WIDER SYSTEM AND DISTRIBUTIONAL IMPACTS OF RECOVERING BALANCING SERVICES COSTS FROM DEMAND

June 2021

CONTENTS

1 INTRODUCTION

Balancing Services Use of System (BSUoS) charges are the means by which the Electricity System Operator (ESO) recovers the costs associated with balancing the electricity transmission system. It is made up of several elements including constraint costs, frequency response services, provision of reserve, the costs of actions taken in the Balancing Mechanism and the ESO's internal costs.

Under the current arrangements, BSUoS charges allocate the cost of the balancing services to demand and transmission connected generation (TG) on the basis of a per unit energy charge (£/MWh) set ex post. Interconnectors, small distributed generators (SDG) and behind the meter generators (BTMG) do not pay BSUoS. BTMG are also able to help load avoid the charge. In principle, this creates a competitive disadvantage to TG relative to other supply sources which could result in distortions to dispatch and investment in the wholesale electricity market.

In November 2018, Ofgem asked the ESO to launch the Balancing Services Charges Task Force to examine potential reforms to BSUoS charges. The task force concluded that BSUoS should be treated as a cost recovery charge and recommended that:

- BSUoS should be recovered from "Final Demand" i.e. it should no longer be recovered from TG in line with other supply sources;
- that the charges should be fixed in advance with a combined notice period of 14-15 months; and
- ESO should manage the forecast risk associated with fixing the charge.[1]

Ofgem accepted that the task force made a good case for reform but highlighted the need for more work to quantify the costs and benefits. The industry is now developing options in line with the task force recommendations through the code modification process:

- CMP308 – Removal of BSUoS charges from generation and recovering all costs from final demand.
- CMP361 – Introduction of an ex ante fixed BSUoS tariff.

Ofgem has commissioned Frontier Economics and Lane Clark and Peacock (LCP) to carry out an analysis of the wider system and distributional impacts of the reforms to inform Ofgem's assessment of the options in this process. The analysis in this report is focused on the wider system and distributional analysis associated with CMP308. Our analysis which is of more relevance to CMP361 will be set out in a separate report.

We carry out the assessment in two stages:

- **Stage 1: System and consumer impact analysis** – we examine the implications of the reform, and in particular the levelling of the playing field

[1] First task force report http://www.chargingfutures.com/media/1348/balancing-services-charges-task-force-final-report.pdf; Second task force report http://www.chargingfutures.com/media/1477/second-balancing-services-charges-task-force-final-report.pdf

between TG and other supply sources, for the total costs[2] of operating the electricity system and costs to consumers up to 2040. This assessment is based on system modelling using the Envision model.

- **Stage 2: Bill impact analysis –** we assess the potential impact on bills for a number of different representative domestic, commercial and industrial user archetypes, consistent with those that we developed for Ofgem as part of our earlier analysis for the Targeted Charging Review (TCR). We first consider a static analysis in which we assess the direct impact of the change in BSUoS incidence on different end users. Then we calculate the impact on users after market changes identified in our system modelling, the most significant being changes to wholesale prices and low carbon support payments.

We note that throughout this quantitative analysis, we have had to make numerous simplifications and assumptions. For example, when assessing future system or customer costs, assumptions are required on factors such as commodity prices and renewables build out. Where we believe that assumptions are key to understanding the results in this report, we have set out the basis for our analysis. Similarly, impacts for different user archetypes will be a function of a number of site specific factors, particularly for larger customers, which it is not possible to capture in the bill impact analysis and therefore, modelled impacts should only be considered illustrative to provide the broad direction of the expected impacts.

Finally, in relation to the analysis in this report, it is our view that quantitative modelling should not be the sole (or in many cases even principal) basis for determining whether particular modifications to a charging regime are appropriate and that a qualitative assessment against clear criteria is of critical importance.

This report is structured as follows:

- In **Section 2**, we set out the quantitative modelling of the system and consumer impacts using Envision.
- In **Section 3**, we set out the quantitative assessment of the static and dynamic distributional impacts for different types of users.
- In **Section 4**, we set out the implications of this analysis for Ofgem.
- Finally, in **Section 5**, we set some key limitations of our analysis.

[2] In common with our analysis of the Targeted Charging Review, we have not sought to quantify explicitly network costs, as to do so would rely on too many assumptions regarding the location of changes in use to render the analysis meaningful.

2 MODELLING OF WIDER SYSTEM AND CONSUMER IMPACTS

In this section, we look at the potential impact that recovering BSUoS entirely from demand could have on the wider system, and understand the impacts that this might have on aggregate consumer welfare.

2.1 Methodology and Assumptions

Changes to the charging arrangements for BSUoS will remove the competitive disadvantage faced by TG relative to interconnectors and SDG, which will have an impact on the system-wide generation mix in the short term by directly affecting plant dispatch and operation. In the longer term, this will impact plant investment and retirement decisions. These changes will affect many areas of the market and have the potential to impact overall system and consumer costs.

LCP's EnVision model, a fully integrated model of the GB power market, which models these direct and indirect effects, has been deployed to assess the impact on system and consumer costs. EnVision was originally developed to model the impact of the UK government's Electricity Market Reforms and was used to undertake the impact analysis for the Embedded Benefits Review.

The model simulates wholesale market dispatch at a granular, half-hourly level, taking into account plant dynamics and constraints such as start costs and ramp rates. It also estimates the revenues available to plant through participation in ancillary markets, including the provision of reserve and balancing services.

EnVision models investment decisions using an agent-based approach, which includes detailed simulations of the annual Capacity Market (CM) auctions. For the purposes of this modelling, non-CM build (e.g., most renewable generation that is supported through other subsidy schemes) and interconnection are held constant between the Counterfactual and Factual scenarios.

We use the LCP EnVision model to examine the impact of changes to network charging arrangements on the following key aspects:

- The economics of different types of generation (transmission-connected, distribution-connected and onsite);
- Changes to the capacity mix;
- CM clearing prices;
- Loss of Load Expectation (LOLE);
- Wholesale prices;
- Carbon emissions;
- Overall system costs; and
- Consumer cost.

It is important to note that relying on modelling outputs as the sole, or potentially even main, basis for changes to charging arrangements has its limitations. While the EnVision model attempts to replicate the decisions made by market participants, it does so against the background of many input variables (e.g., fuel costs, plant capital costs, and demand). The modelling we have undertaken requires inputs for the future value of these inherently uncertain variables. Changes in these inputs and to other modelling assumptions will have potentially significant effects on the results. Therefore, the modelling results should be seen as an indication of the potential direction and broad magnitude of impacts.

We specify our modelling scenarios and key input assumptions in the sub-sections below.

2.2 Modelling scenarios

In the modelling, we compare:

- the Counterfactual where BSUoS is recovered from both TG and demand based on a per unit energy charge (£/MWh) set ex post.
- a Factual scenario where BSUoS is fully recovered from suppliers on a variable £/MWh basis. This would place all generation sources that are not behind the meter (including interconnection) on a "level playing field" in terms of not being exposed to BSUoS. Behind the meter generation (BTMG) would continue to benefit from reducing BSUoS exposure for load, and this benefit would increase (roughly doubling) relative to the counterfactual.

The analysis is conducted using both National Grid's FES 2020 Steady Progression (SP) and Consumer Transformation (CT) market backgrounds, which provide assumptions for projections of commodity prices, demand, low-carbon build and interconnector build.

These core modelling scenarios are summarised in Figure 1.

Figure 1 Core Modelling scenario runs

Scenario	FES 2020 Background	BSUoS assumption
Counterfactual	Steady Progression	Ex post £/MWh charge on final demand and TG
Factual	Steady Progression	Ex post £/MWh charge on final demand
Counterfactual	Consumer Transformation	Ex post £/MWh charge on final demand and TG
Factual	Consumer Transformation	Ex post £/MWh charge on final demand

Source: Frontier/LCP

2.3 Key modelling assumptions

In this section, we explain the key assumptions used in our modelling.

2.3.1 Market background assumptions

Assumptions for commodity prices, demand and the build-out of low-carbon and interconnection are taken from the FES 2020 scenarios (CT and SP). See Annex C for more detail.

The build-out of Capacity Market technologies, including CCGTs, gas peaking plant and battery storage are modelled endogenously through the simulation of the capacity auctions. The cost assumptions used for these technologies, including capital expenditure (capex), operating expenditure (opex) and hurdle rates are taken from BEIS's 2020 electricity generation cost projections.

For the purposes of our system cost analysis, we do not quantify the network cost impacts as they are highly sensitive to changes in the assumed build locations of new plant.

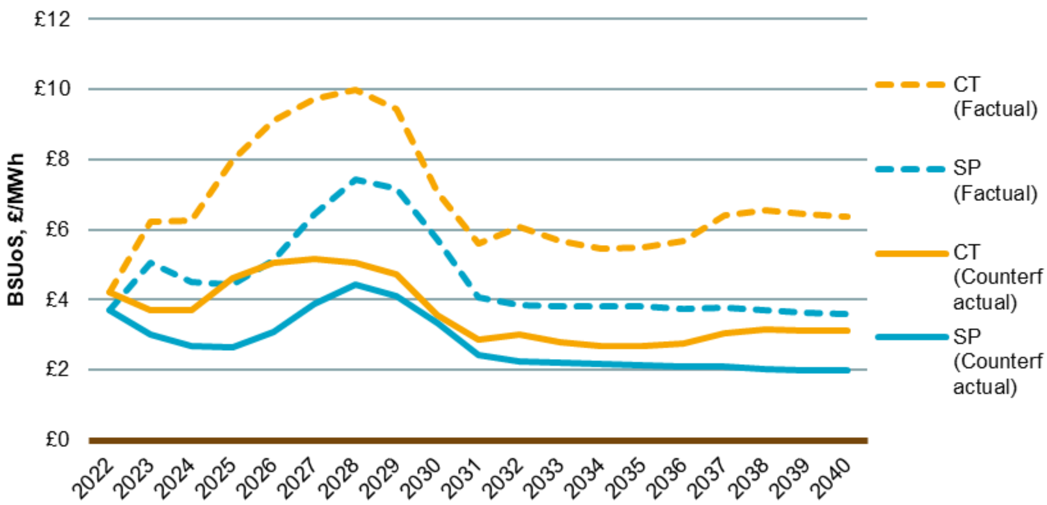
2.3.2 BSUoS assumptions

Our annual BSUoS cost projections have been developed based on three components:

- Thermal constraint costs based on annual projections provided by NG ESO.
- Non-thermal constraint costs based on the same profile, but assuming that thermal rises from 40% of total constraints costs to 75% over the 2022-2026 period.
- Other BSUoS costs based on current levels, scaled in line with total demand in real terms.

The charges used in the four scenario runs are shown below.

Figure 2 Per MWh BSUoS charges in the four scenario runs



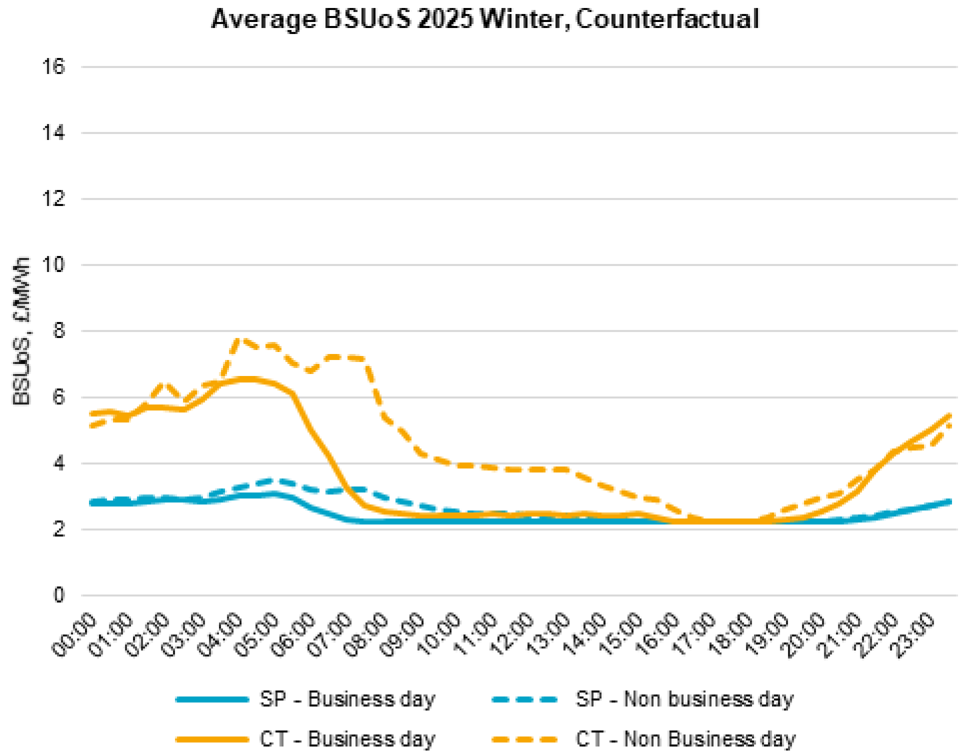
BSUoS charges in the Factual scenario are much higher due to the smaller charging base. In Steady Progression and early years of Consumer Transformation, Factual charges are less than double (1.6-1.8 times) the Counterfactual charges. This is because the generation charging base in the Counterfactual is smaller than the demand base and therefore was recovering less than half of the costs. In later years of Consumer Transformation, charges in the Factual scenario are more than double those in the Counterfactual, as the generation charging base is slightly higher than the demand base due to significant interconnection exports resulting in higher domestic generation.

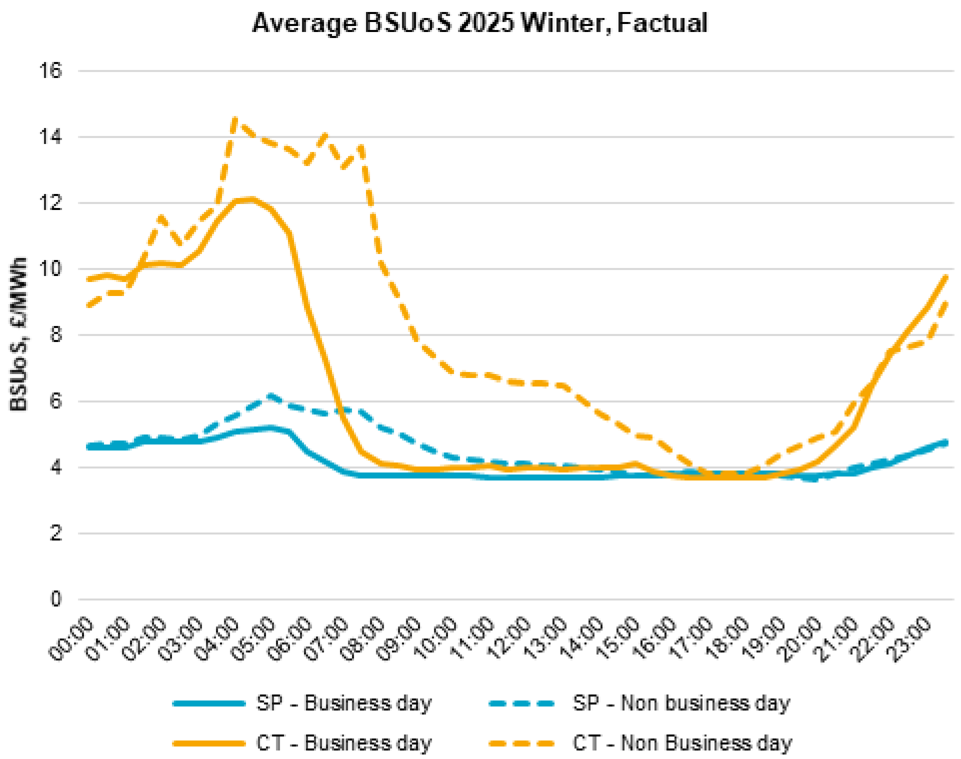
In addition to the annual projections, we also estimate how BSUoS charges vary within the year. BSUoS charges, particularly constraint costs, tend to be much higher during periods of high renewable and must-run generation and low demand. During these periods, expensive actions need to be taken to resolve both thermal and system constraints on the system, including turning down wind and turning up thermal generation.

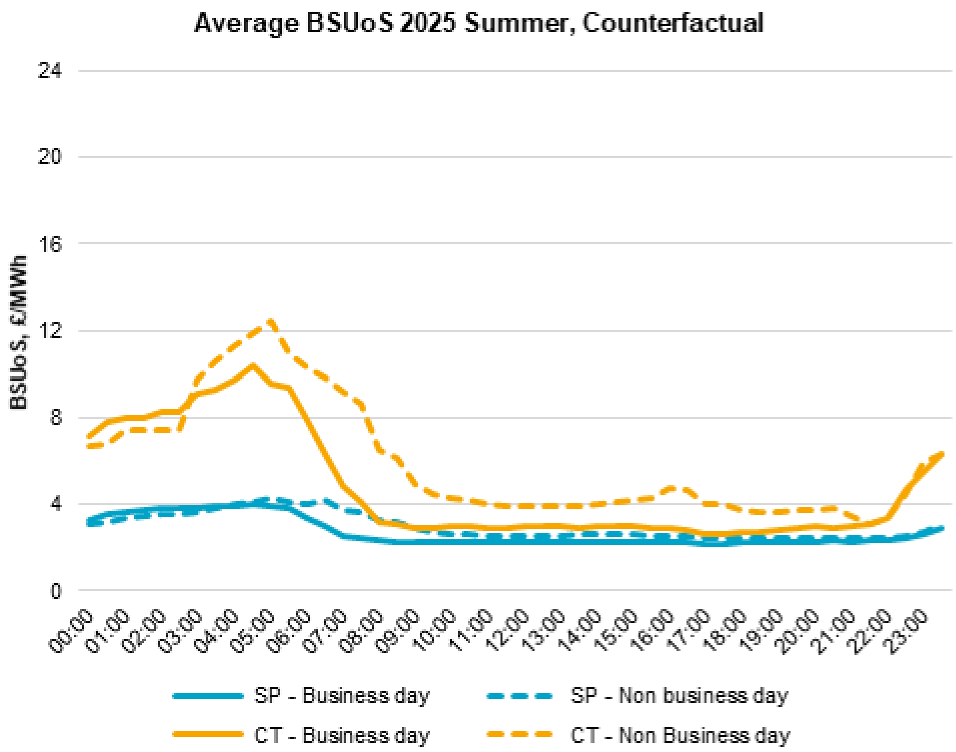
To estimate this, we establish a relationship between BSUoS charges and residual demand (demand net of must-run and intermittent generation), with high BSUoS charges during periods of low residual demand. This relationship is then calibrated so that the average BSUoS charges across the year align with the annual projections shown above.

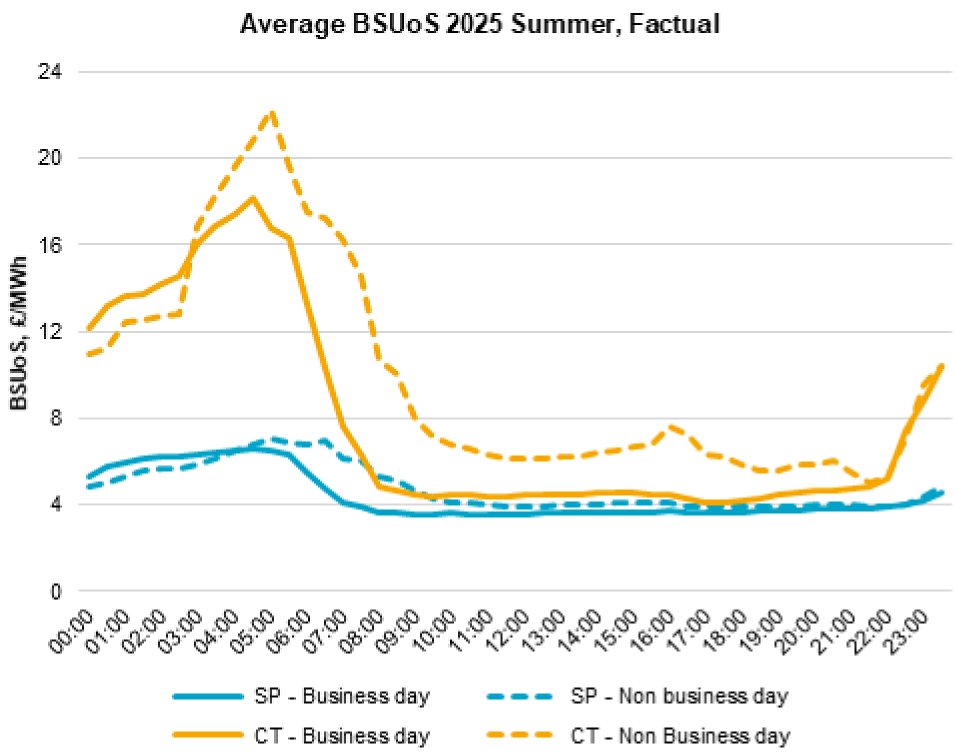
The average BSUoS charges by period assumed for two example seasons in 2025 are shown below.

Figure 3 BSUoS charges by period for 2025









Across all charts, BSUoS charges are higher in Consumer Transformation due to higher renewable penetration resulting in higher constraint costs, as assumed in the projections provided by NGESO. These higher charges are concentrated in overnight and weekend periods where the charging base is lower, and costs are higher as renewables make up a higher proportion of generation. For example, in summer 2025, average BSUoS charges peak at over £20/MWh at 5 am on weekends in the Factual scenario and £12/MWh in the Counterfactual.

In general (and as seen in the 2025 examples above), charges follow the same pattern in the Factual and Counterfactual scenarios (with costs occurring in essentially the same periods) but are typically 1.5 to 2 times higher in the Factual due to the smaller charging base. BSUoS charges per MWh are also typically higher in summer, when the charging base is lower and renewable generation makes up a higher proportion of generation.

2.4 Modelling results

In this section, we discuss the modelling results for each FES background in turn.

- Subsection 2.4.1 outlines the modelling results for the Steady Progression FES scenario.
- Subsection 2.4.2 outlines the modelling results for the Consumer Transformation FES scenario.

2.4.1 Results – Steady Progression

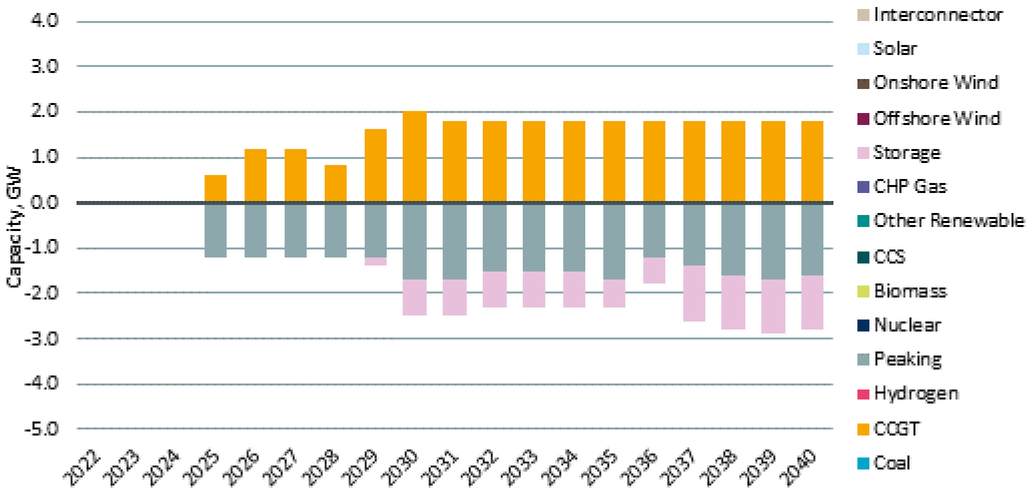
Capacity breakdown

Figure 4 below shows the difference in installed capacity between the Counterfactual and Factual scenario under the Steady Progression background.

In the Factual case, transmission-connected CCGT benefits from the removal of BSUoS charges, resulting in an increase in new capacity. This displaces distribution-connected gas peaking and battery storage, who do not pay BSUoS in the Counterfactual and therefore do not benefit from the change.

It is assumed that the current GB security standard (LOLE of 3 hours per year) is maintained throughout the modelling period (though with some prudence factored into the capacity requirement calculation) and that the current Capacity Market regime endures. This means that the level of system security is maintained at similar levels throughout the period. Note that more nameplate capacity is displaced than added in this scenario due to the low derating factors for displaced battery storage.

Figure 4 Capacity (Factual – Counterfactual), Steady Progression



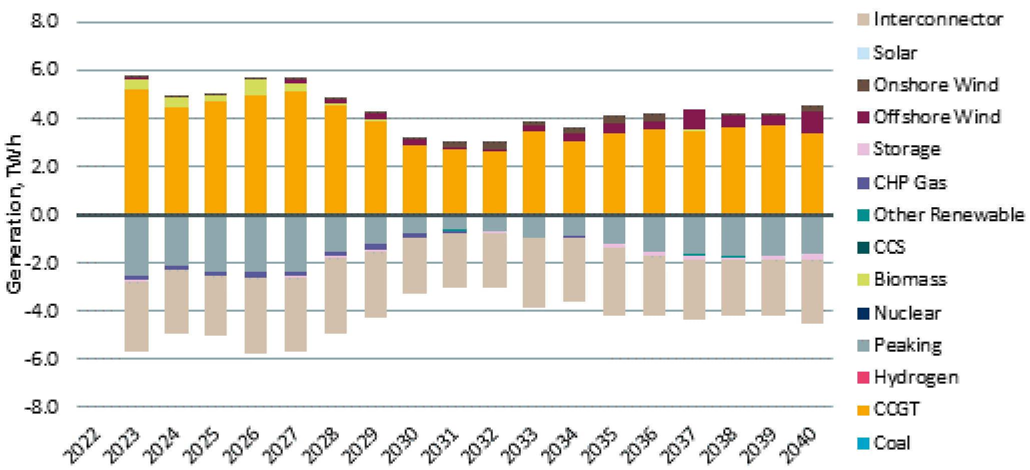
Source: LCP/Frontier

Generation breakdown

Figure 5 below shows the change in generation between the Counterfactual and Factual scenario under the Steady Progression background.

The largest increase in generation comes from existing and new transmission-connected CCGTs, which benefit from the removal of BSUoS charges. There are also increases in generation for the biomass conversions (particularly in the period up to when support ends in 2027) and transmission-connected offshore and onshore wind. These increases predominantly displace distribution-connected gas peaking and interconnection flows, neither of which benefit from the removal of BSUoS charges.

Figure 5 Generation (Factual – Counterfactual), Steady Progression



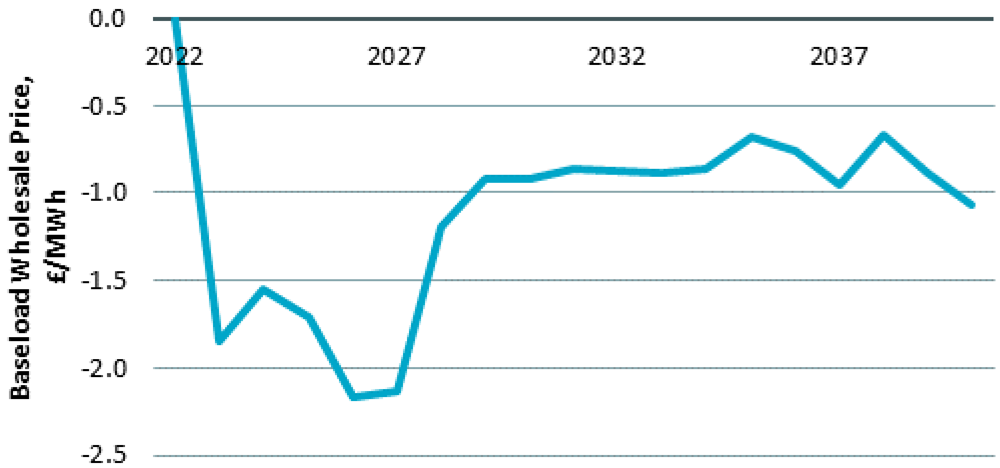
Source: LCP/Frontier

Wholesale prices

Figure 6 below shows the change in baseload wholesale prices between the Counterfactual and Factual scenarios.

In the Factual case, wholesale prices decrease as a result of the reforms, as generators who previously paid BSUoS no longer pass this cost through in their wholesale market bids. However, the pass through of BSUoS charges into the wholesale price is well below 100% (and in fact below 50% in later years), as transmission-connected generation is not always the marginal source of generation. In other words, if the marginal generator does not pay BSUoS, there is no change in wholesale prices when BSUoS is removed. This means that in general, the decrease in baseload wholesale prices is less than the increase in the average BSUoS charge.

Figure 6 Baseload Wholesale Price (Factual – Counterfactual), Steady Progression



Source: LCP/Frontier

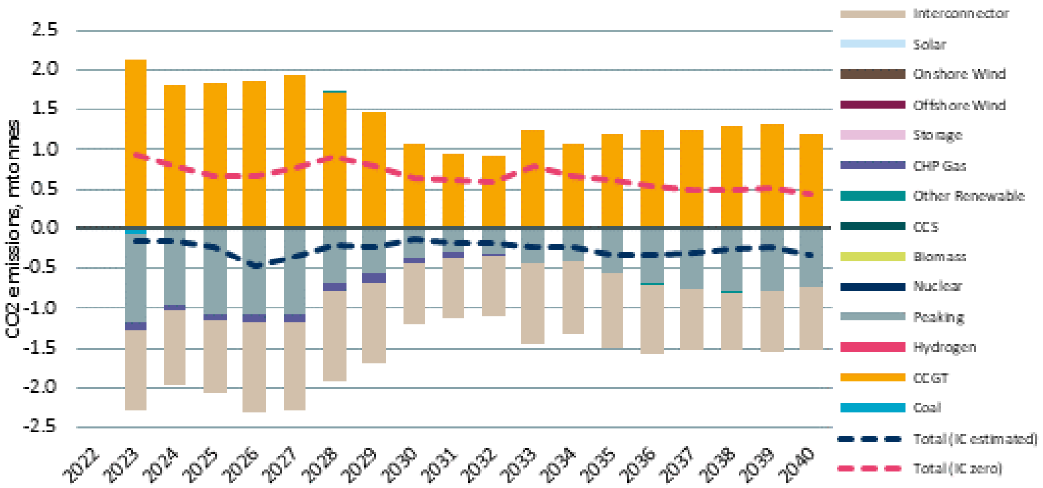
CO_2 Emissions

Figure 7 below shows the difference in annual CO_2 emissions between the Counterfactual and Factual scenarios.

With interconnector flows treated as zero-emission, total carbon emissions increase due to the decrease in net interconnector imports being primarily offset by an increase in CCGT generation. However, if the emissions associated with IC flows are estimated[3] and valued, then emissions decrease in the Factual case, partly due to increased renewable generation from biomass conversions, and partly due to more efficient CCGT displacing less efficient distribution-connected gas generation.

[3] Estimated in the modelling based on assuming the interconnector flows have the same carbon intensity as the nearest domestic generator within the GB merit order.

Figure 7 CO_2 Emissions (Factual – Counterfactual), Steady Progression



Source: LCP/Frontier

System Costs

Figure 8 below shows the change in modelled system costs between the Counterfactual and Factual scenarios.

The proposed reform results in a system benefit of £490m (2022-2040 NPV, using a 3.5% social discount rate). The system benefit results from more efficient dispatch and investment in the Factual scenario, with all generation (including interconnection) now on a level playing field in terms of BSUoS charges.

The change in system costs reflects a small switch in investment from distribution connected peaking plants to transmission connected CCGT, although the overall impact of this switch is small, and positive in some years and negative in others. The most significant impacts relate to the cost of producing energy. The increase in the cost of generation from new and existing domestic CCGT, is more than offset in most years by significant reductions in the cost of imports.

Given the importance of the cost of imports it is worth setting out how these are estimated. We take the average of two different approaches to estimating the cost of imports in the Counterfactual and Factual scenarios:

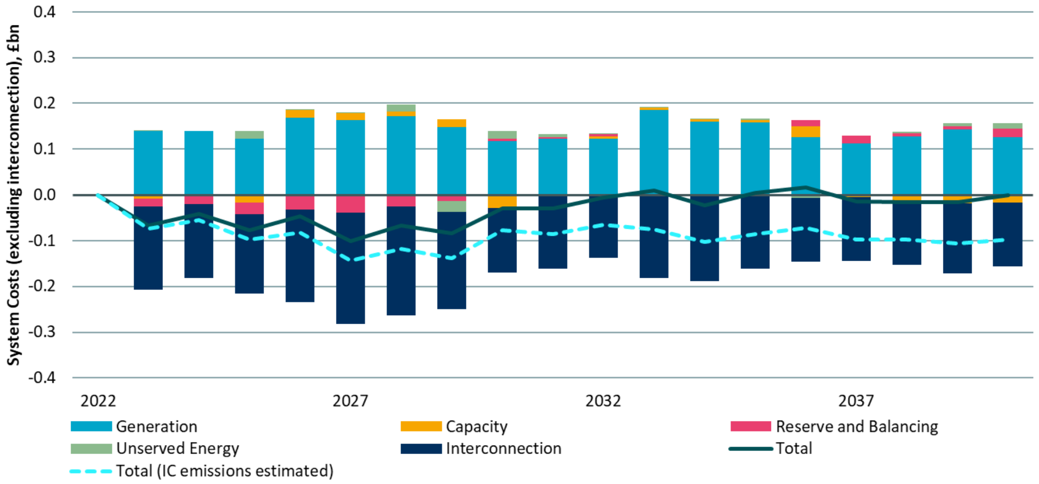
- *First approach* - each interconnector is assumed to be part of the GB power system, and therefore the associated system costs consist of its capex and opex costs and the costs or revenues related with the purchase or sale of its power in the foreign market (at the foreign market's wholesale power price).
- *Second approach* - each interconnector is assumed to be outside of the GB power system, and therefore the associated system costs consist of the costs or revenues related with buying or selling power from or to the interconnector in GB (at the GB wholesale power price), as well as any Capacity Market payments made to the interconnector.

Under the first approach, the capex and opex do not change between the Counterfactual and the Factual and similarly, under the second approach, the capacity payments do not change. Therefore, the reduction in import costs are related to:

- the lower volume of imports valued at the foreign wholesale price (which does not change between scenarios) under the first approach; and
- the lower volume of imports valued at the GB wholesale price, which itself is lower due to the CMP308, under the second approach.

This benefit increases significantly to £1.2bn if emissions associated with interconnector flows are estimated and those emissions are costed at the same level as emissions from a domestic generator (using BEIS carbon appraisal price rather than NGESO FES 2020 projection of EU-ETS market price).

Figure 8 System Cost (Factual – Counterfactual), Steady Progression



Source: LCP/Frontier

Consumer Cost

Figure 9 below shows the change in modelled consumer costs between the Counterfactual and Factual scenarios.

The proposed reform results in consumer benefits of £370m (2022-2040 NPV, 3.5% discount rate). This is due to the increase in direct BSUoS costs for suppliers being outweighed by savings in other costs which are passed through to consumers, including wholesale costs, low carbon support payments and CM payments.

The year-to-year benefits are quite volatile, mainly as a result of the CM payments. CM clearing prices generally decrease but can spike up due to the timing of new build, because the new CCGT build does not always occur in the same year as the distribution-connected new build it displaces.

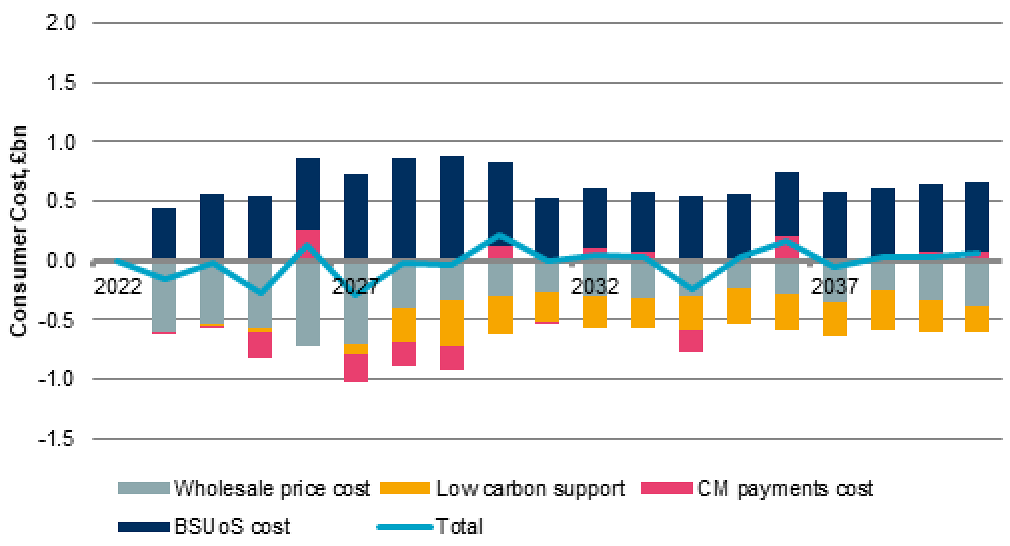
A significant share of the reduction in consumer costs relates to adjustments to low carbon support payments for contracted and new-build plants:

- We assume CfD strike prices for any contracted plant paying BSUoS charges will be adjusted down when its BSUoS charges are removed, and this adjustment outweighs any increase in top-up payments due to lower wholesale prices. It is also worth noting that since the current annual strike price adjustments are currently based on a volume-weighted annual average BSUoS charge, the adjustment will affect different plant in different ways, as, for example, wind-weighted average BSUoS charges tend to be significantly higher than the volume-weighted average charges.

- We also assume that new CfD build (that doesn't currently have a contract) will factor lower BSUoS costs into their CfD AR bids, resulting in lower strike prices.

Overall, these consumer benefits are at a similar level to the system benefits, suggesting a large proportion of the system efficiency gains are passed on to the consumer rather than being retained by producers.

Figure 9 Consumer Cost (Factual – Counterfactual), Steady Progression



Source: LCP/Frontier

2.4.2 Results – Consumer Transformation

Capacity breakdown

Figure 10 below shows the difference in installed capacity between the Counterfactual and Factual scenario under the Consumer Transformation background.

The Consumer Transformation scenario shows a similar result to Steady Progression. Transmission-connected CCGTs benefit from the removal of BSUoS charges, resulting in an increase in new CCGT capacity. This displaces distribution-connected gas peaking and battery storage. Note again that more nameplate capacity is displaced than added due to the low deratings for battery storage.

Figure 10 Capacity (Factual – Counterfactual), Consumer Transformation

Source: LCP/Frontier

Generation breakdown

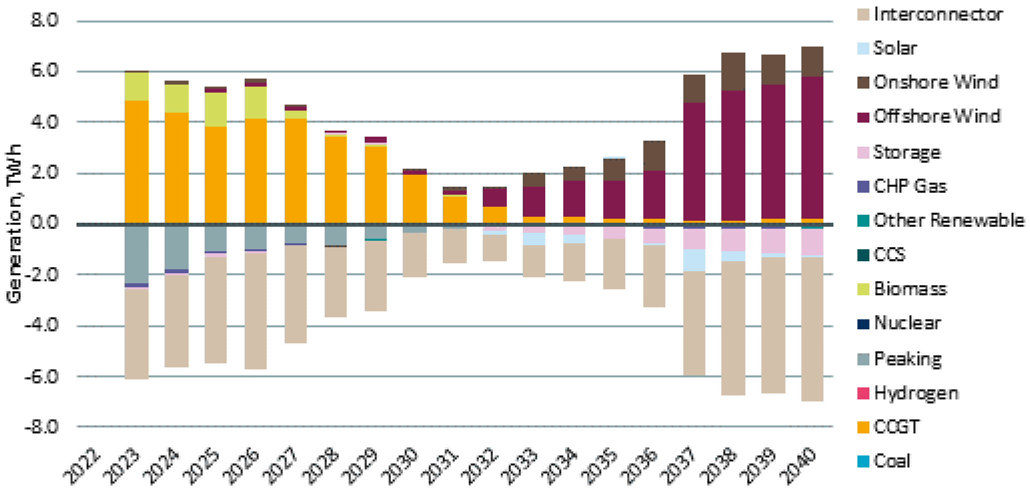
Figure 11 below shows the change in generation between the Counterfactual and Factual scenarios under the Consumer Transformation background.

In the early years, there is increased generation from transmission-connected CCGTs and biomass conversions. These increases predominantly displace distribution-connected gas peaking and interconnection flows. These results are similar to the Steady Progression background.

However, because Consumer Transformation is Net Zero consistent, by the late 2030s there is very little CCGT generation on the margin and many more periods where wind[4] or interconnection are marginal in the Counterfactual. Therefore, the effect of the reform is an increase in transmission-connected offshore and onshore wind, resulting in higher exports (shown as a decrease in interconnector generation).

[4] Although transmission connected supported wind does pay BSUoS in the counterfactual, its removal has a limited effect on bidding behaviour when it is at the margin, because going forward from the next CfD allocation round (AR4) no support payments will be made when prices are negative. Therefore, when CfD supported wind are on the margin, prices will be zero irrespective of whether transmission connected wind pay BSUoS or not. Therefore the effect of the reform is more significant when unsupported transmission-connected wind is marginal (after their support contracts end).

Figure 11 Generation (Factual – Counterfactual), Consumer Transformation



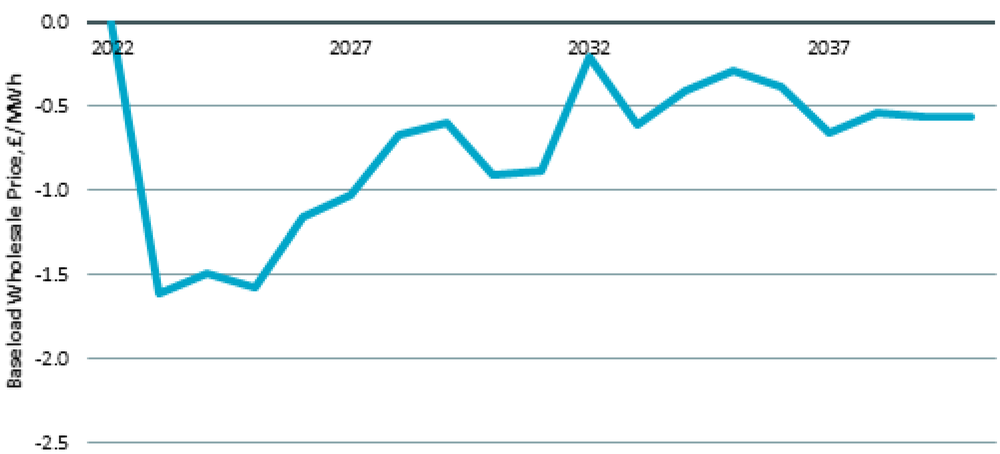
Source: LCP/Frontier

Wholesale prices

Figure 12 below shows the change in the annual baseload wholesale price between the Counterfactual and Factual scenario under the Consumer Transformation background.

Wholesale prices decrease as a result of the reforms, as generators who previously paid BSUoS no longer pass this cost through to wholesale prices. However, as with Steady Progression, passthrough is well below 100% (and below 20% in later years) as transmission-connected generation (that is not CfD supported) is rarely on or near the margin in the Counterfactual. Interconnection or CfD supported renewables are marginal in the majority of periods in later years.

Figure 12 Wholesale Price (Factual – Counterfactual), Consumer Transformation



Source: LCP/Frontier

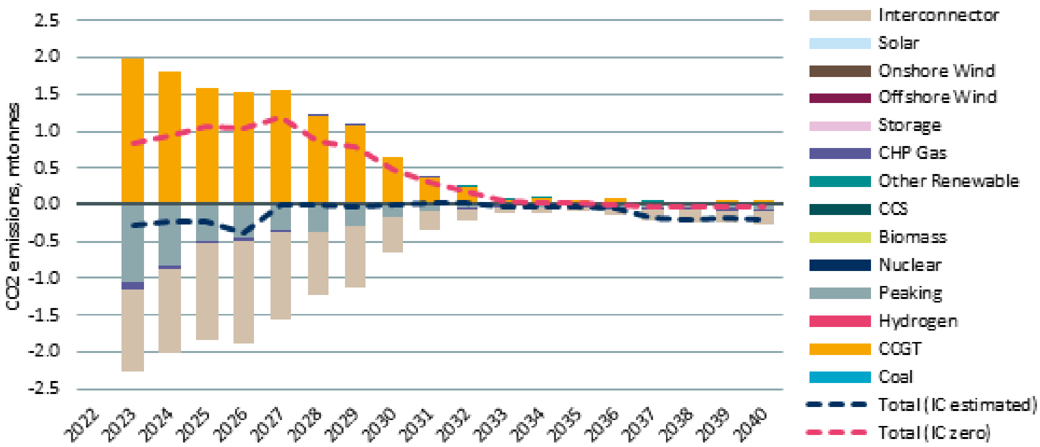
CO_2 Emissions

Figure 13 below shows the change in CO_2 emissions between the Counterfactual and Factual scenario under the Consumer Transformation background.

This shows a similar result to Steady Progression in early years, with emissions increasing if interconnectors are treated as zero emissions and decreasing if their emissions are estimated within the modelling.

In later years this Net Zero consistent scenario has very low emissions, so the reforms have little impact on total emissions.

Figure 13 CO_2 Emissions (Factual – Counterfactual), Consumer Transformation



Source: LCP/Frontier

System Cost

Figure 14 below shows the change in modelled system costs between the Counterfactual and Factual scenario under the Consumer Transformation background.

The proposed reform results in an overall system benefit of £290m (2022-2040 NPV, 3.5% discount rate). This benefit increases to £480m if emissions associated with interconnector flows are estimated and those emissions are costed in the same way as domestic generation (using the BEIS carbon appraisal price rather than NGESO FES 2020 projection of EU-ETS market price). The difference is smaller than under Steady Progression as emissions are much lower in the Consumer Transformation background scenario.

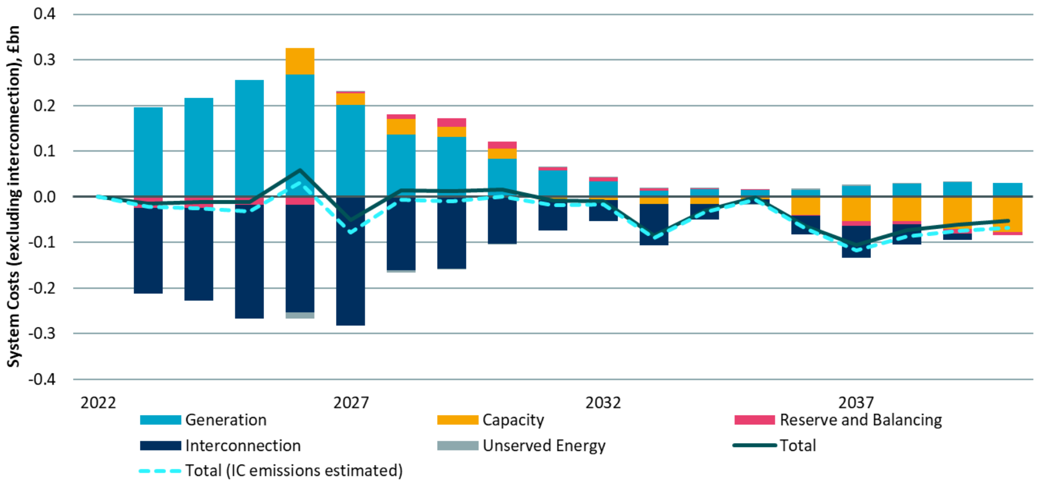
The system benefit results from more efficient dispatch and investment in the Factual scenario, with all generation (including interconnection) now on a level playing field in terms of BSUoS charges.

- In the early years, interconnector costs reduce significantly, and these slightly outweigh the increase in domestic generation costs in most years. However, savings are dampened by other distortions, such as an increase in generation from biomass conversions, which run “out of merit” due to policy support[5].
- In later years, the generation and interconnection cost changes are smaller (as low-cost renewable generation increases and net imports decrease), but there

[5] The system costs associated with supported biomass generation may be higher than the generation it displaces, due to its SRMC being lower as a result of its support payment (e.g. ROC support for biomass conversions is around £50/MWh). This is not a distortion directly created by the reform to BSUoS, but it can exacerbate an existing policy distortion as transmission-connected Biomass generation benefits from the removal of BSUoS and generates more.

are still material system benefits. There are also capacity cost savings (capex and fixed opex costs), due to the changes in investment decisions that result from the change with transmission-connected CCGT capacity replacing gas peaking and battery storage capacity. This results in a capex saving because the CCGT has a higher derating factor than the battery storage, so it displaces more nameplate capacity.

Figure 14 System Cost (Factual – Counterfactual), Consumer Transformation



Source: LCP/Frontier

Consumer Cost

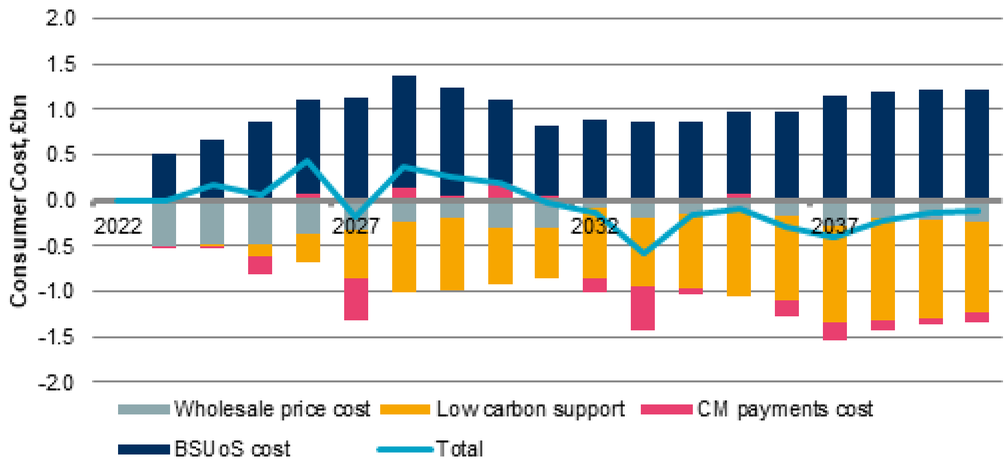
Figure 15 below shows the change in modelled consumer costs between the Counterfactual and Factual scenario under the Consumer Transformation background.

The proposed reform results in a net benefit of £320m (2022-2040 NPV, 3.5% discount rate). This benefit occurs as the increase in direct BSUoS costs for suppliers are outweighed by savings in the other costs which are passed through to consumers, including wholesale costs, low carbon support payments and CM payments. As noted under Steady Progression, the adjustment assumed to CfD strike prices to offset lower BSUoS charges, and new CfD build factoring lower BSUoS charges into their CfD strike price bids, explains the large reduction in low carbon support payments, despite lower wholesale prices.

As in Steady Progression, the year-to-year benefits are quite volatile, often as a result of the CM payments. The CM clearing prices generally decrease but can spike up due to the timing of new build, as the new CCGT build does not always occur in the same year as the distribution-connected new build it displaces.

These benefits are at a similar level to the system benefits, suggesting that most, if not all, of the system efficiency gains are being passed on to consumers rather than retained by producers.

Figure 15 Consumer Cost (Factual – Counterfactual), Consumer Transformation



Source: LCP/Frontier

2.4.3 Overview of system modelling results

Based on the system modelling results set out in this section, the removal of BSUoS from generation seems likely to have a positive impact on system and consumer benefits. NPVs for system cost benefits are £0.49bn under Steady Progression and £0.29bn under Consumer Transformation, and the NPVs for consumer benefits are £0.37bn and £0.32bn respectively. The results should only be interpreted as providing an indication of the direction and broad magnitude of impacts. In relation to consumer costs in particular, the modelling results are sensitive to modelling assumptions.

The tables below summarise the change in the system and consumer costs estimated in the system modelling between each pair of Counterfactual and Factual scenarios over the 2022 to 2040 period. We present two sets of system cost results, one with emissions associated with interconnection treated as zero, and one with the emissions associated with interconnectors estimated in the modelling and costed at the same level as domestic generation emissions.

A decrease in costs (negative value) represents a system or consumer benefit.

Figure 16 Total Cost Change, 2022-2040, £2020 real

FES scenario	System cost (£bn) IC emissions at zero	System cost (£bn) IC emissions estimated	Consumer cost (£bn)
Steady Progression	-0.59	-1.67	-0.35
Consumer Transformation	-0.48	-0.72	-0.92

Source: Frontier/LCP

Figure 17 NPV of Total Cost Change, 3.5%, 2022-2040, £2020 real

FES scenario	System cost NPV (£bn) IC emissions at zero	System cost NPV (£bn) IC emissions estimated	Consumer cost NPV (£bn)
Steady Progression	-0.49	-1.22	-0.37
Consumer Transformation	-0.29	-0.48	-0.32

Source: Frontier/LCP

3 BILL IMPACT ANALYSIS

In this section, we set out our quantitative assessment of the potential bill impacts of CMP308 for different customer types. This analysis is focused on:

- the expected "static" change in customer bills i.e. the estimated £ impact on the annual BSUoS demand charge paid by each user; and
- the expected "dynamic" change in customer bills i.e. the overall estimated £ change in the annual customer bill taking into account wider market changes in customer costs due to CMP308. We consider wider changes in:
  - wholesale prices;
  - low carbon support payments (CfDs and ROCs); and
  - capacity market payments.

It is important to note that the bill impacts illustrated in this section are based on the assumption that BSUoS costs and wider market charges under the baseline and under CMP308 are fully passed through to all consumers. As it currently stands, this may not be the case since suppliers are free to determine how they pass on charges to customers. Further, profile classes 1-4 are still settled on a non half-hourly basis, and as such, the shape of an individual domestic consumer's profile does not matter from the perspective of network charging. However, should half-hourly settlement for profile classes 1-4 be introduced, then domestic consumers with different consumption profile shapes could, where relevant, face different charges if suppliers choose to pass them through.

We have chosen user groups that reflect consumption patterns prevalent today and potentially in the future, e.g. providing for users adopting technologies (electric vehicles and heat pumps) that have the potential of meaningfully altering their level and profile of electricity consumption. This will allow us to understand the potential impacts of the charges on consumption patterns today and in the future.

This section is structured in three parts:

- We first set out our methodology for calculating the bill impacts;
- We then define a set of user groups that we have assumed are representative of particular consumer archetypes, and explain how we have derived the representative load profiles for each of these user groups; and
- Finally, for each of the user groups, we calculate the expected static and dynamic change in customer bills due to CMP308.

3.1 Bill impact methodology

To calculate the static and dynamic bill impacts, we take as an input the changes in customer costs derived from the Envision system cost modelling explained in Section 2. Specifically, we calculate the bill impacts for 2025, 2030, and 2035 for each of the two FES scenarios modelled in Envision.

For the *static* bill impacts, we build up a half-hourly profile of the change in the variable BSUoS charges, based on the Envision outputs for the 8 sample days (business and non-business days for each quarter).

For the *dynamic* bill impacts, we also include the half-hourly profile of changes in:

- wholesale prices;
- low carbon support payments (CfDs and ROCs); and
- capacity market payments.

We then apply the half-hourly values of the static and dynamic impacts to a set of user groups which we describe in the next section. In broad terms, they are based on the same user groups that we have previously used in our TCR distributional analysis and which the BSUoS taskforce has referenced in illustrating distributional impacts.

Compared to the TCR analysis, where customer annual and peak consumption were important drivers of the bill impacts, the impact of CMP308 is also closely linked to the shape of consumption throughout the day. This is because BSUoS varies by half-hour and we typically observe it to be highest overnight when system demand is low.

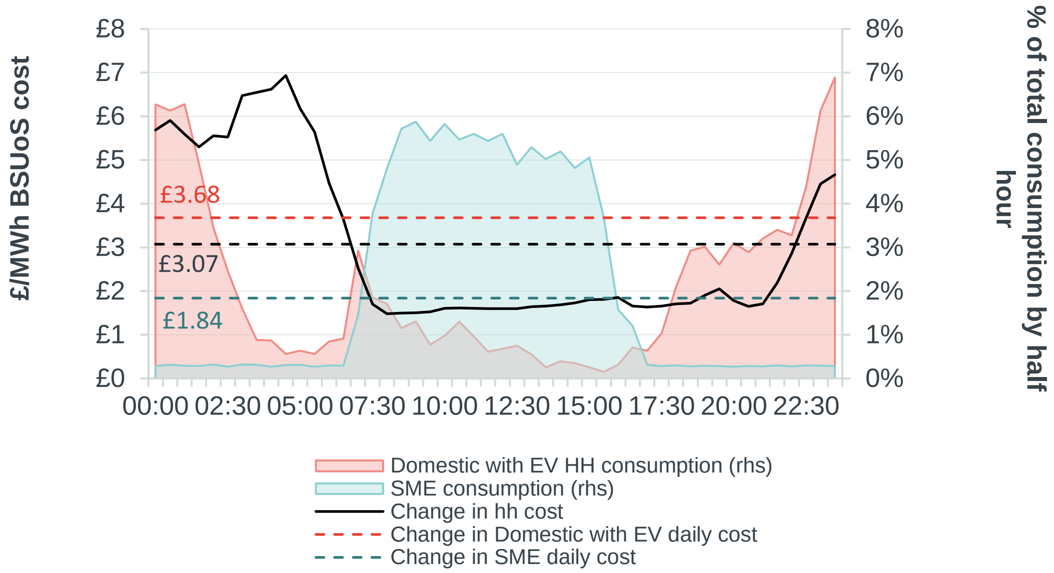
We illustrate the importance of demand shape in Figure 18, where we present two very different daily consumption profiles:

- Electric Vehicle customer (red area) where consumption, as a percentage of total daily consumption, is significant overnight; and
- Commercial customer (blue area) where consumption is more weighted to working hours.

Based on an illustrative day from the Envision outputs, the impact of CMP308 is to increase half-hourly BSUoS costs more significantly overnight (shown by the solid black line). The peak increase is around £7/MWh overnight, but for most of the daytime, the increase is less than £2/MWh. The simple average of these increases (as shown by the black dotted line) is £3.07/MWh. However, the impact is quite different for each of the two users:

- The Electric Vehicle customer's overnight peak coincides with the period in which BSUoS increases are highest, and therefore, their daily costs are increased by £3.68/MWh.
- However, the commercial customer avoids this period of high BSUoS since it barely consumes at night time, meaning that its BSUoS expenses go up by just £1.84/MWh.

Figure 18 Comparison of profiles and costs – Consumer Transformation – Spring weekday in 2030



Source: Frontier Economics analysis

In addition, offsetting dynamic impacts are also likely to have a particular shape:

- Changes in wholesale prices are concentrated in half-hours where a transmission connected generator was the marginal price-setting plant in the Counterfactual;
- Changes in low carbon support payments are spread evenly throughout all hours of the year; and
- Changes in capacity market costs are concentrated between 4-7pm, November to February.

Therefore, in order to explore the implication of different consumption profiles on the impact for different users of CMP308, we have extended the user group definition from annual and peak volumes used in the TCR, to also include a half-hourly profile. We describe in the next section the detail of how the user profiles are produced.

It is important to note that while the profiles against which we measure the impact will be applicable to some users, there is a wide variety of possible customer profile shapes within each of the user groups tested. Therefore our results should only be taken as an indication of the possible scale of any impacts. To help inform discussion of the results, for those profiles where we don't already assume a flat profile, we also present the dynamic impacts based on a simple flat profile.

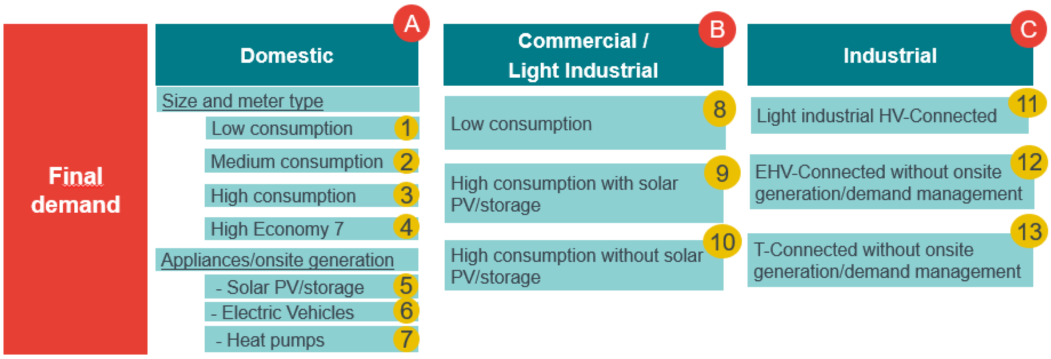
3.2 Defining a set of user groups

As noted above, we have adopted the same user groups that we have previously used in our TCR distributional analysis, and which the BSUoS taskforce has referenced in illustrating distributional impacts.

These user groups were identified in relation to a range of actual consumption profiles of different GB consumers and possible changes in consumption resulting from the installation of technologies like electric vehicles, heat pumps or onsite generation. However, it is important to note that they cannot be representative of all consumers.

The domestic, commercial and industrial user groups that we have identified are outlined in Figure 19. In total, we have identified 14 final demand user groups spread across domestic, commercial and industrial categories. It is important to note that in reality, the boundaries between users may overlap. For example, the baseline results for a larger domestic customer may be more appropriate for certain small commercial customers than our low consuming commercial user group.

Figure 19 User group classifications



Source: Frontier Economics

Note: Note that Group 5 comprises of two sub-groups: solar PV in isolation and solar PV combined with storage.

With each user group defined, we must then specify an example customer for each user group. This is what we call our ‘consumer archetypes’. The consumer archetypes that we have specified were derived in slightly different ways for each set of user groups (A, B and C) show in Figure 19.

User Groups set A

The consumer archetypes for each of the domestic user groups are outlined in panel A of Figure 19. These were developed based on a combination of:

- **Ofgem’s Typical Domestic Consumption Values (TDCVs)**: TDCVs identify the “low”, “medium” and “high” consumption levels[6] for domestic GB electricity consumers (Profile Class 1 and Profile Class 2) and are commonly used to derive typical consumer bills when the actual consumption level is not known.
- **Customer-Led Network Revolution (CLNR) data**: The CLNR trials collected electricity consumption and generation profiles of 13,000 domestic and commercial customers. The CLNR data provides the actual consumption levels

[6] “The median or second quartile is a more representative of the typical “medium” usage. We use the first and third quartiles to represent the typical “low” and typical “high” usage respectively. In real terms, if consumers were ranked in order of energy consumption, the lower quartile reflects the annual consumption that only 25% of all consumers use less than. The higher quartile reflects the annual consumption that only 25% of all consumers use more than.” Ofgem. Decision on revised Typical Domestic Consumption Values for gas and electricity and Economy 7 consumption split. 3 august 2017. Available here: https://www.ofgem.gov.uk/system/files/docs/2017/08/tdcvs_2017_decision.pdf

and patterns of GB domestic and commercial consumers, controlling for changes in consumption resulting from the adoption of technologies like solar panels, electric vehicles and heat pumps.[7]

Domestic users

The annual consumption levels of the first four domestic user groups (Groups 1-4 in Figure 19) are defined with reference to Ofgem's 2020 TDCV values.[8] As part of the TCR work we identified user profiles with annual gross consumption close to the 2017 TDCV values from which we calculated the required peak consumption information. However, as noted above, the impact of the BSUoS charges will also depend on the half-hourly shape of consumption throughout the year. We, therefore, extracted more detailed profile information from the same user profile used for the TCR, and then scaled the consumption to match the consumption of the 2020 TDCV values.

This process gives generic domestic load profiles, which are a horizontal S shape i.e. lower during the first half of the day and peaking in the evening.

Domestic users with low carbon technologies

To test the impact of different domestic technologies, we develop a series of domestic profiles assuming the adoption of solar PV and/or storage, electric vehicles and heat pumps (Groups 5-7 in Figure 19). The CLNR dataset has information on users with low carbon technologies (LCT) that shows the consumption level both with and without the LCT. We have selected example users from these data sets that have gross consumption, excluding the LCT, similar to that of the medium TDCV. We have then scaled the net consumption of these users by the ratio of their non-LCT consumption and 2,900 kWh per year to make them broadly comparable to the medium domestic user with no LCTs. As a result, while the majority of the difference between the medium user (group 2) is due to the addition of the LCT, there may also be some small differences due to differences in the underlying non-LCT gross consumption shape.

For domestic customers with Solar PV (Group 5a), this results in a 'U shaped' load profile with low net consumption in the hours where solar generation is high (approximately between 0800hrs and 1600hrs) on average.[9]

For domestic customers with Solar PV and Storage (Group 5b), the addition of electricity storage allows a further reduction in users' net electricity consumption. This further reduction in net demand is focused on the evening period from 1600-2200 in spring, summer and autumn.

For domestic customers with an EV (Group 6) the addition of the EV increases annual net demand by around 50%. The data available shows that this increase in demand is focused in the evening and early at night.[10]

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[7] CLNR. Developing the smarter grid: the role of domestic and small and medium enterprise customers. 2015.

[8] https://www.ofgem.gov.uk/system/files/docs/2020/01/tdcvs_2020_decision_letter_0.pdf

[9] On average, we note that in summer solar output will likely be higher and cover a larger portion of the day.

[10] We note that the CLNR dataset was compiled a few years ago. However, the EV charging load profile remains comparable to recent load profiles published for the UK, although we recognise that the CLNR profile may not have captured the latest V2G or smart charging technologies.

For domestic customers with a heat pump (Group 7) the addition of the heat pump increases net demand by around 80% annually and by even more in the winter months. It also significantly alters the shape of the load profile. In addition to the usual peak in the morning and evening, the load shape of consumers with heat pumps have a distinct peak in the very early morning (around 0300 hrs) attributed to hot water heating.[11]

User Group set B

For commercial/light industrial users (Groups 8 – 10 in Figure 19), we have relied primarily on the CLNR dataset to infer the level and shape of consumption for representative consumer archetypes. Commercial users who are fully reliant on grid-supplied electricity (Groups 8 and 10) register a fairly flat consumption during business hours (0600 hrs - 1800 hrs) with very limited consumption outside of this period.

When we refer to commercial users with onsite generation and storage (Group 9), we consider commercial users with onsite solar generation and battery storage. The CLNR dataset does not include any users in this group. Therefore, we derive a load profile by scaling up the solar PV generation pattern we observed for domestic users and netting this off the gross consumption of Group 10 users. High solar production during the hours of 0800 - 1600 reduces net consumption in these periods and resulted in a 'U-shaped' load curve for these customers. In addition we scale battery capacity in a similar way, which allows the commercial customer to cover their (small) overnight consumption on days where generation is especially large. We also note that naturally, the addition of PV and battery will have a larger impact on net demand in the warmer months as opposed to the colder months.

User Group set C

For the light industrial user group 11, the CLNR data does not contain users of this size. Therefore, for simplicity, we have assumed a consumption profile that is flatter than our commercial user groups but not completely flat like our large industrial users. Specifically, we assume that 50% of annual consumption occurs between 7am and 7pm on business days (which constitute around 35% of all hours), with the other 50% of consumption taking place between 7pm and 7am and during non-business days. This results in hourly consumption that is around 89% larger during these peak hours than during non-peak hours.

In relation to representative industrial user groups, because of the very significant diversity among industrial users, as part of our TCR analysis, we engaged with industrial stakeholders to develop archetypes. Guided by our discussions at that time with the Energy Intensive Users Group and based on publicly available data from BEIS and Eurostat, we assumed that a typical EHV connected user has an annual gross consumption of 50,000 MWh and a typical transmission connected user has an annual consumption of 100,000 MWh. For simplicity, we assume a

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[11] See page 11 and 12 of CLNR (2015) Insight Report: Domestic Heat Pumps, accessible here.: http://www.networkrevolution.co.uk/wp-content/uploads/2015/01/CLNR-L091-Insight-Report-Domestic-Heat-Pumps.pdf

flat profile for our industrial user archetypes, though we recognise there is a wide variety of different possible profile shapes.

We also recognise that many large users can reduce their gross consumption using onsite generation and demand management. Sites with baseload generation (e.g. CHP), could expect to reduce their load relatively evenly throughout the year (outside of planned and unplanned outages) broadly leaving their profile shape unchanged. In the extreme, net consumption could be reduced to zero in which case the bill impact would also be zero. Alternatively, sites with flexible generation could change the shape of net consumption by reducing peak consumption.

User group summary

It is not possible to present all the details regarding the specific profiles used. However, the figure below provides a high-level summary showing:

- annual net consumption assumed for each archetype; and
- overnight net consumption (11pm to 7am), given the importance of overnight consumption to the impact of the change in the BSUoS charge i.e. those users with a higher share of consumption between 11pm and 7am will typically face a greater impact from the increase in the BSUoS demand charge.

Figure 20 Net demand and overnight consumption share for each consumer archetype

User group	Annual net demand (kWh)	Share of overnight consumption*
1. Domestic – Low consumption	1,800	21%
2. Domestic – Medium consumption	2,900	13%
3. Domestic – High consumption	4,300	16%
4. Domestic – High Economy 7	7,100	25%
5a. Domestic – Medium Solar PV	2,055	36%
5b. Domestic – Medium Solar PV with storage	1,148	43%
6. Domestic – Medium Electric vehicles	4,170	34%
7. Domestic – Heat pumps	5,447	21%
8. Commercial – Low consumption	10,000	9%
9. Commercial – High with onsite generation/storage	8,312	16%
10. Commercial – High without onsite generation/storage	25,000	10%
11. Commercial – Light industrial HV-connected	5,000,000	25%
12. Industrial - EHV-connected without onsite generation/demand management	50,000,000	33%
13. Industrial – T-connected without onsite generation/demand management	100,000,000	33%

Source: Frontier

*Note: *The proposed change has the highest upward impact between 11pm and 7am (wholesale blocks 1 and 2) for the majority of scenarios at most points in the year. Hence customers who consume a disproportionate share of their energy during this time will see marginally worse impacts.*

On this basis, the user groups (12 and 13) without onsite generation or demand management have a net consumption equal to their gross consumption.

3.3 User group impacts

We present our user group results in four sections:

- Domestic – no technologies
- Domestic with technologies
- Commercial
- Light industrial and large industrial

Each chart that we present shows for a particular FES scenario both the:

- *static* impact, illustrated by the teal bar showing an increase in customer bills due to the increase in the BSUoS charge; and
- *dynamic* impact represents the net impact after a number of other, typically, offsetting cost changes.

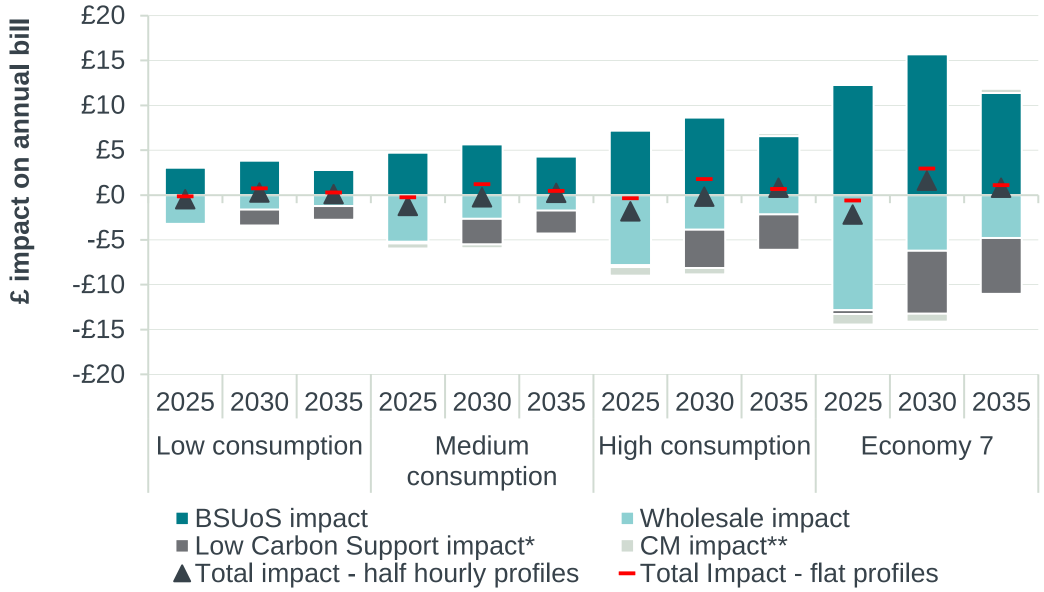
The bars show the impacts based on the assumed load profile for each user group, with the net impact after dynamic changes illustrated by the triangular marker. As noted in the methodology as a sensitivity, we also illustrate the net impact after dynamic changes assuming a simple flat consumption profile, as shown by the red dash added to each set of bars. However, it is worth emphasising that except for the large industrial profiles, for which we assume a flat profile, the bars are not consistent with the red dash as they are based on the assumed specific user profile alternative profile.

For each user group, three sets of bars are shown for 2025, 2030, and 2035.

3.3.1 Domestic customers

In this section, we focus on the four domestic load profiles without LCTs.

Figure 21 Steady Progression – Annual £ impact – Domestic



Source: Frontier Economics analysis

*Note: *Low Carbon Support includes Contracts for Difference and Renewables Obligation Certificates payments.*
***Capacity Market modelling is volatile- we have therefore taken the 5 year average of the forecast (e.g. 2025 is an average of the forecasts from 2023 – 2027 inclusive)*

CMP308 results in a direct "static" increase in the BSUoS bill for all domestic customers under the Steady Progression scenario. The increase in BSUoS peaks around 2030 in line with NGESO's projection of constraint costs, after which the completion of major new transmission network investment is expected to reduce costs. On average, over 2025-2035, BSUoS costs increase by:[12]

- £3.22 per year for a low consuming user (£1.79/MWh);
- £4.90 per year for a medium consuming user (£1.69/MWh);
- £7.46 per year for a high consuming user (£1.73/MWh); and
- £13.12 for a high consuming Economy 7 user (1.85/MWh).

The static increases in BSUoS costs are offset by falls in other costs, particularly wholesale costs and low carbon support costs, resulting in a negligible or slightly negative bill impact for all users in all years. Specifically, the results are:

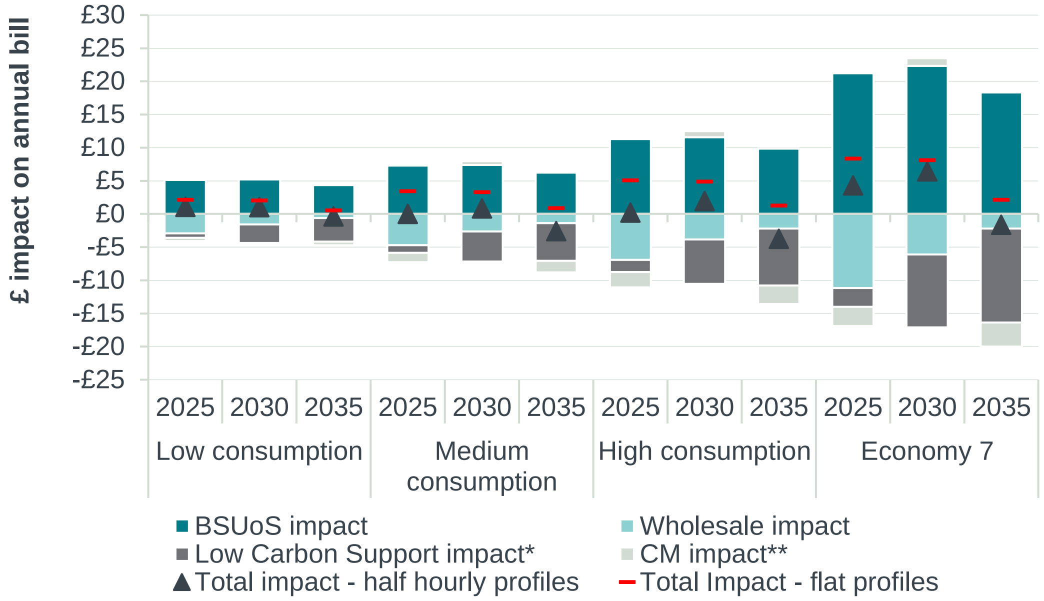
- a benefit of £0.03 per year for a low consuming customer (-£0.02/MWh);
- a benefit of £0.43 per year for a medium consuming customer (-£0.15/MWh);
- a benefit of £0.41 per year for a high consuming customer (-£0.09/MWh); and
- a cost of £0.07 per year for a high consuming Economy 7 customer (£0.01/MWh).

If we had assumed a flat domestic profile, the dynamic bill impact would have been slightly higher, given that a flat profile has more overnight consumption than typically observed for domestic customers. However, the impacts are still

[12] Note that reported annual averages are calculated as the simple average of individual annual impacts for 2025, 2030 and 2035.

extremely small, suggesting that impacts are very small irrespective of profile shape.

Figure 22 Consumer Transformation – Annual £ impact – Domestic



Source: Frontier Economics analysis

*Note: *Low Carbon Support includes Contracts for Difference and Renewables Obligation Certificates payments.*
***Capacity Market modelling is volatile- we have therefore taken the 5 year average of the forecast (e.g. 2025 is an average of the forecasts from 2023 – 2027 inclusive)*

Under the Consumer Transformation scenario, CMP308 increases the BSUoS bill for all domestic customers and this increase is more pronounced than under the Steady Progression scenario.

On average, over 2025-2035, BSUoS costs increase by:

- £4.92 per year for a low consumption user (£2.73/MWh),
- £6.98 per year for a medium consumption user (£2.41/MWh);
- £10.90 per year for a high consumption user (£2.53/MWh); and
- £20.63 for a high consumption Economy 7 user (£2.91/MWh).

As before, the static increases are largely offset by the dynamic changes in wholesale prices and low carbon support costs, resulting in small impacts of:

- a cost of £0.59 for a low consumption user (£0.33/MWh);
- a benefit of £0.58 for a medium consumption user (£0.20/MWh);
- a benefit of £0.52 for a high consumption user (0.12/MWh); and
- a cost of £3.04 for a high consumption Economy 7 user (£0.43/MWh).

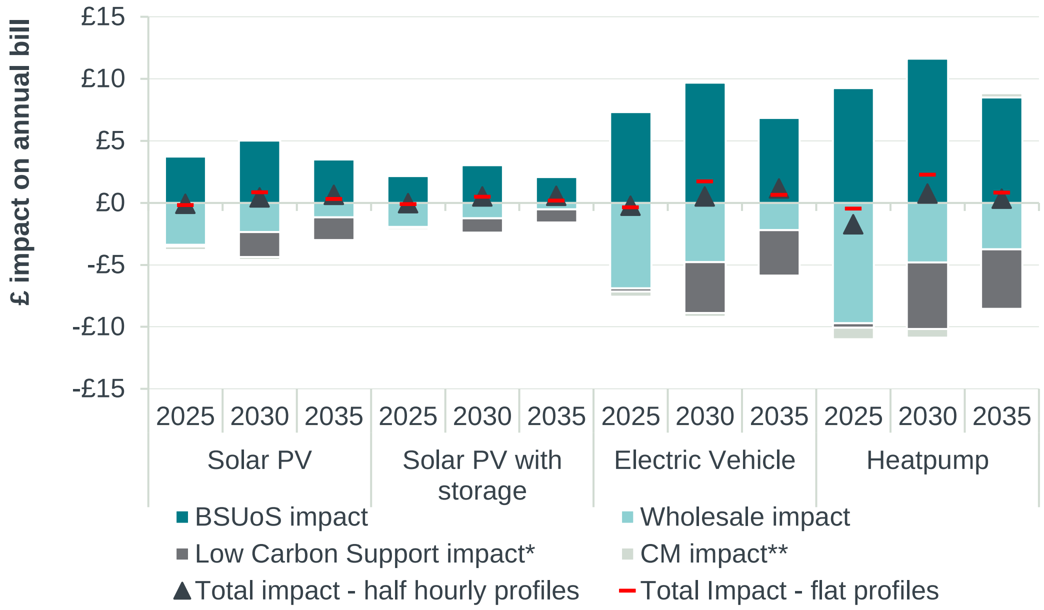
If we had assumed a flat domestic profile, the dynamic bill impact would have been slightly higher, albeit still very small, again suggesting that impacts are very small irrespective of profile shape.

It is worth noting that typically, for a given profile shape, a higher level of consumption results in a larger net impact, whether positive or negative, e.g. if the bill for a low consuming domestic customer is expected to increase slightly, the increase would be higher for a high consuming customer with the same profile. This is because the change on a £/MWh basis (whether positive or negative) should be constant, with the overall bill impact increased by the higher volume of assumed consumption. Differences in the precise shape of consumption between users add another source of variation, changing the average £/MWh impact experienced by each user, which could result in the direction of impacts changing.

In the results above, these two effects combine such that the dynamic bill impacts for the low, medium and high domestic customers are broadly similar and very close to zero. The higher cost for the E7 user reflects a different consumption profile (E7 users consume more overnight) and a higher total consumption volume compared to the other domestic users.

3.3.2 Domestic customers with low carbon technologies

Figure 23 Steady Progression – Annual £ impact – Domestic with low carbon technologies



Source: Frontier Economics analysis

*Note: *Low Carbon Support includes Contracts for Difference and Renewables Obligation Certificates payments.*
***Capacity Market modelling volatile- we have therefore taken the 5 year average of the forecast (e.g. 2025 is an average of the forecasts from 2023 – 2027 inclusive)*

CMP308 results in a direct "static" increase in the BSUoS bill for each of the user groups under the Steady Progression scenario. This increase is greater for customers with electric vehicles and heatpumps than for an equivalent medium sized domestic user. This is because heat pumps and EVs drive up net consumption for these user groups. Conversely, the impact on households with solar or solar and a battery, which reduce net consumption, is smaller. On average, over 2025-2035, BSUoS costs increase by:

- £4.09 for a domestic user with solar PV (£1.99/MWh);

- £2.42 for a domestic user with solar PV and storage (£2.11/MWh);
- £7.96 for a domestic user with an EV (£1.91/MWh); and
- £9.80 for a domestic user with a heatpump (£1.80/MWh).

This compares to a £4.90 increase in BSUoS costs for a medium domestic user with no LCTs.

These increases in static BSUoS costs are largely offset by dynamic reductions in other costs leaving only small impacts in either direction for these users. On average, we estimate the impact on domestic users with LCTs to be very close to zero. Specifically, the results are:

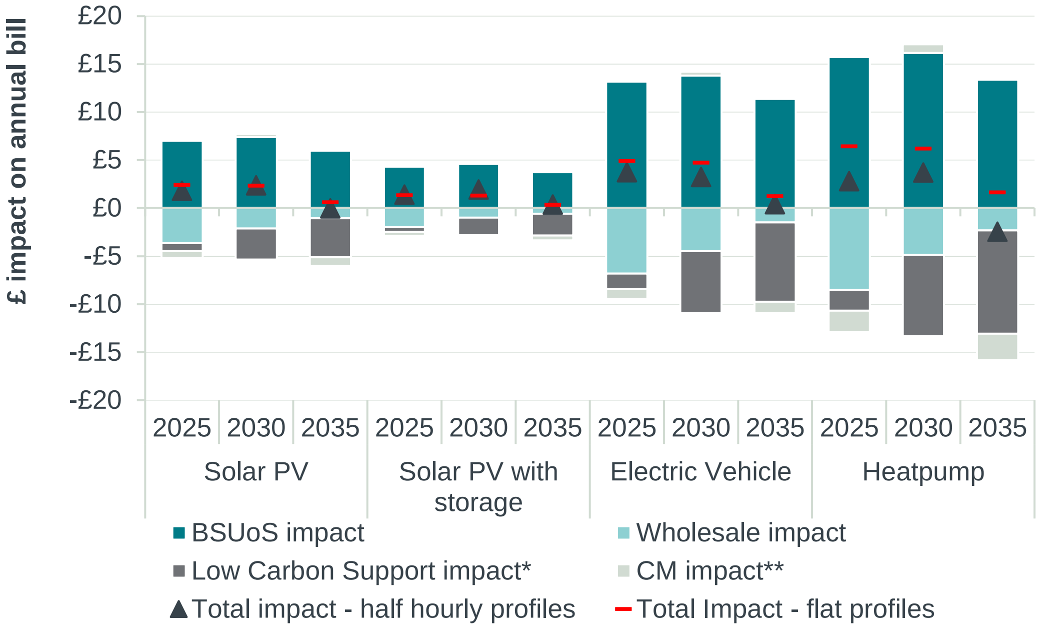
- a cost of £0.33 for a domestic user with solar PV (£0.16/MWh).
- a cost of £0.35 for a domestic user with solar PV and storage (£0.30/MWh)
- a cost of £0.47 for a domestic user with an EV (£0.11/MWh); and a benefit of £0.22 for a domestic user with a heatpump (£0.04/MWh).

This compares to a £0.43 benefit for a medium domestic user with no LCTs.

Assuming a simple flat profile produces very similar answers for these user groups other than for the heatpump user, where a flat profile implies a cost of £0.87 per year compared with a small benefit using our assumed profile.

Overall the difference in impacts between domestic users with and without LCTs is very small.

Figure 24 Consumer Transformation – Annual £ impact – Domestic with low carbon technologies



Source: Frontier Economics analysis

*Note: *Low Carbon Support includes Contracts for Difference and Renewables Obligation Certificates payments.*
***Capacity Market modelling volatile- we have therefore taken the 5 year average of the forecast (e.g. 2025 is an average of the forecasts from 2023 – 2027 inclusive)*

As with other domestic users, under the Consumer Transformation scenario CMP308 increases the BSUoS bill for all domestic customers with LCTs and this increase is more pronounced than under the Steady Progression scenario due to higher BSUoS costs under the Consumer Transformation scenario.

On average, over 2025-2035, BSUoS costs increase by:

- £6.80 for a domestic user with solar PV (£3.31/MWh);
- £4.22 for a domestic user with solar PV and storage (£3.67/MWh);
- £12.77 for a domestic user with an EV (£3.06/MWh); and
- £15.08 for a domestic user with a heatpump (£2.77/MWh).

This compares to a £6.98 increase in BSUoS for a medium domestic user with no LCTs.

As before, the static increases are largely offset by the dynamic changes in wholesale prices and low carbon support costs, resulting in net increases in bills of:

- £1.39 for a domestic user with solar PV (£0.68/MWh);
- £1.25 for a domestic user with solar PV and storage (£1.09/MWh);
- £2.46 for a domestic user with an EV (£0.59/MWh); and
- £1.36 for a domestic user with a heatpump (£0.25/MWh).

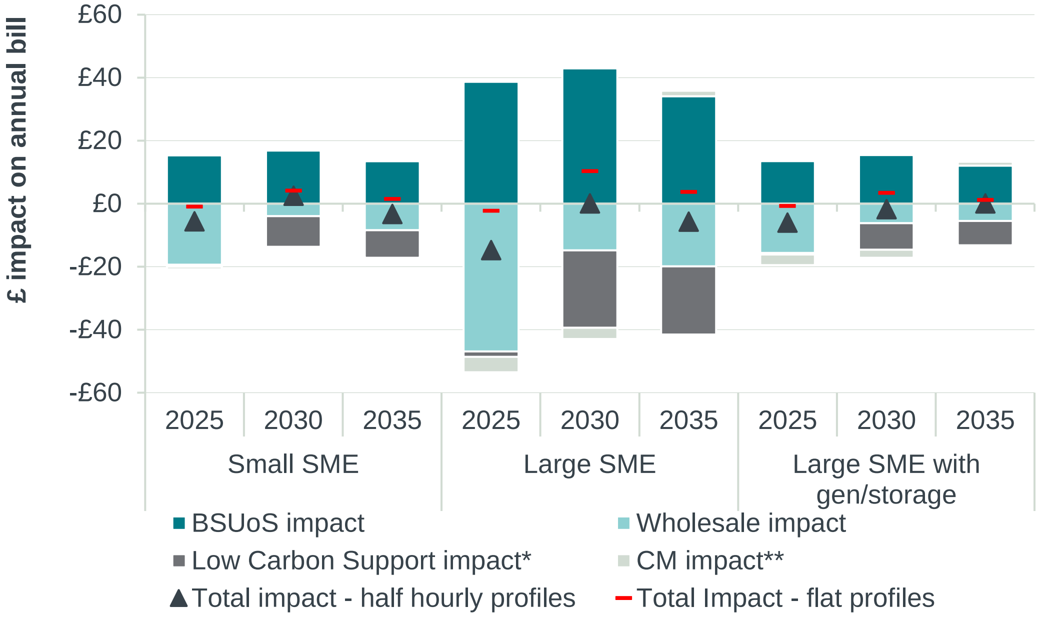
This compares to a £0.58 benefit for a medium domestic user with no LCTs.

Whilst two of the LCTs (heat pumps and EVs) increase demand and two decrease it (solar PV with or without storage), all of the technologies increase the concentration of demand in the overnight period when BSUoS costs are increased the most by CMP308. This drives higher per MWh BSUoS costs for all the LCT user groups resulting in a small net cost of CMP308 compared to a very small net benefit for the medium domestic user without an LCT.

3.3.3 Commercial customers

In this section we focus on the three commercial load profile derived based on CLNR data.

Figure 25 Steady Progression – Annual £ impact – SMEs



Source: Frontier Economics analysis

*Note: *Low Carbon Support includes Contracts for Difference and Renewables Obligation Certificates payments.*
***Capacity Market modelling volatile- we have therefore taken the 5 year average of the forecast (e.g. 2025 is an average of the forecasts from 2023 – 2027 inclusive)*

CMP308 results in a direct "static" increase in the BSUoS bill for all commercial customers under the Steady Progression scenario. The increase in BSUoS peaks around 2030 in line with NGESO's projection of constraint costs. On average, over 2025-2035, BSUoS costs increase by around:

- £15.23 per year for a small commercial user (£1.52/MWh)
- £38.58 per year for a large commercial user without onsite generation or storage (£1.54/MWh)
- £13.65 per year for a large commercial user with onsite generation and storage (£1.64/MWh)

The load profile for commercial businesses is heavily skewed towards working hours with little overnight consumption, whilst the increase in BSUoS costs is focused in the overnight hours. This means that for commercial customers, the increase in static BSUoS costs is more than offset by falls in other costs, particularly wholesale costs and low carbon support costs. On average, we estimate the benefit to commercial users of CMP308 to be:

- £2.10 per year for a small commercial user (£0.21/MWh)
- £6.97 per year for a large commercial user without onsite generation or storage (£0.27/MWh)
- £2.53 per year for a large commercial user with onsite generation and storage (£0.30/MWh)

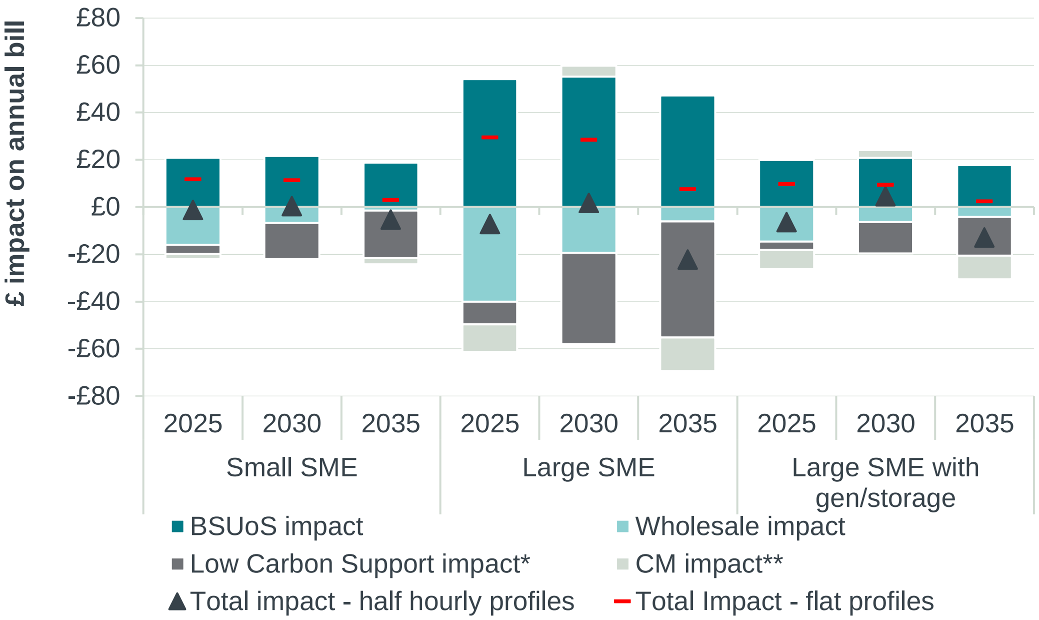
In our analysis, a large SME without onsite solar generation and storage has 10% of its annual consumption in the overnight period, whereas a large SME with onsite solar generation and storage has 16% of its consumption overnight.[13] Therefore, in general, we would expect CMP308 to have a more beneficial impact on the user without onsite generation and storage because of this difference in the time profile of consumption. However, on a per MWh basis, we observe the opposite in our results. The reason for this is that while solar generation significantly reduces total net demand over the course of the year, and a battery also helps to reduce peak consumption, it does not materially reduce net demand during the capacity market charging period of 4-7pm in November to February. Thus, on a per MWh basis, the SME *with* onsite generation is relatively more exposed to changes in capacity market costs.

On average, the Envision modelling shows a reduction in capacity market costs in the factual vs the counterfactual, which the commercial user with onsite generation and storage benefits more from per MWh consumed.

If we adopt a simple flat profile for commercial users, the bill impacts change to a small net cost, given the increase in overnight consumption, although they are still very small. On average, the simple dynamic impact per year is an increase in costs of:

- £1.59 per year for a small commercial user (£0.16/MWh)
- £3.97 per year for a large commercial user without onsite generation or storage (£0.16/MWh)
- £1.32 per year for a large commercial user with onsite generation and storage (£0.16/MWh)

Figure 26 Consumer Transformation – Annual £ impact – SMEs



Source: Frontier Economics analysis

*Note: *Low Carbon Support includes Contracts for Difference and Renewables Obligation Certificates payments.*

[13] This is because the onsite generation and storage are based on solar PV generation that reduce net demand during the day and not overnight.

***Capacity Market modelling volatile- we have therefore taken the 5 year average of the forecast (e.g. 2025 is an average of the forecasts from 2023 – 2027 inclusive)*

Under the Consumer Transformation scenario the increase in the BSUoS bill is more pronounced than under the Steady Progression scenario because of higher BSUoS costs under the Consumer Transformation scenario.

On average over 2025-2035 BSUoS costs increase by around:

- £20.45 per year for a small commercial user (£2.05/MWh)
- £52.20 per year for a large commercial user without onsite generation or storage (£2.09/MWh)
- £19.49 per year for a large commercial user with onsite generation and storage (£2.34/MWh)

As with the Steady Progression scenario the daytime skew of the commercial consumption profiles means that the dynamic impact of CMP308 results in a benefit for these users. We estimate that the dynamic impacts for commercial users is an average net benefit of around:

- £2.04 per year for a small commercial user (£0.20/MWh)
- £9.16 per year for a large commercial user without onsite generation or storage (£0.37/MWh)
- £4.90 per year for a large commercial user with onsite generation and storage (£0.59/MWh)

As with the SP scenario, capacity market recovery means that the comparison of impacts for large commercial users with and without onsite generation and storage runs counter to the general principle that a larger share of consumption overnight results in a greater cost (or smaller benefit). For the Consumer Transformation scenario this is more pronounced because there are larger movements in capacity clearing prices than in SP.

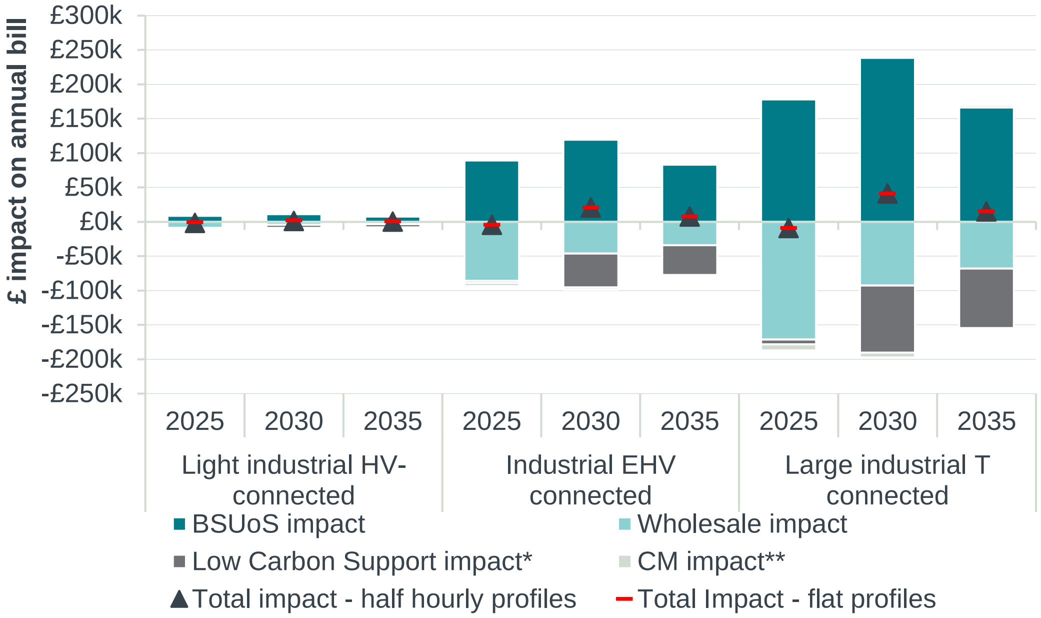
Under a simple approach the dynamic impacts for commercial users are more pronounced than in the Steady Progression scenario. On average the simple dynamic impact per year is an increase in costs of

- £8.74 per year for a small commercial user (£0.87/MWh)
- £21.84 per year for a large commercial user without onsite generation or storage (£0.87/MWh)
- £7.26 per year for a large commercial user with onsite generation and storage (£0.87/MWh)

3.3.4 Industrial customers

In this section we focus on the three assumed industrial load profiles.

Figure 27 Steady Progression – Annual £ impact – Industrials



Source: Frontier Economics analysis

*Note: *Low Carbon Support includes Contracts for Difference and Renewables Obligation Certificates payments.*
***Capacity Market modelling volatile- we have therefore taken the 5 year average of the forecast (e.g. 2025 is an average of the forecasts from 2023 – 2027 inclusive)*

CMP308 results in a direct "static" increase in the BSUoS bill for all industrial customers under the Steady Progression scenario. The increase in BSUoS peaks around 2030 in line with National Grid's projection of constraint costs. On average over 2025-2035 BSUoS costs increase by around:

- £9,070 per year for a light industrial HV-connected user (£1.81/MWh)
- £97,188 per year for an industrial EHV connected user (£1.94/MWh)
- £194,376 per year for an industrial T-connected user (£1.94/MWh)

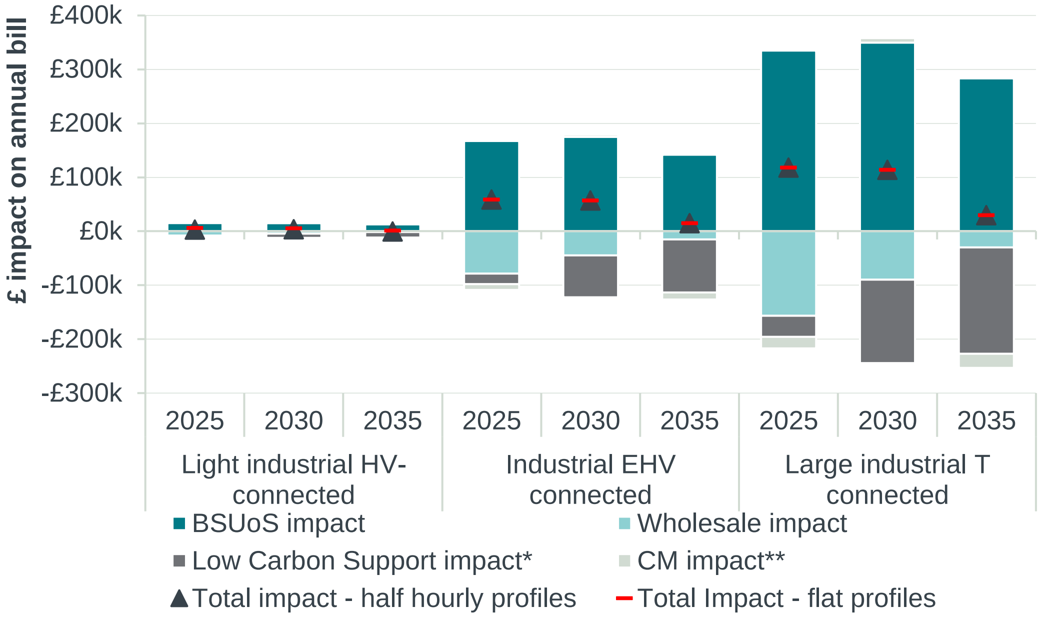
This static impact is mostly offset by reductions in wholesale and low carbon support payments. In some years it is more than offset and in other years it is not fully offset. Overall the average dynamic impact for industrial users is a small bill increase of:

- £56 per year for a light industrial HV-connected user (£0.01/MWh)
- £7,943 per year for an industrial EHV connected user (£0.16/MWh)
- £15,885 per year for an industrial T-connected user (£0.16/MWh)

These results on a £/MWh basis are identical for domestic customers and commercial customers if we assume a flat consumption profile. This means that estimated impacts can be scaled assuming a flat profile i.e. if an industrial user, with a flat load profile had consumption 10% lower than our T-connected user archetype then the impact for that individual user would be £14,400 (10% less than £16,000).

The HV-connected consumer archetype does not have a flat profile. We assume that it has more consumption during the peak than the off peak period, and therefore compared to the simple flat profile, faces a lower cost. Assuming a flat profile the light industrial HV-connected user faces a net cost of £794 per year from the reform or around £0.16/MWh.

Figure 28 Consumer Transformation – Annual £ impact – Industrials



Source: Frontier Economics analysis

*Note: *Low Carbon Support includes Contracts for Difference and Renewables Obligation Certificates payments.*
***Capacity Market modelling volatile- we have therefore taken the 5 year average of the forecast (e.g. 2025 is an average of the forecasts from 2023 – 2027 inclusive)*

Under the Consumer Transformation scenario CMP308 increases the BSUoS bill for all commercial customers and this increase is more pronounced than under the Steady Progression scenario because of higher BSUoS costs under the Consumer Transformation scenario.

On average over 2025-2035 BSUoS costs increase by:

- £14,264 per year for a light industrial HV-connected user (£2.85/MWh)
- £161,314 per year for an industrial EHV connected user (£3.23/MWh)
- £322,629 per year for an industrial T-connected user (£3.23/MWh)

The increase in BSUoS costs is only partially offset by larger declines in other costs compared to Steady Progression scenario. Overall the average dynamic impact for industrial users is a bill increase of around:

- £2,284 per year for a light industrial HV-connected user (£0.46/MWh)
- £43,686 per year for an industrial EHV connected user (£0.87/MWh)
- £87,317 per year for an industrial T-connected user (£0.87/MWh)

3.3.5 Summary

In this section we provide an overview of the impacts on the user groups in the Steady Progression and Consumer Transformation scenarios.

We present the estimated volume weighted average £/MWh static and dynamic impacts for each user group. By presenting the £/MWh impact we are controlling for the total volume of consumption, and therefore any variation between user groups reflects differences in the assumed shape of consumption.

Static bill impacts

In the Steady Progression scenario, all of the user groups experience an increase in the BSUoS charge:

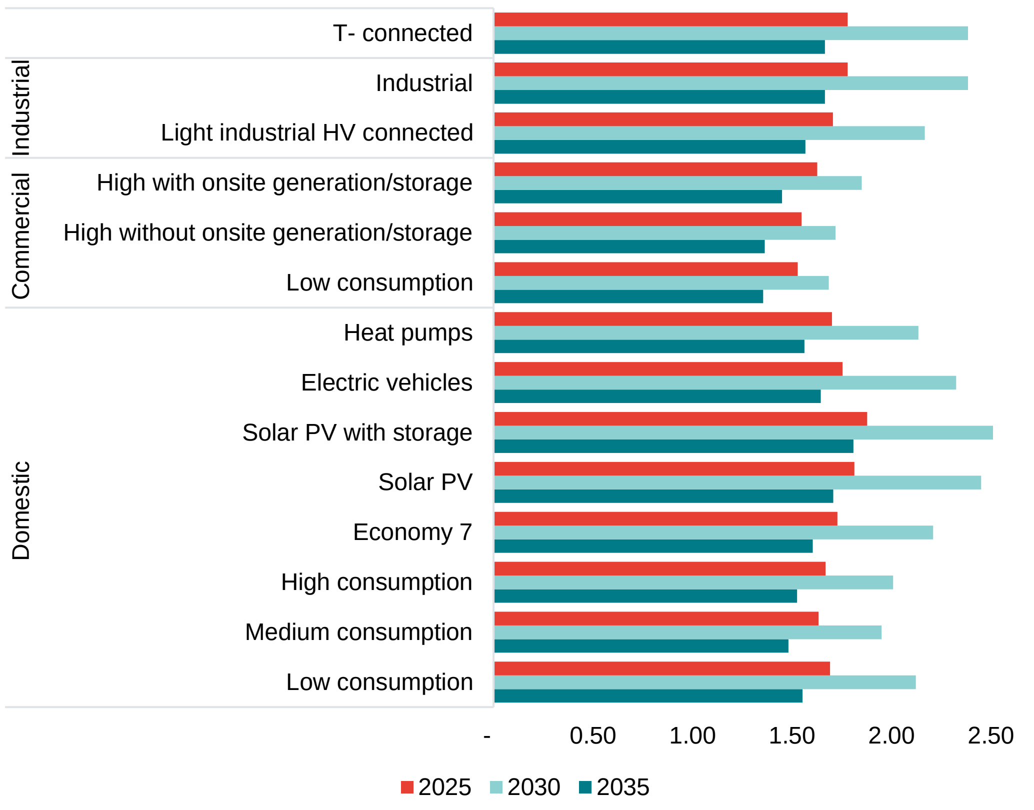
- between £1.53/MWh – £1.88/MWh in 2025;
- between £1.68/MWh – £2.64/MWh in 2030; and
- between £1.35/MWh – £1.81/MWh in 2035 (see Figure 29).

In the Consumer Transformation scenario, impacts are higher due to the higher modelled BSUoS costs in this scenario:

- between £2.08/MWh – £3.75/MWh in 2025;
- between £2.16/MWh – £4.00 and
- between £1.89/MWh – £3.27/MWh in 2035 (see Figure 30).

It is not surprising that all grid-connected demand users experience an increase in their BSUoS bill because the share of BSUoS costs previously borne by generators is now paid for by demand users. The largest increases are for those users with an assumed flat load profile, or a load profile weighted towards the night-time (when £/MWh BSUoS charges are generally higher) e.g. domestic customers with solar PVs and storage, EVs and heat pumps, and the industrial user groups for whom we assumed a flat load profile.

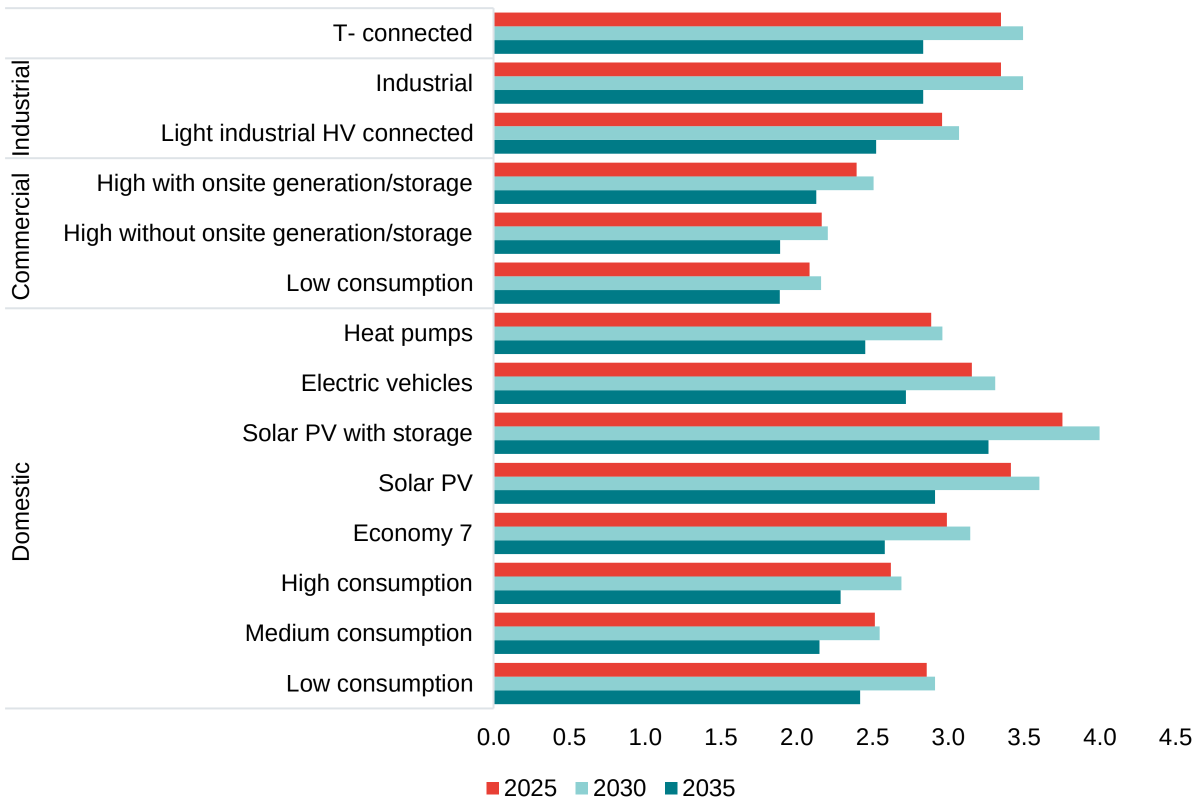
Figure 29 Steady Progression - static BSUoS £/MWh impact across all customer types, 2025, 2030, 2035



Source: Frontier Economics analysis

Note: The £/MWh impact is displayed on the basis of each user type's half-hourly demand profile

Figure 30 Consumer Transformation - static BSUoS £/MWh impact across all customer types, 2025, 2030, 2035



Source: Frontier Economics analysis

Note: The £/MWh impact is displayed on the basis of each user type's half-hourly demand profile

Dynamic bill impact

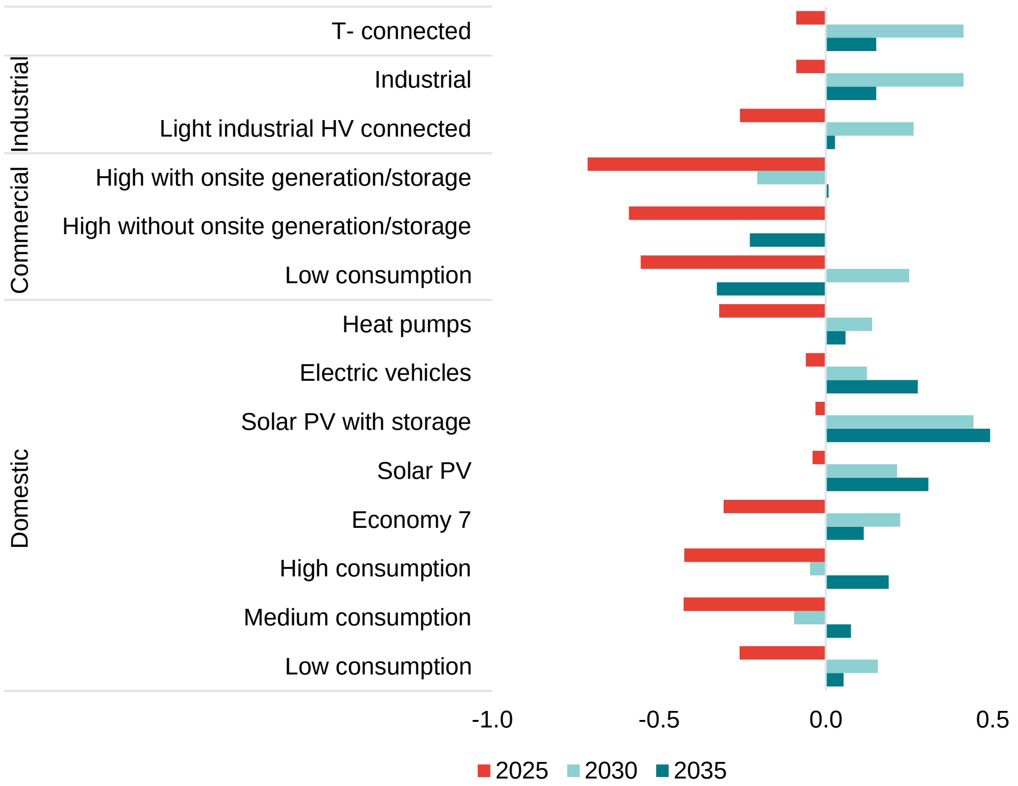
The dynamic impact for all user groups is lower than the static impact as the static increase in BSUoS charges is offset by reductions in other components of the bill, such as wholesale and policy costs. Whether this results in a net increase or decrease in the £/MWh impact varies by user group, and also varies by scenario and over time.

However, as shown in the previous sections, the overall impact on bills for all users is expected to be small. Average affected costs are projected to increase at most by 1.4% over the period 2025 to 2035.[14]

In the Steady Progression scenario, all of the user groups experience a £/MWh reduction in 2025. However, by 2035, most user groups experience a very small increase £/MWh costs. This is shown in Figure 31.

[14] Affected costs consist of: wholesale costs, low carbon support costs (CfDs and ROCs), capacity market costs and BSUoS costs. Average impacts are reported based on a simple average of the impact across the three sample years of 2025, 2030 and 2035.

Figure 31 Steady Progression - dynamic £/MWh impact across all customer types, 2025, 2030, 2035



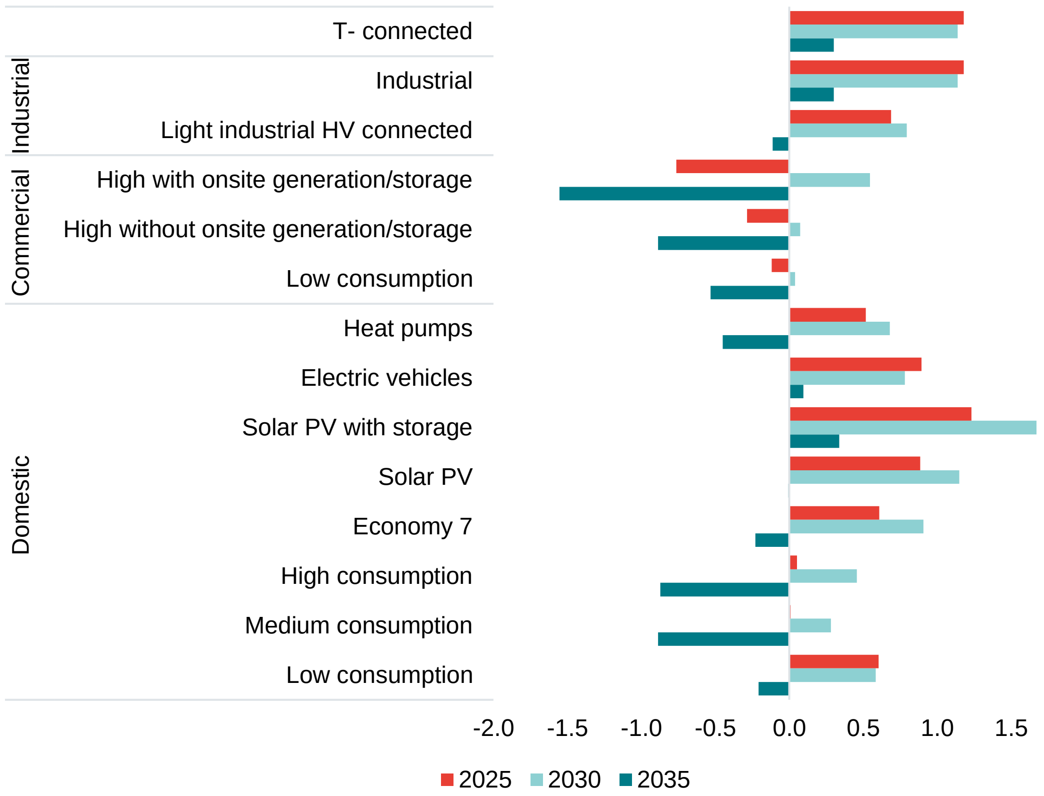
Source: Frontier Economics analysis

Note: The £/MWh impact is displayed on the basis of each user type's half-hourly demand profile

Under the Consumer Transformation scenario, most user groups experience a small increase in costs in 2025, with only commercial users that have consumption strongly concentrated during the 7am to 7pm period seeing a bill reduction in that year. However, by 2035, most user groups (10 out of 14) experience a small reduction in costs. The four groups which experience an increase in £/MWh costs under the factual charging scenario only experience minimal cost increases of less than 50p/MWh. This is shown in Figure 32. This represents an increase of 2.1% of affected costs in 2035 for the domestic user with solar PV and storage and a smaller impact for the other impacted user groups.[15]

[15] Affected costs consist of: wholesale costs, low carbon support costs (CfDs and ROCs), capacity market costs and BSUoS costs.

Figure 32 Consumer Transformation - dynamic £/MWh impact across all customer types, 2025, 2030, 2035



Source: Frontier Economics analysis

Note: The £/MWh impact is displayed on the basis of each user type's half-hourly demand profile

4 OVERALL IMPLICATIONS

Based on the analysis in this report, recovering BSUoS costs entirely from demand is likely to reduce overall system costs and customer costs.

- *System benefits* principally arise due to levelling the playing field between transmission-connected generation and other sources of supply, namely, distributed generation and interconnection.
- *Consumer benefits* principally arise because the increase in the BSUoS demand charge is more than offset by reductions in wholesale prices and low carbon support payments.

System cost benefits are £0.49bn and £0.29bn (NPV) under Steady Progression and Consumer Transformation respectively, and consumer benefits are £0.37bn and £0.32bn (NPV) respectively. While these results should only be interpreted as providing an indication of the direction and broad magnitude of impacts, they do provide comfort that, in aggregate, CMP308 should result in an overall reduction in system and customer costs.

With regard to system benefits, under the Steady Progression scenario, increases in transmission connected CCGT generation are more than offset by reductions in generation from interconnectors and small distribution connected peaking generators. There is a similar dynamic under the Consumer Transformation scenario in the early years of the period, although the impacts are diminished in later years given the much lower levels of CCGT generation in the Counterfactual in this Net Zero consistent scenario. In these years, the effect of the reform is to increase transmission-connected offshore and onshore wind, resulting in higher exports.

With regard to consumer benefits:

- Under Steady Progression and the early years in Consumer Transformation, BSUoS costs increase by around 50-60%. This is because in the counterfactual, the share of revenue collected from transmission connected generation was less than half due to a significant contribution to meeting final demand from supply sources that do not pay BSUoS. Later in the period under Consumer Transformation, the charges more than double relative to those in the Counterfactual, as the generation charging base is slightly higher than the demand base due to significant interconnection exports increasing domestic generation.
- The increase in BSUoS is offset by reductions in wholesale prices and low carbon support costs. Wholesale price impacts are most significant in the early years due to there being a significant share of transmission connected generation on the margin that factored BSUoS into their wholesale market bids pushing up prices in the counterfactual. As the share of low carbon technologies increases later in the period, particularly in the Consumer Transformation scenario, savings due to reductions in the cost of low carbon support payments become much more significant.

While in aggregate the analysis suggests that overall consumers should benefit from the change, these benefits may not be evenly distributed across all customer types. In line with the aggregate analysis, we find that for all customer types considered, the “static” increase in BSUoS costs are significantly offset by the “dynamic” changes to wholesale prices, low carbon support payments and capacity market costs. For some customer types considered, this resulted in an overall reduction in costs, and for others a small increase. However, in all cases, the impacts of CMP308 can be considered small.

To the extent that some customers may experience small increases in costs, these are more likely to be those with a flat consumption profile, as illustrated by our industrial profiles, or those with consumption skewed toward overnight consumption, as illustrated by domestic customers with LCTs such as solar heat pumps and electric vehicles. In contrast, those consumers with consumption skewed to the daytime are more likely to benefit from the change.

5 LIMITATIONS OF THE ANALYSIS

The modelling presented in this report can help to inform the nature, direction and broad magnitude of potential effects of the modifications being considered. However, the modelling outputs we present are dependent on assumptions on a number of inherently uncertain input variables (e.g., fuel prices, demand). Such outputs are best used to complement a more principles-based assessment of the likelihood of modifications better facilitating objectives.

It will be important that sound economic principles form the basis of the final decision in relation to any changes to BSUoS charging arrangements. Such principles relate to minimising distortions, fairness and practical considerations. Charging in a manner consistent with such principles should help ensure an optimum outcome for society as a whole.

The bill impact analysis has been developed based on data from publicly available sources and requests from network owners. The data available to us does not allow the estimation of the exact charges that could be expected if the options are implemented. We have had to make numerous simplifications and assumptions. The user groups are designed to represent a reasonable spread of different levels and shapes of consumption, but they are not representative of all consumers. We also note that we do not consider any evolution in demand patterns between 2025 and 2040 e.g. due to technological improvements related to the LCTs assessed or new tariff arrangements which incentivise different consumption behaviour. As a result, the charges and bill impacts estimated should only be considered illustrative to provide the broad direction of the expected impacts.

The wider system modelling results contained in this report are produced by LCP's dispatch model of the GB power market. The report contains modelled outcomes from 2021 to 2040 under assumptions provided by Ofgem or obtained from publicly available sources where possible.

The results presented in this report are dependent on the assumptions used and the modelling methodology applied. Long-term forecasts are subject to significant uncertainty and actual market outcomes may differ materially from the forecasts presented.

In particular:

- The scenarios presented do not take into account all changes that could potentially occur in the power market. More extreme market outcomes than those presented are therefore possible.
- The relationship between the cost of generation and prevailing market prices has been assessed based on historical data and current forward power prices. To the extent that this relationship changes over time results could vary.
- The modelling results are based on all market participants having a common view on future market outcomes. To the extent that views vary between market participants, the results could be considerably different to those presented in this report.

- The modelling makes use of a power plant database maintained by LCP which is based on publicly available information where possible. Assumptions on individual plant characteristics have been estimated where required.
- We do not take into account the effect that future changes to the market structure may have on the behaviour of market participants.

A further challenge with this type of modelling is that relatively small changes in inputs can result in relatively large changes in outputs, due to “cliff-edge” effects. For example, a small change in charges can be enough to tip the economics of an investment decision for a large new build project from going ahead to not going ahead. When evaluating larger changes to assumptions, these effects tend to get smoothed out, but for smaller changes it can reduce the stability of the modelling and adds an additional area of uncertainty to the modelling results. We have made efforts to minimise the impact of these effects. For example, the renewable build is locked down between scenarios as per the “background” FES scenario.

The static and dynamic bill impact analysis should only be considered illustrative to provide the broad direction of the expected impacts of the changes in customer costs modelled by Envision for different types of consumers. The user groups are designed to represent a reasonable spread of different levels and shapes of consumption, but they are not representative of all consumers.

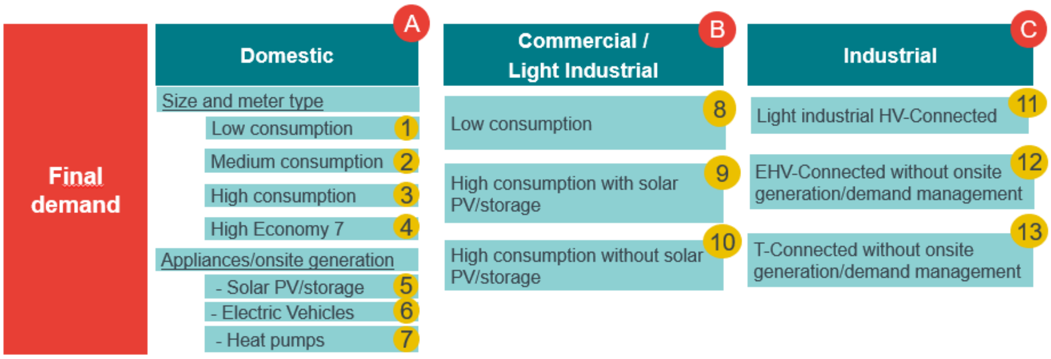
ANNEX A USER GROUP ANALYSIS

As discussed in Section 3, as a first step in our bill impact assessment, we have identified a set of user groups to understand how different types of customers could be affected by proposed changes in the network charging structure related to the recovery of residual costs.

The domestic, commercial and industrial user groups that we have identified are outlined in Figure 33. In total we have identified 13 relevant final demand user groups spread across various consumer types, as well as consumption and voltage levels.

It is important to note that in reality the boundaries between users may overlap. For example, the results for a larger domestic customer may be more appropriate for certain small commercial customers than our low consuming commercial user group. Also noteworthy is that while representing key consumer archetypes, these users group cannot be representative of all consumers.

Figure 33 User group classifications



Source: Frontier Economics

Note: Note that Group 5 comprises of two sub-groups: solar PV in isolation and solar PV combined with storage.

A.1 Development of consumer archetypes

A.1.1 Ofgem's Typical Domestic Consumption Values

Typical Domestic Consumption Values (TDCVs) are industry standard values for the annual gas and electricity usage of a "typical" domestic consumer. TDCVs are commonly used to derive typical consumer bills when the actual consumption level is not known. We have used the latest 2020 TDCVs for GB electricity consumers provided in Ofgem's decision dated 6 January 2020 summarised in Figure 34.[16]

[16] Ofgem. Decision on revised Typical Domestic Consumption Values for gas and electricity and Economy 7 consumption split. 6 January 2020. Available here: https://www.ofgem.gov.uk/publications-and-updates/decision-typical-domestic-consumption-values-2020

Figure 34 Ofgem's TDCVs for Domestic Electricity Consumers in GB

	Consumption levels	Revised TDCV (kWh)
Profile Class 1 *(Domestic Unrestricted Customers)*	Low	1,800
	Medium	2,900
	High	4,300
Profile Class 2 *(Domestic Economy 7 Customers)*	Low	2,400
	Medium	4,200
	High	7,100

Source: *Ofgem. Decision on revised Typical Domestic Consumption Values for gas and electricity and Economy 7 consumption split. 6 January 2020.*

TDCVs identify the "low", "medium" and "high" consumption levels for domestic GB electricity consumers for Profile Classes 1 and 2, calculated using consumption data from February 2016 to January 2018. Profile Class 2 predominantly consists of users with Economy 7 meters, which have two separate rates for peak and off-peak consumption. Profile Class 1 covers most of the remaining domestic consumers.

The median or second quartile of household consumption data is considered to be representative of the typical "medium" usage of GB domestic customers, while the first and third quartiles represent the typical "low" and typical "high" usage domestic consumers respectively. In other words, if consumers were ranked in order of their electricity consumption, 25% of all consumers would have consumption less than the typical "low" usage customer, and 25% of customers would have consumption greater than the typical "high" usage customer.

A.1.2 Customer-Led Network Revolution

Customer-Led Network Revolution (CLNR) was a smart grid project funded by Ofgem's Low Carbon Networks Fund and led by Northern Powergrid in partnership with British Gas, Durham University, Newcastle University and EA Technology. The project collected data on electricity consumption and generation profiles of around 13,000 domestic and commercial customers and is one of the most significant projects of its kind undertaken in the United Kingdom. [17]

The data collected as part of the CLNR trial also provides consumption profiles for domestic customers with low carbon technologies such as solar panels, electric vehicles and heat pumps.

We have drawn information from a number of different CLNR datasets which we describe below.

Domestic users datasets

We have sourced half-hourly consumption data for domestic users from four key CLNR datasets, or so-called 'test cells' (TC). These datasets provide annual half-hourly electricity consumption profiles for actual domestic users and include

[17] CLNR. Developing the smarter grid: the role of domestic and small and medium enterprise customers. 2015.

consumption profiles for domestic users having air source heatpumps, solar PVs and electric vehicles.

Below we briefly describe each of these datasets.

The **basic domestic consumers (TC1a)** dataset contains half-hourly electricity consumption data from October 2012 to September 2013 for more than 9,000 customers with basic smart metering. TC1a was designed to cover households from across different demographic groups providing an overall picture of domestic electricity consumption in the UK.[18] No interventions (such as providing a user with a low carbon technology) were applied to the domestic users in TC1a, allowing it to be used as the baseline against which the impacts of interventions applied to other domestic test cells can be compared. We filtered the dataset to look only at customers with full year of data.

The **domestic consumers with heatpumps (TC3)** dataset contains separate electricity consumption meter readings for the air-source heat pumps and for total household consumption. Both readings were recorded for 381 households every 1 minute for the entire year from May 2013 to April 2014.

We learned from the CLNR documentation on this test cell that there were significant data discrepancies (e.g., missing data from drop-outs) associated with this dataset. We have therefore applied similar filters deployed by CLNR to retain only those households with complete full-year consumption data. Applying these filters brings the actual sample size to 89 households.[19]

The **domestic consumers with solar PV (TC5)** dataset contains electricity consumption meter readings for 143 households as well as electricity generation readings for their respective solar PV cells. The readings were recorded for the entire year from January to December 2013.[20]

The **domestic consumers with electric vehicles (TC6)** dataset contains electricity consumption meter readings for 131 households with electric vehicles for the nine months: July 2014 to March 2015. Given the absence of a full year of data, any aggregated statistics (e.g., annual consumption) were scaled up linearly to a full year for comparison with other datasets. 108 of the EV owners in the study were drawn from employees, or friends and family of employees, of Nissan Motor Manufacturing (UK) Ltd. These owners drove a Nissan Leaf as part of an employee lease car scheme and had limited ability to charge the car at work.[21]

Commercial user groups

For our commercial user groups, we have primarily relied on the **basic small and medium sized enterprise (TC1b)** dataset, which contains half-hourly

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18 CLNR. Insight Report – Baseline Domestic Profile. 2015. Available at: http://www.networkrevolution.co.uk/wp-content/uploads/2015/02/Insight-Report-TC1a.pdf

19 CLNR. Insight Report – Domestic Heat Pumps. 2015. Available at: http://www.networkrevolution.co.uk/wp-content/uploads/2015/01/CLNR-L091-Insight-Report-Domestic-Heat-Pumps.pdf

20 CLNR. Insight Report – Domestic Solar PV Customers. 2015. Available at: http://www.networkrevolution.co.uk/wp-content/uploads/2015/01/CLNR-L090-Insight-Report-Domestic-Solar-PV.pdf

21 CLNR. Insight Report – Electric Vehicles. 2014. Available at: http://www.networkrevolution.co.uk/wp-content/uploads/2015/01/CLNR-L092-Electric-Vehicle-Insight-Report-RW.pdf

consumption readings for around 1,500 small commercial and business users spanning a period of one year from September 2011 to August 2012.

For the high consuming commercial user group, we have provided for the possibility of the commercial user self-generating with solar PV/storage. We have relied on learnings from TC5 with appropriate scaling of net consumption from the level of a typical domestic user to the consumption level of the high commercial user. This is because there was no separate test cell in the CLNR data studying the impact of solar PV/storage adoption for commercial users.

Domestic users with Low Carbon Technologies (Groups 5-7)

User groups 5-7 illustrate the impact for a medium consumer (annual gross consumption of 2,900kWh), of adopting certain low carbon technologies such as heat pumps, solar PV and electric vehicles. This approach allows us to consider the impacts for consumers that adopt these LCTs and those that do not.

To achieve this, we identify consumers in the appropriate CLNR datasets (TC3, TC5, TC6) that have annual household electricity consumption, excluding the impact of the LCT, similar to the medium TDCV. Based on these consumers, we then identify the relevant estimate of net and gross annual demand to observe the effect of adopting the LCTs on the level and pattern of electricity consumption.[22] We present a few key observations for each LCT below.

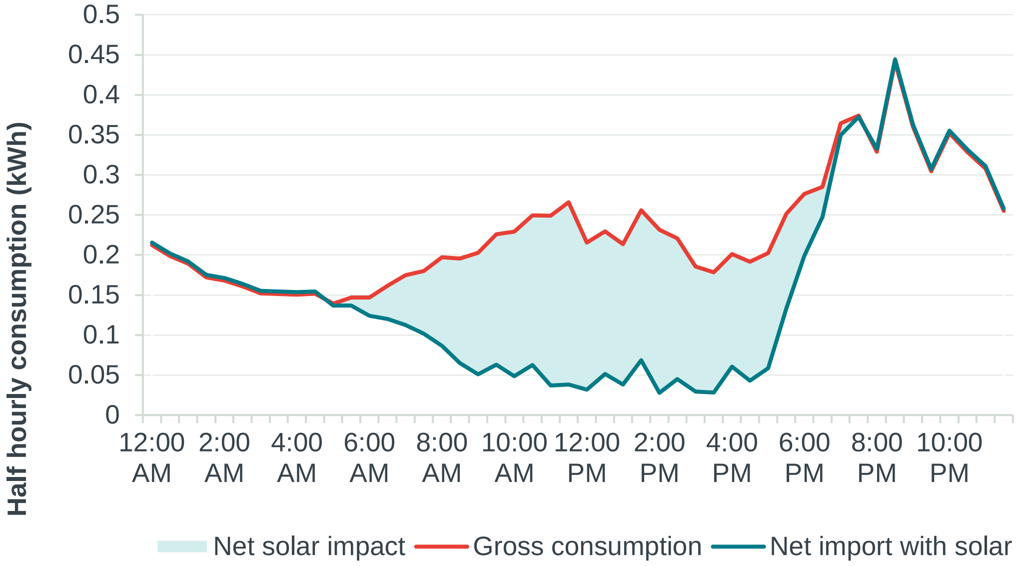
It is important to note that these profiles are meant to provide an illustration of the impact of LCTs on a user's profile and hence provide an understanding of the 'directional' impact of the changes to the charges. However, the observed impact of adopting LCTs may vary significantly depending on several factors, including the type/size of LCT, how it is used and at what time of day. In the observations provided below, we have not attempted to control for these or other such factors.

Domestic with solar PV with and without storage (groups 5a and 5b)

Figure 35 illustrates the impact of adding a solar panel to a domestic customer's consumption for an average Spring weekday, where given high solar output relative to consumption, average net imports are close to zero during daylight hours.

[22] Where we cannot find an LCT consumer with exactly the same electricity consumption as the medium domestic user (3,100 kWh), we find the closest one and scale the gross consumption linearly.

Figure 35 Impact of solar PV installation on consumption of medium domestic consumer (without storage) – Average spring weekday consumption



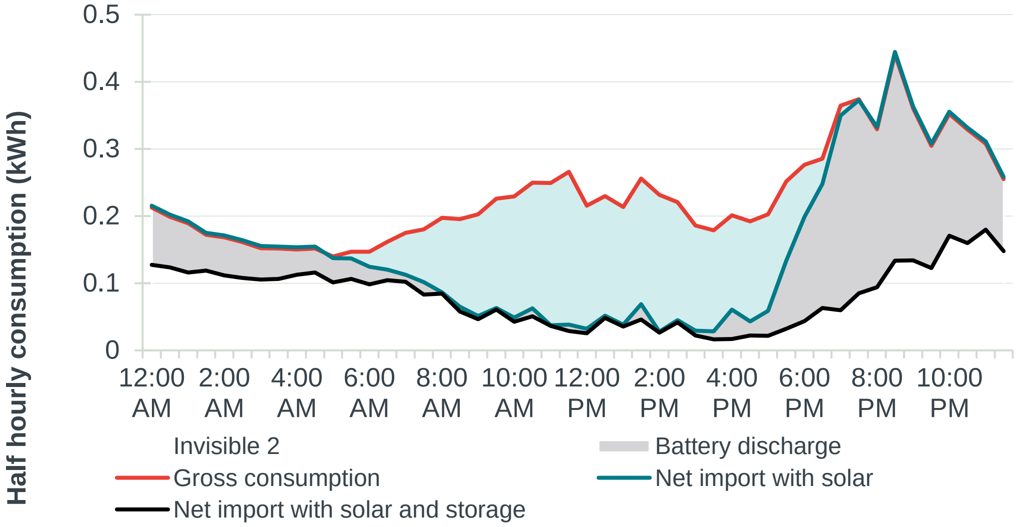
Source: Frontier analysis of CLNR data

Note: In half hours where solar generation exceeds gross consumption "net import with solar" will be 0.

With the installation of a battery storage unit, a further reduction in net electricity consumption can be achieved as the stored excess solar generation can be utilised to reduce net electricity consumption beyond the hours of solar generation.

We have assumed a battery with a capacity of around 4kWh, which is charged whenever solar generation exceeds gross consumption and is discharged until empty overnight. The net result of this is shown by the grey shaded area in Figure 36, which shows the average battery discharge overnight on a spring weekday. During some nights, there is enough storage to meet gross consumption into the following day, reducing net consumption to zero, whilst for others, there is little or no storage. Hence average net consumption is still positive for this example day.

Figure 36 Impact of solar PV installation and storage on consumption of medium domestic consumer – Average spring weekday consumption



Source: Frontier analysis of CLNR data

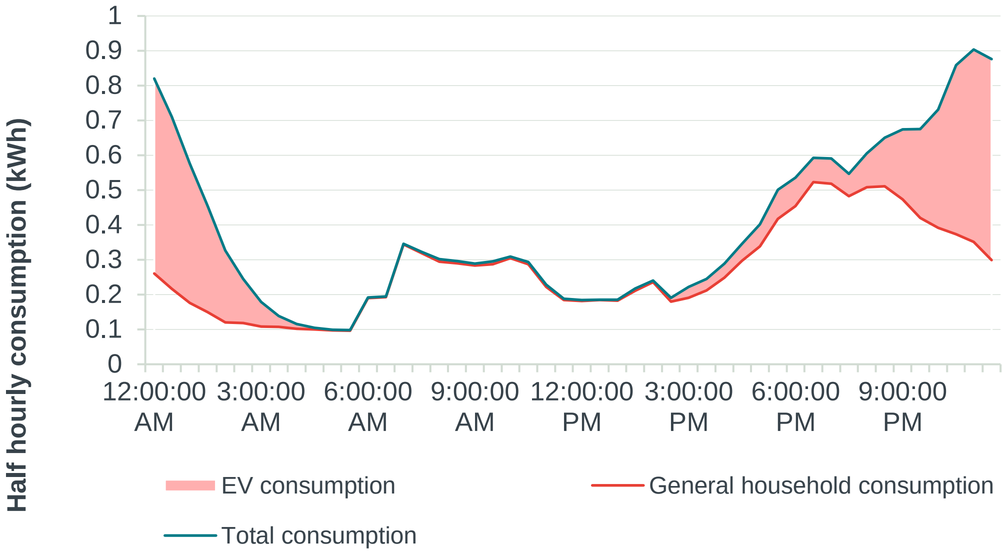
In summary, by choosing to self-generate using a solar PV (or another type of onsite generation), consumers can alter their reliance on the electricity grid. This reduces net demand for user group 5a relative to the medium domestic user without solar PV (group 2), from an annualised 2,900 to 2,055, but increasing the share of consumption during the night time, when BSUoS costs are higher (from 13% to 36%).

If the solar PV is coupled with a storage unit, consumers will be able to store any excess generation to reduce their consumption further into the evening peak. This is reflected as lower net annual demand (1,148kWh) for Group 5b relative to Groups 2 and 5a.

Electric vehicles (Group 6)

The CLNR test cell for **domestic consumers with electric vehicles (TC6)** contains electricity consumption meter readings for 131 households with an EV – a majority of the trial participants drove a Nissan Leaf. Figure 37 breaks down our indicative Electric vehicle customer's average daily consumption by general household consumption excluding EV (red line) and EV consumption (represented by the red shaded area. The blue line represents total consumption.

Figure 37: Average consumption of an electric vehicle customer



Source: *Frontier analysis of CLNR data*

For these consumers in the CLNR dataset, an EV increases the total annual electricity consumption of the domestic consumer by around 50%.[23] We also observe an increase in the consumer's consumption over the night (as shown by the red area), meaning EV customers are particularly exposed to BSUoS charges.

Electric heat pumps (Group 7)

Similar to EVs, electricity consumed by heatpumps represent a significant proportion of total household electricity consumption. In the CLNR test cell for **domestic consumers with heatpumps (TC3)**, the annual electricity consumption for heat pumps is found to be on average 82% of the annual household consumption.[24] Looking specifically at the evening period during a winter month (January) when demand for electricity is likely to be the highest, the average electricity consumption of the heat pump is observed to be nearly 100% of the average household electricity consumption in TC1a (consumers without heat pumps). This implies that installing a heat pump may double the household consumption at times when the electricity network is already likely to be experiencing high levels of demand.[25]

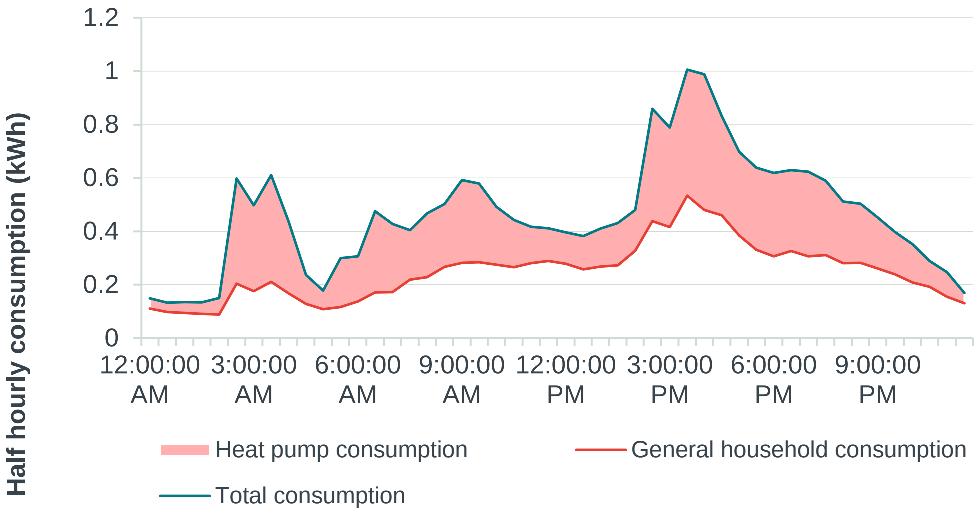
Moreover, we observe in the figure below that consumption of heat pumps (red area) shows a distinct peak in the early mornings (around 3 am) in addition to the typical morning and evening peak periods observed in domestic users' profile.

[23] We recognise that the exact impact will depending on the type of electric vehicle, but also whether the consumer charges the EV at home versus at work or a public charging station, among other factors.

[24] We recognise that the exact impact will depending on the type of electric heat pump, but also on the size of the house, the level of insulation and consumer's preference of room temperature levels, among other factors.

[25] CLNR. Insight Report – Domestic Heat Pumps. 2015. Available at: http://www.networkrevolution.co.uk/wp-content/uploads/2015/01/CLNR-L091-Insight-Report-Domestic-Heat-Pumps.pdf

Figure 38: Average consumption of a domestic customer with a heat pump



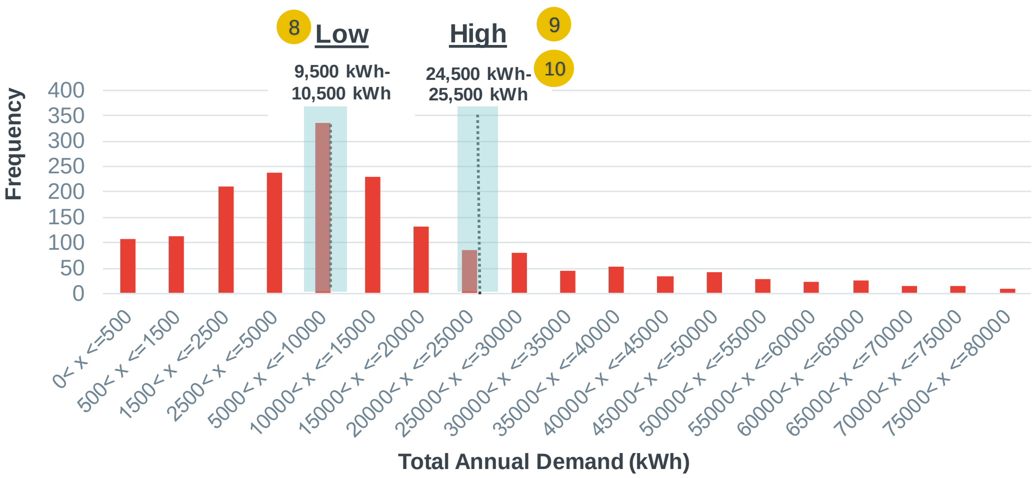
In summary, an electric heat pump can meaningfully alter both the level as well as the pattern or profile of a household's electricity consumption. This results in higher annual gross demand and greater consumption overnight for Group 7 relative to the medium domestic user (Group 2).

Commercial users (Group 8 -10)

We defined our commercial user groups in relation to the CLNR basic small and medium sized enterprise (TC1b) dataset, which contains half-hourly consumption readings for around 1,500 small commercial and business users spanning a period of one year from September 2011 to August 2012.

Figure 39 shows the distribution of annual consumption for commercial consumers in the CLNR TC1b dataset. We have identified low and high consumption commercial user groups guided by the median and 75th percentile of total annual consumption, respectively.

Figure 39: Distribution of annual demand for commercial customers in CLNR dataset

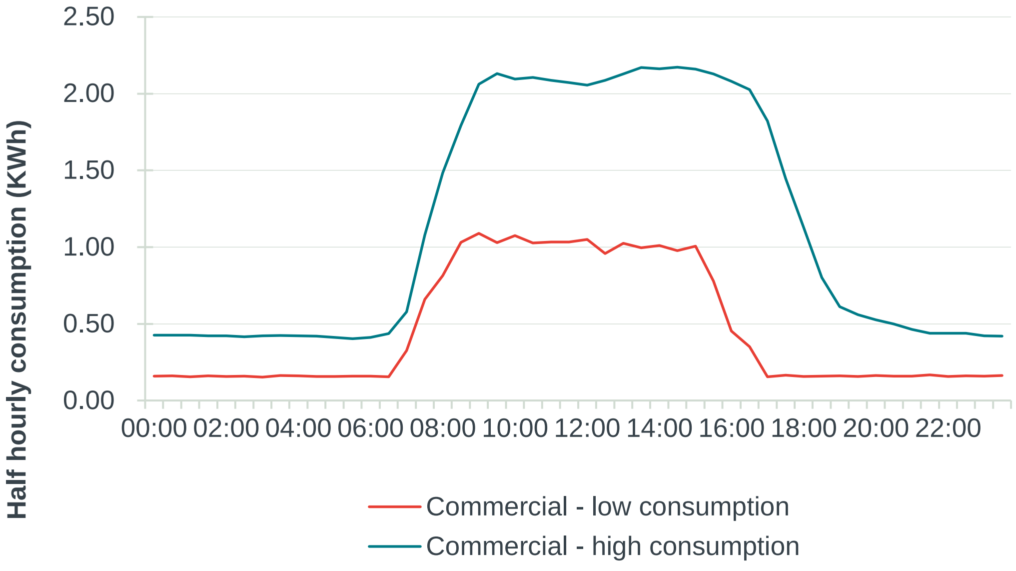


Source: Frontier analysis of CLNR data

To identify the "typical" shape of consumption, we examine the distribution of peak demand for customers with annual consumption close to our user groups, i.e. we added +/- 500kWh (roughly 5% of the low consumption level) to these annual consumption levels to define the annual consumption 'bands' for the two commercial user groups. These are shown in Figure 39 above.

We look at the "typical" shape of half-hourly consumption for these users for selected low and high commercial users in Figure 40. It can be observed that both profiles show electricity being primarily consumed over the commercial operating hours of 7 am to 7 pm. The higher commercial user continues its operations later and consumes more than twice the amount of energy as the lower commercial user.

Figure 40 Average annual half-hourly consumption profile for representative low and high commercial users

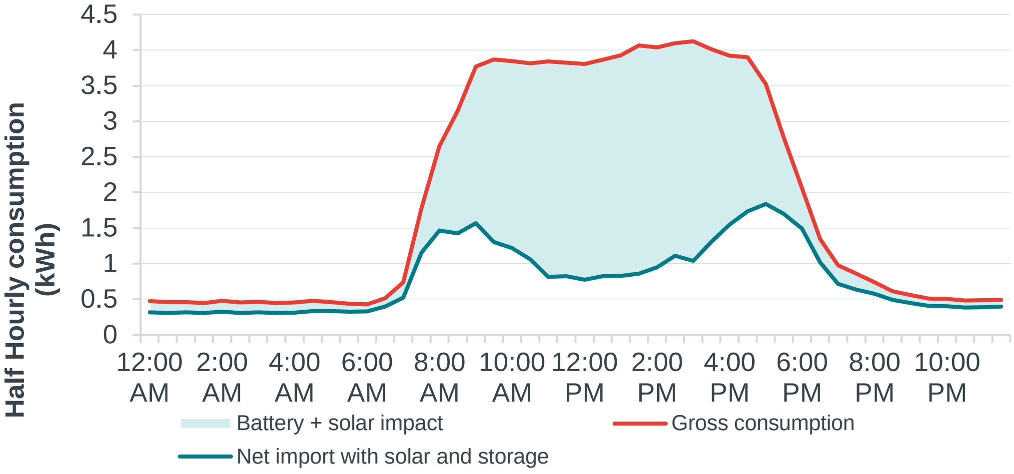


Source: Frontier analysis of CLNR data

We also model for the high consumption group for the possibility of a commercial user offsetting and potentially shifting their consumption using solar PV and storage. Since there is no CLNR test cell for commercial users with solar PV and storage, we have scaled the solar generation and battery storage of the domestic user with solar PV and storage (Group 5b) from the TC5 dataset commensurately with gross consumption.[26] Figure 41 illustrates the impact of installing solar PV and storage on a high commercial user's consumption profile.

[26] We scaled the domestic user's solar panel production profile linearly by the annual gross consumption to obtain this generation/storage curve. This is to simulate a likely commercial size solar/storage unit for a high consuming commercial user.

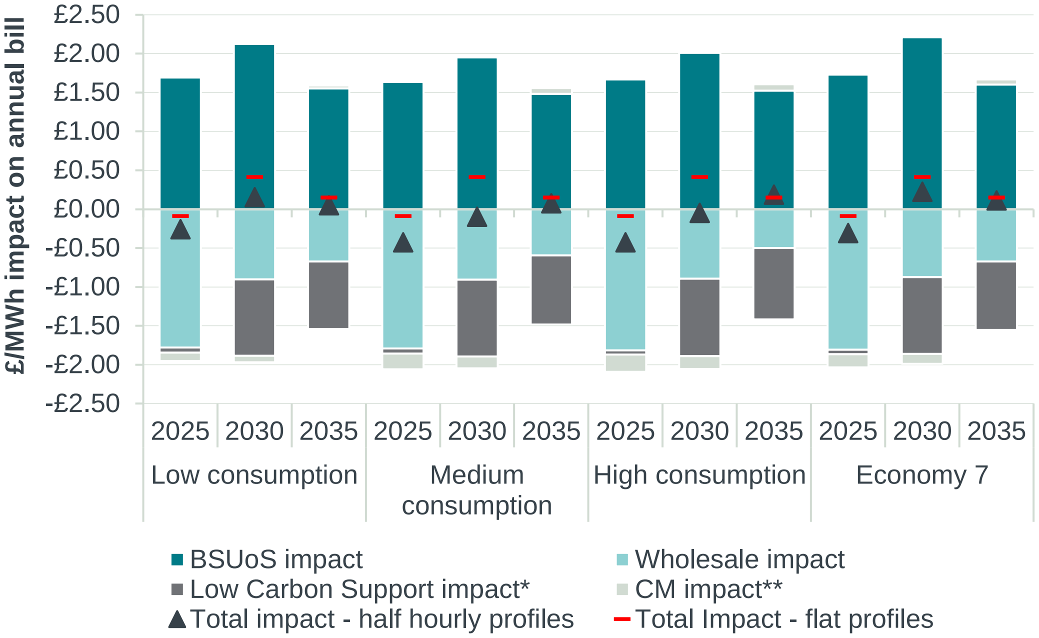
Figure 41 High usage commercial customer annual half hourly net consumption profile with storage unit – Autumn weekday



Source: Frontier analysis of CLNR data

ANNEX B £/MWH DISTRIBUTIONAL CHARTS

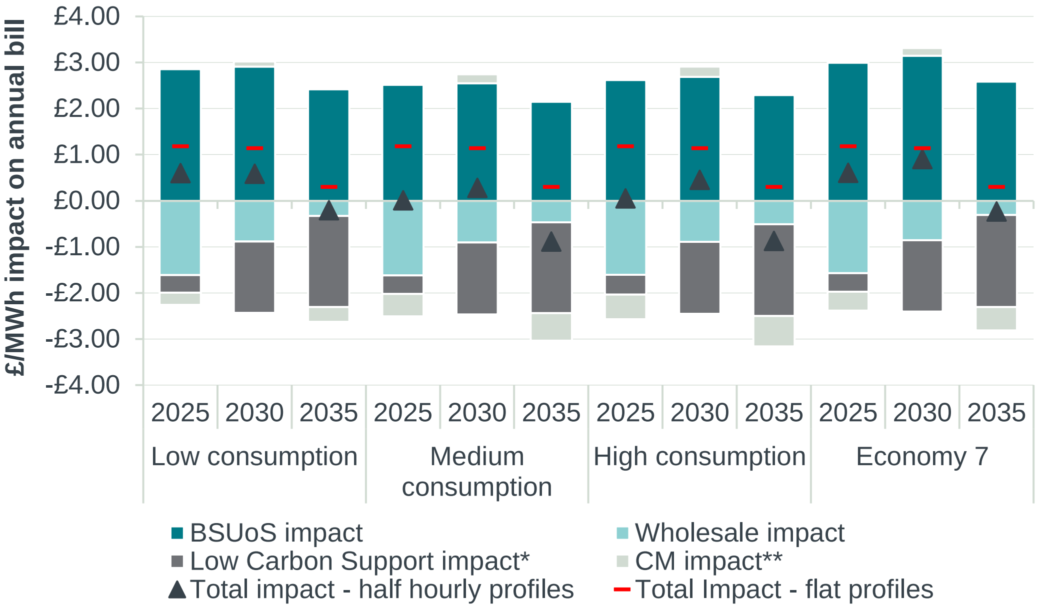
Figure 42 Steady Progression – Annual £/MWh impact – Domestic



Source: Frontier Economics analysis

*Note: *Low Carbon Support includes Contracts for Difference and Renewables Obligation Certificates payments.*
***Capacity Market modelling volatile- we have therefore taken the 5 year average of the forecast (e.g. 2025 is an average of the forecasts from 2023 – 2027 inclusive)*

Figure 43 Consumer transformation – Annual £/MWh impact – Domestic

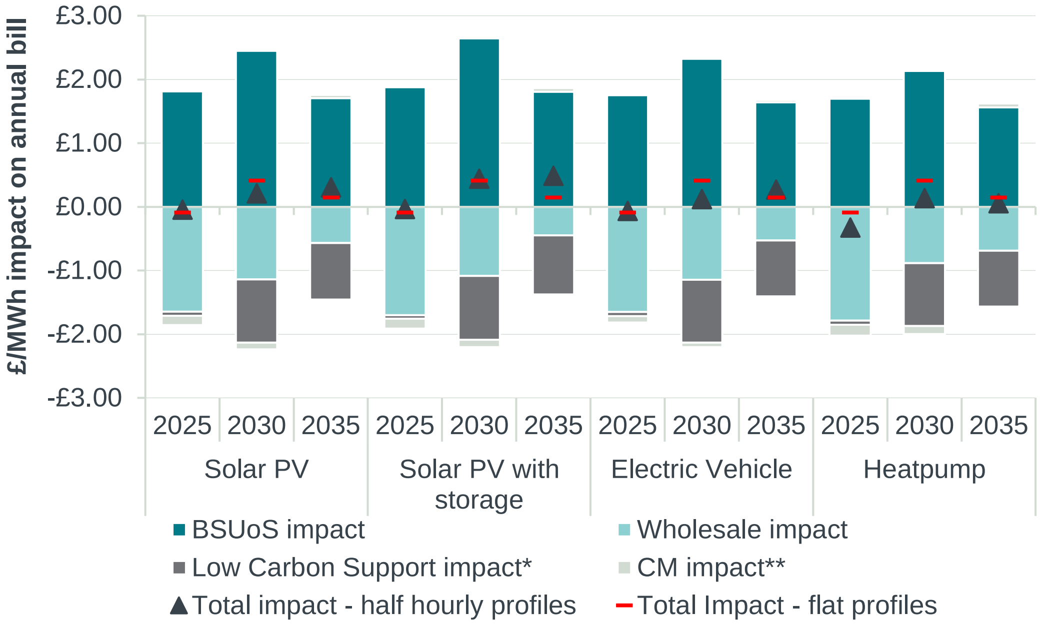


Source: Frontier Economics analysis

*Note: *Low Carbon Support includes Contracts for Difference and Renewables Obligation Certificates payments.*

***Capacity Market modelling volatile- we have therefore taken the 5 year average of the forecast (e.g. 2025 is an average of the forecasts from 2023 – 2027 inclusive*

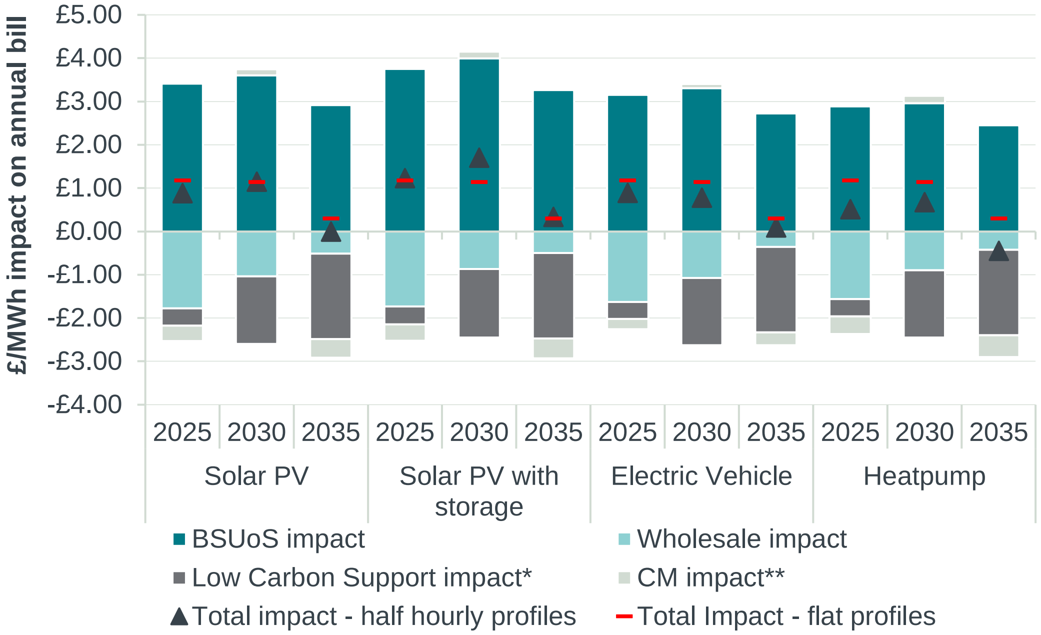
Figure 44 Steady Progression – Annual £/MWh impact – Domestic with low carbon technologies



Source: *Frontier Economics analysis*

Note: **Low Carbon Support includes Contracts for Difference and Renewables Obligation Certificates payments.*
***Capacity Market modelling volatile- we have therefore taken the 5 year average of the forecast (e.g. 2025 is an average of the forecasts from 2023 – 2027 inclusive)*

Figure 45 Consumer Transformation – Annual £/MWh impact – Domestic with low carbon technologies

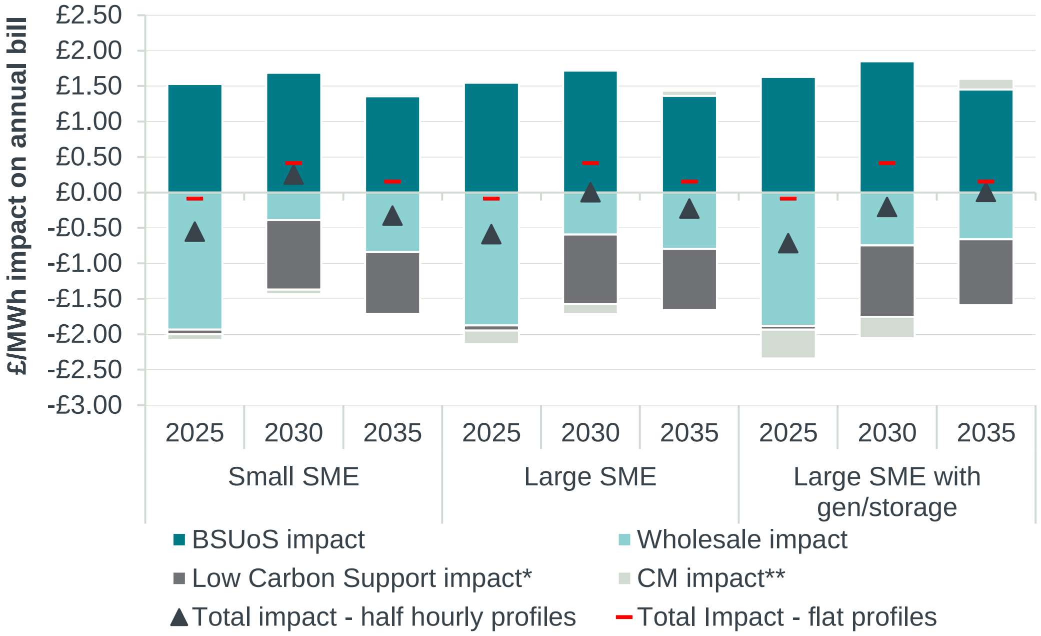


Source: *Frontier Economics analysis*

Note: **Low Carbon Support includes Contracts for Difference and Renewables Obligation Certificates payments.*

***Capacity Market modelling volatile- we have therefore taken the 5 year average of the forecast (e.g. 2025 is an average of the forecasts from 2023 – 2027 inclusive)*

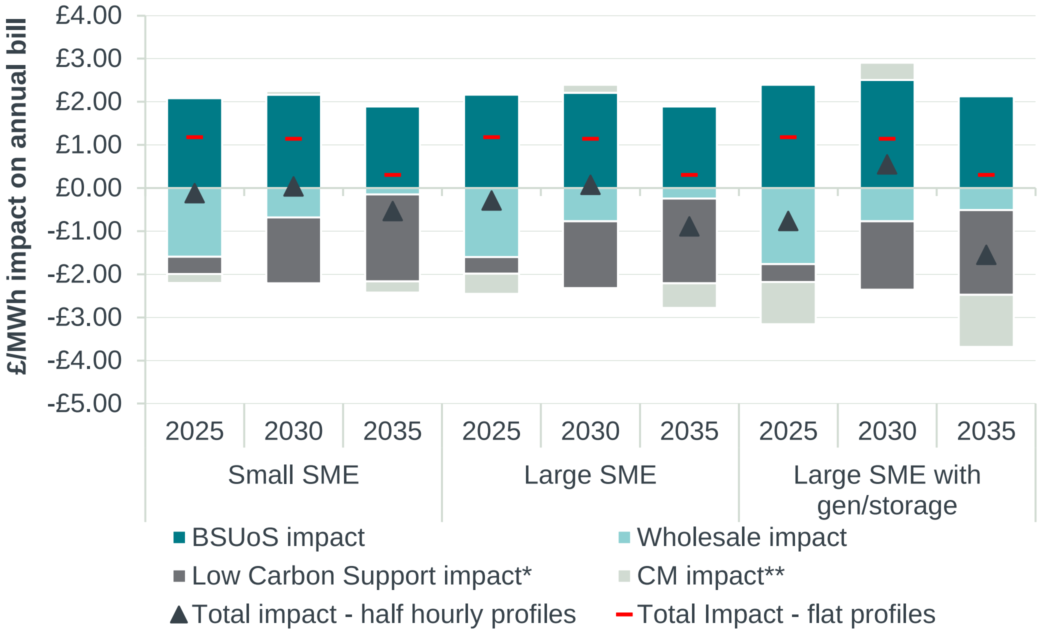
Figure 46 Steady Progression – Annual £/MWh impact – SMEs



Source: *Frontier Economics analysis*

Note: **Low Carbon Support includes Contracts for Difference and Renewables Obligation Certificates payments.*
***Capacity Market modelling volatile- we have therefore taken the 5 year average of the forecast (e.g. 2025 is an average of the forecasts from 2023 – 2027 inclusive)*

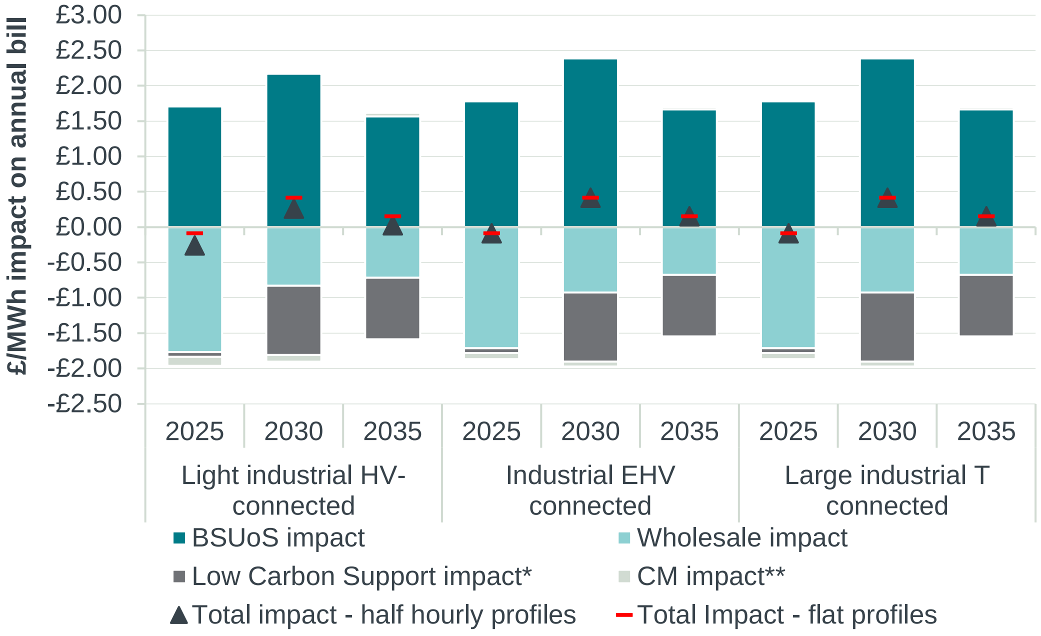
Figure 47 Consumer Transformation – Annual £/MWh impact – SMEs



Source: *Frontier Economics analysis*

Note: **Low Carbon Support includes Contracts for Difference and Renewables Obligation Certificates payments.*
***Capacity Market modelling volatile- we have therefore taken the 5 year average of the forecast (e.g. 2025 is an average of the forecasts from 2023 – 2027 inclusive)*

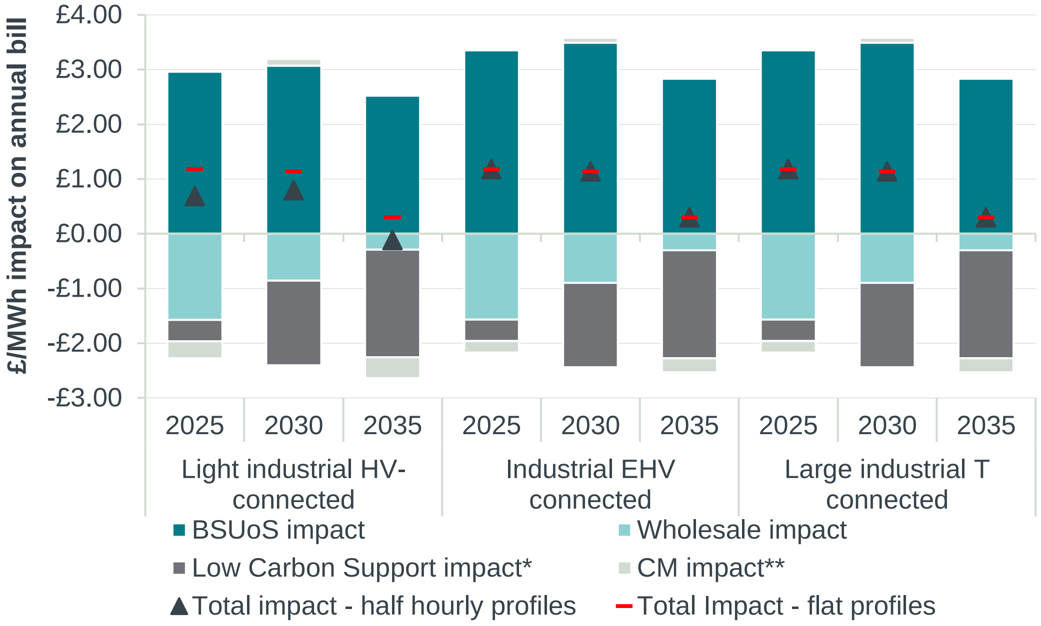
Figure 48 Steady Progression – Annual £/MWh impact – Industrials



Source: Frontier Economics analysis

*Note: *Low Carbon Support includes Contracts for Difference and Renewables Obligation Certificates payments.*
***Capacity Market modelling volatile- we have therefore taken the 5 year average of the forecast (eg. 2025 is an average of the forecasts from 2023 – 2027 inclusive)*

Figure 49 Consumer Transformation – Annual £/MWh impact – Industrials



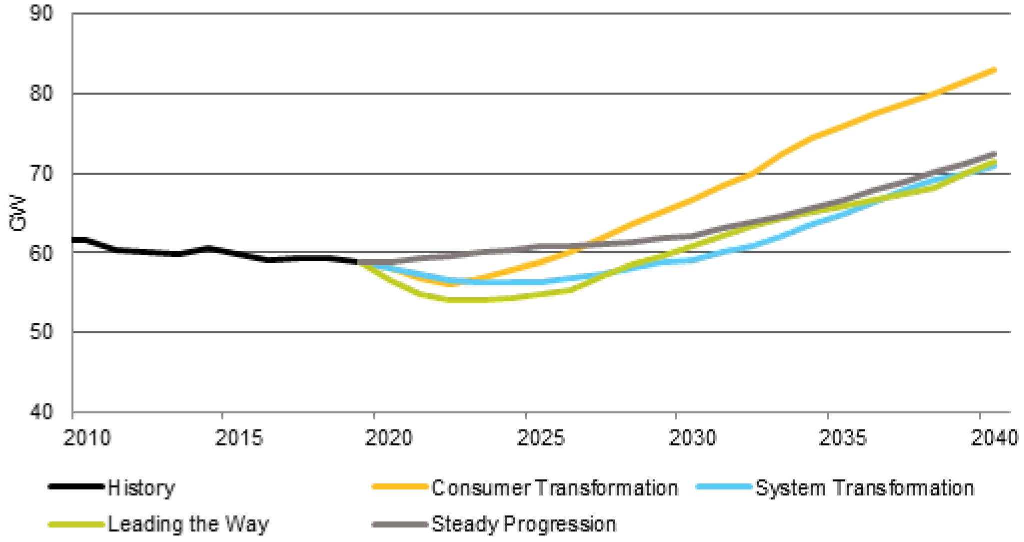
Source: Frontier Economics analysis

*Note: *Low Carbon Support includes Contracts for Difference and Renewables Obligation Certificates payments.*
***Capacity Market modelling volatile- we have therefore taken the 5 year average of the forecast (e.g. 2025 is an average of the forecasts from 2023 – 2027 inclusive)*

ANNEX C ADDITIONAL SYSTEM MODELLING ASSUMPTIONS

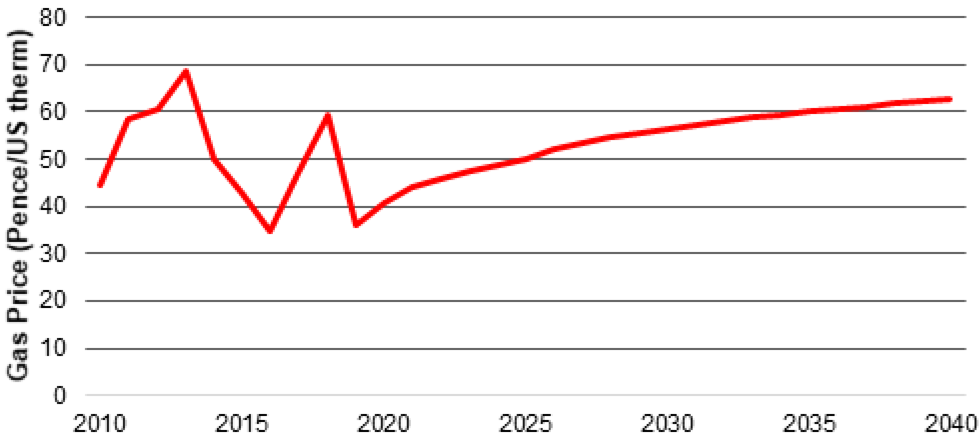
C.1.1 Demand Assumptions

National Grid FES 2020 – Peak Demand, GW

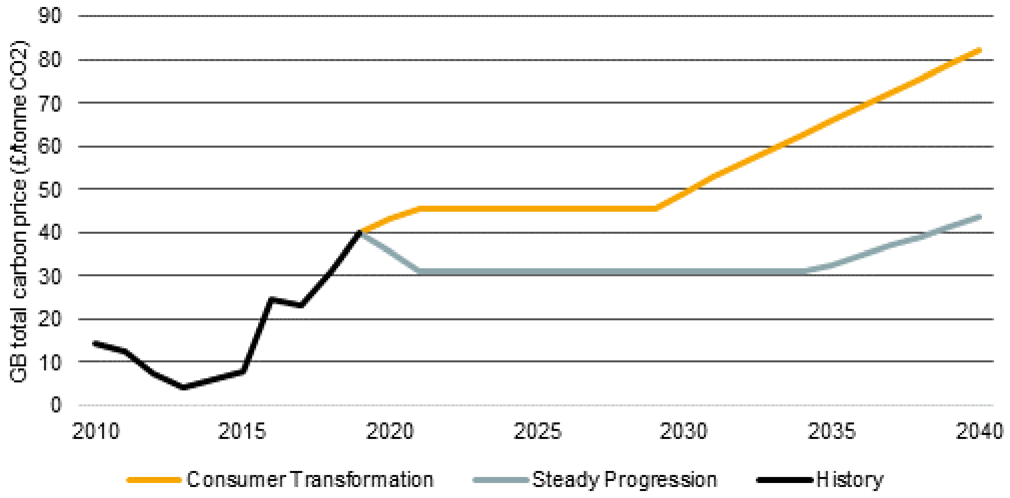


C.1.2 Commodity Prices

National Grid FES 2020 – Base Case Gas Price, p/th

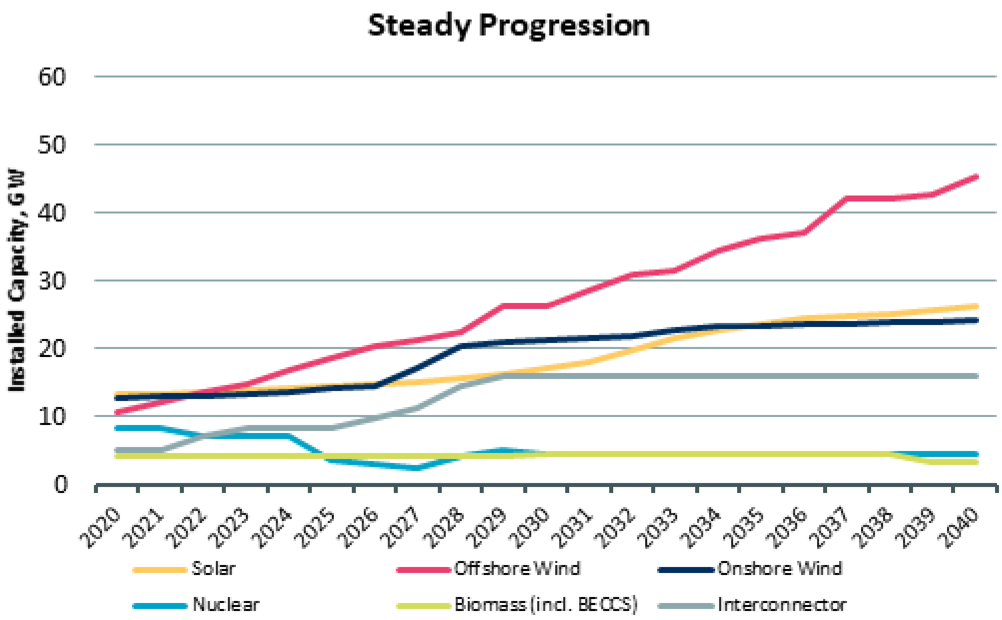


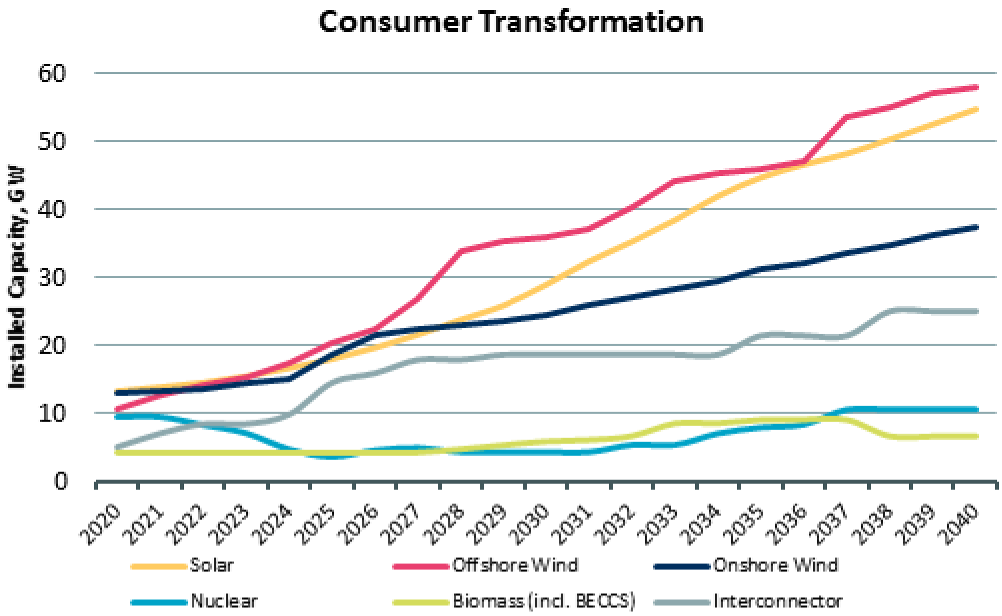
National Grid FES 2020 – Base Case Total Carbon Price, £/t



C.1.3 Low carbon build projections

Projections of post-2020 low carbon build, based on Steady Progression and Consumer Transformation FES 2020 scenarios.




Consumer Transformation
Installed Capacity, GW
60
50
40
30
20
10
0
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2035
2036
2037
2038
2039
2040
Solar
Offshore Wind
Onshore Wind
Nuclear
Biomass (incl. BECCS)
Interconnector

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