TRANSMISSION CHARGING ARRANGEMENTS FOR EMBEDDED GENERATION

March 2017

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1 INTRODUCTION

Electricity generators in GB face a different framework of charges and potential revenues depending on whether they connect to the transmission network or a distribution network. These differences provide 'smaller' (sub-100MW) distribution-connected, or 'embedded' generators, with certain commercial advantages relative to transmission-connected and 'larger' (above 100 MW) distribution-connected generators. These are referred to as 'embedded benefits'.

Ofgem published an open letter on 29 July 2016 seeking responses from industry stakeholders to help inform its position on embedded benefits. In this letter, Ofgem provided guidance on its current thinking on the subject, in particular stating that they believe there is a market distortion caused by embedded benefits, singling out the TNUoS demand residual as their "main concern".[1]

The TNUoS embedded benefits comprise two main aspects:

- **Avoided transmission charges** – a smaller embedded generator does not pay generator TNUoS charges; and
- **Payment element** – a smaller embedded generator can net off their generation against a supplier's demand to reduce the value of the supplier's demand TNUoS charge during the Triad periods – the so-called "Triad benefit".

Industry raised two Connection Use of System Code (CUSC) modification proposals – CMP264 and CMP265 – that attempted to address concerns about the distortions that embedded benefits are causing, particularly in the Capacity Market (CM). Scottish Power raised CMP264 to stop any ***new*** smaller embedded generators[2] from receiving embedded TNUoS benefit after April 2017.[3] EDF raised CMP265 to remove the ability of all smaller embedded generators ***with CM contracts*** to get TNUoS demand residual payments from April 2020.[4]

In addition to the two original proposed modifications, 23 Workgroup Alternative CUSC Modifications (WACMs) were considered in relation to CMP264 and 18 WACMs were considered in relation to CMP265.

Ofgem has engaged Frontier and LCP to provide an independent modelling assessment of the potential impact of changes to network charging arrangements to provide part of the information required to support their decision on whether to approve any of the modification proposals or the proposed alternatives (WACMs), and to contribute to the evidence for Ofgem's impact assessment on their on-going review of network charging arrangements for smaller embedded generators.

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[1] Ofgem. Open letter: Charging arrangements for embedded generation. July 29, 2016.

[2] Defined as connecting after June 30, 2017

[3] National Grid website: http://www2.nationalgrid.com/UK/Industry-information/Electricity-codes/CUSC/Modifications/CMP264/

[4] National Grid website: http://www2.nationalgrid.com/UK/Industry-information/Electricity-codes/CUSC/Modifications/CMP265/

This report is structured as follows:

- In **Section 2,** we provide an overview of the TNUoS embedded benefit.
- In **Section 3,** we describe the methodology and key underlying assumptions of the modelling exercise.
- In **Section 4**, we discuss the modelling results under one modelling scenario, Scenario 3.
- In **Section 5**, we highlight the important features of three other modelling scenarios: Scenario 1, Scenario 2 and the Generator Residual Scenario.
- In **Section 6**, we set out our conclusion.
- Finally, in **Section 7**, we set out some key limitations of our analysis.

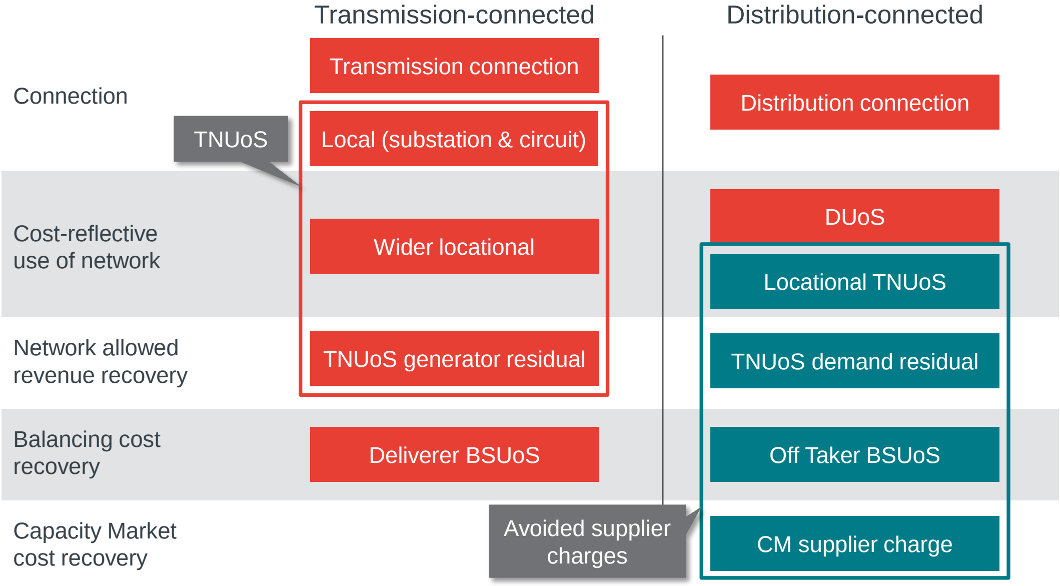
2 OVERVIEW OF EMBEDDED BENEFITS

In this section, we review the current charging framework with regard to embedded benefits. Specifically we provide a high-level view of the charges and revenues faced by Transmission-connected Generators (TGs) and Distribution-connected, or “Embedded” Generators (EGs), for connecting to and using the transmission and distribution networks, and identify the source of the ‘embedded benefit’ for EGs below 100MW (smaller EGs). Subsequently, we provide a more detailed description of the embedded benefit derived from TNUoS charge avoidance – the so-called Triad Benefit – which is the key focus of this engagement.

2.1 Current framework of charges

Embedded benefits derive from the different application of use of system charges on transmission-connected and distribution-connected generators, which includes differences in the way these generators influence the charges facing suppliers.

Figure 1 Overview of current charging framework



Source: Frontier/LCP

Figure 1 provides a visual overview of the current charging framework for TGs and EGs. Under the current arrangements, TGs face three distinct sets of charges related to:

- Connection;
- Transmission Network Use of System (TNUoS); and
- Balancing Services Use of System (BSUoS).

In contrast, EGs face a different charging regime for connection, separate distribution use of system charges (DUoS), and smaller EGs are able to receive a series of payments from suppliers by reducing their net demand, either at peak or throughout the year. Below we briefly describe how embedded benefit arises in relation to each of the following charges:

- ***TNUoS***: TNUoS charges are intended to cover the costs of installing, operating and maintaining the transmission network. Different charges are levied on both generation and demand. Embedded benefits arise both because EGs smaller than 100MW are not charged generator TNUoS directly and because smaller EGs can, through a relationship with a supplier, receive a payment from helping the supplier avoid demand TNUoS charges, which for larger customers are charged on £/kW of demand during the triad period[5].
- ***BSUoS***: BSUoS charges allow the system operator to recover the costs of system balancing actions. They do not reflect the generator’s impact on system balancing costs, but reflect the residual cost recovery element of balancing costs not collected via imbalance charges levied on parties who are out of balance. In contrast to TNUoS, BSUoS is charged on transmission-connected and larger embedded generation and net demand on an energy (£/MWh) basis. This implies that both the smaller EG and the supplier can avoid the charge by netting the smaller EG’s output. The total embedded benefit is equal to twice the BSUoS charge.
- ***CM Supplier Charge***: A smaller embedded generator in the future would have been able to reduce the net demand on which a supplier’s Capacity Market charge is levied, by generating between 4-7pm on weekdays from November to the end of February. The CM Supplier Charge is only levied on suppliers, so the embedded benefit is equal to the size of the avoided charge. As part of on-going consultation (response period ended on 23 December 2016), BEIS has stated that it is minded to amend the supplier charge arrangements so it is calculated on a gross demand basis.[6] This change will effectively remove this embedded benefit stream. At the time of writing, the feedback from this consultation is being analysed by BEIS.

As these charges depend on a generator’s capacity, as well as the size and timing of its output, the value of embedded benefits varies depending on the generator’s specific generation profile, among other factors. Figure 2 provides a summary of the various embedded benefits identified above.

[5] Net demand averaged across the three settlement periods between November and February with the highest transmission system demand, subject to each period being separated by at least ten clear days.

[6] BEIS. “Capacity Market consultation letter – improving the framework.” 28 October 2016.

Figure 2 Summary of embedded benefits

Charge	Avoided charges	Payment element	Total embedded benefit
TNUoS	Smaller EGs do not pay generator TNUoS	"Triad benefit" – by generating in each of the Triad half hours smaller EGs can capture the reduction in a supplier's demand TNUoS	Sum of the demand residual (net of any value retained by the supplier) and the generator residual
BSUoS	Smaller EGs do not pay generator BSUoS	By generating in any half hour of the year, smaller EGs can capture the reduction in a supplier's BSUoS charge	Two times the BSUoS charge (net of any value retained by the supplier)
CM supplier charge	n/a	By generating 4-7pm on workdays from Nov to end of Feb, smaller EGs can capture a reduction in supplier's CM charge	Sum of CM charges (net of any value retained by the supplier)

Source: Frontier/LCP

In the following sub-section, we discuss in more detail the embedded benefit derived from TNUoS charge avoidance – the so-called Triad Benefit – which is the key focus of this engagement.

2.2 Triad benefit

TNUoS charges are levied on both generation and demand. The generator TNUoS charge is paid by TGs and EGs larger than 100MW. It is formed of three distinct components: local charges, a wider locational charge and a residual.

- Local charges, where they apply, cover an estimate of the incremental costs related to the local circuit and substation imposed by the generator.
- The wider locational charge is intended to reflect the incremental costs imposed by the generator on the wider transmission network. This element is negative where a generator effectively reduces costs by reducing the need to flow power over the transmission network. Were this charge to be levied on all users, it would not recover enough money to fund generation's share of National Grid's total allowed revenue. This is because there is no reason that the forward looking incremental costs of transmission investment should equate to the average costs of past investment, which National Grid must also recover.
- The residual, unlike the other elements, is not intended to reflect the costs imposed by the generator, but is required to ensure that the total revenues collected through charges match the revenues that National Grid is allowed to collect. This element can be positive or negative depending on whether the local and wider TNUoS charges are expected to under or over collect relative to generation's share of the transmission network's allowed revenues.

Demand TNUoS consists of two components: a locational charge and a residual.

- The *locational* charge estimates the incremental transmission cost resulting from connections to the transmission network at various locations around GB.

As with generation, were this charge to be levied on all users, it would not recover enough money to fund demand's share of National Grid's total allowed revenue. This is because there is no reason that the forward looking incremental costs of transmission investment should equate to the average costs of past investment, which National Grid must also recover.

- The residual again recovers the sunk costs of the transmission network over and above its estimated forward looking incremental costs.

Smaller EG output during the "triad" half-hours is deducted from supplier's gross demand in order to calculate the supplier's net demand and, consequently, smaller EG affect the charges levied on the relevant supplier. The final payment to the generator is based on an agreement on how to share the avoided charges – typically with the generator securing the majority.

We consider the embedded benefits arising from each component separately.

Locational signals

Within the generator TNUoS charge, the wider locational element of TNUoS is explicitly designed in an attempt to incentivise the efficient location of generation capacity by imposing location-specific charges that aim to reflect the incremental costs to the wider transmission network of increasing generating capacity in the area. In areas where the costs of accommodating incremental generation connections are estimated to be high, this locational element will tend to be a positive charge, discouraging the addition of further capacity that might trigger reinforcement of the transmission network. Conversely, the locational charge is negative in regions where the presence of additional generation capacity would tend to reduce existing transmission flows.

TGs, larger EGs and suppliers face a wider locational charge under TNUoS, based on their capacity and triad demand respectively. The charging zones for generation and demand differ for reasons of metering and settlement, but the assessment of incremental costs stems from the same source – the Direct Current Load Flow Investment Cost Related Pricing (DCLF ICRP) model. In effect, this model attempts to assess the incremental cost impact on the transmission network of increases in generation or demand at different points on the transmission network.

Smaller EGs do not face TNUoS charges directly but, by reducing suppliers' demand, effectively face the inverse of the TNUoS demand charges. To the extent that the locational TNUoS charges facing TGs or larger EGs and suppliers are equal and opposite and smaller EGs fully face the inverse of suppliers' TNUoS charges, all generators face the same locational signals under TNUoS.

In practice however, there are several reasons why TGs and larger EGs may face different wider locational signals from smaller EGs. In particular:

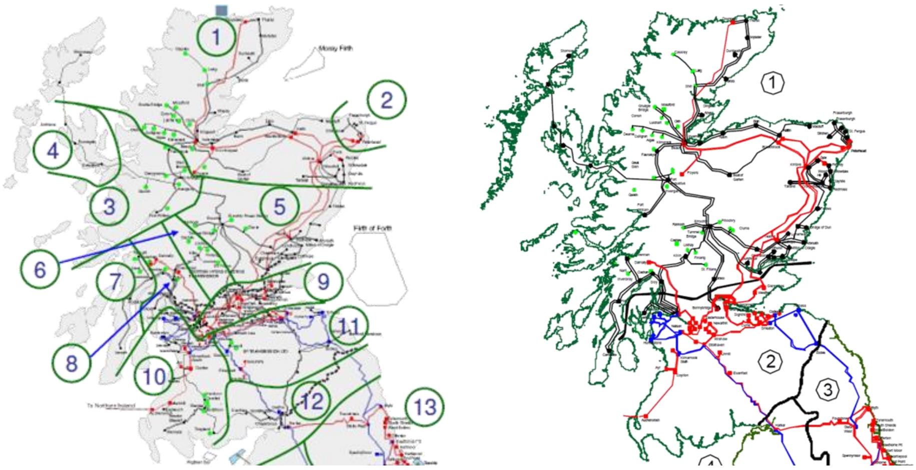
- *Charging base* – Following the introduction of Project Transmit, generator TNUoS is levied on the basis of the generator's capacity and average load factor. Demand TNUoS is levied basis of Triad demand, such that any inverse TNUoS charges facing a smaller EG are on the basis of their Triad generation. There is no reason why the charges implied by these different methodologies should be the same. For example, a large generator with zero output during Triad would face a positive charge under generator TNUoS, but none under the inverse of demand TNUoS.

- *Charging zones* – The locational charges under TNUoS are constructed by averaging the modelled incremental costs at several points on the transmission network. As noted above, the zones used for charging are not the same for generator TNUoS and demand TNUoS, resulting in different averages being calculated and different charges being used. An example of the differences in zone definitions can be seen in Figure 3 below.

Figure 3 Differences between generator and demand charging zones

Generator zones

Demand zones



Source: National Grid

The result is that a smaller EG may receive a benefit or cost depending on the difference between their locational charge and that of an equivalent TG or larger EG.

Cost-recovery residuals

It is the TNUoS residual that makes up the majority of the TNUoS-related embedded benefit. This benefit consists of the avoided demand residual, which is paid to the smaller EGs (net of value retained by the supplier), and the generator residual, which smaller EGs do not have to pay. Historically, avoiding the generator residual has been a benefit to smaller EGs, but in future this 'charge' is expected to become negative, such that smaller EGs are actually disadvantaged by not receiving a negative generator residual. Overall however, this effect is swamped by the value of the avoided supplier demand residual which provides a significant advantage to smaller EGs over TGs and larger EGs.

3 METHODOLOGY AND ASSUMPTIONS

The two original CUSC modification proposals and the variations to these proposal reflected in the WACMs provide a range of scenarios for proposed changes to the embedded benefit arrangements, in particular, a reduction in the demand TNUoS residual. Ofgem is interested in understanding the potential impact of these changes, and its distribution, through market modelling.

Any changes to network charging arrangements are likely to have a direct impact on investment and retirement decisions and on operational behaviour. These will in turn affect many areas of the market. Capturing these effects requires an approach which can analyse these direct and indirect effects.

To do this, we have deployed LCP's EnVision model, a fully integrated model of the GB power market, which models these direct and indirect effects. EnVision was originally developed to model the impact of the UK government's Electricity Market Reforms.

The model simulates wholesale market dispatch at a granular, half-hourly level, taking into account plant dynamics such as start costs and minimum up/down times. It also estimates the revenues available to plant through participation in ancillary markets, such as providing the system with 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 is held constant across the scenarios considered.

We use the LCP EnVision model to examine the impact of changing the demand TNUoS residual on the following key aspects:

- The economics of reciprocating gas and diesel engines;
- The plant mix that results from the CM;
- CM clearing prices;
- Loss of Load Expectation (LOLE);
- Wholesale prices;
- Load factors of different generating technologies;
- Costs of procuring reserve services;
- BSUoS charges;
- Carbon emissions;
- Overall system costs; and
- Consumer cost.

It will be important that sound economic principles form the basis of the final decision in relation to any CUSC modification. Such principles include cost reflectivity and minimising distortions to competition. Charging in a manner consistent with such principles should help ensure an optimum outcome for society as a whole.

Relying on modelling outputs as the sole, or potentially even main, basis for a decision on the CUSC modifications has its limitations. While the EnVision model attempts to replicate the decisions made by market participants, it does so against the background of a number of 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.

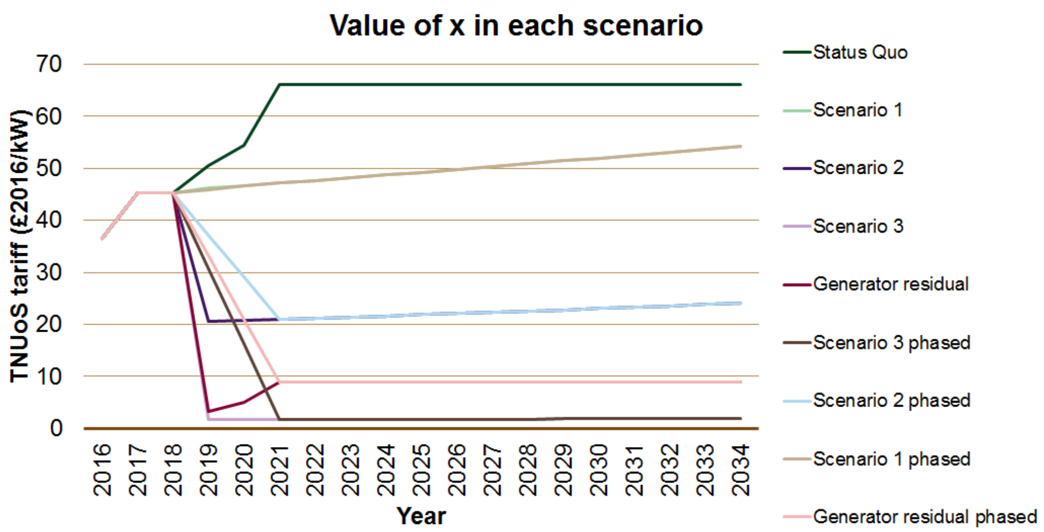
We specify our modelling scenarios and key input assumptions in the sub-sections below.

3.1 Modelling scenarios

Consistent with our discussions with the Ofgem team, we have considered four different scenarios for reducing the demand TNUoS residual, in addition to the Status Quo. These scenarios, summarised in Figure 5 below, have been designed by varying the level of benefit received by smaller embedded generators from the demand TNUoS residual (‘value of x’) so as to cover the majority of WACMs in an efficient manner. The assumptions regarding the demand TNUoS residual used in the report are based on the latest forecasts from National Grid (dated February 2016) available at the time of analysis. National Grid has recently published an updated forecast (dated February 2017). Differences between the two forecasts will not significantly impact the results in this report.

Figure 5. Modelling scenarios

Scenario	Assumption regarding the demand TNUoS residual
Status Quo	The demand TNUoS residual increases in line with National Grid's forecast until 2021, after which it remains flat in real terms at £72.03/kW (£66.0/kW in £2016 terms).
Scenario 1	From 2019, the charge is set at £45.33/kW plus RPI. This is equal to the current demand TNUoS residual level.
Scenario 2	From 2019, the charge is set at £20.12/kW plus RPI. This is equal to the value of avoided GSP investment and future transmission capital costs.
Scenario 3	From 2019, the charge is set at £1.62/kW plus RPI. This is equal to the value of avoided GSP investment.
Generator residual scenario	From 2019, the charge is set to the level of the generator residual tariff (adjusted for CPI).



Source: Frontier

Note: All figures in the table are in £2016 real terms.

Across these scenarios, we have then considered a number of options for any possible modification, as discussed with Ofgem. These "levers" include:

- Grandfathering at £45.33/kW plus RPI for existing capacity commissioned before 1st July 2017;
- Grandfathering at £45.33/kW plus RPI for reciprocating engines with Capacity Market contracts for delivery in 2018/2019 and 2019/2020; and
- Immediate implementation of the removal of triad benefits, from 2018/19, or a more phased approach, including a 3–year phasing.

3.2 Cost assumptions

In the analysis, there are four main technologies that compete to provide new capacity: CCGTs, OCGTs, reciprocating diesel engines and reciprocating gas engines. Figure 6 below outlines the fixed operating expenditure (opex) and build costs (total capital expenditure and infrastructure costs) assumed when modelling these plants.

Figure 6. Cost assumptions

Technology	Build Costs (£2015 real /kW)	Fixed costs (£2015 real /kW/pa)
CCGT	416	17.6
OCGT	339	8.9
Reciprocating diesel	255	11.0
Reciprocating gas	345	11.0

Source: BEIS. Low Assumptions, Electricity Generation Costs. November 2016.

BEIS' Low Assumptions (Nov 2016) form the basis of these figures. The implied total capital expenditure (capex) of a reciprocating diesel engine under these assumptions falls below the requirement of a new build in the capacity mechanism to spend at least £255/kW. Therefore, we have set the build costs of a reciprocating diesel engine to be £255/kW in order to meet this threshold.

3.3 Relationship of modelling scenarios to proposed WACMs

The scenarios we have chosen have been designed in consultation with Ofgem with the aim to try represent the largest spectrum of proposed WACMs in an efficient manner. There is an additional condition laid out in the legal text outlining the implementation of the chosen WACMs, relating to the total demand TNUoS signal a smaller embedded generator should receive. This states that:

$$Total\ demand\ signal\ (£/kW) = Max(0, locational\ signal + x)$$

Here, x is the proposed demand residual that can be offset – this is the value that is assumed to change across our modelling scenarios. Certain demand zones, such as those in Scotland, face negative locational signals. Under Status Quo, the TNUoS demand residual (or x) is large enough to ensure that the total demand signal is always positive regardless of the direction (negative or positive) of the locational signal. However, under certain modelling scenarios, such as Scenario 3, the assumed value of x is small enough to result in a negative number for the total demand signal when the locational signal is large and negative. In this situation, the condition on the total demand signal above implies that it will be floored at zero. As such, in the situation where the locational signal faced by the generators is negative and larger than x, generators will receive an additional 'benefit' in the form of a higher value of x to force the total demand signal to equal zero. Broadly, this implies that while the locational signals approximately average zero, the total demand signal will be skewed to be positive under small values of x.

In the modelling exercise being currently undertaken, it would be spurious and misleading to assign locations to every future plant built. The exact locations of plant built would affect the extent to which this flooring mechanism is applied. As such, we have averaged the locational signal at zero and assumed every plant sees this signal.

3.4 Other key assumptions

Other notable assumptions include:

- Renewable build and demand growth are in line with the ‘Slow Progression’ scenario from National Grid’s 2016 “Future Energy Scenarios” report.
- 90% of embedded benefits are assumed to be shared with the smaller embedded generator in the case that the supplier avoids charges.
- The number of hours a plant must run in order to hit triad is dynamic in the model and is dependent on the deployment of embedded capacity.
- The volume of new reciprocating engine capacity (gas and diesel combined) that can come forward in any one year is limited. The cap is set at 2GW for the delivery year 2021/22, and is set at 1GW thereafter.

4 MODELLING RESULTS

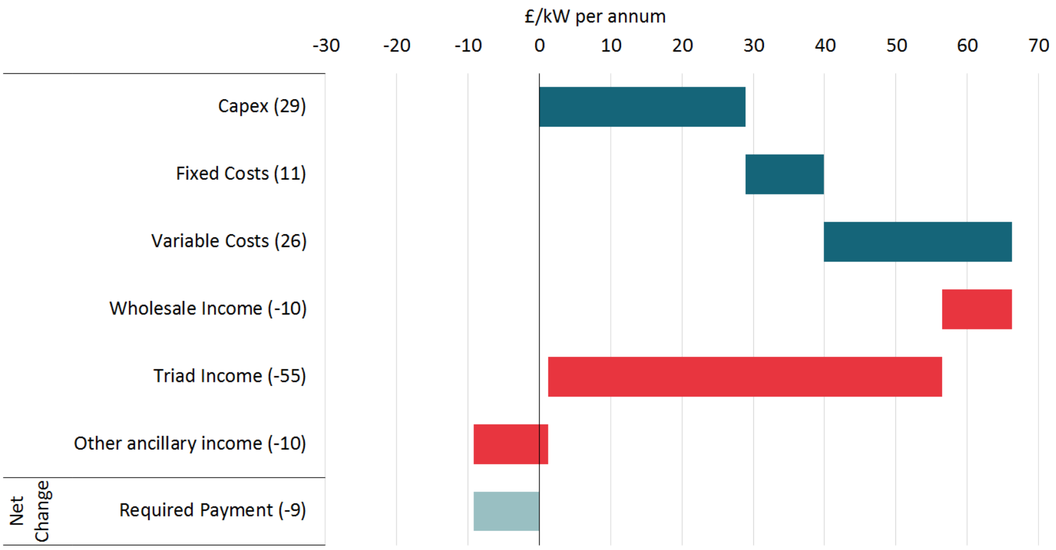
In this section we discuss the modelling results under the Status Quo and Scenario 3, where we have assumed the largest change in the demand TNUoS residual (£1.62/kW from 2019). Key results for Scenarios 1 and 2 can be found in the Appendices. We assess the impact of reducing the demand TNUoS residual (as per Scenario 3) for the period 2017 and 2034.

Unless otherwise stated, all figures in this report are in £2016 real terms.

4.1 Economics of reciprocating engines

The change in the level of the demand TNUoS residual has a significant impact on the profitability of reciprocating engines. In Figure 7 and Figure 8 respectively, for the year 2022 we show the required capacity payment per kW per year for a reciprocating diesel engine under Status Quo and for Scenario 3 based on the modelling assumptions. We display 2022 because this will be the delivery year for the next T-4 Capacity Market auction. The costs and revenue streams shown in the figures are on a £ per kW per year basis, discounted at the technology's assumed hurdle rate of 7.5% where appropriate.

Figure 7. Revenue break down under an archetypal reciprocating diesel engine under Status Quo, 2022[7]

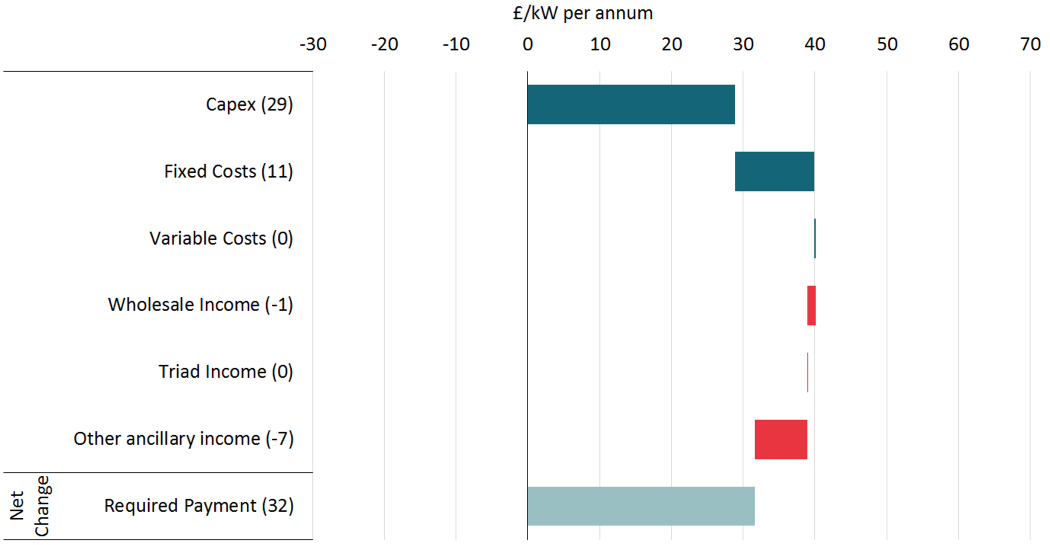


Source: Frontier/ LCP

Under our modelling of the Status Quo, a typical reciprocating diesel unit makes a loss in the wholesale market (variable costs exceed wholesale income) in order to chase triad hours and receive the triad benefit. The significant level of triad benefit available means that a new reciprocating diesel engine does not require any additional capacity payment ("Required Payment" in figure above) to break even, and could therefore bid into the CM at a price near zero.

[7] 'Other ancillary income' includes balancing services such as the provision of STOR.

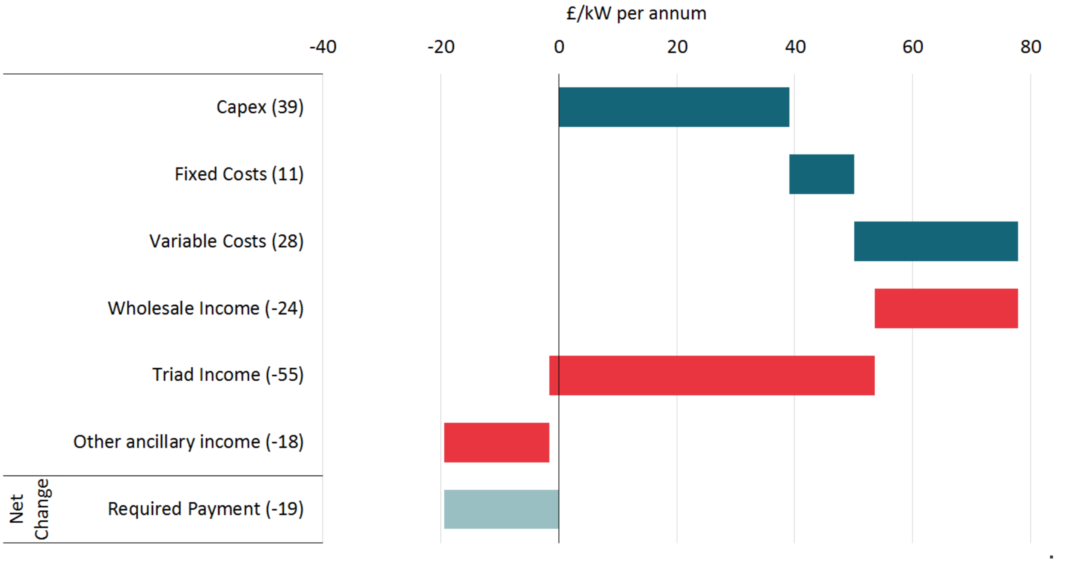
Figure 8. Revenue breakdown under an archetypal reciprocating diesel engine under Scenario 3, 2022



Source: Frontier/LCP

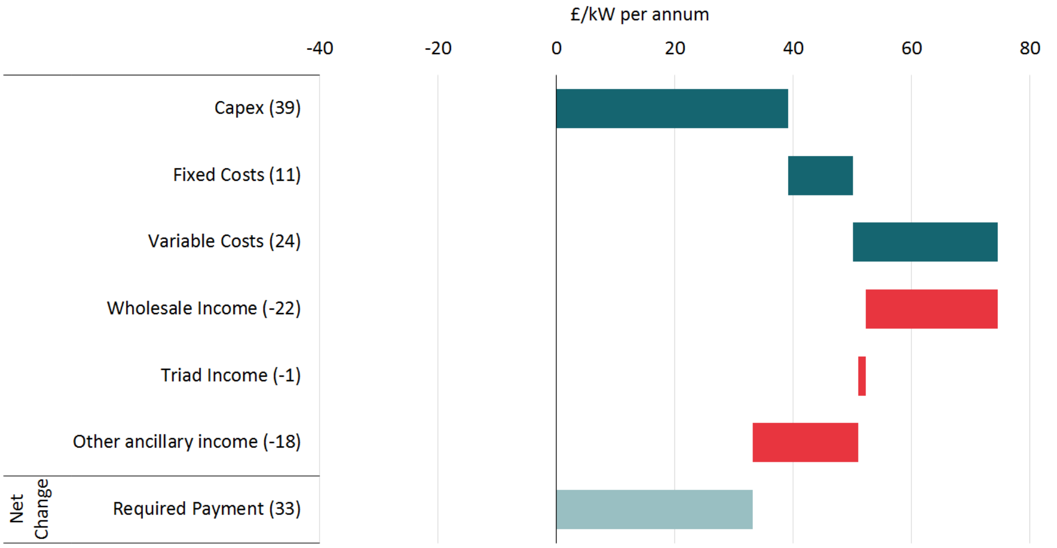
Under Scenario 3, our modelling of the reduction in the triad income increases the level of support required to £32/kW based on these assumptions. Therefore, we would expect to see a significant increase in the CM bid of a reciprocating diesel engine. There is a similar effect on the bids of reciprocating gas engines (Figures 9 and 10 below) when reducing the level of the demand TNUoS residual.

Figure 9. Revenue breakdown under an archetypal reciprocating gas engine under Status Quo, 2022



Source: Frontier/LCP

Figure 10. Revenue breakdown under an archetypal reciprocating gas engine under Scenario 3, 2022

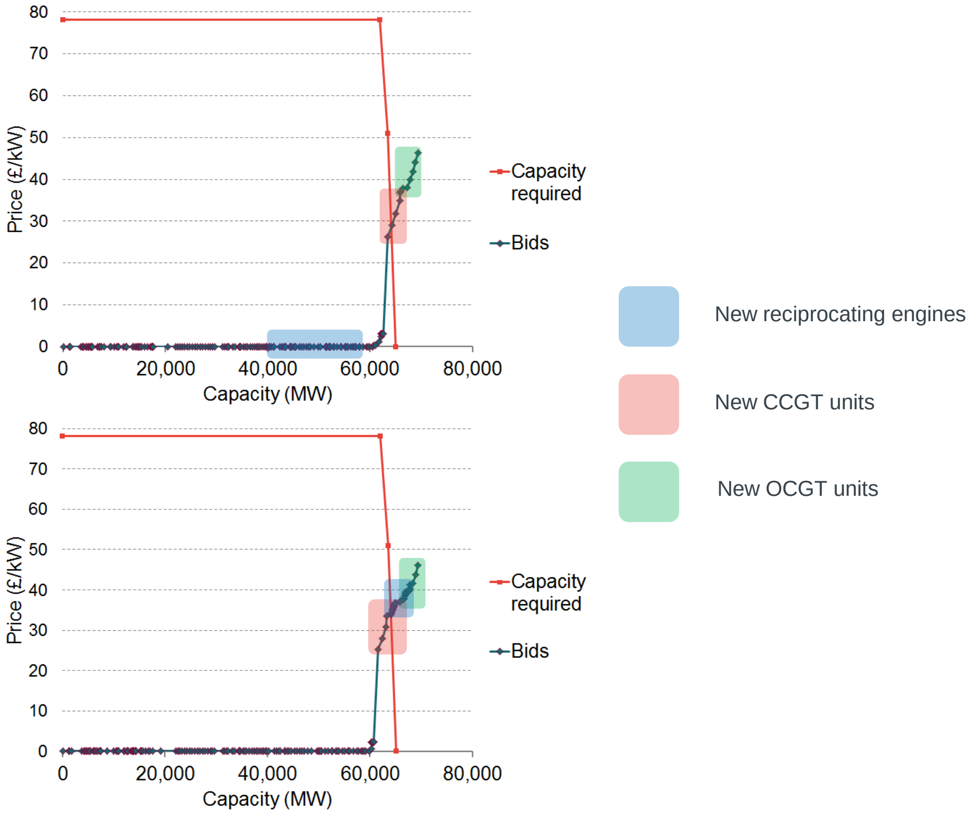


Source: Frontier/LCP

4.2 Capacity Market build

In Figure 11 below, we show the impact on our modelled CM supply curve for the year 2022 under Status Quo and under Scenario 3.

Figure 11. CM bid curve 2022 – Status Quo and Scenario 3

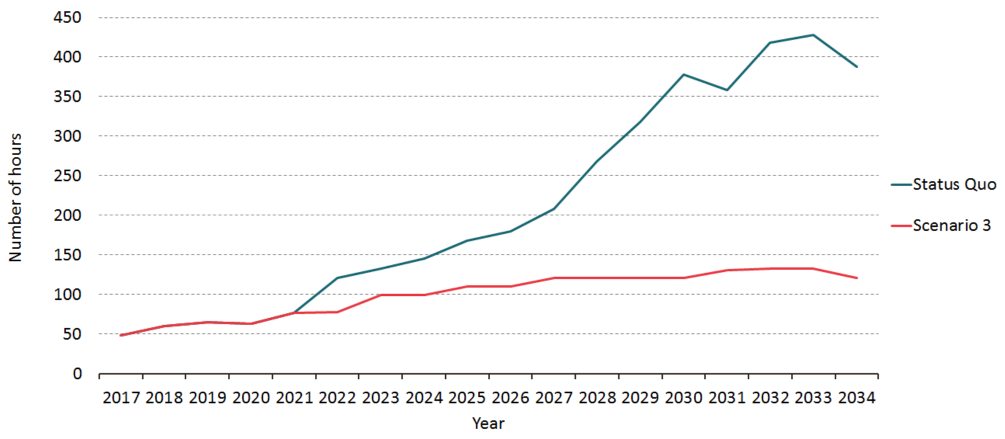


Source: Frontier/LCP

Our modelling indicates reciprocating engines moving from bidding essentially £0/kW under the Status Quo to bidding in the £30-40/kW region, shown by the increased cluster of bids in this region under Scenario 3. Under these assumptions, significantly fewer reciprocating engines are able to clear.

We also consider the number of hours during which embedded plant need to run to be confident of producing during the triad.

Figure 12 Theoretical number of hours required to chase triad

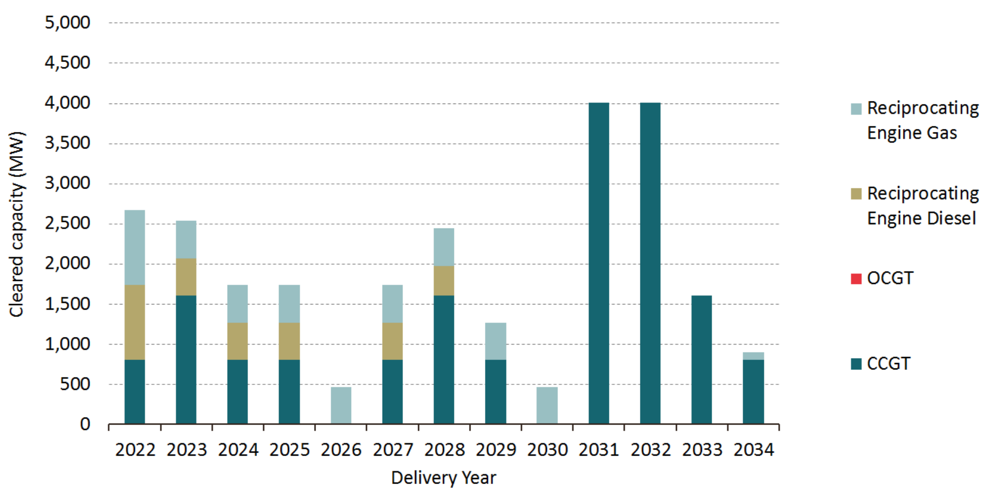


Source: Frontier/LCP

As the volume of smaller embedded generation grows, the number of hours required to run to chase the triad periods increases greatly. The result is that the build out of reciprocating engines slows as the wholesale market losses of running to hit triad trade off against the benefit of receiving triad income.

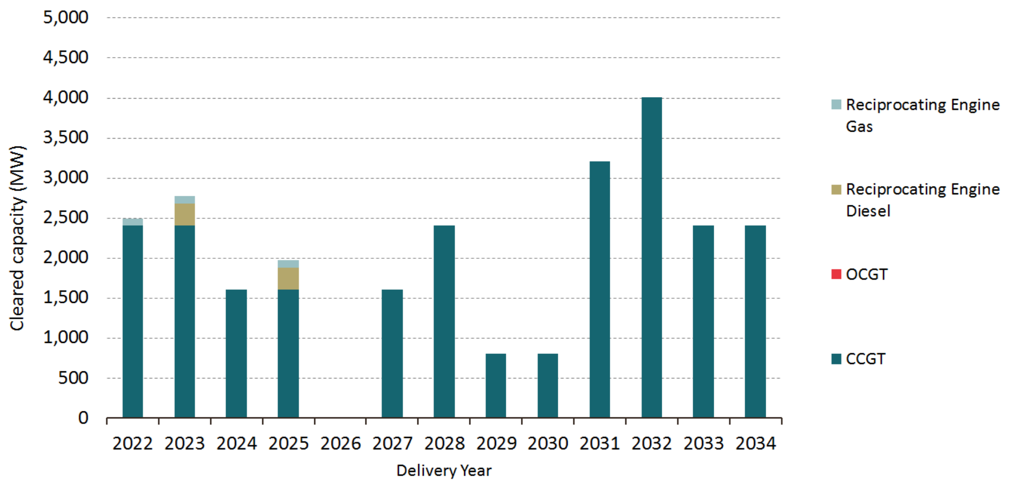
We then consider the CM build under the Status Quo and Scenario 3.

Figure 13. CM build under the Status Quo



Source: Frontier/LCP

Figure 14. CM build under Scenario 3



Source: Frontier/LCP

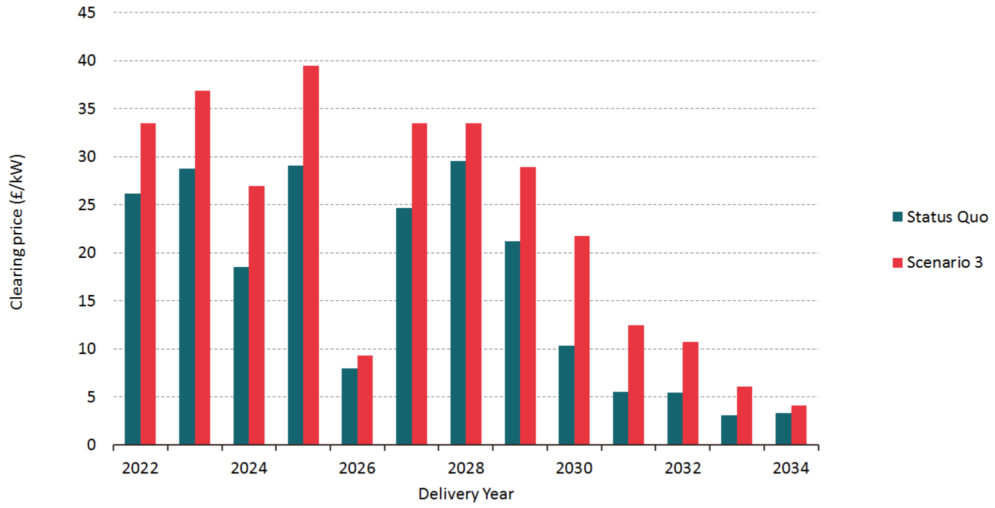
Figure 13 shows that under the Status Quo the maximum volume of reciprocating gas and diesel engines clears in the early years (note that the charts show derated capacity figures). As time progresses and the embedded volume on the system increases, the number of hours required to run to capture the triad benefit increases. We therefore model a decrease in the volume of diesel plant clearing as the losses incurred chasing triad revenues start to outweigh the triad benefit (diesel is not competitive in the wholesale market and the triad benefit represents the majority of its income). Gas reciprocating engines, which are more competitive in the wholesale market, continue to clear for longer, but eventually their build-out slows for a similar reason.

Conversely, our modelling shows very little build out of reciprocating engines under Scenario 3 (Figure 14 above). In our results, the reduction of the demand TNUoS residual in Scenario 3 increases the bids of reciprocating engines. This increase is sufficient to prevent these units from clearing in the CM auction and allows the procurement of alternative new capacity. In our modelling, new CCGT units replace these engines and bids from new OCGT units are not competitive.

4.3 Capacity Market clearing prices

Our modelling shows the reduction in the demand TNUoS residual increasing the CM clearing price in each year. Figure 15 below shows the modelled clearing prices under Status Quo and Scenario 3. The observed increase in CM clearing prices results from the increased reciprocating engine bids. For example, in 2022 our modelling shows the clearing price increasing from £26.2/kW to £33.4/kW due to the building of more (and more expensive) new CCGT units.

Figure 15. CM clearing prices

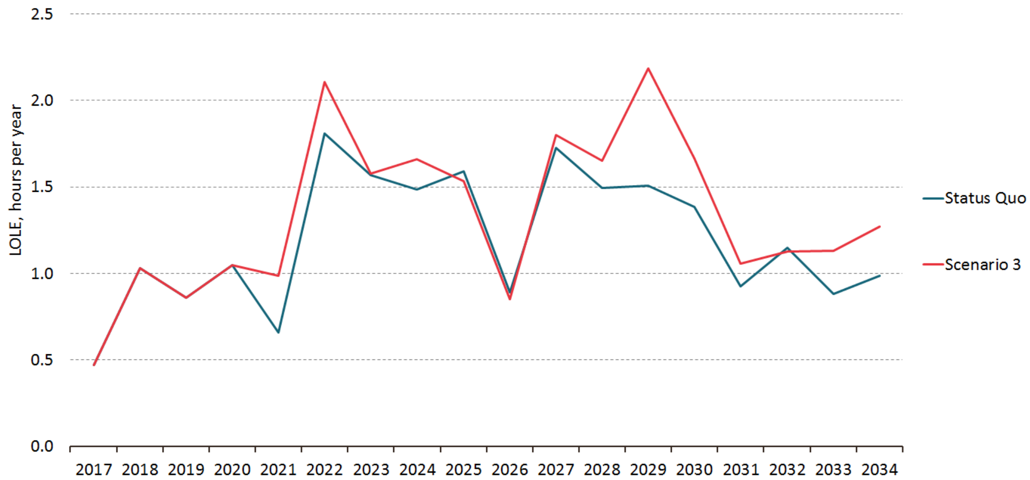


Source: Frontier/LCP

4.4 Loss of load expectation (LOLE)

Figure 16 below compares the loss of load expectation (LOLE) between the Status Quo and Scenario 3. A higher LOLE indicates a less secure system.

Figure 16. Loss of Load Expectation



Source: Frontier/LCP

Both scenarios demonstrate LOLEs below the security standard of 3 hours per year, due to a combination of clearing prices being below the Net-CONE[8] price level, and some prudence used when setting the capacity target. In the Status Quo, our modelling generally shows a lower LOLE due to the lower bids of

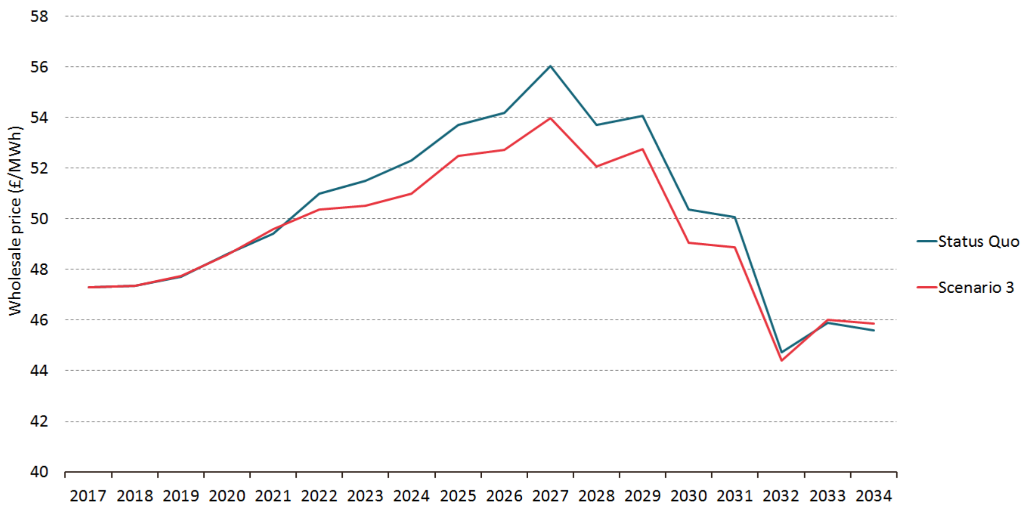
[8] Net-CONE (Cost of New Entrant) is the cost of a new entrant after accounting for wholesale and ancillary market revenues. It is currently based on the lowest CM bid of a new CCGT.

reciprocating engines. This means that the CM clears at a lower price, and hence with more capacity given the slope to the demand curve.

4.5 Wholesale prices

Figure 17 below shows the average annual wholesale price between 2017 and 2034 under each scenario. We can observe that the wholesale prices are lower on average under Scenario 3 as compared to the Status Quo.

Figure 17. Average annual wholesale prices



Source: Frontier/LCP

In our modelling, there are two competing factors affecting wholesale prices in these scenarios. Reciprocating engines will dampen prices in high demand periods by chasing triad hours. Therefore, the large quantity of new build reciprocating engines observed under Status Quo results in a slight wholesale price reduction initially.

However, in Scenario 3 the model dynamically forecasts a greater volume of new build CCGT. These units are more efficient than existing CCGT units, and therefore set lower peak and baseload wholesale prices.

4.6 Load factors

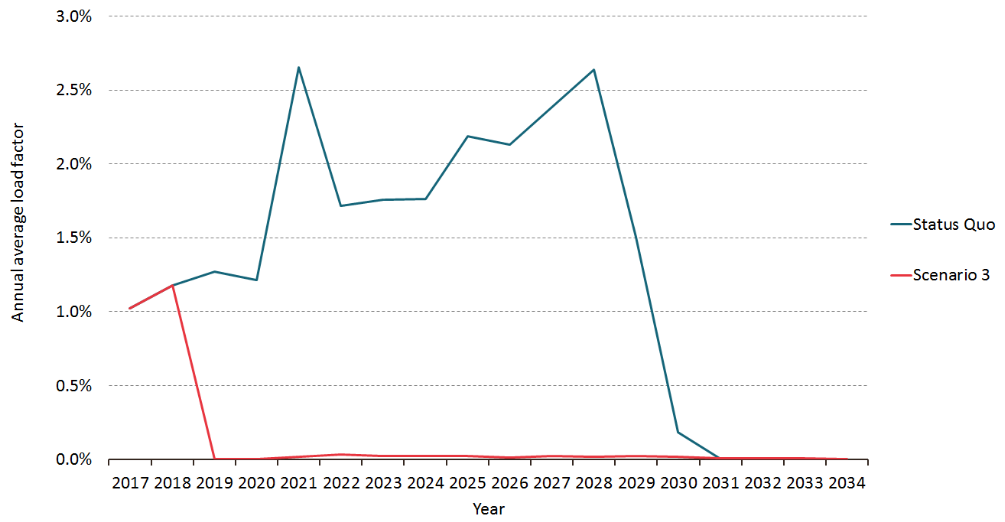
In this section, we consider the effect of the change from Status Quo to Scenario 3 on the average annual load factors for key plant types.

4.6.1 Reciprocating diesel

The reduction of the demand TNUoS residual in Scenario 3 reduces the incentive for a reciprocating engine to chase triad revenue. Therefore, in our modelling these units spend fewer hours chasing triads and have a reduced load factor when compared to the Status Quo. Figure 18 below shows this effect, as the load factor of a diesel reciprocating engine is lower under Scenario 3 than Status

Quo (diesel engines are rarely in merit, and so under Scenario 3 their load factors are close to 0%).

Figure 18. Annual average load factor – reciprocating diesel engine

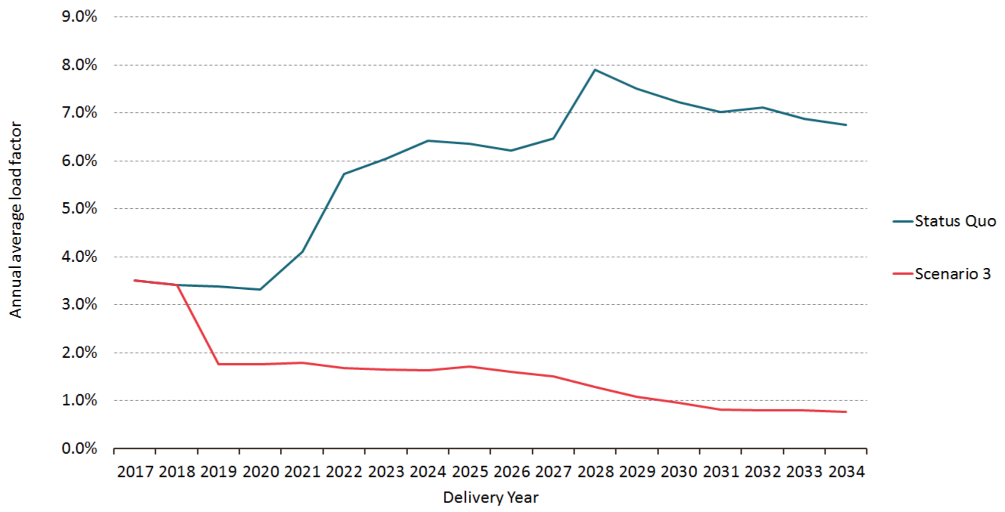


Source: Frontier/LCP

4.6.2 Reciprocating gas

Our modelling also shows reciprocating gas engines having a lower average annual load factor under Scenario 3 than under the Status Quo due to a reduction in hours spent chasing triad (Figure 19). However, in contrast to diesel engines, they remain in merit during high demand periods and maintain a load factor above 0.7% in the period modelled.

Figure 19. Average annual load factor – reciprocating gas engine

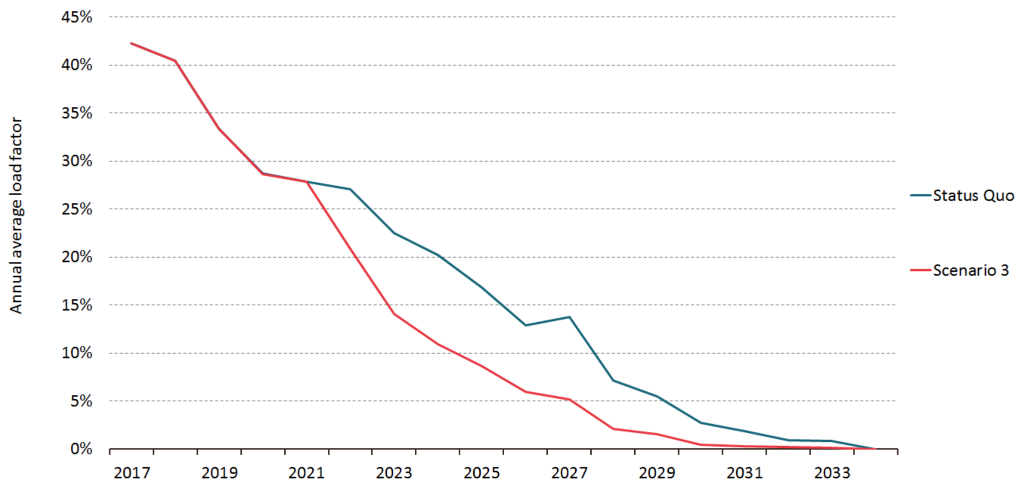


Source: Frontier/LCP

4.6.3 Existing CCGT

Our modelling shows lower average annual load factors for an existing mid-merit CCGT unit under Scenario 3 than under the Status Quo. Under the Status Quo, the existing CCGT unit is not pushed out of merit by new build CCGT, whereas under Scenario 3, our modelling shows more efficient new build CCGT pushing existing CCGT units up the merit order, resulting in these units running less often. OCGT load factors are very low in both scenarios.

Figure 20. Average annual load factor – Existing CCGT

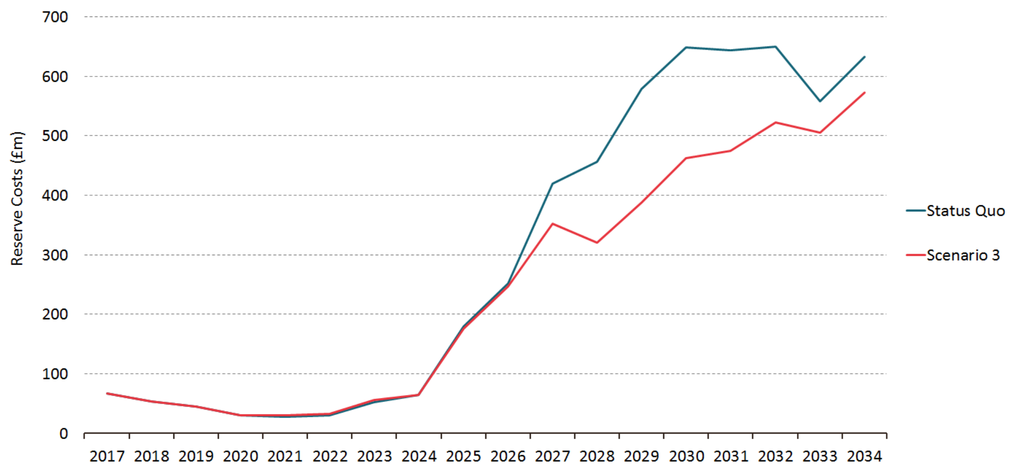


Source: Frontier/LCP

4.7 Reserve costs

Figure 21 below shows the modelled total cost of procuring reserve services. These services include frequency response and inertia.

Figure 21. Reserve costs



Source: Frontier/LCP

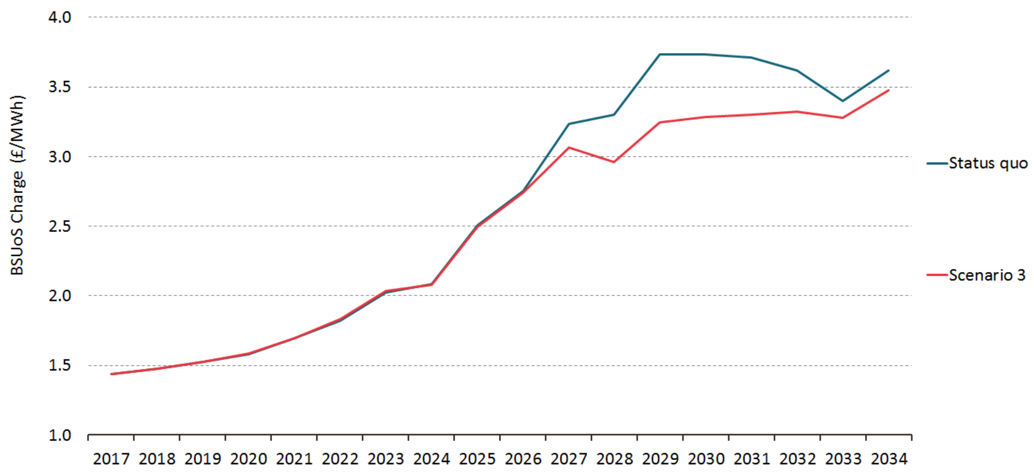
The general increase in reserve costs observed over the modelling period is largely due to the increasing penetration of wind.

Compared to Scenario 3, in our modelling the Status Quo has less CCGT capacity and increased reciprocating engine capacity. This results in greater reserve costs under the Status Quo due to the utilisation of more expensive units for reserve purposes.

4.8 BSUoS charges

Our modelled BSUoS charges, shown in Figure 22, follow a similar trajectory to the reserve costs discussed in previous sections. The charges are broadly similar to the mid-2020s, after which we model a higher charge under the Status Quo than Scenario 3. This is due to both increased reserve costs under the Status Quo, and a larger amount of distributed capacity, which reduces the BSUoS charging base.

Figure 22. BSUoS charges

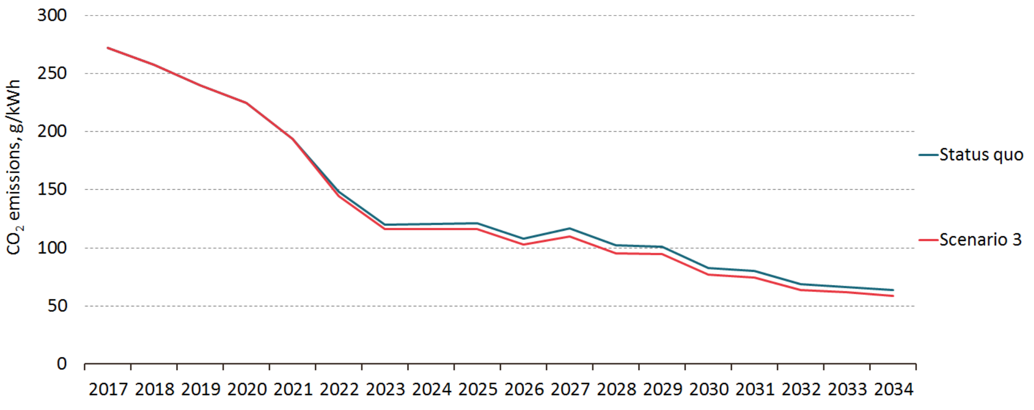


Source: Frontier/LCP

4.9 CO_2 emissions

In our modelling, the levels of total carbon emissions under the two scenarios are broadly similar, as shown in Figure 23.

Figure 23. Carbon emission intensity



Source: Frontier/LCP

In both scenarios, our modelling shows a sharp decline in CO_2 emissions over 2021 and 2022 due to the retirement of the last existing coal plants. The overall trend is downwards as we model renewables becoming increasingly prevalent and more efficient CCGTs coming online.

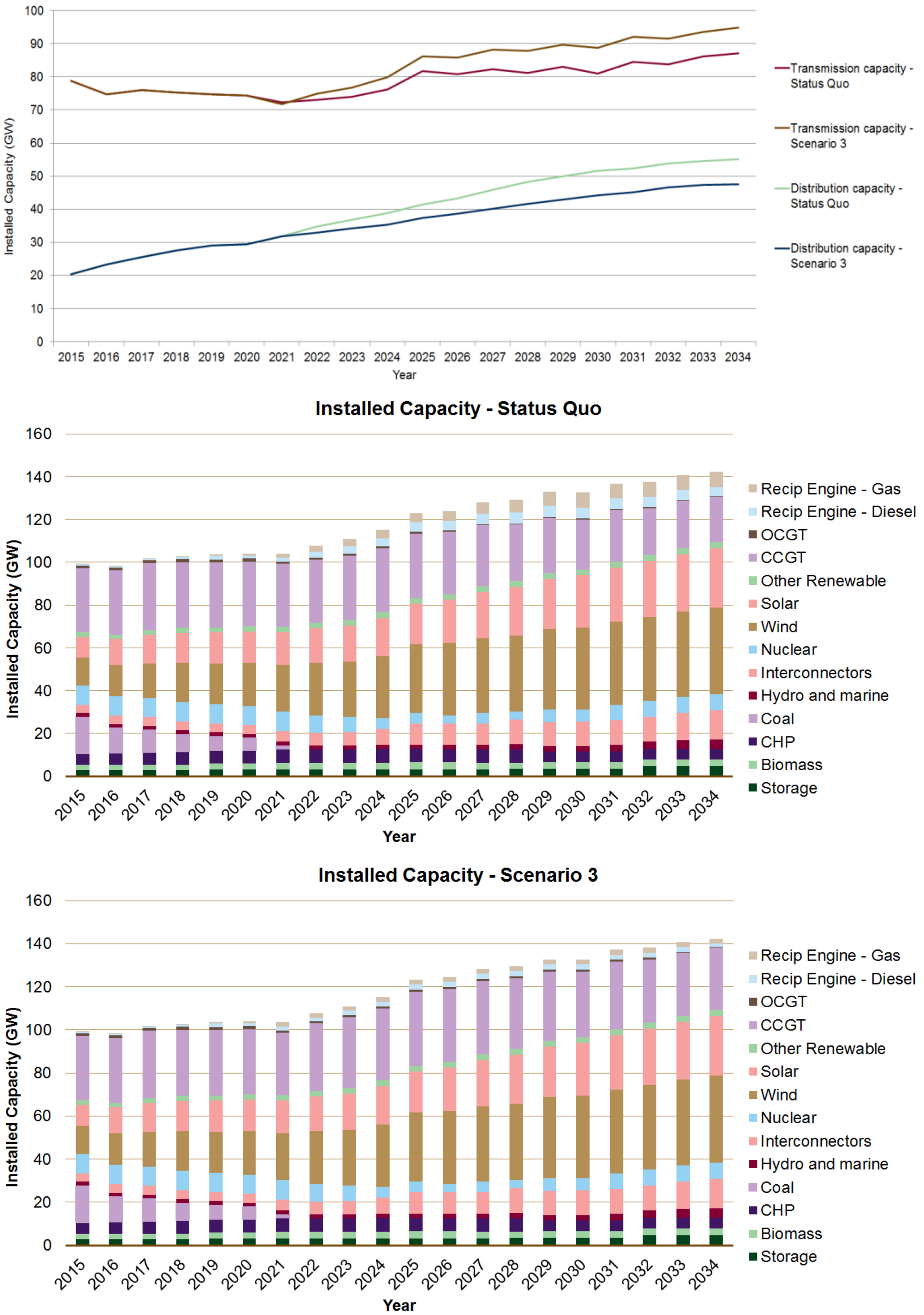
Our modelling shows the level of carbon emissions being slightly lower under Scenario 3 than the Status Quo. This is mainly because under Scenario 3 we see more efficient CCGT build. There is a small further impact from fewer new build reciprocating engines chasing triad.

4.10 Capacity breakdown

Figure 24 below show the volumes of transmission- connected and distribution-connected capacity under each scenario.

Our modelling shows a general increase in total capacity over time as renewables replace baseload capacity. It can be observed from Figure 24 that under Scenario 3, there is an increase in transmission-connected capacity and a decrease in distributed-connected capacity when compared to the Status Quo.

Figure 24. Total transmission and distribution capacity, Status Quo and Scenario 3



Source: Frontier/LCP

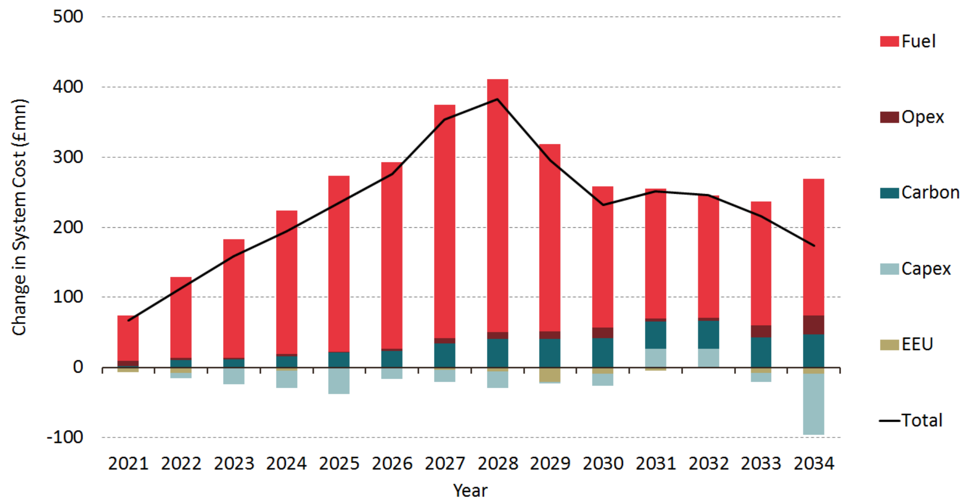
4.11 System cost

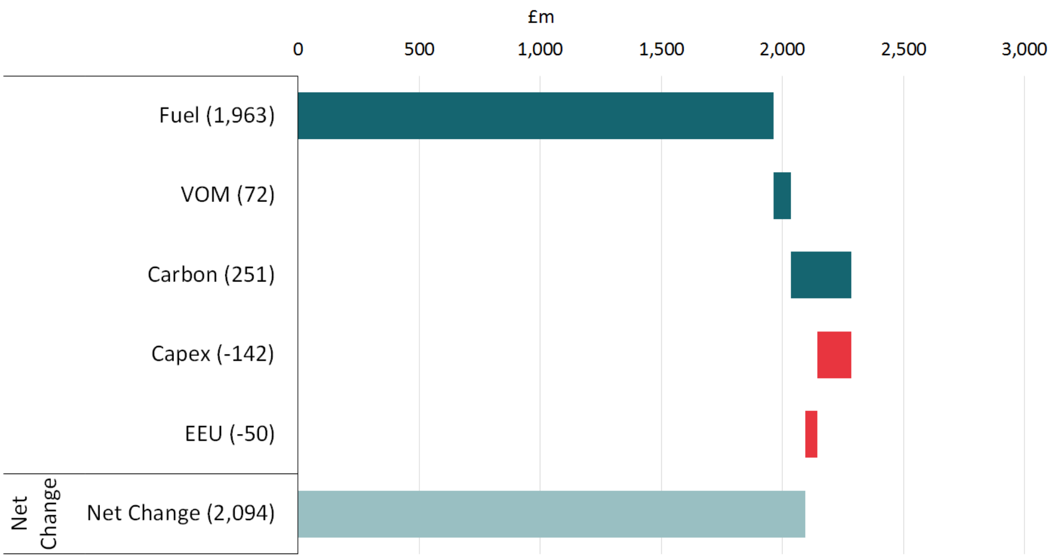
Figure 25 below shows the modelled system cost differences, comparing the Status Quo and Scenario 3. These costs represent the actual resource cost of running the system. The cost categories captured are:

- Fuel – this is the cost of the fuel used by the generating fleet, which is driven by technology type, efficiency and raw fuel cost;
- Variable opex – different technologies have different operating costs, which are represented here;
- Carbon – due to the effective carbon price on emissions, there is a resource cost associated with the emission of carbon;
- Capex – the financing cost of building new plant is represented here. This is driven by the build costs of the plant and the cost of capital; and
- EEU – expected energy unserved, which is assigned a cost of £17,000/MWh. While both scenarios target the security standard through the capacity mechanism, there is the possibility of one scenario achieving a higher or lower LOLE depending on where it exactly clears on the CM curve.

In addition to the areas above, there may be effects on network costs due to the changes proposed. For example, if moving to a lower residual causes more transmission-connected large-scale CCGT to build, it is possible that the costs of maintaining and reinforcing the network would increase. However, in many cases we would expect the new CCGT to be located on the site of an existing or recently decommissioned plant, and in these cases we would not expect a significant impact on overall network costs. In addition, the specific locations of future new build and any associated network reinforcements are extremely uncertain. Any quantitative estimates on the impacts on overall network costs of these investments would be very sensitive to these uncertain input assumptions. As such, we have not provided estimates for the effect on network costs as part of the system cost analysis.

Figure 25.4 System cost-saving between Status Quo and Scenario 3





Source: Frontier/LCP

The upper chart in Figure 25 shows that the most significant saving is due to lower use of fuel for power generation. These fuel savings are large because there is a significantly different mix of technologies between the two scenarios. Over time, under Scenario 3 there is an increasing proportion of generation from new build CCGT and decreasing proportion from existing CCGT when compared to the Status Quo. This represents an increase in efficiency of generation, which lowers system costs. This effect compounds under the Status Quo in the late 2020s, when the reciprocating gas engines that have been built are required to run more, because they have prevented as much new CCGT clearing in the CM as under Scenario 3. These engines are less fuel efficient than new CCGT, increasing the fuel savings of Scenario 3 relative to the Status Quo.

The second chart in Figure 21 shows the NPV of the difference in system costs from 2016 to 2034 using a social discount rate of 3.5%. Under these assumptions, the total saving associated with a move from the Status Quo to Scenario 3 is £2.1billion.

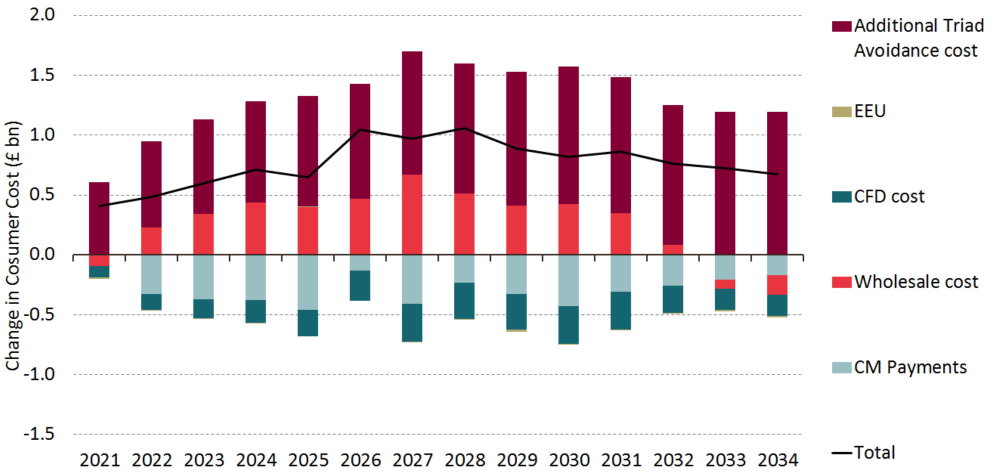
4.12 Consumer cost

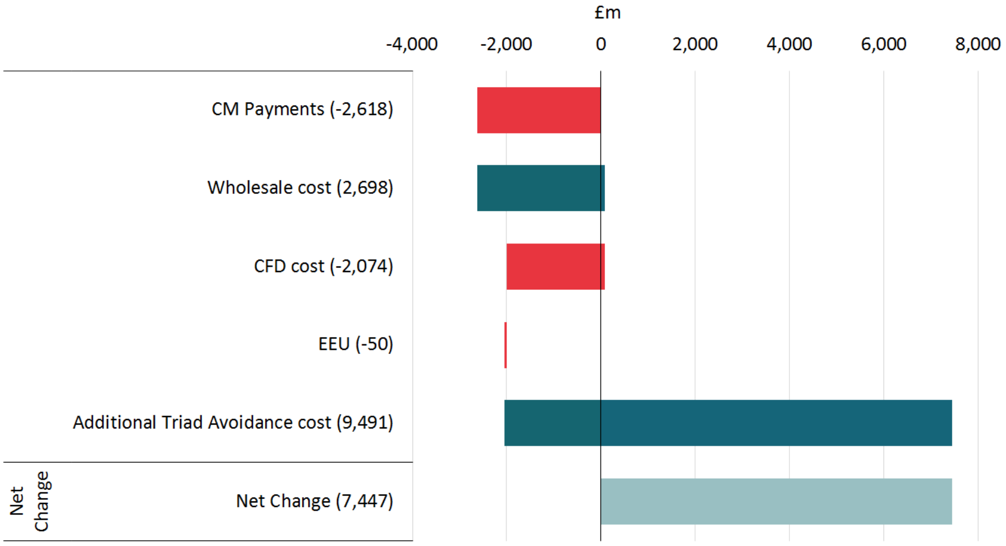
Figure 26 below shows the modelled consumer cost differences in moving from the Status Quo to Scenario 3. Consumer costs measure how consumers are affected by the proposed changes, which is separate to system cost. While system cost represents the true resource cost of running a system, this is independent of who pays and receives money. Consumer costs capture these system-independent transfers. The cost categories captured are:

- Additional triad avoidance – embedded benefits in the form of triad avoidance represent a direct cost to consumers. This is because the entire cost of the demand residual must still be recouped across the non-embedded fleet, but there is an additional payment to all smaller embedded generators. By reducing the amount of residual that can be avoided, a direct saving is made by consumers.
- CM payments – as has been seen through this analysis, the removal of embedded benefits causes the CM bids of these units to increase. This may cause a more expensive plant to clear, increasing the CM payments made by consumers, representing a cost to consumers.
- Wholesale and CfD cost – as more efficient CCGT are able to clear through the CM, consumers benefit as wholesale prices are depressed. This represents a saving to consumers. This will be partially offset by an increase in CfD costs, where strike prices for new CfD plant will increase to account for lost triad and wholesale revenue.
- EEU – as outlined in our description of system cost, this also represents a cost to consumers.

It should be noted that system costs and consumer costs represent fundamentally different economic costs, and as such should not be added or combined to create a total saving. It is possible to have meaningful consumer savings with no system savings, and vice versa.

Figure 26. Consumer cost-saving between Status Quo and Scenario 3





Source: Frontier/LCP

The major consumer saving results from reduced triad avoidance costs paid by the consumer. In reducing the amount that smaller embedded generators can offset, there is a significant saving to consumers.

The largest cost to consumers is the increase in CM payments in line with the increase in CM clearing prices. The reduction in wholesale prices reduces wholesale costs (though this is offset by the increase in CfD payments).

The second chart in Figure 26 above shows the NPV of the difference in consumer costs from 2016 to 2034 using a social discount rate of 3.5%. Under these assumptions, the total savings associated with a move from the Status Quo to Scenario 3 is £7.4 billion.

In Annex A, we provide graphs for the total changes in costs over shorter periods of 5 and 10 years for all scenarios, including Scenario 3.

4.13 Effects of grandfathering and phasing the proposed change

As part of our analysis, following discussions with Ofgem we considered three grandfathering options:

- Grandfathering reciprocating engines with CM contracts for delivery 2018/19 and 2019/20 at the level of Scenario 1 in that year, i.e. £45.33/kW plus RPI (Option A)
- Grandfathering existing build, defined as those plant built by 1/7/2017, at the level of Scenario 1 in that year, i.e. £45.33/kW plus RPI (Option B)
- Both Options A and B (Option C)

We also considered one phasing option, namely to implement the change considered over a 3 year period from 2018 (Option A). Phasing is defined as a linear progression from the value in 2018 to the value in 2021.

Figure 31 details the system and consumer saving NPVs (2016-2034) under a combination of grandfathering and phased implementation scenarios. Note that the grandfathering options are additive (the saving between None and Option A, and None and Option B will total the saving between None and Option C).

Assuming that the generation capacity awarded contracts in the 2014 and 2015 CM auctions delivers as expected, the grandfathering options can be expected to have no material effect on the plant mix, thereby implying that the system costs are largely unchanged.

Figure 31. Impact of grandfathering and phasing

Grandfathering option	Phasing option	System cost saving (NPV, £bn)	Consumer cost saving (NPV, £bn)
None	**None**	2.1	7.4
Option A	**None**	2.1	6.6
Option B	**None**	2.1	4.9
Option C	**None**	2.1	4.1
None	**Option A**	2.1	7.2
Option A	**Option A**	2.1	6.4
Option B	**Option A**	2.1	4.8
Option C	**Option A**	2.1	4.1

Source: Frontier/LCP

4.14 Effects of phasing over a shorter time frame

The figure below shows the NPVs of changes to system costs and consumer costs when moving from the Status Quo to Scenario 3 and Phased Scenario 3 (no grandfathering). Waterfall charts showing the changes in consumer costs to the end of 2024, 2029 and 2034 for every scenario and its phased version can be found in the annex.

Figure 32. Impact of grandfathering and phasing on system costs (NPV, £bn)

Period considered	Scenario 3	Phased Scenario 3
To 2024	0.5	0.4
To 2029	1.5	1.4
To 2034	2.1	2.1

Source: Frontier/LCP

Figure 33. Impact of grandfathering and phasing on consumer costs (NPV, £bn)

Period considered	Scenario 3	Phased Scenario 3
To 2024	2.3	2.0
To 2029	5.3	5.0
To 2034	7.4	7.2

Source: Frontier/LCP

4.15 Impacts on cost of capital

If it were felt that not introducing grandfathering or some form of phasing into the options would reduce investor confidence, there might be a subsequent increase in the cost of capital to finance new generation projects. This would have a knock on effect of higher consumer costs – due to higher CM payments – and offset some of the benefits of not introducing grandfathering or phasing.

It is difficult to quantify how investor behaviour would be affected based on the various grandfathering/phasing options presented. However, it is possible to estimate how much that level of confidence – i.e. the rate of return required by investors – would need to shift to erode the benefits of not introducing grandfathering or phasing.

Consider the first and second consumer cost rows in Figure 31 above. There is a consumer cost of £0.8bn in introducing grandfathering to the CM units. Put another way, there is a consumer saving of £0.8bn by not introducing grandfathering of CM units.

Under the presumption that investor confidence decreases by not introducing grandfathering, we can estimate the amount that the cost of capital would need to increase by to erode the £0.8bn of saving, in the form of higher CM payments. We can do this by estimating the implied change in investor hurdle rates (i.e. required internal rate of return) that this £0.8bn represents through new CM build bids.

To do this, we make two assumptions:

- CM build does not change by increasing the hurdle rates. Given the generally large gap in the supply curve between existing and new build, it is a reasonable assumption that the new plant bids will simply increase in line with the new hurdle rate, and increase the clearing price accordingly without changing the clearing plant;
- Period of time over which the investor confidence is affected. In our modelling, we have assumed investor confidence would be affected until for the next 4 auctions (until delivery in 2025), and back to full confidence from then onwards.

From these assumptions, we calculate the implied increase in CM bid for each in which a new unit is marginal in the CM and apply the increase in CM payments to the consumer savings. We can then calculate an increase in hurdle rate required to fully erode the consumer savings. Note that there would also be a change to system costs by changing the hurdle rate (due to the capex factor) but we have focussed on the consumer benefits here.

Figure 34. Equivalent effects on cost of capital for Scenario 3

Grandfathering option	Phasing option	Consumer cost saving (NPV, £bn)	Consumer cost saving, relative to None-None (NPV, £bn)	Hurdle rate increase required in None-None to offset benefit
None	**None**	7.4	0	0%
Option A	**None**	6.6	-0.8	1.7%
Option B	**None**	4.9	-2.5	4.9%
Option C	**None**	4.1	-3.3	6.4%
None	**Option A**	7.2	-0.2	0.5%
Option A	**Option A**	6.4	-1.0	2.1%
Option B	**Option A**	4.8	-2.6	4.8%
Option C	**Option A**	4.1	-3.3	6.2%

5 COMPARISON TO SCENARIOS 1, 2 AND GENERATOR RESIDUAL

This section highlights the key results under three modelling scenarios – Scenario 1, Scenario 2, and Generator Residual - in relation to the discussion for Scenario 3. More detailed modelling results for these three scenarios are located in Annex A below.

5.1 CM build

Unlike Scenario 3, there is little change in CM build between Status Quo and Scenario 1. The build under Scenario 1 is identical to Status Quo until 2027 when an extra new build CCGT unit clears. More generally, the effect of moving to Scenario 1 is to smooth out the construction of new CCGT units across the time period considered.

In contrast, Scenario 2 sees the displacement of reciprocating engines in the CM with new build CCGT from the first year modelled. The effect is not as dramatic as Scenario 3: reciprocating engines continue to clear until 2029.

The Generator Residual case effectively removes all reciprocating engine build beyond 2022. This suggests that under this particular set of assumptions there is a 'tipping point' between Scenario 2 and the Generator Residual case, which causes a large shift in the ability of reciprocating engines to clear.

5.2 System costs

Under Scenario 1, the change in system costs compared to Status Quo is smaller than under Scenario 3, which is unsurprising given the shift to Scenario 1 is much smaller. The majority of the system cost saving in this scenario is due to savings in fuel costs. The fuel saving is due to a reduction in triad chasing hours for reciprocating engines as well as the displacement of reciprocating engines by a new CCGT unit. The net change in system costs is £0.4bn, compared to £2.1bn under Scenario 3.

The changes in system costs when moving to Scenario 2 are broadly the same as those observed when moving to Scenario 3. The key difference is the change in fuel costs, which is significantly smaller under Scenario 2 due to the increased quantity of reciprocating engines that clear. The net change in system costs is £1.4bn, compared to £2.1bn under Scenario 3.

The Generator Residual case follows the same trend, with a system cost saving of £1.9bn, compared to £2.1bn under Scenario 3.

5.3 Consumer costs

In transitioning from Status Quo to Scenario 1, 2 then 3, the consumer cost savings increase incrementally, with Scenario 3 providing the largest consumer cost saving. The consumer cost savings increase from £1.8bn under Scenario 1 to £5.2bn under Scenario 2, and £7.4bn under Scenario 3. This is mainly driven by avoiding triad payments to different degrees, which represent the largest component of consumer cost savings. CM payments and wholesale cost savings roughly cancel each other out. This makes intuitive sense, as CM payments should broadly speaking represent the missing money required by the units to deliver, which will be increased as wholesale prices decrease (and thus wholesale cost savings to consumers increase).

The consumer cost saving in the Generator Residual scenario of £7.4bn is very close to the Scenario 3 saving (also £7.4bn) - our result shows a marginally larger saving under the Generator Residual scenario due to precise mix of new build cleared through the CM. The key message here is that after the “tipping point” that occurs under this set of assumptions between Scenario 2 and the Generator Residual, consumer cost savings are broadly similar.

Note that all these results are driven by how CM bids fare relative to each other, and these bids are sensitive to a number of assumptions, such as the assumed capital costs of the new build and investors views of the future. The CM’s ‘binary’ nature of clearing or not clearing large chunks of capacity could swing this balance the other way under different assumptions.

6 CONCLUSION

The objective of this engagement was to provide an independent modelling assessment of the potential impact of changes to network charging arrangements proposed under two CUSC modifications (CMP264 and CMP265), as well as the WACMs considered in relation to them.

The results of the modelling assessment presented in this report are intended to assist Ofgem in its decision on whether to approve any of the CUSC modification proposals or the proposed alternatives (WACMs), and contribute to the evidence for Ofgem's impact assessment on their on-going review of network charging arrangements for smaller embedded generators. However, it is important to stress that relying on modelling outputs as the sole, or even main basis for a decision on the CUSC modifications has its limitations, as modelling outputs are sensitive to a number of assumptions on future uncertain variables and behaviours. Changes to these can result in significant changes to outputs.

The two proposed CUSC modifications, and the variations to these proposals reflected in the WACMs, provide a range of scenarios for proposed changes to the embedded benefit arrangements, in particular, a reduction in the demand TNUoS residual. To cover the majority of WACMs in an efficient manner, we have considered four different scenarios, in addition to the Status Quo, designed by varying the level of benefit received by smaller embedded generators from the demand TNUoS residual. These scenarios are:

- Status Quo: The demand TNUoS residual increases in line with National Grid's forecast until 2021, after which it remains flat in real terms at £72.03/kW (£66.0/kW in £2016 terms).
- Scenario 1: From 2019, the charge is set at £45.33/kW plus RPI. This is equal to the current demand TNUoS residual level.
- Scenario 2: From 2019, the charge is set at £20.12/kW plus RPI. This is equal to the value of avoided GSP investment and future transmission capital costs.
- Scenario 3: From 2019, the charge is set at £1.62/kW plus RPI. This is equal to the value of avoided GSP investment.
- Generator residual scenario: From 2019, the charge is set to the level of the generator residual tariff (adjusted for CPI).

Under Scenario 3 we observe that a reduction in the demand TNUoS residual significantly reduces the triad income for reciprocating engines, which incentivises these units to recover the lost triad revenues in the CM by bidding significantly above their expected bids under the Status Quo - from around £0/kW under the Status Quo to £30-40/kW range under Scenario 3. This increase in CM bids of reciprocating engines, on the one hand places an upward pressure on the CM clearing price, and on the other hand, prevents these units from clearing in the CM auction thereby allowing the procurement of alternative new capacity, namely CCGTs. In the wholesale market, we observe lower wholesale energy prices under Scenario 3 as compared to the Status Quo, predominantly as a result of more efficient CCGTs clearing in the CM.

Under Scenario 3 the load factors of reciprocating engines are reduced as these units spend fewer hours chasing triad. Furthermore, the introduction of new CCGTs pushes existing CCGTs out of merit reducing their load factors. The combined impact of these changes is observed in the form of reduced total carbon emissions from electricity generation.

Under Scenario 3, we observe a reduction in system costs (the true resource cost of running the system) relative to the Status Quo as more fuel-efficient new build CCGTs increase the efficiency of the generation fleet. On an NPV basis, our modelling finds that the total savings in system costs to 2034 as a result of moving from the Status Quo to Scenario 3 is £2.1 billion. We similarly observe a net reduction in consumer costs (the financial cost faced by customers) resulting in large part from reduced triad avoidance costs. On an NPV basis, our modelling finds that the total savings in consumer costs to 2034 as a result of moving from the Status Quo to Scenario 3 is £7.4 billion.

Our modelling finds that both grandfathering of existing charging arrangements for certain plant types, and 3-year phasing in the implementation of the new regime reduce the consumer cost savings (there is no impact on system costs, as we assume no change in new build).

In relation to Scenarios 1, 2 and Generator Residual, the “tipping point” in our analysis – at which new reciprocating engines are largely displaced by new CCGTs in the CM – occurs between Scenario 2 and the Generator Residual Scenario. The Generator Residual Scenario gives broadly similar results to Scenario 3. However, this “tipping point” is subject to the particular set of assumptions used, and may move materially one way or the other under a different set of assumptions.

7 LIMITATIONS

The results contained in this report are produced by LCP's dispatch model of the GB power market. The report contains modelled outcomes from 2017 to 2034 under assumptions provided by Ofgem or obtained from publically available sources where possible.

We have already noted the issues with using modelling-based evidence to make a judgement on a set of proposed CUSC changes. While modelling can help to inform the nature, direction and broad magnitude of potential effects of the CUSC modifications being considered, the modelling outputs we present are dependent on assumptions on inherently uncertain input variables. Such outputs are best used to complement a more principles-based assessment of the likelihood of CUSC modifications better facilitating the CUSC objectives.

The results presented in this report are dependent on the assumptions used and the modelling methodology applied. In particular, long-term forecasts are subject to significant uncertainty and actual market outcomes may differ materially from the forecasts presented. We can therefore accept no liability for losses suffered, direct or consequential, arising out of any reliance on the results 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 publically 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.

ANNEX A FURTHER RESULTS

In this Annex we set out the results for Scenarios 1 and 2. We first present summary results tables, and then present the detailed modelling results.

Unless otherwise stated, all figures in this report are in £2016 real terms.

A.1 Scenario 1 summary results

In scenario 1 the long term benefit is equal to the current level so phasing and grandfathering have no effect.

Grandfathering option	Phasing option	System cost saving NPV (£bn)	Consumer cost saving NPV (£bn)	Hurdle rate increase required in None-None to offset benefit
None	**None**	0.4	1.8	0.0%
Option A	**None**	0.4	1.8	0.0%
Option B	**None**	0.4	1.8	0.0%
Option C	**None**	0.4	1.8	0.0%
None	**Option A**	0.4	1.8	0.0%
Option A	**Option A**	0.4	1.8	0.0%
Option B	**Option A**	0.4	1.8	0.0%
Option C	**Option A**	0.4	1.8	0.0%

A.2 Scenario 2 summary results

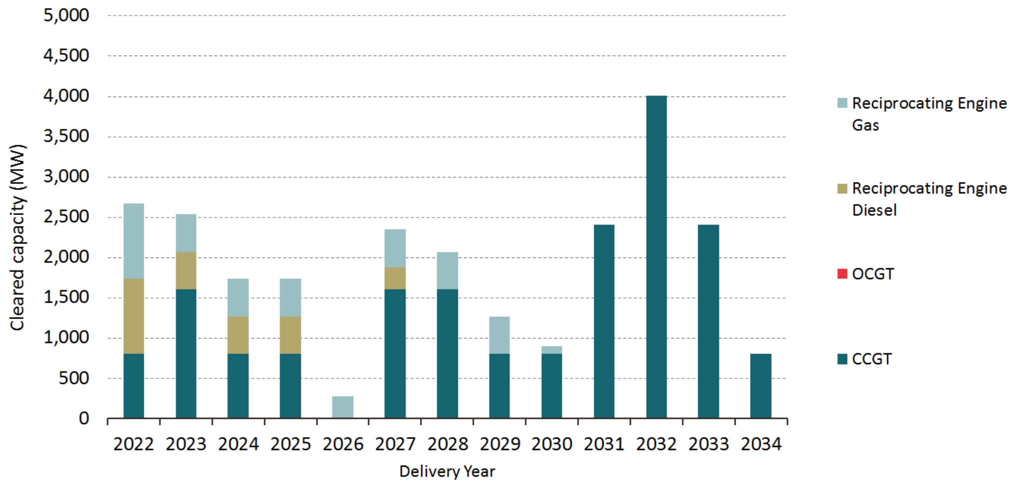
Grandfathering option	Phasing option	System cost saving NPV (£bn)	Consumer cost saving NPV (£bn)	Hurdle rate increase required in None-None to offset benefit
None	**None**	1.4	5.2	0.0%
Option A	**None**	1.4	4.8	1.0%
Option B	**None**	1.4	3.8	3.0%
Option C	**None**	1.4	3.3	3.9%
None	**Option A**	1.4	5.1	0.4%
Option A	**Option A**	1.4	4.6	1.4%
Option B	**Option A**	1.4	3.7	3.2%
Option C	**Option A**	1.4	3.2	4.1%

A.3 Generator residual scenario summary results

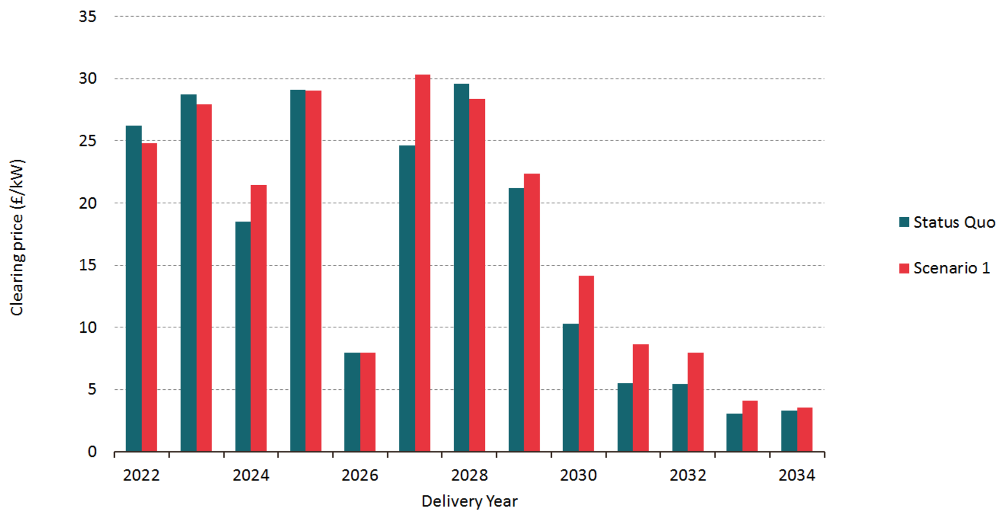
Grandfathering option	Phasing option	System cost saving NPV (£bn)	Consumer cost saving NPV (£bn)	Hurdle rate increase required in None-None to offset benefit
None	**None**	1.9	7.5	0.0%
Option A	**None**	1.9	6.8	1.0%
Option B	**None**	1.9	5.3	2.9%
Option C	**None**	1.9	4.6	3.8%
None	**Option A**	1.8	7.4	0.1%
Option A	**Option A**	1.8	6.7	1.0%
Option B	**Option A**	1.8	5.4	2.6%
Option C	**Option A**	1.8	4.7	3.4%

A.4 Scenario 1 detailed results

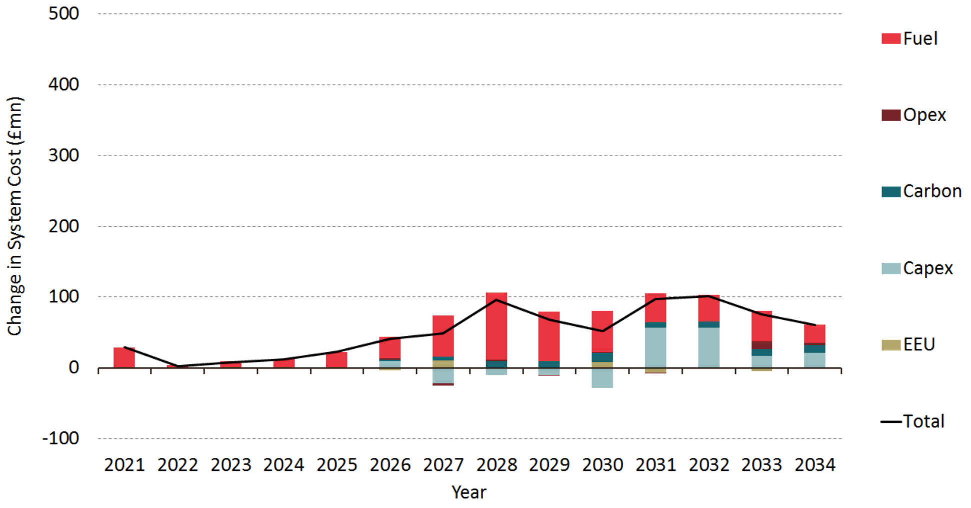
A.4.1 CM build



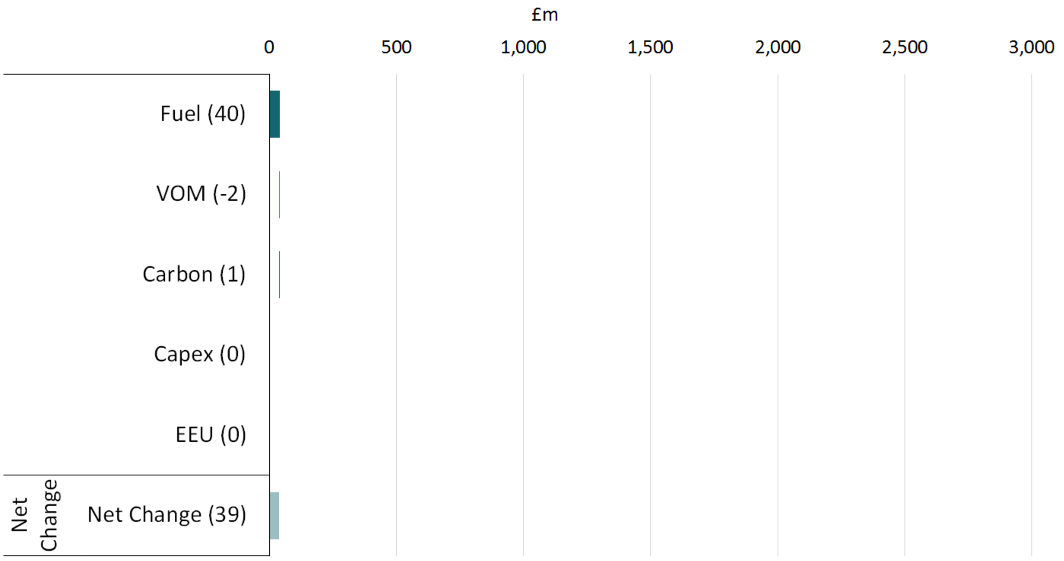
A.4.2 Clearing prices



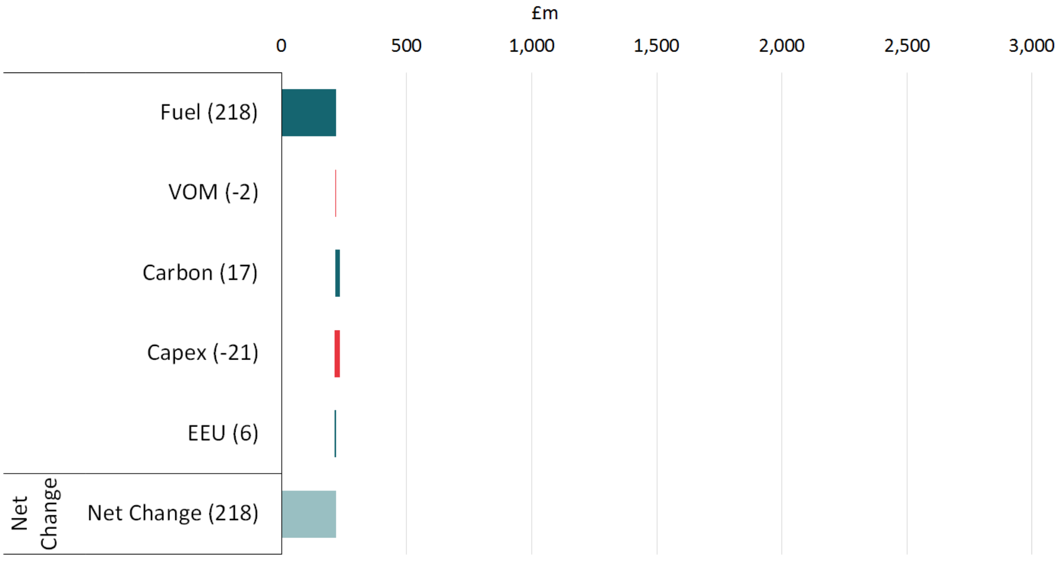
A.4.3 System cost saving



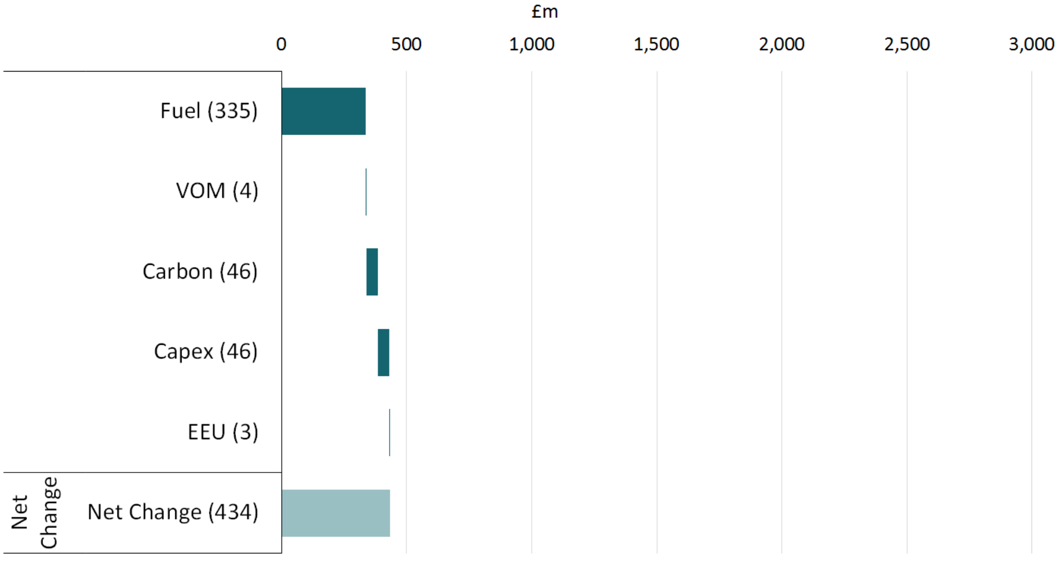
System cost saving, NPV to 2024



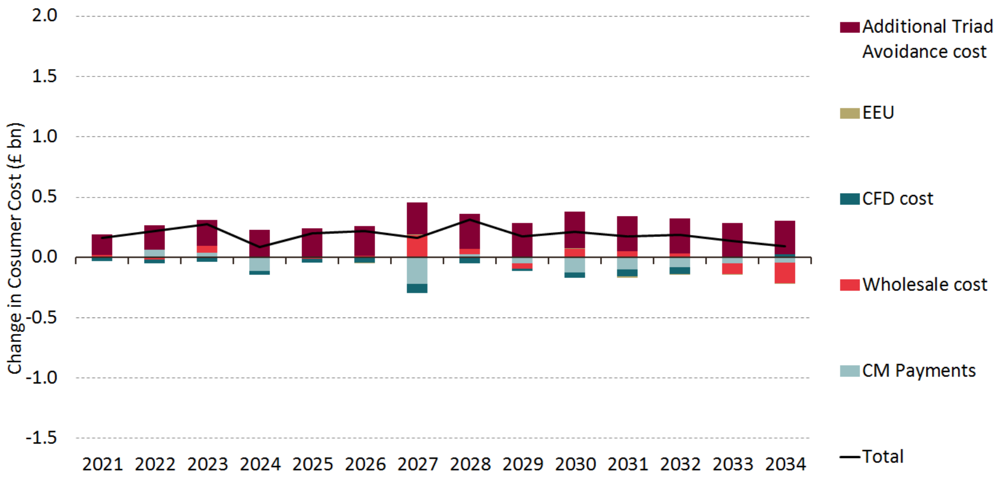
System cost saving, NPV to 2029



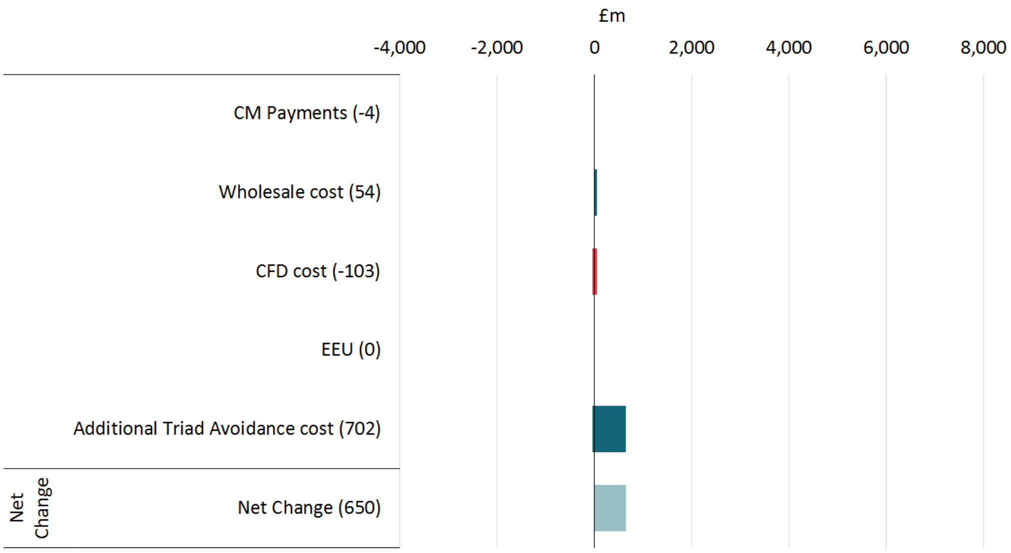
System cost saving, NPV to 2034



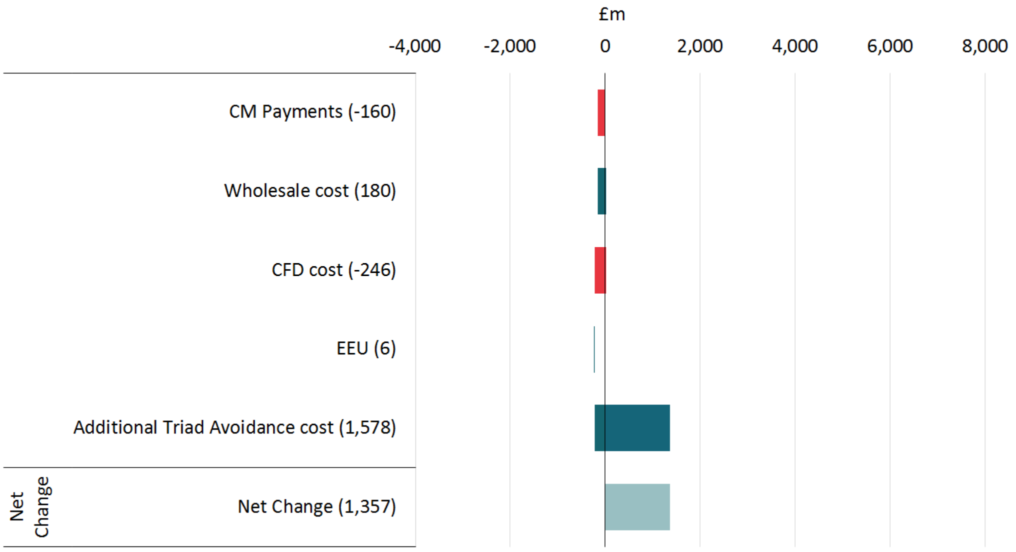
A.4.4 Consumer cost savings



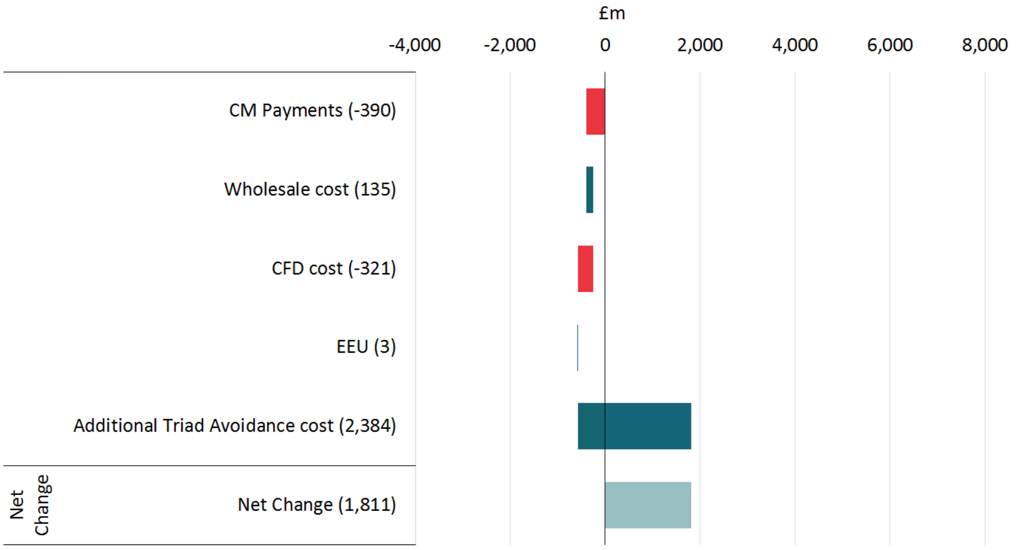
Consumer cost saving, NPV to 2024



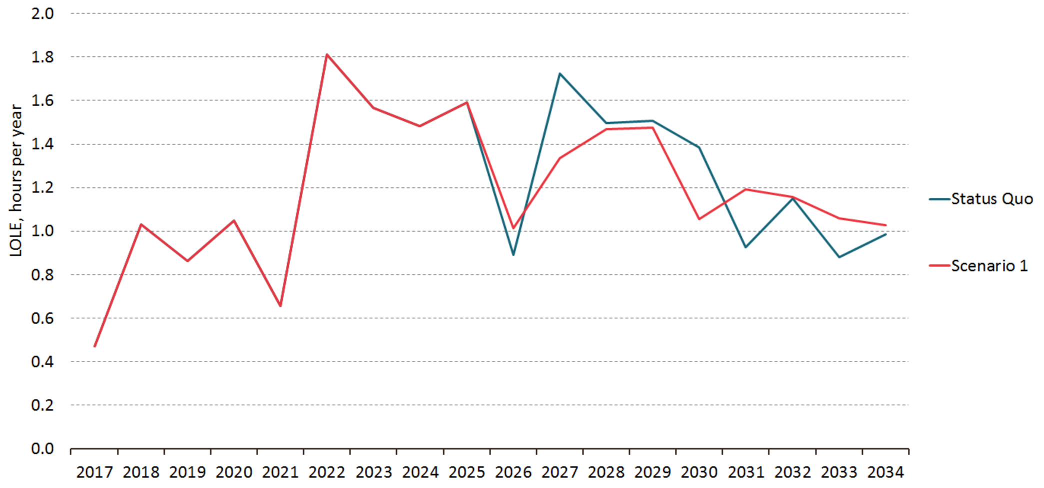
Consumer cost saving, NPV to 2029



Consumer cost saving, NPV to 2034

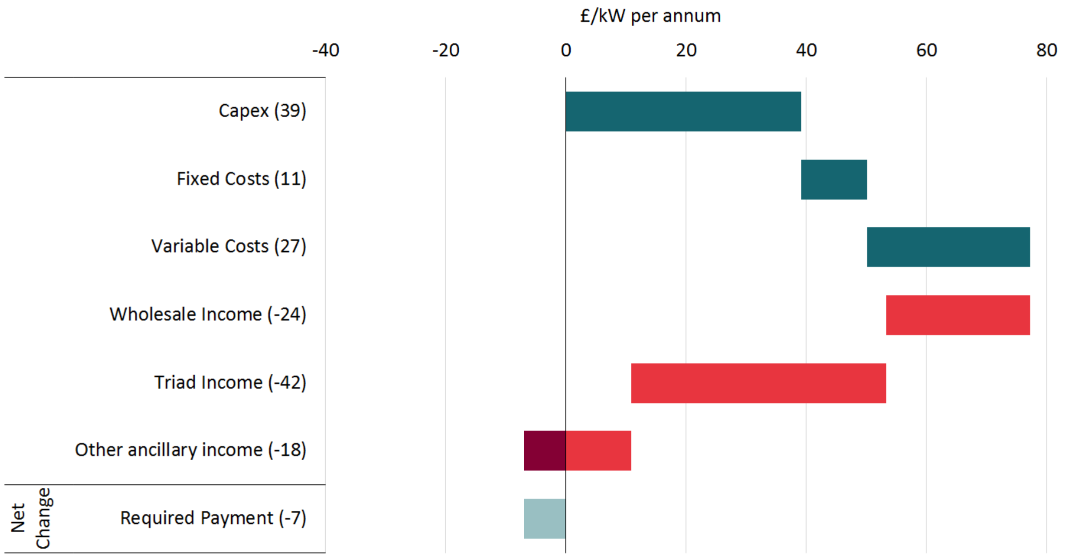


A.4.5 LOLE

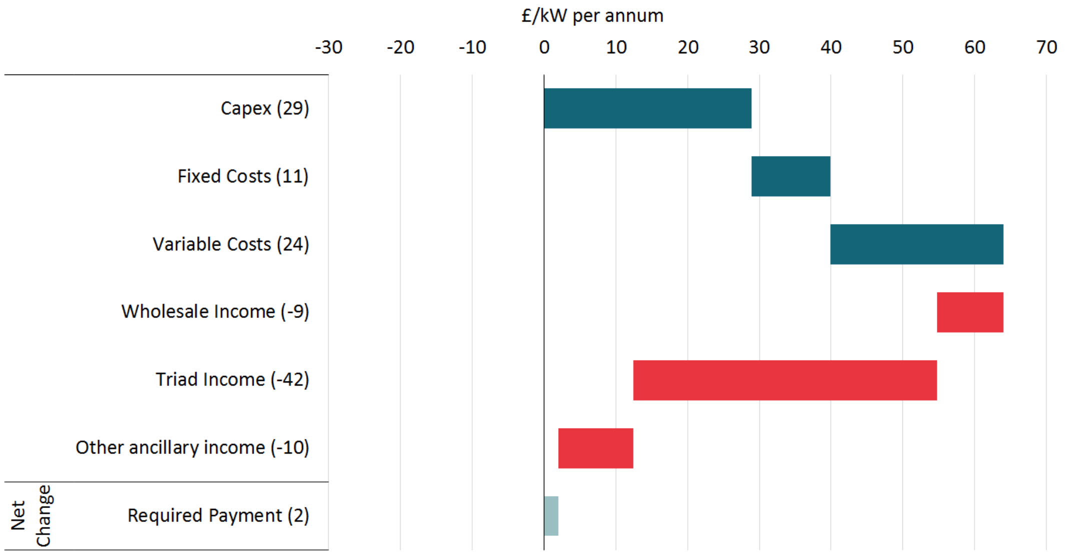


A.4.6 Triad chasing hours

A.4.7 Reciprocating gas revenue breakdown

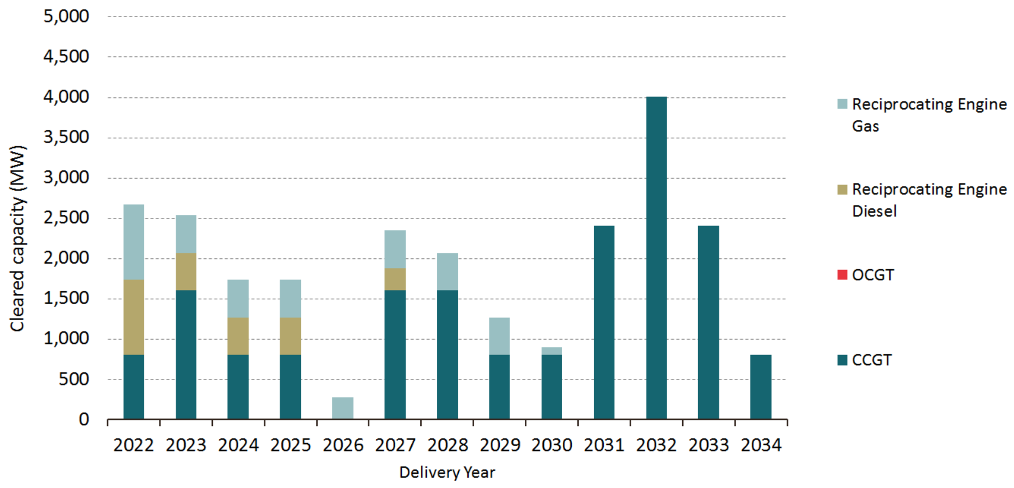


A.4.8 Reciprocating diesel revenue breakdown

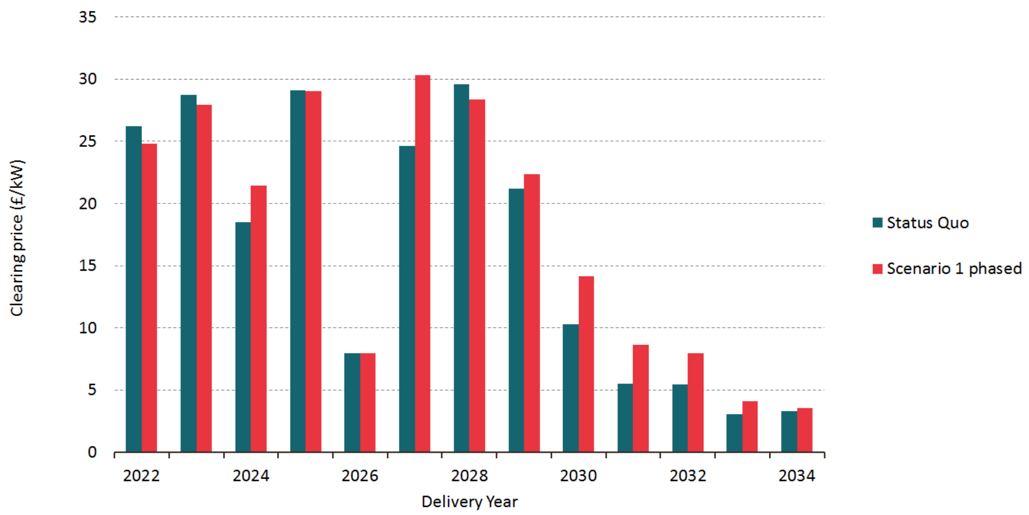


A.5 Scenario 1 phased detailed results

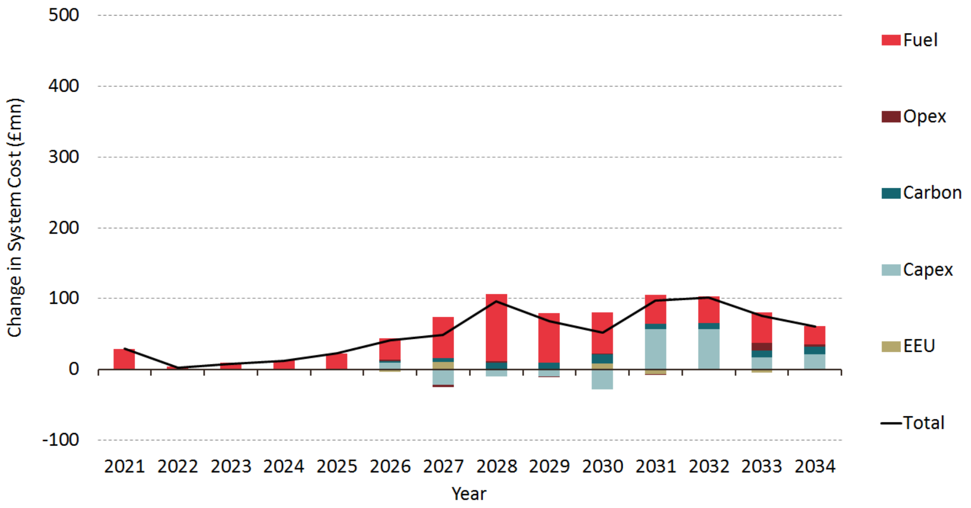
A.5.1 CM build



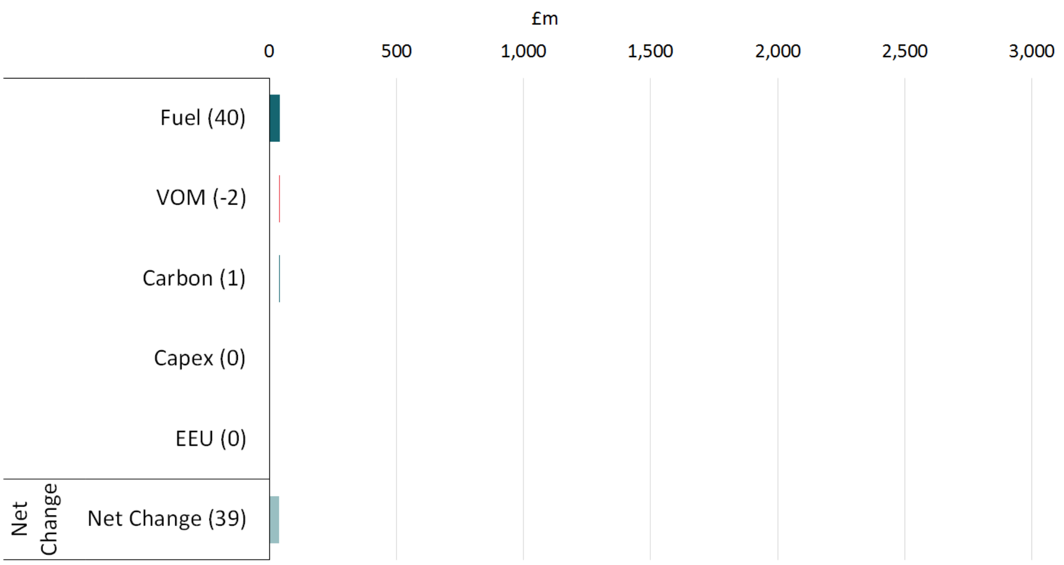
A.5.2 Clearing prices



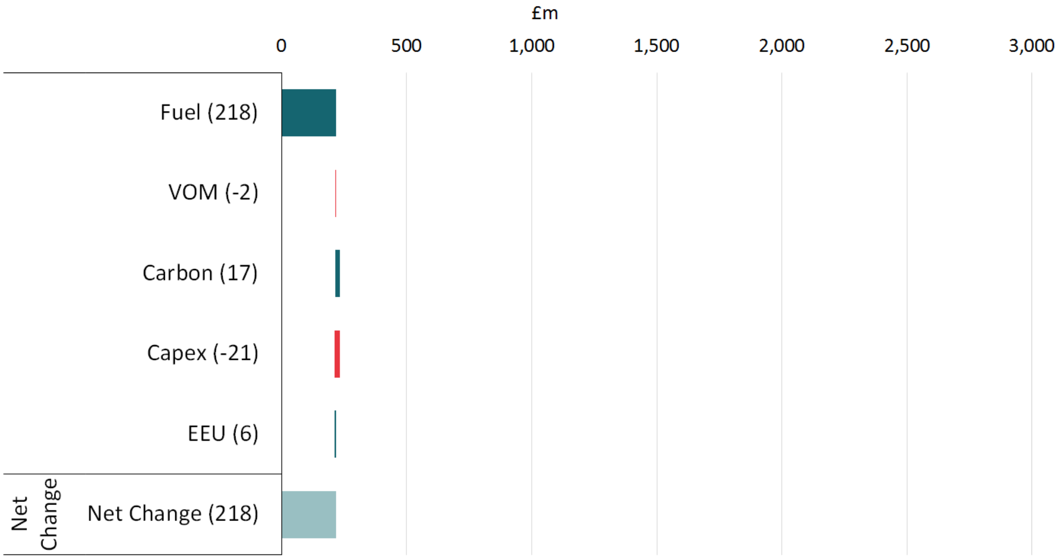
A.5.3 System cost saving



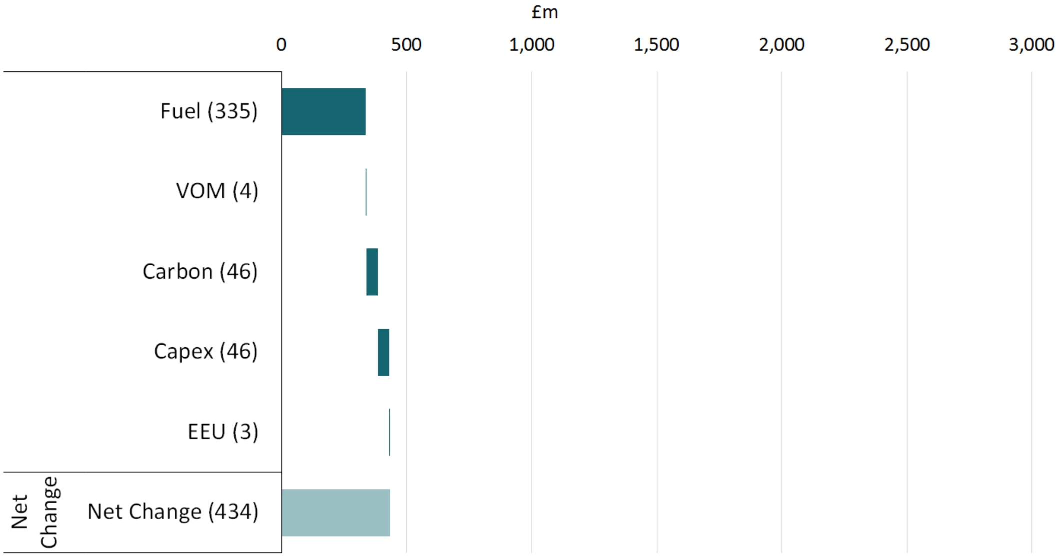
System cost saving, NPV to 2024



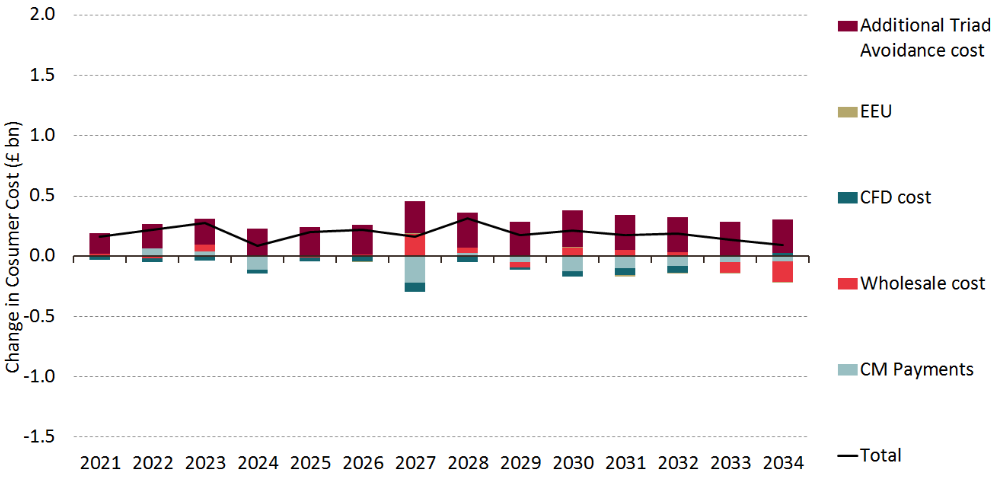
System cost saving, NPV to 2029



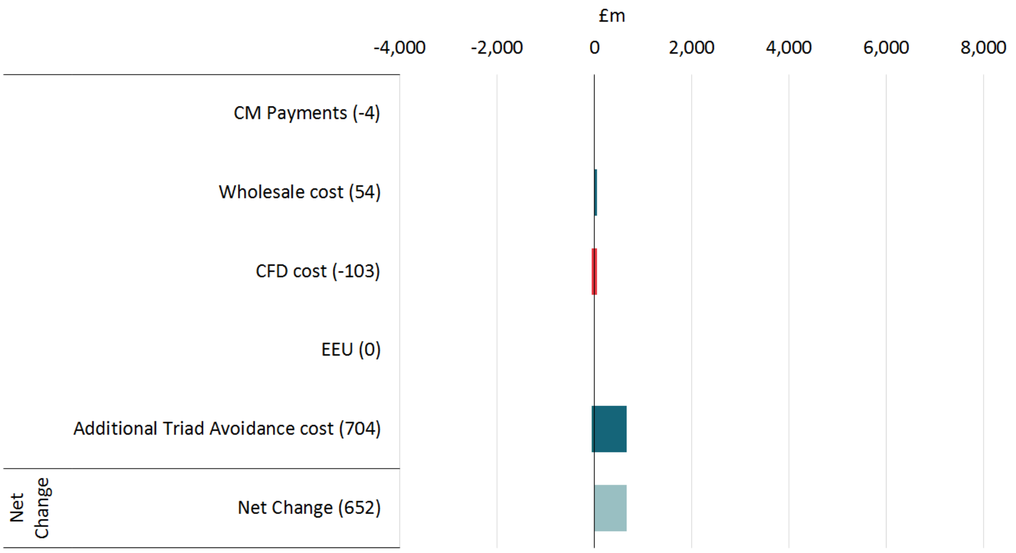
System cost saving, NPV to 2034



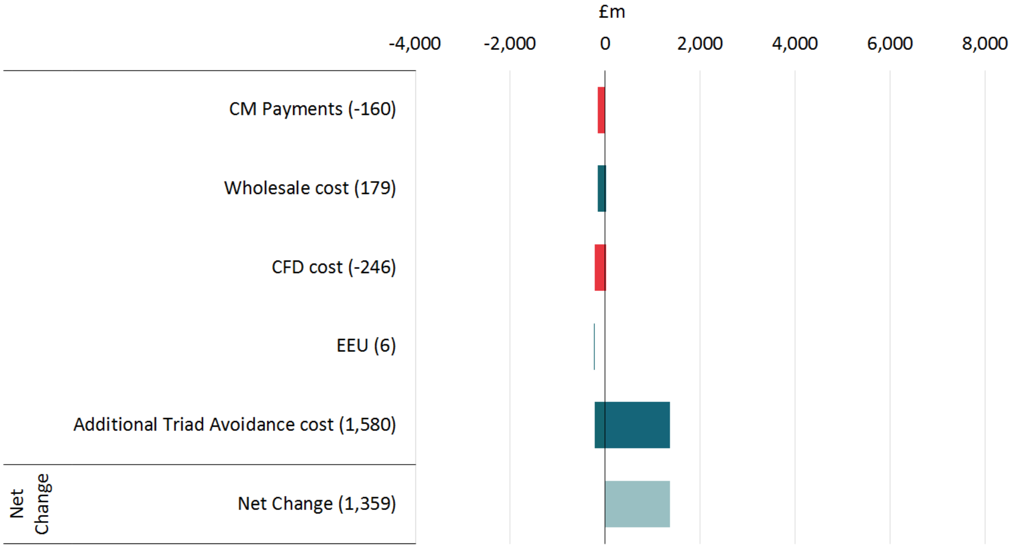
A.5.4 Consumer cost saving



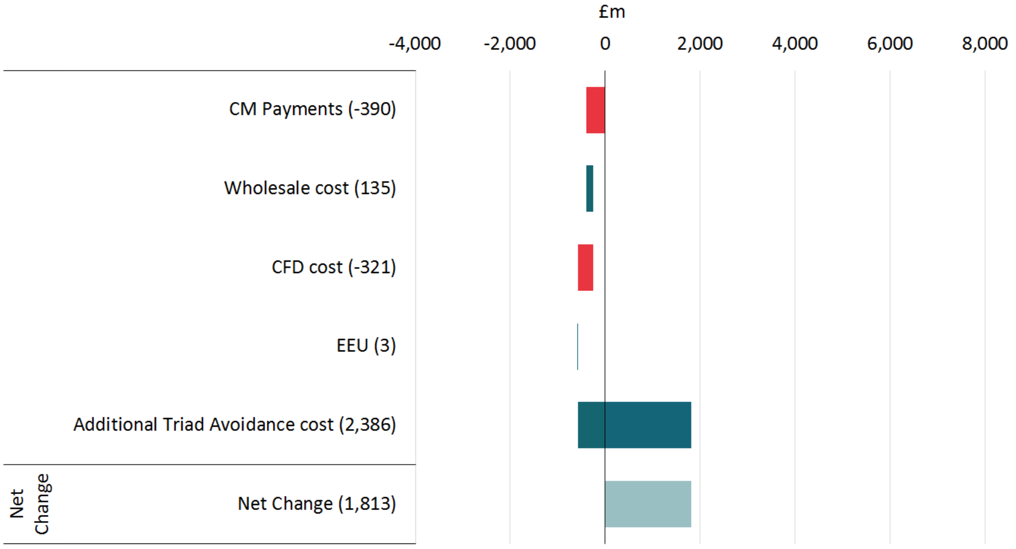
Consumer cost saving, NPV to 2024



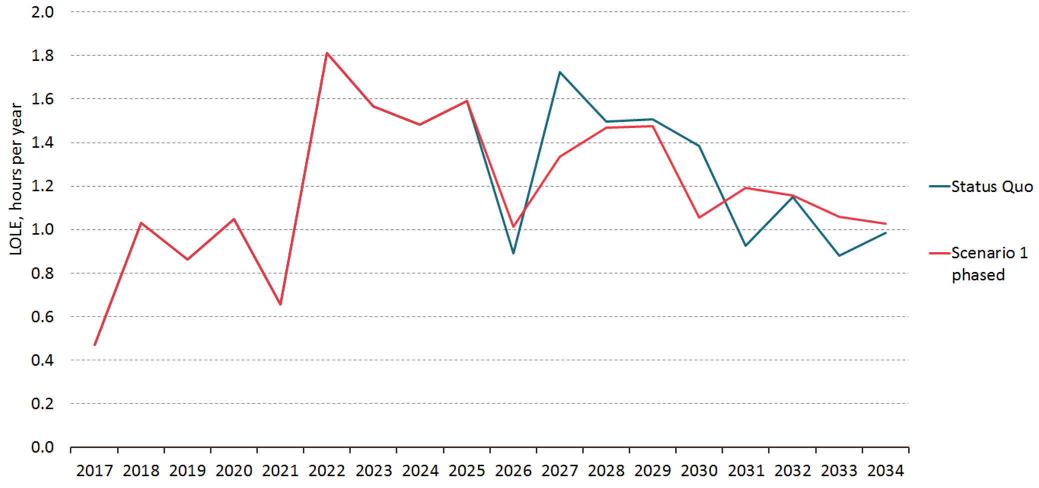
Consumer cost saving, NPV to 2029



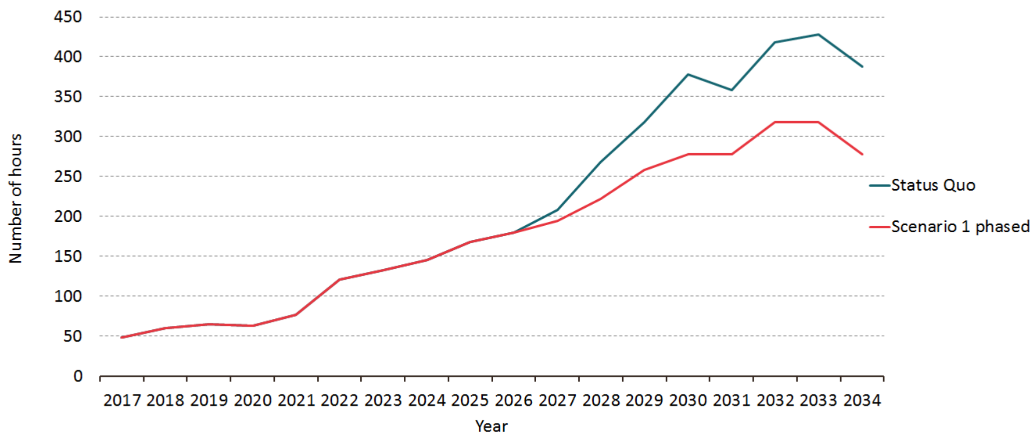
Consumer cost saving, NPV to 2034



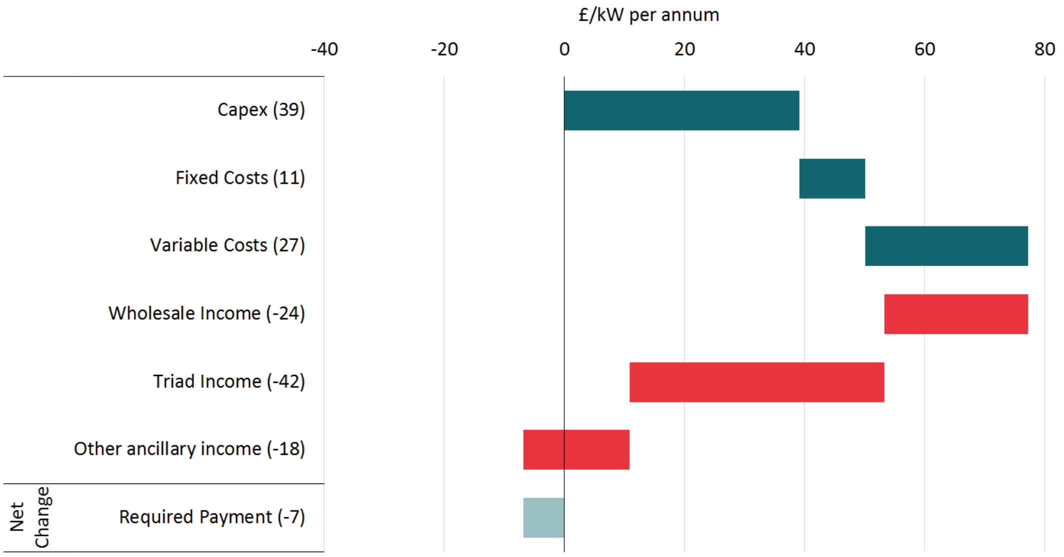
A.5.5 LOLE



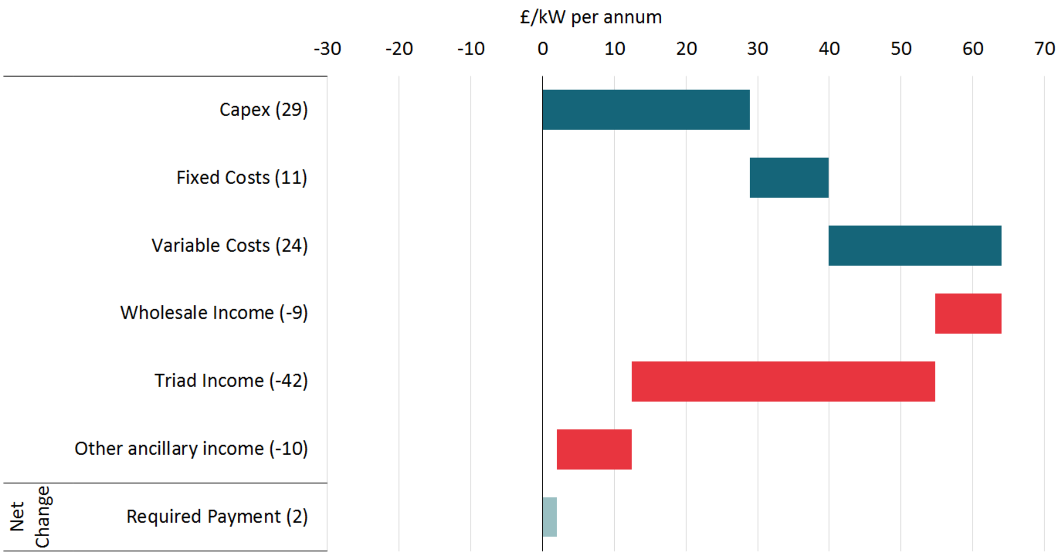
A.5.6 Triad chasing hours



A.5.7 Reciprocating gas revenue breakdown

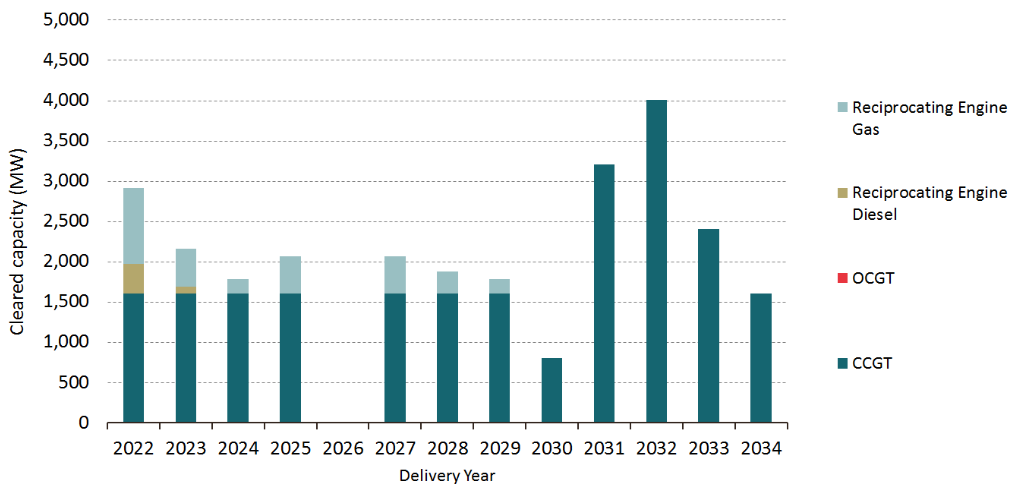


A.5.8 Reciprocating diesel revenue breakdown

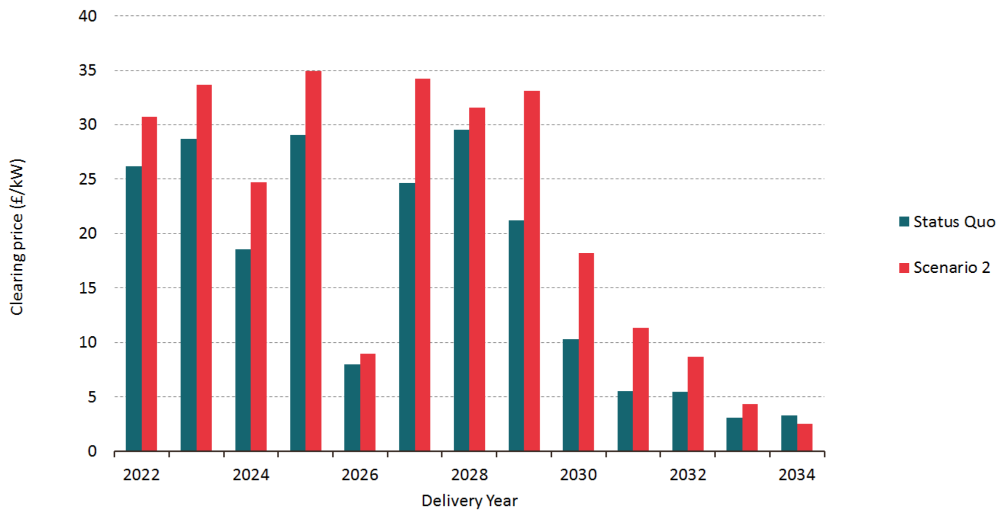


A.6 Scenario 2 detailed results

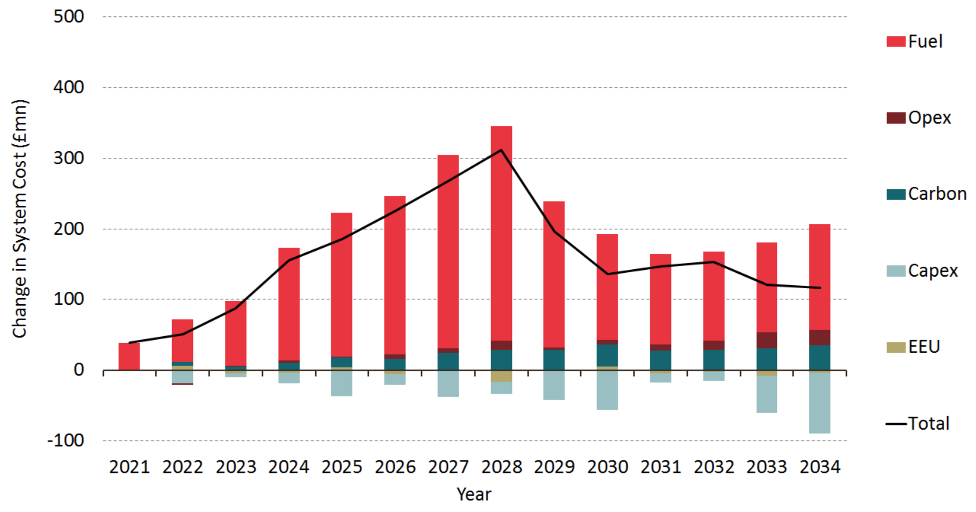
A.6.1 CM build



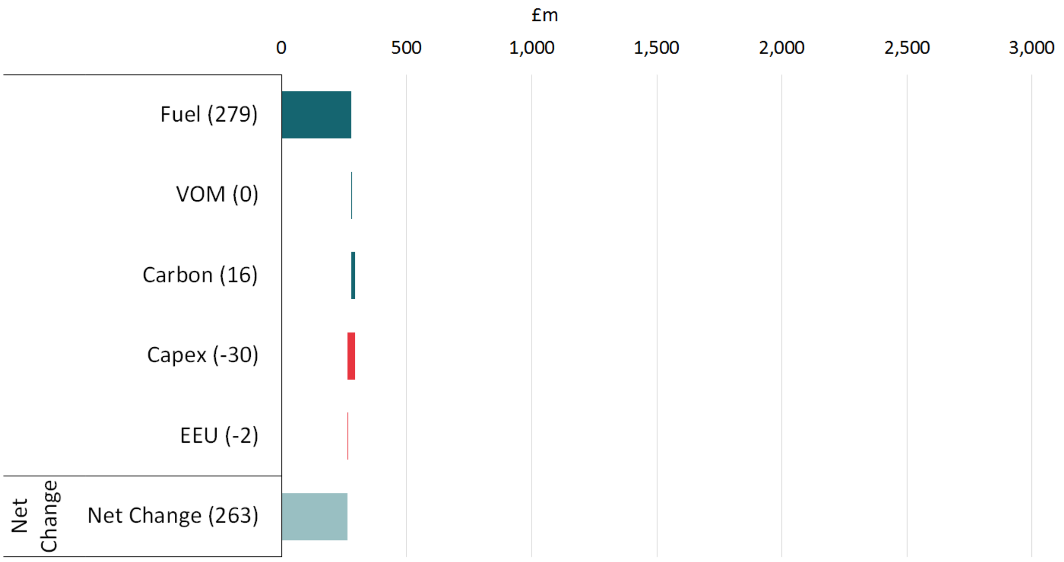
A.6.2 Clearing prices



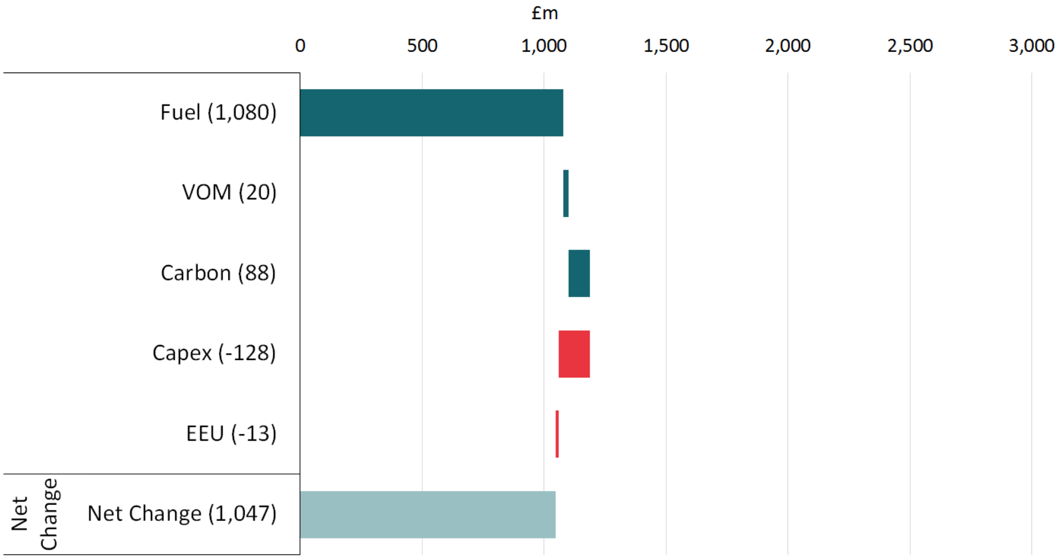
A.6.3 System cost saving



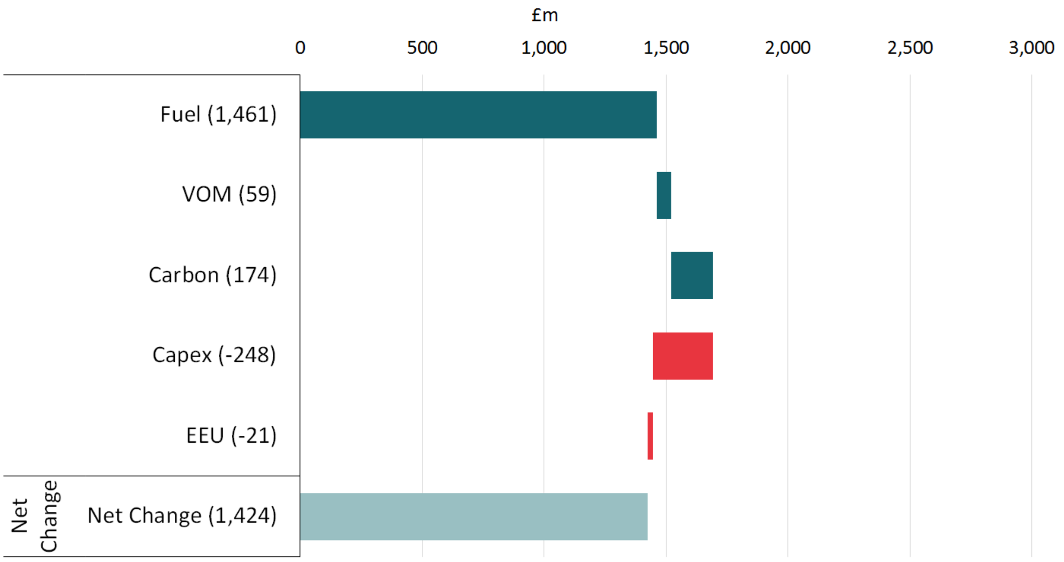
System cost saving, NPV to 2024



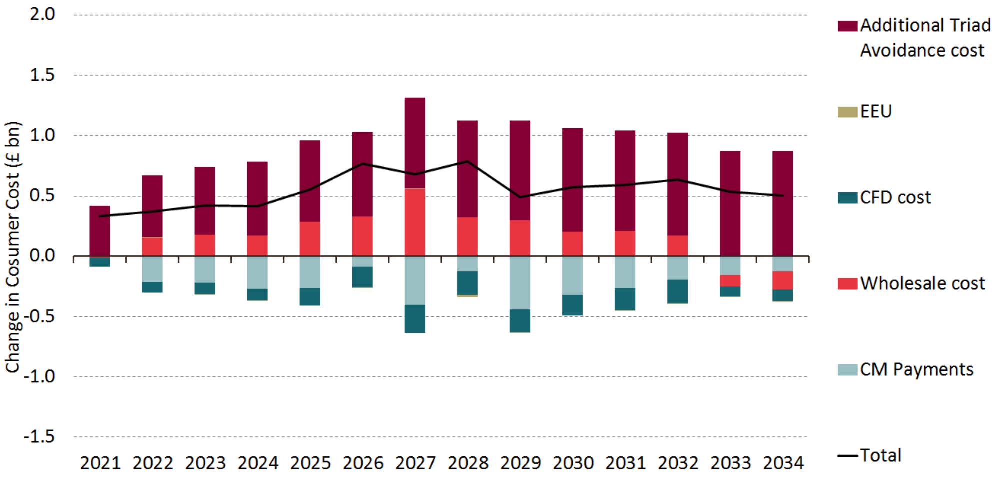
System cost saving, NPV to 2029



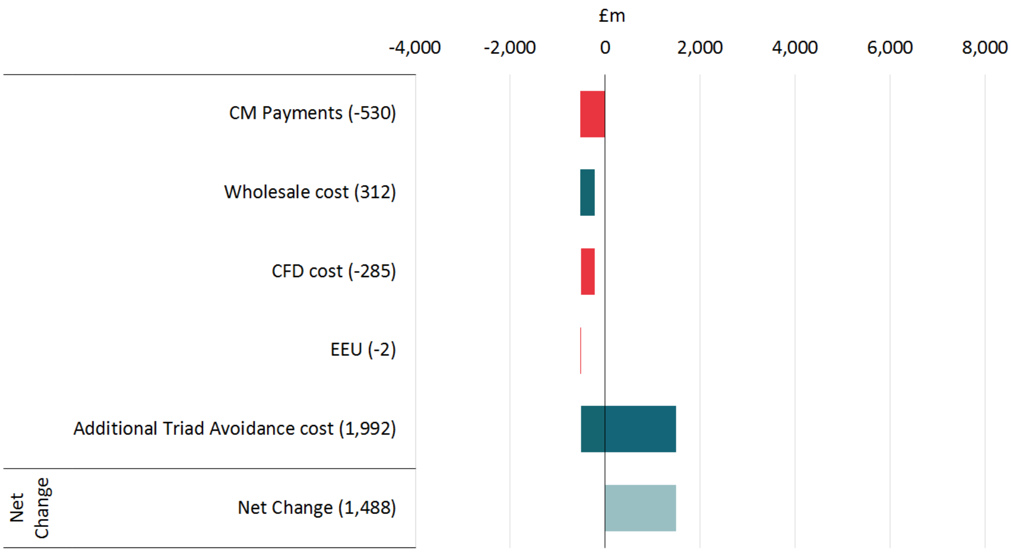
System cost saving, NPV to 2034



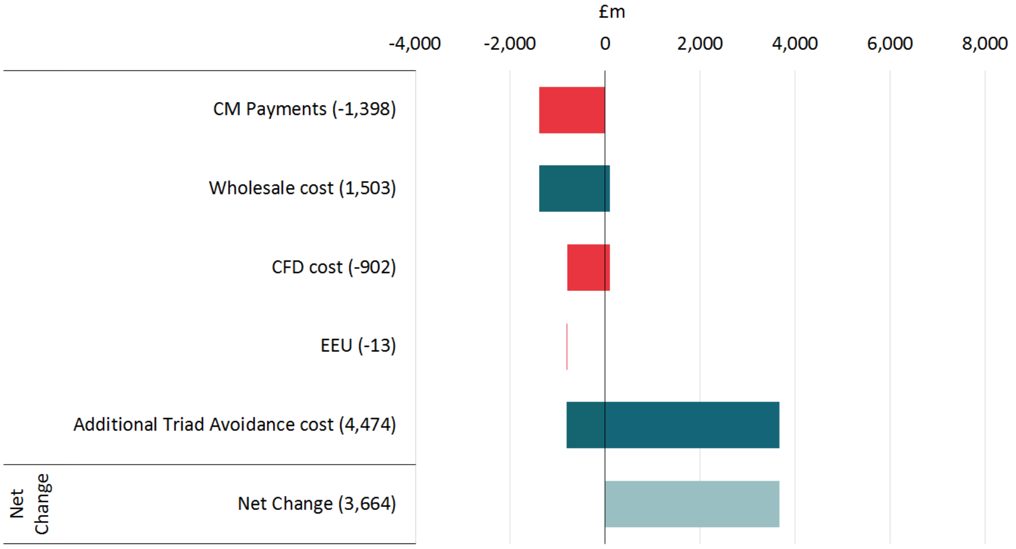
A.6.4 Consumer cost saving



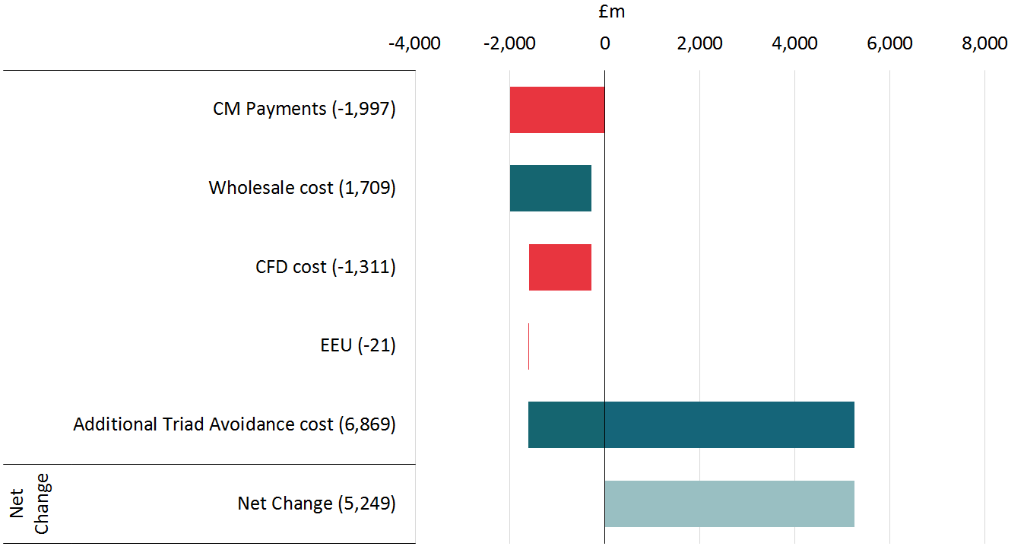
Consumer cost saving, NPV to 2024



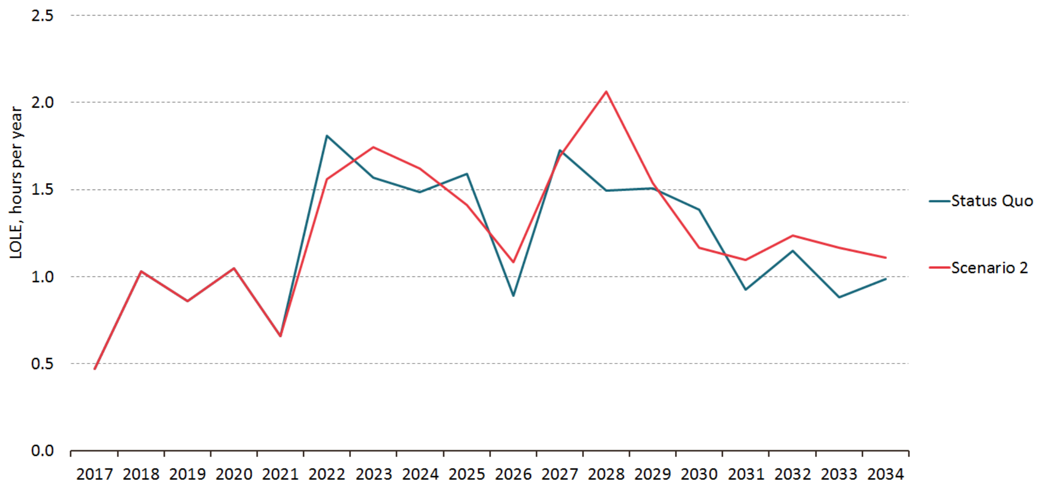
Consumer cost saving, NPV to 2029



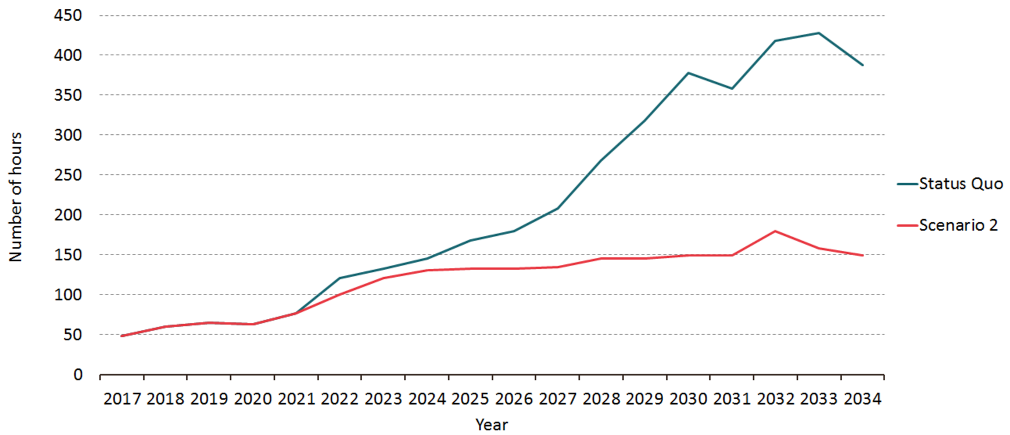
Consumer cost saving, NPV to 2034



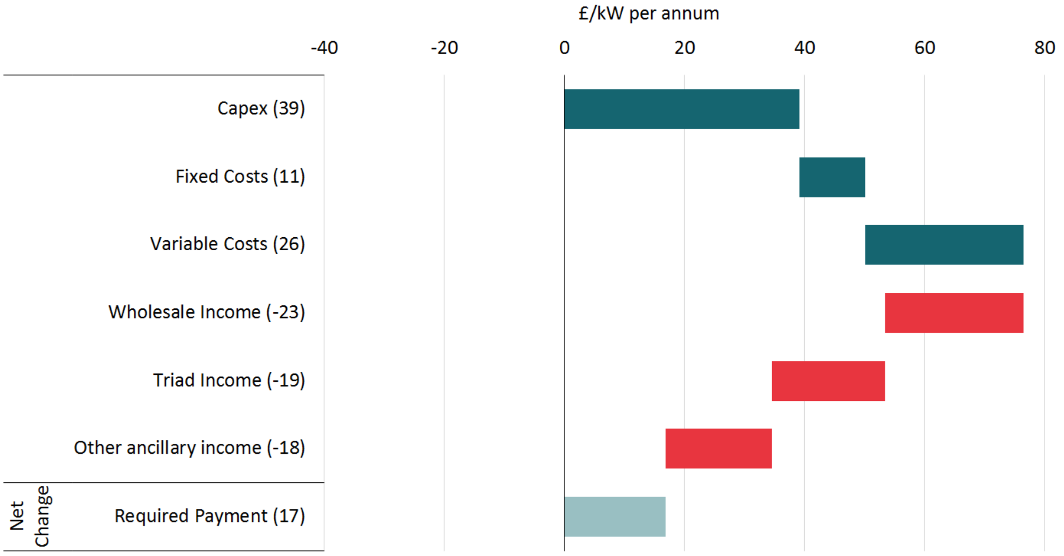
A.6.5 LOLE



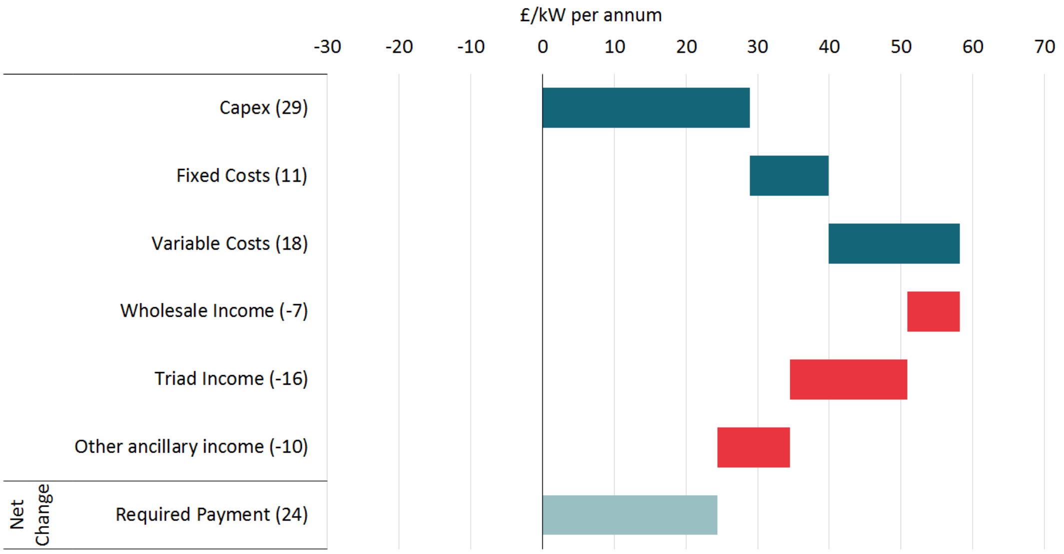
A.6.6 Triad chasing hours



A.6.7 Reciprocating gas revenue breakdown

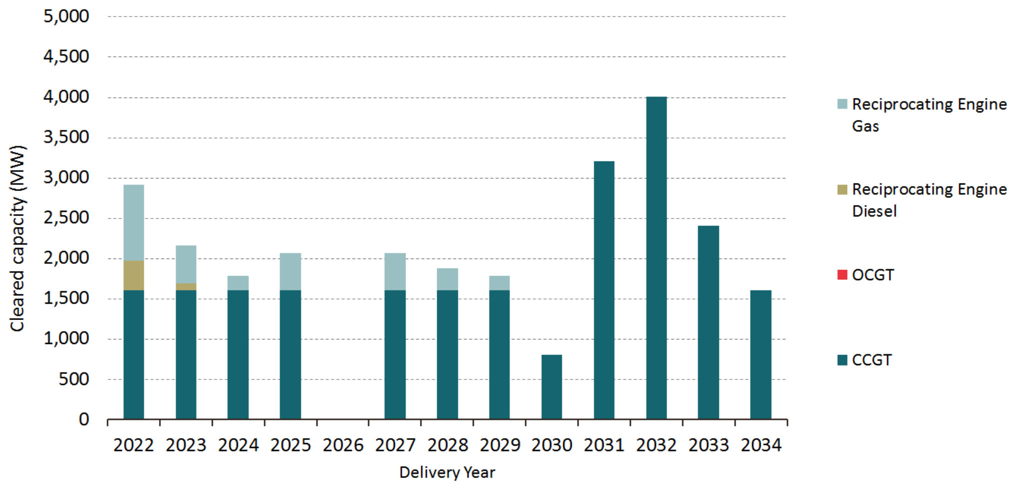


A.6.8 Reciprocating diesel revenue breakdown

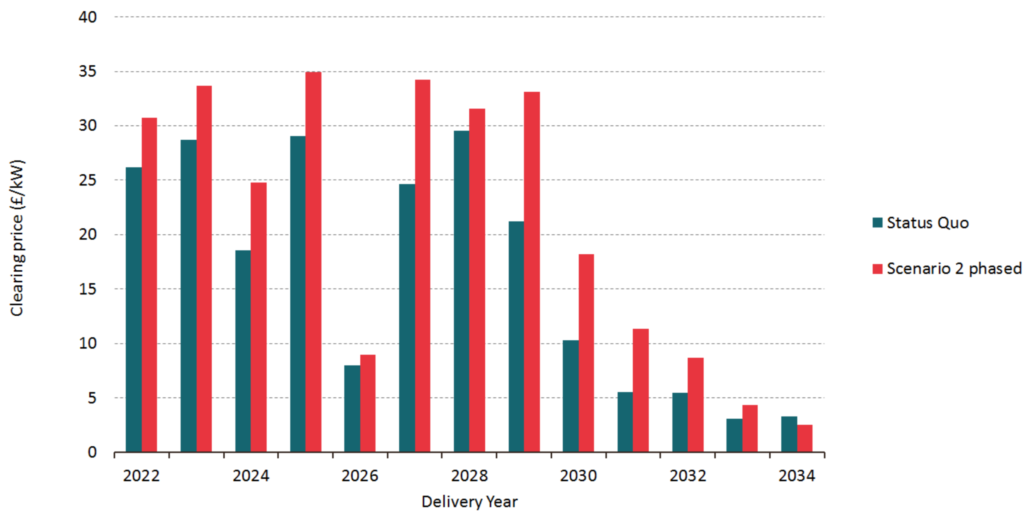


A.7 Scenario 2 phased detailed results

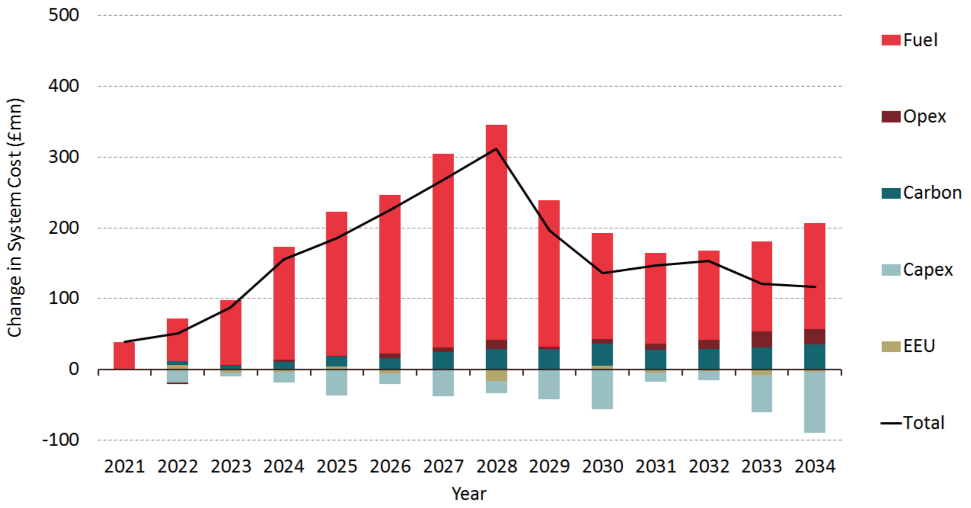
A.7.1 CM build



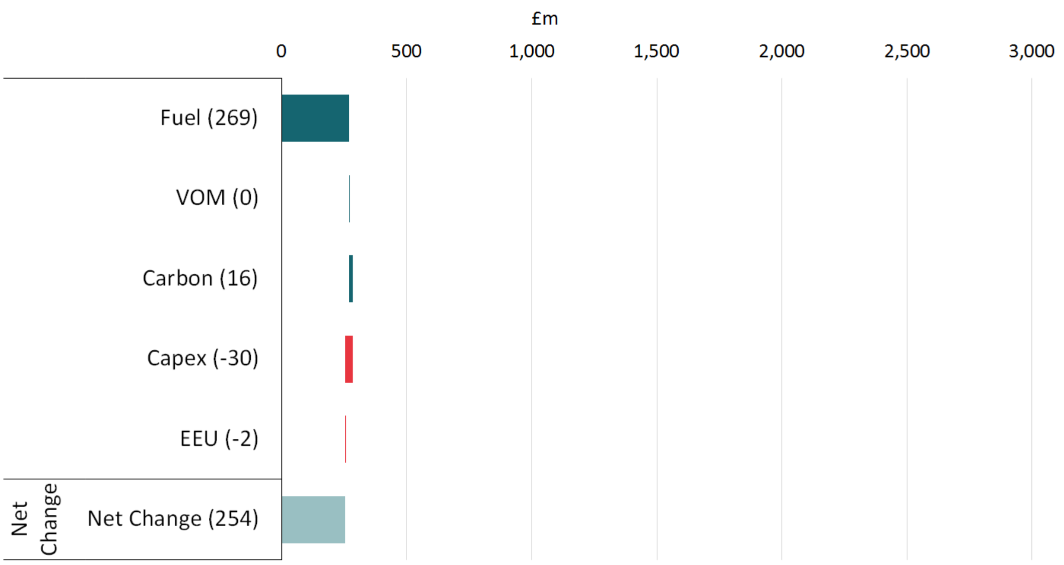
A.7.2 Clearing prices



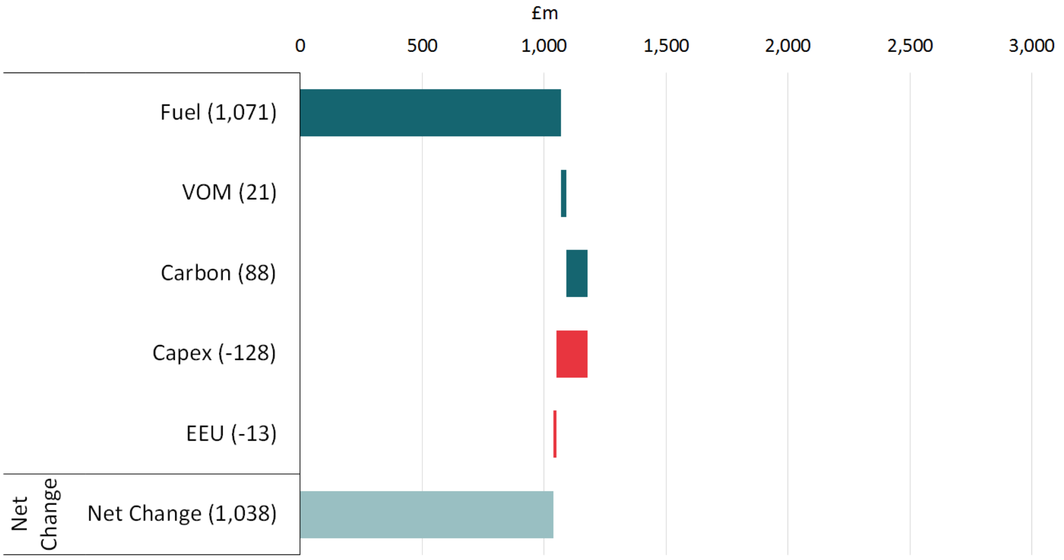
A.7.3 System cost saving



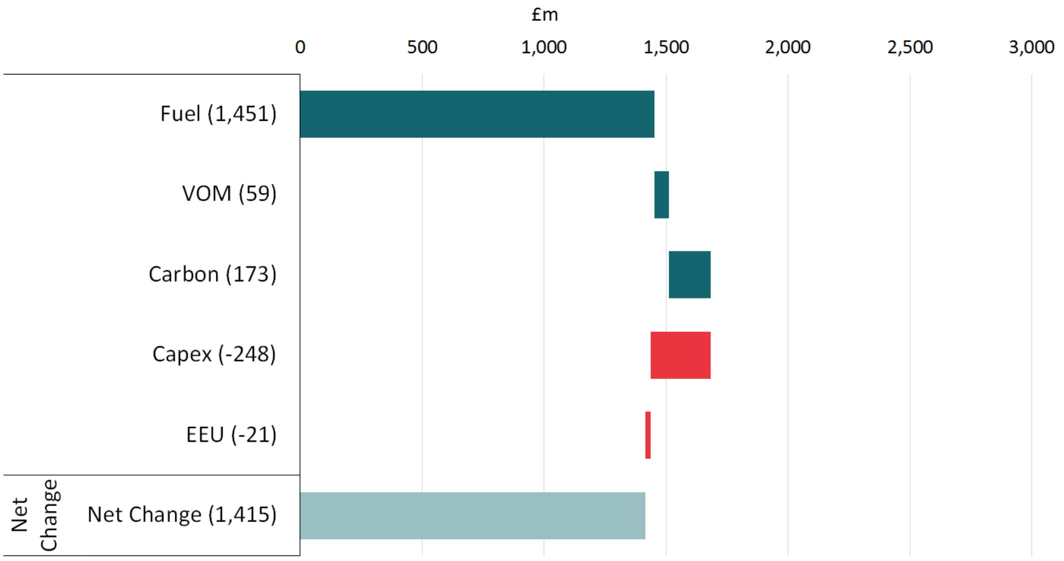
System cost saving, NPV to 2024



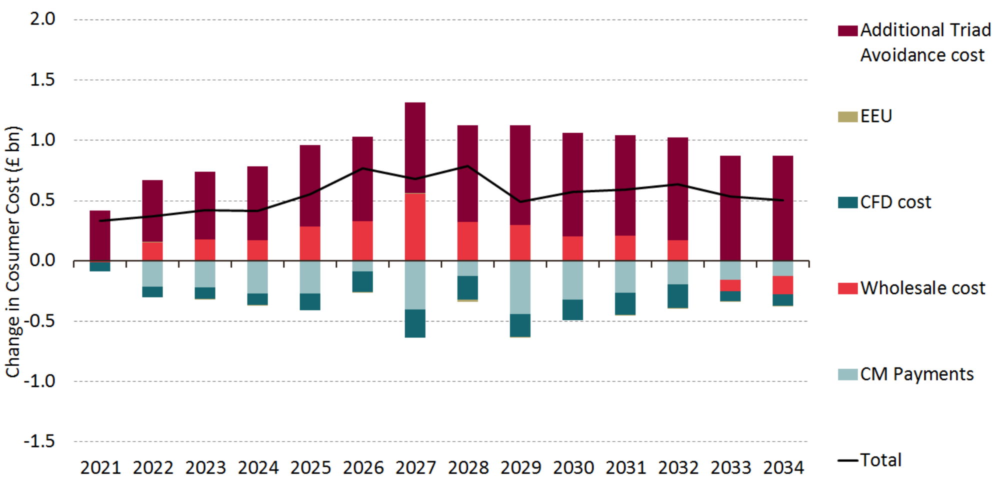
System cost saving, NPV to 2029



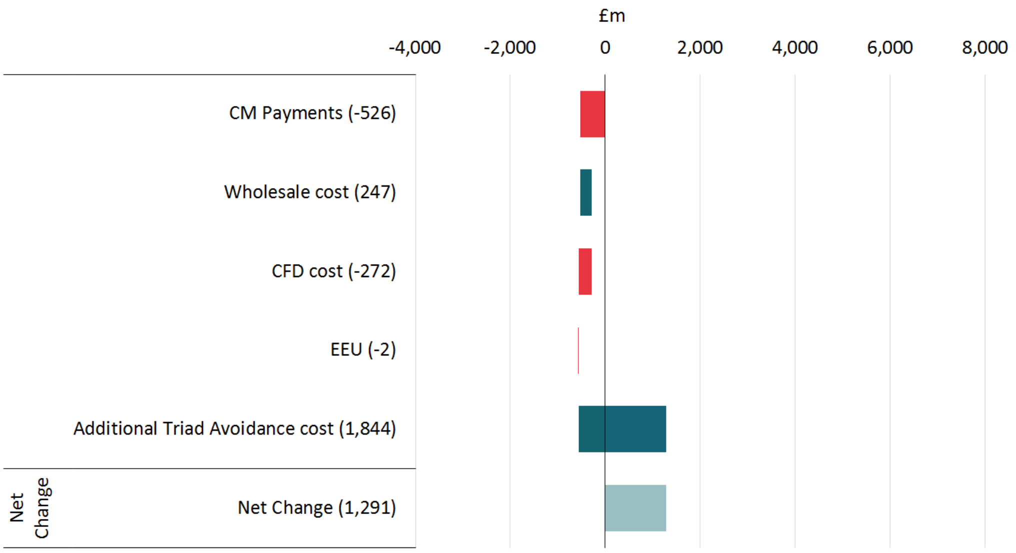
System cost saving, NPV to 2034



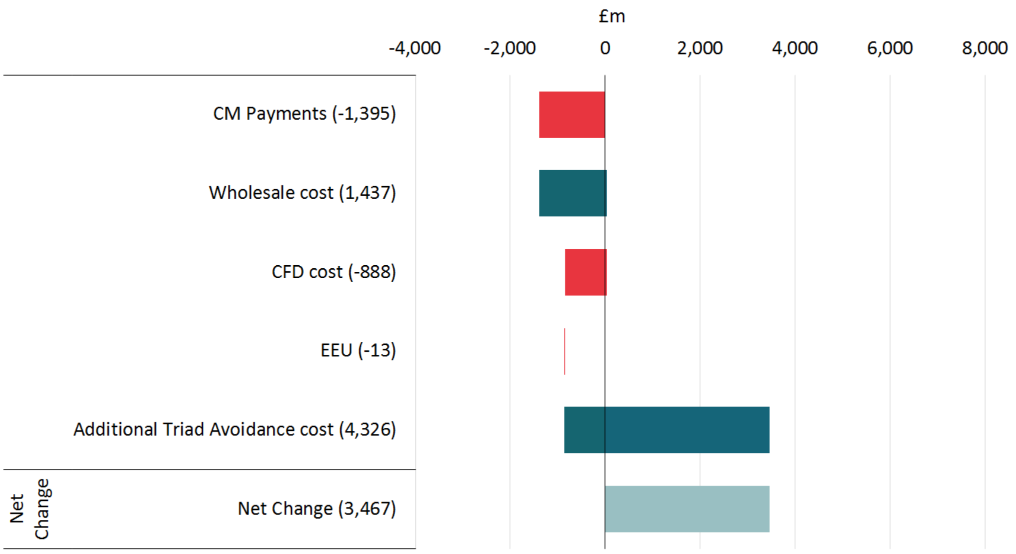
A.7.4 Consumer cost saving



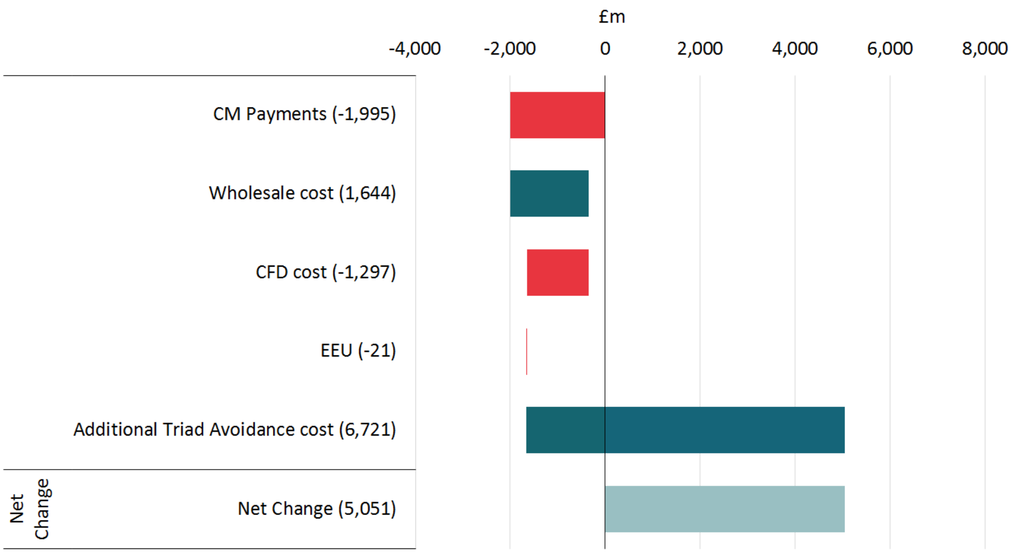
Consumer cost saving, NPV to 2024



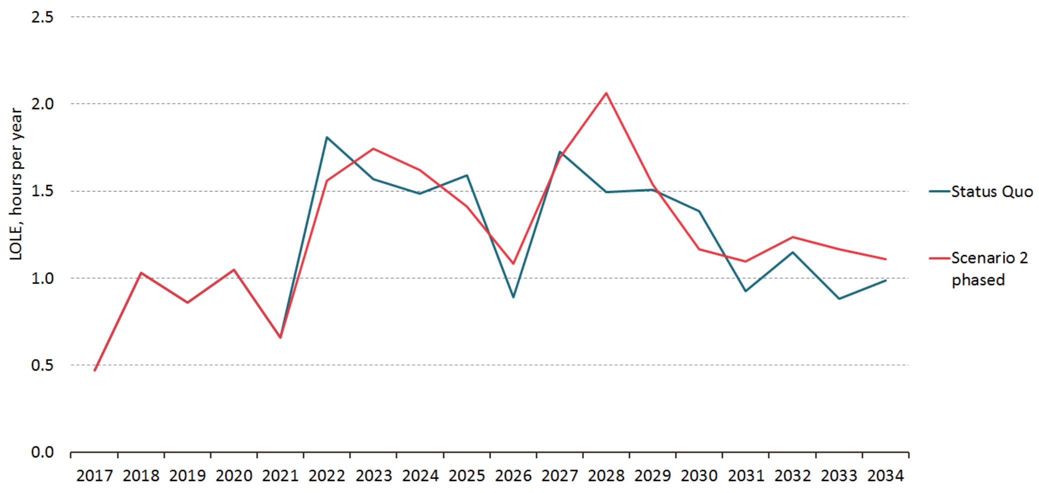
Consumer cost saving, NPV to 2029



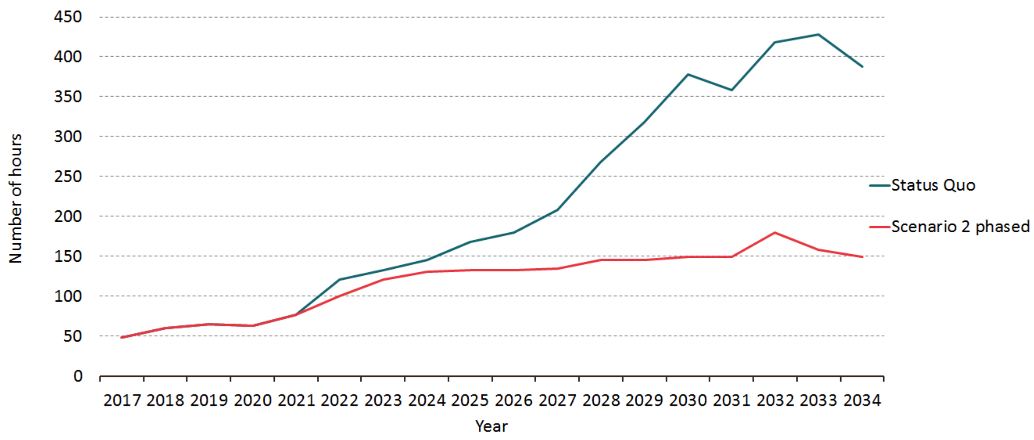
Consumer cost saving, NPV to 2034



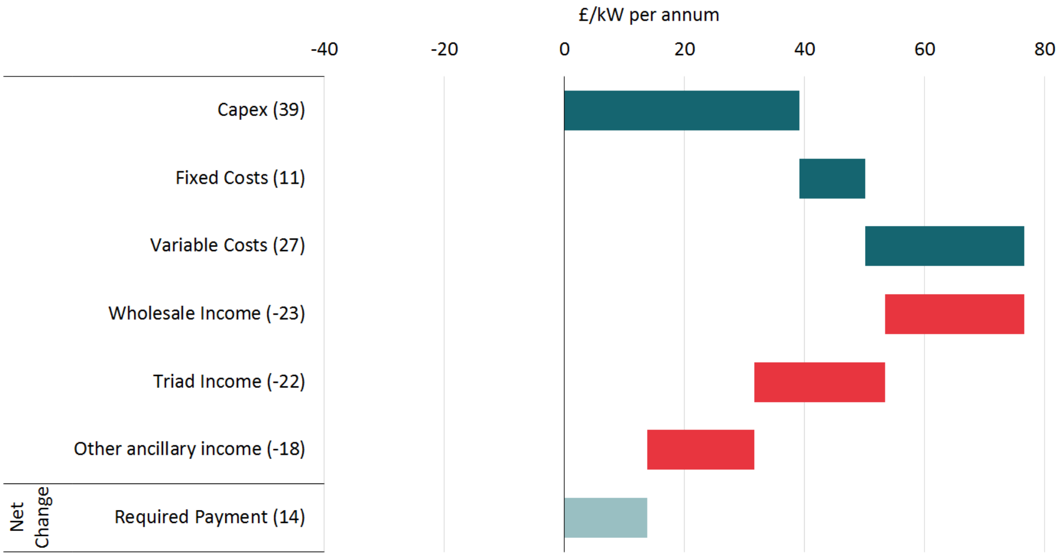
A.7.5 LOLE



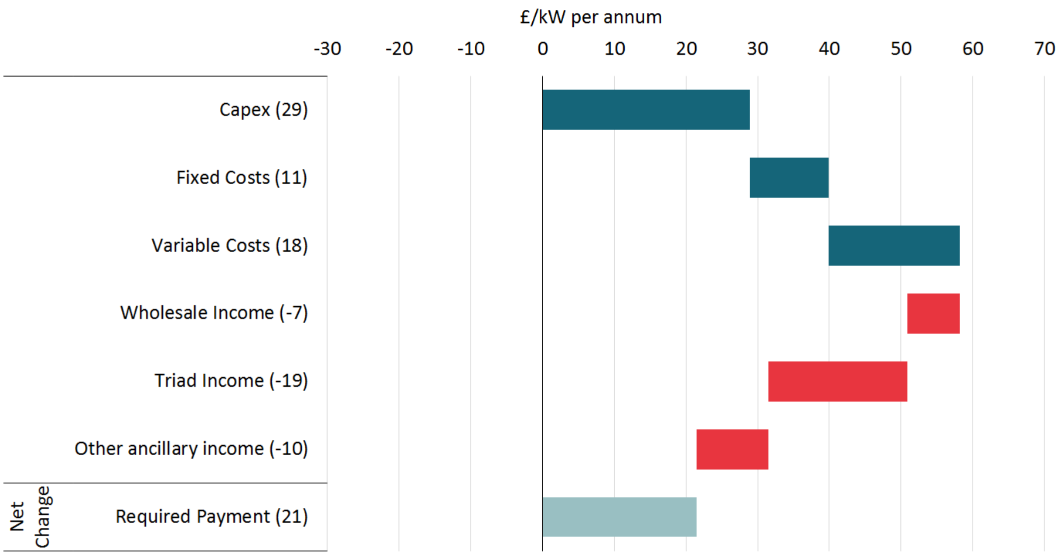
A.7.6 Triad chasing hours



A.7.7 Reciprocating gas revenue breakdown

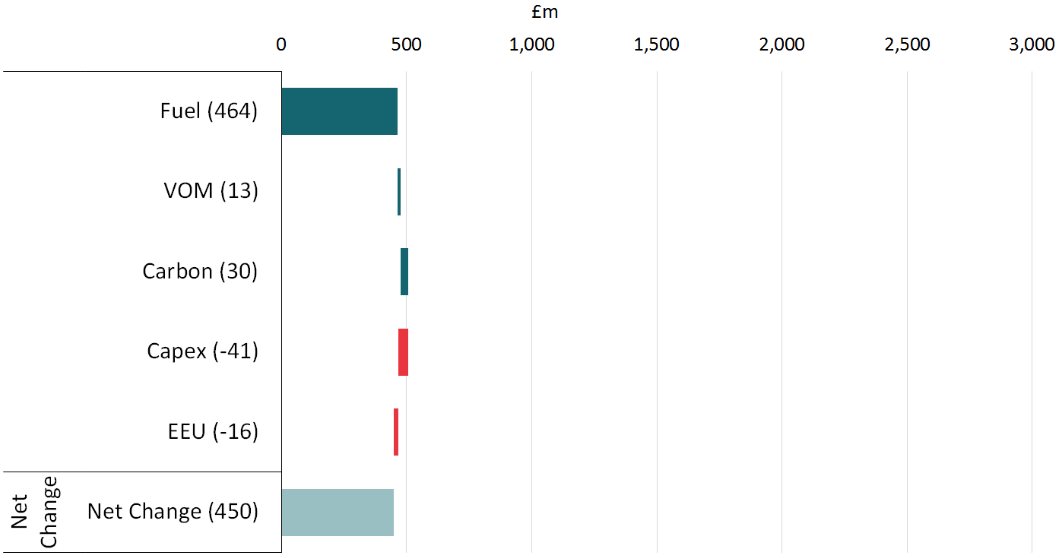


A.7.8 Reciprocating diesel revenue breakdown

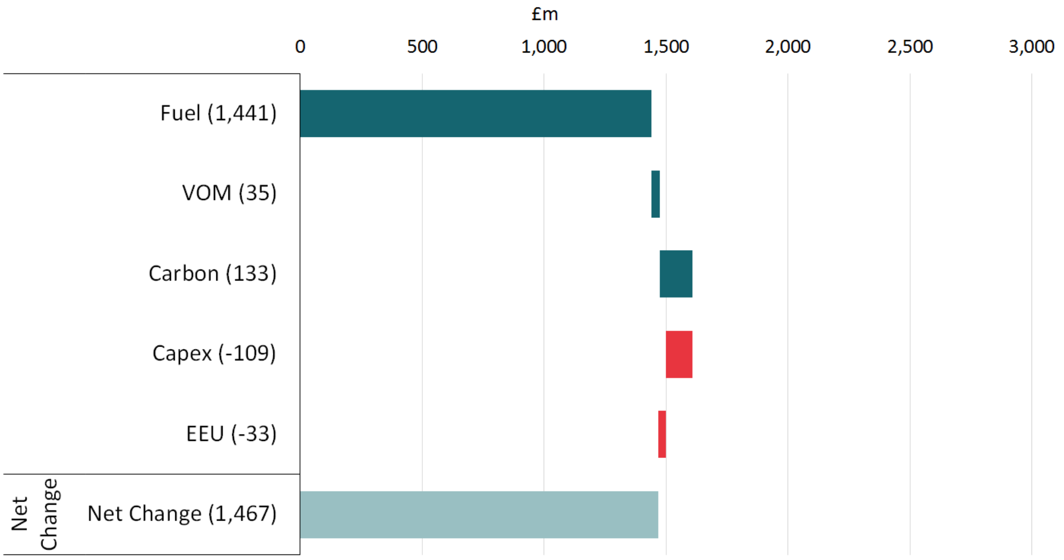


A.8 Scenario 3 additional results

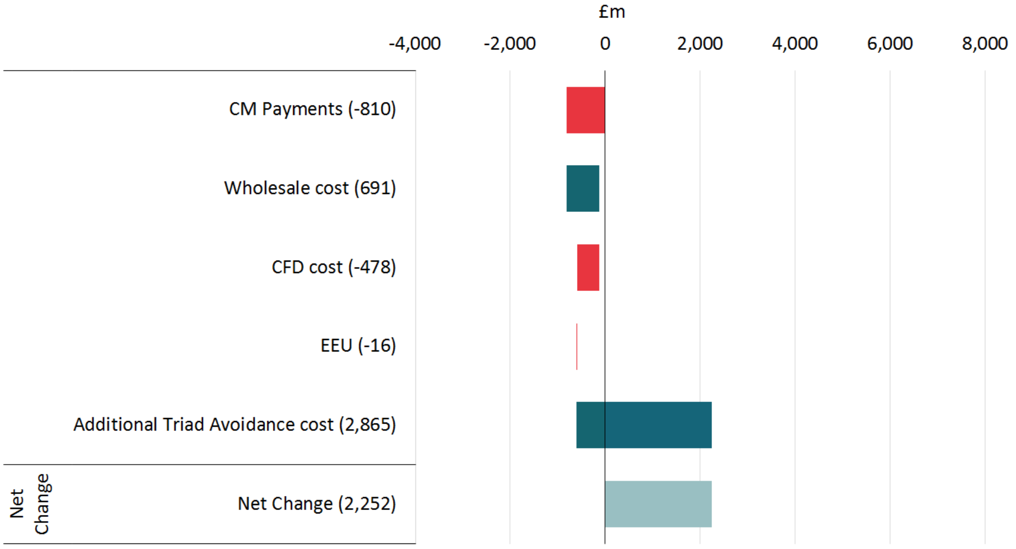
A.8.1 System cost saving, NPV to 2024



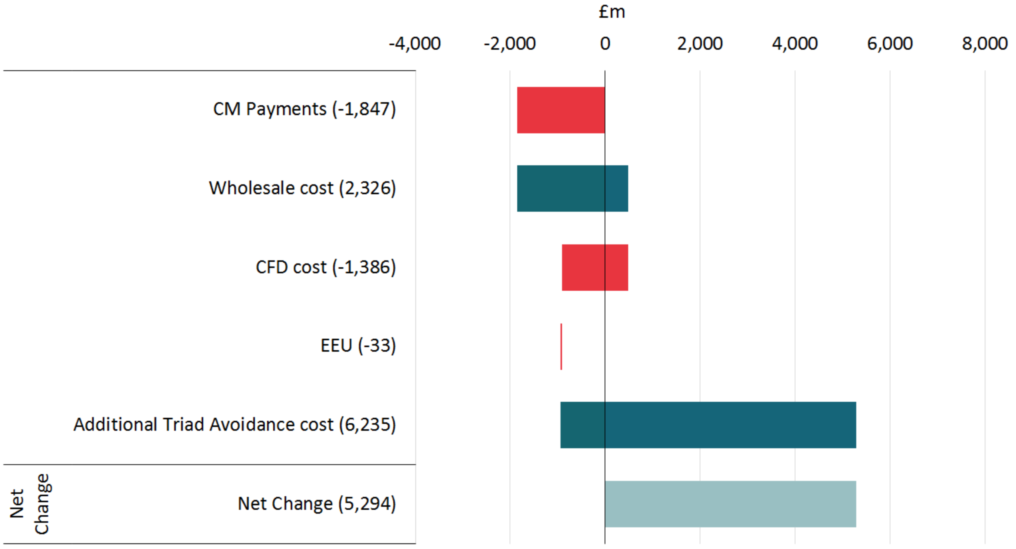
A.8.2 System cost saving, NPV to 2029



A.8.3 Consumer cost saving, NPV to 2024

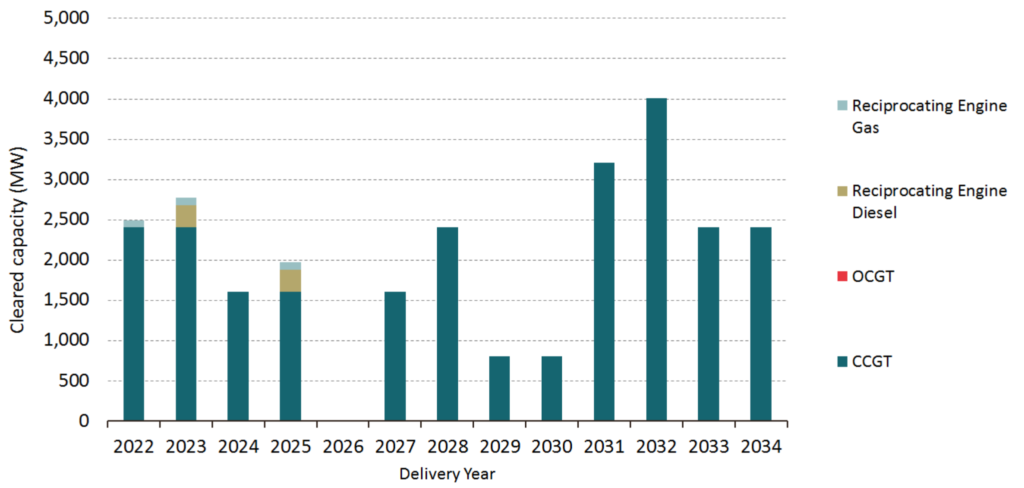


A.8.4 Consumer cost saving, NPV to 2029

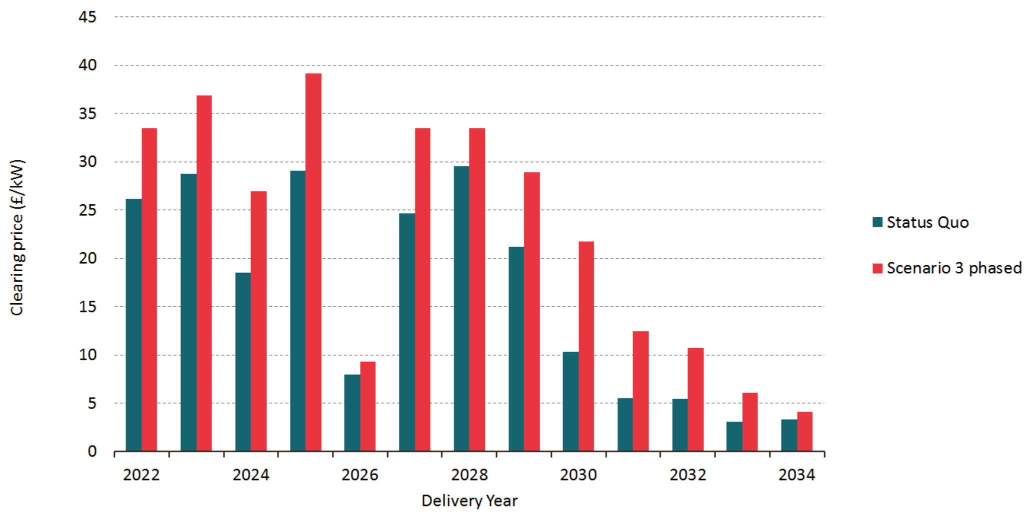


A.9 Scenario 3 phased detailed results

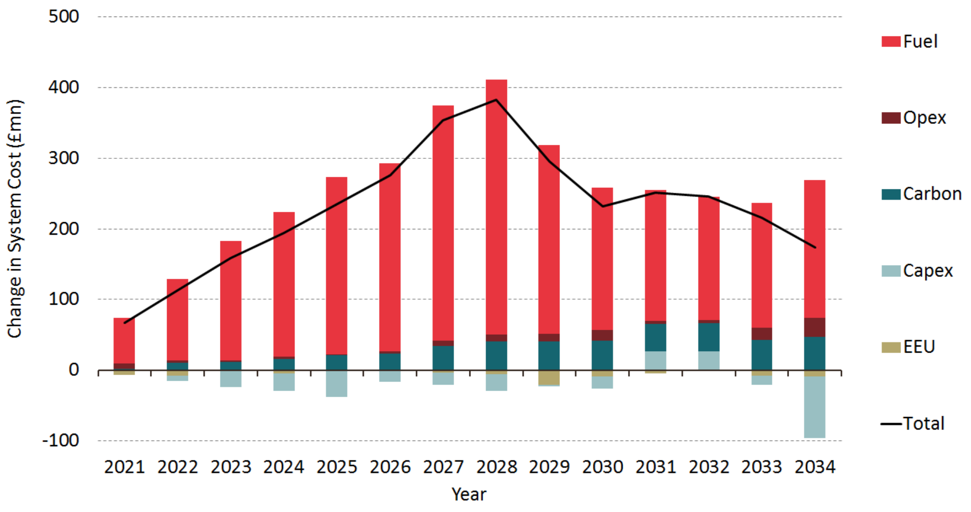
A.9.1 CM build



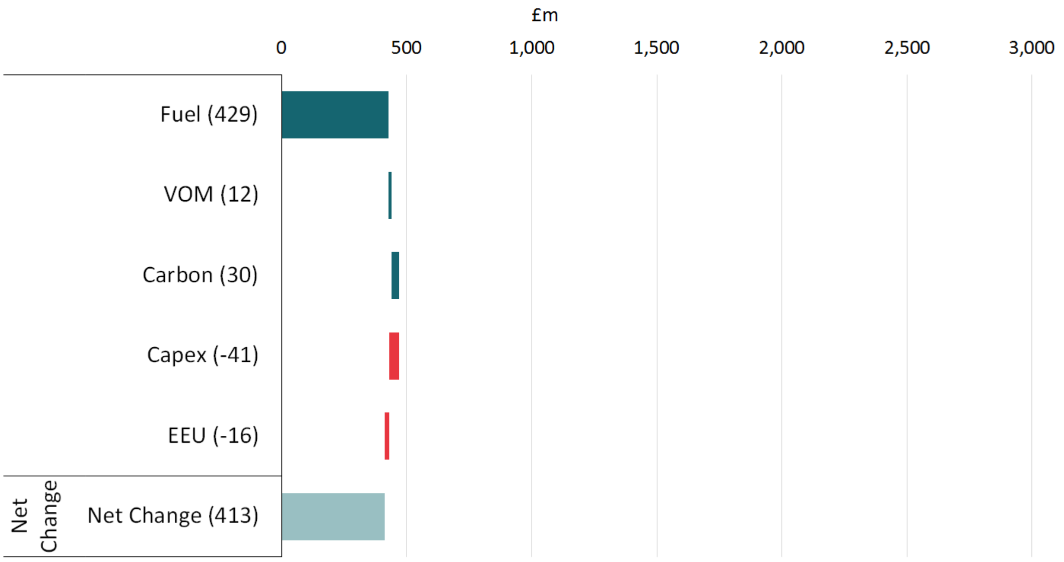
A.9.2 Clearing prices



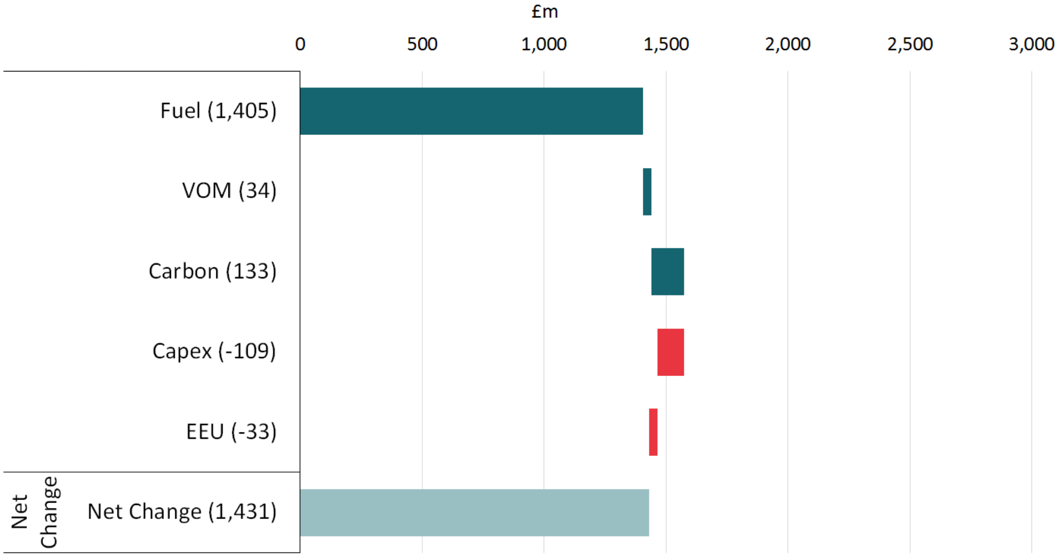
A.9.3 System cost saving



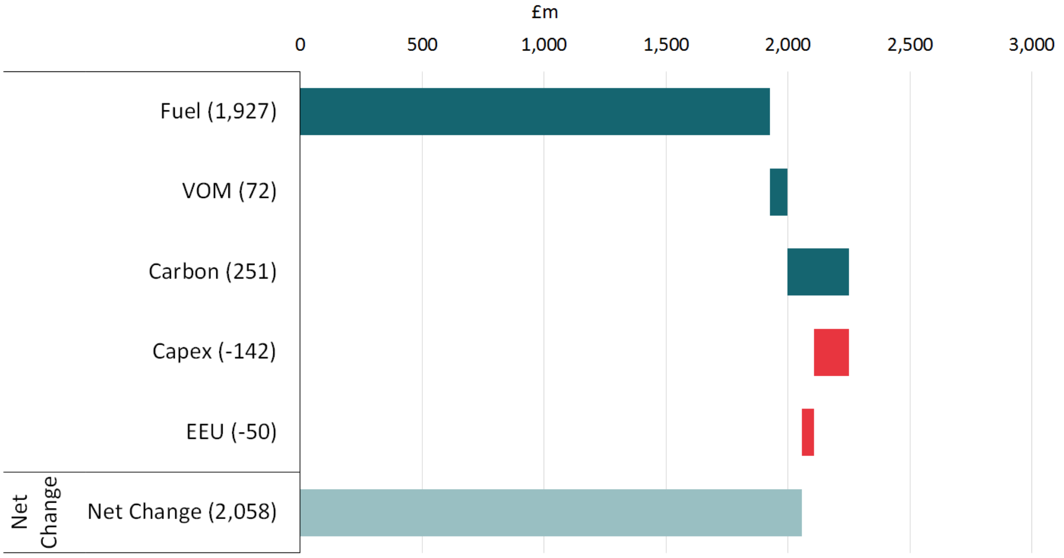
System cost saving, NPV to 2024



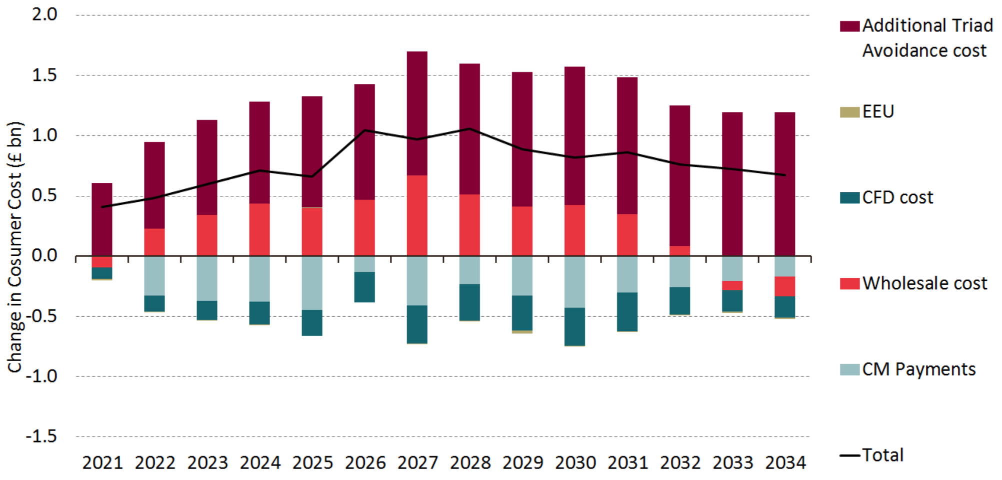
System cost saving, NPV to 2029



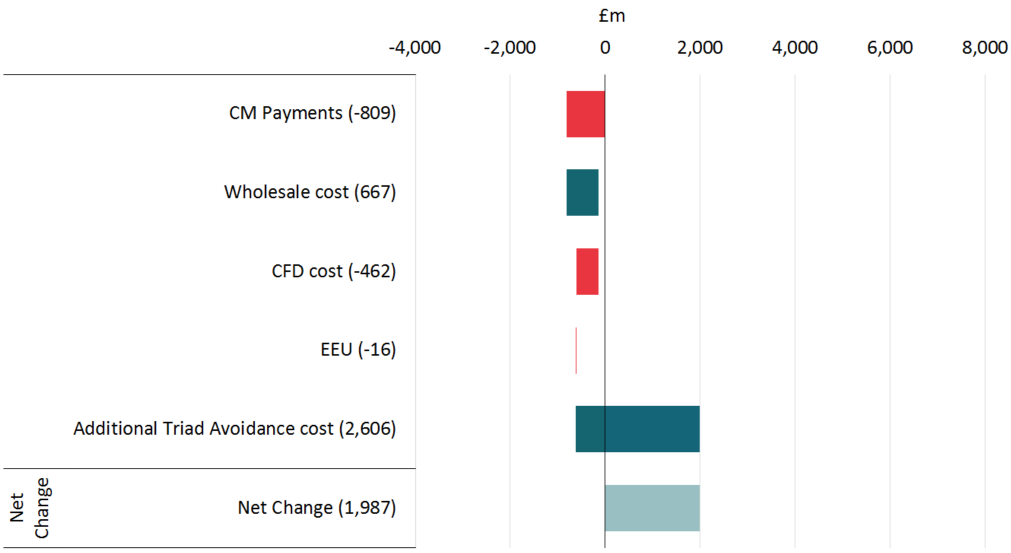
System cost saving, NPV to 2034



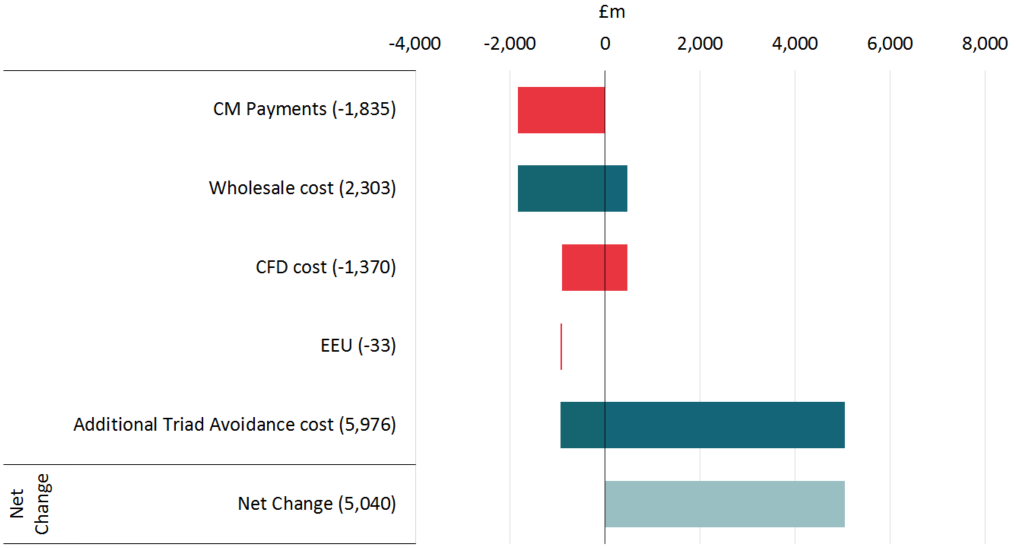
A.9.4 Consumer cost saving



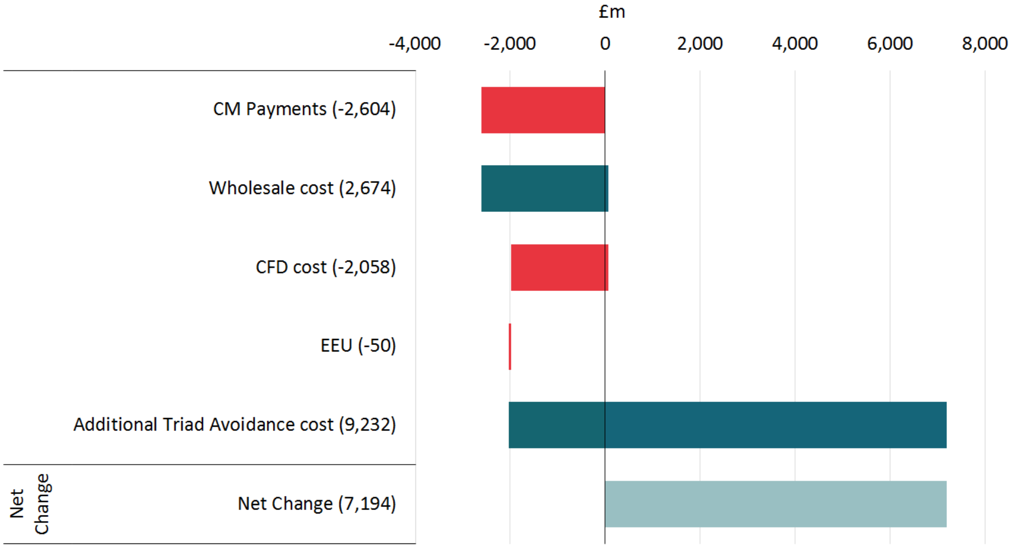
Consumer cost saving, NPV to 2024



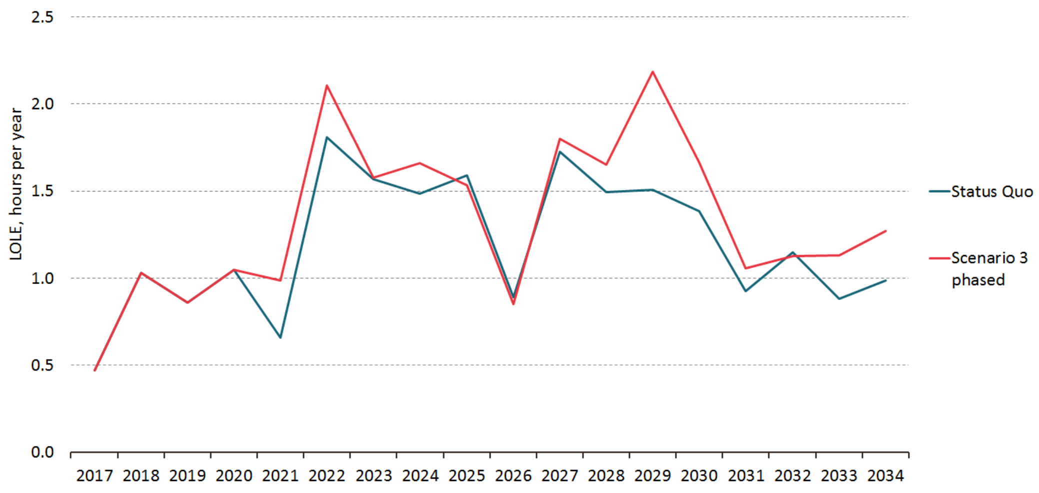
Consumer cost saving, NPV to 2029



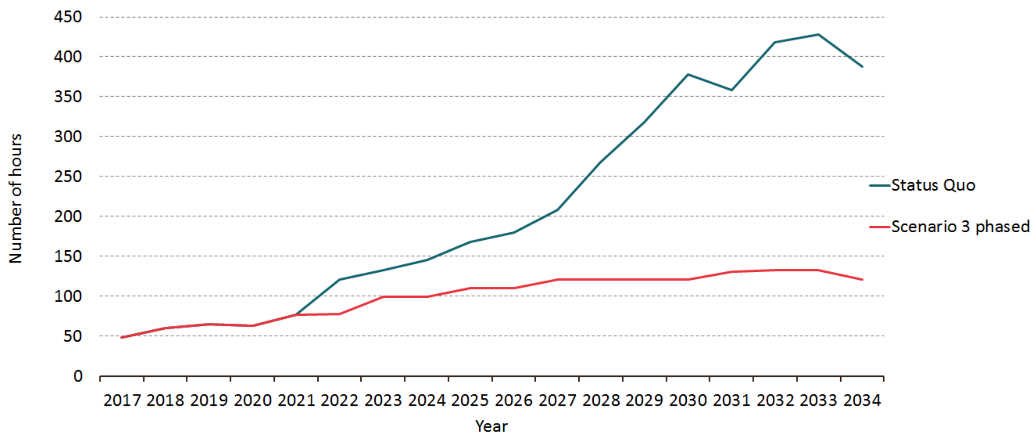
Consumer cost saving, NPV to 2034



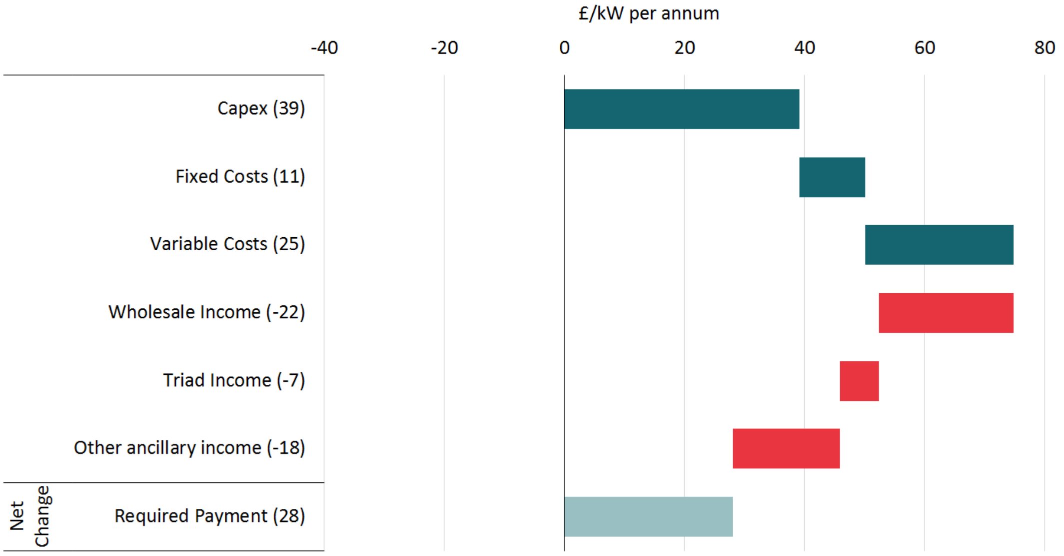
A.9.5 LOLE



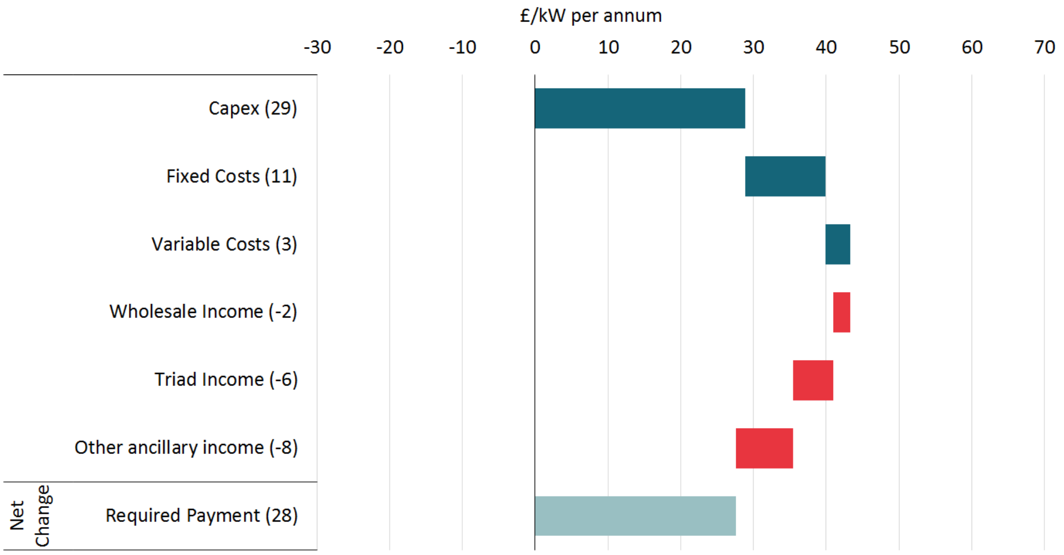
A.9.6 Triad chasing hours



A.9.7 Reciprocating gas revenue breakdown

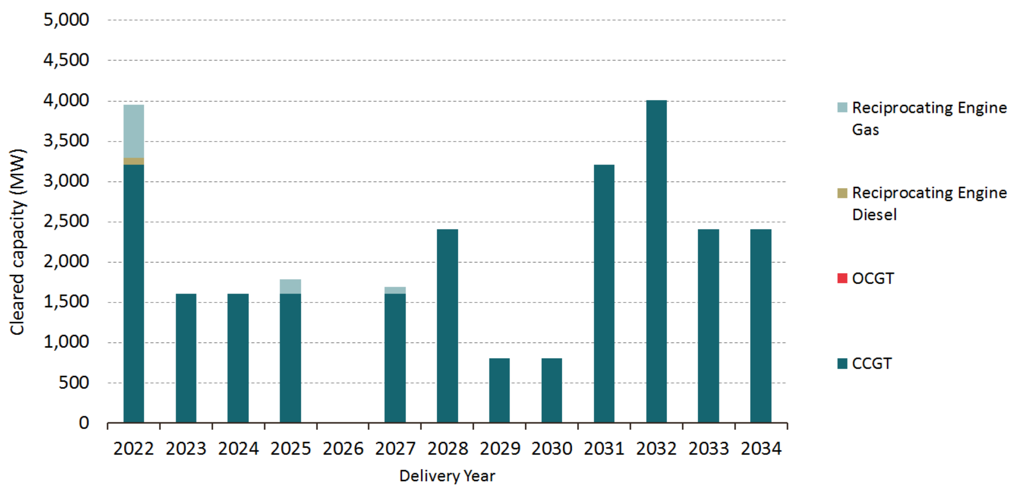


A.9.8 Reciprocating diesel revenue breakdown

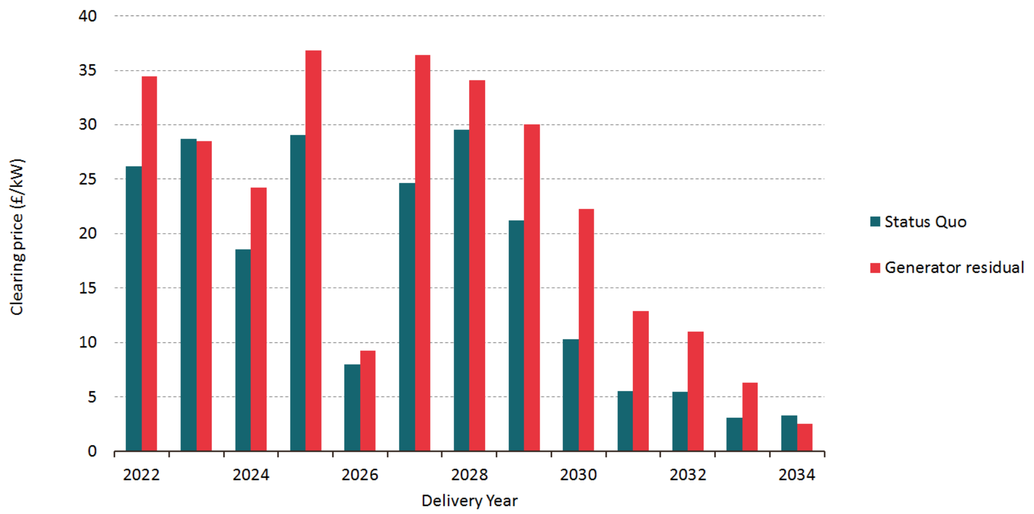


A.10 Generator residual scenario detailed results

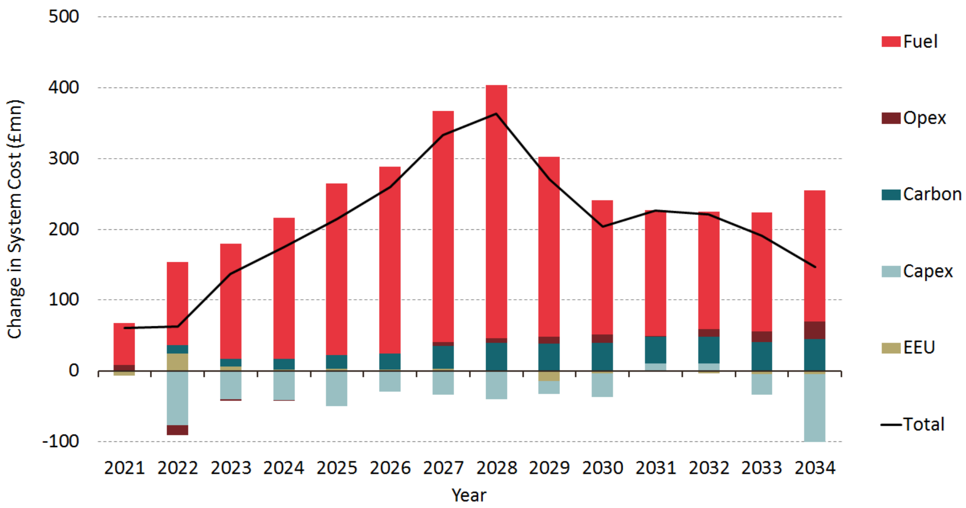
A.10.1 CM build



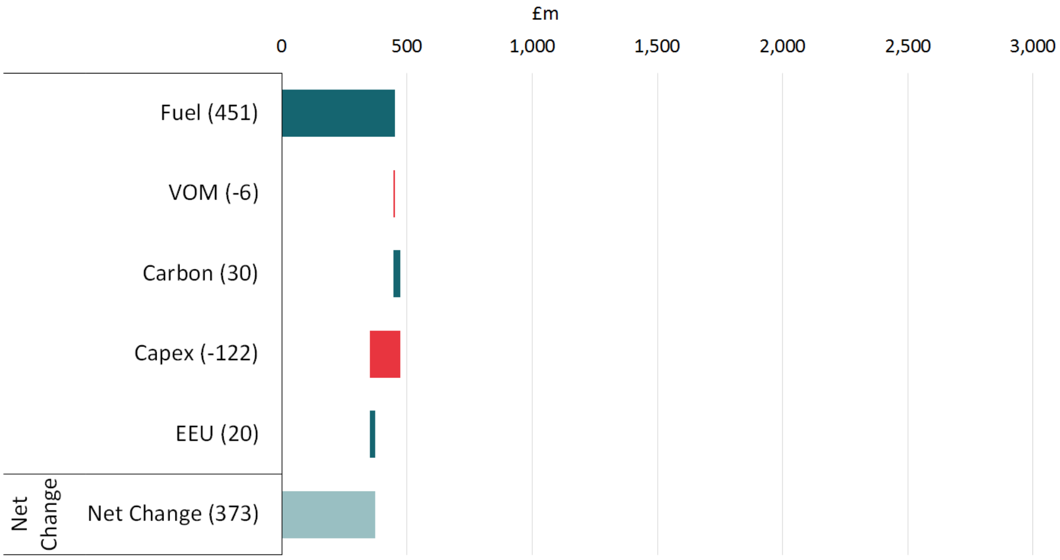
A.10.2 Clearing prices



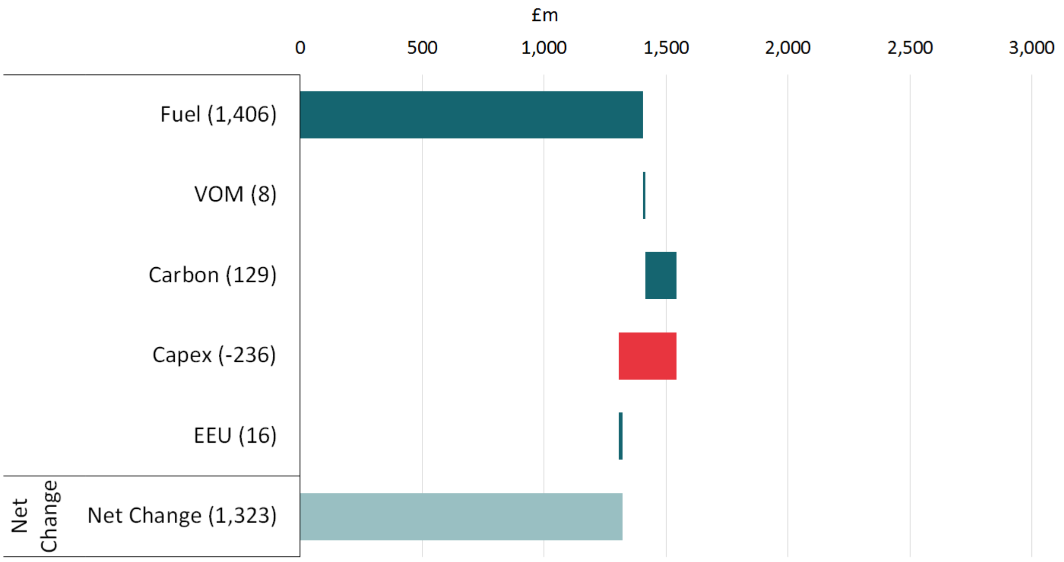
A.10.3 System cost saving



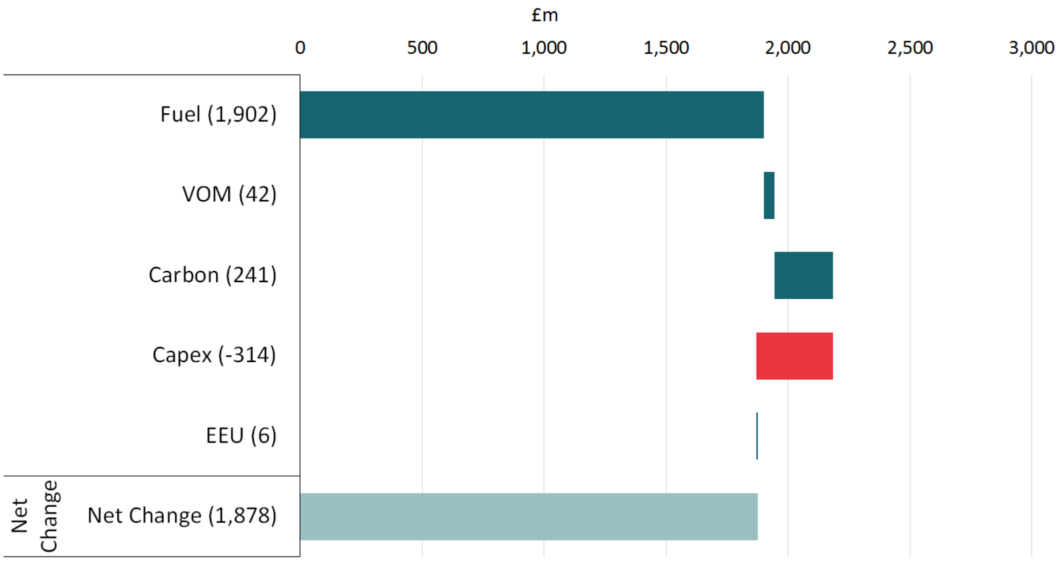
System cost saving, NPV to 2024



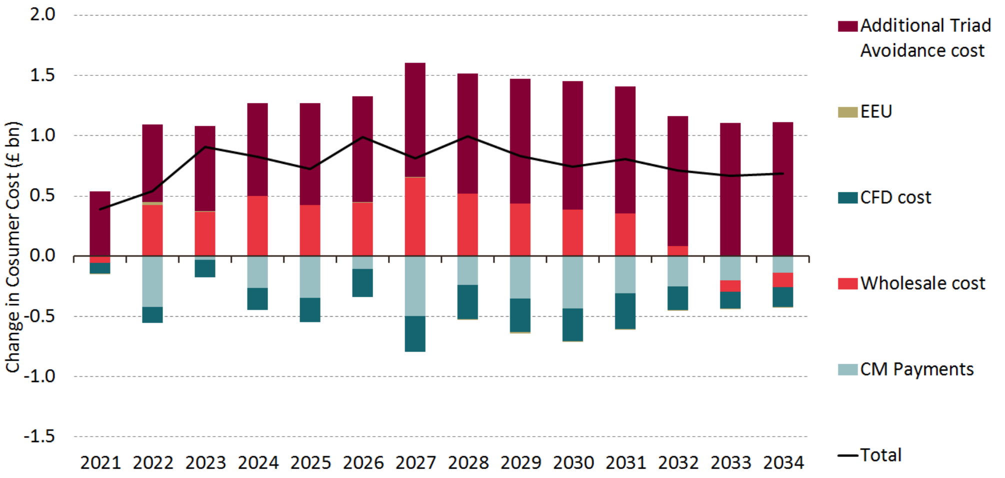
System cost saving, NPV to 2029



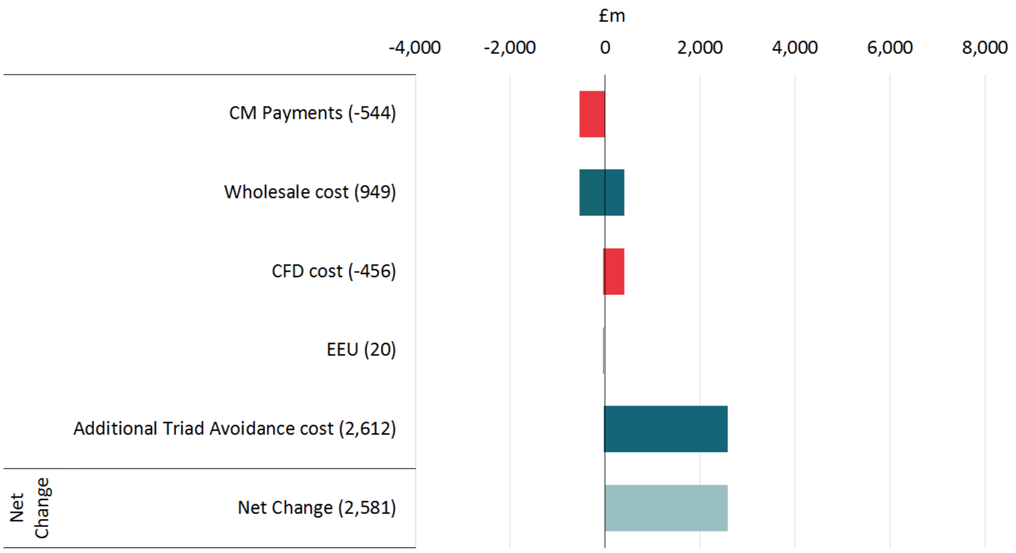
System cost saving, NPV to 2034



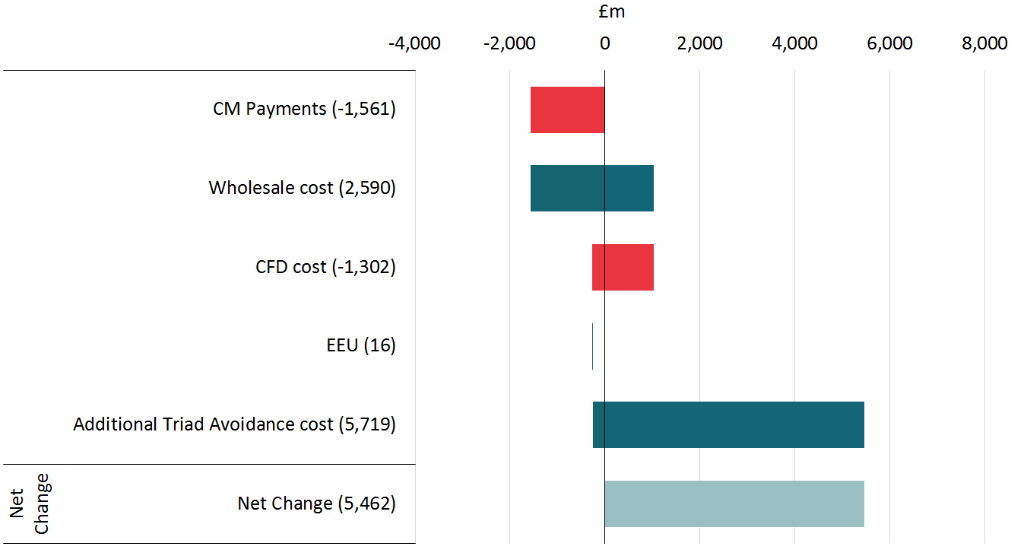
A.10.4 Consumer cost saving



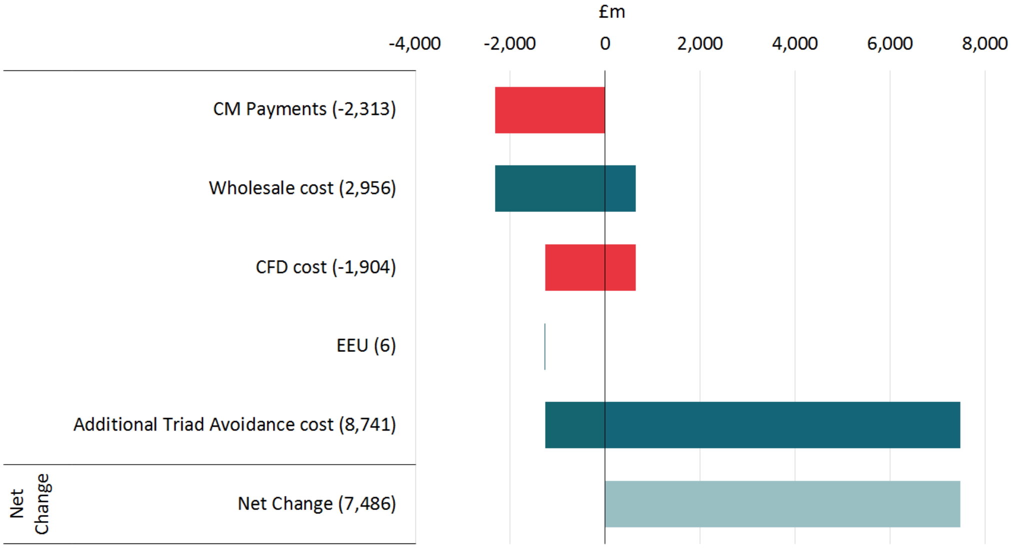
Consumer cost saving, NPV to 2024



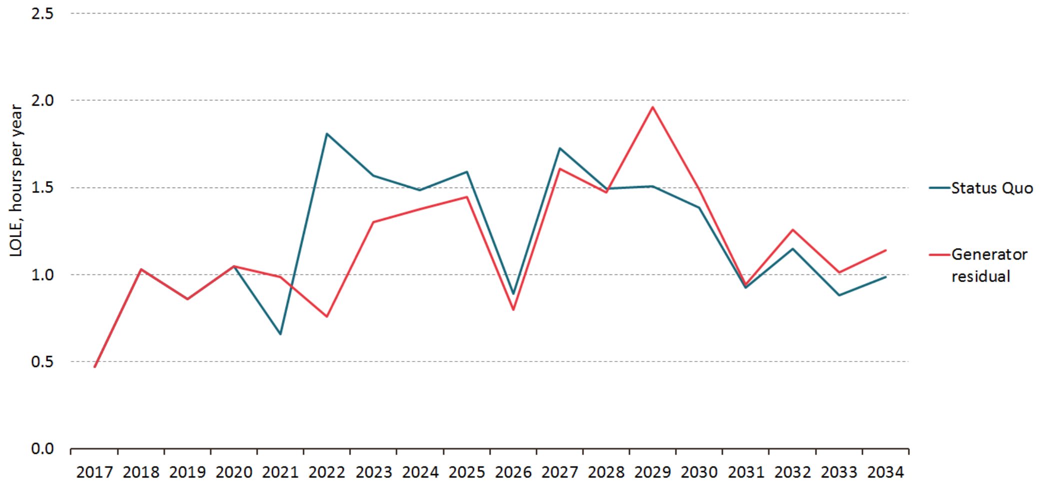
Consumer cost saving, NPV to 2029



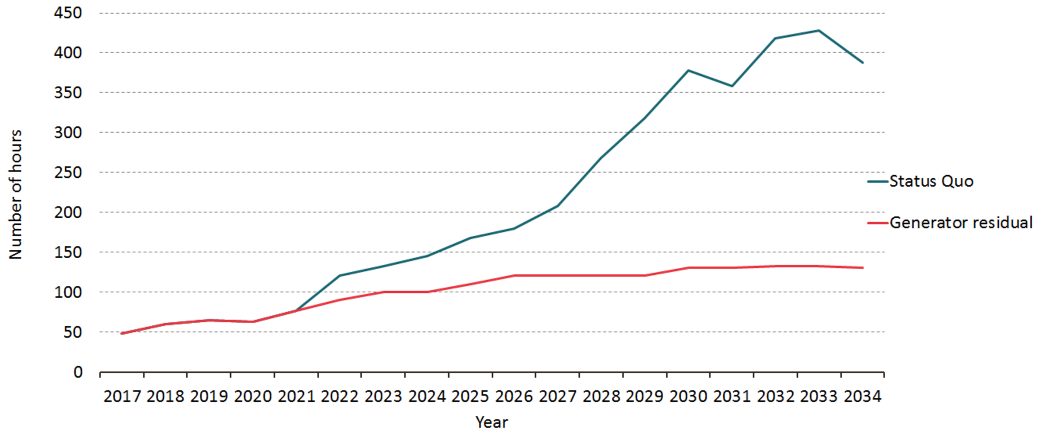
Consumer cost saving, NPV to 2034



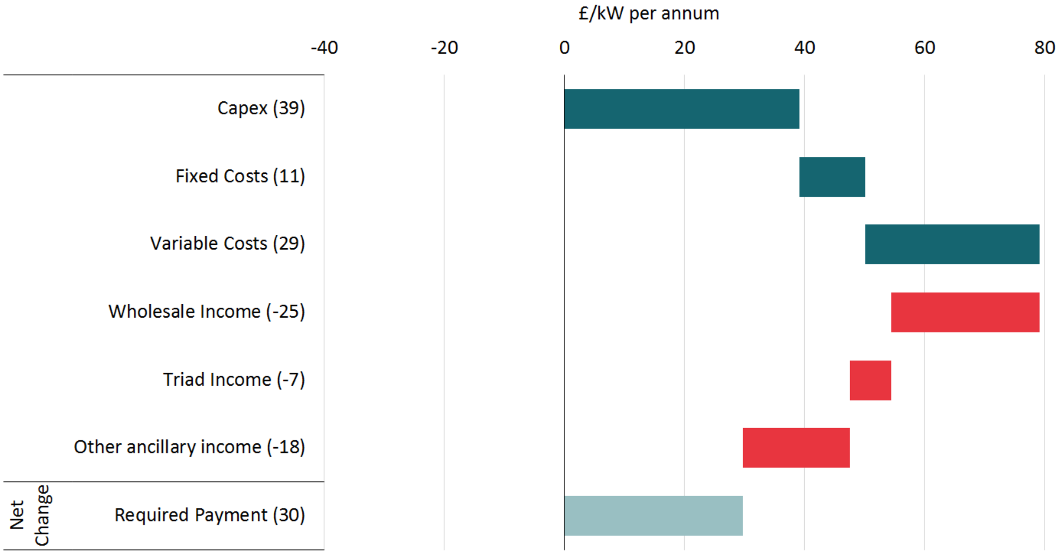
A.10.5 LOLE



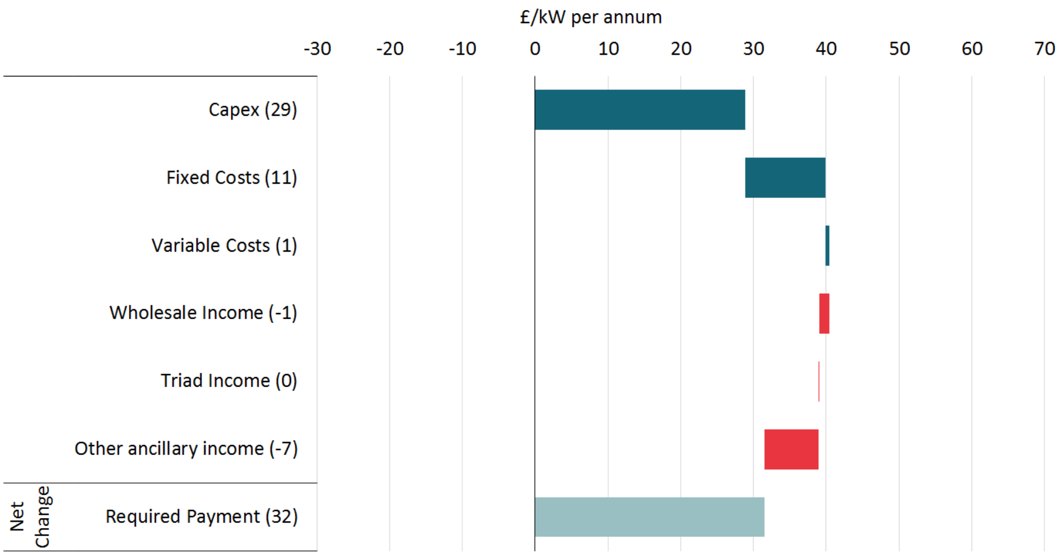
A.10.6 Triad chasing hours



A.10.7 Reciprocating gas revenue breakdown

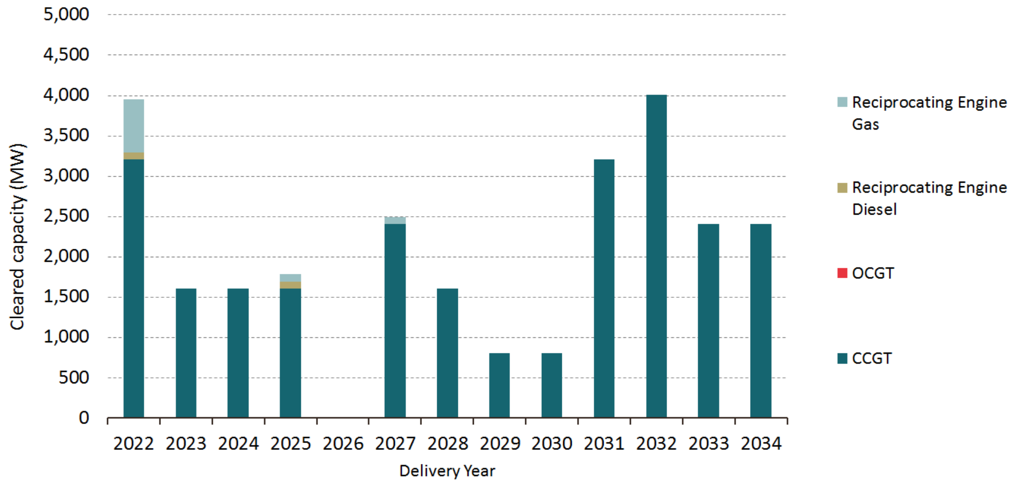


A.10.8 Reciprocating diesel revenue breakdown

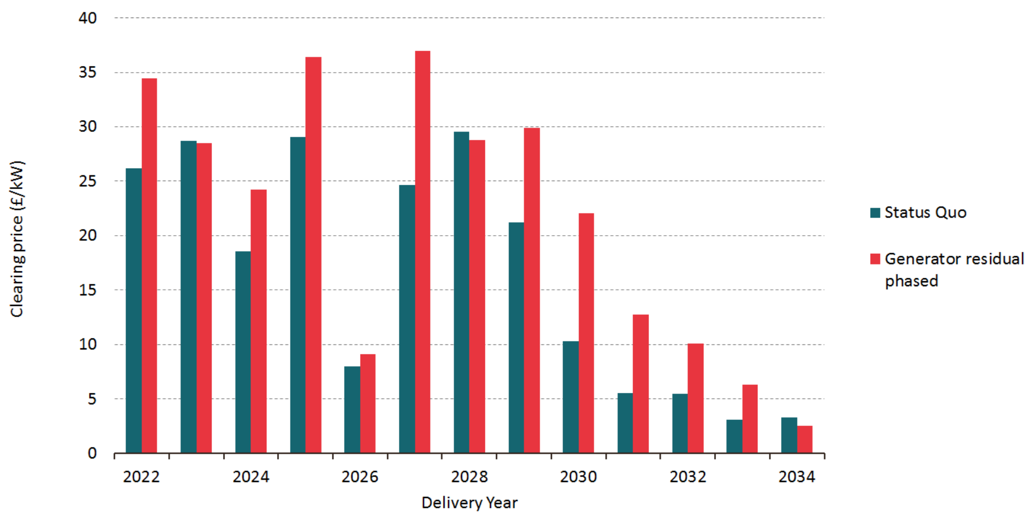


A.11 Generator residual phased scenario detailed results

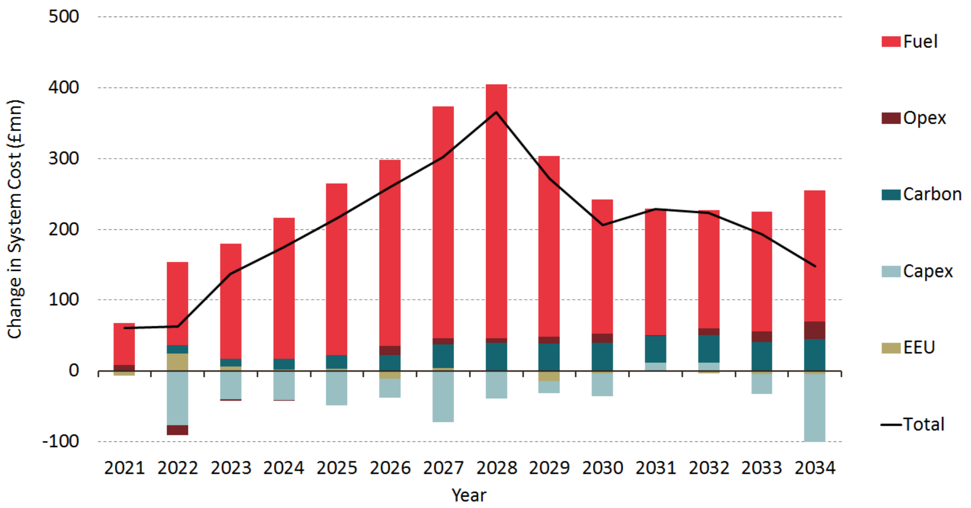
A.11.1 CM build



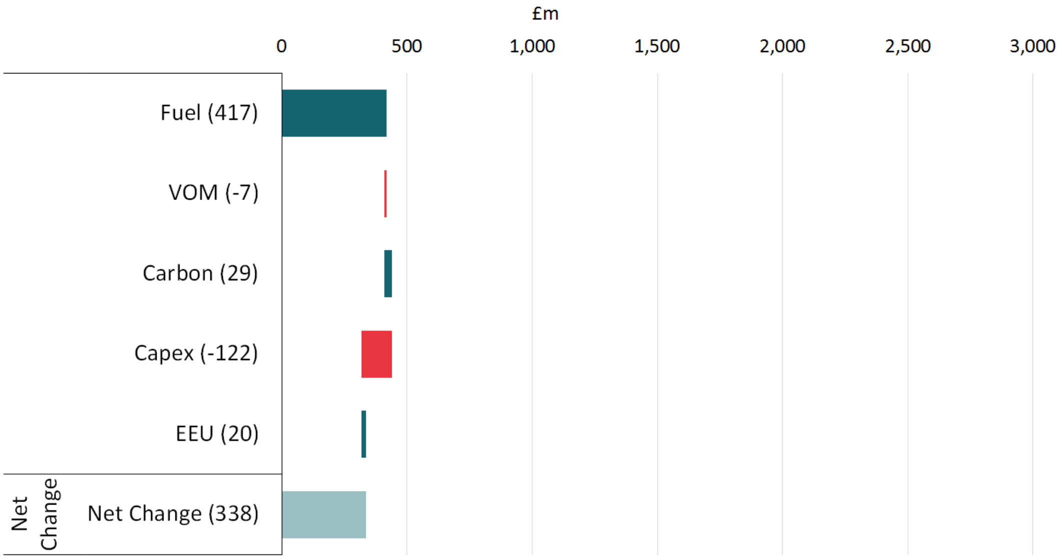
A.11.2 Clearing prices



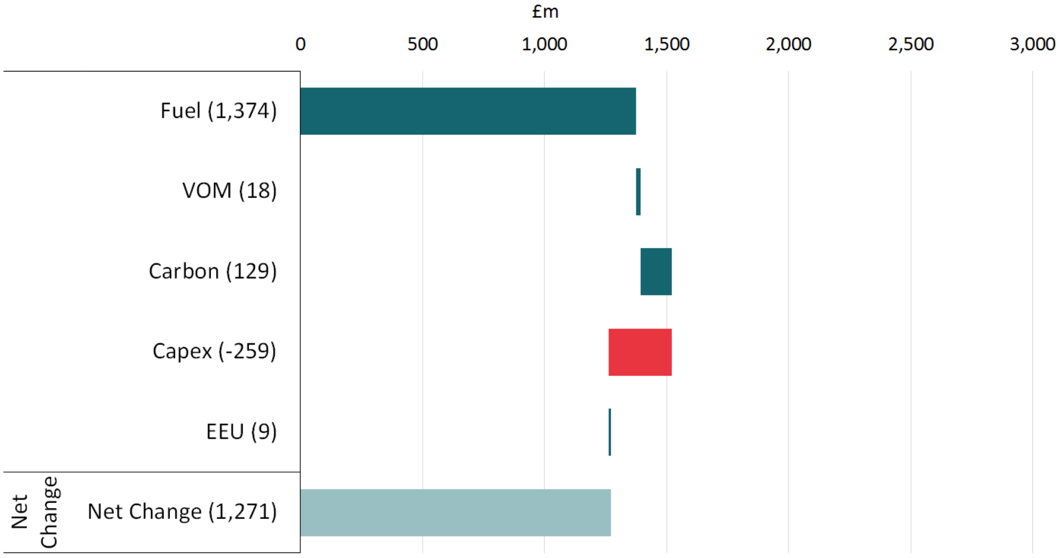
A.11.3 System cost saving



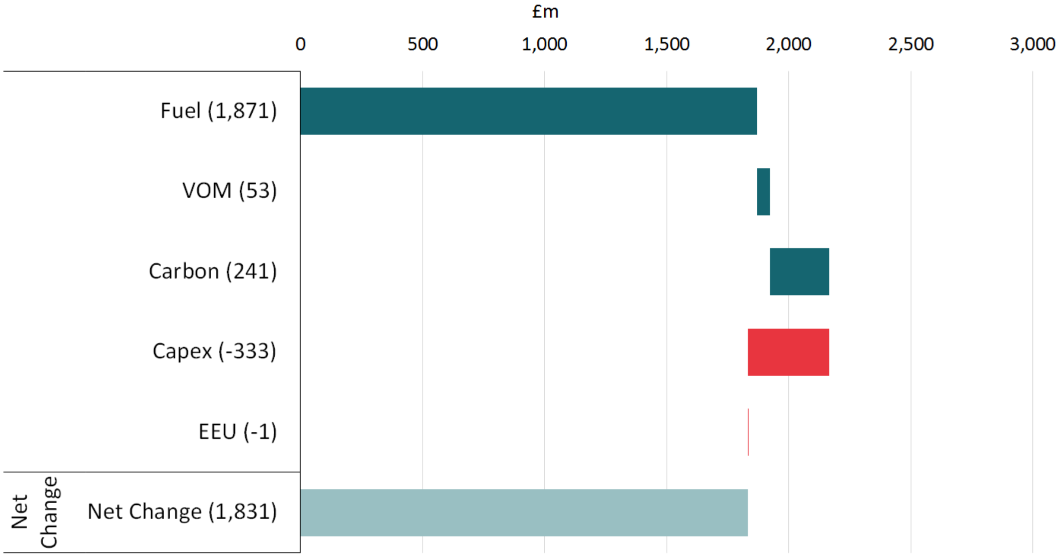
System cost saving, NPV to 2024



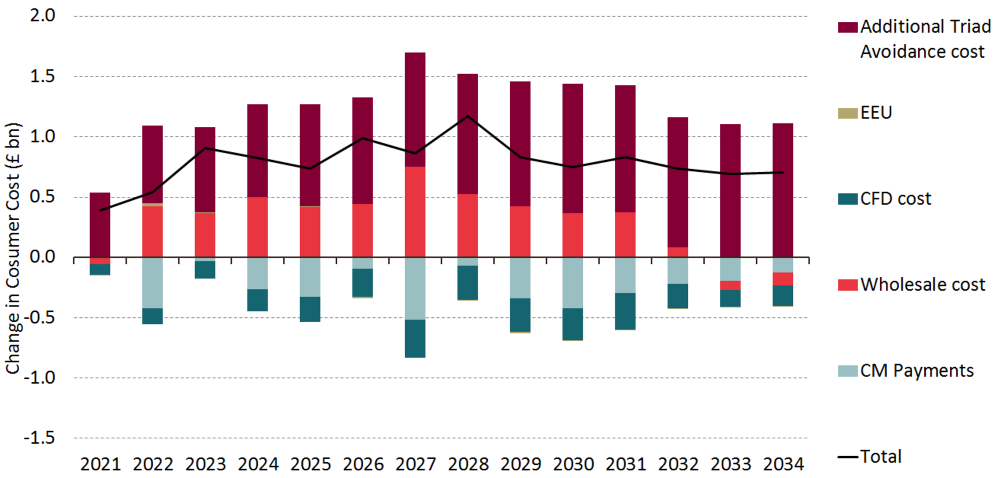
System cost saving, NPV to 2029



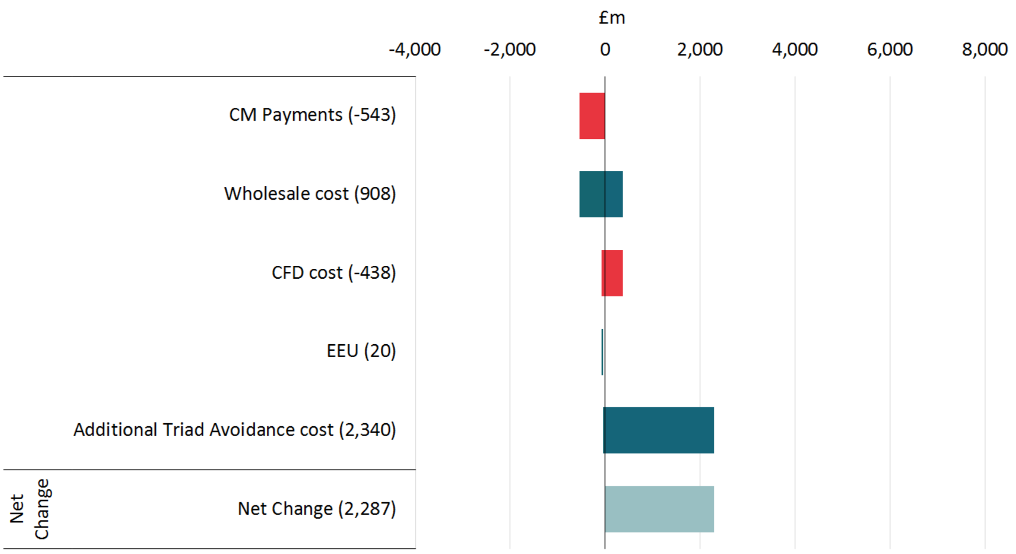
System cost saving, NPV to 2034



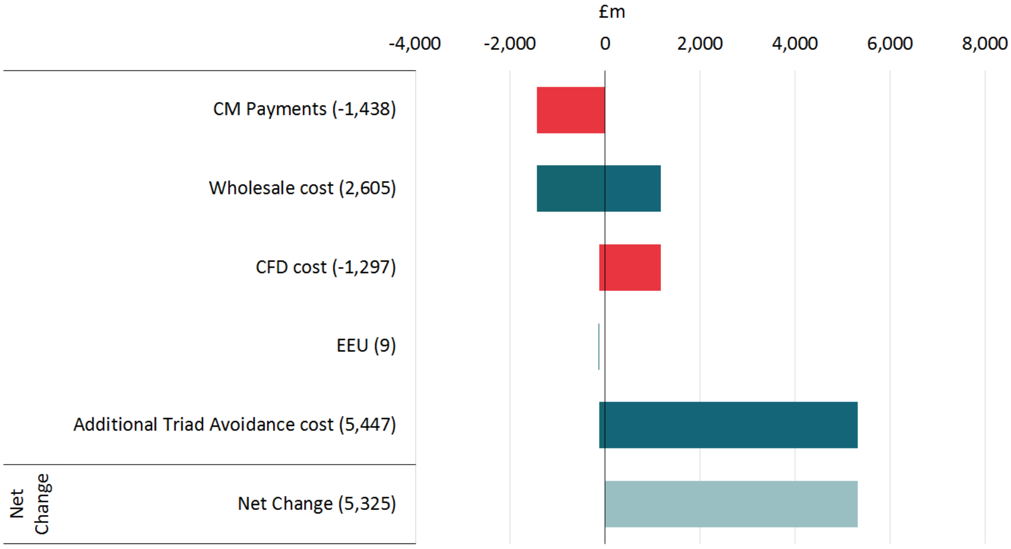
A.11.4 Consumer cost saving



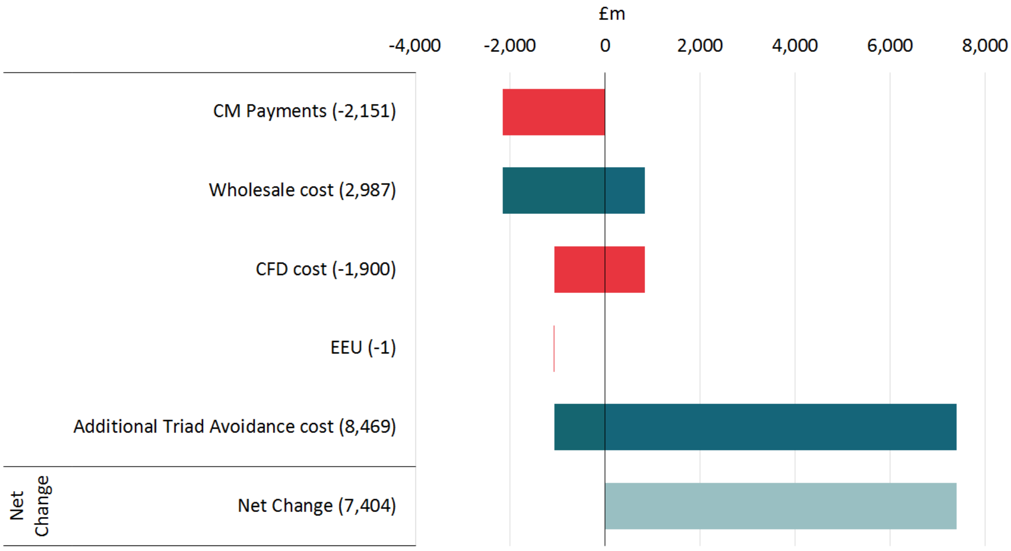
Consumer cost saving, NPV to 2024



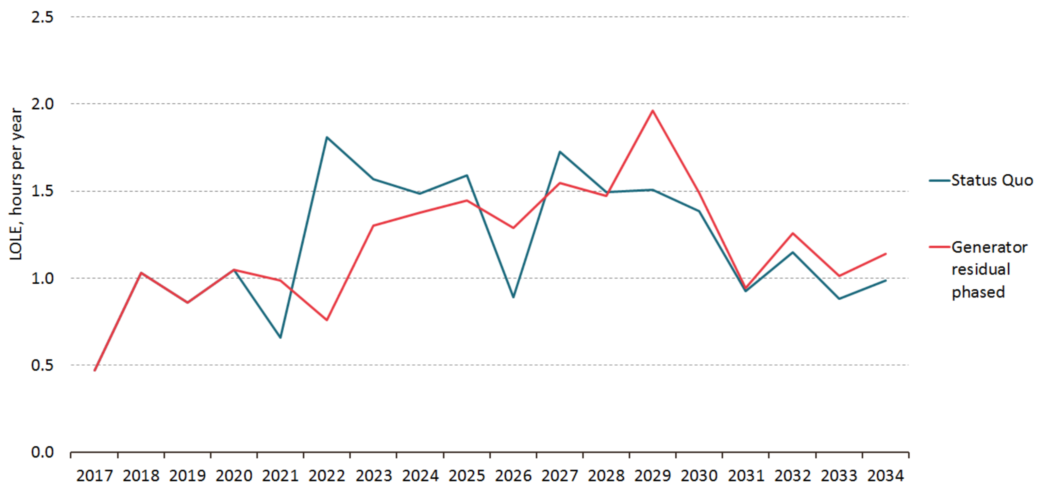
Consumer cost saving, NPV to 2029



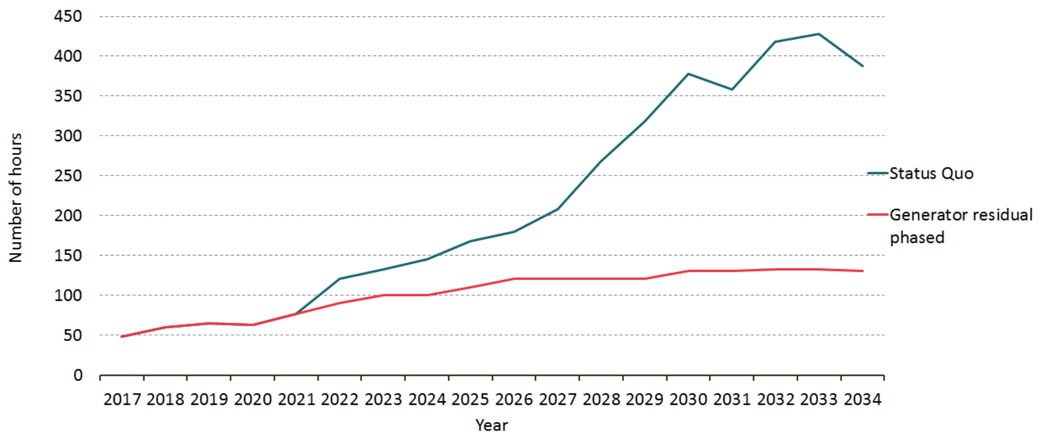
Consumer cost saving, NPV to 2034



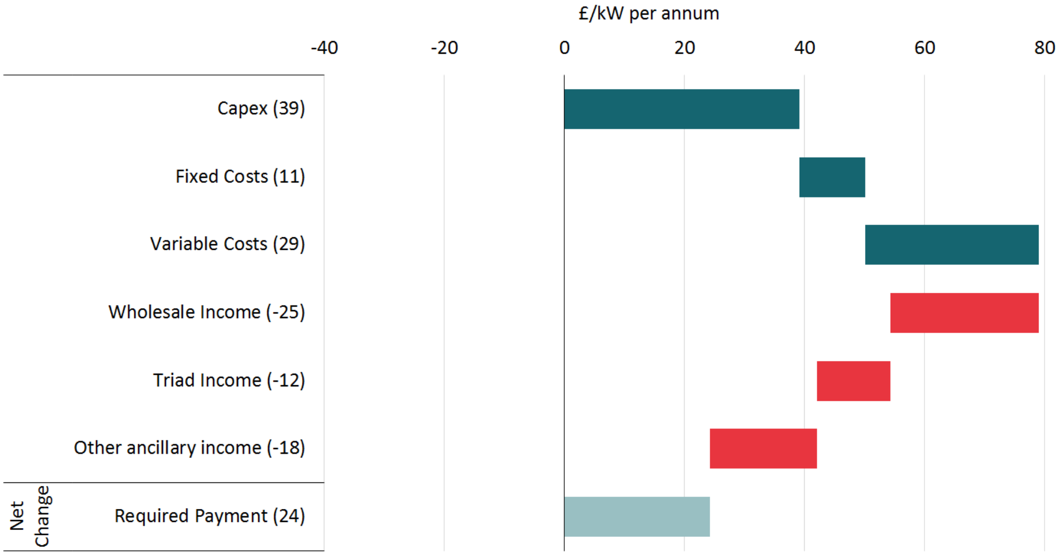
A.11.5 LOLE



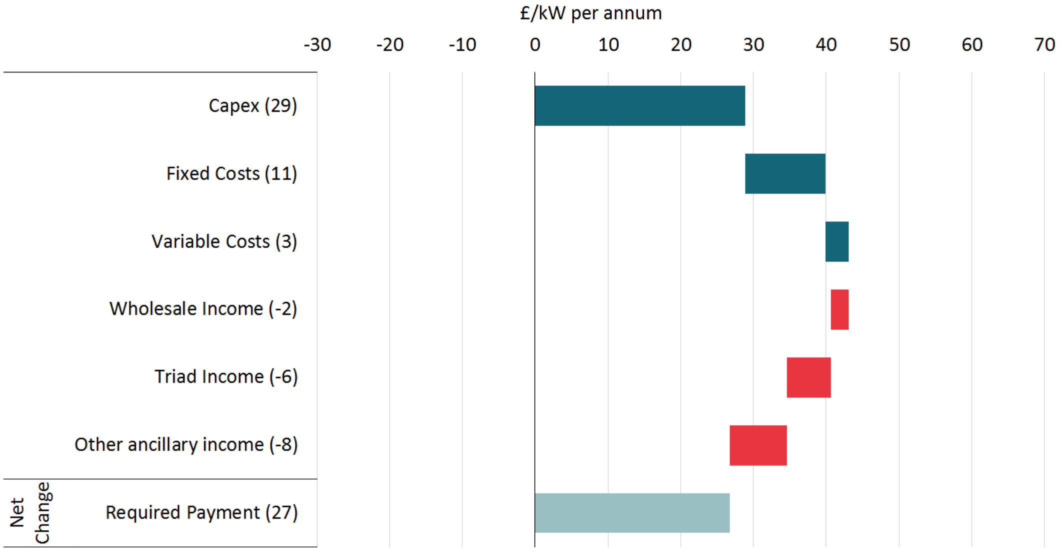
A.11.6 Triad chasing hours



A.11.7 Reciprocating gas revenue breakdown

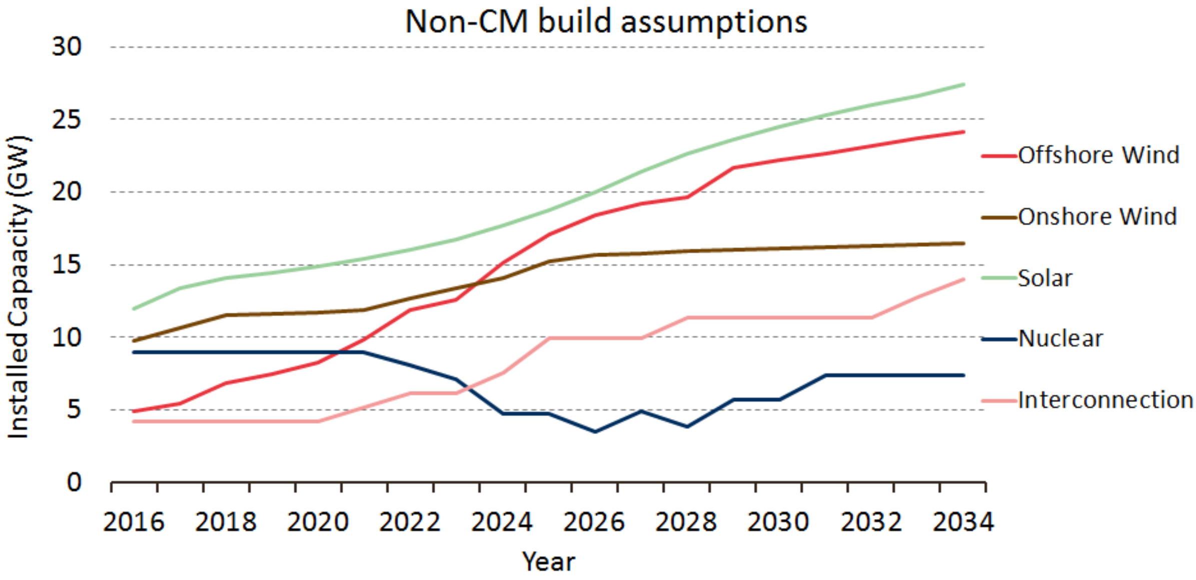


A.11.8 Reciprocating diesel revenue breakdown

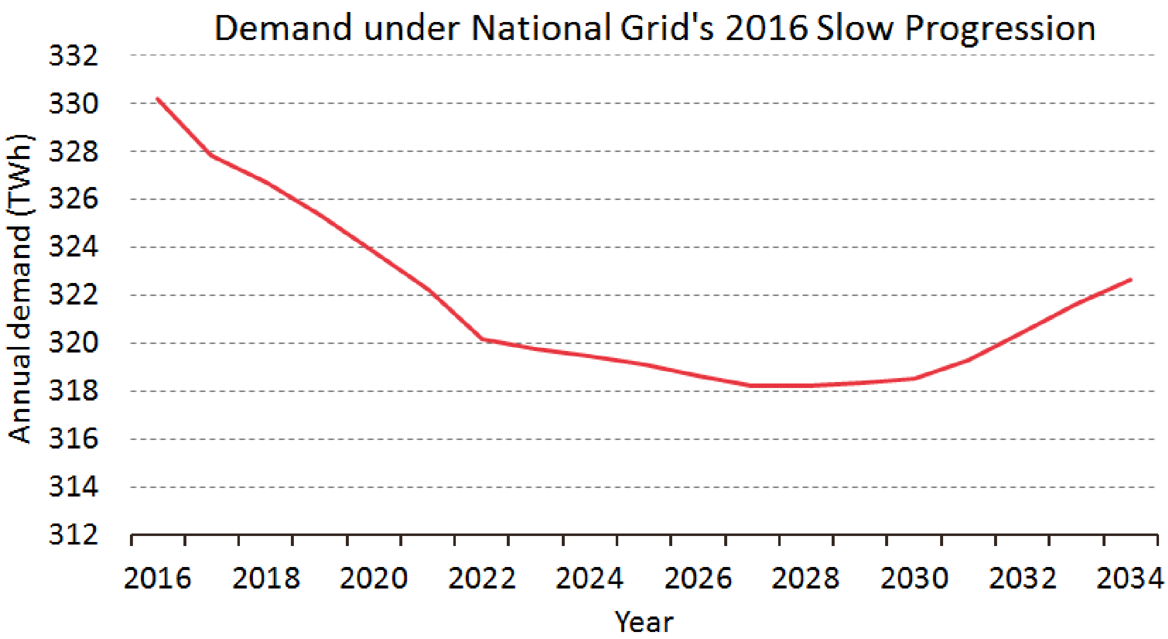


ANNEX B FURTHER ASSUMPTIONS

A.12 Non-CM build assumptions



A.13 Demand assumptions

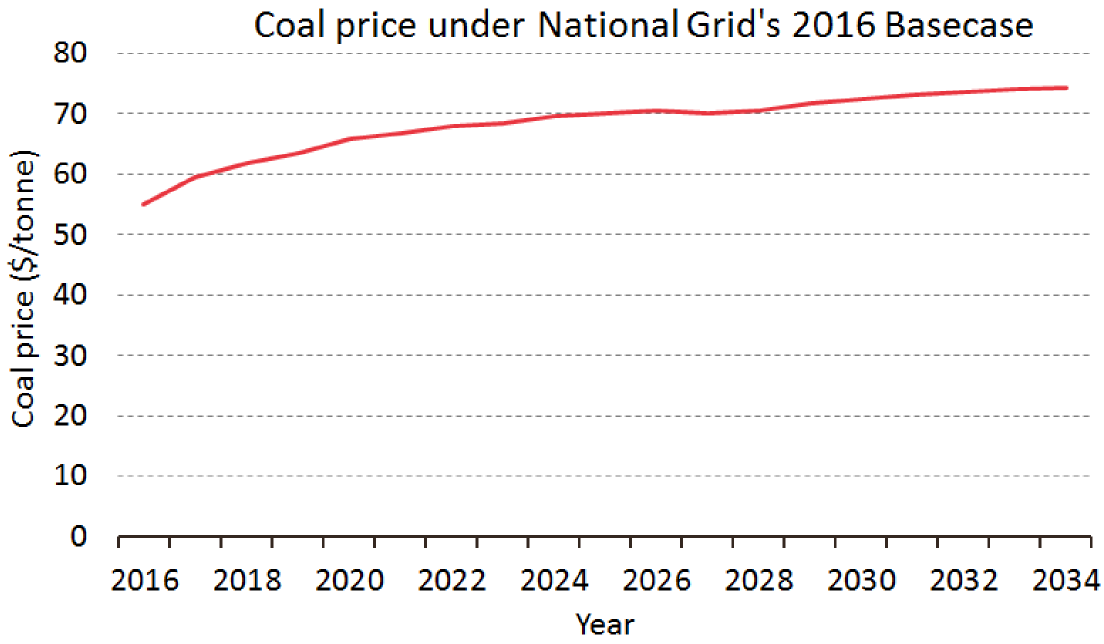


A.14 Maximum build limits and hurdle rates

Technology	Maximum build limit, MW (2018)	Maximum build limit, MW (2019-2034)	Hurdle rate (pre-tax real)
Reciprocating Diesel	1,000	500	7.5%
Reciprocating Gas	1,000	500	7.5%
CCGT	4,500	4,500	7.5%
OCGT	2,825	2,825	7.5%

A.15 Commodity prices

A.15.1 Coal price assumptions



A.15.2 Gas price assumptions