<u>Targeted Charging Review (TCR): minded to decision and draft impact assessment</u>

<u>Consultation Response – E.ON</u>

Executive Summary:

- **E.ON believes that the future of the energy system will be smarter, more flexible, decentralised, decarbonised and digitalised.** As we transition to this future, we accept the need to remove market distortions, including those associated with network charging arrangements, to ensure an efficient outcome for customers. **We are therefore very supportive of Ofgem's guiding principles**, of reducing harmful distortion, ensuring fairness and considering the proportionality and practicality of options.

- However, **E.ON does not believe that the current charging arrangements have the correct balance between forward-looking charges and residual costs**, and we are concerned that there has been no independent analysis to assess whether or not the current split/balance is appropriate. As such, our view is that, in order to deliver the most efficient system for customers, **there are very strong grounds for undertaking a comprehensive review of the underlying drivers of network costs**. This will provide confidence to all investors and customers that the split between forward-looking costs and sunk costs is appropriately reflected within network charges.

- Therefore, E.ON would like to see an **expansion of the scope of the Access and Forward-Looking Charge Significant Code Review (SCR)** to include the required analysis highlighted above and **an alignment of the timetables for delivery and implementation of the TCR SCR and the Access and Forward-Looking Charge SCR.** This will ensure that reforms to residual charges are not delivered prior to appropriate reforms to the forward-looking charges.

- **E.ON recommends that the RIIO-2 framework should clearly describe the cost drivers for network investment in order to establish which costs are forward-looking and which are residual.** The charging methodologies should then reflect these cost drivers. This will allow a transparent regime where network users can see the costs they create but also areas where their decisions will save costs for the system. **Failure to appropriately determine the correct split will result in a less efficient charging regime**, as the signals given through forward-looking charges are dulled, causing customer to pay more than they need to.

- E.ON suggests that the approach Ofgem has taken to the reform of the remaining non-locational embedded benefits, and in particular reform of Balancing Services Use of System (BSUoS), has not been well structured. **E.ON believes that a thorough review of BSUoS is required prior to any decision being made on BSUoS reform**. We welcome the creation of the Electricity System Operators (ESO) led BSUoS task force and believe that this is necessary to determine whether there are any elements of BSUoS which should and can provide cost-reflective forward-looking charges. Ofgem can then form a minded-to decision in this area to allow a consultation with wider industry (given the limited membership of the task force). Only then, should reforms to remaining elements of BSUoS be considered (such as who should pay and on what basis e.g. gross vs. net volumes), either as part of this SCR or through code modifications.

Question 1: *Do you agree that residual charges should be levied on final demand only?*

1. E.ON understand the rationale of levying residual charges on final demand only, given that such charges are effectively paid by final demand either directly through the charges suppliers face and pass through, or indirectly through energy or capacity market prices which seek to recover the charges generators face.
2. Whilst E.ON does not necessarily disagree with levying residual charges on final demand only, this view is entirely dependent upon the residual charge only recovering fixed or sunk costs, which customers should not be able to avoid. We believe that a comprehensive review of the underlying drivers of network charges needs to be undertaken to ensure that the split between forward-looking costs and sunk costs is appropriately reflected in the charges. We have repeatedly outlined[1] several issues which challenge the current split between forward-looking charges and residual charges.
3. We believe that the RIIO-2 framework should clearly describe the cost drivers for network investment in order to establish which costs are forward-looking and which are residual. The charging methodologies should then reflect these cost drivers. This will allow a transparent regime where network users can see the costs they create but also areas where their decisions will save costs for the system. Failure to appropriately determine the correct split will result in a less efficient charging regime, as the signals given through forward-looking charges are dulled, causing customers to pay more than they need to.

Question 2: *Do you agree with how we have assessed the impacts of the changes we have considered against the principles? If you disagree with our assessment, please provide evidence for your reasoning.*

4. E.ON agrees with the principles Ofgem has used to assess the impacts of the proposals. Reducing harmful distortion, ensuring fairness and considering the proportionality and practicality of options are all important in determining the best outcome for customers.
5. However, it is vital that these are applied on a concrete basis of what drives the various network charges. For example, should the current residual charge include substantial elements which should be represented by a forward-looking charge, then there may be less distortion in allowing users to avoid the whole residual. Stopping users avoiding this charge without correcting the costs that are included within the residual charge could result in a less efficient charging regime, increasing costs to customers.
6. Notwithstanding the above, the two leading options identified by Ofgem appear to be the best when assessed against the guiding principles. In many ways, the two leading options are very similar, they just apply different methodologies to determine the arbitrary allocation of costs between charging segments.
7. The fixed charge uses volume to allocate the costs between charging segments. We agree that using historic volume has limitations in that it will effectively lock-in the current allocation of costs. Given that Ofgem believe this includes distortions, it would appear sensible to choose an alternative. Allowing the charges to be updated year on year as volumes change will help to mitigate this. However, the residual charge should recover historic or sunk costs of the networks. Given that historic investment in networks was primarily driven by meeting

[1] E.ON Response to CMP264/265 Consultation in April 2017, Letter to Jonathon Brearley on 23 April 2018, Response to Ofgem Consultation on Access and Forward-looking Charges on September 2018.

capacity needs rather than volumetric needs, it is self-evident that the choice to use volume is an arbitrary regulatory judgement.

8. Whilst the deemed capacity option appears to be based on a more robust rationale by linking charges to capacity, it also has several issues. The first is that once again, an arbitrary regulatory judgement is needed to set the deemed capacity of domestic customers. Initial analysis used a deemed capacity of 18kVA which resulted in domestic customers paying a significantly greater share of the costs than they do now. This option was refined by reducing the deemed capacity to 4kVA, with higher capacities of 6kVA and 8kVA deemed for owners of heat pumps and electric vehicles (EVs). This results in domestic customers paying a similar share of the costs to those they pay now. Again, it is apparent that an arbitrary regulatory judgement was made for this option.

9. Whilst Ofgem endeavoured to refine options to avoid arbitrary regulatory judgements, it is clear that they have been unable to do so. Given that this effectively determines how much each segment contributes towards the sunk costs of the system, we believe that this should be a policy decision rather than a regulatory one.

10. We agree that the deemed capacity option is likely to be a more equitable solution than the fixed charge (assuming the existing charging segments are maintained) but it does have additional issues around practicality. It is not clear how domestic consumers with heat pumps or EVs will be identified to apply the appropriate charges to suppliers and subsequently to these customers. In addition, it is not clear why these technologies should be singled out – it is the overall capacity need of the property that is important, not the technology or purpose of consumption that drives this. It therefore appears that the fixed charge option is likely to be more proportional and practical.

Question 3: *For each user, residual charges are currently based on the costs of the voltage level of the network to which a user is connected and the higher voltage levels of the network, but not from lower voltage levels below the user's connection. At this stage, we are not proposing changes to this aspect of the current arrangements. Are there other approaches that would better meet our TCR principles reducing harmful distortions, fairness and proportionality and practical considerations?*

11. E.ON believes that as the energy system continues to transition towards a smart, low-carbon system supported by decentralised, flexible technologies, there will be an increasing need to operate on a whole systems basis. This includes the expansion of the ESO role to include operation of distribution networks by taking on the role of the distribution system operator (DSO).

12. Under such a world, it is likely that the charging framework should replicate the operating arrangements such that there are whole systems charges for all users, rather than separate charges for transmission network users, distribution network users and balancing services. Currently, there are distinct charges for the transmission system, distribution system and balancing and these are applied differently to users. E.ON believes a whole systems charge would lead to the most efficient outcome for the energy system, thereby minimising costs to customers. However, we do recognise that this would require a substantial overhaul of the current charging arrangements and that it may therefore be better to take a more incremental approach. Ensuring the current charges are fit for purpose is a sensible first step in this.

Question 4: *As explained in paragraphs 4.41, 4.43, 4.46, 4.49, 4.80, we think we should prioritise equality within charging segments and equity across all segments. Do you agree that it is fair for all users in the same segment to pay the same charge, and the manner in which we have set the segments? If not, do you know of another approach with available data which would address this issue? Please provide evidence to support your answer.*

13. In theory, Ofgem's approach to equity and equality seems sensible. It appears fair for similar groups of users to pay similar charges (i.e. equality within charging segment), whilst different groups of users should pay different charges (i.e. equity across segments).
14. However, this approach then increases the importance of establishing correct charging segments. The nature of the residual charge is such that determining the user segments and deciding how much each segment should pay is effectively an arbitrary decision. Having fewer charging segments would result in charges within segment being increasingly inequitable, with significant boundary impacts across segments. However, having too many charging segments increases complexity and reduces the practicality and proportionality of the change.
15. E.ON would suggest that the issues associated with having too few charging segments, particularly for larger non-domestic customers are more significant, and hence Ofgem should have a greater focus on equity across this customer segment when choosing how to divide them up into charging segments.

Question 5: *Do you agree that similar customers with and without on-site generation should pay the same residual charges? Should both types of users face the same residual charge for their Line Loss Factor Class (LLFC)?*

16. In principle, similar customers should pay similar residual charges. However, this is entirely predicated on the residual charge being appropriate by ensuring that the balance between residual and forward-looking charges is correct. Without this being clearly demonstrated in the charging regime, the benefits that sites with on-site generation can bring to the system will not be recognised, thereby inhibiting the deployment of this technology. This would create a major distortion to the market, leading to customers paying more than they should for their electricity requirements.

Question 6: *Do you know of any reasons why the expected consumer benefits from our leading options might not materialise?*

17. The modelling conducted by Frontier Economics to support Ofgem's analysis is subject to significant uncertainty. As is common in such circumstances, numerous scenarios and sensitivities have been modelled to show the potential range of outcomes which result in consumer benefits of £0.52bn to £1.57bn (NPV) for the full reform options. These benefits are calculated over the period 2019 to 2040 and as such are actually a very small fraction of the overall networks costs during this period[2]. The results will therefore be very sensitive to the input assumptions used.
18. In particular, there are some key areas which could have a significant impact on the expected consumer benefits and potentially result in consumer detriment:
    a. In the Steady Progression scenario, the consumer benefits of full reform are expected to be £540m, primarily driven by the savings of reduced triad avoidance payments and

[2] Simply extrapolating the current annual allowed revenues for the networks would lead to close to £200bn of costs. Therefore, even the largest expected consumer benefit is less than 1% of this cost.

reduced distribution charge avoidance payments. These benefits are offset to a degree by the increase in consumer costs associated with increased capacity market (CM) clearing prices. The CM clearing price is highly sensitive to assumptions driving the cost of new entry. It is entirely plausible that the CM prices might go up by more than modelled (e.g. if the capex or opex assumptions increased slightly). A further increase of just £1/kW over the increase already modelled under full reform, would in fact entirely remove the consumer benefit and result in a consumer detriment[3].

b. In the Consumer Renewables scenario, the consumer benefit is expected to be substantially higher at £1.23bn. However, the modelling shows that all of this benefit arises in the 2030s. The Consumer Renewables counterfactual scenario has significantly more flexible Behind the Meter Generation (BTMG) to support the large amounts of intermittent renewables built in the 2030s. The savings from reducing residual charge avoidance payments are therefore large as much of this is replaced by Combined Cycle Gas Turbines (CCGTs). However, it is not clear that CCGTs could deliver the amount of flexibility needed in such an energy system. If it cannot, then BTMG would still be needed to deliver this valuable service. Under the modelling assumptions used, this would increase the capacity market prices, eroding much, if not all of the expected consumer benefit[4].

c. The impact of the size of the residual has also been modelled. This is an extremely important scenario, as we believe that a comprehensive review of the actual cost drivers of the network would likely reduce the residual charge, replacing it with an increased forward-looking charge. Under the Low Residual scenario, the consumer benefit is expected to be £520m, similar to the Steady Progression scenario. This is a counter-intuitive result and further analysis shows that all of this benefit can be attributed to a saving in capacity market costs in the period 2037-2039[5]. Whilst the data provided by Frontier Economics is not complete enough to fully understand this, it appears that new build generation is required in the Low Residual Counterfactual, that is not then required in the full reform scenario. There is then a corresponding reduction in capacity market prices in the full reform scenario which delivers a consumer benefit. Due to the high uncertainty of this particular assumption, it is worth considering the impact if it is removed – namely, all of the consumer benefit disappears.

19. Whilst the issues highlighted above share the same overall uncertainty as the initial modelling conducted by Frontier, they clearly illustrate several plausible circumstances where there is far less consumer benefit and potentially even a consumer detriment as a result of the full residual reform proposals.

20. E.ON has strongly advocated a robust and comprehensive review of network charges as we have highlighted in our answers to previous questions in this consultation. Ofgem have repeatedly suggested that the scale of the distortion created by the current residual charging

[3] The Frontier modelling forecast installed capacities of different technologies over the modelled period. Assuming the current CM de-rating factors remain over that period, then the CM would procure c.50GW. A £1/kW increase from 2023 onwards (the period after current CM agreements) would increase CM costs by £50m/yr. this has a total cost of £900m to 2040, which applying the 3.5% discount rate gives c.£650m NPV cost. Given the expected consumer benefit of £540m, this sensitivity would result in a consumer detriment of £90m NPV over the period.

[4] In the Consumer Renewables scenario, the consumer benefit is expected to be £1.23bn. Using similar logic to above of c.50GW of capacity procured in the CM, an increase of less than £2/kW in the assumed CM prices would eliminate this consumer benefit.

[5] CM cost saving is £313m in 2017, £317m in 2038 and £368m in 2039 for a total cost of £999m. This equates to a cost saving of c.£514m NPV. Given the expected consumer benefit of £520m, removal of just these cost savings would almost entirely remove the overall expected consumer benefit.

framework means that this needs urgent reform ahead of a more thorough review. E.ON believes that the modelling work has shown that Ofgem has over-estimated the scale of any potential issue with residual charges and hence has been mistaken in prioritising this ahead of a broader and more comprehensive review.

Question 7: *Do you agree that our leading options will be more practical to implement than other options?*

21. E.ON agrees that the leading options are likely to be more practical to implement than the other options that were assessed. They would not lead to the need for sweeping changes of the existing tariff structures and hence will be more practical to implement and communicate to our customers.

Question 8: *Do you agree with the approaches set out for banding (either LLFC or deeming for agreed capacity)? If not please provide evidence as why different approaches to banding would better facilitate the TCR principles.*

22. As we have highlighted, the approach for banding is an arbitrary regulatory decision which will determine how much each segment contributes towards the overall costs. We agree with the principles Ofgem have used in their assessment, but believe that it should be a policy decision as to how much each segment pays.

Question 9: *Do you agree that LLFCs are a sensible way to segment residual charges? If not, are there other existing classifications that should be considered in more detail?*

23. E.ON agrees that using existing industry processes will reduce the implementation costs and hence be more practical and proportionate. However, as these processes were not designed with this purpose in mind, they need to be robustly assessed to ensure that there are no unintended consequences and that they are fit for purpose. The use of LLFCs appears reasonable but should be assessed against other potential options such as Measurement Class (MC) to ensure it is the best solution.

Question 10: *Do you agree with the conclusions we have drawn from our assessment of the following?*

a. distributional modelling
b. the distributional impacts of the options
c. our wider system modelling
d. how we have interpreted the wider system modelling?

Please be specific which assessment you agree/disagree with.

24. The modelling conducted by Frontier Economics using the scenario and sensitivity analysis resulted in expected wider system benefits of £0.79bn to £3.22bn (NPV) for the full reform over the period of 2019 to 2040. Again, in relation to the overall system costs during this period, these savings are a small fraction and hence are very sensitive to input assumptions. We highlight several areas where this could impact the conclusions drawn from the modelling:

    a. The expected £1bn system savings in the Steady Progression scenario are calculated using a social discount rate of 3.5%. Whilst this rate might be reasonable for modelling consumer benefits, it is less suitable for modelling system benefits. It is too low to be consistent with the hurdle rates required for investment in generation technologies of all types, particularly given the current environment of regulatory uncertainty. Increasing this hurdle rate to, say 6.5%, reduces the system savings to £650m.

b. £500m of the expected system savings come from a reduction in capex due to delays in the retirement of existing plant and lower capex associated with new build capacity. Whilst the granularity of the data does not allow full examination of the assumptions, it is counter-intuitive to have lower capex under full reform where more expensive CCGTs are built instead of cheaper BTMG. Additionally, delaying the retirement of existing plant should result in higher fuel, variable operating & maintenance (VOM) and opex costs as these plant are less efficient.

c. There are also significant expected system savings of £300m associated with carbon savings from running CCGTs rather than BTMG. The actual carbon emission reductions (and by extension fuel and VOM reductions) can be debated given the impact of the operating regime of these generators at low load factors, but the primary driver of this saving is the carbon price assumed. This uses BEIS's most recent published carbon price, which goes from £4.37/tCO2e in 2019 to £79.43/tCO2e in 2030 (real 2017 prices). This is a significant increase in carbon price and it would be prudent to test the impact against other carbon price assumptions. The Autumn Budget 2017 stated that the current (at the time) total carbon price (i.e. EU emissions trading scheme (ETS) plus the carbon price support (CPS)) was set at about the right level. The 2018 Budget stated it would maintain the CPS at £18/tCO2 until 2021 but reduce it thereafter if the total carbon price remains high (at the time the total carbon price was around £36/tCO2). These statements recognise that it is plausible that the total carbon price could be significantly lower than the BEIS projection. Using a lower carbon price would remove much of the savings associated with carbon.

25. Taken in isolation, the points above are significant, but taken together they could plausibly reduce much of the expected system savings. The expected system savings in the Consumer Renewables scenario are substantially higher at £3.22bn, but the impacts of the above issues scale in a similar way. It is therefore not clear that the expected system benefits of the full reform options will be realised.

Question 11: *Do you agree with our proposed approach to the reform of the remaining non-locational Embedded Benefits?*

26. E.ON believes that the approach Ofgem has taken to the reform of the remaining non-locational embedded benefits, and in particular reform of BSUoS, has not been well structured.

27. The potential impacts of the remaining non-locational embedded benefits (EB) reforms has been assessed against scenarios which assume the proposed full reforms to residual charges takes place. Given that these proposals are currently just a minded-to position, they may not occur to the full extent assumed. It would therefore be good practice to assess the remaining non-locational EB reforms against a counterfactual in which no other reforms (other than those already approved by Ofgem e.g. due to code modifications) take place.

28. It would be good practice to identify the individual impacts of the proposed reforms so that the impact of the transmission network use of system (TNUoS) generation residual (TGR) reform can be separately assessed from the BSUoS reforms. Conflating these together in the analysis makes it difficult to understand the true drivers of the system and consumer savings/costs.

a. In the Steady Progression counterfactual scenario, there is an expected consumer benefit of £4.5bn over the period of 2019 to 2040 for the TGR and full BSUoS reform option. This is driven by £6.9bn consumer savings associated with TGR reform reducing TNUoS demand residual (TDR) payments and £2.6bn consumer savings from reduced BSUoS payments. These are offset by £1.4bn increase in contract for differences (CfD) payments and £4bn increase in capacity market payments.

b. Assessing the TGR and BSUoS reforms together makes it impossible to determine the individual impact in CfD and capacity market payments of each reform. It is therefore not clear how much of the expected consumer benefit can be ascribed to the TGR reform and how much to the BSUoS reform. It is therefore important that the assessment is detailed enough to identify the impacts of the reforms separately.

29. Ofgem's current approach also risks unintended consequences and inefficient outcomes. For example, the full BSUoS reform proposes removing the embedded benefits and charging exporting embedded generators for BSUoS. However, any BTMG will not be impacted by this and hence a discrimination between exporting embedded generation and BTMG will be created with no clear justification. Ofgem recognise this risk and suggest it could be resolved in the future by charging BSUoS on a similar basis to their proposed solution to the network residual charges. Furthermore, given that residual charges are proposed to be levied on final demand only, it appears inefficient to take an approach which introduces charges on exporting embedded generators on the one hand and then removes them at some later point by only charging on demand.

30. E.ON believes that a thorough review of BSUoS is required prior to any decision being made on BSUoS reform. We welcome the creation of the ESO-led BSUoS task force and believe that this is necessary to determine whether there are any elements of BSUoS which should and can provide cost-reflective forward-looking charges. Ofgem can then form a minded-to decision in this area to allow a consultation with wider industry (given the limited membership of the task force). Only then, should reforms to remaining elements of BSUoS be considered (such as who should pay and on what basis e.g. gross vs. net volumes), either as part of this SCR or through code modifications.

31. E.ON also notes that the ESO is preparing a CUSC code modification to address the proposed reform to the TGR. This modification will build upon the decision of Ofgem and the Competition and Markets Authority (CMA) regarding code modification CMP261 and the application of EU Regulation 838/2010 with regards to generation network charges. This modification is likely to be complex and time-consuming in nature and we therefore urge Ofgem to allow this modification to run its course before making any firm decisions on TGR reform.

32. It should also be noted that the modelling shows that the majority of the impact of these reforms falls upon existing renewable generators, who will see their charges alter significantly. Transmission connected renewable generators will see an increase in their TNUoS charge and distribution connected generators will lose the BSUoS embedded benefit and may be charged BSUoS. Unlike conventional generation, which can pass these increased costs through to their CM prices, existing renewable generation will have no way to mitigate these increased costs. Furthermore, the limited ability for onshore wind developments to access CfDs means these reforms will inhibit the future deployment of this technology.

Question 12: *Do you agree with our proposal not to address any other remaining Embedded Benefits at this stage? Which of the embedded benefits do you think should be removed as outlined in xx? Please state your reasoning and provide evidence to support your answer.*

33. Yes, E.ON agrees with this approach given the small size of these embedded benefits and the overall amount of change and reform taking place.

Question 13: *Are there any reasons we have not included that mean that the remaining Embedded Benefits should be maintained?*

34. No comment.

Question 14: *Do you agree with our proposed approach to transitional arrangements for reforms to:*

- *a. transmission and distribution residual charges*
- *b. non-locational Embedded Benefits?*

Please provide evidence to indicate why different arrangements would be more appropriate.

35. The proposed reforms to residual network charges will have a significant impact on the market and therefore it is important to ensure that there is an effective implementation that allows parties to manage these impacts.
36. Suppliers, generators and flexibility providers typically contract at least one year and often several years in advance. Whilst these contracts should have prudently accounted for risks associated with regulatory reform, E.ON believes that implementation in April 2020 could not be fully managed in many of these contracts and therefore agree with Ofgem that implementation should not occur before April 2021.
37. Furthermore, we have highlighted in our previous answers that there is the need for a comprehensive review of forward-looking charges in order to ensure that there is the right balance between forward-looking charges and residual charges to ensure an effective and efficient charging regime. E.ON believes it would be inefficient to implement any reforms to the residual charges ahead of this review and hence it may be required to delay implementation beyond April 2021 to align the timetable.
38. Similarly, E.ON believes that there is significant work required to develop proposals to potentially structurally reform BSUoS and to ensure the reform to TGR can be delivered. An implementation timescale of April 2020 for the currently proposed reforms to TGR and BSUoS risks undermining this work, constraining its depth and detail. We would therefore recommend that implementation should not occur before April 2021 at the earliest.

Question 15: *Do you agree with our minded to decision set out? If not please state your reasoning and provide evidence to support your answer.*

39. E.ON agrees that residual charges should take the form of the Fixed Charges option but only if appropriate analysis has taken place to identify the cost drivers of the network and reflect these in reformed forward-looking charges. To precipitously make reforms to residual charges in advance of this critical piece of work risks unintended consequences and potentially inefficient outcomes.

40. E.ON agrees that it is sensible to try and use existing industry processes to apply the charge. However, these need to be suitably assessed against other options to ensure they are fit for purpose.
41. E.ON believes any reforms which are brought forward should be aligned with the timetable for the Access and Forward-looking charges SCR.
42. E.ON believes that there is a requirement for significantly more analysis to be undertaken before any decisions can be made on reform of the other non-locational embedded benefits. We welcome the creation of an ESO-led BSUoS Task Force and believe this will be critical in taking this area forward. It does not appear sensible to propose charging embedded generation for BSUoS prior to fully understanding the cost drivers of BSUoS and hence determining what the residual component should be, given Ofgem's clear view that residual charges should only be levied on final demand.

Question 16: *For our preferred option do you think there are practical consideration or difficulties that we have not taken account of? Please provide evidence to support your answer.*

43. We have highlight several areas which we think need further consideration earlier in this response.