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Judith Ross
Head of Network Regulation Policy
Ofgem
9 Millbank
London
SW1P 3GE

Dear Judith,

RESPONSE TO OFGEM'S TARGETED CHARGING REVIEW

I attach PeakGen's response to Ofgem's Targeted Charging Review (TCR) consultation.

PeakGen are fully supportive of Ofgem's proposals to conduct a Significant Code Review (SCR) on transmission charging as we believe there is a clear issue with rising costs in the transmission system as the current charging methodology is no longer fit for purpose and requires a full review of the allocation of costs rather than a series partial changes that negatively impact investor confidence.

Given likely delays as a result of the upcoming election, we urge Ofgem to carry out a holistic review of network charging arrangements through an SCR rather than pushing through ill-founded, partial and rushed decision on CMP264 and CMP265 based on flawed assumptions as set out in Ofgem's minded-to decision, which will hinder not help achieve our shared objectives of ensuring the lights stay on at the least cost to consumer.

There has been an oversight in the Governance of the CUSC process:

- Under the CUSC process, Embedded Generators (as well as other parties such as consumer groups etc.) have been ignored.
    - The CUSC Panel failed to recommend to Ofgem *any* of the proposals supported by the majority of the Workgroup.
    - The voting at the CUSC Panel has shut down the rights of smaller embedded generator parties to undertake a merits-based appeal in the process.
- The investors expect Ofgem to follow the process as set out in their statutory duties and consider all arguments before making any changes – which has not been the case.
- PeakGen agree with Ofgem that 'wide industry representation' is required to 'steer the overall charging reform programme' (under the TCR). The smaller players on the network should have a voice through the Charging Coordination Group in the SCR process.

The current charging arrangements are not fit for purpose and there is a need for a holistic review of both residual and locational charges:

- Ofgem repeatedly state that the demand residual charge simply covers the fixed and unavoidable costs of the system but in reality, the charging methodology is failing to allocate the new costs appropriately, causing the residual charge to rise. Under the current charging arrangements, the locational charge does not sufficiently recover the cost of investment and the demand residual contains forward looking costs. This is discussed further in Annex 2 to this letter.
- As illustrated in Annex 2, the demand residual charge does not represent either sunk costs or unavoidable costs, and the basic premise of the TCR that the demand residual is unavoidable and therefore should be charged in a way that is neither cost reflective or avoidable is deeply flawed. By setting up transmission charging in this way we are likely to see ongoing over investment in the transmission system to the detriment of customers. Therefore, we strongly believe that the residual and locational charges must be reviewed together as we highlight in our response to the minded-to decision on CMP264 and CMP265.

Ofgem's current minded-to decision on CMP264 and CMP265 is rushed and based on flawed assumptions, as evidenced by multiple errors and omissions throughout the consultation document, which will damage investor confidence, increase the costs to the consumers and increase the risk of security of supply:

- Like ourselves, many investors entered into Capacity Market agreements in the 2014 and 2015 auctions in good faith. The retrospective nature of this policy change, with no arrangements for grandfathering, will damage investor confidence at a time when Ofgem and the Government are trying to encourage smaller players (like ourselves) to make the transition to a 'Smarter, More Flexible' power system. As illustrated in Annex 3, this will lead to **increased costs to the consumers of around £2-8bn**.
- There is 4GW of conventional embedded generation that secured contracts in the 2014, 2015 and 2016 T-4 Capacity Market auctions. As a number of market participants have made clear, some of this capacity will now be at risk as a result of these changes, increasing risks to security of supply.

We believe that cost reflectivity across network users should be the main principle for assessing the options in the charging review:

- Any charging arrangement should be a function of the benefit provided to the system and the amount of usage – i.e. it must be cost reflective. A fully cost reflective system will ensure a reduction in market distortions, promote fairness in the system and ensure recommendations are proportional and practical.
- We believe that given that the current charging methodology is not cost reflective, Ofgem needs to be mindful of any changes that could create a discriminatory decision against embedded plant by ignoring their benefits to the consumer cost.
    - It is an EU requirement for suppliers to be charged their share of the investment in the transmission system. Embedded generation, as per the security and quality of supply standard (SQSS), reduces the necessary amount of infrastructure required by National Grid and as such that benefit should be recognised.

- SQSS treats embedded generation as negative demand at the grid supply point. The total impact of demand on the network system, where it is offset by embedded plant, would be lower and should therefore face a lower cost for using the network. This is shown in Annex 4.

We welcome Ofgem's proposal to review the transmission charging arrangements, specifically with regards to storage:

- As an owner and developer of battery storage facilities, PeakGen support and welcome Ofgem's view that for the purposes of transmission charging, battery storage should be treated as an embedded generator.

Due to the interdependency of charging arrangements on the network system, demand residual charges and payments to embedded generators should not be considered in isolation. Given the upcoming General Election and the inevitable delay to a decision on CMP264 and CMP265, we urge Ofgem to carry out a holistic review of network charging arrangements through the SCR, to avoid further damage to investor confidence, increase risks to security of supply and increase consumer bills.

Yours sincerely

Mark Draper, CEO, PeakGen

Annex 1 - Response to formal consultation questions

Question 1: Do you agree that the potential for residual charges to fall increasingly on groups of consumers who are less able to take action than others who are connected to the system, is something we should address?

Costs of transmission should be allocated on those that cause them to be incurred. Investors in transmission should take on the risk that assets may become stranded in later years and that they are not able to recover certain assets costs – this is the norm in most competitive industries. By taking on this risk you would expect to see more targeted investment and better risk management by the investors, rather than the certainty that once Ofgem approves the investment they will always be able to recover the cost of the asset from someone.

Question 2: If so, why do you think, or do not think, action is needed?

Action is needed to better allocate transmission costs. Poor allocation of costs means that users are not exposed to the cost impact of their actions on the transmission system. This will lead to poor investments, and the costs of these being carried by other users.

Question 3: We are proposing to look at residual charges in a Significant Code Review. Are there any elements of residual charges that you think should be addressed more urgently? Please say why.

Residual charging is not the issue. The high residual charge is due to the poor allocation of costs in the charging model. Proper allocation of costs will lead to the residual cost tending towards zero. Ofgem should focus their (and industry's) effort on proper allocation of costs, rather than trying to hide real costs in a residual charge that is difficult to avoid. This would include the costs of charging termination fees of users who cause an asset to be built, but then cease to use (and pay for) the asset, and a way of insuring that the TOs take on the impact of over engineering the transmission system.

Consideration should be given to separating Ofgem's role (which appears conflicted) of approving investment in the transmission system and its role of being able to force end users to pay for investment decisions approved on their behalf by Ofgem

Question 4: Are there elements of the approaches in other countries that you think could be appropriate for GB residual charges?

Again, we think that Ofgem has misunderstood what the residual charge is.

Question 5: Are there other approaches that you know about from other jurisdictions, that you think offer relevant lessons for GB?

No opinion.

Question 7: In future, which of these parties should pay the transmission residual charges: generators (transmission- or distribution-connected), storage (transmission- or distribution-connected), and demand, and why? What proportion of these charges should be recovered from each type of user?

We believe that through proper allocation of transmission costs, the residual element could be driven to near zero. This question would then become largely irrelevant.

Question 8: In future, which of these parties should pay the distribution residual charges: generators (transmission- or distribution-connected.), storage (transmission- or distribution-connected), and demand, and why? What proportion of these charges should be recovered from each type of user?

Please see answer to question 7.

Question 9: Do you support any of the five options we have set out for residual charges below, and why?

No. We believe that Ofgem should focus on the proper allocation of transmission costs and work to drive the residual towards 0. When the residual has been driven to zero this question becomes irrelevant.

Question 10: Are there other options for residual charges that you think we should consider, and why*?*

Yes – see Q9

Question 11: Are there any options that you think we should rule out now? Please say why.

We believe that Ofgem should rule out any options that retain the current allocation of costs between locational and residual, as the locational charge clearly does not identify the full costs of the transmission system.

Question 12: Do you think we should do further work to analyse the potential effects of the charging arrangements for smaller EG (called 'embedded benefits')?

We believe that the impact of smaller embedded generation, which has a different impact on the required investment in the transmission system under the SQSS to transmission connected generation should come out of a proper process to allocate costs, as illustrated in Annex 4.

Question 13: Do you think changes are needed to the current charging arrangements for smaller EG, and when should any such changes be implemented?

Overall a review of charges is required, small generation included. Ofgem should consider an implementation with a suitable phasing period once a properly designed solution is available.

Question 14: Of the embedded benefits listed in our table, do you think that any should be a higher or lower priority?

Ofgem clearly need to look at both cost reflective pricing for TNUoS and BSUoS. Given that much of the BSUoS charge is to recover the costs of holding response and reserve to manage the failure of larger generation, Ofgem needs to look to the proper allocation of this cost.

Question 15: Do you think there are other aspects of transmission or distribution network charging which put smaller EG, or any other forms of generation or demand, at a material disadvantage?

Deep entry connection charging for distribution connection compared to shallow entry charging for transmission clearly creates distortions.

Question 16: Do you agree with our view that storage should not pay the current demand residual charge, at either transmission or distribution level?

We do not believe that anyone (including storage) should pay the current level of demand residual charge. We would like to see a proper allocation of transmission costs which would result in a near 0 residual cost.

Question 17: Do you agree with our view that storage should not pay BSUoS on both demand and generation?

We do not see the logic why storage should not pay BSUoS for demand or generation. Storage should be thought of as a power station that uses electricity as it fuel, and it should pay the appropriate cost of fuelling its generation as all other generation does. This proposal would be the equivalent to a CCGT not paying the gas system balancing charge. Storage imposes costs on system operator. We are supportive of the proper allocation of system operational costs, and this may result in smaller costs for storage, although this is presumably driven by the reliability of the storage and the quality of the forecast data it provides to the SO. This would likely vary by instillation.

Question 18: Which of the BSUoS approaches describe is more likely to achieve a level playing field for storage?

A level playing field will be best delivered by cost reflective BSUoS charging, this would involve "breaking out" the components of the different BSUoS elements and charging them appropriately. For example:

i. Black start costs – uniform allocation across demand as all users benefit from the ability to restart the system following a catastrophic failure.
ii. Response and Reserve holding – National Grid holds response and reserve to cover the loss of the largest infeed. So if demand of 5000 MW was being met by 8 x 500 MW generators and 1 x 1000 MW generators, all 9 generators would share the cost of 500 MW of the first 500 MW of reserve. The 1000 MW generator would also pay the full cost of the second 500 MW of reserve (because if this generator were not running, National Grid would not have only held 500 MW rather than 1000 MW of reserve).
iii. Many markets allocate the costs of network congestion by having multiple pricing areas.

Question 19: Do you think the changes in this chapter should be made ahead of any wider changes to residual charging that may happen in future? Do you agree with our view that these changes should be implemented by industry through the standard code change process?

We remain deeply concerned about a change process where industry brings forward CUSC modifications.

Recent experience is that either:

i. a CUSC signatory is able to bring forward a CUSC mod, and that party then effectively controls the modification (for example nature of the defect, ruling certain areas out of scope of the modification); or
ii. A non CUSC signatory is able to ask Ofgem's permission to raise a modification, however to date we have not seen Ofgem grant consent for a non-CUSC signatory to raise a modification.

The process is therefore perceived as biased on the grounds that generally CUSC signatories have or are developing transmission connected storage and therefore have little incentive to level the playing field for embedded storage.

We would strongly urge Ofgem to revise its thinking on the way forward on this processes (and more generally, industry governance).

Question 20: We would welcome your thoughts on the potential make-up of a CCG. Please refer to the potential role, structure, prioritisation criteria and assessment criteria.

We agree with Ofgem that 'wide industry representation' is required to 'steer the overall charging reform programme' (under the TCR). The smaller players on the network should have a voice through the Charging Coordination Group in the SCR process.

Under the CUSC process, Embedded Generators (as well as other parties such as consumer groups etc.) have been ignored.

- The CUSC Panel failed to recommend to Ofgem any of the proposals supported by the majority of the Workgroup.
- The voting at the CUSC Panel has shut down the rights of smaller embedded generator parties to undertake a merits-based appeal in the process.

We expect Ofgem to follow the process as set out in their statutory duties and consider all arguments before making any changes – which has not been the case.

Question 21: Do you agree with our proposed delivery model, including its scope?

Given the variance in opinion of industry we believe it is Ofgem's responsibility to lead **the end-to-end process to develop code modification(s).** This will ensure that all industry participant have a voice and due process is followed. Any other form of delivery model will lead to gross oversights as experienced in the CMP264 and CMP 265 process.

Question 22: Do you agree that our proposed SCR process is most appropriate for taking forward the residual charging and other arrangements for smaller EG discussed in this document?

Yes. As stated previously, we are fully supportive of Ofgem's proposals to conduct a Significant Code Review (SCR) on transmission charging as we believe there is a clear issue with rising costs in the transmission system as the current charging methodology is no longer fit for purpose and requires a full review of the allocation of costs rather than a series partial changes that negatively impact investor confidence.

Annex 2 – The locational charge does not sufficiently recover the cost of investment and the demand residual contains forward looking costs

The transmission allowed revenue is collected via three "pools":

i. The generation charge (locational plus generation residual). Under the CUSC his revenue is fixed at GBP 412 million[1];

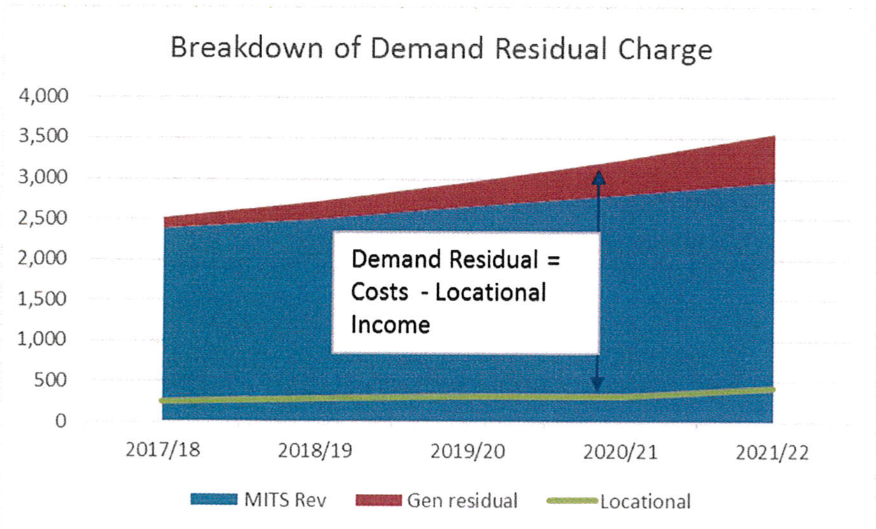
ii. The "cost reflective" demand locational charge. Other than noise due to demand forecast error, this always collects zero revenue

iii. The balance of the allowed revenue is always collected via the demand residual charge.

Explicitly, the demand residual revenue is always Allowed Revenue – GBP 412 million (the generation charge). To suggest that this equation somehow allocates revenue between forward looking and sunk costs is naïve.

Because both the generation charge and the demand locational charge are fixed, the demand residual revenue simply reflects the allowed revenue minus £1.80/MWh times the annual generation. The demand residual charge is therefore does not represent either sunk costs or unavoidable costs, and the basic premise of the TCR that the demand residual is unavoidable and therefore should be charged in a way that is neither cost reflective or avoidable is deeply flawed. By setting up transmission charging in this way we are likely to see ongoing g over investment in the transmission system to the detriment of customers.

In Figure 1 we show the annual allowed revenue for the main interconnected transmission system (MITS), excluding offshore assets and generation only assets (blue area) alongside the forecast payments resulting from the negative generation residual (red area). In addition, we show the forecast income from the locational element of the demand and generation TNUoS charge (green). The difference between the costs (including the generation residual payment) and the locational revenue makes up the demand residual.



[1] For 2019/20. Based on a forecast generation of 229 TWh, being charged 1.80 GBP/MWh derived from the EU price cap of EUR 2.50/MWh with an exchange rate of 1.1 GBP/MWh and an error margin of 21%/.

Figure 1: Development of MITS costs, generation residual payment and income from locational charges 2017 - 2021 (source National Grid[2])

Analysis of the data shows that the statement that the locational charge is forward looking and the residual charge is sunk is clearly untrue. Between 2017 and 2021 the cost of the MITS rises by £560 million, however the rise in the locational charge only recovers £160 million of this revenue meaning that the location charge recovers less than 30% of the cost increase. This would suggest that the locational charge is simply failing to recover costs and potentially resulting in generation and/or demand making incorrect locational signals.

The situation is further exacerbated because the demand locational charge always recovers zero revenue, and the total revenue recovered from generation is set at a fixed level, so the increase in the generation locational charge is neutralised by an offsetting increase of the generation residual payment.

The net effect is that all of the additional costs of the allowed revenue for the MITS permitted by Ofgem is recovered from the demand residual. Therefore, all of the forward-looking costs are recovered from the demand residual.

	2017/18	2018/19	2019/20	2020/21	2021/22
MITS Cost (£ million)	2,391	2,506	2,665	2,804	2,959
Gen residual (£ million)	125	214	304	436	592
Locational (£ million)	261	294	323	322	421
Residual (£ million)	2,255.6	2,425.6	2,645.6	2,916.9	3,129.5

Table 1: Supporting data for Figure 1

2 http://www2.nationalgrid.com/WorkArea/DownloadAsset.aspx?id=8589939106

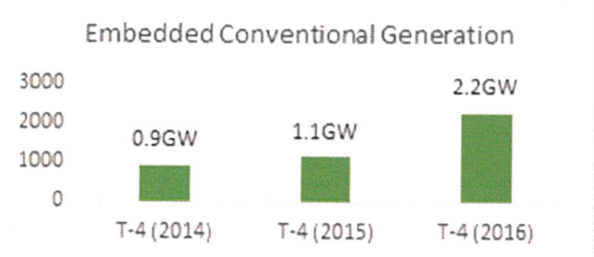
Annex 3 – Modelling Errors in Ofgem's Impact Assessment

The impact of changing the embedded benefits system on the GB Power Market as modelled by Ofgem appears to have a number of **gross oversights and inconsistencies**. Considering the potential impact on the consumer and unintended consequences, we believe it would be inappropriate for Ofgem to make a decision before a full holistic review of charging arrangements is undertaken.

The current modelling conducted by Ofgem does not take a whole system approach and does not capture the benefits of embedded generation on avoiding transmission costs. The modelling conducted by Ofgem does not take a 'whole systems' approach. It is essentially a market model that is unable to capture the benefits of embedded generation on avoiding transmission costs. Without accounting for the transmission system costs benefits, the analysis pre-determines the negative residual payment simply as a redistribution effect (it moves money from end customers to embedded generators), therefore removing embedded benefits will always show a customer saving.

- **Costs to the consumers due to increased regulatory uncertainty have been ignored**
  The decision will inevitably will drive up risk and increase the cost of capital for investment into the energy market. This comes at a time where Government is seeking to attract over a £100bn in the energy sector by 2021[1] and will therefore undoubtedly drive up the cost to the consumer of the total investment. Ofgem's own modelling suggests that this could be in the magnitude of £2-8bn[2] yet this has not been taken into account in the final system cost-benefit analysis to the consumer.

- **Security of Supply concerns**
  Embedded generators have been awarded circa. 4GW of new build capacity across the 2014, 2015 and 2016 T-4 auctions.



Source: Capacity Market Registers

The investors for these plants factored in revenues from triad payments in their Capacity Market bids. Ofgem's own modelling suggests that plants that have secured Capacity Market agreement in the 2014, 2015 and 2016 CM auctions would now become economically unviable as they would need to replace £10-15/kW/year[3] of revenue lost in Triad income. The proposed retrospective change will result in developers re-evaluating their Capacity Market contracts and not delivering on agreements as planned which the analysis fails take in to account. This could lead to security of supply issues, where the capacity will need to be replaced by older and more inefficient existing coal and gas fired generation. Furthermore, if

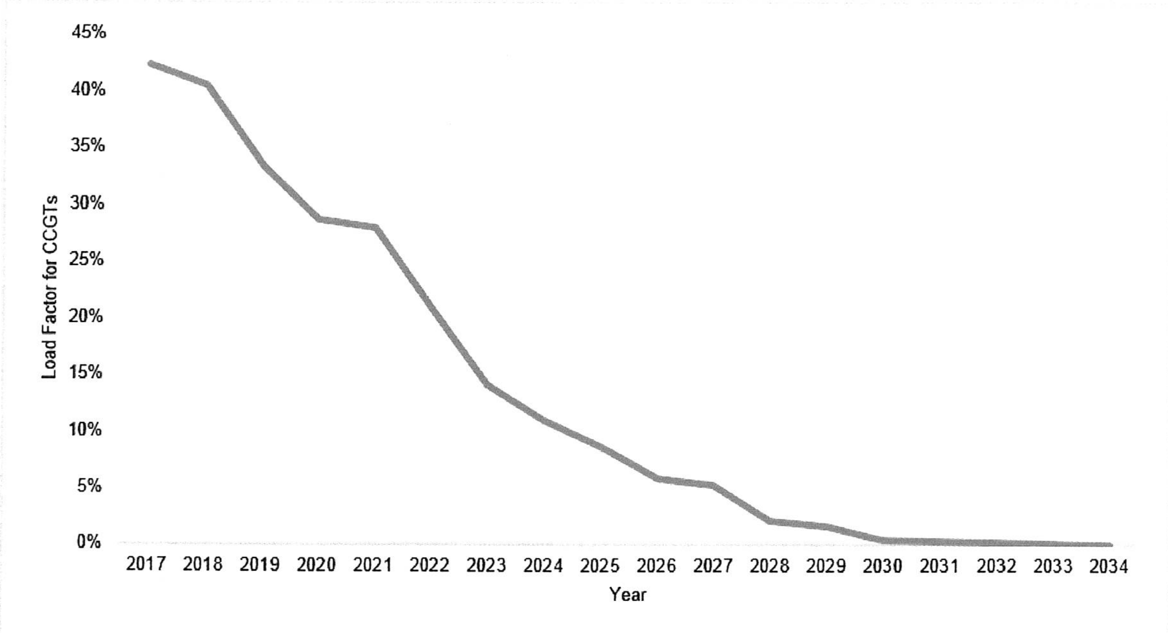
[1] Infrastructure & Projects Authority (March 2016). *National Infrastructure Delivery Plan 2016-2021*

[2] Ofgem modelling shows that the impact on cost of capital could between 1.7%- 6.4%. Frontier & LCP (March 2016) *Transmission Charging Arrangements for Embedded Generation.* p. 33

[3] Frontier & LCP (March 2016) *Transmission Charging Arrangements for Embedded Generation.* p. 15-17

embedded generators do not deliver as planned, it could require life extensions to either coal plants or existing CCGTs that are more CO_2 intensive than new-build efficient peaking embedded plants, increasing the amount of CO_2 emissions to 2025. This has also not been considered as part of Ofgem's modelling.
We believe, Ofgem modelling has underestimated the impact on Capacity Market costs to the consumers and ignored the unintended consequences. Non-delivery of new build capacity (c. 2-4GW) will require more capacity to be procured in the T-1 auctions, leading to higher T-1 auction clearing prices.

- **Higher wholesale prices**
We disagree with Ofgem's assertion that wholesale prices fall as a result of decreased embedded generation. **The analysis is based on a model that contains errors as the analysis assumes that the efficiency of embedded generators is 33%, rather than 43% as in gas reciprocating engines.** This increases wholesale prices artificially in the status quo scenario against other modelled scenarios where CCGTs replaces gas engines.
Furthermore, Ofgem assumes that the higher efficiency of CCGTs will decrease the wholesale prices through operating at a lower short run marginal cost. However CCGTs can only operate efficiently when operating at full load. Ofgem's own analysis suggest that CCGT plant will operate as peaking plant in the future. This can be seen in the below chart as load factors fall to 2035.



Source: Ofgem Analysis, Scenario 3 phased

The modelling conducted by Ofgem is not detailed enough to take account of the different efficiency rates dependent on the load factor. This gross simplification ignores the actual costs to the consumer which will be much higher than predicted.
Furthermore, when correcting for the errors in efficiencies of gas engines (from 33% to 43%) and removing the TNUoS generation distortion, the model shows that gas engines will be built over CCGTs, removing any and all benefits of higher efficiency CCGTs on the wholesale market.

- **Higher than modelled Capacity Market clearing prices**
  The Capacity Market clearing prices modelled by Ofgem are unlikely to deliver new CCGTs. Timera energy's[4] analysis shows that the required Capacity Market clearing prices of £42/kW rather than £36/kW modelled, underestimating the cost to consumer by a factor £400m/year.

- **Higher Balancing Costs**
  Due to the modelling errors (efficiency of embedded plants) the analysis conducted by Ofgem shows that the balancing costs will fall as a result of less embedded generation. However, the rise in embedded generation has significantly increased the competition in the National Grid Balancing Services market, keeping the costs to consumers lower even in a more intermittent electricity system. Currently, the proposed changes will lead to lower investment in embedded generation (due to damage to investor confidence) leading to higher balancing costs.

There will also be unintended consequences from these changes...

- **Higher CO_2 emissions**
  The modelling shows that the CO_2 emissions will fall. However, the analysis fails to take account of the fact that in the short-term, circa. 2-4GW of new build embedded generation is unlikely to deliver on its Capacity Market agreements thus requiring coal to remain online and generate for longer to ensure security of supply. This will increase the amount of CO_2 emissions till new capacity comes on the system.

- **Increased "Behind-the-meter" generation**
  The proposed minded-to-position only impacts the stand-alone embedded generation and fails to capture the "behind-the-meter"/ on-site generation. Penalising stand-alone generation over on-site generation creates an un-levelled playing field in the embedded generation market that Ofgem has ignored. This will lead to significant market distortions as embedded generation gets pushed behind the meter before the Targeted Charging Review is implemented.

[4] http://www.timera-energy.com/the-uk-ccgt-new-build-challenge/

Annex 4 – Different treatment of transmission and small embedded generation under the SQSS

National Grid's investment in the transmission system is determined by the security and quality of supply standard (SQSS) which determines the necessary amount of infrastructure required by National Grid.

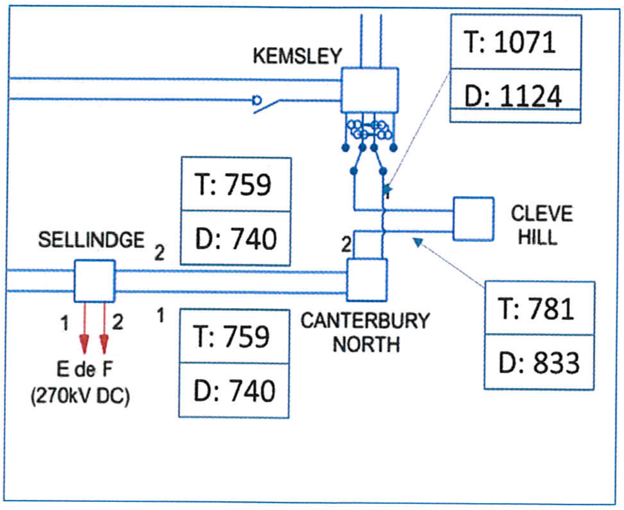
The SQSS treats smaller embedded generation differently to large embedded generation and transmission connected generation and requires different levels of investment in the transmission system to accommodate them. The key difference is:

i. Small embedded generation is treated as negative demand (see definition of ACS demand on page 54, and section 4.4, "minimum transmission capacity requirements") and reflects the generation's actual behaviour over peak;
ii. Larger generation is scaled according to different scenarios, as set out in Appendix C ("security planed transfer") and Appendix E ("economy planned transfer")

The difference is due to the transmission system needing to be robust against generation and transmission faults. Where generation sets are small comparted to the level of demand that they are embedded in, the occasional unavailability of a set can be treated as part of the general uncertainty of the level of demand (for example a 10 MW generator in a 200 MW demand group). However, where a set is large compared to the level of demand, the uncertainty of the generator's availability dwarfs the level of demand uncertainty and it has to be treated separately (for example a 500 MW generator in a 200 MW demand group).

This difference is illustrated in figure 2 where the different levels of investment resulting from the connection of a large 450 MW transmission connected generator at Canterbury North are contrasted with a number of smaller and independent generators being embedded in the distribution network with a total capacity of 450 MW.

Figure 2: MW requirements against the SQSS for either a 450 MW transmission connected generation (T prefix); or 450 MW of small embedded generators connected at Canterbury North (D prefix). Calculated using 2016/17 Final External Model for the economy planed transfer.



Clearly, smaller embedded generation has a different impact on the investment required in the transmission system and therefore the costs of the transmission system. For cost reflective charging this difference in investment needs to be recognized.

A further point to highlight is that the SQSS treats embedded generation as negative demand. Therefore, if two suppliers connect to the same GSP as follows (Figure 3):

i. Supplier A has 60 MW of demand and 40 MW of embedded generation. The SQSS requires 20 MW of demand import capability
ii. Supplier B has 20 MW of demand and no generation. The SQSS requires 20 MW of demand import capability.

Both suppliers impose the same cost on the system, and cost reflective non-discriminatory charging (a requirement if EU law) would require that they face the same charge.

Figure 3: Two suppliers connecting to the same GSP. On supplier has 60 MW of demand and 40 MW of generation, the other supplier simply has 20 MW of generation. Under the SQSS, both suppliers have the same investment requirement and therefore have the same cost impact on the transmission system.