EP UK Investments

Response to Ofgem Consultation on Targeted Charging Review: minded to decision and draft impact assessment

4 February 2019

About EPUKI

EP UK Investments (EPUKI) is a UK energy company, primarily focusing on power generation from conventional and renewable sources.

EPUKI represents the UK interests of Energetický a průmyslový holding (EPH), a leading Central European energy group that owns and operates assets in the Czech Republic, the Slovak Republic, Germany, Italy, the UK and Hungary. EPH is a vertically integrated energy utility covering the complete value chain ranging from highly efficient cogeneration, power generation, and natural gas transmission, gas storage, gas and electricity distribution and supply. The companies in the group employ nearly 25,000 people.

EPH is the largest supplier of heat in the Czech Republic, the biggest electricity producer and the second biggest electricity distributor and supplier in Slovakia and ranks as the second biggest lignite producer in Germany. It is also an operator of a robust transmission network in Europe, a key transporter of Russian natural gas to Europe and the biggest gas distributor in Slovakia. In total it has 24 GW of heat and power capacity including coal, lignite and renewables.

EPH entered the UK market in 2015 through the purchase of Eggborough Power Limited. In 2016, EPH purchased Lynemouth Power Limited, the owner and operator of a 420 MW coal-fired power station in Northumberland which holds a Contract for Difference for full biomass conversion. In September 2017 EPH acquired Langage and South Humber Bank combined cycle gas turbine (CCGT) power stations from Centrica plc, with a combined capacity of 2.3 GW. EPUKI continues actively to pursue other acquisitions and new build opportunities in the UK electricity market, including the Eggborough and King's Lynn B CCGT projects.

General comments

EPUKI welcomes the opportunity to respond to Ofgem's consultation on its minded to decision and draft impact assessment for the Targeted Charging Review (TCR). We have long been concerned that the current charging regime creates distortions between transmission-connected, distributed and onsite generation, all of which compete in the same wholesale, capacity and ancillary service markets. The TCR, together with the Significant Code Review of Electricity Network Access and Forward-Looking Charging, is working towards the removal of these distortions and creating a level playing field between all forms of generation. We are therefore supportive of these reviews and many of the proposals set out in Ofgem's minded to decision.

Our main concern relates to the timescales for implementation of Ofgem's proposals. Some of the changes, such as setting the Transmission Generation Residual (TGR) to zero, could lead to large increase in the level of fixed charges faced by companies. As recognised by the analysis accompanying the consultation, in many cases the only way to recover this would be through higher capacity market clearing prices. However, companies have already entered into capacity agreements through to September 2022 on the basis of the current charging arrangements and so would be unable to recover any increase in charges until then. We therefore consider that implementation should take place on a timetable that respects commercial decisions already taken by companies and allows them to factor in any increase in charges.

Specific comments

1. Do you agree that residual charges should be levied on final demand only?

Yes. As recognised in the consultation document, residual charges are not currently levied equally on all generators and this is leading to distortions in competition in other market mechanisms. We consider that it would be simpler to remove residual charges from generation rather than seek to apply them equally to all generators.

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.

Yes.

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?

No comment.

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.

No comment.

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)?

Yes. We agree that customers with onsite generation should not be able to reduce their exposure to residual charges and that both types of user should therefore face the same residual charge.

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

No comment.

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

No comment.

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

No comment.

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?

No comment.

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.

In general, we agree with Ofgem's assessment. EPUKI has been concerned for some time that the charging arrangements are distorting the capacity market, which should be a technology neutral mechanism, and incentivising the deployment of inefficient and carbon intensive forms of fossil-fuelled generation, such as onsite gas and diesel generators. We therefore agree with the conclusions of the modelling that the proposed changes would lead to a reduced incentive to build inefficient forms of power generation and drive increased deployment of more efficient CCGTs through the capacity market. This would lead to an associated reduction in carbon emissions. However, we note that the earliest that this benefit could be realised is October 2022 as this is the earliest that new build CCGT could be delivered through the capacity market.

We agree that the triad avoidance incentive may no longer be an appropriate signal and basing charges on consumption over the triad does not reflect the equal benefit that all customers receive from a network connection. Ofgem should clarify whether it considers existing market arrangements are sufficient to encourage flexibility over peak periods if the triad avoidance incentive is reduced.

Paragraph 5.33 states that there would not be an increase in the cost of capital arising from changes to network charging arrangements because 'changes in charges should be factored in, with regulatory reviews being well established'. We agree that companies factor in some degree of regulatory risk when making investments. However, companies expect that any regulatory change should be appropriately signalled sufficiently far in advance and introduced in a way that minimises the impact on existing investments. For example, where parties have entered into near-term agreements (such as capacity agreements) on the basis of current charging arrangements then any changes should be introduced on a timescale that respects the expectations that these parties would have had when they entered into the agreements. Additionally, those investors who are looking to enter the market need to have confidence that we have a regulatory regime that is robust and is not subject to dramatic change without an appropriate level of notice.

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

EPUKI supports the concept of removing all charging distortions for generators across transmission and distribution networks. We therefore agree with the proposal for equal application of BSUoS to all generators. The double BSUoS benefit currently received by embedded generators provides an unfair advantage for generation located on the distribution network compared to that located on the transmission network and allows it, for example, to bid a lower price in the capacity market compared to transmission-connected generation. It should not be the case that charging arrangements distort market mechanisms in this way. Many of these embedded generators will be exporting to the transmission network in some periods and contributing to system balancing issues, but are not contributing to the costs of the managing the network. We note that similar distortions are created by the fact that BSUoS is not applied to interconnectors, which are allowed to participate in the capacity market alongside generators which do incur these charges.

In general, EPUKI considers that BSUoS is a cost-recovery charge which does not send sensible signals to which a generator can react. We therefore consider that it should be treated the same as other residual charges and charged solely to demand from April 2020. However, we understand that removing BSUoS charges from all generators may depend on the findings of the Balancing Services

Charges Task Force. Until we know the outcome of that process, we therefore support Ofgem's proposal for full BSUoS reform, ie. both removing BSUoS payments and charging BSUoS to smaller embedded generators. EPUKI also advocates charging TNUoS to embedded generators and these two reforms should ensure complete charging parity between both transmission and distribution-connected generators.

EPUKI recognises that if all residual charges are to be levied on demand then the TGR should be set to zero unless the €2.50/MWh cap on average generator transmission charges is breached. EPUKI does not agree with the revised interpretation of European Commission Regulation 838/2010 set out by Ofgem in its decision on CMP261 and therefore does not support its implementation. However, if a change is made to the application of the €2.50/MWh cap such that the TGR would no longer be negative, we consider that this change must be implemented in a way that does not undermine decisions already taken by companies. Please see our comments relating to compliance with the €2.50/MWh cap and transitional periods in response to questions 13 and 14 below.

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.

We agree that the scale of the remaining embedded benefits is small and therefore not a priority issue. However, we consider that Ofgem should set a timetable to address these in order to ensure the removal of all charging distortions.

Following reform of the charging regime to level the playing field between transmission and distribution-connected plant, we cannot see a case for maintaining the small generator discount and we agree that this should be removed.

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

It is important that the arrangements for the TGR should ensure that GB continues to comply with European Commission Regulation 838/2010 and this may require the TGR to be negative in future. We do not yet know how Ofgem's interpretation of the Regulation will be implemented and therefore cannot form a view of the future trajectory of the TGR. We note that the analysis accompanying Ofgem's minded to decision assumes that the residual stays at zero on an ongoing basis and may therefore be overstating the consumer benefit associated with this reform. It is also essential that Ofgem clarifies whether it considers that the €2.50/MWh cap should continue to apply following the UK's exit from the EU. EPUKI considers that if trading of electricity with other European markets is to continue after Brexit then the cap should be maintained.

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.

Transmission and distribution demand residual charges

We are not able to comment on the timescales necessary to implement changes to the demand residual, but we note that, as with the TGR, some parties may need to recover an increase in fixed charges through the capacity market and cannot now do this until the 2022/23 Delivery Year. Implementation in April 2023 may be therefore be justifiable as this is the first Charging Year following the periods for which capacity agreements have already been issued. This would also avoid the complexity associated with phasing such a change over the period 2021 to 2023. Implementation in April 2023 would also allow coordination with changes which may be taken forward through the Significant Code Review of Electricity Network Access and Forward-Looking Charging, such as changes to distribution charges and the application of triads.

Transmission Generation Residual

Any change to the TGR must respect the commercial decisions already made by power generators. If the TGR is set to zero, the level of change in TNUoS charges faced by generators will be substantial. For example, if the TGR is set to zero in April 2020, this would lead to a £3.53/kW increase in TNUoS charges compared to the previous year, which equates to an additional £9 million a year for a company with a 2.5 GW generation portfolio. An immediate substantial change of this nature is likely to undermine business decisions which generators have already taken in respect of future years.

Ofgem only set out its interpretation of Regulation 838/2010 in November 2017 and this was subject to appeal until February 2018. Power stations holding capacity agreements are therefore unlikely to have factored in an increase in the TGR in their capacity market bids to date. While the possibility of regulatory review may have been factored into bids for longer-term (eg. fifteen year) agreements, companies expect the regulatory landscape to be stable in the near term and are therefore likely to have ruled out such a risk when bidding for one year agreements. The analysis accompanying Ofgem's minded to decision recognises that these plant will not be able to recover an increase in costs between April 2020 and 2023 because they have already committed to capacity agreements.

In order to make the UK an attractive destination for investment in the energy sector, we consider that short-term regulatory stability is essential and changes should not be justified as beneficial to consumers where they undermine near-term investment decisions which have already been taken. We therefore consider that no change should be made to the TGR until April 2023. As a minimum, Ofgem should consider phasing the residual to zero over the period 2020 to 2023 as this would balance the benefits for consumers and the impacts on generators of a change to the TGR and would be consistent with the approach previously taken by Ofgem to changes in the residual.

BSUoS

We support the full BSUoS reform option set out in the consultation document. We do not consider that this necessarily needs to be implemented on the same timescale as the TGR is set to zero. Changes to BSUoS will passed into the wholesale price and the market can accommodate this change faster than a change to the TGR, which can only be addressed in the next capacity market Delivery Year in 2022/23. We therefore consider that there may be a case for removing the BSUoS embedded benefit prior to 2023 and maybe even as early as April 2020. In general, we still consider that it would be preferable for BSUoS to be removed from all generators and applied solely to demand for the reasons set out above and this may solve some of the complexities associated with implementing full BSUoS reform and mitigate the impact on embedded generators.

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

As explained above, we agree with the minded to position on residual charges set out in paragraph 8.4. We consider that implementation in April 2023 may present a good balance between swift realisation of the benefits of this change and the practical considerations associated with its implementation.

We agree with the proposal for full BSUoS reform set out in paragraphs 8.11 a) and b) and consider that this could be implemented in April 2020.

We consider that the TGR should be set to zero no earlier than April 2023 in order to prevent a substantial immediate increase in charges which would be unrecoverable for most generators until 2023. If Ofgem wishes to see earlier changes to the TGR, this should be phased over the period April 2020 to 2023 in accordance with the approach taken to previous changes to the residual.

We agree with the proposal to set the Small Generator Discount to zero once the remaining embedded benefits have been removed.

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.

As explained in our answer to question 14, it is important to give affected parties sufficient visibility of any changes which may affect them. We are particularly concerned about the potential for a large step change in charges for transmission-connected or large distribution-connected generators which would be unrecoverable. We therefore consider that changes to the TGR should either be delayed until April 2023 or phased over the period 2020 to 2023.

We note that setting the TGR to zero will have a substantial impact on the charges faced by some existing renewable generators supported by the Contract for Difference (CfD) or Renewables Obligation schemes, which would be unable to recover an increase in their costs. Undermining the economics of low carbon generators compared to conventional generation seems a perverse outcome of this proposed reform. We consider that Ofgem should consider mechanisms to mitigate the impact on renewable generators, for example by encouraging the Low Carbon Contracts Company to adjust the strike price for plant supported by the CfD to account for the increase in TNUoS charges.