Andrew Self
Ofgem
9 Millbank
London
SW1P 3GE

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Dear Andrew,

Minded to decision and draft impact assessment of industry proposals (CMP 264 and CMP 265) to change electricity charging arrangements for embedded generators.

Scottish Renewables is the representative body for the renewable energy industry in Scotland, working to deliver a low-carbon, secure energy system, integrating renewable electricity, heat and transport at the lowest possible cost.

As you are aware, we have been closely involved in recent work to consider charging arrangements for embedded generators, making the case that Ofgem should tackle issues arising from the TNUoS demand residual through a significant code review with an achievable scope and delivery timescale.

We acknowledge that any benefit that is accrued by embedded generators must reflect the value that they provide to the system. However there is some concern that the minded to decision has uncertain consumer outcomes and high impact on generation, storage and DSR investor certainty.

It is our view that the current position is founded on insufficient analysis. While we acknowledge the need to act to minimise the impact of the rising TDR approval of WACM 4 must be underpinned with a stronger evidence base which includes;

- Independent assessment of NGET's 2013 evaluation of the value avoided at the GSP to determine if this was correctly estimated and whether adjustments should be made to ensure it is a best estimate of cost reflective avoided costs today
- The implications for increased network investment
- Sensitivity analysis on the cost assumptions use for new build plant, which appear to take an optimistic view.

We would encourage Ofgem to consider alternatives – such as limiting the value of the TDR as an interim and allowing for greater coordination with the proposed targeted charging review to deliver an enduring solution.

Finally, it is important to note that the proposed changes to the TNUoS demand residual represent another significant change for renewable generators located in Scotland when considered alongside the recent removal of LECs and introduction of locational charging for transmission losses. This is further compounded by the suggestion of further change to TNUoS generation charging and BSUoS arrangements.

6th Floor, Tara House, 46 Bath Street,
Glasgow, G2 1HG
0141 353 4980 @ScotRenew
www.scottishrenewables.com

Scottish Renewables Forum Limited.
A company limited by guarantee in Scotland No.200074
Registered office: c/o Harper Macleod,
The Ca'd'oro, 45 Gordon Street, Glasgow G1 3PE

While each of these interventions will be judged on their own merits, their combined effect is to undermine investor confidence in an area of the country with significant low cost resource at a time when the government is seeking an additional 24 GW of renewable electricity capacity by 2030 and a policy framework that seeks to encourage decentralised, smart, flexible energy.

We have set out our concerns in response to the consultation questions below and would be happy to discuss if you require any further information.

Yours Sincerely,

Michael Rieley
Senior Policy Manager

Question 1: Do you agree with our problem definition and that the Transmission Network Use of System (TNUoS) Demand Residual (TDR) payments to sub-100MW Embedded Generation ("smaller EG") are distorting dispatch, wholesale price, the capacity market (CM) and that they pose an increased cost to consumers?
While we accept that there is a significant and material impact associated with the current treatment of the demand residual in the TNUoS transmission charging methodology and the consequent payments to sub-100MW embedded generators, it is important to consider that this is a symptom of a much wider problem. The TNUoS demand residual methodology (triad) was founded on the rationale that embedded generation offsets the need for use of the transmission network. While we acknowledge that the rising value of TNUoS demand residual payments (TDR) over time indicates a need to consider their cost reflectivity; It is our view that this fundamental defect has arisen over time as a result of the triad system no longer reflecting the needs of today's energy market. Demand profiles are clearly shifting both across seasons and in terms of geographical spread and the nature of network use has changed significantly over the last twenty years. An enduring solution that tackles the TDR payments must also address this disconnect in a system that was designed for a different time, the relationship between the transmission and distribution network and the long term view of how the smart and flexible system will operate in the future. In addition, it is important to reflect on other fundamental cost drivers when defining the problem - For example, Ofgem's recent annual report on returns under the RIIO framework highlights that the average Return on Regulated Equity (RoRE) for network companies was10% set against a total equity base of £5.6bn for transmission and £7.6bn for distribution networks. With this in mind, there is some concern that a regulated return of this level could be considered as excessive - every 1% reduction in return would see a corresponding reduction in the cost to all network users, including consumers, of £132M per annum. If these businesses collected a rate of return that might be expected for these types of business (circa 5%), then the cost to all network users, including consumers, would reduce by £650M per annum. We would therefore encourage Ofgem to include the level of return within a wider review.
Question 2: Do you agree that rising TDR payments to smaller EG is a problem which needs to be addressed?
Yes. It is clear that rising TDR payments need to be addressed. However, we maintain that this is a problem best tackled through a holistic review that is considered in conjunction with distribution charging. Distortion in the capacity market has been a driving factor behind both modification proposals and it is important to acknowledge the risks of maintaining current price signals which could incentivise unnecessary levels of diesel generation. However, it is our view that this risk can be managed through Capacity Market rules and through the recent work of DEFRA on emissions controls and the UK's implementation of the Medium Combustion Plant Directive (MCPD) – all factors that should be considered in the impact assessment.

Question 3: Do you agree with our interpretation of the applicable CUSC objectives?
Yes Having a clear, consistent and stable regulatory regime is one of the big advantages of the energy system across GB. However, making significant changes to charging arrangements through a relatively terse code change process will weaken the ability for smaller innovators and new market entrants to make investment decisions within the GB market place. While we acknowledge that the rising value of transmission demand residual requires intervention – it is our view that steps can be taken to manage this risk – while allowing for a wider review to tackle the fundamental drivers. The CUSC process is not appropriate for implementing such a holistic review to create truly level competition between all generators. A significant code review is a much more appropriate approach because it gives industry the opportunity to engage and respond to the process – one of the key reasons that the process is going to be significant.
Question 4: Do you agree with our assessment against the applicable CUSC objectives and statutory duties? Please provide evidence for any differing views.
Competition and cost-reflectivity are in our view the most applicable CUSC objectives to assess the proposals against. The minded to decision on CMP264/265 of simply targeting one element of the charging arrangements (demand locational TNUoS tariff) for one type of network user (embedded generation, below 100MW) is likely to result in further market distortion and discrimination between network users. We are concerned that introducing the proposed change under CMP264/265 is going to distort the market further and push triad avoidance activity behind the meter. The incentive for large demand customers to reduce demand (increase on-site generation) remains unaffected by the proposed outcome of CMP264/265. This distortion will remain in place until a fairer arrangement for revenue collection is implemented and another reason to delay implementation until after the conclusion of the current SCR. With this in mind, there is some uncertainty over the extent to which WACM 10 was considered for short listing. This proposal demonstrates an improvement (or is neutral) on the status quo on all criteria. It could be applied as an interim solution while the SCR delivers an enduring cost reflective arrangement. This solution has the added benefit of maintaining investor confidence in commitments to UK generation, storage and demand side response markets by demonstrating that the regulatory framework seeks to mitigate drastic changes in costs and revenues – while maintaining a signal that an enduring change will be implemented through the Targeted Charging Review (TCR).
Question 5: In our assessment against the objectives, do you believe there are any relevant assessments we have not taken into account?

The proposed changes to the charging arrangements under CMP264/265 for embedded export triads are significant. However, these compound changes to the allocation of transmission losses which have been mandated to apply by the Competition and Market Authority. The resulting change proposal to the Balancing and Settlement Code, P350, is due to come into force on 01 April 2018 – alongside the outcome of CMP264/265. The impact of both of these changes together is very significant. By charging year 2021/22, the changes under CMP264/265 will result in a reduction of revenue for a typical embedded wind farm in the north of Scotland of £13-26k per installed MW of capacity (circa £5-10/MWh), based range of wind outputs over triad periods. This is combined with the additional cost of circa £1/MWh associated with BSC P350. With this in mind, we are concerned that Ofgem's current minded to decision on CMP264/265 is likely to further damage appetite for private investment in renewable generation capacity within GB, increasing the cost of capital and the slowing the rate at which GB can continue its world leading transition towards a low carbon, flexible and secure energy future. We are also concerned that the potential for increased cost of capital has not been reflected in the economic analysis performed by Ofgem and the potential benefit of these changes to the consumer isn't particularly well reflected in the impact assessment. Finally we note that the impact assessment is based on the assumption that consumers will realise the savings offered as a result on CMP264/265, but there is no consideration of whether these savings would be passed on from suppliers to consumers. We would like to see more evidence from Ofgem of the reasons that it is confident savings would be passed to the consumer.
Question 6: Do you agree with our assessment that, in this instance, grandfathering as set out in the WACMs would be unlikely to best facilitate the CUSC objectives when compared to the other options available to us?
We agree that grandfathering would not best facilitate the CUSC objectives as all users should be exposed to cost reflective network charges that are transparent and predictable. However, it is clear that a change from £45/kW to £2/kW cannot be considered as 'predictable' or transparent. Phased implementation is useful. However it is not clear what factors led to the decision for a three year period – or if any assessment has been provided to support this.
Question 7: Do you agree with our assessment that the value of the avoided GSP investment cost best facilitates the applicable CUSC objectives?
National Grid has acknowledged that there are other network impacts (positive and negative) over and above the avoided cost of GSP reinforcement arising from embedded generation. With this in mind, we would encourage Ofgem to conduct its own independent assessment of NGET's 2013 evaluation of the value avoided at the GSP in order to determine if this was correctly estimated and whether adjustments should be made to ensure it is a best estimate of cost reflective avoided costs today.
Question 8: Do you agree with our assessment of the impacts on security of supply? Please provide evidence for provided views.

While we appreciate that phased implementation over three years should help to mitigate some unforeseen security of supply risks, we would question whether the implications for increased network investment have been given sufficient consideration in Ofgem's assessment. We have concerns about the impacts on renewable biogas, biomass plant, EfW and CHP which are not reviewed in your analysis. In addition there is some uncertainty as to the cost assumptions for new build plant, which appear to take an optimistic view – without any sensitivity analysis.
Question 9: Please provide evidence to show if there are other cost savings which small EG drive in comparison to larger (over 100MW) EG on the distribution system.
It is our view that further independent analysis is required to determine the costs and savings that EG drive in comparison to larger EG on the distribution system. Clearly the short timeframe and narrow scope of CMP264/5 were insufficient to consider this important question. In line with our previous response it is important that the regulator as an impartial party coordinates any work to determine this value. We would note that there has been no acknowledgement of previous evidence on the impact of wind generation on peak demand submitted by member companies in response to the open letter on embedded benefit.
Question 10: Is there other evidence that payment above avoided GSP/generation residual would better facilitate the applicable objectives?
We strongly encourage Ofgem to reconsider this question. It is far more important to consider whether the triad system peak remains relevant in today's electricity market.
Question 11: Do you believe you have a legitimate expectation or contractual right for the continuation of TDR payments? If so, please provide evidence.
While it is reasonable to expect changes to grid charges, the removal of the net charging principle is a significant change to the charging methodology and should be assessed with a broader scope than the current proposals – ideally taken forward through a significant code review.
Question 12: Do you agree with our assessment of the distributional issues?
We would questions Ofgem's assumption that the revenue impact on distribution-connected sub-100MW Combined Heat and Power (CHP) operators and Energy from Waste (EfW) plants will not be particularly significant. The differences between the charging arrangements at transmission and distribution are extremely complex. We agree that Ofgem's efforts to attempt to create a level playing field across parties that

have their connection points onto these respective systems. However, the reality is that there are very significant, complicated and long standing differences between transmission and distribution in fundamental ways, including: connection charging, network access rights, network reliability, use of system charging and losses.

For example, distribution users pay high costs up front (per MW of capacity) to connect to the electricity network compared to transmission system parties. Transmission connectees tend to have new network investment (extension or reinforcement) socialised across the entire network customer base. Also, distribution connected parties are required to raise finance to procure these assets rather than being able to rely on the network owner's ability to finance and build these assets. Further, distribution connected projects can also be exposed through the statement of works process to transmission related connection charges (and underwriting for transmission reinforcements). However, transmission connected parties are not exposed to distribution system reinforcements.

Further, distribution parities are exposed to transmission losses (albeit often a credit due to offsetting of transmission network flows) as well as distribution losses. However, on the other hand transmission connected parties are not exposed to distribution losses even though their requirement for (and utilisation of) the distribution network is just a significant to a distribution connected party.

With this in mind, it is difficult to envisage where you may strike the balance of equality between transmission and distribution connected customers. Any changes to the charging regime must take full account of the reality of the current charging framework, including the investments made across the industry against a stable charging backdrop.

Question 13: Are there any sectors that we may have overlooked?

There is some concern that the impact on investor confidence in the Renewable electricity sector has not been acknowledged or adequately assessed.

It is also important to acknowledge that work undertaken through the TCR to tackle any incentive for use of Behind the Meter Generation cannot be viewed in isolation. The conclusion f the TCR is unknown and has the potential to deliver a discriminatory outcome.

Question 14: Do you agree with our modelling approach?

We would encourage Ofgem revise the modelling approach to ensure that the network impact costs of the alternative proposals are properly assessed.

Question 15: Do you think that our background assumptions and using FES data is an appropriate approximation for status quo?

The National Grid Future Energy Scenarios are useful in presenting a range of outcomes that the market can deliver. While we accept that this is a reasonable source to use in approximating the status quo we would question the logic in applying only one scenario.

It may also be helpful to consider Governments own view of the direction of travel for the energy market as recently set out in BEIS updated generation and emissions reductions projections.

We would also encourage Ofgem to consider the impact on analysis taking in to account the

implementation of the DEFRA decision on emissions standards
Question 16: Where WACMs are not modelled directly, do you think our assessment is appropriate (see appendix 8 for detail)?
Question 17: Of the options available to us, do you agree that WACM4 best facilitates the applicable CUSC objectives?
The case that WACM4 presents a cost reflective value is weak in the absence of an independent assessment and therefore it is unclear if it best facilitates the CUSC objectives compared to its alternatives. We observe that several are deemed better than the baseline but neither can present an enduring solution. The application of an interim solution should be considered while an enduring solution should be developed via the TCR.
Question 18: Do you believe that an implementation date of April 2018 best facilitates the applicable CUSC objectives?
Based on the points raised in this response, we encourage Ofgem to consider carefully the timing of implementing changes to the collection of transmission demand residual component. We do not consider that the proposed enduring implementation, in April 2018, is a balanced, proportionate position to take on this issue.