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Dear Andrew,

Minded to decision and draft Impact Assessment of industry's proposals (CMP264 and CMP265) to change electricity transmission charging arrangements for Embedded Generators

Thank you for the invitation to respond to the above document. Good Energy is a fast-growing 100% renewable electricity supply company, offering value for money and award-winning customer service. An AIM-listed PLC, our mission is to support change in the energy market, address climate change and boost energy security.

Overview

- The proposed changes present significant implications for other policy areas such as the FiT export rate – leading to reduced competition in the small-scale renewable PPA market.
- The modelling of flows fails to consider information in the Security and Quality of Supply Standard (SQSS).
- Owing to shortcomings in modelling, it is impossible to make robust predictions regarding the impact on security of supply for this change, however given the significant revenue changes it is reasonable to assume a number of small generators may choose to renege on their Capacity Market contracts – with a commensurate negative impact on security of supply.
- Proposed changes abandon the established cost-reflective principle of 1MW of embedded generation being equivalent to 1MW of reduced demand.
- The entire CMP264/265 process has been hastily pushed through, without proper analysis, which leaves the decision open to judicial review – creating yet more uncertainty.

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?

Although we recognise that transmission demand charges have increased significantly in recent years, and that this has led to some concerns regarding a distortionary impact of payments made by suppliers to embedded generators, defining the problem as specifically relating to the TDR has resulted in an overly-narrow approach to the solution. Given that the impact on the transmission system of 1MW of embedded generation has the same effect on the transmission system as 1MW of reduced demand, it is appropriate that this is reflected in the charging methodology (as it is currently). The proposed solution risks producing a new set of market distortions and unintended consequences. Where there is a case for reforming the charging regime, it would be

inappropriate to depart from the basic premise of 1MW of embedded generation being equivalent to 1MW of demand reduction.

Question 2: Do you agree that rising TDR payments to smaller EG is a problem which needs to be addressed?

As set out above, defining the issue as one of relating solely to TDR payments to smaller EG has resulted in an overly-simplistic, narrow response, to what is a complex and multi-faceted issue. This has created significant uncertainty in the industry, particularly for highly flexible distributed generation which is supportive of an electricity system with increased penetration of renewable generation. Ofgem's TCR offers a significant opportunity for more holistic response to the challenges facing the transmission network, and so offers a much more appropriate avenue for change.

Question 3: Do you agree with our interpretation of the applicable CUSC objectives?

CUSC Objective A

The proposed changes are not supportive of CUSC objective A, as they risk significantly undermining investor confidence in the energy sector, which risks leading to decreased investment and reduced competition. This is due not only to the changes themselves, but also the way they have been introduced. The almost complete removal of triad benefit could manifestly reduce the level of competition in the PPA market for smaller renewable generators. Any such changes, introduced over a short timescale, have the potential to create significant security of supply issues going forward.

Regulatory Risk

The consultation asserts that 'prudent investors know that charging arrangements are subject to change through the code governance process'. Whilst this is true, the code modification governance framework has historically been used to deliver small-scale incremental change. The change set out in this minded-to position however is a significant one. It abandons the long-standing basic premise of the transmission charging regime that treats embedded generation as equivalent to negative demand. Such significant changes are more appropriately delivered through an SCR process. The acceptance of such significant changes through a governance framework which is designed for incremental change will introduce significant levels of risk for all market participants going forward.

In addition, the way that this modification has been executed has also fostered greater levels of uncertainty. As set out below, CMP264/265 has been hastily taken through the modification process leading to insufficient scrutiny of the possible implications. This has led to a situation where, in spite of Ofgem's aims to introduce phasing, generators in a number of regions would see their triad payments removed completely within the second year of the change.

Political Risk

Investors' perception of political risk has also been increased by this process. There is a widespread perception in the industry that this process has been designed to deliver on the Government's commitment to a new generation of CCGT plants, by means of delivering a higher clearing price in the capacity market. This objective appears to have taken precedence for the regulator, over its other duties. If the industry is to enter an age where the independent regulator has become an arm of government, willing to intervene in the market in response to perceived political problems, then this will lead to significantly decreased investment and competition, particularly in highly flexible, distributed plant.

Small Scale Renewables PPA Market

As set out below, Triad payments are an important revenue stream for a number of renewable generators, including variable generators such as wind sites. These therefore allow FiT licensees to offer PPA rates above the FiT guaranteed export rate. If these payments were to be cut, it is likely that the FiT guaranteed export rate will exceed the combined value of the power + embedded benefits. This means suppliers are obliged to purchase power at an above-market rate. This has already led Smartest Energy to withdraw from administering the FiT, and a number of suppliers including Engie, Co-Op and Ovo to reportedly cease offering PPA contracts to FiT generators. This significantly reduces the level of competition in the PPA market for small-scale renewable generators.

CUSC Objective B

The proposed changes are not supportive of CUSC objective B, as they depart from the basic premise of charging units of energy for use only of the assets that they actually use – instead charging transmission costs on units of energy that never flow on to or off of the transmission system.

It is self-evident that a generator which never flows electricity on to the transmission system does not have the same impact on the system as a generator connected directly on to the transmission system. It is overtly not cost reflective to charge kWhs which are injected onto a distribution system, then off-taken by customers connected to the same distribution system, as if they have flowed over the transmission system.

The effect on the transmission system of an additional megawatt of embedded generation is equal and opposite to an additional megawatt of demand, and therefore should be charged as such. Any departure from this basic principle risks introducing new distortions into the market.

The argument that the addition of 450MW of embedded generation just below the GSP has the same effect on the transmission system as 450MW of transmission-connected generation just above the GSP is not only reliant upon a particular set of specific circumstances, but also ignores the fact that it is the System Security and Quality of Supply Standard (SQSS) which affects investment and operation decisions, not theoretical flow models as set out in the minded-to position.

CUSC Objective C – No view

CUSC Objective D – No view

Question 4: Do you agree with our assessment against the applicable CUSC objectives and statutory duties? Please provide evidence for any differing views.

It appears that getting a *quick* answer to the issues raised in CMP264/265 has been prioritised over getting the *right* answer – this presents significant risks for current and future consumers.

It is evident that the CMP264/265 modification process, and the formation of accompanying minded-to position, were hastily conducted. In spite of the modification not being granted 'Urgent' status, timescales for the modification were too short to allow code signatories adequate time to fully assess the impact of the wide range of WACMs. This meant it was not possible for due diligence to be sufficiently carried out in assuring that any of the WACMs offer a level of benefit reflective of the costs and benefits that embedded generators bring to the system (**objective b**). This leads to significant risk of unintended consequences which may result in undermining investment in the industry – this would clearly lead to reduced competition (**objective a**) in the wholesale and PPA markets, resulting in significant harm to consumers and lead to reduced security of supply.

The manifest drafting error in the CMP264 legal text which precipitated a consultation with a 2-day response time (between the 22nd and 24th of November 2016)¹, the multiple errors in the minded-to document (only some of which have been subsequently corrected), and the reliance upon a hastily-sketched hand-drawn flows diagram for evidence of possible impacts are all symptomatic of the way that the CMP264/265 modification process was conducted.

It appears that the modelling process by Frontier economics was also hastily conducted, with no consideration of the impact of plants renegeing on their capacity market contracts; this is in spite of the modelling done on these impacts by Aurora Energy Research, and investigation by ICIS Heren. In addition there is seemingly little critical analysis applied to any of the underlying assumptions, and no sensitivity analysis carried out to provide insight of degrees of certainty around the likely impacts. Many of the assumptions in the modelling appear to rely on new-build CCGT plant coming forward, however there is little consideration of the impact to consumers if this new plant is not forthcoming. It is clear that the way the review has been conducted to date does not appear consistent with Ofgem's principal duty to protect the interests of current and future consumers. Furthermore, we have concerns that decision-making in this way exposes Ofgem to challenge by judicial review, which would bring further uncertainty to the future of the charging methodology – such uncertainty would too not be in the best interests of consumers.

It is also not clear that Ofgem's duty to consider the future of a sustainable energy system has been adequately considered. The consultation argues that the level of income that embedded benefits offer to embedded renewable generators is not of manifest importance. As a supplier with PPAs with over 1000 small scale renewable generators, we are well-positioned to demonstrate that these are an important revenue stream for small-scale renewable generators. In addition, it is not clear however how Ofgem reconcile the position that payments to renewable generators are not of a scale sufficient to impact their business models if removed, but are of a scale that may be deemed to be having a manifest distortionary impact. In many cases the impact on renewable generators will be even greater than on their fossil-based embedded counterparts. This is because they are unable to benefit from increased clearing prices in the CM, and many of whom are unable to enter into the STOR market (where prices are also expected to increase).

Question 5: In our assessment against the objectives, do you believe there are any relevant assessments we have not taken into account?

It is not clear that the net impact of the changes, when combined with the locational charge, has been taken into account in the impact assessment – this has a material impact on the phasing in particular. Although the proposed changes to total embedded charge has a floor applied at zero, the scale of the locational charge means that in a number of regions, generators will not experience the same degree of phasing in the change to their revenues, and will lose the entirety of their embedded benefit in the second year. We propose that phasing should be applied on a region-by-region basis to ensure all generators are able to benefit from the phasing process.

Although we support the introduction of a floor to avoid perverse incentives, we would argue it should be above zero, to reflect the value that embedded generation brings to the system – a floor at zero ignores all benefit that embedded generators bring to the system, including that of avoided GSP reinforcement costs.

¹ <http://www2.nationalgrid.com/WorkArea/DownloadAsset.aspx?id=8589937692>

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 do not agree with this approach. The level of uncertainty that the currently proposed change introduces, risks significantly weakening security of supply (although quantitative modelling is not possible owing to shortcomings in the modelling). This level of uncertainty would be significantly reduced with the introduction of grandfathering, or grandfathering at a frozen level – at least temporarily until a more thorough piece of work may be carried out under the SCR process.

Question 7: Do you agree with our assessment that the value of the avoided GSP investment cost best facilitates the applicable CUSC objectives?

No – as set out above, any arrangement which effectively introduces transmission charges for units of electricity which never flow onto or off of the transmission system are in no way cost reflective. Although there are arguments for reform to the transmission charging methodology, a departure from the basic principle where an additional 1 MW of embedded generation is equal to a reduction of 1 MW in demand is to depart from the basic foundations of the existing charging structure.

Question 8: Do you agree with our assessment of the impacts on security of supply? Please provide evidence for provided views.

It is not possible to robustly examine the security of supply implications of this change because of shortcomings in the modelling exercise. The Frontier modelling assumes no capacity market participants renege on their contracts, in spite of many of them losing significant revenues from triad payments. Although Ofgem asserts that it does not expect any reneging of Capacity Market contracts to have a significant impact on security of supply, there is no rationale offered for this assumption. There is also no rationale offered for Frontier's assumption that no generators will renege on their Capacity Market contracts, in spite of a report from ICIS quoting Frontier Economics' energy director stating that a number of firms with capacity market contracts are likely to pay the penalty and renege on their capacity market contracts. There is also no sensitivity analysis offered in the Frontier modelling, which makes it impossible for respondents to consider the impact on energy security of different turns of events. Finally there is no justification for Ofgem's view, set out in table 15 (page 50 of the consultation) that those greater cuts to payments are conducive to a greater level of energy security. Given concerns in recent years regarding levels of security of supply, we propose that a more cautious approach needs to be taken.

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.

Appropriate consideration of cost savings are a product of the charging regime. Although a thorough review of the methodology for levying transmission charges may be appropriate, a piecemeal approach which treats embedded generation as no longer equivalent to reduced demand risks simply exchanging one set of market distortions for another. It is also not clear that the differing treatment of the embedded and transmission-connected generation by the SQSS, which drives investment decisions, has been considered (see below, question 14).

Question 10: Is there other evidence that payment above avoided GSP/generation residual would better facilitate the applicable objectives?

This implies that the only way to achieving a more competitive, cost-reflective, charging regime is through the current piecemeal approach set out in CMP264/265. Ofgem has announced it is considering the launch of an SCR examining the most appropriate design for transmission charging. The SCR process would be likely to deliver a more robust lasting charging methodology. Failing to put in place a robustly considered charging regime is likely to precipitate continued revisiting of the subject in years to come – with the risk of creating yet more uncertainty for the industry, which has inevitable costs for consumers.

Question 11: Do you believe you have a legitimate expectation or contractual right for the continuation of TDR payments? If so, please provide evidence.

As set out above (see question3), the code modification governance framework has historically been used to deliver small-scale incremental change, any major-scale changes such as this could legitimately be expected to have a longer lead time than is being proposed in this consultation.

Question 12: Do you agree with our assessment of the distributional issues?

As set out above, it is not possible to adequately undertake sensitivity analysis and assess the distributional impacts of the change without a more thorough modelling of the range of possible outcomes.

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

There appears to be minimal consideration of the impacts on embedded renewable plants. A number of these will suffer significant cuts to their revenues but will be unable to benefit from increased revenues which are anticipated in uplifted CM or STOR markets, which are accessible to small fossil-based embedded generators². This will create greater distortions between different types of embedded generators. There is also limited consideration on the impact that will be had on the development of nascent storage technologies such as batteries.

Question 14: Do you agree with our modelling approach?

There are a number of aspects to the modelling which give cause for concern. The first of these relate to the load-flows modelling which the minded-to position relies upon to suggest that embedded generators have the same impact on investment in the system as a transmission-connected generator. Although prima facie this flow diagram appears compelling, it fails on two counts. Firstly the assumptions on which the flows model is based, justified as simplifying the modelling, are non-trivial – the categorisation of all transmission generation as CCGT is clearly not reflective of a real-world environment. Secondly, this modelling does not take account of what *actually* drives National Grid's investment and operational decisions - the System Security and Quality of Supply Standard (SQSS). This establishes, for the purposes of grid investment and operation, small-scale embedded generation as equivalent to negative demand. However, transmission-connected generators are treated differently; having a scaling figure applied to their output. This is significant because the modelled flows as set out in the minded-to decision do not take account of this different treatment of embedded and

² See Aurora Energy Research Presentation 'The investment case for reciprocating engines after embedded benefit reform' 24 March, 2017

transmission-connected generators. In order to be cost-reflective, the charging structure must reflect the way that the SQSS, which drives National Grid's investment and operational decisions, treats different sorts of generation.

The second shortcoming with modelling relates to the work undertaken by Frontier and LCP modelling approach is severely limited – without any sort of sensitivity analysis for the results, it is not possible to fully assess the likely impacts of the changes. At the stakeholder event on Tuesday 21st March, Francis Warburton was very clear on the point that Ofgem had little interest in diverting from its minded to position unless a manifest cost to consumers could be demonstrated. However, it is not clear why particular variables were selected, or why sensitivity analysis was not undertaken to investigate different levels of impact under different outcomes. This leaves it up to industry stakeholders to attempt to calculate the range of possible outcomes on their customers, generators, and the wider market. This not only means that Ofgem are making this decision with only partial information, but also significantly disadvantages smaller counterparties who may not have the capacity necessary to carry out their own modelling.

There also appear to be some inherent assumptions in the modelling which are not effectively justified, for example the level of deployment of wind, solar, and 'other renewables' does not change, irrespective of the level of deployment of CCGT vs. OCGT or reciprocating engines. This is in spite of the fact that these different forms of thermal generation have differing operating parameters with regard to flexibility which in reality would be likely to support a different level of deployment of renewables.

Finally, we have concerns that there appears to be no consideration for the impacts on consumers of the potential for increased STOR prices, and the number of generators which will move over to the FiT guaranteed export rate. Both of these are likely to have significant negative cost implications for end consumers.

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

It is not clear why the modelling makes use of the FES 'Slow Progression' scenario, and does not compare against any of the other FES scenarios. Given that National Grid does not apply any sort of probability to the FES scenarios, it is severely limited to only consider one of the four. It is also not clear why the BEIS Low Cost assumptions were used, rather than a central cost estimate – again this makes it impossible to assess the different possible outcomes under different scenarios.

Question 16: Where WACMs are not modelled directly, do you think our assessment is appropriate (see appendix 8 for detail)?

It is not possible to make an informed judgement on this question, this is both due to the limitations of modelling which was applied to those WACMs which are modelled (see questions 14 and 15), but due to the short timescale of the modification process, there was limited consideration by the working group of the range of WACMs raised (see question 4).

Question 17: Of the options available to us, do you agree that WACM4 best facilitates the applicable CUSC objectives?

It has not been conclusively demonstrated that WACM 4 best facilitates the applicable CUSC objectives. We believe sending back the modification would be the most appropriate course of action, to allow time for thorough analysis and modelling – the rushed nature of the modification means that due consideration has not

been given to the impact of the different options. The lack of firm consensus among the working group or the panel is symptomatic of a lack of sufficient consideration and analysis to allow a best option to be arrived at.

Question 18: Do you believe that an implementation date of April 2018 best facilitates the applicable CUSC objectives?

The proposed timescale of April 2018 is far too short to safeguard competition in the industry. As set out above, the significant level of uncertainty this introduces will deter new investment, push up risk premiums, and threaten security of supply. The current blanket phasing which is applied means that generators in some regions will lose the entirety of their triad payment in the second year – this leaves them with insufficient time to prepare for the change.

Furthermore, in the context of the TCR, which has the potential to cause the changes that result from this modification to be altered again in a very short period of time, there is a strong argument for an implementation date after there is more clarity regarding the course of the TCR. If the CMP264/265 solution was held until after the TCR is complete – this creates the greatest level of stability, whilst still delivering a clear path to change, should the TCR not affect this aspect of network charging.

I hope you find this response useful. If you have any questions, please do not hesitate to contact me.

Kind regards,

Tom Steward

Wholesale Regulatory Officer