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23 September 2016

Dear Frances,

Open letter: Charging arrangements for embedded generation

ScottishPower welcomes the opportunity to respond to Ofgem's open letter on charging arrangements for embedded generation.

We believe that the current charging arrangements for embedded generators (EG) ('embedded benefits') are leading to over-reward, and are having an increasing impact on the energy system. In particular, the non-cost reflective incentive signals are distorting dispatch and investment decisions leading to inefficient outcomes in the capacity auctions. To address these distortions in time for the next capacity auction, ScottishPower raised CUSC modification CMP264 to stop new EG (ie commissioned after June 2017) receiving embedded TNUoS ('triad avoidance') benefit.

Triad Avoidance

When we first raised CMP264 we thought it likely that Ofgem would choose to implement enduring changes through a Significant Code Review and our modification was therefore intended to be temporary. The open letter now proposes to rely on the industry modification process, in particular CMP264 and CMP265 raised by ScottishPower and EDF respectively, since this can achieve the necessary changes more quickly than an SCR. Accordingly, given that CMP264 was only intended as a temporary solution, we would favour an implementation approach that could lead to the approval of two separate modifications based on CMP264 (for the near term) and CMP265 (for the longer term).

Adopting two modifications could provide greater flexibility around the timing of any changes and whether there is a need for transitional arrangements. While it may be preferable to approve both modifications together, this approach would also provide flexibility for earlier approval of CMP264, should the CMP265 solution be delayed as a result of strong opposition. Early implementation of CMP264 is vital to avoiding competitive distortions in upcoming capacity auctions, since embedded generators would otherwise be able to factor in up to three years' worth of embedded benefits (2017/18 to 2019/20) in their bids¹. Given that there are few alternatives that have progressed through the modification process that address both the immediate and longer term issues, the importance of this type of approach has increased.

¹ This distortion could be equivalent to £17/kW in CM bid value – a level nearly as high as the clearing price in the two previous auctions (see Annex 2).

We believe this approach of adopting the two complementary modifications within a relatively short space of time can be facilitated by using common terms in legal drafting, so that CMP265 (or a variant thereof) can seamlessly over-write CMP264² provisions without the need for subsequent changes to the Connection and Use of System Code (CUSC) or The Balancing and Settlement Code (BSC).

Given the level of activity since the publication of Ofgem's open letter and in the interests of investor certainty, we would encourage Ofgem to consider issuing a brief update in advance of the December CM auction. This would be an opportunity for Ofgem to provide an update on its views and on the timescales in the light of the responses received to the open letter.

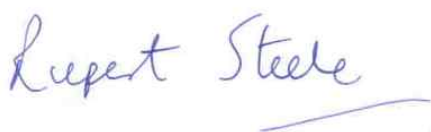
Wider Issues and Further Work

It is clear to us that the implementation of either or both CMP264 and CMP265 would create a more competitive and cost reflective framework than the current baseline. However, we also recognise Ofgem's concern that, if implemented, they may drive more generation to connect behind the meter or via private wires, which means that some inefficient outcomes may persist. More broadly, given that the electricity system has evolved considerably, it is important to consider if policy and regulatory frameworks remain fit for purpose and whether the existing system cost recovery models are becoming obsolete. Those who consume less but remain reliant on the transmission system for security of supply have to be charged appropriately. While we believe that embedded generation has an important role in the overall energy system, it is important that hidden subsidies are not allowed to drive "disruption".

As Ofgem highlights in its letter, there is work ongoing across the industry looking at wider issues and the appropriateness of different elements of the existing network and use of system charging arrangements. We support Ofgem's commitment to engage with industry on how best to take these wider issues forward in a coordinated manner. We have set out some preliminary thoughts on these wider issues in Annex 1 attached.

We would welcome the opportunity to discuss this response further. In the meantime, if you have any questions, please do not hesitate to contact me.

Yours sincerely,



Rupert Steele
Director of Regulation

² Our thinking around CMP264 has evolved during the working group stage. To assist with implementation, we now propose a 'with effect from' date of 1 April 2018 (but still with a cut-off date for New Embedded Generation (NEG) of 30 June 2017). Our proposal now retains the locational charge for NEG, but due to the perverse dispatch signal that this would create for northern generators, floored at zero. We are also supporting a variant of CMP264 which excludes plant with 2014 and 2015 CfD/CM agreements from the definition of NEG, to give transitional protection for investment made to fulfil obligations under those contracts. We would also support capping embedded TNUoS benefits at the current level from 1 April 2018 to protect consumers from netting of the forecast rise in the demand residual tariff element – but we note that this affects all plant, not just a handful of new ones, so it may be harder to implement quickly.

CHARGING ARRANGEMENTS FOR EMBEDDED GENERATION WIDER ISSUES AND FURTHER WORK - SCOTTISHPOWER RESPONSE

1. Introduction

Given the scale of the distortion arising from the benefits currently available for triad avoidance, we welcome Ofgem's view that TNUoS, and in particular the demand residual charging arrangements, should be treated as a priority. However, we also recognise the need to coordinate efforts on the wider issues. This annex considers these wider issues and also how to address the concern that the implementation of CMP 264 or 265 may push more connection of generation behind the meter or incentivise connection via private wires, which is likely to continue to lead to some inefficient outcomes.

2. Network Charging – Demand

The electricity system has evolved considerably and charging regimes based on the sizing of the transmission network to meet peak demand are being called into question. The arguments are reinforced by trends in network costs (increasing), and overall system demand (falling). This pattern is driven by various factors such as unavoidable sunk and fixed costs, and the investment required to achieve UK decarbonisation goals.

There are clear arguments, however, that support retaining some form of peak charging. For instance, those who have solar installations may consume less imported electricity on an annual basis, but yet they are likely to retain a similar reliance on the transmission and distribution system for security of supply as their units are unlikely to generate on winter evenings. If these consumers are not charged appropriately, others will bear the cost and the incentive to invest in localised energy solutions will be driven by non-cost reflective hidden subsidies (which have the potential, like triad avoidance, to spiral out of control), leading to inefficient outcomes.

We consider the four points below key to the reform of network charging regimes, which, with the introduction of smart meters and half hourly settlement (HHS) at a domestic level, could apply to any consumer:

- Consumers should continue to be incentivised to reduce demand, in particular their peak demand. Consumers' awareness of their peak demand may well lead to an overall reduction in consumption.
- Individual consumers' peak demand may not coincide with overall peak demand.
- Peak electricity prices should act as an incentive to drive down overall peak demand.
- Where possible the charging regime should be designed to avoid unduly rewarding behind the meter generation. If the design creates significant hidden subsidies it is very unlikely that an overall efficient outcome will be achieved.

These considerations have led us to an initial conclusion that the overall approach to network charging, from domestic through to industrial demand, should be based on a measure of an individual's peak demand rather than its contribution to the system peak. This is mirrored in generation TNUoS charging, where each generator's contracted transmission entry capacity is based on its own maximum capability to produce.

Example of an approach to network charging and the behaviours it would drive.

To illustrate this point, we think there could be merit in exploring a framework whereby suppliers are charged for their customers' network use based on each customer's average peak consumption in the 100 (say) half hour settlement periods in which that customer's consumption is highest. Economic factors can be expected to encourage suppliers to pass on these price signals to their customers.

The three scenarios illustrated in Figure 1 (overleaf) demonstrate how such an approach could work.

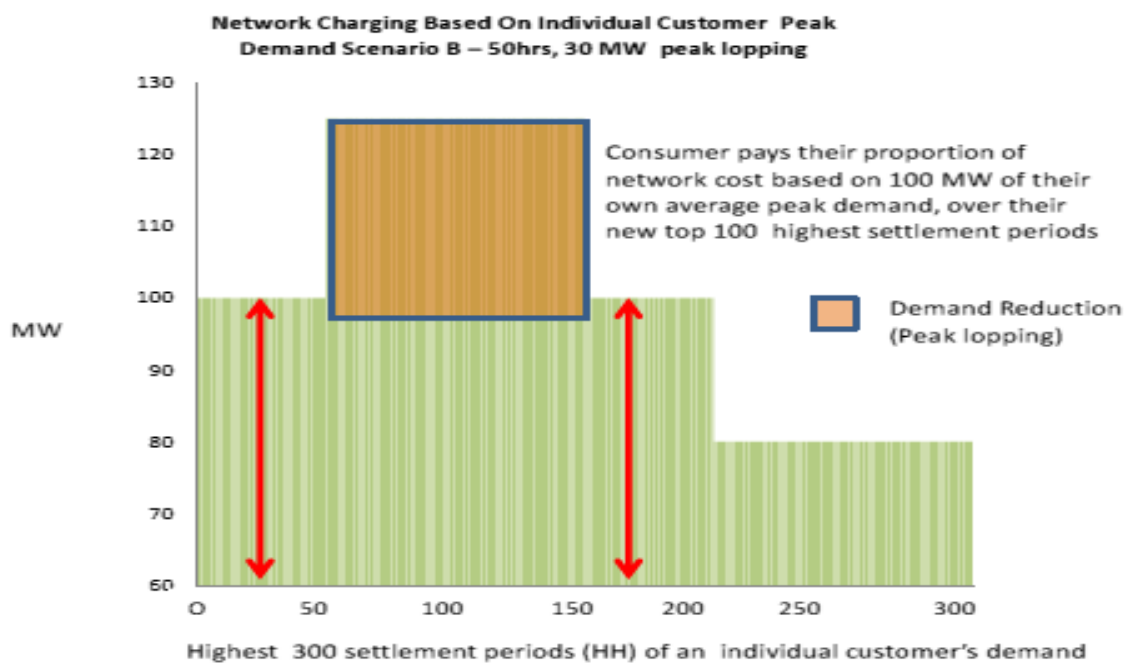
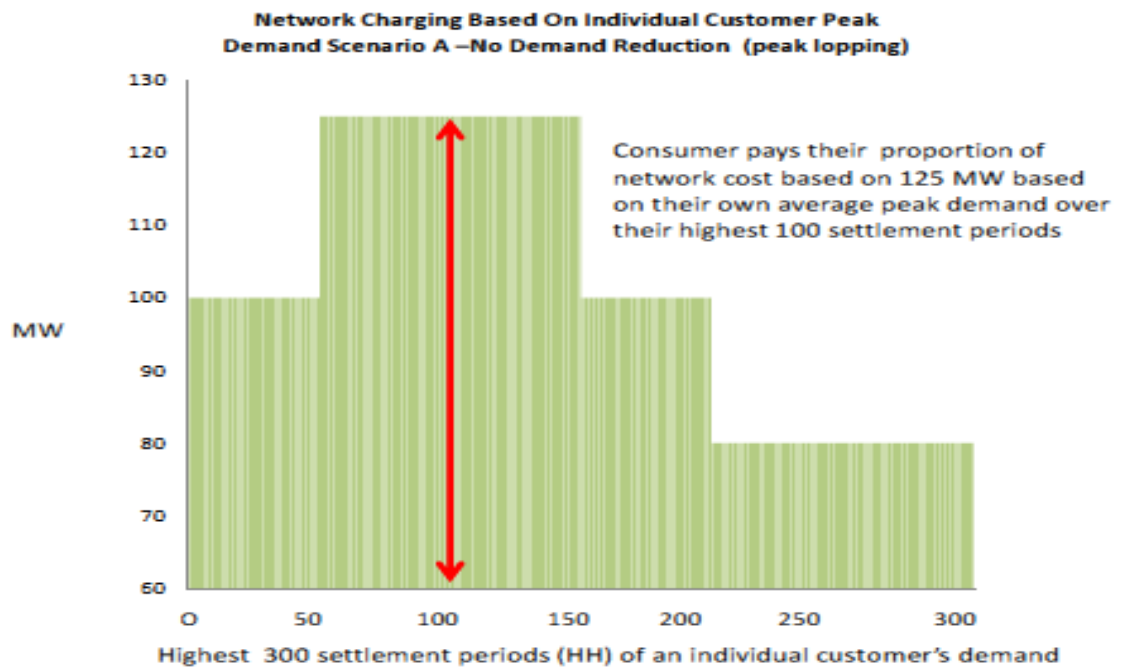
- **Scenario A (Base Case):** A consumer with an average demand of 125 MW over their top 100 settlement periods (50 hrs), will pay a share of the total network costs, proportionately, based on 125MW.
- **Scenario B:** This scenario illustrates that if the consumer takes action to reduce consumption in their 100 highest settlement periods only, they will then be charged based on their next 100 highest settlement periods.
- **Scenario C:** This scenario illustrates that if a consumer employs a fixed level of demand reduction all year round, they will reduce their network charges. However, the charges will be based on the same settlement periods as scenario A.

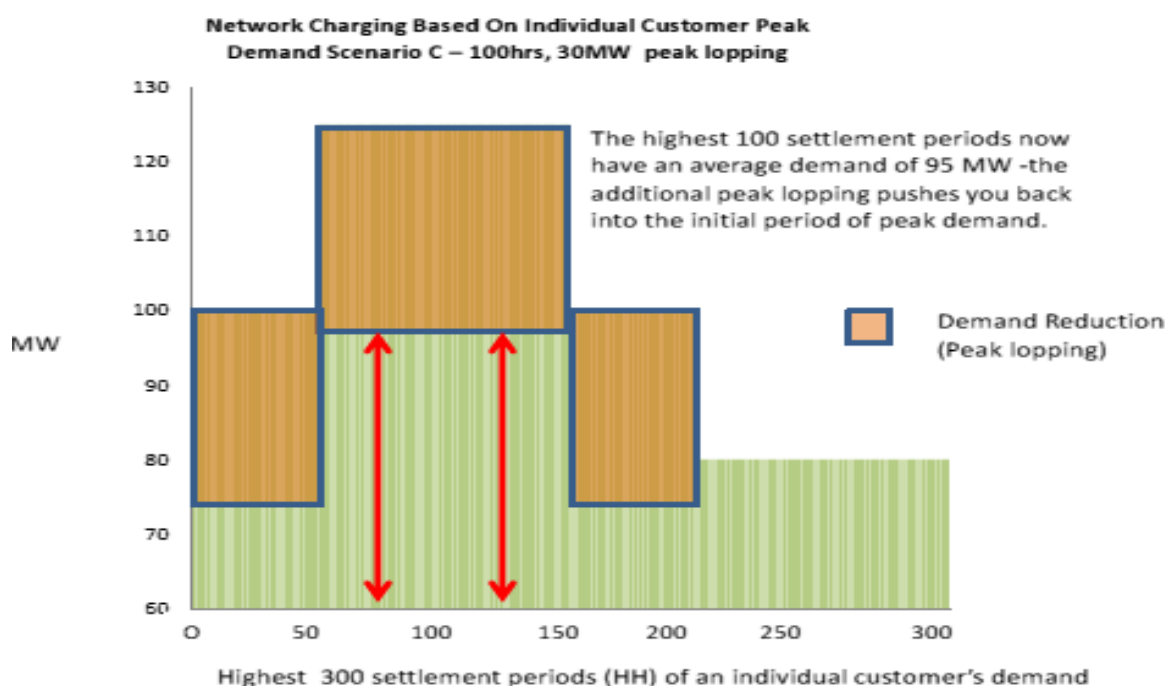
While more analysis is required to determine the optimal number of settlement periods to be used, our example demonstrates that appropriate incentives are retained. Moreover, we believe that this approach will address the concern that those that rely on the system for security of supply need to bear the appropriate costs. Again, with the introduction of smart meters and half hourly settlement we believe that this approach could apply across the entire demand customer base.

Such an approach may give rise to supplier concerns that costs would difficult to forecast, but this could be mitigated by having a bedding-in period for both the System Operator (SO) and supply companies. During this period the alternative tolerances of over and under recovery within the charging regimes could be justifiable (this would avoid the SO being penalised unduly in the form of time value of money).

For avoidance of doubt our proposed approach would retain a locational signal, and any cost reflective value of avoided costs in transmission investment.

Figure 1 - Network charging scenarios based on each customer's peak consumption





3. Capacity Market Supplier Charge (CMSC)

We believe it is very important that the UK Government sticks to its commitment to consult on reform of the Capacity Market Supplier Obligation to address over-reward for embedded generation. The current recovery of these costs based on net demand distorts the market and is another factor that prevents a level playing field in the Capacity Market auction.

4. Balancing Services Use of System (BSUoS)

We agree that BSUoS creates less significant distortions than TNUoS demand residual payments, but it is clear that the distortions arising from the non-cost reflectivity of the treatment of transmission and distribution connected generation need to be addressed. Furthermore, for storage this distortion is doubled in magnitude due to BSUoS charges being levied on both charge and discharge volumes.

The costs of balancing services procured by the SO are currently recovered via BSUoS charges from suppliers based on their net supply volumes (net of offsetting embedded generation volumes) and from generators based solely on their metered output. BSUoS charges are calculated ex-post and are highly volatile, presenting considerable uncertainty to BSUoS payers.

As can be seen from the table of historic BSUoS data below, costs have been rising and the charging base diminishing over recent years, leading to materially higher BSUoS prices for the subset of generator and supplier licensees from whom they are recovered:

- Total BSUoS costs: The costs of balancing the GB system have risen significantly in recent years as a consequence of de-carbonisation policies and are forecast by the SO to double within five years³

³ Telegraph article on 27 June 2016, attributable to Julian Leslie (Head of Electricity Network Development).

- Total BSUoS volumes: The charging volume has fallen significantly in recent years due to the growth in embedded generation and interconnector import volumes, neither of which is liable for BSUoS charges.
- BSUoS price: The BSUoS levy imposed on qualifying licensees has increased significantly over recent years, driven by both cost and charging volume factors.

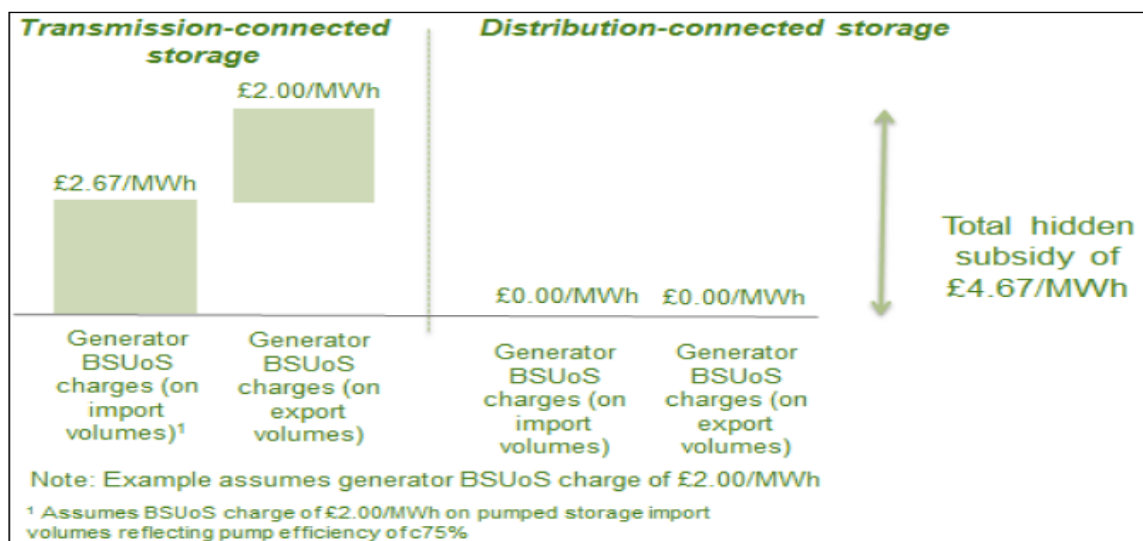
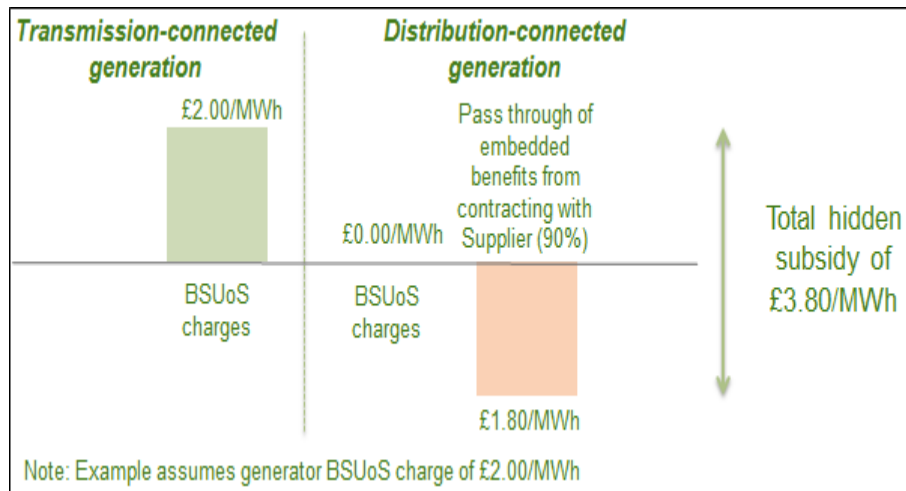
	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17 forecast
Total BSUoS costs (£m)	707	911	899	1,029	1,047	1,091	1,032 (excludes £113m for black start deals)
Total BSUoS volume (TWh)	633	604	602	562	543	528	583 (NGET acknowledge risk of 50TWh reduction based on 2015/16 outturns)
BSUoS price (£/MWh)	1.12	1.51	1.49	1.83	1.93	2.07	1.77 (combined effect results in risk of £0.38/MWh increase to £2.15/MWh)

Source of 2016/17 BSUoS forecast: National Grid Operational Forum presentation 30 June 2016 (<http://www2.nationalgrid.com/WorkArea/DownloadAsset.aspx?id=8589935690>)

We believe that all customers benefit from the balancing services procured by the SO and it is therefore appropriate that suppliers are charged based on gross supply volumes. The present charging arrangements in respect of supplier charges would only be cost-reflective if the offsetting customer volume were supplied exclusively from the contracted embedded generation in a closed loop system which met their requirement for balancing services on a continuous basis, providing the necessary reserve, response, congestion management and black start services at all times. This is clearly not the case.

Insofar as it is appropriate to recover BSUoS costs from generators, we believe that it is right to apply charges to all volumes which contest the generation market, ie transmission-connected generators, distribution-connected generators and interconnector imports. All three categories are able to, and do, contest the ancillary service and balancing markets. Any distortion to competition created by failing to treat them the same in respect of BSUoS charging pollutes the energy and capacity markets.

The two figures below demonstrate how the distortions to competition arise and seek to quantify the distortions in respect of transmission and distribution connected generation and of transmission and distribution connected storage respectively.



We believe that to achieve a level playing field, BSUoS charging arrangements need to be amended such that:

- Suppliers are charged based on their gross supply volumes (excluding embedded generation volumes);
- Generators are charged at all sites which are half hourly metered;
- Generation sites are charged BSUoS on a net basis (or not charging for imports), where imports are being used for the purposes of producing electricity.

5. Government obligations

The costs incurred in delivering Government obligations across schemes such as the RO, FiT and CfD are recovered via supplier levies which are calculated on suppliers' gross volumes, ie not taking account of any offsetting embedded generation with which suppliers have contracted. In principle, we support this approach as being more cost reflective and less likely to distort competition and we note the contrast with charging methodologies of other levies which are based on suppliers' net volumes.

However, we note that customers with behind-the-meter generation are effectively exempted from such charges in respect of demand which is met from their own generation volumes. Given the rapid growth in behind-the-meter capacity and generation over recent years (notably domestic roof-top solar PV), this is potentially a source of concern, particularly bearing in mind that those who are able to invest in such capacity are typically wealthier than the average. This means that the cost of such Government obligations is being disproportionately recovered from less well-off consumers and is in effect a regressive form of taxation.

We would therefore support consideration of revisions to charging methodologies which addressed this issue by ensuring that the costs incurred in meeting these schemes were evenly recovered across all consumers based on a truly gross demand basis. A charging regime based on an individual's peak demand (see section 2 above) could go some way to alleviating this problem.

ScottishPower
September 2016

CALCULATION OF THE £17 /kW/YEAR DISTORTION FROM TRIAD AVOIDANCE 2017/18 TO 2019/20

Estimate of the equivalent CM contract value (£/kW) of securing Triad Avoidance benefit in the Charging Years 2017/18 to 2019/20

TNUoS Demand Residual Charge per National Grid Forecast from 2017/18 to 2020/21

Table 23

£/kW	Assume 1MW project commissioned before winter 2017/18 and receiving Triad avoidance benefit until removed by CMP265 in 2020/21				
2017/18	46.34	Assume new build plant securing a 15 year CM contract			
2018/19	52.91	Assume project cost of capital 10%			
2019/20	58.13	Assume embedded generator secures 90% of the embedded benefit from the Supplier			
2020/21	72.03	Assume inflation 2%			

NPV	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34	2034/35	2035/36
Inflation Factor	1.00	1.02	1.04	1.06	1.08	1.10	1.13	1.15	1.17	1.20	1.22	1.24	1.27	1.29	1.32	1.35	1.37	1.40	1.43	
Triad Avoidance Income	£105,978	0	41,706	47,619	52,317	0	0	0	0	0	0	0	0	0	0	0	0	0	0	141,642
CM Payment equivalent	£105,978	0	0	0	18,313	18,680	19,053	19,434	19,823	20,219	20,624	21,036	21,457	21,886	22,324	22,770	23,226	23,690	24,164	0
																				316,701

CM equivalent to Triad revenue (£/kW/year) 16.92

Equivalent to CM Contract of £16.92 /kW from 2020/21