CMP213 modelling

Review of CMP213 Impact Assessment Modelling for Ofgem

Version:1 **Date:**31/07/13

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Version History

Version	Date	Description	Prepared by	Approved by
1	30/07/2013	Final	Nick Screen	

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1 Introduction

Under the Project TransmiT Significant Code Review (SCR), Ofgem commissioned Redpoint Energy to model the impacts of the transmission charging options considered. Two options were developed by the TransmiT Technical Working Group and were analysed in detail: (i) Improved ICRP which involves enhancements to the current ICRP methodology to include a year-round as well as peaking element to transmission charges; and (ii) socialised charging under which all generators would pay a uniform tariff for using the transmission system, irrespective of their location or type. Redpoint developed a modelling suite, the TransmiT Decision Model (TDM), to model the impact of transmission charging regimes on transmission and generation investment decisions. With National Grid's support, we incorporated National Grid's Transport and Tariff model and ELSI model. The results of our study along with our recommendations were published in December 2011[1].

Ofgem's decision on Project TransmiT included a direction for the Connection and Use of System Code panel (CUSC panel) to develop a modification to the CUSC (CMP213). National Grid has undertaken further analysis and modelling in the TDM to assess proposals developed under CMP213.The key features of the Improved ICRP option have been retained in the Original proposal that National Grid raised as CMP213, although there are differences as outlined in sections 2.1.9 and 2.1.12 of this report. Additionally, National Grid's analysis included four more charging options: (i) Original 50% HVDC, which uses a similar approach as the Original however with a reduction in converter cost by 50% for both parallel HVDC circuits and island connections comprised of sub-sea HVDC cable technology; and (ii) three Diversity options (Diversity 1, Diversity 2 and Diversity 3) that aim to address low-carbon and carbon generation plant type diversity.

In light of the updated modelling undertaken by National Grid, Ofgem required support to review and assess the new results produced by the model. Specifically, Ofgem required support in the following three key areas:

1. Reviewing changes to the input assumptions and assessing the likely impact of these changes;
2. Reviewing changes made to model functionality as well as any changes to the mechanistic process underpinning the analytical approach and assessing the likely impact of these changes.
3. Comparing the outputs of the updated modelling against results produced during TransmiT and identify the key factors driving potential differences.

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

- In Section 2 we review the assumptions that have been updated or changed in the CMP213 modelling from the TransmiT modelling. We consider the source of the new data, the reason for the change and the potential impact on modelling results. These assumptions include (i) sustainability goals, (ii) commodity prices, (iii)

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

electricity demand, (iv) potential generation build, (v) generation life expectancy, (vi) generation capital and operational cost information, (vii) interconnectors, (viii) transmission reinforcements, (ix) island subsea links, (x) allowed transmission revenues, (xi) transport and tariff model assumptions, and (xii) Generation:Demand(G:D) split.

- In Section 3 we review the changes made to model functionality since the TransmiT modelling, and the likely impact of these changes. Specifically we focus firstly on the changes made to the Transport & Tariff model (e.g. the new approach to calculating impedances for HVDC bootstraps and the diversity options) and then on a range of other enhancements that were made to the modelling suite.
- In Section 4 we compare the Status Quo model runs from the TransmiT and CMP213 modelling, before analysing the results for the CMP213 Original and Alternative policy variants.
- Finally, Section 5 presents our main conclusions with regards to the key factors driving potential differences in results, along with our understanding of the emerging messages stemming from this analysis.
- In Appendix A, we present a high level summary of the charging options considered under the CMP213 modification process. In Appendix B we present the CfD strike prices used in the modelling, and in Appendix C we present the CBA results for three additional model runs (Diversity 1 50% HVDC Converter Cost. Diversity 2 50% HVDC Converter Cost, Diversity 3 50% HVDC Converter Cost) that are out of the scope of this review.

2 Assumptions review

In this section we review the assumptions that have been updated or changed in the CMP213 modelling from the TransmiT modelling. We consider the source of the new data, the reason for the change and the potential impact on modelling results.

2.1.1 Sustainability goals

For the TransmiT modelling, the model runs were conducted with two different approaches to the setting of CfD strike prices:

- **Equivalent** levels of low carbon support (RO/CfDs) across the three options in order to isolate the impacts of the different charging options on deployment rates (**"Stage 1"**)
- **Adjusted** levels of low carbon support to deliver the same 2020 renewables output (~30%) and 2030 carbon intensity (~100 g/kWh) to facilitate the comparison of costs across the transmission charging options (**"Stage 2"**)

The Stage 2 approach results are more suitable for comparing costs across policy options, as each meets broadly the same renewable targets and low carbon objectives.

The Base Case Status Quo model was calibrated to meet renewable and low carbon targets in 2020 and 2030 respectively (Table 1). Levels are based on Government strategies to comply with the EU Renewable Energy Directive in 2020 and plans for decarbonisation to 2030 consistent with carbon budgets.

Table 1 Renewable and low carbon targets (TransmiT)

Metric	Units	2020 target	2030 target
Renewable share (% of demand)[2]	% of demand	30%	-
Carbon intensity	g/kWh	-	~100

For CMP213, the modelling has been completed with a 'Stage 2' approach to the setting of CfD strike prices across different transmission charging policy variants. Under this approach, each model has been calibrated to meet Government targets[3] to comply with the EU Renewable Energy Directive in 2020 and plans for decarbonisation to 2030 consistent with carbon budgets. The range allowed in renewable generation under CMP213 is larger than the variation in this value in in the TransmiT results. This larger range reduces the need for large numbers of model iterations on CfD strike prices but delivers

[2] Electricity demand is based on EU definition (includes energy industry own use and pumped storage, excludes consumption in rail transport). Carbon intensity excludes emissions from embedded CHP.

[3] Coalition Announces Transformation of Power Market, DECC Press Release, December 2010 (https://www.gov.uk/government/news/coalition-announces-transformation-of-power-market).

CBA results that require more careful interpretation in terms of the impact of different levels of renewables.

The workgroup also agreed that there should be a fixed amount of nuclear capacity in 2030, of 14 GW. This is an additional constraint compared to the TransmiT results. However in outturn the TransmiT results did have very similar levels of nuclear between Status Quo and Improved ICRP (12.8 GW in Status Quo compared to 12.4 GW in Improved ICRP). The choice of 14 GW is consistent with TransmiT, given that the level of nuclear new build is similar and the difference is due to recently announced extensions of existing nuclear generators (section 2.1.5)

The following table (Table 2) provides a summary of these targets, and the allowable deviations assumed.

Table 2 Renewable and low carbon targets (CMP213)

Metric	2020 target	2030 target	Allowable range
Renewable share (% of demand)	30%	-	30% to 32% in 2020
Carbon intensity(g/kWh)	-	~100	95 to 105 in 2030
Nuclear capacity (GW)	-	14	-

In addition to these targets the total level of subsidy payments made to low carbon generation was set at a level that ensures that the governments Levy Control Framework level target spend[4] for 2020/21, announce as part of the recent Energy Bill will not be exceeded. Under the modelled scenario, this does not constraint the results.

The approach to sustainability goals is consistent with TransmiT and has been implemented correctly.

2.1.2 Commodity prices

For Project TransmiT, fuel and carbon prices were based on forward prices as of August 2011 and Redpoint projections thereafter[5].

For CMP213, commodity price assumptions for Gas and Coal have been updated to the Central scenario from DECC's 2012 *Energy and Emissions Projections*[6], converted to £/MWh

[4] An Energy Bill to power low-carbon economic growth, protect consumers and keep the lights on, DECC Press Release, November 2012 (https://www.gov.uk/government/news/an-energy-bill-to-power-low-carbon-economic-growth-protect-consumers-and-keep-the-lights-on).

[5]Coal price based on continuation of prevailing forward price levels. Gas prices based on a straight line increase to the IEA new policies scenario figure for 2030 (IEA, World Energy Outlook (November 2010)). Carbon prices based on the price of emissions allowances in the EU ETS for 2011 and 2012, and published trajectory for Carbon Price Support from 2013.

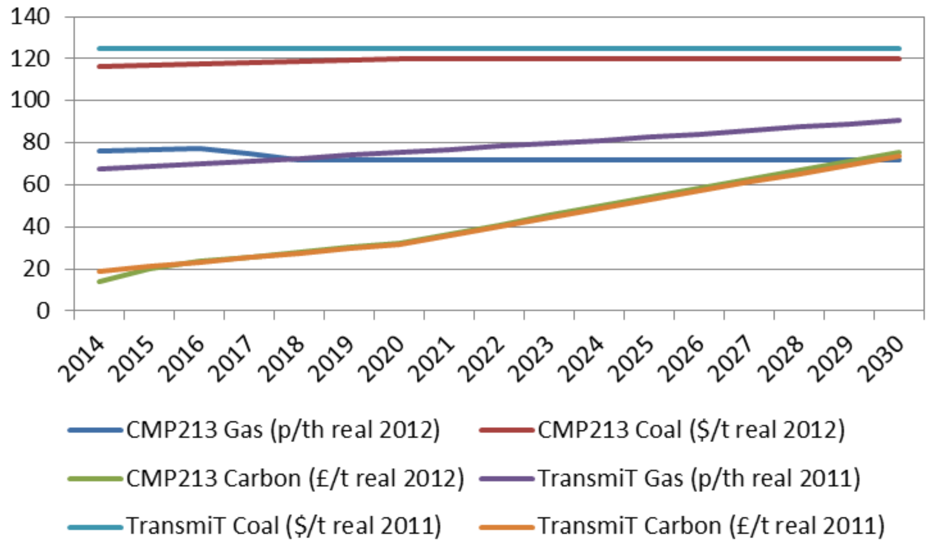
[6]Annex F, https://www.gov.uk/government/publications/2012-energy-and-emissions-projections,

prices[7]. This constitutes a change in the source of the assumptions. We believe these assumptions are appropriate because these projections are largely similar to the previous modelled values and are widely familiar to industry stakeholders.

For CMP213, assumptions for the cost of carbon that generators will face are in line with DECC's forecasts published in the *Updated short-term traded carbon values for modelling purposes*[8] document inclusive of the Carbon Price Floor. This is the same source of long run carbon price assumptions as for Project TransmiT

Overall, the change in the assumptions is small except for gas prices as shown in Figure 1. Gas prices under CMP213 are flat after 2017, whilst under TransmiT they increased. This is a result of the change in source to DECC Central values. One implication of this is that CCGT Short Run Marginal Costs will increase more slowly under CMP213 than under the TransmiT modelling, and therefore the scenario under CMP213 will be more gas-favouring (relative to generation from coal) in the long run.

Figure 1 Fuel and carbon price assumptions



Whilst DECC's updated price projections include an updated view of crude oil prices, and this is the main driver behind oil product prices, no view of these has been published. Therefore for Fuel Oil and Gas Oil prices, historic data[9] published by DECC has been

[7] A calorific value of 25.1GJ/t for coal has been assumed (based on quoted values for ARA (Antwerp-Rotterdam-Amsterdam) coal).

[8] Table 2, Updated short-term traded carbon values used for modelling purposes, DECC, October 2012 (https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/41797/6664-carbon-values-used-in-deccs-emission-projections-.pdf)

[9] Table 3.2.1 Average prices of fuels purchased by the major UK power producers and of gas at UK delivery points (Fuel Oil Prices) & Table 3.1.4 Annual prices of fuels purchased by manufacturing industry (p/kWh) (Gas Oil Prices) of DECC's Quarterly Energy Price Publication, December 2012 (https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/65940/7341-quarterly-energy-prices-december-2012.pdf)

utilised, to undertake a simple linear regression against DECC's crude oil price projections to obtain updated price forecasts. The same methodology was used to derive the Fuel Oil and Gas Oil prices for Project TransmiT, albeit with an older data, sourced from Platts.

Biomass and nuclear fuel costs have been inflated from the TransmiT values by RPI to 2012/13 prices.

The TransmiT modelling used a constant EUR-GBP exchange rate of 0.88 and a USD-GBP exchange rate of 0.61. Under CMP213 these values were updated to the values used in the DECC UEP 2012 (0.87and 0.62respectively)

For CMP213 a single commodity price scenario has been constructed. No commodity price sensitivities have been modelled.

Overall we believe that the commodity price updates are appropriate and have been implemented correctly. Other than the gas price, the changes are expected to have little impact on the modelling results.

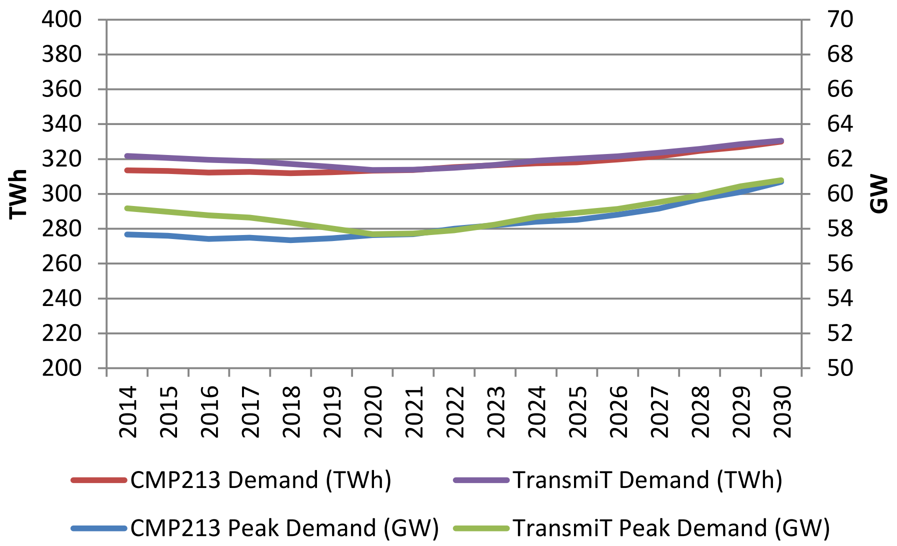
2.1.3 Electricity demand

For Project TransmiT, demand assumptions were based on National Grid's 2010 'Gone Green' scenario. Electricity demand figures exclude demand met by embedded generation. For CMP213, demand assumptions have been updated to the National Grid 2012 Gone Green scenario, as published in the National Grid 2012 Ten Year Statement[10]. This provides peak demand assumptions and references National Grid's Future Energy Scenarios[11] for annual demand assumptions. The CMP213 demand assumptions are lower in the near term (reflecting recent history of lower outturn demand) but are similar from 2020 onwards. Demand assumptions are shown graphically in Figure 2.

[10] Gone Green Peak Outturn and Forecast, Figure 2.3.1, National Grid's 2012 Ten Year Statement (http://www.nationalgrid.com/uk/Electricity/ten-year-statement/current-elec-tys/).

[11] Figure 24, *http://www.nationalgrid.com/NR/rdonlyres/2450AADD-FBA3-49C1-8D63-7160A081C1F2/56766/UKFutureEnergyScenarios2014.pdf)*

Figure 2 Demand assumptions[12]



The National Grid Gone Green 2010 demand data (as defined in National Grid's ELSI tool and used in Project TransmiT) has a constant ratio of peak to annual demand throughout the modelling horizon. Under National Grid Gone Green 2012, the ratio of peak to annual demand changes across the modelling horizon, based on structural changes to GB electricity demand. This is a reasonable assumption; however a limitation of the current TransmiT Decision Model models is that the ELSI inputs do not currently allow for a change in the shape of demand over time. Therefore for the CMP213 modelling the ratio of peak to annual demand has been kept constant over time. The impact of this is that annual demand is 330 TWh in 2030, rather than the 340 TWh in Gone Green 2012. This will have the impact of reducing the amount of low carbon generation required to meet a 100g/kWh carbon intensity target, by approximately 7 TWh.

Overall the change in the demand assumptions is expected to have little impact on the comparison of charging options, other than as a contributory factor to the reduced level of low carbon generation required in 2030 under CMP213.

2.1.4 Potential generation build

For CMP213, the list of generation projects assumed for 2011-14 has been fixed based upon the contracted generation background as published in the TEC register, based upon the logic that such projects are either already delivered or at a sufficiently advanced stage of their development that their year of commissioning will be as expected.

The impact of this is that the model results for generation investment decisions will be identical up to and including calendar year 2014. The implicit modelling assumption is that changes to transmission charging policy can have no impact prior to this point. An

[12]Total demand based on National Grid 'updated Gone Green' (June 2010) scenario. Relationship between total and peak demand based on historical analysis.

implementation date of 1st April 2014 or 1st April 2015 would have no impact on the modelling. Given that the model assumes that generators have a one year ahead view of outturn transmission charges, in either case the changes will be known by 2014 at the latest, which is the first date that generators can make different retirement decisions.

From 1st Jan 2015 onwards, the assumed list of available generation projects, and underlying global maximum and minimum build assumptions for each technology type are the same as for the TransmiT modelling.

In compiling the final data, the total potential capacity for each technology type has been compared with both the contracted background and that assumed in National Grid's Accelerated Growth scenario[13]. The Accelerated Growth scenario represents a scenario with a high growth of renewable capacity, and has been used as an amalgamated source of the current known renewable projects to 2020. In cases where the total capacity for a technology type under the 2012 Accelerated Growth scenario outweighs the assumptions previously made for TransmiT, or where additional projects are contracted that do not align with the generic generation categories used under the previous modelling, the background has been amended to include the additional generation. Most notable changes include:

i) updates to available offshore wind capacity to match the maximum of contracted TEC and dates, the 2012 Accelerated Growth scenario, and the previous TransmiT assumptions: total capacity of offshore wind projects of 39 GW in 2020 compared to 23 GW under Project TransmiT;
ii) the addition of available biomass capacity to match the accelerated growth scenario: additional 300 MW by 2020;
iii) the addition of available hydro capacity to match the accelerated growth scenario: an increase of 118 MW of capacity from 2016;
iv) the addition of potential Scottish Island based tidal plant of up to 40 MW by 2020;
v) the addition of potential Alderney based tidal plant of up to 8 GW capacity by 2025; and
vi) the addition of a potential 490MW CHP station connecting at Pembroke.

Of these changes, the offshore wind change is most significant. For Project TransmiT, the source was the Accelerated Growth scenario as described in the 2011 Offshore Development Information Statement (ODIS), which describes an additional 21.3 GW of offshore wind capacity. The 2012 Accelerated Growth scenario[14] has a much more rapid deployment of offshore wind (33 GW by 2020) and using this as a source for the maximum build capacities alongside the TEC register and the previous TransmiT assumptions results in a major change to available capacities, to 39 GW by 2020. The overall impact of the change on the output build is restricted by the global build constraints on offshore wind (7.5 GW/year) and by the profitability of projects under the CfD levels used. However we do observe more offshore wind deployed in the near term in the CMP213 modelling(5 GW

[13] Accelerated Growth Fuel Type Mix, Table F2.3, National Grid's 2012 Ten Year Statement (http://www.nationalgrid.com/uk/Electricity/ten-year-statement/current-elec-tys/).

[14] http://www.nationalgrid.com/NR/rdonlyres/86C815F5-0EAD-46B5-A580-A0A516562B3E/50819/10312_1_NG_Futureenergyscenarios_WEB1.pdf

total offshore wind in 2014 compared to 3 GW for Project TransmiT, section 4.1), which has the impact of reducing the amount of onshore wind required to meet the 30% RES-E target in 2020.

The Alderney tidal change would be expected to be significant; however the high costs of this project mean that it does not come forward under any of the transmission charging options.

Updates have also been made in relation to existing generation to reflect revised TECs as of March 2013. This includes changes (mainly reductions) to coal and CCGT TECs that have occurred in the past 18 months, and adjustments to a small number of wind TECs. This has the effect of reducing installed capacity and de-rated capacity margins and is consistent with the best view of current capacity at the time the assumptions were updated in March 2013. The TransmiT modelling was mostly carried out in October 2011 whilst the CMP213 modelling was carried out in May 2013.

The location of a number of Scottish onshore wind farms has also been revised to adjust a number of cases where the original ELSI plant list (as brought into the TransmiT modelling exercise) did not have these mapped to the correct zones. Our understanding is that this was typically due to the exact electrical connection for the wind farm not being known at the time it was entered into ELSI. In total, about 600 MW of existing or contracted wind capacity has been relocated into a neighbouring zone from that used under Project TransmiT. In our view this change is valid and the impact of this change is not likely to be significant. This impact is limited to small changes in internal Scottish transmission constraints.

2.1.5 Generation life expectancy

With the exception of nuclear stations, no amendments have been made to expected station closure dates previously assumed. After discussion with the Working Group, the following assumptions on the life expectancy of the existing nuclear fleet were assumed (Table 3).

Table 3 Nuclear life extensions

Plant	Capacity (MW)	TransmiT closure date	CMP213 closure date
Dungeness B	1081	2018	2018
Hinkley Point B	1261	2018	2023
Oldbury	215	2012	2012
Hunterston	1074	2018	2023
Torness	1215	2023	2030
Hartlepool	1207	2019	2019
Heysham 1	1203	2019	2019
Heysham 2	1203	2028	2030
Sizewell B	1212	2035	2035
Wylfa	890	2012	2014

These assumptions include seven year life extensions for Torness and two years for Heysham 2 (noting that any further extension would be outside of the modelling horizon). Note that these extensions are subject to approval. EdF Energy expects on average seven year life extensions across its AGR fleet[15] (including extensions previously announced for Hinkley Point B and Hunterston B).

The assumed life extensions, particularly Torness and Heysham, reduce the amount of new low carbon generation required in 2030 to meet the 100g/kWh carbon intensity target by 17 TWh.

We believe these changes are valid as they make use of the most recent available market information.

2.1.6 Generation Capital and Operational Cost Information

The costs of new generation technologies have been updated to reflect the outputs of the latest studies commissioned by DECC. The capital and (non-use of system) operating costs (fixed and Variable Operations & Maintenance costs) have been updated for conventional[16] and non-marine based renewables[17] based upon these studies.

[15] EDF Energy announces seven year life extension to Hinkley Point B and Hunterson B nuclear power stations, Press Release, December 2012 (http://www.edfenergy.com/media-centre/press-news/EDF-Energy-announces-seven-year-life-extension-to-Hinkley-Point-B-and-Hunterston-B-nuclear-power-stations.shtml).

[16] For conventional plant the majority of data was taken from: Electricity Generation Cost Model – 2012 Update of Non Renewable Technologies, Parsons Brinckerhoff (on behalf of DECC), August 2012 (https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/65712/6884-electricity-gen-cost-model-2012-update.pdf). However, revised CO_2 transportation costs for CCS plant were updated in DECC's subsequent Electricity

Identical learning rates to those used in the TransmiT analysis have been applied to nth of a kind capital costs for nuclear and CCS technologies to model the reduction in the cost of emerging technology as time progresses. For operational costs, nth of a kind costs were assumed for both technology types.

Table 4 and Table 5 describe the capital cost assumptions employed under the TransmiT and CMP213 modelling respectively. Note that TransmiT figures are in real £ 2011 terms whilst CMP213 figures are in real £ 2012 terms.

Table 4 Capital cost assumptions (real 2011, TransmiT)

Capital costs (£/kW)	2015	2020	2025	2030
Nuclear (EPWR single)	3193	3065	2886	2794
Biomass (>50MW)	2393	2337	2315	2293
Offshore wind (R3)[1]	2488	2143	1950	1808
Onshore wind (>5MW)	1501	1446	1410	1374
Wave	5107	3496	2340	1818
Tidal Stream	4233	2963	2261	1800
Gas CCGT	669	669	669	669
Gas CCGT with CCS	1566	1493	1399	1356
Coal with CCS (ASC with FGD & CCS)	3348	3152	3007	2958
OCGT	599	599	599	599

Generation Costs report, October 2012 (https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/65713/6883-electricity-generation-costs.pdf).

[17]Government response to the consultation on proposals for the levels of banded support under the Renewables Obligation for the period 2013-17 and the Renewables Obligation Order 2012, DECC, July 2012 (https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/42852/5936-renewables-obligation-consultation-the-government.pdf).

Table 5 Capital cost assumptions (real 2012, CMP213)

Capital costs (£/kW)	2015	2020	2025	2030
Nuclear (EPWR single)	3741	3536	3366	3270
Biomass (>50MW)	2379	2331	2309	2286
Offshore wind (R3)[1]	2699	2211	1954	1784
Onshore wind (>5MW)	1466	1421	1385	1349
Wave	5260	3600	2410	1873
Tidal Stream	4360	3052	2329	1854
Gas CCGT	604	604	604	604
Gas CCGT with CCS	1486	1416	1326	1286
Coal with CCS (ASC with FGD & CCS)	3035	3035	2852	2852
OCGT	525	525	525	525

All other generation cost data, including balancing costs and gas exit capacity charges has been inflated by RPI to 2012/13 prices.

In our opinion the changes are reasonable and do not have a significant impact on the comparison of transmission charging options.

2.1.7 Interconnectors

Interconnector capacity assumptions were provided by Ofgem for Project TransmiT and have been kept unchanged for CMP213. In our view these assumptions continue to be reasonable. Interconnector assumptions are shown in Table 6.

Table 6 Interconnector assumptions (CMP213)

Interconnector	Capacity (GW)	Start Date
IFA (France)	2	already active
GB-IE (Ireland - Moyle)	0.5	already active
GB-NL (Netherlands - Britned)	1	already active
GB-IE (Ireland - East West)	0.5	already active
GB-BE (Belgium)	1	2017
GB-FR (France - additional)	2 x 1	2018 and 2022
GB-IE (Ireland - additional)	1	2020
GB-NO (Norway - additional)	1	2025

2.1.8 Transmission reinforcements

The list of potential transmission reinforcements and associated cost information previously used in the Project TransmiT analysis were updated, based upon the final RIIO proposals for each TO[18] [19].

Where specific cost information was not available, press releases and information direct from each TO were examined. If such information was not made publically available, then Redpoint's cost assumptions were inflated by RPI to 2012/13 prices.

Furthermore, where specific capability information was not available in the final RIIO proposals for each reinforcement the National Grid Ten Year Statement was used to provide this.

Table 7 compares the assumptions used in TransmiT and CMP213. 'Pre-committed (20xx)' means that the reinforcement occurs in all model runs, and is commissioned in the year specified. All projects to be delivered by 2015 have been set as pre-committed as these projects are assumed to have been initiated due to timescales involved.

Some of the most significant changes are:

- Western HVDC Link #1 moved back from 2015 to 2016, and assumed pre-committed, based on joint NG-SP report;
- Eastern HVDC Link #1 cost increased from £882m to £1,442m based on latest RIIO proposals;
- Anglo-Scottish Series & Shunt Compensation commissioning date moved back to 2015.

These changes apply across all policy options. The actual reinforcements which go ahead under each policy option are shown in Table 15.

In addition to known reinforcements, an identical set of generic reinforcements for each boundary to those used in Redpoint Energy's previous analysis were assumed, at a cost inflated by RPI to 2012/13 prices.

[18] Final RIIO-T1 proposals for SP Transmission Ltd and Scottish Hydro Electric Transmission Ltd (http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=190&refer=Networks/Trans/PriceControls/RIIO-T1/ConRes)

[19] Final RIIO-T1 proposals for NGET (http://www.ofgem.gov.uk/Networks/Trans/PriceControls/RIIO-T1/ConRes/Documents1/1_RIIOT1_FP_overview_dec12.pdf)

Table 7 Comparison of reinforcement packages

Reinforcement package	TransmiT Boundaries reinforced	TransmiT Cost (£m real 2011)	TransmiT Earliest possible	CMP213 Boundaries Reinforced	CMP213 Cost (£m, real 2012)	CMP213 Earliest Date
Beauly-Denny overhead line	B1, B2, B4	-	Pre-committed (2014)	B1, B2, B4,	618	Pre-committed (2015)
400kV Ring Kintore Reactive Compensation	B1, B2, B4	-	Not modelled	Not modelled - assume contributes to existing boundary capacities		
Denny-Kincardine 400kV	B4	-	Not modelled	Not modelled		
East Coast (Kincardine - Harburn) 400kV	Not modelled			B5,	129	2018
Western HVDC Link	B6, B7a	866	2015	B6, B7a,	1082	Pre-committed (2016)
Anglo-Scottish Series & Shunt Compensation	B5,B6	380	Pre-committed (2014)	B6, B11,	391	Pre-committed (2015)
Eastern HVDC Link	B2, B4, B5, B6, B7a	891	2018	B2, B4, B6, B7a,	1442	2018
Penwortham QBs	B7a	31	Pre-committed (2014)	B7a,	31	Pre-committed (2014)
New Hinkley Point - Seabank OHL and associated works	B13	628	2019	B10, B13,	647	2018
Reconductoring circuits in East Anglia	EC5	93	2015	EC5,	95	2019
New OHL & reconductoring work in East Anglia	EC5	263	2017	EC5,	270	2019
QBs in East Anglia	EC5	41	2015	EC5,	42	2021
Establish 2nd Pentir-Traw 400kv circuit	NW2	185	Pre-committed (2016)	NW2,	191	2018

Reinforcement package	TransmiT			CMP213		
	Boundaries reinforced	Cost (£m real 2011)	Earliest possible	Boundaries Reinforced	Cost (£m, real 2012)	Earliest Date
Series compensation and reconductoring work in North Wales	NW2	103	2016	NW2,	106	2016
Wylfa-Pembroke 2GW HVDC link	B202,NW2	834	2018	B8, B9, B12, B17, B202, NW2,	834	2018
Daines 225MVAR MSC DNs	B8,B9	5	Pre-committed (2014)	B8, B9,	5	Pre-committed (2014)
Sundon and Ratcliffe 225MVAR MSCs	B8,B9	10	2015	B8, B9,	11	Pre-committed (2015)
North London Reinforcements & St John's Wood - Hackney cable	B14	474	Pre-committed (2016)	B14, B15,	488	Pre-committed (2016)
Turn in Sundon - Cowley circuit at East Claydon	B8,B9, B14	52	2019	B8, B9, B12, B14,	53	2017
North East London uprate to 400kV	B15	88	2019	B14, B15,	90	2019
East London reinforcements	B15	31	Pre-committed (2014)	B15,	32	2014
East London reconductoring	B15	72	2016	B15,	74	2016
Kingsnorth-Cobham reconductoring	B15	21	2016	B15, EC5,	21	2016
South London reconductoring	B15	77	2015	B15,	80	2016
Essex reconductoring	B15	36	2015	B15,	37	2016
Tees Crossing refurbishment	B7a	52	Pre-committed (2012)	Not modelled - assume contributes to existing boundary capacities		
QBs in Sundon-Wymondley circuits	B14	31	2015	B14,	32	Pre-committed (2015)

	TransmiT			CMP213		
Reinforcement package	**Boundaries reinforced**	**Cost (£m real 2011)**	**Earliest possible**	**Boundaries Reinforced**	**Cost (£m, real 2012)**	**Earliest Date**
London MSCs, East End reconductoring	B14	46	Pre-committed (2015)	B14,	48	Pre-committed (2015)
New reactor at Rayleigh	B15	36	2015	B15,	37	2016
Kemsley QBs	B15	31	Pre-committed (2012)	Not modelled - assume contributes to existing boundary capacities		
Rowdown, Canterbury, Sellinge and Dungeness reinforcements	B15	118	2019	B15,	122	2019
Iver, East Claydon, Grendon&Elstree new MSCs	B8,B9	31	Pre-committed (2015)	B8, B9,	32	Pre-committed (2015)
Cottam - West Burton reconductoring	B8	5	Pre-committed (2014)	B8,	5	Pre-committed (2014)
West Weybridge 275kV additional MSC	B9,B14	5	2017	B9, B14,	5	2017
Knocknagael	B1	43	Pre-committed (2011)	Not modelled - assume contributes to existing boundary capacities		
Beauly-Blackhillock-Kintore	B1	88	Pre-committed (2014)	B1,	91	Pre-committed (2014)
Hunterston-Kintyre link	B3, B4, B5	130	2018	B3,	213	Pre-committed (2015)
East Coast Upgrade	B2, B4, B5, B6	272	2015	B2, B4, B5,	402	2017
Humber - Walpole HVDC	B8, B9, B11	595	2020	B8, B9, B11,	613	2020
Caithness - Moray HVDC	B1	800	2017	B1,	1061	2018
Eastern HVDC Link #2	B6	891	2020	B6, B7a,	769	2019
Western HVDC Link #2	B6, B7a	866	2020	B6, B7a,	1082	2020

Reinforcement package	TransmiT			CMP213		
	Boundaries reinforced	Cost (£m real 2011)	Earliest possible	Boundaries Reinforced	Cost (£m, real 2012)	Earliest Date
Elstree London	B14	100	2020	Not modelled - assume contributes to existing boundary capacities		
West Midlands MSC	B17	50	2015	B17	50	Pre-committed (2022)
B1	B1	73	2021	B1,	75	2021
B2	B2	73	2021	B2,	75	2021
B3	B3	110	2021	B3,	113	2021
B4	B4	98	2021	B4,	100	2021
B5	B5	98	2021	B5,	100	2021
B6	B6	146	2021	B6,	150	2021
B7a	B7a	166	2021	B7a,	171	2021
B8	B8	117	2021	B8,	121	2021
B9	B9	234	2021	B9,	241	2021
B10	B10	15	2021	B10,	15	2021
B11	B11	200	2021	B11,	206	2021
B12	B12	24	2021	B12,	25	2021
B13	B13	332	2021	B13,	342	2021
B14	B14	50	2021	B14,	52	2021
B15	B15	7	2021	B15,	8	2021
B16	B16	29	2021	B16,	30	2021
B17	B17	100	2021	B17,	103	2021
B201	B201	50	2021	B201,	52	2021
B202	B202	7	2021	B202,	8	2021
EC5	EC5	24	2021	EC5,	25	2021
NW2	NW2	49	2021	NW2,	50	2021

The costs for HVDC bootstraps, which are relevant both for transmission reinforcement and for transport model expansion factor calculations, have been sourced from 2011 Offshore Development Information Statement[20], inflated to 2012 prices. The cable cost components were increased from the ODIS values after discussions with the relevant TOs, to reflect their feedback on the current market pricing for HVDC cable.

[20] http://www.nationalgrid.com/NR/rdonlyres/8C387FB2-DB94-4CE7-881A-749008F7E047/49513/2011_ODIS_EntireChapters_Protected.pdf

Table 8 HVDC bootstrap costs

Component	Rating (GW)	Cost (£m)
DC Cable	2 GW	£1.3m/km
DC Cable	1 GW	£1.1m/km
DC Cable	0.5 GW	£0.9m/km
Onshore Converter Station (per station)	2 GW	£130m
Onshore Converter Station (per station)	1 GW	£115m

2.1.9 Island subsea links

The TransmiT modelling used Redpoint estimates of the local island link circuit tariffs, based on capital cost and capacity figures from SHETL public RIIO business plan. The tariffs shown in Table 9 represent only the additional tariff relating to the island link and is in addition to the tariff for the mainland zone to which the island groups connect: TNUoS zone 1 (North Scotland) for Orkney and Western Isles, TNUoS Zone 2 (Peterhead) for Shetland.

Table 9 Island wind: transmission costs (TransmiT)

Site	Capital expenditure (£m)	Capacity (MW)	Security factor		Final Island tariff (£/kW/yr)	
			Status Quo	Improved ICRP	Status Quo	Improved ICRP
Orkney	125	180	1.8	1.0	94	52
Shetland	450	600	1.0	1.0	57	57
Western Isles[21]	400	450	1.8	1.0	121	67

For CMP213, the costs were recalculated using information provided by SHE-T and are replicated in Volume 2, Annex 17 of the CMP213 Code Administrator Consultation[22]. The specific link costs shown include the full HVDC converter costs. The costs for Orkney are

[21] We note that SHE-T has recently withdrawn the application for funding for the planned Western Isles HVDC cable. This occurred after the modelling assumptions had been agreed.

[22] http://www.nationalgrid.com/NR/rdonlyres/F56663B3-F29B-43F9-86C0-3630F98C12AA/60494/Volume2v10.pdf

based on an HVDC connection rather than an AC connection. The increase in Western HVDC and Orkney HVDC costs (to a lesser extent) decrease the competitiveness of island wind, all other things being equal.

Under the 50% HVDC converter cost option, the specific link costs are reduced, resulting in the tariffs as shown below in Table 10. Note that the Status Quo policy option differs from TransmiT in that it uses a security factor of 1 for all islands. This recognises the fact that there current charging methodology does not deal specifically with island charging, and focuses the modelling on the impacts of different sharing options on the wider network.

Table 10 Island wind: transmission costs (CMP213, all modelled options)

Site	Capital expenditure (£m)	Capacity (MW)	Security factor	Final Island tariff (£/kW/yr)	
			All options	100% HVDC converter costs	50% HVDC converter costs
Orkney	428	600	1.0	54	39
Shetland	560	600	1.0	71	64
Western Isles	606	450	1.0	101	82

In our opinion the changes to the island costs to use the most recent values available is appropriate.

2.1.10 Allowed Transmission Revenues

For Project TransmiT, the base TO revenues relating to non-load related investment were estimated based on initial RIIO proposals and publically available data. This forms a baseline for the model. The model calculates an additional load related revenue element from the transmission investment that results from the transmission decision element of the model.

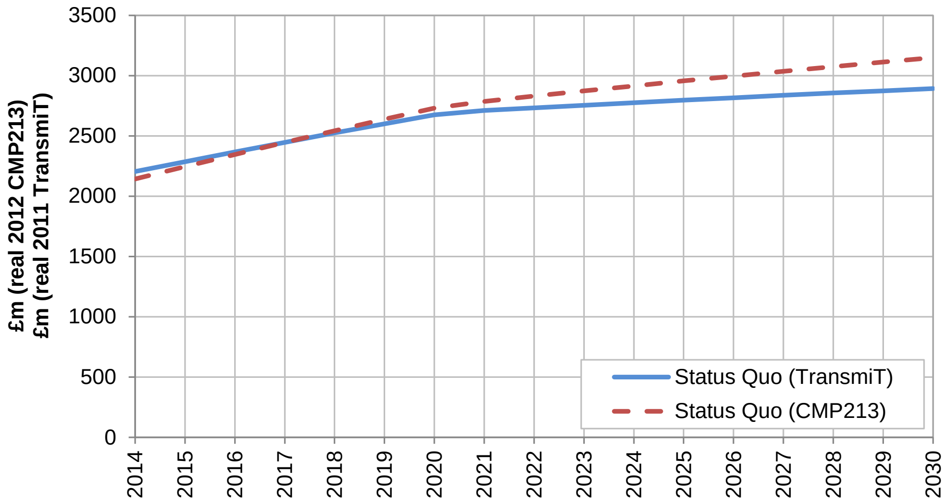
For CMP213, base TO revenues relating to non-load related investment have been calculated in line with the final RIIO proposals[23] [24], and have been projected forwards beyond the end of the forthcoming price control period out to 2030/31.The Base Maximum Allowed Revenue (MAR) values are show in Figure 3, and are somewhat higher for CMP213 after 2020, due to the cumulative effect of the extrapolation of a slightly higher level of non-load related capex in the RIIO-T1 period. This will have the impact of slightly increasing both generation and demand tariffs.

[23] Final RIIO-T1 proposals for SP Transmission Ltd and Scottish Hydro Electric Transmission Ltd (http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=190&refer=Networks/Trans/PriceControls/RIIO-T1/ConRes)

[24] Final RIIO-T1 proposals for NGET (http://www.ofgem.gov.uk/Networks/Trans/PriceControls/RIIO-T1/ConRes/Documents1/1_RIIOT1_FP_overview_dec12.pdf)

In our opinion the updates to the Transport & Tariff model assumptions are reasonable and will have limited impact on the overall results.

Figure 3 Base MAR under TransmiT Status Quo versus CMP213 Status Quo



The related financing and rate of return assumptions have been updated in line with the final proposals.

2.1.11 Transport & Tariff Model Assumptions

Whilst the model has not been updated to use the latest 2013/14 generation TNUoS zones, other Transport & Tariff Model data, including the expansion constant and expansion factors have been updated to represent the values used in the calculation of final TNUoS tariffs for 2013/14[25]. To maintain a 2012/13 price base for the modelling, the expansion constant was converted to 2012/13 prices, by deflating the 2013/14 by RPI. The transmission network within the Transport and Tariff models is based on 2012/13 data updated with changes for 2013/14 and 2014/15, with account taken of HVDC bootstraps.

The onshore network data used for the TransmiT SCR model was identical to that used by National Grid to produce their 2010-11 5-year forecast of TNUoS tariffs information paper published in January 2011[26], which covered the period 2011-12 to 2015-16. As an analysis to prepare an updated 5-year forecast for the 2012-13 report was underway when National Grid commenced its CMP213 modelling, the view of the network data was updated as follows:

- 2011-12 data matched that used in the calculation of actual 2011-12 tariffs;
- 2012-13 data matched that used in the calculation of actual 2012-13 tariffs;
- 2013-14 data matched that used in the calculation of actual 2013-14 tariffs);

[25]Section 3.3.1, http://www.nationalgrid.com/NR/rdonlyres/E1CC114B-4815-447D-BDE9-39D2FC31D08B/58728/FinalTNUoSTariffsin13_14.pdf

[26]https://www.nationalgrid.com/NR/rdonlyres/1DB70FA2-D218-4E6E-BA7D-0714A6B5A1E3/45139/201011Forecastoflongtermtariffs.pdf

- 2014-15 data matched that used in the calculation of forecast TNUoS tariffs published in April 2013);
- 2015-16 data (and beyond) is the same as that used for 2014-15, as the transport model data had yet to be confirmed when the CMP213 analysis was undertaken).

The transmission investment that had the most noticeable effect on tariffs in the previous 5-year forecast analysis was the Beauly-Denny 400kV reinforcement (modelled in 2013-14, having up to a £2.80/kW decreasing effect on generation tariffs in Northern Scotland). This reinforcement has now been delayed to 2015-16, which is beyond the period for which network data was used for the modelling. This means that the effect due to this reinforcement on the locational tariff elements that was observed in the TransmiT SCR modelling results is not present in the recent analysis. However, it is worth noting that in the previous analysis the reinforcement had been modelled as 100% 400kV overhead line, and, following changes to the circuit route design resulting from the governmental planning decision since the 2010-11, a proportion of the circuit will now be built as more expensive 400kV underground cable. As a result, the originally observed decreasing effect on tariffs would diminish if based on the latest plans.

In our opinion the updates to the Transport & Tariff model assumptions are reasonable given the partial information available at the time of the update.

2.1.12 G:D split

Unlike the previous analysis undertaken for Project TransmiT, a Generation:Demand revenue recovery split of 27:73 has been assumed throughout the modelling.

The Transmit modelling assumed a change in the G:D split to 15:85 in 2015. This was an assumption based on advice from National Grid on the change required in order to be consistent with potential future EU tariffication guidelines and its review was within scope of the TransmiT SCR. The conclusions of the TransmiT SCR were that it was not necessary to change the G:D split, although National Grid has been directed to keep under review.

In our opinion the change to the G:D split assumption is reasonable, for the reasons given above. It will have a significant impact on both generation and demand tariffs.

2.2 Summary of input assumption changes

We have reviewed the changes to modelling assumptions and functionality for the CMP213 modelling. We are of the opinion that these changes are reasonable. The updates to the assumptions use updated versions of the same sources except for:

- Commodity price assumptions: DECC values used rather than Redpoint assumptions. We are of the opinion that the use of DECC assumptions is equally valid. Furthermore they are well recognised by stakeholders and are similar in overall level to the TransmiT assumptions;
- G:D split: maintained at 27:73 based on Ofgem's direction not to consider changes to the G:D split;
- A specific target for nuclear generation in 2030 of 14 GW based on a Workgroup decision.

Of the changes to the assumptions and functionality, the most significant are:

- The increase in the total available offshore wind capacity by 2020 to reflect the latest National Grid 2012 Accelerated Growth scenario, which makes ambitious assumptions in terms of total possible offshore wind deployment (33 GW by 2020);
- The increase in total nuclear capacity in (and beyond) 2030, due to increase in nuclear life expectancies.

3 Functional changes review

In this section we review the changes made to model functionality for the CMP213 modelling, and the likely impact of these changes.

3.1 Changes to the Transport& Tariff model

3.1.1 Changes to all transport models: HVDC bootstraps

The Transport and Tariff Model relies on the fact that the electrical properties of the transmission system (specifically, the impedance) determine the power flows on the system. The flow of power on HVDC bootstraps is controllable, and therefore a methodology must be defined to calculate a value for the impedance to use in the Transport Model.

The approach developed by the TransmiT workgroup was to set the impedance of the HVDC bootstrap so that the ratio of flows on the bootstrap to the flows onshore is in proportion to the capacity of the offshore and onshore transmission lines. This calculation is complicated by the fact that HVDC bootstraps often cross multiple boundaries, and there may be two bootstraps in parallel.

For Project TransmiT, the implementation of this approach into the model was based on a static view of boundary capacities – a relatively simple approach given the time available. For CMP213, the implementation has been further developed to better reflect the changing parameters of the system. This includes an iterative approach, to deal with the situation when the impedance set for one bootstrap changes the flows on another.

The revised approach is more robust to the impact of multiple bootstraps. However the change does not appear to have a significant impact on modelling results, in part because the number of bootstraps built under CMP213 is limited to two (Table 15 on page 58 and Table 22 on page 83).

3.1.2 Diversity options

Following the work of the CMP213 Workgroup, three possible methods were devised in order to address the diversity issues within the TNUoS charging methodology[27]. These options are summarised in Table 11, with further detail of the modelled and non-modelled variants in Appendix A.

The three Diversity options are each based on the concept of the 'sharing' of transmission capacity by different types of generation (Carbon emitting and low carbon), as a method for calculating the application of annual load factor to the capacity (TEC) used in the calculation of the Year Round elements of the tariff.

[27]Section 3.3.1, http://www.nationalgrid.com/NR/rdonlyres/E4113B9D-FE0A-4312-9DD5-E5DC1044FD89/60493/Volume1v10.pdf

1) Diversity 1 – Year Round shared/not shared split based on low carbon/carbon generation ratio: under this approach sharing occurs until the volume of low carbon generation exceeds 50% behind a transmission boundary. Beyond this point the sharing benefit is gradually reduced.
2) Diversity 2 – Year Round shared/not shared split based on percentage minimum of low carbon or carbon generation to total: under this potential alternative, maximum sharing (50%) occurs when there are equal proportions of low carbon and carbon plant behind a boundary. With either more or less carbon (or low carbon) sharing reduces. The benefit is specific to an individual generator based on its own annual load factor.
3) Diversity 3 – Single background shared/not shared split based on percentage minimum of low carbon generation to total: under this approach maximum sharing (50%) occurs when there are equal proportions of low carbon and carbon plant behind a boundary. The benefit is applied equally to all generators behind a boundary via a single part locational tariff with no account being taken of a generator's individual annual load factor.

The main distinguishing factors between the methods developed include whether or not a two background approach is utilised as the starting point of the calculation and what proportion of MWkms are allocated as shared behind a transmission boundary. This approach would then either lead to a two part (Peak Security + Year Round) or three part (Peak Security + Year Round Shared + Year Round Not-Shared) wider locational element of the TNUoS tariff for generators. Finally, the methods distinguish further whether a generator specific sharing factor would apply to the shared elements or whether a zonal average sharing factor would be applied. In Diversity 3, only one part wider locational element is employed i.e. just Year Round.

The diversity options are further discussed in the overall review of the modelled and non-modelled variants in Appendix A.

Table 11 Alternative options considered for addressing low carbon and carbon generation plant type diversity issues

	Original	Diversity 1	Diversity 2	Diversity 3
Dual background	Yes	Yes	Yes	No
How sharing is applied	Sharing on Year Round background only	Sharing on Year Round background only	Sharing on Year Round background only	Sharing applied to all (only Year Round background)
Wider locational tariff components	2 (Year Round & Peak Security)	3 (Year Round shared, Year Round non-shared, Peak Security)	3 (Year Round shared, Year Round non-shared, Peak Security)	1 (Year Round)
MITS sharing	All Year Round incremental costs	Year Round split into shared / not shared	Year Round split into shared / not shared	All incremental costs with zonal sharing factors
Sharing method	Load factor on all MWkm	Load factor on shared MWkm, capacity on not-shared, effective max sharing 100%	Load factor on shared MWkm, capacity on not-shared, effective max sharing 50%	Effective MWkm = not shared/total; i.e. 10% shared → charging is on 90% effective, max sharing 50%.
Application of generator specific sharing factor	Yes	Yes; to shared element	Yes; to shared element	No
Diversity calculation	None	Based on deterministic relationship between low carbon / carbon ratio. All MWkm shared at 0% to 50%; sharing reduces from 50% to 100% low carbon.	Based on minimum of low carbon / carbon generation behind a boundary	Based on minimum of low carbon / carbon generation behind a boundary

	Original	Diversity 1	Diversity 2	Diversity 3
Method for split of Incremental Costs	None	Zonal boundary length using transmission boundaries of influence	Zonal boundary length using transmission boundaries of influence	Zonal boundary length using transmission boundaries of influence

3.2 Other modelling changes

A range of enhancements were made to the modelling suite. These are described in the following sections.

3.2.1 Capacity mechanism modelling

For the Project Transmit modelling, the Capacity Mechanism was assumed to be operational from the start of the modelling period. It was modelled as a simple capacity auction in which existing and new plant (excluding those supported under the Renewables Obligation (RO) or under CfDs) bid in the additional revenue (if any) that they require to stay open (in the case of existing plant) or commit to new build (for new plant). In each year the auction results in a capacity payment value set by the price of the marginal capacity to reach the security standard. All eligible existing and new plant receive this value, based on their de-rated availability. Further details can be found in our Project TransmiT report.

For the CMP213 modelling, the Capacity Mechanism functionality was revised to more closely match the options presented in the Energy Bill 2012[28].

The first change was to add a start date for the Capacity Mechanism. The modelling assumes that the first payments are made in 2018. Note that new plant have a 5 year forward view of revenues and so are aware of expected capacity payment levels from 2013 onwards.

The second change is new generators (that are not supported under the RO or CfDs) receive a multi-year contract. The Energy Bill assumes that this will be for up to ten years; however the updated modelling assumes that this lasts until the end of the modelling horizon (I.e. a maximum of 12 years from 2018 to 2030). In following years, the derated capacity of new CCGTs is excluded from bidding in the auction, and subtracted from the total capacity requirement.

Both changes have the effect of reducing capacity margins, and reducing the amount paid by consumers in capacity payments. The overall impact is to reduce average capacity margins, as shown for Status Quo in Figure 35 and Figure 36. In our view the

[28] The updated modelling was completed before the publication of further Capacity Mechanism details by DECC in June 2013.

changes are appropriate as they more closely replicate the Capacity Mechanism as described in the Energy Bill documents.

3.2.2 Revised transmission cost calculation

The calculation of the capex of modelled transmission reinforcements is an input to the Cost Benefit Analysis (CBA). Under Project TransmiT, the CBA results were originally presented using a forward view of the transmission costs rather than the final ex-post values. In an Addendum[29] to the report, we presented the results on an ex-post basis and these are the values quoted in this report.

For CMP213, the model has been updated so that final transmission values are used automatically and the model is therefore consistent with the final Project TransmiT modelling.

3.2.3 Revised generation capital cost calculation

The calculation of the capex of modelled generation investments is an input to the Cost Benefit Analysis. For the purposes of the CBA, the capital spent recognised across the economic life of each asset, by annuitizing the capital across this period. For Project TransmiT, the annuitised capital cost was based on the prevailing capital cost in that year, rather than tracking the historic costs that applied when different plant were built. The CBA calculation has been changed to use these 'vintaged' costs. This is a more accurate approach and therefore a reasonable change to the modelling. The impact between different policy options is unlikely to be significant because all the options deploy broadly similar generation mixes.

3.2.4 Revised offshore wind depth to cost relationship

For Project TransmiT, the impact of depth on offshore wind costs was approximated through a capital cost reduction adder depending on whether the depth of the water at location of the offshore wind project is shallower / deeper than 50m. This reflected in a simple way the higher cost of deeper foundations.

For CMP213, this function has been revised to be a more accurate reflection of the impact of depth on foundation costs. The result is that offshore wind capital costs are more sensitive to depth, and shallower projects are relatively cheaper. This change does not clearly manifest in differences in results between transmission charging options.

3.2.5 Usability changes

In addition to the changes above, a set of changes were made to make the modelling suite easier to use, by streamlining and rationalising certain elements. These changes included:

- Rationalisation of model links;
- Removing unused buttons and functionality;

[29] http://www.ofgem.gov.uk/Networks/Trans/PT/Documents1/Addendum%20-%20Modelling%20the%20impact%20of%20transmission%20charging%20options.pdf

- Reviewing and updating model progress messages;
- Adding additional error handling;
- Rationalisation of key input data tables;
- Rationalisation of data transfer between model components;
- Further automation of outputs generation.

These changes do not impact on the model results.

3.3 Summary

In our view the modelling changes described above are justifiable. The changes to the Capacity Mechanism have a significant impact on capacity margins, which are typically around 10% lower in the period 2018-2030 as shown in Figure 35 and Figure 36. The impact appears to be consistent across transmission charging options.

The changes to transmission and generation cost calculations do not affect the generation and transmission decisions but do affect the overall level of reported costs. The impact appears to be consistent across transmission charging options.

4 Results review

In this section we compare the Status Quo model runs from the TransmiT and CMP213 modelling, before analysing the results for the CMP213 Original and Alternative policy variants.

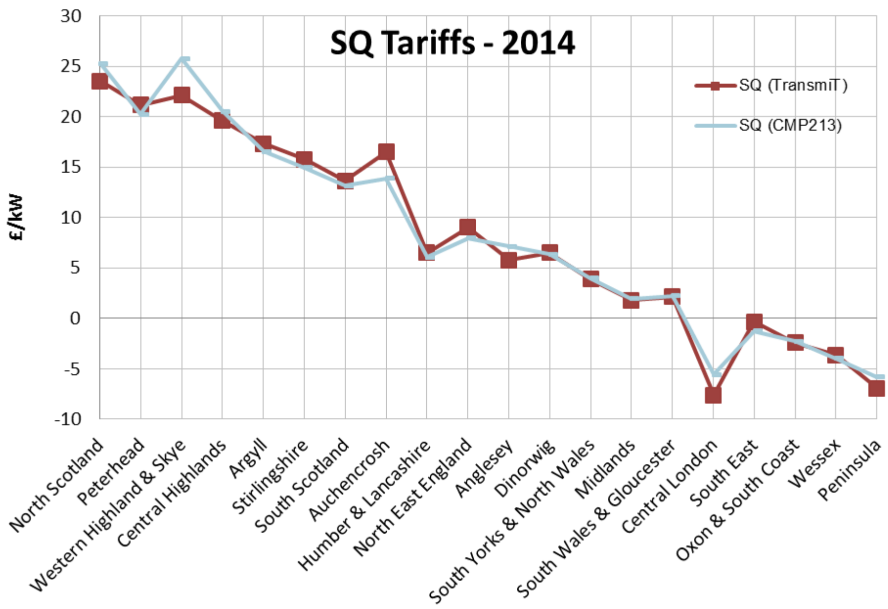
4.1 Comparison to Project TransmiT results: Status Quo

The modelling and assumption changes are the cause of a number of differences in the CMP213 results from the TransmiT results. These changes are common across the policy variants. In the following sections we compare the Status Quo model runs from Project TransmiT and the CMP213 analysis, and indicate which functionality and assumption changes drive these differences. We follow the structure of the results section for our report for Project TransmiT.

4.1.1 Impact on transmission charges

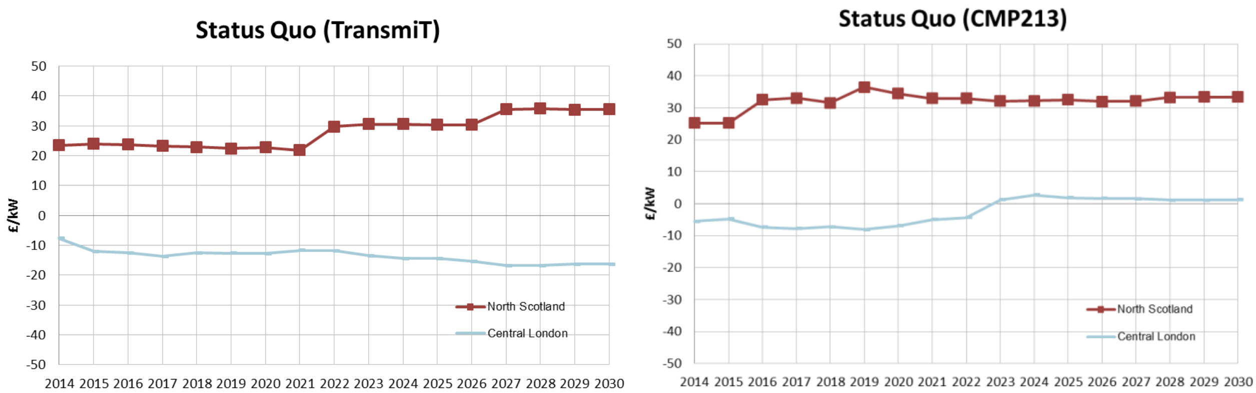
As expected, transmission charges for 2014 are very similar between the two model runs since the generation background changes are also minimal as explained in Section 2.1.4. There are, however, some differences in the tariffs for some zones as can be seen in Figure 4 and these are largely due to differences in retirement decisions with an additional 1.6 GW of gas plant (in North Scotland, South England and South Wales and North England) and 1.6 GW of coal plant (in North England and South England and South Wales) retiring by 2014 under the CMP213 Status Quo run. On the other hand, there is also considerably more offshore wind capacity (roughly 2.4 GW more) as well as new-build CCGT capacity (2.4 GW more) which is mostly developed in Midlands & North Wales and Northern England.

Figure 4 Status Quo generation tariffs - 2014



In the longer term, however, results show significant differences in transmission tariffs, as shown in Figure 5 for the North Scotland and Central London zones.

Figure 5 Status Quo generation tariffs –Selected zones



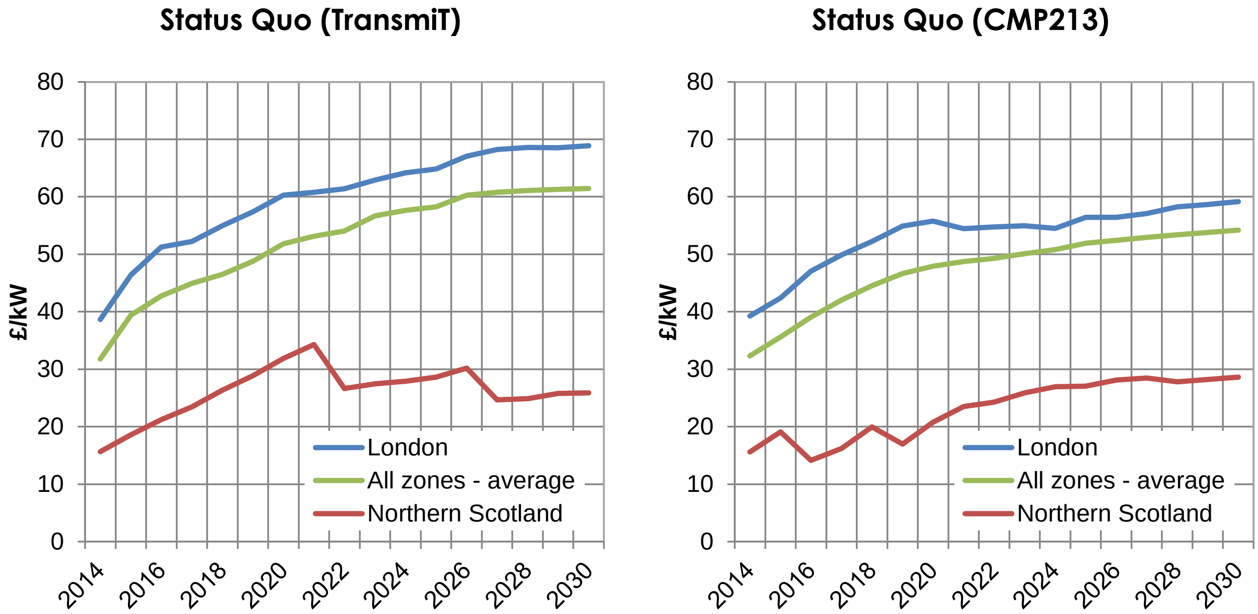
In the CMP213 modelling, the step change in tariffs in 2016 for North Scotland is due to the commissioning of the Western HVDC bootstrap, which is assumed to be a committed reinforcement. In the TransmiT modelling, this occurs one year earlier in 2015. However the expected increase in the tariff is almost exactly offset by the switch to a 15:85 G:D split. The CMP213 modelling maintains the G:D split at 27:73, which has the impact of increased tariffs from 2015 onwards, due to a larger residual component to the tariff.

In the TransmiT modelling, the step changes in tariff in 2022 and 2027 are clear. These are due to HVDC bootstraps being commissioned (Eastern HVDC Link #1 and Eastern HVDC Link #2). In the CMP213 modelling, the step change in 2019 is due to the commissioning of the Eastern HVDC Link #2. The Eastern HVDC Link #1 is not built under CMP213, for the reason that the cost assumption has been updated (as discussed in section 2.1.8) and is almost double the TransmiT value. Eastern HVDC Link #2 takes a shorter route and is commensurately cheaper. It reinforces the key boundaries on which constraints are observed (B6 and B7a).

Central London tariffs step down in 2016 and in 2019 in the CMP213 results – as a result of the 2016 commissioning of the Western HVDC and the 2019 commissioning of Eastern HVDC Link #2. In both cases the Scottish tariffs increase and tariffs south of the HVDC link decrease (in order to maintain the same overall revenue recovery). In the longer term, rather than an increasing split in tariffs we observe a closing of the gap across the period 2020-2025. As discussed below, this is due to the increasing nuclear and CCS capacity which is rebalancing generation towards the south – whereas in TransmiT there was continuing growth in onshore wind (particularly in Scotland) to 2030.

Figure 6 compares the highest, lowest and average demand TNUoS for half hourly metered customers under Status Quo for TransmiT to CMP213. Demand tariffs are almost identical in 2014, but higher in 2015 for TransmiT due to the G:D split changing to 15:85. Consistent with the generation tariffs, the gap between the highest and lowest demand tariffs closes over the period 2020-2025 under CMP213.

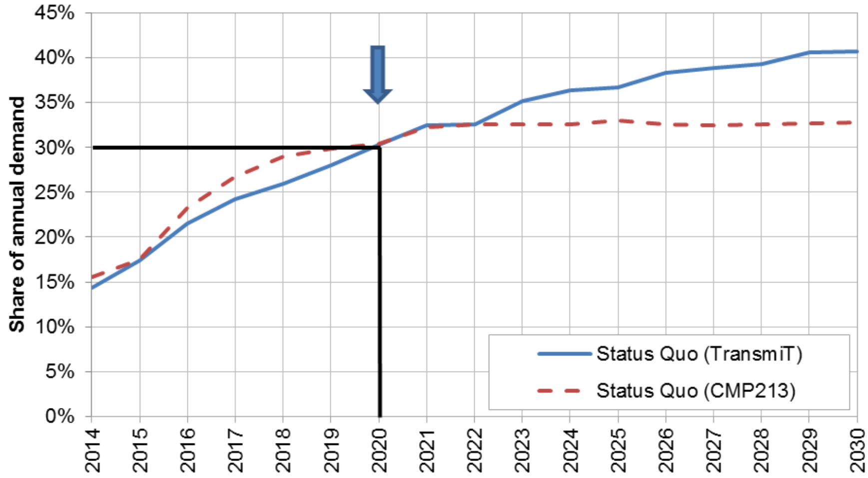
Figure 6 Demand wider TNUoS for half hourly metered customers



4.1.2 Impact on Sustainability goals

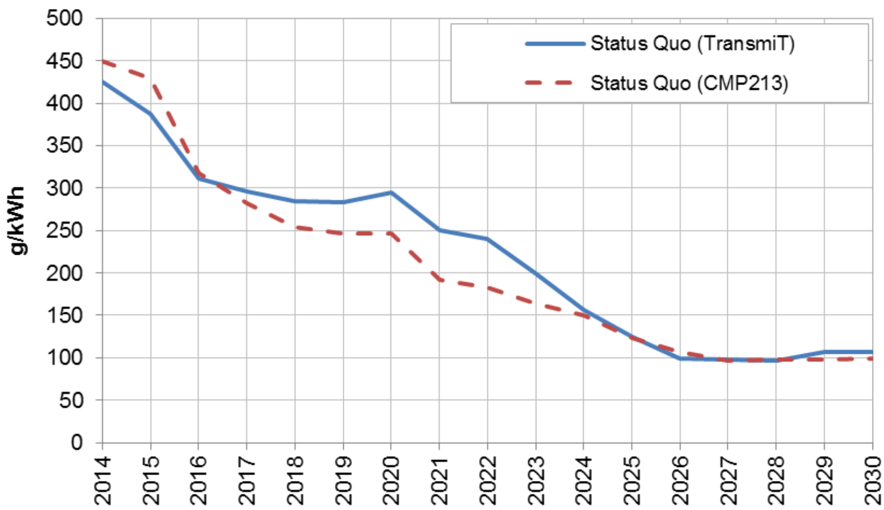
The Stage 2 approach is to set CfDs such that the policy variants meet the same sustainability goals in 2020 and 2030, to allow for comparisons of costs across the variants. The approach is the same in CMP213 and the goals are the same: 30% renewables in 2020 and 100 g/kWh in 2030. Figure 7 and Figure 8 show the total renewables generation as a proportion of annual demand and carbon intensity respectively. It is clear that whist the sustainability goals are met, there are some significant differences between these outputs in other years. In the TransmiT modelling, renewable generation continued to increase after 2020, reaching over 40% of annual demand by 2030, whereas under CMP213 it is broadly flat, only increasing up to 33% by 2030. Less renewable generation is required to meet the 2030 target due to the reduced demand and increased generation from nuclear and CCS.

Figure 7 Status Quo renewables generation (% of annual demand)



Carbon intensity has dropped in 2020, largely due to the nuclear lifetime extensions described in section 2 (resulting in an additional 2.3 GW of nuclear capacity by 2020) but also due to coal plant retiring earlier (resulting in a reduction in coal capacity by about 5 GW by 2020). By 2030 the carbon intensity is the same in the two model runs as shown in Figure 8. However, this carbon intensity is met with a significantly different capacity mix - mainly through increased contribution by nuclear (2 GW more) and CCS (3.4 GW more CCGT with CCS) and reduced contribution by onshore wind (4.4 GW less), offshore wind (5.1 GW less) and marine energy (3 GW less). This is a result of differences in the relative levels of CfD strike prices (shown in Appendix A) for the various low carbon generation technologies.

Figure 8 Status Quo carbon intensity



4.1.3 Overall cost impacts

Capacity mix

Figure 9 shows the new generation build in the two Status Quo models. The first new nuclear station is commissioned in 2020 in the CMP213 modelling, one year later than in the TransmiT modelling, with a similar total of just over 11 GW in 2030 (11.2 GW in the CMP213 modelling compared to 11.6 GW in the TransmiT modelling). The deployment of CCGT with CCS is significantly higher in the new modelling, resulting in an additional CCS capacity of 3.4 GW by 2030.

In 2020, the CMP213 Status Quo has less new onshore wind, with a total of 5.6GW being built compared to 7GW in TransmiT. Conversely, CMP213 Status Quo has more offshore wind with a total of 9.9 GW compared to 7.6GW in TransmiT. One reason for this is the earlier availability of a greater number of offshore wind projects assumed for CMP213 (section 2.1.4).

In the TransmiT modelling, renewables continue to grow after 2020, to around 40% of total generation. Under CMP213, a lower proportion of renewables is required to meet the carbon intensity target, due to the greater deployment of CCS, and nuclear life extensions as previously explained.

The deployment of new CCGT is driven by the Capacity Mechanism and the overall capacity requirement given the capacity of other generation deployed. It is similar across the two Status Quo models, with approximately 12 GW of new CCGT capacity being developed by 2020, and between 19.6 GW (CMP213) to 21.9 GW (TransmiT) by 2030.

Figure 9 Status Quo new build

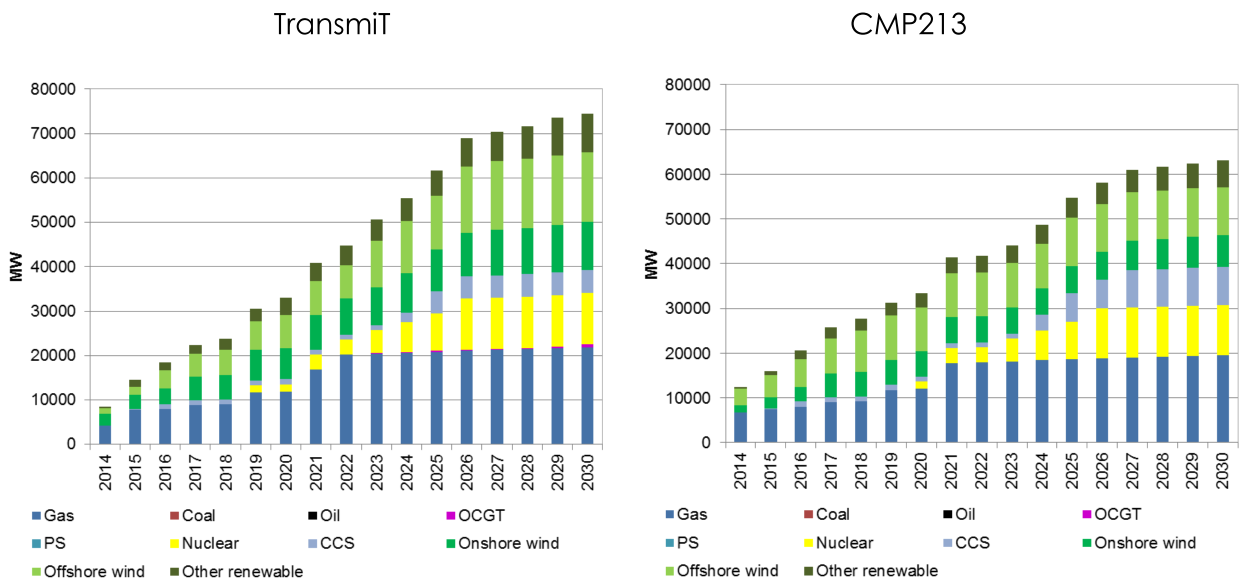
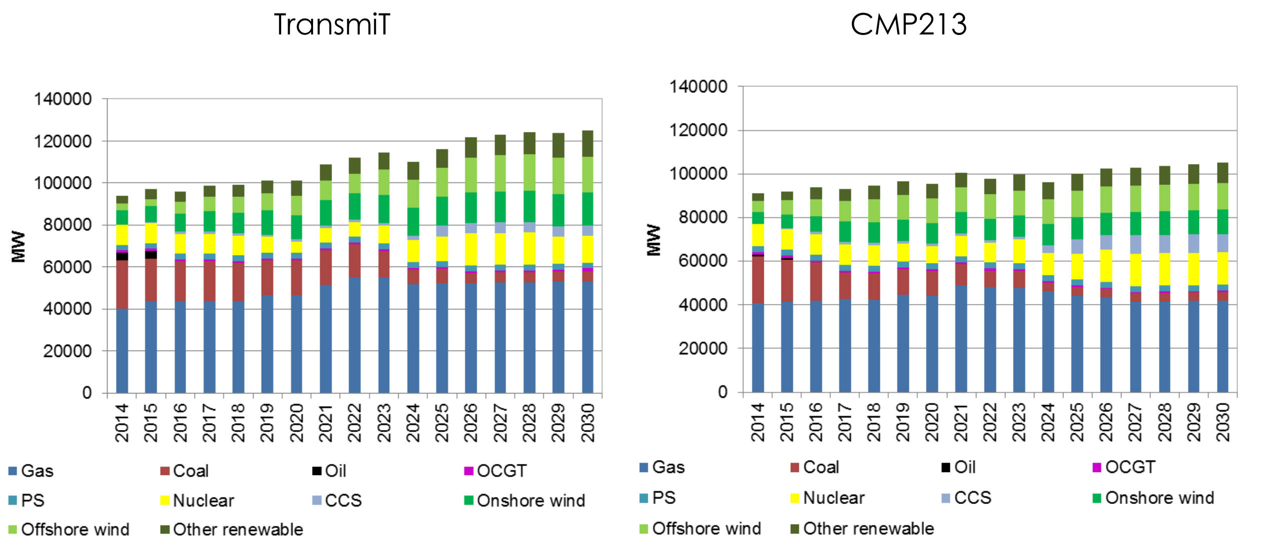


Figure 10 Status Quo generation capacity



These results are consistent with the sustainability targets (as shown in Figure 7 and Figure 8), but represent a different outcome compared to TransmiT modelling, with considerably less generation capacity on the system under CMP213 as Figure 10 shows. From a geographical perspective, a reduction in installed capacity is observed mainly in South England & South Wales (37.7 GW compared to 45.4 GW), in Scotland (11.5 GW compared to 14.4 GW) and offshore (11.8 GW compared to 20.3 GW). This has significant implications for transmission reinforcements and constraint costs as discussed below.

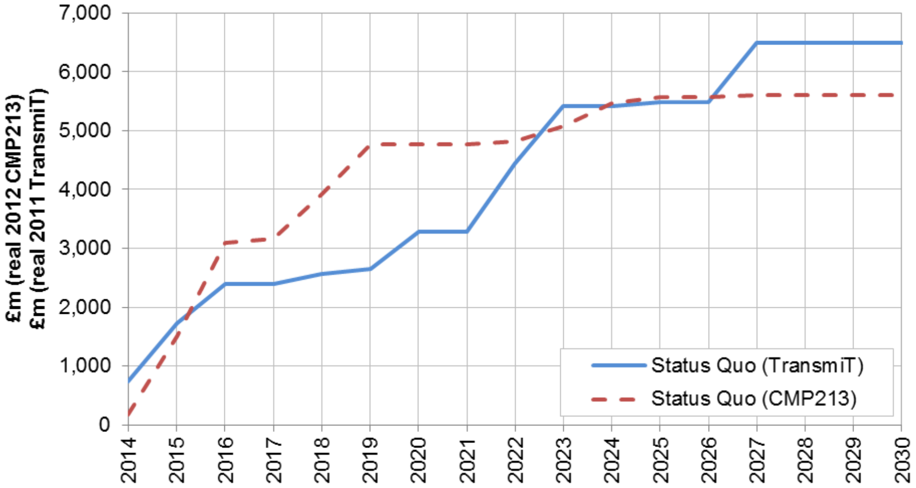
Transmission reinforcement decisions and costs

Figure 11 shows the cumulative costs of modelled reinforcements to the onshore transmission system (Main Interconnected Transmission System, MITS). The two model runs both show significant investment in the 2014 – 2016 period. There is a continuing increase under CMP213 in the 2017 – 2020 period, which is associated with the Eastern HVDC Link #2 reinforcement and also with new Overhead Line between Hinkley Point and Seabank.

Furthermore, it is also worth noting that there is very little transmission investment in the CMP213 results after 2020. This is because the level of onshore wind deployment remains broadly flat after this point (as shown in Figure 7) and as a result the need for onshore transmission reinforcement is reduced.

Under CMP213, a number of reinforcements which have been built or are under construction are not counted towards the transmission reinforcement costs, because these are captured in the baseline boundaries capacities and the baseline Maximum Allowed Revenue.

Figure 11 Modelled reinforcement costs to the Main Interconnected Transmission System



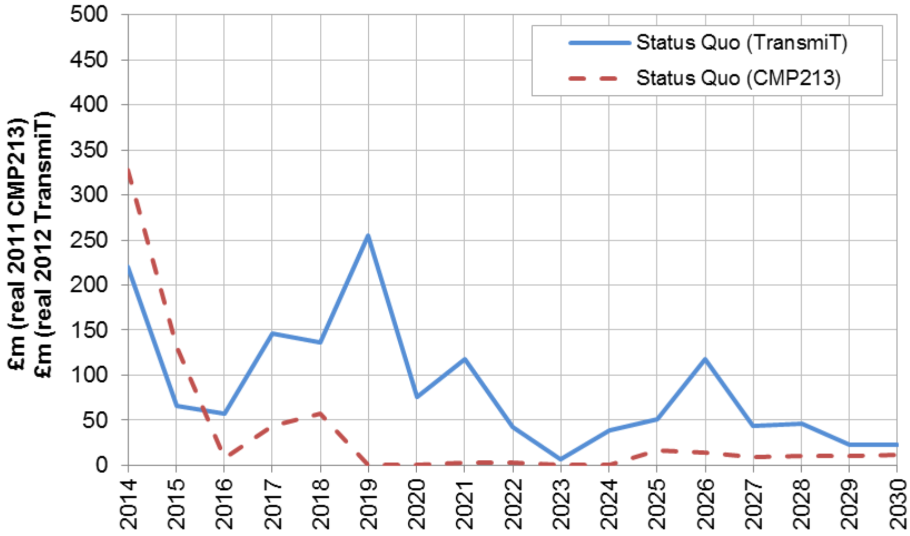
Constraint costs

Figure 12 shows constraint costs for the two Status Quo runs. Constraint costs are higher for CMP213 in 2014 due to a delay in a 1 GW onshore B6 reinforcement from 2014 to 2015 (based on latest information, as described in section 2.1.8). Constraint costs for both models drop with the commissioning of the Western HVDC bootstrap (2015 in TransmiT, 2016 in CMP213). Constraint costs are close to zero after 2019 for Status Quo CMP213. This is related to earlier transmission investment then less growth in renewables and more nuclear and CCS in England & Wales relative to TransmiT.

A large proportion of the post 2020 on-going constraint costs in the TransmiT SQ run are due to constraints on the England-Scotland boundary (B6, Cheviot). Under CMP213, these costs are reinforced away by the Eastern HVDC Link #2. After 2019, the unconstrained flows over B6 and B7a (Northern England) actually reduce. There is little growth in Scottish onshore wind after 2020, and 2.4 GW of North England nuclear plant closes in 2019. Further constraints do not manifest themselves and as a result constraint costs are close to zero from 2019 onwards. This result is consistent with the scenario of lumpy transmission investment capacity and a stable renewables penetration level, as described below.

There is significant spare boundary capacity on B6 once Eastern HVDC Link #2 is commissioned. This is a feature of the lumpiness of transmission investment decisions. The annuitized reinforcement cost for the 2 GW Eastern HVDC Link #2 is lower than the expected constraint costs. However if a lower capacity option (e.g. 1 GW) were available, this would be a more efficient choice. A consequence of this is that there is significant spare capacity on the boundaries that are reinforced. This is an important driver of differences in results seen in later sections.

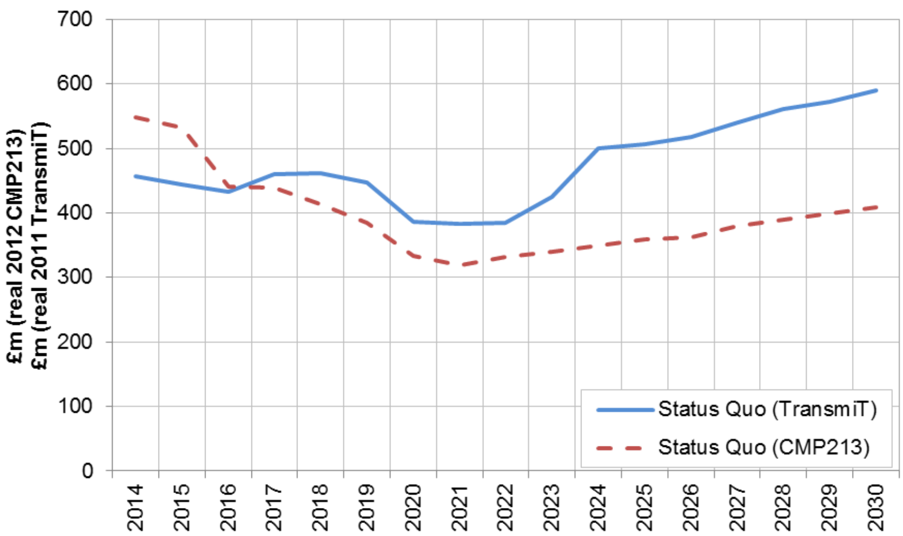
Figure 12 Status Quo constraint costs



Transmission losses

Figure 13 shows the transmission losses in the TransmiT and CMP213 Status Quo model runs. The peak in transmission losses in 2014 and 2015 under the CMP213 modelling appears to be due higher north to south flows over this period resulting in a higher loading on existing transmission lines. In the longer run, however, the higher renewables deployment under the TransmiT modelling also leads to higher North-South flows and therefore higher transmission losses.

Figure 13 Status Quo transmission losses



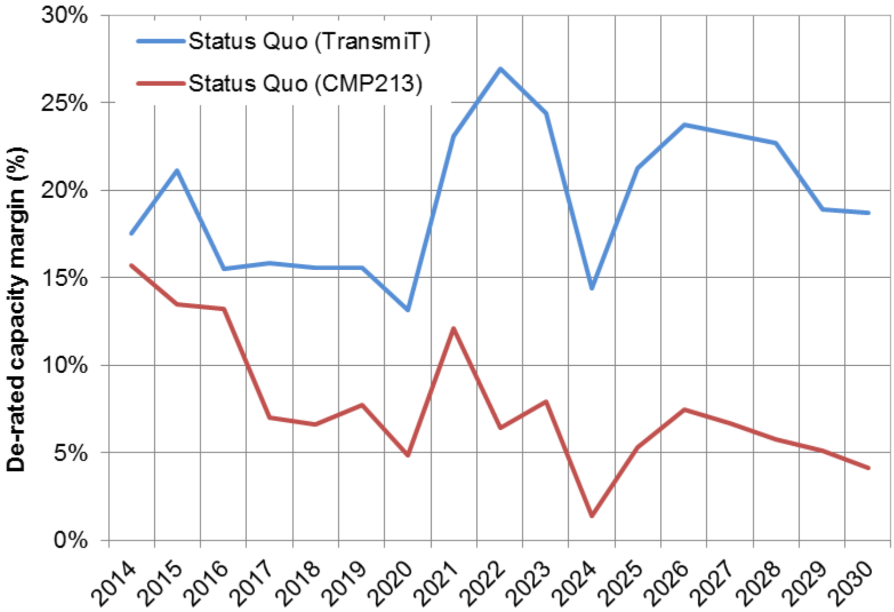
4.1.4 Impacts on security of supply

Figure 14 shows the de-rated capacity margins for the two model runs. The near term difference of lower margins from 2014 onwards is due to changes to the announced retirements, with a significant capacity closing in 2013. The lower margins throughout the period are as a result of changes to the Capacity Mechanism. Firstly, the mechanism does not start until 2018. Secondly, the capacity of new CCGTs is removed from the requirement, which has the outcome of typically lower Capacity Mechanism prices and leading to a lower total level of capacity. The lower level of total capacity increase wholesale prices and hence consumer bills increase.

The Capacity Mechanism is a major driver of capacity margins. However, outturn capacity margins are also affected by the profile of regulated closures (LCPD opt out, nuclear closures, impact of Industrial Emissions Directive on coal and gas plant) as well as the new build under the RO or CfDs. These capacity changes (which are unaffected by the capacity mechanism) create capacity shocks which are not completely smoothed out by the simple capacity mechanism assumed in the modelling approach. For example, coal plant which have taken derogations under the Industrial Emissions Directive are required to retire at the end of 2019 (under The Transitional National Plan) or in 2023 (under the Limited Lifetime Obligation). The impact in terms of short term reductions in capacity margins is clear in both the TransmiT and CMP213 modelling. The build of new generation incentivised by the capacity mechanism is limited by build constraints and available of projects.

The reduction in capacity margin has a major impact on costs to consumers. Capacity payments are lower, but wholesale prices are generally higher (for the same underlying fuel and carbon costs).

Figure 14 Status Quo de-rated capacity margins[30]



It is not appropriate to compare CBA results between the two Status Quo models. The CBA is designed to show the relative impact of policy changes on power sector costs and consumer bills. In this case the two models are for the same policy option, but with different underlying cost due to the assumptions updates that have been made. These include major cost drivers such as:

- Commodity prices;
- Demand;
- Transmission costs;
- Real 2012 terms compared to real 2011.

The CBA is dominated by the changes in these assumptions. For example the lower gas price under the CMP213 modelling increase power sector costs – but this provides no useful information about the transmission charging option itself.

4.1.5 Summary

There are significant changes in the CMP213 results compared to the TransmiT modelling, which are the direct result of the changes to the input assumptions and functionality described above. In particular, the increase in offshore wind capacity in 2020 and in nuclear and CCS capacity in 2030 is significant, as it reduces the requirement for onshore wind build. This in turn reduces constraint costs, transmission reinforcement costs and

[30] The near term de-rated capacity margins presented here are higher compared to the 2012/13 – 2016/17 de-rated capacity margins presented in Ofgem's 2012 Electricity Capacity Assessment (http://www.ofgem.gov.uk/Markets/WhlMkts/monitoring-energy-security/elec-capacity-assessment/Documents1/Electricity%20Capacity%20Assessment%202012.pdf). The main driver behind these differences are the higher de-rating factors used for thermal plant for the purposes of our analysis (90% compared to between 81-87% under Ofgem's Electricity Capacity Assessment).

transmission losses. Overall the scenario requires less transmission reinforcement. This in turn exposes fewer differences between the charging options.

The lower capacity margins in the CMP213 modelling are a result of updates to the retirement dates of existing generation, along with the revised Capacity Mechanism modelling and later start date for the Capacity Mechanism.

4.2 Comparison to Project TransmiT results: Improved ICRP / Original

This section describes and explains the comparative changes between the Status Quo and Improved ICRP runs during the TransmiT modelling versus differences between the Status Quo and Original runs in the CMP213 results. The Improved ICRP option has been renamed as Original for CMP213. This name comes from the Original proposal that National Grid raised as CMP213, which reflects the key features of Improved ICRP.

4.2.1 Impacts on transmission charges

Under the TransmiT modelling, the MAR under Status Quo was projected to increase over the next 20 years as new generation capacity (particularly renewables) is connected to the system leading to greater expenditure in transmission network reinforcements. It was assumed, however, that in 2015 the G:D split of charging would change from 27%:73% to 15%:85% in order to comply with EU tarification guidelines. As a result, despite the overall increase in MAR, the total revenues recovered from generators were found not to exceed (in real terms) 2014 levels before 2030.

Total expenditure on transmission reinforcements to 2030 under Improved ICRP was found to be very similar, thus also leading to similar levels of total revenue to be recovered as shown in Figure 15. This is because Improved ICRP under TransmiT modelling was found to result to a very similar overall pattern of retirement and new build to Status Quo as will later be explained.

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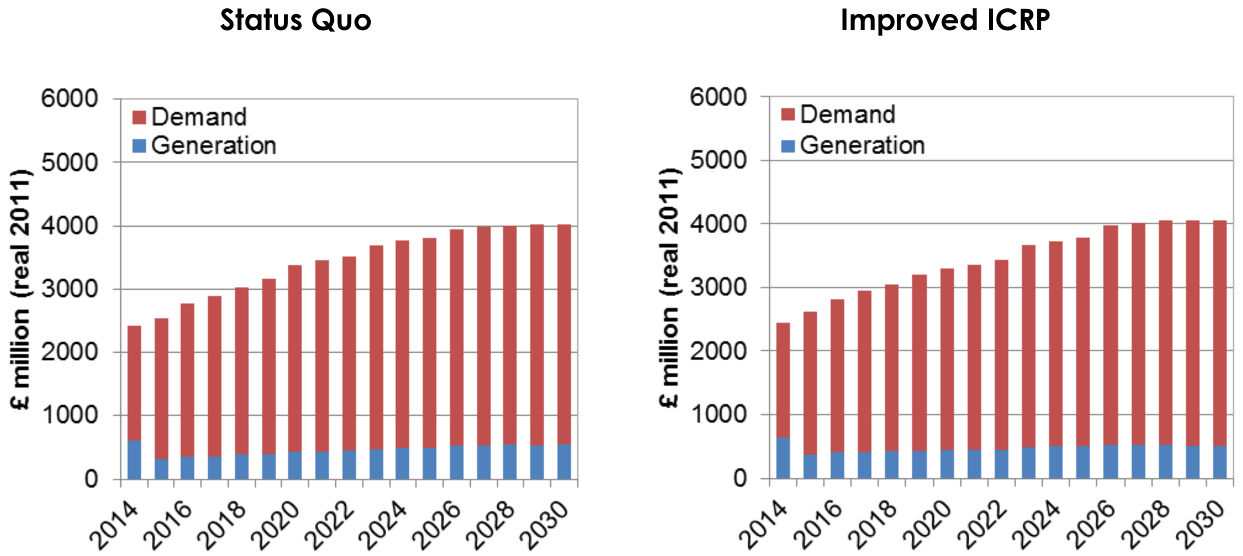
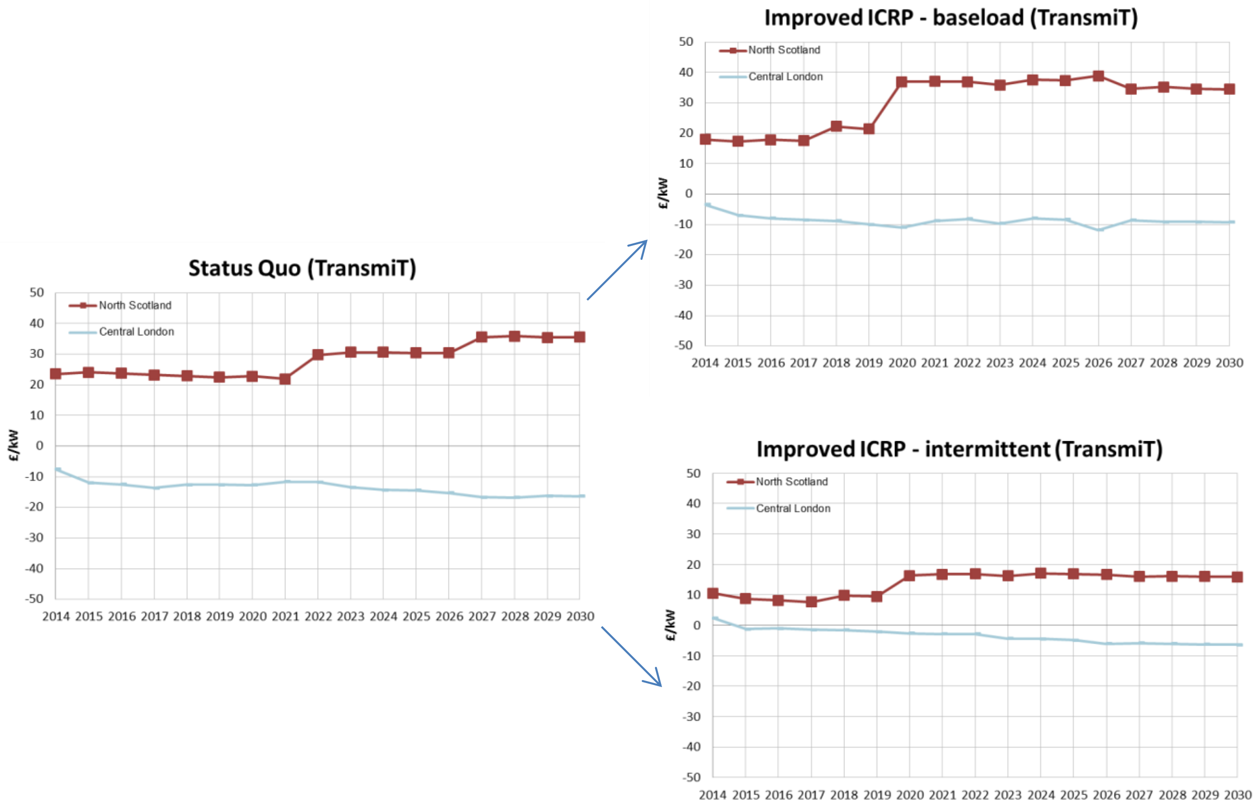
Figure 15 MAR: Status Quo and Improved ICRP (TransmiT modelling)



Despite similarities in total revenue requirements across the two options, considerable differences were observed in TNUoS charges to generators. This is because the range in Generator TNUoS tariffs was more compressed under Improved ICRP, in particular for low load factor generators. The compression in charges under Improved ICRP can be seen in Figure 16.

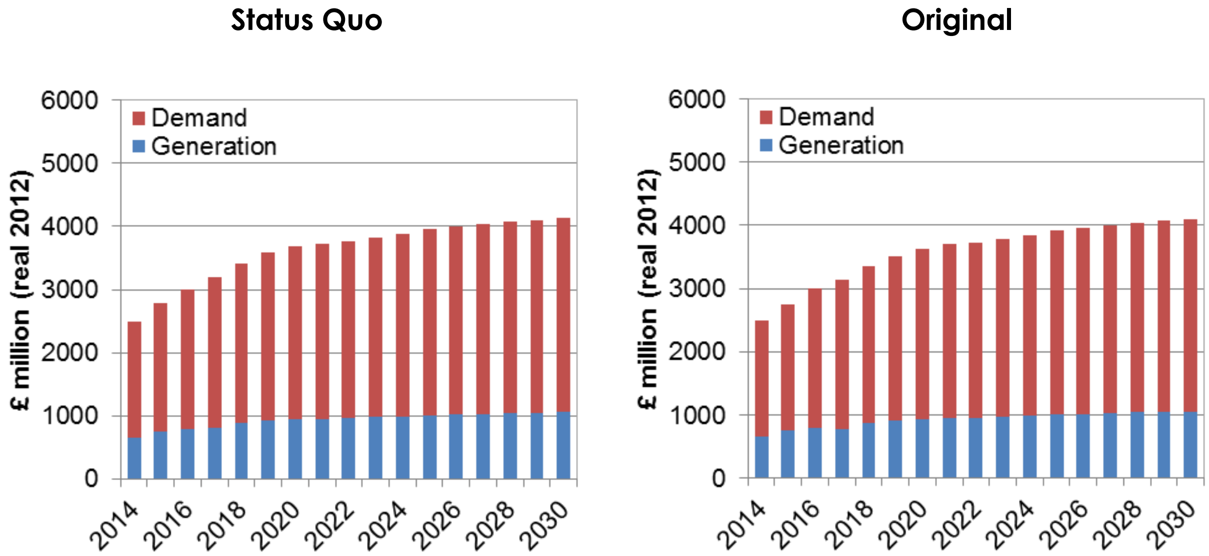
Figure 16 Generator wider TNUoS – locational and residual (TransmiT modelling)



Under CMP213 modelling, the MAR under Status Quo is projected to increase by 2030 to roughly the same levels as for Status Quo under Project TransmiT modelling (approximately £4.2bn). A key difference, however, is that the G:D split of charging is now assumed to remain at 27%:73% from 2015 onwards, thereby resulting in continuously increasing revenues recovered from generators. By 2030, these revenues rise to £1.1bn, i.e. roughly double compared to the revenues recovered from generators during Project TransmiT modelling.

Total expenditure on transmission reinforcements to 2030 under the Original charging option was found to be very similar, thus also leading to similar levels of total revenue to be recovered as shown in Figure 17 below.

Figure 17 MAR: Status Quo and Original (CMP213 modelling)

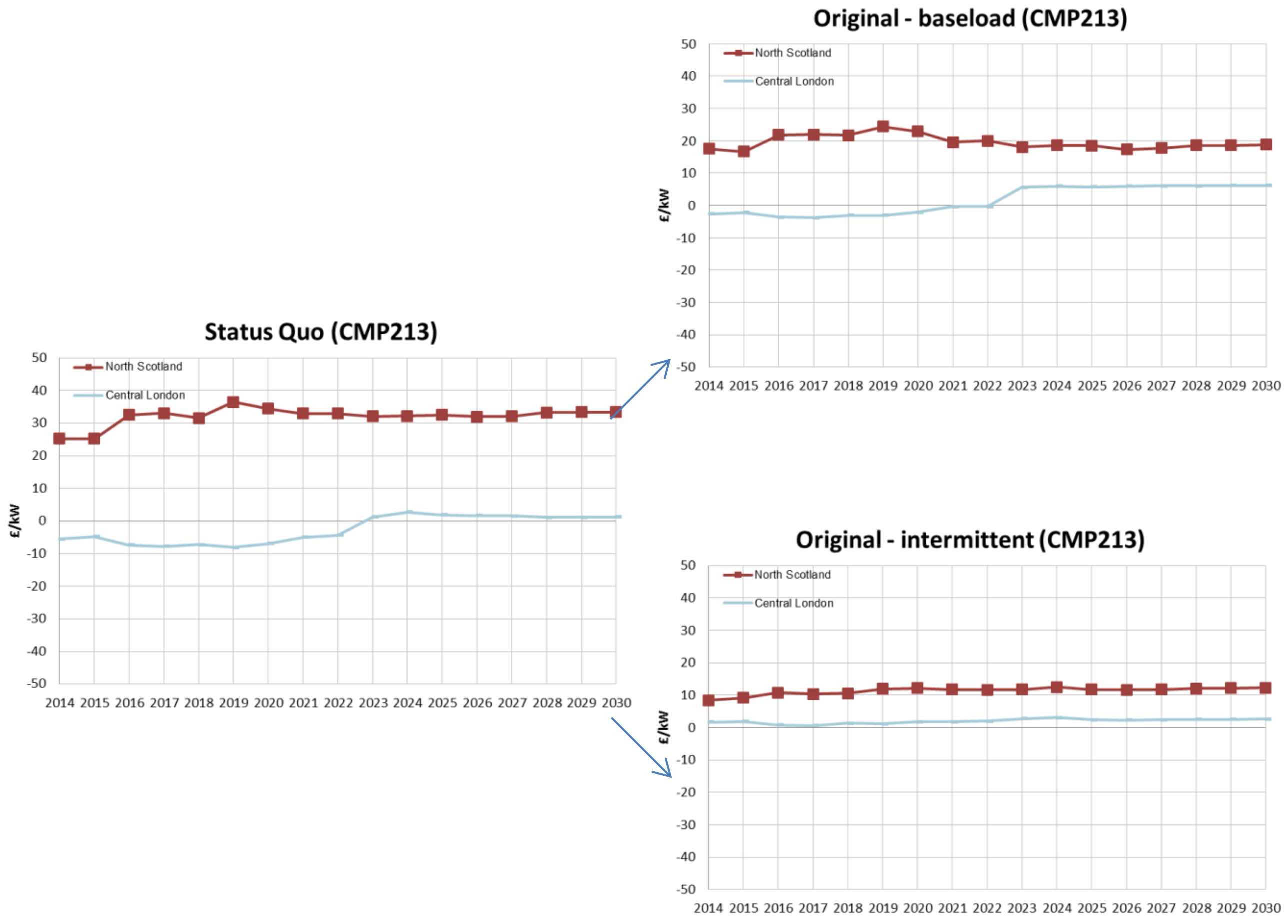


Again, considerable differences were observed in TNUoS charges to generators across the two options despite similarities in total revenue requirements. This is because the range in Generator TNUoS tariffs is considerably more compressed under the Original option compared to Status Quo.

For example, wider tariffs under Status Quo in 2014 ranged from -£6/kW per year in London (the cheapest zone) to about £26/kW in North Scotland and the Western Highlands and Skye (the most expensive zones). Under the Original charging option, tariffs ranged from -£3/kW (Central London) to £18-19/kW (North Scotland and the Western Highlands and Skye) for baseload generators, and from about £1/kW (Peninsula) to £8-9/kW (North Scotland and the Western Highlands and Skye) for intermittent generators. These results can be shown graphically in Figure 16.

It also worth noting that, comparing Figure 16 against Figure 18 shows that the Original approach results in flatter Generator TNUoS tariffs compared to the Improved ICRP charging option, both for baseload as well as for intermittent plant. As for the comparison of the two Status Quo models, this is due to the reduced number of HVDC interconnections and the lower proportion of Scottish renewables.

Figure 18 Generator wider TNUoS – locational and residual (CMP213 modelling)



4.2.2 Impacts on sustainability goals

Improved ICRP under TransmiT modelling was found to result in a similar overall pattern of retirement and new build to Status Quo. The main difference that was observed was that an additional 2.8 GW of onshore wind and 0.7 GW of offshore wind were developed by 2030 as a consequence of lower TNUoS charges for intermittent generators in positive generator TNUoS zones. As a result, renewable penetration under the Improved ICRP option was found to be almost 1% higher compared to the Status Quo by 2030. Accordingly, slightly less baseload generation was required to meet demand and carbon intensity targets (100g/kWh), thus resulting in 400 MW less of new nuclear capacity. These results are shown in Table 12 and Table 13.

Table 12 2020 carbon intensity and renewable penetration results

2020 Results	**Status Quo (TransmiT)**	**Improved ICRP (TransmiT)**	**Status Quo (CMP213)**	**Original (CMP213)**
Onshore Wind (GW)	11.5	12.7	9.6	10.1
Offshore Wind (GW)	9.3	8.9	11.3	10.1
Renewable Penetration (%)	30.3%	30.2%	30.4%	29.7%
Nuclear (GW)	5.3	5.3	7.6	7.6
CCS (GW)	1.1	1.1	1.1	1.1
Carbon intensity (g/kWh)	294.6	294.9	246.8	251.6

Table 13 2030 carbon intensity and renewable penetration results

2030 Results	**Status Quo (TransmiT)**	**Improved ICRP (TransmiT)**	**Status Quo (CMP213)**	**Original (CMP213)**
Onshore Wind (GW)	15.5	18.3	11.1	11.7
Offshore Wind (GW)	17.2	17.9	12.2	11.0
Renewable Penetration (%)	40.7%	41.6%	32.8%	32.1%
Nuclear (GW)	12.8	12.4	14.8	14.8
CCS (GW)	5.0	5.0	8.4	9.3
Carbon intensity (g/kWh)	106.3	106.1	99.0	96.6

Under CMP213 modelling, the 30% renewable penetration target by 2020 is achieved using a greater contribution from offshore wind at the expense of onshore wind as shown in Table 12. Slightly higher CfD strike prices are assumed under the Status Quo charging option for offshore and onshore wind, thus leading to a higher renewables output compared to Original by approximately 0.7 percentage points. In terms of renewable new build, there are two key differences between these two charging options both of which occur by 2020:

1. The Original charging methodology results in 600 MW more onshore wind capacity being developed, all of which is located in Scotland.
2. The Status Quo charging methodology results in 1,200 MW more offshore wind capacity being developed, all of which is located in South England.

These differences come as a direct result of differences in Generator TNUoS charges (combined with the Stage 2 approach for CfD strike price setting), with plant located in the South of England generally being subject to higher transmission charges under the Original option, whilst conversely plant located in Scotland benefit from lower charges.

Comparatively, there is a larger difference in renewable penetration between Status Quo and Original than between Status Quo and Improved ICRP. This is an important factor in the observed differences in the CBA results as will be explained in Section 4.2.5.

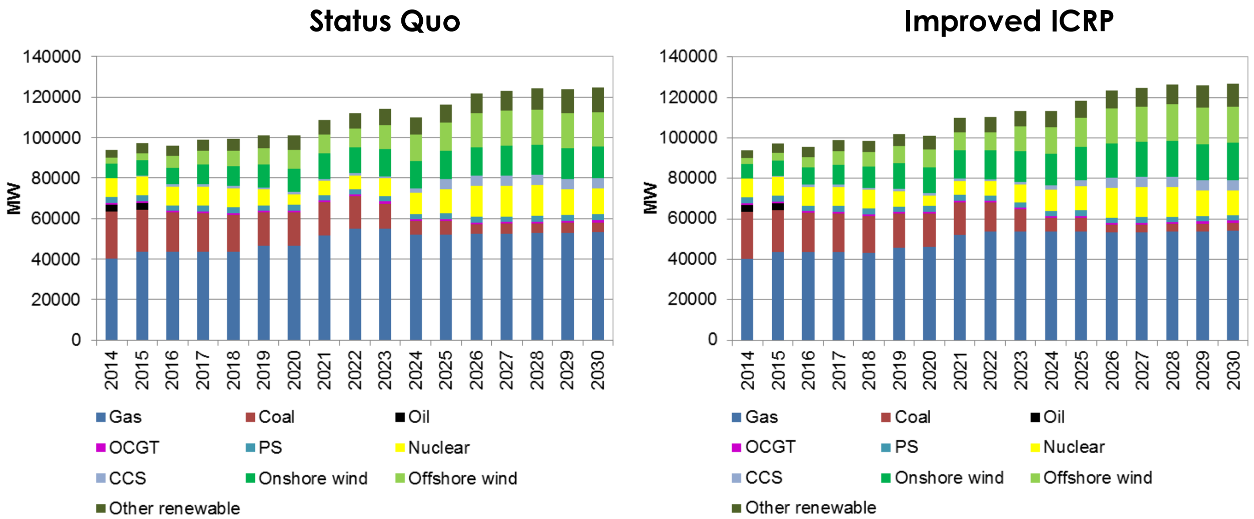
4.2.3 Overall cost impacts

During the TransmiT modelling, low carbon support was adjusted across the different charging options in order to ensure that renewable and carbon intensity outcomes were approximately equal, thus facilitating cost comparisons on a 'like with like' basis.

Capacity mix

Under Improved ICRP an additional 2.8GW of onshore wind capacity and 0.7 GW of offshore wind capacity was developed by 2030, with a corresponding reduction in new nuclear capacity of 0.4GW, tidal stream capacity of 0.4 GW and biomass capacity of 0.5 GW compared to the Status Quo. In general, however, the overall capacity mix across the two charging options was found to be fairly consistent as shown in Figure 19.

Figure 19 Total generation capacity (TransmiT modelling)



Despite the similar overall capacity mix, however, significant locational variations were observed. Differences in cumulative new build by region are shown in Figure 20 (to 2020) and Figure 21 (to 2030). Under Improved ICRP, the compression of locational variations in generation charges (particularly for low load factor generators) was found to favour plant with low load factors in what are currently high TNUoS charging zones. The TransmiT analysis showed that zones which currently have high TNUoS charges would become relatively more attractive for siting plant with lower load factors, including intermittent renewables. This would drive more onshore wind build in North Scotland and also encourage more offshore wind capacity to be developed in Scotland and less in South

England. Similarly, wave and tidal projects would face more favourable tariffs in Scotland and less favourable tariffs in South England compared with Status Quo. However, these tariff reductions were not found to be sufficient to drive any more development of wave and tidal in Scotland, whereas less tidal capacity was found to be developed in South England between 2020 and 2030. The reduction in biomass capacity under Improved ICRP occurred in Northern England, in a zone with relatively low (but positive) TNUoS tariffs under Status Quo.

Furthermore, wind generation in the Scottish islands was found to be favoured under Improved ICRP both by lower security factors (and thus lower charges) for cables linking the Orkneys and Western Isles with the mainland, as well as by lower wider charges for use of the onshore network from the connection point with the existing onshore network. This was found to facilitate slightly more build of onshore wind in the Orkneys after 2020. However, development of onshore wind generation in the Western Isles, where load factors were not assumed to be as high as those in the Shetlands and Orkneys, was unaffected.

Figure 20 New build by location to 2020 (TransmiT modelling)

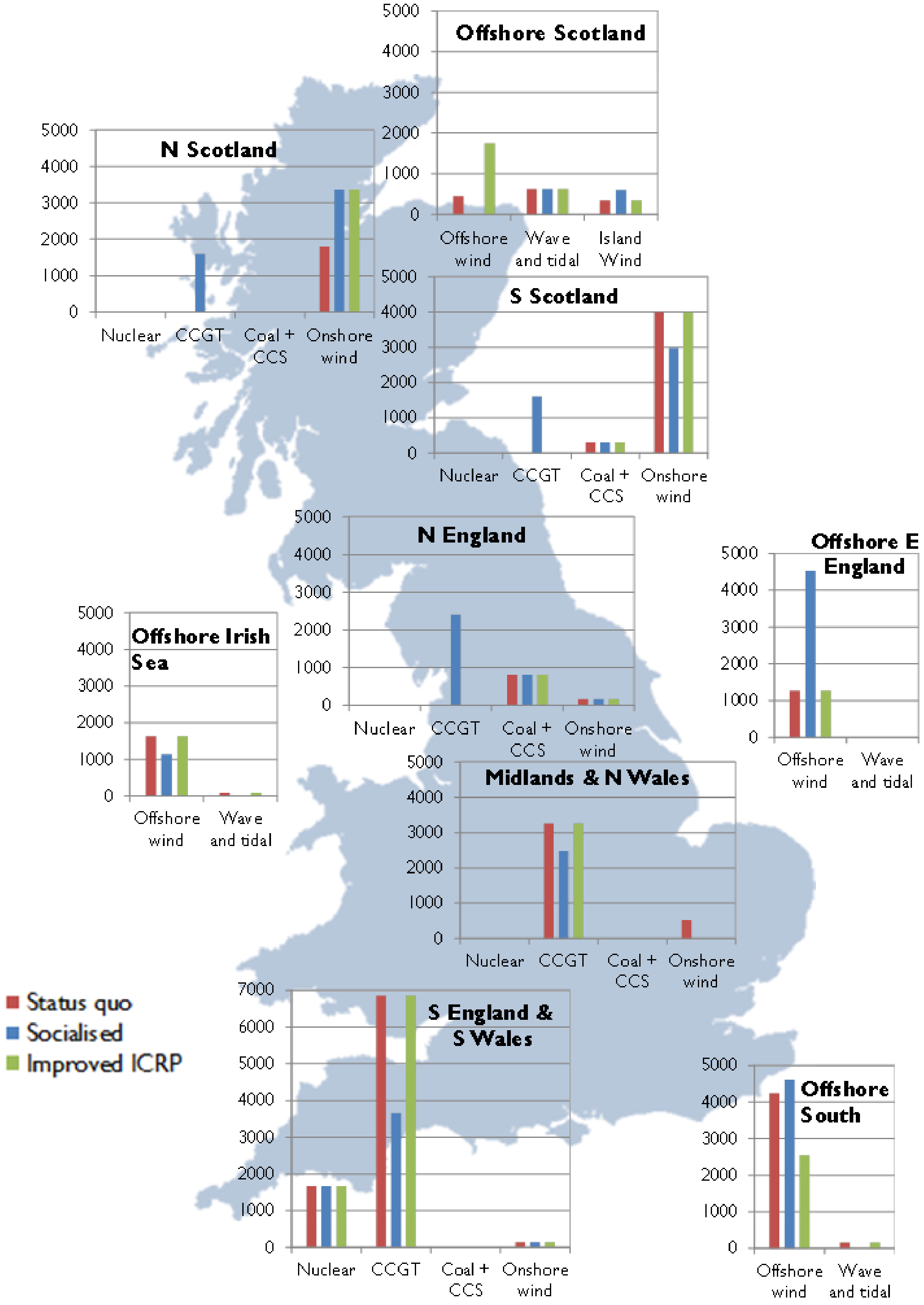
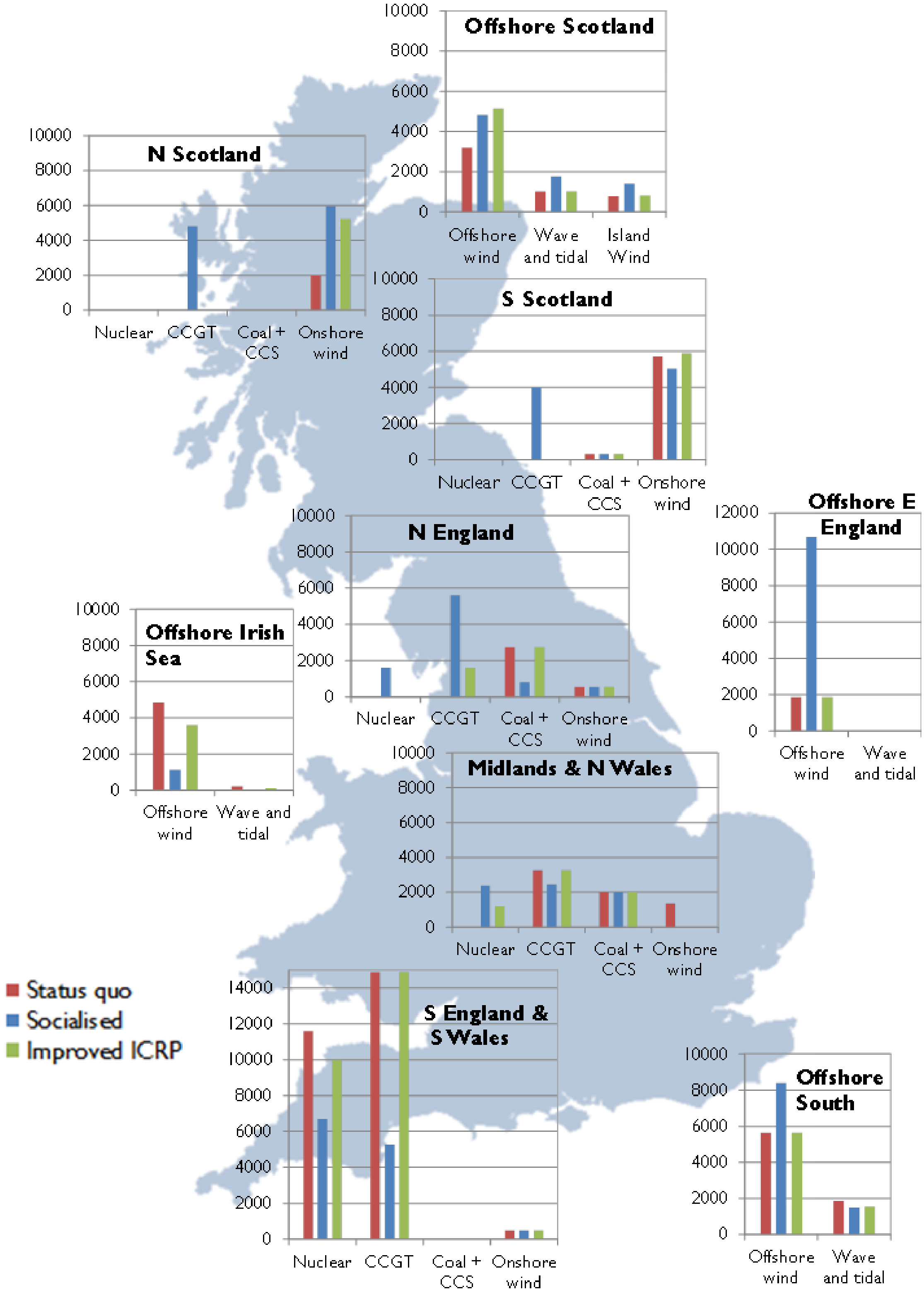
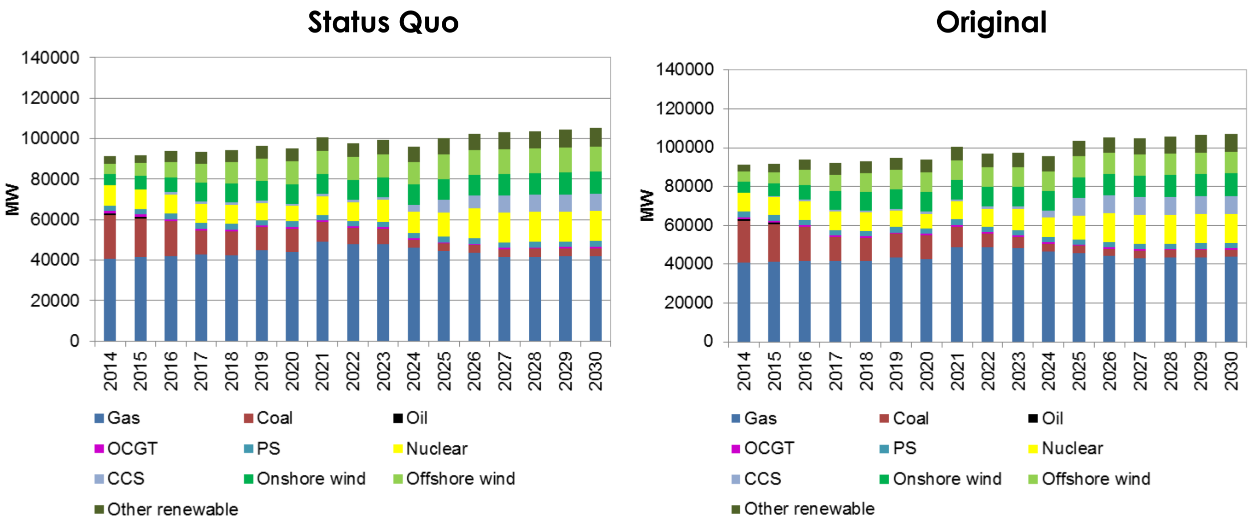


Figure 21 New build by location to 2030 (TransmiT modelling)



The compression of locational variations in generation charges (particularly for low load factor generators) under the Original charging option was also found to favour plant with low load factors in what are currently high TNUoS charging zones. As a result, compared to Status Quo the Original charging option results in an additional 0.6 GW of onshore wind capacity being developed in Scotland, at the expense of 1.2 GW of offshore wind capacity in South England. The deficit in wind capacity is replaced by an additional 0.9 GW of gas CCS in the mid-to-late 2020s. Status Quo and Original were found to deliver the same amount of wind generation in the Scottish islands, in Orkney and Shetland[31].

Figure 22 Total generation capacity (CMP213 modelling)



Overall, the differences between Status Quo and Original in terms of capacity mix are small under both TransmiT and CMP213. The differences are arguably smaller under CMP213. This may be due in part to the alignment of the island wind charging arrangements, and the overall lower level of onshore wind deployment which itself limits the increase in tariffs in North Scotland (via fewer bootstraps).

[31]We note that DECC has recently published a study examining the deployment of renewables on the Scottish islands which concluded that no further onshore wind would be built on Orkney and Shetland under current policy due to a number of economic and regulatory barriers. The CMP213 modelling does not account for these conclusions https://www.gov.uk/government/publications/scottish-islands-renewable-project-final-report

Figure 23 New build by location to 2020 (CMP213 modelling)

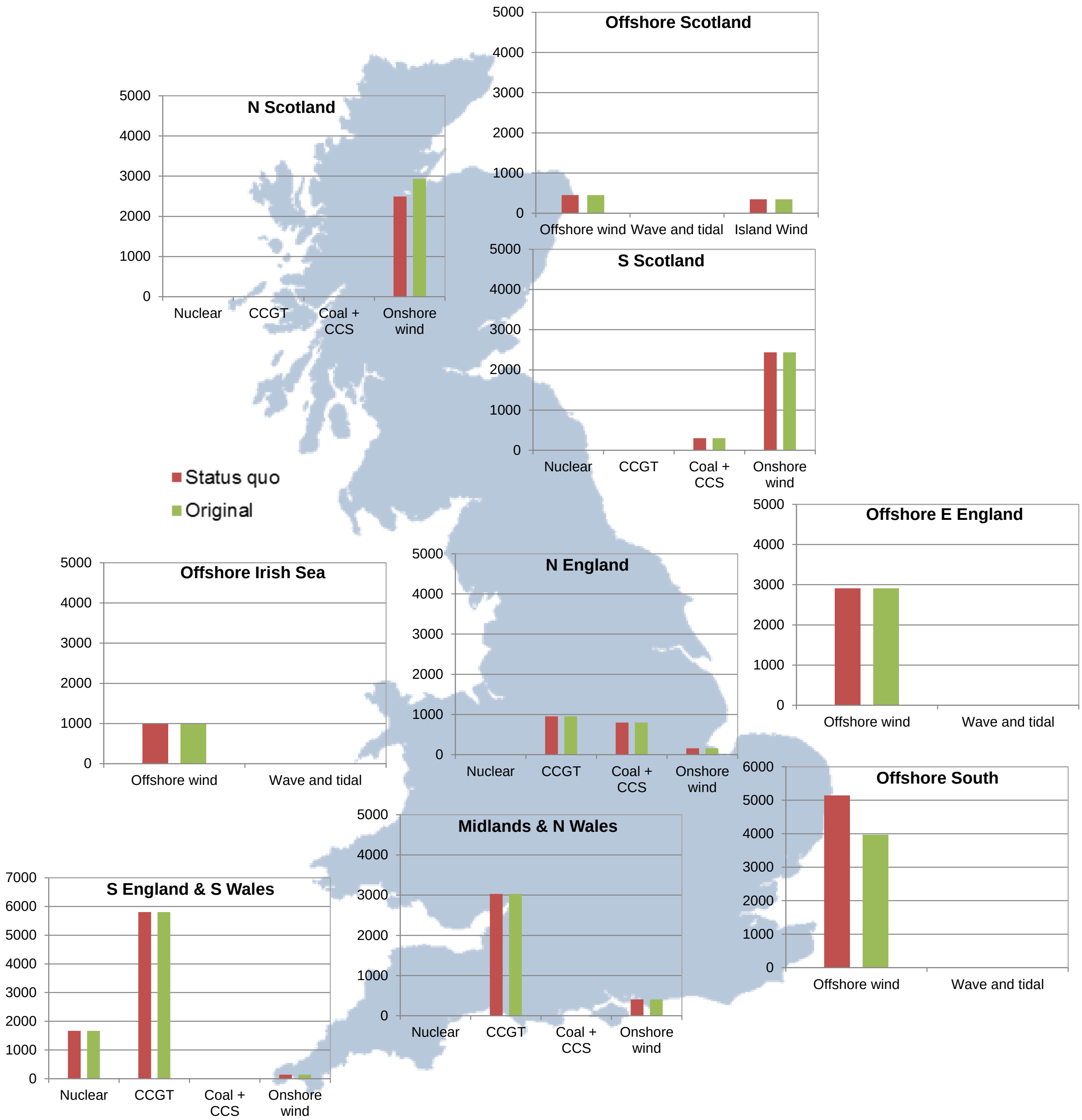
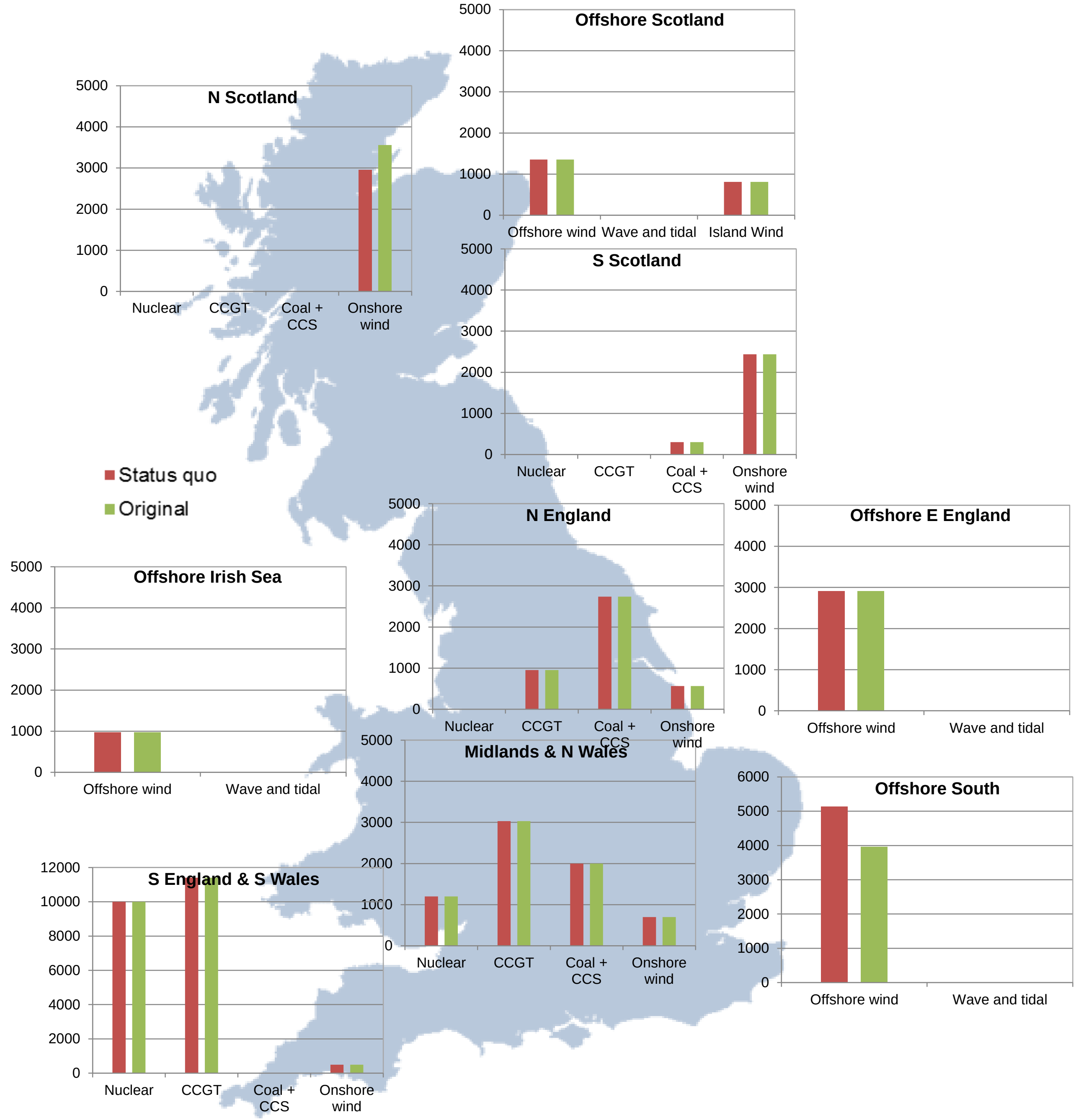


Figure 24 New build by location to 2030 (CMP213 modelling)

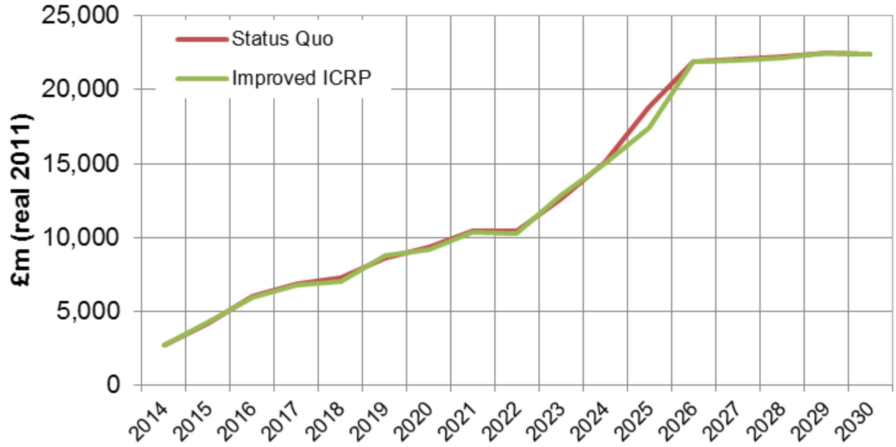


Generation costs of low carbon deployment

Figure 25 shows the cumulative cost of low carbon generation under the Status Quo and Improved ICRP charging options during TransmiT modelling. This figure includes all costs associated with low carbon generation: fixed operation and maintenance costs, variable operations and maintenance costs, and fuel costs for all low carbon plant, as well as annualised capital costs for new build. All transmission costs and charges to generators (such as TNUoS and BSUoS) are excluded. Generation costs for fossil fuel generation are also excluded, but are included as an important part of total generation costs used for the full cost benefit analysis later in this section.

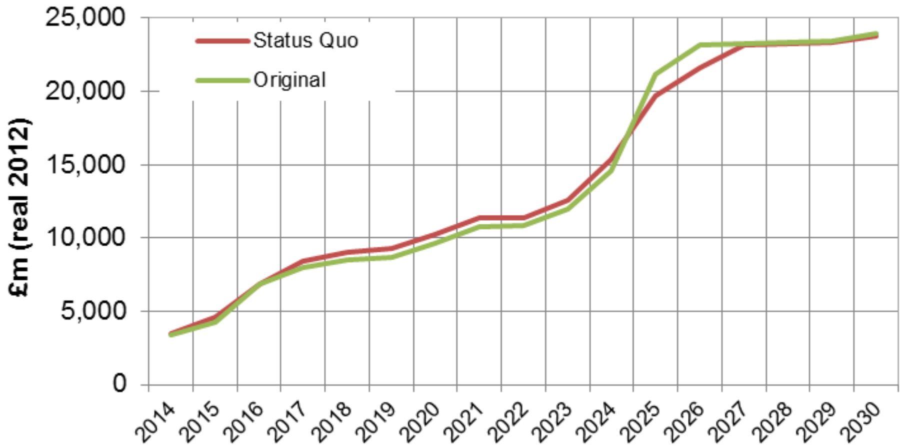
It can be seen that the results for Status Quo and Improved ICRP were found to be very similar, reflecting the fact that the differences between these two options in terms of generation mix are relatively small as previously explained. In terms of renewable technologies, the key differences are that Status Quo results by 2030 in approximately £0.5bn/year lower costs in onshore wind, however that is roughly offset by an increase in biomass by approximately £0.4bn/year.

Figure 25 Low carbon generation costs (TransmiT modelling)



Similarly, Figure 26 shows the cumulative cost of low carbon generation under the Status Quo and Original charging options during CMP213 modelling. Again results were broadly similar reflecting similarities in the capacity mix. In 2020, Original has slightly lower generation costs due to a slightly lower deployment of renewables and a greater proportion of onshore relative to offshore wind. In terms of low carbon technologies, the key differences are that Status Quo results by 2030 in approximately £0.7bn/year lower costs in onshore wind, however that is roughly offset by an increase in offshore wind by approximately £0.6bn/year.

Figure 26 Low carbon generation costs (CMP213 modelling)



Transmission reinforcement decisions and costs

Figure 27 shows the cumulative costs of modelled reinforcements to the MITS under the Status Quo and Improved ICRP charging options during TransmiT modelling. The increase in generation capacity further away from the main demand centres under the Improved ICRP option was found to result in a greater number of reinforcement projects to be undertaken, thus leading to higher total investment costs that must be recouped through transmission charging.

The increase in transmission costs was found to be driven in particular by the increase in onshore wind build in the North of Scotland, which brought forward build of new HVDC links that reinforce boundaries between Northern Scotland and demand centres further south as shown in Table 14. In particular, the second Eastern and Western HVDC links were built earlier than under Status Quo.

Offshore transmission build is also important to total transmission costs. Under Improved ICRP, offshore transmission costs were found to be almost identical with Status Quo (albeit slightly lower) as seen in Figure 28.

Figure 27 Modelled reinforcement costs to the Main Interconnected Transmission System (TransmiT modelling)

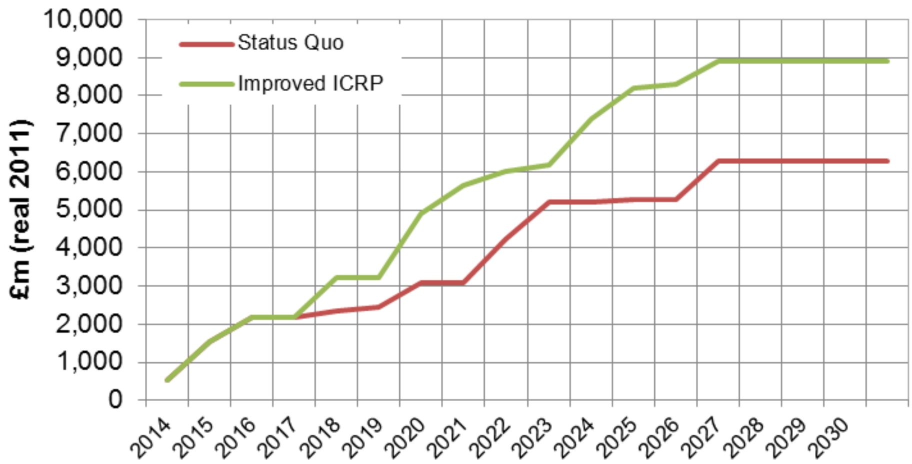


Table 14 Timing of new HVDC links (TransmiT modelling)

Reinforcement	Capacity (MW)	Boundaries	Status Quo	Improved ICRP
Western HVDC Link	2000	B6, B7a	2015	2015
Western HVDC Link #2	2000	B6, B7a	2023	2020
Eastern HVDC Link	2000	B2, B4, B5, B6, B7a	2022	2018
Eastern HVDC Link #2	2000	B2, B4, B5, B6, B7a	2027	2024
Wylfa-Pembroke 2GW HVDC link	2000	B202, NW2	-	-
Caithness - Moray HVDC	600	B1	-	2020
Humber - Walpole HVDC	2000	B8, B9, B11, B16	-	2027

Figure 28 Offshore and island transmission: cumulative investment costs (TransmiT modelling)

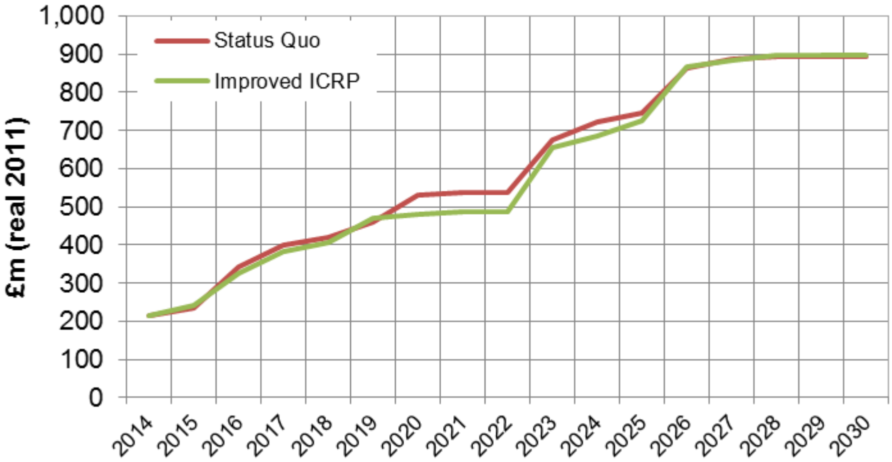


Figure 29 shows the cumulative costs of modelled reinforcements to the MITS under the Status Quo and Original charging options during CMP213 modelling. In section 4.1.3 we explain that the overall level of onshore reinforcement is lower under CMP213 due to lower renewables deployment. Original results in slightly higher onshore reinforcement costs (particularly due to the increase in onshore wind in Scotland), however differences are relatively modest. This is particularly evident in Table 15 where it can be seen that timing for HVDC links does not change across the two charging options. With regards to offshore and island transmission costs, however, it can be seen from Figure 30 that some cost reductions are realised under the Original charging option as fewer offshore wind projects are developed.

Figure 29 Modelled reinforcement costs to the Main Interconnected Transmission System (CMP213 Modelling)

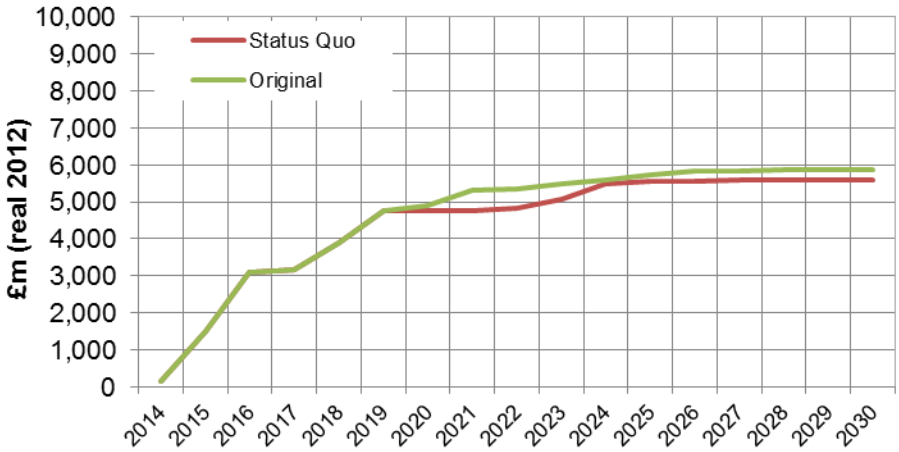
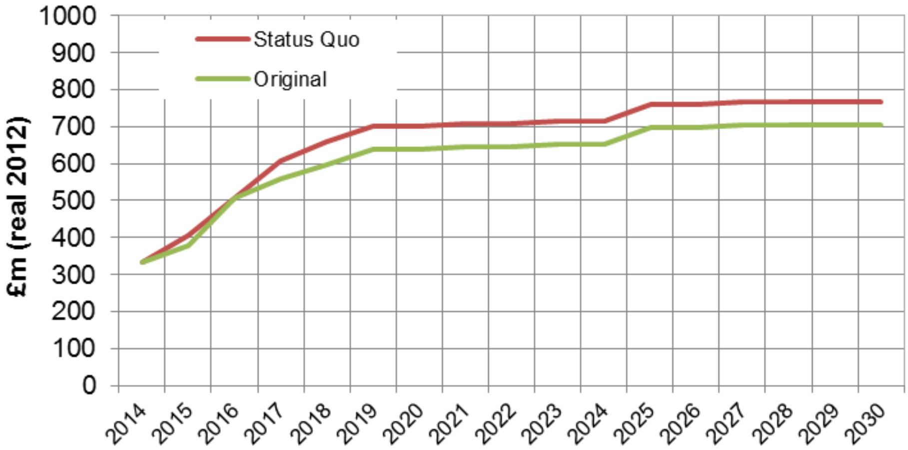


Table 15 Timing of new HVDC links (CMP213 modelling)

Reinforcement	Capacity (MW)	Boundaries	Status Quo	Original
Western HVDC Link	2000	B6, B7a	2016	2016
Western HVDC Link #2	2000	B6, B7a	-	-
Eastern HVDC Link	2000	B2, B4, B5, B6, B7a	-	-
Eastern HVDC Link #2	2000	B2, B4, B5, B6, B7a	2019	2019
Wylfa-Pembroke 2GW HVDC link	2000	B202, NW2	-	-
Caithness - Moray HVDC	600	B1	-	-
Humber - Walpole HVDC	2000	B8, B9, B11, B16	-	-

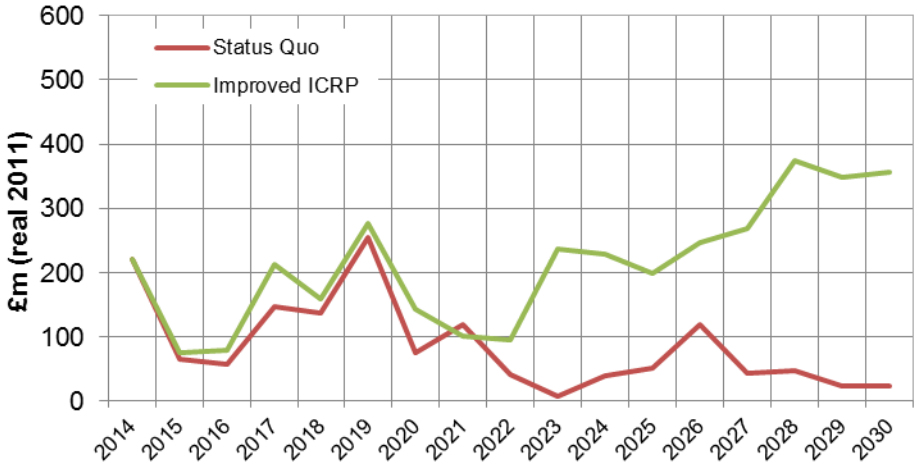
Figure 30 Offshore and island transmission: cumulative investment costs (CMP213 modelling)



Constraint costs

Constraint costs under the Improved ICRP and Status Quo options until 2022 ranged between approximately £100m to £200m per year (Figure 31). Additional transmission reinforcement under Improved ICRP was then found to relieve most of the additional transmission constraints associated with more onshore wind in North Scotland. After 2022, however, the level of reinforcements does not quite keep pace with the greater levels of renewable deployment in Scotland and constraint costs were found to rise as a result. After 2025, the full range of identified HVDC links available to reinforce north-south constraints between Scotland and England have already been built, so there is limited scope to undertake further reinforcement. Also, the generic reinforcement possibilities on key north-south boundaries which are assumed in the modelling are generally exhausted between 2021 and 2025.

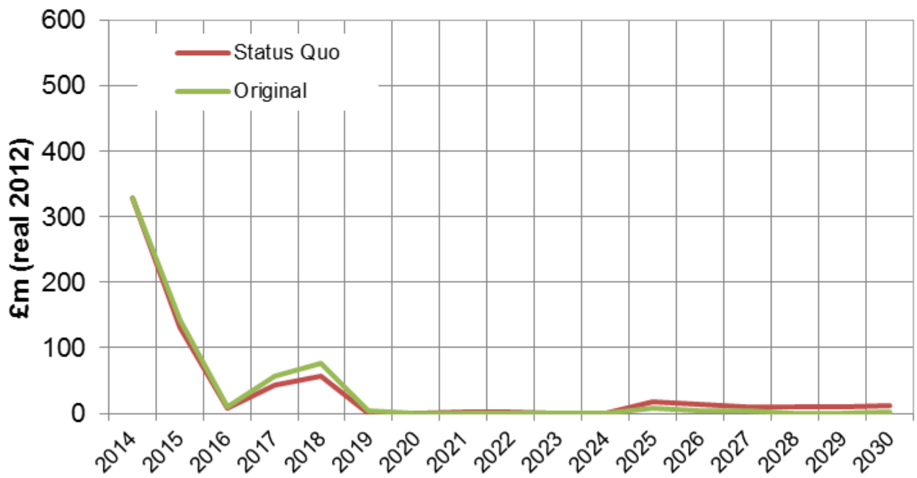
Figure 31 Constraint costs (TransmiT modelling)



In the CMP213 modelling, constraint costs under the Status Quo and Original options are very similar as shown in Figure 32. They both start from approximately £330m in 2014 and are progressively reduced down to roughly £10 million per year from 2019 onwards as transmission reinforcement takes place.

The differences in constraints costs between TransmiT and CMP213 have already been discussed in section 4.1. The lack of continued renewable growth means that differences in constraint costs do not manifest themselves – as both runs have more reinforcement than required. In this particular case, the lumpy nature of transmission investment favours Original, which makes more use of the Eastern HVDC bootstrap. In other words, the optimal size of the Eastern HVDC Link #2 is smaller. This was also discussed in section 4.1.1.

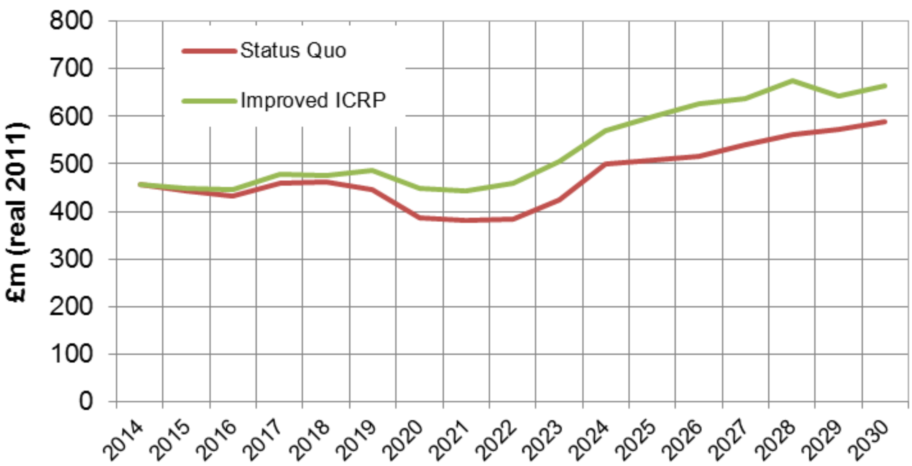
Figure 32 Constraint costs (CMP213 modelling)



Transmission losses

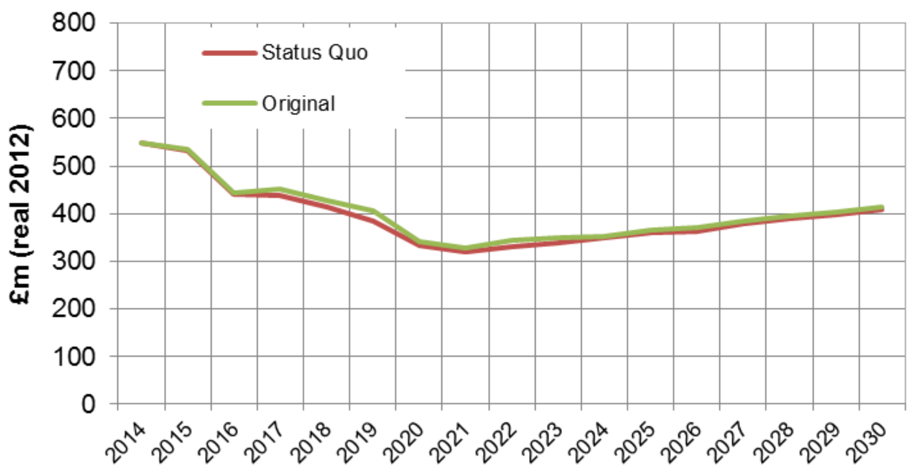
Figure 33 shows the costs of transmission losses produced by the TransmiT model. In general transmission losses are greater the greater the average distance that power needs to be transported to reach the demand centres. Hence, transmission losses were found to be greater under Improved ICRP than Status Quo, mainly due to higher deployment of onshore wind in Scotland.

Figure 33 Transmission losses (TransmiT modelling)



Similarly, Figure 34 shows the costs of transmission losses under the Status Quo and Original charging options (CMP213 modelling). It can be seen that differences in transmission losses under these two charging options are almost negligible due to the very similar resultant capacity mix.

Figure 34 Transmission losses (CMP213 modelling)

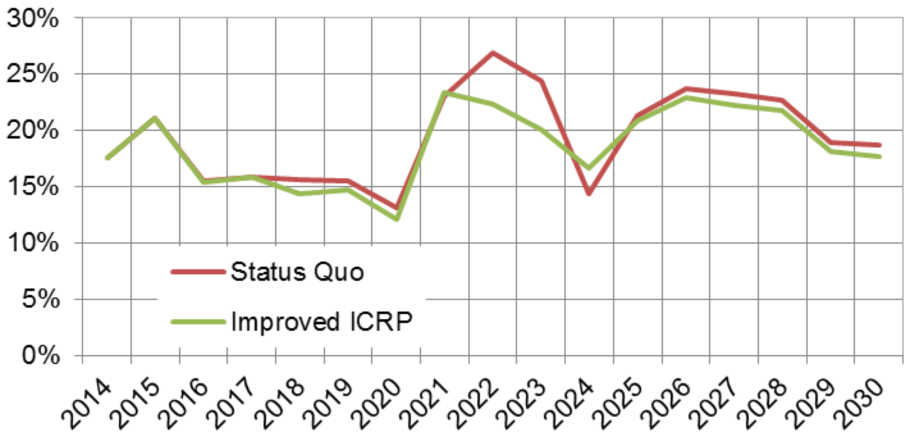


4.2.4 Impacts on security of supply

For the purposes of the TransmiT modelling we included a simple form of universal capacity mechanism based on annual capacity auctions. With a capacity mechanism in place, the differences between the Status Quo and Improved ICRP charging options in terms of security of supply are not that great.

Figure 35 shows the de-rated capacity margin produced by the model under the two charging options. The reductions in de-rated capacity margins observed in 2016 and 2024 reflect enforced closures under the LCPD and IED respectively. In general, very little difference was found to exist between the two charging options, thus resulting in similar levels of security of supply. In general, we do not believe that there is evidence to suggest that the different charging options drive materially different levels of security of supply.

Figure 35 De-rated capacity margins (TransmiT modelling)



Note: Capacity margins based on the peak demand shown in Figure 2. De-rating factors used were 90% for conventional, nuclear and biomass thermal plant, 70% for hydroelectricity, 100% for pumped storage, 15% for wind and 30% for tidal and wave.

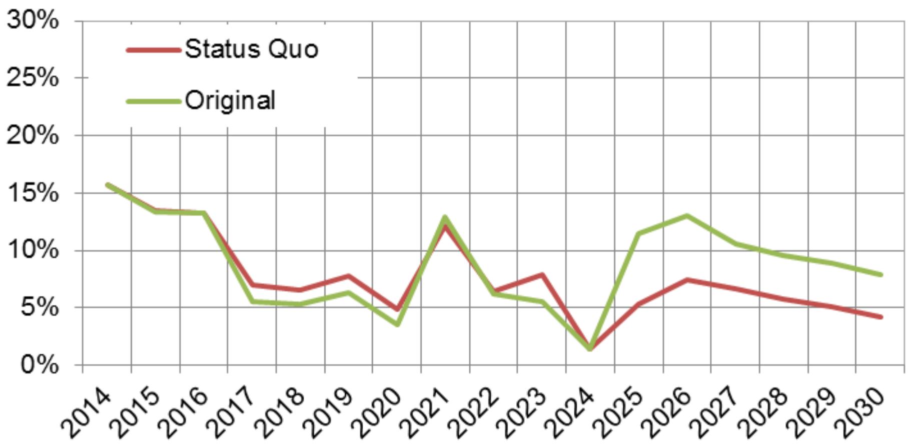
Figure 36 shows the de-rated capacity margin produced by the CMP213 model under the two charging options considered here (Status Quo and Original). The reasons for the lower capacity margins relative to Project TransmiT are discussed in section 4.1.4. In the 2017 – 2020 period, Original has lower capacity margins by about 2%. This is due to:

1. Earlier retirement of about 1 GW of Midlands and North England CCGTs over this period (as a result of the marginal impact of higher transmission charges), partially offset by later retirement of a Scottish coal unit.
2. A reduction in offshore wind of about 1.1 GW which is only partially offset by the increase in onshore wind of 260 MW.

It can be seen that the Original charging option results in higher de-rated capacity margins relative to Status Quo from 2025 onwards due to the following two factors:

1. Less CCGT capacity retires in the North of England by 2030 (3.6 GW rather than 5.2 GW) due to lower transmission charges in that area;
2. In meeting the 100g/kWh target in 2030, the capacity mix under the Original run contains more gas CCS and less offshore wind. This has a positive impact on security of supply from 2025 onwards since gas CCS is a more flexible technology than offshore wind, and thus has a higher de-rating factor (90% for gas CCS compared to 15% for offshore wind). This difference in the long term is a result of the Stage 2 CfD strike price setting approach, which targets the same decarbonisation level across runs but not the same security of supply.

Figure 36 De-rated capacity margins (CMP213 modelling)



4.2.5 Cost benefit analysis

Table 16 presents the CBA results for Improved ICRP (relative to Status Quo) over two ten year time periods, 2011 to 2020 and 2021 to 2030. It is broken down into power sector costs and consumer bills. The results are presented in net present value (NPV) terms, discounted using the Government's guidance of a 3.5% real discount rate to 2011.

Over the period 2011-2020, results under the TransmiT modelling suggested that Improved ICRP could be broadly neutral in terms of power sector costs compared to Status Quo, suggesting that the additional constraint costs, losses and transmission expenditure may not be fully offset by reductions in generation costs. Between 2021 and 2030, power sector costs were projected by the model to be slightly higher overall. These differences with Status Quo are small relative to the overall cost of supplying electricity (less than 0.2%), and hence Improved ICRP was found to appear broadly neutral with Status Quo with respect to power sector costs.

The impact on consumer bills was found to be somewhat greater than the change in power sector costs over the period 2011-2020, but still small, averaging an additional £1.50 per year for each domestic customer.

Table 16 Cost Benefit Analysis: Improved ICRP (TransmiT modelling)

		Improved ICRP (£m real 2011)	
		NPV 2011-2020	NPV 2021-2030
Benefit relative to Status Quo			
Power sector costs	Generation costs	313	965
	Transmission costs	-271	-1,300
	Constraint costs	-171	-1,089
	Carbon costs	-11	-2
	Decrease in power sector costs	**-141**	**-1,425**
Consumer bills	Wholesale costs (inc. capacity payments)	-1,227	-182
	BSUoS	-85	-547
	Transmission losses	-123	-491
	Demand TNUoS charges	-126	-688
	Low carbon support	441	644
	Decrease in consumer bills	**-1,120**	**-1,263**

Power sector costs

The NPV of generation costs was found to be lower under the improved ICRP charging option due to a decrease in fuel and operating costs. These cost differences can be explained by differences in the generation mix, primarily an additional 3 GW of onshore wind generation and 2 GW less biomass and 1 GW less offshore wind. Furthermore, due to a geographical shift in the location of onshore wind towards North Scotland and away from Wales, additional generation cost savings were achieved through a higher average load factor given greater wind resource in these locations.

Differences in transmission costs can be disaggregated into differences in onshore and offshore transmission costs, and also transmission losses. Under Improved ICRP, onshore reinforcement costs were found to be higher as transmission investments are brought forward (in particular, the Eastern, Caithness-Moray and Humber-Walpole HVDC links). Transmission losses were also slightly higher. On the other hand, the cost of building offshore links was lower as there is less offshore build under Improved ICRP than Status Quo. These differences were observed from 2020 onwards.

Constraint costs were higher under Improved ICRP since the levels of transmission reinforcement did not completely keep pace with the increases in north-south constraints between Scotland and England (Figure 31). Again, these differences were mostly found during the period 2021-2030.

As previously explained, low carbon support levels were set to achieve broadly the same outcomes in terms of the 2020 renewables target and carbon intensity in 2030. Hence, differences in the costs of carbon emissions were found to be negligible, although small variations did arise as a result of slightly different decarbonisation trajectories.

It can be concluded that under Improved ICRP power sector costs were found to be similar (albeit slightly higher) to Status Quo, with the increase in transmission and constraint costs roughly being offset by lower generation costs.

Consumer bills

The CBA for consumer bills is broken into wholesale costs, BSUoS, transmission losses, demand TNUoS and low carbon support.

The majority of wholesale cost differences across policy options are driven by differences in market prices, although this category also captures the cost of the modelled capacity mechanism. Within the model, market prices are a function of two factors:

- the short run marginal cost of the marginal generating plant in each period; plus
- a calibrated 'uplift' function[32], which adds a margin to the system short run marginal cost depending on the tightness (capacity margin) in each period.

Under Improved ICRP charging, a small increase in wholesale costs relative to the Status Quo was found, driven by an increase in modelled market prices during the period 2018-2020. This is because capacity margins were somewhat lower during that period, thus leading to increased price uplift[33]. Figure 37 shows the change in the bill (averaged throughout GB) for an average domestic customer using 4000 kWh of electricity each year, under Improved ICRP charging. The impact of Improved ICRP on consumer bills is small over the period 2012-2020, averaging an additional £1.90 per year for each domestic customer. The average increase per year for each domestic customer is £2.30 per year from 2021 to 2030.

A small part of the increase in wholesale costs was driven by BSUoS charges and transmission losses. BSUoS charges were higher under Improved ICRP as a consequence of higher constraint costs. Transmission losses, like constraint costs, increase with more generating capacity in northern GB and thus increased under the Improved ICRP charging option.

Conversely, the reductions in required low carbon support observed under the Improved ICRP option (due to a greater proportion of onshore wind to offshore wind) were not sufficient to offset these higher wholesale costs for consumers. Furthermore, the Improved ICRP option was also found to result in marginally reduced demand TNUoS charges as will be explained in the next section.

[32] The uplift function within the model was calibrated using 2009/2010 data.

[33] This represents a very small transfer from consumers to producers during the period 2011-2020 (an increase of about 0.5% in the net present value of consumer bills over the period).

Figure 37 Change in an average annual domestic customer bill relative to Status Quo (TransmiT modelling)

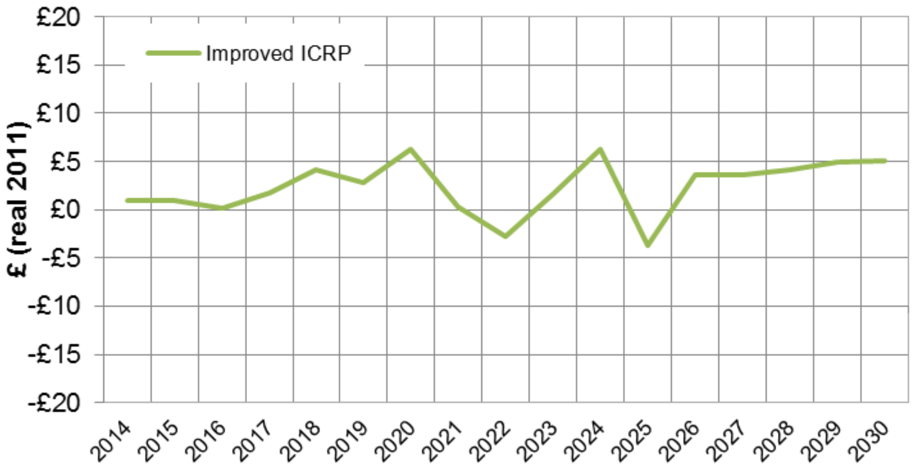


Table 17 presents the CBA results for Original (relative to Status Quo) over two time periods, 2014 to 2020 and 2021 to 2030. Over the period 2014-2020, results suggest that Original could lead to a reduction in power sector costs, but also increase consumer bills albeit at a lower level. Between 2021 and 2030, the model projects that the Original charging option would have a positive impact both in terms of power sector costs as well as on consumer bills.

Table 17 Cost Benefit Analysis: Original (CMP213 modelling)[34]

		Original (£m real 2012)	
		NPV 2014-2020	NPV 2021-2030
Benefit relative to Status Quo			
Power sector costs	Generation costs	958	-84
	Transmission costs	137	214
	Constraint costs	-40	33
	Carbon costs	-104	257
	Decrease in power sector costs	**950**	**420**
Consumer bills	Wholesale costs (inc. capacity payments	-1,729	4,194
	BSUoS	-20	17
	Transmission losses	-48	-42
	Demand TNUoS charges	135	187
	Low carbon support	892	-397
	Decrease in consumer bills	**-770**	**3,958**

Power sector costs

The NPV of generation costs were found to be lower under the Original charging option due to savings in generation capital costs and fixed costs associated with replacing

[34] It is worth noting that the NPV period covers the years 2011-2030 in order to ensure consistency with the TransmiT modelling, however there are no differences under the various CMP213 modelling runs for years 2011-2014.

expensive offshore wind with onshore wind and gas CCS. This benefit is partly due to the replacement of offshore wind with onshore, but also due to the later deployment and lower level of renewables under Original in 2020. The benefit if the capacity mixes were matched in terms of renewables is expected to be of the order of half the value. At the same time, fuel costs are also increased due to higher gas usage.

Differences in transmission costs can be disaggregated into differences in onshore and offshore transmission costs, and also transmission losses. Under Original, onshore reinforcement costs were found to be very similar to reinforcement costs under Status Quo (Figure 29), albeit slightly higher due to increased onshore wind generation in Scotland. Transmission losses were also slightly higher. On the other hand, however, the cost of building offshore links was lower as there is less offshore build under Original than Status Quo. These differences were observed from 2017 onwards as seen in Figure 30. The reduction in offshore transmission costs outweighed the increase in onshore transmission costs, leading to a net benefit under Original.

Constraint costs were very similar between the two runs (Figure 32), whilst there are also some additional carbon savings under Original from 2025 onwards.

The increase in carbon costs is an indication that Original lags Status Quo in terms of decarbonisation over the 2014-2020 period.

Consumer bills

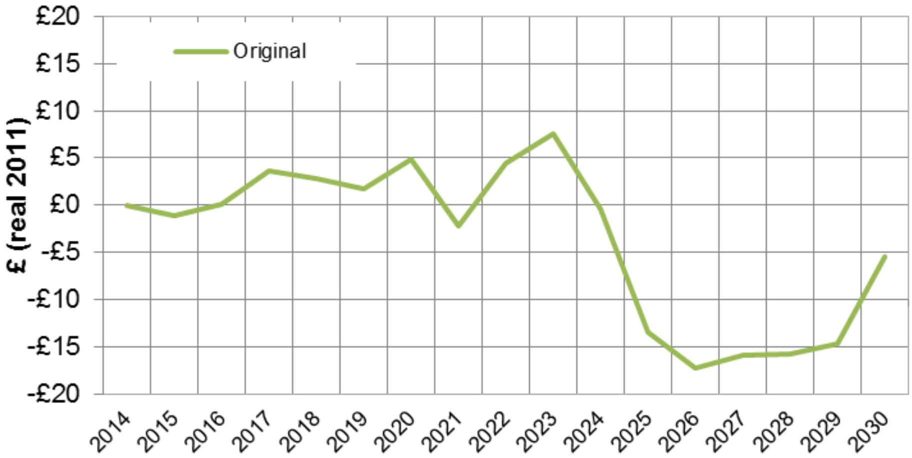
Under Original charging, wholesale costs were found to be higher until 2020 due to lower capacity margins (Figure 36), caused mainly by earlier retirements (discussed in section 4.3.4), however this trend is reversed from 2025 onwards and thus by 2030 wholesale cost reductions (close to £2.5bn) are observed. Figure 38 shows the change in the bill (averaged throughout GB) for an average domestic customer using 4000 kWh of electricity each year, under Original charging. The differences in consumer bills are larger than for TransmiT, because the capacity margin differences are larger, particularly after 2023.

A very small part of the changes in wholesale costs is driven by BSUoS charges (-£20m) and transmission losses (-£48m). BSUoS charges are slightly higher under Original charging until 2020 as a consequence of higher constraint costs, and conversely are slightly lower from 2021 onwards. Transmission losses increase with more generating capacity in northern GB (particularly Scotland) and thus increase under the Original charging option.

Low carbon support is reduced between 2014-2020 as a result of higher wholesale prices (themselves a result of lower capacity margins) which reduce the payments paid under CfDs. Low carbon support is then increased from 2021 onwards for the opposite reason.

Finally, there are also savings for consumers in terms of demand TNUoS as will be explained in the following section.

Figure 38 Change in an average annual domestic customer bill relative to Status Quo (CMP213 modelling)



4.2.6 Regional impacts

Regional impacts on consumers

Regional impacts on consumers are driven solely by differences in demand TNUoS charges which are set across 14 different charging zones. This is because differences in wholesale costs, BSUoS, transmission losses and low carbon support across charging options are likely to be passed through relatively evenly to consumers in different locations.

Under Status Quo, demand TNUoS charges are higher in major demand centres (for example, London) and lower in regions where generation is greater than demand (for example, throughout Scotland).

As can be seen in Table 18, in 2020 the greatest reduction in charges under the Improved ICRP option was found to exist in Scotland, where an increase in generation capacity under Improved ICRP reduces the cost of getting electricity to consumers. By 2030 this situation has reserved. The low volume of demand makes Scotland most sensitive to changes in generation background.

Table 18 Change in demand TNUoS component of consumer bills for average domestic consumer, relative to Status Quo (TransmiT modelling)

	Status Quo			Improved ICRP – change from Status Quo		
	£/year			£/year		
	2014	2020	2030	2014	2020	2030
N Scotland	£8.80	£17.66	£12.91	+£0.59	- £4.57	+£4.67
S Scotland	£11.96	£21.16	£18.04	+£0.27	- £4.29	+£3.08
N England	£17.19	£29.61	£33.48	+£0.11	- £0.43	+£2.06
Midlands & N Wales	£19.96	£33.01	£36.88	- £0.13	- £0.51	+£1.23
S England & S Wales	£22.51	£34.56	£36.26	- £0.05	- £0.78	- £0.95

Table 19 shows the same calculations for Original in the CMP213 modelling. Compared to Status Quo, tariffs are higher in Scotland under Original. The low volume of demand makes Scotland most sensitive to changes in generation background.

Table 19 Change in demand TNUoS component of consumer bills for average domestic consumer, relative to Status Quo (CMP213 modelling)

	Status Quo			Original – change from Status Quo		
	£/year			£/year		
	2014	2020	2030	2014	2020	2030
N Scotland	£8.92	£11.46	£14.22	+£1.88	+£2.40	+£3.56
S Scotland	£12.69	£15.36	£18.37	+£1.25	+£2.35	+£3.71
N England	£18.10	£28.19	£29.48	+£0.26	+£0.03	+£0.26
Midlands & N Wales	£20.39	£30.98	£32.24	+£0.20	- £0.44	- £0.27
S England & S Wales	£22.80	£31.37	£30.77	+£0.06	- £0.26	- £0.59

The results from the model for the average domestic customer (consuming 4000 kWh per year) under Status Quo and Improved ICRP are shown in Figure 39.

Figure 39 Demand TNUoS charges: annual cost for average domestic consumer (TransmiT modelling)

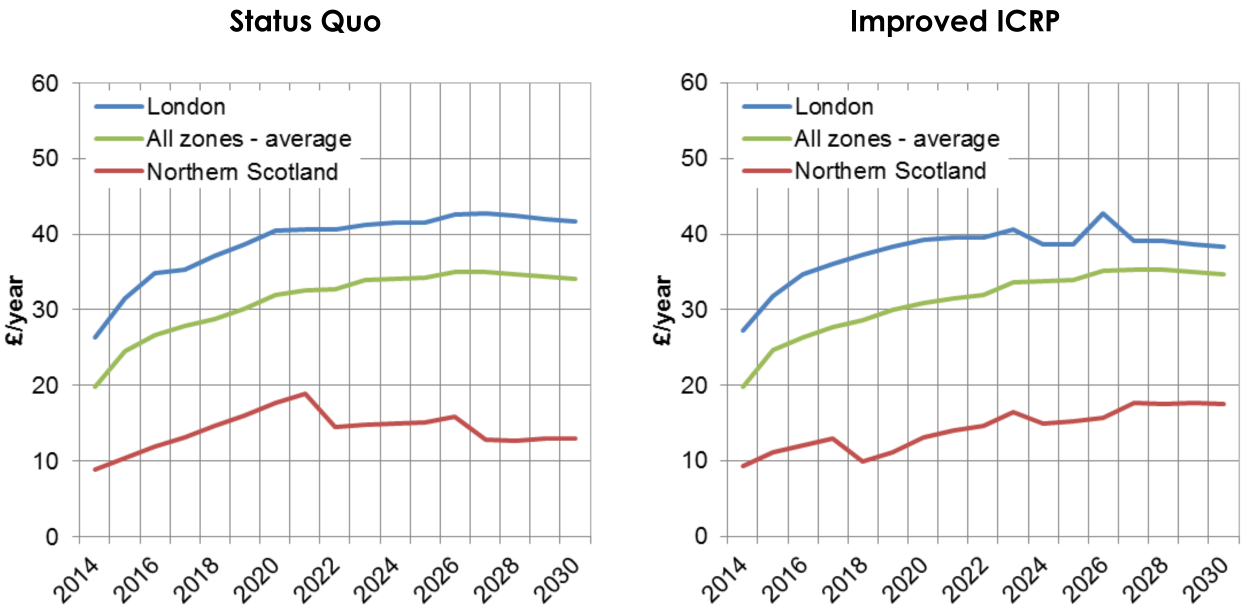
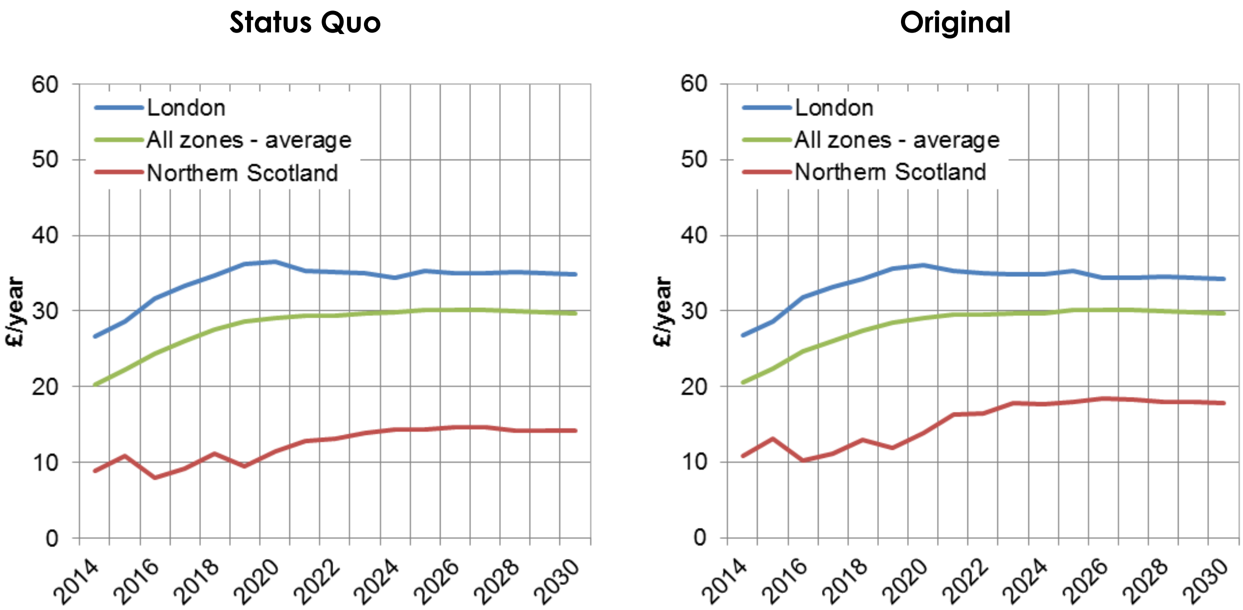


Figure 40 shows the same results for the Status Quo and Original under the CMP213 modelling. The trends in costs follow the demand tariffs as described in section 4.1.1. In the long term, the spread in tariffs is smaller under Original compared with Status Quo.

Figure 40 Demand TNUoS charges: annual cost for average domestic consumer (CMP213 modelling)



Regional impacts on generators

The different transmission charging options could change the profitability of generating plant according to their location. Figure 41 shows the annual difference in generator profits under Improved ICRP by region and offshore, over the periods 2014-2020 and 2021-2030. Profits are calculated for each generator as wholesale revenues (including CfD payments) less total costs, including capital costs for new plant. Total profits are the sum of individual generator profits throughout each region, which is a function of both the profitability of individual generators as well as the number of generators in a region.

For the Improved ICRP charging option, generators on the whole were estimated to make higher profits between 2014 and 2020 as a consequence of higher wholesale prices, for the reasons described above. During the period 2021 to 2030, however, total generator profits were found to be similar across the two charging options.

In general, the Improved ICRP charging option was found to favour generators in currently high TNUoS charging zones under Status Quo. Specifically, under Improved ICRP generator profits were found to be higher in Scotland, at the expense of generators in south England, the Midlands and Wales as Figure 41 below shows.

Figure 41 Average annual change in total generator profits, relative to Status Quo (TransmiT modelling)

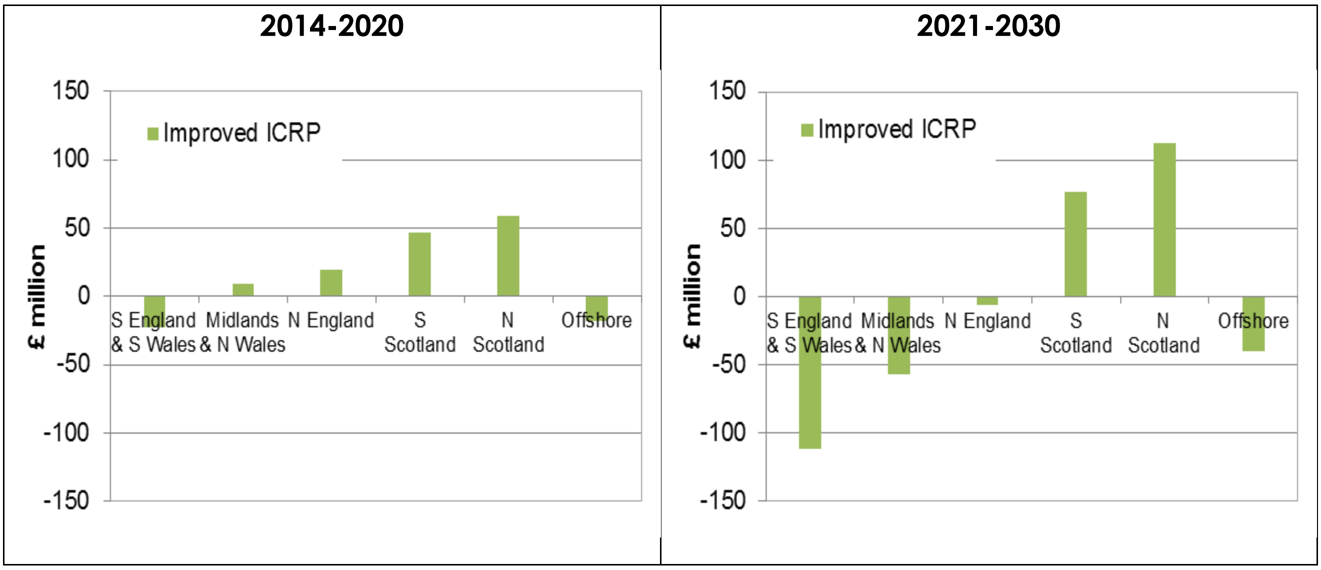
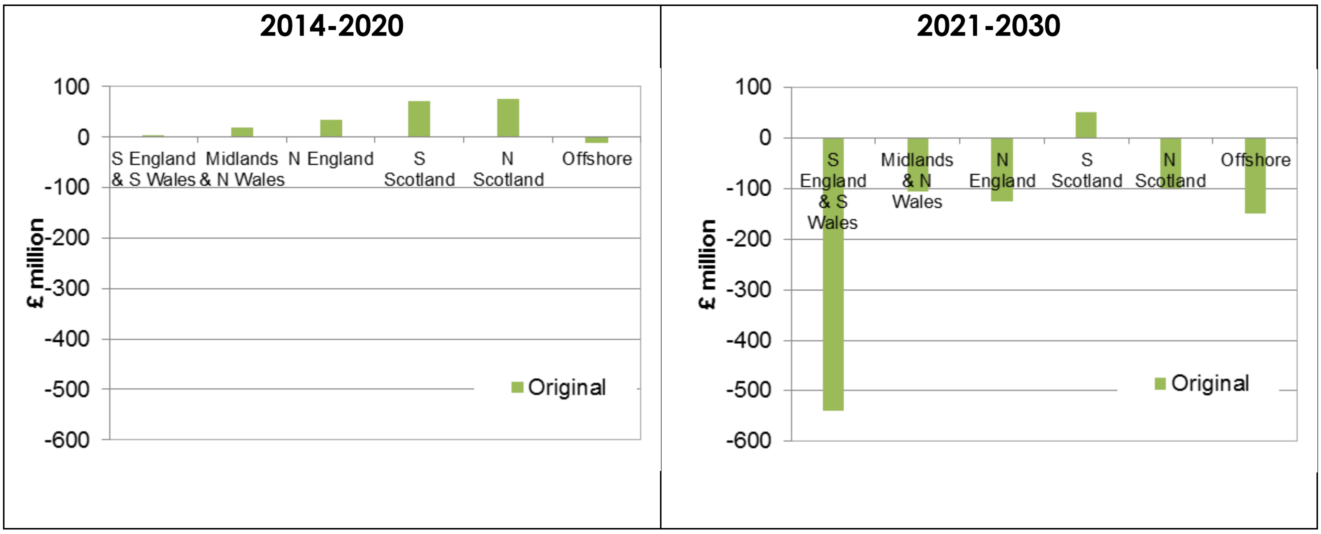


Figure 42 shows the annual difference in generator profits under the CMP213 modelling of the Original charging option by region and offshore, over the periods 2014-2020 and 2021-2030.

Generators on the whole were estimated to make higher profits between 2014 and 2020 as a consequence of higher wholesale prices, for the reasons described above. During the period 2021 to 2030, however, when wholesale electricity prices were found to drop significantly, total generator profits were also found to follow suit. The drop in wholesale electricity prices (and thus also generator profits) is particularly evident from 2024 onwards as Figure 38 shows. Our analysis also shows that generators in the South are mostly affected due to the fact that this is the area with the highest generation capacity of non-CfD operating plant whose revenues still depend on the wholesale electricity market. Revenues for offshore wind plant were also found to be considerably lower under the Original charging option due to reduced investment in this generation technology (11 GW by 2030 compared to 12.2 GW as previously seen in Table 13).

Figure 42 Average annual change in total generator profits, relative to Status Quo (CMP213 modelling)



4.2.7 Summary

In both the TransmiT modelling and the CMP213 modelling, the results demonstrate that the differences in transmission charges between Status Quo and Improved ICRP/Original have only a relatively small impact on overall power sector costs (in the context of the total power sector costs), and that renewables and decarbonisation targets can be meet under either option.

Under CMP213, Original shows a £900m NPV benefit in power sector costs relative to Status Quo in the period to 2020. This benefit is partly due to the replacement of offshore wind with onshore, but also due to the later deployment and lower level of renewables under Original in 2020. The benefit if the capacity mixes were matched in terms of renewables is expected to be of the order of half the value.

Under the TransmiT results, the total renewable generation was much closer overall, which is one reason for the closer power sector costs.

The lumpiness of transmission investment may be relatively favouring Original compared to Status Quo. The Eastern HVDC Link #2 is a net benefit in both cases, but under Original this avoids a greater level of constraint costs. This means that the incremental cost of more onshore wind is low because Eastern HVDC Link #2 creates a lot of spare boundary capacity. This effect did not occur under the TransmiT results because of the on-going increase in onshore wind generation throughout the modelling horizon.

Overall, whilst the Original shows a benefit relative to Status Quo, we expect that a scenario with more similar low carbon build to the TransmiT results, and with similar levels of renewables, could show a closer result.

Original shows a small increase in consumer bills compared to Status Quo in the period to 2020, and a significant reduction after 2025. In the TransmiT results, Improved ICRP showed a relatively small increase in consumer bills throughout the modelled period. Generally, the results for consumer bills are inherently more variable than power sector costs as small differences in capacity margin can lead to large differences in consumer bills.

4.3 Alternatives

This section discusses the results for Original, 50% HVDC and the three Diversity runs in the CMP213 results. The modelling assumptions for these variants are discussed in section 3.1.2.

4.3.1 Impacts on transmission charges

In terms of MAR, the four options are very similar as shown in Figure 43. By 2030, charges recovered from generators are roughly £1bn under all options, whilst charges recovered from demand are approximately £3bn. Moreover, it is assumed that the G:D split of charging remains at 27%:73% from 2015 onwards under all options.

Figure 43 MAR: Alternative Options (CMP213 modelling)

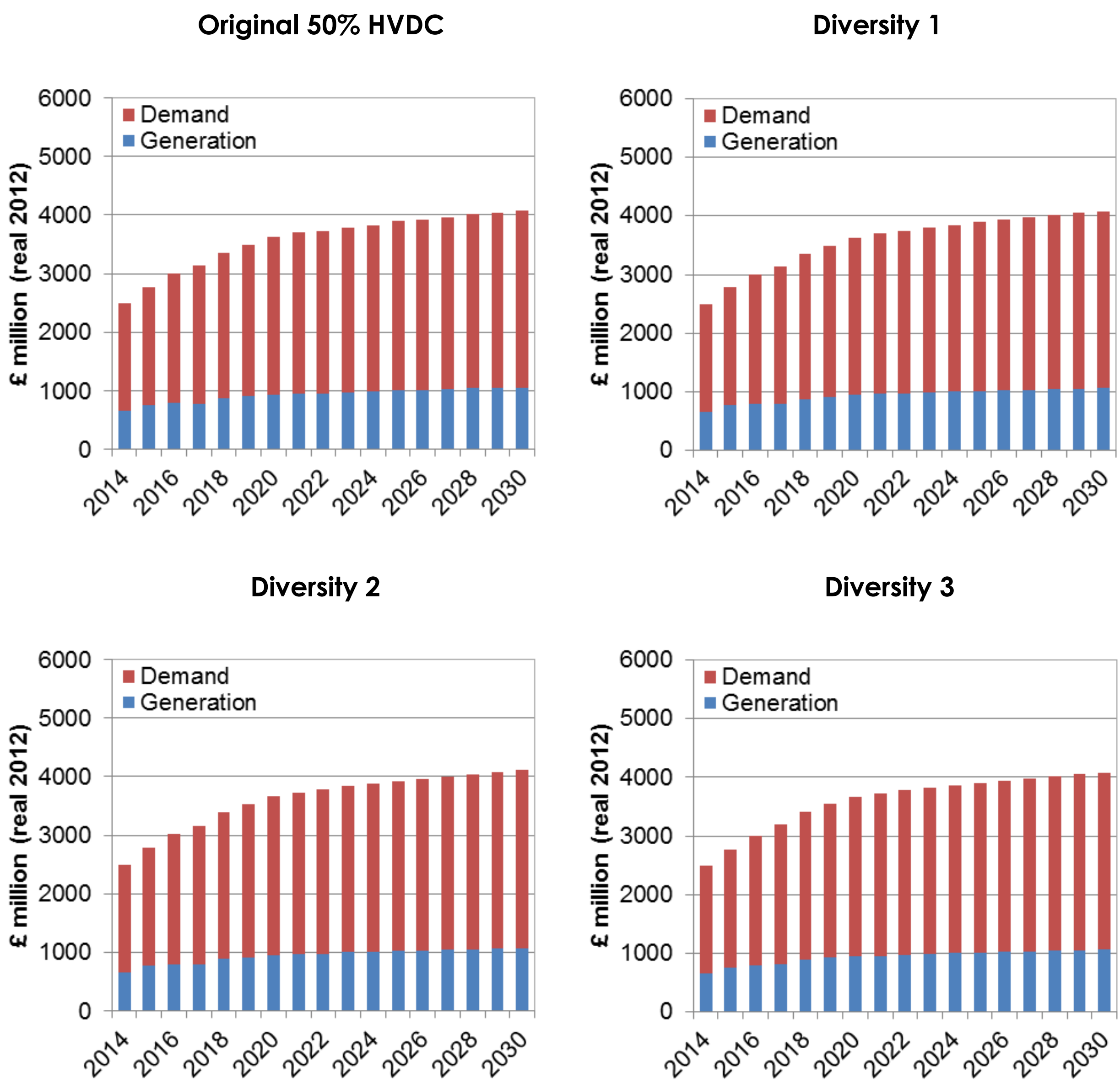


Figure 44 shows the generator wider TNUoS charges for the four alternative options considered here. Diversity 3 is the only option for which all types of generators connected in a particular zone would be subject to the same transmission charges.

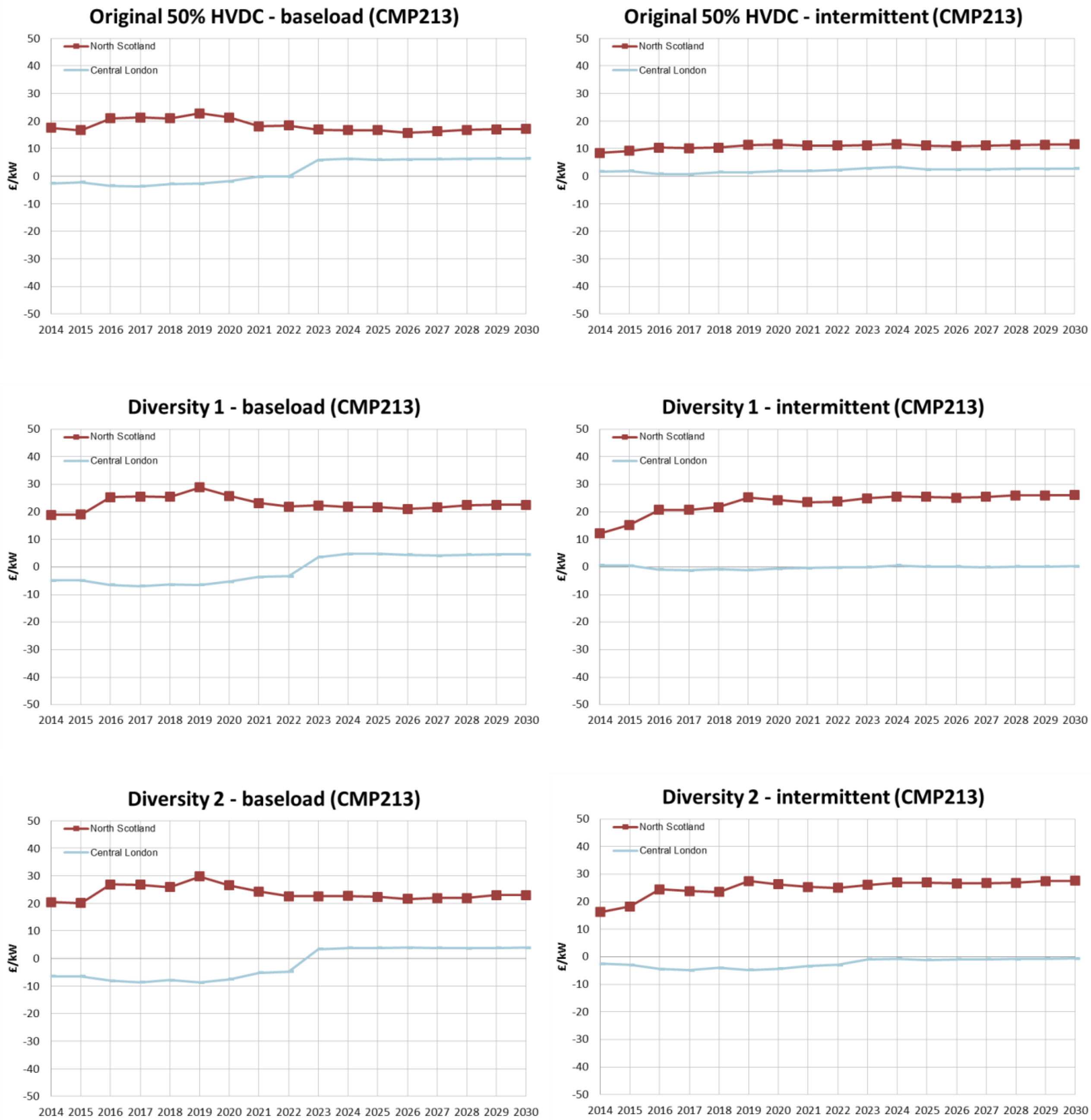
The Original 50% HVDC Converters option leads to the most compressed tariffs, particularly so for low load factor intermittent plant. In 2014 for example, tariffs ranged from -£3/kW (Central London) to £18/kW (North Scotland) for baseload generators, and from about £2/kW (Central London) to £8/kW (North Scotland) for intermittent generators. In 2030, however, tariffs now range from £6/kW (Central London) to £17/kW (North Scotland) for baseload generators, and from about £3/kW (Central London) to £12/kW (North Scotland) for intermittent generators. Compared to the generation tariffs produced under the Original approach (Figure 18) these tariffs are now even more compressed for both baseload as well as intermittent generators, albeit to a relatively small degree.

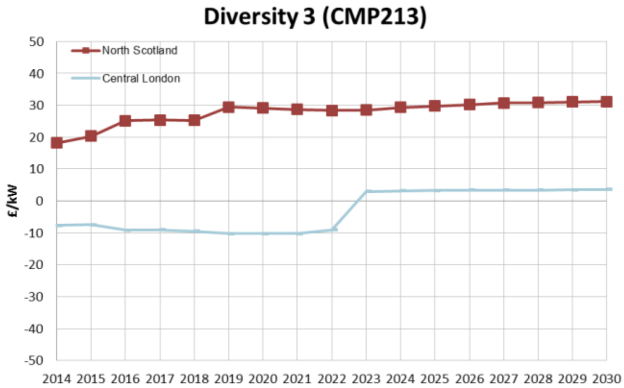
Generator wider TNUoS charges under Diversity 1 and Diversity 2 are very similar as shown in Figure 44. On average, however, tariffs are slightly more compressed under Diversity 1 compared to Diversity 2 for both baseload as well as intermittent plant. In 2014 for example, tariffs under Diversity 1 ranged from -£5/kW (Central London) to £19/kW (North Scotland) for baseload generators, and from about £1/kW (Central London) to £12/kW (North Scotland) for intermittent generators. The equivalent figures for Diversity 2 are between -£6/kW (Central London) to £20/kW (North Scotland) for baseload generators, and from about -£3/kW (Central London) to £16/kW (North Scotland) for intermittent generators.

Finally, Diversity 3 results in the least compressed tariffs and as a result is the option with the strongest locational signals (i.e. the option that most closely resembles Status Quo). In 2014 for example, tariffs ranged from -£8/kW (Central London) to £18/kW (North Scotland), whereas in 2030 TNUoS charges now ranged between £4/kW (Central London) to £31/kW (North Scotland).

In general, even though some differences have been observed, changes in the generation tariffs produced by the various Alternative charging options considered here have not been found to be significant, particularly so for baseload plant. As a result, transmission and generation investment profiles would also be expected to be broadly similar over the modelling horizon (2014 – 2030).

Figure 44 Generator wider TNUoS – locational and residual – Alternative Options (CMP 213 modelling)





4.3.2 Impacts on sustainability goals

The renewable penetration and carbon intensity targets are reached under all four alternative options considered here as shown in Table 20 and Table 21. However, the following important differences in terms of the resultant capacity mix of each modelling run can be observed (see also cumulative new build by location in Figure 46 and Figure 47):

1. The Original 50% HVDC Converters option results in the greatest deployment of onshore wind, roughly 0.2 GW more compared to the other options by 2020 and 0.4 GW more by 2030. All of this additional wind capacity is located in North Scotland since the Original 50% HVDC Converter option results in the most compressed generator TNUoS tariffs.
2. The capacity mix under Diversity 1 and Diversity 2 is very similar, with the only difference being that Diversity 2 results in an additional 0.8 GW of offshore wind capacity, all of which is located in the South. This is because Diversity 2 results in slightly less compressed tariffs compared to Diversity 1 and as a result locating generation plant in the South is more attractive under the Diversity 2 option.
   The strongest locational investment signals are retained under the Diversity 3 charging option. Compared to Diversity 1, Diversity 3 results in less onshore wind and more offshore wind by 2030, with capacity more concentrated in the south.

Table 20 2020 carbon intensity and renewable penetration results – Alternative Options (CMP213 modelling)

2020 Results	Original 50% HVDC (CMP213)	Diversity 1 (CMP213)	Diversity 2 (CMP213)	Diversity 3 (CMP213)
Onshore Wind (GW)	10.1	9.9	9.9	9.9
Offshore Wind (GW)	10.1	10.1	10.9	10.7
Renewable Penetration (%)	29.7%	29.6%	30.3%	30.1%
Nuclear (GW)	7.6	7.6	7.6	7.6
CCS (GW)	1.1	1.1	1.1	1.1
Carbon intensity (g/kWh)	251.6	252.1	248.7	249.7

Table 21 2030 carbon intensity and renewable penetration results – Alternative Options (CMP213 modelling)

2030 Results	Original 50% HVDC (CMP213)	Diversity 1 (CMP213)	Diversity 2 (CMP213)	Diversity 3 (CMP213)
Onshore Wind (GW)	11.8	11.4	11.4	11.1
Offshore Wind (GW)	11.0	10.1	10.9	10.7
Renewable Penetration (%)	32.2%	31.3%	31.9%	31.3%
Nuclear (GW)	14.8	14.8	14.8	14.8
CCS (GW)	9.3	9.3	9.3	9.3
Carbon intensity (g/kWh)	96.5	99.5	97.5	100.6

4.3.3 Overall cost impacts

Capacity mix

The main differences in terms of investment in low carbon generation technologies were explained in the previous section. With regards to CCGT build, there are no differences across the four runs until 2020, with 5.8 GW of new-build CCGTs located in South England and South Wales, 3 GW in Midlands and North Wales and 1 GW in North England (Figure 47).

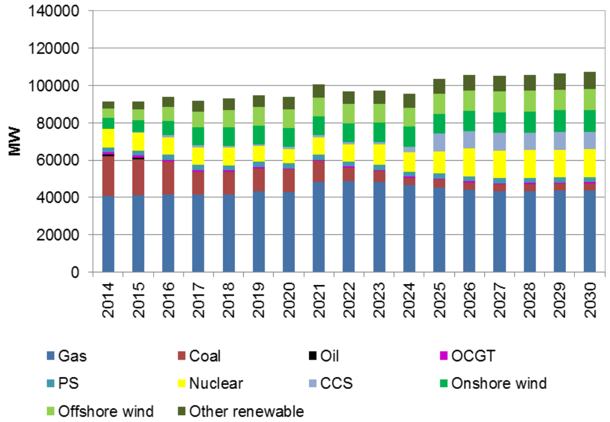
With the exception of Diversity 3, all other charging options result in the same CCGT build by 2030, with investment continuing in the South England and South Wales region only, where total new CCGT capacity reaches 11.4 GW by 2030. Modelling results from the Diversity 3 charging option, however, show that under this option a further 1.1 GW of CCGTs are developed in South England and South Wales and a further 1.6 GW in North England.

Analysis of plant retirement decisions, meanwhile, shows that there are no differences in coal plant retirements for the duration of the modelling horizon, whilst there are also no differences in gas plant retirements until 2020. By 2030, however, there are considerable differences in gas plant retirement decisions across the four charging options:

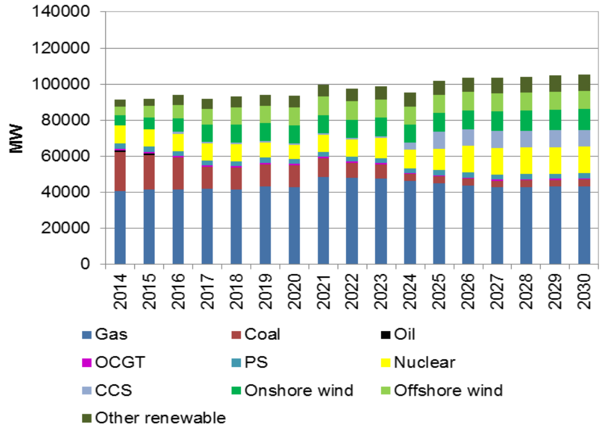
- The Original 50% HVDC Converters charging option results in the lowest amount of CCGT capacity to be retired by 2030, a total of 11.4 GW;
- The Diversity 1 option results in an additional 0.5 GW of CCGT capacity located in North England to be retired by 2030 (i.e. a total 11.9 GW);
- The Diversity 2 option results in an additional 1.1 GW of CCGT capacity located in North England and 0.7 GW of CCGT capacity located in South England and South Wales to be retired by 2030 (i.e. a total of 13.7 GW);
- Finally, the Diversity 3 option results in an additional 0.2 GW of CCGT capacity located in South England and South Wales to be retired by 2030 (i.e. a total of 13.9 GW).

Figure 45 Total generation capacity – Alternative Options (CMP213 modelling)

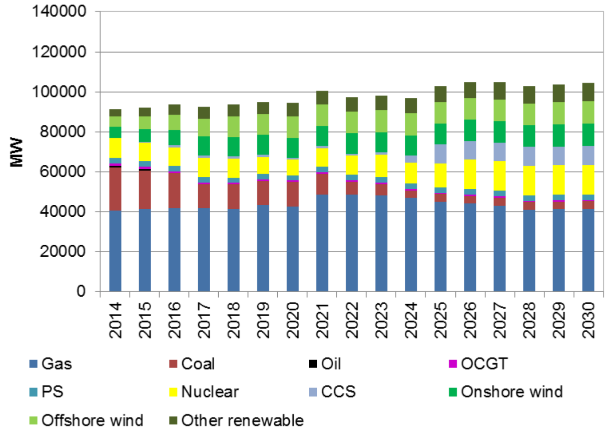
Original 50% HVDC



Diversity 1



Diversity 2



Diversity 3

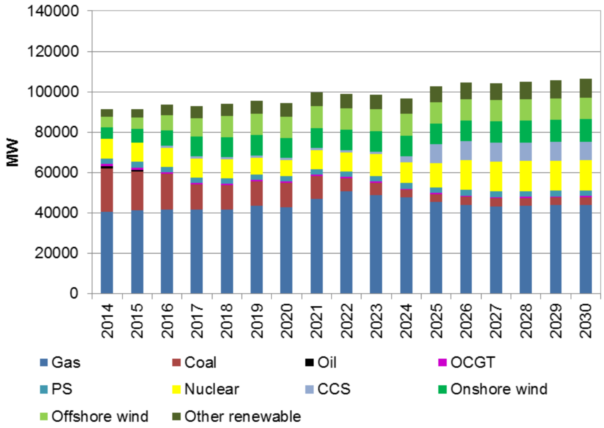


Figure 46 shows cumulative new build by location to 2020, for the Alternatives. By 2020, the main differences are that Original 50% has more onshore wind in North Scotland than the Diversity options, and that Diversity 2 and Diversity 3 deploy more offshore wind in the south whilst Diversity 3 deploys less wind in the East of England.

Figure 46 New build by location to 2020

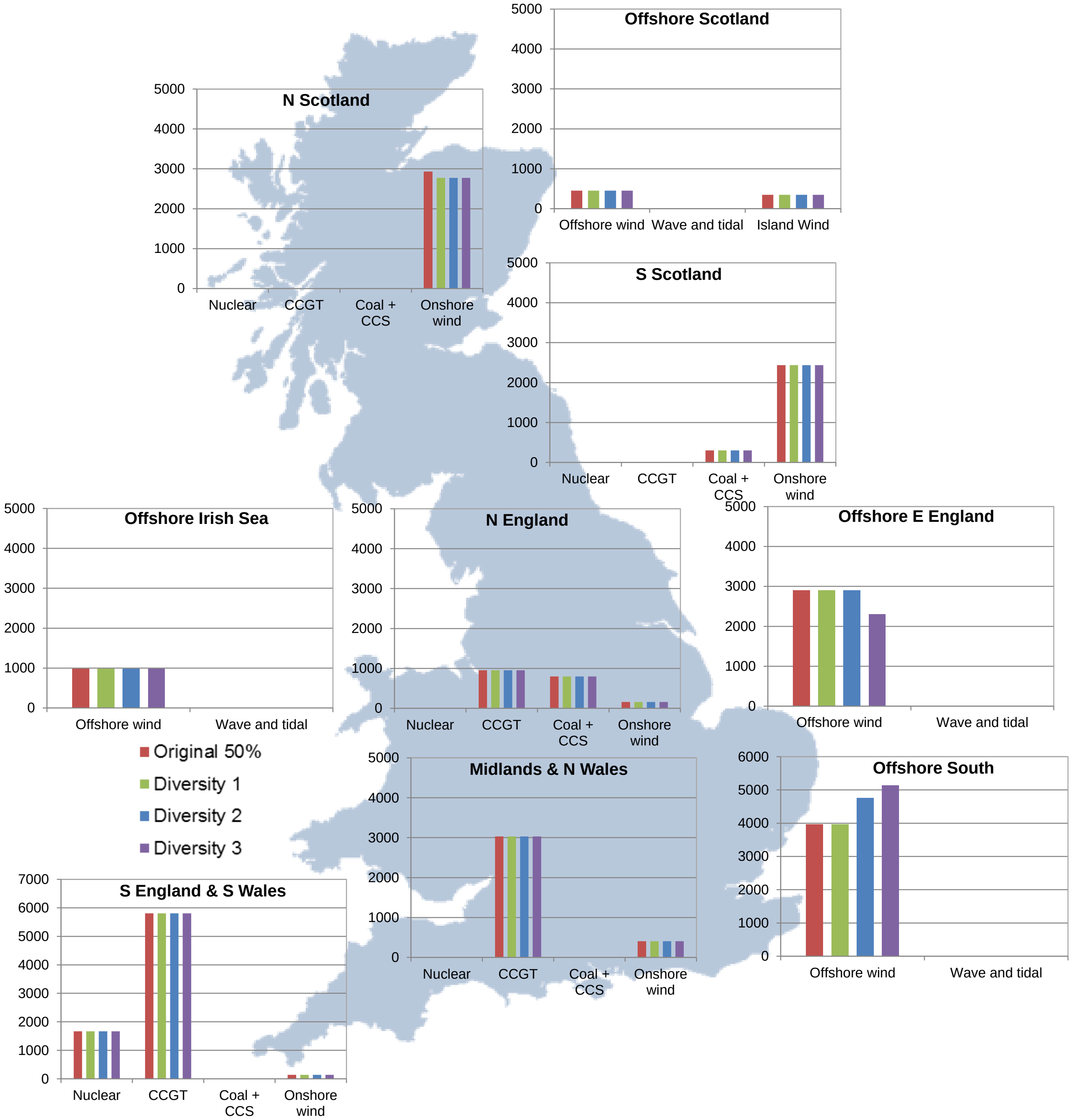
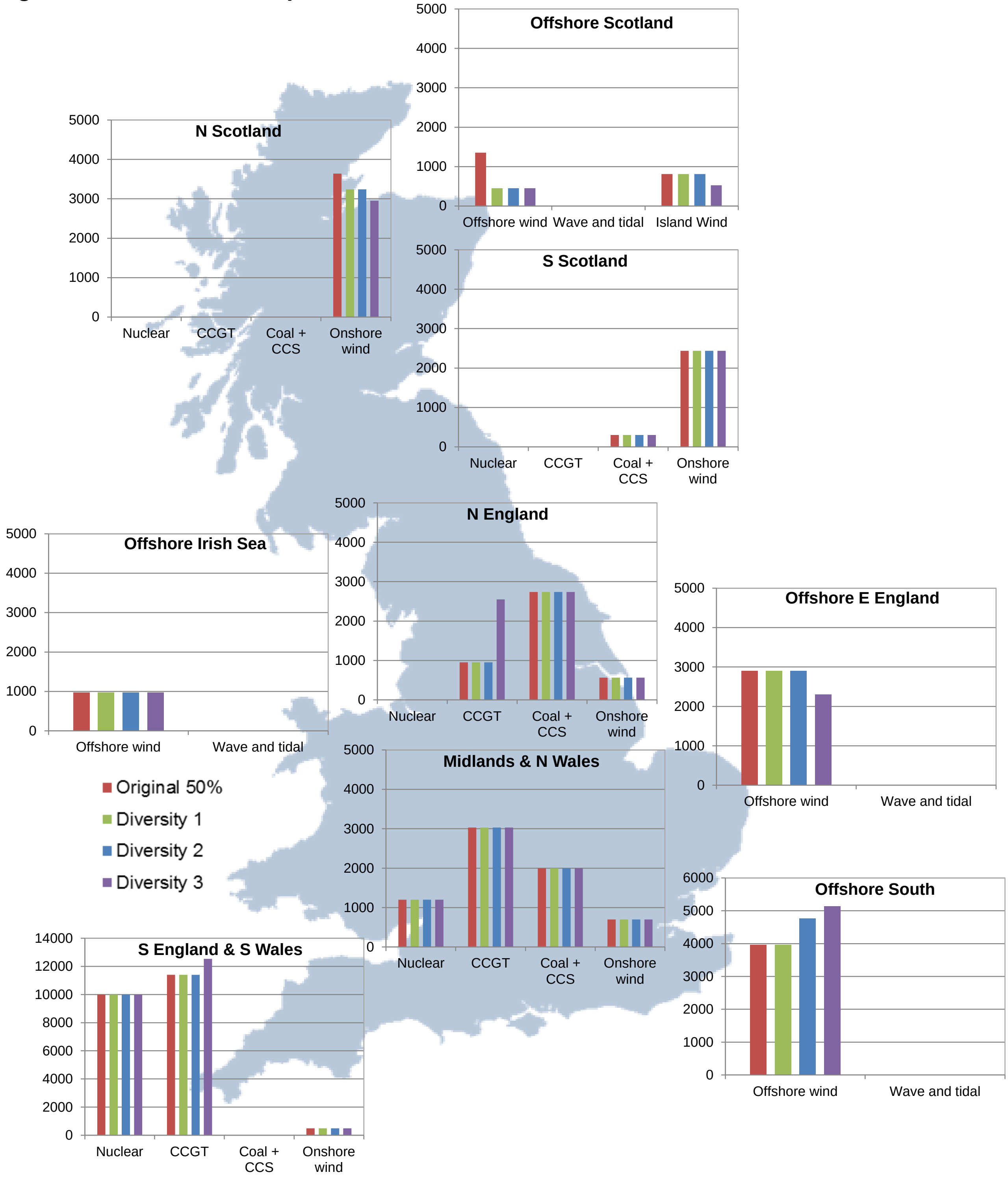


Figure 47 shows cumulative new build by location to 2030, for the Alternatives.

Figure 47 New build by location to 2030

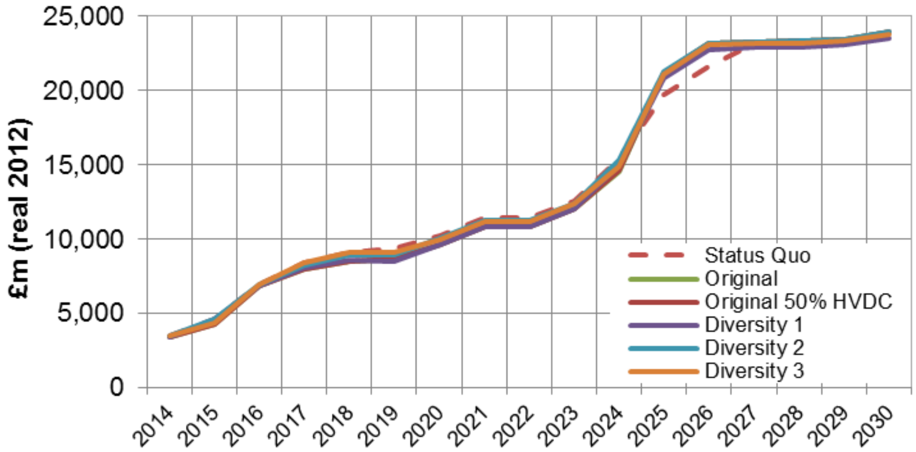


Generation costs of low carbon deployment

Figure 48 shows the cumulative cost of low carbon generation under the Alternative charging options. It can be seen that these costs are broadly consistent across the options. By 2030 Diversity 1 results in the lowest overall annual low carbon generation costs (roughly £23.6bn/year). The following other trends have been observed:

1. Diversity 3 leads in the highest annual nuclear costs by 2030 (roughly £8.2bn/year compared to roughly £8bn/year under the other runs);
2. Small differences have been observed for onshore wind costs which by 2030 amount to roughly £2.5bn/year;
3. Regarding offshore wind, Diversity 1 has been found to result in the lowest offshore wind costs (£3.9bn/year) whilst the other Alternative options result in approximately £4.3bn/year.

Figure 48 Low carbon generation costs



Transmission reinforcement decisions and costs

Figure 49 shows the modelled reinforcement costs to the Main Interconnected Transmission System under the alternative options considered here. It can be seen that network reinforcement is identical up to 2019, and there are also no differences in terms of HVDC links (Table 22).

After 2019 there is a relatively slow rate of investment in the onshore transmission system due to a lower growth rate in renewables compared to TransmiT modelling. In this period the key difference in terms of reinforcement projects is that the Original and Alternative charging options bring forward the East Coast Upgrade, which takes place 3 years later under the Status Quo option. This upgrade reinforces internal Scottish boundaries.

Figure 50 shows the offshore and island transmission costs which are highest under the Status Quo charging option followed by Original 50%. This is because these two scenarios result in the greatest deployment of offshore wind by 2030 (12.2 GW and 11.0 GW respectively). The lowest deployment of offshore wind is observed under the Diversity 1 (10.1 GW) followed by the Diversity 2 (10.9 GW) charging option and as expected these are also the two scenarios with the lowest offshore reinforcement costs.

Figure 49 Modelled reinforcement costs to the Main Interconnected Transmission System – Alternative Options (CMP213 modelling)

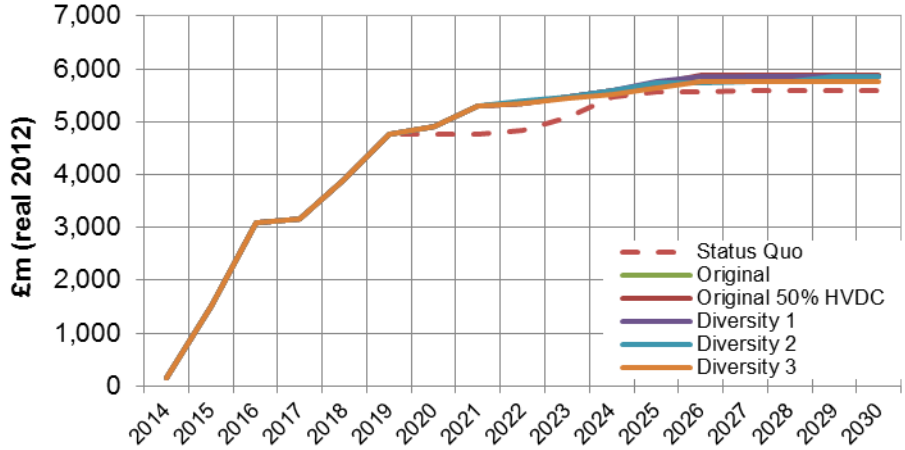
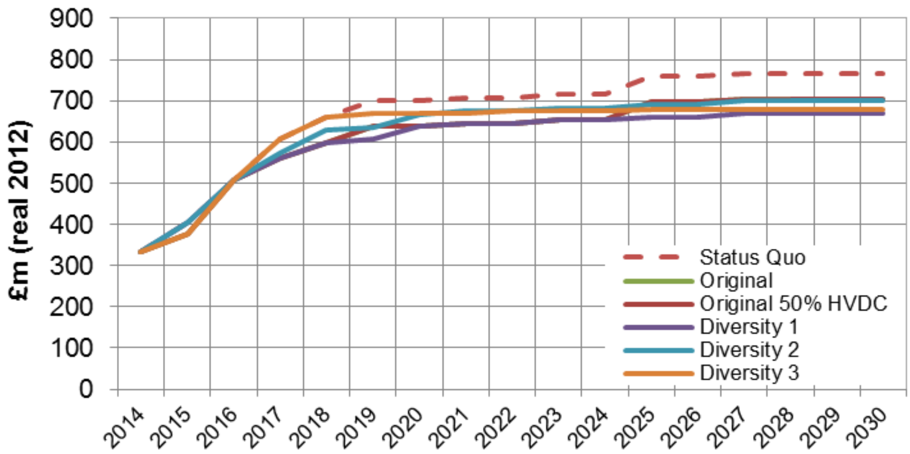


Table 22 Timing of new HVDC links – Alternative Options (CMP213 modelling)

Reinforcement	Status Quo	Original	Original 50% HVDC	Diversity 1	Diversity 2	Diversity 1
Western HVDC Link	2016	2016	2016	2016	2016	2016
Western HVDC Link #2	-	-	-	-	-	-
Eastern HVDC Link	-	-	-	-	-	-
Eastern HVDC Link #2	2019	2019	2019	2019	2019	2019
Wylfa-Pembroke 2GW HVDC	-	-	-	-	-	-
Caithness - Moray HVDC	-	-	-	-	-	-
Humber - Walpole HVDC	-	-	-	-	-	-

Figure 50 Offshore and island transmission: cumulative investment costs – Alternative Options (CMP213 modelling)

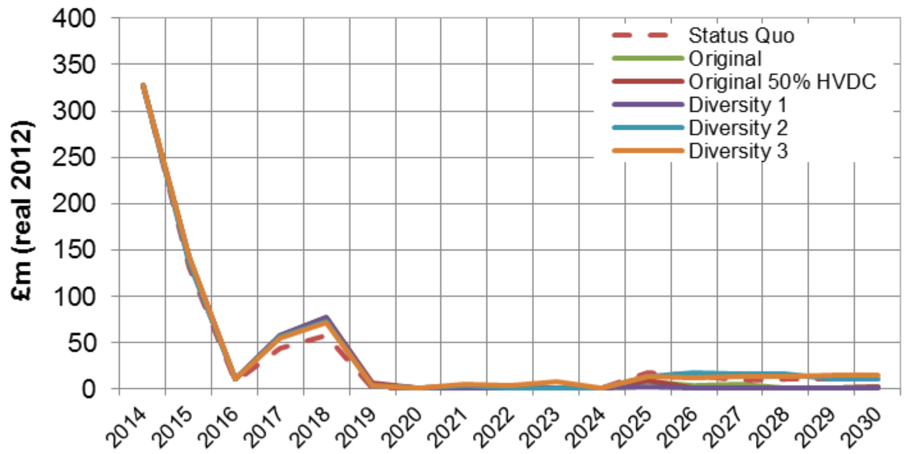


Constraint costs

Constraint costs for the CMP213 modeling runs are shown in Figure 51. Constraint costs can mainly be attributed to transmission constraints on boundaries B6 and B7a, which are reinforced away by the two HVDC bootstraps (the Western HVDC link which is operational from 2016 and the Eastern HVDC Link #2 which is operational from 2019).

It can be seen that constraint costs are almost fully relieved (typically less than £10m per year) with the commissioning of the Eastern HVDC Link #2 from 2019 onwards. There is a small increase in constraint costs from 2025 onwards but due to the very slow growth in renewables in the 2020s constraint costs are kept at minimal levels.

Figure 51 Annual constraint costs – Alternative Options (CMP213 modelling)

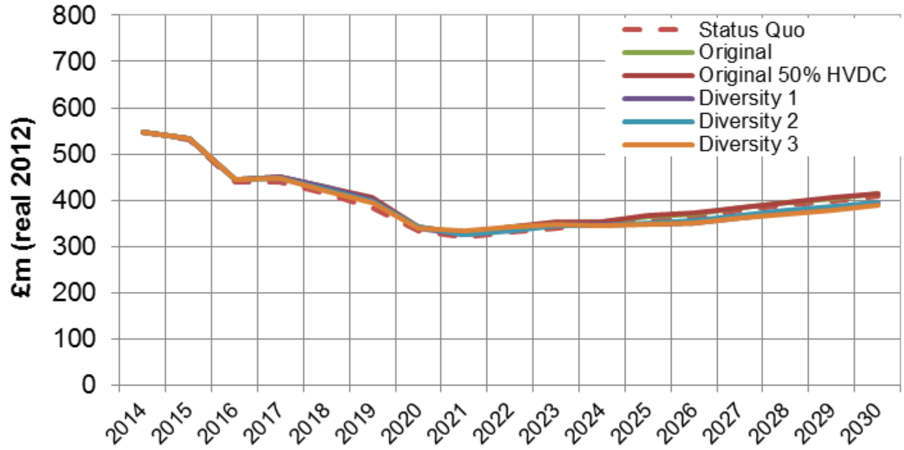


Transmission losses

Transmission losses for the CMP213 modelling runs are shown in Figure 52. It can be seen that all six models follow the same trend, with small differences that are mainly due to differences in onshore wind capacity, a large portion of which is often located far from centres of demand.

The highest losses are observed under the Original 50% HVDC and Original charging options which are the two scenarios with the highest onshore wind capacity, whilst conversely the lowest losses are observed under the Diversity 3 charging option.

Figure 52 Transmission losses – Alternative Options (CMP213 modelling)



4.3.4 Impacts on security of supply

Figure 53 shows the calculated de-rated capacity margins for the CMP213 modelling runs. The following main trends can be observed:

1. In the period between 2017 and 2020 de-rated capacity margins under the four Alternative runs are lower compared to the Status Quo. In part this can be attributed to reduced investment in offshore wind, however this is largely due to earlier retirements under all Alternative runs for a total of 1.3 GW of CCGT capacity in North England and Midlands & North Wales.
2. In the period 2021 – 2023 there is significant new CCGT build (roughly 6 GW), which along with the development of 5 GW of new nuclear allows de-rated capacity margins to recover to above 6% under all modelling runs.
3. De-rated capacity margins fall in 2024 due to closure of LLO (Limited Lifetime Obligation) plant. Again, no significant differences are observed across the different options with de-rated capacity margins for that year ranging between 1-3%.
4. Finally, in the period 2025-2030 de-rated capacity margins recover back to above 5% mainly due to investment in nuclear, CCS and, to a lesser extent, unabated CCGT. The lowest margins during this period are observed under the Diversity 2 option (along with the Status Quo) due to earlier CCGT retirements in South England and Wales and North England. On the other hand, the highest margins are observed under the Diversity 3 option due to increased investment in new CCGT and new nuclear capacity which takes place in South England and South Wales.

Figure 53 De-rated capacity margins – Alternative Options (CMP213 modelling)

Note: Capacity margins based on the peak demand shown in Figure 2 De-rating factors used were 90% for conventional, nuclear and biomass thermal plant, 70% for hydroelectricity, 100% for pumped storage, 15% for wind and 30% for tidal and wave.

4.3.5 Cost benefit analysis

Table 23, Table 24, Table 25, and Table 26 present the CBA results for the Original 50% HVDC Converter, Diversity 1, Diversity 2 and Diversity 3 runs respectively.

Of the four modelled alternatives, Diversity 1 leads to the lowest power sector costs due to the greatest reduction in generation and transmission costs, whilst Diversity 3 leads to the lowest consumer bills due to the greatest reduction in wholesale electricity costs.

Table 23 Cost Benefit Analysis: Original 50% HVDC converter cost (CMP213 modelling)

		50% HVDC Converter Cost Option (£m real 2012)	
		NPV 2014-2020	NPV 2021-2030
Benefit relative to Status Quo			
Power sector costs	Generation costs	952	-116
	Transmission costs	135	205
	Constraint costs	-41	37
	Carbon costs	-102	274
	Decrease in power sector costs	**943**	**399**
Consumer Bills	Wholesale costs (inc. capacity payments	-1,728	4,226
	BSUoS	-21	18
	Transmission losses	-49	-49
	Demand TNUoS charges	135	186
	Low carbon support	885	-454
	Decrease in consumer bills	**-779**	**3,927**

Table 24 Cost Benefit Analysis: Diversity 1 (CMP213 modelling)

		Diversity 1 (£m real 2012)	
		NPV 2014-2020	NPV 2021-2030
Benefit relative to Status Quo			
Power sector costs	Generation costs	931	517
	Transmission costs	143	407
	Constraint costs	-34	43
	Carbon costs	-116	58
	Decrease in power sector costs	**924**	**1,025**
Consumer Bills	Wholesale costs (inc. capacity payments	-1,725	3,517
	BSUoS	-17	21
	Transmission losses	-42	32
	Demand TNUoS charges	135	274
	Low carbon support	930	666
	Decrease in consumer bills	**-719**	**4,510**

Table 25 Cost Benefit Analysis: Diversity 2 (CMP213 modelling)

		Diversity 2 (£m real 2012)	
		NPV 2014-2020	NPV 2021-2030
Benefit relative to Status Quo			
Power sector costs	Generation costs	349	-579
	Transmission costs	73	236
	Constraint costs	-29	-3
	Carbon costs	-45	304
	Decrease in power sector costs	**348**	**-41**
Consumer Bills	Wholesale costs (inc. capacity payments	-1,382	2,895
	BSUoS	-15	-1
	Transmission losses	-33	28
	Demand TNUoS charges	78	152
	Low carbon support	359	-464
	Decrease in consumer bills	**-992**	**2,609**

Table 26 Cost Benefit Analysis: Diversity 3 (CMP213 modelling)

		Diversity 3 (£m real 2012)	
		NPV 2011-2020	NPV 2021-2030
Benefit relative to Status Quo			
Power sector costs	Generation costs	308	-762
	Transmission costs	28	324
	Constraint costs	-32	-9
	Carbon costs	-35	-128
	Decrease in power sector costs	**269**	**-576**
Consumer Bills	Wholesale costs (inc. capacity payments	-1,166	7,070
	BSUoS	-16	-5
	Transmission losses	-28	33
	Demand TNUoS charges	41	212
	Low carbon support	224	-1,210
	Decrease in consumer bills	**-944**	**6,102**

Power sector costs

The NPV of generation costs were found to be considerably lower under the Original 50% HVDC and Diversity 1 charging options due to savings in generation capital costs and fixed costs associated with replacing expensive offshore wind with onshore wind. By 2030 Diversity 1 results in the lowest overall renewable level (31.3% as seen in Table 23) and as a result this also reduces generation costs and thus presents the Diversity 1 run in a more favourable light than if the renewable generation matched exactly. A similar story holds true for Original 50% HVDC however some additional investment in offshore wind in the 2020s results in this option to appear as more expensive.

Differences in transmission costs can be disaggregated into differences in onshore and offshore transmission costs, and also transmission losses. Onshore reinforcement costs (Figure 49) and transmission losses (Figure 52) were found to be very similar across the four Alternatives. However, Diversity 3 has been shown to lead to increased OFTO costs (Figure 50) due to increased investment in offshore wind and as a result this option also leads to highest transmission costs.

Constraint costs and carbon costs are almost identical across the four runs and are therefore not major factors driving the CBA.

Overall, Diversity 1 leads to the lowest power sector costs, followed by Original 50% HVDC, whilst Diversity 3 leads to the highest power sector costs. These differences can largely be explained by differences in generation costs, which are mostly driven by different investment profiles in renewable technologies. In general, generation cost savings are realised under runs with lower levels of renewable penetration, or where expensive offshore wind is replaced by onshore wind or gas CCS.

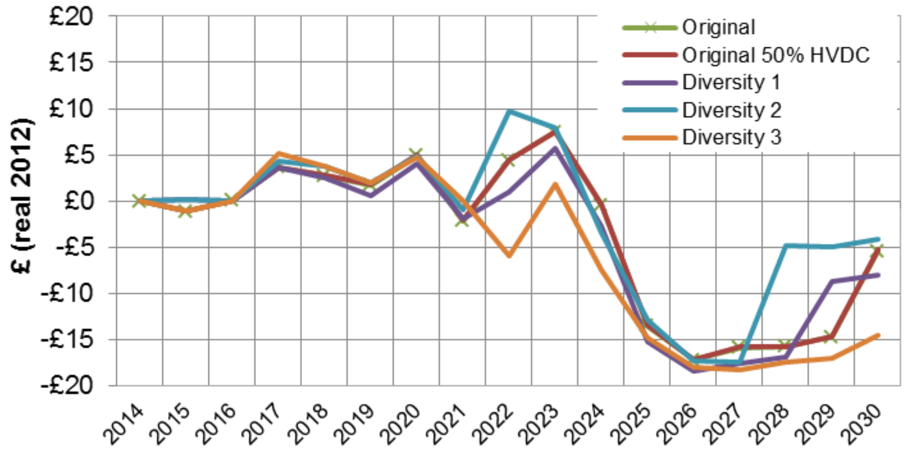
Consumer bills

The changes in consumer bills (shown below in Figure 54) include effects from BSUoS, losses, demand TNUoS and Low carbon support. However they are dominated by changes in the wholesale cost of power (including capacity payments). Fuel and carbon prices are unchanged across the transmission charging options, and that the capacity mixes are similar overall. Therefore, the differences in wholesale cost are mainly a result of different capacity margins, with tighter margins leading to an uplift in power price. This uplift in wholesale electricity prices is somewhat offset by lower capacity payments to generators, however this is not fully offset.

Under all Alternative options, wholesale costs were found to be higher compared to the Status Quo until 2020 due to tighter capacity margins (Figure 53). However, this trend is reversed from 2025 onwards and thus by 2030 considerable wholesale cost reductions are realised under all runs. The greatest reductions were observed under the Diversity 3 option for reasons previously explained (i.e. highest margins and also greatest investment in low carbon technologies which have low short run marginal costs). On the other hand, however, low wholesale prices mean that this option also leads to the highest low carbon support (due to CfD top-up payments).

Figure 54 shows the change in the bill (averaged throughout GB) for an average domestic customer using 4000 kWh of electricity each year. Diversity 3 leads to the greatest savings, while conversely Diversity 2 leads to almost no savings due to persistently tight capacity margins resulting in price uplift.

Figure 54 Change in an average annual domestic customer bill relative to Status Quo– Alternative Options (CMP213 modelling)



4.3.6 Regional impacts

Regional impacts on consumers

As previously mentioned, regional impacts on consumers are driven solely by differences in demand TNUoS charges which are set across 14 different charging zones. This is because differences in wholesale costs, BSUoS, transmission losses and low carbon support across charging options are likely to be passed through relatively evenly to consumers in different locations. Table 27 shows the change in the demand TNUoS component of consumer bills under all Alternative options relative to Status Quo.

The Original 50% HVDC option has been found to be the option most similar to Original, with considerable reductions compared to Status Quo in consumer bills for regions where demand is greater than generation but increases for consumers located in regions where generation is greater than demand. A similar trend has also been found to take place under the Diversity 1 and Diversity 2 charging options, with the greatest increase in charges taking place in Scotland and the greatest reduction in South England and South Wales.

On the other hand, demand TNUoS charges under the Diversity 3 option are very similar to the Status Quo as shown in Table 27. There are some small increases for customers in Scotland due to differences in transmission and generation investment however the regional impact on consumers between the two runs remains is very similar.

Table 27 Change in demand TNUoS component of consumer bills for average domestic consumer, relative to Status Quo– Alternative Options (CMP213 modelling)

	Original 50% HVDC Converters– change from Status Quo			Diversity 1 – change from Status Quo		
	£/year			£/year		
	2014	2020	2030	2014	2020	2030
N Scotland	+£1.88	+£3.71	+£4.81	+£1.60	+£3.27	+£4.38
S Scotland	+£1.25	+£3.75	+£5.06	+£0.81	+£3.25	+£4.21
N England	+£0.26	+£0.01	+£0.25	- £0.12	- £0.19	+£0.23
Midlands & N Wales	+£0.20	- £0.61	- £0.46	+£0.04	- £0.72	- £0.62
S England & S Wales	+£0.06	- £0.42	- £0.75	+£0.37	- £0.20	- £1.08

	Diversity 2 – change from Status Quo			Diversity 3 – change from Status Quo		
	£/year			£/year		
	2014	2020	2030	2014	2020	2030
N Scotland	+£1.60	+£3.53	+£4.63	- £0.03	+£0.35	-£0.02
S Scotland	+£0.81	+£3.54	+£4.61	- £0.47	+£0.53	-£0.12
N England	- £0.12	+£0.11	+£0.46	- £0.14	-£0.07	-£0.44
Midlands & N Wales	+£0.04	- £0.44	- £0.46	+£0.09	+£0.31	-£0.34
S England & S Wales	+£0.37	- £0.02	- £0.87	+£0.61	+£0.29	-£0.03

Regional impacts on generators

All four Alternative options have been found to result in reduced generator profits relative to the Status Quo due to reduced wholesale electricity prices for reasons previously explained. Out of the four options considered here, Diversity 3 has been found to result in the lowest generator profits with Diversity 2 resulting in the highest.

Figure 55 shows the average annual change in total generator profits for the Original 50% HVDC option compared to the Status Quo. By 2020, this option results in the greatest profits compared to the other Alternative options. This is mainly due to profits from generators located in Scotland (both South and North Scotland) as a result of increased investment in Scottish onshore wind. After 2021, however, generator profits are considerably reduced, particularly for generators located in the South.

The Diversity 1 and Diversity 2 options lead to very similar profits for generators, with Diversity 2 leading to slightly higher profits over the period 2021 – 2030 due to a combination of higher wholesale prices and higher investment in offshore wind.

The Diversity 1 (Figure 56) and Diversity 2 (Figure 57) options lead to very similar profits for generators, with Diversity 2 leading to slightly higher profits over the period 2021 – 2030 due to a combination of higher wholesale prices and higher investment in offshore wind.

Finally Diversity 3 (Figure 58) is the charging option that results in the lowest wholesale costs and as a result this is also the option that results in the lowest generator profits overall despite increased investment in new-build capacity.

Figure 55 Average annual change in total generator profits, relative to Status Quo – Original 50% HVDC converter cost (CMP213 modelling)

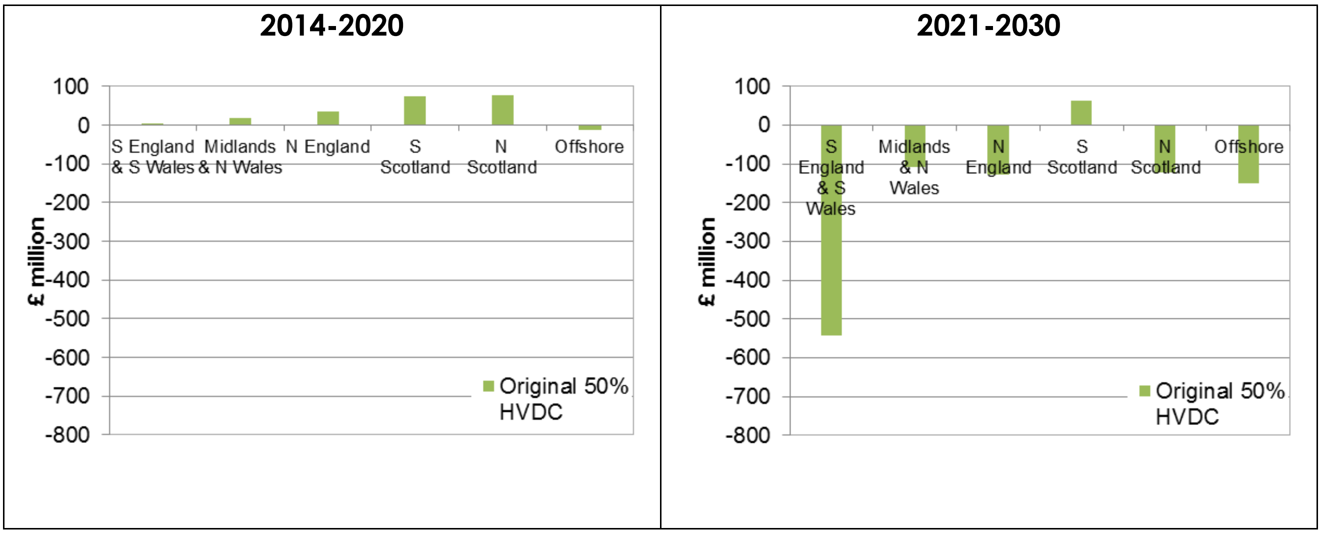


Figure 56 Average annual change in total generator profits, relative to Status Quo – Diversity 1 (CMP213 modelling)

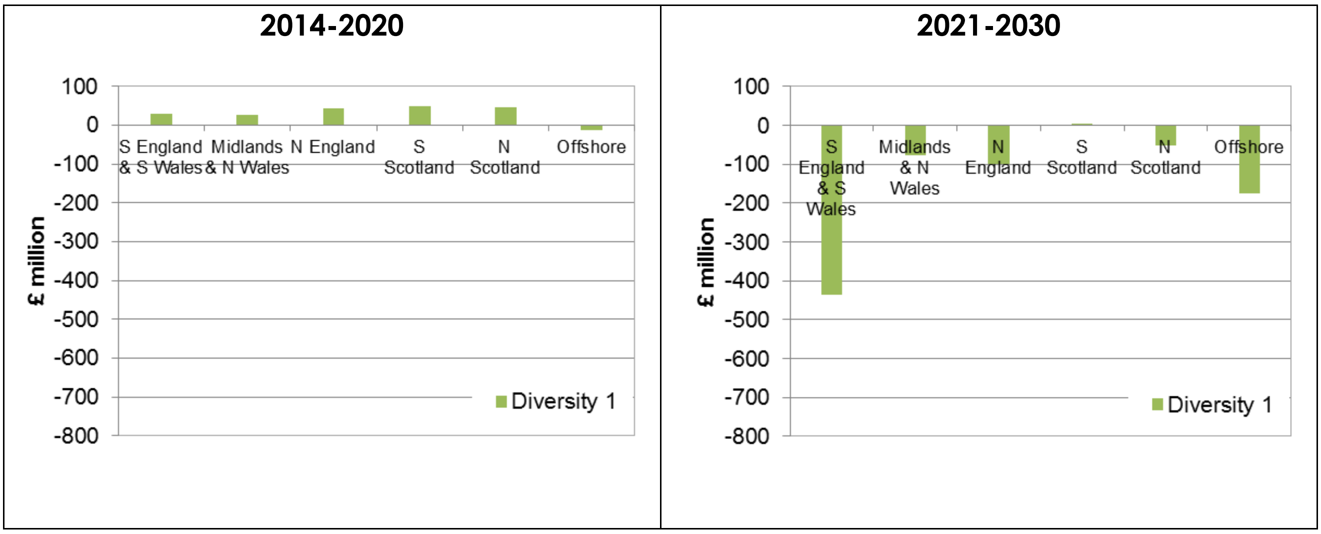


Figure 57 Average annual change in total generator profits, relative to Status Quo – Diversity 2 (CMP213 modelling)

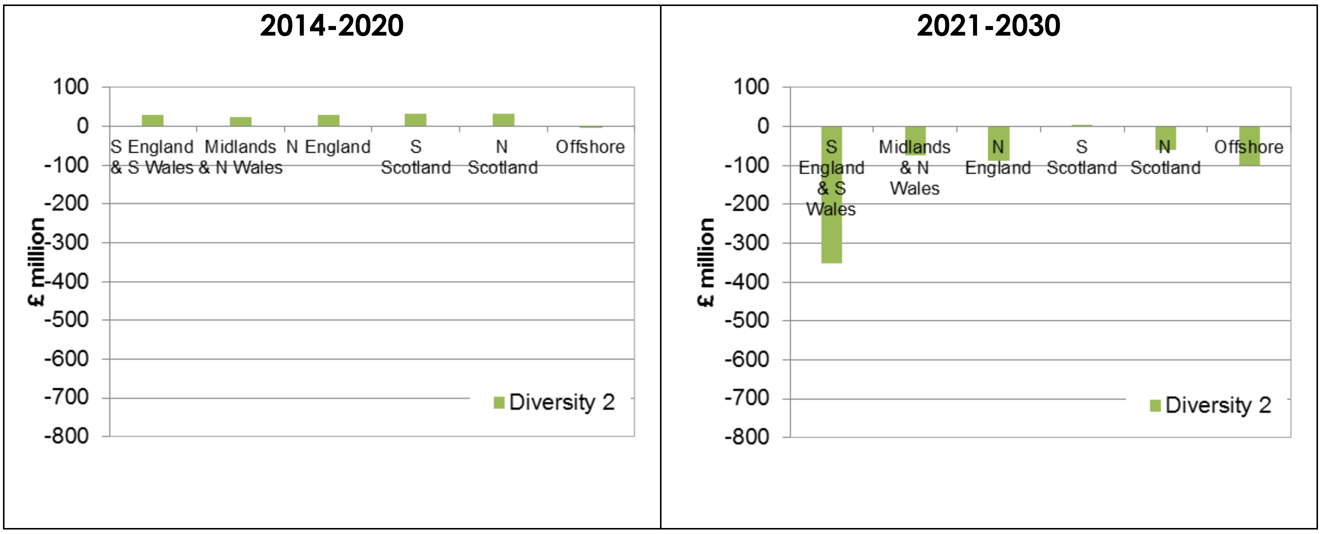
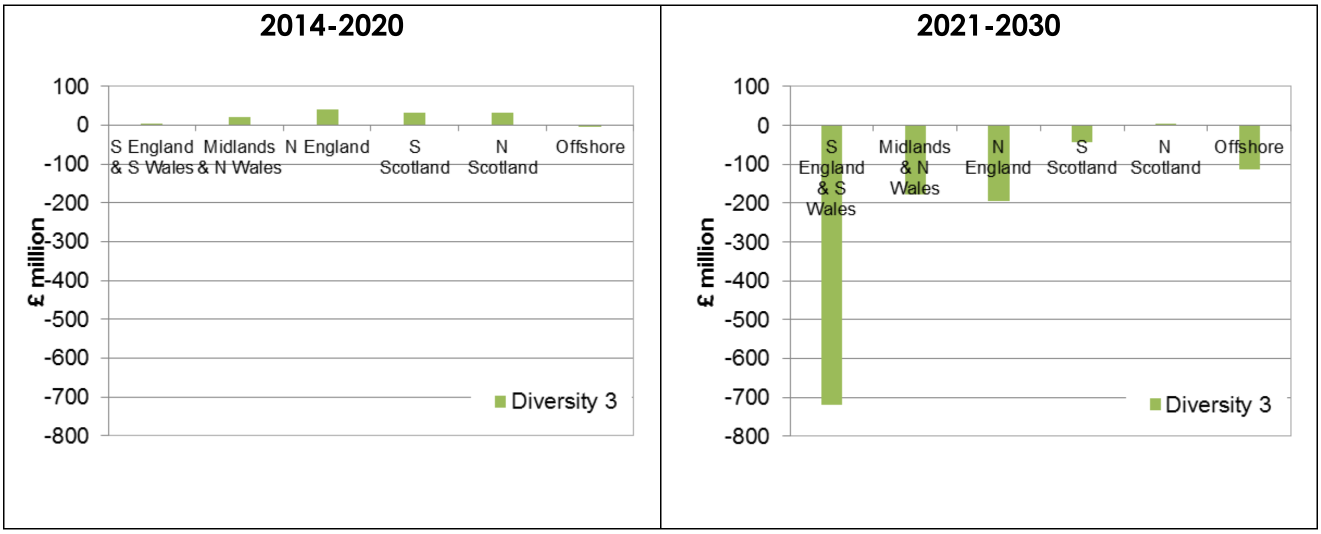


Figure 58 Average annual change in total generator profits, relative to Status Quo – Diversity 3 (CMP213 modelling)



4.3.7 Summary

The Alternatives share many of the characteristics of either Status Quo or Original. The Original 50% is very similar to Original. The Diversity options can be broadly considered to form a range between Status Quo and Original with Diversity 3 being closer Status Quo in terms of outturn tariffs, and Diversity 1 and Diversity 2 closer to Original. The results in the period to 2020 generally reflect this. After 2020 there are larger differences which to some extent are explained by differences in the total renewables build.

Based on the single scenario modelled, the tariffs produced by the Diversity options appear to be similar enough that they do not have a different long term impact on generation investment.

5 Conclusions

In this section we present the conclusions from our review of the CMP213 modelling.

Changes to the assumptions and functionality

We have reviewed the changes to modelling assumptions and functionality for the CMP213 modelling. We are of the opinion that these changes are reasonable. The updates to the assumptions use updated versions of the same sources except for:

- Commodity price assumptions: DECC values used rather than Redpoint assumptions. We are of the opinion that the use of DECC assumptions is equally valid. Furthermore they are well recognised by stakeholders and are similar in overall level to the TransmiT assumptions.
- G:D split: maintained at 27:73 based on Ofgem's direction not to consider changes to the G:D split.
- A specific target for nuclear generation in 2030 of 14 GW: based on a Workgroup decision.

The updates to the assumptions and functionality which have the most significant impact on the results are:

- The increase in the total available offshore wind capacity by 2020 to reflect the latest National Grid 2012 Accelerated Growth scenario, which makes ambitious assumptions in terms of total possible offshore wind deployment (33 GW by 2020).
- The increase in total nuclear capacity in (and beyond) 2030, due to increase in nuclear life expectancies.
- The change to the start date and modelling approach for the Capacity Mechanism.

The first two changes above lead to increases in offshore wind and nuclear capacity, which drive most of the changes in power sector costs as described below.

Changes to the results compared to TransmiT

There are significant changes in the CMP213 results compared to the TransmiT modelling, which are the direct result of the changes to the input assumptions and functionality described above. In particular, the increase in offshore wind capacity in 2020 and in nuclear and CCS capacity in 2030 is significant, as it reduces the requirement for onshore wind build. This in turn reduces constraint costs, transmission reinforcement costs and transmission losses. Overall the scenario requires less transmission reinforcement. This in turn exposes fewer differences between the charging options.

The lower capacity margins in the CMP213 modelling are a result of updates to the retirement dates of existing generation, along with the revised Capacity Mechanism modelling and later start date for the Capacity Mechanism.

Overall, the changes to the results are consistent with the changes to assumptions and functionality.

Summary of the revised results

Original shows a £900m NPV benefit in power sector costs relative to Status Quo in the period to 2020. This benefit is partly due to the replacement of offshore wind with onshore, but also due to the later deployment and lower level of renewables under Original in 2020. The benefit if the capacity mixes were matched in terms of renewables is expected to be of the order of half the value.

Under the TransmiT results, the total renewable generation was much closer overall, which is one reason for the closer power sector costs.

The lumpiness of transmission investment may be relatively favouring Original compared to Status Quo. The Eastern HVDC Link #2 is a net benefit in both cases, but under Original this avoids a greater level of constraint costs. This means that the incremental cost of more onshore wind is low because Eastern HVDC Link #2 creates a lot of spare boundary capacity. This effect did not occur under the TransmiT results because of the on-going increase in onshore wind generation throughout the modelling horizon.

Overall, whilst the Original shows a benefit relative to Status Quo, we expect that a scenario with more similar low carbon build to the Original TransmiT results, and with similar levels of renewables, could show a closer result.

Original shows a small increase in consumer bills compared to Status Quo in the period to 2020, and a significant reduction after 2025. In the TransmiT results, Improved ICRP showed a relatively small increase in consumer bills throughout the modelled period. Generally, the results for consumer bills are inherently more variable than power sector costs as small differences in capacity margin can lead to large differences in consumer bills.

The Diversity options can be broadly considered to form a range between Status Quo and Original with Diversity 3 being closer Status Quo in terms of outturn tariffs, and Diversity 1 and Diversity 2 closer to Original. The results in the period to 2020 generally reflect this. After 2020 there are larger differences which to some extent are explained by differences in the total renewables build.

Based on the single scenario modelled, the tariffs produced by the Diversity options appear to be similar enough that they do that have a different long term impact on generation investment. This conclusion holds for the 50% HVDC versions of these options as well.

Original 50% HVDC does not show significant differences to Original, mainly because the overall tariffs are very similar. However, under scenarios with higher numbers of HVDC bootstraps commissioned, the differences between these options could become more material.

Summary of key impacts of charging options relative to Status Quo

	Original & Original 50%	Diversity 1	Diversity 2	Diversity 3
Impact on costs[35]				
Generation costs	↓	↓	↔	↑
Transmission costs	↓	↓	↓	↓
Consumer bills	↓	↓	↓	↓
Impact on security of supply	↔	↔	↔	↔

↑	Increase in metric	(green)	Positive impact
↔	Little or no impact on metric	(grey)	Broadly neutral impact
↓	Decrease in metric	(red)	Negative impact

Interpreting the revised results

We are of the opinion that the revised results are a reasonable update of the TransmiT results. However the updates have changed the results significantly which in turn has changed the relative comparisons of Status Quo and Original. The relatively subtle differences in transmission charges can be dominated by other effects, and the differences between Original and Status Quo should be considered in the context of these other factors. We believe these factors fall into four broad categories:

1. The problem is heavily constrained by the availability of sites for new low carbon generation, and deployment rates for renewables technologies, and hence the relatively subtle changes in locational signals under Original have less of an impact on low carbon investment than might otherwise be the case.
2. The differential support levels for low carbon generators under the Renewables Obligation and assumed under EMR are a much stronger driver of investment behaviour than relatively small changes in transmission charges.
3. The lumpiness of onshore transmission reinforcement can favour one option if the reinforcement is closer to optimal sizing under that option.
4. Constraint costs may increasingly become 'polluted' by low carbon support payments with low carbon generators bidding below their true short run costs in order to continue to receive support payments (which we assumed would also be

[35] Under approximately the same level of renewables and carbon intensity under Stage 2 modelling.

the case under Contracts for Differences based on the Government's EMR publications).

This last point highlights the difficulties in assessing the impact of changes in transmission charging given the uncertainties surrounding the outcomes of EMR, particularly in the 2020s. Different designs for Contracts for Difference or the Capacity Mechanism from those assumed in the modelling could materially affect the results.

A Review of change proposals

In this appendix we review the options for change proposed by the CMP213 Workgroup. The Workgroup considered three main areas for modification:

1. The extent and form of sharing in order to more accurately reflect the costs imposed by different types of low carbon and carbon generators on the electricity transmission network;
2. The treatment of High Voltage Direct Current (HVDC)circuits that will run parallel to the AC transmission network; and
3. The treatment of potential island connections comprised of sub-sea cable technology such as those currently being considered in Scotland.

The potential alternative areas considered by the CMP213 Workgroup are shown in Table 28.

Table 28 Potential alternative components considered by the CMP213 Workshop

Area of Modification	Potential alternative area
Extent of sharing	No Diversity Diversity 1 Diversity 2 Diversity 3
Form of sharing	Year Round – Annual Load Factor historic specific (5 years) Year Round – Hybrid
Parallel HVDC links	Specific Expansion Factor 100% Converter + 100% Cable (Original) Specific Expansion Factor; Generic 40% Converter + 100% Cable (AC sub +Quadrature Booster) Specific Expansion Factor; Generic 50% Converter + 100% Cable (AC sub) Specific Expansion Factor; specific x% Converter cost reduction (AC sub)
Island links	Specific Expansion Factor 100% Converter + 100% Cable (Original) Specific Expansion Factor; Generic 30% Converter + 100% Cable (AC sub +STATCOM) Specific Expansion Factor; Generic 50% Converter + 100% Cable (AC sub) Specific Expansion Factor; specific x% Converter cost reduction (AC sub)

In the following sections we describe each of the component parts developed by the CUSC process under each area.

Extent of sharing

Traditionally, the electricity transmission network has been planned to be robust during periods of peak electrical demand and without taking into account the specific characteristics of the generators connected to the system. With the introduction of low carbon generators (and particularly low load factor intermittent generators), however, the electricity transmission network is increasingly planned based on a cost-benefit approach reflecting the year round operation of the system. This approach aims to take into account the fact that some network sharing takes place between different types of generators.

Original

The key features of the Original policy option relative to the Status Quo are the application of a dual background approach for assessing the incremental transmission network costs imposed by generators and the use of a load factor in the locational tariff.

The current ICRP methodology modelled under Status Quo focuses only on system peak conditions, whereas the Original proposal also considers year round conditions.

The Original methodology therefore involves the development of two system backgrounds, and leads to a two part wider locational tariff for generators. Unlike the Status Quo approach, the proposed methodology differentiates between generator types in applying technology specific scaling factors to derive the generation background. The peak security background sets intermittent generators (eg wind) and interconnectors to zero, and then scales the remaining plant types to meet demand. The year round background assumes zero contribution from peaking plant (such as oil and OCGTs) and fixed or variable scaling factors for other plant types. This is consistent with changes to the SQSS under GSR009[36].

The peak security and year round backgrounds are then converted into two wider locational tariffs:

- *A Peak Security Wider Tariff* charged on a TEC capacity (MW) basis for conventional generators as under the Status Quo, but zero for intermittent generation.
- *A Year Round Wider Tariff* charged on TEC capacity scaled by an annual load factor (ALF), specific to each generator and based on rolling average historic data (for existing plant).

There are no changes to the methodology used to calculate demand TNUoS under the dual background approach. Hence, demand charges under Original will only differ from Status Quo to the extent that the generation and transmission backgrounds change in response to different resulting investment patterns.

Diversity options

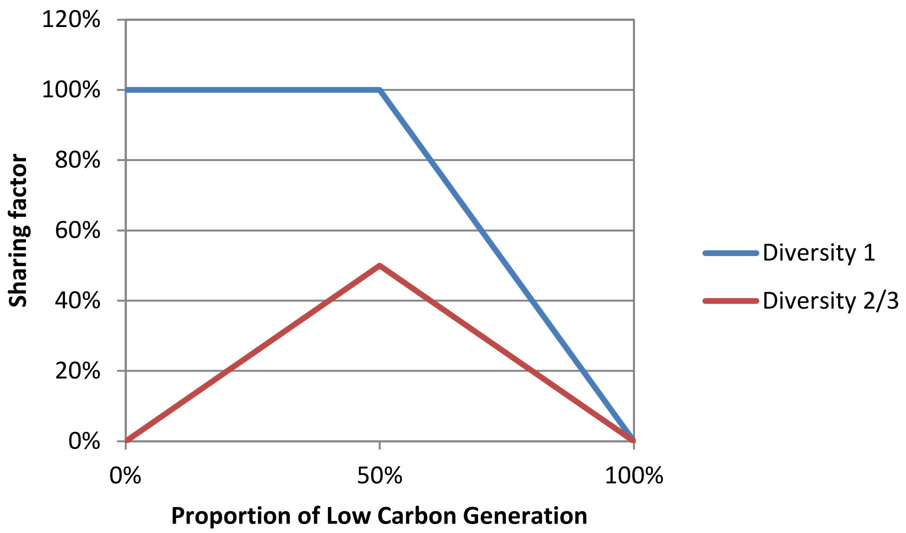
The relationship between load factor and incremental constraint costs has been shown by the Workgroup to deteriorate in areas with little diversity between generation plant types. This is particularly evident in areas with significant amounts of low carbon generation where the price to constrain off generation can be expensive relative to conventional generation. The Workgroup has therefore developed three alternative approaches to limit sharing on the system when diversity behind a transmission boundary reduces. Two of these approaches still include a proportion of the Year Round charge to be based on the Annual Load Factor while the third considers diversity within a part of the system and only on the Year Round background (i.e. it does not consider Peak Security requirements). The Diversity options are described in section 3.1.2. Here we provide further description and context.

[36]http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=26&refer=Networks/Trans/ElecTransPolicy/SQSS

Diversity 1 splits the year round component into two, giving a total of three tariff components: Year Round shared, Year Round non-shared, and Peak Security.

For each generation zone, the network is split into shared and non-shard proportions. The sharing factor for each zone is based on the ratio of carbon emitting to low carbon generation capacity behind the boundary. The sharing calculation is shown in Figure 59. If there is a proportion of low carbon less or equal to 50%, the sharing factor is 100%. This is the maximum sharing factor that can occur and in this case this is equivalent to the Original option. If there only low carbon in a zone, the sharing factor is 0%.

Figure 59 Sharing factors



The shared and non-shared proportions are calculated behind each transmission boundary, which correspond to the interfaces between generation zones.

To calculate tariffs, the generator specific ALF is applied to the Year Round shared component, whereas the TEC is applied to the Year Round non-shared. The Peak Security component is unchanged from Original. Compared to the Original, Diversity 1 results in higher tariffs in positive TNUoS zones where there is limited diversity of generation.

Diversity 2 is similar to Diversity 1, expect for a different method to calculate the sharing factor, as shown in Figure 59. In this case the maximum sharing that can occur is 50%.

Diversity 3 differs from the previously described options in that there is only one background, which is a Year Round background. The calculation of the sharing factor matches the Diversity 2 option. This is applied such that only the non-shared portion is charged. Tariffs are calculated on the capacity of each generator – there is no application of an ALF. Of the Diversity options, Diversity 3 is most similar to Status Quo, albeit with a recognition of sharing.

Table 29 Alternative options considered for addressing low carbon and carbon generation plant type diversity issues

	Original	Diversity 1	Diversity 2	Diversity 3
Dual background	Yes	Yes	Yes	No
How sharing is applied	Sharing on Year Round background only	Sharing on Year Round background only	Sharing on Year Round background only	Sharing applied to all (only Year Round background)
Wider locational tariff components	2 (Year Round & Peak Security)	3 (Year Round shared, Year Round non-shared, Peak Security)	3 (Year Round shared, Year Round non-shared, Peak Security)	1 (Year Round)
MITS sharing	All Year Round incremental costs	Year Round split into shared / not shared	Year Round split into shared / not shared	All incremental costs with zonal sharing factors
Sharing method	Load factor on all MWkm	Load factor on shared MWkm, capacity on not-shared, effective max sharing 100%	Load factor on shared MWkm, capacity on not-shared, effective max sharing 50%	Effective MWkm = not shared/total; i.e. 10% shared → charging is on 90% effective, max sharing 50%.
Application of generator specific sharing factor	Yes	Yes; to shared element	Yes; to shared element	No
Diversity calculation	None	Based on deterministic relationship between low carbon / carbon ratio. All MWkm shared at 0% to 50%; sharing reduces from 50% to 100% low carbon.	Based on minimum of low carbon / carbon generation behind a boundary	Based on minimum of low carbon / carbon generation behind a boundary

Form of sharing

In the Original option described above, the Year Round tariff component is applied to generators through the application of a generator specific ALF. This is also applied in Diversity 1 and 2. The ALF is called for each generator based on the average of five years' historic load factors (after discarding the highest and lowest years). For new plant, where this historic data is not available, generic load factors by plant type are used. The generic load factors are derived from the average annual output of the ten most recent GB generators of that type commissioned.

The Workgroup also developed an alternative called the hybrid approach. Under this approach, the ALF is first calculated based on the average of the previous five charging years for renewables (excluding biomass) and the average of the previous two years for biomass and non-renewables.

Generators will then have the option to submit User Forecasts of load factor, which will be used to calculate tariffs. After the charging year, a reconciliation will be performed, whereby if the generator's load factor exceeds the forecast by more than 2%, the generator will be charged for the difference at 1.5 times the applicable TNUoS charge.

Treatment of parallel HVDC links

A number of HVDC links are currently under consideration that would run parallel to the AC transmission network. The CMP213 Modification proposal seeks to address two areas to reflect this new transmission technology into the charging methodology:

1. The treatment of power flows in the TNUoS charging model given that power flows on the HVDC circuits are controllable (unlike AC circuits);
2. The calculation of an appropriate expansion factor (i.e. relative unit cost) for these circuits.

With regards to the treatment of power flows, under both the CMP213 Original Proposal as well as all other Alternative options power flows on HVDC circuits are treated as if they were AC circuits.

An HVDC link is composed of the HVDC cable itself, along with an AC/DC converter station at each end of the line where it connects to the AC transmission system. Regarding the calculation of the expansion factor, the key parameter that needs to be considered here is whether a proportion of converter station costs required for HVDC links should be removed from the base calculation and socialised rather than being charged locally. As Table 28 shows, the CMP213 Original Proposal includes all generic costs (of both the cable as well as the converter stations) in the HVDC link specific expansion factor; however three additional alternatives have been considered where elements of these converter station costs have been removed:

Specific Extension Factor; Generic 40% Converter + 100% Cable (AC sub +Quadrature Booster)

In this option, 40% of the generic costs of a Converter are used in the calculation of the expansion factor. This is intended to represent the removal of the costs of an AC sub-station and a Quadrature Booster (a piece of transmission system equipment which is used to direct power flows on an AC system by changing the phase of the power). The intention is to charge the expansion factor taking account of the additional benefits which an HVDC link can provide, which are not charged directly when part of the AC system.

Specific Extension Factor; Generic 50% Converter + 100% Cable (AC sub)

In this option, 50% of the generic costs of a Converter are used in the calculation of the expansion factor. This is intended to approximate the converter elements which have the equivalent AC substation characteristics.

Specific Extension Factor; specific x% Converter cost reduction (AC sub)

In this case the costs included for the Converter station are reduced to reflect the converter elements which have the equivalent AC substation characteristics, based on National Grid's best assessment on a case-by-case basis.

Island links

A number of prospective sub-sea island connections are currently under consideration, such as for example to the Scottish island groups of the Western Isles, Orkney and Shetland. The CMP213 Workgroup has mainly focused on the Main Interconnected Transmission System (MITS) charging definition and its consequential implications on local and wider TNUoS charges and the expansion factor calculation for island links.

As Table 28 shows, the CMP213 Original Proposal would calculate specific expansion factors for each sub-sea circuit. These circuits would predominantly use HVDC technology. Furthermore, the CMP213 Workgroup developed three additional alternatives in line with those raised under the HVDC area of the Modification.

Specific Expansion Factor; Generic 30% Converter + 100% Cable (AC sub +STATCOM)

In this option, 30% of the generic costs of a Converter are used in the calculation of the expansion factor. This is intended to approximate the converter elements which have the equivalent AC substation characteristics and a Static Compensator (a piece of transmission system equipment which provides fast acting reactive power). The intention is to charge the expansion factor taking account of the additional benefits which an HVDC link can provide, which are not charged directly when part of the AC system.

Specific Expansion Factor; Generic 50% Converter + 100% Cable (AC sub)

In this option, 50% of the generic costs of a Converter are used in the calculation of the expansion factor. This is intended to approximate the converter elements which have the equivalent AC substation characteristics.

Specific Expansion Factor; specific x% Converter cost reduction (AC sub)

In this case the costs included for the Converter station are reduced to reflect the converter elements which have the equivalent AC substation characteristics, based on National Grid's best assessment on a case-by-case basis.

B CfD strike prices

Table 30 CfD strike prices – Status Quo (CMP213)

(£/MWh)	2018-2020	2021-2023	2024-2026	2027-2028	2029-2030
Nuclear	104	100	95	93	92
Coal + CCS	137	137	136	135	137
CCGT + CCS	103	102	101	101	101
Onshore wind	98	90	89	88	87
Offshore wind	142	123	117	113	109
Wave	350	280	236	216	199
Tidal Stream	336	262	237	217	200
Biomass regular	120	110	110	110	109

Table 31 CfD strike prices – Original (CMP213)

(£/MWh)	2018-2020	2021-2023	2024-2026	2027-2028	2029-2030
Nuclear	104	100	96	93	92
Coal + CCS	137	137	136	135	137
CCGT + CCS	103	102	102	102	102
Onshore wind	96	89	88	87	86
Offshore wind	141	123	118	114	110
Wave	347	280	235	215	198
Tidal Stream	336	265	240	219	202
Biomass regular	121	112	111	111	111

Table 32 CfD strike prices – Original 50% HVDC Converter (CMP213)

(£/MWh)	2018-2020	2021-2023	2024-2026	2027-2028	2029-2030
Nuclear	104	101	96	93	92
Coal + CCS	137	137	136	135	137
CCGT + CCS	103	102	102	102	102
Onshore wind	96	89	88	87	86
Offshore wind	141	123	118	114	110
Wave	347	280	235	215	198
Tidal Stream	336	265	240	219	202
Biomass regular	121	112	111	111	111

Table 33 CfD strike prices – Diversity 1 (CMP213)

(£/MWh)	2018-2020	2021-2023	2024-2026	2027-2028	2029-2030
Nuclear	104	100	95	93	92
Coal + CCS	137	137	136	135	137
CCGT + CCS	103	102	102	101	101
Onshore wind	96	87	86	85	84
Offshore wind	140	120	114	110	106
Wave	346	273	230	211	194
Tidal Stream	333	256	232	212	195
Biomass regular	120	108	107	107	107

Table 34 CfD strike prices – Diversity 2 (CMP213)

(£/MWh)	2018-2020	2021-2023	2024-2026	2027-2028	2029-2030
Nuclear	104	100	95	93	92
Coal + CCS	137	137	135	135	137
CCGT + CCS	103	102	102	101	101
Onshore wind	96	87	86	85	84
Offshore wind	140	120	114	110	106
Wave	346	273	230	211	194
Tidal Stream	333	256	232	212	195
Biomass regular	119	108	107	107	107

Table 35 CfD strike prices – Diversity 3 (CMP213)

(£/MWh)	2018-2020	2021-2023	2024-2026	2027-2028	2029-2030
Nuclear	104	100	95	93	92
Coal + CCS	137	137	136	135	137
CCGT + CCS	103	102	102	101	101
Onshore wind	97	87	86	86	85
Offshore wind	141	120	114	111	107
Wave	346	273	230	211	194
Tidal Stream	333	256	232	212	196
Biomass regular	119	108	107	107	107

C Additional modelling results

In this section with present the CBA results for Diversity 1 50% HVDC converter cost, Diversity 2 50% HVDC converter cost, and Diversity 50% HVDC converter cost. These model runs were completed by National Grid after the model runs discussed in the main document, and are outside the scope of the discussions.

Table 36 Cost Benefit Analysis: Diversity 1 50% HVDC converter cost

		Diversity 1 - 50% HVDC (£m real 2012)	
		NPV 2011-2020	NPV 2021-2030
Benefit relative to Status Quo			
Power sector costs	Generation costs	931	615
	Transmission costs	143	402
	Constraint costs	-34	43
	Carbon costs	-116	34
	Decrease in power sector costs	**924**	**1,094**
Consumer Bills	Wholesale costs (inc. capacity payments	-1,740	3,300
	BSUoS	-17	21
	Transmission losses	-42	33
	Demand TNUoS charges	135	270
	Low carbon support	929	708
	Decrease in consumer bills	**-735**	**4,332**

Table 37 Cost Benefit Analysis: Diversity 2 50% HVDC converter cost

		Diversity 2 - 50% HVDC (£m real 2012)	
		NPV 2011-2020	NPV 2021-2030
Benefit relative to Status Quo			
Power sector costs	Generation costs	929	750
	Transmission costs	141	402
	Constraint costs	-34	43
	Carbon costs	-116	32
	Decrease in power sector costs	**921**	**1,226**
Consumer Bills	Wholesale costs (inc. capacity payments	-1,776	1,626
	BSUoS	-17	21
	Transmission losses	-43	32
	Demand TNUoS charges	135	270
	Low carbon support	929	1,212
	Decrease in consumer bills	**-771**	**3,161**

Table 38 Cost Benefit Analysis: Diversity 3 50% HVDC converter cost

		Diversity 3 - 50% HVDC (£m real 2012)	
		NPV 2011-2020	NPV 2021-2030
Benefit relative to Status Quo			
Power sector costs	Generation costs	308	-723
	Transmission costs	28	255
	Constraint costs	-32	-9
	Carbon costs	-35	-79
	Decrease in power sector costs	**269**	**-557**
Consumer Bills	Wholesale costs (inc. capacity payments	-1,180	5,900
	BSUoS	-16	-5
	Transmission losses	-28	17
	Demand TNUoS charges	41	173
	Low carbon support	224	-1,044
	Decrease in consumer bills	**-959**	**5,042**