Making a positive difference for energy consumers

Annex 5 - Reform to non-locational Embedded Benefits

Introduction

1.1 In this Annex, we set out the options and assessment for the second element in the scope of the Targeted Charging Review (TCR) SCR, namely changes to the remaining non-locational Embedded Benefits. The term Embedded Benefits is used to describe the different transmission charging arrangements (including balancing system charges) for smaller (sub 100MW) embedded generators (those connected to the distribution network) verses larger generators.[1]

1.2 These Embedded Benefits typically arise because these charges are only levied on larger generators and suppliers, with demand charges to suppliers being levied on a 'net' demand basis at the point the transmission network meets the distribution network (Figure 1). In some cases, suppliers effectively receive a discount on their charges for contracting with smaller embedded generators, the majority of which are passed onto smaller embedded generators in the form of payments from suppliers. In addition, smaller embedded generators can contract with National Grid to receive these payments directly. In other cases, smaller embedded generators avoid charges that larger generators face.

1.3 We are continuing a process of reform to Embedded Benefits. In July 2016, we set out our concerns with Embedded Benefits in an open letter.[2] We indicated that our immediate concern was related to the Transmission Demand Residual (TDR) payments to smaller embedded generators. We provided an update in December 2016, and in 2017 industry presented proposals for reform via Code Modification Proposals (CMP) 264 and 265. We consulted on our draft Impact Assessment in March 2017, and in June 2017 we decided to approve the option known as WACM 4, to phase out the Transmission Demand Residual Embedded Benefit, via the introduction of the Embedded Export Tariff (EET). The changes were implemented in April 2018, with a phased reduction of the EET over three years.

1.4 We said in the TCR SCR launch statement that we are prepared to take further action during the SCR if evidence emerges that the remaining Embedded Benefits create significant distortions to competition and have negative impacts on consumers' interests. Our analysis has indicated that there is a sufficient basis for further action, as set out later in this section.

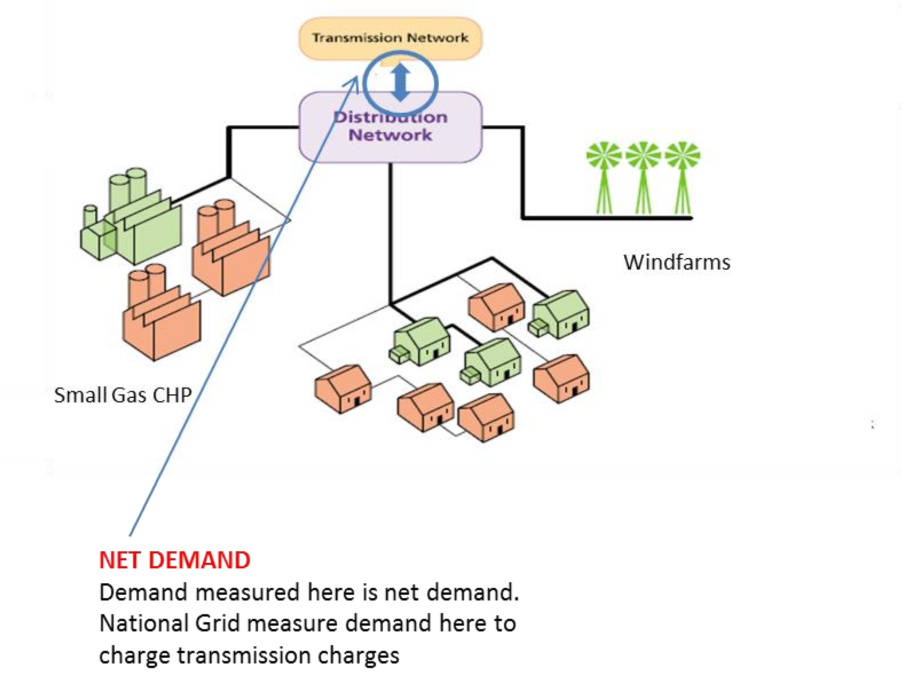
1.5 On-site generation does not pay network charges in general, and can receive similar benefits to smaller embedded generation when it exports onto the network. So we have also considered the benefits that on-site generation can receive in respect of transmission and balancing charges compared to metered generation, and how our

[1] These used to confer benefits to smaller generators, but they are now a mix of benefits and dis-benefits. Larger generators in this context includes all those liable for transmissions charges

[2] https://www.ofgem.gov.uk/publications-and-updates/open-letter-charging-arrangements-embedded-generation

proposals will affect these benefits. Our proposals will address some of these differences, as discussed below. Further reforms to balancing services charges could address the remaining differences.

Figure 1: illustration of net metering at point transmission and distribution networks meet leading to 'embedded benefits'



1.6 The main non-locational Embedded Benefits are described in Table 1 below, which also indicates how our proposals will affect smaller embedded generation and onsite generation. Differences in forward-looking network charges between smaller embedded generation and larger transmission connected generation are being considered within the scope of our Electricity Network Access Project, and are not covered by these proposals.[3]

[3] https://www.ofgem.gov.uk/publications-and-updates/getting-more-out-our-electricity-networks-through-reforming-access-and-forward-looking-charging-arrangements

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Table 1: The main non-locational Embedded Benefits

Embedded Benefit	Description	Size (2018/19)	Smaller embedded generation	On Site Generation
Transmission Demand Residual	Smaller embedded generation can receive these payments from suppliers and National Grid. On-site generators can receive the same payments when exporting and can save demand users the same charges	£47/kW £350m/year cost to consumers	Phased out between 2018 and 2020 (CMP 264/265 decision)	Phased out for exporting on-site generation by CMP 264/265. Remainder addressed by proposed reform of T and D residual charges.
Transmission Generation Residual	Smaller embedded generation does not pay or receive the generation residual. Neither does on-site generation.	-£2.34/kW Payment to transmission generators increase size of Transmission Demand Residual and distorts wholesale markets	Addressed by proposed reforms of T and D residual charges.	Addressed by proposed reforms of T and D residual charges.
BSUoS charges: payments from suppliers	The demand BSUoS charge is based on a supplier's net consumption from the transmission system, so smaller embedded generation can offset demand and receive payments for reducing charges for suppliers. On-site generators can receive the same payments when exporting and can save demand users the same charges.	£2 to £2.5/MWh £100m to £150m per year additional to consumers	Addressed by proposed reforms to other Embedded Benefits	Addressed by proposed reforms to other Embedded Benefits for exporting on-site generation. Non-exporting on-site generation could be addressed in future if BSUoS is levied on similar basis to T and D residual charges.[4]

[4] If BSUoS were levied entirely on final demand on the same basis as the proposed Transmission and Demand residual charges, then the current BSUoS benefits to on-site generation would be removed. This will be considered further following the completion of the BSUoS task force.

Embedded Benefit	Description	Size (2018/19)	Smaller embedded generation	On Site Generation
BSUoS charges: avoided charges	Smaller embedded generation currently does not pay generation BSUoS charges	£2 to £2.5/MWh £100 to £150m per year additional to consumers	Addressed by proposed reforms to other Embedded Benefits.	Addressed by proposed reforms to other Embedded Benefits for exporting on-site generation. Non-exporting on-site generation could be addressed in future if BSUoS is levied on similar basis to T and D residual charges.[5]

1.7 There are other, smaller Embedded Benefits which are lower in value, shown in Table 2. We have not considered Residual Cashflow Reallocation Cashflow (RCRC) and Assistance for Areas with High Electricity Distribution Charges (AAHEDC) as candidates for reform since they are low in value and hence unlikely to be causing significant distortions.[6] Nor are we considering reforms to the treatment of transmission losses. An Embedded Benefit due to transmission losses exists for two reasons: smaller embedded generators avoid paying the generator share of transmission losses, and reduce the contribution suppliers must make to transmission losses. This benefit is approximately four times smaller than the total BSUoS Embedded Benefit. The introduction of zonal losses in April 2018 added cost-reflective forward-looking signals but does not remove this Embedded Benefit. We welcome views on our proposal not to address these smaller Embedded Benefits.

[5] Ibid

[6] Furthermore, the AAHEDC charge was introduced by the Energy Act 2004 and is levied on electricity supply by licenced suppliers, implemented via licence conditions.

Table 2: Lower priority Embedded Benefits

Embedded Benefit	Description	Size (2018/19)
Transmission Losses	Transmission losses are the difference between the volumes entering and exiting the transmission system. They are applied 45% to generation and 55% to suppliers and are derived for each half hour. Suppliers can offset smaller embedded generation against demand therefore the losses are applied over a smaller demand base. The locational element of losses (in place since April 2018) is cost-reflective and is not an Embedded Benefit as generation and demand are both affected. However, the non-locational element remains a small Embedded Benefit.	Metered volumes are scaled up by c. 1%. Net effect compared to transmission is approximately 2% increase in electricity income stream
Assistance for Areas with High Electricity Distribution Charges (AAHEDC)	Charge paid to assist Scottish Customers with the high cost of electricity distribution. Charge is applied as a single unit based charge to each supplier based on their settled consumption. Consumption derived after embedded generation deducted therefore becomes an Embedded Benefit. If the supplier does not have offsetting demand, the generation is treated as negative demand and a credit is received.	Estimated to be £9.1 m/year total in 2015/16[7]
Residual Cashflow Reallocation Cashflow (RCRC)	A surplus or deficit of funds remaining to be reallocated after settlement of charge in the Balancing Mechanism (BM). Expected to be small since implementation of single pricing for cash out	Varying – direction has changed with single pricing in BM. ~ -£10m. Small and uncertain in direction

1.8 A related benefit is the reduction in transmission charges for certain small generators, known as the Small Generator Discount. The Small Generator Discount was introduced[8] by the UK Government at the time of BETTA in 2005.[9] The aim of the discount was to create a level playing field between under 100MW 132kV transmission connected generators in Scotland and offshore generators, and those that are distribution connected at 132kV in England and Wales. The expiry date has been extended four times to date, with a current expiry date of 31 March 2019. We have considered the

[7] https://www.theade.co.uk/assets/docs/resources/A_review_of_Embedded_Generation_Benefits_in_Great_Britain.pdf
[8] https://www.ofgem.gov.uk/sites/default/files/docs/2004/05/6951_9604.pdf
[9] The British Electricity Trading and Transmission Arrangements (BETTA), joined the wholesale market in England & Wales to that in Scotland

appropriateness of the continuation of this discount in light of potential changes to Embedded Benefits. We propose to extend the Small Generator Discount while we are carrying out the review of the non-locational Embedded Benefits.

1.9 A further difference is that smaller generators are treated as 'negative demand' for the forward-looking transmission charges, which provides benefits in some locations and dis-benefits in others. However, with the introduction of the EET through CMP 264/265, smaller embedded generators are no longer exposed to charges (and only receive payments). This is being considered through our work on reform of electricity network access and forward-looking charges.

1.10 Embedded generators also do not pay transmission local charges, which are the charges to recover costs of local assets used to connect some generators (particularly offshore windfarms) to the transmission system. Currently, all local assets are used to directly connect generators to the transmission system without use of the distribution networks. However, if an embedded generator was connected to the transmission system via local assets, then we think it would make sense for such a generator to contribute to these local charges. This is also being considered through our work on reform of electricity network access and forward-looking charges.

1.11 We are proposing reforms to the main remaining non-locational Embedded Benefits, which result in difference between the revenues or costs of smaller embedded generation (and on-site generation) and larger generation, which does not reflect a difference in the value provided or cost imposed on the system. These are distortions, which negatively impact consumers in the following ways:

a) **Directly increased consumer costs:** Where some generators avoid residual charges, the avoided charges have to be recovered either from consumers overall through a higher per unit charge, or from other generators. Where smaller embedded generators (and exporting on-site generation) receive payments for helping suppliers reduce their residual charges (or receive payments directly from National Grid), or where larger generators receive a transmission residual payment, these payments are added onto consumer bills. Where higher per unit charges are levied on other generators, these charges costs will be largely passed through to consumers via wholesale costs (as set out below).

b) **Wholesale price and dispatch:** where the Embedded Benefit is received based on the amount of electricity generated, there is a distorted incentive for those receiving the benefit to run "out of merit" (generate ahead of lower cost generators) and hence distort dispatch. This has the effect of increasing whole system costs for consumers and failing to send efficient signals to the generators that should be running. This potentially also changes the balance between imports and exports on interconnectors.

c) **Capacity Market (CM):** Capacity Market prices are set by means of an auction through which eligible generation (mainly non-renewable generation) enters bids for the fixed annual payment they require, to either keep open an existing generator or build new capacity. Embedded Benefits that provide additional revenue can distort CM bids, increasing the apparent competitiveness of the generator and hence making this generator more likely to clear in the auction, at the expense of capacity which is more cost-effective.

d) **Contracts for Difference (CfDs):** Low carbon generators bid for CfDs in the CfD allocation process. Those generators receiving an Embedded Benefit may bid a lower required Strike Price, and hence receive contracts ahead of other more cost-effective generation and distort awarded Strike Prices.

e) **Inefficient investment in generation capacity:** as a result of the effects above, decisions to build generation capacity will not result in the most efficient capacity mix, and hence whole system costs will be increased.

f) **Ancillary services:** Embedded Benefits will lead to some parties having a competitive advantage when bidding for ancillary services contracts.

1.12 We believe the distortions outlined above lead to higher consumer costs. Generators that are more efficient could be pushed out of the market, while consumers have to pay additional money to allow suppliers to reduce their residual charges. As the amount of money recovered through residual charges is largely fixed over the short to medium term, where these charges are avoided, they will have to be picked up by other users. If they are picked up by generators, they may be passed through to consumers via the impact on prices in wholesale markets. In addition, payments could lead to inefficient investment in network capacity. Inefficient investment in generation connected to either the transmission or distribution networks would lead to inefficient additional network investment, raising costs to consumers.

1.13 In our CMP 264/265 Impact Assessment and Decision (and preceding documents), we clearly stated that benefits gained from charging smaller embedded generators in this way were inappropriate and that whilst we were prioritising the largest and most immediate issue, we intended to address other Embedded Benefits through the TCR.[10] Our view is that smaller EG can offset the need for reinforcement which arises from an increase of demand at each Grid Supply Point (GSP) – the point where the transmission and distribution networks meet. We therefore consider payments that reflect these savings (known as the Avoid Grid Infrastructure Cost, AGIC) to be cost reflective. The evidence we received did not present clear evidence of additional benefit brought to the transmission system over and above this level.

Decision making framework

1.14 We have used the same framework for assessment of reforms to the remaining non-locational Embedded Benefits as for the assessment of options to reform the charging of transmission and distribution residuals. The principles have been applied as follows:

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[10] For example, we stated in our Open Letter on Embedded Benefits (July 2016) that "A negative residual charge prevents generators facing the full costs they impose on the transmission system, effectively subsidising all generators that pay TNUoS charges. We do not consider that this is consistent with the aim of a well-functioning wholesale market "

a) **Reducing harmful distortions:** this is the major consideration for options for reform of Embedded Benefits, since these Embedded Benefits can be shown to have significant distortions as described above. Our analysis of the distortions and wider system impacts is used to assess options for reform against this principle.

b) **Fairness:** as we set out in our TCR Launch Statement, we are considering 'fairness' as it applies to, and between, end-consumers (and by extension, charges to suppliers as a proxy for fairness to consumers). We think that reasonable treatment of industry parties is appropriately covered under our 'reducing distortions' principle, which will facilitate a level playing field between competing network users, and under proportionality and practical considerations, which includes consideration of the potential effects of material changes to charges.

c) **Proportionality and practical considerations:** the options considered are assessed based on their practicality, the likely cost (at a high level) and hence the overall proportionality of the changes (which can be weighed against the expected benefits of the change). As set out below, the options considered generally constitute a low level of industry change (from the perspective of practicality and cost) relative to the changes to the charging of transmission and distribution residuals, and hence practicality and cost are less likely to be critical factors.

1.15 All of the principles and their application to reforming the remaining non-locational Embedded Benefits have been considered in the context of our principal objective and statutory duties.

Remaining Embedded Benefits considered

1.16 We have considered reform of three of the remaining Embedded Benefits: two related to BSUoS charges, and one related to the Transmission Generation Residual. These arrangements provide differing degree of benefits to different types of generators. We show illustrative examples later in this Annex, in Figure 2.

BSUoS Embedded Benefits

1.17 Balancing services are charged to generators and suppliers through Balancing Services Use of System (BSUoS) charges, based on their generation or net demand on the transmission system. Hence, the costs of BSUoS charges are recovered approximately 50:50 from generators and suppliers. There are two types of Embedded Benefits that relate to BSUoS charges:

a) **BSUoS charges: payments** - smaller embedded generators can get paid for helping suppliers reduce their contribution to the costs of balancing the system.[11]

[11] Exporting on-site generation can also receive these payments, so references to smaller embedded generation is assumed to be included in the description of this benefit.

Suppliers pass on most of these savings to smaller embedded generators through contractual arrangements and then recover the cost of these payments from customers. These payments directly add to consumer costs.

b) **BSUoS charges: avoided charges** – smaller embedded generators[12] also avoid paying generation BSUoS charges, which all other generators connected to transmission and distribution networks are required to pay.

1.18 We have set a clear expectation through our previous work on Embedded Benefits that this way of charging gives smaller embedded generators an undue advantage against other types of larger generators.

1.19 When we launched the TCR, we indicated if BSUoS charges remain a cost-recovery charge, it would make sense to consider aligning charging for BSUoS with any reformed transmission and distribution residual charging arrangements developed as part of the SCR. We now think that a further review of BSUoS is needed before this change can be considered.

1.20 Our consultation on Access Reform proposed setting up a BSUoS charges task force. Having analysed responses to that consultation, we have asked the ESO to launch a task force to provide analysis to support decisions on the future direction of BSUoS charges.[13] In particular, it will examine the potential and feasibility for some elements of balancing charges being made more cost-reflective and hence provide stronger forward-looking signals, and is due to report its findings in spring 2019.

1.21 On conclusion of this work, further consideration can be given to the treatment of any BSUoS charges which will remain principally cost recovery charges. We have therefore limited our consideration to options which remove the BSUoS Embedded Benefits without changing the overall structure of these charges. One implication is that, ahead of any future changes arising from the task force, non-exporting on-site generation will continue to benefit from avoiding BSUoS charges and reducing balancing charges for on-site demand. However, our proposed reforms will address the distortions related to balancing payments for exporting on-site generation. Alongside this, our proposed reforms to transmission and distribution residual charges will address other areas of difference in charging between on-site generation and directly-connected generation.

1.22 We will consider the report from the task force carefully in the context of the TCR and the responses to this consultation. This will include consideration of the relationship with any potential changes to the BSUoS Embedded Benefits.

Transmission Generator Residual Embedded Benefits

1.23 The current methodology for charging transmission residuals to generation currently results in larger generators (those over 100MW) receiving a fixed rebate (ie a negative charge) for being connected to the system. This results from the implementation of a

12 On-site generation avoid all network charges, including BSUoS charges to generators.

13 Published alongside this consultation

cap on the average level of transmission network charges which generators should pay. Smaller embedded generators do not receive this rebate (negative charge), and are now at a disadvantage to larger generators. In the past, this different treatment resulted in a benefit to smaller embedded generators.

1.24 The cap is set out in European Commission Regulation 838/2010[14], which sets a range for average transmission charges for generators of 0 to €2.50/MWh. We recently set out that the definition being used to calculate this payment was incorrect (through our decision on a code modification referred to as CMP 261[15]). This decision was challenged and successfully defended at the Competition and Markets Authority (CMA). Whilst the Transmission Network Use of System (TNUoS) charging methodology has not yet been changed, the implication is that the Transmission Generation Residual charge should currently be positive, not a rebate.

1.25 Within this Consultation, we consider the option of setting the Transmission Generation Residual to zero. This would align with our proposal to charge residuals to final demand only, as set out in Section 8 of our Consultation. It would also align with the changes required to the TNUoS methodology in order to align with the correct interpretation of 838/2010. We envisage that the Transmission Generation Residual would be zero. A separate adjustment may be required to maintain average transmission generation charges within the range 0 to €2.50/MWh. This would be zero unless required.

Options considered for reforming remaining Embedded Benefits

1.26 Our 'baseline' for considering our proposed changes to the remaining Embedded Benefits is the arrangements resulting from the implementation of the proposed solution for transmission and distribution residuals in 2020[16] in order to show the interaction between the two proposed reforms. We set out the combined impact of the two reforms in Annex 7. Against this baseline, we considered two combinations of reform to the three Embedded Benefits described above.

1.27 In all cases, we propose that the Transmission Generation Residual should be set to zero in order to comply with our decision on CMP 261 and with our proposed principle that residuals should be charged to final demand. We ruled out the option of removing the Transmission Generation Residual benefit only, on the basis that it would remove a benefit to larger generators while leaving the two benefits favouring smaller embedded generators in place. Our analysis indicates this would lead to a worsening in the comparative treatment of these types of generators.

1.28 We think that alongside the removal of the Transmission Generation Residual, we should remove one or both of the BSUoS Embedded Benefits for smaller embedded

14 https://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=OJ:L:2010:250:0005:0011:EN:PDF
15 https://www.ofgem.gov.uk/publications-and-updates/cmp261-ensuring-tnuos-paid-generators-gb-charging-year-201516-compliance-25mwh-annual-average-limit-set-eu-regulation-8382010-part-b-3
16 In addition to the changes implemented under CMP 264/5 to remove the TDR Embedded Benefit for smaller embedded generators.

generation. We have therefore considered two reform packages for these Embedded Benefits:

a) **TGR & partial BSUoS reform:** TGR reform and removing the ability of smaller embedded generators to receive payments from reducing suppliers' contributions to BSUoS charges.

b) **TGR & full BSUoS reform:** TGR reform, removing the BSUoS payments, and requiring smaller embedded generators to pay BSUoS charges.

1.29 These options are shown in Table 3.

Table 3: Reform options for the remaining non-locational Embedded Benefits

Embedded Benefit removed	TGR & Partial BSUoS reform	TGR & Full BSUoS reform
BSUoS payments to smaller embedded generation	√	√
BSUoS charges to smaller embedded generation		√
Reforming the Transmission Generation Residual	√	√

1.30 At a high level, removing the BSUoS Embedded Benefits would reduce revenues and increase costs for smaller embedded generators, and reforming the Transmission Generation Residual would reduce revenues for larger generators. Our assessment indicates that equivalence between smaller embedded generation and larger generators would be reached by removing both Embedded Benefits related to BSUoS charges: the avoided charges and the payments received from suppliers. Consumers will benefit from these changes from both reduced payments to smaller embedded generators and improved system efficiencies over time.

1.31 Our analysis of both options is relative to a baseline option which assumes our proposed changes to the transmission and distribution residuals are implemented in 2020. This is the Full reform scenario, as described in section 5. In the following sections, we first consider comparisons of these Embedded Benefits for different illustrative generation types, and then present wider system modelling for the two options. We then consider the assessment against our TCR principles, before making our overall assessment.

1.32 We consider implementation options for reform of these Embedded Benefits in April 2020, April 2021 and a phased implementation from 2021 to 2023. Earlier implementation is likely to lead to greater savings for consumers and removes distortions earlier, but has earlier impacts for particular generation types.

Treatment of on-site generation

1.33 The proposed reforms to the transmission (and distribution) residual charges and the proposed reforms to the Transmission Generation Residual Embedded Benefit would remove the differential treatment of on-site generation compared to other generation in respect of these transmission residual charges. This is because no forms of generation would pay transmission generation residual charges and no forms of generation would receive payments/benefits from transmission demand charges.

1.34 However, the proposed reforms for BSUoS would leave some potential benefits for non-exporting on-site generation compared to other forms of generation since:

a) Non-exporting on-site generation would continue to benefit from avoiding paying generation BSUoS, alongside avoidance of network and policy costs in general; and

b) Non-exporting on-site generation would continue to receive benefits from helping to reduce demand BSUoS for the site on which it is located.

1.35 In relation to these potential benefits, it is important to note that:

a) exporting on-site generation is similar to similarly-located metered generation (directly connected to the transmission or distribution network) from a network usage perspective and receives equivalent treatment under our proposals;

b) non-exporting on-site generation is similar to demand side response from the perspective of network usage and impacts, and in fact cannot usually be discernible from the measured impacts of network usage;

c) displacement effects mean that from the perspective of system operation, a unit of demand reduction has a similar effect as a unit of increased generation in the same location, regardless of whether it is metered or not;

d) it is important that forward-looking charges reflect a user's impact on future network costs and incentivise users to change their behaviour where this will lead to lower costs. Since residual charges need to avoid creating undue distortions, they should not encourage users to take action to avoid paying them.

e) our proposed approach to transmission and distribution residual charges addresses these issues, and if applied to BSUoS charges, would also address these issues in respect of BSUoS charges; and

f) we will consider the recommendations from the BSUoS task force alongside the responses to this consultation in making our final decisions on the proposals set out in this document, and in deciding whether further changes to BSUoS outside of the SCR should take place.

Assessment of remaining non-locational Embedded Benefits

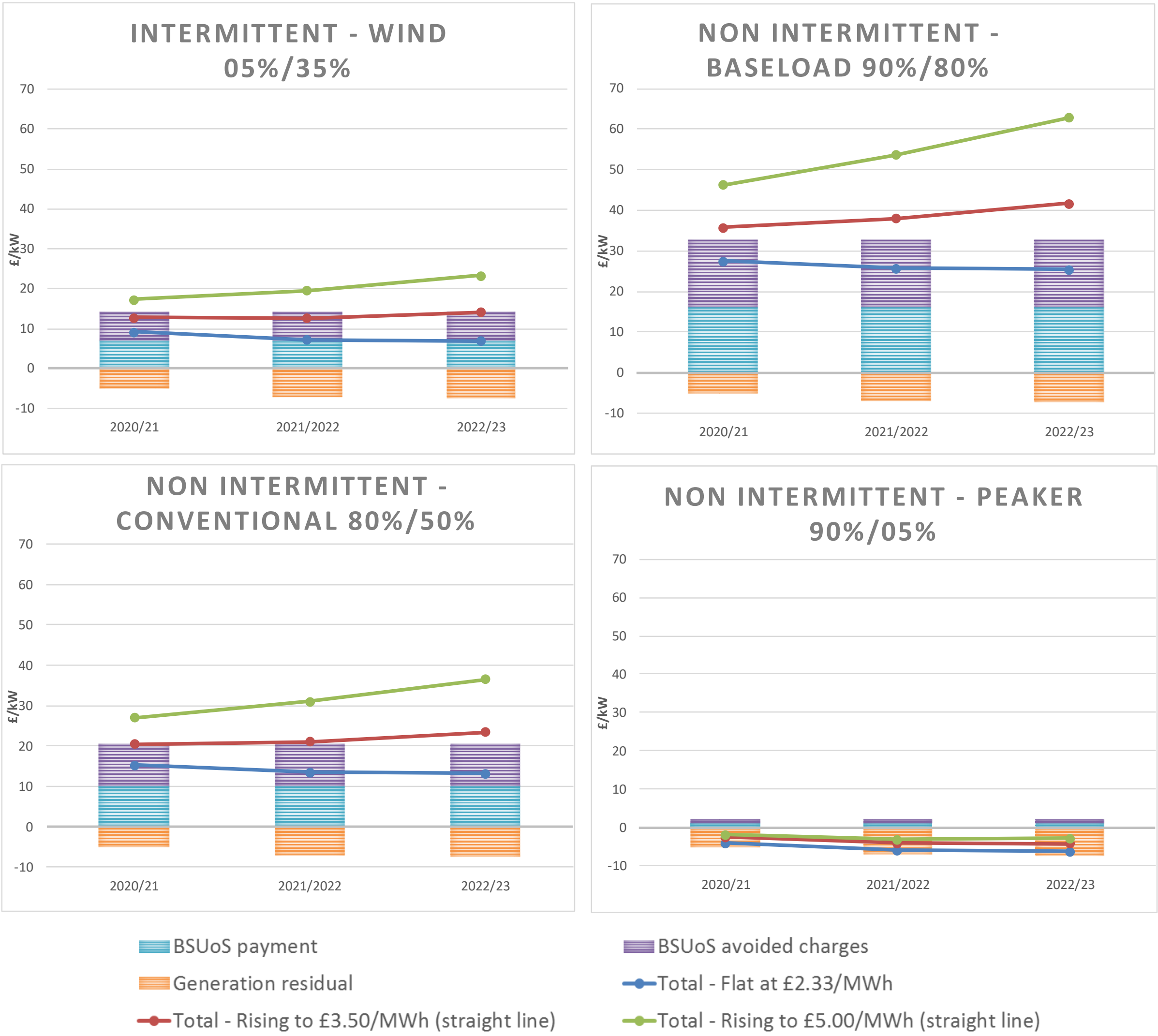
1.36 We have analysed the net impact of the level of these three Embedded Benefits using four different illustrative generation scenarios. This does not include the Embedded Export Tariff (EET) introduced as part of CMP264/265 as of 1st April 2018, since the residual element of this tariff is being phased out by April 2020. We conducted the assessment for four illustrative generation types shown in Table 4.

Table 4: Illustrative generation scenarios

Illustrative scenario name	Generator type	Peak output	Annual load factor
Intermittent	Wind	5%	35%
Non-intermittent 90/80	Baseload	90%	80%
Non-intermittent 80/50	Conventional (carbon)	80%	50%
Non-intermittent 90/05	Peaker	90%	5%

1.37 We have found that current Transmission Generation Residual and BSUoS charging arrangements continue to provide most smaller embedded generators with a competitive advantage relative to larger generation (Figure 2). The relative benefit is larger for high load factor technologies (since the BSUoS Embedded Benefits are received on a per MWh basis). The only one of the four illustrative generation types where the overall benefit is negative is the peaker type, with a low annual load factor.

Figure 2: Illustrative remaining non-locational Embedded Benefits for generation types[17]



1.38 The analysis indicates the distortion due to the remaining non-locational Embedded Benefits continues to be significant in a number of cases. We can conclude from the analysis above that in most cases, the overall benefit to smaller embedded generators is positive for our illustrative generation types.

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17 Source National Grid TNUoS forecast (November 2017), Ofgem analysis. For the purpose of this analysis, we use an average BSUoS level of £2.33/MWh. These are illustrative scenarios only, and do not necessarily reflect the actual Embedded Benefits realised by any particular smaller EG. Neither do they account for the locational elements of charges. In all of these scenarios, for simplicity it is assumed that the full embedded benefit is passed onto the generator. These values exclude the Embedded Export Tariff (including the Avoided Grid Infrastructure Cost which is currently £3.32/kW)

Wider system modelling

1.39 To support our principle-based assessment, we commissioned wider system modelling of the policy options for removal of Embedded Benefits, using the same model as used to assess the reform of transmission and distribution residuals. Further detail on this analysis can be found in the Frontier/LCP report[18]. The options modelled are shown in Table 5, and include two Future Energy Scenarios (FES) background scenarios (Steady Progression (SP) and Community Renewables (CR)). All options are modelled against a baseline assuming reform to transmission and distribution residuals is implemented in 2020, which is the earliest date we have considered for these reforms. We are consulting on a range on implementation options for reforms to transmission and distribution residual reform.

Table 5: Modelled options for reform of Embedded Benefits

Name	FES Background	EB reform option	Implementation date
SP TGR & Full BSUoS reform	Steady Progression	TGR & Full BSUoS reform	2020
CR TGR & Full BSUoS reform	Community Renewables	TGR & Full BSUoS reform	2020
SP TGR & Partial BSUoS reform	Steady Progression	TGR & Partial BSUoS reform	2020
CR TGR & Partial BSUoS reform	Community Renewables	TGR & Partial BSUoS reform	2020

1.40 The modelling also includes the following implementation option for the Embedded Benefits:

a) One year delay to 2021 for both reform Options (SP and CR)

b) Implementation over 2021-23, for the TGR & Full BSUoS reform (modelled for SP only)

1.41 Overall the modelling provides estimates of the impacts on System Costs and Consumer Costs, as shown in Table 6. System Costs represent the expected cost of running the GB electricity system[19]. Consumer costs represent the costs faced by electricity consumers in their electricity bills.[20] A negative cost means a reduction in cost, in other words this is a benefit.

18 Frontier and LCP, *wider system impact of TGR and BSUoS reforms*
19 This includes, fuel costs, variable and fixed operational and maintenance costs, capital costs, carbon costs (priced at appraisal value) and the cost to society of any expected energy unserved.
20 This includes wholesale energy costs, network charges, renewable subsidies, capacity market payments and any other charges passed on by suppliers, such as the triad avoidance payments made to on-site generation.

Table 6: Modelled System Costs and Consumer Costs for implementation in 2020[21]

Name	System Cost (NPV 2019-2040, £bn)	Consumer Cost (NPV 2019-2040, £bn)
SP TGR & Full BSUoS reform	-0.11	-4.52
CR TGR & Full BSUoS reform	0.10	-5.99
SP TGR & Partial BSUoS reform	-0.03	-3.33
CR TGR & Partial BSUoS reform	0.16	-4.11

1.42 The impact on system costs is relatively small. There is some change in generation build, as a result of the change in competitiveness between CCGT and on-site and peaking generation (which is quite finely balanced due to offsetting effects from the removal of the different Embedded Benefits), and some reduction in the development of smaller embedded storage.

1.43 Both reform options reduce consumer costs under both scenarios modelled. This saving is significantly larger than the impact on system costs. Consumers see a direct saving in TNUoS payments through the reduction in their transmission charges (specifically, in the Transmission Demand Residual which no longer needs to recover the TGR payments). They also see a direct saving in BSUoS payments due to the expansion of the charging base and consequent reduction in the unit charge. The impact of these changes (before any dynamic impacts from changes to capacity market prices, CfD strike prices or generator investment decisions) is as follows:

a) Transmission Generation Residual: £7 to 8/kW (via reduction in TDR)

b) BSUoS charges - payments: £0.25/MWh reduction in 2021 in BSUoS charge due to suppliers being charged for a larger amount of demand, with an additional similar sized impact expected from a reduction in wholesale prices due to a reduction in the charges paid by larger generation.

c) BSUoS charges - avoided charges: a further £0.21/MWh reduction in 2021 in BSUoS charge due to smaller embedded generation paying charges, with an additional similar sized impact expected from a reduction in wholesale prices due to a reduction in the charges paid by larger generation.

1.44 The changes to the Embedded Benefits lead to changes in the profitability of generation types. The modelling assumes responses from generators through changing bidding in the wholesale market, Capacity Market and in the allocation of renewables support from Contracts for Difference.

1.45 Table 7 sets out the expected impacts of removal of each of the three Embedded Benefits, for some illustrative generation types. The most affected generation types are

21 Source: Frontier/LCP. Real 2016 terms

likely to be those that see a loss as a result of the changes. This includes existing larger renewable generation supported under either the Renewables Obligation (RO) or Contract for Difference feed-in tariff (CfD). Increases in costs for these generators are as a result of the removal of the Transmission Generation Residual credits. Existing smaller embedded renewables are also impacted due to loss of the BSUoS avoided payments and the introduction of BSUoS charges for smaller embedded generation.

Table 7: Potential impact on different generation types

Generation type	TGR set to zero	Smaller embedded generation does not receive BSUoS payments	Smaller embedded generation charged BSUoS
Larger generation, CM eligible	Loss from increased transmission charges. Likely to lead to increased CM bid prices and therefore offset by CM prices	Becomes more competitive relative to smaller embedded generation, and relative to interconnectors	Becomes more competitive relative to smaller embedded generation, and relative to interconnectors
Larger renewables (CfD)	Loss from increased transmission charges. For CfD generation with agreed contracts, not offset by other effects. For new CfD generation, expect Strike Prices to increase	No net impact (assuming Balancing Cost adjuster term in CfD for larger generation)	No net impact (assuming Balancing Cost adjuster term in CfD)
Larger renewables (RO)	Loss from increased transmission charges. No offsetting effect.	Becomes more competitive relative to smaller embedded generation, and relative to interconnectors	Becomes more competitive relative to smaller embedded generation, and relative to interconnectors
Smaller embedded generation, CM eligible	Increases relative competitiveness in CM auction	Decreases relative competitiveness in CM auction and in wholesale market	Decreases relative competitiveness in CM auction and in wholesale market
Smaller embedded renewables (CfD)	Become more competitive in CfD allocation relative to larger CfD projects (new only). No direct impact for existing.	For existing generation, loss of value of BSUoS (assuming no change to the CfD). New – expect Strike Prices to increase	For existing generation, loss of value of BSUoS (assuming no change to the CfD).[22] New – expect Strike Prices to increase
Smaller embedded renewables (RO)	No direct impact, since these generators do not compete in CM auction	Loss of value of BSUoS (loss of payments from suppliers)	Loss of value of BSUoS (charged BSUoS)
On-site generation (unspecified)	May benefit from higher CM prices or higher Capacity Market Supplier Charge	Lower BSUoS unit charge (due to larger charging base) reduces on-site generation benefit. Lose BSUoS benefit on any export	Lower BSUoS unit charge (due to larger charging base) reduces on-site generation benefit. May make BSUoS payments on any export

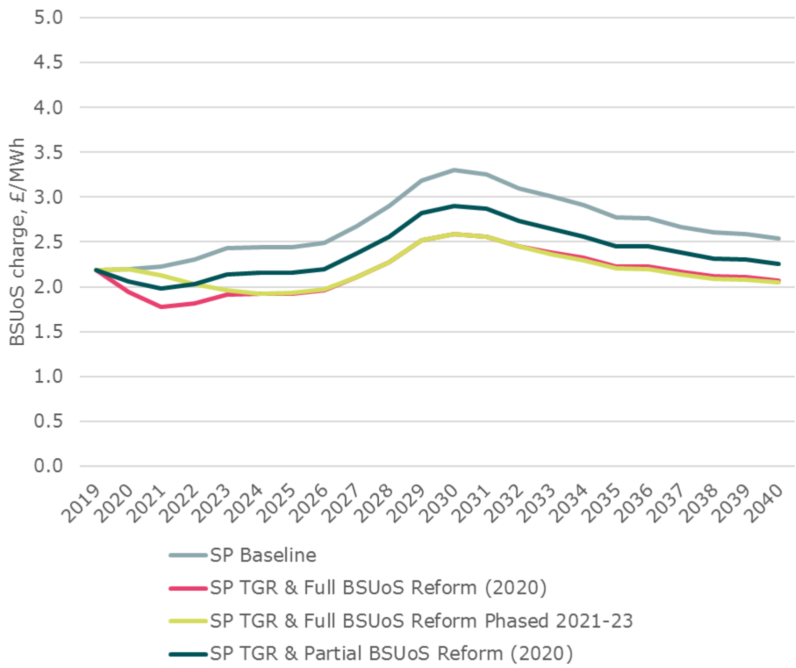
[22] The wider systems modelling assumes that CfD generators which did not previously pay BSUoS charges receive an adjustment to their CfD to offset this change. Our understanding is that these parties do not typically have Balancing Cost Adjuster terms in their CfDs.

1.46 In the following sections we describe the results for TGR & Full BSUoS reform in a Steady Progression scenario. We then turn to the other modelled cases and then consider a number of implementation options.

Steady Progression TGR & Full BSUoS reform

1.47 Figure 3 shows the change in the BSUoS charge (levied on generation and demand) relative to the baseline under three reform options. The larger charging base for BSUoS leads to a reduction of around 20% in BSUoS charges in £/MWh terms under TGR & Full BSUoS reform.

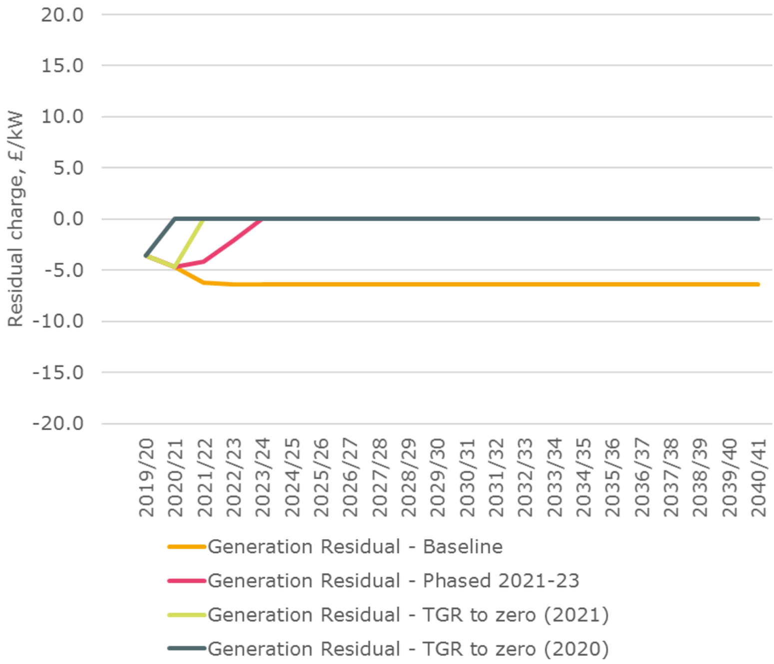
Figure 3: Change in BSUoS charges (Steady Progression)[23]



1.48 Figure 4 shows the change in the Transmission Generation Residual under three reform options. In the baseline, the Transmission Generation Residual is forecast to increase over time. Setting the Transmission Generation Residual to zero means that these costs do not have to be recovered in the Transmission Demand Residual charge and hence has the impact of reducing the Transmission Demand Residual by approximately £7-8/kW (real 2016 terms).

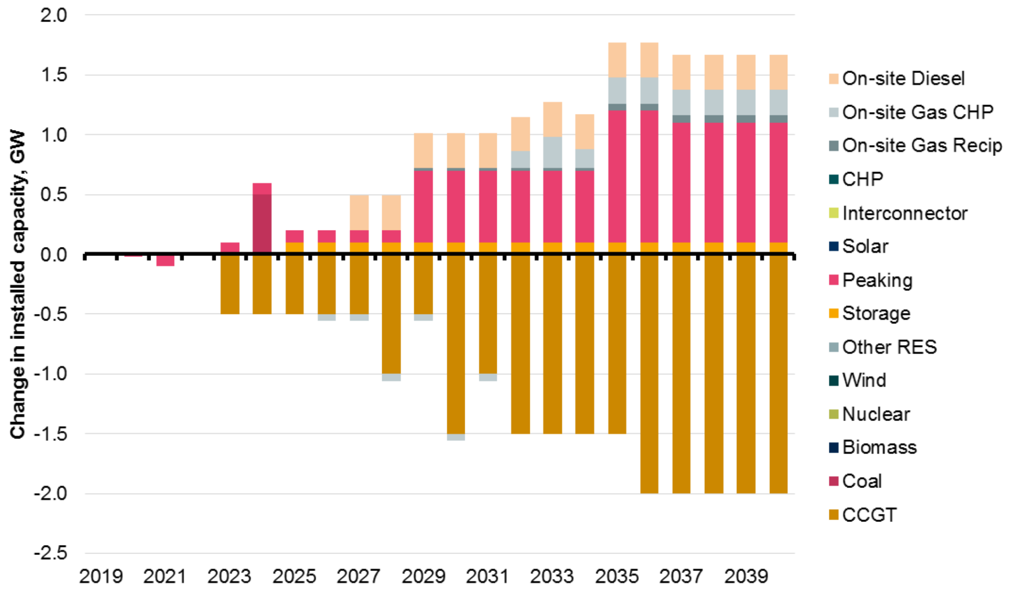
23 Source: Frontier/LCP. Real 2016 terms

Figure 4: Change in Transmission Generation Residual (Steady Progression, TGR & Full BSUoS reform)



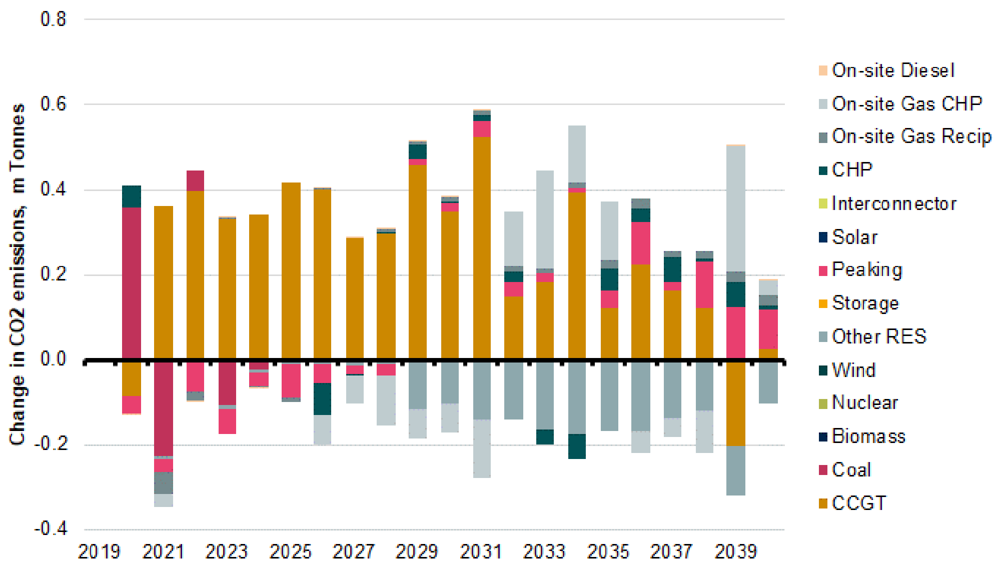
1.49 The change in capacity mix is a reduction in the amount of transmission-connected capacity with CCGT units being displaced by a mixture of distribution-connected peaking and on-site generation (Figure 5). The removal of the Transmission Generation Residual changes the relativity between CCGT and competing forms of generation, and some CCGT is replaced by peaking capacity and on-site generation.

Figure 5: Change in generation build and retirement (Steady Progression, TGR & Full BSUoS reform)[24]



1.50 Changes in annual carbon dioxide emissions are shown in Figure 6. Emissions increase in all years by an average of around 0.2m tonnes/year, with an important driver being the increase in domestic generation. Net imports decreases because the advantage of interconnectors (which do not pay BSUoS) over larger generation decreases. Within the modelling, non-GB emissions are not accounted for which means that the overall impact on total carbon dioxide emissions cannot be established from the modelling.

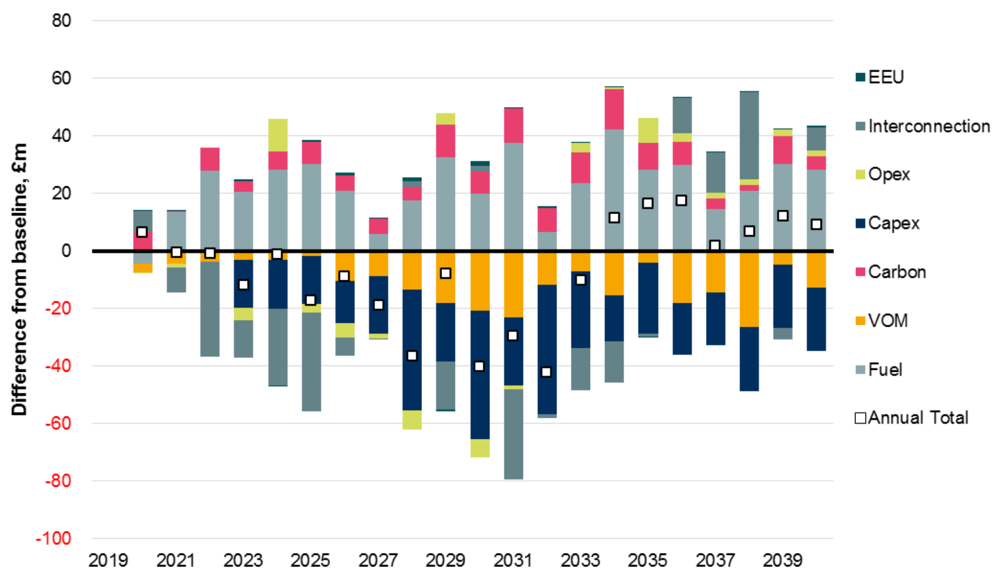
Figure 6: Change in carbon dioxide emissions (Steady Progression, TGR & Full BSUoS reform) [25]



24 Source: Frontier/LCP
25 Source: Frontier/LCP

1.51 System cost changes are shown in Figure 7. Overall there is a system cost saving with the net cost of interconnection falling and capex spend reducing. This is partially offset by an increase in fuel and emissions costs. The changes in the investment in new capacity and in closures is small, and hence changes in system costs are small. This results in a small overall system cost decrease of £0.11bn in NPV terms to 2040.

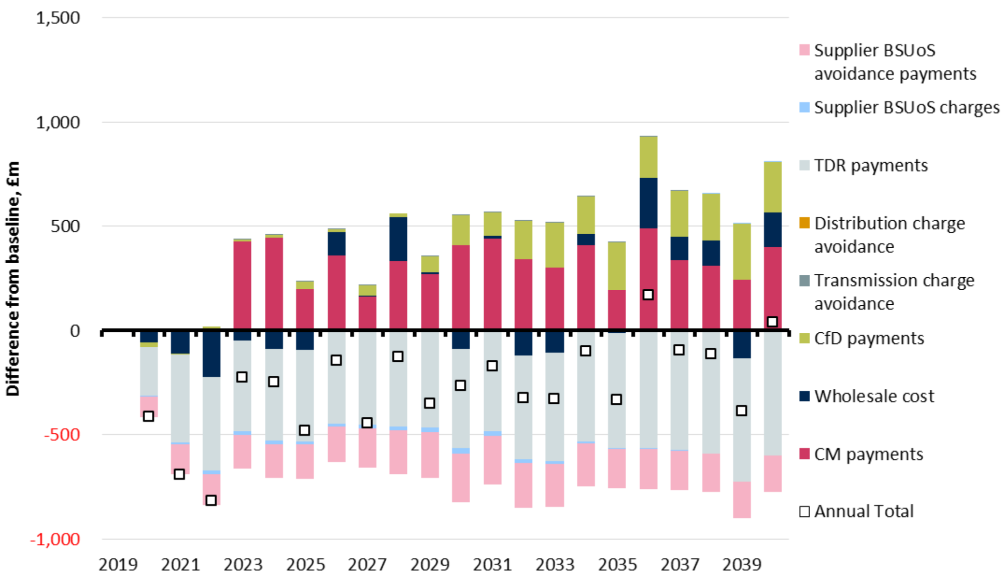
Figure 7: changes in System Costs (Steady Progression, TGR & Full BSUoS reform)[26]



1.52 The consumer cost savings are shown in Figure 8. In the first full year of implementation, there is an annual saving of almost £700m from the reductions in BSUoS and TNUoS payments, and consequent reductions in wholesale costs. Savings from reduced TNUoS and BSUoS continue throughout the scenario. From 2023, these benefits are partially offset by increases in CM payments (due to higher clearing prices set by transmission generators which have seen an increase in TNUoS charge) and increases in CfD payments, due to higher Strike Prices being set in the allocation rounds. There is a net saving in most years, although this is reduced by the end of the modelling horizon.

26 Source: Frontier/LCP. Real 2016 terms

Figure 8: Consumer cost changes (Steady Progression, TGR & Full BSUoS reform)[27]



1.53 The large reductions in TDR payment and in demand BSUoS payments are offset to some extent by increases in Capacity Market costs and CfD payments, but the net result is a significant saving to consumers of £4.52bn (NPV to 2040).

1.54 The impacts on different generation types is shown in Table 8. Most forms of generation are negatively affected in the near term, ahead of any changes to Capacity Market prices or CfD strike prices. The majority of the reduction in generator revenues falls on existing renewables supported under the Renewables Obligation. Larger RO-supported generation loses out due to the increase in transmission charges, whereas smaller RO-supported generation loses out due to the loss of both elements of the BSUoS Embedded Benefit. In both cases, the size of the benefits available continues to increase in the baseline compared to today's levels. The impact on existing CfD generators is mitigated by the assumption of an increase in Strike Prices to account for the charging of BSUoS to these generators.

27 Source: Frontier/LCP. Real 2016 terms

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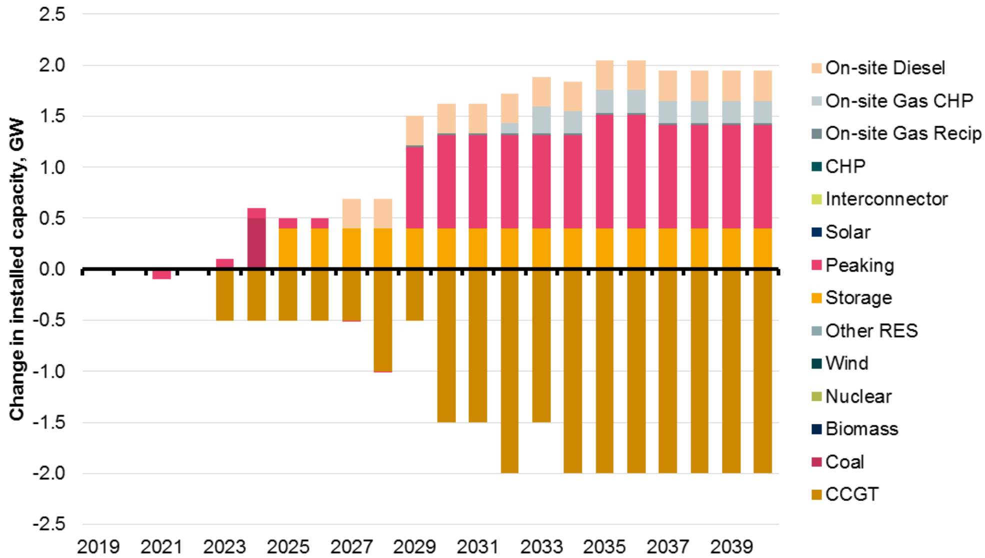
Table 8: Impacts by generation type (Steady Progression, TGR & Full BSUoS reform)[28]

Generator group	Overall impact, £bn NPV (2019-2040)	Capacity in group (GW)	Explanation
Larger generation in CM, 2020-22	-0.7	43.2 (2023)	CM capacity is unable to recover TGR increases in 2020-22 through the CM
Larger generation in CM, 2023-40	-0.3	43.2 (2023)	From 2023, CM capacity recovers majority of TGR increase through higher CM prices
Smaller embedded generation in CM, 2020-22	-0.1	7.8 (2023)	CM capacity is unable to recover BSUoS increases in 2020-22, but impact is limited due to low load factors of these generators
Smaller embedded generation in CM, 2023-40	0.3	7.8 (2023)	SEG benefits from higher CM prices (set by larger generator bids), offsetting increased costs due to BSUoS charging
CM Other (Interconnectors and On-site generation)	0.8	9.9 (2023)	Interconnection & on-site generation benefit from higher CM prices
Larger generation, Renewable Obligation (RO)	-1.4	15.0 (2019)	RO plant are unable to recover TGR increase
Larger generation, CfD - online	-0.2	2.3 (2019)	Online CfD plant are unable to recover TGR increase
Larger generation, CfD - contracted not yet online	-0.5	9.3 (max)	CfD plant already contracted (but not online) are unable to recover TGR increase
Larger generation, CfD - future	0.2	35.3 (max)	Future CfD build is able to recover TGR increase through higher Strike Prices
Smaller embedded generation in RO	-2.5	15.8 (2019)	Smaller embedded RO plant are unable to recover increased costs due to BSUoS charging and loss of BSUoS avoidance charges
Smaller embedded generation in CfD-online	-0.0	0.2 (2019)	Only small amount of online CfD capacity is smaller embedded generation. Can recover BSUoS charges (Strike Price adjustment) but not loss of BSUoS avoidance payments
Smaller embedded generation in CfD-contracted not online	-0.0	0.2 (max)	Only small amount of contracted CFD capacity is smaller embedded generation. Can recover BSUoS charges (via Strike Price adjustment) but not loss of BSUoS avoidance payments
Smaller embedded generation in CfD - future	-0.1	11.7 (max)	Future CfD build is able to recover BSUoS costs through higher Strike Prices
Total impact	**-4.4**		Aligns closely to full consumer benefit (£4.52bn), minus the system cost saving (£0.11bn)

Slow Progression TGR & Partial BSUoS reform

1.55 Under this option, smaller embedded generation is not charged for BSUoS, which leads to these generators retaining a relative benefit compared to larger generation. Hence, there is greater displacement of CCGT than under the TGR & Full BSUoS reform option (Figure 9).

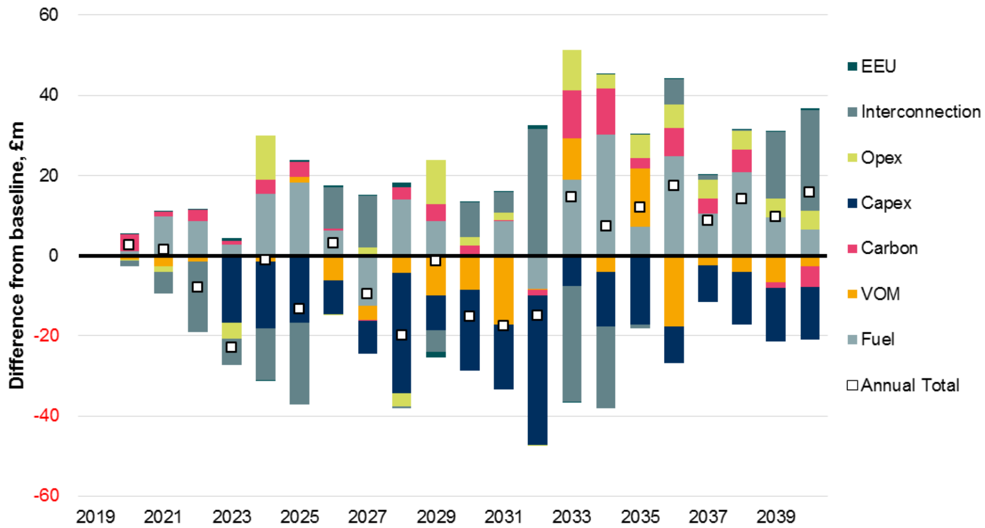
Figure 9: Change in generation build and retirement (Steady Progression, TGR & Partial BSUoS reform, 2020 implementation)[29]



1.56 Figure 10 shows the system cost saving under TGR & Partial BSUoS reform. Savings in capital expenditure from the reduction in CCGT build are partially offset by increases in fuel and variable operations and maintenance costs. The modelled saving in NPV terms is small, at £0.03bn.

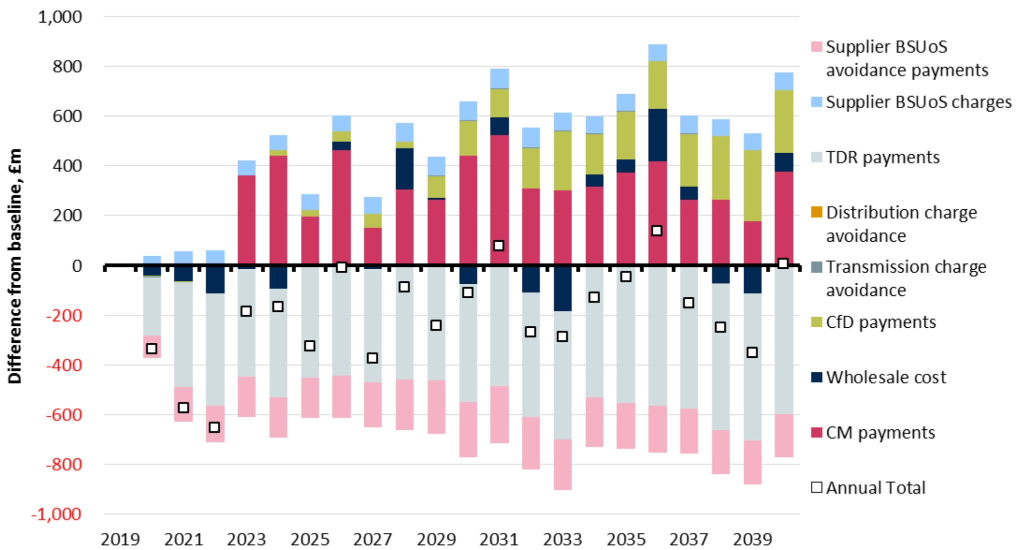
28 Source: Frontier/LCP. Real 2016 terms. This specific element of the analysis only considers the direct impact of the changes to BSUoS and TGR charges, and the recovery of these charges through the CM and CFD mechanisms. It does not account for any second order impacts, such as changes in wholesale prices.
29 Source: Frontier/LCP.

Figure 10: System cost changes, (Steady Progression, TGR & Partial BSUoS reform, 2020 implementation)30



1.57 The consumer cost saving (Figure 11) under TGR & Partial BSUoS reform is smaller than under TGR & Full BSUoS reform, due to smaller embedded generation still receiving an Embedded Benefit. The consumer cost saving is £3.34bn in NPV terms, compared to £4.52bn under TGR & Full BSUoS reform.

Figure 11: Consumer cost changes (Steady Progression, TGR & Partial BSUoS reform, 2020 implementation)31

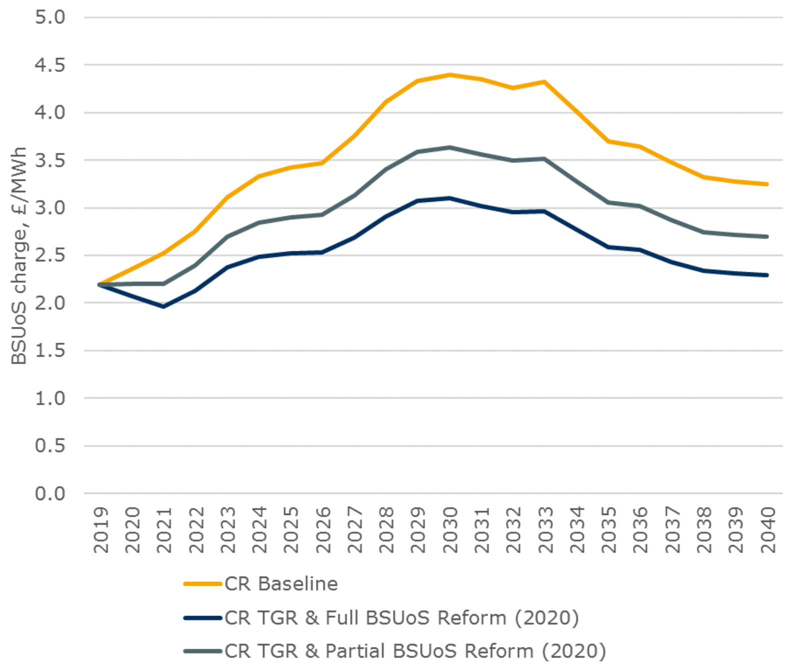


30 Source: Frontier/LCP. Real 2016 terms
31 Source: Frontier/LCP. Real 2016 terms. Note that the apparent increase in supplier BSUoS charges is offset by reductions to BSUoS charges on generation, which are passed into wholesale prices and seen by consumers as an offsetting decrease in wholesale costs.

Community Renewables

1.58 Community Renewables has a greater proportion of intermittent renewables leading to higher projected BSUoS costs. The Embedded Benefits from the BSUoS are therefore larger. Figure 12 shows the profile of BSUoS charges (which are equal for generation and demand) and the reduction through TGR & Full BSUoS reform and TGR & Partial BSUoS reform.

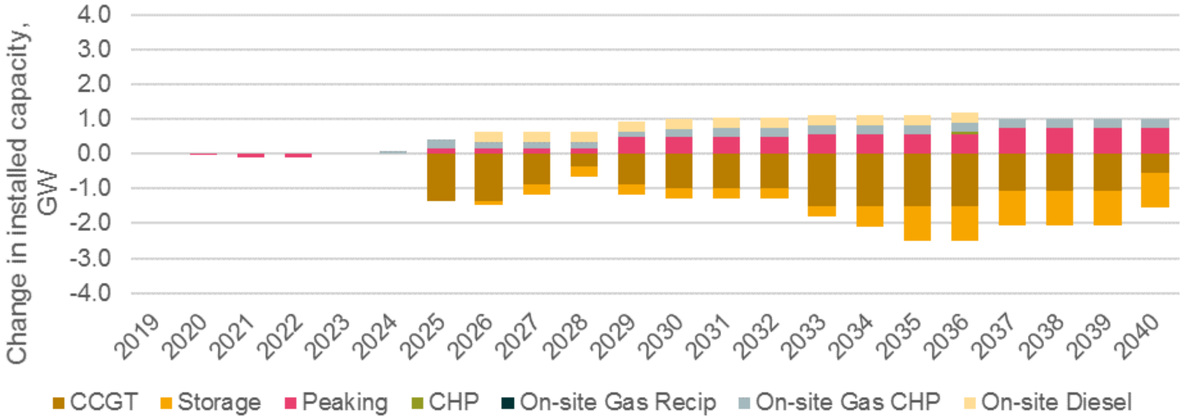
Figure 12: Change in BSUoS charges (Community Renewables)[32]

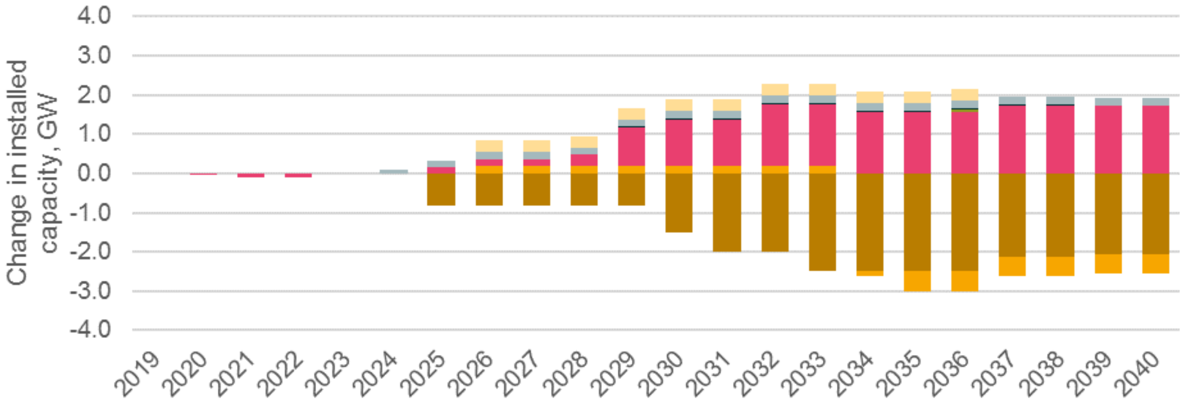


1.59 Figure 13 shows the generation build changes under TGR & Full BSUoS reform and TGR & Partial BSUoS reform for the Community Renewables background, both implemented in 2020. The displacement of CCGT is much greater in TGR & Partial BSUoS reform because smaller embedded generation is at more of a relative advantage. Under TGR & Full BSUoS reform, there is a reduction in storage. This is due to the model assumption that storage would be charged BSUoS for both import and export (as larger storage is today). We note that industry is progressing modifications in this area.

32 Source: Frontier/LCP.

Figure 13: Generation build changes (Community Renewables TGR & Full BSUoS reform (Top) and TGR & Partial BSUoS reform (Bottom), 2020 implementation)[33]

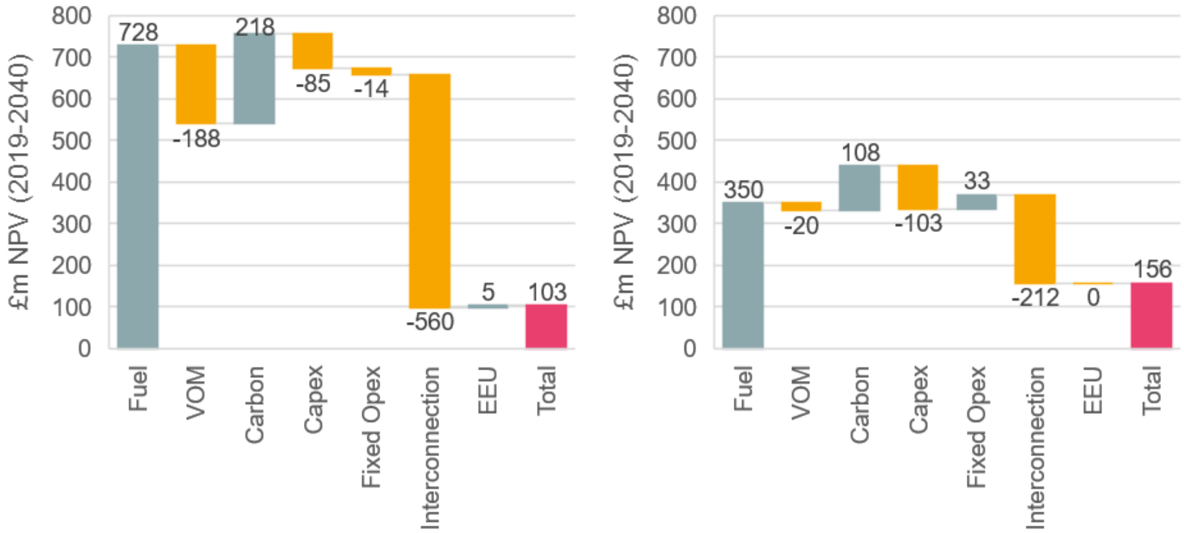




1.60 The system cost savings under TGR & Full BSUoS reform and TGR & Partial BSUoS reform (2020 implementation) are shown in Figure 14. In TGR & Full BSUoS reform, fuel and carbon costs increase, offset by a reduction in interconnection costs, Variable Operations and Maintenance (VOM) costs and, in later years, capex. In TGR & Partial BSUoS reform, the slight increase in system cost is driven primarily by the replacement of more efficient new build CCGTs with on-site generation and distribution-connected peaking plants. These have higher associated fuel and carbon costs, leading to increased system costs. In both cases, there is a small system cost increase relative to the Baseline, of £0.1bn under TGR & Full BSUoS reform and £0.16bn under TGR & Partial BSUoS reform.

[33] Source: Frontier/LCP.

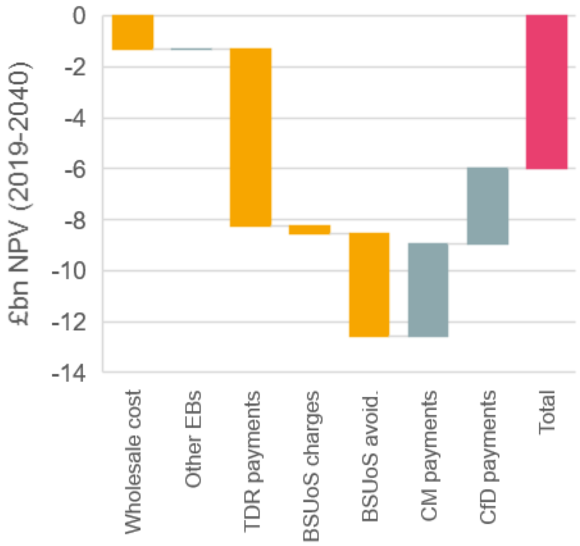
Figure 14: System cost changes (Community Renewables TGR & Full BSUoS reform (Left) and TGR & Partial BSUoS reform (Right), 2020 implementation)[34]

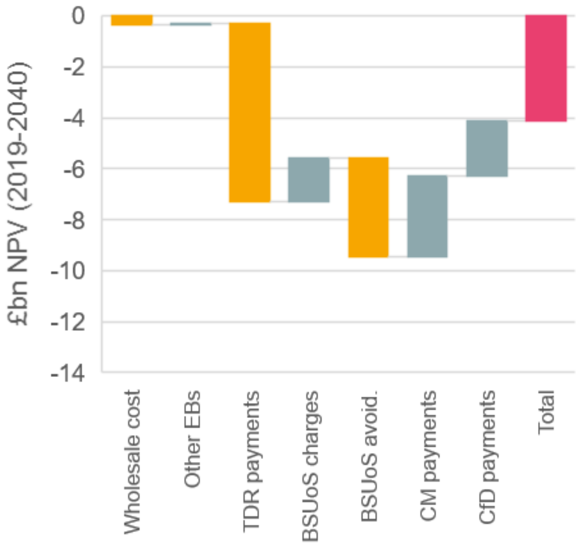


1.61 The consumer cost saving (Figure 15) under TGR & Partial BSUoS reform (2020 implementation) is smaller than under TGR & Full BSUoS reform (2020), due to smaller embedded generation still receiving an Embedded Benefit. Under TGR & Full BSUoS reform, the saving is £6.0bn (greater than the £4.52bn saving for the same option under Steady Progression). Under TGR & Partial BSUoS reform, the consumer cost saving is £4.11bn (compared to £3.33bn in Steady Progression).

[34] Source: Frontier/LCP. Real 2016 terms

Figure 15: Consumer cost changes (Community Renewables TGR & Full BSUoS reform (Left) and TGR & Partial BSUoS reform (Right), 2020 implementation)[35]





Implementation options

1.62 The impact of a one year delay to 2021 has been calculated assuming no knock-on effects on capacity build and retirements, as shown in Table 9. The loss to consumers from a delay is £0.6bn under TGR & Full BSUoS reform and £0.5bn under TGR & Partial BSUoS reform. Results are similar for the two FES backgrounds, due to the similar BSUoS and TNUoS costs in 2019 and 2020.

Table 9: Impact of implementation in 2021[36]

Name	Consumer Cost relative to 2020 implementation (NPV 2019-2040, £bn)
SP TGR & Full BSUoS reform, 2021	0.6
CR TGR & Full BSUoS reform, 2021	0.6
SP TGR & Partial BSUoS reform, 2021	0.5
CR TGR & Partial BSUoS reform, 2021	0.5

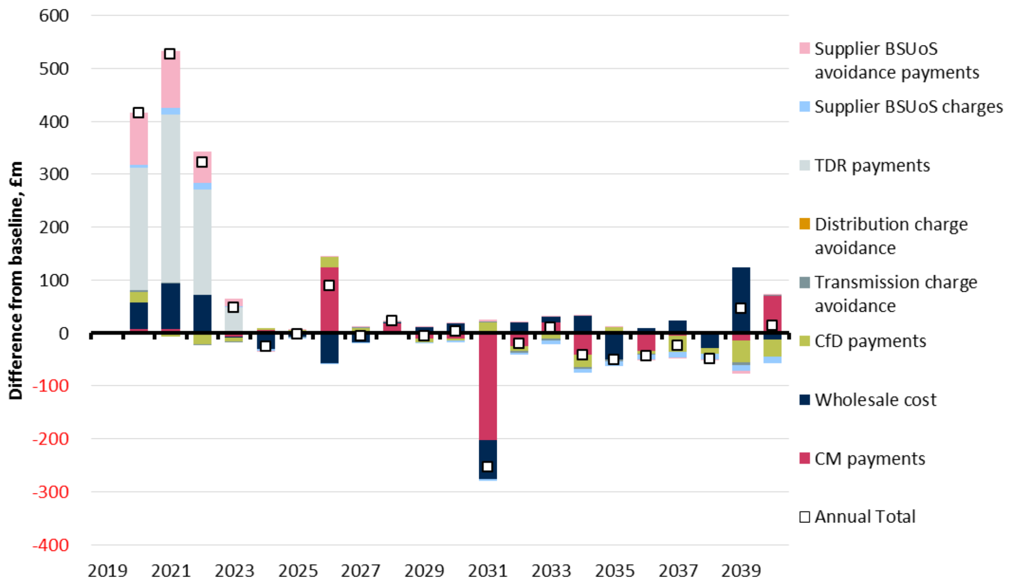
1.63 A three year phased implementation option from 2021 to 2023 has also been modelled, for TGR & Full BSUoS reform. In a Steady Progression scenario, phased removal of the Embedded Benefits over the period 2021 to 2023 leads to similar impact on the level of system costs savings compared to 2020 implementation at -£0.1bn in NPV terms.

1.64 There is a £1.02bn increase in consumer costs relative to 2020 implementation, which is almost all concentrated over the transitional 2021-23 period. This is due to the

[35] Source: Frontier/LCP. Real 2016 terms
[36] Source: Frontier/LCP. Real 2016 terms

consumer savings from TDR payments and BSUoS payments that customers benefit from in the 2020 implementation, and are reduced under the phased approach. The knock-on effects in later years are generally quite small, with one material impact in 2031 due to a lower CM clearing price. Without these effects, the additional costs attributed to phasing, compared to 2020 implementation, would be around £1.3bn.

Figure 16: Change in consumer costs due to delay from 2020 to phased implementation (2021 to 2023), Steady Progression TGR and Full BSUoS reform[37]



Overall assessment of wider system modelling

1.65 The wider system modelling outputs indicate that the two options for reform are broadly neutral in terms of their impacts on system costs. The modelling shows a significant consumer cost reduction from removing Embedded Benefits, which is a larger magnitude for TGR & Full BSUoS reform (by -£1.19bn for Steady Progression and -£1.88bn for a Community Renewables background, Table 10). Hence, in terms of removing harmful distortions, TGR & Full BSUoS reform is indicated to be more effective.

1.66 On the basis of the modelling, the proposed reforms would have relatively limited effects on wholesale energy prices, which means that consumer benefits are much greater than system benefits (effectively, the reforms would result in a transfer of surplus from generators as a group to consumers). The scale of consumer benefits could be smaller if wholesale prices were to increase as a result of the reforms.

1.67 Carbon dioxide emissions increase by between 0.1 and 0.6m tonnes/yr across the options and backgrounds considered, in large part due to an increase in domestic GB generation. Carbon emissions from non-GB generators are not accounted for, and hence a complete picture of carbon emission impacts is not provided by the analysis. Our

37 Source: Frontier/LCP. Real 2016 terms

proposed package of reforms, including residual reform as well as reforms to Embedded Benefits, leads to a slight decrease in GB carbon emissions.

1.68 Table 10 below shows the consumer cost impacts of implementing the two options for reforming Embedded Benefits in 2020, 2021 and phased implementation from 2021 to 2023.

Table 10: Summary of consumer cost impacts[38]

		SP	CR	Cost of delay from 2020	
2020 implementation	TGR & Partial BSUoS reform	-3.3	-4.1		
	TGR & Full BSUoS reform	-4.5	-6.0		
	Difference	**-1.2**	**-1.9**		
				SP	CR
2021 implementation	TGR & Partial BSUoS reform	-2.9	-3.6	0.5	0.5
	TGR & Full BSUoS reform	-4.0	-5.4	0.6	0.6
	Difference	**-1.1**	**-1.8**		
2021-23 phased implementation	TGR & Partial BSUoS reform				
	TGR & Full BSUoS reform	-3.5		1.0	
	Difference				

1.69 Considering implementation options, implementation in 2021 would cost consumers an additional £0.5 to 0.6bn compared to implementation in 2020. A phased implementation in 2021-23 would further reduce the consumer cost savings compared to implementation in 2020 or 2021.

1.70 We note the following limitations in this analysis (in addition to those noted in Frontier and LCP’s report):

1.70.1 The analysis has been performed compared to a counterfactual which assumes that our proposed changes to transmission and distribution residual charging are implemented in 2020. This is consistent with our proposal to address both residual charge reform and Embedded Benefits, however we are consulting on a range on implementation options for wider residual reform. We do not expect that the relative benefits from reform of Embedded Benefits will be significantly different under residual charge reform in 2021 or phased over 2021 to 2023, but we plan to undertaken this further sensitivity modelling before reaching our final decision.

1.70.2 The impact of the reform to the Transmission Generation Residual calculation on consumer costs is estimated based on the assumption that this value does not change after 2023. The size of the Transmission Generation Residual would in reality be expected to change over time due to change in the overall transmission costs to be

[38] Source: Frontier/LCP. Real 2016 terms

recovered, the amount of generation capacity to which this is charged, and the amount recovered by forward-looking locational transmission charges.

1.70.3 The modelling assumes that CfD contracts for existing CfD generators (and those with CfD contracts who have not yet commissioned) are not adjusted as a result of the reforms to the Transmission Generation Residuals or the removal of BSUoS payments. The modelling does assume that future CfD Strike Prices for existing smaller embedded generation do increase when these generators are charged BSUoS (ie under TGR & Full Reform).[39] If Strike Prices were further adjusted for any reason, consumer cost savings might reduce although there would remain a significant consumer cost saving.

1.70.4 The modelling does not assume changes to BSUoS charging arrangements for storage when importing from the grid, and the options as modelled increase the issues related to 'double charging' of storage.[40] We expect that changes to avoid double charging of storage will be progressed by industry.

1.70.5 The modelling assumes a Transmission Generation Residual of zero. If a residual value is required in order to maintain compliance with the €0 – 2.50/MWh range in EC 838/2010, then the consumer costs savings may be smaller than stated.

Overall assessment

Reducing harmful distortions

1.71 As set out above, TGR & Partial BSUoS reform and TGR & Full BSUoS reform both remove harmful distortions and improve cost reflectivity relative to the baseline of no reform. The wider system analysis indicates that both options are broadly neutral with regards to system costs. TGR & Full BSUoS reform leads to a greater consumer benefit, which is consistent with our assessment that it removes more harmful distortions.

Fairness

1.72 As we set out in our TCR Launch Statement, we are considering 'fairness' as it applies to, and between, end-consumers (including charges to suppliers as a proxy for fairness to consumers). Since end-consumers are broadly equally affected by changes to these arrangements, with savings under our two options broadly proportional to contributions to balancing and transmission charges, there is no need to consider fairness further within this assessment.

[39] This modelling assumption does not represent a policy position or an expectation in regards to CfDs, and should not be interpreted as such.
[40] Double charging is when storage facilities are charged balancing, network or other costs on both the import and export of electricity

Proportionality and practical considerations

1.73 Charging BSUoS to suppliers based on their gross demand would require a change to codes and to settlement systems. We understand that the data exists for this, since similar data is required for the charging of the EET. The internal costs for suppliers would be expected to be small.

1.74 One approach to charging BSUoS to smaller embedded generation would involve charging each Balancing Mechanism Unit (BMU) registrant on a gross basis for their generation and demand at the Grid Supply Point (the boundary between transmission and distribution system). Where a supplier portfolio includes smaller embedded generation, a supplier would likely want to ensure that contractual arrangements allow this charge to be passed on to the generator. We welcome views on this approach and whether there are other options to consider.

1.75 Removing the negative Transmission Generation Residual would require implementation of the updated interpretation of EC regulation 838/2010 as a result of CMP 261. Practically, it would require changes to the residual calculation in the methodology and in the ESO's Transport and Tariff model, but would not require new systems, processes or data flows.

1.76 Therefore, whilst both options are relatively low cost and effort to implement, TGR & Full BSUoS reform is slightly harder to implement due to the need to levy BSUoS charges on smaller embedded generation.

Overall assessment

1.77 Our overall assessment is that TGR & Partial BSUoS reform and TGR & Full BSUoS reform both remove harmful distortions and improve cost reflectivity relative to the baseline of no reform. The wider system analysis indicates that both options are broadly neutral with regards to system costs.

1.78 TGR & Full BSUoS reform leads to a greater consumer benefit, which is consistent with our assessment that it removes more harmful distortions. The increased benefits to consumers from proceeding with full BSUoS reform rather than partial BSUoS reform is £1.2bn to £1.9bn in present value terms.

1.79 The differences between TGR & Partial BSUoS reform and TGR & Full BSUoS reform in terms of practicality and cost appear to be small in proportion to the additional benefits available. On this basis, we currently propose TGR & Full BSUoS reform, but are consulting on both options, particularly as we propose to consider the findings of the BSUoS charges task force alongside responses to these proposals.

1.80 Under both options, some forms of generation will be adversely affected, particularly in the short to medium term. However, we have set a clear expectation for the review of the remaining Embedded Benefits, and the approach we are consulting on aligns with our decision last year on the largest of the Embedded Benefits. Within that decision (and preceding documents) we clearly stated that benefits gained were inappropriate[41] and that whilst we were prioritising the largest and most immediate issue, we intended to address the other Embedded Benefits in due course. The size of the Embedded Benefits have increased dramatically over the past few years[42], and are forecast to continue to increase from today's levels if no reforms are made. Hence, it is unlikely that the scale of these future revenues were expected when historic investments were made.

1.81 There is a risk that these changes could lead to the cancellation of some projects, including renewable generators which have been awarded CfD contracts and peaking generators which have been awarded CM contracts, which are not yet online and which would face an increase in charges under both of our options.

1.82 Both options for reform leave in place a distortion for on-site generation (when not exporting). This could be resolved in future by charging BSUoS on a similar basis as our proposed solution for Transmission and Distribution residual charges. As set out above, we will consider this when the BSUoS Task Force has reported its conclusions.

Implementation options for changes to Embedded Benefits

1.83 We have considered the same range of implementation options for the other Embedded Benefits as we have for the wider transmission and distribution residual reform. These are implementation in April 2020, implementation in April 2021, and phased implementation over three years from April 2021 to March 2023.

1.84 Implementation in 2020 is considered feasible, and is consistent with our May 2018 open letter on TCR.[43] However, we believe that a 2020 implementation could be quite challenging for some market participants. Certain generator types will be adversely affected by this implementation timescale as there is less time to adjust business models.

1.85 There is a risk that the benefits to consumers of a 2020 implementation may not be fully realised. This reform is expected to lower wholesale power prices when implemented and reduce BSUoS avoidance payments which are added to consumer bills. Some suppliers will have bought much of their customers' power for the 2020/21 year, so savings through lower wholesale prices (which result from removal of the BSUoS avoidance benefit) may not be passed on to customers. The removal of the BSUoS Embedded Benefits payments would be expected to be mostly passed through to consumers, however, as would savings on transmission charges for demand.

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[41] for example, we stated in our Open Letter on Embedded Benefits (July 2016) that "A negative residual charge prevents generators facing the full costs they impose on the transmission system, effectively subsidising all generators that pay TNUoS charges. We do not consider that this is consistent with the aim of a well-functioning wholesale market "

[42] The Transmission Generation Residual has declined from a positive value and became negative in the 2017/18 charging year, and BSUoS charges have increased from an average £1.50/MWh in 2011/12 to the current value of around £2.33/MWh

[43] https://www.ofgem.gov.uk/publications-and-updates/ofgem-s-views-following-decision-reject-cmp261

1.86 Implementation in 2021 means suppliers are likely to have purchased a smaller proportion of energy for their customers, meaning it is much more likely that savings through lower wholesale prices will feed through to consumers. However, a one-year delay would lead to a loss of consumer benefit of £0.5bn - £0.6bn (depending on the scenario and reform option). There is therefore a trade-off between these factors in assessing whether it would be better to remove these Embedded Benefits in 2020 or 2021.

1.87 We have also considered a phased removal from 2021 to 2023 to align with one of our proposed options for the reforms to transmission and distribution residual charging. This would allow more time for generators to adjust their business models. However, there is almost a four year gap between indicating our intention to address Embedded Benefits (in 2016) and an implementation of 2020 (and a five year gap if implementing in 2021). We undertook modelling to assess the phased implementation of TGR & Full BSUoS reform from 2021 and 2023 and the loss in consumer benefits was found to be £1bn under Steady Progression (and would like be higher under Community Renewables). Hence, we do not consider a longer implementation phase is warranted in this case, in light of the substantially increased costs to consumers.

1.88 We are consulting on phased implementation from 2021 to 2023 for the revised residual charging arrangements since some of the distributional impacts for similar consumers (those within the same customer segment but with differing levels of consumption) are significant and hence a longer transition period is beneficial in allowing the affected consumers time to adjust. For the remaining Embedded Benefits, the distributional impact on end energy consumers is not a concern, since similar end consumers will see the same effect. Some generators will be affected by the loss of non-cost reflective benefits, which we have indicated since 2016 to be distortions and not justified.

1.89 Given our discussion above that Embedded Benefits are increasing in size and are unlikely to have been factored into business models for historic investment decisions, we do not believe that grandfathering of Embedded Benefits is appropriate. This would impose significant additional costs on consumers.

1.90 We are consulting on TGR & Partial BSUoS reform and TGR & Full BSUoS reform for removing the remaining (non-locational) Embedded Benefits in either 2020 or 2021, and are seeking views on this through this consultation.

1.91 National Grid ESO is currently developing proposals to change the CUSC methodology to align with the definition of connection assets we set out in our decision on CMP261. We expect this modification to be raised and implemented alongside and concurrently with the modifications required to implement our final decision on the proposed reforms in this document.

1.92 To ensure that transmission charges remain in the range €0 – 2.50/MWh, the Transmission Generation Residual may need to deviate from zero. Our proposal is that the ESO should raise proposals which maintain the Transmission Generation Residual at zero unless a deviation is explicitly required to comply with the range set out by EC 838/2010, for such time as this regulation applies.

1.93 Alongside this Consultation, We are also launching a Statutory Consultation on extending the Small Generator Discount from the current end date of 31 March 2019, for two years until 31 March 2021. We will align this with the timing of our decision on the reforms of the remaining Embedded Benefits, and intend to set the Small Generator Discount to zero if our reforms are implemented. If our proposed reforms do not proceed, we would maintain the Small Generator Discount until 31 March 2021.

Proposed decisions

1.94 We are proposing to make the following decisions:

a) Charge suppliers BSUoS charges based on gross demand at the GSP, having the effect of removing the BSUoS Embedded Benefit: payments. Implemented in either April 2020 or April 2021. We propose to direct the ESO to raise the relevant CUSC modification.

b) Charge BSUoS Charges to Smaller Embedded Generation, implemented in either April 2020 or April 2021. We propose to direct the ESO to raise the relevant CUSC modification. This will be dependent on the option to remove both elements of BSUoS Embedded Benefit continuing to be our preferred option.

c) Set the Transmission Generation Residual to zero, subject to maintaining compliance with 838/2010. The ESO is developing a modification which would enact the post CMP 261 definition of the 838/2010 range, and would allow us to direct that our policy position of no residuals charged to generation is met.

d) Launch a Statutory Consultation to extend the Small Generator Discount from the current end date of 31 March 2019 to a revised end date of 31 March 2021, with the intention that this will be set to zero once the changes set out above are implemented.[44] Views on the Small Generator Discount should be provided as responses to the Statutory Consultation, which closes on Friday 4 January 2019.

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44 https://www.ofgem.gov.uk/publications-and-updates/statutory-consultation-our-proposal-modify-standard-licence-condition-c13-adjustment-use-system-charges-small-generators-electricity-transmission-licence