

Frances Warburton  
Ofgem  
9 Millbank  
London, SW1P 3GE

**RE: Ofgem Open Letter - Charging Arrangements for Embedded Generation**

Dear Frances,

Thank you for the opportunity to respond to your Open Letter regarding charging arrangements for embedded generation. This response is submitted jointly on behalf of Innogy Renewables UK Limited, Npower, RWE GenCo, RWE Cogen RWE Supply & Trading GmbH. The charging arrangements for embedded generation have significant impacts that are wider than the direct impact on embedded Capacity Market (CM) sites— this subject is of concern to renewable generation, electricity retail, conventional generation, and combined heat and power generation. This response reflects perspectives on each of these areas and our business' wide-ranging experience working with transmission and distribution charging methodologies.

Following the general introduction, the structure of our submission aligns with that of your Open Letter. Our key points are as follows:

- *A holistic review is needed and Ofgem should not rule out a Significant Code Review.*
- *We have concerns around the process being followed for the CMP264/265 CUSC Mods.*
- *There are some key considerations missing from the background picture that Ofgem have initially presented in this letter.*
- *The Triad signal on its own is no longer a cost reflective charging signal.*
- *Some affected stakeholders are missing from your reflections.*
- *An Impact Assessment for consumers is critical and should look holistically across all costs*
- *Implementation date should be 3 years from the date of Ofgem decision.*
- *Creating as level a playing field between distributed & transmission connected generation is supported as an aspiration but differences in connection arrangements must be recognised.*
- *Potential services that embedded generators could offer networks actually remain hidden and untapped because the commercial framework for them is absent.*
- *CMP264/265 were never intended to be an enduring solutions to the known defects and the incremental changes that would arise are inefficient.*
- *CMP264/265 carry a risk of unintended consequences they are not an improvement.*
- *An enduring solution that addresses defects is needed instead to improve investor certainty.*
- *BSUoS reform should not be a priority. We oppose the suggested isolated BSUoS review.*

Should you have any questions please do not hesitate to get in touch,

Kind Regards,

*Fruzsina*

Fruzsina Kemenes  
Regulation & Policy Manager  
Innogy Renewables UK Limited

## **Introduction**

We recognise that today's Demand TNUoS charging arrangements and the subsequent Triad embedded benefit payment system is no longer fit for purpose. Network costs have an important impact on relative competition among participants in the energy market as well as on short- and long-term economic efficiencies of the whole electricity industry. For example, the RWE generation business has first-hand experience of the impact of some 'New Build Generation CMUs' taking advantage of the Triad embedded benefit income in the Capacity Market (CM).

- *A holistic review is needed building on National Grid findings*

National Grid recently outlined a wide range of issues surrounding the TNUoS charging methodology at their recent stakeholder events. We agree that the following factors all contribute to the rapid rise of the TNUoS demand residual tariff (the major component that supplier's Triad embedded benefit payments are based on):

- the rise of the total allowed revenue, the 2.50euro cap suppressing recovery from transmission connected generation and shifting it to demand, the treatment of Offshore user assets as a component of generator TNUoS charges, the charging arrangements for interconnectors and the observation that the triad signal that results in large customer subsets not contributing to the sunk costs of the system, leaving an ever smaller subset of customers with the burden to pay.

In addition to National Grid's observations, in our view a fundamental flaw in the current demand charging arrangements that has led to the current 'symptoms' being observed in distortions to the CM and elsewhere is that the Demand Charging methodology is not cost reflective of current SQSS requirements. The growth in intermittent generation connecting to the transmission system has changed the nature of investment planning in the Security Standard and the locational signals.

Traditionally, transmission investment has been driven by the need to ensure peak security in an environment dominated by conventional generators. However, due to intermittent generation significant transmission investment now relates year round conditions on the transmission system and the need to avoid increasing year round constraint costs.

There is a pressing case for a holistic review of network charging arrangements. The nature of connection customers and network use is going through a historic shift with smart demand, renewables and storage technologies. The timescale for reform should be set by the recognition that the next generation of generation projects are all now dependent on auction based competitions whereby having foresight of longterm network costs is essential. The switch to HH smart meters for all domestic and small business customers via the smart metering rollout completion in 2020 is also significant when considering timelines for this process.

In general we advocate cost reflective network charging because providing locational signals at the onset of projects is economically efficient. Our support is based on the conviction that cost reflective charges should result in a fair allocation of costs and that they should be relatively predictable with only incremental changes being made. Significant changes to the core basis of charging methodology (such as switching from net to gross) are unexpected, disruptive and should come with sufficient lead times to implementation to retain investor confidence.

## **Our feedback on Ofgem's outlined process:**

- *We ask Ofgem to consider conducting a Significant Code Review (SCR).*

Given the complex nature of the issues that cut across different network charging arrangements this is a subject for SCR or holistic review of some form. Making changes in numerous steps will be more disruptive, costly and inefficient compared to taking a holistic review and introducing a comprehensive whole system solution. While an SCR will take some time, piecemeal reform will take even longer and will leave more uncertainty on the subject that will undermine investor confidence across a range of sectors in GB.

An SCR has the benefits that:

- It can offer a proactive solution as opposed to a reactive set of changes;
- provide a more holistic approach enabling consideration of the network as a whole including distribution;
- consider generation and demand connection and network development signals in their own right alongside constraint dynamics, dispatch and market signals;
- enable a longer term sustainable network charging model to be developed;
- give all industry parties adequate timescales to consider a robust solution which will address many of the known issues.

Arriving at the optimal solution for recovering network costs should be the priority, as opposed to "addressing distortions in the CM". If the former is resolved, the latter should be a by-product.

- *Concerns around the process being followed for the CMP264 and CMP265 CUSC Mods:*

### ***Concerns regarding the accelerated time-scales***

The accelerated timescale for making a decision ahead of the next CM auction is inappropriate given: the complexity of the charging methodology, the fact that around 40 options for change are being considered, the range of consequent change processes that are required (i.e. to BSC), the lack of opportunity to conduct independent quantitative assessment of the proposals and the potential severity of the impact on generators, suppliers and their customers.

Really, the effect of the Triad embedded benefit on CM clearing prices should have been identified and dealt with in advance of the first CM auction. Given that we are where we are now, it is not right to rush to introduce a sticking plaster solution that may well lead to severe unintended consequences.

### ***An appropriate lead time to implementation is needed***

For suppliers the key is that once a robust decision is made by Ofgem, 3 years is provided to allow for implementation. Given the indicated major shift in charging arrangements (from net to gross charging under all options) this is pivotal to accommodate the necessary series of systems changes (e.g. implementation of potentially significant changes to pricing, forecasting, settlement and billing systems) and to allow existing customer supply contracts and PPAs to run their course.

### ***Concerns from our customer base regarding the ability of retail customers to engage with the CUSC process***

Our electricity retail business customers would like to engage directly with Ofgem to make them aware of the potential risks and challenges they would face if no SCR were to take place. SCR would offer customers a fair and consistent playing field to positively influence the future charging arrangements for transmission. It would be inappropriate to introduce a short-term charging methodology and potential recalibration which results in exposure to additional costs to GB business and then in parallel inhibit or prohibit activity which would otherwise have provided system support (i.e. through directly connected embedded generation or behind the meter generation). In our customer base a significant proportion of 'DSR active' distributed generation chooses not to participate in the CM. This absence is largely as a result of perceived access barriers, onerous CM pre-qualification administration, bid-bonds and penalties when compared to other, more established DSR commercial opportunities<sup>i</sup>. Addressing the issue of new build gas/diesel farm CMUs should not undermine and unduly compromise this latter group of DG who provide flexibility to the network operators.

### ***An Impact Assessment is needed as a minimum for Ofgem to form a robust decision on CUSC proposals***

In the event that Ofgem calls for the implementation of any of the relevant CUSC Modification Proposals it must conduct an Impact Assessment. Due to the accelerated timescale for the Working Group, quantitative analysis cannot be conducted before the options are presented to Ofgem.

#### **1. Background**

##### **1.1 Ofgem suggest that changes to the CUSC and BSC in play will affect cost reflectivity, competition, security of supply and consumer bills;**

- *There are some other key considerations missing from the background picture that Ofgem have initially presented in this letter:*

##### ***Carbon emissions***

The outcome of the proposals will also have an impact on Carbon emissions that Ofgem should include in its impact assessment<sup>ii</sup>.

##### ***Holistic view of consumer interest***

Ofgem should seek to assess what is in the best 'interest of the consumer' in the wider energy-system sense – not just focusing in on the narrow network impact on short term costs to the consumer. Making changes to an element of network charging can have wide ranging impacts on cost of the CM, wholesale electricity prices, risk premiums applied to new projects investing, and would also influence whether renewables projects can site themselves most efficiently relating to resource availability.

## ***Investor confidence & associated long term security of supply***

Investors in UK generation seek a stable, predictable investment environment. Ofgem should be aware that the course of action they take should minimise impact on investor confidence as this can have knock-on impacts for security of supply and consumer bills. Our preference is for a charging solution that addresses fundamental defects in the current methodology rather than addressing symptoms of defects and leading to a series of changes and related uncertainty. A minimum of 3 years from the point of decision to implementation should be provided for any major changes to charging arrangements. Any methodological changes thereby made to TNUoS Charges, and related embedded benefits, should endure for at least 5 years to give an element of certainty to prospective investors.

### **2. Transmission charging arrangements for sub-100MW EG – embedded benefit**

#### **2.1 Do you have any comments on Ofgem’s understanding of the charging arrangements for sub-100MW embedded generation?**

- *Where embedded users are providing a net reduction in network investment, charges should reflect this.*

We see the economic rationale in the netting of demand TNUoS charges. The value of the credits paid out to embedded generators must be as cost reflective as possible and the principle of net charging to reflect demand load reduction still prevails in our view. There can be tangible long-term benefits of avoided transmission costs from distribution connected generation.

One issue that has been overlooked in this letter is consideration of exporting GSPs. The current TNUoS charging methodology does not reflect the impact on power flows that export at GSP’s has. NGET reported in its 2015 ‘Charging Arrangements for Exporting GSPs’ consultation that the incidence, duration and volume of export at GSPs is gradually increasing. This export is being driven chiefly by increased embedded generation behind such points on the network and also relative reductions in demand. The charging methodology should differentiate between those GSPs where embedded users are still providing a net reduction in network investment need and those where there is actually a net increase in use of the main integrated transmission network.

- *The Triad signal on its own is no longer a cost reflective charging signal*

We agree with others who question the ongoing appropriateness of the Demand Triad signals.

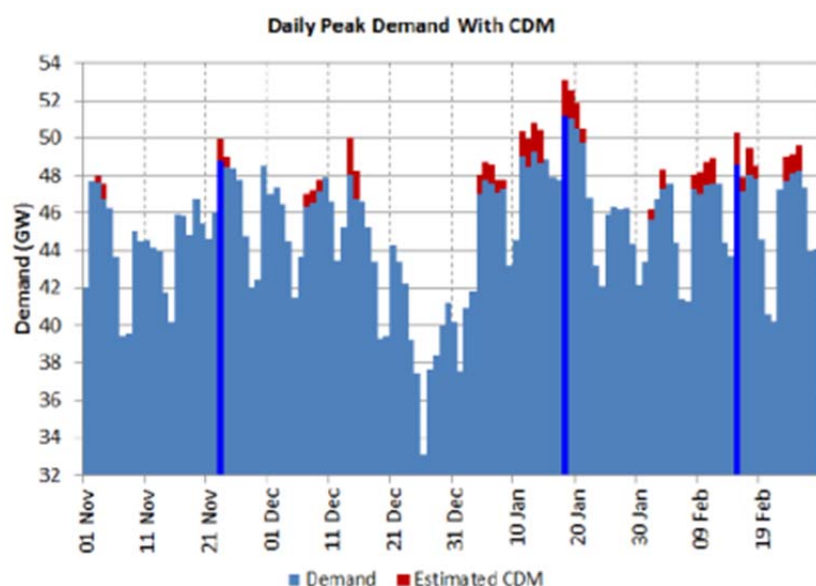
Triads have been historically been used to avoid network investment by giving a clear charging signal at the time of transmission system peak. The transmission network is no longer heavily invested in to provide increasing capacity. Instead current and future investment is to facilitate connection and distribution of Renewable power that is often more geographically diverse. However peak avoidance charging i.e. triads are still used to provide a demand signal even though there is diminishing economic rationale for doing so.

The status quo price signals have been designed to encourage change in behaviour across the GB peak. The ‘success’ of Triad has resulted in the phenomenon that we are experiencing now with a greater than ever level of Triad management and the significant change in permitted NG income

(from £3.2bn to £3.8bn) is compounding the effect for consumers. Additional, time-coincidental charges for DUoS Red-Rates and Capacity Market Supplier Recharge will naturally result in further significant 'load management' events undertaken by the business and DG community.

Ofgem should examine NGET's evidence as to whether or not the current '3-peak' model actually results in effective avoidance of network reinforcement.

- Consider whether for certain regions or specific locations, transmission constraints may also be experienced at other times of the year
- Noting that grid benefits from reduced peak loads on the system across a growing spectrum of periods (as represented in the 2015/16 image below\*):



*\*Source: Jeremy Caplin, Energy Forecasting Manager 'Customer Demand Management' presentation – National Grid (Ops Forum, March 2016)*

### **3. Impacts of the TNUoS and BSUoS embedded benefit**

**3.1 Do you have any comments on the impacts of the TNUoS and BSUoS embedded benefit (as described by Ofgem)?**

- *We question the way in which the efficiency of the generation mix is being presented*

Regarding the 1<sup>st</sup> bullet in your description - It is not appropriate to refer to "more efficient larger transmission connected generators" – the mix of generation should be dictated by the combination of Capex, fixed and variable costs, network losses, energy efficiency and emissions impacts not just the variable costs relating to the plant efficiency.

- *Some affected stakeholders are missing from your reflections*

There is no recognition in your letter that any changes to how TNUoS demand residual charges are allocated will impact hydro, biomass, biomass CHP and conventional CHP, and behind the meter generation technology investments. We can confirm that for such investments the TNUoS / Triad

payments have been considered an important revenue stream. All this should be considered by Ofgem in the full IA.

Npower would also flag that the potential impacts on customers who are DSR investors should be borne in mind. Without concurrent amendments to improve access to the CM, with changes to Triad arrangements there could be a natural re-set of the relatively immature DSR sector (and enabling business community) which could undermine investor confidence and the recent progress in understanding, I&C business and their contributions to future system flexibility requirements.

### **3.4 Do you have any comments on the BSUoS demand and generation charges?**

- ***We are concerned about an isolated review of BSUoS arrangements.***

BSUoS arrangements should only be looked at as part of a holistic review/ SCR.

We support your initial finding that BSUoS review is not a priority.

We agree that BSUoS embedded benefit very rarely impacts on despatch decisions and should not be a priority. Neither its receipt nor its removal would impact on embedded generator dispatch.

For embedded conventional and CHP plant dispatch decisions are determined mainly by wholesale market price signals and Triad warnings. For renewable energy generators, there are no fuel costs and are naturally at the bottom of the merit order. Some of the CMP 264/65 WACM proposals would introduce perverse drivers for renewable generators to stop generating exactly at the time that the system demand is highest. Having a high locational charge at Triad (forecast at up to £22/kW) would lead to renewable energy generators turning off out of merit. Operational dispatch for transmission connected renewables sites is governed by bilateral arrangements e.g. BOAs, Schedule 7As, commercial intertrips. Distribution sites can be subject to Schedule 7As and commercial intertrips. As DSOs emerge we would call for a BOA mechanism equivalent at the distributed level.

We also note that BSUoS benefits, in contrast to Triad benefit, turns negative in areas of high penetration of embedded generation.

### **3.5 Do you have any comments on whether EG provides any other benefit?**

Renewable generation has been increasingly meeting local distributed network demand- periods that might have once been peak have been dampened by local generation outputs and the total peak demand at peak has also reduced over time.

- ***Potential services that embedded generators could offer networks actually remain hidden and untapped because the commercial framework for them is absent.***

Renewables could be delivering , voltage control, frequency response and other ancillary system services.

Embedded generation can also provide benefits to the DNOs by helping constraint management, reactive power delivery, contributing to the reinforcement and running costs of the distribution networks, and by balancing supply and demand through a range of ‘ancillary’ services.



Some of these services are not properly remunerated by network companies. For example it has always been the case that DNO's require embedded wind farms to meet a 0.95 power factor lead and lag capability (this determines the MVAr's either exported or imported). Normally, the DNO's identify a fixed value within these limits. However, as a consequence of recent instruction by NG, connections now often require the wind farm to run leading. The effect of this operating regime is to seek to pull the network voltage down to manageable levels for NG and without this, NG would have to find some other means of controlling network voltage.

Other forms of despatchable DG and behind the meter generation can seek contracts (bilaterally or through services provided by the relatively immature DSR Aggregator community) for the provision of economic and efficient flexibility in the form of grid reserve and response.

- *Ofgem should not forget its environmental obligations in assessing the benefits of EG*

Ofgem should also in its IA consider the wider energy system 'cost to the consumer'. Embedded renewable energy generation is clearly beneficial to the environment. Networks should enable the lowest cost transition to a low carbon generation future.

#### **4. Ofgem's proposed approach**

##### **4.1 Would it be acceptable if Ofgem did not carry out an Impact Assessment before reaching a decision on any change?**

- *An IA for consumers is critical and should look holistically across all costs,*

e.g., a reduction in the demand tariff resulting from a reduction in embedded benefits could result in an increase in the CM cleared price, an increased gross winter peak load (and related consequences), the potential inflation of reserve prices (if a significant income stream is suppressed/removed) and an overall increase in the costs to consumers. The direct and predicted layered changes to NGET, Elexon and supplier systems that follow should not be overlooked in the IA.

The IA is also important for a fair and transparent outcome given the significant losses and gains faced by large transmission connected CM parties vs embedded generation CM parties. It is clearly set out in your letter that Ofgem's key driver is to address the distortions observed in the CM. Renewable energy generators cannot enter the CM and are now being caught out by an issue that stems from this mechanism. In contrast to conventional generation plants that can receive an upside from any consequent increases to CM cleared prices – reductions in embedded benefits are a pure loss to renewable generators. The economics of our embedded generation portfolio is being directly threatened by the proposals put forward under the CMP264 & CMP265 working groups. A significant annual revenue stream has to date been paid to us by suppliers in relation to the net demand reduction that our Triad output has had on electricity networks.

##### **4.2 What are your views on the different timing approaches?**

- *Implementation date should be 3 years from the date of Ofgem decision*  
which is anticipated to take us to April 2020.



This would a) allow time for a complete review, b) allow sufficient notice to suppliers and c) broadly coincide with T-4 CM auctions already cleared and d) minimise the risk of embedded generation closing (as a result of embedded benefit removal) before opportunities to support the DNO are created. For suppliers and their customers this implementation timescale could ensure contractual arrangements in place have sufficient time to unwind. It would also accommodate the implementation of potentially significant changes to pricing, forecasting, settlement and billing systems.

## **5. Potential Distortions from other charging arrangements**

### **5.1 Any comments on Ofgem's conclusions regarding potential distortions from other charging arrangements?**

- *Creating as level a playing field as possible between distributed and transmission connected generation is a supported aspiration.*

This should take account of DNO charges and the benefits brought to the distribution network by embedded generators.

#### ***Missing considerations regarding a comparison on DNO and transmission arrangements***

In our assessment connecting to the DNO network can be more expensive and carries a very different risk profile compared to connecting to transmission. The decision on what network to connect to for renewables, CHP sites and other forms of DG is often made primarily on the basis of the project capacity, what networks exists in the vicinity of the planned site. The closest network will generally provide the more cost effective solution and in many parts of the country this is then limited to distribution.

Embedded generators contribute to the reinforcement and running costs of the distribution networks whilst transmission connected generators do not. Where embedded generators have a direct impact on transmission networks they are also obliged to accept appropriate security and liability arrangements. Any transmission sole use assets are also paid for directly by such embedded generators.

## **6. Ongoing code modifications related to embedded benefits**

### **6. 1 Do you have any high level feedback on CMP264 & 265, alternative WACMs or other Mods proposed that Ofgem must be aware of?**

- *CMP264/265 were never intended to be an enduring solutions to the known defects and the incremental changes that would arise are inefficient*

Without a holistic review we may end up with a number of layered changes which have been implemented to counteract other defects that arise as a result of a previous change. This could be timely and costly and have adverse impacts to consumers including those that are investing in assets that contribute to the needs of the GB energy system. Incremental system changes or manual workarounds are required under some of the proposals and this will open to operational risk and will require assurances/governance to be in place.

- *CMP264/265 carry a risk of unintended consequences*

Some of the CMP264/265 WACM Options would drive all new generators to apply for transmission connections. Would the costs of expanding the transmission system, potentially to areas that were amenable to a DNO connection not ultimately result in higher costs to the consumer?

- *A solution that addresses the drivers of non-cost reflective charging signals should instead be found.*

A more holistic CUSC based approach is possible that can address the root causes of the distortions that you describe in your letter. Longer term wider solutions can emerge through your broader review.

## **7. Are Ofgem's 'related work themes' that they plan to consult on this Autumn appropriate?**

Prioritising storage related activity should be encouraged.

We agree with your original suggestion that reviewing BSUoS arrangements is not a priority. We are concerned about an isolated review of BSUoS arrangements. BSUoS arrangements should only be looked at as part of a holistic review/ SCR.

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<sup>ii</sup> Note, re emissions:

1. There is a parallel review of distributed generation emission limit values (ELVs) and implications of MCPD
2. while challenging the perception of 'inefficient' DG, given that behind-the-meter-generation (BTMG) is by its very nature optimally located (at/within the point of demand)
  - a. low/no distribution / transmission losses
  - b. location-efficient
  - c. uses only the available and consented distribution system
  - d. does not use the transmission system
  - e. the acknowledged mode of operations for BTMG can displace a significant proportion of sub-optimal asset test running (more often tested weekly/monthly inefficiently off-load)