Ofgem's Targeted Charging Review Impact Assessment

A review by Oxera

Prepared for
Innogy, RES, ScottishPower
and Vattenfall

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Executive summary

Innogy, RES, ScottishPower and Vattenfall requested that Oxera provide a review of the analysis undertaken by Frontier and LCP (Frontier/LCP)[1] for Ofgem on the impact of the Targeted Charging Review (TCR) reforms. Specifically, Oxera was asked to evaluate the impact assessment (IA) relating to the prospective Transmission Generation Residual (TGR) and Balancing Services Use of System (BSUoS) reform.

Ofgem's approach to the TCR reforms has been firmly rooted in a desire to reduce harmful distortions to competition and to promote fairness, while ensuring that the reforms are also proportionate and practical. Oxera—and, we understand, the sponsors of this report—agree with these principles, and that creating a level playing field and ensuring fair and non-discriminatory treatment of different generation and demand-side resources can be welfare-enhancing. However, it is unclear that Ofgem's current approach to the TGR/BSUoS reform will deliver these objectives in a way that is in the best interests of consumers, given the uncertainty over the impacts on the costs to consumers and the system overall.

In the context of the GB electricity market, the assessment of the impacts of the TGR/BSUoS reform is complex. This is because changes to the network charging arrangements would be expected to affect the outcomes in the capacity and wholesale markets, as well as the auctions of future contracts for difference (CfDs). In turn, the economic viability of any unsupported generation could also be materially affected by the TGR/BSUoS reform.

Oxera's review has identified that the TGR/BSUoS reform exposes consumers and the electricity system to a number of risks, the probability and/or impact of which are not sufficiently explored in the Frontier/LCP analysis, or are otherwise not considered by Ofgem. These risks are as follows.

1. Depending on the assumed baseline for future generation, the impact on the electricity system as a whole may be positive or negative, ranging from

[1] Frontier Economics and LCP (2018), 'Wider System Impacts of TGR and BSUoS Reforms', November; and Frontier Economics and LCP (2018), 'Distributional and wider system impacts of reform to residual charges', November.

around £100m to around -£100m, according to Frontier/LCP's estimates (see the table below).[2]

Frontier/LCP estimates of the impact of the TGR/BSUoS reform under different scenarios

Frontier/LCP scenario	Underlying FES scenario	CO_2 target met?	System cost savings (NPV £m)	Consumer cost savings (NPV £m)
Baseline	Steady Progression	No	+113	+4,524
Alternative FES background	Community Renewables	Yes	-103	+5,995

Note: NPV, net present value; FES, National Grid's 2018 Future Energy Scenarios.

Source: Frontier Economics and LCP (2018), 'Wider System Impacts of TGR and BSUoS Reforms', November; and National Grid (2018), 'Future Energy Scenarios', July, Figure 2.1.

2. The economic viability of renewable generation technologies that may not be supported by policy measures in the future would be undermined by the TGR/BSUoS reform. Oxera's analysis concludes, over the period 2019–40, that this may increase the costs to consumers by as much as **£1.3bn** (Frontier/LCP's baseline scenario) or **£7.6bn** (Frontier/LCP's alternative FES scenario) compared to Frontier/LCP's estimate.

3. While Frontier/LCP have relied on BEIS-recommended values for the social cost of carbon in analysing the system cost impact of the residual charges reform, they have used different and significantly lower values in analysing the system cost impact of the TGR/BSUoS reform. Correcting this inconsistency reduces their projected system cost saving from £113m to £14m (Frontier/LCP's baseline scenario) and from **-£103m to -£333m** (Frontier/LCP's alternative FES scenario).

4. Ofgem's IA does not consider what the impact on the system would be if alternative, and reasonable, parameter assumptions were adopted on the emission intensities of different generation technologies as well as CO_2 and natural gas prices. If these parameters were to evolve in line with the upper end of BEIS's and National Grid's range estimates, system cost impacts could be significantly greater than those assumed by Ofgem. Oxera's analysis suggests that the overall impact of these sensitivities could be to **increase system costs by a further c. £168m–£879m** over the period 2019–40, for Ofgem's baseline and alternative scenarios respectively.

[2] Frontier Economics and LCP (2018), 'Wider System Impacts of TGR and BSUoS Reforms', November, Figure 45.

5. The increased regulatory uncertainty resulting from the TGR/BSUoS reform and other charging reform processes under way could lead to a shrinking universe of investible generation projects and technologies in the short term, especially when considered alongside the uncertainty regarding the future of the capacity market and the availability of CfDs. As explained above, it is not clear whether the resultant shortfall would be mitigated by other policy measures, and, if so, how quickly.

6. Related to the implications for consumer and system costs, the TGR/BSUoS reform is likely to have negative implications for decarbonisation in the UK. Frontier/LCP estimate the additional CO_2 emissions in Great Britain as a result of the TGR/BSUoS reform to be between 0.20m tonnes and 0.42m tonnes per annum, averaged over the period 2019–40. Using plausible alternative emission factors, as described in section 2C, would increase this to between 0.24m tonnes and 0.56m tonnes per annum. To put this into context, the additional emissions resulting from the TGR/BSUoS reform are equivalent to 1–2% of the CCC's total electricity grid emissions budget for 2032, i.e. the end of the fifth carbon budget.[3]

It therefore appears that the TGR/BSUoS reform could ultimately be counterproductive to achieving Ofgem's main objectives of affordability, security of supply and sustainability.[4] This reform could result in Ofgem failing to meet its statutory obligations 'to protect the interests of existing and future consumers […], including their interests in the reduction of greenhouse gases'.[5]

Given the uncertainty over the impact of the TGR/BSUoS reform itself and the potential interactions with other reforms that may arise in the course of the recently launched Significant Code Review or that may be proposed by the Balancing Services Charges Task Force, it may be prudent to withhold any final decision with regard to the TGR/BSUoS reform until Ofgem has fully assessed the impacts of its proposals, to what extent the expected upsides are likely to materialise, and whether the potential upsides justify the risks taken.

[3] CCC (2016), 'CCC fifth carbon budget: central scenario data', 6 June.
[4] Ofgem, 'Promoting value for money', accessed 28 February 2019.
[5] Ofgem (2013), 'Powers and duties of GEMA', 19 July, para. 1.4.

Contents

Figures and tables

1 Introduction

1.1 On 28 November 2018, Ofgem published its minded-to decision and a draft impact assessment of the Targeted Charging Review (TCR) reforms,[6] as well as the accompanying analysis conducted by its advisers, Frontier Economics and LCP (Frontier/LCP).[7] Ofgem has also launched a Significant Code Review (SCR) of network access and forward-looking charging arrangements, as well as a review of balancing services charges, which is being carried out by the Balancing Services Charges Task Force led by the electricity system operator.[8]

1.2 In light of these developments, Innogy, RES, ScottishPower and Vattenfall asked Oxera to review the TCR impact assessment (IA) conducted by Ofgem and its advisers on the effects of the proposed Transmission Generation Residual (TGR) and Balancing Services Use of System (BSUoS) charging reform ('the TGR/BSUoS reform').[9] For the avoidance of doubt, this report does not consider other proposals within the TCR, such as the reform of transmission demand residual and distribution residual charges.

1.3 LCP's EnVision model, on which the IA of the TGR/BSUoS reform is based, is widely used by policymakers and market participants to model a variety of scenarios for the evolution of the GB power market.[10] We have not provided an alternative market simulation-based analysis at this stage. Instead, we have focused on some of the potential limitations of the scenarios and assumptions used by Frontier/LCP in this particular application of the EnVision model, and their implications for the calculation of the costs and benefits of the prospective TGR/BSUoS reform. These limitations include the following:

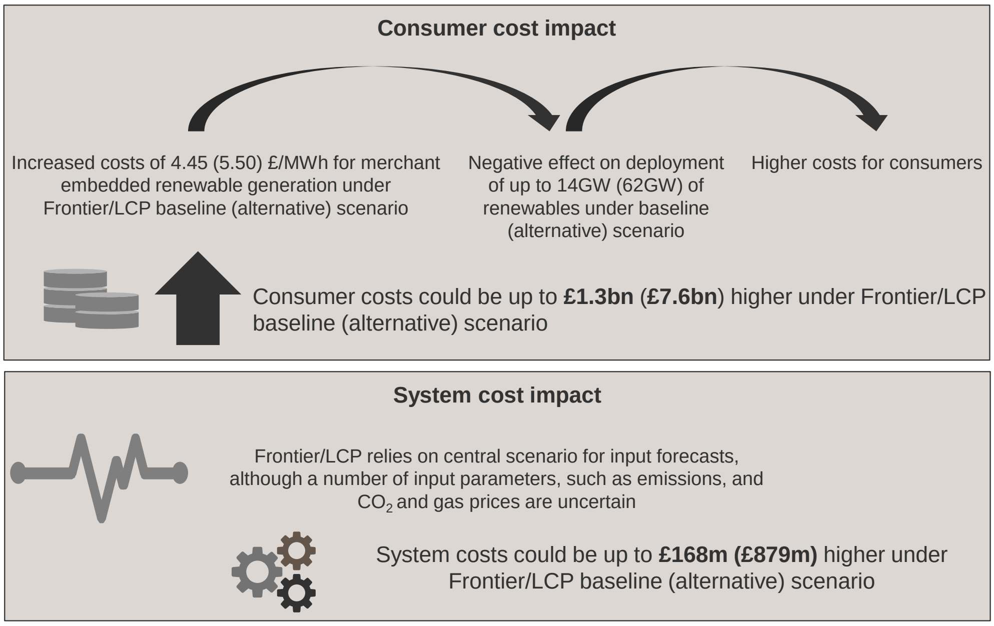
- the implicit assumption that deployment of unsupported embedded generation is not affected by the reform and that, for supported renewables, sufficient CfD support will be available to cover any cost increases caused by the reform;

[6] Ofgem (2018), 'Targeted charging review – minded to decision and draft impact assessment', November.
[7] Frontier Economics and LCP (2018), 'Wider System Impacts of TGR and BSUoS Reforms', November; and Frontier Economics and LCP (2018), 'Distributional and wider system impacts of reform to residual charges', November.
[8] Ofgem (2018), 'Targeted charging review – minded to decision and draft impact assessment', November, p. 11.
[9] Only the impact of the 'full' TGR/BSUoS reform option is considered in this report.
[10] Ofgem (2018), 'Targeted charging review – minded to decision and draft impact assessment', November, para. 5.9 and footnote 55.

- the inconsistency between the social cost of carbon values used in assessing the system cost impacts of TGR/BSUoS reform and the (BEIS-recommended) values used in assessing the system cost impacts of residual charges reform;[11] and
- the sensitivity of the results with regard to changes in various key input parameters.

1.4 The key conclusions from our review are illustrated in Figure 1.1.

Figure 1.1 Summary of Oxera's review of the TGR/BSUoS reform



Source: Oxera analysis based on Frontier Economics and LCP (2018), 'Wider System Impacts of TGR and BSUoS Reforms', November; Department for Business, Energy and Industrial Strategy (2018), 'Updated short-term traded carbon values. Used for UK public policy appraisal', press release, January; and National Grid (2018), 'Future Energy Scenarios', July, Figure 2.1.

1.5 The TGR/BSUoS reform exposes consumers and the electricity system to a number of risks, the probability and/or impact of which Ofgem does not consider in detail. In particular, we note the following risks.

- The economic viability of renewable generation technologies that generate low-cost power but are not supported by contracts for difference (CfDs) may be undermined by the TGR/BSUoS reform, thereby potentially further increasing the costs to consumers and the system as a whole.
- Depending on the assumed baseline future generation scenario, the impact on the electricity system as a whole may be positive or negative. Moreover,

[11] Department for Business, Energy and Industrial Strategy (2018), 'Updated short-term traded carbon values. Used for UK public policy appraisal', January.

plausible variation in the emission intensities of different generation technologies, as well as CO_2 and natural gas prices, highlights the potential for the costs to the system overall to be significantly greater than those presented by Ofgem and its advisers.

- The increased regulatory uncertainty resulting from the TGR/BSUoS reform, and other charging reform processes currently under way, could lead to a shrinking universe of investible renewable generation projects and technologies, especially when considered alongside the uncertainty over the future of the capacity market and the availability of CfDs. If distributed renewable investment is negatively affected by the reform, this may jeopardise the delivery of UK's carbon reduction targets and/or lead to a capacity shortfall.

1.6 Given the uncertainty over the impact of the TGR/BSUoS reform itself and the potential interactions with other reforms that may arise in the course of the recently launched SCR, or that may be proposed by the Balancing Services Charges Task Force, it may be prudent to withhold any decision on the TGR/BSUoS reform until the impacts of all such related proposals and the issues raised in this report have been fully taken into account, and assessed together.

1.7 The report is structured as follows:

- section 2 sets out our review of the Frontier/LCP IA;
- section 3 discusses the potential implications of the reform for energy policy.

2 Review of the Frontier/LCP impact assessment

2.1 In policy impact assessment, just as in investment appraisal, it is important to take into account not only the expected benefit of the policy, but also the risk of adverse unintended consequences associated with the proposed reforms.

2.2 The Frontier/LCP IA does not account for the effect of the TGR/BSUoS reform on the deployment of certain renewable generation technologies. For example, if this reform were to undermine the investment case of 'merchant' or unsupported renewable generation technologies, there would be a risk of a shortfall in renewable investment relative to the two baseline scenarios. This could lead to a future electricity system that is more costly if the shortfall in capacity were replaced by other, more expensive, generation technologies that benefit from separate policy interventions, such as the Capacity Market. Indeed, the costs of these alternatives could themselves be affected by the TGR/BSUoS reform. Ultimately, this could affect the costs to consumers in ways that are not reflected in the Frontier/LCP analysis.

2.3 Furthermore, the Frontier/LCP IA does not sufficiently account for the uncertainty associated with specific input parameters. Notably, Ofgem's IA does not consider the sensitivity of its findings on the costs and benefits of the TGR/BSUoS reform to the CO_2 emissions intensity of thermal generation, the CO_2 price trajectory, and natural gas prices.

2.4 Finally, the increased regulatory uncertainty resulting from the TGR/BSUoS reform (which follows in the wake of a series of policy and regulatory changes and uncertainties) could lead to higher financing costs and lower expected cash flows for some generation investments, depending on how an investment project is appraised. In turn, this could reduce or defer generation investment and thereby further increase the costs to the system as a whole and to consumers.

2.5 It therefore appears that the TGR/BSUoS reform may ultimately be counterproductive to achieving Ofgem's main objectives of value for money, security of supply, and sustainability.[12] If so, this reform would result in Ofgem failing to meet its statutory obligations 'to protect the interests of existing and future consumers […], including their interests in the reduction of greenhouse gases'.[13]

[12] Ofgem, 'How we work', accessed 5 March 2019.
[13] Ofgem (2013), 'Powers and duties of GEMA', 19 July, para. 1.4.

2.6 These issues are discussed below in more detail.

2A Sensitivity to the future generation mix

2A.1 The benefits of the TGR/BSUoS reform depend on the assumption of the future generation mix

2.7 Frontier/LCP rely on National Grid's 2018 Future Energy Scenarios (FES) to inform their assumptions about the evolution of the GB electricity system.[14] The FES contains a variety of forecasts on energy demand and supply in GB. The 2018 FES defines four scenarios for the future of the GB electricity system, each varying across two main dimensions: i) the speed of decarbonisation; and ii) the degree of decentralisation.[15] In only two of these scenarios, 'Community Renewables' and 'Two Degrees', does the UK manage to meet its 2050 CO_2 emission reduction targets.[16] In the two other scenarios, 'Steady Progression' and 'Consumer Evolution', the CO_2 emission reduction targets are not met.

2.8 In their IA, Frontier/LCP consider two scenarios: i) a 'baseline' scenario; and ii) an 'alternative FES background' scenario. They do so because these two scenarios differ greatly in their assumed penetration of decentralised generation.[17]

- For the 'baseline' scenario, Frontier/LCP rely on the FES Steady Progression scenario, under which the 2050 CO_2 emission reduction targets are not met.[18] In this scenario, the TGR/BSUoS reform results in a small cost reduction to the electricity system as a whole.[19]
- For the 'alternative FES background' scenario, Frontier/LCP rely on the FES Community Renewables scenario. As noted above, this scenario assumes that Great Britain does meet its 2050 CO_2 reduction targets. However, under this scenario, Frontier/LCP modelling also shows that the TGR/BSUoS reform results in a small cost increase to the electricity system.[20]

2.9 In contrast, Frontier/LCP assess the impact on consumers in both the baseline and alternative FES background scenarios to be many times greater and

[14] National Grid (2018), 'Future Energy Scenarios', July.
[15] National Grid (2018), 'Future Energy Scenarios', July, Figure 2.1.
[16] National Grid (2018), 'Future Energy Scenarios', July, Figure 2.1.
[17] ,Ofgem (2018), 'Targeted Charging Review – Minded to decision and draft impact assessment', November, para. 5.11.
[18] Frontier Economics and LCP (2018), 'Wider System Impacts of TGR and BSUoS Reforms', November, Figure 1.
[19] Frontier Economics and LCP (2018), 'Wider System Impacts of TGR and BSUoS Reforms', November, Figure 45.
[20] Frontier Economics and LCP (2018), 'Wider System Impacts of TGR and BSUoS Reforms', November, Figure 45.

unambiguously positive—i.e. consumers experience significant cost reductions.

2.10 Table 2.1 summarises the results for each of Frontier/LCP’s scenarios.

Table 2.1 Frontier/LCP estimates of the impact of the TGR/BSUoS reform under different scenarios

Frontier/LCP scenario	Underlying FES scenario	CO_2 reduction target met?	System cost savings (NPV £m)	Consumer cost savings (NPV £m)
Baseline	Steady Progression	No	+113	+4,524
Alternative FES background	Community Renewables	Yes	-103	+5,995

Note: NPV, net present value.

Source: Frontier Economics and LCP (2018), ‘Wider System Impacts of TGR and BSUoS Reforms’, November; and National Grid (2018), ‘Future Energy Scenarios’, July, Figure 2.1.

2.11 In other words, Frontier/LCP’s analysis suggests that the TGR/BSUoS reform will not necessarily have a positive impact on the productivity of the electricity system overall (in the form of system cost savings). Ofgem has also acknowledged that the benefits to consumers will be largely the result of a welfare transfer from generators to consumers.[21] This transfer from generators could lead to long-term changes to the electricity system that may ultimately be detrimental to consumers.

2.12 Notwithstanding Ofgem’s decision to rely on scenarios that differ substantially in terms of the quantity of decentralised generation within the overall generation mix, Ofgem’s IA does not directly consider the impact of its reforms on the deployment of unsupported embedded generation in either scenario.

2.13 Frontier/LCP’s modelling suggests that the TGR/BSUoS reform poses a dilemma for the future of the electricity system. On the one hand, if the system evolves along the baseline (Steady Progression) scenario, the TGR/BSUoS reform would yield a small system cost saving, but the CO_2 reduction targets would not be met. On the other hand, if the system evolves along the alternative FES background (Community Renewables) scenario, the CO_2 reduction targets would be met but the TGR/BSUoS reform would result in an increase in overall system costs. Ofgem’s ambivalence about whether the UK’s long-term decarbonisation target is met seems to be at odds with its objective of promoting sustainability. It also appears at odds with the recent instruction to

[21] Ofgem (2018), ‘Targeted charging review – minded to decision and draft impact assessment’, November, Annex 7, p. 14.

the Committee on Climate Change to set a date for a net zero emissions target.[22]

2.14 Moreover, the overall effect of the TGR/BSUoS reform, whether positive or negative, is inherently uncertain, given that it depends on the evolution of generation costs and the availability of CfDs, as well as the Capacity Market, the wholesale market, and the Balancing Mechanism, among others. As a result, adopting different assumptions on parameters such as the CO_2 emissions intensity of thermal plants, the CO_2 price, and natural gas prices would be expected to have a significant impact on the competitiveness of merchant generators.

2.15 In turn, the overall deployment (encompassing new investment, repowering, or retirement decisions) of unsupported renewable generation could be significantly affected by the TGR/BSUoS reform, and this impact would depend on the specific assumptions used in any particular modelling scenario. This uncertainty is compounded by the fact that the benefits of the reform, if any, would be realised over a 20-year period.

2A.2 The TGR/BSUoS reform could significantly reduce deployment of renewable generation, thereby increasing the costs to consumers as alternative forms of generation could become significantly more expensive

2.16 In their IA, Frontier/LCP assume that 'non-CM build [capacity] is held constant across the scenarios considered.'[23] However, while Frontier/LCP suggest that the estimated increase in the CfD strike price would mitigate the effect of the TGR/BSUoS reform,[24] Oxera notes that not all types of generation can benefit from CfDs; and for the May 2019 CfD auctions, the strike prices may not be able to adjust.[25] In particular, onshore wind, and solar with a capacity at or below 5MW, are no longer eligible for the CfD auctions.[26] Meanwhile, the proposed additional BSUoS costs and the removal of the embedded benefits will adversely affect the financial performance of small embedded generators,

[22] Department for Business, Energy and Industrial Strategy (2018), 'Climate experts asked for advice on net zero target', press release, 15 October.
[23] Frontier and LCP (2018), 'Wider System Impacts of TGR and BSUoS Reforms', November, p. 6.
[24] Frontier and LCP (2018), 'Wider System Impacts of TGR and BSUoS Reforms', November, p. 13.
[25] For offshore wind bidding in the May 2019 'Pot 2' CfD auction, CfD prices may not be able to adjust to reflect cost increases due to the TGR/BSUoS reform. This is because BEIS's administrative strike prices were set before Ofgem's minded-to decision on TCR. The cost increases arise from proposed changes to the TGR stemming from Ofgem's CMP261 decision, and the proposal to set TGR to zero.
[26] Department of Energy and Climate (2014), 'Budget Notice for the CFD Allocation Round 1', October, p. 1.

and there is currently no policy or market mechanism to allow small embedded generators to recover these costs and lost revenues.[27]

2.17 In addition, the collection of 'Pot 1' renewable technologies including onshore wind and solar has not taken part in CfD auctions since the first allocation round in 2015.[28] While another Pot 1 CfD auction for these technologies might be held in the future, it is unclear when the support would come, how large the budget for established renewable generation technologies would be, or the extent to which there might be further auctions in the future.

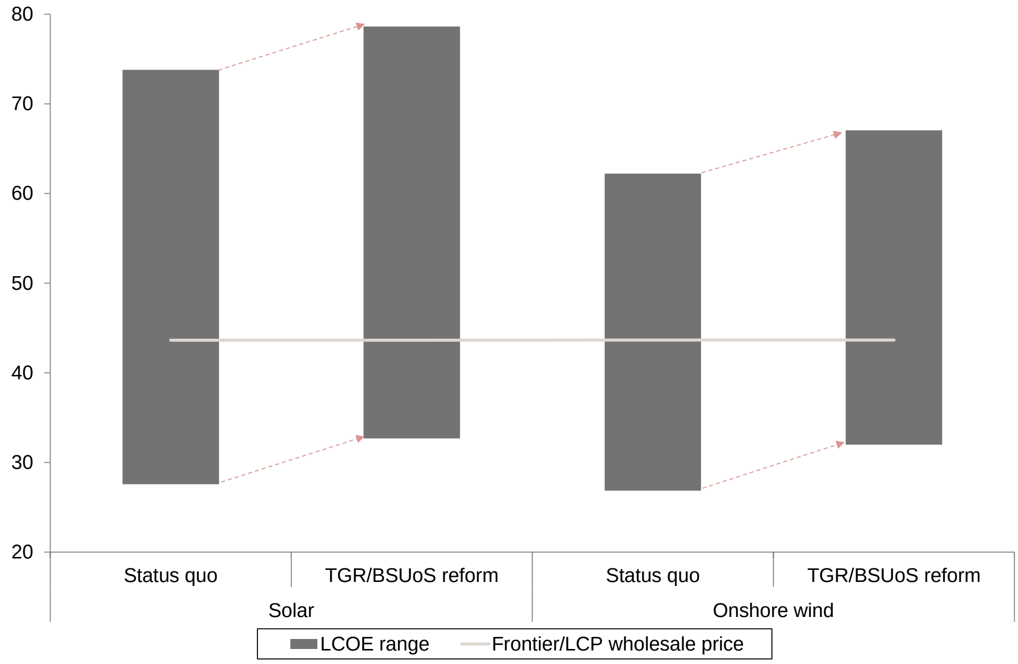
2.18 For less-established 'Pot 2' technologies, such as offshore wind, a CfD auction is planned for this year.[29] However, while Frontier/LCP estimated that the TGR/BSUoS reform would lead to additional CfD payments of £1.4bn–£3.0bn,[30] the latest CfD budget from HM Treasury for future CfD auctions amounts to only £557m in 2011/12 prices (and it is possible that this will be available to less-established 'Pot 2' technologies only).[31] It is therefore unclear whether the necessary funding will be available to sustain the growth in renewables contemplated by Ofgem's economic advisers and required under legally binding carbon reduction targets.[32]

2.19 To assess the extent to which the TGR/BSUoS reform could affect investment incentives, Oxera has used publicly available sources to calculate the range of the levelised cost of energy (LCOE)[33] for distribution-connected onshore wind and solar, before and after the TGR/BSUoS reform.[34]

2.20 Figure 2.1 illustrates the range of LCOE estimates and compares these to the wholesale price reported by Frontier/LCP.[35]

[27] Ofgem (2018), 'Targeted charging review – minded to decision and draft impact assessment', November, para. 6.14.
[28] Department for Business, Energy and Industrial Strategy (2017), 'Contracts for Difference Second Allocation Round Results', 11 September.
[29] Department for Business, Energy and Industrial Strategy (2019), 'Contracts for Difference (CfD): Allocation Round 3', 14 February, accessed 20 March 2019.
[30] Frontier/LCP (2018), 'Backing data TGR and BSUoS quantitative modelling', November. When considering the increase in CfD payments for the TDR and TGR/BSUoS reforms together, the net effect of CfD payment increases is £1.0bn (Steady Progression) to £1.8bn (Community Renewables).
[31] HM Treasury (2017), 'Control for Low Carbon Levies', 22 November, para. 1.6; Department for Business, Energy and Industrial Strategy (2017), 'The Clean Growth Strategy', October (amended April 2018), p. 15; Department for Business, Energy and Industrial Strategy (2018), 'Contracts for Difference (CfD): Draft Budget Notice for the third allocation round, 2019', November 20.
[32] See section 3.
[33] LCOE here includes the embedded benefits as a negative cost in the 'no reform' scenario.
[34] Department for Business, Energy and Industrial Strategy (2016), 'Electricity Generation Costs', Table 19: Capital and operating cost assumptions for all technologies; International Renewable Energy Agency (2018), 'Renewable Power Generation Costs in 2017'; Lazard (2018), 'Lazard's Levelized Cost of Energy Analysis, Version 12.0', 8 November.
[35] Frontier/LCP (2018), 'Backing data for residual charging wider system impacts', November. Annual wholesale prices have been time-weighted in line with the asset life of the corresponding technology.

Figure 2.1 Effect of TGR/BSUoS reform on LCOE (£/MWh) for distribution-connected onshore wind and solar generation



Note: The LCOE numbers account for the embedded benefits.

Source: Oxera analysis based on Frontier/LCP (2018), 'Backing data for residual charging wider system impacts', November; Department for Business, Energy and Industrial Strategy (2016), 'Electricity Generation Costs', Table 19: Capital and operating cost assumptions for all technologies; International Renewable Energy Agency (2018), 'Renewable Power Generation Costs in 2017', Lazard (2018), 'Lazard's Levelized Cost of Energy Analysis, Version 12.0', 8 November; and National Grid (2018), 'Future Energy Scenarios', July.

2.21 Figure 2.1 yields two insights. First, under the status quo, a significant part of the range of solar and wind LCOEs lies above the average wholesale price, in spite of considerable cost savings during the past few years. The share of capacity represented by these investments would therefore not be viable without government support. This challenge is aggravated by the divergence between capture and wholesale prices. As Hirth (2013) and others show,[36] the prices that renewable generators are able to capture are most likely to be lower than the average annual wholesale price. This is due to the coincident production of large quantities of electricity during certain periods when renewable resources are available.[37] Since this effect grows with the

[36] Hirth, L. (2013), 'The market value of variable renewables: The effect of solar wind power variability on their relative price ', *Energy Economics*, **38**. Cornwall Insight (2018), 'Wholesale Power Price Cannibalisation', accessed March 14 2019. Aurora Energy Research (2017), 'Government has underestimated subsidy cost of latest offshore wind sites by almost 50% or £80m per year', accessed March 14 2019.

[37] Hirth (2013) indicates that a high penetration of wind (30%) and solar (15%) could result in respective capture prices being as low as 50% of the wholesale price. Cornwall Insight (2018) predicts capture prices of around 75% of the wholesale price for wind and around 90% of the wholesale price for solar. Aurora (2017) estimates capture prices to be around £5/MWh below the average annual wholesale price.

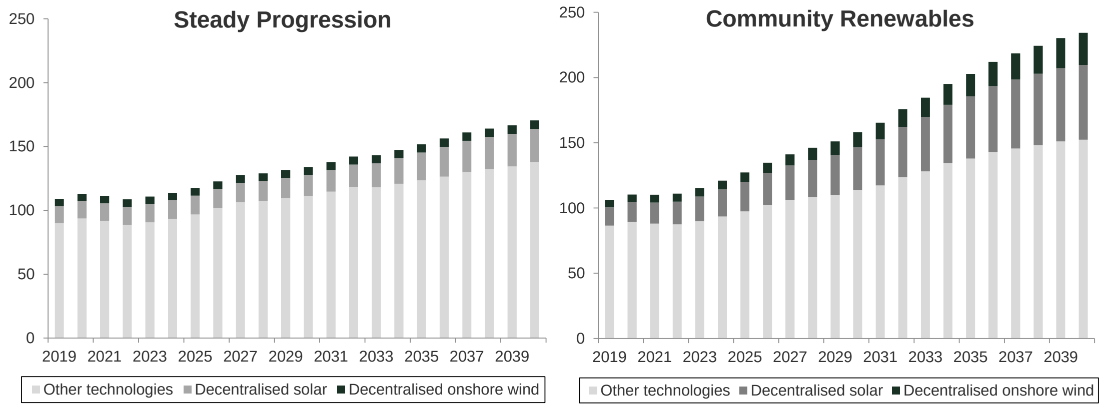
increasing deployment of renewables, the capture price of such projects could further decrease in the future.

2.22 Second, the analysis shows that the TGR/BSUoS reform could increase the LCOE of distributed solar or wind generation by £4.45–£5.50/MWh, depending on the assumed scenario for the value of BSUoS. Given that a large portion of the LCOE range shown above is likely to be above the price levels 'captured' by these plants, this reform is therefore likely to have a material and adverse impact on the investment decisions pertaining to these plants. It is therefore unclear whether, following the implementation of the TGR/BSUoS reform, a significant amount of distributed onshore wind and solar generation would continue to be viable and would come into operation, as implicitly assumed in the Frontier/LCP modelling scenarios.

2.23 Given the limited disclosure from Frontier/LCP on its assumptions, it is not possible to determine what proportion of new embedded generation capacity was assumed by Frontier/LCP to be immune to the effect of the increase in charges through additional CfD support.[38] However, Oxera notes that National Grid predicts between 14GW and 62GW of new-build decentralised onshore wind and solar capacity by 2040,[39] over and above the current level of around 19GW.[40] Thus, to the extent that decentralised onshore wind and solar investment cases could be at risk as a result of the TGR/BSUoS reform, it is conceivable that the amount of new capacity affected by the reform could be as high as 62GW. Moreover, to the extent that the reform could affect the incentives of the existing plants to decommission earlier—for example, when their Renewables Obligation Certificates (ROCs) expire—the adverse impact on future capacity could be even greater. In a high renewables system, flexibility—for example, through embedded generation—is key in keeping system costs low,[41] so this shortfall in deployment is likely to have an adverse impact.

[38] Email correspondence and spreadsheet from Ofgem, 1 March 2019.
[39] Under the Steady Progression and Community Renewables scenarios respectively. Steady Progression forecasts 1GW and 13GW for wind and solar respectively. Community Renewables predicts 19GW of new onshore wind and 43GW of new solar. See National Grid (2018), 'Future Energy Scenarios – Data Workbook', 17 July, Sheet ES1.
[40] National Grid (2018), 'Future Energy Scenarios – Data Workbook', 17 July, Sheet ES1.
[41] Aurora (2018), 'Power sector modelling: System cost impact of renewables—Report for the National Infrastructure Commission', 24 May, p. 38.

Figure 2.2 Decentralised capacity forecast until 2040 (GW)



Source: National Grid (2018), 'Future Energy Scenarios', July.

2A.3 Replacing onshore wind and solar with alternative technologies could lead to significantly higher costs to consumers and the system overall

2.24 The potential reduction in onshore wind and solar deployment relative to the Frontier/LCP modelling raises the question of which technologies could fill the resulting generation shortfall relative to the baseline. At least two options appear available:

- other renewables, such as offshore wind; and/or
- thermal generation, such as CCGT plants.

2.25 The long-term effects of the TGR/BSUoS reform would be expected to differ depending on which technologies would replace the assumed FES levels of decentralised onshore wind and solar. In particular, if offshore wind investments increase, this could raise the overall system cost due to the current LCOE of offshore wind being higher than the LCOEs of onshore wind and solar.[42] If other technologies replaced onshore wind and solar, these may have even higher LCOEs.[43] Over the long term, some of this system cost increase could conceivably be mitigated by more strategic and integrated approaches to investment in offshore generation, connection, and interconnection capacity.[44] The costs of offshore and other established technologies would also be expected to converge to some extent after successive CfD allocation rounds.

[42] For instance, according to the latest estimates from BEIS, LCOE for offshore wind, solar and onshore wind amounts to 106, 67 and 63 £/MWh respectively. See Department for Business, Energy and Industrial Strategy (2016), 'Electricity Generation Costs', Table 2.
[43] For instance, according to the latest estimates from BEIS, LCOE for OCGT amounts to 166 £/MWh. See Department for Business, Energy and Industrial Strategy (2016), 'Electricity Generation Costs', p. 25 Table 2.
[44] Strbac, G. Konstantelos, I., Aunedi, M., Pollitt, M. and Green, R. (2016), 'Delivering future-proof energy infrastructure', Report for the National Infrastructure Commission, February, p. 15.

2.26 Assuming that any reduction in onshore and solar capacity would be replaced by offshore wind, the additional cost to consumers could lie in the range from £800m to £1.3bn in the Steady Progression scenario, or be in the region of £4.3bn–£7.6bn in the Community Renewables Scenario. As set out below, these additional costs would significantly reduce, if not eliminate entirely, the consumer benefit expected from the TGR/BSUoS reform. We estimate this impact in two steps.

2.27 First, we estimate the additional cost per MWh that would need to be incurred if embedded onshore wind and solar were to be replaced with offshore wind. We consider that the difference in the CfD strike prices between the respective technologies provides a good indication of what the cost could be. This is because the price obtained through a competitive auction is designed to reveal information about the underlying cost of the project. Using the CfD strike price forecast for onshore wind estimated by BVG Associates,[45] the CfD auction results from Allocation Rounds 1 and 2,[46] and administrative strike prices from the upcoming Allocation Round 3,[47] we estimated the annual cost of offshore wind over and above the costs of onshore wind and solar generation. A similar calculation was carried out for solar generation. These sources provide estimates until 2025. Different sensitivities were carried out to account for relative future developments in CfD strike prices for these technologies after this date. To provide a range estimate for this effect, the difference between the offshore and onshore (solar) CfD strike prices is assumed to remain constant after 2025, at around £12/MWh (£19/MWh), or to converge to zero by 2030.[48]

2.28 As a second step, the difference in CfD strike prices is applied to the generation affected by the TGR/BSUoS reform. While it is unclear exactly how much onshore wind and solar capacity would be affected, in the extreme case, without CfD support, all of the prospective embedded onshore wind and solar capacity could be placed at risk. Using load factors from BEIS,[49] we then calculate the amount of generation equivalent to the capacity affected. For

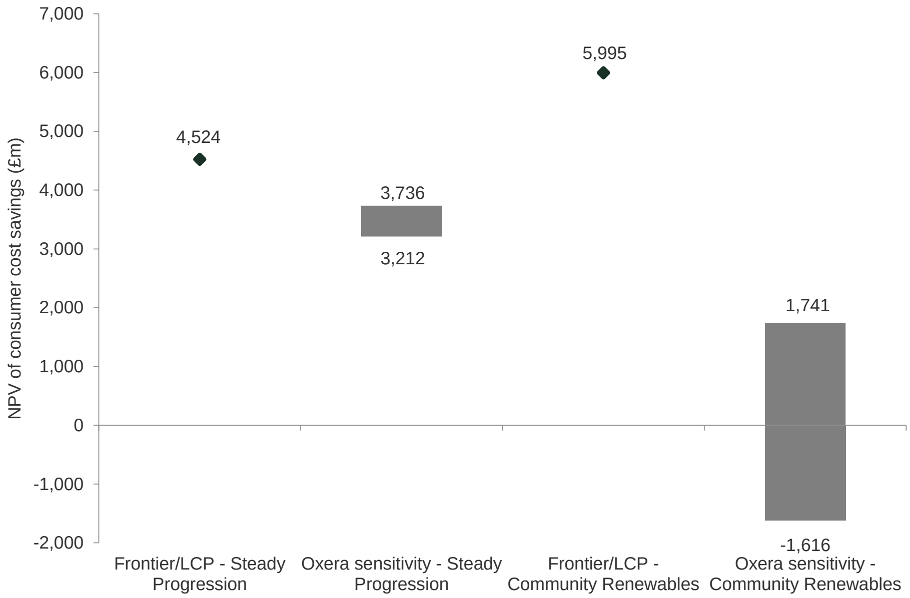
[45] BVG Associates (2018), 'The Power of Onshore Wind', June.
[46] Department of Energy and Climate Change (2015), 'Contracts for Differences (CFD) Allocation Round One Outcome', 26 February; and Department for Business, Energy and Industrial Strategy (2017), 'Contracts for Difference Second Allocation Round Results', 11 September.
[47] Department for Business, Energy and Industrial Strategy (2018), 'Methodology used to set Administrative Strike Prices for CfD Allocation Round 3', December.
[48] This convergence assumption has been derived from recent cost reduction trends.
[49] Department for Business, Energy and Industrial Strategy (2016), 'Electricity Generation Costs', Table 19: Capital and operating cost assumptions for all technologies.

every year, the CfD strike price differential is then applied to the amount of generation that could be affected from 2019 to 2040.

2.29 The results are summarised in Figure 2.3.

- In the Steady Progression scenario, the impact of onshore wind and solar being displaced as a result of the TGR/BSUoS reform lowers consumer cost savings, estimated by Frontier/LCP, by around £800m–£1.3bn. This would lead to consumer cost savings between £3.2bn and £3.7bn, as opposed to Frontier/LCP's estimate of £4.5bn.
- In the Community Renewables scenario, it is assumed that much more decentralised onshore wind and solar will be built. The overall cost of replacing this capacity could therefore be much higher. The estimated impact compared to Frontier/LCP's consumer cost savings is between £4.3bn and £7.6bn, which could turn the estimated consumer cost savings negative. That is, it would lead to consumers incurring additional costs as a result of the TGR/BSUoS reform. This would lead to consumer cost savings of between -£1.6bn (i.e. an increase in consumer cost of £1.6bn) and £1.7bn compared to Frontier/LCP's estimate of £6.0bn.

Figure 2.3 Consumer cost savings—net present value (£m)



Source: Oxera analysis based on Frontier/LCP (2018), 'Wider System Impacts of TGR and BSUoS Reforms', November, Figure 15 (Steady Progression) and Figure 25 (Community renewables); Frontier/LCP (2018), 'Backing data for residual charging wider system impacts'; BVG Associates (2018), 'The Power of Onshore Wind', June; Department of Energy and Climate Change (2015), 'Contracts for Differences (CFD) Allocation Round One Outcome', 26 February; Department for Business, Energy and Industrial Strategy (2017), 'Contracts for Difference Second Allocation Round Results', 11 September; and Department for Business, Energy and

Industrial Strategy (2018), 'Methodology used to set Administrative Strike Prices for CfD Allocation Round 3', December.

2.30 An alternative scenario would be that only some of the onshore wind and solar capacity reduction caused by the TGR/BSUoS reform is replaced with offshore wind, with the remainder of the generation shortfall being met by thermal generation.

2.31 To the extent that the shortfall in onshore wind and solar generation is expected to be met by additional generation from either existing or new thermal plants, the wholesale market prices would also be expected to rise alongside an increase in CO_2 emissions. As an illustration, if the annual baseload price were to rise by £1/MWh, the additional cost of meeting the annual demand of 300TWh would be £300m per annum. However, any increase in the wholesale price would also be expected to reduce the CfD top-up payment and Capacity Market clearing prices; as such, the net impact on the cost to consumers would be lower than £300m.

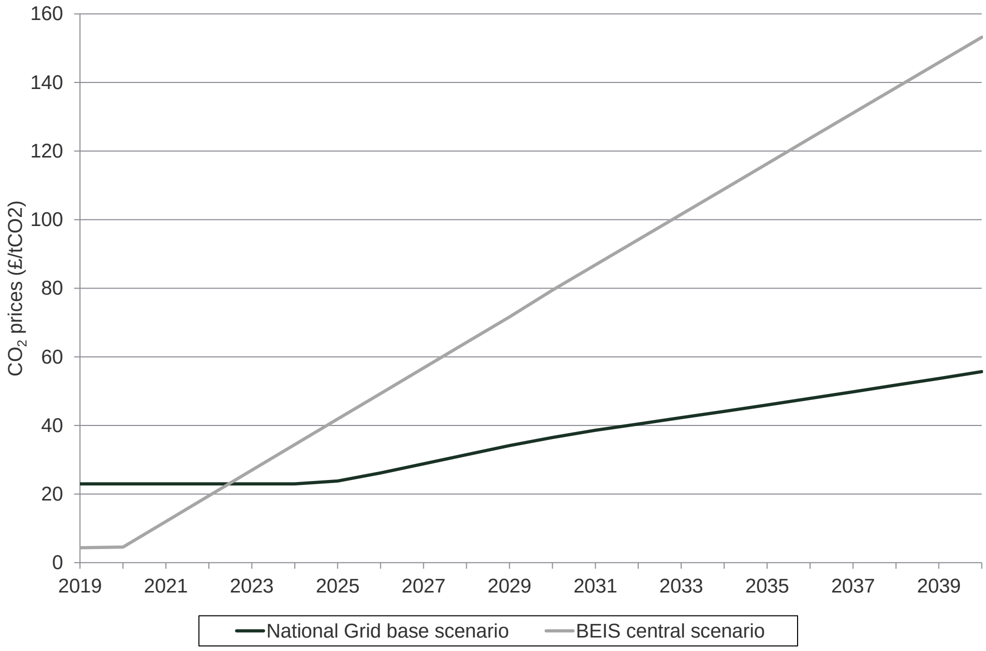
2.32 Given the uncertainty regarding the reduction in onshore wind and solar capacity that could arise from the implementation of the TGR/BSUoS reform, the technologies that would replace the potential gap, and their respective cost, it seems reasonable to consider undertaking an additional sensitivity analysis to test the robustness of the TGR/BSUoS reform's impact on consumer and system costs.

2B Inconsistent appraisal of CO_2 emissions

2.33 When assessing the effect of CO_2 emissions on society, it is important to consider not only the cost of carbon certificates, but also the wider social cost of emissions.

2.34 Indeed, for the purposes of policy appraisal, BEIS recommends a set of CO_2 prices that are significantly higher than the projected cost of carbon certificates. Figure 2.4 compares BEIS CO_2 appraisal prices to National Grid's CO_2 price central scenario.

Figure 2.4 CO_2 prices—National Grid's central scenario and BEIS central scenario appraisal prices



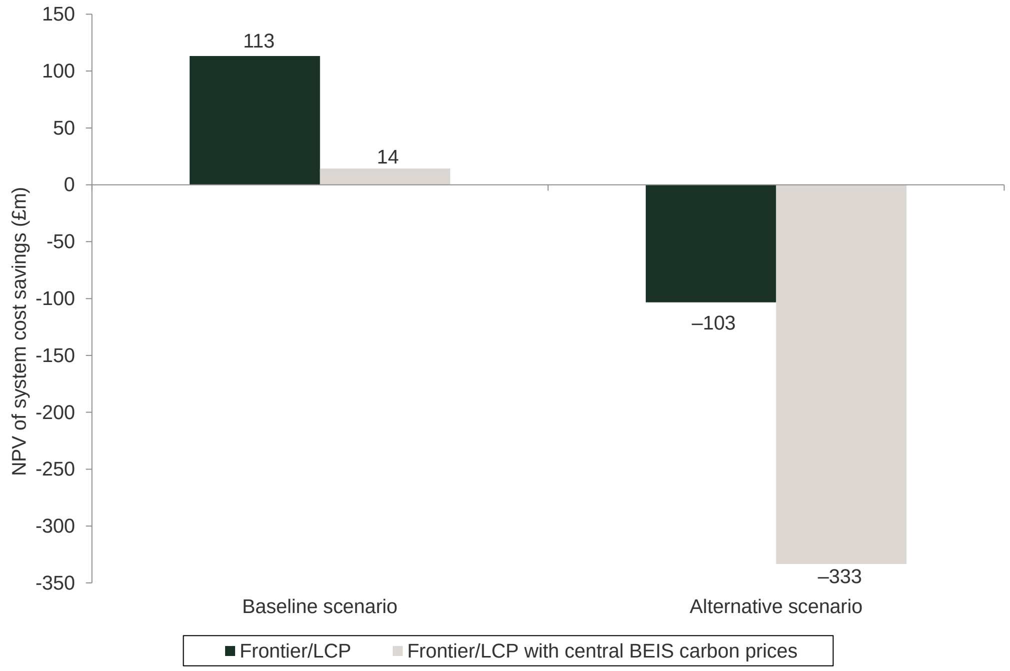
Source: Department for Business, Energy and Industrial Strategy (2018), Data_tables_1-19_supporting_the_toolkit_and_the_guidance_2017__180403_.xlsx'; and National Grid (2018), 'Future Energy Scenarios', July.

2.35 While Frontier/LCP have relied on BEIS-recommended prices in their analysis of system cost impacts of the residual charges reform,[50] they have used National Grid's central forecast in the analysis of the TGR/BSUoS reform.[51] It therefore appears that Frontier/LCP have appraised the CO_2 emissions expected from the TGR/BSUoS reform in a manner that is inconsistent with BEIS guidelines and with their own assessment of the to residual charges reform.

2.36 Correcting this inconsistency almost entirely eliminates the system cost savings in the baseline scenario and increases the additional system costs under the alternative FES background scenario by more than three times. This is illustrated in Figure 2.5.

[50] Frontier Economics and LCP (2018), 'Distributional and wider system impacts of reform to residual charges', November, p. 93, fn 38.
[51] This can be confirmed by dividing the cost of carbon, reported in the 'System costs' tab of the TGR/BSUoS backing data, by the carbon emissions, reported in the 'Carbon' tab of the TGR/BSUoS backing data.

Figure 2.5 Correcting the CO_2 emission appraisal inconsistency



Source: Oxera analysis based on Department for Business, Energy and Industrial Strategy (2018),' Data_tables_1-19_supporting_the_toolkit_and_the_guidance_2017__180403_.xlsx'; and Frontier Economics and LCP (2018), 'Backing data for BSUoS and TGR reform'.

2C Low assumption for CO_2 emissions intensity

2.37 Our review has highlighted that, for certain generation technologies, the emissions intensities implied by Frontier/LCP's modelling appear low compared with estimates available in the public domain.

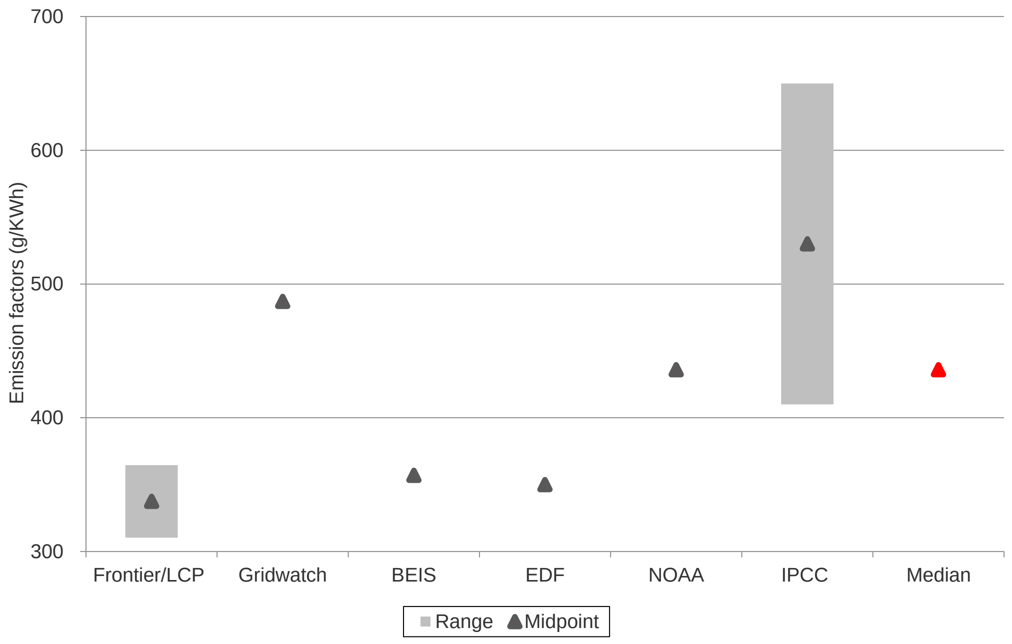
2.38 To illustrate, the CCGT emissions intensity implied by the Frontier/LCP baseline scenario ranges from 310g to 365g of CO_2 per kWh generated (g/kWh)[52] over the forecast horizon, from 2019 to 2040. In comparison, other sources in the public domain estimate a CCGT emissions intensity of 350g/kWh to 650g/kWh, with a median of 436g/kWh.[53] Similarly, the emissions intensity for coal, implied by Frontier/LCP's modelling in the baseline scenario,

[52] Frontier/LCP's emission intensities vary significantly between scenarios and over time. For example, based on Frontier/LCP's data, the implied CCGT emissions intensity in 2038 is 365g/kWh in the baseline scenario (Steady Progression), and 360g/kWh in the alternative scenario (Community Renewables) scenario. In the following year (2039), the implied emission factor drops to 310g/kWh in the base scenario, but remains unchanged at 360g/kWh in the alternative scenario. While there could be reasons for emission factors to fluctuate, no explanation has been given for these results. The implied emissions intensities are calculated as ratios of the incremental CO_2 emissions generation for a given technology (reported in Figure 11 of Frontier/LCP's report) to the incremental generation by that technology (reported in Figure 9 of Frontier/LCP's report).

[53] EDF Energy (2019), 'The climate challenge for each energy sources', accessed 12 March 2019; Department for Business, Energy and Industrial Strategy (2018), 'Fuel mix disclosure data tables', 3. Environmental impact; Gridwatch (2019), 'UK Electricity National Grid co2 Output per Production Type', accessed 27 February 2019; de Gouw, J.A., Parrish, D.D., Frost, G.J. and Trainer, M. (2014), 'Reduced emissions of CO_2, NOx, and SO_2 from U.S. power plants owing to switch from coal to natural gas with combined cycle technology', *Earth's Future*, **2**, pp. 75–82; Intergovernmental Panel on Climate Change (2014), 'Annex III: Technology-specific Cost and Performance Parameters', in 'Climate Change 2014: Mitigation of Climate Change. Working Group III Contribution to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change'.

ranges between 821g/kWh and 880g/kWh. In contrast, publicly available estimates range from 740g/kWh to 918 g/kWh, with a median of 880g/kWh.[54] These findings are summarised in Figure 2.6 and Figure 2.7 respectively.

Figure 2.6 Benchmarking of Frontier/LCP's emission factors—CCGT

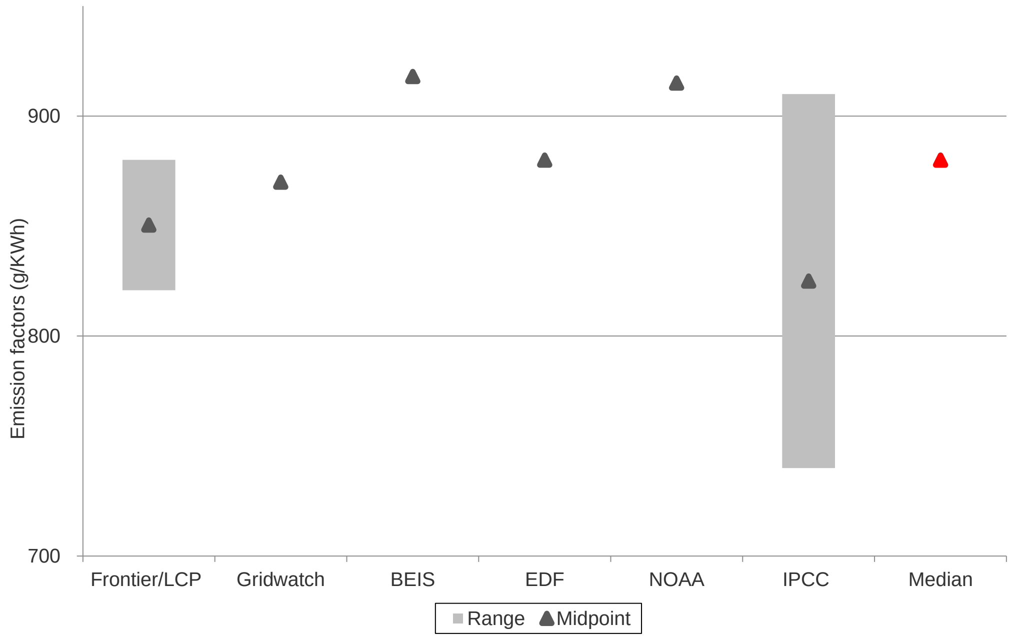


Note: Frontier/LCP figures are the minimum/maximum across the analysis period and both scenarios: baseline and alternative FES background. IPCC (Intergovernmental Panel on Climate Change) figures are the minimum/maximum values, with a marker at the median.

Source: Oxera analysis based on data from Frontier/LCP; EDF Energy (2019), 'The climate challenge for each energy sources', accessed 12 March 2019; Department for Business, Energy and Industrial Strategy (2018), 'Fuel mix disclosure data tables' 3. Environmental impact; Gridwatch (2019), 'UK Electricity National Grid co2 Output per Production Type', accessed 27 February 2019; de Gouw, J. et al. (2014), 'Reduced emissions of CO_2, NOx, and SO_2 from U.S. power plants owing to switch from coal to natural gas with combined cycle technology', Chemical Sciences Division, NOAA Earth System Research Laboratory, Boulder, Colorado, USA, *Earth's Future*, **2**: pp. 75–82; Intergovernmental Panel on Climate Change (2014), 'Annex III: Technology-specific Cost and Performance Parameters', in 'Climate Change 2014: Mitigation of Climate Change. Working Group III Contribution to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change'.

[54] Frontier/LCP; EDF Energy (2019), 'The climate challenge for each energy sources', accessed 12 March 2019; Department for Business, Energy and Industrial Strategy (2018), 'Fuel mix disclosure data tables' 3. Environmental impact; Gridwatch (2019), 'UK Electricity National Grid co2 Output per Production Type', accessed 27 February 2019; de Gouw, et al. (2014), 'Reduced emissions of CO_2, NOx, and SO_2 from U.S. power plants owing to switch from coal to natural gas with combined cycle technology', *Earth's Future*, **2**, pp. 75–82; Intergovernmental Panel on Climate Change (2014), 'Annex III: Technology-specific Cost and Performance Parameters' in: 'Climate Change 2014: Mitigation of Climate Change. Working Group III Contribution to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change'.

Figure 2.7 Benchmarking of Frontier/LCP's emission factors—coal

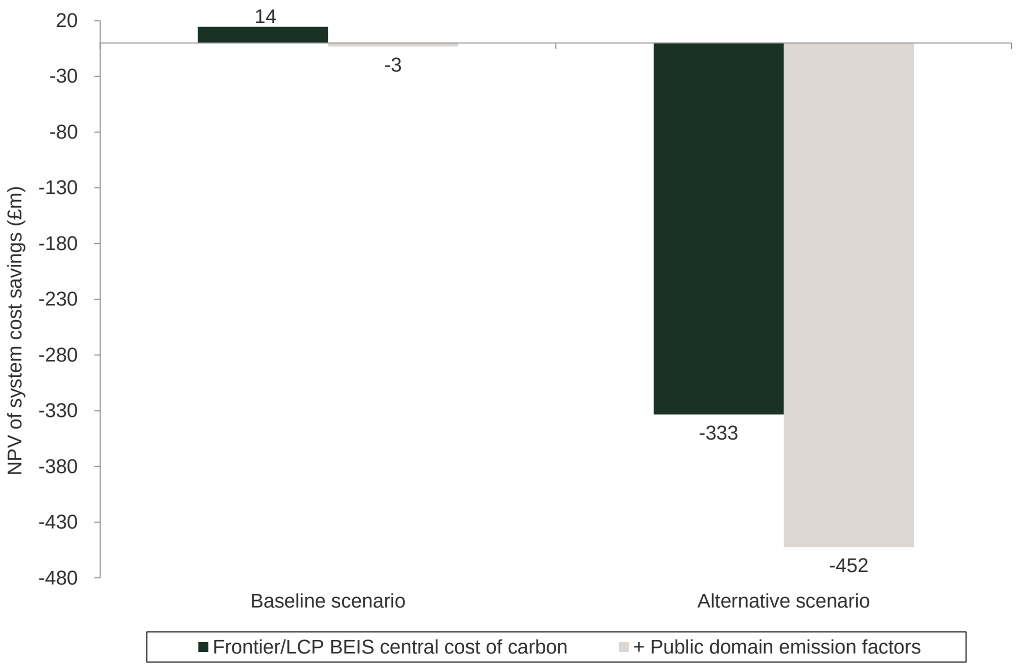


Note: Frontier/LCP figures are the minimum/maximum across the analysis period and both scenarios: baseline and alternative FES background.

Source: Oxera analysis based on data from Frontier/LCP; EDF Energy (2019), 'The climate challenge for each energy sources' , accessed 12 March 2019; Department for Business, Energy and Industrial Strategy (2018), 'Fuel mix disclosure data tables' 3. Environmental impact; Gridwatch (2019), 'UK Electricity National Grid CO2 Output per Production Type', accessed 27 February 2019; de Gouw, et al. (2014), 'Reduced emissions of CO_2, NOx, and SO_2 from U.S. power plants owing to switch from coal to natural gas with combined cycle technology', Chemical Sciences Division, NOAA Earth System Research Laboratory, Boulder, Colorado, USA, *Earth's Future*, **2**, pp. 75–82; Intergovernmental Panel on Climate Change (2014), 'Annex III: Technology-specific Cost and Performance Parameters', in 'Climate Change 2014: Mitigation of Climate Change. Working Group III Contribution to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change'.

2.39 The impact of using median emissions intensities from public sources on the system cost saving estimated from the TGR/BSUoS reform is illustrated in Figure 2.8 below. Under the corrected baseline scenario (i.e. using the BEIS central scenario CO_2 appraisal prices), adjusting for an alternative public domain estimate of emission factors increases system costs by £20m. Under the corrected alternative FES background scenario, the increase in system costs amounts to c. £80m.

Figure 2.8 Net present value of system cost savings using alternative emissions intensity assumptions



Note: A negative system cost saving means an additional system cost.

Source: Oxera analysis based on Frontier Economics and LCP (2018), 'Wider System Impacts of TGR and BSUoS Reforms', November, Figure 13 (Steady Progression) and Figure 23 (Community renewables); Frontier Economics and LCP (2018), 'Backing data for BSUoS and TGR reform', November; and various emissions intensity estimates from the public domain. See Figure 2.6 and Figure 2.7.

2D Risk analysis and cumulative impact

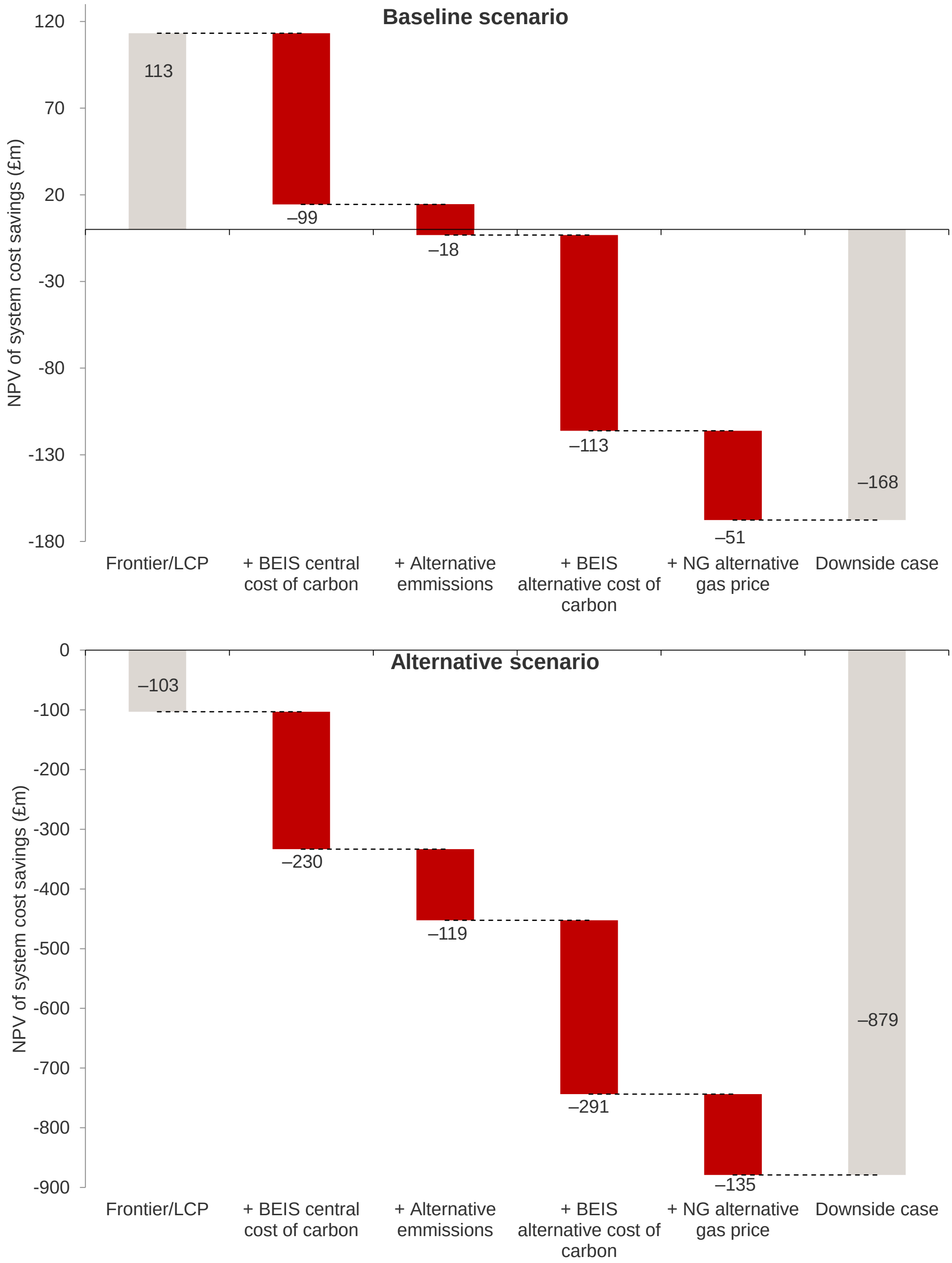
2.40 In their analysis of the TGR/BSUoS reform Frontier/LCP rely exclusively on 'central projections'.[55] However, the sources underpinning Frontier/LCP's analysis contain not just a single central scenario, but also a range of plausible estimates. It therefore appears appropriate to examine the risk associated with the TGR/BSUoS reform, in case the system cost drivers develop according to an unfavourable scenario.

2.41 In this report, as a sensitivity, we have examined a downside scenario in which the CO_2 prices and the gas prices both evolve in line with the upper estimates of the estimated range. In undertaking this sensitivity analysis, for CO_2 prices, we have used the high scenario, as defined by BEIS for the purposes of policy appraisal.[56] For gas prices, we have used the high scenario, published by National Grid in its Future Energy Scenarios.[57]

[55] Frontier Economics and LCP (2018), 'Wider System Impacts of TGR and BSUoS Reforms', November, p. 15.
[56] Department for Business, Energy and Industrial Strategy (2018),' Data_tables_1-19_supporting_the_toolkit_and_the_guidance_2017__180403_.xlsx'.
[57] For the avoidance of doubt, the same publication was used by Frontier/LCP.

2.42 As demonstrated in Figure 2.9, the TGR/BSUoS reform could lead to system cost savings being -£168m in the baseline scenario and -£879m in the alternative scenario if the CO_2 and gas prices were to evolve in line with the upper end of the range estimates by BEIS and National Grid respectively (cumulatively with the corrected cost of carbon values and alternative emissions factors discussed in sections 2B and 2C above).

Figure 2.9 Cumulative impact of alternative emissions intensity assumptions, CO_2 prices, and natural gas prices on system cost savings (£m)



Note: The numbers in this chart do not exactly reconcile with the numbers in all other figures in this report, due to rounding.

Source: Oxera analysis based on Frontier/LCP (2018), 'Backing data for residual charging wider system impacts', November; various emissions intensity estimates from the public domain. See Figure 2.6 and Figure 2.7; and National Grid (2018), 'Future Energy Scenarios', July.

2.43 The fact that the system costs increase significantly in the downside scenario does not on its own invalidate the case for the TGR/BSUoS reform. However, it indicates the need for further examination of risks and the design of risk mitigation mechanisms, to ensure that the negative effect of potential unintended consequences of the TGR/BSUoS reform are minimised.

2E When considered alongside Ofgem's other charging reforms and the uncertain outlook for other policy measures, the TGR/BSUoS reform increases regulatory uncertainty

2.44 Another aspect of the TGR/BSUoS reform that could materially affect future generation investment is the lack of clarity on how the TGR will be set to zero in future. Depending on the precise approach taken by Ofgem and National Grid to achieve this, further charging reforms could have significant adverse impacts on consumers, generators, and the system overall.[58] In particular, this reform could affect different generators very differently, potentially compounding the perception of regulatory uncertainty.

2.45 Moreover, the TCR is part of a longer-term set of reforms that are subject to significant uncertainty. The process is expected to last for a significant period of time, with the impacts of individual decisions being tightly linked. It is therefore unclear that the structure of network tariffs will prove stable over the medium term, which further increases regulatory uncertainty.

2.46 Ultimately, this regulatory uncertainty could make project cash flows more volatile and unpredictable from an ex ante perspective. Depending on how an investment project is appraised, this uncertainty can manifest itself in investors either adjusting downwards their expectations of project cash flows or using higher hurdle rates. In either case, the universe of potentially investible projects and technologies could shrink.

2.47 In the case of generation investments characterised by high sunk costs, the impact of greater uncertainty over future regulation could significantly increase the value of deferring a project. To the extent that investors exercise their 'option' to defer investment, this could lower the value of consumer and system

[58] National Grid (2018), 'Compliance with European Regulation 838/2010 Part B: Guidelines for A Common Regulatory Approach to Transmission Charging', 30 May.

benefits estimated by Frontier/LCP, either because 'marginal' projects are not taken forward, or because the realisation of the modelled benefits is delayed (and so discounted more heavily in Frontier/LCP's cost–benefit analysis).

2.48 Similarly, considerable uncertainty remains over future charging arrangements as a result of Ofgem's wide-ranging review of electricity network access and charging, including the potential for further BSUoS reform.

2.49 While valuing the cost of regulatory uncertainty is not straightforward, it is worth noting that the UK Competition and Markets Authority (previously the Competition Commission) opined on this matter in the Phoenix Natural Gas Limited appeal:

> We are not able to quantify the effects of a lack of regulatory stability, but we consider that the qualitative evidence suggests, notwithstanding the statutory position and the right of appeal, that such an effect [to increase the cost of capital] exists and that it is not so small that it can be disregarded.[59]

2.50 In addition, in the context of its decision on the mid-period review for RIIO-ED1, Ofgem has recognised that the 'benefits of maintaining regulatory confidence outweigh any short-term benefits to consumers', citing the evidence that reductions in 'regulatory confidence' could have the effect of increasing the cost of capital for distribution network operators.[60]

[59] Competition Commission (2012), 'Phoenix Natural Gas Limited price determination', 28 November, para. 33.
[60] Ofgem (2018), 'Decision on a Mid-Period Review for RIIO-ED1', 30 April, paras 3.21–3.23.

3 Implications of the proposed TGR and BSUoS reform

3.1 When proposing changes to the energy market, Ofgem needs to ensure that the impacts of any reform are in line with its policy objectives:

> The central aim of our energy policy is to deliver an affordable, secure and sustainable energy system. This supports our principal objective, which is to protect the interests of present and future consumers.[61]

3.2 As demonstrated in the previous section, our review of the Frontier/LCP IA has uncovered risks with the TGR/BSUoS reform, which may prove counterproductive to achieving Ofgem's key policy objectives.

3.3 In particular, in order for Ofgem to deliver the central aim of its energy policy any reform needs to promote the affordability, security of supply, and sustainability of the energy system. In the context of the assessment in this section, we focus on the decarbonisation agenda as a key element in delivering a sustainable energy system. Specifically, we note Ofgem's statutory obligations 'to protect the interests of existing and future consumers […], including their interests in the reduction of greenhouse gases'.[62] Accordingly, we discuss each of affordability, security of supply and the decarbonisation agenda, in turn, below.

3A Implications for affordability

3.4 An increase in system costs affects all energy customers, from small domestic households to large businesses. As costs are passed through the supply chain, one of Ofgem's objectives is to ensure an affordable energy system in which the prices that customers pay deliver value for money while having regard for the other two objectives. Ofgem aims to achieve this objective by promoting efficiency and encouraging energy suppliers and network companies to deliver value for money, and by ensuring that customers have access to transparent market information to make informed choices.[63]

3.5 To the extent that the TGR/BSUoS reform will generate a cost shock to the supply side of the market, the reform may have implications for affordability. Indeed, a report for the National Infrastructure Commission estimates that '[i]n a system with a high degree of flexibility, 80% RES [renewable energy source]

[61] Ofgem, 'Promoting value for money', accessed 28 February 2019.
[62] Ofgem (2013), 'Powers and duties of GEMA', 19 July, para. 1.4.
[63] Ofgem, 'Promoting value for money', accessed 28 February 2019.

becomes the cost-optimizing option.'[64] This pathway could 'save consumers up to £58 per year'.[65]

3.6 As set out in section 2, and illustrated in Figure 2.3, the TGR/BSUoS reform could lead to additional consumer costs of £800m–£1.3bn in the baseline scenario and £4.3bn–£7.6bn in the alternative scenario, relative to Frontier/LCP's estimates.

3B Implications for security of supply

3.7 Ofgem states that the legal framework in which it operates requires that it supports the interests of consumers, which includes the security of the energy system. To achieve this objective, Ofgem's work programme is designed to give energy companies confidence that the investments they make will be appropriately remunerated over the life of the assets.[66]

3.8 To the extent that the TGR/BSUoS reform results in a welfare transfer from existing generators while also adversely affecting the investment incentives for a significant share of future capacity, as described in the previous section, the TGR/BSUoS reform may have security of supply implications.

3.9 In their IA, Frontier/LCP touch on the impact of the TGR/BSUoS reform on security of supply by considering the effect of the report on the Loss of Load Expectation (LOLE). Frontier/LCP conclude that, while the reform has a negative impact on LOLE, there should be no concerns for security of supply:[67]

> The LOLE is shown to increase in most years, indicating the system is less secure. This is a result of higher CM [Capacity Market] 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.

3.10 However, if any of the risks examined in section 2 were to materialise, it is not clear whether the LOLE would remain within its target range.

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[64] Aurora (2018), 'Power sector modelling: System cost impact of renewables—Report for the National Infrastructure Commission', 24 May, p. 38.
[65] Aurora (2018), 'Power sector modelling: System cost impact of renewables—Report for the National Infrastructure Commission', 24 May, p. 40.
[66] Ofgem, 'Promoting security of supply', https://www.ofgem.gov.uk/about-us/how-we-work/promoting-security-supply, accessed 28 February 2019.
[67] Frontier and LCP (2018), 'Wider System Impacts of TGR and BSUoS Reforms', November, p. 17.

3.11 For instance, the negative potential effect of the TGR/BSUoS reform on investment in unsupported distributed wind and solar generation, as described in section 2A.2, is not considered in the Frontier/LCP IA.

3C Implications for decarbonisation

3.12 In line with the UK's decarbonisation agenda and its statutory duties, Ofgem promotes sustainability in the GB energy system. This includes reducing greenhouse gas emissions and in general contributing to the achievement of sustainable development, including air quality and associated impacts from thermal generation. Ofgem recognises the challenges that energy companies face in moving to a low-carbon economy, and intends to address these challenges when deciding on regulatory reforms.[68]

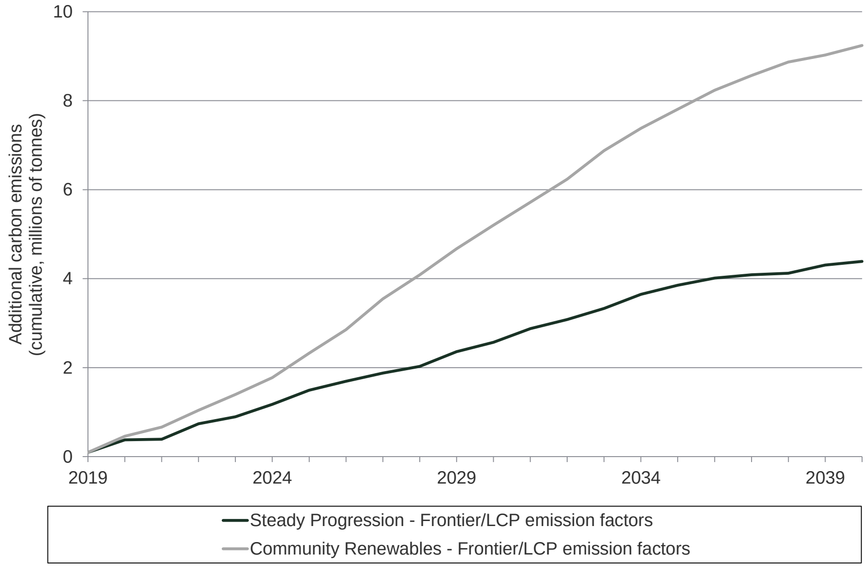
3.13 To the extent that the TGR/BSUoS reform will affect the investment incentives for distributed renewable capacity, as described in section 2, the TGR/BSUoS reform may have significant implications for the UK's legally binding decarbonisation and air quality targets.

3.14 The basis of the UK's decarbonisation agenda is the Climate Change Act 2008.[69] The Act stipulates that the UK government must reduce greenhouse gas emissions by 2050 by at least 80% relative to the levels recorded in 1990. To achieve this, the Act requires the government to set five-year carbon budgets—caps on the amount of greenhouse gases emitted in the UK—and to develop policies and proposals that ensure that the budgets are met.[70] Currently agreed carbon budgets require the UK to reduce greenhouse gas emissions by 51% by 2025 and 57% by 2030.[71] In addition, in 2016 the UK ratified the 'Paris Agreement', which provides a framework to keep global warming below 2°C. As part of the Paris Agreement negotiations, the UK government supported several key initiatives, such as improving national carbon-reduction strategies and advancing innovation to drive forward clean energy.[72] According to the CCC, the UK government's current plans and proposals to meet the carbon budgets are not sufficient.[73]

[68] Ofgem, 'Promoting sustainability', https://www.ofgem.gov.uk/about-us/how-we-work/promoting-sustainability, accessed 28 February 2019.
[69] Climate Change Act 2008, accessed 28 February 2019.
[70] Climate Change Act 2008, accessed 28 February 2019.
[71] Committee on Climate Change (2018), 'Reducing UK emissions. 2018 Progress Report to Parliament', p. 30, accessed 28 February 2019.
[72] Department for Business, Energy and Industrial Strategy (2016), 'UK ratifies the Paris Agreement', accessed 28 February 2019.
[73] Committee on Climate Change (2018), 'Reducing UK emissions. 2018 Progress Report to Parliament', p. 36, accessed 28 February 2019.

3.15 The TGR/BSUoS reform is expected to increase CO_2 emissions in GB. The additional carbon emissions calculated by Frontier/LCP as a result of introducing the TGR/BSUoS reform are shown in Figure 3.1 below. The average annual increase in CO_2 emissions as a result of the TGR/BSUoS reform is 0.20m tonnes in the baseline scenario, and 0.42m tonnes in the alternative FES background.

Figure 3.1 Additional CO_2 emissions resulting from the TGR/BSUoS reform, as estimated by Frontier/LCP



Source: Oxera analysis based on data from Frontier/LCP.

3.16 Frontier/LCP explain that the increase in CO_2 emissions illustrated above is a result of:[74]

- a reduction in electricity imports, which increases emissions within GB, but not necessarily in Europe as a whole, since the emissions intensity of imports is assumed to be zero (following the 'production-based' accounting convention); and
- a reduction in the change in renewable generation as a result of the TGR/BSUoS reform in later years within GB.

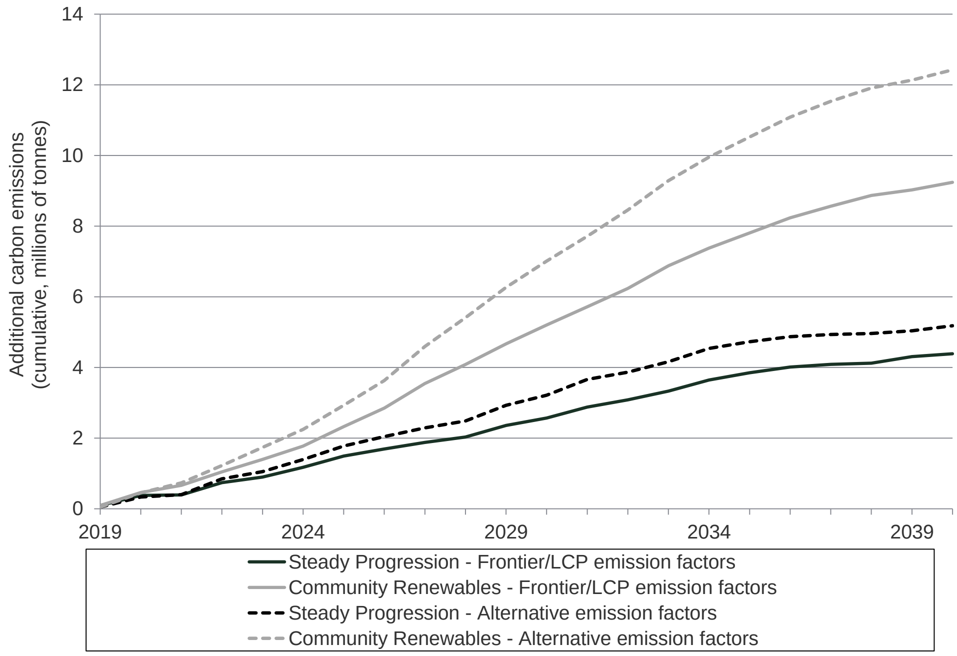
3.17 Frontier/LCP estimate the additional CO_2 emissions in the Great Britain as a result of the TGR/BSUoS reform to be between 0.20m tonnes and 0.42m tonnes per annum, averaged over the period 2019–40. As illustrated in section 2C, the emission factors implied by Frontier/LCP's modelling appear low for coal and gas generation. Using median emissions factors sourced from the

[74] Frontier and LCP (2018), 'Wider System Impacts of TGR and BSUoS Reforms', November, p. 20.

public domain (which are more consistent with BEIS values for policy appraisal) implies that the additional emissions resulting from the TGR/BSUoS reform range from 0.24m tonnes to 0.56m tonnes (see Figure 3.2 below).

3.18 To put this into context, the additional emissions resulting from the TGR/BSUoS reform are equivalent to 1–2% of the CCC's total electricity grid emissions budget for 2032, i.e. the end of the fifth carbon budget.[75]

Figure 3.2 Potential additional CO_2 emissions resulting from the TGR/BSUoS reform, based on alternative emissions intensity estimates



Source: Oxera analysis based on data from Frontier/LCP, Department for Business, Energy and Industrial Strategy (2018), 'Fuel Mix Disclosure Data Table', 3. Environmental impact; and various emissions intensity estimates from the public domain. See Figure 2.6 and Figure 2.7.

3.19 In sum, Frontier/LCP modelling appears to indicate that the TGR/BSUoS reform could have a detrimental impact on CO_2 emissions in GB. This is particularly relevant given the scale of the challenge to meet the UK's 2050 CO_2 reduction targets.

[75] CCC (2016), 'CCC fifth carbon budget: central scenario data', 6 June.

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