



**Ofgem**

**Andrew Self,**

Head of Electricity Network Charging,

Submitted electronically to:

electricitynetworkcharging@ofgem.gov.uk

Contact: Fruzsina Kemenes

Phone: 075 577 58488

E-mail: Fruzsina.kemenes@innogy.com

12/04/2017,

**RE: CMP264 & CMP265 Ofgem Minded to Decision Response**

Dear Andrew,

innogy SE, is a newly established European energy company. Formally part of RWE AG, innogy SE has three business segments Grid & Infrastructure, Retail and Renewables.

The UK is a core territory for both our retail and renewables segments.

Please find attached our response to the CMP264/5 Minded to Decision. This reflects the views of innogy SE's UK arms: npower and innogy renewables UK Ltd.

Kind Regards,

*F. Kemenes*

Fruzsina Kemenes

Policy & Regulation Manager

Innogy SE

## Responses to specific consultation questions

### CHAPTER 1

**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?**

The problem definition is incorrect as it describes symptoms of an issue rather than the fundamental underlying defects.

On one hand it is evident that there is a significant and material impact associated with the current demand residual in the TNUoS transmission charging methodology and the consequent payments to sub-100MW embedded generation. Escalating TNUoS demand residual payments to embedded generation pose an increased cost to consumers and we agree that this needs to be addressed. Residual driven payments have escalated in value and are not cost reflective of the impacts of network users. The evidence presented demonstrates distortions to the CM clearing price and the types of units that succeed in securing CM contracts.

However, it should be recognised that the fundamental defect stems from the fact that the current charging system is no longer reflective of today’s evolving energy system where demand and generation profiles have shifted so significantly from conventional patterns. A telling illustration of the transformation of the system’s use is the precedent on Saturday 25th March when midday peak was lower than previous night’s demand.

If the demand residual is creating the wrong market signals this leads us to question if the underlying Tariff and Transport model is actually fit for purpose. Making arbitrary changes to targeted subsets of tariffs does not resolve such a fundamental problem.

CMP264/5 is simply too narrow in its approach to provide an enduring cost reflective solution. We would advocate a review of the transmission charging model to deliver a fair and cost reflective outcome for all users of the transmission network. This may involve extending to other time periods for example consumption all year round, peak year round etc. The charging must reflect customer’s use of the network. Any review of the charging model must lend itself to delivering a future proof solution where possible. Instead of the rushed yet enduring CMP264/5 Minded to Solution that has been presented, the more considered approach would be an immediate freeze to the embedded generator triad value to limit consumer costs, and to allow for the Targeted Charging Review (TCR) to establish a more cost reflective enduring solution. In effect this would be an interim application of WACM 10, an option already assessed and deemed as better than the baseline by the Panel, Ofgem and Frontier. As an interim solution the costs to the consumer could be limited over WACM4 if the outlined TCR confirms the enduring solution. This would strike the balance between the need to stop further escalation of these tariffs and the costs to consumers and the need to establish a truly cost reflective and enduring solution.

Under the TCR the relative impacts of winter peak use and year round system use should be considered to establish enduring demand and embedded generation charging arrangements.

Ofgem's current Mindful To Decision has uncertain consumer outcomes, potential for unintended consequences and high impact on generation, storage and DSR investor certainty. These concerns are voiced by npower's generation customers, wider industry members at the NationalGrid Power Responsive event and other fora.

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

Addressing pressures on the consumer purse should always be a key priority. We advocate an interim halt to rising TDR payments and the concurrent development of the enduring solution.

Your TCR and NGET's wider review acknowledge that rising TDR payments to embedded generators are not the only problems that need to be resolved. The underlying charging principles which are perpetuating the TDR payment escalation need to be addressed as it implies that the tariffs produced by the model are not sending the correct market signals overall.

Regarding the impacts of the rising TDR payments on competition - the material impact on generator competition should have been pre-emptively resolved by BEIS and DEFRA in looking at the CM regulations and emissions limits. This was a foreseeable commercial strategy for generators and thus a foreseeable distortion to the CM market. Ideally, the CM rules should stipulate that triad income and CM contracts are mutually exclusive.

Critically, for the impact assessment: the analysis fails to acknowledge the recent work of DEFRA on emissions controls. This should be an important factor when describing the problem. The UK's implementation of the Medium Combustion Plant Directive (MCPD) will help to reduce air pollution by bringing in emission controls for combustion plants in the 1-50MWth range with implementation by 2019 at the latest. The additional measures will specifically limit proliferating diesel generation. This should be assessed before the Authority can make a final decision, as it is a key determinant of the extent to which CM market will continue to be distorted and subsequent costs to consumers. We ask that Ofgem provide a view of the impacts on the emissions controls on CM and in turn on the sums paid out to embedded generators in the form of Triad benefit. Limiting the volumes of reciprocating peaking plant that can Triad chase, should in turn lead to lower TDR related payments and consumer cost savings in its own right. This could further justify the strategy of applying an interim solution at this stage. The temporary and immediate freeze to the embedded generator triad value (e.g. at the 2016/17 level) would provide the opportunity for the targeted charging review to establish a holistic enduring solution.

## CHAPTER 2

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

Yes.

But please note that regarding the objective of striving for cost reflectivity – there will be limits to which the market can react to the signals created, even if they were theoretically economically perfect. Ofgem must be mindful of important limiting factors; such as Planning and Consenting constraints in particular

when assessing to what extent cost reflective charging can actually achieve the intended policy outcomes.

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

The option of applying an 'interim solution' ahead of a TCR has not been assessed by Ofgem, even though it was a suggested approach in one of the original proposals. We ask that the merits of an 'interim solution' vs permanent application of a CMP264/5 WACM are assessed by Ofgem before the final decision is made.

WACM 10 has particular merits as an interim solution- Panel members considered it better than the baseline, and Ofgem's own impact assessment demonstrates that WACM 10 is an improvement on the status quo (or neutral) against all the criteria assessed it against. Therefore, it would not be in conflict with the objectives or statutory duties of the Authority, to select this as an interim solution while a holistic solution is determined. The costs of doing so against a phased introduction of WACM4 would be limited.

The enduring solution could in the meantime be identified over the coming months through your TCR and CMP271 with an enduring solution implemented three years from the point of an Ofgem decision. We would advocate 3 years of notice from the point of a decision from Ofgem before implementation of any changes because this will allow suppliers and consumers sufficient notice of changes and allow the new charging methodology to be reflected in customer contracts going forwards.

WACM10 would have an added benefit over WACM4 in protecting the desirability for future investors to commit to the UK generation, storage and DSR markets- observing that Ofgem is fair and mindful to mitigate drastic changes in costs and revenues. It would be pragmatic from an immediate implementation perspective. The market has now received the clear signal that change is expected and therefore stakeholders can now anticipate the status quo to end and be replaced by enduring change to be developed through your TCR.

(We could also support WACM 7 serving as an interim solution. We can see the merits that NGET have laid out in support of this alternative over WACM4).

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

While we understand your key mission to address a market distortion 'as soon as possible', we are concerned that having left the arrangements to persist for over a decade, recommending this WACM as the solution has been a knee-jerk reaction and this could have unintended consequences for the energy market and future consumers.

A benefit of a temporary and immediate freeze to the embedded generator triad value would be to provide the opportunity for a holistic enduring solution to emerge. This need not take an endless number of years- the TCR is forecast to take 18 months by your own estimate and we believe that under the CMP271 Original Proposal a more rational solution that addresses the underlying drivers of distortion of

Triad payments would have emerged. CMP271 would also be simpler by avoiding the need to identify, separately tag and charge certain user classes (such as embedded generators).

**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?**

Yes, ultimately we accept that grandfathering is inappropriate as all network users should ultimately be exposed to cost reflective network charges that are transparent and predictable. The problem in this case is that the charging arrangement has apparently been left as non-cost reflective for over a decade and TDR related payment trajectories have been allowed to balloon.

Grandfathering network charges would create significant IT and administrative burden for suppliers, and other parties. This is another reason we do not support grandfathering here.

However, we ask that the Authority is cognisant when implementing any change that the speed and scale of the proposals are of substantial concern to our renewable energy portfolio of wind and hydro projects; npower's storage and industrial user customers and the supply business itself.

We also retain a strong concern regarding the pressure on supplier's IT systems and the costs that will be borne by planned implementation in April 2018. The related Elexon Modifications (P348 and P349) have not yet come to conclusion and there will be a very short time allowed for what is a significant change-involving identifying a new and distinct user class, moving from net to gross demand charging etc. Only the 'Option 2' of the BSC Mod is in any way feasible by April 2018. (WACM 10 would fall under this and would be feasible as an interim solution from this date).

The original targeted implementation date for P348 was November 2019. We believe that any modification that makes such significant changes to the demand charging principles should allow a minimum of 3 years from the date of the Ofgem decision to implementation. This delay is necessary for suppliers and consumers because it enables systems and processes to be updated to accommodate the changes required. In addition it will enable current contractual agreements to unwind which will allow the required changes to be factored into future contracts. We would like to highlight that during the course of the BSC consultation window for P348/P349 Ofgem published their minded to position on CMP264/265. We would have found it more logical for the BSC consultation window to only open after the CMP264/5 minded to decision was published. As a result of this timing it was challenging to fully impact assess the proposed BSC options as no final decision had been made on CMP264/265.

We feel it would be prudent to wait until Ofgem make their final ruling on CMP264/265 in May rather than start developing either of the BSC options any further (most likely option 3 as this has been identified as addressing any of the possible CMP264/5 outcomes) before this. This is because option 2 is likely to fulfil the regulators determined solution and the other options would cause significant and most likely unnecessary work for many of the parties involved. Elexon has now brought the implementation date forward to November 2017. Given that the BSC modification is still at the Options stage, and that new DTC dataflows are being suggested, we feel that not only is this date ambitious, but it is also unrealistic in terms of allowing suppliers sufficient time to make the necessary changes to their systems.

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

No.

NGET publically recognise that there are other network and system impacts – both positive and negative from embedded generation that are over and beyond the ‘avoided GSP costs’. Ofgem should provide an independent and transparent calculation of the cost reflective value for ‘avoided GSP costs’.

The Ofgem Minded to Decision should be accompanied by Ofgem’s own or a commissioned independent assessment of whether NGET’s 2013 evaluation of the value avoided at the GSP based on winter peak use was correctly estimated – we are not convinced that the methodology used is suitable. A logical question we pose to Ofgem is whether a regional avoided GSP cost would be more appropriate in providing a cost reflective signal?

Furthermore as part of the TCR, and through collaboration with NGET and the other network businesses Ofgem should determine what other embedded generation system impacts need to be accounted for via market design and broader charging arrangements.

*(In the event that you do not examine this, please be aware that your consultation paper does not clearly explain to stakeholders that the NGET value needs revaluating prior to implementation to ensure it is a best estimate of cost reflective avoided costs today and that RPI is applied to the value).*

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

The assessment is incomplete as it only focused on the impacts on reciprocating gas and diesel and CCGT. There is an unjustified assumption that the energy mix is otherwise unaltered from the FES ‘slow progression’ trajectory.

The current landscape of industry changes is resulting in a higher cost of capital; impacting investor confidence as there is less certainty in the stability of the transmission charging model. This is leading to developers cancelling projects, which in turn is inhibiting Generation, growth. This poses a risk to the security of supply.

A further point for consideration is if we start to lose the element of price signals across the peak; does that peak escalate in the winter. Could this introduce a risk on the security of supply.

We do not understand why the assessment of the impacts on security of supply does not include modelling scenarios whereby the reduction in the embedded benefits causes new build embedded generators to default on their capacity market agreements won in the 2014 and 2015T-4 auctions. This would appear to be a probable outcome that even Frontier have since acknowledged and should therefore have included (2017.04.10, ICIS).

**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.**

This should be properly assessed as part of the TCR.

Ofgem needs to compare the full set of arrangements to ensure fair treatment of different energy system parties. Focusing narrowly on transmission charging arrangements would carry high risk of leading to distortions. There are definitely impacts that are not reflected in the full set of arrangements, such as the potential of generation sited so close to/ onsite with demand to reduce overall network losses, there are also setbacks experienced by embedded generators to consider: deep connection charging, no firm access rights, exclusion from ancillary services markets etc.

Allowing time to do this assessment provides a further reason to implement an interim solution (WACM10 or 7) for now and address the assessment that was missed due to the rushed nature of CMP264/5 process.

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

We would advocate a review of the transmission charging model to deliver a fair and cost reflective outcome for all users of the transmission network. This may involve extending to other time periods for example consumption all year round, peak year round etc. The charging must reflect customer's use of the network. Any review of the charging model must lend itself to delivering a future proof solution where possible.

Regarding the options proposed under CMP264/5 - exposing embedded generation to the locational peak signals is important as is ensuring that a perverse incentive of limiting embedded generation at system peak demand is avoided.

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

There is a longstanding legitimate expectation around the principle that siting generation closer to demand is efficient, avoids some network costs and that this shall be recognised via net charging.

The usage of the transmission network is related to net transfer on or off the transmission system. Net flows onto and off networks trigger investment rather than gross flows and that if generation and demand were balanced locally then there would be a reduced need for transmission assets. We believe that the long-standing net charging principle can be very valuable for reflecting the network value that embedded generators can bring in reducing network demand and system pressures. It is critical to ensure that the network charging tariff itself produces a cost reflective signal to all parties. While it is clear from your analysis that including the residual payment does not provide the correct economic signal we are not convinced that WACM 4 produces this either.

#### Impact on Npower business customer feedback:

There are a number of innovative projects driven by business customers which are now being shelved due to possibility of the minded to outcome. These projects are now considered un-investable. Wider implications of the minded to decision could result in the loss of load management, which may in turn increase prices over the winter peak. This further supports our request for this to be addressed via a TCR/SCR. Adopting this approach will enable the bigger picture to be considered as part of moving charges around.

#### *Major industrial connection customer example:*

We are aware of a business customer who has a number of CHP sites who spill – the proposed minded to decision will result in this no longer being commercially viable for them going forwards.

#### *DSR and storage investor feedback*

We have feedback from DSR interested parties that they are less likely to go ahead with the uncertainty opened up by this minded to decision.

In our view changes to Triad arrangements need to be complemented by a clear layout of the new opportunities for DSR – such as CM and ancillary service provision.

## **CHAPTER 5**

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

Suppliers – We retain a strong concern regarding the pressure on supplier's IT systems and the costs that will be borne by rushed implementation. We have consistently highlighted the request for 3 years notice from point of a decision from Ofgem. We advocate 3 years of notice from the point of a decision from Ofgem before implementation of any changes. This will allow consumers sufficient notice of changes and allow the new charging methodology to be reflected in customer contracts going forwards.

The related Elexon Modifications (P348 and P349) have not yet come to conclusion and there will be a very short time allowed for what is a significant change- involving identifying a new and distinct user class, moving from net to gross demand charging etc. Only the 'Option 2' of the BSC Mod is in any way feasible by April 2018. The original targeted implementation date for P348 was November 2019. We believe that any modification that makes such significant changes to the demand charging principles should allow a minimum of 3 years from the date of the Ofgem decision to implementation. This delay is necessary for suppliers and consumers because it enables systems and processes to be updated to accommodate the changes required. In addition it will enable current contractual agreements to unwind which will allow the required changes to be factored into future contracts. As no final decision has been made we feel it would be prudent to wait until Ofgem make their final ruling in May rather than start developing either of the other options (most likely option 3 as this has been identified as addressing any of the possible CMP264/5 outcomes) before this. This is because option 2 is likely to fulfil the Authority determined solution and the other options would cause significant and most likely unnecessary work for many of the parties involved. Elexon has now brought the implementation date forward to November 2017. Given that the BSC modification is still at the Options stage, and that new DTC dataflows are being suggested, we



feel that not only is this date ambitious, but it is also unrealistic in terms of allowing suppliers sufficient time to make the necessary changes to their systems.

Renewables – the main focus of your assessments has clearly been on reciprocating fossil fuelled plant. Although there is a narrow view on the impacts of this Mod on some renewables, this has been provided in isolation:

As a renewable energy business we are questioning the attraction of investing in developing any new distribution connected projects in the UK. We are not alone – the UK has slipped to 14th place in the Ernst & Young world renewable energy country attractiveness index. Ofgem's minded to decision not only reduces the value but more significantly changes the fundamental principle of a long standing revenue stream. It adds to a string of developments that deteriorates the economics of DG renewables. Ofgem's suggestion of further changes i.e. to consider introducing TNUoS generation charging and changes to BSUoS arrangements specifically targeting embedded generators, the recent removal of LECs, BEIS's closure of the RO, changes to FITs, exclusions from CfD support access etc. all point to an implicit UK policy against DG renewables. For intermittent renewables this was a small but nonetheless important revenue stream and we feel that your impact assessment has overlooked our industry's perspective. The impact on our hydro projects is particularly hard in combination with other recent changes.

#### Storage

Insights from npower customers:

Distribution connected storage customers will also be impacted by this change.

### **CHAPTER 6**

#### **Question 14: Do you agree with our modelling approach?**

A clear and critical weakness of the modelling approach is that while the cost to consumers of status quo network costs is the key issue- you have not modelled the network impact costs of the alternative proposals. This is important to address as you don't want to risk future consumer costs rising if significant network reinforcement was a consequence of the change.

It also seems misleading for Frontier to only model the impacts of this proposal beyond April 2021 (the start of RIIO-T2) whereas only the near term impacts would seem more certain.

All the CMP264/5 options, including WACM 4 are imperfect solutions that rely solely on a dated winter peak driven system that inevitably needs to change to accommodate a Smart and Flexible System.

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

The status quo should assume the implementation of the DEFRA decision on emissions standards is implemented.

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

WACM 10 should have been shortlisted and its impacts modelled as an 'interim solution'.

It is not clear why WACM10 was excluded from your original shortlisting. If you looked at it as an 'interim solution' it could serve as the best option in our view.