

18 April 2017

Andrew Self
The Office of Gas and Electricity Markets
9 Millbank
London
SW1P 3GE

Welsh Power Group Limited

First Floor
18 Park Place
Cardiff
CF10 3DQ
Tel: +44 (0)2920 547200
Fax: +44 (0)2920 398248
info@welshpower.com

electricitynetworkcharging@ofgem.gov.uk
andrew.self@ofgem.gov.uk

Dear Andrew,

Please find attached Welsh Power's response to OFGEM's consultation on its 'Minded to decision and draft Impact Assessment of industry's proposals (CMP264 and CMP265) to change electricity transmission charging arrangements for Embedded Generators.'

Background

Welsh Power Group is a privately-owned energy company with a strong track-record in the development, construction and operation of both conventional and renewable power generation projects. The company has owned large thermal generating plant, Uskmouth Power; developed and financed a new build 850MW CCGT, Severn Power; established a successful supply business, Haven Power; and constructed a small 50MW peaking portfolio which it sold to Alkane Energy in July 2014.

Since 2014 Welsh Power has been working in partnership with an investor to bring forward a portfolio of new flexible, efficient gas fired generating capacity to the UK market. Having participated in both the 2014 and 2015 Capacity Market auctions Welsh Power currently has over 300 MW of gas fired embedded generating capacity either operational or actively under construction.

The development, finance and build cycle of these plants is typically three years. The company is part way through the build out programme and is deeply concerned at the proposed changes to the treatment of embedded benefits following proposal CMP264 and CMP265 submitted to the CUSC Panel by Scottish Power and EdF respectively.

Introduction

The current 'minded to' decision to select WACM4 is at the extreme low end of options available to the Authority and will result in a substantial drop in the income of a wide range of embedded generators. At a stroke the decision will reverse a long standing revenue stream which has been a pillar of both equity and debt finance and inevitably lead to both new and established investors exiting the UK energy market at a time of unprecedented need for new infrastructure investment.

Whilst Welsh Power fully supports cost reflective charging and the elimination of market distortions we do not believe that an adequate case has been made for WACM4 to be adopted. We believe each of the following make the current basis for decision unsafe:

- the qualitative analysis supporting the decision is inadequate. Evidence provided to

support WACM4 is extremely lightweight amounting to little more than a hand drawn diagram describing network flows and four paragraphs from a National Grid report from 2014. The network flow diagram describes an obvious fact that if you change two practically identical parameters whilst fixing all other variables the outcome will be the same. This does not in any way accurately describe the complex interactions of network investment and costs.

- The quantitative analysis contained in the consultation is both limited and inaccurate. Only one outcome is modelled despite a significant uncertainty as to the likely outturn of events. The postulated outcome does not look sensible on any objective view of the future capacity mix as the forecast dominance of new built large CCGT's is extremely unlikely to materialise. The single scenario is also built on a materially inaccurate assumption on gas engine efficiency and the existence of 'tipping points' in the model indicate that a correction to this single assumption will result in a fundamentally different result and a total elimination of the forecast system savings.
- the rushed CUSC process undertaken on an accelerated timescale was unduly influenced by the vested commercial interests of large incumbent companies. The scope of the working group was necessarily restricted due to the overly ambitious timescales with no time permitted to explore and model the impacts of the proposed changes on industry participants and consumers. A lack of representation beyond the established large energy companies on the CUSC Panel resulted in a narrow subset of WACM's being recommended to the Authority all of which were at the extreme low end of the possible range. Despite the Authority and Panel's assertions of objectivity it is difficult to envisage any other process where the two proposers of the initial modifications were permitted to vote on the outcome. It is telling that the Consumer Representative on the CUSC Panel felt unable to vote due to a lack of evidence.
- The underlying presumption that the forward looking locational signals generated by the DCLF Transport and Tariff model are wrong. At best the model provides a relative signal to guide the location of generation and/or demand but makes no attempt to reflect the actual costs of locating demand and generation in a specific location. The existence of negative generation zones would indicate a reduction in system cost from locating generation in these areas. It is clear that no such cost saving is realised from any location decisions and in fact total transmission costs increase irrespective of where you locate new connections on the network. This false distinction between cost reflectivity and cost recovery has contributed to a flawed decision on charging arrangements.
- The RIIO incentive framework provides clear evidence of a quantifiable and enduring embedded benefit. Transmission Owner revenues are adjusted based on variations in connections to the network. Described as 'Load Related Expenditure' (LRE) these costs reflect the absolute size and cost of the transmission system. During the current RIIO incentive period LRE has significantly under spent against the baseline and to the extent that distribution connected generation is displacing transmission connected generation these savings to end consumers in the form of lower transmission network charges are a direct result and evidence of an enduring embedded benefit.

The remainder of this consultation response details the evidence for an embedded benefit materially higher than the £1.62/kw proposed 'value of X' before responding to each of the consultation questions contained within OFGEM's document.

Value of x - avoidable network investment costs

At the beginning of the CMP264/265 working group process working group members from a DG background made representations that in the absence of the significant volumes of generation connected to the DNO network the physical transmission system would be different (bigger) and costs to consumers would also be different (higher) than they currently are. This seemed an obvious point and clear evidence and justification of an enduring embedded benefit. This was wrongly termed a 'sunk benefit' and much time was spent in the working group arguing about how and if this should be recognised and rewarded. The counter argument is that historic investment is sunk and it is only the forward looking marginal cost signals which result from the locational element of the DCLF Transport and Tariff Model that are cost reflective. All other charges are simply revenue recovery mechanisms to arrive at the correct total allowed revenue for the TOs'.

In the 'minded to' consultation document it was accepted that DG can avoid demand led reinforcement and hence the £1.62/kw 'value of x' which currently forms the basis of OFGEM's minded to consultation. We believe that the £1.62/kw both understates the avoided demand led reinforcement cost and is only one of a number of transmission investment costs which DG avoids when it is built in substitution of transmission connected generation.

On reviewing the RIIO incentive mechanism which sets the TOs' total allowed revenue it is apparent that the TOs' allowed revenue is varied based on the volume of generation connections to the transmission system. The TOs' are currently significantly underspending against their baseline allowances as a result of the reduction in generation connecting to the Transmission system and this is leading to a reduction in the total revenue being recovered from the end consumer.

The RIIO incentive mechanism is designed to vary the TOs' allowed revenue based on changes to outputs over the incentive period. National Grid's TO RIIO incentive includes allowed revenues for Load-Related (LR) capex

5.17 'LR capex is the investment on the network to accommodate changes in the level or pattern of electricity generation and demand. This is split further into a number of funding mechanisms, the largest of which are for (i) connecting new electricity generation sources, (ii) connecting new demand sources, and (iii) 'wider works' which are associated reinforcements that facilitate these connections whilst maintaining network integrity....' [RIIO ET-1 Annual Report 2015-16 (Page 53)]

5.21 'In setting the price control, Ofgem used a baseline allowance to reflect its expectation of c£4.5 billion of varying costs (that change in line with measurable outputs) and c£1.4 billion of non-variant costs (for works that are needed but do not deliver a directly measurable output such as MW)

National Grid was set the following variant capex allowances over the RIIO incentive period:

	Special condition section	2013/14 £m 2009/10	2014/15 £m 2009/10	2015/16 £m 2009/10	2016/17 £m 2009/10	2017/18 £m 2009/10	2018/19 £m 2009/10	2019/20 £m 2009/10	2020/21 £m 2009/10	RIIO Total £m 2009/10
Variant allowance category										
Generation connections volume driver	6F	130.5	185.2	184.1	220.7	117.4	96.0	42.5	20.7	997.1
Baseline and strategic wider works outputs	6I	161.7	230.4	208.9	20.1	-	-	-	-	621.1
Network development and wider works volume driver (NGET only)	6J	277.0	303.3	264.3	283.2	133.2	70.3	27.3	8.6	1,367.1
Undergrounding volume driver	6K	25.5	68.3	89.0	132.5	75.2	41.0	27.5	3.3	462.3
Demand related infrastructure volume driver	6L	47.8	36.2	32.4	32.8	50.6	41.4	12.5	0.9	254.6
Total		642.5	823.4	778.7	689.3	376.4	248.6	109.7	33.4	3,702.1
RPI Forecast	RPIft	1.180	1.205	1.227	1.233	1.271	1.309	1.343	1.384	
Inflated variant allowance		758.1	992.3	955.2	849.9	478.4	325.4	147.4	46.3	4,553.0

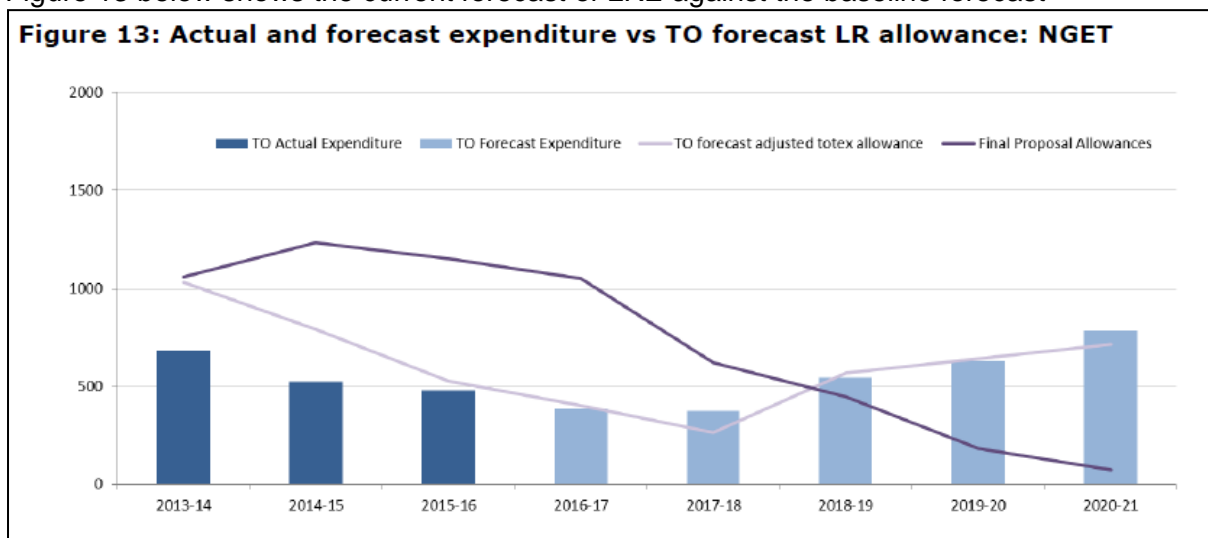
The latest annual report on RIIO states the following in relation to Load Related (LR) Capex:

5.22 Baseline allowances were set on the basis of a baseline of 33GW of generation connecting over the RIIO period. Now in the third year of the price control, NGET's connection profile is estimated as 14GW. Demand connections have also fallen. These changes will lead to a downward adjustment to the allowances across the price control period.

5.23 In light of the reduction in volume of demand and generation connections, NGET currently anticipates that a large amount of wider works expenditure, required to maintain network integrity within and across network boundaries, has either become unnecessary or will be deferred beyond RIIO-ET1.....

5.24 In aggregate, NGET has underspent its revised LRE allowances over the first three years of the control by £663m and is forecasting to underspend its revised allowances over the 8 years period by £544m.

Figure 13 below shows the current forecast of LRE against the baseline forecast



The TOs' allowances are flexed annually based on outputs to determine the allowed revenue to be recovered through TNUoS charges. **A reduction in Load Related Expenditure reduces the total TNUoS costs to be recovered from consumers.** The adjustments to National Grids revenue are contained within its Licence with Special Conditions 6F, 6I, 6J, 6K and 6L detailing the adjustments for each category of costs.

Special condition 6F - connections volume driver

Generation connections volume driver is set based on the following assumed generation connections over the RIIO period

Table 1: Baseline Generation Connections and Allowed Expenditure

	Relevant Year							
	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21
BGCO (MW)	504.0	1597.0	3264.0	3553.0	1540.0	3797.0	5649.5	13819.0
BLOHL (circuit km)	5.4	0.0	0.0	100.0	0.0	70.0	40.0	0.0
BGCE (£m)	130.524	185.228	184.112	220.710	117.364	95.965	42.494	20.662

The variant capex is set at a rate of £27/kw (in 2009/10 prices) for each MW connected and £1.1m for each km of overhead line (BLOHL). The phasing of the allowed expenditure is set by reference to Table 4 of special condition 6F of NGT's Transmission Licence¹

$$VGCE_{t,n} = \{(AGCO_{t-2} - BGCO_{t-2}) \times £0.027\text{million} + (ALOHL_{t-2} - BLOHL_{t-2}) \times £1.1\text{million} + (\sum_{\text{for all } x} \sum_{m=1 \text{ to } 15} ASLCBL_{x,m,t-2} \times COUCA_m)\} \times RPE_n \times WFG_{t-2,n}$$

National Grid's allowed totex is reduced or increased by £27/kw for each connected MW variance from the above schedule. Note that NG's allowed capex is adjusted by a standardised £27/kw irrespective of the actual incurred connection cost. A new CCGT built on the site of an existing connection would increase NG's allowed capex even if actual incurred connection costs are very low.

Special condition 6J - Incremental wider works (IWW)

Network development and wider works volume driver capex allowances are set where new connections trigger boundary reinforcement requirements:

'wider works' are associated reinforcements that facilitate these connections whilst maintaining network integrity.'

9.1 The term 'Wider Works Outputs' refers to reinforcement of the national electricity transmission system to reinforce or extend it to meet existing and future customer requirements. The reinforcement will provide additional transmission capacity and/or boundary transfer capability. [ET1 Price Control Financial Handbook – Chapter 9]

Where connections do not materialise the wider works allowed capex is also adjusted. Eg wider works to reinforce boundary B14e are no longer required within this incentive period due to the cancellation of a CCGT project in greater London and the postponement of offshore windfarms off the coast of South East England.

The incremental wider works capex totals £1.4 billion over the RIIO Period and represents £1.37 per £ of generation connections allowances. Based on the £27/kw allowance the value of the connection allowance together with the IWW totals £64/kw (2009/10 prices). Inflated to

¹ <https://epr.ofgem.gov.uk/Content/Documents/National%20Grid%20Electricity%20Transmission%20Plc%20-%20Special%20Conditions%20-%20Current%20Version.pdf>

2017/18 prices per the TNUoS charging model (inflator 1.271) provides a 2017/18 generation related avoided cost of £81.33/kw. Applying National Grid's annuity factor of 0.066 gives an annualised saving of £5.37/kw

Special condition 6L - demand related infrastructure

Special condition 6L appears to be the origins of the £1.62/kw proposed 'value of x' where an average annuitized cost (excluding the super grid transformer 'SGT') of avoided transmission infrastructure investment at GSPs was calculated. In the calculation it is unclear why the value of the Super Grid Transformer (SGT) is ignored. Whilst this might be deemed a connection asset and chargeable to the DNO this cost will still be levied on the end consumer via distribution charges. The consumer saving should be the total avoided infrastructure cost including the SGT.

NGET RIIO incentive on demand related infrastructure is varied based on the number of installed SGT's using the formula below

$$VDRI_{t,n} = [(AQSGT_{t-2} - BQSGT_{t-2}) \times \text{£3.9million}] + \{ (ADOHL_{t-2} - BDOHL_{t-2}) \times \text{£1.1million} \} + \{ \sum_{\text{for all } x} \sum_{m=1 \text{ to } 15} (ADCBL_{x,m,d} \times COUCA_m) \} \times RPE_n \times WFD_{t-2,n}$$

It would appear that NGET receive an allowance of £3.9m for each SGT installed irrespective of whether these are paid for by the DNO. There appears to be no reason to discount these assets from the £1.62/kw.

It is unclear whether the SGT allowance is based on a specific capacity. With a likely SGT capacity of between 60MVA and 240MVA the incremental capex would be between £16/kw and £65/kw. Inflated to 2017/18 prices and annuitized this represents an additional annual embedded benefit of between £1.34/kw and £5.45/kw

IT IS CLEAR THAT CHANGES IN CONNECTION VOLUMES ON THE TRANSMISSION SYSTEM LEAD TO REDUCTIONS IN THE TOs' ALLOWED REVENUES WHICH HAVE A DIRECT IMPACT ON CONSUMER CHARGES. THERE IS A MEASURABLE BENEFIT FROM REPLACING TRANSMISSION CONNECTED GENERATION WITH DG.

SPECIFIC CONSULTATION QUESTIONS

Chapter 2 - Background

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?

Whilst Welsh Power accepts that a continually escalating TDR will inevitably lead to market distortions we believe that the escalating TDR is a symptom rather than the cause of the issue. The escalating TDR is due to the significant increases in the costs of the transmission owners and the cap on charges that can be levied on generators connected to the transmission system. We believe that the presentation of the issue as being driven by a declining charging base is misleading.

Further we believe that a system which is designed around serving system peak demand should rightly levy the charges on or over the annual demand peak and that the principle of net charging is appropriate for this as it measures demands placed on the system over the peak period. To the extent that certain of the costs contained within the TDR are simply recovering the allowed revenue of the TOs' then a separate charging methodology should be adopted which reflects the unavoidable nature of these charges. We would however strongly suggest a review of network charging to understand what costs are truly fixed in nature and over what timescales. It seems inadequate for the cost reflective element of charging to recover a relatively insignificant proportion of the costs of the system. We do not believe that the DCLF model's allocation of costs into cost reflective locational charges and cost recovered residual charges is accurate.

Welsh Power accepts that the size of the Triad payment will affect dispatch decisions over winter peak and affect (lower) wholesale power prices over this peak. We also accept that embedded generators have factored Triad payments into their CM bids which will have resulted in lower clearing prices in the 2014 and 2015 CM auctions. Whilst these impacts on the market are clear it is debatable whether the net effect of higher CM payments (to all generators in a pay as cleared auction), higher peak power prices and substantially higher transmission system costs if more larger plant were to be connected to the system, would lead to a net saving to the consumer.

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

We believe that a continually escalating TDR is unsustainable and needs to be addressed however this should be done through a wide ranging review, most likely an SCR, which would be able to look at network charging in detail. It is clear with the rapid development of the energy system and shift from the centralised generation model that the current charging arrangements are not fit for purpose and are in need of wholesale reform. The CUSC process is wholly unsuitable for this reform which can only be progressed by an independent regulator free of the commercial motivations evident in CUSC modification proposals.

The review, done properly, is likely to take time. In the meantime it is important that the size of the embedded benefit is frozen either at its current level (WACM10) or more likely at a level which we believe can be objectively justified (WACM7).

Chapter 4 - Assessment against decision making criteria

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

The CUSC objectives are laid down in the CUSC. To the extent they have been listed in the consultation document we believe they are uncontentious however we do not agree with their application and provide further details in our response to Q4.

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

We would make the following points relating to each CUSC objective in turn:

(a) Facilitating competition

The implementation of WACM4 without a fuller more rigorous analysis of charging arrangements risks distorting competition in favour of large transmission connected

generators. Welsh Power has identified clear evidence in the RIIO framework of a genuine and enduring embedded benefit from avoided transmission costs materially in excess of the avoided GSP costs and therefore implementing WACM4 would lead to an under rewarding of EG relative to the benefits they bring to the system.

Implementing WACM4 would also create a new competitive distortion relating to behind the meter generators who would retain access to the full Triad value. Ignoring the negative generator residual also further exacerbates the competitive distortion between transmission and distribution connected generators.

(b) Cost-Reflective Charging

We do not believe that the DCLF model provides cost reflective locational signals as assumed in the consultation document. The consultation document relies on the distinction between cost reflective charges and cost recovery and deems all charges other than the locational charges to fall into the latter category. We believe the segregation of costs into locational and residual to be arbitrary based on arbitrary scaling factors, artificially low expansion constants and modelling based on a built transmission system. Whilst the DCLF may give approximate relative locational signals it does not provide a measure of the actual incremental costs. Further information is provided in Appendix 1.

(c) Facilitating charges that take account of the developments in the transmission licencees' transmission businesses

We do not believe that the current charging arrangements or the proposed reduction in TDR correctly reflects the TOs' businesses. The RIIO incentive provides a clear link between connections (outputs) and costs. This relationship is not reflected in the current charging arrangements and is further distorted if WACM4 were to be implemented.

(d) Taking account of European Legislation

We have no comment on this CUSC objective

(e) Promotion of efficiency in implementation and administration of charging methodology

We do not believe it is efficient to implement a short term charging change whilst acknowledging that this is not the final answer to the charging review. The ongoing CUSC modifications 271/274 and 276 all focus on this area so change is expected to continue and OFGEMs recently announced TCR/SCR will relook at the issue.

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

As outlined in the introductory section of this consultation response Welsh Power believes that NGETs RIIO-T1 incentive arrangements provide clear evidence of an enduring embedded benefit in excess of the £1.62/kw proposed in OFGEMs minded to decision. No time was spent in the CUSC working group to explore the detail of the TOs' allowed revenue or the relationship between the growth of DG and the total allowed revenues the TOs are able to recover. No mention has been made of this relationship in any of OFGEMs correspondence on this matter and it would appear to be the case that this has not been considered.

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?

Whilst Welsh Power is sympathetic to the argument that investment decisions taken prior to the CUSC process were made on the reasonable expectation of continuing Triad payments we also believe that there will be compensating adjustments in other areas of the energy market most likely in the form of higher CM clearing prices and higher peak power prices. To grandfather existing or CM obligated capacity would lead to windfall gains for those assets which were operational prior to the cut-off period as they would also benefit from the adjustments elsewhere in the energy market.

Welsh Power believe a proportionate response would be a longer implementation period to allow adjustments to be made or for companies to be able to terminate their 2014 and 2015 CM agreements with no penalty.

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

Welsh Power believes, as explained earlier in this consultation response, that the £1.62 avoided GSP investment cost understates the value of this avoided cost by ignoring the cost of the super grid transformer. In addition the avoided demand led reinforcement cost is only one element of the transmission costs avoided as a result of the construction of embedded generation. Full account should be taken of the additional elements of Load Related Expenditure that are adjusted based on the volume of capacity connected to the transmission system.

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

No we do not agree with OFGEMs assessment of the impacts on security of supply. The consultation assesses two aspects of security of supply; the non delivery of CM obligated plant and changes in dispatch behaviour of plant. No analysis has been provided to assess the likely effects of the reduction in TDR and the analysis amounts to little more than assertions without any supporting evidence. It was evident during the working group that no single organisation, OFGEM and National Grid included, have any accurate information on the total of the volume of DG that is currently despatching to benefit from the Triad revenues. Estimates ranged from 2GW to 7.5GW and with this level of uncertainty in capacity let alone a sense of what these plants will now do in the absence of a Triad signal to generate it seems impossible to conclude that there is no security of supply risk.

The consultation states 'The T-4 and T-1 CM auctions ensure there is sufficient capacity on the system to meet the government's reliability standard.' It should be remembered that the capacity to procure in the CM auction is based on an assessment of peak transmission system demand which is net of embedded generation. It is certain that the changes to TDR payments will have an effect on DG dispatch over the demand peak and consequently it is not possible to rely on the CM procured capacity to ensure security of supply.

We again consider there to have been a lack of rigorous analysis to support the fundamental changes to charging arrangements and to assess the likely impact on the energy system of the changes that will flow from the proposal.

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.

As a result of adjustments made to the TOs' allowed revenue from variations in outputs

under the RIIO incentive structure the substitution of transmission connected plant with DG leads to a reduction in the total costs borne by the end consumer from transmission system charging. These savings do not present themselves in the locational signals generated by the DCLF model and are not fully valued in the avoided GSP proposal.

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

Yes as outlined above and elsewhere in the response a value materially in excess of the avoided GSP cost is justified. Taken together the adjustments to load related expenditure total in excess of £10/kw of annualised savings. Further the cap on generation charges and negative generator residual represent a direct subsidy to transmission connected power plant and a competitive distortion if allowed to persist. Whilst OFGEM recognise that this is an issue that needs to be addressed its ability to do so is compromised as the cap is an EU imposed rule. Welsh Power believes that to avoid competitive distortions, inefficient investment decisions and windfall gains this negative generator residual or an approximations of the credit should also be paid as an adder to the 'value of x'.

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

Whilst we do not believe that a contractual right to this revenue stream exists the longevity of the charging arrangements and the previous reviews conducted on this area have crystallised a legitimate expectation that the charging arrangements would endure. As such any changes should be measured, proportionate and phased in appropriately. We do not believe that the current proposal meets any of these criterions.

Chapter 5 - Distributional Issues

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

The analysis of distributional issues simply shows who will lose from the changes and to what extent. We agree that the chapter dealing with this has identified each of those groups who are likely to suffer however to asses the full distributional impact it is important to identify the winners from this change as well.

We believe the proposed changes will lead to higher CM clearing prices and higher peak energy prices. The higher CM clearing prices will clearly benefit larger generators who will now accrue income in excess of their marginal bid price due to the 'pay as clear' nature of the auction. We also believe that the absence of DG generating over the Triad will lead to materially higher power prices across the winter demand peak. This will benefit larger thermal plant that will be able to capitalise on a tight market to extract scarcity rent over the winter peak. There is no reason to believe that the extreme prices observed at times over the past two winters will not become a more regular feature of the energy market.

As demonstrated in the introduction to this response the total transmission costs will increase substantially if more plant connects to the transmission system. The RIIO incentive mechanism provides an incremental allowance for each MW of capacity added to the transmission system. Due to the super shallow connection methodology on the transmission system the costs of connecting large new plant will be socialised through the TNUoS charges. This can be compared to the situation on the distribution system where new plants pay a deep connection charge and through the Statement of Works process can only

connect to the system if their impact on the transmission system is benign. Further detail of the SoW process is provided in Appendix 1.

The extent to which these factors counteract the reduction in TDR payments to DG will determine the net cost or benefit to the consumer.

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

We believe that analysis of the impact on suppliers in particular new entrants to the market should be undertaken. The complexity of the new arrangements and their implementation costs should be assessed but more importantly suppliers' ability to manage the higher and potentially extreme winter price spikes should be considered. Most new suppliers in the market do not forward purchase their power due to either market liquidity issues or the requirement to run a collateral light business model. As such power is purchased in the day ahead market or from cash out arrangements. The extreme pricing observed in September and October 2016 created major issues for suppliers who were short and are likely to have contributed to participants exiting the market over the course of the winter. This issue is only likely to get worse as a result of the proposed changes.

Chapter 6 - Quantitative modelling results

Question 14: Do you agree with our modelling approach?

No we believe the modelling approach to be fundamentally flawed. It is generally accepted that the impact of the proposed changes are extremely uncertain as they will affect all aspects of the energy market. This is set against a backdrop of unprecedented change in the market as the UK transitions away from a centralised generation model. The quantitative analysis contained in the consultation is both limited and inaccurate. Only one outcome is modelled despite a significant uncertainty as to the likely outturn of events. For OFGEM to have commissioned LCP to run a single modelling scenario and to present this in the IA as the lower bound to the expected consumer benefit is misleading. The consultation states 'The assumptions used are conservative in nature, and so may understate the potential benefits of these changes.' We believe this statement to misrepresent the results of modelling the change.

The postulated outcome does not look sensible on any objective view of the future capacity mix as the forecast dominance of new built large CCGT's is extremely unlikely to materialise. The single scenario is also built on a materially inaccurate assumption on gas engine efficiency and the existence of 'tipping points' in the model indicate that a correction to this single assumption will result in a fundamentally different result and a total elimination of the forecast system savings.

Welsh Power was given the opportunity to explore the modelling work and assumptions at both the industry workshop and a separate focused session with LCP. In both workshops it was apparent that the system cost savings arise only in the situation that new build CCGTs become the dominant new build technology and that this only happens as their calculated CM bid price is marginally lower than that of reciprocating engines. The CM exit bid of reciprocating engines derived from the missing money calculation was based on an assumed efficiency of 32% for this technology class. Whilst taken from a DECC/BEIS publication this efficiency value bears no relationship to real world efficiencies which are materially in excess of 39%. We believe correcting this single assumption would reverse the

CM bid merit order between reciprocating technology and CCGT's leading to very few new build CCGT's being brought forward. This result would reverse the system cost saving analysis resulting in an unchanged capacity mix from the status quo but requiring higher CM clearing prices and higher peak energy prices. Whilst it is uncertain what the final effect on the consumer would be it is safe to say that the any consumer benefit, if any were to arise, would be materially lower than that presented in the IA.

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

Whilst we do not consider it unreasonable to use National Grid's FES data as the background to the modelling work we are surprised that only one scenario, namely Slow Progression, was modelled. As there is a wide range to possible outcomes we believe it would have been beneficial to run a range of background scenarios to provide a range of potential outcomes and costs/savings. In addition to running multiple FES scenarios we also believe there would have been benefit in considering a range of inputs to test the range of modelled outcomes. This approach, showing savings of between x and y, would have more accurately reflected the uncertain environment in which the decision is being taken.

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

Since we believe the approach to the modelling work to be fundamentally flawed we do not believe it appropriate to comment on the modelling of specific WACMs.

Chapter 7 - Assessment of shortlisted options

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

No we do not believe that WACM4 best facilitates the CUSC objectives. It fails on CUSC objectives a, b and c for the following reasons:

(f) Facilitating competition

The implementation of WACM4 without a fuller more rigorous analysis of charging arrangements risks distorting competition in favour of large transmission connected generators. Welsh Power has identified clear evidence in the RIIO framework of a genuine and enduring embedded benefit from avoided transmission costs materially in excess of the avoided GSP costs. Implementing WACM4 would also create a new competitive distortion relating to behind the meter generators who would retain access to the full Triad value. Ignoring the negative generator residual also further exacerbates the competitive distortion between transmission and distribution connected generators.

(g) Cost-Reflective Charging

We do not believe that the DCLF model provides cost reflective locational signals as assumed in the consultation document. The consultation document relies on the distinction between cost reflective charges and cost recovery and deems all charges other than the locational charges to fall into the latter category. We believe the segregation of costs into locational and residual to be arbitrary based on arbitrary scaling factors, artificially low expansion constants and modelling based on a built transmission system. Whilst the DCLF may give approximate relative locational

signals it does not provide a measure of the actual incremental costs.

(e) *Promotion of efficiency in implementation and administration of charging methodology*

We do not believe it is efficient to implement a short term charging change whilst acknowledging that this is not the final answer to the charging review. The ongoing CUSC modifications 271/274 and 276 all focus on this area so change is expected to continue and OFGEMs recently announced TCR/SCR will relook at the issue.

Recognising something needs to be done in the short term to address the escalating Triad payment and that any short term measure is likely to introduce new distortions to the market we believe it preferable for this decision to do the least harm. A reduction of the Triad payment to near zero as proposed by WACM4 should only be done if OFGEM is certain that this option reflects the correct long term result. Based on the evidence presented in this response we do not believe that to be the case and call for OFGEM to implement WACM7 as the correct holding modification whilst OFEGM conduct their full review.

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

We believe that April 2018 implementation date is too soon and should either be delayed by a further year or for a different phasing to be applied however we do recognise that this second option may not be available to OFGEM through the CUSC process. The current implementation timescales offer insufficient time for contracts to be renegotiated, systems changed and commercial models adjusted. It would also allow more time for level access to be provided for DG in Ancillary Services and the Balancing Market.

Welsh Power believes that the minded to decision risks creating new distortions in the market and replacing one imperfect charging arrangement with another. We believe the supporting modelling work to be fundamentally flawed and the qualitative evidence to offer insufficient justification for the proposed change. Our consultation response identifies clear evidence of additional transmission cost savings from the construction of EG in the form of lower transmission system investments and the fact that this evidence appears to have escaped the process thus far speaks to the rushed nature of the proposals and call on OFGEM to properly investigate the correct embedded charging benefit in its SCR. Whilst we do not believe that sufficient rigour has been applied to a process of such significance we also recognise the need to halt the unsustainable escalation in TDR payments. To this end we recommend that OFGEM accept WACM7 as an alternative to WACM4. WACM7 maintains a TDR payment that can be objectively justified from the RIIO framework.

Please do not hesitate to contact me should you have any questions regarding our consultation response.

Yours faithfully



Matthew Tucker
Finance Director