WIDER SYSTEM IMPACTS OF TGR AND BSUOS REFORMS

November 2018

CONTENTS

1 INTRODUCTION

In 2017 Ofgem launched the Targeted Charging Review (TCR), which is a Significant Code Review (SCR) with the objective to review and reform the network charging arrangements related to the recovery of fixed costs of the electricity transmission and distribution networks. The TCR is motivated by concerns that the current framework for residual charges may drive inefficient behaviours from some network users, and result in adverse impacts on others. The TCR's other main objective is to keep the other 'embedded benefits' that may be distorting investment or dispatch decisions under review.

Our independent assessment of key aspects of the alternative residual charging options being considered by Ofgem can be found in the Distributional and Wider System Impacts of Reform to Residual Charges report, hereafter referred to as the 'main TCR report'.

This report sets out supplementary analysis to that contained in the main TCR report, focused on assessing the system impact of two further changes to the charging arrangements that Ofgem has asked us to consider:

- Removing the so-called 'embedded benefit' derived from Balancing Services Use of System (BSUoS) charges; and
- Setting the Transmission Generation Residual (TGR) to zero going forward.

Under the current arrangements, BSUoS charges allocate the cost of the balancing services procured by the Electricity System Operator (ESO) to demand and generation on the basis of a per unit energy charge (£/MWh). It is our view that BSUoS is a cost recovery charge, in that it recovers costs associated with the day-to-day operation of the transmission system which can no longer be avoided by the actions of network users

Transmission connected generators and larger distribution connected generators pay the generation BSUoS charge, and suppliers are charged on the basis of their net demand, i.e. net of any associated on-site or smaller distribution-connected generation. Not only does smaller distribution-connected generation not pay the generation BSUoS charge, they can help suppliers avoid their share of demand BSUoS and typically receive a majority of the avoided charge as payment from suppliers for doing so. This means that the total BSUoS embedded benefit received by smaller distribution connected generation is approximately equal to twice the BSUoS charge.

This BSUoS embedded benefit has the potential to distort competition between smaller distribution connected generation and larger distribution connected and transmission connected generators, and drive inefficient dispatch and investment decisions.

Similarly, under the current arrangements, transmission connected generators and larger distribution connected generators pay or receive the Transmission Generation Residual charge. Smaller distribution connected generation is not exposed to this charge. At present, the Transmission Generation Residual charge is negative, implying that transmission connected and larger distribution connected generators receive a payment which smaller distribution connected generation does not. This has the potential to distort competition between smaller distribution connected generation and other generators, in particular in relation to investment and retirement decisions.

Ofgem has engaged Frontier and LCP to provide an independent quantitative assessment of system and consumer impacts of changes to charging arrangements for BSUoS and the TGR that they may consider alongside any broader changes to transmission and distribution residual charging. This report is intended to support the wider assessment work being carried out by Ofgem, and is focused on the wider system and consumer impacts of proposed changes to BSUoS and TGR charging.

In relation to the analysis in this report, we reiterate our previously expressed 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 describe the quantitative modelling of the wider system impacts, including the methodology deployed, the underlying assumptions, and modelling results.
- In **Section 3**, we provide an overview of the results and implications of this analysis for Ofgem.
- Finally, in **Section 4**, we set out some key limitations of our analysis.

2 MODELLING OF WIDER SYSTEM IMPACTS

In this section we look at the potential impact that the changes to the charging of TGR and BSUoS could have on the wider system, and understand the impacts that this might have on consumer welfare.

2.1 Methodology and Assumptions

Changes to the charging arrangements for BSUoS will have an impact on the system-wide generation mix in the short term by directly affecting plant dispatch and operation, and in the longer term this will impact plant investment and retirement decisions. The changes to TGR will affect the fixed costs incurred by plant in each year, which will, in the longer term, impact plant investment and retirement decisions. These changes will in turn 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 Ofgem's 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 generators 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) is held constant across the scenarios considered, but any changes in the costs of supporting these plant is captured.

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

- The economics of transmission and distribution-connected generation;
- 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 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. Equally, we use exogenous forecasts of future network charges. 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 consider the impact of changes to three aspects of the network charging arrangements for transmission and distribution-connected generation:

- The **Transmission Generation Residual (TGR)** charge is set to zero. Based on National Grid's projections, this represents an increase in the charge faced by transmission-connected generation, from a negative residual charge (i.e. a payment) to zero.
- For smaller distribution-connected generation the benefit of **avoiding Balancing Services Use of System (BSUoS)** charges by reducing suppliers' net metered consumption is removed. Distribution-connected generation currently receives avoidance payments for reducing suppliers' BSUoS obligation.
- For smaller distribution-connected generation, the benefit of not having to pay generator **Balancing Services Use of System (BSUoS)** charges on all generation exported onto the distribution network is removed.

The impact of these changes are tested in two reform scenarios – Full and Partial Reform:

- Under Full Reform, all three changes are implemented from April 2020. The TGR increases to zero, and smaller distribution-connected generation no longer receive a benefit from supplier BSUoS charge avoidance and have to pay the generator BSUoS charge.
- Under Partial Reform the TGR is still increased to zero, and smaller distribution-connected generation no longer receive a benefit from BSUoS charge avoidance. However, as is currently the case, smaller distribution-connected generation does not pay generator BSUoS charges.

Each reform scenario is tested against a counterfactual in which the current TGR and BSUoS charging arrangements remain in place. As a basis for these counterfactuals we use the 'Full Reform' scenarios from the wider system modelling in the main TCR report. This includes the following two changes to the benefits captured by on-site generation:

- The benefit of avoiding the **Transmission Demand Residual (TDR)** is removed, and replaced by the Avoided GSP Infrastructure Cost (AGIC). This is equal to the future payment received by in-front-of-the-meter generation.
- The benefit of avoiding the CDCM **distribution residual** by using on-site generation to reduce net metered consumption is removed.

The comparison between reform scenarios and counterfactuals is conducted using both National Grid's FES 2018 Steady Progression and Community Renewables market backgrounds, which provide assumptions for projections of demand, renewable build and interconnector build.

A single transitional arrangement scenario has also been run in which the Full Reform scenario is phased in between 2021 and 2023. This is modelled under the Steady Progression market background. We have also estimated the impacts of a delay to the 2020 implementation of the reforms by 1 year.

The scope of our analysis is summarised in Figure 1 below.

Figure 1 Core Modelling scenario runs

Scenario	FES Background	Counterfactual or Factual scenario in this analysis	Assumption regarding TGR	Assumption regarding the BSUoS charge for distribution connected generation
Baseline*	Steady Progression	Counterfactual	The charge decreases in line with National Grid's forecast until 2023, after which it remains flat in real terms (-£6.41/kW in £2016 terms).	Distribution connected generation is not liable to pay the charge, and benefits from the avoidance of these charges. Suppliers pass-through 90% of this benefit.
Alternative FES background: Baseline**	Community Renewables	Counterfactual	As per "Baseline" scenario	As per "Baseline" scenario
TGR and Full BSUoS Reform	Steady Progression	Factual	From 2020 the charge is set to zero.	Distribution connected generation is now liable to pay the full charge from 2020 and receives no benefit from the avoidance of these charges.
Alternative FES background: TGR and Full BSUoS Reform	Community Renewables	Factual	As per "TGR and Full BSUoS Reform" scenario	As per "TGR and Full BSUoS Reform" scenario
Phased TGR and Full BSUoS Reform	Steady Progression	Factual	The charge increases to zero between 2021 and 2023 remaining at zero thereafter.	Distribution connected generation transitions from receiving the benefit to paying the charge between 2021 and 2023.
TGR and Partial BSUoS Reform	Steady Progression	Factual	From 2020 the charge is set to zero.	Distribution connected generation neither pay this charge nor receive any avoidance benefit for this charge.
Alternative FES background: TGR and Partial BSUoS Reform	Community Renewables	Factual	As per "TGR and Partial BSUoS Reform" scenario	As per "TGR and Partial BSUoS Reform" scenario

Source: Frontier/LCP

*Note: * this scenario is equivalent to the "Full Reform" scenario in the main TCR report's wider system modelling*

*** this scenario is equivalent to the "Alternative FES scenario: Full Reform" in the main TCR report's wider system modelling*

2.2.1 Assumptions

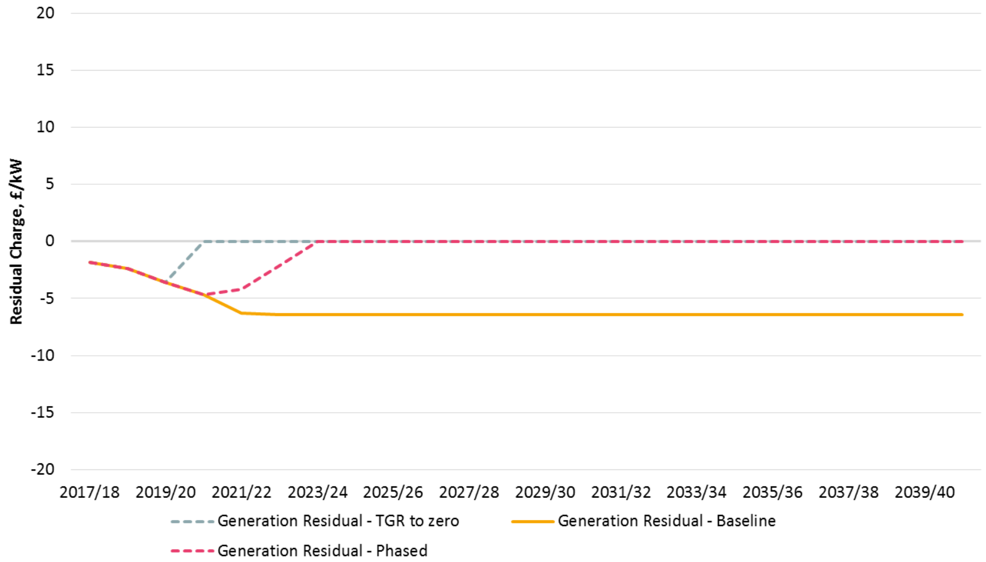
In this section we explain our assumptions to the extent they are different from those used in the wider system modelling set out in the main TCR report.

2.2.2 Transmission residual charge assumptions

Our counterfactual modelling uses the National Grid 5-year forecast from November 2017. Following the end of this forecast, the charges are assumed to remain flat in real terms.

In scenarios in which the charge is increased to zero, the amount of revenue which needs to be recovered to support the transmission system reduces. Consequently we reduce the transmission demand residual: we multiply the TGR by the modelled transmission charging base to give the total payment to generators, and then remove this amount from the total revenue recovered from the TDR.

Figure 2 Value of the transmission generation residuals



Source: Frontier/LCP

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

It is important to note that in our modelling the TGR is factored into the Capacity Market bids of transmission-connected generation. The increase in the residual charge will result in affected generation bidding in higher to the Capacity Market auctions. Distribution-connected generation is not directly affected in the longer term, as its revenues are no longer directly linked to TDR through triad avoidance as a result of the CMP264/265 changes. The bid stack therefore changes with transmission-connected generation becoming less competitive in comparison to distribution-connected generation.

Our modelling also factors in the change in Contracts for Difference (CfD) strike prices required for new transmission-connected capacity. CfD strike prices for new CfD plant (that do not already have an agreed strike price) are increased in order to recover the increase in TGR. However, CfD and Renewable Obligation Certificate (ROC) eligible plant that already have contracts agreed are assumed to be unable to recover the increase in TGR. Note that we do not assume any change in the amount of new low-carbon capacity as a result of the increase in TGR, only a change in the cost of supporting this capacity.

2.2.3 BSUoS charge assumptions

Since BSUoS is currently charged on a net demand basis, a distribution-connected generator can receive a benefit up to the level of the BSUoS charge from a supplier because their generation acts to lower a supplier's net demand. In our modelling we assume that distribution-connected generators receive a payment of 90% of the prevailing BSUoS charge when this benefit is available.

Our BSUoS charge projections for the counterfactual scenarios are based on the National Grid 2-year ahead forecast. In the longer term we use the internal estimate of BSUoS charges within the EnVision model. These baseline projections are then adjusted prior to being used as inputs for the factual scenario runs.

The following changes are applied:

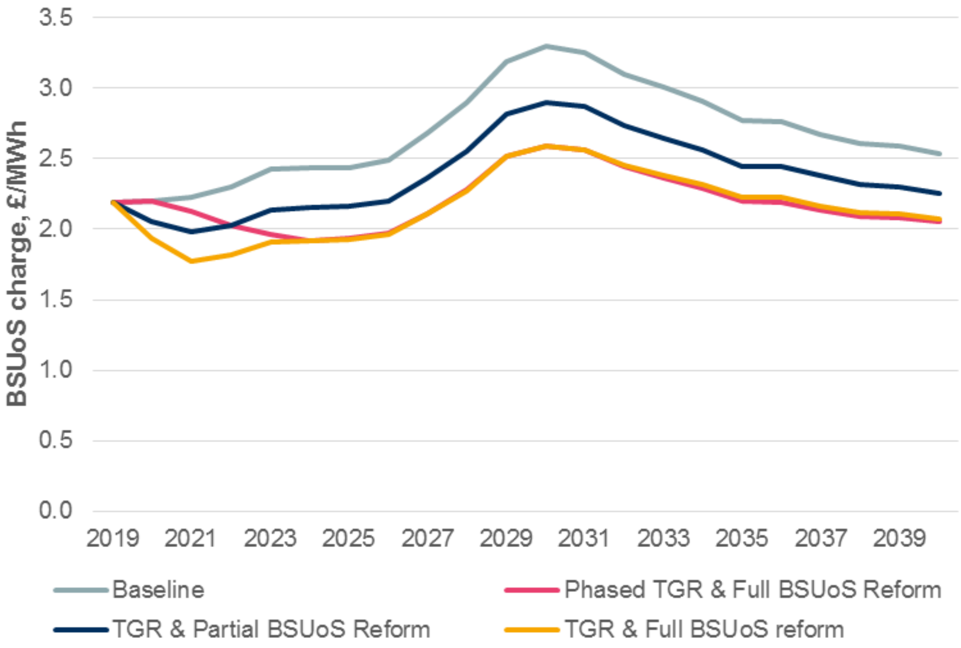
- Under "TGR and Partial BSUoS Reform", the BSUoS demand charging base is increased with suppliers being charged on a gross demand basis.
- Under "TGR and Full BSUoS Reform", in addition to the above, the generation charging base increases as distribution-connected generation also pay the TGR and is added to the charging base.

Both of these changes act to reduce the BSUoS unit charge projections, because while the total recovered revenues remain static, the underlying charging bases increase.

Figure 3 shows the counterfactual Baseline scenario and associated factual scenarios under a Steady Progression market background.

Figure 4 shows the equivalent charges under the alternative Community Renewables market background. The projected charges are higher, due to the higher penetration of intermittent generation resulting in a higher overall cost of system services.

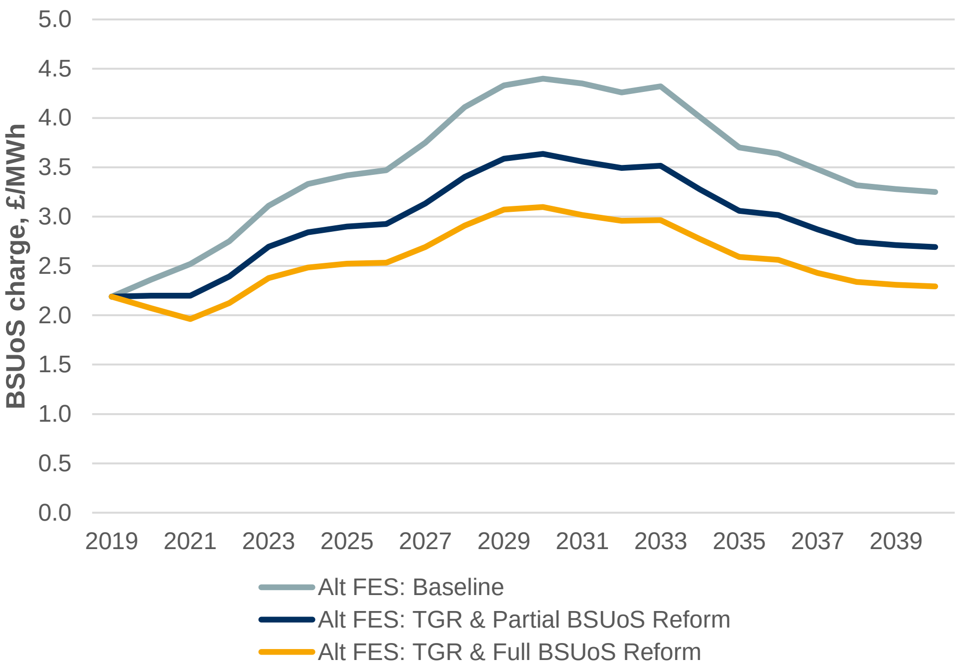
Figure 3 Value of the BSUoS charge under Steady Progression



Source: Frontier/LCP

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

Figure 4 Value of the BSUoS charge under Community Renewables



Source: Frontier/LCP

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

It is important to note that in our modelling the impact of changes to BSUoS charges, both in terms of the costs or benefits incurred by plant and the impact on wholesale prices, is factored into the Capacity Market bids.

Our modelling also factors in the changes to BSUoS charges into CfD strike prices. We make the following assumptions:

- CfD strike prices for **transmission connected** plant are adjusted for the changes in BSUoS charges, and this is applied to both existing and new contracts.
- **Distribution-connected** plant with **new CfD contracts** recover the loss of BSUoS avoidance payments, and, under Full Reform, recover the addition of BSUoS charges, through higher CfD strike prices.
- **Distribution-connected** plant with **existing CfD contracts** are unable to recover the loss of BSUoS avoidance payments in their CfD strike price. However, under Full Reform, it is assumed that their CfD strike prices are adjusted up to cover for the increase in the BSUoS charge they face (i.e. from zero to being liable to pay the full charge).

Application of BSUoS charges to grid-connected storage

The change in application of the BSUoS charge has particular implications for storage units. Below we clarify the methodology taken in our modelling for transmission and distribution-connected storage assets.

Transmission-connected

Storage on the transmission system is subject to the charging of BSUoS on both imports and exports. Transmission-connected storage is only affected by the decreases in the BSUoS rate due to the increase in charging base.

Distribution-connected (In front of the meter)

On the distribution system, storage owners:

- **Pay** BSUoS charges for load (imports)[1]
- **Receive** a BSUoS benefit from suppliers for generation (exports)

Suppliers benefit from a reduction in net demand as storage units discharge and thus avoid BSUoS charges on the netted demand volume. This benefit is shared between the supplier and storage plant; we assume 90% of the benefit is received by the storage plant. Note that given the round-trip efficiency, the overall impact on a storage plant of paying for imports and receiving a benefit for exports will be a cost, assuming a flat BSUoS charge.

The table below outlines how these arrangements change under the considered scenarios. It is worth noting that charging BSUoS to storage on its load and generation under the Full Reform scenario could introduce a new inefficiency[2]. In our opinion, as it is currently structured BSUoS is a cost recovery charge (i.e. it

[1] Assessment of whether this is appropriate is beyond the scope of this report.

[2] We are aware that industry is progressing modifications to address issues with the double charging of storage (charged on imports and exports), but these modifications are not incorporated in the modelling.

recovers costs which can no longer be avoided by the actions of network users), and therefore in general should be levied in a way to minimise distortions to behaviour by network users. However, use of storage can be particularly sensitive to cost reflective charges such as BSUoS, because they distort the relative hourly wholesale price signals faced by storage. As a result this could lead to inefficient dispatch and investment in storage. In other words, by acting to remove the BSUoS embedded benefit from distribution connected generation, without further policy change in relation to storage, it has the potential to create a new inefficiency with respect to the use of storage.

Figure 5 Overview of assumptions for storage

Scenario	Distribution-connected Storage
Baseline	▪ Pay BSUoS charge for load ▪ Receive a 90% of the BSUoS benefit for generation
TGR and Partial BSUoS Reform	▪ Pay BSUoS charge for load ▪ Neither pay nor receive BSUoS charge for generation
TGR and Full BSUoS Reform	▪ Pay BSUoS charge for load ▪ Pay BSUoS charge for generation

Source: Frontier/LCP

Application of BSUoS charges to on-site generation and storage

As discussed in the previous section, the change to BSUoS charging arrangements does not affect non-exporting on-site (behind-the-meter) generation other than reducing the size of any BSUoS avoidance payments they receive, due to the lower BSUoS charges. On-site storage is similarly unaffected, other than reducing the BSUoS element of the price they pay for imports and the size of any BSUoS avoidance payments they receive. Therefore, to a large extent, the BSUoS embedded benefit remains for on-site generation and storage under the reform scenarios, creating the potential for a competitive distortion.

Application of BSUoS charges to interconnection

The change to BSUoS charging arrangements does not affect interconnection, which remains exempt from BSUoS charges. Under the baseline, interconnection have a competitive advantage over transmission connected generation which pays the charges, and a competitive disadvantage relative to distribution connected generation. Under the reform scenarios:

- BSUoS charges fall for transmission connected generation reducing the competitive advantage of interconnection; but
- Under Full Reform, BSUoS charges are levied on distribution connected generation, creating a competitive disadvantage relative to interconnection.

2.2.4 Other key assumptions

Other notable assumptions include:

- Low-carbon build, interconnector build and demand growth are in line with the ‘Steady Progression’ and ‘Community Renewables’ scenarios from National

Grid's 2018 "Future Energy Scenarios" report. Under Community Renewables the assumed level of decentralisation is significantly higher, reaching 50% by 2035 compared with only 30% in Steady Progression.

- Commodity prices are in line with the central projections from National Grid's 2018 FES report.
- New build is assumed to build in a 'generic GB' location. This removes any possible locational distortions to the results due to new build bidding in to the capacity market at differing levels. 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 Modelling Results

In this section we discuss the core modelling results for the following scenarios:

- Subsection 2.3.1 outlines the modelling results for the TGR & Full BSUoS Reform scenario, relative to the Baseline. This scenario implements changes to the transmission generation residual and full reforms to BSUoS being applied from 2020.
- Subsection 2.3.2 outlines the modelling results for the TGR & Full BSUoS Reform, re-run under the Alternative FES background scenario, relative to the Baseline that is also run against this background.
- Subsection 2.3.3 outlines the modelling results for the Phased TGR & Full BSUoS Reform scenario, relative to the Baseline. In this scenario the changes to the TGR and BSUoS charging arrangements are phased in over three years between 2021 and 2023.
- Subsection 2.3.4 outlines the modelled results for the TGR and Partial BSUoS Reform, relative to the Baseline. Under Partial BSUoS Reform, distribution-connected generation can no longer benefit from BSUoS charge avoidance payments, but is not liable to pay BSUoS charges.
- Subsection 2.3.5 outlines the modelled results for the TGR and Partial BSUoS Reform re-run under the Alternative FES background scenario.

2.3.1 Results – TGR and Full BSUoS Reform

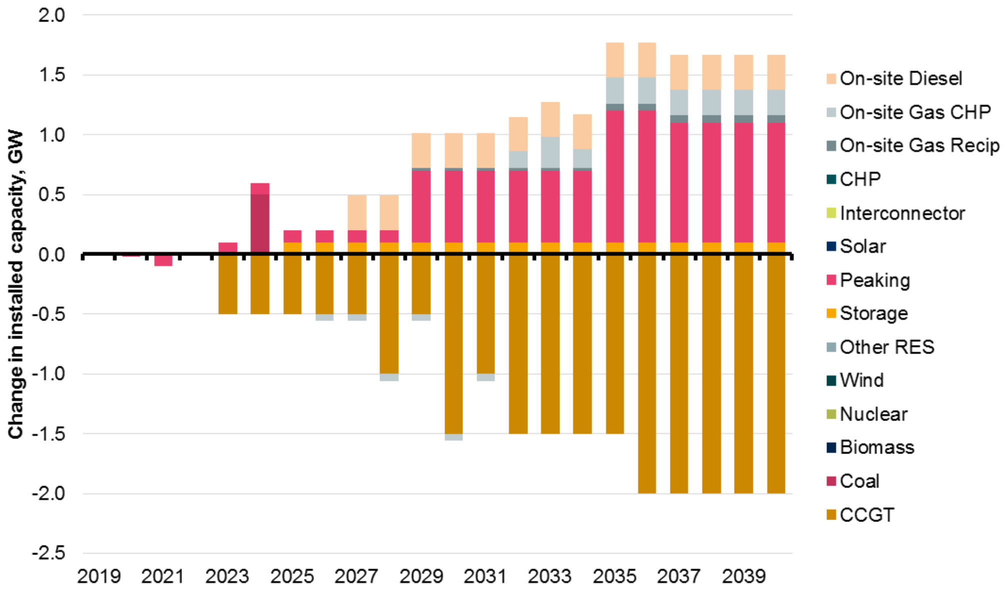
Capacity breakdown

Figure 6 below shows the difference in installed capacity between Baseline and TGR & Full BSUoS Reform.

Our results show a reduction in the amount of transmission-connected capacity with CCGT units being displaced by a mixture of distribution-connected peaking and on-site generation. The removal of the TGR benefit for transmission-connected generation leads to a decrease in new CCGT investment as their capacity market bids increase by £5-10/kW/yr.

Distribution-connected generation is adversely affected by the change to BSUoS charging. However, this charge is volumetric, therefore the impact varies with the load factor of the affected units. The impact to the economics of distribution-connected peaking units is limited due to their low load factors.

Figure 6 Difference in installed capacity between Baseline and TGR & Full BSUoS Reform



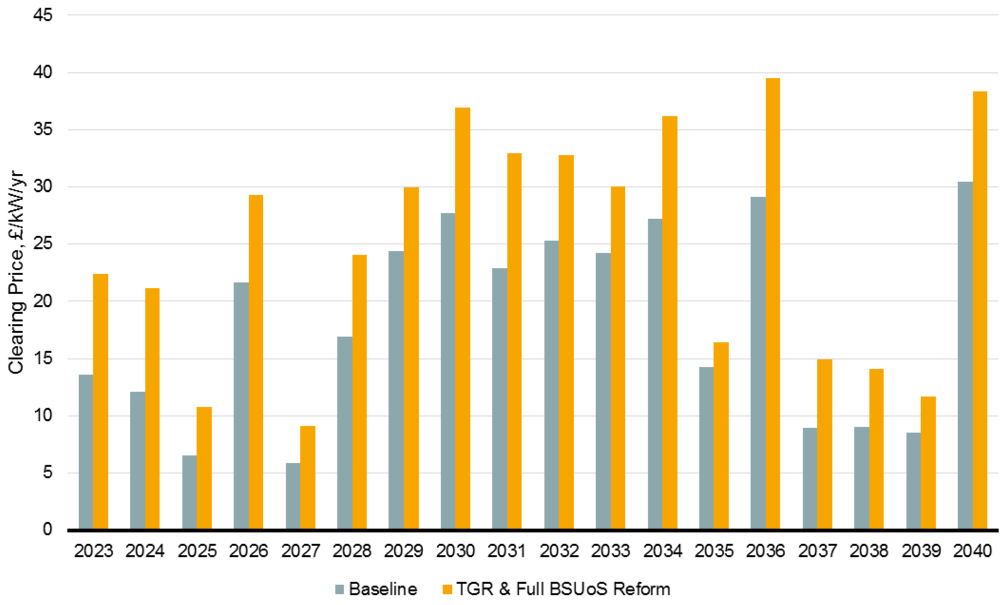
Source: Frontier/LCP

Capacity Market clearing prices

Figure 7 compares the Capacity Market clearing prices of Baseline and TGR & Full BSUoS Reform scenarios. The change in the transmission charge directly affects the Capacity Market bids of transmission-connected generation with Capacity Market bids consistently increasing by £5-10/kW/yr. The TGR reform typically pushes transmission-connected generation to the margin, setting the overall price.

The capacity market bids for distribution-connected generation will also increase due to the BSUoS charge reforms. However the extent of this impact is limited for peaking generation with low load factors.

Figure 7 CM clearing prices



Source: Frontier/LCP

Loss of Load Expectation

Figure 8 below compares the loss of load expectation (LOLE) between the Baseline and TGR & Full BSUoS Reform scenarios. The LOLE is shown to increase in most years, indicating the system is less secure. This a result of higher CM clearing prices meaning that less capacity is procured (as the demand for capacity decreases as the price increases). However, in both scenarios the LOLE is well below the security standard of 3 hours per year. This is because clearing prices remain below the Net-CONE[3] price level, but also due to an assumption that there will be some prudence used when setting the capacity target.

[3] Net-CONE (Cost of New Entrant) is the cost of a new entrant value used in the Capacity Market parameters to set the Demand Curve price that corresponds to an LOLE of 3 hours.

Figure 8 Loss of Load Expectation

Source: Frontier/LCP

Generation breakdown

Figure 9 shows the change in generation between Baseline and TGR & Full BSUoS Reform scenarios. Changes in the BSUoS charging, which benefit transmission-connected generation (lower charges due to larger charging base), and adversely impact distribution-connected generation (BSUoS moves from a benefit to a charge) are the primary reasons for the changes. However changes in investment due to the change in TGR will also drive changes in the longer term.

CCGT generation increases as it benefits from the reduced BSUoS charge which benefits domestic generation relative to interconnectors which are exempt from this charge. Additionally, some distribution-connected generation is also displaced as their marginal costs increase.

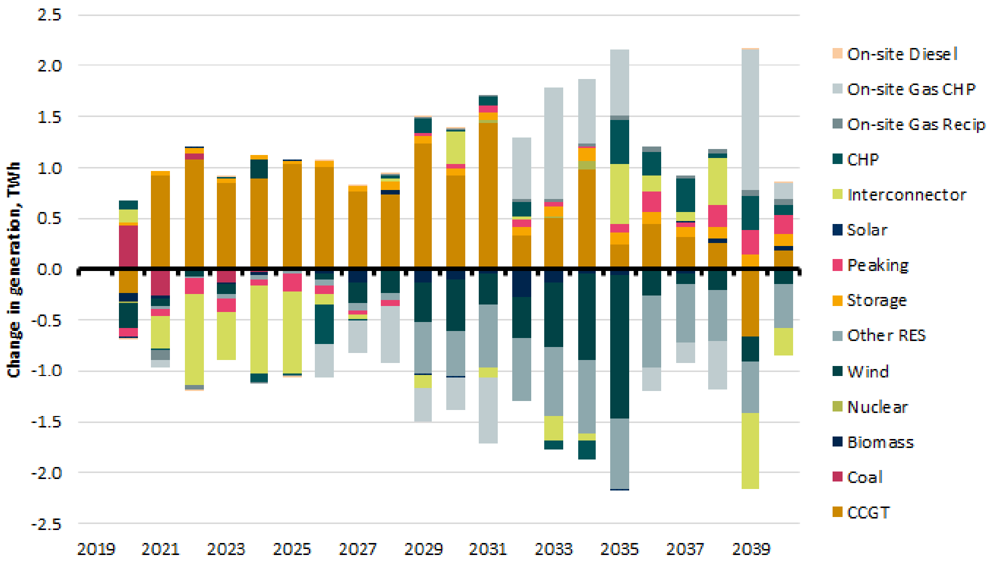
In the longer term, there is an increase in on-site generation, which is not directly impacted by the reforms. There is also a decrease in distribution-connected renewable generation. This is partly a result of the BSUoS charges they now face, which means they are less competitive with other generation sources, including on-site generation and interconnection. In some periods in later years, distribution-connected wind generation is curtailed when demand is lower due to reduced interconnector exports.

The decrease in renewable generation is also partly a result of the higher charges faced by storage meaning storage decreases its activity, resulting in increased curtailment of renewable generation at times of low demand.

Note that this decrease in storage activity shows up as an *increase* in storage generation on the chart below. This is because the chart shows the change in storage's net generation, and each charge/discharge cycle results in power being drawn from the system, so a decrease in activity means less power is drawn from the system, equivalent to an increase in net generation.

Overall though, the change in generation is small, generally less than 1.5-2TWh per year (in terms of net changes between different technologies).

Figure 9 Difference in generation between Baseline and TGR & Full BSUoS Reform



Source: Frontier/LCP

Wholesale prices

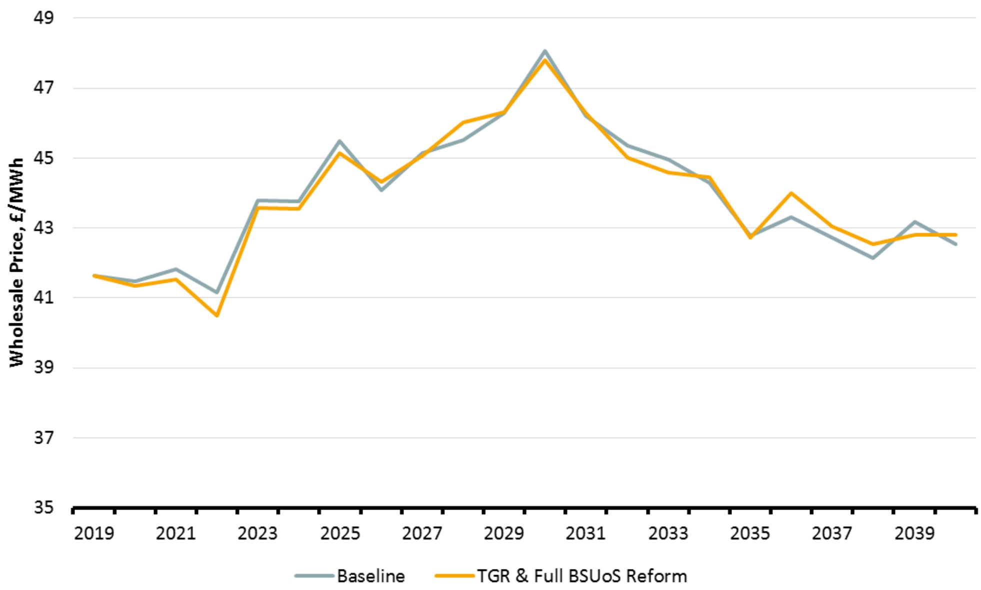
Figure 10 below compares average annual wholesale price between Baseline and TGR & Full BSUoS Reform scenario. The wholesale price initially decreases but increases are seen towards the back end of the projection. The changes observed are essentially a result of three effects:

- With the reduction in the BSUoS charge the wholesale price falls when transmission-connected are at the margin.
- With distribution-connected generation now charged BSUoS, wholesale prices will increase when distribution-connected plant are marginal. This becomes more of a driver in later years as the proportion of distribution-connected capacity increases, including a significant increase in renewable generation and batteries.
- The removal of the TGR reduces the amount of CCGT capacity available. This in turn raises wholesale prices as demand, in particular peak demand, is met by less efficient plant.

The first effect is apparent in the beginning of the projection, with the second and third effects driving overall results from 2030 when a more significant amount of

CCGT capacity is displaced. Overall the impact is limited as the effects offset each other.

Figure 10 Average annual wholesale prices



Source: Frontier/LCP

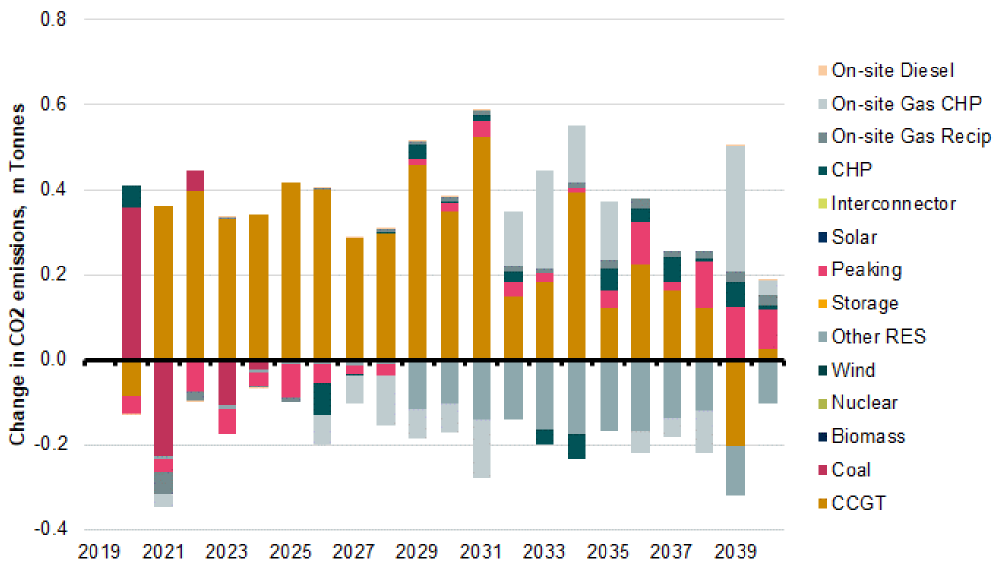
CO_2 Emissions

Figure 13 shows the difference in annual CO_2 emissions between Baseline and TGR & Full BSUoS Reform scenarios. CO_2 volumes increase in all years. A major reason for this rise, particularly in the earlier years, is a rise in domestic generation at the expense of interconnector imports. Interconnectors are exempt from BSUoS charges and so enjoy a competitive advantage over domestic generation. Due to the reduction in the BSUoS charges this advantage reduces, reducing imports overall. Interconnector imports make no contribution to GB CO_2 emissions (although clearly they may result in emissions in other countries).

The average annual increase across the modelling period is 0.2 million tonnes of CO_2, which represents a rise of about 0.8% in total GB power sector CO_2 emissions at 2030 levels.

In later years there is also a reduction in renewable generation, due to distribution-connected renewable generation and storage plant facing higher charges.

Figure 11 Difference in CO_2 emissions between Baseline and TGR & Full BSUoS Reform



Source: Frontier/LCP

System Cost

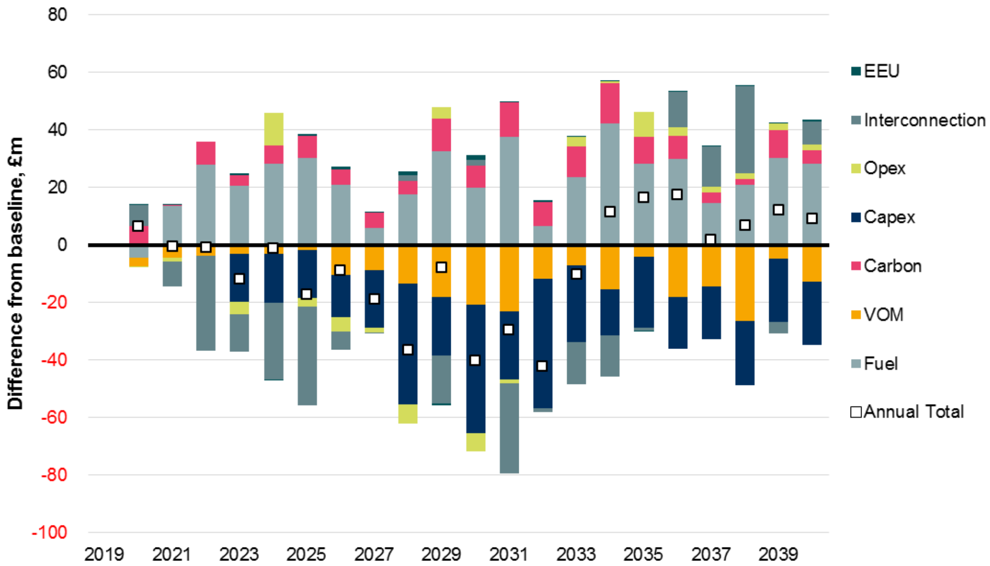
Figure 12 shows the modelled system cost differences, comparing Baseline to TGR & Full BSUoS Reform scenarios. Overall there is a system cost saving of just over £100m with the net cost of interconnector flows (the net cost of buying and selling power in foreign markets) falling and capex spend reducing. This is partially offset by an increase in fuel and emissions costs. This is however a very small saving in the context of total system costs, and therefore difficult to differentiate from zero.

The changes to the cost of interconnection, fuel and emissions must be considered together. Interconnector imports decrease as the impact of their BSUoS charge exemption lessens when the charge reduces. Domestic generation increases to meet demand, bringing increases in fuel and GB emissions costs.

Capex spend reduces with less new CCGT capacity coming online due to the removal of their TGR benefit. This results in more new peaking capacity investment and as a result delays in plant retirement of existing CCGTs. Variable Operation and Maintenance (VOM) costs also reduce - one reason for which is a decrease in the activity of distribution-connected storage plant, which have a VOM cost associated with each charge and discharge cycle.

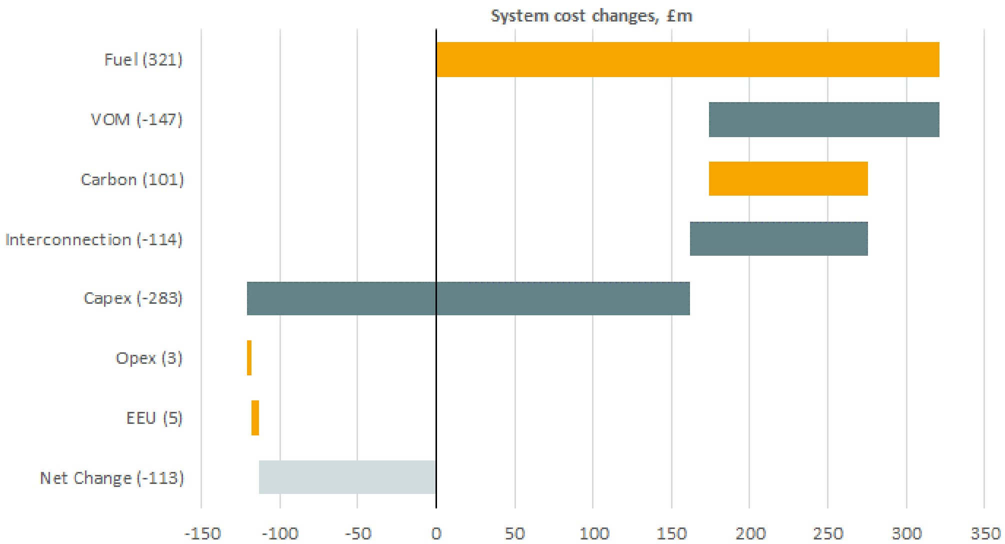
Figure 13 shows the total impact in NPV terms over the 2019-2040 period. The social discount rate of 3.5% (real) is used. Overall there is a system cost saving of £113m in NPV terms.

Figure 12 Difference in system costs between Baseline and TGR & Full BSUoS Reform



Source: Frontier/LCP

Figure 13 NPV of the difference in system costs between Baseline and TGR & Full BSUoS Reform (2019-2040, 3.5%)



Source: Frontier/LCP

Consumer Cost

Figure 14 shows the modelled consumer cost differences between Baseline and TGR & Full BSUoS Reform scenarios. Specific consumer cost categories have been added to highlight the impact of the reforms considered:

- Supplier BSUoS charges – the BSUoS costs levied on suppliers by National Grid. Under the baseline, this is charged on a net demand basis.
- Supplier BSUoS avoidance payments – payments made by suppliers to generators on the distribution system who act to reduce the suppliers' net demand. We assume that the BSUoS cost saving is split between the supplier and embedded generator with 90% of the benefit being passed on to the generator.
- Transmission demand residual (TDR) payments – the saving to consumers due to the lower transmission demand residual charges. TDR charges are reduced to offset the increase in TGR.

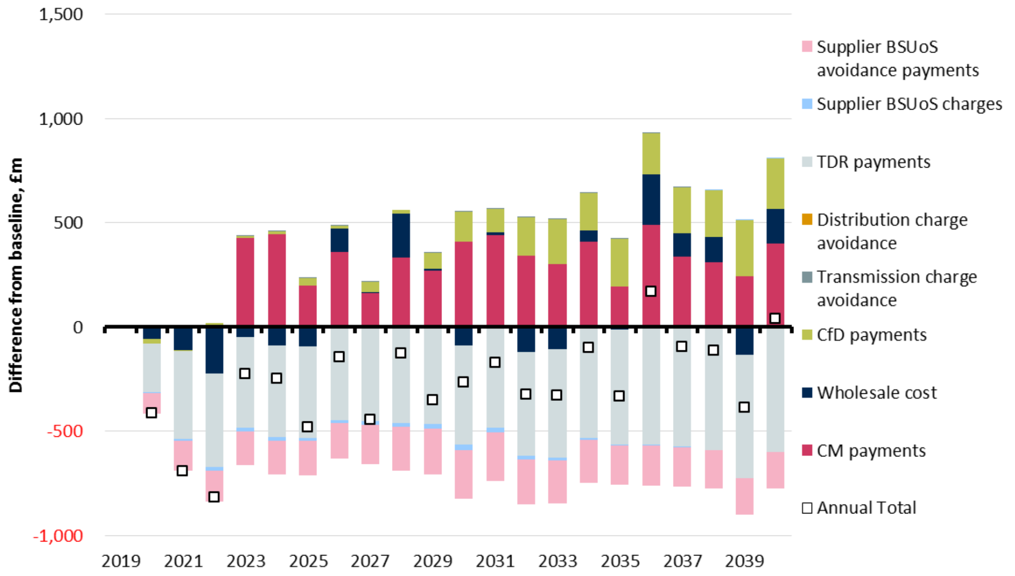
The results show a large consumer cost saving which arises from lower TDR and Supplier BSUoS avoidance payments. Capacity market and CfD payments increase due to the removal of the TGR and BSUoS embedded benefits resulting in higher clearing and strike prices. However, plants with existing contracts are not able to pass on these increases in costs to consumers so the net result is a consumer cost saving. In particular, plant outside of the capacity market such as existing plants built under the Renewables Obligation or those with existing CfDs are not able pass-through the increase in TGR costs.

We only see small changes in the Supplier BSUoS charges. This is because the increase in the demand charging base (as a result of the move from net to gross charging) is offset by lower per unit BSUoS charges (£/MWh).

Figure 15 shows the total impact in NPV terms over the 2019-2040 period. The social discount rate of 3.5% is used. Overall there is a consumer cost saving of £4.52bn in NPV terms.

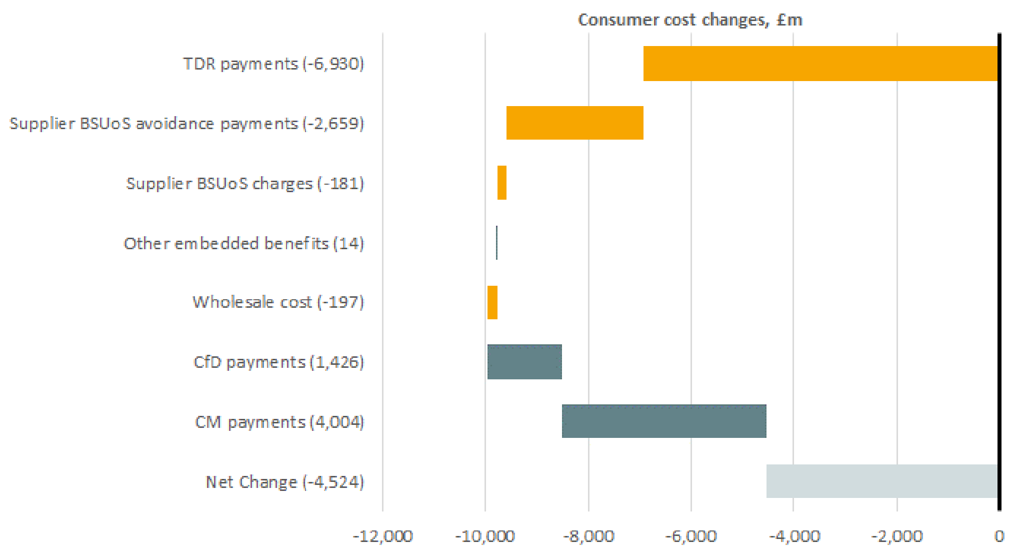
The large consumer cost saving relative to a smaller system cost saving suggests that there is a transfer from producers to consumers.

Figure 14 **Difference in consumer costs between Baseline and TGR & Full BSUoS Reform**



Source: Frontier/LCP

Figure 15 **NPV of the difference in consumer costs between Baseline and TGR & Full BSUoS Reform (2019-2040, 3.5%)**



Source: Frontier/LCP

2.3.2 Results – Alternative FES TGR & Full BSUoS Reform

In this section we present our results under an alternative FES market background. The Baseline and TGR & Full BSUoS Reform scenarios are both re-run under National Grid's Community Renewables FES 2018 market background. This background assumes a greater penetration of renewable generation and higher level of decentralisation than Steady Progression whilst also achieving 2050 climate targets.

Capacity breakdown

Figure 16 shows the change in the installed capacity under the alternative FES background between Baseline and TGR & Full BSUoS Reform scenarios.

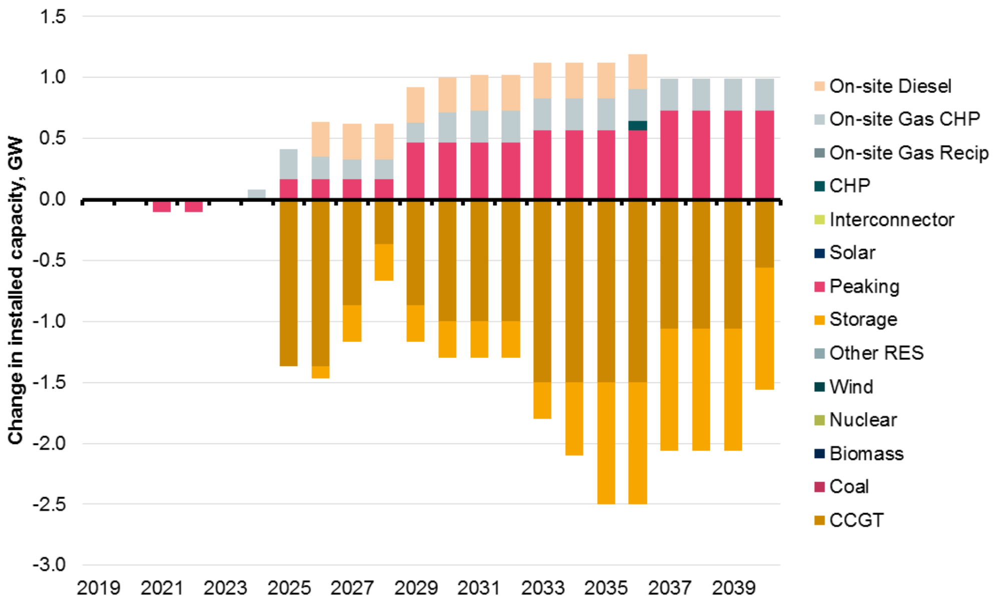
As in the Steady Progression runs, CCGT capacity decreases, as they bid £5-10/kW higher into the CM to cover the increase in TGR, and are displaced by distribution connected and on-site generation.

Storage capacity also decreases, as distribution connected battery storage is now charged BSUoS on its exports (as well as imports), rather than receiving the BSUoS avoidance benefit, and its CM bids are pushed up.

Though distribution connected peaking generation is now charged BSUoS, this only pushes up its CM bids slightly, as it typically has low load factors. This means its CM bids do not increase as much as those of CCGT units, and more of this capacity clears. There is also additional on-site generation which are unaffected by the changes to TGR or BSUoS.

Overall, the amount of capacity procured through the CM decreases. In addition to the general "lumpiness" of new build, the lower levels of capacity being procured in the CM are also a direct result of higher CM clearing prices (and hence the CM auctions clearing further down the CM demand curve). It is also a result of the lower CM derating factors associated with the storage capacity being removed, meaning that lower amounts of replacement capacity are required to supply the same amount of derated capacity.

Figure 16 Difference in capacity under Alternative FES scenario between Baseline and TGR & Full BSUoS Reform

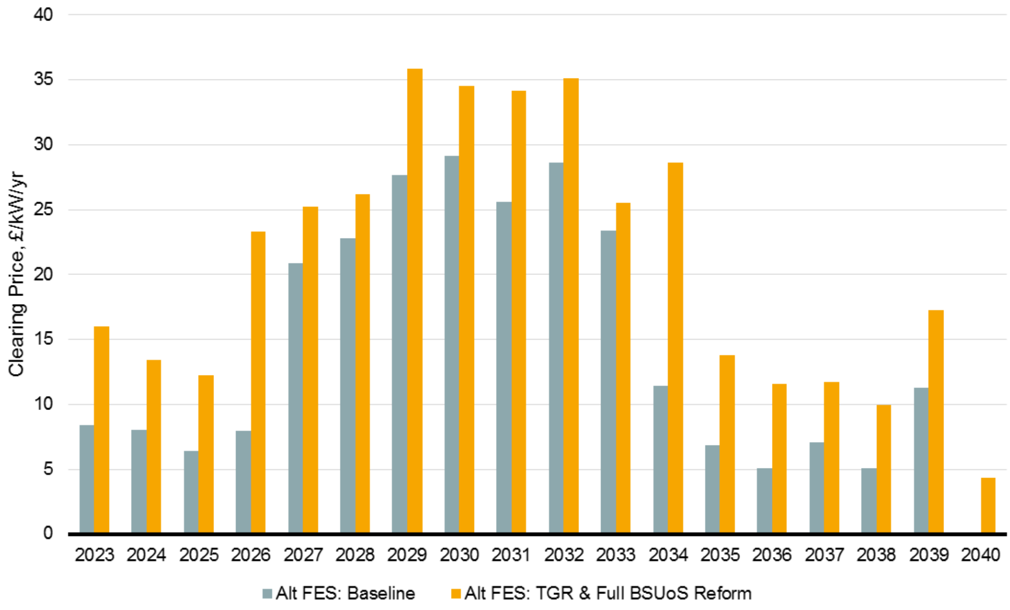


Source: Frontier/LCP

Capacity Market clearing prices

Figure 17 shows the clearing prices as modelled under the alternative market background for Baseline and TGR & Full BSUoS Reform scenarios. There is a consistent increase in the CM clearing price across all years due to the removal of the TGR benefit for transmission connected generation, which results in an increase in clearing prices of £5-10/kW in most years. The BSUoS charges on distribution connected generation also push their CM bids up slightly.

Figure 17 CM clearing prices for Alternative FES Baseline and TGR & Full BSUoS Reform



Source: Frontier/LCP

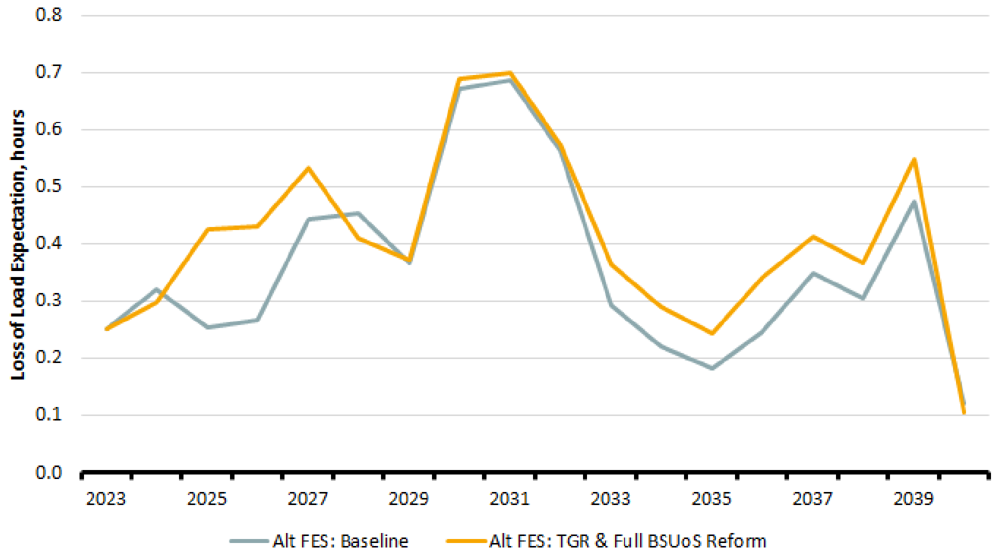
Loss of Load Expectation

Figure 18 below compares the loss of load expectation (LOLE) between the Baseline and TGR and TGR BSUoS Reform scenarios under the alternative FES market background.

The LOLE is shown to increase in most years, indicating the system is less secure. This a result of higher CM clearing prices meaning that less capacity is procured, as the demand for capacity decreases as the price increases. However, in both scenarios the LOLE is well below the security standard of 3 hours per year. This is because clearing prices are below the Net-CONE[4] price level, but also due to an assumption that there will be some prudence used when setting the capacity target.

[4] Net-CONE (Cost of New Entrant) is the cost of a new entrant value used in the Capacity Market parameters to set the Demand Curve price that corresponds to an LOLE of 3 hours.

Figure 18 Loss of Load Expectation for Alternative FES Baseline and TGR & Full BSUoS Reform



Source: Frontier/LCP

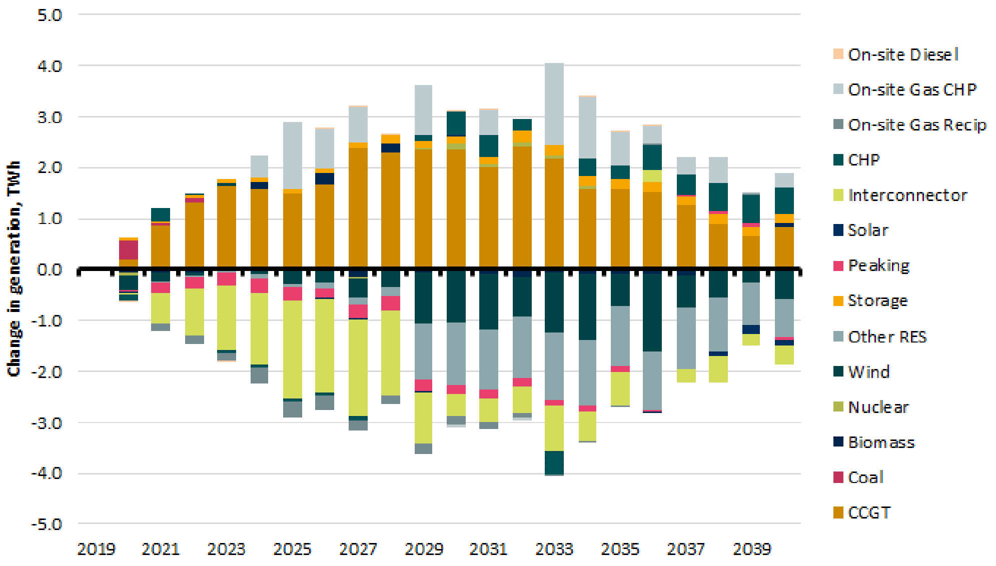
Generation breakdown

Figure 19 shows the change in generation between Baseline and TGR & Full BSUoS Reform under the Alternative FES market background. Changes in the BSUoS charging, which benefit Transmission connected generation (lower charges due to larger charging base), and adversely impact distribution connected generation (BSUoS moves from a benefit to a charge) are the primary reasons for the changes. However changes in investment due to TGR will also drive changes in the longer term.

There is a larger impact than under the Steady Progression, driven by the higher BSUoS charges under this scenario. As before, transmission-connected CCGT generates more, mainly displacing interconnection in the early years.

In later years there is an increase in curtailment of renewable generation, including wind. The higher charges faced by distribution connected renewable generation relative to interconnection lead to a reduction in exports. There is also a reduction in activity from storage, which is faced with higher BSUoS charges and has a reduced capacity. These changes result in lower demand in periods of high wind output, which leads to increased curtailment of renewables. In earlier years this curtailment is limited to actions related to balancing and reserve services, but in later years (2030s) there is also some curtailment at in the wholesale market.

Figure 19 Difference in generation under Alternative FES Baseline and TGR & Full BSUoS Reform



Source: Frontier/LCP

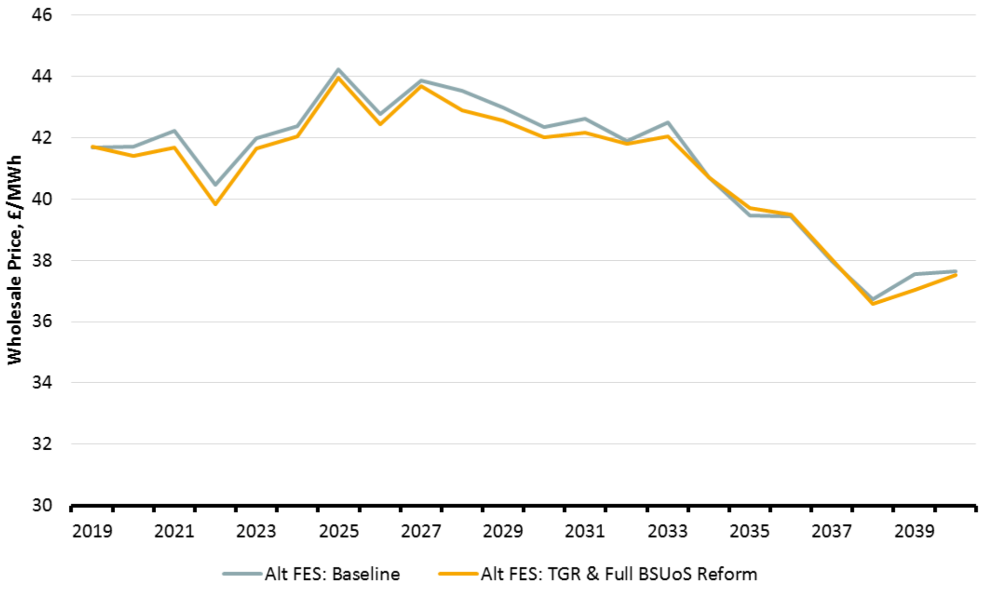
Wholesale prices

Figure 20 below compares average annual wholesale price between Baseline and TGR & Full BSUoS Reform scenarios under the alternative FES market background. The wholesale price decreases in a large number of years, with some exceptions in the back end of the projection. The changes observed are essentially a result of three effects:

- With the reduction in the BSUoS charge the wholesale price falls when transmission-connected are at the margin.
- With distribution connected generation now charged BSUoS, wholesale prices will increase when distribution connected plant are marginal. This becomes more of a driver in later years as the proportion of distribution connected capacity increases.
- The removal of the TGR raises wholesale prices as demand, in particular peak demand, is met by less efficient plant.

The first effect is the main driver through most of the projection period, as prices decrease in most years. BSUoS charges have been reduced by a larger amount under this market background, with reductions of about £1/MWh on average, almost double the reduction seen under Steady Progression.

Figure 20 Average annual wholesale prices for Alternative FES Baseline and TGR & Full BSUoS Reform

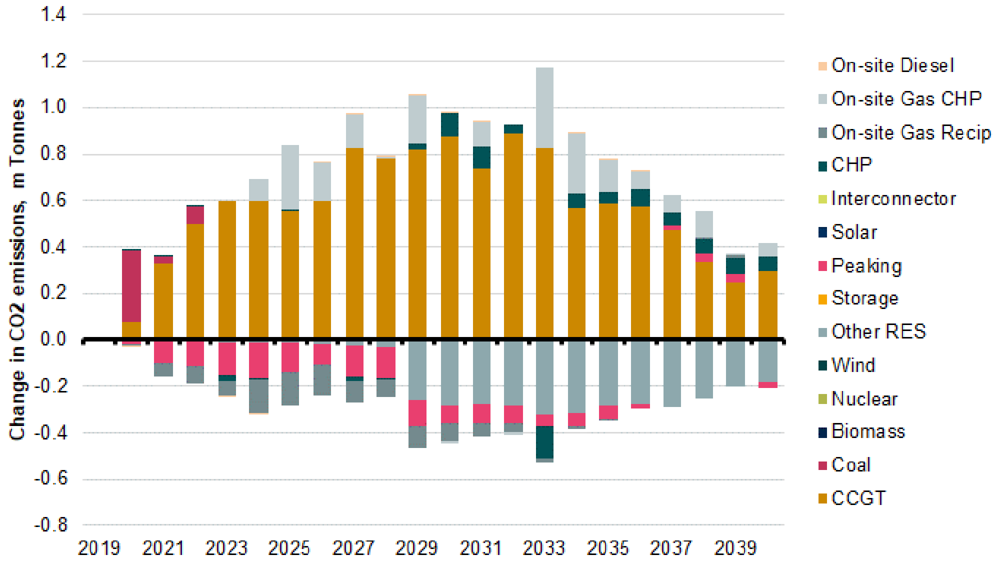


Source: Frontier/LCP

CO_2 Emissions

As in the Steady Progression background there is an increase in domestic CO_2 emissions. One reason for this is that CCGT and some on-site gas generation displaces interconnector flows. In addition, renewable curtailment increases due to the higher charges faced by distribution-connected renewables and lower activity from storage. In earlier years this renewable curtailment is limited to actions related to balancing and reserve services.

Figure 21 Difference in CO_2 emissions under Alternative FES Baseline and TGR & Full BSUoS Reform



Source: Frontier/LCP

System Cost

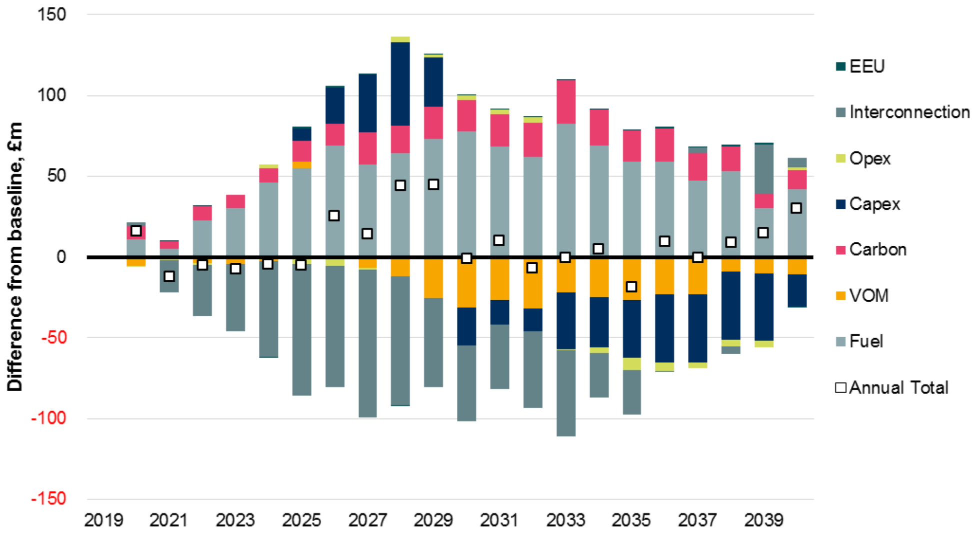
In general, fuel and carbon costs increase, offset by a reduction in interconnection costs, VOM and, in later years, capex.

The NPV shows a system cost increase of just over £100m which is relatively small in the context of total system costs. Therefore, similar to the Full Reform scenario under Steady Progression where we observe a benefit, it is difficult to differentiate from zero.

However, to the extent that the increase in system costs under this scenario with Community Renewables as the background tells us something about the direction of impacts, it may be evidence of some inefficiencies we identified earlier that remain under the Full Reform scenario related to storage and on-site generation:

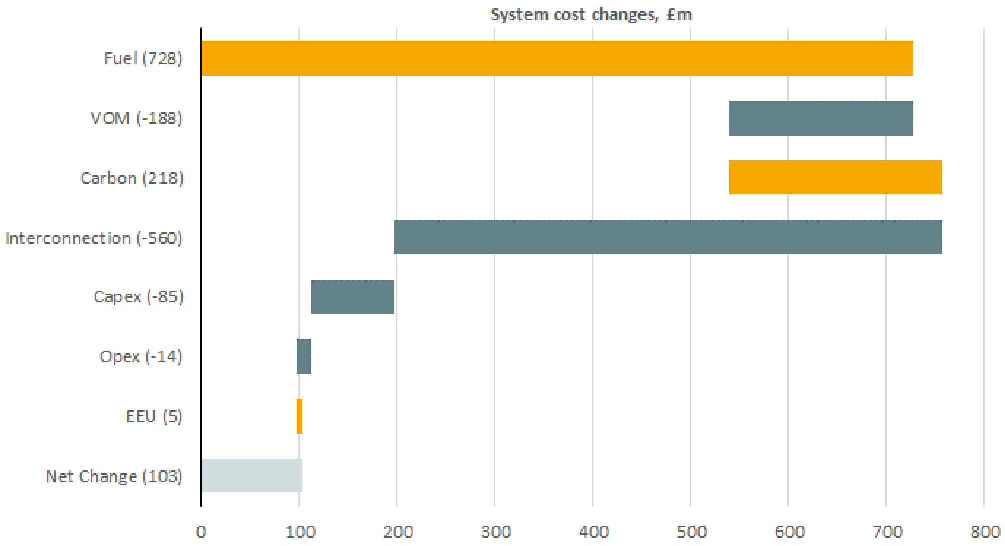
- The scenario shows a decrease in storage capacity, because it is paying BSUoS on its generation under the Full Reform scenario. This is particularly the case against the Alternative FES background given the higher projected amounts of storage capacity and the higher BSUoS charges. As a result, we observe lower storage capacity, and this contributes to higher levels of renewable generation curtailment in some periods, increasing system costs.
- The scenario shows an increase in on-site capacity (Gas CHP) which still receives BSUoS embedded benefits, and is therefore incentivised instead of more efficient grid-connected generation, resulting in an increase in system costs.

Figure 22 Difference in system costs under Alternative FES Baseline and TGR & Full BSUoS Reform



Source: Frontier/LCP

Figure 23 NPV of the difference in system costs under Alternative FES Baseline and TGR & Full BSUoS Reform (2019-2040, 3.5%)



Source: Frontier/LCP

Consumer Cost

Figure 24 shows the modelled consumer cost differences between the Baseline and associated TGR & Full BSUoS Reform scenarios under the Alternative FES market background.

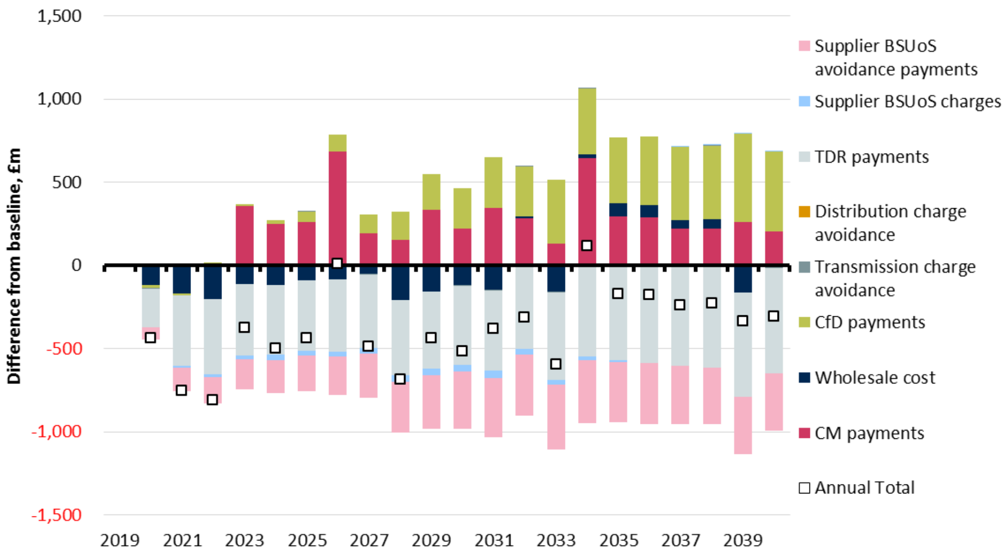
As in the Steady Progression market background, the results show a large consumer cost saving which arises from lower TDR and Supplier BSUoS avoidance payments, that are not completely offset by higher Capacity Market and CfD payments

Figure 25 shows the total impact in NPV terms over the 2019-2040 period. The social discount rate of 3.5% is used. Overall there is a consumer cost saving of £6bn in NPV terms.

This is larger than the benefit shown in the Steady Progression market background. This is mainly due to the higher BSUoS charges projected under this scenario, which leads to a larger benefit from removing the avoidance charges.

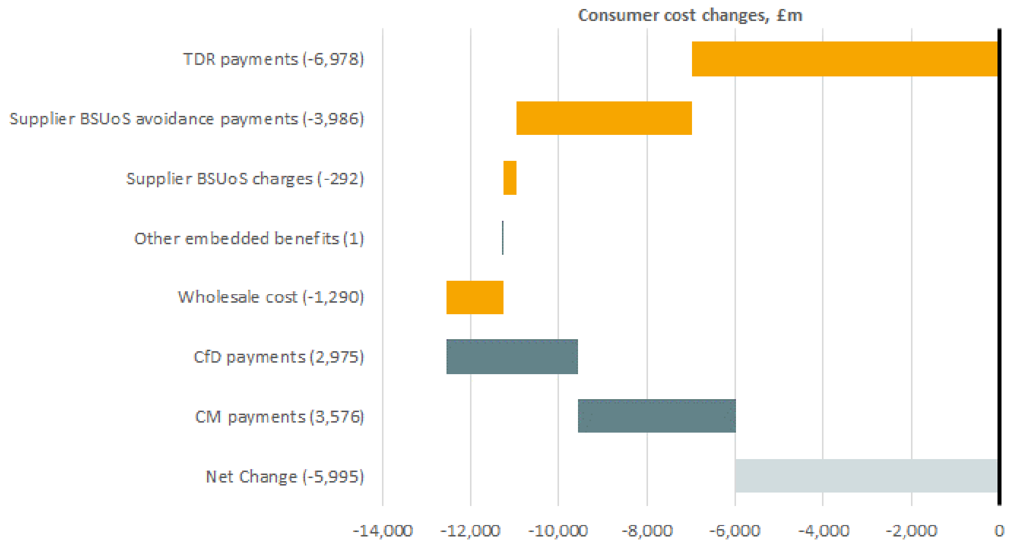
The large consumer cost saving relative to a slight increase in system costs would suggest that there is a large transfer from producers to consumers.

Figure 24 Difference in consumer costs under Alternative FES Baseline and TGR & Full BSUoS Reform



Source: Frontier/LCP

Figure 25 NPV of the difference in consumer costs under Alternative FES Baseline and TGR & Full BSUoS Reform (2019-2040, 3.5%)



Source: Frontier/LCP

2.3.3 Results – Phased TGR & Full BSUoS Reform

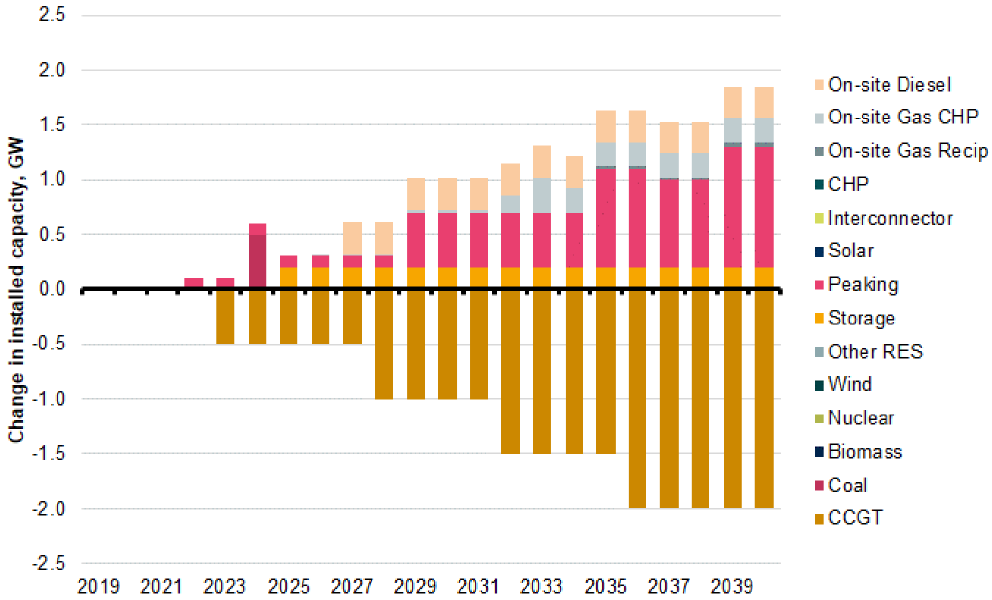
This scenario has the same assumptions as the “TGR & Full BSUoS Reform”, except the changes are phased in the changes over a 3 year period from 2021-23, rather than full implementation in 2020.

Capacity breakdown

The capacity changes are very similar to the results under the 2020 implementation. CCGT capacity decreases replaced by distribution connected and on-site capacity.

There are some small differences in the changes after 2023, meaning the modelling is showing knock-on effects from the phased implementation. One reason for this is that CfD strike prices, set to cover the increase in TGR or BSUoS charges, will be slightly different as a result of the phased reforms.

Figure 26 Difference in installed capacity between Baseline and Phased TGR & Full BSUoS Reform

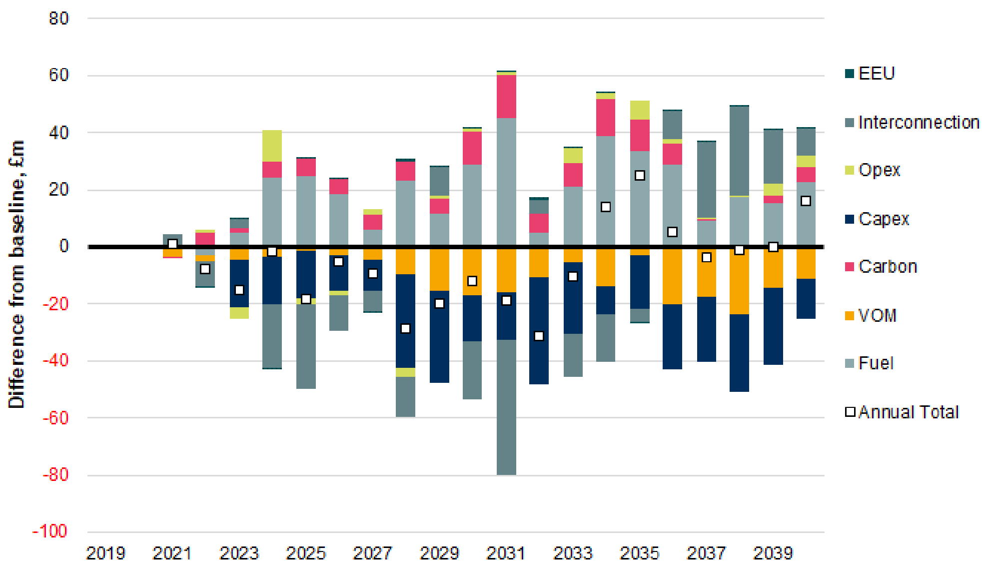


Source: Frontier/LCP

System Cost

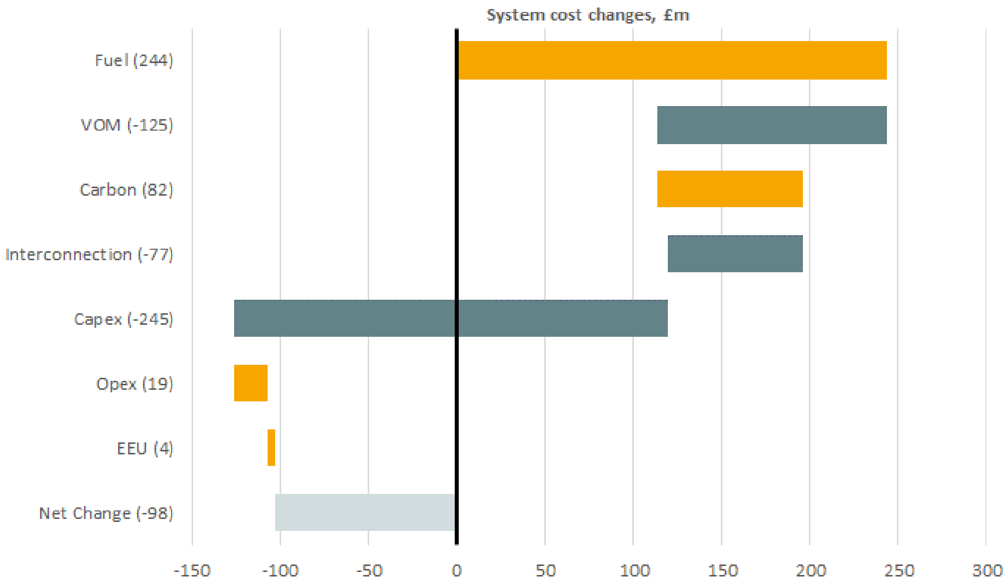
Figure 28 shows that overall the system costs show a relatively small system benefit of around £100m. This is of a similar magnitude to the savings under the 2020 implementation scenario.

Figure 27 Difference in system costs between Baseline and Phased TGR & Full BSUoS Reform



Source: Frontier/LCP

Figure 28 NPV of the difference in system costs between Baseline and Phased TGR & Full BSUoS Reform (2019-2040, 3.5%)



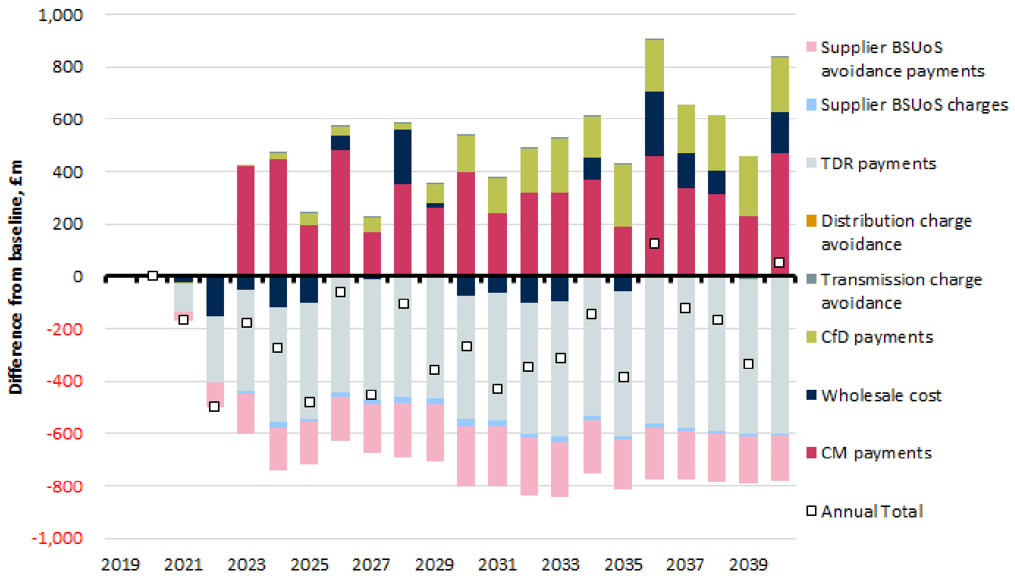
Source: Frontier/LCP

Consumer Cost

Figure 29 and Figure 30 show the consumer cost results for the Phased scenario relative to the Baseline. As in the 2020 implementation, after 2023 the reductions savings to consumers from reduced TDR payments and the removal of the BSUoS avoidance payments are only partially offset by increases in CM payments and CfD support costs.

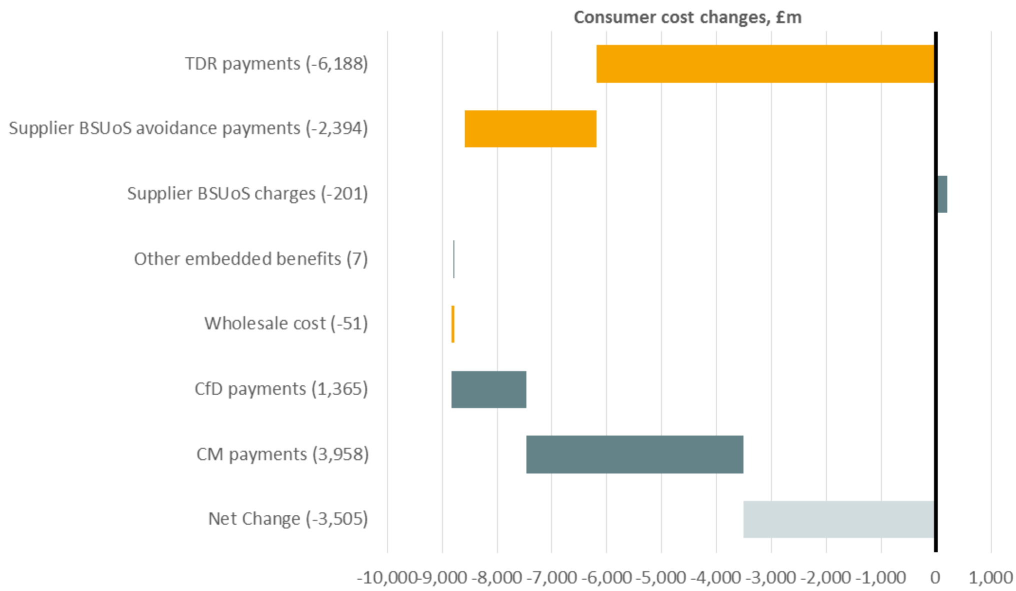
The overall NPV is a saving of just over £3.5bn, around £1.0bn lower than with the 2020 implementation.

Figure 29 Difference in consumer costs between Baseline and Phased TGR & Full BSUoS Reform



Source: Frontier/LCP

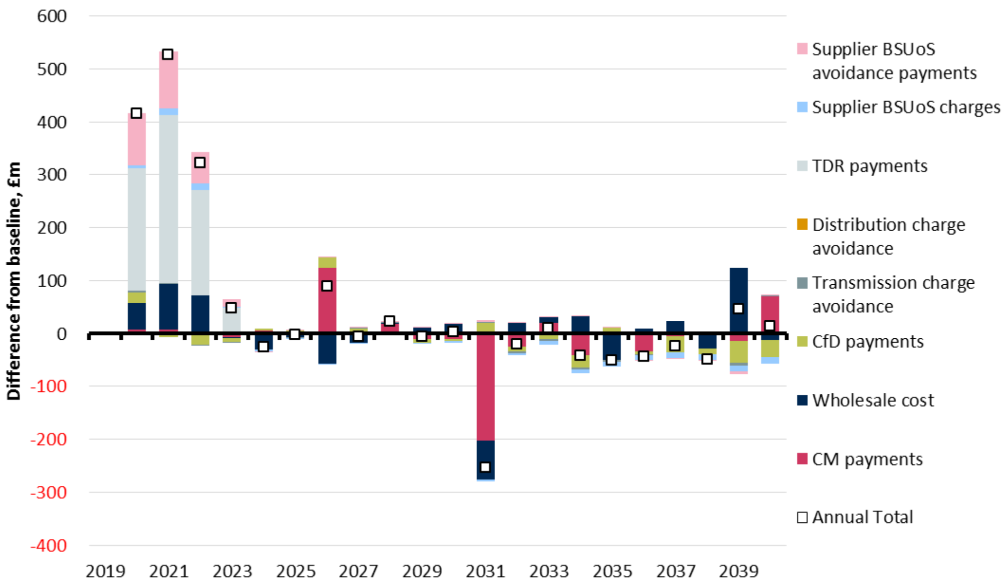
Figure 30 NPV of the difference in consumer costs between Baseline and Phased TGR & Full BSUoS Reform (2019-2040, 3.5%)



Source: Frontier/LCP

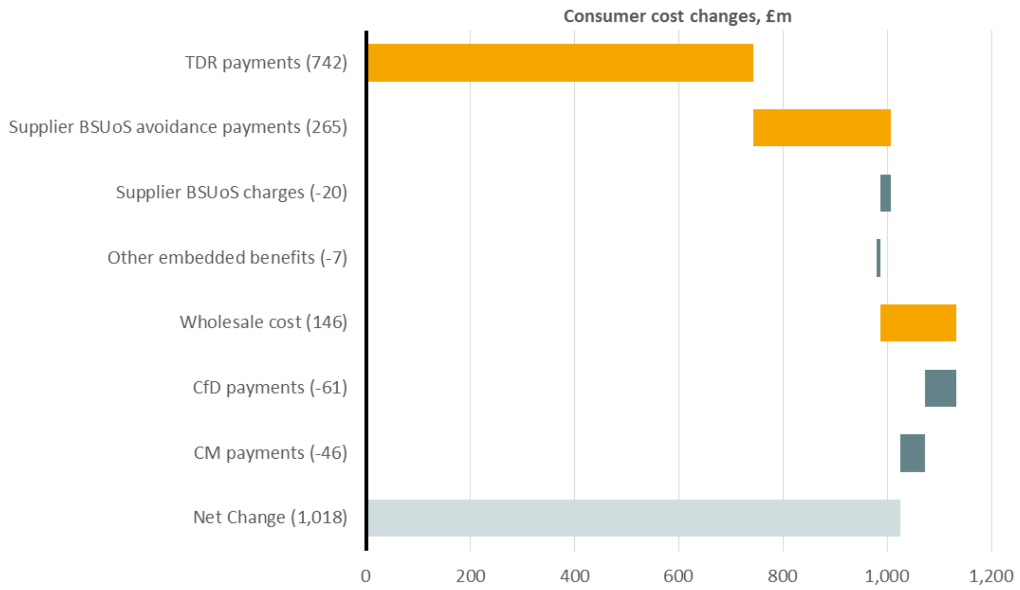
Figure 31 shows the direct comparison between the Phased scenario and the 2020 implementation. The £0.5bn increase in consumer costs is almost all concentrated over the transitional 2021-23 period. This because the consumer savings from TDR payments and BSUoS payments are reduced under the phased approach. The knock-on effects in later years are generally quite small, with two material impacts in 2026 and 2031 due to a changes in the CM clearing price. Without these knock-on effects the additional costs attributed to phasing would be around £1.3bn.

Figure 31 Difference in consumer costs between TGR & Full BSUoS Reform and Phased TGR & Full BSUoS Reform



Source: Frontier/LCP

Figure 32 NPV of difference in consumer costs between TGR & Full BSUoS Reform and Phased TGR & Full BSUoS Reform (2019-2040, 3.5%)



Source: Frontier/LCP

2.3.4 Results – TGR and Partial BSUoS Reform

In this section we present our results for the TGR and Partial BSUoS reform scenario against the Steady Progression FES background.

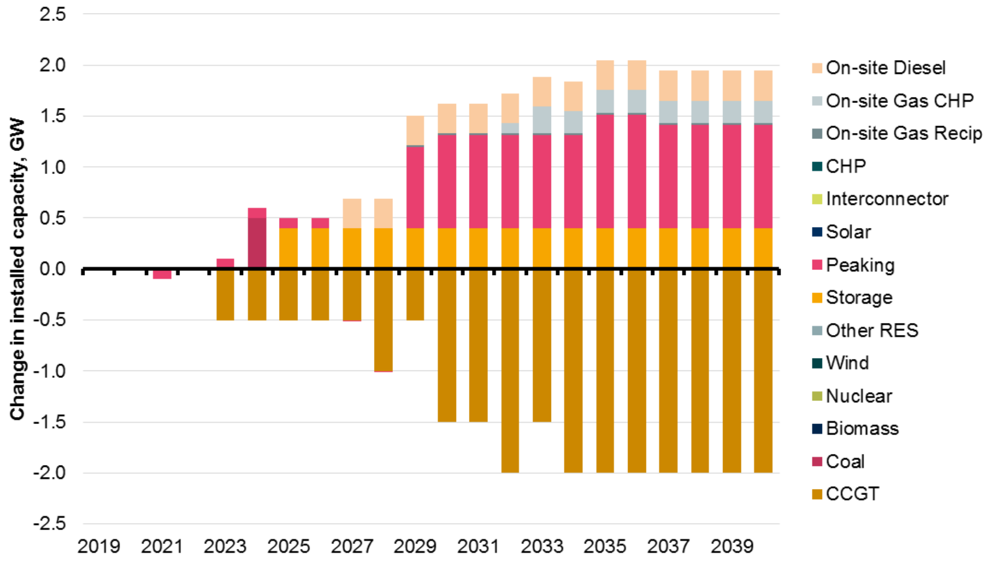
Capacity breakdown

The removal of the TGR benefit adversely affects the profitability of transmission-connected generation. As under the other runs, the CM bids of CCGT units increase by around £5-10/kW as a result of this change. This leads to a decrease in the procured capacity of new build CCGT. This capacity is replaced by distribution-connected peaking and on-site generation.

The partial BSUoS change adversely affects distribution-connected peaking generation. However, because the charge is volumetric, their low load factors mean that the impact is relatively small. This effect leads to the displacement of CCGTs with distribution-connected peaking generation and storage.

Relative to the TGR & Full BSUoS Reform scenario considered above, the increase in bids of distribution-connected generation is smaller, as they avoid paying the BSUoS charge. Therefore, we see greater displacement of new build CCGTs than previously observed, as shown in Figure 33 below.

Figure 33 Difference in installed capacity between Baseline and TGR and Partial BSUoS Reform



Source: Frontier/LCP

System Cost

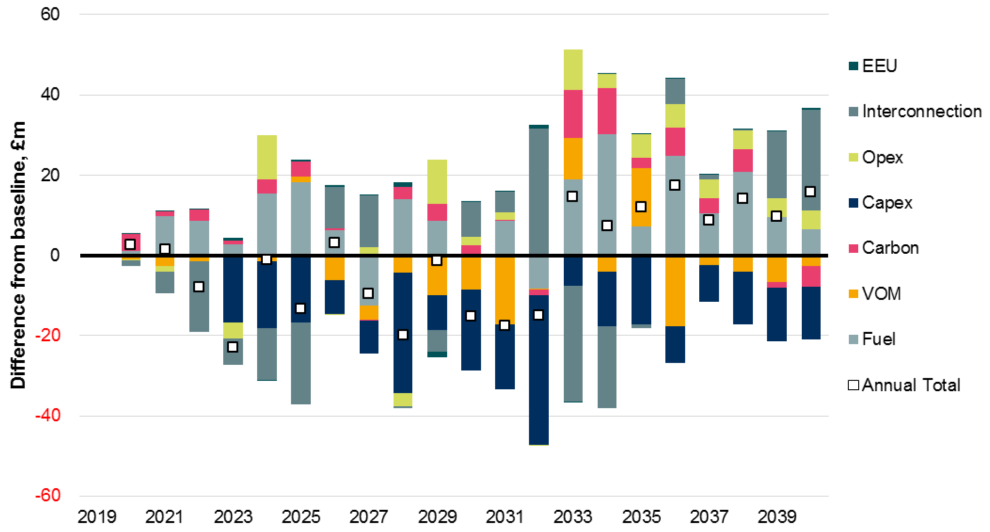
Figure 34 below shows the modelled system costs differences, comparing Baseline to TGR and Partial BSUoS Reform. Overall, there is a small system cost saving associated with the reform.

The removal of the benefit from offsetting supplier's BSUoS charges increases the BSUoS charging base, leading to a reduction in the calculated charge. This erodes the relative advantage afforded to interconnection. Overall, this leads to a small reduction in the cost of interconnection. This cost reduction is more than offset by increases in fuel and GB emissions costs from the domestic generation that displaces interconnection.

However, there are relatively larger reductions in the overall capex cost because there are fewer new build CCGT units and more plants choose to delay their retirements.

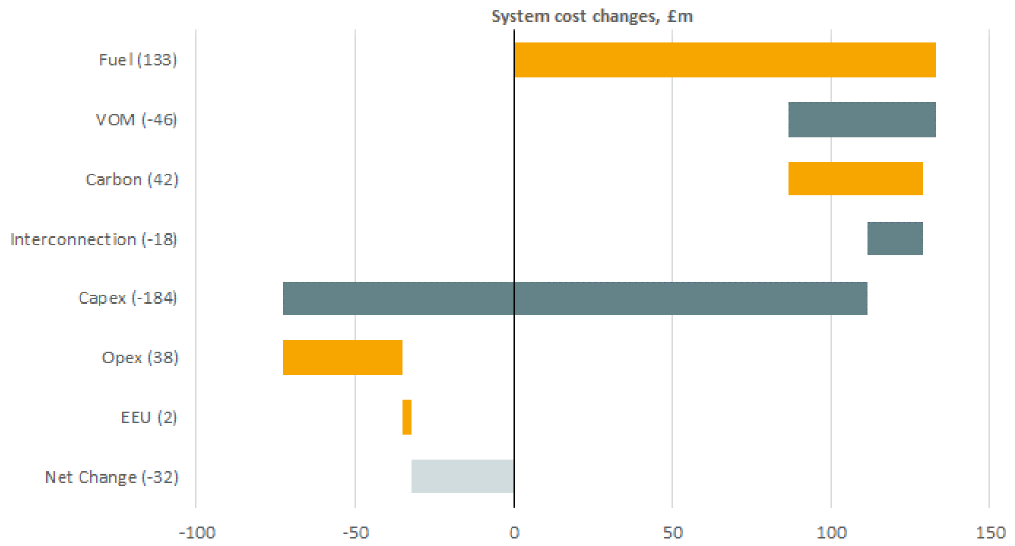
Figure 35 shows the total impact in NPV terms over the 2019-2040 period. The social discount rate of 3.5% is used. Overall, there is a system cost saving of £32m in NPV terms.

Figure 34 Difference in system costs between Baseline and TGR and Partial BSUoS Reform



Source: Frontier/LCP

Figure 35 NPV of the difference in system costs between Baseline and TGR and Partial BSUoS Reform (2019-2040, 3.5%)



Source: Frontier/LCP

Consumer Cost

Figure 37 shows the modelled consumer cost differences between the Baseline and TGR & Partial BSUoS Reform.

Consistent with the results for the TGR & Full BSUoS Reform scenario, there is a significant consumer cost saving. This saving is driven by significant reductions in TDR and supplier BSUoS avoidance payments. As was the case under Full Reform, only a portion of these costs to generators can be passed through to consumers through increased CfD and CM payments.

In contrast to the Full BSUoS Reform scenario, there is an increase in supplier BSUoS charges. Under this scenario, the BSUoS charging base for load has increased and the charging base for generation has remained fixed. This leads to a reduction in the BSUoS charge applied to both. However, the relative sizes of the charging bases for load and generation have changed, so a greater proportion of the total cost is now paid by load. This drives an increase in supplier BSUoS charges, as shown in the simple hypothetical example below.

Figure 36 Illustrative example of Supplier BSUoS

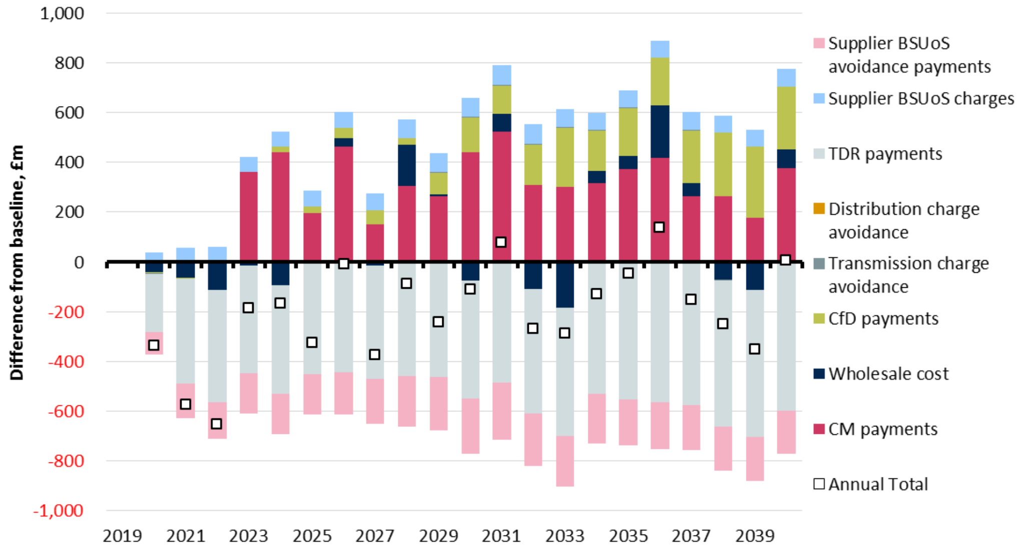
Scenario	Baseline	Partial BSUoS Reform	Full BSUoS Reform
Total cost to recover, £m	880	880	880
Charging base, TWh	Generation: 220TWh Load: 220TWh	Generation: 220TWh Load: 290TWh	Generation: 290TWh Load: 290TWh
BSUoS rate for generation and load, £/MWh	2.00	1.73	1.52
Supplier BSUoS charges, £m	440.0	500.4	440.0

Source: Frontier/LCP

However, this change also reduces the BSUoS charges on generation, which are passed into wholesale prices and seen by consumers as an offsetting decrease in wholesale costs.

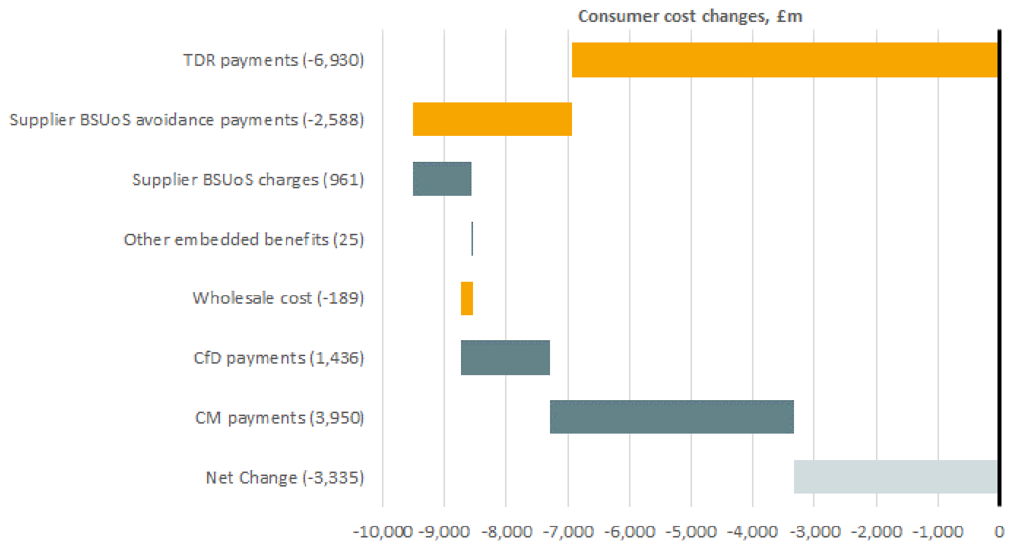
Figure 38 shows the total impact in NPV terms over the 2019-2040 period. The social discount rate of 3.5% is used. Overall, there is a consumer cost saving of £3.33bn in NPV terms.

Figure 37 Difference in consumer costs between Baseline and TGR and Partial BSUoS Reform



Source: Frontier/LCP

Figure 38 NPV of the difference in consumer costs between Baseline and TGR and Partial BSUoS Reform (2019-2040, 3.5%)



Source: Frontier/LCP

2.3.5 Results – Alternative FES TGR and Partial BSUoS Reform scenario

In this section we present our results for the TGR and Partial BSUoS reform scenario against the Community Renewables FES background.

Capacity breakdown

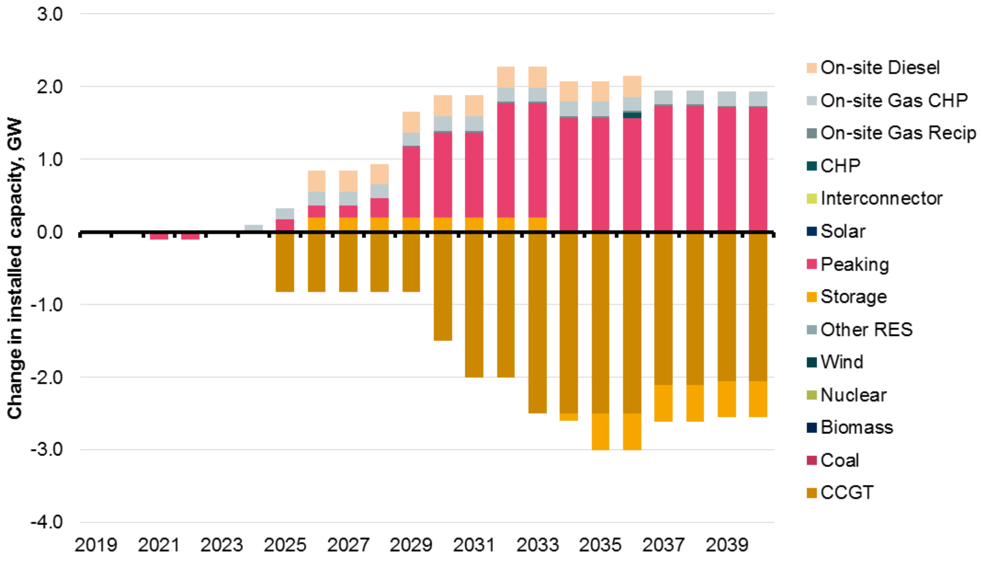
The removal of the TGR benefit adversely affects the profitability of transmission-connected generation. As under the other scenarios, the CM bids of new build CCGT units increase by around £5-10/kW/yr as a result of this change. This leads to a decrease in the procured capacity of new build CCGT. This capacity is replaced by distribution-connected peaking and on-site generation.

The partial BSUoS change adversely affects distribution-connected peaking generation. However, because the charge is volumetric, their low load factors mean that the impact is relatively small.

Compared to the Full Reform scenario under Community Renewables where there was a significant reduction in total storage capacity, the reduction in storage capacity under Partial Reform is more modest. This is likely to be because storage does not pay BSUoS on its generation under the Partial Reform scenario, and therefore we are likely to see higher storage investment than under Full Reform.

There is still a reduction in storage later in the period relative to the baseline. This is likely to be due to the removal of Supplier BSUoS avoidance payments to storage. The impact of this is larger under Community Renewables due to the higher penetration of storage and the higher BSUoS charges compared to Steady Progression.

Figure 39 Difference in installed capacity between Alternative FES Baseline and TGR and Partial BSUoS Reform



Source: Frontier/LCP

System Cost

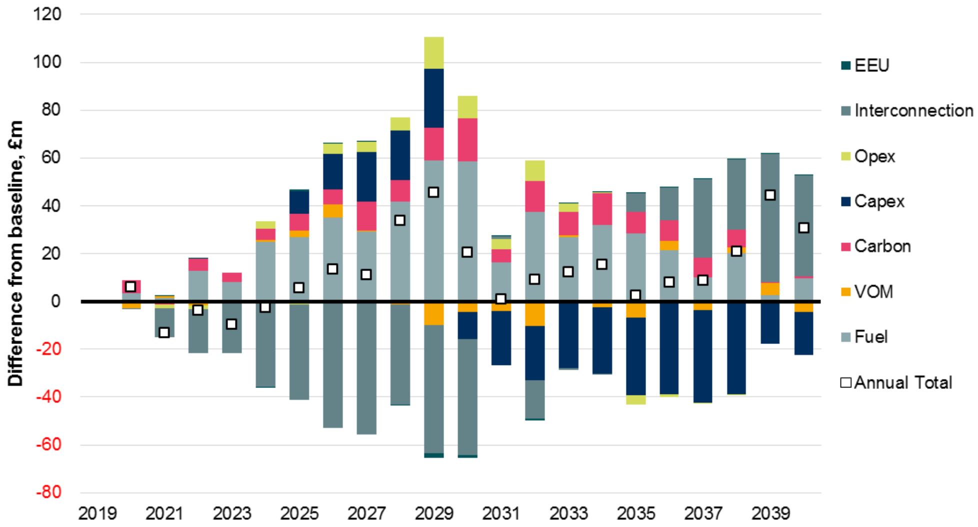
Figure 40 below shows the modelled system costs differences, comparing Baseline to TGR and Partial BSUoS Reform under Community Renewables. Overall, there is a system cost increase associated with the reform. Similar to the other scenarios, this is a relatively small increase in system costs, and it is difficult to clearly differentiate this from zero.

As seen under previous scenarios, the reduction in the BSUoS charge leads to interconnection imports being displaced by domestic generation. Therefore, we observe a reduction in interconnection costs and an increase in fuel and carbon costs.

However, in this scenario the displacement of new build CCGTs with less efficient on-site generation that continue to receive embedded benefits, and distribution-connected peaking plants, mean that there is an increase in fuel and GB carbon costs.

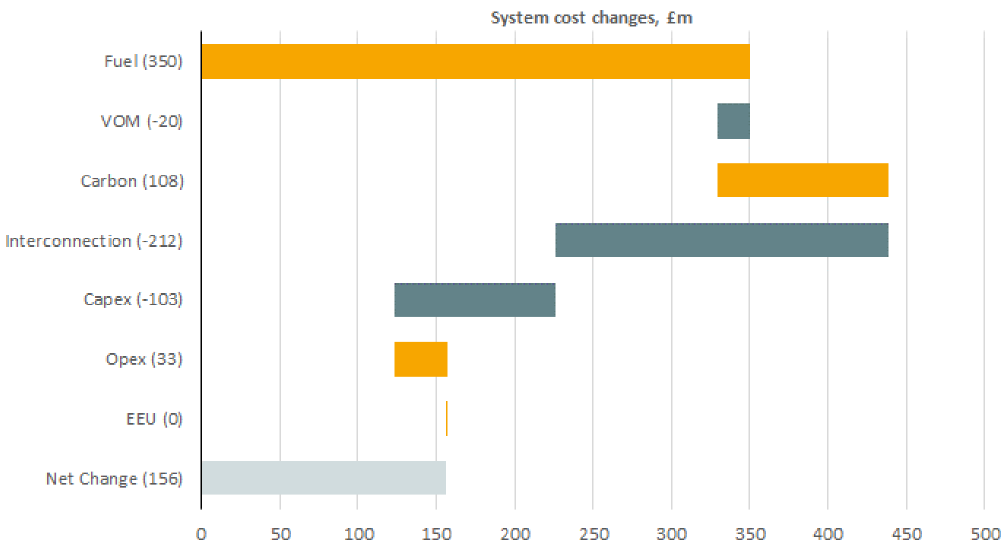
Figure 41 shows the total impact in NPV terms over the 2019-2040 period. The social discount rate of 3.5% is used. Overall, there is a system cost increase of £156m in NPV terms.

Figure 40 Difference in system costs between Alternative FES Baseline and TGR and Partial BSUoS Reform



Source: Frontier/LCP

Figure 41 NPV of the difference in system costs between Alternative FES Baseline and TGR and Partial BSUoS Reform (2019-2040, 3.5%)



Source: Frontier/LCP

Consumer Cost

Figure 42 shows the modelled consumer cost differences between the Baseline and TGR & Partial BSUoS Reform.

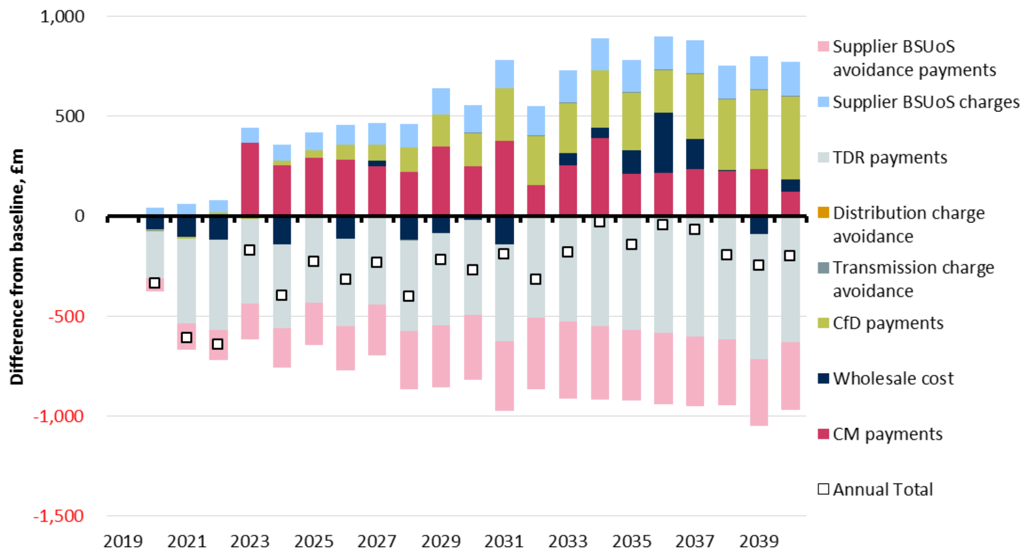
Consistent with the results for the TGR & Full BSUoS Reform scenario, there is a significant consumer cost saving. This saving is driven by significant reductions in TDR and supplier BSUoS avoidance payments. As was the case under Full Reform, the increase in cost due to the removal of the TGR and BSUoS embedded benefits does in part pass through into higher capacity market clearing prices and CfD strike prices. However, these mechanisms do not allow all of these charges to be passed on to consumers so the net result is a consumer cost saving.

As observed for the BSUoS Partial Reform scenario under Steady Progression, there is a significant increase in Supplier BSUoS payments due to a shift in how to total balancing cost is split between generation and load. However, this cost increase is offset by generators passing through the reduction in BSUoS into wholesale price reductions.

The reduction in supplier BSUoS payments is more pronounced under Community Renewables than under Steady Progression due to the higher penetration of distribution-connected generation.

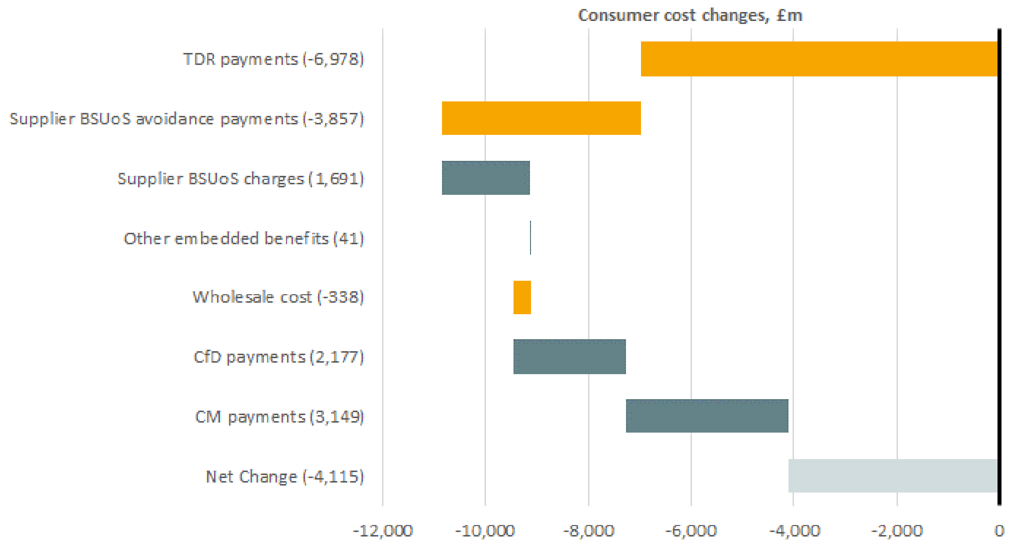
Figure 43 shows the total impact in NPV terms over the 2019-2040 period. The social discount rate of 3.5% is used. Overall, there is a consumer cost decrease of £4.11bn in NPV terms.

Figure 42 Difference in consumer costs between Alternative FES Baseline and TGR and Partial BSUoS Reform



Source: Frontier/LCP

Figure 43 NPV of the difference in consumer costs between Alternative FES Baseline and TGR and Partial BSUoS Reform (2019-2040, 3.5%)



Source: Frontier/LCP

3 OVERVIEW OF SYSTEM MODELLING RESULTS

Based on the analysis set out in this report, the changes to the TGR and BSUoS tested seem likely to have a positive impact on consumers due to lower TDR and BSUoS charges. NPVs for consumer cost benefits range from £3.3bn to £6bn.

The changes do not have a significant impact on system costs, with the results showing a reduction in some scenarios and an increase in others both of which are very small given the uncertainties inherent in the analysis. The results should only be interpreted as providing an indication of the direction and broad magnitude of impacts. In relation to system costs in particular, it is not obvious that they provide a clear reading in either direction.

The tables below summarise the change in the system and consumer costs estimated in EnVision between each pair of counterfactual and factual scenarios over the 2019 to 2040 period. A decrease in costs (negative value) represents a system or consumer benefit.

Figure 44 Total cost change, 2019-2040

Counterfactual	Factual	System cost (£bn)	Consumer cost (£bn)
Baseline*	TGR & Full BSUoS Reform	-0.14	-5.85
Alternative FES background – Baseline**	Alternative FES background – TGR & Full BSUoS Reform	0.16	-8.05
Baseline*	Phased TGR & Full BSUoS Reform	-0.12	-4.88
Baseline*	TGR & Partial BSUoS Reform	-0.02	-4.33
Alternative FES background – Baseline**	Alternative FES background – TGR & Partial BSUoS Reform	0.26	-5.42

Source: LCP/Frontier

Figure 45 NPV of Total Cost Change, 3.5%, 2019-2040

Counterfactual	Factual	System cost NPV (£bn)	Consumer cost NPV (£bn)
Baseline*	TGR & Full BSUoS Reform	-0.11	-4.52
Alternative FES background – Baseline**	Alternative FES background – TGR & Full BSUoS Reform	0.10	-5.99
Baseline*	Phased TGR & Full BSUoS Reform	-0.10	-3.51
Baseline*	TGR & Partial BSUoS Reform	-0.03	-3.33
Alternative FES background – Baseline**	Alternative FES background – TGR & Partial BSUoS Reform	0.16	-4.11

Source: LCP/Frontier
Notes:* this scenario is equivalent to "Full Reform" in the main TCR report's wider system modelling
** this scenario is equivalent to "Alternative FES scenario: Full Reform" in the main TCR report's wider system modelling

Small reductions in system costs under the Steady Progression scenarios are derived from lower system variable (fuel, GB CO_2 and interconnection costs) costs and capex costs in particular:

- System variable costs are lower because the competitive disadvantage between transmission connected generation and interconnection (which does not pay BSUoS) is reduced, as a result of lower BSUoS unit charges under the reform scenarios. This results in a small re-balancing away from imports to domestic generation with the effect of overall lower costs. Under Full Reform, this can be offset by the fact that distribution connected generation pay BSUoS creating a competitive disadvantage with interconnection.
- Capex costs are reduced because fewer CCGTs clear in the capacity market, compared to smaller less capital intensive peaking plants. This is because CCGTs become less competitive in the capacity market due to the increase in the TGR, but small distribution connected peaking plants are relatively unaffected by the changes to BSUoS.

Under the alternative FES background (Community Renewables) system costs increase, albeit by a small amount, which similar to the scenarios in which we observe benefits are difficult to differentiate from zero. However, to the extent that the increase in system costs under the scenarios with Community Renewables as the background tell us something about the direction of impacts, it may be evidence of a number of the inefficiencies that remain under the reform scenarios that we identified earlier related to storage and on-site generation:

- Storage is likely to be adversely affected under the Full Reform scenario, however, it is particularly true against the Alternative FES background given the higher projected amounts of storage capacity and the higher BSUoS charges. As a result, we observe lower storage capacity resulting in higher levels of renewable generation curtailment in some periods, increasing system costs. We do not expect this inefficiency under the Partial Reform case where storage would not face BSUoS charges on its generation.

- On-site generation could be inefficiently incentivised as it still receives the BSUoS embedded benefit, which could lead to investments in on-site generation instead of more efficient grid-connected generation, resulting in an increase in system costs. This inefficiency could be present under both the Full and Partial Reform scenarios.

With respect to interconnection the implications for system costs from the reforms are more ambiguous. On the one-hand, the distortion between transmission connected generation is reduced. On the other hand, distribution connected generation moves from having a competitive advantage over interconnection in the baseline to being competitively disadvantaged under the Full Reform scenario.

As a result, while it is difficult to draw firm conclusions as to the exact impact on system costs, if Ofgem were to implement these changes, complementary changes to the BSUoS charging arrangements for storage and generation (on-site and grid-connected) could be beneficial from the perspective of minimising system costs.

In contrast to system cost effects, the consumer benefits are significant under all scenarios, and in general are derived from:

- lower TDR payments, as a result of removing the negative TGR payments which were previously paid for through TDR; and
- the removal of the supplier BSUoS avoidance payments.

The increase in cost due to the removal of the TGR and BSUoS embedded benefits does in part pass through into higher capacity market clearing prices and CfD strike prices. However, these mechanisms do not allow all of these charges to be passed on to consumers so the net result is a consumer cost saving. In particular, plant outside of the capacity market such as existing plants built under the Renewables Obligation or those with existing CfDs are not able pass-through the increase in TGR costs.

The Partial BSUoS Reform scenarios show a lower consumer saving than the Full BSUoS Reform scenario. This is partly because some of the savings from removing the BSUoS avoidance payments flow to generators. Under Partial Reform the demand charging base increases due to the switch to gross charging, however, the generator charging base remains unchanged. This results in more of the BSUoS costs being recovered from load. This shift does not take place under Full BSUoS Reform, and hence consumers receive the full benefit of removing the BSUoS avoidance payments.

The Alternative FES market background shows a significantly larger benefit than Steady Progression. This is primarily because higher BSUoS charges are projected under this market background, and hence there is a larger benefit from removing the BSUoS avoidance payments.

The Phased scenario, which phases the reforms in over the 2021-23 period, shows a lower consumer saving than the 2020 implementation, with an increased consumer cost of about £1.0bn (saving decreased from £4.52bn to £3.51bn).

3.1.1 Delayed implementation

Using the results of the scenario model runs, we can also estimate the impact on consumer cost of delaying the April 2020 implementation by 1 year, assuming there would be no knock-on effects on capacity build and retirements.

These are estimated based on assuming all of the consumer savings accrued during the 1 year period would be lost, and that there are no knock-on effects of the delay beyond this period.

The results show that under the Full Reform scenario a 1 year delay would result in £0.56bn of additional consumer cost. The Partial Reform scenario, shows a slightly lower additional cost, of £0.46bn. The results are similar under the Alternative FES scenario for both Full and Partial Reform.

These results assume that reforms are still announced at the same time, but there is a longer lead time to implementation. If the announcement was also delayed by 1 year then generators may continue to factor existing arrangements into their CM and CfD bids during the interim period, delaying increases in capacity market and CfD payments. This delay could offset some or all of the consumer costs shown below.

Figure 46 NPV of Total Cost Change, 3.5%, 2019-2040

Scenario	Consumer cost NPV (£bn) with 1 year delay
TGR & Full BSUoS Reform	0.56
Alt FES: TGR & Full BSUoS Reform	0.59
TGR & Partial BSUoS Reform	0.46
Alt FES: TGR & Partial BSUoS Reform	0.47

Source: Frontier/LCP

Note that these figures are higher than the consumer cost savings shown in the scenarios' respective years because the scenarios present results for calendar years. The figures for a 1 year delay represent the additional costs incurred from April 2020 to April 2021, so incorporate 2020 and part of the 2021 results.

4 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 network charging arrangements. Such principles relate to minimising distortions, fairness and practicality considerations. Charging in a manner consistent with such principles should help ensure an optimum outcome for society as a whole.

The 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 2019 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. 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:

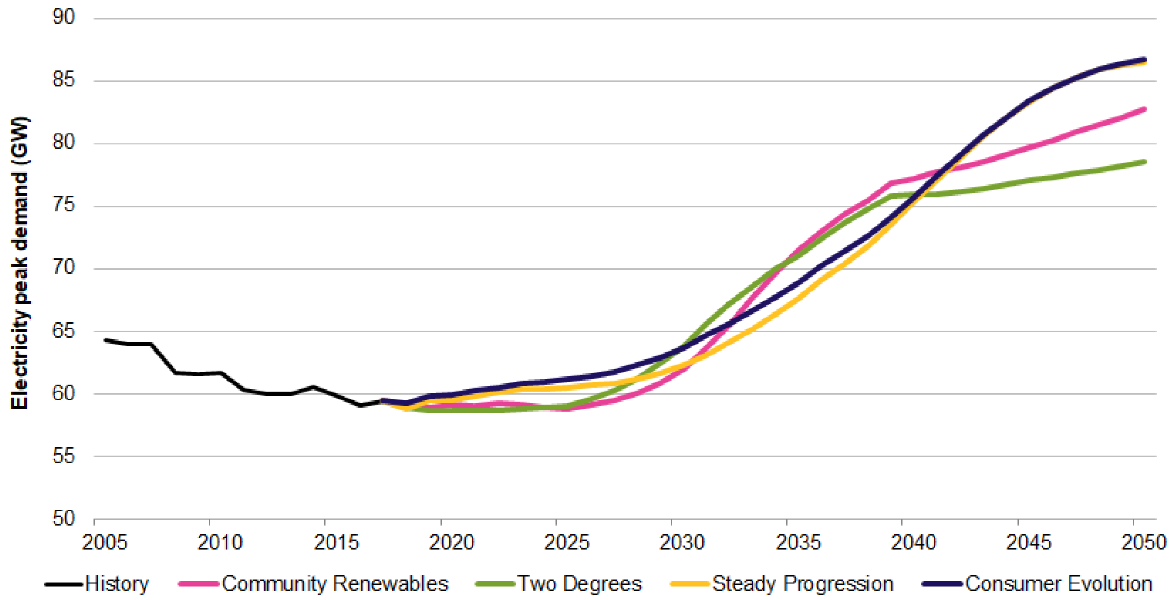
- The scenarios presented do not take into account all changes that could potentially occur in the power market. More extreme market outcomes than those presented are therefore possible.
- The relationship between the cost of generation and prevailing market prices has been assessed based on historical 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 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.

ANNEX A ADDITIONAL SYSTEM MODELLING ASSUMPTIONS

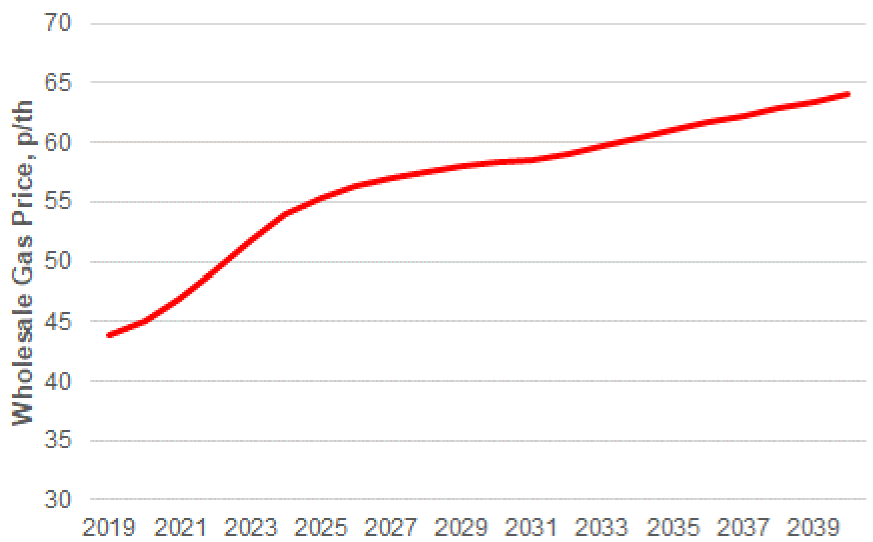
A.1.1 Demand Assumptions

National Grid FES 2018 – Peak Demand, GW

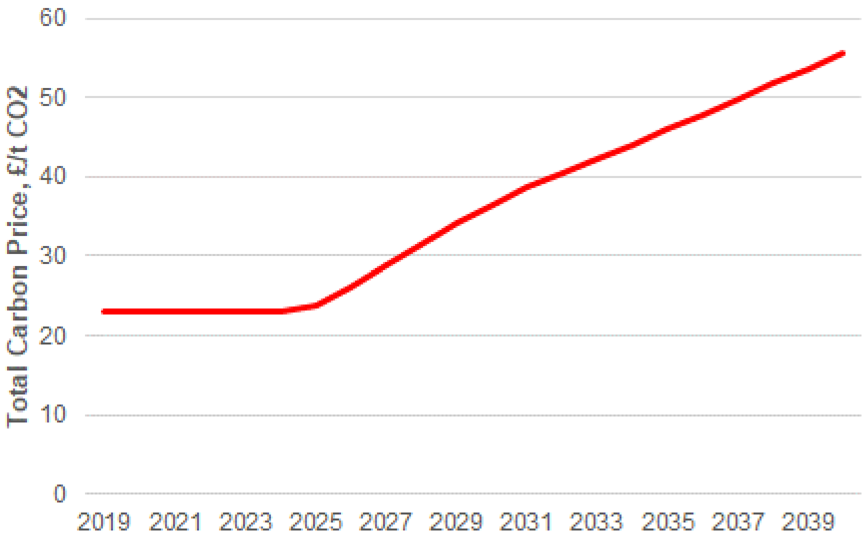


A.1.2 Commodity Prices

National Grid FES 2018 – Base Case Gas Price, p/th

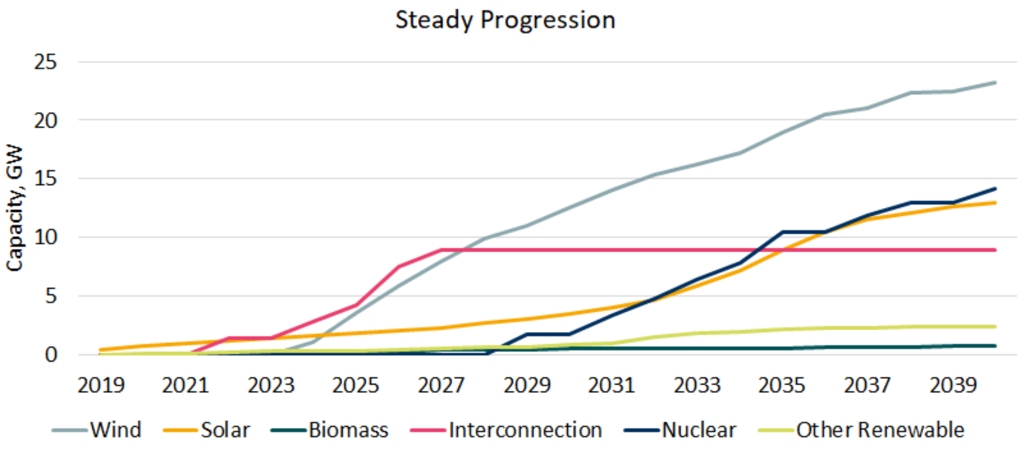


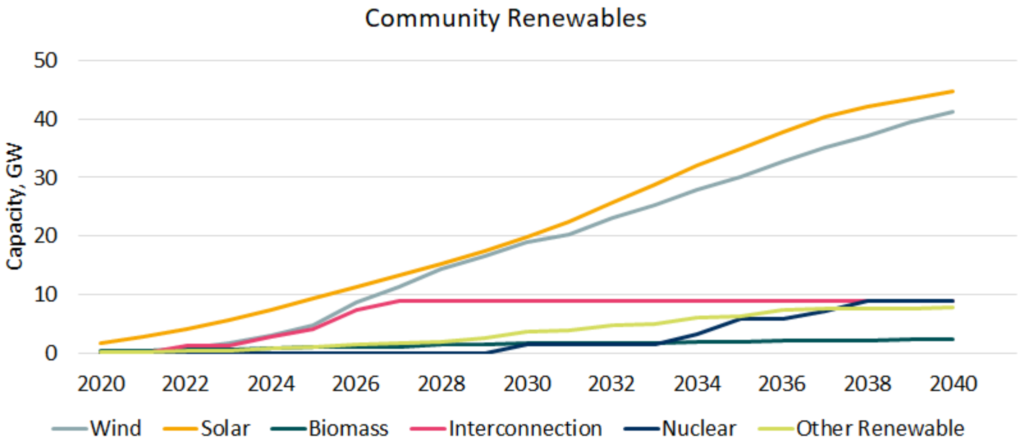
National Grid FES 2018 – Base Case Total Carbon Price, £/t



A.1.3 Low carbon build projections

Projections of post-2018 low carbon build, based on Steady Progression and Community Renewables FES 2018 scenarios.





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