Modelling the Impact of Transmission Charging Options

A report by Redpoint Energy

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1 Executive Summary

Background

The current regime for setting Transmission Network Use of System (TNUoS) charges, based on an Investment Cost Related Pricing (ICRP) methodology, was introduced in 2005 under the British Electricity Trading and Transmission Arrangements (BETTA), when the Scottish and England and Wales markets were integrated. The ICRP methodology is designed to provide transmission users with efficient signals that reflect the cost of establishing and running transmission infrastructure. The methodology applies to the use of the electricity network across the whole of Great Britain (GB). The charges produced are reflective of the costs that a user imposes on the transmission network. The charging methodology therefore provides charges that vary by region reflecting the costs imposed by users located at different points of the transmission network.

The country now faces an unprecedented investment challenge driven by the need to connect large amounts of new and low carbon generation to the electricity networks to meet climate change targets, while continuing to ensure quality and security of supply and value for money for consumers. It is therefore timely to review the charging arrangements, to ensure they are fit to meet the new challenges we are facing for the operation and reinforcement of the grid in the coming years.

Project TransmiT

Ofgem started Project TransmiT, its independent review of transmission charging and associated connection arrangements, with a Call for Evidence in September 2010. In May 2011, Ofgem issued an open letter setting out the approach that it intended to adopt to its work on electricity transmission charging under Project TransmiT, and in July 2011 a Significant Code Review (SCR) of charging arrangements that seek to recover the costs of the electricity transmission network was launched. The aim of the transmission charging SCR is to consider a range of potential charging options and to assess which option would best further the objectives of achieving sustainability targets, ensuring security of supply and providing best value for money for current and future consumers. Redpoint Energy was commissioned by Ofgem to provide a quantitative assessment of how the different charging options might impact on these objectives.

Options considered

The following two options were developed by the TransmiT Technical Working Group of industry representatives and analysed in detail in this study:

- ***Improved ICRP***, involving enhancements to the current ICRP methodology to include a year-round as well as peaking element to the charges, designed to reflect better the costs that different generating technologies impose on the transmission network, and
- ***Socialised charging***, a ‘postalised’ or ‘postage stamp’ approach under which all generators would pay a uniform tariff for using the transmission system, irrespective of their location or type.

The Improved ICRP option analysed involved no changes to the methodology for calculating demand charges, whereas the Socialised option analysed included uniform charging on the demand side also. Both of these options were compared to the ‘Status Quo’ option (continuation of the current arrangements) over the period 2011-2030. Two of a wide range of potential variants to these two charging options were also analysed.

Analytical approach

The analytical approach assesses the impact of the transmission charging options on investment in generation and transmission. Transmission charges will influence the decisions of generators regarding where to locate their plant, and which plant to retire. This in turn has an impact on transmission charges; as well affecting the level of constraint costs which will drive future decisions on when and where to reinforce the transmission network. These reinforcements then feed into transmission charges which then also influence generators' decisions.

To undertake the analysis we developed a modelling framework in conjunction with Ofgem and National Grid Electricity Transmission (NGET) that incorporated modules for transmission charging, system dispatch, market pricing, constraint forecasting, and generation and transmission investment decision making. Feedback was sought from the Technical Working Group on the methodology and assumptions, and a number of updates to the approach were made on the basis of this feedback. The modelling was presented at two wider stakeholder presentations in August and November 2011.

Impact on tariffs

The modelling suggests that in all cases the maximum allowed revenue (MAR) for transmission operators is likely to increase as a result of the additional transmission costs associated with connecting large volumes of new generating capacity to the networks. This would be reflected in increasing charges on average under any transmission charging option. For generators this may be offset to a degree by a possible change in the split in the recovery of costs between the generation and demand side which may be required in the future to comply with EU tarification guidelines.[1]

In general, the effect of the Improved ICRP approach is to 'compress' locational variations in generation TNUoS charges, particularly for low load factor generators, including intermittent renewables. Hence, zones which currently have high TNUoS charges, such as North Scotland, become relatively more attractive for siting plant with lower load factors and zones which currently have low, or negative TNUoS charges, such as South of England, become relatively less attractive for plant with this characteristic. There is no material impact on demand TNUoS charges, other than as a consequence of different levels of MAR which may result from different patterns of investment in response to the changing price signals on the generation side or changes to the split of revenue collection between generation and demand.

By making all charges uniform, the Socialised approach has a very significant impact on locational price signals for generators. Companies are incentivised to develop sites with the greatest resource potential/lowest generation costs without consideration of the associated transmission costs. On the demand side, demand charges also vary by location, but in inverse proportions to those for generation. Hence, charges are currently lower in the north of Scotland than in the south of England, differences in demand TNUoS (which can vary by more than £15 per year for an average domestic customer under the current arrangements) would be removed.

Impact on sustainability

The modelling suggests that, for the same level of low carbon support, Improved ICRP could somewhat increase the probability of hitting the 2020 renewables target on time, by increasing the deployment of onshore wind in Scotland.

The impact of Socialised charging is to further facilitate the deployment renewables, and in particular offshore wind. This suggests that there could be a significant benefit of the Socialised approach as

[1] National Grid, *Project TransmiT: Theme 6 – EU Transmission Tarification Guidelines; GB Analysis,* http://www.ofgem.gov.uk/Networks/Trans/PT/WF/Documents1/TransmiT%20WG%20postMtg4_EU%20Tarification%20Guidelines.pdf

measured by the speed of renewables deployment. Where other non-economic factors constrain the rates of renewables deployment this difference with Status Quo might be narrowed.

Impact on locational build

Under Improved ICRP charging, the compression of tariffs for use of the wider transmission network for low load factor generators favours intermittent generators, including wind, in what are currently high TNUoS charging zones. This drives more onshore wind build in North Scotland. It also encourages more offshore wind in Scottish waters and less off South England. There is little change in build patterns for non-renewable technologies.

Under Socialised charging, there is an absence of locational signals to reflect the economic costs of establishing and operating transmission infrastructure. The individual financial appraisals of market participants will therefore be dominated by other costs and operating efficiencies which are likely to vary by location and generation technology, which will drive decisions on where to locate new generation and close existing generation. Against this background, Socialised charging tends to favour the build of new renewable generation in the best resource sites at the lowest generation cost, ignoring transmission costs. This leads to greater onshore wind build relative to the Status Quo in regions that are frequently windy, and thus offer high load factors, specifically North Scotland, offshore and the Scottish islands. The lack of locational signals also leads to a greater geographical spread of new combined cycle gas turbines (CCGTs) and nuclear build relative to Status Quo where southern sites are favoured.

Impact on power sector costs

Over the period 2011-2020, the results suggest that Improved ICRP could lead to a small reduction in power sector costs compared to the status quo, suggesting that the additional constraint costs, losses and transmission expenditure could be offset by reductions in generation costs[2]. The decrease in generation costs is a consequence of cost savings from targeting onshore wind sites with high load factors in North Scotland in preference to biomass, offshore wind and onshore wind in Wales. Between 2021 and 2030, power sector costs are projected by the model to be slightly higher overall, due to an increase in the transmission costs associated with increased deployment of intermittent generation at more peripheral locations. These differences with Status Quo are small relative to the overall cost of supplying electricity, and hence Improved ICRP appears broadly neutral compared with Status Quo with respect to power sector costs.

The modelling suggests that under Socialised charging, power sector costs would be significantly higher compared to Status Quo, with the higher constraint, losses and transmission costs exceeding savings in generation costs, particularly in the period 2021-2030. The removal of locational signals from transmission charges results in the development of a more widely dispersed generation mix, across more remote locations, which increases the level of constraints and triggers additional costs from network reinforcement and transmission losses.

Impact on consumer bills

The impact of Improved ICRP on consumer bills is small over the period 2012-2020, averaging an additional £1.50 per year for each domestic customer. The average increase per year for each domestic customer is £1 per year from 2021 to 2030.

[2] Generation costs are the costs of establishing and operating generation assets (including operating and maintenance costs, fuel costs and capital costs of generating plant) and do not include the costs of transmission infrastructure necessary to send the power produced from this site to the end user.

The higher power sector costs under Socialised charging are reflected in greater costs for consumers. The model projects that between 2011 and 2020, the average annual domestic customer bill would be £11 per year higher between 2012 and 2020. The average increase per year for each domestic customer is £23 per year from 2021 to 2030. These increases would not be uniform: consumers in high demand TNUoS zones in the south of England would be favoured by Socialised charging, while consumers in Scotland would pay more.

Summary of impacts

An indicative summary of the impacts of the options relative to Status Quo is shown in the table below.

Summary of key impacts of charging options relative to Status Quo

	Improved ICRP	Socialised
Impact on achieving sustainability goals[3]		
Achieving 2020 renewables target	↑	↑↑
Achieving 2030 decarbonisation objectives	↔	↔
Impact on costs[4]		
Generation costs	↓	↓↓
Transmission costs	↑	↑↑↑
Consumer bills	↔	↑↑
Impact on security of supply	↔	↔

↑	Increase in metric		Positive impact
↔	Little or no impact on metric		Broadly neutral impact
↓	Decrease in metric		Negative impact

These results appeared robust to the sensitivities that were undertaken on the analysis.

Policy variants and sensitivities

Two policy variants were modelled:

- **HVDC sensitivity** on Improved ICRP. The removal of all converter station costs of applicable HVDC links that run parallel to the onshore AC network (i.e. 'bootstraps') from the basis for calculating locational charges, and

[3] Assuming no compensating adjustment in low carbon support. The modelling was run with two stages. Under Stage 1, low carbon support levels were held constant across the transmission charging options. Under Stage 2, support was adjusted to deliver approximately the same level of renewables and carbon intensity.

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

- **Socialised (wider only) sensitivity**. A version of socialised charging whereby generators face charges for local assets, but wider assets are still socialised.

The results of the HVDC variant are similar to Improved ICRP up to 2020, but over the period 2020-2030 an increase in transmission and constraint costs is observed, to accommodate more generating capacity in North Scotland and offshore Scotland, as a consequence of less cost-reflective charging for HVDC links. The increase in consumer bills above Status Quo from 2021-2030 is still relatively small at £2 per year (compared to £1 per year under Base Case Improved ICRP).

The Socialised (wider only) variant leads to higher tariffs for offshore wind that reflect the costs of the offshore links. As a result, relative to the fully Socialised option, there are savings in transmission costs from a reduction in offshore transmission costs. The average impact on consumer bills in the period 2012 to 2020 of £9 per year is still significant but is slightly less than under fully Socialised charging. However, there is an increase in constraint costs from 2025 onwards.

2 Introduction

2.1 Background

Since liberalisation of the market was introduced in Great Britain with the *Electricity Act 1989*, the principle of cost reflective charging has been applied to users of the transmission networks. The current regime for setting Transmission Network Use of System (TNUoS) charges, based on an Investment Cost Related Pricing (ICRP) methodology, was introduced in 2005 under the British Electricity Trading and Transmission Arrangements (BETTA), when the Scottish and England and Wales markets were integrated.

The current TNUoS charging methodology provides for transmission charges which vary by location, designed to reflect the costs that users (both generation and suppliers) impose on the network. Since transmission investments and costs are a function of the distance over which power is transported, generators located far from the main centres of demand pay higher TNUoS charges. Conversely, generators that reduce the need for network capacity overall enjoy negative charges. Demand charges also vary by location, but in inverse proportion to those for generation, reflecting the fact that additional demand will have the opposite effect to additional generation in bringing forward or delaying network investment. These locational price signals are designed to ensure that generation (and demand) siting decisions internalise the cost of transmission, through providing an incentive to locate in a manner that promotes the efficient use and development of the transmission network as a whole at the lowest cost to the end consumer.

The existing arrangements have been effective in providing these incentives. However, the country now faces an unprecedented investment challenge driven by the need to connect large amounts of new and low carbon generation to the electricity networks to meet climate change targets[5], while continuing to ensure value for money for consumers and security of supply. It is therefore timely to review the charging arrangements, to ensure they are fit to meet the new challenges we are facing.

The requirement rapidly to connect large volumes of new capacity poses challenges for the operation and reinforcement of the grid. Hence, the locational signals provided by TNUoS may become increasingly pertinent to ensuring the most cost efficient outcome. Conversely, very high charges in some remote areas, including offshore, could present a barrier to exploiting the best renewable resources and jeopardise hitting the country's renewable and decarbonisation targets.

These challenges are not unique to the UK. This was recognised at the European Council where Members States agreed that work market coupling and network codes should be accelerated in order to complete the internal energy market by 2014.[6]

[5] Under the terms of the EU Renewables Directive, the United Kingdom is committed to meet 15% of its energy requirements from renewable resources by 2020. In addition, the Government has adopted legally binding requirements to reduce significantly carbon emissions across the economy. Associated challenges will include the deployment of new renewable generation, retirements driven by the Large Combustion Plant Directive and Industrial Emissions Directive and the development of additional low-carbon generation, including nuclear and plant fitted with carbon capture and storage.

[6] http://www.consilium.europa.eu/uedocs/cms_data/docs/pressdata/en/ec/119175.pdf

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2.2 Current transmission charging arrangements

The owners of the transmission network are able to recover the cost of building and maintaining the network through administered pricing. There are three electricity transmission owners covering Great Britain: National Grid Electricity Transmission plc (NGET) covering England and Wales, Scottish Power Transmission Limited (SPTL) covering south and central Scotland, and Scottish Hydro-Electric Transmission Limited (SHETL) for Northern Scotland. Each of these are able to recover their costs according to the Maximum Allowed Revenue (MAR) determined as part of regular price controls.

Currently, the cost of the transmission network is recovered through TNUoS charges, split 27% from the generation side and 73% from the demand side. Both generation and demand TNUoS charges are made up of a locational element and a residual element. The locational element serves to provide a signal of incremental network costs associated with locating in a given area of the network, whilst the residual element does not vary by location and serves to collect the total allowed revenue of Transmission Owners. To provide greater stability, and for administrative simplicity, tariffs are grouped into pre-determined geographic "zones" and a zonal average is calculated. In addition, generators pay local asset charges, specific to each site, to connect to the Main Interconnected Transmission System (MITS). For most generators the local asset charge is a relatively small proportion of the overall charge. The exception is for offshore generators, and those generators located on islands, where longer cables may be required to connect the generator to the MITs. The local asset charge is calculated using a 'security factor' which reflects the level of redundancy within the connection to the network. For onshore plant this is typically equal to 1 (compared with the global security factor which is currently 1.8 for the MITS network) reflecting the fact that there is no redundancy in cable connections from individual generators or groups of generators to the MITs.

Charging arrangements for offshore generators are based on an extension of arrangements onshore. Accordingly, the cost of capacity used by the generator is reflected in local charges. There is typically no redundancy in cable connections and thus a security factor of 1 is applied. However, where there is additional security provided through two or more transmission circuits, local asset charges are adjusted upward for the additional security (capped at the current MITS security factor of 1.8). Charging for offshore generators could require amendments if coordinated transmission networks are developed offshore, which could serve multiple generators through multiple routes to shore. Issues relating to the development of coordinated networks offshore are currently under consideration as part of Ofgem and DECC work for the Offshore Transmission Coordination Project[7]. These issues will be progressed as part of the normal governance processes after the conclusion of the TransmiT SCR process.

The wider zonal charges are calculated using a global security factor (currently a value of 1.8) reflecting the level of redundancy within the MITs required to meet the National Electricity Transmission System Security and Quality of Supply Standard (NETS SQSS) as set out in transmission licences and calculated on a network wide basis in accordance with the TNUoS charging methodology.

The locational element of transmission charges reflects the long-run forward-looking costs of connecting an incremental megawatt (MW) of generation at a given point on the transmission network. The same principles apply on the demand side. Tariffs vary by region with the highest charges in demand centres furthest from the main sources of generation. However, the locational element of the transmission charges does not recover the total amount of revenue allowed to the companies. This is because:

- the transmission network is not optimally sized due to the 'lumpy' nature of additional capacity, and

[7] Ofgem and DECC, Offshore Transmission Coordination Project, http://www.ofgem.gov.uk/Networks/offtrans/pdc/pwg/OTCP/Pages/OTCP.aspx

- because the network comprises "non-locational" assets, such as substations, that contribute to overall security.

Hence, once the locational tariff has been calculated, a non-locational factor, generally called a residual charge, is applied to the tariffs. The operation of this residual factor ensures that 27% of total allowed revenue is recovered from generators and 73% is recovered from demand customers. TNUoS charges are calculated on an ex-ante annual basis.

TNUoS charges for generators are currently levied based on the Transmission Entry Capacity (TEC) of each plant, regardless of how the plant operates. Hence, a baseload gas plant, peaking oil unit or variable wind generator in the same zone would pay the same wider locational tariff (differences may exist in local asset charges).

This raises the question of whether the current regime produces charges that accurately reflect the true costs that different types of generators impose on the system. In particular, it raises a question as to whether the locational signals are appropriate and not unduly preventing the exploitation of the best renewables resources, which are frequently in remote locations and hence subject to the highest tariffs under the current regime.

2.3 Project TransmiT

Ofgem kicked off Project TransmiT, its independent review of transmission charging and associated connection arrangements, with a Call for Evidence in September 2010. In May 2011, Ofgem issued an open letter setting out the approach that it intended to adopt to its work on electricity transmission charging under Project TransmiT, and in July 2011 a Significant Code Review of electricity transmission charging was launched.

National Grid Electricity Transmission plc (NGET) is responsible, in conjunction with other stakeholders as appropriate, for ensuring that appropriate electricity transmission charging arrangements are in place. Ofgem's role is to set out the principles that NGET must adopt in carrying out this role and provide support and challenge as necessary to achieve this. Ultimately, Ofgem's role is to approve any appropriate changes to the charging methodology developed by NGET and industry through the open governance arrangements set out in the Connection and Use of System Code (CUSC). Under the SCR, Ofgem is reviewing the TNUoS charging principles and will change these as necessary. It will also set out its view of the charging framework needed to deliver these principles and direct NGET to raise the necessary modifications accordingly if appropriate. This would be followed by the aforementioned governance process.

The aim of the TNUoS charging SCR is to consider a range of potential charging options and to assess which option would best further the objectives of achieving sustainability targets, ensuring security of supply and providing best value for money for current and future consumers. The options that are being considered include continuation of the current regime, evolution of the ICRP approach to enhance the cost reflective signals, and approaches in which part or all of the costs relating to shared transmission assets are recovered through a uniform tariff that would apply to all users of the transmission system irrespective of where they are located, the so-called 'socialised' or 'postage stamp' approach.

To support the development of the different transmission charging options, the Technical Working Group was established with industry representatives. The group, chaired by Ofgem, met on an approximately fortnightly basis. Each meeting focused on a specific issue of the transmission charging arrangements, with

NGET taking lead responsibility for drafting the technical working group report[8]. Input from the technical working group was instrumental in the formulation of the transmission charging options analysed in this report. The group also provided valuable feedback on the modelling methodology and input assumptions used for the analysis[9].

This report accompanies the consultation document published by Ofgem on Tuesday, 20 December 2011[10].

2.4 Electricity Market Reform

Project TransmiT is taking place against the backdrop of the Electricity Market Reform (EMR) programme. In its July 2011 White Paper, the Government set out proposals to introduce new mechanisms for supporting low carbon generation and to limit emissions from fossil fuel plant. It also included a consultation on the possibility of introducing a capacity mechanism to the Great Britain electricity market. There are clearly interactions between the transmission charges paid by low carbon generators and the levels of support they may need to compete with fossil generators. These interactions will need to be considered in future policy and regulatory decisions.

[8] TransmiT Technical Working Group, *Project TransmiT: Electricity Transmission Charging Significant Code Review*, Initial Report of the Technical Working Group, http://www.ofgem.gov.uk/Networks/Trans/PT/WF/Documents1/TransmiT%20WG%20Initial%20Report.pdf (September 2011).

[9] TransmiT Technical Working Group, *Project TransmiT: Electricity Transmission Charging Significant Code Review*, Addendum to the Initial Report of the Technical Working Group, http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=166&refer=NETWORKS/TRANS/PT/WF (Nov 2011)

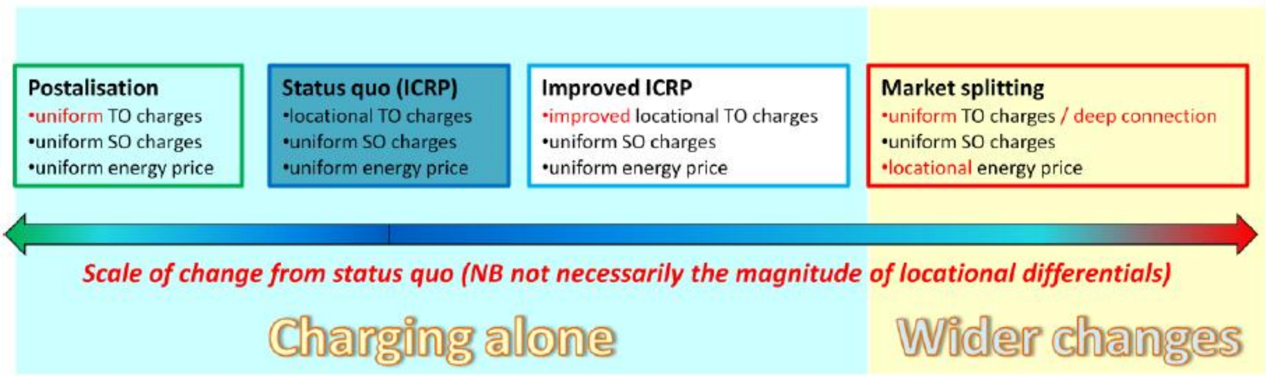
[10] Published alongside this document

3 Options to improve transmission charging

3.1 Overview

In launching the transmission charging SCR, Ofgem confirmed the scope was to develop and assess a range of options that focus on TNUoS charging alone, as illustrated in Figure 1 (reproduced from Ofgem's letter 27 May 2011). Proposals such as market splitting which imply wider changes to the current trading arrangements and issues associated with embedded generation are outside the scope of the SCR.

Figure 1 Schematic of scope of potential charging reforms



The spectrum of potential charging reforms includes two broad policy options:

- ***Improved ICRP***, involving enhancements to the current ICRP methodology for establishing locational system user tariffs, and
- ***Socialised charging***, a 'postalised' or 'postage stamp' approach under which all generators would pay a uniform tariff for using the transmission system, irrespective of their location or type.

This study aims to assess the costs and benefits of these policy options relative to the Status Quo charging arrangements. The Technical Working Group was tasked with working up the details of the Socialised and Improved ICRP policy options to support our economical modelling assessment, with Ofgem taking the final decisions on design questions where the Working Group did not achieve a consensus. The deliberations of the Working Group are summarised in its initial report[11]. In this section, we set out the key features of the policy options modelled.

3.2 Policy options

The key features of the three policy options we studied are summarised in Table 1.

[11] TransmiT Technical Working Group, *Project TransmiT: Electricity Transmission Charging Significant Code Review*, Initial Report of the Technical Working Group, http://www.ofgem.gov.uk/Networks/Trans/PT/WF/Documents1/TransmiT%20WG%20Initial%20Report.pdf (September 2011).

Table 1 Summary of transmission policy options

	Status Quo	Improved ICRP	Socialised
Wider investment	Locational	As for Status Quo	Socialised
Local asset charges	Asset specific	As for Status Quo	Uniform: no locational differentiation (onshore, offshore and islands)
G:D split	27%:73%, moving to 15%:85% from 1 April 2015	As for Status Quo	As for Status Quo
Capacity or energy (wider tariff)	Capacity (MW)	Dual criteria, based on two part 'peak' and 'year round' tariff; with the year round element multiplied by a specific load factor (calculated ex-ante based on historical data)	Energy based
HVDC lines: expansion factor	Full costs, including converter stations	No change from Status Quo	Not relevant
HVDC lines: treatment in load flow modelling	Apportioning flows in proportion relative to circuit ratings across key network boundaries	No change from Status Quo	Not relevant
Local security factors	(i) Onshore and island link connected to onshore local network: Generator specific, 1.0 or wider factor (ii) Offshore: Generator specific (1.0-1.8) (iii) Island links connected directly to the MITS: Security factor 1.8.	As for Status Quo, but for island links, security factor effectively reduced to 1.0 where there is no redundancy	Not relevant

We highlight key elements of each policy option below. Further details can be found in Ofgem's Consultation Document. Note that in all cases we assumed that there would be no change to the mechanism for recovering the costs of balancing services (including constraint costs), which are currently recovered equally across all users, and that uniform location loss factors would apply[12].

[12] Ofgem, *Balancing and Settlement Code (BSC) P229: Introduction of a seasonal Zonal Transmission Losses scheme (P229)*, http://www.ofgem.gov.uk/Licensing/ElecCodes/BSCode/BSC/Documents1/P229%20D.pdf, Decision letter (September 2011).

3.2.1 Status Quo

Although the Status Quo option is based upon a continuation of the existing ICRP approach, the Technical Working Group realised that the methodology would need to be adapted to accommodate additional factors likely to become important within the modelled period, such as new transmission technologies (HVDC) and proposed new links to the Scottish islands. Hence, a number of decisions needed to be taken to establish the baseline shown in Table 1.

The existing ICRP charging methodology was developed for application to the current GB transmission network of interconnected AC transmission circuits. The methodology involves simulating the change in power flows along AC circuits for a given change in nodal injections and withdrawals on the network. However, there are proposals to deploy other transmission technologies such as undersea high voltage direct current (HVDC) 'bootstrap' links in parallel with the main AC transmission system. The current Transport Model is not designed to accommodate HVDC links, since the power flows on HVDC links are controlled and do not respond automatically to changing system conditions. The Technical Working Group considered a range of options for incorporating the power flows on HVDC links within the charging methodology. We have adopted the Technical Working Group's recommended approach of calculating base case flows in proportion to circuit ratings on multiple transmission boundaries.

Incorporating HVDC technologies in the charging methodology also requires an assumption on the relevant HVDC costs to include in the expansion factor[13] calculation. The impact of including more cost components in the expansion factor calculation is greater locational differentiation in the resulting tariffs. The Technical Working Group was unable to reach consensus on the issue of whether all the costs of HVDC links (subsea cable and converter stations) should be included. Consistent with the current charging approach for offshore wind farms, we have assumed all the costs of HVDC links are included in the expansion factor under the Status Quo and Improved ICRP policy options. However, as described below, we have also explored a sensitivity of excluding converter station costs for parallel HVDC links under the Improved ICRP model.

Irrespective of the treatment of converter station costs, the expansion costs of HVDC links are typically high relative to overhead AC lines. Previous studies by NGET[14] have demonstrated that the incorporation of HVDC links can have a significant impact on locational generation tariffs, increasing zonal charges for generators on the exporting side of the link. These effects can be seen within the results of this study.

Regarding the proposed Scottish island links (to the Western Isles, Orkney and Shetland), we have assumed in the Status Quo model that the GB global, or wider, security factor (currently 1.8) used in the calculation of a generator's TNUoS tariff would apply to island links connected directly to the MITS. This is equivalent to making each of them a new TNUoS zone. A lower security factor of 1.0 was assumed to apply where island links do not connect directly to the MITS.

Finally, the Technical Working Group noted that the EU tarification guidelines, which limit the average transmission charges for generators to an equivalent of €2.50/MWh, might require the 'G:D split' to be changed in the future. In line with the Technical Working Group recommendations, we assumed that the

[13] The expansion factor is used in the Transport Model to reflect the difference in cost between different types of transmission circuit and is measured relative to the cost of 400kV overhead line. This is used to expand the effective length of more expensive circuits, thereby reflecting the additional cost of investing in these circuits compared to 400kV overhead line.

[14] NGET Presentation to Technical Working Group, http://www.ofgem.gov.uk/Networks/Trans/PT/WF/Documents1/TransmiT%20WG%203%20-%20treatment%20of%20HVDC.pdf

'G:D split' changes to 15% on generation and 85% on demand from April 2015 under Status Quo. The same assumption has been applied to the other policy options.

3.2.2 Improved ICRP

The key features of the Improved ICRP 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 Improved ICRP proposal also considers year round conditions.

The Improved ICRP 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[15].

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).

Further details of the proposed Improved ICRP methodology can be found in the Working Group Initial Report and NGET's Working Group presentation of 28 July 2011.

Relative to the Status Quo option, it is to be expected that low load factor (i.e. intermittent and peaking) generators in positive charging zones will see lower transmission tariffs under the Improved ICRP methodology, and vice versa in negative charging zones.

One other distinction between the Status Quo and Improved ICRP policy options concerns the assumed security factors for proposed island links. We have assumed that security factors will effectively be lowered for links with no redundancy in the subsea component of the transmission link, even for links considered to be part of the wider network for charging purposes (i.e. MITS). This assumption lowers the transmission tariffs for some island generators relative to the Status Quo.

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

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

3.2.3 Socialised

The Socialised policy option we have assessed envisages a uniform energy-based (per MWh) transmission tariff for all generators, in place of the locational wider tariffs and local asset charges under Status Quo and Improved ICRP.

The postage stamp approach removes the geographic variation across charging zones, eliminating the current North-South differentiation in charges. The socialisation of local asset charges is particularly significant for offshore wind and island generators, which face material local charges under Status Quo and Improved ICRP.

The Working Group had a wide range of views on the details of the Socialised policy option. One of the key issues in the debate was whether all infrastructure costs should be socialised (as assumed here), or whether some elements of cost-reflectivity such as local asset charges should be retained. Reflecting this debate, we conducted a sensitivity on the treatment of local asset charges under the Socialised policy option which is included in this report.

The Socialised approach does not involve load flow modelling or locational security factors and so HVDC and island links do not require different treatment under this policy option.

Demand charges would also be socialised on an energy basis under this approach, thus removing regional variations.

3.3 Policy option variants

We conducted two variants on the charging option designs, reflecting two of the key points of discussions in the Working Group:

- The exclusion of converter station costs in HVDC expansion factors under Improved ICRP, and
- The retention of local asset charges under the Socialised model, with the uniform tariff only replacing wider charges.

As summarised in Table 2, the two sensitivities are in all other aspects identical to the underlying policy options.

Table 2 Summary of transmission policy sensitivities

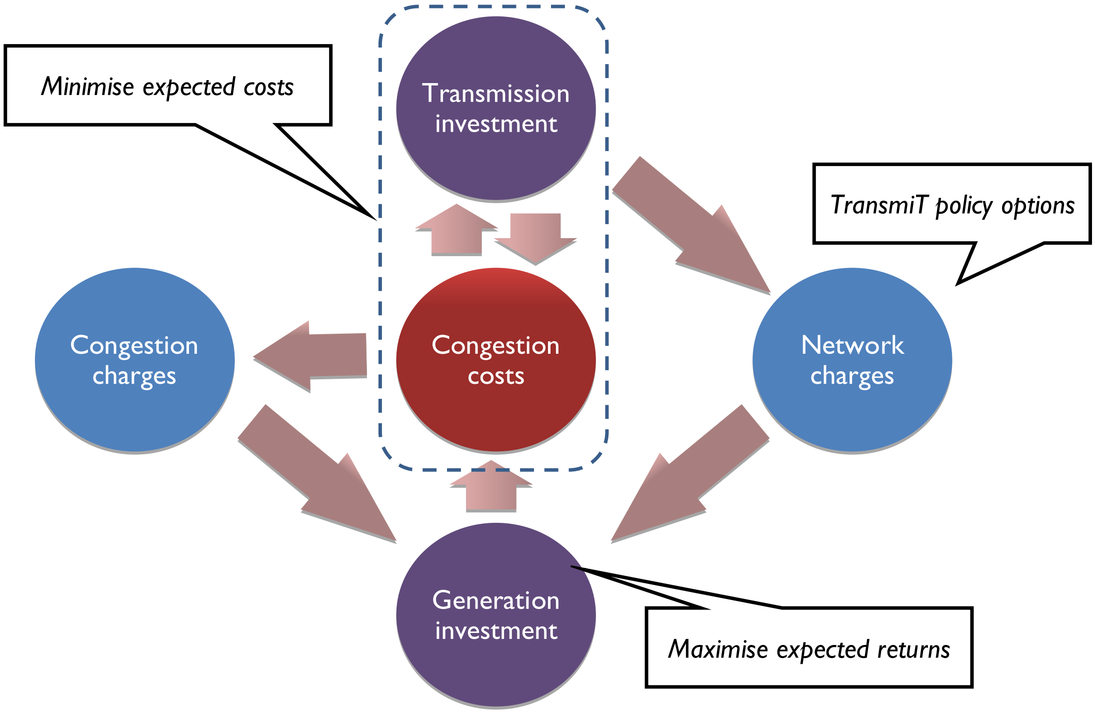
	Improved ICRP (HVDC sensitivity)	Socialised (wider only)
Wider investment	As for Improved ICRP	As for Socialised
Local asset charges	As for Improved ICRP	**As for Status Quo – local asset charges retained**
G:D split	As for Improved ICRP	As for Socialised
Capacity or energy (wider tariff)	As for Improved ICRP	As for Socialised
HVDC: expansion factor	**Costs exclude converter station costs**	Not relevant
HVDC lines: treatment in load flow modelling	As for Improved ICRP	Not relevant
Local security factors	As for Improved ICRP	Not relevant

4 Approach to the analysis

4.1 Overview

The analysis of the different transmission charging options is complex given the interdependencies between different factors, as illustrated in Figure 2 below. Transmission charges will influence the decisions of generators regarding where to locate their plant, and which plant to retire. This in turn affects transmission charges. Furthermore, the location of generating plant on the system affects the level of constraint costs which will drive future decisions on when and where to reinforce the transmission network. These reinforcements then feed into transmission charges which then also influence generators' decisions.

Figure 2 **Schematic of scope of potential charging reforms**



The scope for this study was limited to the impacts of transmission charging on transmission connected generation. We have not explicitly modelled the impacts on embedded (distribution connected) generation, which experience negative demand TNUoS charges, due to the relatively small proportion of embedded capacity and limited potential for this to respond to locational price signals. We do include the impact of the different policy options on demand TNUoS charges but have not attempted to model any long term impacts on the location of demand centres, or changes in short term demand side response behaviour in response to different transmission charging arrangements.

In this section, we provide an overview of the modelling approach and assumptions used. Further details can be found in Appendixes A and B respectively. In addition we have provided numerical results in a separate Excel file[16].

4.2 Objective

The key objective of the modelling is to provide a quantitative assessment of how the different charging options might impact on delivering sustainability objectives, whilst continuing to provide safe, secure, high quality network services cost effectively to existing and future customers. This required a modelling approach that for a certain set of starting assumptions could produce detailed outputs for capacity mix, generation output, capacity margins, power prices, constraint costs, transmission reinforcement costs, carbon emissions, as well as overall impacts on power sector costs and consumer bills. The impacts of alternative charging options were quantified by comparing the metrics to the Status Quo counterfactual.

Ofgem wished to understand the impacts of the different charging options from 2012 to 2030. In the period to 2020 there is a reasonable degree of visibility of potential generation and transmission projects and likely retirements, whereas beyond 2020 there is more uncertainty. Accordingly, the results of the analysis were to be considered in the context of these two different timeframes.

4.3 Modelling methodology

The modelling approach is based on an agent simulation engine that aims to mimic players' decision-making in response to expectations of future revenues (or costs in the case of constraints) relative to project costs. Generation decisions respond to different transmission charges as these form part of project costs, while transmission decisions are made in response to the location and type of generation[17] and thus can also vary across different policy options.

The modelling is based on running three linked models sequentially on a year-by-year basis[18]:

- The TransmiT Decision Model, which incorporates the following functionality:
  - Generation decision rules: using Redpoint's Investment Decision Model to simulate generation investment decisions based on future expectations of returns (both through the wholesale market and low carbon support mechanisms) and retirement decisions based on near term profitability expectations
  - Transmission decision rules: new functionality created for the study whereby transmission reinforcement takes place endogenously within the model where the expected future benefits in terms of avoided constraints costs exceed the investment and operational costs of the additional transmission capacity
  - Outputs: where the results across the modelling suite are aggregated and the costs and benefits of the different charging options can be compared

[16] Published alongside this document on Ofgem's website

[17] Transmission decisions will also depend on the location and quantity of demand, but this is held constant across policy options.

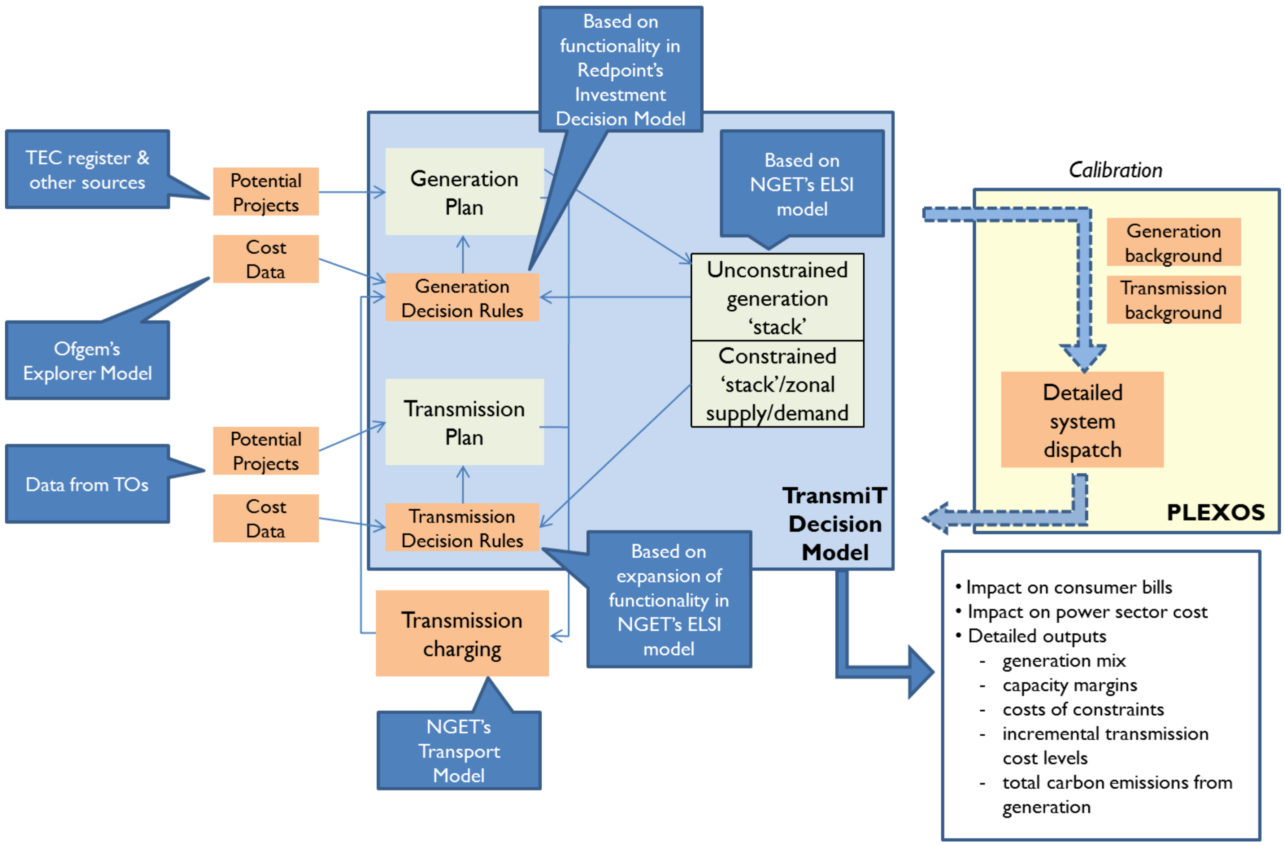
[18] The modelling is based on tariff years beginning 1 April and ending 31 March. For convenience, throughout the report we refer to 1 April 2011 – 31 March 2012 as "2011" (and so on).

- Control module: which schedules the running of the different modelling components

- National Grid's Electricity Scenario Illustrator (ELSI) model, which is used to model market dispatch on both an unconstrained and constrained basis in order to calculate generator earnings and constraint costs
- National Grid's Transport Model, a DC load flow model used to calculate TNUoS charges, and which has been enhanced by National Grid to capture the different policy options under consideration.

Outputs across the three interlinked models are aggregated within the TransmiT Decision Model. Results for the generation and transmission background are run through the power market simulation tool PLEXOS for benchmarking of constraint cost forecasts[19]. The modelling framework is illustrated schematically in Figure 3 below.

Figure 3 Overview of modelling framework



[19] PLEXOS is used by both NGET and Ofgem for the purposes of forecasting constraint costs. It models the market at a greater level of detail than ELSI, but the run time made it unsuitable for incorporation within the TransmiT Decision Model. This study is not per se about forecasting future constraints costs, but Ofgem believed it important that the analysis was undertaken using a realistic representation of constraint costs. Hence we undertook an extensive calibration exercise between PLEXOS and ELSI.

Investment and retirement decisions in the modelling are based on agent simulation under a set of pre-configured decision rules. Perfect foresight is not assumed and hence returns to generation and transmission investments might diverge from those expected at the time an investment is committed. An agent simulation approach was adopted for the core modelling since the study must consider how players respond to different locational signals, making any least cost optimisation inappropriate. The Technical Working Group was of the view that this was the correct approach to the study. However, it requires assumptions on how different players will behave, and Ofgem was keen to explore how the results might differ under the assumption of perfect foresight. In order to undertake this analysis we adopted an iterative approach which is described in more detail in Appendix A. The results for modelling under perfect foresight are included as part of the sensitivity analysis.

A capacity mechanism was assumed to be in place for the modelling, as being proposed under the EMR. Details are yet to be finalised but we included a simple form of universal capacity mechanism based on annual capacity auctions in the modelling. Further details are provided in Appendix A.

4.3.1 Modelling of low carbon support

There are important interactions between transmission charging and the levels of support that different forms of low carbon generation require to be built. Whilst Project TransmiT is essentially a review of transmission charging it was realised that these interactions could not be ignored, and that Project TransmiT and the Government's Electricity Market Reform are closely related.

Changes to transmission charging could in future:

- Accelerate or decelerate the rate of low carbon deployment, and/or
- Change the level of support required to achieve a certain level of deployment

To capture these two different effects, the modelling was undertaken on two bases as follows:

- **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 Technical Working Group members had differing views on whether the Stage 1 or Stage 2 results should be the basis for evaluating the different policy options. Ofgem believed that both sets of results would be relevant for the decision making. In this report we present the results from the two stages in a way which we believe best illustrates the differences between the policy options. In general, we believe that Stage 1 results are more suitable for estimating the impact of different charging regimes on deployment, under fixed levels of low carbon support, whilst Stage 2 results are more suitable for comparing costs across policy options, as each meets broadly the same renewable targets and low carbon objectives. Full details of results not covered in the main body of the report are included in supporting Excel files, as described in Appendix C.

It should be noted that there are currently no details available on the likely level of support (in the form of Contracts for Differences) to be introduced under EMR. Furthermore, we undertook the analysis prior to the launch of the Government's consultation of revised Renewables Obligation banding levels[20]. As such we necessarily had to make assumptions on the levels of support that would be available to low carbon generators and selected values that could deliver (on the basis of the economics) the 2020 renewables target of approximately 30%. We consulted the Department of Energy and Climate Change (DECC), and it was happy with this approach, but the strike prices for Contracts for Difference used in this study cannot be assumed to reflect future Government policy. We also made assumptions on the design of the CfDs, in particular that they are paid on output, as opposed to the alternative of paying on availability (section A.2).

4.4 Assumptions

As a general principle we drew on the most recent publically available and respected sources for input assumptions. We also consulted with the Technical Working Group on certain assumptions, most notably on available projects and realistic maximum build rates. Key assumptions were drawn from the following sources:

- Plant information and existing transmission boundaries from Ofgem's Balancing Services Incentive Scheme PLEXOS model
- Electricity demand and embedded generation based on National Grid's 'Gone Green' scenario
- Capital and operating costs for different generation technologies based on studies undertaken for the Department of Energy and Climate Change[21]
- Available generation projects to 2020 based largely on the Transmission Entry Capacity register and inputs from the Technical Working Group, with a broader range of sites assumed to be available to 2030
- Available transmission reinforcement projects sourced from National Grid, with further generic boundary reinforcements available from 2021
- The cost of other work to the onshore transmission network, including repairs and maintenance to existing assets, estimated using public RIIO business plan submissions from the three Transmission Owners (NGET, SPT and SHETL)
- Commodity prices based on Redpoint Reference Case (July 2011) and based on data from the IEA World Energy Outlook

The core modelling was undertaken on a Base Case set of assumptions. Sensitivities were also run on gas prices and RO banding levels. Further details on assumptions and data sources are contained in Appendix B.

[20] We subsequently undertook a sensitivity which includes the proposed new banding levels and is included in this report.

[21] Marine technologies from Ernst and Young, *Cost of and Financial Support For Wave, Tidal Stream and Tidal Range Generation in the UK*, Study for DECC (October 2010); Biomass, CHP and co-firing from Arup, *Review of the Generation Costs and Deployment Potential of Renewable Electricity Technologies in the UK*, Study for DECC (June 2011); Other renewables based on unpublished data from 2011 Ernst and Young study for DECC; Non-renewable technologies from PB Power, *Electricity Generation Cost Model – 2011 Update*, Study for DECC (June 2011).

4.5 Process

The modelling approach and assumptions were developed in close conjunction with NGET and the Technical Working Group. NGET provided considerable support through data provision and assistance with linking the TransmiT Decision Model with its ELSI and Transport Models. Valuable feedback was received from the Technical Working Group following presentation of the draft approach (1 August 2011), provisional modelling results and underlying assumptions (10 October 2011) and the Base Case results for Stage 1 and Stage 2 (9 November 2011).

Further detail on the modelling approach is contained in Appendix A.

5 Modelling results

5.1 Introduction

Key results for the modelling of transmission charging options are presented in this section. Results are presented under Status Quo, Improved ICRP and Socialised charging for:

- **Impacts on transmission charges:** different transmission charges impact upon the economic incentives facing generators and can thus affect generation deployment and power sector costs
- **Impacts on sustainability goals:** estimated using the results of Stage 1 modelling, with low carbon support held fixed across the different charging options
- **Overall cost impacts**: based on Stage 2 modelling, where renewable and low carbon targets are met equally across all three modelled policy options
- **Impacts on security of supply**: measured using de-rated capacity margins, based on Stage 2 modelling, and
- **Cost benefit analysis and distributional impacts**: aggregate impacts on power sector costs and consumer bills, also based on Stage 2 modelling.

Key results are also presented for **policy variants** and **sensitivity analyses**.

5.2 Impacts on transmission charges

There would be immediate impacts on transmission charges by moving to the Improved ICRP or Socialised methodologies. These immediate impacts are reflected by changes in modelled charges in 2012, which was the original assumed implementation date for the alternative charging options[22].

Changes to the basis used to set transmission charges can also have longer term impacts on the charges themselves via differences in the generation and transmission background. Over time, generation and transmission investment decisions respond to different transmission charges. Differences in the generation and transmission background will affect charges as estimated in the Transport Model by changing power flows and associated marginal costs, as well as through changes to the total level of transmission costs that need to be recovered through charging.[23]

We first compare charges under Status Quo with those under Improved ICRP. We then look at the results under Socialised. Given the different basis for charging under Socialised, on a per MWh basis rather than per kW basis, the comparison with Status Quo is less straightforward. Impacts on tariffs for generators located on Scottish islands (Orkney, Shetland and Western Isles) are set out in Appendix B.

[22] Due to changes to scope and timings of the TransmiT process it now looks as if changes to charging under the TransmiT SCR could not be implemented through the industry process until mid-2012 at the earliest.

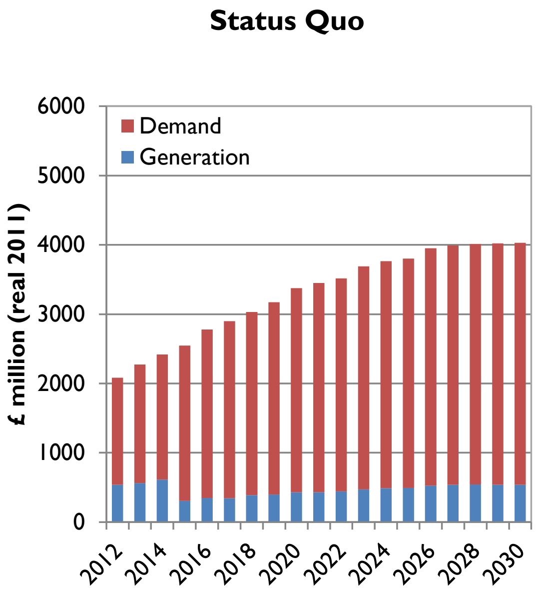
[23] These longer-term impacts are different across Stage 1 and Stage 2 modelling, as different retirement and investment decisions lead to different charges. In this section, transmission charging comparison is based on Stage 2 modelling, to compare charges that would deliver the same renewable level in 2020 and carbon intensity in 2030.

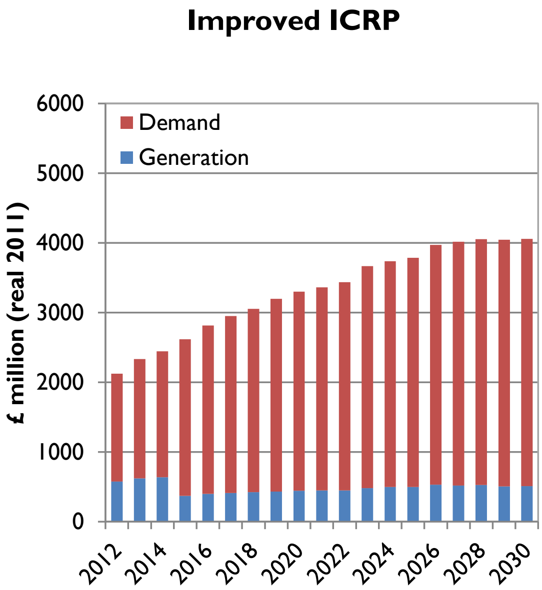
5.2.1 Status Quo and Improved ICRP charging

The Maximum Allowed Revenue (MAR) for transmission owners sets the amount of revenue that will be recovered through charges from network users in the model (Figure 4). The MAR under Status Quo is 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. In 2015, the G:D split of charging is assumed to change from 27%:73% to 15%:85% to comply with EU tarification guidelines as explained in Section 3. This can be seen in the drop in the blue bars. The charts demonstrate that because of this, and in spite of the overall increase in MAR, the total revenues recovered from generators are unlikely in real terms to exceed 2014 levels before 2030. In isolation this change in revenue collection does not impact on the locational differential of tariffs under an ICRP approach to charging. However, as more of the fixed proportion of total revenue collected from generators comes from offshore generators, the proportion collected from onshore generators will decrease.

A similar level of total revenue is recovered under Status Quo and Improved ICRP. This is a consequence of a similar level of total expenditure on transmission reinforcements to 2030, as explained further below.

Figure 4 MAR: Status Quo and Improved ICRP



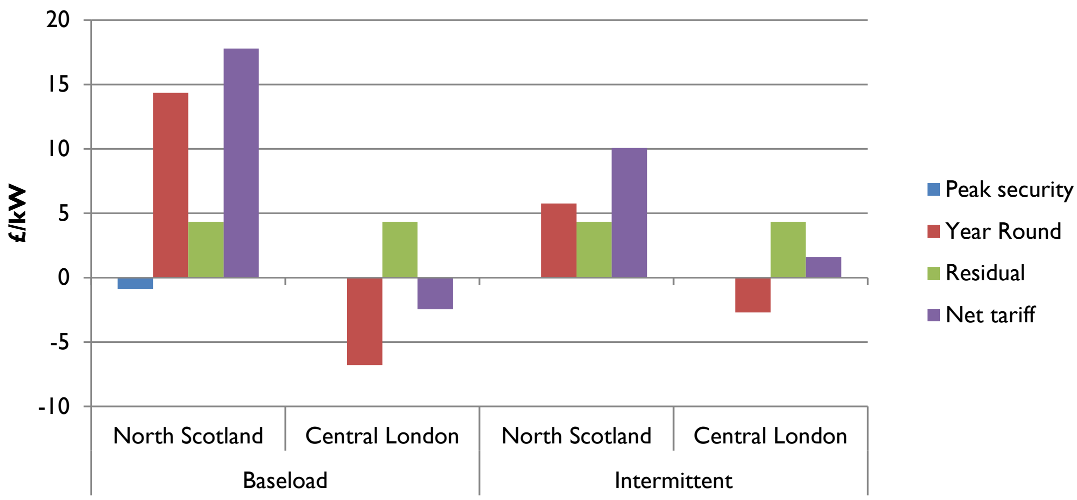


Although total revenue requirements are similar across the two options, there are significant differences in TNUoS charges to generators under Improved ICRP, in particular for low load factor generators, including wind. As described in Section 3, Improved ICRP charging aims to be more cost reflective by taking into account the fact that generation with different characteristics drive different investment costs on the transmission network. This is achieved through charging for two separate components of wider system use: a Peak Security charge for network capacity requirements driven at peak demand conditions and a

Year Round charge for network capacity requirements driven throughout a year of operation[24]. The Peak Security charge is typically of a smaller magnitude than the Year Round charge. These charges are added to the network-wide residual to calculate wider TNUoS charges.

Wider TNUoS charges under Improved ICRP are demonstrated for a generic baseload generator (with a load factor of 70%) and intermittent generator (load factor of 28%) in Figure 5. The net tariff for a baseload generator includes a Peak Security component, which is negative for North Scotland[25] and positive but very small for Central London. In other zones (such as South Wales and Gloucester) the Peak Security component is estimated to be significantly positive in 2012. The intermittent generator is not subject to the Peak Security component and pays a lower tariff in North Scotland than the baseload generator as a consequence of its lower load factor. However, the intermittent generator does not benefit from negative tariffs in Central London to the same extent as the baseload generator. A low load factor thermal generator would still be subject to the Peak Security component but would have its Year Round component adjusted for its low load factor. For example, a thermal plant with a load factor of 28% would face very similar tariffs to a wind generator with the same load factor in North Scotland or Central London, given the small impact of the Peak Security component in these zones.

Figure 5 Derivation of wider TNUoS charges under Improved ICRP charging



The range in Generator TNUoS tariffs is more compressed under Improved ICRP, in particular for low load factor generators. For example, wider tariffs[26] under Status Quo in 2012 range from -£14/kW per

[24] The expansion cost of each circuit is allocated to the background in which the flow on that circuit is highest. We find that the majority of circuits are allocated to the Year Round background. This is one reason for the magnitude of the Year Round Tariffs being larger than the Peak Security Tariffs

[25] The outcome that the Peak Security component for North Scotland for 2012 is negative whereas the Year Round component is positive indicates that under the Peak Security background, the direction of flow on certain circuits is reversed compared to the Year Round background, and that incremental generation at peak in North Scotland would reduce the flows on these circuits.

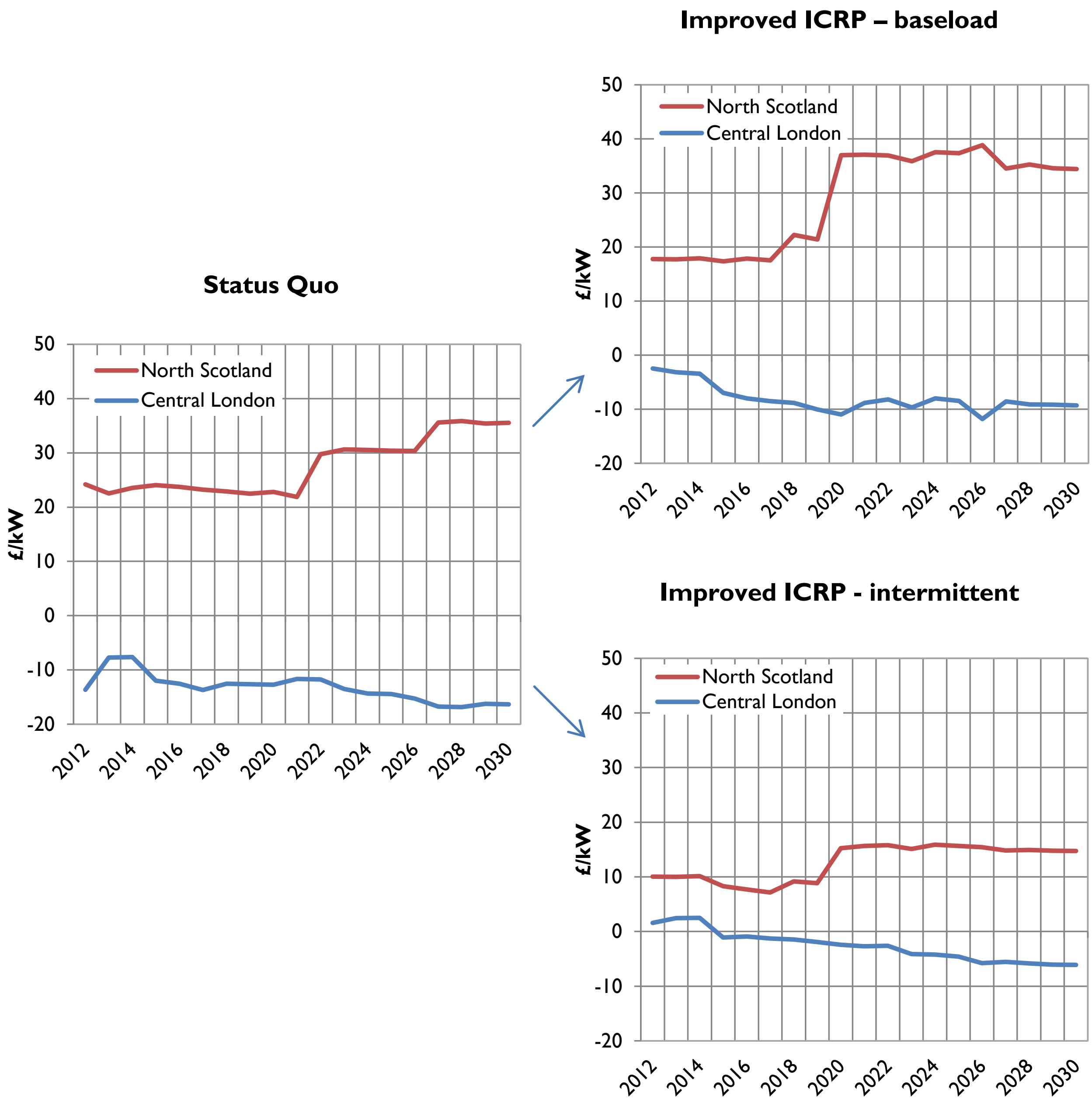
[26] As set out in Section 2, the locational element of Status Quo charging is split into local (generator-specific) and wider charges. Local charges cover the cost of the transmission connection from a generator to the MITS and are calculated individually for each generator. These are typically a small proportion of the overall charge, with the exception of offshore generators or those located on islands a long way from the MITS. Wider locational charges are calculated for all generators within pre-determined geographic zone (of which there are currently 20) and are the same for all generators within that zone.

year in London (the cheapest zone) to about £25/kW in North Scotland and the Western Highlands and Skye (the most expensive zone)[27]. Under Improved ICRP, tariffs range from -£2/kW (Central London) to £18/kW (North Scotland and the Western Highlands and Skye) for baseload generators, and from about £1/kW (Peninsula) to £10/kW (North Scotland and the Western Highlands and Skye) for intermittent generators. The spread of charges for lower load factor thermal plant is smaller than that for baseload generators, but is generally wider than for intermittent generators. A thermal plant in a high positive TNUoS charging zone, and with the same annual load factor as an intermittent generator in the same zone, would generally pay more under the two part pricing of Improved ICRP. This is because the low load factor thermal generator would be expected on average to have higher output at times of peak load and the peak security element is typically positive. The compression in charges under Improved ICRP can also be seen through a flatter pattern of charges across different zones in Figure 7.

Some tariff changes in later years are driven by transmission reinforcement decisions. For example, increases in tariffs in North Scotland in 2022 and 2027 under Status Quo are a consequence of the model choosing to build the first and second Eastern HVDC links in these years under this charging regime. Similarly, the increase in generator TNUoS in North Scotland in 2020 under Improved ICRP is a consequence of the model choosing to build the Caithness – Moray HVDC link in this year (not built under Status Quo) while there are smaller increases associated with the two Eastern HVDC links in 2018 and 2024. The treatment of HVDC links in the modelling is set out in Appendix A. Figure 6 shows tariffs for the highest and lowest TNUoS charging zones (on average) coming from the model over the period to 2030.

[27] Note there is no difference in charges for baseload and intermittent generators under the current Status Quo approach.

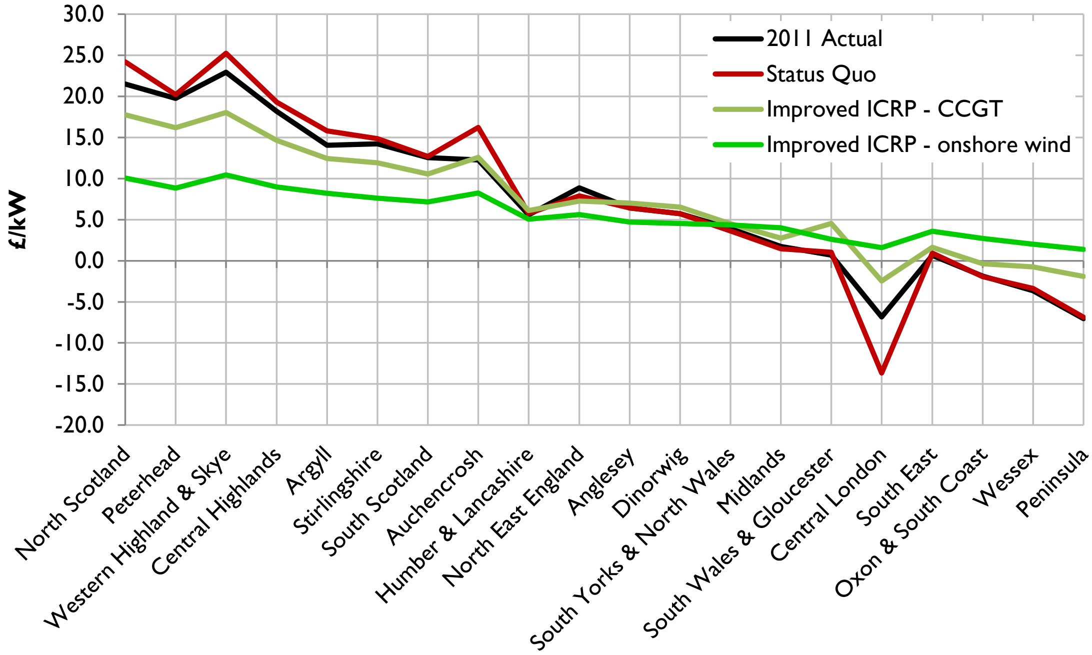
Figure 6 Generator wider TNUoS (locational and residual)



Note: Wider locational and residual charges only; excludes any local charges. Baseload generator assumes 100% load factor at peak and 70% annual load factor. Intermittent generator assumed 28% annual load factor, representing a typical onshore wind generator and no use of system at peak.

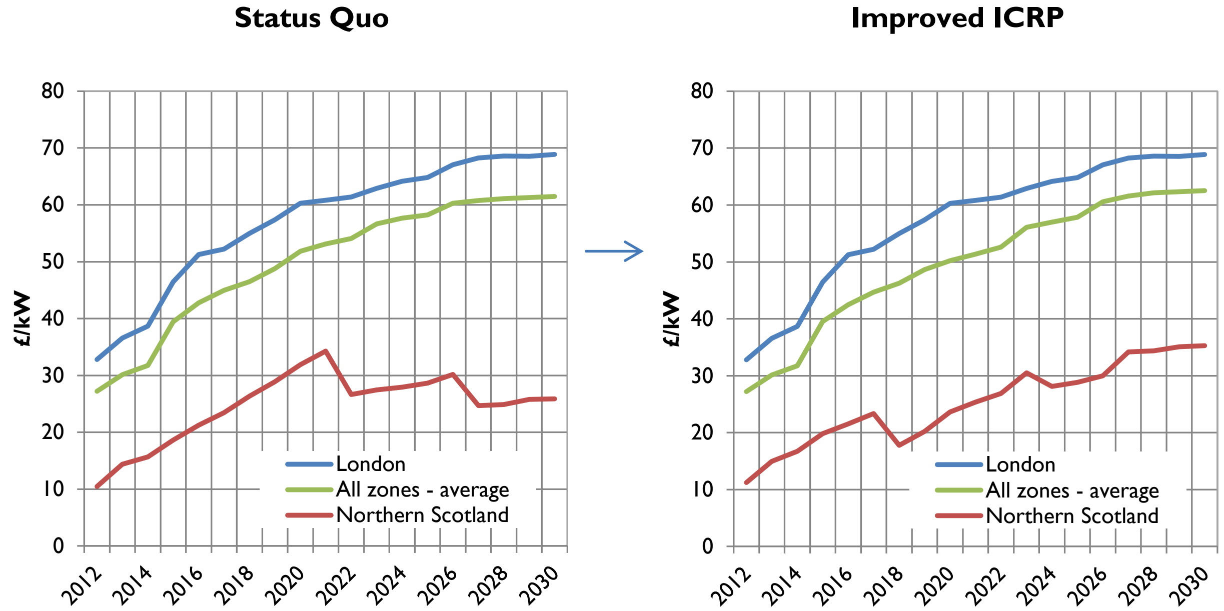
Figure 7 compares the Generator TNUoS charges under Improved ICRP and Status Quo for all zones for a single year, 2012. Charges by zone for all years of the modelling period are provided in Appendix C.

Figure 7 Generator wider TNUoS across all zones (locational and residual), 2012



Differences in demand TNUoS charges between Status Quo and Improved ICRP are relatively minor, driven almost entirely by differences in generation and transmission backgrounds, since the methodology for calculating demand charges are assumed to be the same. For both Status Quo and Improved ICRP, demand TNUoS charges generally increase over time to recoup increasing MAR (and increase further due to the higher demand share from 2015). The exceptions are following the commissioning of new HVDC links which tend to lead to drops in charges in Northern Scotland. Figure 8 compares the highest, lowest and average demand TNUoS under Improved ICRP to Status Quo.

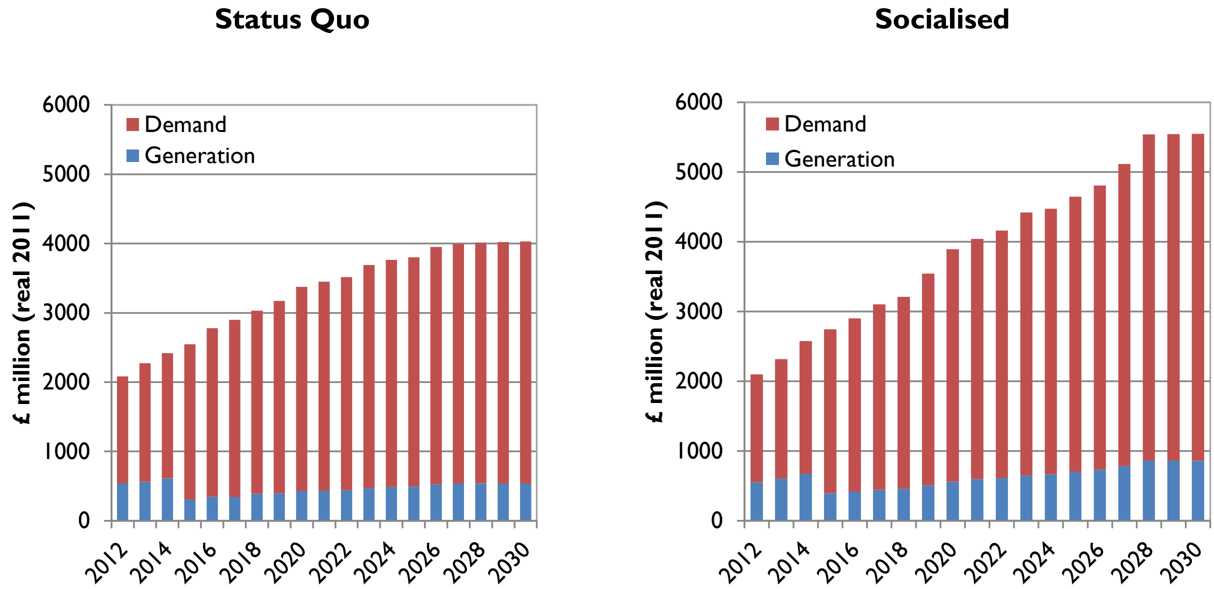
Figure 8 Demand wider TNUoS for half hourly metered customers



5.2.2 Socialised charging

There is a more rapid increase in MAR under Socialised charging, as more transmission reinforcement is required to accommodate the resulting generation background as explained below.

Figure 9 MAR: Status Quo and Socialised

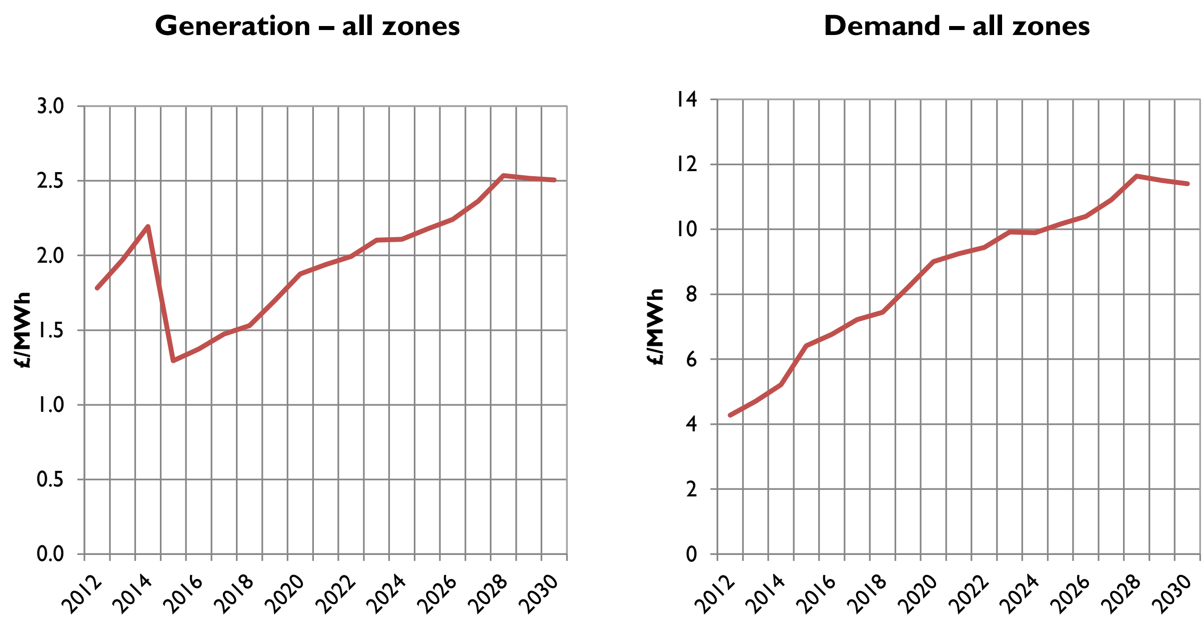


As explained in Section 3, charges under Socialised are set on a uniform basis per unit of electricity generated or used (£/MWh) rather than on the basis of capacity (£/kW). The uniform charges for both generation and demand increase over time to recoup increasing MAR.

Under Socialised charging, generators that are currently in high TNUoS charging zones will face lower charges. This is particularly the case for generators with low load factors (such as wind generators) as these generators will generate less MWh of energy (the basis for Socialised charges) for the same Transmission Entry Capacity (the basis for Status Quo charges). Conversely, generators currently in low or negative TNUoS charging zones will face higher charges, particularly those operating at baseload. Hence, from our examples above the intermittent generator in North Scotland would be the greatest winner and the baseload generator in London the greatest loser. Offshore generators would also benefit under the Socialised approach, since under the model chosen for analysis the costs of local assets[28] would also be shared, reducing, significantly in some cases, the costs of the offshore transmission operator (OFTO) asset. Offshore generators were assumed to bear 80% of the costs of OFTO assets required to connect them to the MITS, as set out in Appendix B.

We present the generation and demand charges produced by the model under Socialised in Figure 10 below[29].

Figure 10 Socialised TNUoS charges



[28] We also included the sensitivity where local asset charges would be retained within a Socialised approach as presented below.

[29] Note that these Socialised charges include the full costs of all local assets. The charges presented above for Status Quo and Improved ICRP were the wider zonal charges excluding the site specific local asset charges.

5.3 Impacts on sustainability goals

The results in this section demonstrate the potential impact on the speed of deployment of renewables and other forms of low carbon generation under the three different charging options, assuming the same level of low carbon support across the options. All the results in this section are based on Stage 1 modelling. At this stage we are only considering the national picture, and not examining locational differences between the options.

5.3.1 Capacity mix

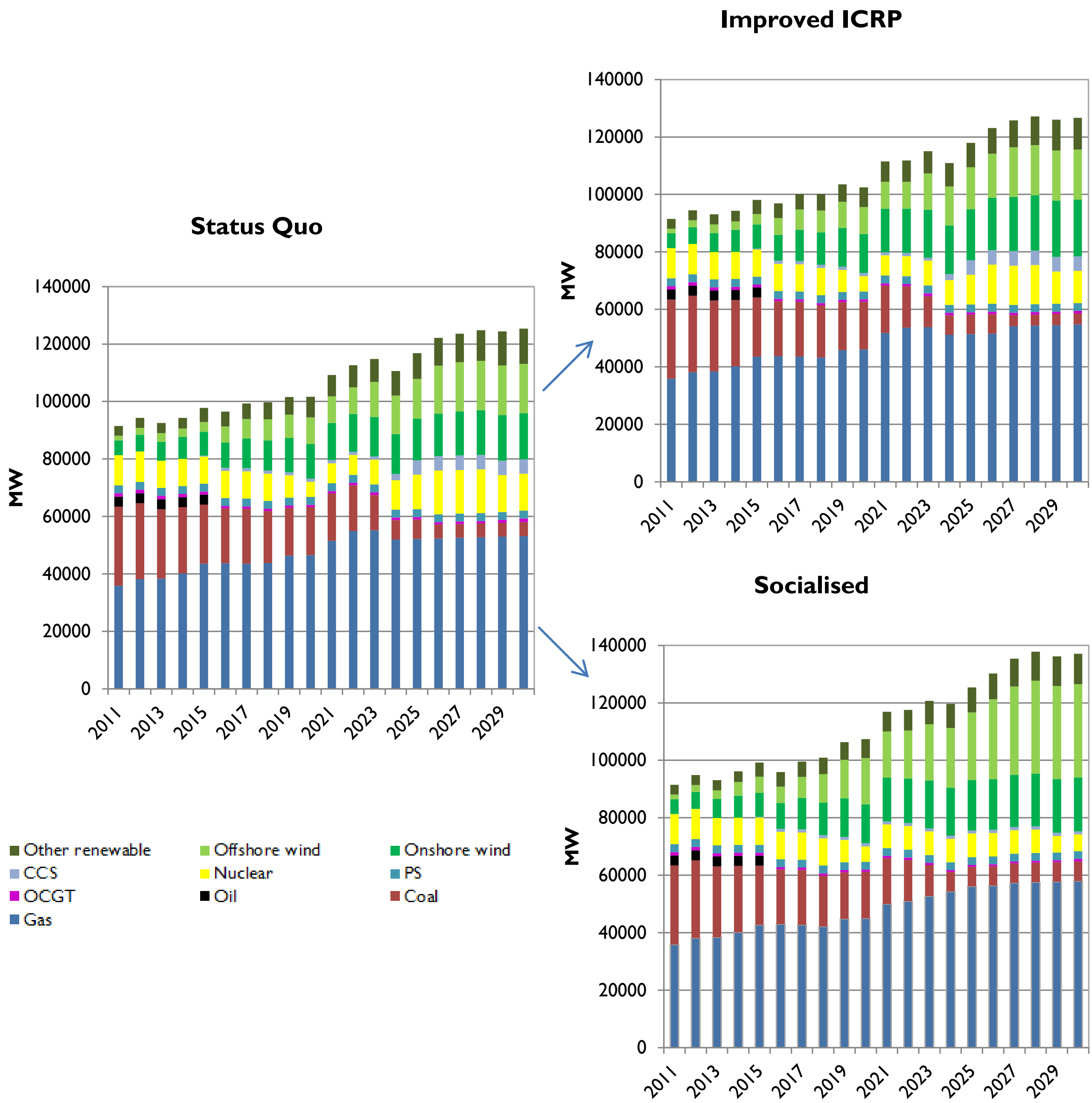
The charts in Figure 11 below show how the capacity mix evolves under the three charging options according to the model. Changes result as a consequence of retirements of existing plant and new investment.

Under Status Quo the results include retirement of coal, oil and some combined cycle gas turbine (CCGT) plant in line with the Large Combustion Plant Directive (LCPD) and Industrial Emissions Directive (IED), and nuclear plant in line with lifetime assumptions based on industry data (Appendix B). Around 15% of capacity closures are driven by plant economics, unrelated to the LCPD, IED or nuclear lifetime assumptions.

New investment leads to a net overall increase in capacity over the next twenty years to meet increasing demand with a greater renewable share. CCGT and nuclear capacity is higher by 2030, as new build more than offsets the plant that are retiring. There is also a substantial increase in renewable capacity (in particular, onshore and offshore wind) to meet renewables targets, and some deployment of coal plant fitted with carbon capture and storage (CCS) brought forward through support provided under EMR[30].

[30] Note that the model had the option of building OCGT plant but it did not build any on the basis of wholesale market revenues alone. Future build of new OCGT plant may be supported by contracts for provision of balancing services but this was not included in the modelling framework.

Figure 11 Total generation capacity (Stage 1 modelling)



Improved ICRP shows a similar overall pattern of retirement and new build to Status Quo. There is an additional 3 GW of onshore wind build as a consequence of lower TNUoS charges for intermittent generators in positive generator TNUoS zones. Accordingly, slightly less baseload generation is required to meet demand and there is one less nuclear plant by 2024.

There are more significant differences under Socialised charging. In particular, there is more build of new renewable generation. This effect is most pronounced for onshore and offshore wind:

- In zones with positive TNUoS charges under Status Quo, generators with low load factors are favoured by Socialised charging based on actual electricity generated (£/MWh) rather than Transmission Entry Capacity (£/kW). This tends to advantage onshore and offshore wind.
- Offshore wind build is further facilitated because generators do not face local charges for the cost of their connection to the onshore network. This can be a significant charge, estimated to range from just under £25/kW to as much as £125/kW depending on the distance offshore of specific sites (details in Appendix B).

A further significant difference in the capacity mix under Socialised is the lower volume of nuclear capacity by 2030. This because as a baseload generator, nuclear pays a greater proportion of the overall generator charges, and the effect is exacerbated by the fact that many of the nuclear sites are in the south of the country and would otherwise have benefitted from low or even negative locational charges under Status Quo. For similar reasons there is less CCS capacity under Socialised than under Status Quo or Improved ICRP.

5.3.2 Renewables deployment and carbon intensity

In Figure 12 below we show the impact of these different capacity mix outcomes on renewables output and in particular how they might affect the achievement of the 2020 renewables target (which we assume to be around 30% in the generation sector).

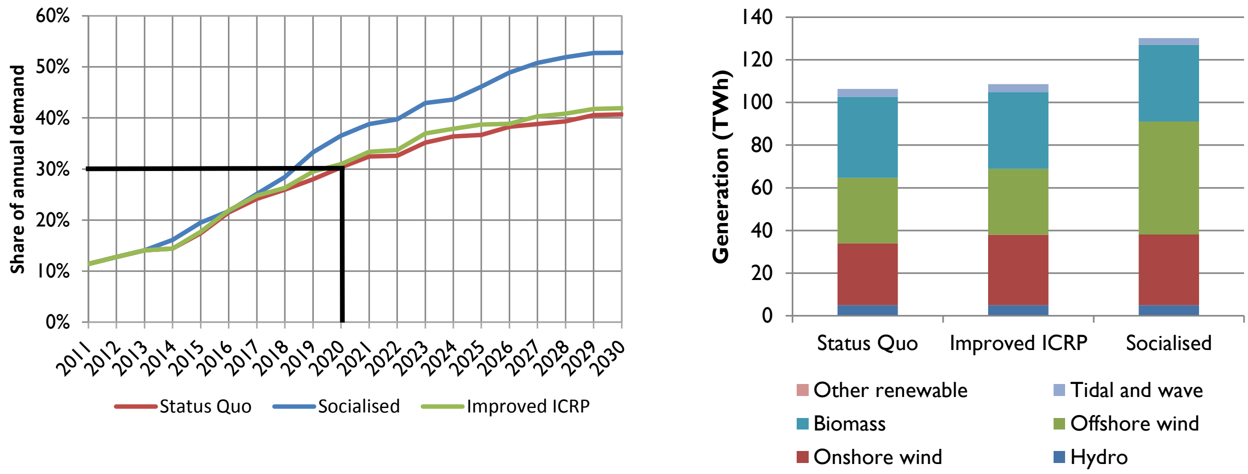
In the modelling, the support levels were set to achieve 30% renewables generation under Status Quo with the Base Case assumptions. For the same level of support, renewables output is slightly higher under Improved ICRP, by 0.6 percentage points by 2020, suggesting that this charging option could somewhat increase the probability of hitting the 2020 target on time. Under Socialised, renewables output is 6.2 percentage points higher by 2020[31]. This suggests that there could be a significant benefit of the Socialised approach as measured by the speed of renewables deployment. Where other non-economic factors constrain the rates of deployment this difference with Status Quo might be narrowed[32].

Figure 12 also demonstrates that the bulk of the additional renewables generation in 2020 under Socialised is coming from offshore wind. There is also an increase in onshore wind deployment under Socialised charging. The Socialised approach reduces TNUoS charges on average for both onshore and offshore wind, but savings are greater for offshore generators as they benefit from socialisation of local charges (up to £125/kW). There is slightly less biomass generation under Socialised charging, because of the higher load factor associated with biomass plant and the location of most available projects in the south, where transmission charges are relatively low under Status Quo.

[31] There is likely to be some additional constraining off of wind to address transmission locational constraints under Socialised charging, but modelling estimates suggest this would only reduce the increase in renewable share from 6.2 percentage points to 6.0 percentage points.

[32] Note that in the draft analysis presented to the Technical Working Group the differences between the options were much smaller but it was felt that the model was unduly constraining build in certain locations and hence some of the build rates were relaxed based on information provided by the Technical Working Group.

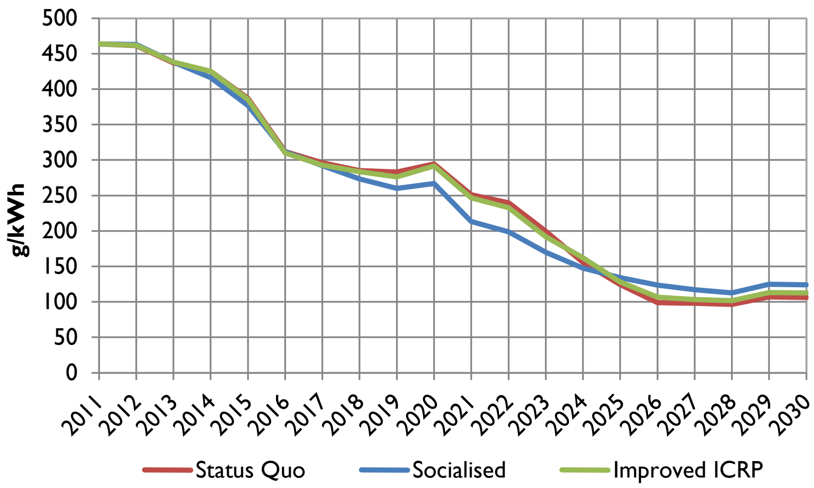
Figure 12 Renewable generation, 2011-2030 and breakdown in 2020



Note: Renewable generation based on the unconstrained generation schedule. (Results adjusting for constraining off of renewables are presented in Appendix C.)

Figure 13 shows the carbon intensity of generation as produced by the model under the three charging options. The lower trajectory up to 2025 under Socialised is a function of the higher renewables deployment. Thereafter, the lower deployment of nuclear and CCS under this option leads to a higher carbon intensity than under Status Quo or Improved ICRP.

Figure 13 Carbon intensity



5.4 Overall cost impacts

To compare overall cost impacts of the different charging options, low carbon support was adjusted so that renewable and carbon intensity outcomes were approximately equal across all three modelled policy options, facilitating comparison on a 'like with like' basis. All results in this section are based on the Stage 2 modelling. Stage 2 modelling involved setting low carbon support initially based on the average long run marginal cost (LRMC) of each technology (which differs across the three charging options) and then scaling support under Improved ICRP and Socialised charging uniformly to achieve the same renewable share (in 2020) and approximately the same carbon intensity (in 2030) as under Status Quo.

For Improved ICRP, this involved setting Contracts for Difference (CfDs) as proposed under EMR with only small variations in support compared with Status Quo, as can be seen in Table 3. The CfD level for onshore wind is slightly lower due to the lower average LRMC of onshore wind under improved ICRP, which itself is a direct consequence of lower average TNUoS charges for onshore wind.

For Socialised charging, setting CfDs initially based on LRMCs and then scaling down to achieve the same renewable target as Status Quo results in significant divergences in support for different technologies relative to Status Quo. Support for offshore wind can be materially reduced, and small reductions for onshore wind are possible while still meeting the 2020 target. However, CfDs for nuclear and CCS need to be increased in order to achieve same level of decarbonisation as Status Quo, reflecting the higher average level of transmission charges that these generators face.

Table 3 Assumed CfD levels (2020) (Stage 2 modelling)

	Improved ICRP	Socialised
	% of Status Quo	% of Status Quo
Nuclear	100%	104%
Gas + CCS	100%	104%
Coal + CCS	100%	102%
Onshore wind	99%	99%
Offshore wind	100%	93%
Biomass	100%	102%

Note: These support levels reflect the differences in the average LRMCs under the different options and were scaled to ensure that all three charging options achieve approximately the same renewable share (in 2020) - but from a different capacity mix - and a similar level of carbon intensity (in 2030) as under Status Quo.
Source: Redpoint modelling.

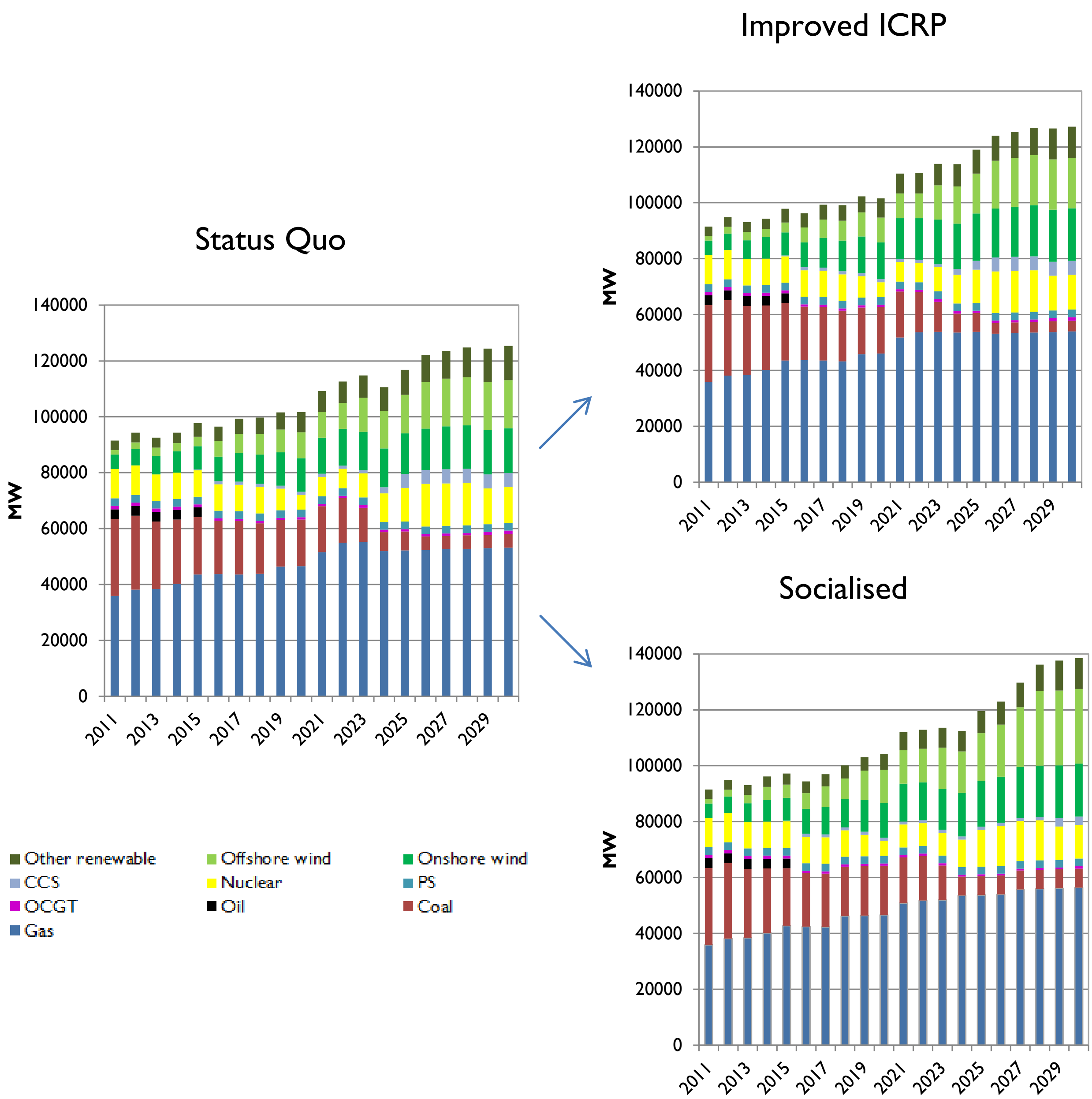
5.4.1 Capacity mix

Differences in the capacity mix are smaller than under Stage 1 modelling, as low carbon support levels have been adjusted to achieve similar outcomes in terms of 2020 renewables generation and carbon intensity in 2030. In general, however, the same technologies that come forward under Stage 1 modelling are favoured under Stage 2, despite adjustments in support levels.

For example, under Improved ICRP there is 1150 MW more onshore wind capacity, and 290 MW less biomass and 400 MW less offshore wind than under Status Quo.

Under Socialised charging there is more offshore wind and less biomass than under Status Quo. As under Stage 1, offshore wind build is facilitated because generators do not face local charges for the cost of their connection to the onshore network[33].

Figure 14 Total generation capacity (Stage 2 modelling)



[33] This relates to the steepness of the cost curve across different offshore sites under different charging options. Under Socialised charging, offshore generators do not face local transmission charges, which increase substantially with distance from shore. Accordingly, there is little difference in costs across different offshore sites in GB waters (the choice of location is instead driven mainly by differences in water depth), so where CfDs are high enough to promote offshore build, a wide range of high-resource offshore sites are developed. Under the Status Quo and Improved ICRP charging approaches, there is greater variation in the costs faced by offshore generators in different locations due to the inclusion of local charges (which vary considerably with distance from shore) and wider tariff signals. Under Status Quo and Improved ICRP, therefore, CfDs will not only need to be higher than under Socialised to promote offshore build, but cost variation across projects will mean that only a limited subset of available sites might be developed for a given CfD level.

Whilst the overall capacity mix from the Stage 2 modelling is similar across the three charging options, there are significant locational variations. Differences in cumulative new build by region are shown in Figure 15 (to 2020) and Figure 16 (to 2030).

Under Improved ICRP charging, the compression of locational variations in generation charges (particularly for low load factor generators) favours plant with low load factors in what are currently high TNUoS charging zones. The analysis shows that zones which currently have high TNUoS charges become relatively more attractive for siting plant with lower load factors, including intermittent renewables. This drives more onshore wind build in North Scotland. It also encourages more offshore wind in Scotland and less in South England. Similarly, wave and tidal projects face more favourable tariffs in Scotland and less favourable tariffs in South England compared with Status Quo. However, these tariff reductions are not sufficient to drive any more development of wave and tidal in Scotland, whereas there is less capacity developed in tidal projects in South England between 2020 and 2030. The reduction in biomass capacity under Improved ICRP occurs in Northern England, in a zone with relatively low (but positive) TNUoS tariffs under Status Quo.

Under Status Quo, wind is developed in the Scottish islands of Shetland and Orkney. Levelised costs for these islands are lower than the average mainland onshore wind project, as a result of the assumed load factor of 45% outweighing the higher TNUoS charges relative to mainland onshore wind. There is a small increase in the development of wind generation in the Scottish islands under Improved ICRP compared to Status Quo. Wind generation in the Scottish islands is favoured under Improved ICRP both by lower security factors (and thus lower charges) for cables linking the Orkneys and Western Isles with the mainland[34], as well as by lower wider charges for use of the onshore network from the connection point with the existing onshore network. This facilitates slightly more build of onshore wind in the Orkneys after 2020. However, it is not sufficient to facilitate development of onshore wind generation in the Western Isles, where load factors are assumed not to be as high as those in the Shetlands and Orkneys. (Assumptions on load factors and the charging treatment of island links are detailed in Appendix B.)

Under Socialised charging, there is an absence of locational signals, which tends to favour the build of new renewable generation in the best resource sites, ignoring transmission costs. The analysis shows that this leads to greater onshore wind build in regions that are frequently windy and thus offer high load factors, specifically North Scotland and the Scottish islands, relative to onshore sites in Wales and England. Offshore sites are chosen on the basis of water depth, since development costs increase with depth of water. Relative to Status Quo, this favours many sites that are shallow but relatively far offshore. Under Status Quo (and Improved ICRP), offshore generators face higher charges as transmission costs increase with distance offshore. For example, offshore development is more rapid under Socialised off the east coast of England, where sites such as Hornsea and Dogger Bank are far offshore but on average shallower than wind farms in the Irish Sea. Additional onshore wind capacity in the Scottish islands results predominantly from development of the Western Isles (in addition to the capacity on the Shetlands and Orkneys), which offers higher load factors than those available from onshore wind on the mainland.

For wave and tidal, load factors were assumed to be the same across different locations, but the lack of locational charging signals under Socialised still results in more development of sites in Scotland by 2020.

[34] As described in Appendix B, these links were modelled as local circuits in the Transport Model. If built, island links to the Orkneys and Western Isles could form part of the MITS, in which case they would form new charging zones subject to wider charges that reflect the incremental cost of these transmission links. The homogeneity of generation in the new charging zones (predominantly onshore wind) means that tariffs would be comparable whether modelling as local or wider tariffs, and in either case there would be benefits to island generators from lower charges as a consequence of lower security factors.

There is less development of sites in South England, as these would no longer benefit from the negative TNUoS charges under Status Quo.

The lack of locational signals also leads to a greater geographical spread of new CCGTs and nuclear build relative to Status Quo. CCGT[35] new build by 2030 extends throughout GB (but limited to realistic sites) under Socialised charging, rather than being limited to England and Wales as under Status Quo. Nuclear build under Socialised is also spread more widely than under Status Quo, with development of sites in North England and Wales, as there are no locational signals from transmission charging influencing development of specific pre-determined sites.

[35] The location of new gas plant will be affected by charges associated with use of the gas transmission network (gas exit charges) which were estimated for new and existing plant based on prevailing charges in 2011 and projections for 2012, 2013 and 2014. Gas exit charges were assumed to remain at 2014 levels for the remainder of the modelled period.

Figure 15 New build by location to 2020 (Stage 2 modelling)

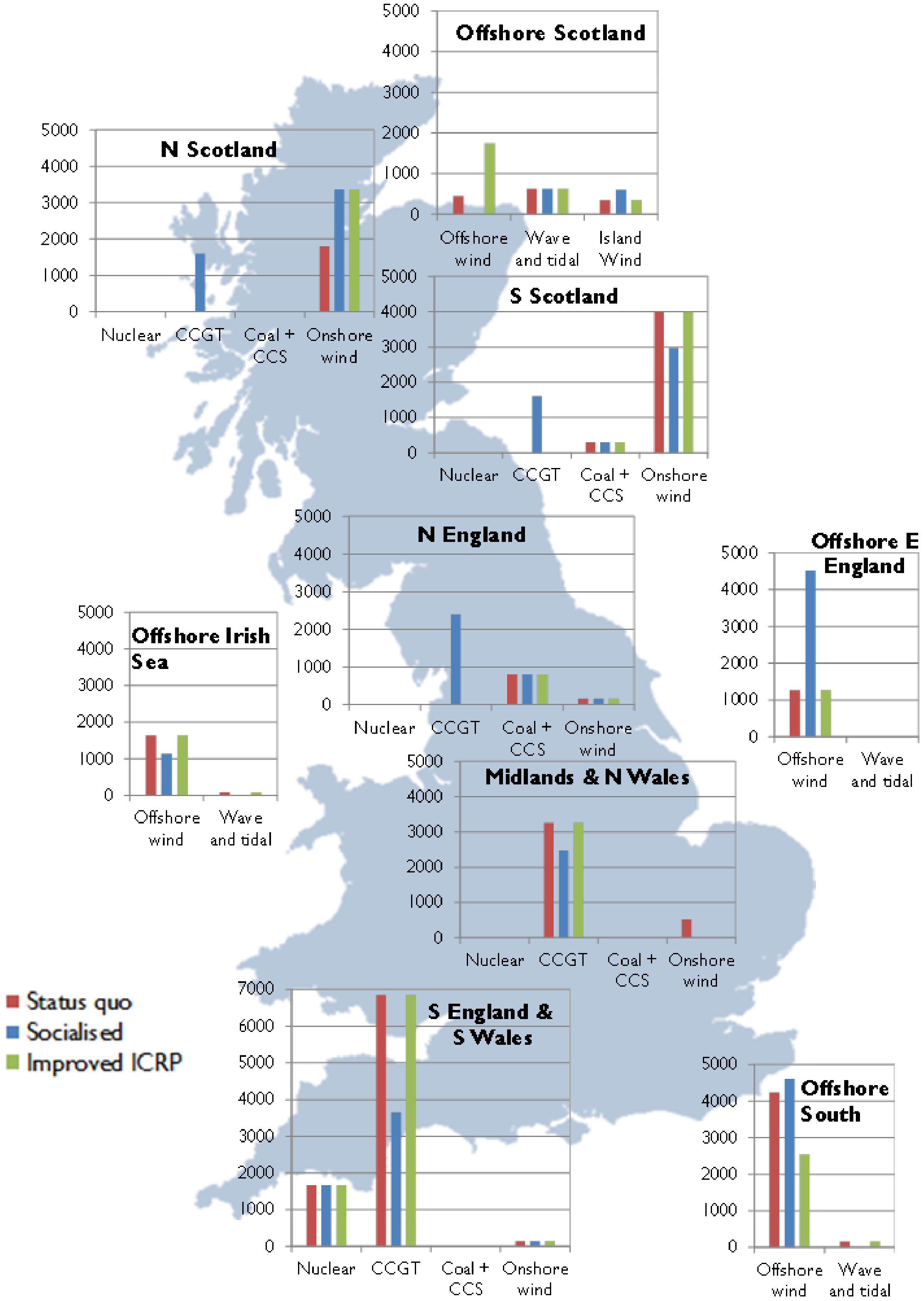
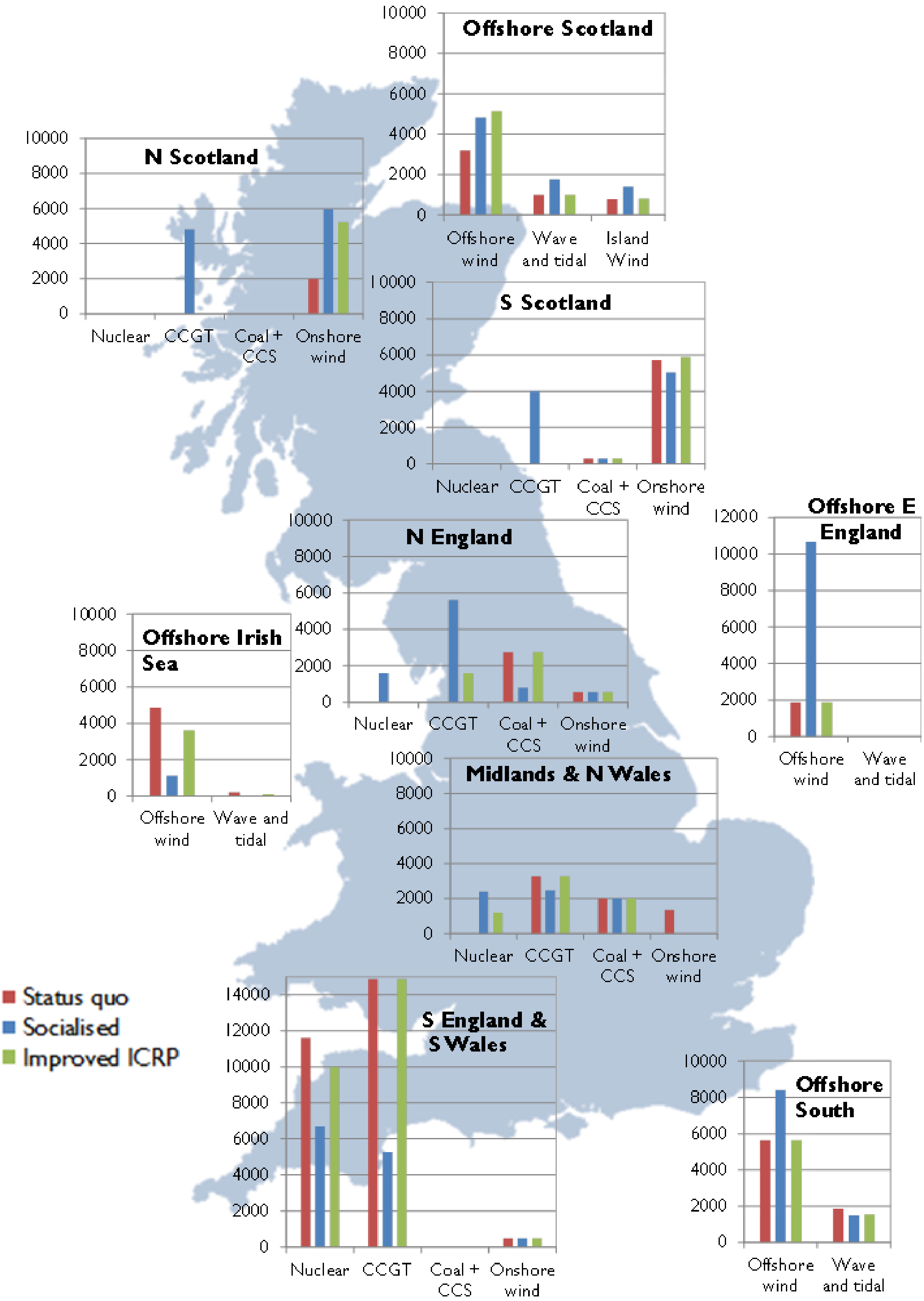


Figure 16 New build by location to 2030 (Stage 2 modelling)



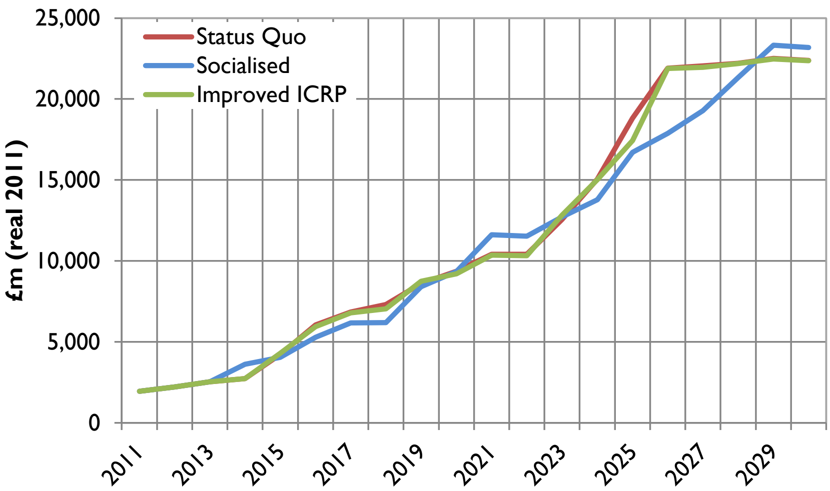
5.4.2 Generation costs of low carbon deployment

Figure 17 shows the cumulative cost of low carbon generation under the three transmission charging options produced by the model. This 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.

The results for Status Quo and Improved ICRP are very similar, reflecting the fact that the differences between these two options in terms of generation mix are relatively small.

The results for Socialised are different to the other two charging options. There are two key effects driving the differences. On one hand, Socialised charging encourages investment in sites with the best resource potential, leading to cost savings in generation. By locating wind generation (in particular) in locations with higher available load factors in North Scotland, Scottish islands and offshore, the assets installed are more 'cost effective' in terms of producing a greater level of output from the same level of assets compared with the same technology in areas on the mainland where lower load factors are available. On the other hand, by encouraging more offshore wind, which is assumed to be more expensive than onshore wind or biomass due to the challenges involved in installing wind generation offshore, Socialised leads to higher costs. These two effects largely offset each other, with similar generation costs for low carbon generation by 2020 and 2030. Differences in generation costs during interim years are largely driven by differences in the timing of renewable investment, but also by short term differences in the trade-off between targeting of cheaper, higher resource sites and greater development of more expensive offshore wind generation. For example, the rapid increase in generation costs between 2018 and 2019 under Socialised is driven by new build of more than 2 GW of additional offshore capacity, where the trade-off between higher utilisation of the wind resource (relative to onshore) is outweighed by the higher costs associated with installing and running assets in these offshore locations. Higher costs in 2021 are a consequence of the timing of one new nuclear plant, which is built two years earlier under Socialised than under Status Quo.

Figure 17 Cumulative costs of low carbon generation



5.4.3 Transmission reinforcement decisions and costs

Transmission reinforcement decisions respond within the model to the location of generation capacity, based on the economic trade-off between expected constraint costs on different boundaries and the cost of new transmission reinforcements.

Figure 18 shows the cumulative costs of modelled reinforcements to the MITS across the three charging options. Expenditure on reinforcement is required under Status Quo to reduce constraint costs with increasing deployment of renewables. Under both Improved ICRP and Socialised charging, the increase in generation capacity further away from the main demand centres brings forward the need for further transmission reinforcement to the onshore network. As a result, a greater number of reinforcement projects are undertaken under both Improved ICRP and Socialised charging. Each project involves specific costs, which are reflected in higher total investment costs and thus higher annual transmission owner costs that must be recouped through transmission charging.

The increase in transmission costs under Improved ICRP and Socialised charging is driven in particular by the increase in onshore wind build in the North of Scotland[36], which brings forward build of new HVDC links as shown in Table 4. The significant increase in onshore wind deployment in North Scotland under Improved ICRP brings forward build of HVDC links that reinforce boundaries between Northern Scotland and demand centres further south. In particular, the second Eastern and Western HVDC links are built earlier than under Status Quo, and earlier even than under Socialised. HVDC links are a relatively high cost means of reinforcing the network. As a consequence, reinforcement costs under Improved ICRP are higher than those under Socialised between 2018 and 2021. After this time, the wider spread of build under Socialised triggers a need for earlier build of additional reinforcement projects, for example the Humber-Walpole HVDC link.

Offshore transmission build is also important to total transmission costs. There are further increases in transmission costs under Socialised charging due to an increase in offshore wind build. Under Improved ICRP, on the other hand, offshore transmission costs are slightly lower than under Status Quo, offsetting additional costs from onshore reinforcement (Figure 19). The overall costs of onshore, offshore and island transmission are reflected in differences in the maximum allowed revenue for transmission owners, presented above.[37]

[36] There is a (smaller) decrease in onshore wind development in low TNUoS charging zones in Wales under Improved ICRP and Socialised charging. Onshore wind in England is assumed to be all embedded (connected to the distribution rather than transmission network), and thus modelled as a fixed level of generation that does not respond to transmission charging.

[37] This includes some background reinforcement and maintenance costs, which are assumed to be the same across all the charging options.

Figure 18 Modelled reinforcement costs to the Main Interconnected Transmission System

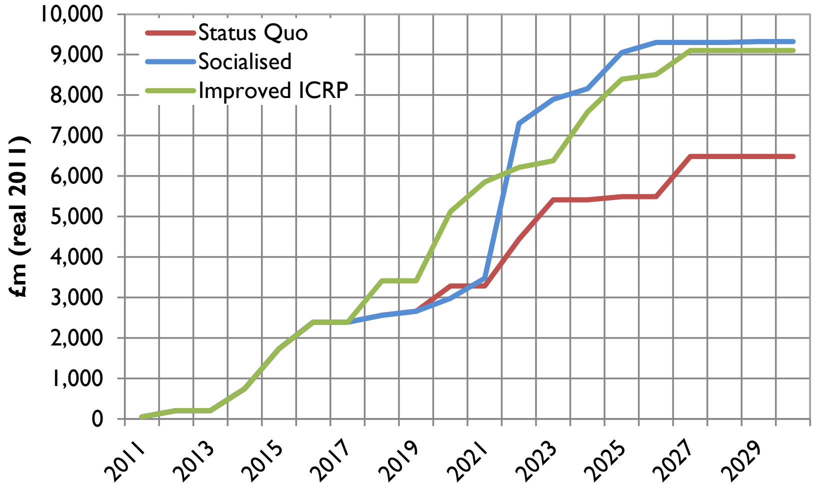
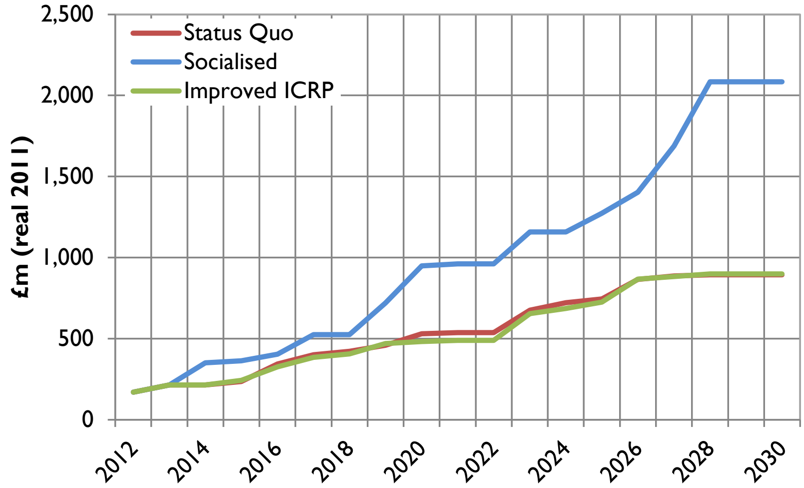


Table 4 Timing of new HVDC links

Reinforcement	Capacity (MW)	Cost (£m, real 2011)	Boundaries reinforced	Assumed earliest feasible date	Status Quo	Socialised	Improved ICRP
Western HVDC Link	2000	866	B6, B7a	2015	2015	2015	2015
Western HVDC Link #2	2000	866	B6, B7a	2020	2023	2022	2020
Eastern HVDC Link	2000	891	B2, B4, B5, B6, B7a	2018	2022	2022	2018
Eastern HVDC Link #2	2000	891	B2, B4, B5, B6, B7a	2020	2027	2025	2024
Wylfa-Pembroke 2GW HVDC link	2000	834	B202, NW2	2018	-	-	-
Caithness - Moray HVDC	600	800	B1	2017	-	2022	2020
Humber - Walpole HVDC	2000	595	B8, B9, B11, B16	2020	-	2023	2027

Figure 19 Offshore and island transmission: cumulative investment costs



5.4.4 Constraint costs

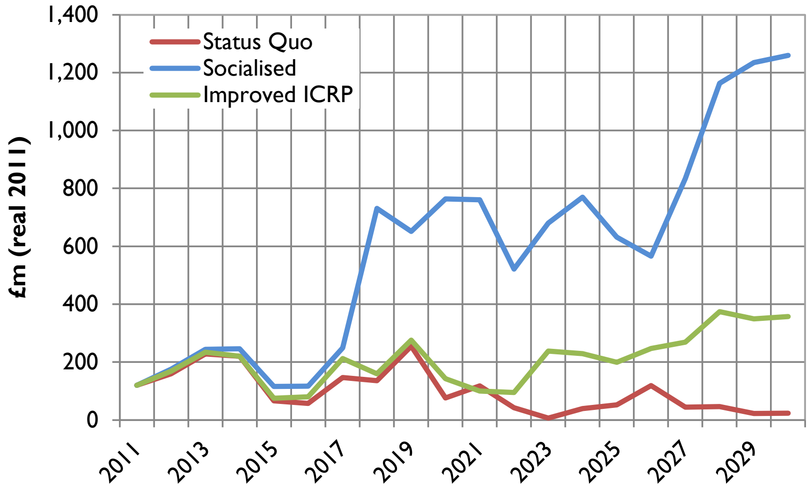
Constraint costs occur where the System Operator (NGET) has to buy-off generation behind a transmission constraint and replace it with more expensive generation on the other side of the constraint. Generators submit bids and offers to decrease or increase generation respectively, with a spread between the bid and offer prices (section B.3.4) – these spreads are a major driver of constraint costs. Transmission reinforcements can act to ease constraint costs, but it will normally be economically efficient to have some level of constraint costs on the system because this may be cheaper than reinforcing the network to the point that all constraints are eliminated. This is particularly likely when intermittent generation means that lines will only be congested some of the time, for example when the wind is blowing hard in a particular region. As a consequence, constraint costs are expected to increase as more intermittent renewable generation is connected to the system. Further, it may not be possible for new reinforcements to keep pace with the additional requirements on the system[38].

Constraint costs are similar between Improved ICRP and Status Quo until 2020, averaging between £100m and £200m per year. Additional transmission reinforcement under Improved ICRP is sufficient to relieve most of the additional transmission constraints associated with more onshore wind in North Scotland. After 2020, the level of reinforcements does not quite keep pace with the greater levels of renewable deployment in Scotland and constraint costs rise as a result. After 2025, the full range of identified HVDC links available to reinforce north-south constraints between Scotland and England halve 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.

There is a marked increase in constraint costs under Socialised charging after 2017, caused by the different locational pattern of build, of both renewables and CCGT. The rate of reinforcement does not keep pace with increase in constraint costs, and annual constraints costs produced by the model over the period are typically around £600m between 2017 and 2025. By 2025, the possible reinforcements assumed in the model are exhausted and hence constraint costs begin to rise further. These costs continue to increase after 2025. It is possible that some of these constraints could be reduced if more transmission reinforcement options were available (above and beyond the range of possible projects proposed by the Transmission Owners and the additional generic projects we have included as described in section B.3) but this would require additional spend on transmission reinforcement.

[38] This has been reflected in regulatory arrangement through the implementation of 'Connect and Manage', whereby generators are allowed to connect to the grid immediately after local works have been completed, rather than waiting for the transmission companies to carry out the 'deep reinforcements' of the wider network necessary to support the additional generation on the system.

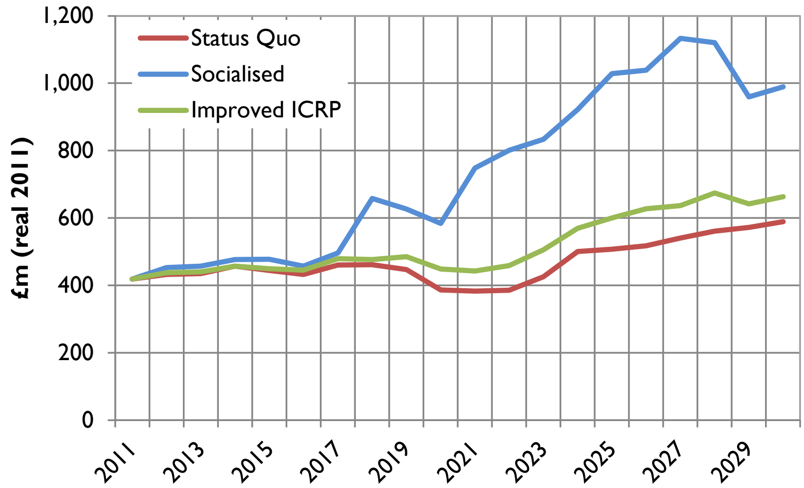
Figure 20 Constraint costs (Stage 2 modelling)



5.4.5 Transmission losses

Figure 21 shows the costs of transmission losses produced by the model (derived as described in Appendix A). 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 are greater under Improved ICRP than Status Quo, with the higher deployment of onshore wind in Scotland, and significantly greater under Socialised driven to a large part by the greater proportion of offshore wind further from shore.

Figure 21 Transmission losses (Stage 2 modelling)



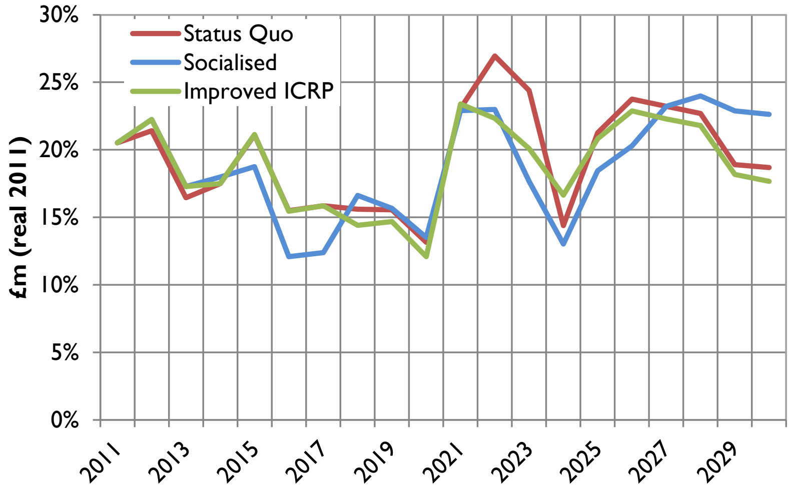
5.5 Impacts on security of supply

At the national level we assume that security of electricity supply is a function of the margin of excess capacity over peak demand. At the local level security of supply is also a function of network capacity and reliability.

For the purposes of the TransmiT modelling we assumed that a capacity mechanism is in place, as being proposed under the EMR. Details are yet to be finalised but we included a simple form of universal capacity mechanism based on annual capacity auctions in the modelling. Further details are provided in Appendix A.

With a capacity mechanism in place, the differences between the three charging options in terms of security of supply are not that great. Figure 22 shows the de-rated capacity margin produced by the model under the three charging options. The reductions in de-rated capacity margins seen in all three cases in 2016 and 2024 reflect enforced closures under the LCPD and IED respectively. In general, de-rated capacity margins are slightly lower under Socialised which in the near term is the result of more rapid retirement of older gas plant currently benefiting from low or negative TNUoS charges. In the longer term this reflects slightly delayed new CCGT investment for similar reasons.

Figure 22 De-rated capacity margins (Stage 2 modelling)



Note: Capacity margins based on the top 1% demand level. 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.

Transmission capacity can be important for locational security of supply through determining whether electricity generated can be delivered to demand. Modelling results do not suggest there will be specific locational security of supply issues under these capacity margins and with the transmission reinforcements modelled. However, at lower de-rated capacity margins (and the decision on capacity mechanisms is yet to be taken), the risks to security of supply may manifest themselves first in locational issues before there is necessarily an issue at the national level.

5.6 Cost benefit analysis and regional impacts

5.6.1 Introduction

In this section we present the results of the quantitative cost benefit analysis (CBA) by comparing the impact on overall power sector costs and consumer bills of the two alternative charging options, Improved ICRP and Socialised, relative to Status Quo.

The CBA for power sector costs summarises the impact of the two competing factors illustrated above of more efficient exploitation of generation resources (particularly renewables) under the revised charging options, versus higher transmission costs (reinforcement, constraints and losses).

The differences in underlying power sector costs are also reflected in the impact on consumer bills, but variations in wholesale electricity costs and levels of low carbon support under the options also affect the outcomes.

In addition to the aggregate impact on consumers, we also explore the regional variations under the different options, and look at the profitability of generators in different areas[39].

5.6.2 Cost benefit analysis results

Table 5 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 sub-categories are explained further in Appendix A. 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, the results suggest that Improved ICRP could lead to a small reduction in power sector costs, suggesting that the additional constraint costs, losses and transmission expenditure could be offset by reductions in generation costs. Between 2021 and 2030, power sector costs are 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 appears broadly neutral with Status Quo with respect to power sector costs.

The impact on consumer bills is 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.

[39] There could also be changes in profits accruing to transmission owners and suppliers, but these were not modelled as part of this study.

Table 5 Cost Benefit Analysis: Improved ICRP (Stage 2 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	-8	-418
	Constraint costs	-171	-1,089
	Carbon costs	-11	-2
	Decrease in power sector costs	**122**	**-543**
Consumer bills	Wholesale costs (inc. capacity payments)	-1,227	-182
	BSUoS	-85	-547
	Transmission losses	-123	-491
	Demand TNUoS charges	98	62
	Low carbon support	441	644
	Decrease in consumer bills	**-897**	**-512**

Table 6 presents the CBA results for the Socialised option. This suggests that power sector costs would be higher under this option compared to Status Quo, with the higher constraint, losses and transmission costs exceeding savings in generation costs, particularly in the period 2021-2030.

Socialised charging is estimated by the model to lead to just under £3 billion in additional power sector costs between 2011 and 2020, and closer to £11 billion between 2021 and 2030.

These higher power sector costs are reflected in greater costs for consumers. The model projects that between 2011 and 2020, the average annual domestic customer bill would be £11 higher between 2011 and 2020, and £23 higher between 2021 and 2030.

Table 6 Cost Benefit Analysis: Socialised (Stage 2 modelling)

		Socialised (£m real 2011)	
		NPV 2011-2020	NPV 2021-2030
Benefit relative to Status Quo			
Power sector costs	Generation costs	453	1,803
	Transmission costs	-1,569	-7,873
	Constraint costs	-1,452	-4,535
	Carbon costs	-201	-218
	Decrease in power sector costs	**-2,769**	**-10,823**
Consumer Bills	Wholesale costs (inc. capacity payments)	-6,157	-6,843
	BSUoS	-723	-2,276
	Transmission losses	-553	-2,693
	Demand TNUoS charges	-849	-4,402
	Low carbon support	1,406	3,342
	Decrease in consumer bills	**-6,876**	**-12,873**

Below we provide further explanation of the CBA results.

Power sector costs

The NPV of generation costs are lower under both improved ICRP and Socialised than under Status Quo. The reasons for this, however, differ across the two alternative charging options.

For Improved ICRP, cost savings are explained by a decrease in fuel and operating costs. These cost differences are 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. There is also a geographical shift in the location of onshore wind towards North Scotland and away from Wales, saving generation costs through a higher average load factor given greater wind resource in these locations. Under Socialised, there are also generation cost savings from a shift in the location of build to exploit higher wind speeds. Similarly, the location of offshore wind build has shifted from the Irish Sea and Moray Firth zones to relatively shallower locations at Dogger Bank and Hornsea, resulting in savings in generation costs. There are also lower fuel costs as a result of more wind build and less biomass. These savings under Socialised are greater than the increase in capital costs which result in particular from the higher deployment of offshore wind.

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

Under Socialised charging, onshore reinforcements are brought forward, transmission losses are higher and there is a significant increase in the cost of offshore transmission to accommodate greater offshore build, at sites that are further offshore (for example, Dogger Bank is developed under Socialised, but not under the other policy options). Constraint costs are higher under both Improved ICRP and Socialised charging since the levels of transmission reinforcement do not completely keep pace with the increases in north-south constraints between Scotland and England. This is particularly the case under Socialised.

Carbon costs represent the economic cost of differences in total carbon emissions across options but are not particularly important for the CBA results due to the calibration to the same renewable and low-carbon targets across all charging options. As described in Appendix A, these costs represent the marginal environmental, social and financial costs associated with carbon emissions and are estimated using UK prices for Carbon Price Support and EU carbon emissions permit prices as proxies for economic costs. Under the Stage 2 modelling, 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 are relatively small, although small variations arise as a result of slightly different decarbonisation trajectories.

Under Improved ICRP, power sector costs are very similar to Status Quo and the additional transmission costs are approximately offset by lower generation costs. Under the Socialised option, the savings in generation costs are significantly less than the additional transmission costs. One reason that the savings in generation costs are not greater is because the model is building more offshore wind under Socialised, which is a relatively expensive technology, with capital costs of approximately £2140/kW in 2020 compared to £1450/kW for onshore wind. If long run marginal costs for offshore wind were to fall to similar levels as those of onshore wind, the increase in power sector costs relative to Status Quo in the period 2011-2020 would be approximately £1bn lower than shown in Table 6.

Consumer bills

The CBA for consumer bills is broken into wholesale costs, 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[40], 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 is driven by an increase in modelled market prices during the period 2018-2020, when capacity margins are somewhat lower[41]. Figure 23 shows the change in the bill (averaged throughout GB) for an average domestic customer using 4000 kWh of electricity each year, under Improved ICRP and Socialised charging.

Under Socialised charging, there is an immediate increase in wholesale costs due to an increase in the short run marginal cost element of market prices, as a result of the energy based (£/MWh) tariffs. This effect is offset to the extent that generators can rely less on price uplift and capacity payments to cover the fixed annual transmission charges under Status Quo. Due to some earlier retirements under Socialised of plant that benefit from negative TNUoS charges under Status Quo, market prices are higher between 2016 and 2017 as a result of tighter capacity margins. The combination of these factors results in consumer bills increasing by more than the increase in power sector costs under Socialised. After 2020, these effects

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

[41] 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).

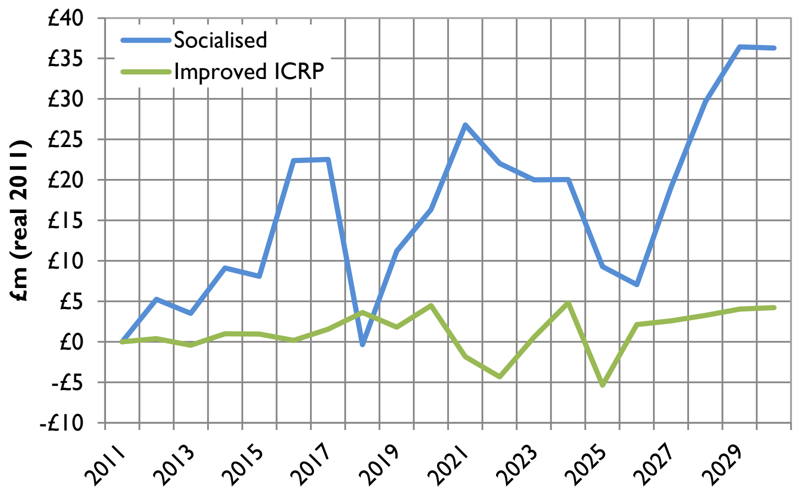
become less important and the higher consumer bills under Socialised broadly reflect the higher power sector costs.

A small part of the increase in wholesale costs under the alternative charging options is driven by BSUoS charges and transmission losses. BSUoS charges are higher under both Improved ICRP and Socialised as a consequence of higher constraint costs. Transmission losses, like constraint costs, increase with more generating capacity in northern GB and thus increase under both Improved ICRP and Socialised charging.

Demand TNUoS charges are higher under Socialised charging due to the higher MAR associated with greater transmission investment.

The reductions in required low carbon support seen under both Improved ICRP and Socialised are not sufficient to offset higher wholesale costs for consumers. Greater savings could be achieved under Socialised if less offshore wind was built under this option, or if the costs of offshore wind were to come down as noted above.

Figure 23 Change in in average annual domestic customer bill, relative to Status Quo



5.6.3 Regional impacts

Consumers

Regional impacts on consumers will be driven by differences in demand TNUoS charges. Demand TNUoS charges are set across 14 different charging zones. 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. Demand TNUoS charges, on the other hand, vary by region. Under Status Quo, these are higher in major demand centres (for example, London) and lower in regions where generation is greater than demand (for example, throughout Scotland).

As discussed above in Section 5.2, differences in demand TNUoS charges between Status Quo and Improved ICRP are relatively minor, driven entirely by differences in generation and transmission backgrounds. There are only very small changes in demand TNUoS in 2012 under Improved ICRP because the methodology for calculating demand charges is the same across these two charging approaches. By 2012, charges are affected by differences in generation and transmission decisions. A slightly lower MAR under Improved ICRP in 2020 results in lower charges across all regions in this year. The greatest reduction in charges is in Scotland, where an increase in generation capacity under Improved ICRP reduces the cost of getting electricity to consumers (although differences in transmission investment also have the potential to affect the locational pattern of demand TNUoS charges).

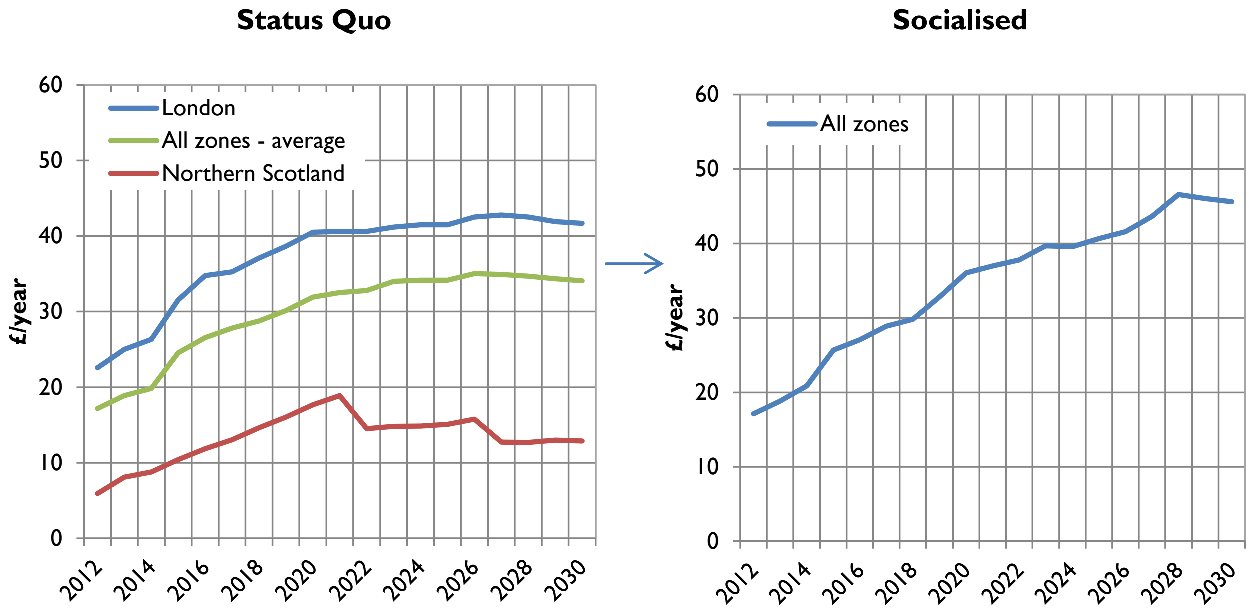
Compared with Status Quo, demand TNUoS charges under Socialised charging are higher in Northern Scotland and lower in London, as reported in Table 7. Under Socialised charging, demand charges are assumed to be the same for consumers throughout Great Britain. In 2012, under the Socialised charging approach an average domestic consumer in Northern Scotland would face an additional £11 per year in their bill compared to Status Quo, whereas the same consumer in South England and South Wales would face a charge around £2 per year less (as much as £5 less in London), assuming that the differences in demand TNUoS charges to suppliers are fully passed through to consumers.

Table 7 Change in demand TNUoS component of consumer bills for average domestic consumer, relative to Status Quo

	Status Quo	Improved ICRP – change from Status Quo		Socialised – change from Status Quo	
	£/year	£/year		£/year	
	2012	2012	2020	2012	2020
N Scotland	£5.93	£0.43	-£4.57	£11.24	£18.48
S Scotland	£9.79	£0.11	-£4.29	£7.37	£14.98
N England	£14.91	-£0.15	-£0.43	£2.26	£6.53
Midlands & N Wales	£17.55	-£0.28	-£0.51	-£0.38	£3.13
S England & S Wales	£19.50	£0.16	-£0.78	-£2.33	£1.58

By 2020, demand TNUoS charges produced by the model are higher in all zones under Socialised charging, reflecting the increasing MAR. The results from the model for the average domestic customer (consuming 4000 kWh per year) under Status Quo and Socialised are shown in Figure 24 below.

Figure 24 Demand TNUoS charges: annual cost for average domestic consumer

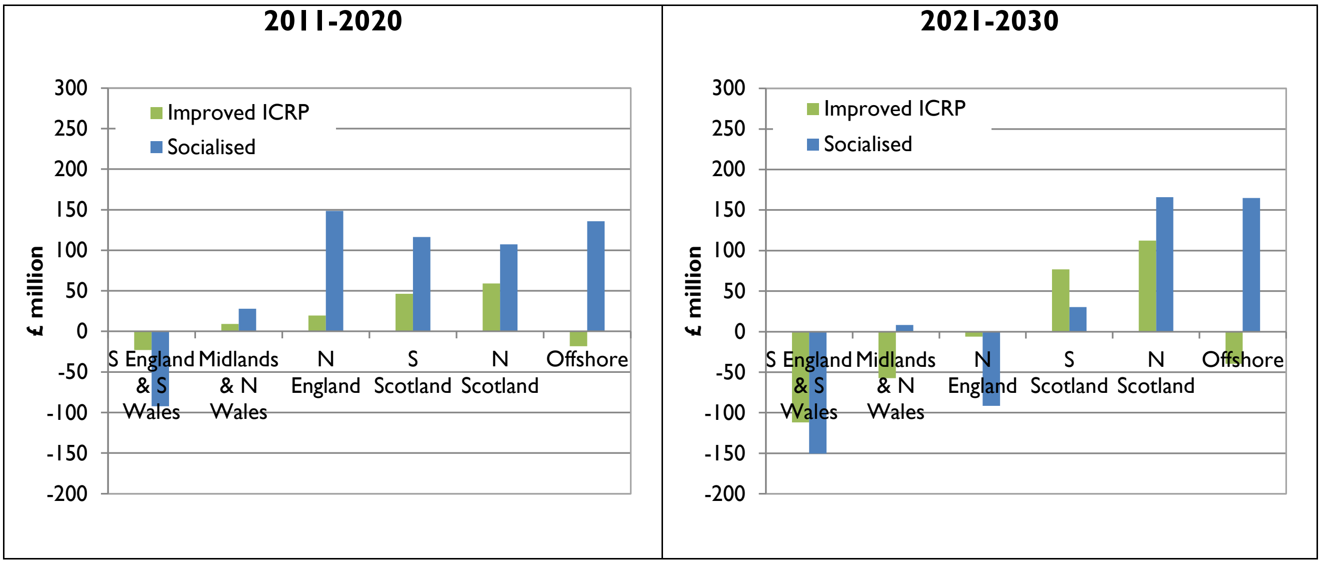


Generators

The different transmission charging options could change the profitability of generating plant according to their location. Figure 25 shows the annual difference in generator profits under Improved ICRP and Socialised by region and offshore, over the periods 2011-2020 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 both Improved ICRP and Socialised, generators on the whole are estimated to make higher profits between 2011 and 2020 as a consequence of higher wholesale prices, for the reasons described above. During the period 2021 to 2030, total generator profits are similar across the three charging options.

Both Improved ICRP and Socialised relatively favour generators in high TNUoS charging zones under Status Quo. Specifically, under Improved ICRP generator profits are higher in Scotland, at the expense of generators in south England, the Midlands and Wales. Socialised charging increases overall generator profits in Scotland and offshore, but profits are lower in South England and Wales and (after 2021) in North England.

Figure 25 Average annual change in total generator profits, relative to Status Quo



5.7 Policy variants

5.7.1 Overview

As described in Section 3, two policy variants were modelled. These were:

- **HVDC sensitivity** on Improved ICRP. A variant on Improved ICRP whereby the costs of converters on HVDC links were excluded from the tariff calculations for those links that parallel the onshore AC network, and
- **Socialised (wider only) sensitivity**. A version of socialised charging whereby generators face charges for local assets, but wider assets are still socialised.

All sensitivity results reported are based on Stage 2 modelling to focus on overall cost impacts.

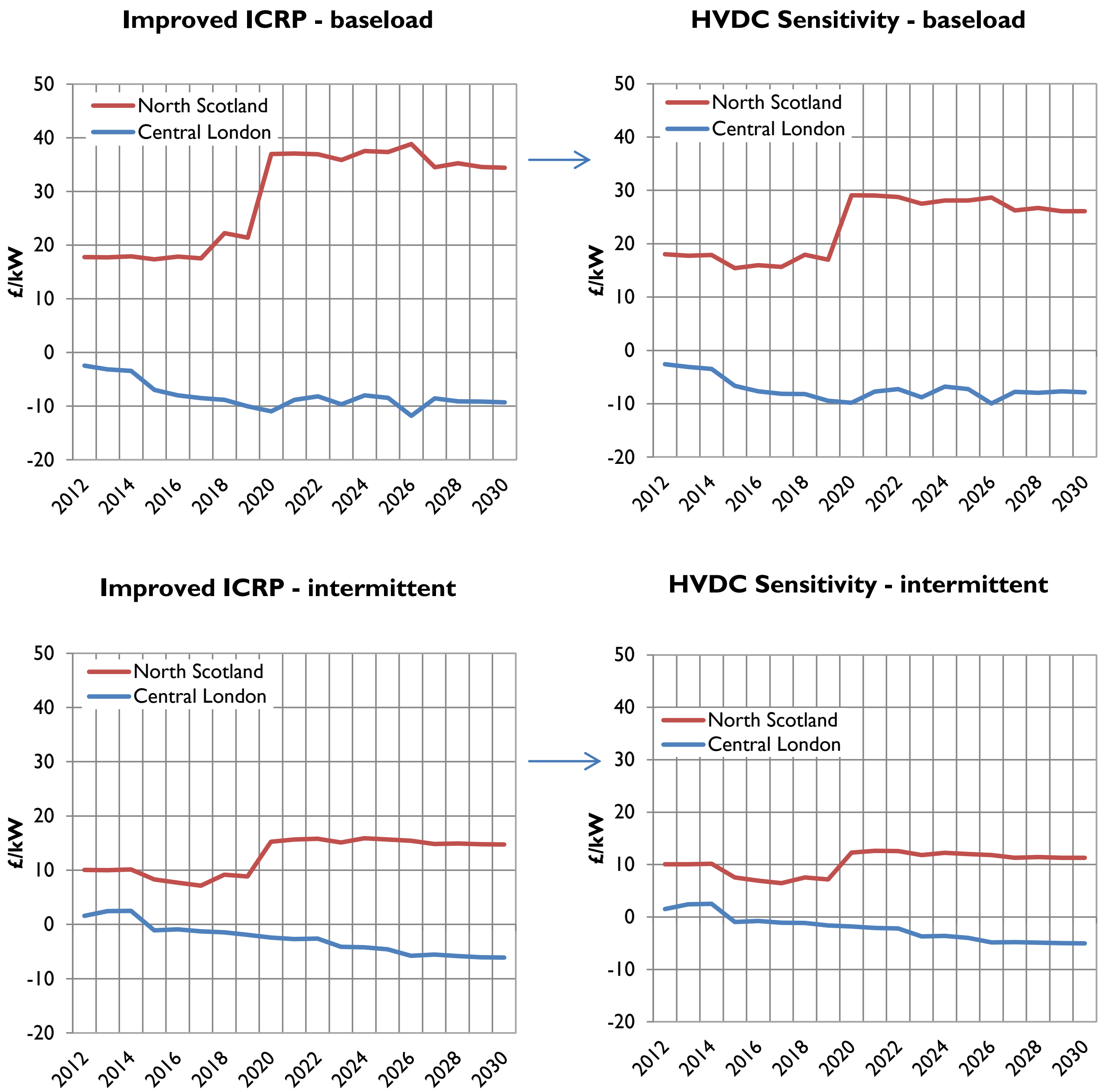
5.7.2 HVDC sensitivity

HVDC converters are a significant part of the cost of HVDC links. In this sensitivity, HVDC converters are excluded from the basis for calculating locational charges[42].

This accentuates the compression of charges under Improved ICRP charging (Figure 26). Tariffs are slighter higher (due to an increase in the residual) for zones that do not use HVDC links to export their power (for example, in Central London). Conversely, tariffs in zones that rely on HVDC links to export power (for example, charges in North Scotland with build of Caithness-Moray link in 2020) do not increase to the same extent as they would under the core Improved ICRP option.

[42] Specifically, the cost apportioned to HVDC links through the 'expansion factor' in the Transport Model was re-calculated to exclude the costs of the converters, thereby reducing the effect of HVDC links on locational tariffs. The remaining costs of HVDC links – primarily cable costs – were still included in the calculation of locational tariffs.

Figure 26 Generator TNUoS: Improved ICRP and HVDC sensitivity



The change in tariffs does not lead in the modelling to any change in locational build relative to the core Improved ICRP option to 2020. Relative to core Improved ICRP, there is a small increase in build in offshore Scotland (additional 500 MW) and onshore North Scotland (additional 150 MW) by 2030, with slightly less build offshore in the Irish Sea (reduction of 575 MW).

Transmission constraint costs to 2020 are similar under the HVDC sensitivity as under core Improved ICRP. The increase in build of renewables in Scotland leads to higher constraint costs in the late 2020s.

Figure 27 Constraint costs: HVDC sensitivity

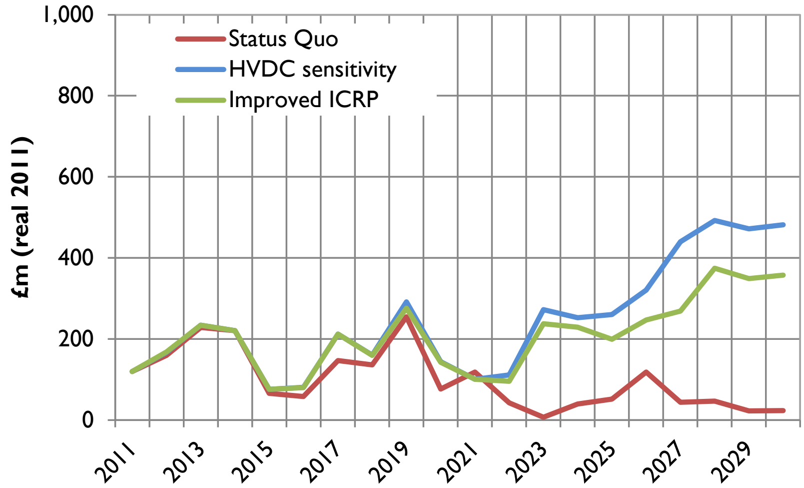


Table 8 presents the CBA results for the HVDC sensitivity (relative to Status Quo) over two ten year time periods, 2011 to 2020 and 2021 to 2030. The results to 2020 are similar to core Improved ICRP, with little change in power sector costs relative to Status Quo. Results to 2030 show an increase in power sector costs and consumer bills relative to both Status Quo and core Improved ICRP. The increase in power sector costs over this period (NPV of -£1,968m) relative to core Improved ICRP (-£543m, Table 8) is due to higher transmission and constraint costs to accommodate more generating capacity in North Scotland and offshore Scotland, as a consequence of less cost-reflective charging for HVDC links. The increase in consumer bills relative to Improved ICRP is due to the pass through of higher transmission and constraint costs to consumers. The increase in consumer bills above Status Quo from 2021-2030 is still relatively small at £2 per year (compared to £1 per year under core Improved ICRP).

Table 8 Cost Benefit Analysis: HVDC sensitivity (stage 2 modelling)

		HVDC sensitivity (£m real 2011)	
		NPV 2011-2020	NPV 2021-2030
Benefit relative to Status Quo			
Power sector costs	Generation costs	332	698
	Transmission costs	-225	-1,332
	Constraint costs	-183	-1,500
	Carbon costs	-5	166
	Decrease in power sector costs	**-82**	**-1,968**
Consumer Bills	Wholesale costs (inc. capacity payments)	-1,421	323
	BSUoS	-91	-753
	Transmission losses	-128	-485
	Demand TNUoS charges	-82	-720
	Low carbon support	458	560
	Decrease in consumer bills	**-1,265**	**-1,075**

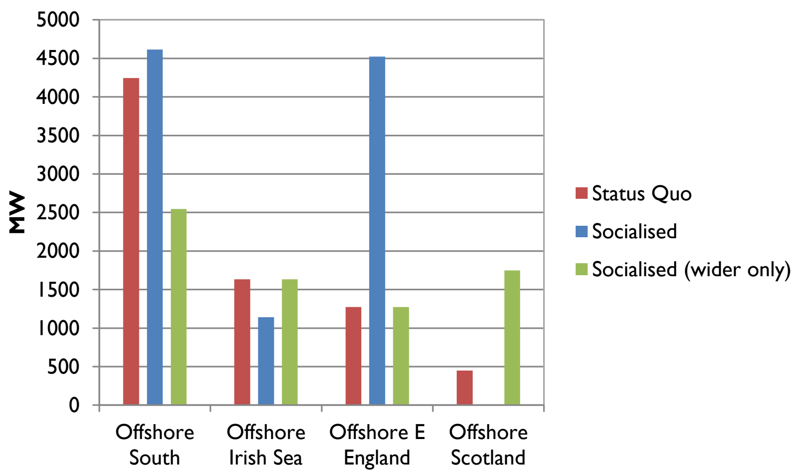
5.7.3 Socialised (wider only) sensitivity

Retaining local charges leads to an increase in total tariff for those generators with large local tariffs, specifically offshore wind. Generators with low or zero local charges see a reduction in their total tariff.

Without adjustments to the levels of support received by offshore wind under this sensitivity, significantly less offshore wind would be built. However, by adjusting the support level to achieve similar outcomes in terms of renewables generation (the Stage 2 modelling approach), this sensitivity leads to different locational patterns of offshore development rather than less overall. With the exception of offshore wind, the pattern of new build is generally similar to fully Socialised charging, although there is more onshore wind in south Scotland.

Under Socialised (wider only) charging, offshore wind is exposed to offshore tariffs (local) but not to the wider onshore element of the tariff. This favours sites that are near to shore, and in general the pattern of offshore wind build is more similar to Status Quo than to fully Socialised (Figure 28). Relative to fully Socialised, there is significantly less Offshore South and Offshore East of England, with increase in the Irish Sea (where projects tend to be closer to shore and therefore have lower local charges). Under Socialised (wider only) there is also more offshore wind in Scotland than in either Status Quo or Socialised. Offshore Scottish wind benefits from relatively low local charges whilst avoiding the wider component which is high under Status Quo.

Figure 28 Offshore wind deployment (2020): Status Quo, Socialised and Socialised (wider only)



Until 2020, constraint costs are similar between the Socialised (wider only) sensitivity and fully Socialised charging (Figure 20). From 2025, constraint costs are higher under the Socialised (wider only) sensitivity. This is due to the greater generation from renewables in Scotland from the additional onshore and offshore wind built under Socialised (wider only).

Figure 29 Constraint costs: Socialised (wider only) sensitivity

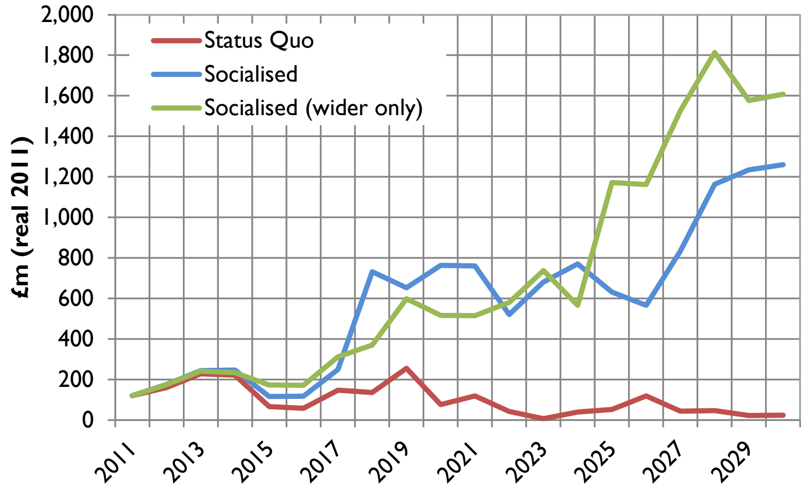


Table 9 shows the CBA results for Socialised (wider only) sensitivity relative to Status Quo. As for fully Socialised option, there are still significant increases in power sector costs from a change to Socialised (wider only) charging (-£1,424m to 2020 compared to -£2,769m under core Socialised, Table 6). Relative to the core Socialised option, there are savings in total transmission costs from a reduction in the costs of offshore cables. However, there is an increase in onshore constraint costs from 2025 onwards as more offshore generation is connected into Scotland. The average impact on consumer bills in the period 2012 to 2020 of £7.80 per year is slightly less than under core Socialised charging.

Table 9 Cost Benefit Analysis: Socialised (wider only) sensitivity (stage 2 modelling)

		Socialised (wider only) (£m real 2011)	
		NPV 2011-2020	NPV 2021-2030
Benefit relative to Status Quo			
Power sector costs	Generation costs	325	1,285
	Transmission costs	-559	-4,519
	Constraint costs	-1,089	-6,072
	Carbon costs	-101	391
	Decrease in power sector costs	**-1,424**	**-8,914**
Consumer bills	Wholesale costs (inc. capacity payments)	-4,311	-2,957
	BSUoS	-542	-3,048
	Transmission losses	-433	-3,128
	Demand TNUoS charges	-107	-1,183
	Low carbon support	621	595
	Decrease in consumer bills	**-4,772**	**-9,720**

5.7.4 Other variants

We have modelled just two of a range of possible transmission charging variants on the three main options. One further variant on Socialised would be to apply uniform charging for generators on a capacity (£/kW/yr) basis rather than an output (£/MWh) basis.

Without conducting the quantitative modelling, we have considered the possible impact of this variant based on likely outcomes in the modelling.

Impact on tariffs

Basing the Socialised approach on a capacity rather than output basis would increase the proportion of TNUoS recovered from lower load factor generators relative to those with higher load factors. This would include intermittent renewables and lower load factor thermal plant such as older CCGTs and coal plant restricted by emissions legislation (LCPD and IED), and any potential new peaking plant (OCGTs). The relative winners would be nuclear and newer/more efficient CCGTs and CCS plant (i.e. plant with higher load factors). However, tariffs for offshore wind and northern Scottish wind would still be lower than under Status Quo.

Impact on sustainability

Socialised (capacity basis) would disfavour new build of intermittent renewables relative to Socialised (output basis). It is possible we would observe lower deployment of onshore and offshore wind. However, we expect that the deployment of offshore wind and northern Scottish wind would still be higher than under Status Quo. For the same levels of CfD strike prices, we would expect some increase in deployment of nuclear and CCS under Socialised (capacity basis) than Socialised (output basis).

Impact on costs

Assuming that CfDs are set to achieve the same overall level of renewables deployment and carbon intensity, it is more complex to predict model outcomes. In particular, the mix of onshore and offshore wind relative to Socialised (output) will be important in driving costs, but it is not clear what the outcome would be.

With no locational signals for generation investment, we would expect transmission reinforcement costs, constraint costs and transmission losses to remain high.

Impact on Cost Benefit Analysis

It is not clear whether power sector costs would increase or decrease relative to Socialised (output). We expect that the relative change in costs will be small relative to the difference in costs between Socialised (output) and Status Quo.

In the short run there would be a reduction in consumer bills. As a fixed rather than variable charge, this would not be a direct pass through so consumer bills would be lower, with equivalent lower profitability for generators. We expect this difference to close in the longer term as wholesale prices adjust to allow plant that remain open to recover their higher fixed costs.

5.8 Sensitivities

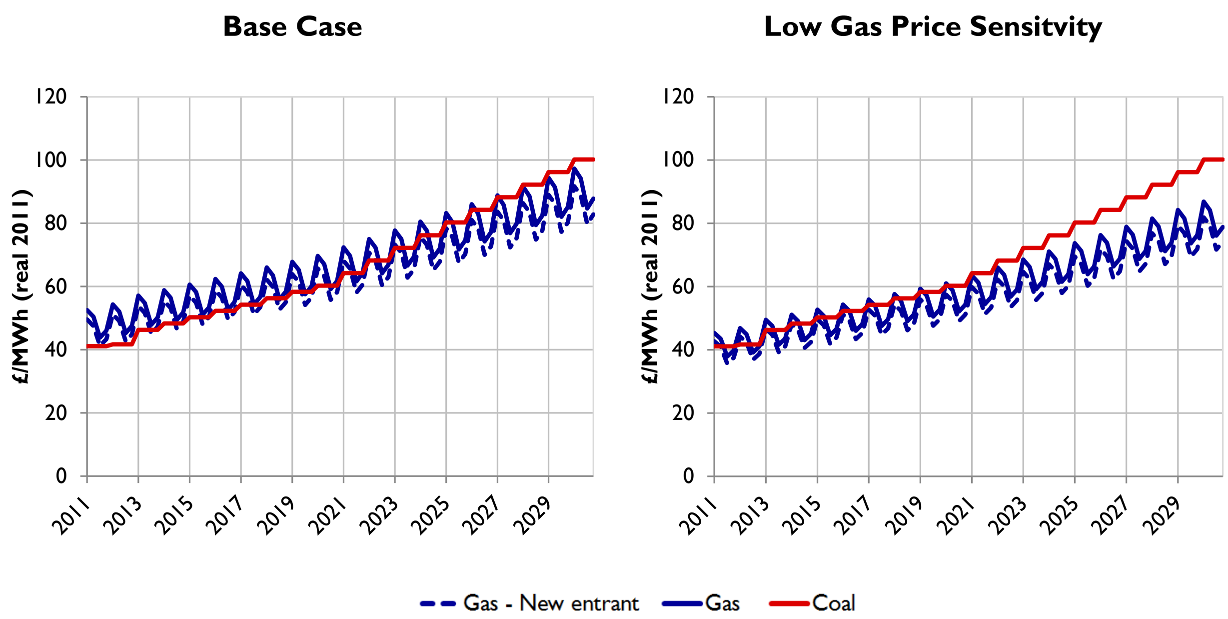
Two sensitivities were run against the three core charging options:

- **Low Gas Price Sensitivity**. This sensitivity was chosen in recognition of the uncertainty surrounding future gas price and the importance of coal and gas differentials in driving constraint costs.
- **RO Banding Review sensitivity**. The Government's consultation on proposed RO bands was published in October 2011[43] after the majority of the analysis for Project TransmiT had been completed. It was considered important to rerun the Stage 1 modelling under these assumptions to understand better the impact of the charging options assuming no further changes to renewables support before 2017.

5.8.1 Low Gas Price Sensitivity

The Low Gas Price Sensitivity represents a 15% reduction in the gas price throughout the modelling period. Figure 30 shows the impact of a lower gas price on the Short Run Marginal Costs (SRMCs) of CCGTs, compared to a typical coal generator. CCGTs are more competitive relative to coal under the low gas price sensitivity, meaning they are more likely to run ahead of coal generators.

Figure 30 CCGT and coal SRMCs: Low Gas Price Sensitivity[44]

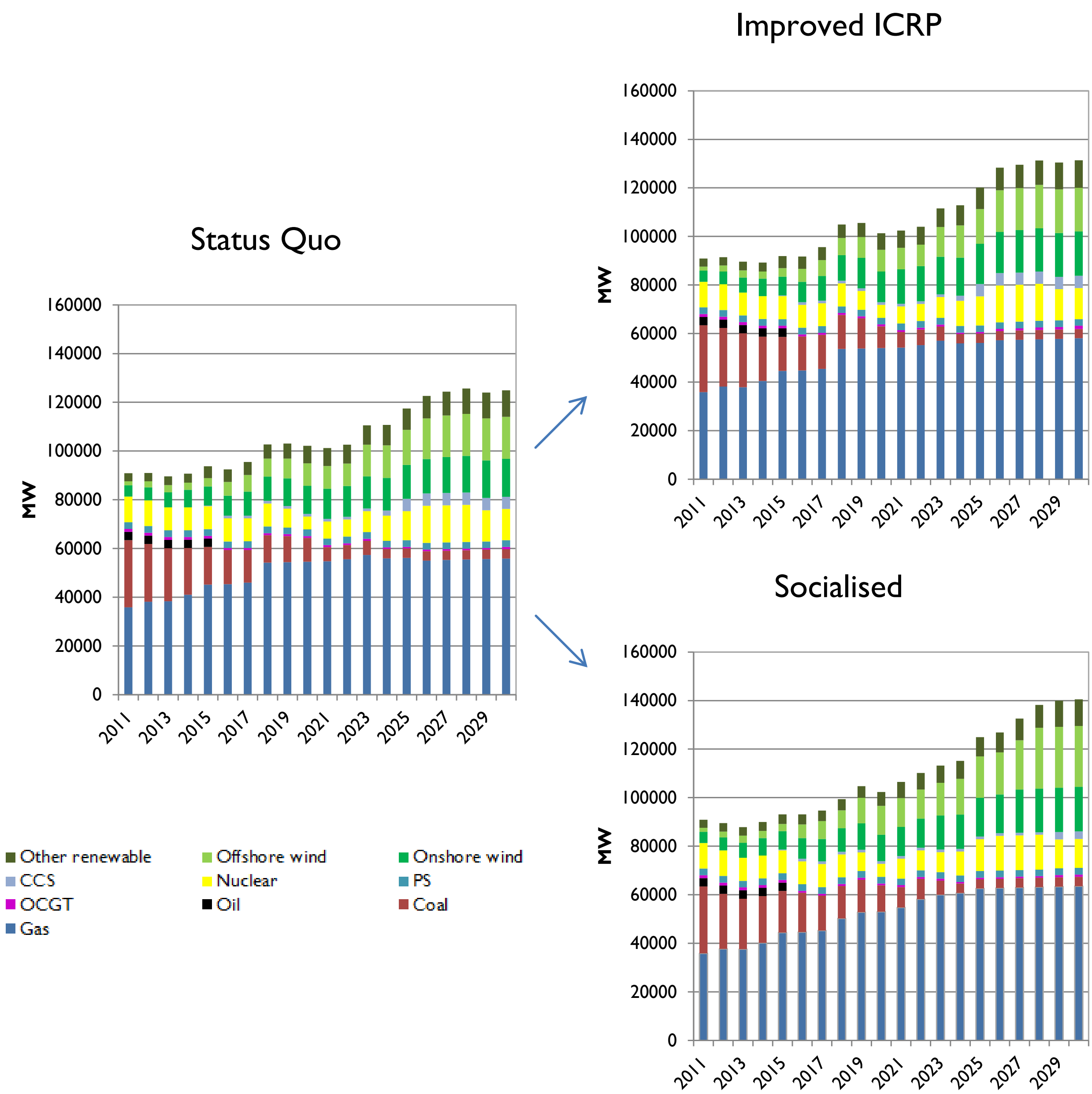


Under lower gas prices, generation from coal is less profitable and a number of coal plant retire earlier across all three charging options. The model builds additional CCGT compared to the Base Case, particularly under Socialised, as shown in Figure 31. Under Status Quo and Improved ICRP this additional build is concentrated mainly in South England whereas under Socialised it is distributed across GB.

[43] http://www.decc.gov.uk/en/content/cms/consultations/cons_ro_review/cons_ro_review.aspx

[44] CCGT (new build) efficiency 52% Higher Heating Value (HHV), CCGT (existing) efficiency 49% HHV, coal efficiency 36% (Lower Heating Value)

Figure 31 Total generation capacity: Low Gas Price Sensitivity



Under the Low Gas Price Sensitivity, constraint costs are lower in the near term (Figure 32) than for the Base Case assumptions (for example, £100m in 2012 under Status Quo compared to £159m under the Base Case assumptions). In the Low Gas Price Sensitivity, there is more generation from CCGTs relative to coal. The distribution of existing CCGT plant tends to be more towards the south of the country than the coal fleet, leading to a reduction in north-south flows and reduced constraint costs in general. In the longer term, constraint costs under Status Quo are similar between the Base Case and the Low Gas Price Sensitivity, as are transmission reinforcements. The same is true for Improved ICRP. On the other hand, constraint costs are lower throughout the modelled period for Socialised under the low Gas Price sensitivity. This is driven initially by the distribution of existing CCGT plant, but is also a consequence of bringing forward several key reinforcements over the period 2018 to 2023. Towards the end of the modelling period there is very little existing CCGT plant remaining, but constraint costs are lower than under Base Case Socialised due to more generation by new CCGT plant in England and Wales, in particular by new plant located in South England and South Wales.

Figure 32 Constraint costs: Low Gas Price Sensitivity

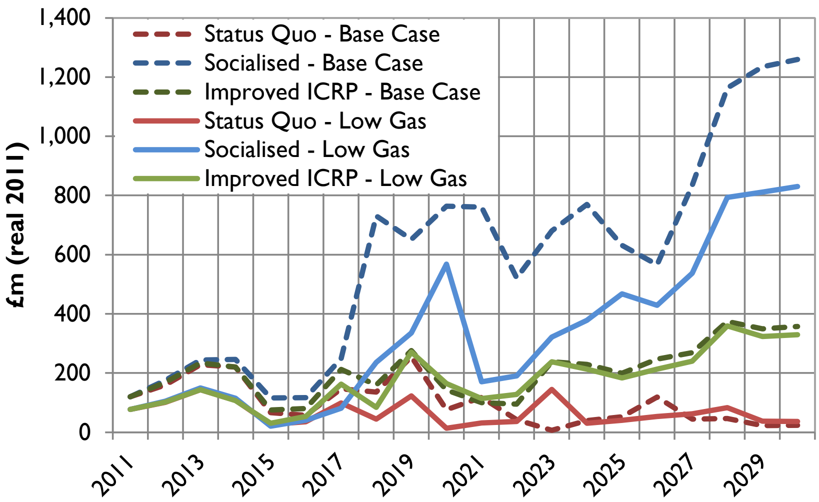


Table 10 presents the CBA results for Improved ICRP (relative to Status Quo) under the Low Gas Price Sensitivity. In general the Improved ICRP option appears relatively less favourable when compared with Status Quo than under the Base Case assumptions, both in terms of power sector costs and consumer bills. In the period to 2020, the small difference in power sector costs (-£316m under the Low Gas Price Sensitivity compared with +£122 in the Base Case) is a result of relative increases in constraint costs and transmission costs under Improved ICRP Low Gas Price, relating to lower deployment of onshore wind in North Scotland under Status Quo Low Gas Price. Consumer bills in this period are higher under Improved ICRP than Status Quo Low Gas Price by £3.50 per year because of the pass through of transmission costs into BSUoS and TNUoS, and also because of changes in wholesale prices related to changes in capacity margin.

In the period 2021-2030 the increase in power sector costs (-£3,433m under the Low Gas Price Sensitivity compared with -£543m in the Base Case) is made up of increases in generation costs and transmission costs due to deployment of higher cost renewables. In particular, there is an increase in the relative deployment of biomass and tidal and wave generation under Improved ICRP in the Low Gas Price Sensitivity. However, the majority of these additional costs are not passed through to consumers due to a decrease in wholesale costs, and the impact on consumer bills is almost identical to the Base Case Improved ICRP results (-£519m under the Low Gas Price Sensitivity compared with -£512m in the Base Case).

Table 10 Cost Benefit Analysis: Improved ICRP (Low Gas Price Sensitivity)

		Improved ICRP (£m real 2011)	
		NPV 2011-2020	NPV 2021-2030
Benefit relative to Status Quo			
Power sector costs	Generation costs	302	-1,442
	Transmission costs	-299	-1,314
	Constraint costs	-316	-1,011
	Carbon costs	-3	334
	Decrease in power sector costs	**-316**	**-3,433**
Consumer bills	Wholesale costs (inc. capacity payments)	-2,200	2,809
	BSUoS	-157	-507
	Transmission losses	-184	-479
	Demand TNUoS charges	-98	-710
	Low carbon support	526	-1,633
	Decrease in consumer bills	**-2,112**	**-519**

Table 11 presents the corresponding CBA results for Socialised relative to Status Quo under the Low Gas Price Sensitivity. There is little increase in power sector costs to 2020 under Socialised (in contrast to the Base Case results). However, in the period 2021-2030 the higher power sector costs and consumer bills are similar to the Base Case results. As with the Base Case the higher constraint, losses and transmission costs exceed savings in generation costs.

Table 11 Cost Benefit Analysis: Socialised (Low Gas Price Sensitivity)

		Socialised (£m real 2011)	
		NPV 2011-2020	NPV 2021-2030
Benefit relative to Status Quo			
Power sector costs	Generation costs	2,009	808
	Transmission costs	-1,307	-7,266
	Constraint costs	-697	-2,446
	Carbon costs	-327	-444
	Decrease in power sector costs	**-322**	**-9,348**
Consumer Bills	Wholesale costs (inc. capacity payments)	-6,713	-5,642
	BSUoS	-347	-1,227
	Transmission losses	-423	-2,309
	Demand TNUoS charges	-751	-4,214
	Low carbon support	2,806	3,314
	Decrease in consumer bills	**-5,428**	**-10,077**

5.8.2 RO Banding Sensitivity

This sensitivity uses the latest proposed RO bands for the period 2013-2017 as published in the RO banding consultation in October 2011 (Table 12). The Longannet CCS demonstration project was also removed from the plant list for this sensitivity, following Scottish Power's announcement in October 2011 that it was no longer pursuing this project.

Table 12 RO bands: RO Banding Sensitivity

ROCs / MWh	Current	2013	2014	2015	2016
Onshore wind	1.0	0.9	0.9	0.9	0.9
Offshore wind	2.0	2.0	2.0	1.9	1.8
Wave	2.0	5.0	5.0	5.0	5.0
Tidal stream	2.0	5.0	5.0	5.0	5.0
Biomass	1.5	1.5	1.5	1.4	1.4

Since the main focus on this sensitivity is the impact of the transmission options on renewables deployment under the new proposed RO bands, and with the RO assumed to be closed to new accreditations after 2017, the results for this sensitivity are presented only to 2020. For the period 2017 to 2020 we assume that CfDs are set at levels equivalent to a continuation of the RO.

Comparing the total revenue for renewables under the RO Banding Sensitivity (comprised of revenue from ROCs, LECs and power sales) to the support levels assumed in the Base Case modelling, there are significant differences. Relative to the Base Case modelling, the total revenue for onshore wind is around £14/MWh higher between 2014 and 2017, whilst the offshore wind revenue is lower by about £10/MWh over the same period.

Figure 33 shows the proportion of generation from renewables under each charging options. All three options meet the 2020 renewable targets (~30%), with Socialised achieving a 37% renewable share by 2020. Under Status Quo and Improved ICRP, a significant proportion of the renewables that contribute to the target are built under CfDs once the RO has closed to new accreditations. The major difference between the options is that there is no offshore wind plant commissioned between 2013 and 2018 under Status Quo and Improved ICRP, whereas there is rapid deployment under Socialised.

Figure 33 Renewables generation: RO banding sensitivity

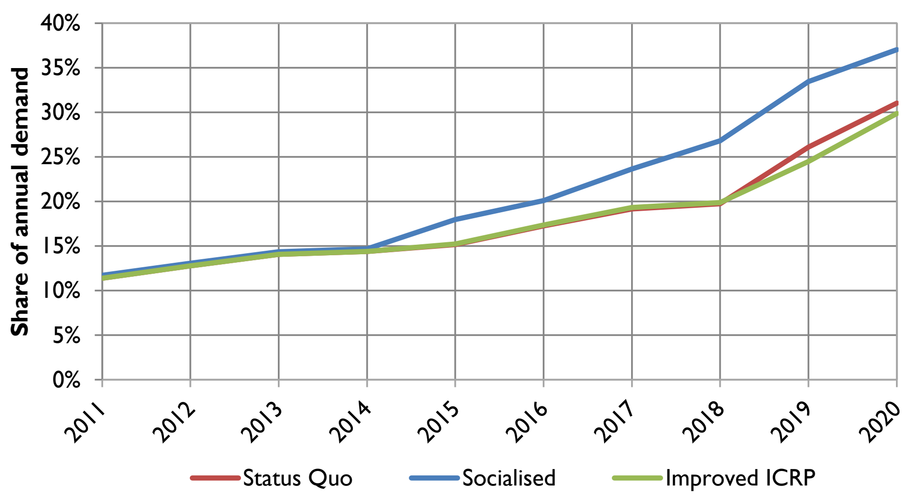
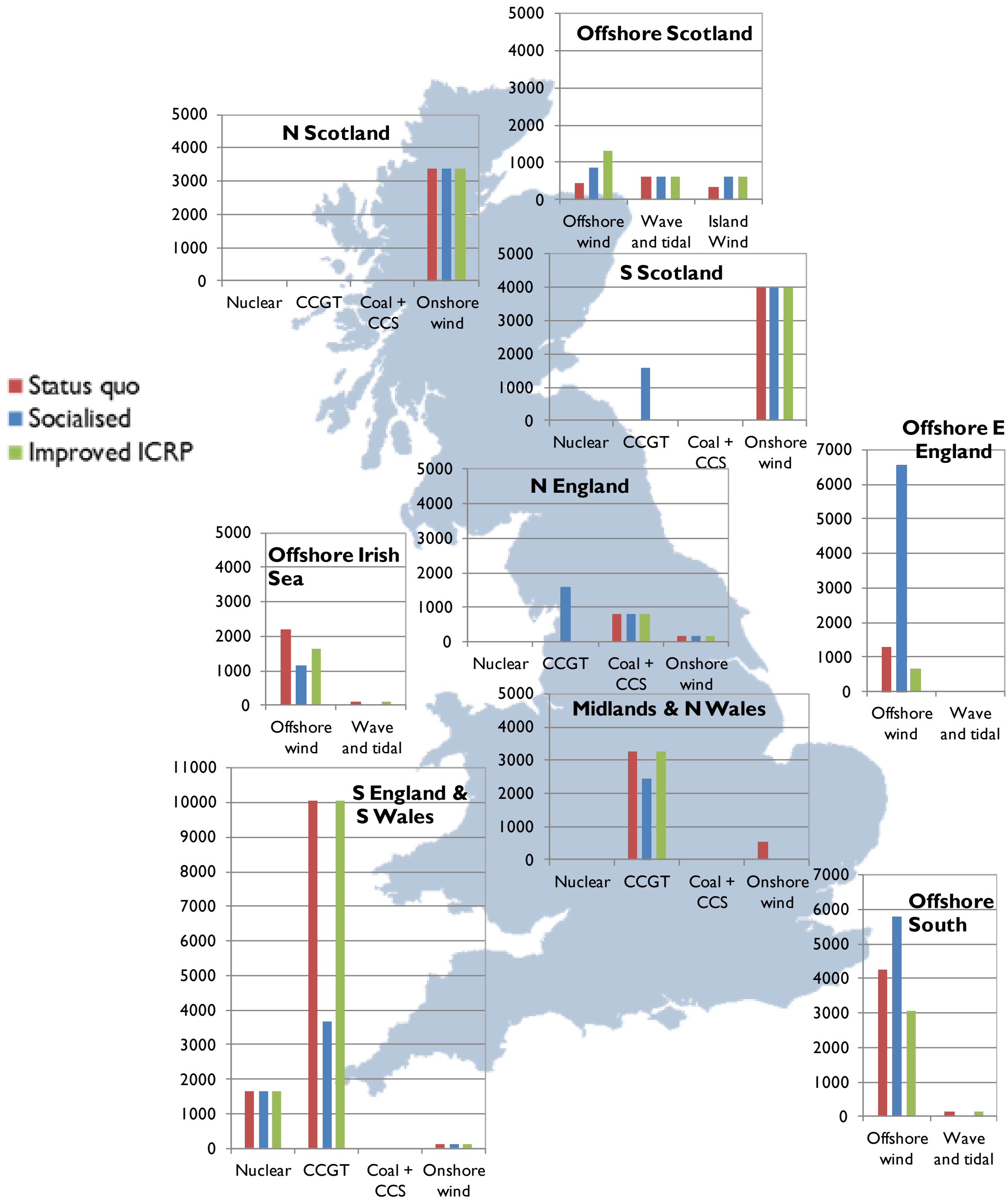


Figure 34 shows differences in cumulative new build by region for the three charging options in the RO Banding Sensitivity.

Improved ICRP charging is no longer more effective in bringing forward renewable deployment in this sensitivity because all the available onshore wind projects in mainland GB are already built under Status Quo. There is also a slight delay in offshore wind build in regions with negative TNUoS and therefore less favourable tariffs under Improved ICRP.

Socialised charging brings forward significant additional renewables (in particular offshore wind) for the same reason as with the Stage 1 modelling under Base Case assumptions, namely that the socialisation removes the offshore local tariffs, which for most projects are a significant cost.

Figure 34 New build: RO banding sensitivity (2020)



5.9 Summary of modelling results

We summarise the impacts of the charging options relative to Status Quo in Table 13 below. The table indicates the relative benefit or disbenefit for each charging option on achieving sustainability goals, costs, security of supply and regional impacts.

Table 13 Summary of key impacts of charging options relative to Status Quo

	Improved ICRP	Socialised
Impact on achieving sustainability goals[45]		
Achieving 2020 renewables target	↑	↑ ↑
Achieving 2030 decarbonisation objectives	↔	↔
Impact on costs[46]		
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

Improved ICRP potentially has a small positive impact on achieving sustainability goals, since for the same level of low carbon support it should bring forward more renewable generation by 2020. It should lead to lower generation costs, by encouraging the development of sites with best renewable resources, but this is likely to be offset by greater transmission costs. The overall impact on consumers is likely to be small. Improved ICRP will likely benefit lower load factor plant generally and renewables generators in zones which currently have high TNUoS charges.

The Socialised approach could significantly increase the amount of renewables deployment, particularly offshore wind, for the same level of low carbon support. However, by discouraging nuclear and CCS the overall impact on decarbonisation by 2030 may be neutral. The modelling suggests that the additional transmission costs exceed the savings in generation costs, and consumers would pay more under this option, averaging around £11 per year more for a domestic customer (for the same level of renewables/decarbonisation as Status Quo). By levelling TNUoS charges lower load factor plant would be strong beneficiaries, as would plant in currently high generator TNUoS zones and offshore wind.

[45] Assuming no compensating adjustment in low carbon support. The modelling was run with two stages. Under Stage 1, low carbon support levels were held constant across the transmission charging options. Under Stage 2, support was adjusted to deliver approximately the same level of renewables and carbon intensity.

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

Consumers in high demand TNUoS zones in the south of England would be favoured by Socialised charging, while consumers in Scotland would pay more.

These results appear robust to lower gas prices.

The results of the HVDC variant are similar to Improved ICRP up to 2020, but in the 2020s an increase in transmission and constraint costs is observed, to accommodate more generating capacity in North Scotland and offshore Scotland, as a consequence of less cost-reflective charging for HVDC links. The increase in consumer bills above Status Quo from 2021-2030 is still relatively small at £2 per year (compared to £1 per year under core Improved ICRP).

The Socialised (wider only) variant leads to higher tariffs for offshore wind that reflect the costs of the offshore links. As a result, relative to the fully Socialised option, there are savings in transmission costs from a reduction in offshore transmission costs. However, there is an increase in constraint costs from 2025 onwards. The average impact on consumer bills in the period 2012 to 2020 of £9 per year is slightly less than under fully Socialised charging.

A Modelling methodology

This appendix contains further details on the modelling methodology used for the study.

A.1 Modelling framework

An overview of the modelling framework, the "TransmiT Decision Model", is given in Section 4.3. In the section below we provide further details on the modelling framework, the sequencing of model components in each model run, and the rules for making generation investment and retirement and transmission reinforcement decisions.

A.1.1 Model components

Generation build and closure decisions

The logic for generator build and retirement decisions comes from Redpoint's Investment Decision Model. Decisions are made by evaluating future expectations of profitability, derived by comparing expected future gross margins with the expected future levelised non-fuel costs for a pre-defined look forward period. The logic for new investments is shown in Figure 35 below. For new generators the levelised non-fuel cost includes capital costs and annual fixed costs. The gross margin is calculated as the expected margin from power revenues, capacity payments and subsidies minus fuel and carbon costs and non-fuel variable costs.

There are two trigger points which a project must pass in order to progress to construction. If a project is "in the money" it enters planning. If it continues to be in the money at the end of the planning period, the project is committed to the construction phase, and will become operational after a pre-defined number of years.

Total annual investment in a particular technology is limited by the global build constraint, defined in MW. This imposes an additional constraint which limits the total rate of deployment of a particular technology. If this constraint is binding, the projects with the highest expected returns will progress.

Figure 35 Generator build decisions

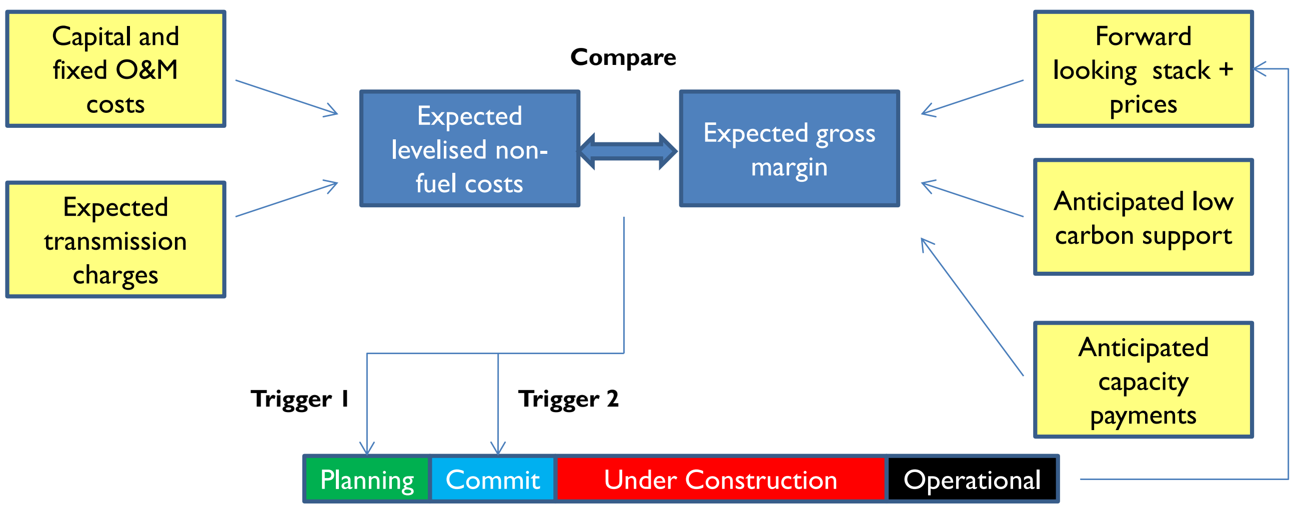
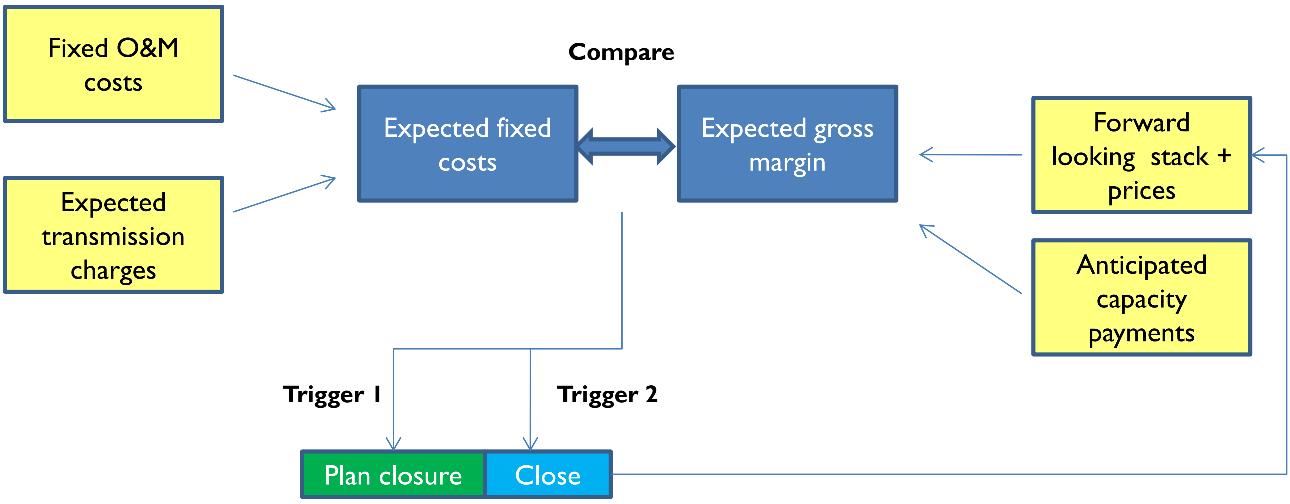


Figure 36 shows the logic for closure decisions of existing generators. The logic is analogous to that for new investments, with the difference that capital already invested is ignored as this is a sunk cost (and we assume that no further capital investment is required to keep the plant open).

Figure 36 Generator closure decisions

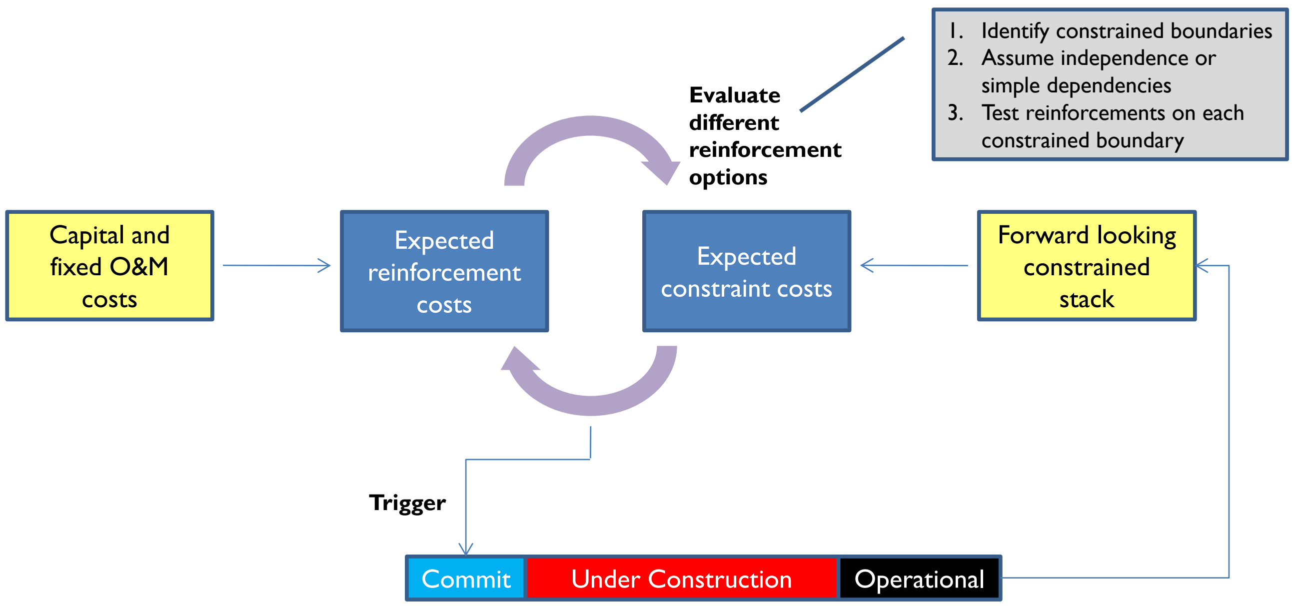


Transmission Investment Decisions

The transmission investment decision logic has been developed specifically for this study. The transmission investment decision rules attempt to minimise the total combined future costs of constraints and transmission reinforcements, subject to the imperfect information available on siting of future generation.

Considering all transmission reinforcement projects (section B.3.1) the model first pre-filters those projects which are available to be built and which are active in relieving a constrained boundary. For each filtered reinforcement in turn, the model assesses the savings in constraint costs that would be expected if that reinforcement were to be made, relative to a baseline without the reinforcement. This is compared to the levelised cost of the transmission reinforcement. Those reinforcements which are expected to provide a net reduction in cost are committed in the model and enter a construction period, to become operational a minimum of three years later.

Figure 37 Transmission investment decisions



Unconstrained and constrained generation dispatch

Generation dispatch is performed in NGET's ELSI model[47]. This model uses a Linear Programming formulation to minimise the cost of generation subject to the constraint that national supply must equal national demand (in the Unconstrained run) and additionally that flows across boundaries must not exceed the boundary limits (in the Constrained run).

The model takes inputs from the TransmiT Decision Model including the generator capacities as well as demand levels, wind output and short run marginal costs of generation plant.

The model uses 102 sample periods to represent a year. Each sample represents a group of hours from a particular season. Wind output is modelled using a set of input wind profiles for the modelled wind zones (section B.2.1). The wind output profiles are based on actual wind speed data, converted to wind generator output using a turbine power curve.

Interconnectors (the capacities of which are exogenous input assumptions, described in section B.3.3) are dispatched by the model using different tranches to represent export, float (no flow) and import. Interconnector imports and exports are priced as a spread around a typical CCGT generation cost. Similarly, pumped storage is modelled in three tranches, representing pumping, float and generation.

For each of the 102 sample periods, ELSI first dispatches the generation to meet demand at least cost, assuming there are no transmission constraints. The key outputs from the run are the generation levels and profitability, and power prices. ELSI then re-dispatches generation to comply with transmission constraints. The re-dispatch is priced using assumptions on generator bid/offer spreads (section B.3.4). The key output of the constraint run is the total constraint costs.

[47] A description of the stand-alone ELSI model is given at: http://www.nationalgrid.com/NR/rdonlyres/CBB795B4-EFB6-48C0-95E7-51136C48F66D/46096/ElectricityScenarioIllustrator.pdf, 23rd March 2011

ELSI also estimates transmission loss volumes and costs. In a zonal model (as opposed to a full network model), transmission losses will necessarily be an estimate only. Transmission loss volumes are estimated using the concept of a boundary "thickness", which is an estimate of the distance that power travels by virtue of having crossed a particular boundary. In combination with the model results for flows over each boundary, it is possible to estimate transmission losses. The cost of transmission losses is calculated by multiplying the loss volume in MWh by the demand weighted annual marginal cost price.

Transport Model

The Transport Model calculates the TNUoS charges. The different transmission charging options are implemented through different versions of the Transport Models. The Status Quo Transport Model performs identical calculations to the publically available Transport and Tariff model for 2011-12[48]. Limited changes were made to implement the agreed approaches on HVDC charging (section A.3). NGET developed the Improved ICRP and Socialised versions of the Transport Model during the course of the study.

Key inputs are the generation background and transmission background and the MAR (Maximum Allowed Revenue). The transmission background is held constant, other than for HVDC bootstraps (based on advice from NGET that AC network reinforcements have limited impact on tariffs). The key outputs are the generation tariffs for individual generators basis, and the zonal generation and demand tariffs.

A.1.2 Model execution

Model sequence

Under the imperfect foresight modelling approach, the TNUoS tariffs and the generation and transmission investment decisions evolve as the model steps through the modelling period year-by-year. In each year, each model component is executed, based on an imperfect view of future tariffs, and generation and transmission investment decisions.

The model begins with an initial view of the near term generation and transmission background from 2011 based on the generation and transmission investments that we consider as committed (known).

In each model year, the first stage is to run the Transport Model using the expected generation and transmission background for next year (Y+1). The Transport model is also run for Y+5, based on expectations of the future generation and transmission background. This creates a view of future TNUoS charges.

The second step is to run the Unconstrained and Constrained dispatch for both the current year (Y0) and a set of future years (Y+1, Y+3, Y+5). These results form the inputs to the Generation and Transmission Decision components. The generator closure decisions use a view of Y+1 whereas the generator investment decisions use Y+5. The transmission investment decisions are made on the basis of Y+3 and Y+5.

The generation retirement and build decisions and the transmission reinforcement decisions are input to the next year of the simulation. As the model progresses year by year the Generation and Transmission Decisions evolve in parallel.

[48] Information available at http://www.nationalgrid.com/uk/Electricity/Charges/transportmodel/

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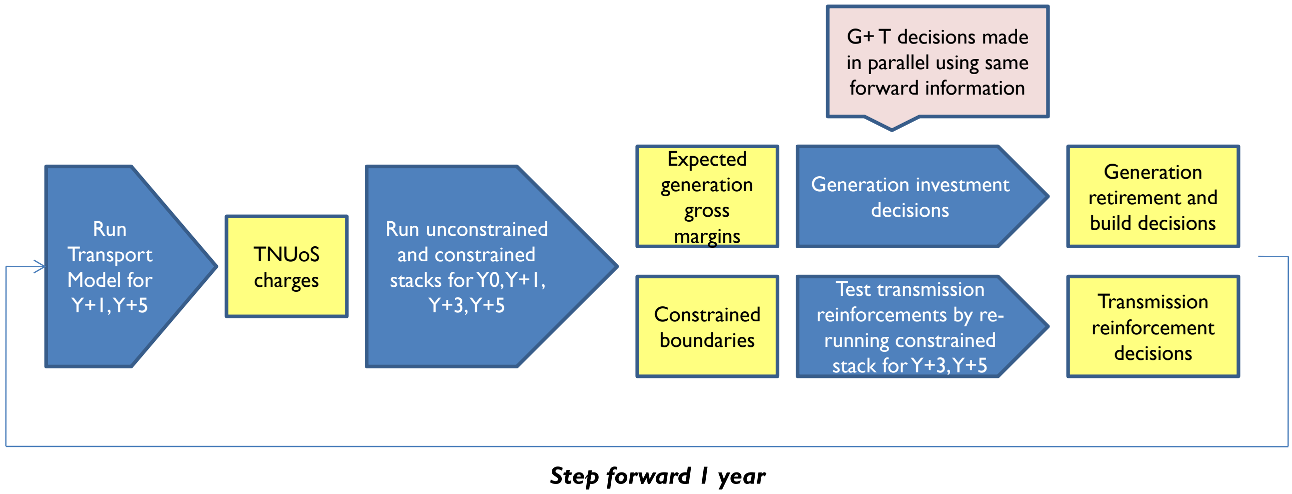
Figure 38 Model sequence (imperfect foresight)

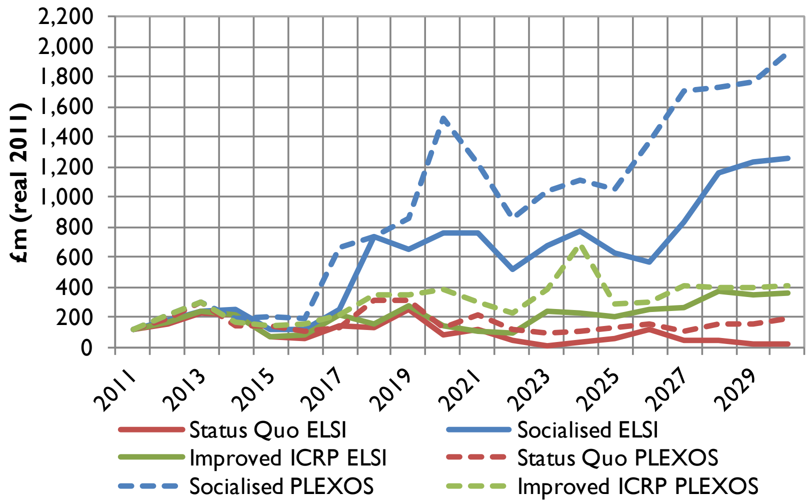


Calibration of constraint costs to PLEXOS

PLEXOS is used by both NGET and Ofgem for the purposes of forecasting constraint costs. It models the market at a greater level of detail than ELSI, but the run time made it unsuitable for incorporation within the TransmiT Decision Model. This study is not per se about forecasting future constraints costs, but Ofgem believed it important that the analysis was undertaken using a realistic representation of constraint costs. Hence we undertook an extensive calibration exercise between PLEXOS and ELSI. The PLEXOS model was updated with the assumptions used in this study for choice of zones and boundaries, boundary capacities and demand.

We benchmarked the Stage 2 Base Case results for the three charging options. For each case we updated the generation capacities and transmission reinforcement in PLEXOS to match the model outputs from the TransmiT Decision Model. Figure 39 shows a comparison of the ELSI and PLEXOS constraint costs. The results show that there is a very good match between constraint cost estimates in the near term. Over the longer term the levels of constraint costs diverge somewhat but there is consistency in relativity and direction.

Figure 39 **Comparison of ELSI and PLEXOS constraint costs: Stage 2 results**



A.2 Modelling of Electricity Market Reform

Low Carbon Support

Government support for low carbon technologies is currently under review as part of the Electricity Market Reform process. Government has proposed that low carbon technologies (renewables, nuclear and carbon capture and storage) are supported through Contracts for Difference (CfDs) from 2014. These CfDs would be struck against a wholesale price index, with a strike prices set for different technologies at levels sufficient to attract investment (although Government has indicated a desire to move to technology neutral auctions in the longer term).

The Government has indicated that the current scheme for supporting renewables in the UK, the Renewables Obligation (RO), will stay open for accreditation of new projects until 31 March 2017. After this date, projects in the scheme would continue to receive ROCs but no new projects would be allowed to enter.

There are important interactions between transmission charging and the levels of support that different forms of low carbon generation require to be built. Whilst Project TransmiT is essentially a review of transmission charging it was realised that these interactions could not be ignored, and that Project TransmiT and the Government's Electricity Market Reform are closely related.

Changes to transmission charging could in future:

- Accelerate or decelerate the rate of low carbon deployment, and/or
- Change the level of support required to achieve a certain level of deployment.

To capture these two different effects, the modelling was undertaken on two bases as follows:

- **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"**), and

- **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"**).

In both cases we assumed that CfDs are available from 2014, and strike prices are reset every 3 years. For the Base Case modelling, for simplicity we assume that from 2014 all renewable generators choose a CfD rather than entering the RO. We also undertook an RO Banding Sensitivity where new renewables generators would opt to operate under the RO until 2017 with the recently published revised RO bands.

In Stage 1, we set the CfD strike prices based on the average levelised cost (including TNUoS charges) of the technology under Status Quo[49]. We then adjusted the CfD strike price (uniformly) to achieve a specific level of renewables deployment in 2020, of 30%, and a similar level of carbon intensity in 2030. We then kept these CfD strike prices fixed across the Improved ICRP and Socialised charging options. The results of Stage 1modelling illustrate the impact on deployment of low carbon technologies purely from changes to TNUoS. The CfD strike prices used in the Stage 1 modelling are shown in Table 14. The reductions over time are a result of assumed decreases in the costs of the technologies (section B.2.1).

Table 14 CfD strike prices under Stage 1 approach: all charging options (2011 real)

(£/MWh)	2014-2016	2017-2019	2020-2022	2023-2025	2026-2028	2029-2030
Nuclear	94	92	90	84	81	79
Coal + CCS	139	138	134	133	133	134
CCGT + CCS	100	102	104	106	109	112
Onshore wind	94	90	88	87	86	85
Offshore wind	159	145	137	132	128	124
Wave	471	368	319	267	236	220
Tidal Stream	468	346	283	261	229	211
Dedicated biomass	122	120	118	118	118	117

In Stage 2, to compare overall cost impacts of the different charging options, low carbon support was adjusted so that renewable and carbon intensity outcomes were approximately equal across all three modelled policy options. Stage 2 modelling involved setting low carbon support initially based on the average long run marginal cost (LRMC) of each technology (which differs across the three charging options) and then scaling support under Improved ICRP and Socialised charging uniformly to achieve the same renewable share (in 2020) and carbon intensity (in 2030) as under Status Quo. The resulting CfD strike prices are shown in Table 15 and Table 16. There is no change to Status Quo under Stage 2 since under Stage 1 this option was set to meet the targeted renewables share in 2020.

[49] This is the average of the levelised costs of all projects that fall under that category of low carbon support. For example, the average levelised for onshore wind is based on the average of the levelised costs for all potential onshore wind projects, including the Scottish islands.

Table 15 CfD strike prices under Stage 2 approach: Improved ICRP (2011 real)

(£/MWh)	2014-2016	2017-2019	2020-2022	2023-2025	2026-2028	2029-2030
Nuclear	94	93	90	84	81	80
Coal + CCS	139	138	135	133	133	133
CCGT + CCS	100	102	104	107	109	114
Onshore wind	92	88	87	86	84	82
Offshore wind	159	144	137	132	127	122
Wave	467	361	318	264	231	211
Tidal Stream	468	346	283	261	228	208
Dedicated biomass	122	119	119	118	118	116

Table 16 CfD strike prices under Stage 2 approach: Socialised (2011real)

(£/MWh)	2014-2016	2017-2019	2020-2022	2023-2025	2026-2028	2029-2030
Nuclear	96	95	93	88	84	84
Coal + CCS	140	139	137	135	136	138
CCGT + CCS	102	104	108	110	113	118
Onshore wind	91	87	87	86	86	87
Offshore wind	148	134	128	122	119	117
Wave	467	363	313	259	230	213
Tidal Stream	469	347	286	264	234	218
Dedicated biomass	123	120	121	121	122	123

CfD design

The detailed design of the CfDs has not yet been published by the Government. Two important design issues are whether the CfDs are paid on output or availability, and the choice of wholesale price index. We assumed that CfDs are paid on output but placed a floor on bids from renewables generators behind constraints equivalent to the premium of their CfD strike price above forward market prices. In reality generators may bid differently to this. Constraint costs are very sensitive to this assumption, highlighting the important interactions between CfD design and transmission costs.

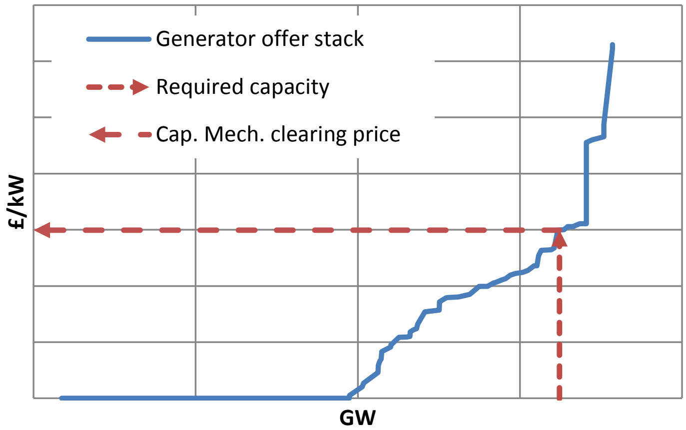
Capacity Mechanism

For the purposes of the TransmiT modelling we assumed that a capacity mechanism is in place, as being proposed under the EMR. At the time of the analysis, details were yet to be finalised but we included a simple form of universal capacity mechanism based on annual capacity auctions in the modelling.

A defined capacity adequacy security standard is required for the capacity mechanism. This was set at a10% de-rated capacity margin – i.e. the de-rated capacity required is 10% greater than peak demand.

The market wide capacity mechanism takes the form of an annual capacity auction where generators offer in their capacity and the clearing price is determined by the price of the marginal capacity (an example is shown in Figure 40).

Figure 40 Capacity mechanism bid stack



Generator offer prices are determined by evaluating the additional revenues they require above expected wholesale market revenues to stay open or build a new plant. For existing generators, this is the margin made in the wholesale market after all variable costs and fixed annual costs. For new projects, this also includes the annuitised capital cost of the project. Many generators will be making a positive margin without an additional payment. For these cases, their offer prices are set to zero. We assume that all plant operating under a CfD do not participate in the capacity mechanism, and hence their offer price is effectively zero.

The auction is based on stack of all the offer prices, where the volume element (x-axis) is the de-rated capacity of the generators. We find the point in the stack at which the de-rated capacity meets the security standard. The offer price of this marginal generator then sets the capacity price for that year. The mechanism will clear either on older existing plant which would otherwise be losing money, or on potential new build. If the mechanism clears on a new build project, the model assumes that this plant will subsequently be built.

All generators (excluding those on CfDs) receive this clearing price for that year, for their de-rated availability. We assume that capacity payments are paid by all consumers.

The capacity mechanism has an impact on wholesale power prices. 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[50], which adds a margin to the system short run marginal cost depending on the tightness (capacity margin) in each period.

The capacity mechanism will tend to stabilise the annual margin of capacity over peak demand, and therefore reduce the impact of uplift on power prices.

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

A.3 Modelling of charging options

This section provides additional detail on treatment of HVDC bootstraps and island links in the charging methodologies. Further details of the charging options can be found in the Technical Working Group documentation[51].

HVDC bootstraps: expansion factor

A number of sub-sea HVDC 'bootstraps' have been proposed, which run parallel to the main AC network in order to facilitate the long distance transmission of power by alleviating specific constraints on the onshore AC network[52]. HVDC bootstraps constitute a new technology which is not provided for in the current TNUoS charging methodology. The Technical Working Group provided input on two areas: the expansion cost to be used for HVDC bootstraps, and impedance to be used in the Transport Model[51].

Under Status Quo and Improved ICRP, the full cost of the HVDC link was included in the expansion factor. We also modelled a variant of Improved ICRP (HVDC variant) where the costs of AC/DC converter stations for the 'bootstrap' links were removed from the expansion factor calculation[53].

Under Socialised the costs of HVDC links are shared along with all other transmission costs.

HVDC bootstraps: impedance

The Technical Working Group Initial Report describes in some detail the reasons why the existing ICRP methodology does not work for HVDC 'bootstraps', and a number of methodologies that could be adopted. The recommended approach was to model each HVDC link as an AC circuit, using an impedance calculated as the average of a ratio of total network boundary rating versus HVDC link rating for all boundaries that the link crosses.

This approach was implemented for Status Quo and Improved ICRP. It was not relevant for Socialised charging where the costs of HVDC links are shared.

A.4 Cost Benefit Analysis framework

The CBA is separated into two parts: impacts on power sector costs and impacts on consumer bills.

Power sector costs can be used as a measure of welfare as they represent the change in total cost to the economy of meeting electricity demand (excluding flow-on effects outside the electricity industry). Consumer bill impacts are not an overall welfare measure, but rather the impact on just one part of society. In calculating consumer bill impacts, we assume that suppliers directly pass through to consumers the changes in charges and prices that they face. The difference between impacts on power sector costs and on consumer bills is producer surplus, which represents earnings by generators and transmission owners above their long-run cost of producing and delivering electricity.

[51] For further discussion see with Technical Working Group Initial Report: http://www.ofgem.gov.uk/Networks/Trans/PT/WF/Documents1/TransmiT%20WG%20Initial%20Report.pdf

[52] The discussion in this section applies only to HVDC links that parallel the AC network, and not to radial HVDC links that do not parallel the network (i.e. offshore and island radial links). For these redial links, the full expansion cost is used in all cases.

[53] Under this approach, the expansion factor (i.e. multiple of 400kV OHL costs) for HVDC links was re-calculated to exclude the costs of the converters, thereby reducing the effect on locational tariffs, but not completely removing the cost from the locational signal.

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For both power sector costs and consumer bills, we focus on the results for each policy option relative to the Status Quo baseline, facilitating comparison across charging options. The modelling approach is designed to indicate the change across options rather than the absolute level of costs. For example, depreciated capital costs for existing plant are not included in the analysis, as these will be the same across all policy options.

The different components of the costs and benefits produced by the modelling framework estimated are described below.

Power sector costs

Power sector costs are made up of four aggregated sources of costs:

- **Generation costs**, comprising:
  - Annuitised capital costs: the annual capital charge for new generation built, based on a market rate of return for generation assets that depends, among other things, on the cost of equity, cost of debt and gearing ratios.
  - Fixed operating cost: annual fixed operating and maintenance cost, including gas exit charges but excluding fixed TNUoS charges.
  - Variable operating cost: variable operating and maintenance costs, excluding fuel costs, variable TNUoS and BSUoS.
  - Fuel cost: cost of gas, coal, nuclear and biomass fuel for thermal plant (but excluding carbon costs).
  - Net interconnector imports: the value of interconnector imports less interconnector exports, where interconnector flows are priced according to the long run marginal cost of the marginal generating unit (assumed to be new CCGT) and there is assumed to be a 10% spread between buy and sell prices.

- **Transmission costs**, which include onshore, offshore and island links, comprising:
  - Annuitised capital cost: the regulated capital charge and depreciation costs for transmission assets.
  - Annual operating cost: cost of operating and maintaining the transmission network.
  - Transmission losses: power losses in transmission, valued at the system marginal price.

- **Constraint costs**: the cost of diverging from the economic running of generation as defined by the market due to transmission constraints, measured by payments to generators to constrain them on or off.[54]

[54] This approach assumes that bid/offer spreads are reflective of true costs incurred by generators (in particular, start-up and shutdown costs, and cost associated with operating flexibly at short notice). We therefore assume that there are no rents to generators associated with constraint payments. If there were a component of generator profits associated with bid/offer spreads in the balancing market, then this should not feature in the welfare cost calculation. Note that for generators receiving low carbon support, the assumed bid/offer spreads do recognise the subsidy payment lost when that generator is constrained off.

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- **Carbon costs**: the economic cost attached to CO_2 emissions from electricity generation, based on Carbon Price Support in 2013 (and estimated Carbon Price Support thereafter) and EU carbon emissions permit prices for 2011 and 2012.[55]

Consumer bills

Consumer bills are made up of three aggregated sources of costs:

- **Wholesale costs**, comprising:
  - Demand-weighted wholesale electricity prices
  - consumer BSUoS charges, which include the consumer share of constraint costs
  - capacity payments
  - differences in transmission losses across policy options
- **Demand TNUoS charges:** the demand share of total TNUoS charges.[56]
- **Low carbon support**, comprising:
  - ROC payments
  - CfD difference payments
  - LEC subsidies: the cost of Levy Exemption Certificates from the Climate Change Levy.

The costs above represent the changes in the costs that suppliers face in serving their customers. We have assumed that suppliers pass these costs changes directly through to consumers. We assume that consumers are fully exposed to regional TNUoS variations but no other regional differentials.

Changes in power sector costs and changes in consumer bills may diverge in some years, particularly through variations in wholesale costs. Wholesale prices are set by the marginal costs of generation plus and additional 'uplift' element which is related to capacity tightness. Capacity payments may also be higher in years of capacity tightness. These two factors result in consumers paying more in years of capacity tightness, and less in years with higher capacity margins.

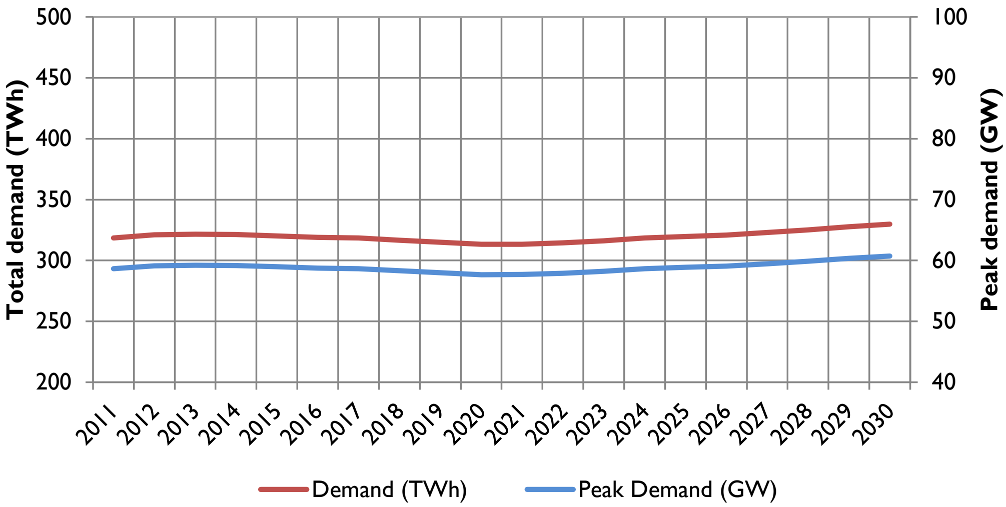
[55] There is considerable uncertainty about the economic costs of carbon emissions. These economic costs are related to the anticipated damages from climate change and are dependent upon the future path for global emissions (among other things). In the absence of certainty about estimated damages and future emissions paths, carbon prices faced by generators were used as a proxy for the economic costs associated with carbon emissions. In reality, carbon prices will only be equal to damage costs under efficient mitigation policy that equates the marginal cost of reducing carbon emissions with the marginal damages from emissions.

[56] The demand share is currently 73% of total TNUoS and is assumed to change to 85% from 1st April 2015.

B Assumptions is followed below.

Demand assumptions were based on National Grid's 'Gone Green' scenario. There is projected to be little increase in demand to 2030 (Figure 42). Electricity demand figures exclude embedded generation.

Figure 42 Demand assumptions



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

B.2 Generation

The list of available generation projects was based on known projects to 2020, with a broader range of generic projects available to 2030 (Table 18). For established technologies (for example, CCGT, OCGT and onshore wind) some flexibility in locational decisions was allowed by incorporating some additional projects that are not yet in the TEC register, based on the potential for these projects to be delivered before 2020. An annual cap on build rates by technology was also applied to reflect supply-side constraints (Table 19).

Table 18 Maximum build assumptions

(MW)		S England & S Wales	Midlands & N Wales	N England	S Scotland	N Scotland	Total	Growth from existing
New nuclear	2020	1,670	0	0	0	0	1,670	1,670
	2030	13,200	3,600	4,850	0	0	21,650	21,650
	TEC register							21,650
New CCGT	2020	12,000	4,800	7,200	1,600	1,600	27,200	27,200
	2030	28,000	9,600	13,600	4,800	4,800	60,800	60,800
	TEC register							13,755
New OCGT	2020	2,000	800	800	400	800	4,800	4,800
	2030	4,000	1,600	1,600	800	1,600	9,600	9,600
	TEC register							0
Coal + CCS	2020	0	0	800	1,950	0	2,750	2,750
	2030	0	2,000	2,740	1,950	0	6,690	6,690
	TEC register							2,450
CCGT + CCS	2020	0	0	0	0	0	0	0
	2030	4,786	0	2,000	0	0	6,786	6,786
	TEC register							0
Onshore wind	2020	138	1,071	158	6,532	7,531	17,000	11,496
	2030	491	1,501	563	8,230	9,245	21,600	15,047
	TEC register							6,052
Dedicated biomass	2020	350	0	879	97	0	4,130	1,229
	2030	515	299	879	347	0	6,551	1,943
	TEC register							1,546
(MW)		**Offshore south**	**Offshore Irish Sea**	**Offshore North Sea**	**Offshore Scotland**		**Total**	**Growth from existing**
Offshore wind	2020	7,735	4,691	6,817	3,835		23,078	21,413
	2030	12,879	5,891	19,595	9,610		47,975	46,310
	TEC register							25,564
Tidal and wave	2020	155	85	0	1,359		2,000	1,589
	2030	5,000	400	0	5,210		11,925	10,600
	TEC register							3,232

Note: Excludes embedded capacity.
Sources: New sites to 2020 based on the TEC Register (National Grid, *Transmission Entry Capacity (TEC) Register*, 23 August 2011) and existing sites; broader range of generic locations allowed to 2030. Upper limits for onshore wind, offshore wind and tidal and wave were based on feedback from the TransmiT Technical Working Group following Meeting 7 on 10 October 2011. For offshore wind, capacities available from specific development zones were based on National Grid, *2011 Offshore Development Information Statement (ODIS)*.

Table 19 Maximum annual build assumptions

Plant type	Maximum annual build (MW)
New nuclear	4,000
New CCGT	6,000
New OCGT	300
Coal + CCS	4,000
CCGT + CCS	4,000
Onshore wind	4,000
Dedicated biomass	2,000
Offshore wind	7,500
Tidal and wave	2,000

Sources: Redpoint assumptions, incorporating Technical Working Group feedback.

B.2.1 Capital and operating costs

Capital and operating costs were sourced from recent studies for the Department of Energy and Climate Change (Table 20 and Table 21). For wind generation, locational load factors are also important, which were estimated as set out in Table 22. Offshore wind capital costs were adjusted for water depth. Gas-fired generators will incur costs associated with use of the gas transmission network (gas exit charges) which were estimated for new and existing plant based on prevailing charges in 2011 and projections for 2012, 2013 and 2014.[57] Gas exit charges were assumed to remain at 2014 levels for the remainder of the modelled period.

Table 20 Capital cost assumptions (real 2011 £s)

Capital costs (£/kW)	2011	2015	2020	2025	2030
Nuclear (EPWR single)	3335	3193	3065	2886	2794
Biomass (>50MW)	2447	2393	2337	2315	2293
Offshore wind (R3)[1]	2925	2488	2143	1950	1808
Onshore wind (>5MW)	1555	1501	1446	1410	1374
Wave	6386	5107	3496	2340	1818
Tidal Stream	11193	4233	2963	2261	1800
Gas CCGT	669	669	669	669	669
Gas CCGT with CCS	1566	1566	1493	1399	1356
Coal with CCS (ASC with FGD & CCS)	3441	3348	3152	3007	2958
OCGT	599	599	599	599	599

[57] From National Grid, *The Statement of Gas Transmission Transportation Charges*, Effective from 1 April 2011 and National Grid, *Notice of NTS Exit Capacity Charges Ahead of the 2011 Application Window for Enduring Annual NTS Exit (Flat) Capacity*, letter to Ofgem (April 2011).

Note: [1] Offshore wind capital costs also adjusted for water depth, according to an estimated saving of £9/kW/m for each metre of water depth under 50m.
Sources: Marine technologies from Ernst and Young, *Cost of and Financial Support For Wave, Tidal Stream and Tidal Range Generation in the UK*, Study for DECC (October 2010); Biomass, CHP and co-firing from Arup, *Review of the Generation Costs and Deployment Potential of Renewable Electricity Technologies in the UK*, Study for DECC (June 2011); Other renewables based on unpublished data from 2011 Ernst and Young study for DECC; Non-renewable technologies from PB Power, *Electricity Generation Cost Model – 2011 Update*, Study for DECC (June 2011).

Table 21 Operating cost assumptions (new build)

	Variable operating and maintenance (£/MWh)	Fixed operating and maintenance (£/kW)
Nuclear	2.50	70
Biomass	5.00	100
Offshore wind	1.99	80
Onshore wind	2.94	14
Wave	1.10	200
Tidal Stream	1.10	200
Gas CCGT	0.40	23.2
Gas CCGT with CCS	3.84	33
Coal with CCS	8.95	65
OCGT	1.00	23

Note: Plant-specific assumptions for existing plant derived from Redpoint plant database. Fuel costs calculated separately according to the commodity price assumptions detailed above in this Appendix. Gas-fired plant subject to gas exit charges, estimated as detailed above.
Sources: Marine technologies from Ernst and Young, *Cost of and Financial Support For Wave, Tidal Stream and Tidal Range Generation in the UK*, Study for DECC (October 2010); Biomass, CHP and co-firing from Arup, *Review of the Generation Costs and Deployment Potential of Renewable Electricity Technologies in the UK*, Study for DECC (June 2011); Other renewables based on unpublished data from 2011 Ernst and Young study for DECC; Non-renewable technologies from PB Power, *Electricity Generation Cost Model – 2011 Update*, Study for DECC (June 2011).

Table 22 Load factor assumptions for wind generation

Generation type	Location	Average load factor
Onshore wind	Orkney and Shetland Isles	45.0%
Onshore wind	Western Isles	35.0%
Onshore wind	North Scotland	29.0%
Onshore wind	South Scotland	28.0%
Onshore wind	England	26.0%
Onshore wind	Wales	27.0%
Offshore wind	All offshore zones	37.6%

Sources: Scottish islands from Econnect Consulting, *2116 Validation of Relative Economics of Wind Farm Projects in the Scottish Islands' Study*, Technical Note 02 (March 2008). Other locations based on Arup, *Review of the Generation Costs and Deployment Potential of Renewable Electricity Technologies in the UK*, Study for DECC (June 2011).

B.2.2 Economic lifetime, planning and construction

Assumptions for economic lifetime, planning and construction times for each technology are shown in Table 23. Capital costs were based on an estimated equity beta and debt gearing ratio specific to each plant type, in conjunction with standard assumptions for the risk free rate (5.0%), tax rate (24.0%) and debt and equity premia (1.5% and 4.0% respectively).

Table 23 Plant build characteristics

Type	Economic life (years)	Planning (years)	Construction (years)	Cost of capital
Nuclear	30	2	5	11.5%
Biomass	20	3	3	11.0%
Offshore wind	20	3	2	11.0%
Onshore wind	20	2	2	9.0%
Wave	20	4	2	13.0%
Tidal Stream	20	4	3	13.0%
Gas CCGT	20	2	2	8.2%
Gas CCGT with CCS	20	4	4	12.0%
Coal with CCS	20	5	4	12.0%
OCGT	20	2	2	8.2%

B.2.3 LPCD/IED

The Large Combustion Plant Directive (LCPD) is currently applied to the power sector to limit SOx, NOx and particulate emissions. This affects the coal and oil fleet in GB. Operators had the option to 'opt in', which required them to fit Flue Gas Desulphurisation (FGD) equipment to meet environmental standards, or 'opt out', with plant operation limited to a total of 20,000 hours between 2008 and 2015, at which point they must close. In GB, there are 9 GW of coal plant and 3 GW of oil fired plant that are 'opted out' and must close by the end of 2015.

The Industrial Emissions Directive (IED) recasts seven existing Directives, including the LCPD and the Integrated Pollution Prevention and Control Directive, with tighter limits in particular for NOx emissions, coming into force in 2016. Unlike the LCPD, some older gas plant will also be affected. There are four options available to plant which do not meet the NOx limits:

- Comply by fitting Selective Catalytic Reduction (Fit SCR) equipment. For gas plant, SCR is not usually an economic upgrade.
- Enter a Limited Lifetime Obligation (LLO). This is analogous to opting out of the LCPD. Plant can operate up to 17,500 hours over an 8 year period to 2023 and then must close.

- Operate under the Transitional National Plan (TNP) as set out by individual Member States. During the period 2016 to mid-2020 plant will be able to operate as a function of historic generation levels and have the option of fitting SCR before June 2020 to comply fully.
- Enter a derogation. Under this option, plant will be permitted to run for a maximum of 1,500 hours per year, but with no date for closure. Plant operating under the TNP can opt to enter a derogation at the end of the TNP in June 2020, but plant operating under the LLO cannot.

Table 24 Plant subject to LCPD/IED

Constraint	IED option	Plant types affected	Capacity affected (MW)
LCPD	n/a	Coal, Oil	10937
IED	IED - Fit SCR	Coal	7016
IED	IED - LLO	Coal, CCGT	16407
IED	IED - TNP	CCGT	5385

Sources: Redpoint assumptions.

The choice for individual plant between the various IED options was based on consideration of the economics of these choices, depending on historic and expected load factors.

B.2.4 Nuclear retirements and lifetime extensions

Closure dates for existing nuclear plant are based on estimates from the Nuclear Installations Inspectorate.

Table 25 Nuclear retirement assumptions

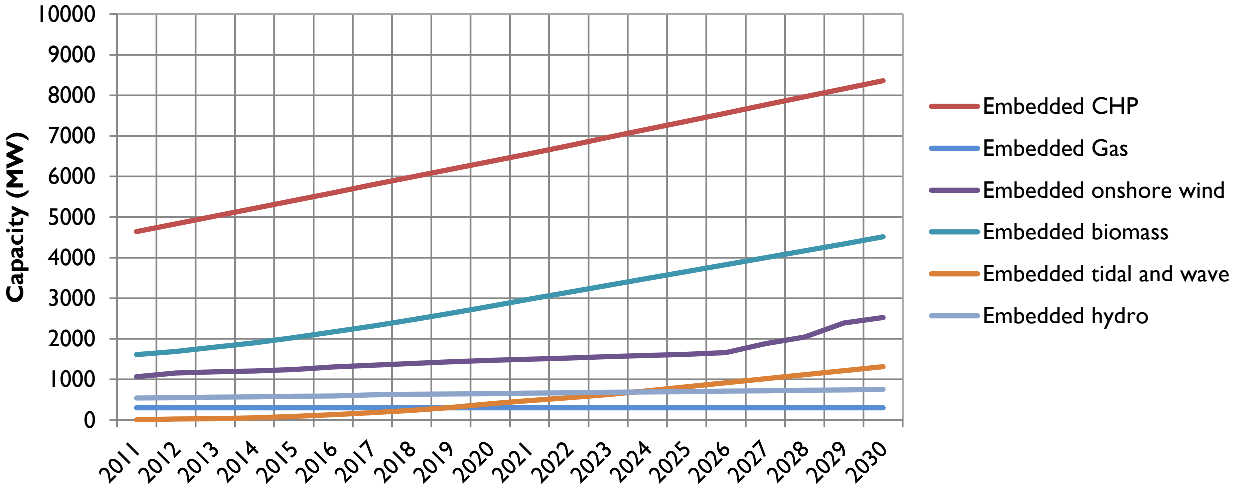
Plant	Capacity (MW)	Closure date
Dungeness B	1081	2018
Hinkley Point B	1261	2018
Oldbury	215	2012
Hunterston	1074	2018
Torness	1215	2028
Hartlepool	1207	2019
Heysham 1	1203	2019
Heysham 2	1203	2028
Sizewell B	1207	2035
Wylfa	890	2012

Source: Nuclear Industry Association.

B.2.5 Embedded generation

Embedded generation assumptions were taken from National Grid's 'Gone Green' data and assumed to be the same across all charging and sensitivity scenarios. All onshore wind in England was assumed to be embedded and fixed across all scenarios, while onshore wind in Wales and Scotland was assumed to be transmission connected and allowed to vary across scenarios (and thus excluded from the embedded assumptions). All offshore wind was assumed to be all transmission connected and modelled explicitly as part of the transmission network.

Figure 43 Embedded generation capacity



Sources: National Grid, 'Gone Green' scenario.

B.3 Transmission reinforcement

Transmission reinforcements were separated into three separate categories:

- *Available reinforcement projects*: reinforcements to the onshore network that were modelled explicitly based on the economic trade-off between investment costs and savings in constraint costs
- *Background reinforcement*: costs of maintaining and operating the onshore network (excluding the available reinforcement projects that were modelled explicitly as described above), and
- *Offshore and island connections:* costs of offshore and island links were included in the total cost of transmission reinforcement wherever they are required on the basis of generation investment decisions.

Available reinforcement projects

A list of potential transmission reinforcements were modelled explicitly. These included a list of known projects, as well as some generic reinforcements to selected boundaries (Table 26).

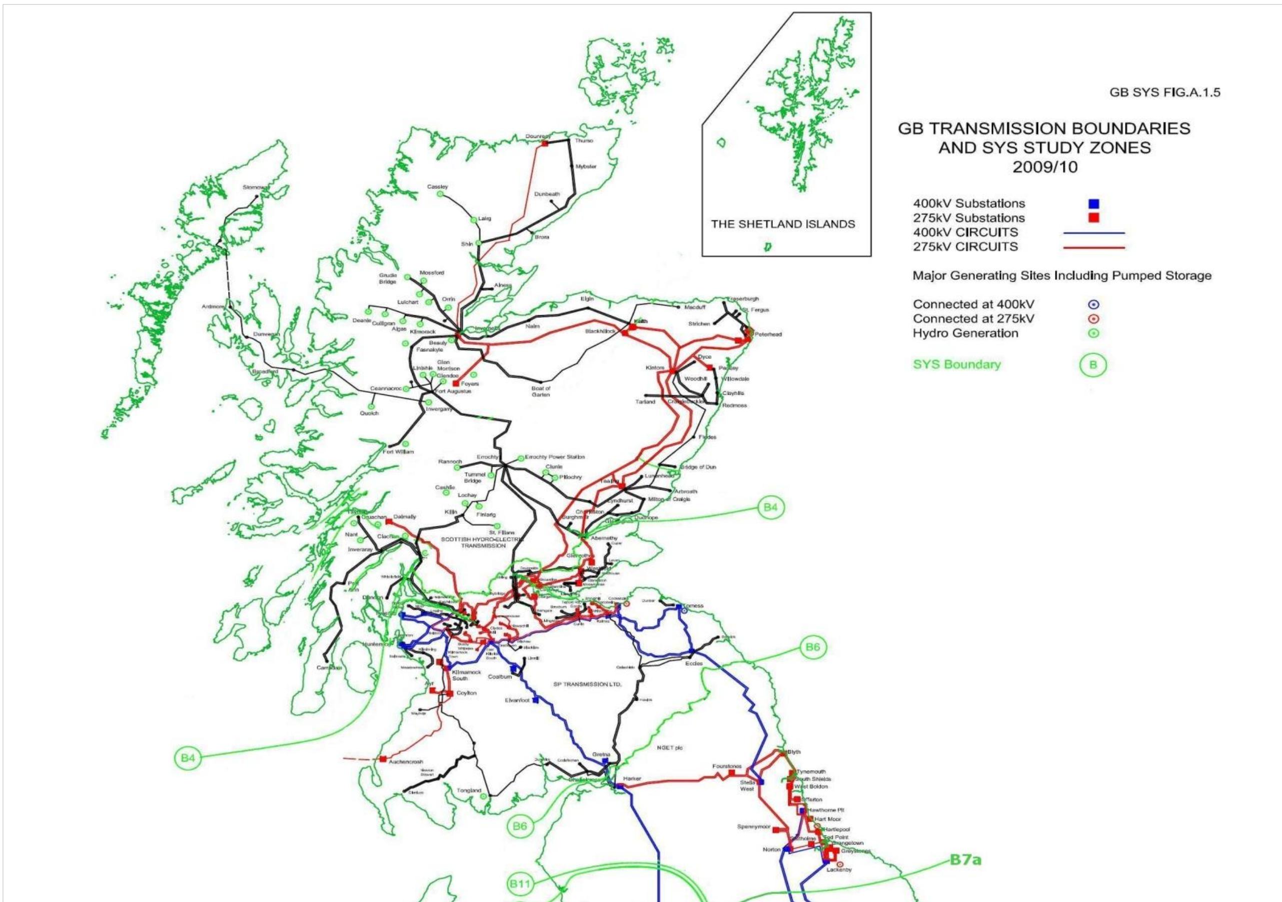
Table 26 List of available reinforcement projects

Reinforcement package	Boundaries reinforced	Cost (£m)	Earliest possible
Beauly-Denny overhead line	B1, B2, B4	Pre-committed	2014
400kV Ring Kintore Reactive Compensation	B1, B2, B4	Pre-committed	2016
Denny-Kincardine 400kV	B4	Pre-committed	2016
Western HVDC Link	B6, B7a	866	2015
Anglo-Scottish Series & Shunt Compensation	B5,B6	380	2014
Eastern HVDC Link	B2, B4, B5, B6, B7a	891	2018
Penwortham QBs	B7a	31	2014
New Hinkley Point - Seabank OHL and associated works	B13	628	2019
Reconductoring circuits in East Anglia	EC5	93	2015
New OHL & reconductoring work in East Anglia	EC5	263	2017
QBs in East Anglia	EC5	41	2015
Establish 2nd Pentir-Traw 400kv circuit	NW2	185	2016
Series compensation and reconductoring work in North Wales	NW2	103	2016
Wylfa-Pembroke 2GW HVDC link	B202,NW2	834	2018
Daines 225MVAR MSC DNs	B8,B9	5	2014
Sundon and Ratcliffe 225MVAR MSCs	B8,B9	10	2015
North London Reinforcements & St John's Wood - Hackney cable	B14	474	2016
Turn in Sundon - Cowley circuit at East Claydon	B8,B9, B14	52	2019
North East London uprate to 400kV	B15	88	2019
East London reinforcements	B15	31	2014
East London reconductoring	B15	72	2016
Kingsnorth-Cobham reconductoring	B15	21	2016
South London reconductoring	B15	77	2015
Essex reconductoring	B15	36	2015
Tees Crossing refurbishment	B7a	52	2012
QBs in Sundon-Wymondley circuits	B14	31	2015
London MSCs, East End reconductoring	B14	46	2015
New reactor at Rayleigh	B15	36	2015
Kemsley QBs	B15	31	2012
Rowdown, Canterbury, Sellinge and Dungeness reinforcements	B15	118	2019
Iver, East Claydon, Grendon & Elstree new MSCs	B8,B9	31	2015
Cottam - West Burton reconductoring	B8	5	2014

Reinforcement package	Boundaries reinforced	Cost (£m)	Earliest possible
West Weybridge 275kV additional MSC	B9,B14	5	2017
Knocknagael	B1	43	2011
Beauly-Blackhillock-Kintore	B1	88	2014
Hunterston-Kintyre link	B3, B4, B5	130	2018
East Coast Upgrade	B2, B4, B5, B6	272	2015
Humber - Walpole HVDC	B8, B9, B11	595	2020
Caithness - Moray HVDC	B1	800	2017
Eastern HVDC Link #2	B6	891	2020
Western HVDC Link #2	B6, B7a	866	2020
Elstree London	B14	100	2020
West Midlands MSC	B17	50	2015
Generic reinforcements			
B1	B1	73	2021
B2	B2	73	2021
B3	B3	110	2021
B4	B4	98	2021
B5	B5	98	2021
B6	B6	146	2021
B7a	B7a	166	2021
B8	B8	117	2021
B9	B9	234	2021
B10	B10	15	2021
B11	B11	200	2021
B12	B12	24	2021
B13	B13	332	2021
B14	B14	50	2021
B15	B15	7	2021
B16	B16	29	2021
B17	B17	100	2021
B201	B201	50	2021
B202	B202	7	2021
EC5	EC5	24	2021
NW2	NW2	49	2021

Source: National Grid.

Figure 44 GB Transmission Boundaries 2010/2011



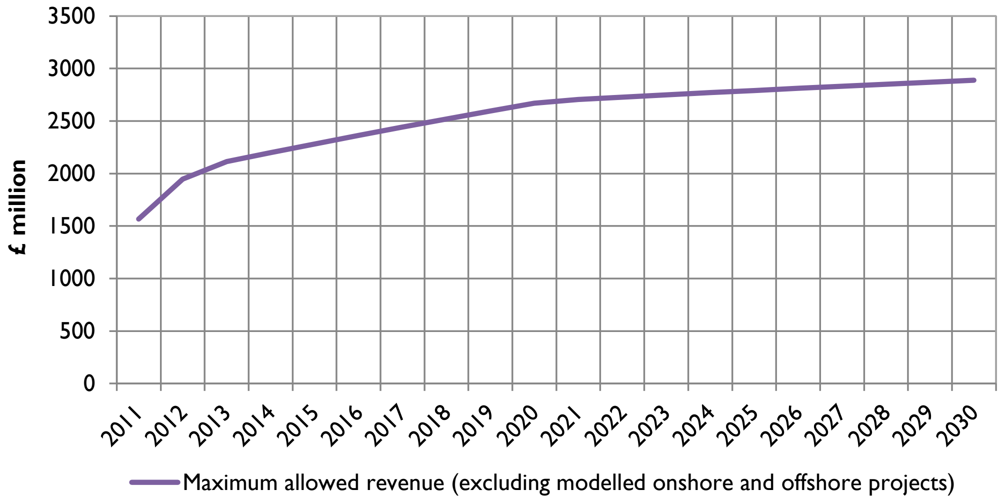
Source: National Grid, ELSI Model.

B.3.1 Background reinforcement

The cost of other work to the onshore transmission network, including repairs and maintenance to existing assets, has been estimated using public RIIO business plan submissions from the three Transmission Owners (NGET, SPT and SHETL) as follows:

- Total capital and operating expenditure allowances for the three transmission owners for the 8 years covered by the RIIO business plans were calculated
- Explicitly modelled transmission reinforcements projected to occur during the RIIO timeframe were removed from capital and operating expenditure allowances to arrive at 'net' allowances
- 'Underlying' Maximum Allowed Revenue was estimated on the basis of net capital and operating expenditure, by estimating annual depreciation and regulatory asset values
- Net capital and operating expenditure were extrapolated out to 2030 to extend underlying maximum allowed revenue estimates.

Figure 45 Annual underlying cost of onshore network



Source: Redpoint estimates, based on RIIO business plans for NGET, SPT and SHETL.

B.3.2 Offshore and island connections

All offshore transmission was assumed to be delivered through radial, point-to-point links as required to connect offshore generation capacity. The annual network cost of offshore transmission (including onshore substations) was estimated using OFTO transfer values for completed projects, and extrapolation of these results to estimate network costs for future developments. Costs for onshore substation assets, any over-specification of offshore substation assets and oversizing of cables (where this does not provide security benefits) are recovered through the residual tariff, such that 80% of the cost of offshore transmission was assumed to be passed directly to offshore generators through local tariffs under Status Quo charging[58].

[58] For example, under the worked example prepared by National Grid (updated for changes to the charging regime in July 2010), 78% of OFTO charges would be passed on to the generator and the remainder would be recovered through residual charges. Worked example available at National Grid, *Guidance Note: TNUoS charges for Offshore Generators*, http://www.nationalgrid.com/NR/rdonlyres/869AF29F-0CBE-4189-97D5-562CBD01AD86/44194/GuidetooffshoreTNUoStariffs .pdf (November 2010).

Additional wider charges were included in the total tariff for offshore generators to account for their use of the onshore network.

Table 27 Offshore wind: transmission costs

Offshore wind site	Distance offshore (km)	Annual offshore transmission network cost (£/kW)	Estimated local tariff (£/kW)
Argyll Array	5.0	29.05	23.24
Beatrice	15.0	37.10	29.68
Docking Shoal Windfarm	20.0	41.13	32.91
Forth Array	21.2	42.10	33.68
Greater Gabbard Extension	36.0	54.03	43.22
Gwynt Y Mor	13.0	61.54	49.23
Humber Gateway Stage 1 + 2	8.0	84.37	67.50
Inch Cape	16.0	37.91	30.33
London Array	20.0	87.55	70.04
Neart na Gaoithe	15.0	37.10	29.68
R3 Bristol Channel	25.0	38.84	31.07
R3 Dogger Bank	197.2	158.18	126.54
R3 Firth of Forth	77.0	74.88	59.90
R3 Hastings	19.8	35.24	28.19
R3 Hornsea	99.5	90.47	72.38
R3 Irish Sea	37.7	47.64	38.11
R3 Moray Firth	27.5	40.57	32.46
R3 Norfolk	54.4	59.21	47.37
R3 West of Isle of Wight	21.4	36.34	29.08
Race Bank Windfarm	27.0	96.62	77.30
Triton Knoll	33.0	51.61	41.29
West of Duddon Sands	15.0	76.01	60.80
Westernmost Rough	8.0	31.46	25.17

Sources: Redpoint estimates, based on results of OFTO transfer values for completed transitional tenders as of October 2011 (Robin Rigg, Walney 1, Gunfleet Sands and Barrow) from Ofgem, and distances offshore from 4C Offshore, *Global Offshore Wind Farms Database*, http://www.4coffshore.com/windfarms/.

For the purposes of TransmiT modelling, we modelled three distinct island groups: Orkney, Shetland and Western Isles. The cost of island wind transmission was assumed to be entirely recovered through charges to generators under Status Quo and Improved ICRP charging (Table 28). Note that the tariffs below are the island components only – they do not include the mainland part of the tariff. The total tariff faced by an island generator is the sum of the island tariff and the tariff for the relevant mainland zone.

Table 28 Island wind: transmission costs

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	400	450	1.8	1.0	121	67

Sources: Redpoint estimates, based on capex and capacity figures from SHETL public RIIO business plan. The tariffs shown 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.

As noted in Section 3, there are differences in charges for island connections between Status Quo and Improved ICRP, due to differences in security factors assumed for these links. We based this on advice from NGET on which of these island groups would likely become part of the Main Interconnected Transmission System (MITS) in future as island links are built. Those island groups that are assumed to become part of the MITS (Orkney and Western Isles) would likely form their own TNUoS zones with significantly higher tariffs than the nearest mainland zone. The impact of these island groups forming their own zones is that the expansion cost of the island link is multiplied by the wider security factor of 1.8[59]. For Shetland, the island link is assumed to be treated as a local connection and the security factor is assumed to be 1.

Under Improved ICRP, the Technical Working Group recommended an option which set the security factor to 1 for the non-redundant elements of island transmission. We have assumed that the security factor for the entire link is set to 1 in all cases.

B.3.3 Interconnectors

Interconnection capacity assumptions were assumed exogenously and provided by Ofgem (Table 29). Total interconnector capacity reaches 9 GW in 2035.

Table 29 Interconnector assumptions

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	2012
GB-BE (Belgium)	1	2017

[59] Note that the re-zoning was not modelled explicitly in the Transport Model. We modelled the islands links as local assets and used the security factor to account to for the re-zoning. This approach gives an identical numerical result in the instance of a single radial connection.

GB-FR (France - additional)	2 x 1	2018 and 2022
GB-IE (Ireland - additional)	1	2020
GB-NO (Norway - additional)	1	2025

Sources: Ofgem

B.3.4 Bid/offer spreads

Generator bid/offer spreads are an important input into constraint cost modelling. The bid price represents the price a generator pays to reduce generation to relieve a constraint and the offer price the price a generator receives to increase generation. We used absolute values for renewables and peaking plant, with the bid prices representing the opportunity cost of lost payments of low carbon support (as these are based on generation output). For CCGTs, coal and nuclear we used multipliers on the short run marginal costs of these generators.

Table 30 Generator bid/offer spread assumptions

Plant type	Bid price £/MWh	Offer price £/MWh	Bid SRMC multiplier	Offer SRMC multiplier
CCGT			0.6	1.5
Coal			0.6	1.5
Nuclear			0	1.5
Oil	0	300		
OCGT	0	300		
Onshore wind	-40	-		
Offshore wind	-80	-		
Wave	-120	-		
Tidal	-120	-		
Dedicated biomass	-20	-		

Sources: Redpoint

C Additional results

Additional numerical results of the modelling are included in the associated Excel file, published alongside this report. This file contains supporting data and results from the analysis undertaken, and is provided to aid understanding of the modelling approach and results.

The TNUoS charges presented are the result of a modelling exercise and are not forecasts of future TNUoS charges.

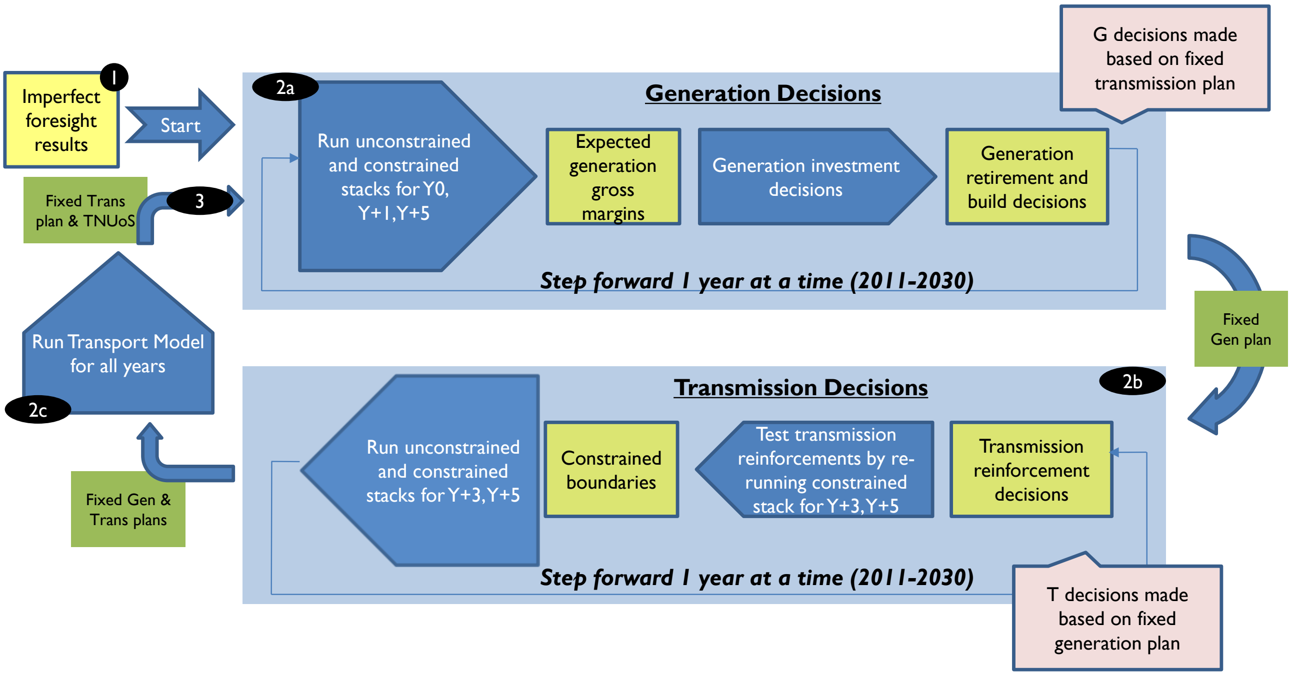
For each model run, the following results are included:

- TNUoS charges for Generation and Demand, by zone
- Generation data including capacity and generation of each technology by region
- Modelled transmission reinforcements
- Other key metrics

D Perfect Foresight modelling

The analysis presented in this report is based on an imperfect foresight approach. An alternative approach was tested, which we refer to as Perfect Foresight. Under Perfect Foresight, each of the three key components (Transport model, generation decisions and transmission decisions) has a full view of the results of the other two components.

Figure 46 Perfect Foresight modelling methodology



This requires an iterative approach as shown in Figure 46 and described below.

1. Imperfect Foresight results are used as a starting point for the Perfect Foresight model
2. Run the three model components iteratively in the order below
    a. Generation investment/retirement decisions (2011-2030)
    b. Transmission investment decisions (2011-2030).
    c. Transport model (2011-2030)
3. Begin the next iteration, using the results of step 2 as inputs
4. Run until model converges (generation and transmission investment decisions are stable) or max of 5 iterations

In addition to the iterative approach described above, the key differences in the Perfect Foresight approach are that generators have perfect foresight on future TNUoS, and transmission investment decisions are made with a perfect view of the generation capacity in the forward years.

Note that foresight is unchanged in a number of areas not related to transmission charging, for example the forward view of commodity prices is unchanged.

D.1 Perfect foresight results

Perfect Foresight was run for the three charging options under Base Case assumptions, with a Stage 1 approach to low carbon support (CfD strike prices are the same across all three options)

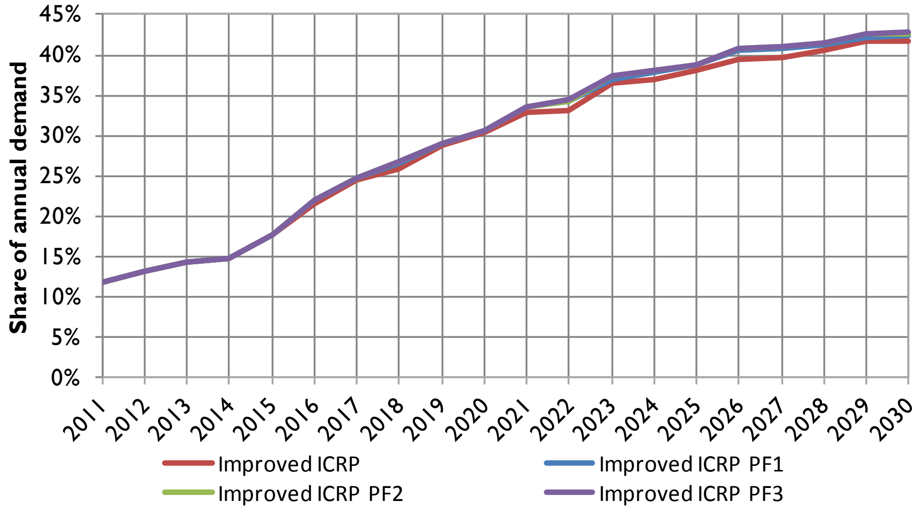
We find that Perfect Foresight produces convergent results on two of the three options: Improved ICRP and Socialised. For each of the charging options we demonstrate the amount of convergence through comparison of outputs that might be expected to change: renewables proportion, transmission investment and constraint costs.

D.1.1 Improved ICRP

Improved ICRP Perfect Foresight was run for three iterations, for which some convergence was observed, with no significant differences between iterations.

Figure 47 shows the total renewables generation, which is slightly higher for the Perfect Foresight iterations than for the Imperfect foresight starting point. The changes are an increase in generation from biomass but a small decrease in onshore wind in northern Scotland. Between the perfect foresight iterations the renewables deployment does not vary significantly.

Figure 47 Renewables generation: Improved ICRP Perfect Foresight



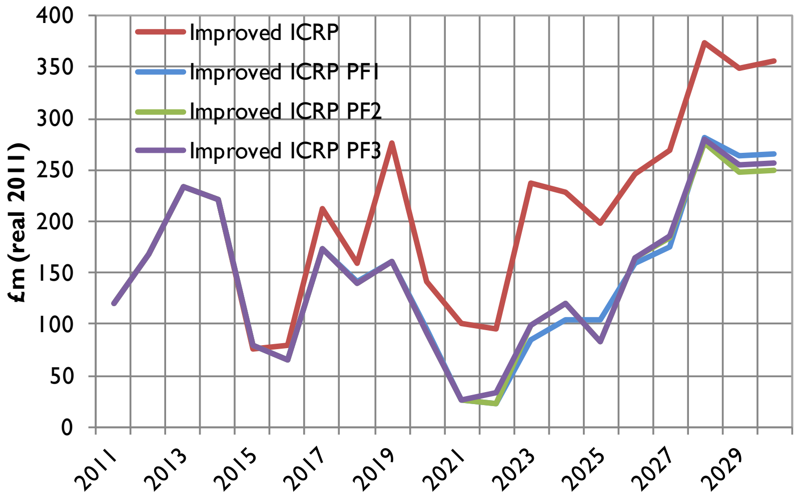
The changes in HVDC transmission reinforcements between iterations are small, as shown in Table 31.

Table 31 HVDC reinforcements: Improved ICRP Perfect Foresight

Reinforcement	Boundaries	Improved ICRP	Improved ICRP PF1	Improved ICRP PF2	Improved ICRP PF3
Western HVDC Link	B6, B7a	2015	2015	2015	2015
Western HVDC Link #2	B6, B7a	2020	2020	2020	2020
Eastern HVDC Link	B2, B4, B5, B6, B7a	2018	2018	2018	2018
Eastern HVDC Link #2	B2, B4, B5, B6, B7a	2024	2025	2025	2025
Wylfa-Pembroke 2GW HVDC link	B202, NW2	-	-	-	-
Caithness - Moray HVDC	B1	2020	2019	2019	2019
Humber - Walpole HVDC	B8, B9, B11, B16	2027	2025	2025	2025

Constraint costs are lower for Perfect Foresight (due to the reduction in northern Scotland onshore wind build) but do not vary significantly between the iterations of Perfect Foresight.

Figure 48 Constraint costs: Improved ICRP Perfect Foresight



It is clear from these results that Improved ICRP comes close to convergence but does not reach full convergence. Between Perfect Foresight iterations, changes in timing of retirements and investments for thermal capacity do occur, but have limited directional effect on the overall results. The results are similar to the starting point of the Improved ICRP Stage 1 result but are not identical.

D.1.2 Socialised

We observe complete convergence in Perfect Foresight results under Socialised, however there are differences from the Imperfect Foresight results. Figure 49, Table 32, and Figure 50 show the renewables proportion, HVDC transmission reinforcements and constraint costs respectively. In each case there is some change between the Imperfect Foresight and Perfect Foresight results. The significant changes in the Perfect Foresight results are a reduction in onshore wind in Scotland and an increase in biomass which, along with some earlier HVDC reinforcements, leads to lower constraint costs in some years

There is no difference between any of the Perfect Foresight iterations – they immediately converge to a single result.

Figure 49 Renewables generation: Socialised Perfect Foresight

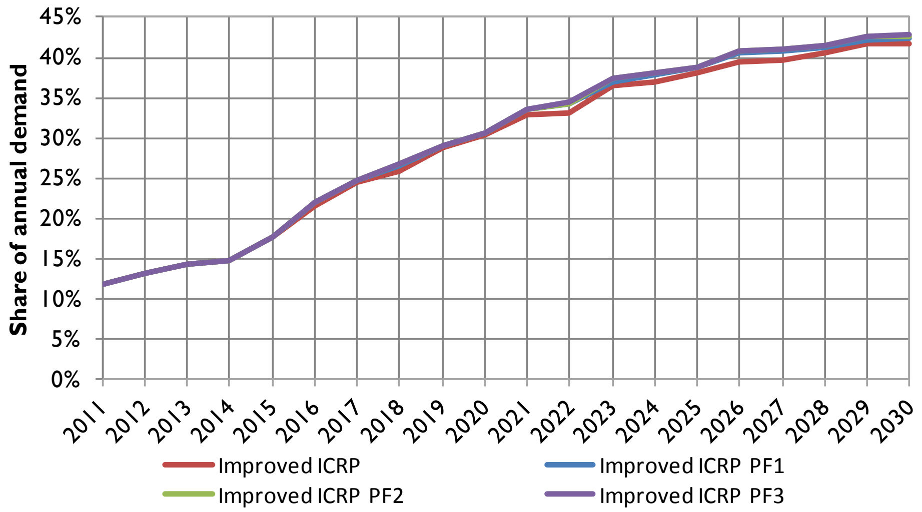
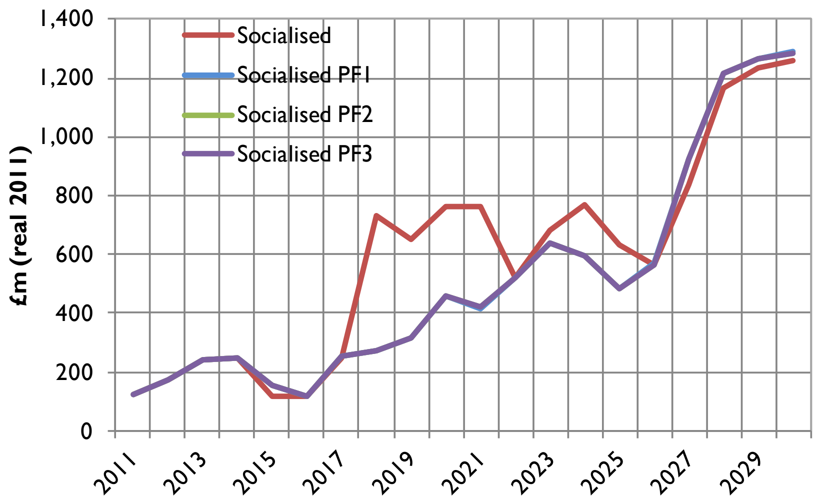


Table 32 HVDC reinforcements: Socialised Perfect Foresight

Reinforcement	Boundaries	Socialised	Socialised PF1	Socialised PF2	Socialised PF3
Western HVDC Link	B6, B7a	2015	2015	2015	2015
Western HVDC Link #2	B6, B7a	2022	2022	2022	2022
Eastern HVDC Link	B2, B4, B5, B6, B7a	2022	2019	2019	2019
Eastern HVDC Link #2	B2, B4, B5, B6, B7a	2025	-	-	-
Wylfa-Pembroke 2GW HVDC link	B202, NW2	-	-	-	-
Caithness - Moray HVDC	B1	2022	2019	2019	2019
Humber - Walpole HVDC	B8, B9, B11, B16	2023	2020	2020	2020

Figure 50 Constraint costs: Socialised Perfect Foresight

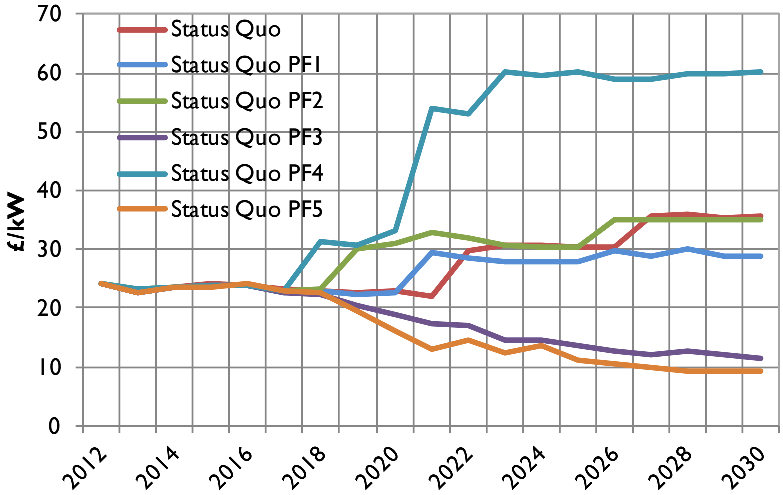


Under Socialised charging, we expect the feedback between Perfect Foresight iterations to be weaker, because tariffs are not sensitive to the location of generation. Because future Socialised tariffs are relatively stable, knowledge of future tariffs does not change expectations of generator profitability and therefore generation investment does not change.

D.1.3 Status Quo

Under Status Quo, the Perfect Foresight iterations do not converge to a single result. In fact the differences between consecutive iterations increase in later iterations. Analysis of the results suggests that the major driver of differences is the interaction between wind build in Scotland and HVDC reinforcement of Scottish & Northern England boundaries. The feedback is through the mechanism of changing generator TNUoS in Scotland. Figure 51 shows the tariffs for Northern Scotland in the Perfect Foresight iterations. The differences between Perfect Foresight (PF) iterations is reasonably small for the first two iterations, but from Status Quo PF3 the differences between consecutive iterations is large.

Figure 51 Northern Scotland generator TNUoS: Status Quo Perfect Foresight



The low tariff for Status Quo iteration 3 is passed through as the starting point for iteration 4 generation investment decisions. The low tariff encourages more build of wind in Scotland. This higher wind deployment leads to additional HVDC reinforcement in iteration 4 compared to iteration 3 (Table 33) as well as higher constraint costs (Figure 53). When tariffs are recalculated in iteration 4, the additional HVDC bootstraps cause Scottish generator tariffs to be higher. In iteration 5 this discourages Scottish onshore wind build, leading to a result that is similar to iteration 3.

Figure 52 Renewables generation: Status Quo Perfect Foresight

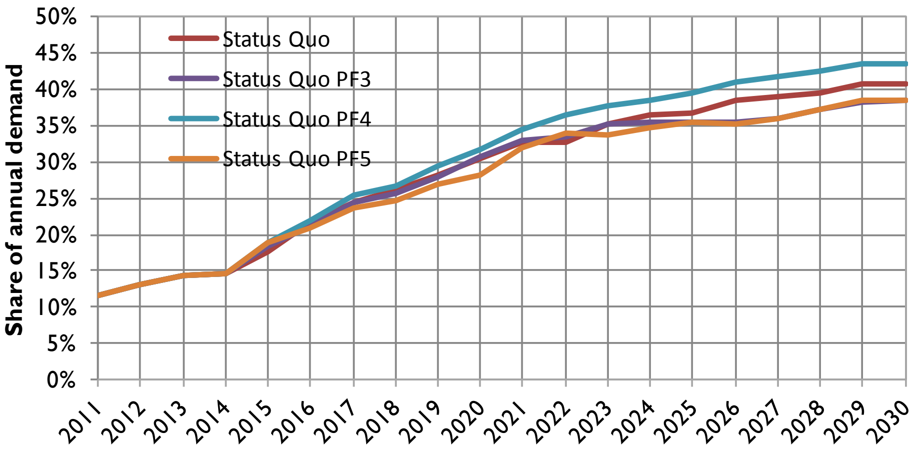
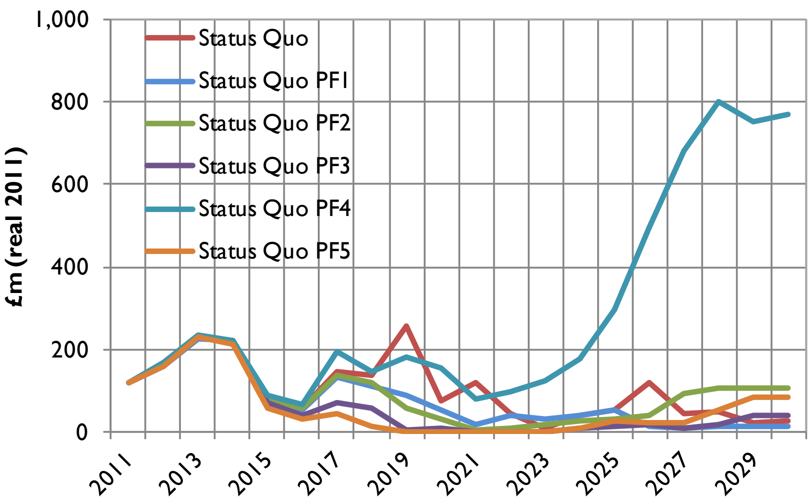


Table 33 HVDC reinforcements: Status Quo Perfect Foresight

Reinforcement	Boundaries	Status Quo	Status Quo PF1	Status Quo PF2	Status Quo PF3	Status Quo PF4	Status Quo PF5
Western HVDC Link	B6, B7a	2015	2015	2015	2015	2015	2015
Western HVDC Link #2	B6, B7a	2023	2026	2021	-	2020	-
Eastern HVDC Link	B2, B4, B5, B6, B7a	2022	2021	2019	-	2018	-
Eastern HVDC Link #2	B2, B4, B5, B6, B7a	2027	-	2026	-	2023	-
Wylfa-Pembroke 2GW HVDC link	B202, NW2	-	-	-	-	-	-
Caithness - Moray HVDC	B1	-	-	-	-	2021	-
Humber - Walpole HVDC	B8, B9, B11, B16	-	-	-	-	2023	-

Figure 53 Constraint costs: Status Quo Perfect Foresight



This analysis suggests that further iterations would demonstrate similar or greater levels of divergence between consecutive iterations. We note that the two extremes of Status Quo Perfect Foresight results are above and below the Imperfect Foresight world in term of renewables (specifically Scottish wind).

In summary the Perfect Foresight analysis showed that where convergence occurred the results were similar to the Imperfect Foresight results. Compared to Imperfect Foresight, the convergent results indicate lower constraint costs in some years as transmission investment is brought forward and Scottish wind build reduces slightly. Under Status Quo where convergence did not occur, the Imperfect Foresight result sits between the extremes of the Perfect Foresight iterations.