine the most effective method for calculating zonal losses, but we hope that the CMA will find the work helpful in providing an updated view on consumer benefits and we would be very happy to discuss further, should that be required.

The Welfare Effects of Locational Transmission Loss Factors in the British Wholesale Electricity Market

Prepared for RWE

11 May 2015

NERA Project Team

Sean Gammons
Richard Druce
Peter Davies
Zhaoxin Pu

Imperial College Project Team

Prof Goran Strbac
Dr Christos Konstantinidis
Dr Rodrigo Moreno

NERA Economic Consulting
Marble Arch House, 66 Seymour Street
London W1H 5BT
United Kingdom
Tel: 44 20 7659 8500 Fax: 44 20 7659 8501
www.nera.com

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Executive Summary

Background

In a recent working paper produced in the course of its Energy Market Investigation ("EMI"), the Competition and Markets Authority ("CMA") asked interested parties to submit evidence regarding the benefits of enhancing "locational signals" in the British wholesale electricity market. This report, commissioned from NERA Economic Consulting ("NERA") and Imperial College London ("Imperial") by RWE, presents an initial estimate of the welfare benefits of introducing locational Transmission Loss Multipliers ("TLMs").

Under current trading arrangements, generators are asked to produce a little extra electricity to cover around half of total transmission losses, and consumers are asked to buy a little more electricity to cover the remainder. The shares of transmission losses allocated to generators and consumers do not vary according to their location. However, some generators are located a long way from areas with high demand (relative to supply), so their output has to travel long distances and results in relatively high losses. Similarly, some consumers are located a relatively long distance from the generation required to supply them, so a relatively high proportion of the generation required to supply them is lost. The overall consequences are that the allocation of losses does not promote efficient behaviour by producers and consumers, and that some parties bear a greater share of the cost of losses than they impose (and vice versa).

To contribute to the CMA's consideration of locational signals in the British power market, this report provides a preliminary estimate of the welfare benefits of introducing zonal loss factors, or TLMs, in the British wholesale market. The intention of such a reform would be to better signal to consumers and producers the marginal cost of losses they impose on the system, and promote more efficient decision making as a result. For instance, efficient locational loss factors would encourage more efficient decisions regarding generation despatch, investment and closure, and may also promote efficiency on the demand side as consumers adjust their decisions too. In particular, locational loss factors might affect the locations at which large industrial consumers decide to develop new facilities.

Our Approach

We have conducted "fundamentals" modelling of the British power market and transmission system to estimate the welfare effects of introducing zonal TLMs. Our approach combines two models: NERA's model of the British wholesale electricity market, implemented primarily using the "Aurora" platform,[1] and Imperial's load flow model of the British transmission system, known as the Dynamic Transmission Investment Model ("DTIM"). We use the following modelling procedure:

- Using the network topography and generation locational decisions predicted in our 2014 modelling of the "WACM2" TNUoS charging methodology, performed during the Project TransmiT process, we use DTIM to compute Transmission Loss Factors ("TLFs")

1 Aurora is vended by Epis Inc, a US firm specialising in power market simulation software.

by estimating how total transmission losses change from injecting marginally more power into the system in different locations;

- From these TLFs, we estimate zonal TLMs for each hour of the modelling horizon, which vary with transmission load flow conditions caused by variation in demand and wind production;
- We then run NERA's market model without zonal TLMs (the "status quo" case) to predict patterns of generation investment, power prices and generation costs (such as fuel, CO_2, etc);We then run two scenarios of the market model in which we assume generators are subjected to zonal TLMs: in one case we assume the locational spread in TLMs is fixed throughout each season, and in the second we assume TLMs vary from hour-to-hour with wind and demand and so more accurately reflect the marginal losses associated with generation in different locations. The seasonal TLM scenario follows broadly the same approach as prescribed the most recent proposal to introduce zonal loss factors, BSC Modification P229.[2] The hourly TLM scenario allows for more time variation in marginal loss factors than under P229 in order to better reflect how marginal losses depend on load flow conditions on the transmission system. In both scenarios, we allow our model to change despatch, but not generation investment decisions;[3]
- We use these runs of the market model to estimate changes in generation costs and power prices (energy and capacity prices) in the two locational scenarios as compared to the status quo. We estimate the change in transmission losses by multiplying the change in output at each plant by the relevant TLF,[4] summing across hours and zones; and
- Finally, we perform welfare calculations to estimate the change in power sector costs and the change in costs to the consumer from the introduction of zonal TLMs.

Projections of Zonal TLMs

In 2016, our modelling implies a spread in generator TLMs, illustrated in Figure 1, between:

- Around +0.5% in the north of country, where increasing injections into the transmission system materially increases overall losses because the additional power needs to be transported to load centres in the south; and
- As low as -2% in the south of the country, where increasing injections reduces overall losses, because it reduces the need to bring generation from other plant that is located further from load.

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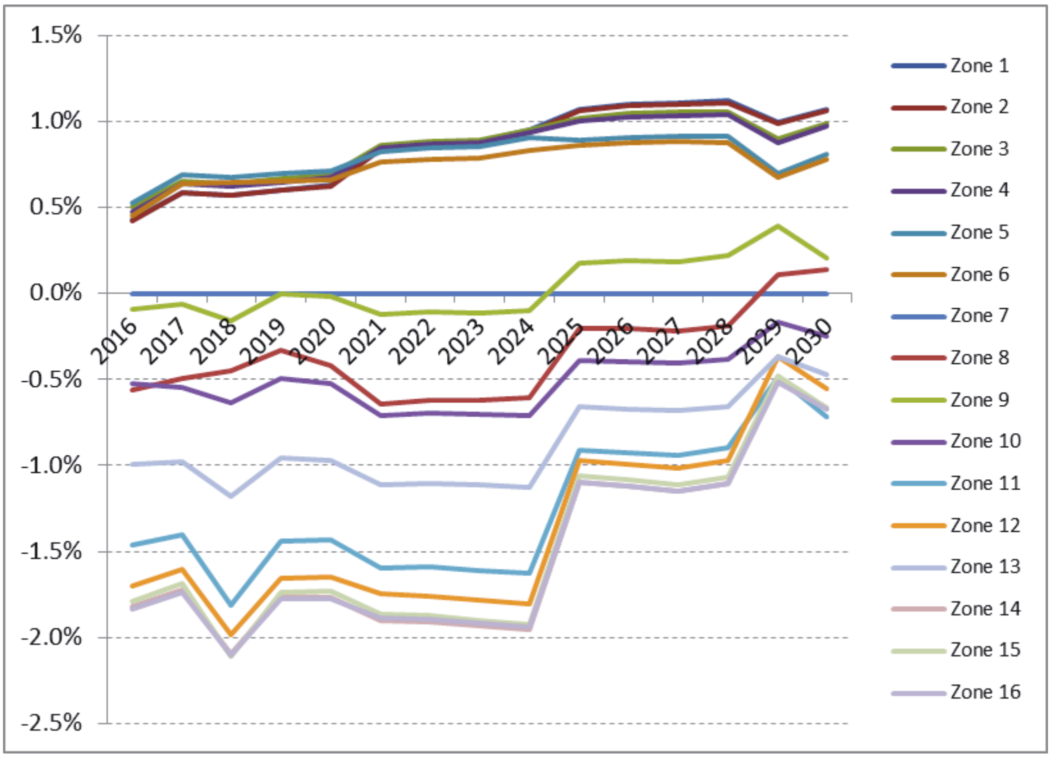
2 Charles Ruffell, RWE Npower November 2008, *Modification Proposal – BSCP40/03 (https://www.elexon.co.uk/wp-content/uploads/2012/02/p229.pdf)*

3 We performed some initial runs of the model, in which we demonstrated that the impact on investment decisions from the implementation of zonal TLMs was negligible. We therefore hold investment decisions constant across these scenarios.

4 We multiply changes in plants' output by TLFs (rather than TLMs) because TLFs represent the underlying change in losses resulting from a change in production by a given generator. In contrast, the TLMs represent the share of losses caused by changing output (essentially, the share of the TLF) for which the generator is deemed responsible under British power trading arrangements.

Our modelling suggests that TLMs change over time, as the transmission system expands and the generation mix changes. In particular, we see some convergence in TLMs across the country. The main driver of this effect seems to be the new CCGT generation capacity that our model predicts will connect to the system in England and Wales. These investments mitigate the current deficit of energy production (relative to demand) in the south. Hence, marginally increasing injections in the south reduces losses to a lesser extent as time goes on.

Figure 1
Annual Average Generator TLMs (%) by DTIM Zone



Source: NERA/Imperial[5]

Savings in Power Sector Costs

The introduction of zonal TLMs improves the efficiency of plant despatch by forcing generators to account of the impact of their despatch decisions on system losses. As Figure 2 shows, the reduction in losses as a result of zonal TLMs increases from around 0.1 TWh per annum to around 0.2 TWh by the mid-2020s. The impact diminishes from the late 2020s onwards, as the variation in transmission loss factors across the different parts of the transmission system reduces (see Figure 1). Transmission losses (and hence total system demand) fall by around 0.15 TWh per annum on average over the whole modelling horizon to 2030.

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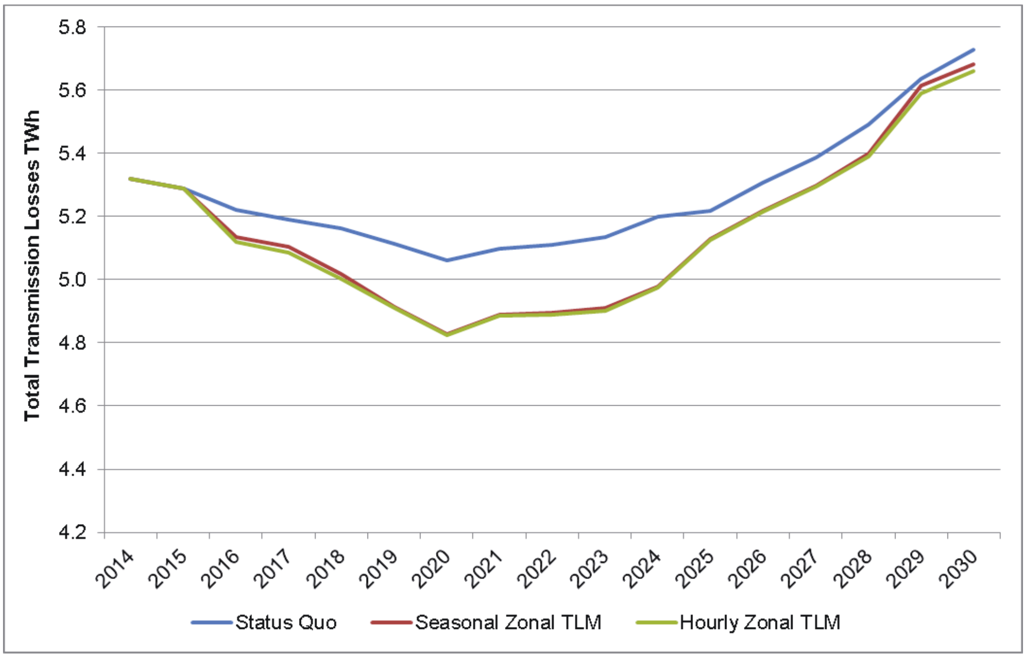
5 Note, a TLM of +1% means that a 1 MWh increase in injections increases system losses by 0.01 MWh. TLMs in zone 7 are always 0%, as this is the reference node.

Figure 2
Transmission Losses (TWh) - All Scenarios



Source: NERA/Imperial

Valued at the demand-weighted power price emerging from our modelling, this reduction in losses implies a reduction in system costs of £9 million per annum in the seasonal TLM scenarios and £11 million per annum in the hourly TLM scenario, as Figure 3 and Figure 4 show. This equates to £108 million and £129 million in NPV terms over the period 2016 – 2030 in the seasonal TLM and hourly TLM scenarios respectively, as Table 1 below shows. However, losses savings come at the cost of somewhat higher generation operating costs (fuel, CO_2, plus variable O&M).

Specifically, when we run the model with uniform loss factors, the model essentially chooses despatch to minimise generators' variable operating costs without any regard for the impact of despatch on losses. Zonal TLMs, on the other hand, force the model to account for the impact of despatch on losses, and select a different pattern of despatch that minimises the combination of generators' variable operating costs plus the costs of losses. Because the pattern of despatch has changed from the uniform case, it necessarily produces higher variable operating costs for generators. Taking the costs of losses and generators' own operating costs together, however, zonal loss factors improves the efficiency of despatch because the cost of losses falls by more than the offsetting increase in generators' variable costs.

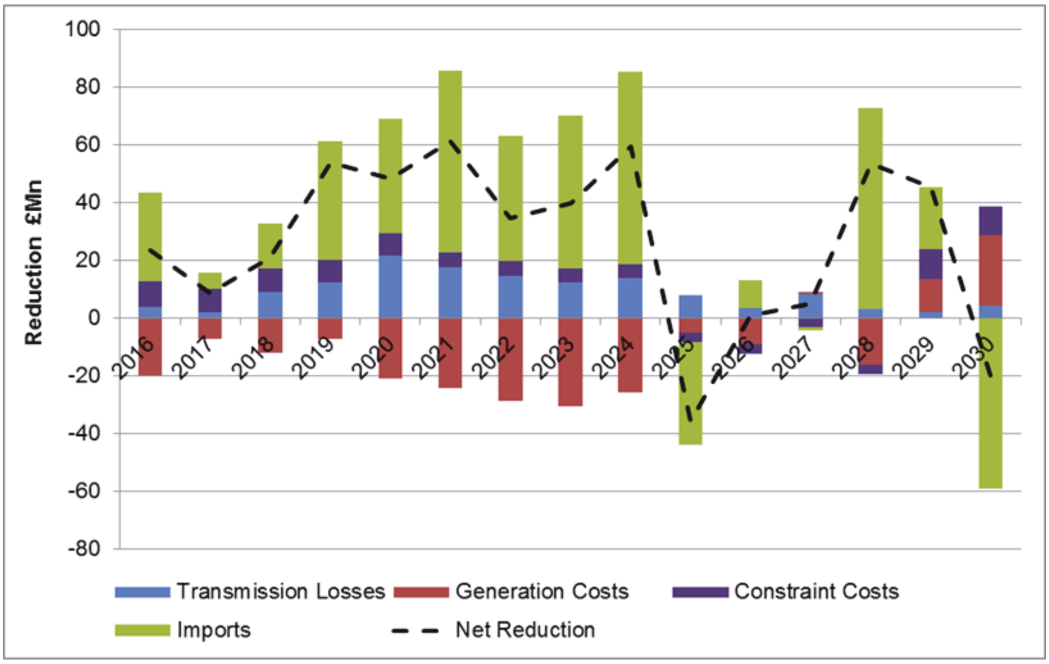
We also identify a saving in import costs. As discussed below, the introduction of zonal loss factors reduces the marginal cost of generation by plant towards the south of the country. These plants, which are predominantly thermal generation, tend to set the price in the wholesale market in our modelling, and as such, wholesale power prices in Britain fall. Lower wholesale prices in Britain have two effects. First, lower prices in Britain relative to its neighbouring markets mean Britain imports power less frequently, which reduces import costs.

Second, our modelling suggests that in many hours the transfer of energy from Ireland to Britain, or vice versa, is less than the available transmission capacity between the two markets. This means that Britain and Ireland have a single price, and this price tends to be lower as a result of zonal TLMs. In hours when transmission capacity is unconstrained, Britain is importing, and prices are lower as a result of zonal TLMs, the cost to the British power sector of importing power from Ireland falls, because we value these imports at the price prevailing in the Irish market.

Zonal loss factors result in lower despatch of generators towards the north of the country, and more despatch from generation in the south. This change in despatch reduces the extent to which power needs to be transported long distances across the transmission system, and thus reduces the incidence and cost of constraints by around £4 million per annum on average over the modelling horizon.

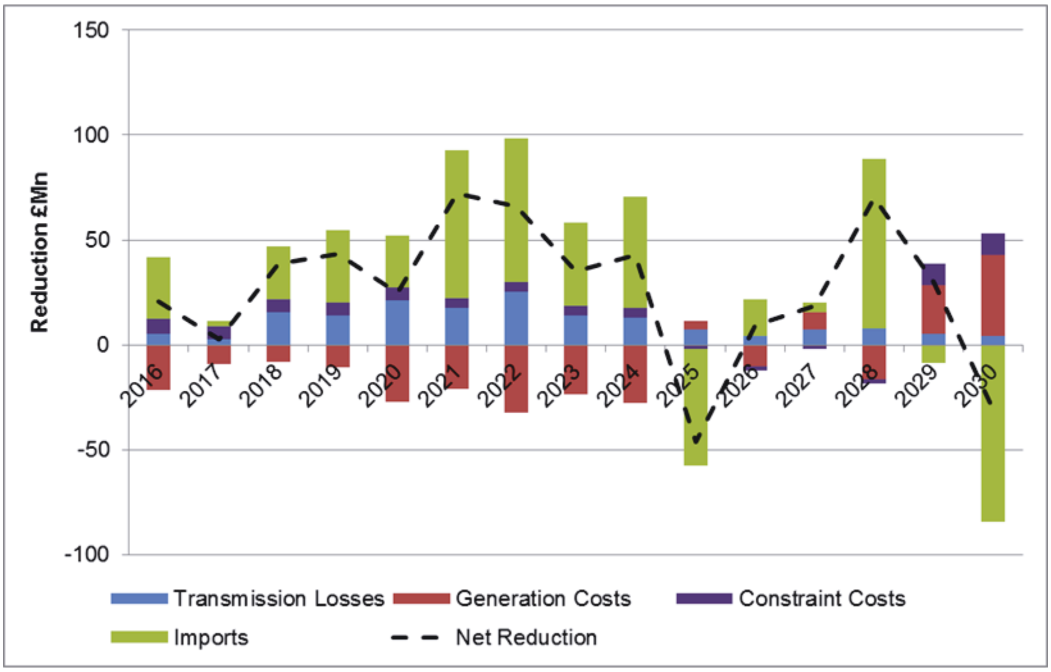
Figure 3 and Figure 4 show the cumulative effects of these changes in cost over the modelling horizon, which produce overall savings of around £26 million per annum in both the seasonal TLM scenario and hourly TLM scenarios.

Figure 3
Composition of the Change in Power Sector Costs (2014 £ million) – Uniform Case vs. Seasonal TLMs



Source: NERA/Imperial

Figure 4
Composition of the Change in Power Sector Costs (2014 £ million) – Uniform Case vs. Hourly TLMs



Source: NERA/Imperial

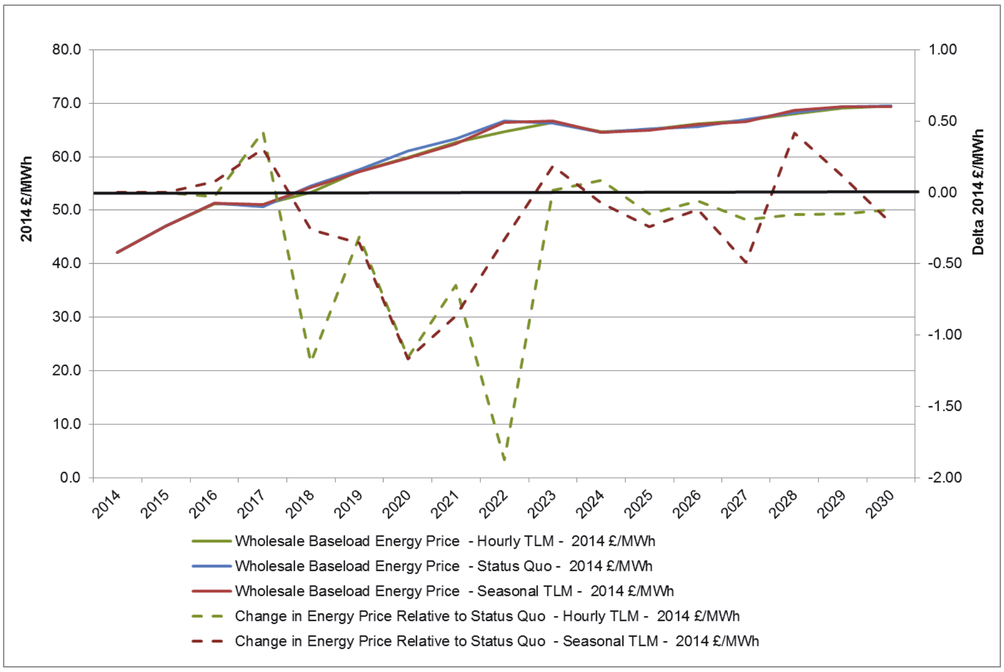
Reductions in Power Prices

We find that locational generator TLMs (both seasonal and hourly) result in lower energy prices compared to the status quo from 2018 until the mid-2020s, as illustrated by Figure 5

The key driver of this result is the reduction in TLMs in the locational scenarios for thermal plant in the south of Great Britain, where most new thermal plants are located in our modelling. Lower TLMs for new generators reduce the level to which wholesale energy and capacity prices need to rise to remunerate new generation investment. However, as the regional spread in TLMs diminishes over time (see Figure 1 above), so too does the impact on wholesale prices.[6]

[6] This convergence in TLMs results from the regional placement of generation predicted by the "WACM2" scenario of our Project TransmiT modelling. Different TNUoS methodologies would alter this result.

Figure 5
Baseload Energy Prices by Scenario (Left Axis) and Delta to Status Quo (Right Axis), 2014 £/MWh



Source: NERA/Imperial

Conclusions

As summarised in Table 1 below, we find a reduction in consumers' bills as a result of zonal losses through lower wholesale prices, as well as reduced losses and constraints, partly offset by an increase in the subsidies paid to low carbon generation:

- Reductions in wholesale power prices reduce consumers' bills by £0.8 billion and £1.7 billion in the seasonal and hourly scenarios respectively;
- Because of the reduction in power prices, the costs of subsidies paid to low carbon generation, such as through the CFD FIT mechanism, rise by £77 million and £265 million in the seasonal and hourly scenarios respectively, which slightly offsets the reduction in costs to consumers.
- Consumers' bills also fall as a result of lower losses and constraints by a total of £180 million in the hourly TLM scenario and £163 million in the seasonal scenarios. In total, consumers' bills fall (in NPV terms to 2030) by between £884 million and £1,590 million in the two scenarios.

The overall improvement in welfare, which we approximate by the change in power sector costs resulting from our modelling, amounts to between £315 million and £318 million in NPV terms in the hourly and seasonal scenarios respectively. This effect results from lower losses and constraint costs, lower import costs, albeit slightly offset by higher generation costs, as described above.

Our finding that the reduction in power sector costs, a proxy for the improvement in welfare resulting from zonal loss factors, is less than the benefit to consumers implies a reduction in the profits earned by generators (i.e. "producer surplus") of between £0.6 billion and £1.3 billion depending on the scenario.

Table 1
Welfare Impact of Introducing Zonal TLMs for Generators (2014 £ million, NPV to 2030)[7]

	Welfare Impact - 2016 - 2030 (2014 £Mn)	
	Seasonal TLMs	**Hourly TLMs**
Impact on Consumers		
Power Purchase Costs (inc. capacity payments)	-798	-1,675
Low Carbon Subsidies	77	265
Constraints	-56	-51
Losses	-108	-129
Total	-884	-1,590
Power Sector Costs		
Generation Costs (excluding TNUoS)	142	121
Import Costs	-297	-257
Constraints	-56	-51
Losses	-108	-129
Total	-318	-315

Source: NERA/Imperial. Note, all NPVs are calculated between 2016 and 2030 at a real discount rate of 3.5%, following the HM Treasury Green Book. Impact per consumer is an annual benefit. Increases in costs are shown in red whilst decreases are shown in black.

We note that more work would be required to improve the accuracy of our results and to examine the impact of alternative assumptions. Despite this limitation, the results we present represent a reasonable estimate of the effects of introducing marginal loss factors in the British wholesale market. In fact, the omission from our modelling of the potential benefits of more efficient generation investment and the benefits of enhanced efficiency on the demand side mean our estimated welfare effects may somewhat understate the potential savings.

7 Note that the sub-categories of costs under the two headings, "*Impact on Consumer Bills*" and "*Power Sector costs*" are distinct from each other (in other words they do not overlap). In particular, constraint costs are the costs associated with bids and offers in the balancing mechanism for National Grid and are not therefore included in generation costs.

1. Introduction

In a recent working paper produced in the course of its Energy Market Investigation ("EMI"), the Competition and Markets Authority ("CMA") asked interested parties to submit evidence regarding the benefits of enhancing "locational signals" in the British wholesale electricity market. This report, commissioned from NERA Economic Consulting ("NERA") and Imperial College London ("Imperial") by RWE, presents an initial estimate of the welfare benefits of introducing locational Transmission Loss Multipliers ("TLMs").

1.1. The Costs of Transporting Electricity

Electricity is a homogenous good at the points of production and consumption, but is characterised by material transport costs. Transmission and distribution infrastructure is required to transport power from generators to consumers, and if insufficient network capacity is available to transport generators' desired levels of output to consumers, the System Operator ("SO") incurs "constraint costs" when it compensates them for their inability to sell output to the market.

The cost of transmission infrastructure is recovered under current regulatory arrangements through Transmission Use of System ("TNUoS") charges.[8] To the extent that variation in these charges reflect the differences in the costs different types of generator impose on the transmission system, then generators in different parts of the country will receive efficient or "cost reflective" locational signals, providing economic information that allows them to make a trade-off between how their own costs and the costs they impose on the transmission system vary across the country. The total revenue recovered from TNUoS charges in 2013/14 was £2.5 billion.[9]

The SO recovers the costs of constraints as one component of Balancing Services Use of System ("BSUoS") charges, which are also used to recover other costs of system operation such as ancillary service costs. BSUoS charges are currently structured as a £/MWh that is recovered from all generators and consumers. There is no locational variation in BSUoS charges, so there is no attempt to reflect in tariffs locational differences in the constraints and other operational costs caused by different generators in different parts of the country. The total revenue recovered from BSUoS charges in 2014 was £1 billion, of which £340 million was required to cover the costs of transmission constraints.[10]

When power flows across transmission and distribution lines, some of it is wasted, or "lost". Hence, in addition to network infrastructure and constraints, transmission losses represent another material component of electricity transport costs. Specifically, transmission losses accounted for 1.7% (5.3 TWh) of total energy production in Great Britain in 2014.[11] Valued

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8 The costs of the distribution networks, recovered through Distribution Use of System ("DUoS") charges, are beyond the scope of this report.

9 National Grid January 2015, Final TNUoS Tariffs for 2015/16, Tables 18 – 20, pages 25 - 27

10 National Audit Office May 2014, Electricity Balancing Services, Briefing for the House of Commons Energy and Climate Change Select Committee, Figure 7, page 15 & para 3.4, page 25.

11 National Grid 2014, *Transmission Losses Report: Reporting Period 1 April 2013 to 31 March 2014*, Table 1, page 2

at the annual average wholesale electricity price in 2014 of £42.1/MWh, the total cost of losses to the British power system was £223.2 million.

1.2. Zonal Loss Factors

Electricity generators and consumers are allocated a share of transmission losses. Essentially, generators are asked to produce a little extra electricity to cover around half of transmission losses, and consumers are asked to buy a little more electricity to cover the remainder.

Specifically, when an electricity generator produces electricity, the amount of energy for which it is credited in settlement is reduced slightly by a TLM. Under the current BSC, the TLM by which generators' output is reduced is determined hourly by the SO. In essence, all generators output are reduced by a common factor that allocates 45% of losses to them, with the remaining 55% allocated to consumers. There is no geographic variation in generators' allocation of losses (on a per MWh basis).

The current arrangement for allocating transmission losses has been in place since the British electricity industry was privatised in 1990. However, as set out in the CMA's recent working paper,[12] the regulator and industry have on several occasions considered implementation of zonal loss factors that would set generators' and consumers' respective shares of losses closer to the losses they are estimated to cause. The most recent proposal to introduce zonal loss factors, BSC Modification P229,[13] was rejected by the Gas and Electricity Markets Authority ("the Authority") in September 2011.[14]

The intention of such a reform is better to signal to consumers and producers the marginal cost of losses they impose on the system, and promote more efficient decision making as a result. For instance, more efficient loss factors would encourage more efficient decisions regarding generation despatch, investment and closure. More efficient loss factors may also promote efficiency on the demand side, such as by influencing the locations at which large industrial consumers decide to develop new facilities.

1.3. Scope of this Report

To contribute to the CMA's consideration of locational signals in the British power market, this report provides a preliminary estimate of the welfare benefits of introducing zonal loss factors in the British wholesale market. Specifically, we consider two scenarios on how zonal loss factors might be implemented: the first follows broadly the same approach as prescribed under P229, and the second approach allows for more time variation in marginal loss factors than under P229 in order to better reflect how marginal losses depend on load

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12 Competition and Markets Authority February 2015, *Energy Market Investigation: Locational pricing in the electricity market in Great Britain,* paras 15-17, pages 5-6

13 Charles Ruffell, RWE Npower November 2008, *Modification Proposal – BSCP40/03 (https://www.elexon.co.uk/wp-content/uploads/2012/02/p229.pdf)*

14 Ofgem September 2011, *Balancing and Settlement Code (BSC) P229: Introduction of a seasonal Zonal Transmission Losses scheme (P229)*

flow conditions on the transmission system. We estimate the welfare effects of both scenarios compared to the counterfactual in which the current uniform loss factors remain.

However, as discussed further below, the short time available for performing this study means there are some caveats attached to our results, and more work would be required in order to estimate the impact of zonal losses more rigorously. In particular, while have modelled the welfare benefits that result from more efficient despatch, generation investment and exit decisions and transmission investment decisions, we have not modelled the impacts of more efficient decisions on the demand side. We also highlight some limitations to the modelling framework we have applied in this study. Nonetheless, we consider that our estimates constitute a reasonable estimate of the order of magnitude of welfare benefits that would result from the introduction of zonal losses.

The remainder of this report is structured as follows:

- Chapter 2 describes our approach to modelling the economic impact of zonal transmission loss factors;
- Chapter 3 describes our modelling results
- Chapter 4 presents an initial assessment of the welfare impacts of zonal loss factors; and
- Chapter 5 concludes.

2. Our Approach

2.1. Our Modelling Tools

We employ two modelling tools for this assignment: Imperial's Dynamic Transmission Investment Model ("DTIM"), and NERA's power market model. We apply these models to estimate the welfare effects of implementing zonal TLMs in the British power market using the procedure described below in Sections 2.1.2 and 2.3.

2.1.1. Our power market modelling tools

NERA's power market modelling tool, implemented using the "Aurora" power market modelling software platform (vended by EPIS Inc of the US), is a fundamentals model that optimises the despatch of generation, as well as generators' decisions to enter and exit the market. It does so by despatching generators using a Mixed Integer Linear Program (or "MIP") that chooses plant despatch patterns to meet demand at least cost, simulating, in essence, a process of competition between generators. It also optimises flows across interconnectors to neighbouring markets.

Aurora defines market prices by the marginal cost of the marginal generator required to meet demand in each hour, plus an uplift function that ensures those generators in the least cost despatch schedule can recover their unit commitment costs, such as the costs of starting-up their plant.

By iterating and performing this despatch multiple times, Aurora optimises the timing and location of new thermal generation investments such that those generators who can enter the market profitably will do so, and those who do not cover their costs (including a normal return on capital) exit the market.

Separate from Aurora, we have also developed a tool to optimise the timing and location of new wind generation investments. This model selects the cheapest new wind investments form a range of potential development sites, subject to constraints such as on the total amount of wind capacity that can be developed in each zone, or the year when certain projects can be developed. In essence, this model optimises the trade-off between sites with different fixed costs of development, load factors, TNUoS, TLMs, and so on.

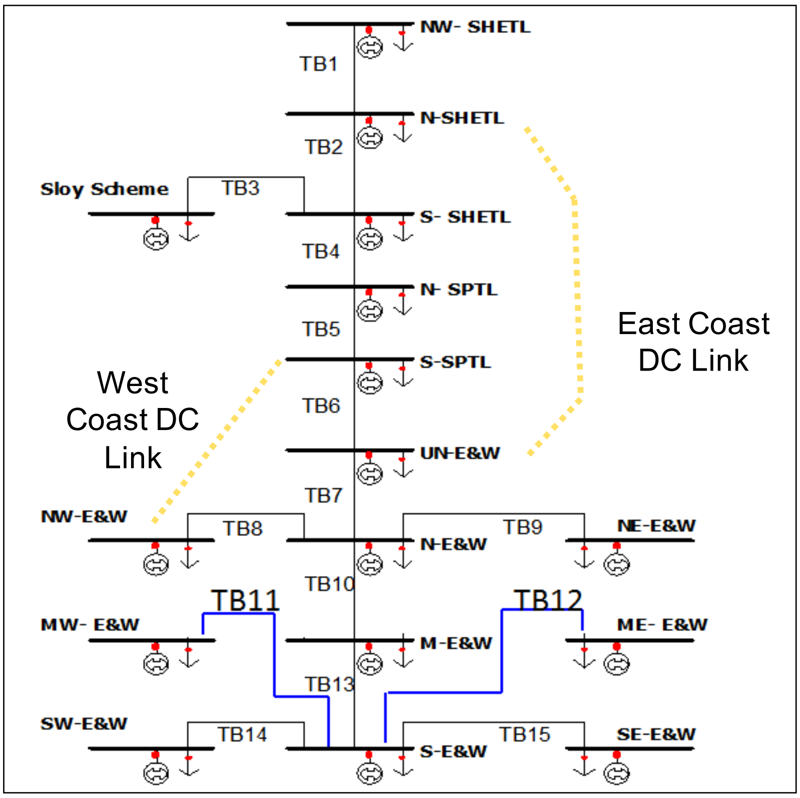
2.1.2. Our transmission system models

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 can balance the costs of network constraints and transmission losses against 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). 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.

DTIM uses a 16-zone, 15-boundary radial network to represent the GB transmission system, as shown in Figure 2.1. Each node represents a GB zone, and each branch represents a boundary.[15]

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 2.1
DTIM Radial Network



Source: Imperial Analysis

2.2. Step 1: Computing Transmission Loss Multipliers (TLMs)

The starting point for our modelling work was a calculation of Transmission Loss *Factors* (TLFs) using the DTIM model. The modelling assumptions (network topography, generation background, etc) used for this model run is based on the NERA/Imperial modelling

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15 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.

performed during 2014 in the context of Ofgem's Project TransmiT process.[16] From this work, we used the scenario with the "WACM2" TNUoS methodology.[17]

We use DTIM to estimate TLFs by computing the change in total system losses resulting from injecting an additional MWh of production into a given node of the DTIM network, and a MWh of demand at a reference node (DTIM zone 7). By performing this calculation for each of the 16 DTIM nodes and for each DTIM snapshot, we can estimate the variation in TFLs across the British power system, as well as how these loss factors vary across time, and with the level of demand and wind production.[18]

- For instance, at present, a large proportion of wind generation in Great Britain is located in Scotland. Therefore, north-south power flows are highest on windy days. As a result, the additional losses caused by increasing generation slightly in Scotland (ie. the locational TLF for Scottish generators) are higher on a windy day.[19] Table 2.1 illustrates this pattern for the years 2008-12: marginal loss factors in Scotland are higher when wind production is also higher. We see the reverse effect towards the south of GB, as Table 2.2 illustrates for zone 11 in the South West of Great Britain.
- High levels of demand are also associated with relatively high marginal loss factors, as Table 2.1 and Table 2.2 illustrate for the years 2008-12 in both Scotland and a zone in the South West of the country.[20] Both tables show a tendency for marginal loss factors to increase with demand.

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[16] NERA Economic Consulting and Imperial College London, Project TransmiT: Updated Comparison of the WACM 2 and Status Quo Charging Models: Prepared for RWE, 27 May 2014.

[17] We have selected this scenario because Ofgem has decided to implement the "WACM2" TNUoS methodology. This decision is currently subject to legal challenge. However, we anticipate that the choice of which scenario we took from this work would have a minor impact on our results, on the basis that the other scenario in our TransmiT modelling (with "status quo" TNUoS charges) had a similar regional distribution of plants, which is the main driver of the regional variation in transmission loss factors. Note, we also took TNUoS charges for our market modelling from this run for our market modelling.

[18] This procedure produces 510 TLFs for each of the 16 zones and for 5 epochs, giving a database of 40,880 (= 510 x 16 x 5) marginal loss factors.

[19] Increasing flows across transmission lines that are already heavily loaded because of high wind production in the north causes relatively high levels of additional losses. This phenomenon occurs because losses on a transmission line are an increasing and quadratic function of current on that line.

[20] Increasing flows across transmission lines that are already heavily loaded because of high demand in the country as a whole causes relatively high levels of additional losses. This phenomenon occurs because losses on a transmission line are an increasing and quadratic function of current on that line.

Table 2.1
Transmission Loss *Factors* in DTIM Zone 1 (North Scotland), Epoch 1 (2008-12)

DTIM GB Demand (MW)	DTIM Wind Load Factor (%)									
	3%	8%	15%	25%	35%	45%	55%	65%	75%	85%
32,694	0.3%	0.5%	0.8%	1.3%	1.7%	2.1%	2.3%	2.2%	2.2%	2.1%
33,663	0.3%	0.5%	0.8%	1.3%	1.7%	2.1%	2.3%	2.2%	2.2%	2.1%
39,233	1.4%	1.6%	1.9%	2.3%	2.7%	3.1%	3.5%	3.4%	3.3%	3.3%
40,765	1.1%	1.4%	1.7%	2.1%	2.5%	2.9%	3.3%	3.4%	3.4%	3.3%
42,556	1.0%	1.2%	1.6%	2.0%	2.4%	2.8%	3.2%	3.6%	3.5%	3.4%
43,713	1.0%	1.2%	1.5%	1.9%	2.3%	2.7%	3.2%	3.6%	3.6%	3.5%
43,766	1.0%	1.2%	1.5%	1.9%	2.3%	2.8%	3.2%	3.6%	3.5%	3.5%
45,493	0.8%	1.0%	1.3%	1.7%	2.1%	2.6%	3.0%	3.4%	3.6%	3.5%
46,885	0.7%	0.8%	1.1%	1.5%	1.9%	2.4%	2.8%	3.2%	3.6%	3.6%
49,898	1.8%	2.1%	1.5%	1.3%	1.7%	2.1%	2.5%	2.9%	3.3%	3.7%

Source: NERA/Imperial[21]

Table 2.2
Transmission Loss *Factors* in DTIM Zone 11 (South West), Epoch 1 (2008-12)

DTIM GB Demand (MW)	DTIM Wind Load Factor (%)									
	3%	8%	15%	25%	35%	45%	55%	65%	75%	85%
32,694	-5.2%	-5.6%	-6.1%	-6.4%	-6.7%	-6.9%	-6.9%	-6.8%	-6.6%	-6.5%
33,663	-5.4%	-5.5%	-6.0%	-6.7%	-7.0%	-7.2%	-7.2%	-7.1%	-6.9%	-6.7%
39,233	-4.3%	-4.9%	-4.7%	-5.9%	-6.0%	-7.5%	-7.8%	-7.8%	-7.8%	-7.8%
40,765	-4.0%	-4.4%	-4.8%	-5.1%	-5.5%	-6.3%	-7.8%	-7.8%	-7.8%	-7.8%
42,556	-3.6%	-3.9%	-4.2%	-5.1%	-5.4%	-6.2%	-7.6%	-7.8%	-7.9%	-7.9%
43,713	-3.3%	-3.6%	-4.2%	-4.6%	-5.5%	-5.9%	-6.2%	-7.7%	-7.9%	-7.8%
43,766	-3.4%	-3.7%	-4.3%	-4.7%	-5.6%	-6.0%	-6.2%	-7.0%	-7.2%	-7.9%
45,493	-3.3%	-3.4%	-3.7%	-4.4%	-4.9%	-5.8%	-6.2%	-6.9%	-7.2%	-7.8%
46,885	-3.4%	-3.5%	-3.7%	-4.0%	-4.7%	-5.2%	-5.9%	-6.5%	-6.9%	-7.1%
49,898	-3.9%	-3.9%	-3.8%	-4.2%	-4.6%	-4.8%	-5.2%	-5.9%	-6.3%	-7.2%

Source: NERA/Imperial[22]

The next step of our analysis is to map these TLFs, which depend on wind production and demand, onto the hourly demand and wind production profiles in our market models, which we do using the methods explained in more detail in Appendix B.

We then convert these TLFs into generator Transmission Loss Multipliers (TLMs), which would be used to adjust generators' output in settlement, and thus convey a marginal signal to generators regarding their marginal impact on transmission losses. In essence, because generators pay for 45% of transmission losses under current trading arrangements, we compute *generator TLMs* by multiplying the *TLFs* we derive from the Imperial modelling by 45%.

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21 Note, a loss factor of +1% means that a 1 MWh increase in injections increases system losses by 0.01 MWh.

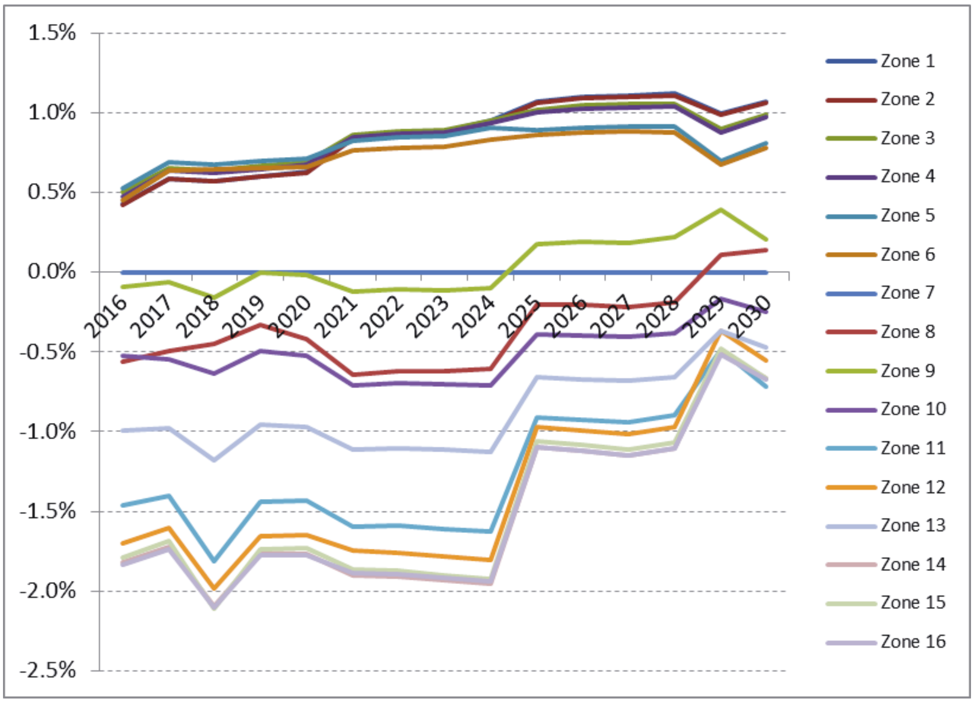
22 Note, a TLM of +1% means that a 1 MWh increase in injections increases system losses by 0.01 MWh.

In 2016, the result is a spread in generator TLMs, illustrated in Figure 2.2, between:

- -0.5% to 0.5% in the north of country, where increasing injections into the transmission system materially increases overall losses because the additional power needs to be transported to load centres in the south; and
- -1 to -2% in the south of the country, where increasing injections reduces overall losses, because it reduces the need to bring generation from other plant that is located further from load.

Our modelling suggests that TLMs change materially over time, as the transmission system expands and the generation mix changes. In particular, we see some convergence in TLMs across the country. The main driver of this effect seems to be the new CCGT generation capacity that our model predicts will connect to the system, and we assume is primarily spread throughout England and Wales based on the results of our recent modelling performed during the Project TransmiT process. These investments mitigate the current deficit of energy production (relative to demand) in the south. Hence, marginally increasing injections in the south reduces losses to a lesser extent at the end of the modelling horizon.

Figure 2.2
Annual Average Generation TLMs (%) by DTIM Zone



Source: NERA/Imperial[23]

23 Note, a TLM of +1% means that a 1 MWh increase in injections increases system losses by 0.01 MWh. TLMs in zone 7 are always 0%, as this is the reference node on the DTIM network.

2.3. Step 2: Market Modelling and Welfare Analysis

Using the TLMs we derived (as described above) for each hour of the modelling horizon, we ran our market models under the three scenarios, in order to predict generation despatch and investment, and power prices:

- In the "Status Quo" case, we assume no locational variation in loss factors – we simply apply the same national TLM to all generation;
- In the "Hourly Locational Loss Factor" scenario, we allow the zonal loss factor to vary every hour as demand and wind output change (see above); and
- In the "Seasonal Locational Loss Factor" scenario, we hold the spread in loss factors across DTIM zones constant within each season, based on the average spread in the hourly loss factors across the country within each given season. This scenario is intended to mimic, albeit imprecisely, the types of zonal loss factors prescribed by BSC Mod 229, under which locational variation in generators' and consumers' transmission loss factors would be set based on seasonal averages. The seasonal average loss factors we used in our modelling in this scenario are presented in Appendix C.

In all three scenarios, we held constant the locational investment decisions of generators, as well as transmission investments. After running our market models, we estimate the change in transmission losses by multiplying the hourly marginal TLFs for each plant by the change in generation across scenarios, and summing across plants.

Because we assumed no change in generation and transmission investment, the welfare effects we identify in Chapter 4 relate solely to changes in despatch and the resulting reduction in losses and changes in generators' variable operating costs.

2.4. Modelling Assumptions

2.4.1. Approach to modelling the Capacity Market

Our modelling framework explicitly accounts for the GB Capacity Market ("CM"), which was introduced as part of the government's Electricity Market Reform ("EMR") programme to provide both existing and new build generators with a predictable stream of payments from 2018/19 in return for delivering reliable capacity. It is operated by National Grid through competitive auctions held four years-ahead (T-4) and one year-ahead (T-1) of each delivery year. The first auction T-4 auction was held in December 2014.

Our modelling of the CM has the following key features

- In line with current plans, we assume that capacity payments start in 2018/19.[24]
- We define the volume of capacity that generators bid into the capacity market by applying the technology-specific de-rating factors used in the first T-4 auction. A plant's de-rated

[24] As our market model is organised around calendar years, we assume that payments start in January 2019. In reality, payments will begin in October 2018, the first month of the 2018/19 delivery year.

capacity reflects its expected availability at peak time, taking into account forced outage probabilities, the duration of planned outages and fuel availability.

- As per the current arrangements, we assume that subsidised low carbon generators are not eligible to participate in the CM. We do, however, account for the contribution of low carbon generation to system reliability using the de-rating factors adopted by National Grid when determining the target volume to be procured in the first T-4 auction.[25]
- We model the volume of capacity procured in the CM assuming procurement of capacity to achieve a 4 per cent reserve margin, selected for the following reasons:
  - DECC has set an enduring reliability standard of 3 hours of Expected Loss of Load ("LOLE"), which National Grid takes into account when determining the target volume for the CM.
  - National Grid's Capacity Market Modelling Report for the T-4 2018/19 auction sets out the de-rated capacity that would be required to meet this LOLE target under a range of supply/demand scenarios. The reserve margin is close to 4% in the majority of these scenarios and is around 4% on average.
  - We therefore adopt a 4% RM target as proxy for the 3 hour LOLE.[26]
- Existing generators, refurbishment projects and new entrants can all set the price in the capacity market, as per the current CM design; and
- Our approach assumes that generators bid into the CM in a competitive way, such that they seek to recover no more than their fixed costs (levelised over the life of the plant) through the CM, net of any margins earned from the energy and ancillary services markets. Hence, the marginal generator should recover its total costs in net present value terms through the margins earned from the energy, ancillary service and capacity markets.

We also take into account the results from the first T-4 auction:

- We assume that all existing plants that were awarded contracts in the T-4 auction stay online for the duration of their contract and net off the de-rated capacities of these plants from our modelled CM target for each year of their respective contracts to give the residual demand. For 2018/19, the residual demand represents our estimate of demand for the T-1 auction for this year.
- We incorporate the 2.6 GW of de-rated new-build capacity awarded Capacity Agreements in the T-4 auction, which comprises the 1.6 GW Trafford CCGT and around 1 GW of small embedded generation.
- We assume that the 8.5 GW of existing capacity that did not receive a contract at the T-4 auction is eligible to take part in the T-1 auction for 2018/19, as well as T-4 auctions for

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[25] We apply the station availabilities listed in National Grid June 2014, Electricity Capacity Report, Table 35, page 90. National Grid has not published a de-rating factor for wind though its Capacity Market report does state that its estimate of the contribution of wind generation to peak is based on a concept referred to as Equivalent Firm Capacity (EFC). We have therefore calibrated our de-rating factor for wind to Ofgem's estimate of EFC, from its 2014 Electricity Capacity Assessment, which decreases as the proportion of wind capacity on the system rises. Our estimated de-rating factor for wind falls steadily from 22% in 2014 to 15% in 2035

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

subsequent years, and retain them as options within the model for meeting the residual capacity requirement in 2018/19 and beyond.

- Existing plants that won a contract in the T-4 auction receive the T-4 clearing price of £19.40 in 2018/19, whilst remaining eligible plants compete for a T-1 contract for 2018/19. The T-1 clearing price is determined endogenously through our CM model.

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

2.4.2. Approach to modelling wind deployment

Our approach to modelling the deployment of wind generation is unchanged from our previous modelling performed in the course of Project TransmiT.[27] Our model deploys additional wind capacity to meet the required RES output not provided by existing wind farms or from other renewable generation sources. To do so, it selects investments from a list of 143 potential offshore and onshore projects, which differ in terms of their geographic location, water depth (for offshore wind) and load factor. Deployment is selected by the model to minimise wind development and operating costs over the horizon to 2030. This approach is informed by DECC's stated intention to introduce competition in the allocation of CfD contracts and to minimise the impact of renewables subsidies on consumer bills.

The model adopts the following approach:

- It takes data on onshore and offshore wind farm costs (e.g. construction and operating costs, including TNUoS), load factors of potential wind generation projects by region, the availability of generation sites by region, earliest available online dates, etc;
- It then runs a linear program that selects the lowest cost wind investment projects (per MWh of output over the lifetime of the asset) available, subject to assumed constraints on the timing and rate of project development;
- In each year new wind capacity is added to meet the increasing target levels of RES (we assume a linear increase in the RES share between 2014 and the 2020 target of 30%. RES expansion beyond 2020 continues at a slower rate as expansion of nuclear capacity further contributes to the decarbonisation of the UK power sector, with the total RES share reaching 37% by 2030)
- The optimised deployment of wind projects is then reintegrated into the overall RES forecast to provide the generation mix in each year from renewable sources.

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27 NERA Economic Consulting and Imperial College London, Project TransmiT: Updated Comparison of the WACM 2 and Status Quo Charging Models: Prepared for RWE, 27 May 2014, Section 2.3.

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

2.4.3. Transmission investment costs

The assumptions we made in modelling the transmission system are set out in a report we prepared for RWE in February 2014 in the course of Project TransmiT.[28] Section B.1 in Appendix B of this report sets out our assumptions in relation to existing transmission boundary capacities and network topography.

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: [29]

- *'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.[30]

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[28] NERA Economic Consulting and Imperial College London (21 February 2014), Assessing the Cost Reflectivity of Alternative TNUoS Methodologies: Prepared for RWE.

[29] 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

[30] 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).

2.4.4. Transmission constraints

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 mechanism. For our modelling, we have applied the bid/offer prices assumed in the Redpoint/National Grid modelling conducted as part of the Project TransmiT process. These are set out in a Redpoint modelling report from 2011.[31]

2.4.5. Other assumptions

Table 2.3 summarises a range of our other assumptions in relation to the generation background and generation costs.

Table 2.3
Summary of Other Key Modelling Assumptions

Assumption	Details of Our Approach
Nuclear Penetration	• We assume new nuclear comes online from 2023 (earliest feasible online date for the first new unit at Hinkley Point). Thereafter, we assume that one new EPR comes online every other year, such that 4 new EPRs are online by 2030 - one at Hinkley Point, one at Sizewell and one at Sellafield, in that order. This equates to around 6 GW of capacity by 2030. This is in line with the expected expansion rate reported in the government's 2013 updated energy and emissions projections – 10 GW of new nuclear capacity between 2020 and 2030 – delayed a few years to reflect a more realistic time frame, based on recent developments.
Renewables Penetration	• We assume a mix of renewable technologies that is broadly in line with government aspirations. • The renewables share of total electricity demand reaches 32 % by 2020, which is just above DECC's stated objective of achieving at least a 30% RES. RES expansion beyond 2020 continues at a slower rate as expansion of nuclear capacity further contributes to the decarbonisation of the UK power sector. • Our renewables investment model selects the location of wind investments to provide the volume of energy we assume needs to be delivered from onshore and offshore wind.

31 Modelling the Impact of Transmission Charging Options, Redpoint Energy, December 2011.

Assumption	Details of Our Approach
CCS	• We assume that the two government-backed CCS demonstration projects, White Rose coal plant and Peterhead gas plant, are commissioned in 2019 and 2020 respectively based on current projections. Both of these projects have a capacity of 400 MW. • We allow Aurora to optimise the timing, volume and location of deployment of additional CCS, and we allow investment patterns to change in response to changes in TNUoS and other factors such as CO_2 prices. However, we find that CO_2 prices do not rise to a level that remunerates new CCS capacity before 2030
Electricity Demand	• For baseline demand, excluding electric vehicles and heat pumps, we take the growth rate implied by the "central" scenario for electricity consumption from DECC's 2014 updated energy and emissions projections, and apply it to actual demand (including losses) from 2013, as reported in DECC's 2014 Digest of UK Energy Statistics . Our electric vehicles and heat pump projections are based on the "Gone Green" scenario from National Grid's *Future Energy Scenarios.*
Fuel Pricing	• Our short-term forecasts for gas, crude oil and coal price forecasts are based on forward prices as of 31st December 2014: – For gas, we use NBP forward curves from Heren – For coal, we use API2 index from Bloomberg – For oil, we use Brent crude futures contract prices from Bloomberg • From 2018, we interpolate between to the IEA "Current Policies" scenario from the 2014 World Energy Outlook (WEO).
CO_2 Pricing	• Our EU ETS price forecasts are based on forward prices as of 31st December 2014, followed by interpolation to the IEA "New Policies" scenario forecast from the 2014 WEO. • We also account for the announcements made during the 2014 Budget regarding the reduction in Carbon Price Support (CPS) rates. We adopt confirmed CPS rates up to 2016/17 and assume that CPS rates remain constant at £18/tonne up to 2019, in line with the Government's recently announced "price freeze." From 2020 onwards, we assume that the CPS rate remains fixed in real terms, such that UK power generators face a constant premium on the EU ETS price.
Generator Opex and Capex	• Our generator cost assumptions are taken from PB power's *Electricity Generation Cost Model 2013 Update of Non-Renewable Technologies*, prepared for DECC

3. Modelling Results

This chapter presents the key results from our power market and transmission system modelling to examine the effects of introducing the zonal TLMs, derived as shown in the preceding chapter.

3.1. Supply-Demand Fundamentals

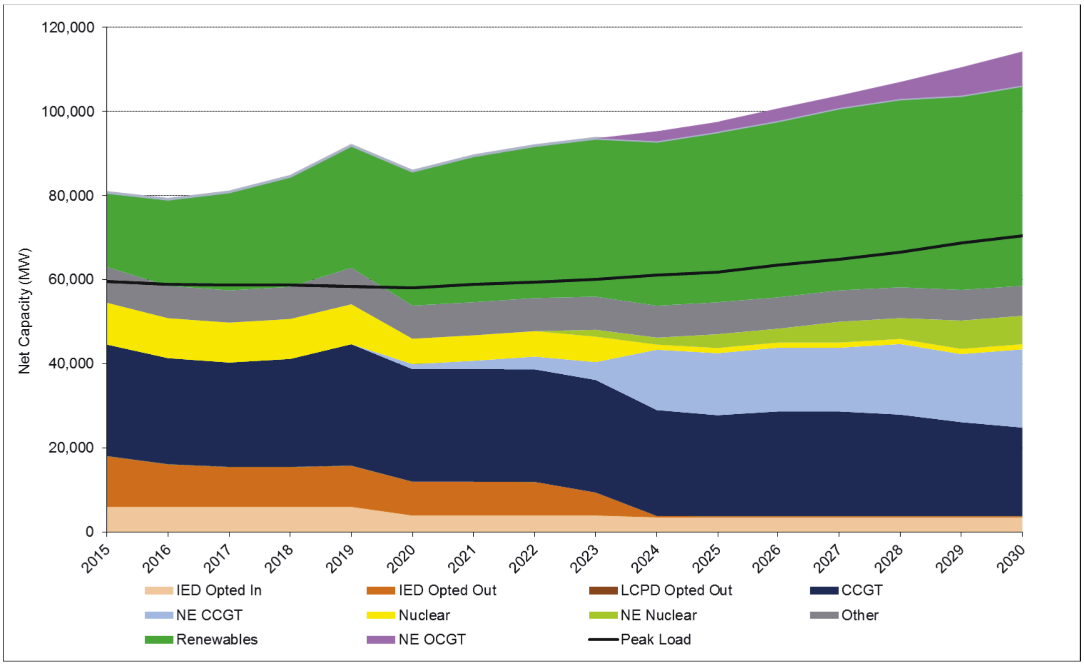
3.1.1. The capacity mix

Figure 3.1 shows our projections of peak demand and installed generation capacity in the Status Quo case, and Figure 3.2 shows cumulative retirements over the modelling horizon. Over the period to 2023, the coal plant that is opted out of the IED closes gradually, with relatively little coal plant remaining in the generation mix out to 2030. Existing nuclear plants also close gradually over the modelling horizon, in accordance with licenced life extensions. We assume new nuclear plants come online from 2023, as noted in Section 2.4 (Table 2.3).

Existing CCGT capacity grows in the period to 2018/19 reflecting the outcome of the recent Capacity Market auction, and specifically, the contract awarded to the 2GW Trafford CCGT. The model develops new CCGT capacity endogenously from 2020 onwards, and starts to build some new OCGT capacity from around the same time, which according to this modelling is the most efficient means of meeting the reserve margin we assume is required to meet the security standard applied through the Capacity Market of 3 hours of LOLE per annum.

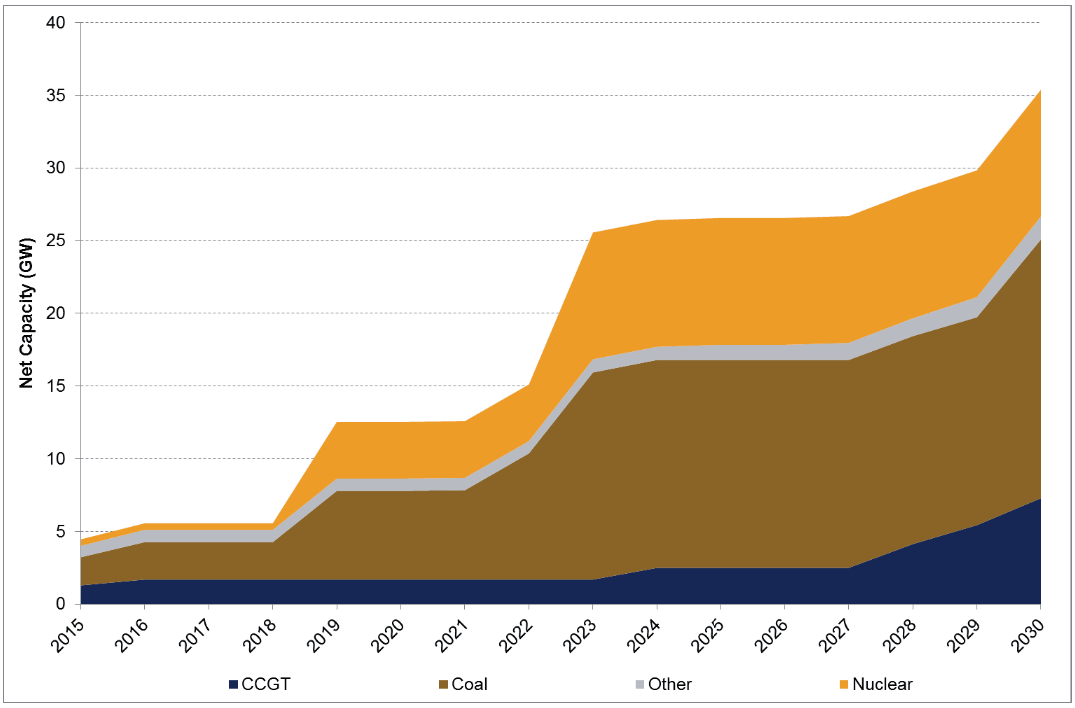
As noted above, we allow our model to deploy CCS generation capacity if it can be developed economically based on prevailing fuel and CO_2 prices, but as Figure 3.1 shows, the model does not choose to develop it.

Figure 3.1
Projected Supply-Demand Balance – Status Quo



Source: NERA/Imperial

Figure 3.2
Projected Cumulative Retirements – Status Quo

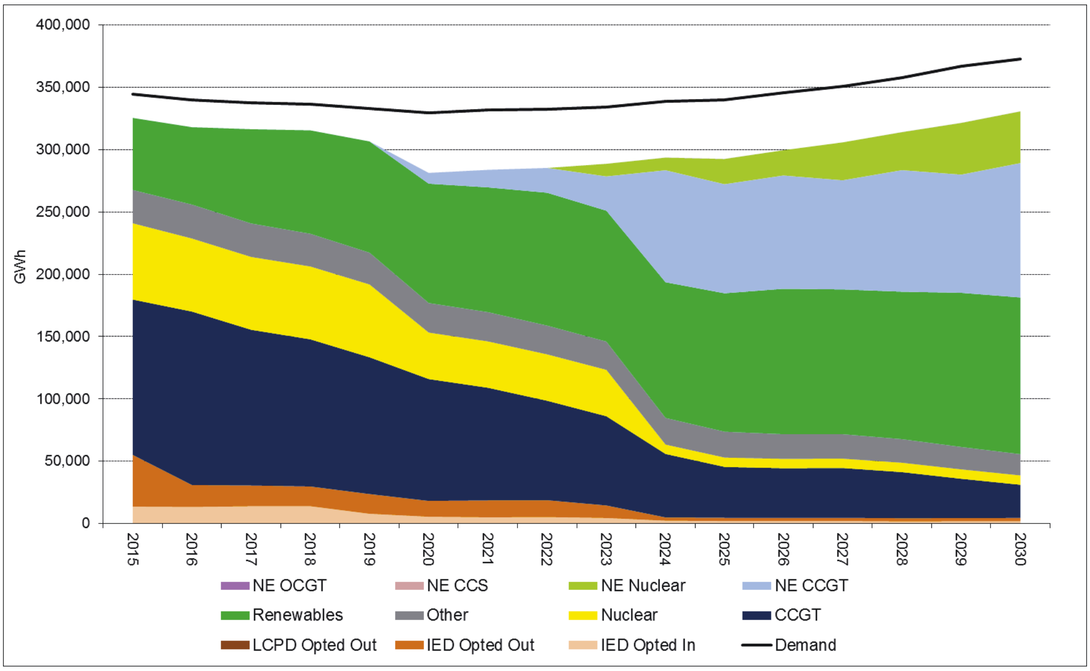


Source: NERA/Imperial

3.1.2. The production mix

Figure 3.3 shows the production mix from the status quo case.[32] Our modelling shows that production from existing coal, gas and nuclear plants is gradually replaced throughout the modelling horizon by output from renewables, new nuclear and new gas-fired CCGT capacity. Some coal-fired generation remains on the system throughout the period to 2030, but it accounts for only a small share of energy generated. Our modelling suggests that the British market is a net importer of energy throughout the period to 2030, driven in part by the relatively high CO_2 prices in Britain compared to Continental Europe (see Table 2.3).

Figure 3.3
Generation Mix (GWh) – Status Quo



Source: NERA/Imperial

[32] As for the capacity mix shown in Figure 3.1, the differences between the three TLM scenarios are negligible at the level of the market as a whole, so we

3.1.3. CO2 Emissions Intensity

As Figure 3.4 shows, CO_2 emissions from the power sector fall in all scenarios from around 390g/kWh in 2014 to around 160g/kWh by 2030. As yet, no formal target for CO_2 emissions intensity from the power sector has been set by government, although DECC and other organisations like the Committee on Climate Change (CCC) have mooted tighter targets than our model predicts for 2030, in the region of 50-100g/kWh. We find a negligible difference in emissions across the three scenarios.

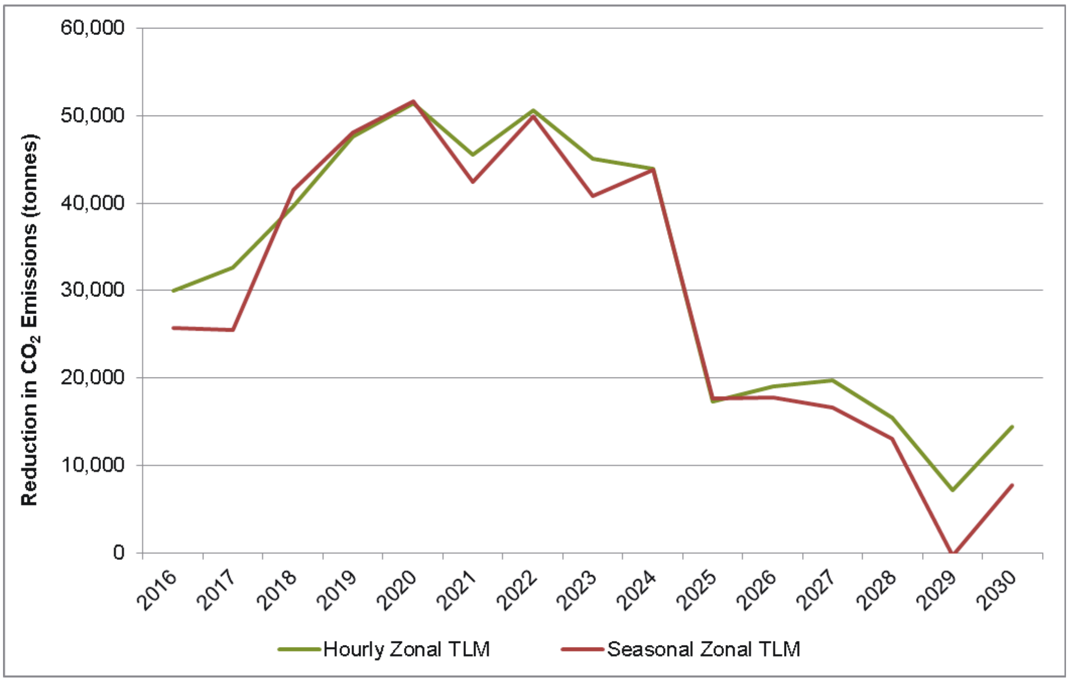
Figure 3.4
CO2 Emissions Intensity – All Scenarios (kg/MWh)

Source: NERA/Imperial

However, in reality zonal loss factors would reduce emissions slightly. As described in Chapter 2, we perform three runs of Aurora with different loss factors, intended to estimate the change in wholesale prices and generation costs from re-despatching the generation fleet with zonal loss factors, but without adjusting the total energy production in the market as a whole required to cover transmission losses. Separately, we use DTIM to estimate the change in transmission losses implied by this change in despatch due to zonal loss factors, with no iteration between the two models. Because the emissions intensity projections in Figure 3.4 emerge from the Aurora model, they do not capture the impact of reducing total energy demand.

By multiplying the reduction in transmission losses (in TWh) estimated using DTIM (see Section 2.2) by the average emissions intensity in (kg/MWh) in Figure 3.4, we estimate the reduction in emissions from the power sector, as shown in Figure 3.5 below. Our modelling suggests that the introduction of zonal TLMs would result in CO2 emissions reductions of the order 25,000 – 28,000 tonnes on average over the period 2016 – 2030. This saving is factored into our welfare analysis in Chapter 4, but amounts to a saving of around £1 million per annum.

Figure 3.5
Reduction in CO2 Emissions from the Power Sector as a Result of Zonal TLMs (tonnes)

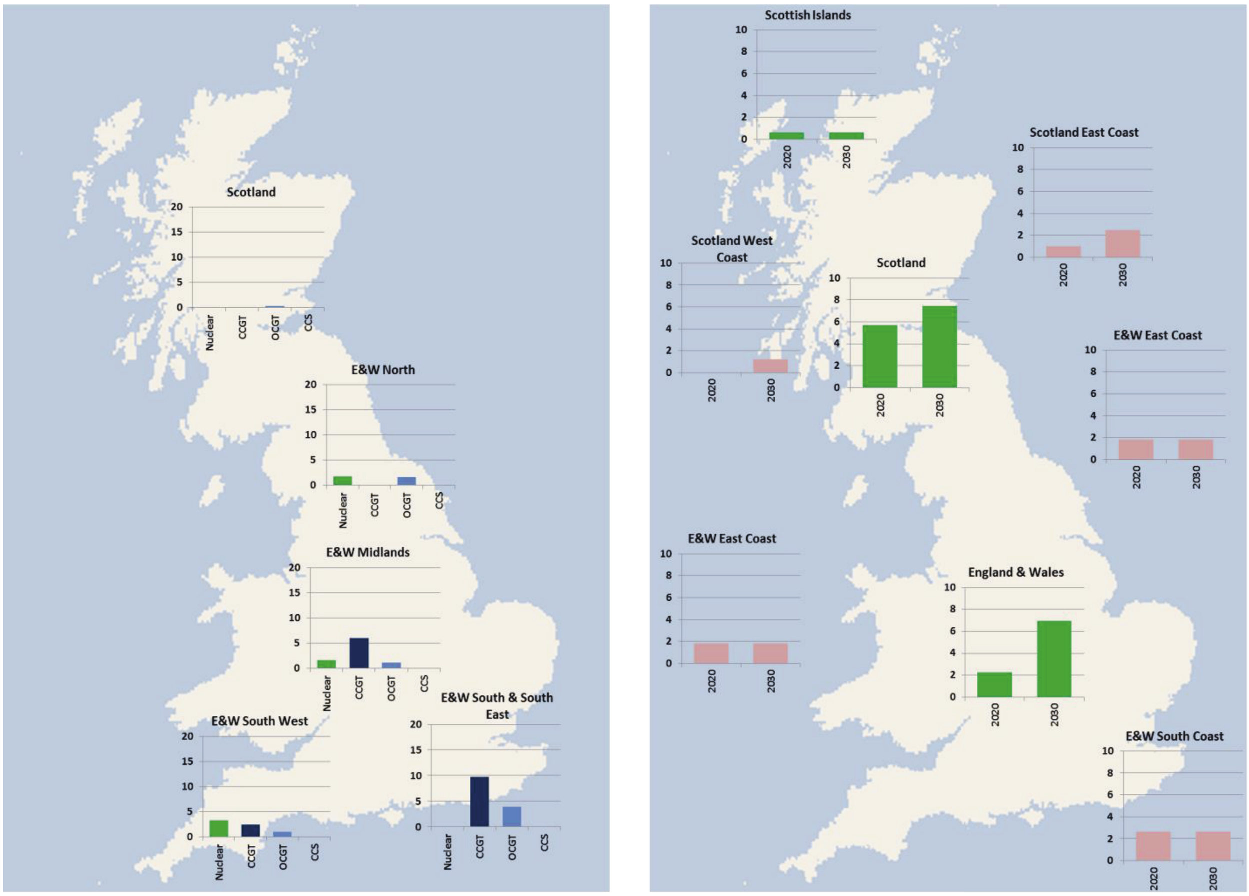


Source: NERA/Imperial

3.1.4. Locational investment decisions

Figure 3.6 shows the location of new thermal generation (on the left hand side) and wind generation investments (on the right hand side) in the status quo case. Investment in new gas-fired generation is located primarily in the midlands and the southern regions of England and Wales, reflecting lower transmission charges compared to northern locations.

Figure 3.6
Location of New Generation Investments by 2030 – Status Quo



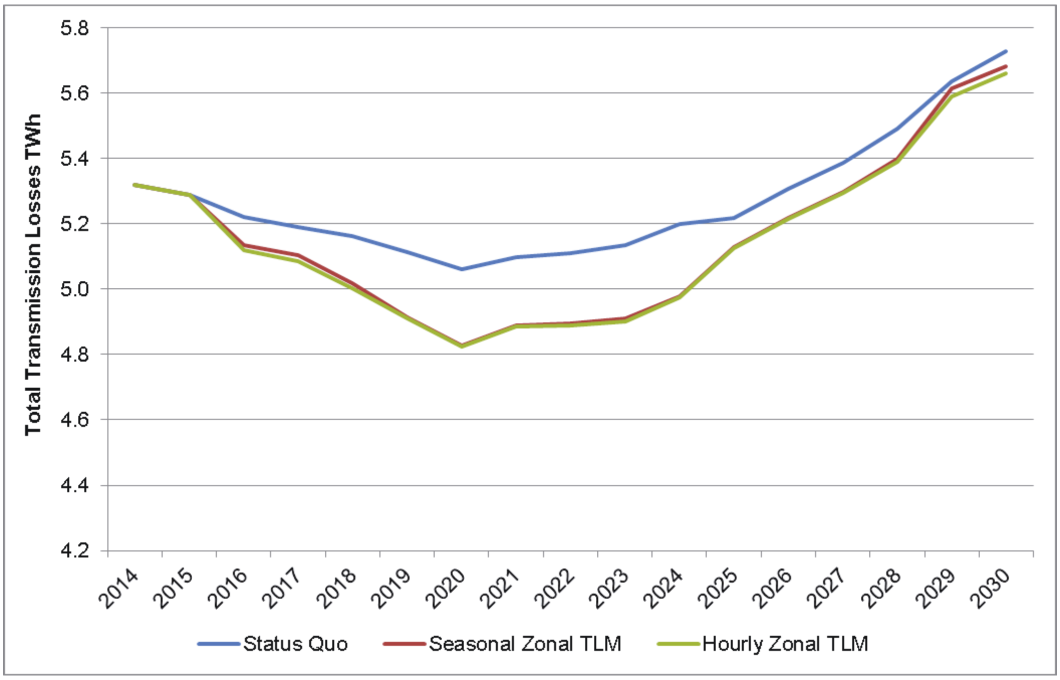
Source: NERA/Imperial

We investigated the impact of zonal TLMs on investment in new generation and found that the differences in the location of new investments and retirements were negligible. This result suggests that differences in TLMs are too small materially to affect the location of new investment. We therefore decided to hold constant the generation background (and hence transmission investment) across our three scenarios. This approach ensures that any change in welfare resulting from zonal loss factors can be traced back to improvements in the efficiency of plant despatch to support the system in minimising losses.

3.2. Savings in Generation Costs from Zonal Loss Factors

The introduction of zonal TLMs improves the efficiency of plant despatch by forcing generators to account of the impact of their despatch decisions on system losses. As Figure 3.7 shows, the reduction in losses as a result of zonal TLMs increases from around 0.1 TWh per annum to around 0.2 TWh by the mid-twenties. The impact diminishes from the late twenties onwards, as the variation in transmission loss factors across the different parts of the transmission system reduces (see Figure 2.2). Losses (and hence total system demand) fall by around 0.15 TWh per annum on average over the whole modelling horizon to 2030.

Figure 3.7
Transmission Losses (TWh) - All Scenarios



Source: NERA/Imperial

Valued at the demand-weighted power price, this reduction in losses implies a reduction in system costs of £9 million per annum in the seasonal TLM scenarios and £11 million per annum in the hourly TLM scenario, as Figure 3.8 and Figure 3.9 show. This equates to £108 million and £129 million in NPV terms over the period 2016 – 2030 in the seasonal TLM and hourly TLM scenarios respectively, as Table 4.1 below shows. However, these savings in losses come at the cost of somewhat higher generation operating costs (fuel, CO_2 plus variable O&M).

Specifically, when we run the model with uniform loss factors, the model essentially chooses despatch to minimise generators' variable operating costs without any regard for the impact of despatch on losses. Zonal TLMs, on the other hand, force the model to account for the impact of despatch on losses, and select a different pattern of despatch that minimises the combination of generators' variable operating costs plus the costs of losses. Because the pattern of despatch has changed from the uniform case, it necessarily produces higher variable operating costs for generators. Taking the costs of losses and generators' own operating costs together, however, zonal loss factors improves the efficiency of despatch because the cost of losses falls by more than the offsetting increase in generators' variable costs.

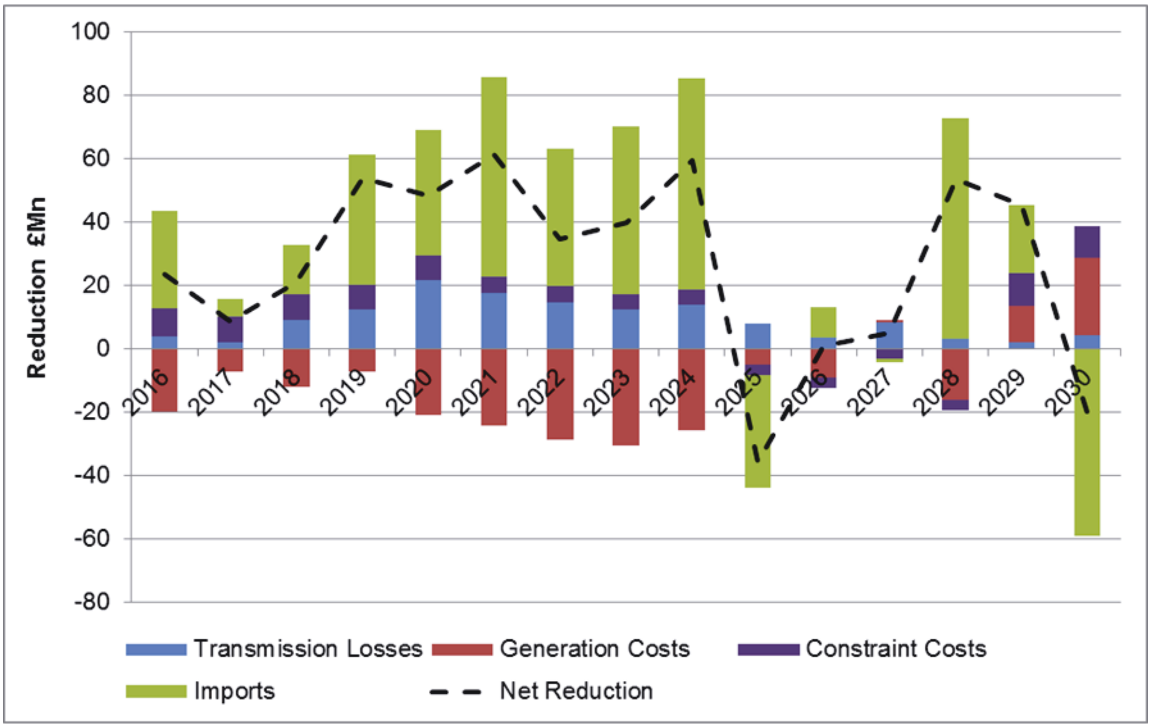
We also identify a saving in import costs. As discussed below in Section 3.3, the introduction of zonal loss factors reduces the marginal cost of generation by plant towards the south of the country. These plants, which are predominantly thermal generation, tend to set the price in the wholesale market in our modelling, and as such, wholesale power prices in Britain fall. Lower wholesale prices in Britain have two effects. First, lower prices in Britain relative to its neighbouring markets mean Britain imports power less frequently, which reduces import costs.

Second, our modelling suggests that in many hours the transfer of energy from Ireland to Britain, or vice versa, is less than the available transmission capacity between the two markets. This means that Britain and Ireland have a single price, and this price tends to be lower as a result of zonal TLMs. In hours when transmission capacity is unconstrained, Britain is importing, and prices are lower as a result of zonal TLMs, the cost to the British power sector of importing power from Ireland falls, because we value these imports at the price prevailing in the Irish market.

Zonal loss factors result in lower despatch of generators towards the north of the country, and less despatch from generation in the south. This change in despatch reduces the extent to which power needs to be transported long distances across the transmission system, and thus reduces the incidence and cost of constraints by around £4 million per annum on average over the modelling horizon.

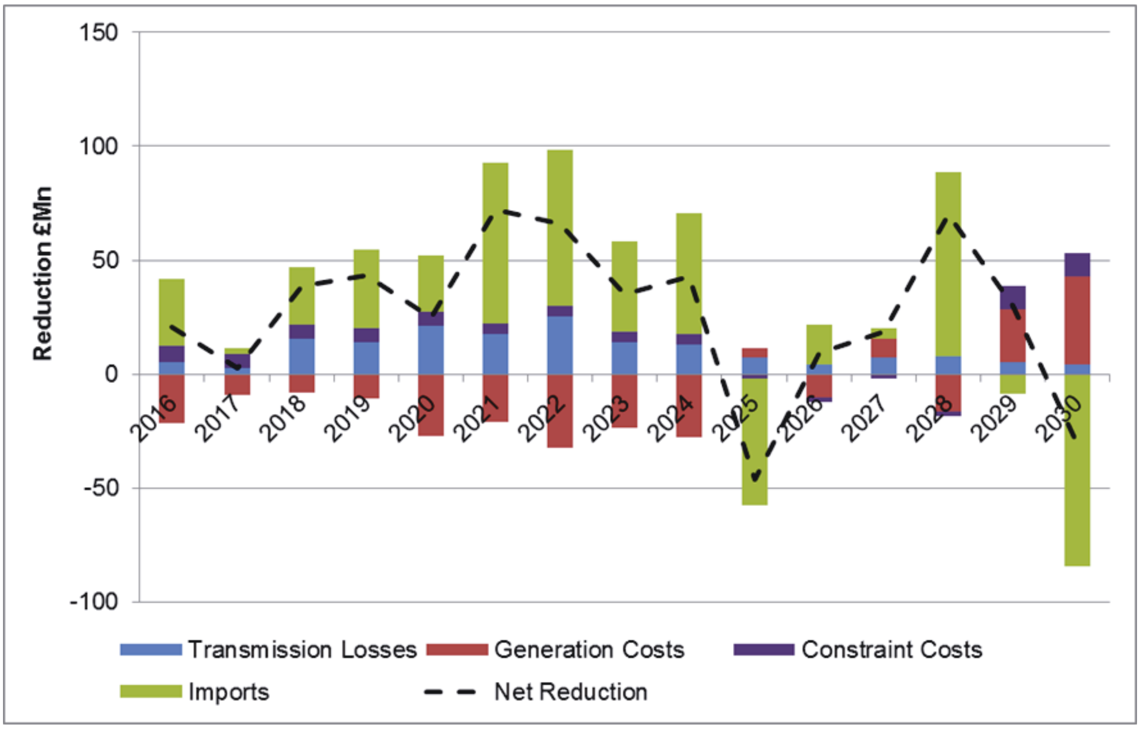
Figure 3.8 and Figure 3.9 show the cumulative effects of these changes in cost over the modelling horizon, which produce overall savings of around £26 million per annum in both the seasonal TLM scenario and hourly TLM scenarios.

Figure 3.8
Composition of the Change in Power Sector Costs (2014 £ million) –
<u>Seasonal</u> Zonal TLMs



Source: NERA/Imperial

Figure 3.9
Composition of the Change in Power Sector Costs (2014 £ million) – <u>Hourly</u> Zonal TLMs



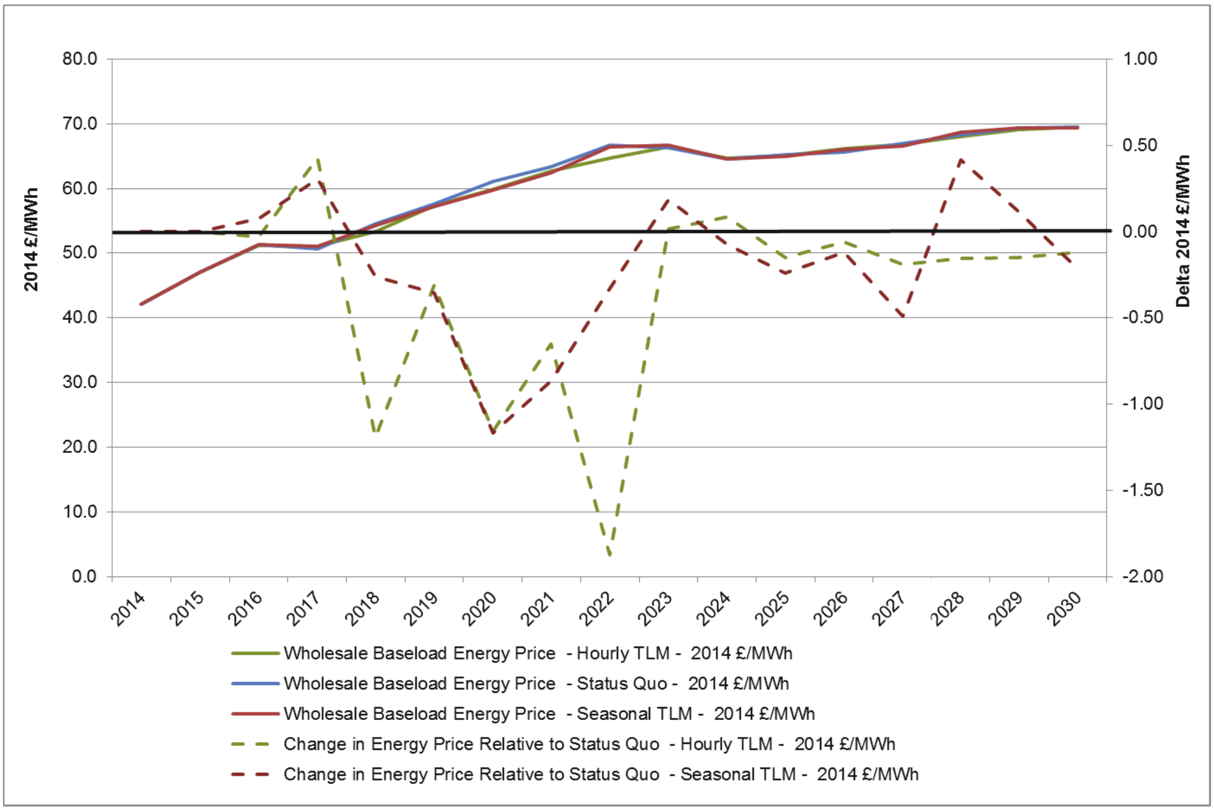
Source: NERA/Imperial

3.3. Wholesale Prices

Figure 3.10 and Figure 3.11 show our projections of both energy and capacity prices across the three scenarios. Energy prices rise over time with changes in fossil fuel and CO_2 prices (see Table 2.3 above).

As Figure 3.10 shows, locational TLMs (both seasonal and hourly) result in lower energy prices compared to the status quo from 2018 until the mid-2020s. The key driver of this result is the reduction in TLMs in the locational scenarios for thermal plant in the south of Great Britain, where, as Figure 3.6 shows, most new thermal plants are located in our modelling. Lower TLMs for new generators reduce the level to which wholesale energy and capacity prices need to rise to remunerate new generation investment. However, as the regional spread in TLMs diminishes over time (see Figure 2.2 above), so too does the impact on wholesale prices.

Figure 3.10
Baseload Energy Prices by Scenario (Left Axis) and Delta to Status Quo (Right Axis), £/MWh



Source: NERA/Imperial

Capacity prices start in 2019, the first full calendar year of the Capacity Market's operation at the clearing price achieved in the recent auction (by assumption). In effect, we impose the outcome of the 2018/19 Capacity Market as an assumption, also ensuring that all plants that received capacity contracts through this auction remain online until that year. The model predicts growth in capacity prices between 2018/19 and 2019/20, as more new entry is required and higher capacity payments are required to remunerate capital costs of new entrant plant. The price rises sharply again in 2024 as IED opted-out coal retires and is replaced by new build CCGT and OCGT. In the long-term, the capacity price is, in effect, capped in our modelling by the fixed costs of a new entrant OCGT, as the model can develop as many of these plants as required to meet the required reserve margin.

Figure 3.11
Capacity Prices (£/kW/yr) – All Scenarios

Source: NERA/Imperial

As Figure 3.11 shows, the capacity price is similar across the three scenarios. This reflects the fact that capital cost of new entrant plant, one of the key drivers behind capacity prices, is fixed across scenarios. Furthermore, the variation in the energy margins of new entrant plant across scenarios is small. In particular, new entrant OCGTs which set the capacity price in a number of years, run at very low load factors and the introduction of zonal TLMs therefore has a negligible impact on the energy margins of these plants.

3.4. Conclusions

The modelling results presented above indicate the change in generation costs and power prices that would result from implementing zonal transmission loss factors in the British wholesale market.

However, while our modelling uses state-of-the art power sector simulation techniques, there are some inherent uncertainties associated with this type of modelling, as the CMA's recent working paper notes.[33] In particular, it uses a number of assumptions that may influence results and it has not been possible for us to examine the sensitivity of our results to changes in these assumptions. Also, with more time, it would have been desirable to iterate between

[33] Competition and Markets Authority February 2015, *Energy Market Investigation: Locational pricing in the electricity market in Great Britain*, para. 24, page 9

the transmission and market models to reflect how TNUoS charges and marginal loss factors change with the location of generation and the topography of the network.

Nonetheless, while more work would be required to improve the accuracy of our results and to examine their sensitivity to our assumptions, we consider that the results presented in this chapter represent a reasonable estimate of the effects of introducing marginal loss factors.

4. Welfare Analysis

4.1. Potential Improvements in Efficiency on the Supply-Side

As summarised in Table 4.1 below, we find a reduction in consumers' bills as a result of zonal losses through lower wholesale prices, as well as reduced losses and constraints, partly offset by an increase in the subsidies paid to low carbon generation:

- Reductions in wholesale power prices reduce consumers' bills by £0.8 billion and £1.7 billion in the seasonal and hourly scenarios respectively;
- Because of the reduction in power prices, the costs of subsidies paid to low carbon generation, such as through the CFD FIT mechanism, rise by £77 million and £265 million in the seasonal and hourly scenarios respectively, which slightly offsets the reduction in costs to consumers.
- Consumers' bills also fall as a result of lower losses and constraints by a total of £180 million in the hourly and £163 million in the seasonal scenarios. In total, consumers' bills fall (in NPV terms to 2030) by between £884 million and £1,590 million in the two scenarios.

The overall improvement in welfare, which we approximate by the change in power sector costs resulting from our modelling, amounts to between £315 million and £318 million in NPV terms in the hourly and seasonal scenarios respectively. This effect results from lower losses and constraint costs, lower import costs, albeit slightly offset by higher generation costs, as described above.

Our finding that the reduction in power sector costs, a proxy for the improvement in welfare resulting from zonal loss factors, is less than the benefit to consumers implies a reduction in the profits earned by generators (i.e. "producer surplus") of between £0.6 billion and £1.3 billion depending on the scenario.

Table 4.1
Welfare Impact of Introducing Zonal TLMs for Generators (2014 £ million, NPV to 2030)[34]

	Welfare Impact - 2016 - 2030 (2014 £Mn)	
	Seasonal TLMs	Hourly TLMs
Impact on Consumers		
Power Purchase Costs (inc. capacity payments)	-798	-1,675
Low Carbon Subsidies	77	265
Constraints	-56	-51
Losses	-108	-129
Total	-884	-1,590
Power Sector Costs		
Generation Costs (excluding TNUoS)	142	121
Import Costs	-297	-257
Constraints	-56	-51
Losses	-108	-129
Total	-318	-315

Source: NERA/Imperial. Note, all NPVs are calculated between 2016 and 2030 at a real discount rate of 3.5%, following the HM Treasury Green Book. Impact per consumer is an annual benefit. Increases in costs are shown in red whilst decreases are shown in black.

4.2. Potential Improvements in Efficiency on the Demand-Side

As noted in Chapter 2, our model takes demand as given, assuming it is perfectly inelastic with the same distribution of demand around the transmission system in all the cases we model. For this reason, the welfare benefits we model come from a more efficient use of generation resources (ie. supply-side effects), not from the more efficient consumption. For instance, over time the application of zonal loss factors to load might lead to higher levels of consumption in areas where the costs incurred by end users decrease as a result of favourable zonal TLMs, and fall in areas where consumers see higher allocations of losses with zonal TLMs.

To illustrate the potential quantum of such benefits, suppose that, with uniform loss factors, the costs faced by consumers are an average of 1% higher than the "true" marginal costs their consumption imposes in areas where consumption causes relatively low additional losses, and

[34] Note that the sub-categories of costs under the two headings, "*Impact on Consumer Bills*" and "*Power Sector costs*", are distinct from each other (in other words they do not overlap). In particular, constraint costs are the costs associated with bids and offers in the balancing mechanism for National Grid and are not therefore included in generation costs.

1% lower in areas where consumption causes relatively high losses. Implementing zonal loss factors, and thus correcting this distortion will therefore increase or decrease prices to consumers by 1%, with the direction of change depending on where they are in the country. Assuming a price elasticity of demand for electricity of 5%,[35] demand will rise or fall by 0.05% following this 1% change in price. The improvement in efficiency can be computed as follows:[36]

Efficiency Saving = (0.05% x Demand in TWh) x (1% x Price in £/MWh) / 2

If demand is 300 TWh per annum, and the price is £60/MWh, this saving amounts to a relatively modest efficiency saving of £45,000 per annum. Hence, the quantum of this additional saving from modelling the efficiency gains associated with more efficient placement of load is likely to be modest. As shown in the previous chapter, the welfare savings that come from more efficient plant despatch are of a materially higher order of magnitude.

4.3. Distributional Effects Amongst Generators

As well as the quantifiable benefits of introducing zonal TLMs, estimated above, such a change in market rules may have a range of other effects which are not the subject matter of this report. One such effect would be the distributional effects caused by increasing the costs of generation to companies located mainly in the north of Britain, and reducing the costs of generation to companies located mainly in the south.

Consumers would also see distributional effects. While the generality of consumers benefit from zonal TLMs through a reduction in power prices and a reduction in total losses (see above), zonal TLMs would also increase the costs incurred by some consumers in zones with negative TLFs (mainly towards the south of Britain – see Figure 2.2), and reduce the prices paid by consumers in zones with positive TLFs (mainly in Scotland).

This factor was stated by the Authority in its decision not to implement BSC modification P229: [37]

> "*We note, however, to the detriment of the achievement of objective (c), that the redistributional impacts of both P229 proposals are relatively high and certain and the NPV is relatively low and subject to a degree of uncertainty, at least in the shorter term.*"

However, the intention of the regulator to introduce of a zonal transmission losses scheme has been well signalled since the privatisation of the electricity industry.

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35 ie. a 1% change in price, changes consumption by 0.05%.

36 This expression is, in essence, designed to estimate the size of the deadweight loss associated with pricing electricity slightly above or under the true marginal cost.

37 Ofgem (28 September 2011), Decision on "Balancing and Settlement Code (BSC) P229: Introduction of a seasonal Zonal Transmission Losses scheme (P229)", page 5.

4.4. Conclusions

As set out above, our modelling suggests that the introduction of zonal loss factors would benefit consumers materially through lower power prices and reduced overall losses. Overall welfare, approximated by the change in power sector costs, also improves because of lower losses. For the reasons noted in Section 3.4 above, these estimated welfare effects are subject to some uncertainty, but they provide a reasonable estimate of the welfare effects from introducing zonal TLMs. In fact, the omission from our modelling of the potential benefits of more efficient generation investment and the benefits of enhanced efficiency on the demand side mean our estimated welfare effects may somewhat understate the potential savings.

In deciding whether to implement zonal TLMs, other considerations may be relevant, such as distributional effects and any resulting perceptions of regulatory risk, interactions with changes in the TNUoS regime, or any other potential changes to trading arrangements to that the CMA may prescribe through the EMI. These topics are beyond the scope of this report.

5. Conclusions

In response to the CMA's EMI Working Paper that asks interested parties to submit evidence regarding the benefits of enhancing "locational signals" in the British wholesale electricity market, this report estimates the welfare benefits of introducing locational TLMs.

We find that zonal TLMs would improve the efficiency of plant despatch, reducing power sector costs, a measure of welfare, by up to £320 million over the period to 2030. A large portion of this decrease is due to the reduction in transmission losses, valued in our modelling at around £130 million. Costs to the consumer would also fall by up to £1.6 billion, driven mainly by a reduction in the dispatch costs of marginal plant, which in turn reduces power prices.

As this report notes, more work would be required to improve the accuracy of our results and to examine their robustness through sensitivity analysis. Despite this limitation, the results we present represent a reasonable estimate of the effects of introducing marginal loss factors in the British wholesale market. In fact, the omission from our modelling of the potential benefits of more efficient generation investment and the benefits of enhanced efficiency on the demand side mean our estimated welfare effects may somewhat understate the potential savings.

In deciding whether to implement zonal TLMs, other considerations may be relevant, such as distributional effects and any resulting perceptions of regulatory risk, or any other potential changes to trading arrangements to that the CMA may prescribe. The extent to which this change in trading arrangements has been signalled by the regulator since privatisation might also affect the assessment of whether the distributional effects of this reform should affect a decision over whether or not to implement it. However, considering such effects of zonal loss factors are beyond the scope of this report.

Appendix A. Wind Modelling Assumptions

A.1. Algorithm

As noted above in Section 2.4.2, the updated version of our renewables investment model selects investments in the lowest cost wind generation sites. Hence, the objective function that the model seeks to minimise calculates the net present value of the lifetime costs of those wind farms deployed by the model. The model takes data on the costs of developing new wind farms (see Sections A.3.3.2 and A.3.4.1 below), including TNUoS charges (see Sections A.3.4.1.2 and A.5 below), and load factors (see Sections A.3.3.1 and A.3.4.3). It then minimises total cost, subject to the following constraints:

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

A.2. Model Outputs

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

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

A.3. Model Inputs

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

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

The starting point for our RES forecast out to 2030 is the existing capacity of different technology types as at the end of 2013, based on Energy Trends data, published by DECC.[38] To the existing capacity we add NERA's forecast for the deployment of solar PV, bioenergy, hydro and other RES technologies (including tidal, wave and geothermal, but excluding wind) between 2014 and 2030. These forecasts are based on detailed pipeline information for each technology, DECC's Renewable Energy Roadmap (including annual updates) and National Grid modelling as part of the EMR delivery plan, as well as supplementary technology specific sources and NERA analysis.[39]

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

  We assume that 95 percent of the capacity of new dedicated biomass plants under construction are built, remaining within the cap of 400 MW on further Renewables obligation support. We also forecast almost 900 MW of new energy from waste capacity to 2020, reflecting DECC's development pipeline, with a reduced annual rate of deployment between 2021 and 2030.[40]
- **Solar**: We assume that capacity expands at approximately 1 GW a year to reach approximately 10 GW by 2020, which is at the conservative end of the projected range in DECC's renewable energy roadmap. Whilst there has been a significant increase in deployment in the first quarter of 2014, the government has made recent proposals to curb support for new solar under the Renewables Obligation scheme from 2015, and it is likely to struggle to compete effectively with onshore wind developments under the proposed CfD allocation of contracts via auctioning.[41] Capacity then expands at roughly half this rate between 2021 and 2030.
- **Other RES**: Our forecast assumes limited additional capacity from other RES types including established technologies such as hydro, landfill gas and sewage gas as well as

[38] DECC. Energy Trends. Table 5.1. April 2014.

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

[40] DECC's development pipeline is available via the RESTATS online portal.

[41] DECC. Consultation on changes to financial support for Solar PV. 13 May 2014.

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

We calculate the renewable electricity output from all technologies, with the exception of new wind projects, by applying technology specific load factors to both existing capacity and our capacity projections. Then, using our demand forecast to 2030 we calculate the additional renewable output required from new wind projects to meet the target RES shares of 30% in 2020, rising to 37% by 2030. Our wind project selection tool is set up to deliver this RES *deficit* in each year from a selection of potential onshore and offshore wind farms that differ in terms of both their location as well as their load factor. The tool is programmed to achieve the target level of RES at least cost, as described in the following paragraphs.

A.3.2. The range of wind development zones

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

We include 19 onshore zones, plus two on the Scottish Islands (Western Islands and Shetlands/Orkney), with five different types of sites available within each of these zones. Hence, in total, we define (19+2) x 5 = 105 onshore development zones. The five types of site differ according to their assumed load factor, such that in each zone we assume that a range from high to low load factor sites are available, with the distribution of sites informed by the range of load factors achieved by existing onshore wind farms (see below).[42]

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

A.3.3. Onshore wind assumptions

A.3.3.1. Load factors

A.3.3.1.1. Importance of load factor assumptions

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

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

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

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

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

A.3.3.1.2. Our approach to estimating regional load factors

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

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

Table A.1
Onshore Load Factor Distribution

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

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

A.3.3.2. Costs

We take cost estimates for onshore wind construction and operating costs from DECC's electricity generation costs report (December 2013).[43] DECC differentiates between onshore, offshore Round 2 and offshore Round 3 technology types and reports the costs associated with pre-development, construction and operational (split between fixed and variable) stages of a project as well as insurance costs. We use DECC's "medium" cost scenario. For onshore wind farms commissioning in 2016, this means we use a capital cost of £1,600/kW, and an annual O&M cost of £40.1/kW. To this we add a variable operational cost of £5/MWh.[44] In

[43] DECC. Electricity Generation Costs Report December 2013. p54

[44] All cost estimates are in 2012 prices.

line with DECC's projections we assume that costs decrease over time, in real terms. Projects commissioning in 2020 – the last year for which DECC reports costs – have a levelised cost 5% below that of projects commissioning in 2016. Beyond 2020 we assume no further decrease in the levelised cost of onshore wind farms that come online.

We annualise upfront construction costs using an assumed weighted average cost of capital (WACC), which is based on NERA's analysis for DECC on the required hurdle rates under the new CfD FIT regime. DECC sets out its assumptions on the WACC for each technology in its recent report on electricity generation costs.[45] This results in a real pre-tax WACC for onshore wind of 7.1%. NERA's analysis for DECC was specifically focused on the cost of capital under the new CfD FIT payments and is therefore directly applicable to new wind projects that will be subsidised under this regime.[46]

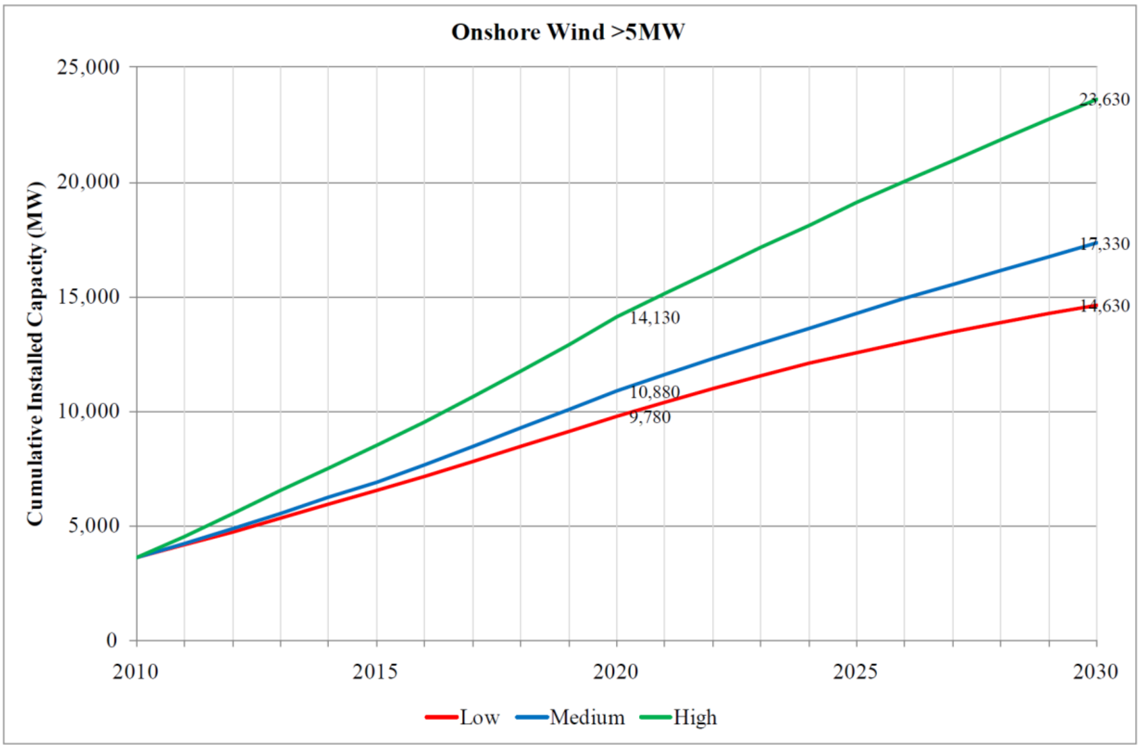
A.3.3.3. National build rates and resource potential

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

45 DECC. Electricity Generation Costs Report December 2013. p45

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

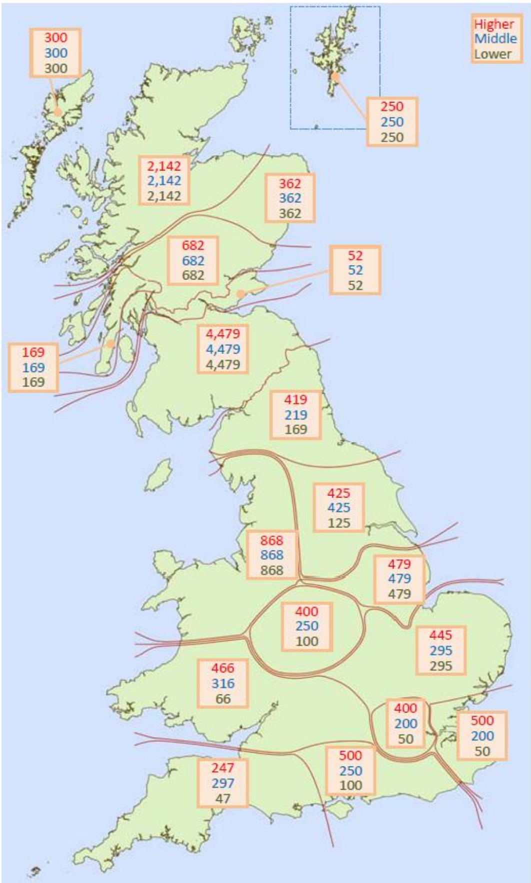
Figure A.1
Arup Onshore Resource Potential Estimates



Source: Arup (2011), Figure 9.

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

Figure A.2
Wind Resource by Region



Source: SKM (2008)[47]

In addition to applying a cap on the total level of investment in each transmission zone we also impose constraints on the earliest build date for new projects. For capacity on the mainland we assume that new projects come online from the start of 2016. For the Westland Isles we assume an earliest available online date of 2017 and for the Shetlands the earliest online date is set as 2018.[48]

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

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

A.3.4. Offshore Wind

A.3.4.1. Costs

A.3.4.1.1. Turbine, tower and foundations costs

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

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

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

As per the treatment of onshore wind, we take cost information from DECC (2013), based on its "medium" cost estimates. We use different cost estimates for Round 2 and Round 3 offshore wind farms. Offshore wind developments in Scottish Territorial Waters are assumed to have similar costs to Round 2 sites. For Round 2 offshore wind farms commissioning in 2016, this means we use a capital cost of £2,570/kW, and an annual O&M cost of £74.3/kW. To this we add a variable operational cost of £2/MWh. For Round 3 offshore wind farms commissioning in 2016, we use a capital cost of £2,705/kW, an annual O&M cost of £103.7/kW and no additional variable operational cost.[49] In line with DECC's projections we assume that costs decrease over time, in real terms. Round 2 (3) projects commissioning in 2020 – the last year for which DECC reports costs – have a levelised cost 9 (10)% below that of projects commissioning in 2016. Beyond 2020 we assume that the levelised cost of offshore wind farms coming online (both Round 2 and 3, as well as those in Scottish Territorial Waters) decreases by 1% per year to 2025 and then by 0.5% per year between 2026 and 2030.

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

Therefore, we adjust construction costs by £9/kW/metre of seabed depth either above or below this level, corresponding to the slopes of the lines in Figure A.3.[50]

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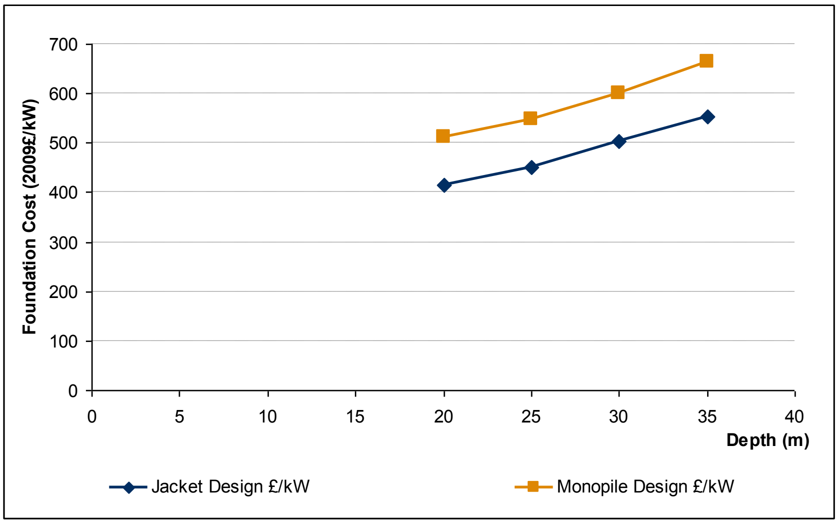
[49] All cost estimates are in 2012 prices.

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

Figure A.3
Seabed Depth vs. Foundation Cost



Source: NERA/Imperial Analysis of data from Ramboll[51]

We recognise some statements from the wind generation industry that indicate costs may increase substantially when developing offshore wind sites in water depths beyond 30 metres, and that beyond a certain water depth, it may become more efficient to build floating wind turbines, rather than turbines with fixed foundations. For instance, the British Wind Energy Association states on its website that:[52]

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

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

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

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

than 30 metres.[53] Hence, this study does not contradict our assumption that there is no step-change in costs beyond 30 metres of depth.

A.3.4.1.2. Infrastructure costs

Our infrastructure investment cost assumptions for offshore wind projects, which define the local asset charges each offshore wind site pays, are set out in Table A.2 below. These are based on Redpoint estimates from a December 2011 modelling report prepared in the course of Ofgem's Project TransmiT.

Table A.2
Offshore Transmission Investment Costs

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

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

A.3.4.1.3. Financing costs

As for onshore wind, we annualise upfront construction costs using an assumed weighted average cost of capital, which is based on NERA's analysis for DECC on the required hurdle rates under the new CfD FIT regime. For Round 2 and Scottish Territorial Waters offshore wind projects we apply a real pre-tax WACC of 9.7%. For Round 3 projects, the WACC is slightly higher at 10.1%.[54]

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

54 DECC. Electricity Generation Costs Report December 2013. p45

A.3.4.2. Build rates and resource potential

For each potential offshore wind project we take the earliest available online date from a report by Renewable UK on offshore wind project timelines.[55] We have verified these dates, and supplemented them in certain instances, with additional information from the relevant websites of project developers.

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

A.3.4.3. Load Factors

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

- We estimated a mathematical relationship between the average load factor of offshore wind sites and the "wind intensity" of a site using data from the Carbon Trust (2008);[56]
- To estimate the average annual load factors of offshore sites throughout the UK, we take wind speed data from the "wind atlas", convert these into "wind intensity", and use the above relationship to estimate average annual load factors by site; and
- We calibrated the function we use to convert wind speed to load factor to ensure that on average, wind sites achieve a load factor of 37.7%, based on the Arup (2011) assumption.[57]

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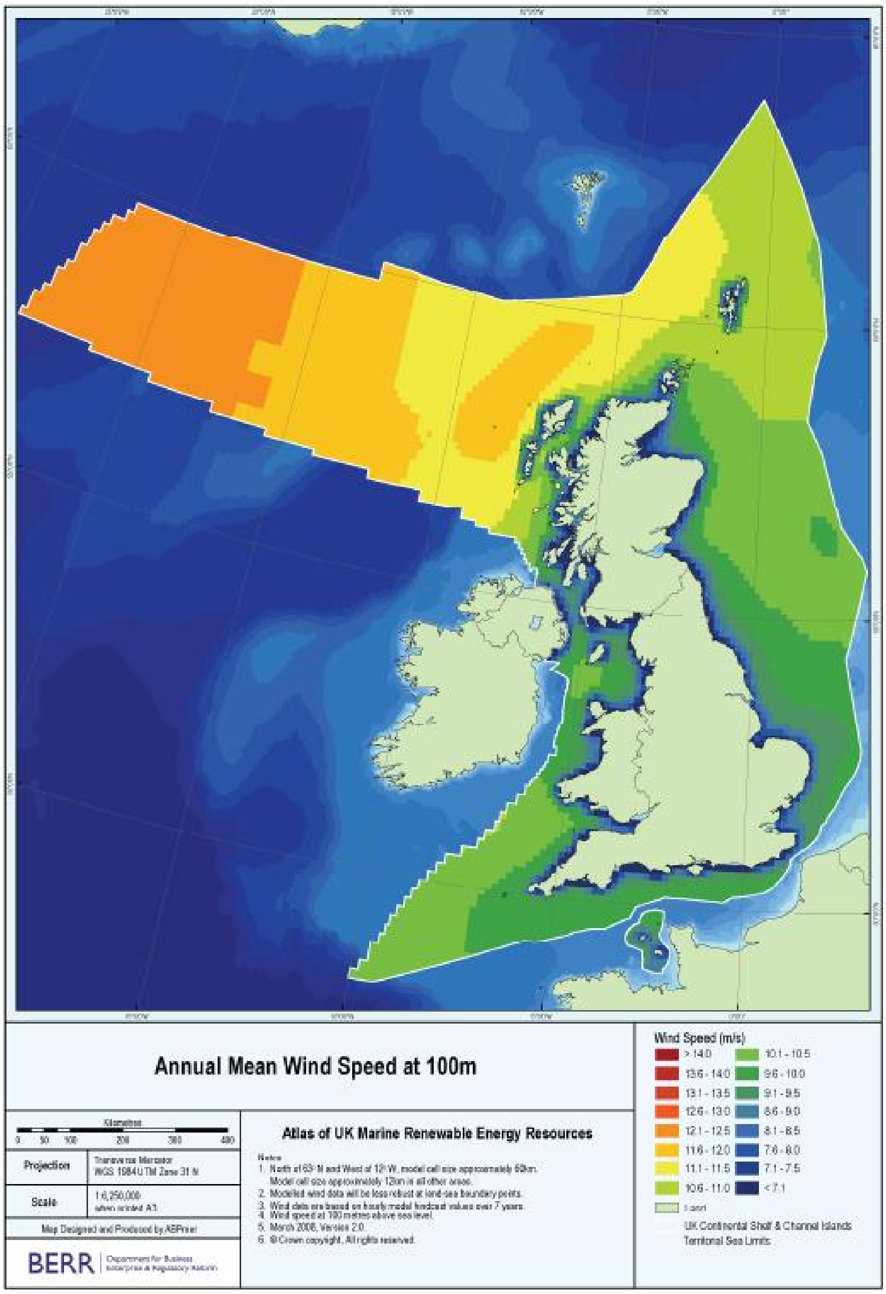
55 Renewable UK. Offshore Wind Project Timelines 2013. June 2013.

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

57 Arup (2011), Appendix F.

Figure A.4
GB Wind Speed Atlas



Source: The Renewables Atlas (2008)[58]

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

Table A.3
Median Load Factors for Offshore Development Zones

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

Source: NERA Analysis

A.4. Renewables Subsidies

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

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

Our estimates of support under the CfD FIT scheme are calculated by assuming that all technologies, with the exception of new wind projects which are selected via the wind project selection tool, receive the maximum CfD strike price published by DECC in December 2013.[59] These strike prices are either maintained or decrease over time. For the horizon beyond which DECC has published maximum strike prices, we forecast the levels of support that will be provided by continuing the observed trend forward. The total support is then calculated by subtracting either the projected baseload or intermittent power price (dependent on the technology) from the assumed strike price. Support for projects under the CfD regime is provided for 15 years, after which the project receives the prevailing market price and no additional government support.

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

A.5. TNUoS Charges

Our wind investment model takes TNUoS charges from the final result of the WACM2 scenario of our May 2014 modelling report, prepared in the course of Project TransmiT.[60]

A.6. Wholesale Power Prices

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

59 DECC. Investing in renewable technologies – CfD contract terms ansd strike prices. December 2013.

60 NERA Economic Consulting and Imperial College London, Project TransmiT: Updated Comparison of the WACM 2 and Status Quo Charging Models: Prepared for RWE, 27 May 2014.

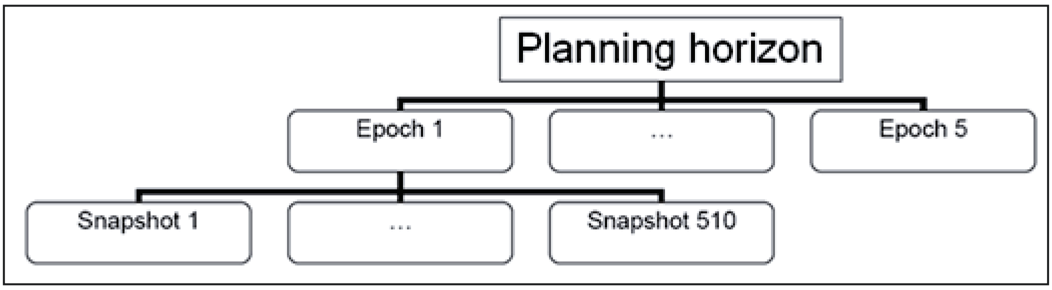
Appendix B. Forecasting Transmission Loss Factors

B.1. Granularity of DTIM Modelling

B.1.1. Definition of "snapshots" for different levels of demand and wind production

For this assignment, we divided the 2010-2030 modelling horizon into five "epochs" of four-five years for the purpose of our modelling using DTIM. 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.

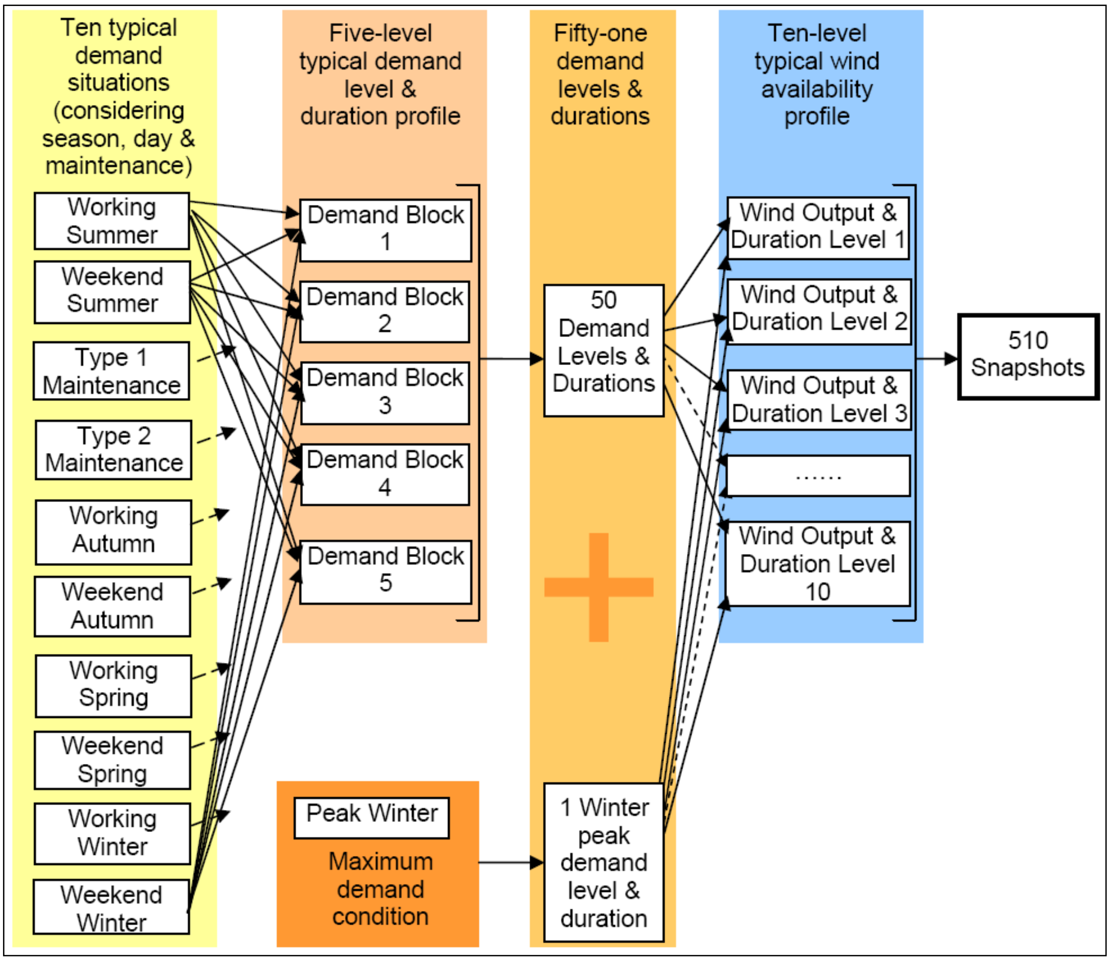
Figure B.1
DTIM Epochs



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 B.2 summarises this process.

Figure B.2
DTIM Snapshot Definitions



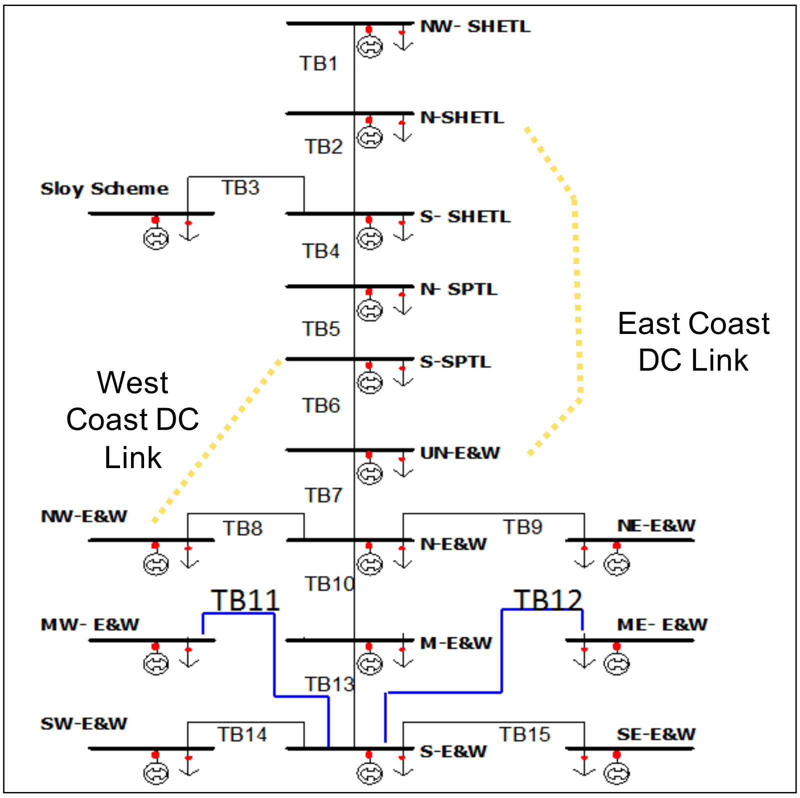
Source: Imperial College

B.1.2. Network topography and assumed boundary capacities

DTIM uses a 16-zone, 15-boundary radial network to represent the GB transmission network, as shown in Figure B.3. 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 B.3
DTIM Radial Network



Source: Imperial Analysis

B.2. Converting DTIM Loss Factors into Hourly Loss Factors

Rather than representing how conditions change across a number of "snapshots" like the approach implemented in DTIM, our market models define demand and wind production with an hourly "shape" based on historic market data. We shift these "shapes" upwards over time as wind capacity and demand rise.

This difference in approach required that we map the DTIM marginal loss factors (produced using DTIM for discrete levels of demand and wind production) onto a demand curve that varied per hour. We performed this mapping using a regression equation. Essentially, for every season, zone and epoch, we estimated a regression equation using the DTIM results that sought to predict marginal loss factors as a function of demand and wind production. We used these regression equations to predict hourly loss factors for each zone based on the assumed demand and level of wind production in that hour.

We estimated 320 regressions in total (= 16 zones x 5 epochs x 4 seasons). The specification of the regression equations was as follows:

$$\textit{Loss Factor} = \textit{Constant} + a_1 \times \textit{Wind} + a_2 \times \textit{Wind}^2 + a_3 \times \textit{Demand} + a_4 \times \textit{Demand}^2 + a_5 \times (\textit{Wind} \times \textit{Demand}) + \textit{Error}$$

- The term "Loss Factor" represents the marginal loss factor using the same units as in Table 2.1 and Table 2.2 in the main body of this report;

- "Wind" represents the level of wind production as a load factor ranging from 0 to 1; and
- "Demand" is power demand on the British system in MW.
- The "Error" term represents the variation in loss factors not explained by the other parts of the equation.

We estimated the a_1 to a_5 terms using a weighted least squared technique, placing most weight on those DTIM snapshots that are intended to represent the highest number of hours in the year. In general, these regressions achieved a very strong statistical "fit", with R-squared parameters above 0.8 in the vast majority of cases. See Section B.3 for our detailed regression results.

We also estimated a further regression equation in order to predict the system-wide average loss factor as a function of demand and wind production, in order to calculate the non-locational loss factor that applies in each hour of the year in the status quo case.[61] In other scenarios that assume locational loss factors, the locational loss factors we estimate for each DTIM zone define the amount by which this national average loss factor varies across the country. Specifically, as noted in the main report, we defined two scenarios:

- In the "Hourly Locational Loss Factor" scenario, we allow the zonal loss factor to vary every hour, such that loss factors between zones varies with levels of demand and wind production, and ; and
- In the "Seasonal Locational Loss Factor" scenario, we hold the spread in loss factors across DTIM zones constant within each season, based on the average seasonal spread in the hourly loss factors. This scenario is intended to mimic, albeit imprecisely, the types of zonal loss factors prescribed by BSC Mod 229, under which locational variation in generators' and consumers' transmission loss factors would be set based on seasonal averages. The seasonal average loss factors we used in our modelling in this scenario are presented in 0.

B.3. Regression Model Performance

As noted above, we have used these regressions as a means of transposing the TLMs produced by DTIM for each "snapshot" onto chronological time. The histogram below illustrates the high fit of the model, as measured by the R-squared parameter, which for most regressions is about 80%. The only zones for which the fit is regularly lower is DTIM zone 8, in which there are relatively few generation plants (two pumped storage plants, Dinorwig and Ffestiniog, in North Wales plus some wind farms).

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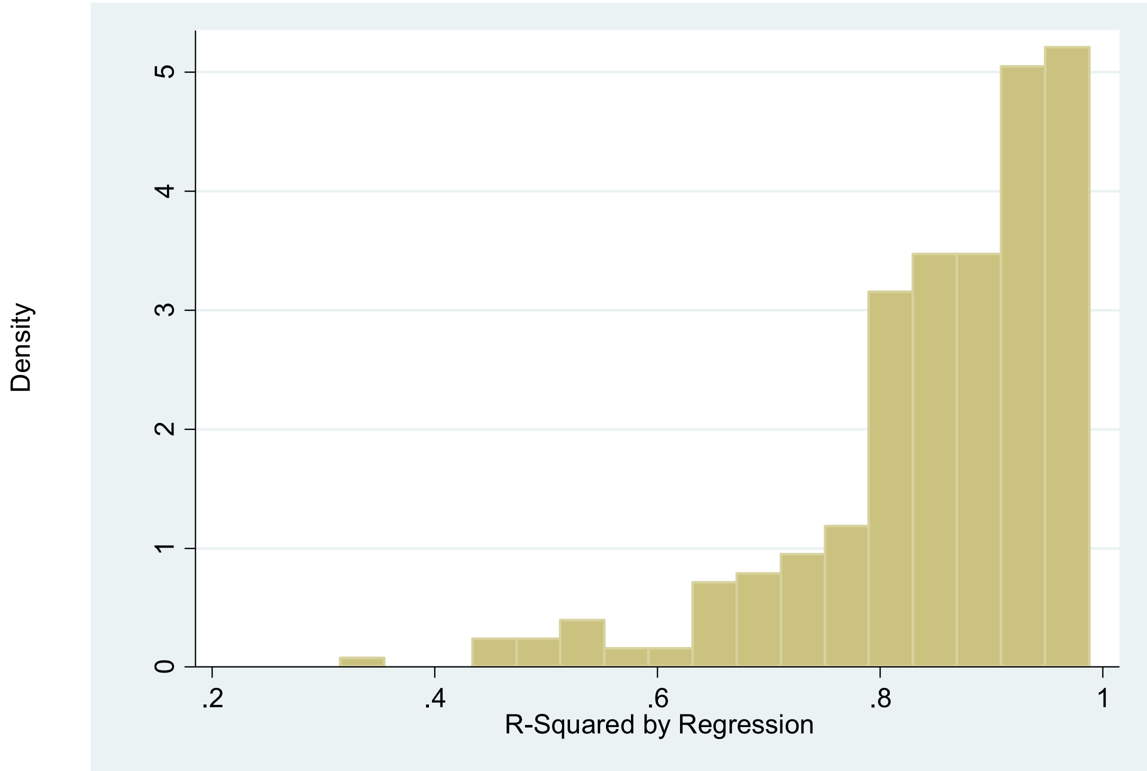
61 This regression equation, which we estimated for each season and epoch (20 times) had the same specification as the loss factor for each zone, as described above.

Figure B.4
Histogram of R-Squared by Regression Model



Source: NERA/Imperial

Appendix C. Seasonal Loss Factors by Quarter

	Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	Zone 6	Zone 7	Zone 8	Zone 9	Zone 10	Zone 11	Zone 12	Zone 13	Zone 14	Zone 15	Zone 16
2016-Q1	0.64%	0.64%	0.71%	0.67%	0.69%	0.60%	0.00%	-0.83%	-0.38%	-0.81%	-1.81%	-2.03%	-1.31%	-2.17%	-2.14%	-2.19%
2016-Q2	0.04%	0.04%	0.14%	0.12%	0.23%	0.18%	0.00%	0.07%	0.61%	0.16%	-0.54%	-0.92%	-0.21%	-1.02%	-0.97%	-1.01%
2016-Q3	0.12%	0.12%	0.21%	0.19%	0.28%	0.22%	0.00%	-0.14%	0.36%	-0.06%	-0.93%	-1.20%	-0.48%	-1.30%	-1.26%	-1.30%
2016-Q4	0.90%	0.90%	0.95%	0.92%	0.89%	0.79%	0.00%	-1.33%	-0.97%	-1.37%	-2.57%	-2.64%	-1.95%	-2.79%	-2.78%	-2.83%
2017-Q1	0.78%	0.78%	0.85%	0.82%	0.86%	0.79%	0.00%	-0.76%	-0.34%	-0.86%	-1.98%	-2.15%	-1.40%	-2.28%	-2.26%	-2.30%
2017-Q2	0.27%	0.27%	0.36%	0.35%	0.45%	0.42%	0.00%	0.22%	0.64%	0.15%	-0.56%	-0.85%	-0.21%	-0.93%	-0.87%	-0.92%
2017-Q3	0.32%	0.32%	0.39%	0.38%	0.46%	0.42%	0.00%	-0.17%	0.34%	-0.10%	-0.74%	-0.98%	-0.44%	-1.08%	-1.02%	-1.08%
2017-Q4	0.97%	0.96%	1.02%	0.99%	0.99%	0.92%	0.00%	-1.26%	-0.89%	-1.38%	-2.35%	-2.44%	-1.87%	-2.61%	-2.59%	-2.65%
2018-Q1	0.75%	0.75%	0.82%	0.80%	0.84%	0.77%	0.00%	-0.69%	-0.33%	-0.85%	-1.96%	-2.11%	-1.37%	-2.24%	-2.22%	-2.26%
2018-Q2	0.23%	0.23%	0.31%	0.31%	0.42%	0.42%	0.00%	0.32%	0.54%	0.06%	-1.06%	-1.32%	-0.45%	-1.38%	-1.39%	-1.37%
2018-Q3	0.28%	0.28%	0.34%	0.34%	0.43%	0.44%	0.00%	-0.09%	0.05%	-0.36%	-1.82%	-1.99%	-0.99%	-2.06%	-2.14%	-2.06%
2018-Q4	1.03%	1.02%	1.08%	1.04%	1.02%	0.94%	0.00%	-1.33%	-0.89%	-1.40%	-2.40%	-2.52%	-1.91%	-2.69%	-2.67%	-2.73%
2019-Q1	0.79%	0.78%	0.85%	0.83%	0.87%	0.82%	0.00%	-0.36%	-0.16%	-0.71%	-1.95%	-2.16%	-1.28%	-2.27%	-2.27%	-2.28%
2019-Q2	0.24%	0.25%	0.32%	0.31%	0.41%	0.40%	0.00%	0.54%	0.70%	0.26%	-0.56%	-0.85%	-0.12%	-0.89%	-0.87%	-0.89%
2019-Q3	0.33%	0.33%	0.41%	0.39%	0.47%	0.43%	0.00%	-0.20%	0.32%	-0.12%	-0.85%	-1.09%	-0.50%	-1.19%	-1.14%	-1.19%
2019-Q4	1.04%	1.03%	1.09%	1.05%	1.03%	0.95%	0.00%	-1.31%	-0.88%	-1.41%	-2.40%	-2.52%	-1.92%	-2.70%	-2.68%	-2.74%
2020-Q1	0.79%	0.79%	0.85%	0.83%	0.85%	0.78%	0.00%	-0.58%	-0.24%	-0.79%	-1.90%	-2.09%	-1.32%	-2.22%	-2.20%	-2.23%
2020-Q2	0.27%	0.28%	0.36%	0.35%	0.46%	0.43%	0.00%	0.32%	0.66%	0.18%	-0.63%	-0.93%	-0.22%	-0.99%	-0.96%	-0.99%
2020-Q3	0.33%	0.34%	0.41%	0.40%	0.48%	0.43%	0.00%	-0.20%	0.31%	-0.13%	-0.89%	-1.13%	-0.52%	-1.23%	-1.18%	-1.23%
2020-Q4	1.11%	1.10%	1.14%	1.11%	1.07%	0.98%	0.00%	-1.23%	-0.81%	-1.34%	-2.31%	-2.44%	-1.83%	-2.62%	-2.59%	-2.65%
2021-Q1	1.04%	1.03%	1.06%	1.03%	1.00%	0.92%	0.00%	-0.80%	-0.35%	-0.95%	-2.03%	-2.17%	-1.44%	-2.33%	-2.30%	-2.32%
2021-Q2	0.49%	0.48%	0.53%	0.52%	0.58%	0.54%	0.00%	-0.24%	0.30%	-0.26%	-0.92%	-1.14%	-0.57%	-1.24%	-1.20%	-1.22%
2021-Q3	0.48%	0.47%	0.51%	0.50%	0.53%	0.50%	0.00%	-0.40%	0.18%	-0.35%	-0.97%	-1.15%	-0.64%	-1.27%	-1.22%	-1.26%
2021-Q4	1.39%	1.37%	1.35%	1.32%	1.19%	1.12%	0.00%	-1.14%	-0.61%	-1.28%	-2.45%	-2.52%	-1.80%	-2.76%	-2.72%	-2.74%
2022-Q1	1.11%	1.09%	1.10%	1.08%	1.02%	0.93%	0.00%	-0.65%	-0.27%	-0.86%	-1.91%	-2.06%	-1.32%	-2.21%	-2.19%	-2.19%
2022-Q2	0.49%	0.49%	0.54%	0.53%	0.59%	0.55%	0.00%	-0.23%	0.28%	-0.27%	-0.96%	-1.19%	-0.59%	-1.28%	-1.25%	-1.26%
2022-Q3	0.50%	0.50%	0.54%	0.53%	0.56%	0.52%	0.00%	-0.43%	0.16%	-0.37%	-1.04%	-1.24%	-0.69%	-1.35%	-1.31%	-1.34%
2022-Q4	1.41%	1.39%	1.36%	1.33%	1.20%	1.12%	0.00%	-1.15%	-0.61%	-1.29%	-2.46%	-2.54%	-1.81%	-2.78%	-2.75%	-2.76%
2023-Q1	1.11%	1.10%	1.10%	1.08%	1.03%	0.94%	0.00%	-0.65%	-0.27%	-0.86%	-1.92%	-2.08%	-1.33%	-2.23%	-2.21%	-2.22%
2023-Q2	0.49%	0.49%	0.54%	0.53%	0.60%	0.55%	0.00%	-0.22%	0.26%	-0.27%	-0.98%	-1.22%	-0.60%	-1.30%	-1.27%	-1.28%
2023-Q3	0.51%	0.51%	0.55%	0.54%	0.58%	0.53%	0.00%	-0.45%	0.15%	-0.39%	-1.07%	-1.28%	-0.71%	-1.40%	-1.35%	-1.38%
2023-Q4	1.42%	1.40%	1.37%	1.34%	1.21%	1.13%	0.00%	-1.17%	-0.60%	-1.29%	-2.47%	-2.57%	-1.82%	-2.80%	-2.77%	-2.78%
2024-Q1	1.12%	1.10%	1.11%	1.09%	1.04%	0.94%	0.00%	-0.65%	-0.26%	-0.86%	-1.93%	-2.10%	-1.34%	-2.26%	-2.23%	-2.24%
2024-Q2	0.49%	0.49%	0.55%	0.54%	0.61%	0.56%	0.00%	-0.21%	0.25%	-0.28%	-1.00%	-1.25%	-0.61%	-1.33%	-1.31%	-1.32%
2024-Q3	0.53%	0.52%	0.57%	0.55%	0.59%	0.54%	0.00%	-0.46%	0.14%	-0.40%	-1.11%	-1.33%	-0.73%	-1.44%	-1.40%	-1.43%
2024-Q4	1.66%	1.63%	1.58%	1.55%	1.37%	1.27%	0.00%	-1.09%	-0.53%	-1.28%	-2.46%	-2.54%	-1.82%	-2.79%	-2.74%	-2.77%
2025-Q1	1.04%	1.03%	1.00%	0.98%	0.87%	0.81%	0.00%	-0.30%	-0.04%	-0.50%	-1.10%	-1.16%	-0.79%	-1.27%	-1.24%	-1.27%
2025-Q2	0.86%	0.85%	0.84%	0.83%	0.78%	0.78%	0.00%	-0.02%	0.47%	-0.12%	-0.48%	-0.61%	-0.33%	-0.70%	-0.66%	-0.70%
2025-Q3	0.67%	0.67%	0.65%	0.64%	0.59%	0.60%	0.00%	-0.04%	0.41%	-0.10%	-0.35%	-0.44%	-0.27%	-0.54%	-0.49%	-0.54%
2025-Q4	1.70%	1.68%	1.57%	1.55%	1.31%	1.24%	0.00%	-0.45%	-0.12%	-0.83%	-1.70%	-1.68%	-1.25%	-1.89%	-1.86%	-1.89%
2026-Q1	1.15%	1.13%	1.08%	1.07%	0.93%	0.86%	0.00%	-0.27%	0.00%	-0.50%	-1.13%	-1.16%	-0.79%	-1.28%	-1.24%	-1.28%
2026-Q2	0.88%	0.87%	0.86%	0.85%	0.80%	0.80%	0.00%	-0.02%	0.46%	-0.13%	-0.50%	-0.65%	-0.35%	-0.74%	-0.70%	-0.74%
2026-Q3	0.67%	0.67%	0.65%	0.64%	0.59%	0.60%	0.00%	-0.06%	0.40%	-0.11%	-0.36%	-0.46%	-0.28%	-0.55%	-0.51%	-0.56%
2026-Q4	1.70%	1.68%	1.57%	1.55%	1.31%	1.23%	0.00%	-0.47%	-0.11%	-0.84%	-1.71%	-1.69%	-1.26%	-1.91%	-1.88%	-1.91%
2027-Q1	1.15%	1.13%	1.08%	1.06%	0.93%	0.86%	0.00%	-0.28%	-0.01%	-0.51%	-1.14%	-1.18%	-0.80%	-1.30%	-1.26%	-1.29%
2027-Q2	0.89%	0.89%	0.88%	0.87%	0.83%	0.83%	0.00%	-0.03%	0.45%	-0.14%	-0.53%	-0.70%	-0.36%	-0.78%	-0.75%	-0.78%
2027-Q3	0.68%	0.68%	0.66%	0.65%	0.60%	0.61%	0.00%	-0.08%	0.39%	-0.12%	-0.38%	-0.49%	-0.29%	-0.58%	-0.54%	-0.59%
2027-Q4	1.71%	1.68%	1.58%	1.55%	1.31%	1.23%	0.00%	-0.49%	-0.11%	-0.85%	-1.72%	-1.71%	-1.27%	-1.93%	-1.90%	-1.93%
2028-Q1	1.16%	1.14%	1.09%	1.07%	0.94%	0.87%	0.00%	-0.28%	0.00%	-0.52%	-1.15%	-1.20%	-0.82%	-1.32%	-1.28%	-1.32%
2028-Q2	0.89%	0.89%	0.88%	0.87%	0.84%	0.83%	0.00%	-0.02%	0.43%	-0.14%	-0.55%	-0.73%	-0.37%	-0.80%	-0.77%	-0.80%
2028-Q3	0.69%	0.69%	0.67%	0.66%	0.61%	0.62%	0.00%	-0.10%	0.38%	-0.13%	-0.40%	-0.53%	-0.31%	-0.62%	-0.57%	-0.62%
2028-Q4	1.74%	1.72%	1.58%	1.55%	1.27%	1.20%	0.00%	-0.34%	0.07%	-0.74%	-1.49%	-1.44%	-1.13%	-1.67%	-1.63%	-1.67%
2029-Q1	0.93%	0.92%	0.84%	0.83%	0.66%	0.62%	0.00%	-0.01%	0.22%	-0.26%	-0.60%	-0.53%	-0.45%	-0.65%	-0.62%	-0.66%
2029-Q2	0.80%	0.80%	0.73%	0.72%	0.59%	0.58%	0.00%	0.24%	0.57%	0.00%	-0.24%	-0.14%	-0.18%	-0.24%	-0.22%	-0.26%
2029-Q3	0.70%	0.69%	0.63%	0.61%	0.49%	0.49%	0.00%	0.24%	0.55%	0.03%	-0.16%	-0.02%	-0.11%	-0.14%	-0.12%	-0.15%
2029-Q4	1.55%	1.52%	1.37%	1.35%	1.06%	1.00%	0.00%	-0.03%	0.23%	-0.45%	-0.96%	-0.77%	-0.73%	-0.97%	-0.95%	-0.98%
2030-Q1	1.15%	1.13%	1.05%	1.04%	0.86%	0.81%	0.00%	0.08%	0.14%	-0.32%	-0.78%	-0.66%	-0.55%	-0.77%	-0.76%	-0.78%
2030-Q2	0.97%	0.97%	0.92%	0.91%	0.79%	0.76%	0.00%	0.32%	0.35%	-0.08%	-0.52%	-0.38%	-0.29%	-0.45%	-0.48%	-0.46%
2030-Q3	0.67%	0.67%	0.61%	0.60%	0.50%	0.50%	0.00%	0.25%	0.48%	0.02%	-0.22%	-0.09%	-0.13%	-0.19%	-0.18%	-0.20%
2030-Q4	1.49%	1.48%	1.36%	1.34%	1.10%	1.04%	0.00%	-0.08%	-0.12%	-0.60%	-1.34%	-1.09%	-0.91%	-1.25%	-1.26%	-1.26%

Report qualifications/assumptions and limiting conditions

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NERA Economic Consulting
Marble Arch House, 66 Seymour Street
London W1H 5BT
United Kingdom
Tel: 44 20 7659 8500 Fax: 44 20 7659 8501
www.nera.com