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The Association for
Decentralised Energy



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Combined Heat & Power
District Heating & Cooling
Demand Side Services

A Review of the Embedded Benefits accruing to Distribution Connected Generation in GB

Prepared by:
Andy Pace, Jo Lord, Tom Edwards, Jonathan Davison

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- market entry.

2 Millennium Plain
Bethel Street
Norwich
NR2 1TF

T +44 (0) 1603 604400
F +44 (0) 1603 568829
E info@cornwallenergy.com
W www.cornwallenergy.com

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I Executive Summary

Cornwall Energy has been commissioned by the Association for Decentralised Energy to review the level of embedded benefits that are currently available to generation and storage that connects directly to the distribution network. Embedded benefits exist as distribution connected generators and the export from storage offset costs incurred by the distribution and transmission network operators. However, the level of embedded benefits has been consistently rising and concern has been raised that these benefits no longer reflect the avoided costs which they are meant to represent.

This report explores the various types of embedded benefit that are available to a distribution connected generator and assesses whether the benefit in each case is representative of the actual cost savings to the network companies. The approach adopted is to look at the principle behind the costs savings that can be achieved through different types of generation connecting to the distribution network and to back this up with numerical analysis and modelling work to determine whether each benefit is over or undervalued.

Although this report reviews embedded benefits from the perspective of embedded generation, it is possible to draw a parallel with storage which is an emerging technology that has the potential to revolutionise how networks are managed. Many of the issues considered within this report apply equally to storage which is reliant on embedded benefits to become economically viable. Given the potential benefits that storage could bring to the GB electricity industry, it is important that the impact of changing embedded benefits and the uncertainty that this creates for investors are taken into account during any review of embedded benefits.

The report findings are summarised below for each area of embedded benefits and a summary table is included at the end of the section.

HEADLINE FINDINGS

The headline finding of this report is that the current level of embedded benefits are providing a fair level of reward to embedded generators for the costs that they avoid on behalf of network operators. However, some benefits are overvalued at transmission, but undervalued at distribution. Therefore, any reduction in triad benefits without concurrent increases in distribution benefits would result in the embedded benefit regime becoming less cost reflective overall.

In addition, any changes in the value of the TRIAD charge must treat both demand and distributed generation equally or it risks sending different price signals for the same result –a unit of reduced demand on the transmission network.

There is a risk that the current level of embedded benefits will increase above the level of the avoided costs going forward. This challenge can be addressed by reviewing options to more cost-reflectively recover transmission costs and by removing the ‘double benefit’ for distributed generators from the Capacity Market Supplier Charge.

Finally, our analysis found that the removal of embedded benefits would not result in any increased new build Combined Cycle Gas Turbine (CCGT) capacity in the capacity market, and could reduce the amount of new build capacity delivered by gas engines in the auction.

THE PHILOSOPHY OF NET CHARGING

The report considers the options of charging on gross/net flows to either Suppliers or DNOs and concludes that moving to a gross system of charging would undervalue the avoided TNUoS benefits that are attributable to embedded generation. We consider that an increment of generation should be valued at the same price as a reduction in demand to provide a consistent price signal to the industry and prevent asymmetrical pricing.

In addition, any change that results in an overall charge for some embedded generation would potentially result in charging generation for using the transmission network when their output is clearly absorbed in the local distribution network. A more beneficial approach would be to amend the calculation of the triad charge to improve its cost reflectivity, continue to apply it on a net basis and charge Grid Supply Points when they export on the transmission network and that export leads to an increase in costs on the transmission network.

Locational/ Residual charging – The report considers the option of applying the locational element of the TNUoS charge as an embedded benefit. The report concludes that the locational element is a small element of the charge which is beneficial for allocating TNUoS costs on a regional basis but is not representative of the avoided costs that can be attributed to embedded generation.

Variable/ Sunk costs - The report examines the principle of classifying costs as sunk or variable and concludes that they should be aligned with the characteristics of the user. In the case of embedded generators, the decision to invest depends on a forecast of future revenues which includes embedded benefits. The expected life of an embedded generator can be in the region of 15 to 45 years and consequently, network costs that can be offset across this timeframe should be considered as variable, even though in the short term they may appear sunk.

POTENTIAL IMPACTS OF THE EMBEDDED BENEFIT'S REMOVAL

This report has also considered some of the potential impacts from the removal of the TNUoS embedded benefit:

- **Impact on the capacity market** – The report considers the impact on the capacity market of removing the triad benefit from embedded generators. The report concludes that the resultant increase in the clearing price would be unlikely to lead to the development of new build CCGT plant.
- **Impact on the wholesale market** – The report considers the impact on the wholesale market of reducing or removing the triad benefit. The report concludes that the impact would have a minimal impact on peak wholesale power prices of between £0.63/MWh and £2.84/MWh, increasing consumer costs between £10m and £45m a year.

TRANSMISSION AND DISTRIBUTION USE OF SYSTEM CHARGES

The current level of generation credits awarded at low and high voltage under the Common Distribution Charging Methodology (CDCM) are reflective of the costs incurred by the Distribution Network Operators (DNOs), with a slight bias to the DNOs undervaluing the costs saved by embedded generators. Embedded non-intermittent generators offset costs at the voltage level of connection as well as at voltage levels above the level of connection, but at present are not rewarded for this. We estimate that this would increase the level of benefits by between £7.4/kW and £16.6/kW

The level of the Transmission Use of System (TNUoS) charge has consistently grown over the last eight years and this trend is forecast to continue by National Grid. Our analysis suggests that the current level of the TNUoS triad charge is overvaluing the costs of the transmission network for both demand users and embedded generation. We also found the actual costs savings of distributed generators is much higher than the estimates put forward by National Grid in various documents over the last five years.

In total, we estimate that an appropriate TNUoS Triad charge would be £32.3/kW, a reduction from the 2015-16 rate of £45.80/kW. Both demand and distributed generation should receive TRIAD benefits which reflect the full value of this charge. The findings are set out below:

- The minimum cost that should be attributed to embedded generation has been derived from the capital cost of a number of National Grid schemes under consideration with a total potential spend of £8.8bn. The average annuitised cost across all the schemes is £18.5/kW on a 2015-16 price basis. This cost does not include the ongoing costs associated with these schemes such as operations and maintenance or the non-quantifiable impacts such as visual amenity. Consequently, we conclude that the minimum embedded benefit that should be attributable to embedded generation should be £18.5/kW
- The elements of the TNUoS allowed revenue that is recovered via the triad charge can be broken into components that are demand related in the short term, long term or not demand related at all. The majority of the revenue can be considered as demand related over the long term. From a short term perspective, these costs could be considered as sunk and therefore not attributed as an avoidable cost to embedded generation. However, when a longer term view is adopted, these elements of cost will change as the transmission infrastructure evolves to meet the changing demand. As the investment in embedded generation is a long term decision and they offset demand over the life of their connection, it is appropriate that embedded generation should benefit from offsetting long term costs in addition to short term costs. We estimate these elements to equate to c£13.8/kW in 2016-17.
- The target revenue for demand TNUoS is recovered across the triad demand which is consistently falling year on year. However, the allowed revenue is set to recover the long term cost of developing and operating the transmission network. From a principles perspective, recovering the long term cost over a short term peak demand is not a consistent approach as the timeframe of the costs and the demand are substantially different. This analysis suggests that the use of peak demand overstates the value of the triad charge, and therefore the triad benefit, by approximately £9.2/kW in 2016-17.
- A number of the elements that make up the target revenue for Transmission Network Use of System (TNUoS) are fixed in nature, yet recovered from a demand based charge. Our analysis of the allowed revenue suggests that these components of cost overstates the value of the triad charge by approximately £4.4/kW.

BALANCING SERVICES USE OF SYSTEM (BSUoS)

The largest component of BSUoS is constraint costs. The application of BSUoS at a flat rate means that all embedded generation is rewarded regardless of its location and the impact it may have on transmission network constraints. In principle, the constraints element of the BSUoS charge could be made more cost reflective if it was applied on a locational basis but the principle of applying constraint costs to the generators who create the constraints would be likely to impose excessive costs on those plants and could

result in them becoming uneconomic. This report concludes that the socialisation of constraint costs via BSUoS is an equitable approach and should continue in its current format.

The remaining elements of BSUoS covers primarily reserve and frequency response services and the increasing amount of intermittent generation at transmission and distribution is driving National Grid to procure new services such as enhanced frequency response and demand turn up. This report concludes that intermittent generation should not receive a benefit for reducing the reserve and frequency response costs of the system operator when they are partially driving these costs. However, although differentiating between intermittent and non-intermittent generation when applying these elements of BSUoS charges as an embedded benefit could be considered more cost reflective, it would be difficult to implement from a practical perspective and could lead to unforeseen consequences such as intermittent generation moving behind the meter or installing private wires to fully capture the BSUoS embedded benefits.

OTHER EMBEDDED BENEFITS

This report has examined the embedded benefits associated with transmission losses which is estimated at around £0.40/MWh. The recent Competitions and Market Authority (CMA) investigation has proposed that transmission losses should be assigned to transmission connected generation and this will remove transmission losses as an embedded benefit. However, embedded generation generally reduces the level of transmission losses except where connected to an exporting GSP. Consequently, we conclude that the decision by the CMA to assign transmission losses to transmission connected generation is removing an important incentive on embedded generation to continue to reduce GSP demand and the level of transmission losses.

This report has also reviewed the application of distribution losses and assistance for areas with high distribution costs as embedded benefits and concludes that the current arrangements are appropriate and do not require further change.

The final embedded benefit that is assessed within this report is the Capacity Market Supplier Charge (CMSC). This charge recovers the costs of the capacity market and is also an embedded benefit to any generator that exports between 4pm and 7pm on weekdays, November to February. The value for the CMSC is minimal at present but is expected to rise to around £17.5/kW in 2018-19 for a generator that exports 90% of its capacity during the CMSC period. This report concludes that the CMSC is potentially rewarding embedded generators twice, both through the capacity market if they are successful within the tender and then again through the avoidance of the CMSC. The principle of awarding generation twice for offering the same service potentially distorts the price at which embedded generation may bid into the capacity market and the resultant clearing price and this is an area that needs further review.

Embedded Benefit	Avoidable Costs Over/ Understated	Issues	Recommendations
Transmission System Embedded Benefits			
Transmission Network Use of System (TNUoS)	Overstated	- Triad charge includes non-demand related elements - Triad charge recovers long term costs over short term demand - Impact assessed at c£13.6/kW in 2016-17	- Remove non-demand related costs from triad charge and socialise their recovery - Amend triad charge calculation by replacing triad demand with maximum demand over a ten year period.
Balancing Services Use of System (BSUoS)	=	- Constraint element is locational but recovered via national charge - Intermittent generation driving some balancing service costs - No contractual relationship between National Grid and most embedded generators	- No change proposed
Transmission losses	Understated	- Embedded generation reduce transmission losses, except at exporting GSPs - CMA proposal removes as embedded benefit - Impact assessed at c£0.40/MWh in 2016-17	- Transmission losses to be applied regionally - Transmission losses to remain as embedded benefit
Areas of Assistance (AAHDC)	=	- Low materiality	- No change proposed
Capacity Market Supplier Charge	Overstated	- Potentially rewards embedded generators twice for the same service through capacity market and by avoiding capacity market supplier charge - Value is minimal until 2017-18 - Impact assessed at c£17.5/kW in 2018-19 for a generator exporting at 90% capacity during CMSC period	- The issue of the CMSC double benefit should be reviewed
Distribution System Embedded Benefits			
Distribution Use of System (DUoS)	Understated	- Credits slightly lower than benchmark analysis (Impact assessed in range of £2.6/kW to £6.5/kW across 2014-15 to 2016-17) - Non-intermittent generation benefit the network at the voltage of connection (Impact assessed in range of £7.4/kW and £16.6/kW in 2016-17) - Intermittent generation benefit the network at extra high voltage but are not currently rewarded	- Consider the application of DUoS credits at the voltage of connection for non-intermittent generation - Consider the application of credits to intermittent generation at extra high voltage
Distribution losses	=	- Current level of distribution losses are cost reflective - Generation dominated areas could impact on the level of distribution losses for embedded generation.	- No change proposed

Figure I: Summary of Report Findings

2 Background

2.1 Introduction

Embedded generation is a term used to describe generation which is directly connected to a distribution network either on a standalone basis or grouped with demand behind a meter. Embedded generation offsets demand within the distribution network and as a consequence reduces the cost of network operators at distribution and transmission. In return for this reduction in costs, most embedded generators¹ are rewarded through a number of benefits which are not available to a transmission connected generator. These benefits are referred to as embedded benefits and are intended to reflect the avoided cost of connecting directly to a distribution network. The benefits are also equally attributable to storage when it is exporting which is treated as generation for settlement purposes. This section explains the background to embedded benefits and their context within the GB marketplace before exploring the issues associated with embedded benefits in the subsequent sections.

2.2 Types of Embedded Benefits

Embedded generation receives a number of benefits by connecting to distribution rather than the transmission network. These benefits can be split into avoided costs at the distribution level or transmission level. The table below shows the benefits available to embedded generators and the categorisation of the benefit by network type:

Transmission System Embedded Benefits	Distribution System Embedded Benefits
Transmission Network Use of System (TNUoS)	Generator Distribution Use of System (GDUoS)
Balancing Services Use of System (BSUoS)	Distribution losses
Transmission losses	
Areas of Assistance(AAHDC)	
Residual Cashflow Reallocation Cashflow (RCRC)	
Capacity Market Supplier Charge	

Figure 2: Types of embedded Benefits

2.3 Scale of Embedded Generation

The amount of embedded generation in GB has grown substantially over recent years. This is largely down to the attractive support that is available for renewable generation and the increasing level of embedded benefits that can be achieved by connecting directly to the distribution network. More detail on the scale and reasons behind the increase in embedded benefits is contained in section 3.

Between 2011 and 2014, the level of embedded generation has increased from 12.4GW to 19.1GW. The largest areas of growth have been solar and wind which have grown by 534% and 185% respectively. The graph below shows how embedded generation has grown over the previous four years.

¹ Embedded generators over 100MW or classified as large under the Grid Code and without a Bilateral Embedded Licence Exemptible Large Power Station Agreement (BELLA) will not be exempt from TNUoS charges.

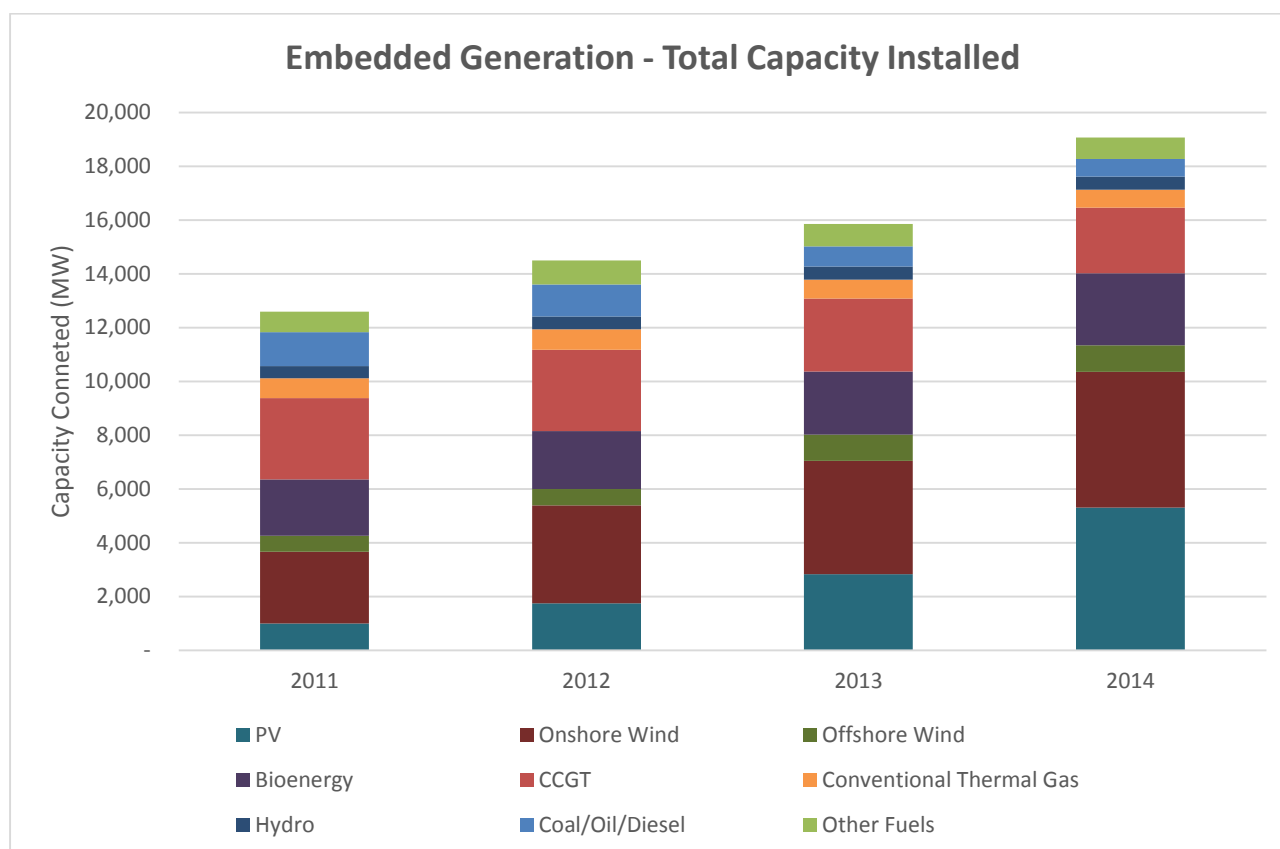


Figure 3: Total Capacity installed by Fuel Type²

The trend of increasing embedded generation is expected to continue. National Grid highlight this as one of the factors that will influence how the transmission network will need to develop in the future³. One of the consequences of the increasing level of embedded generation has been to reduce peak demand on the transmission system. This has led to an increase in Transmission Network Use of System (TNUoS) charges for demand customers (which is an embedded benefit for embedded generators) as the transmission network costs are spread over a lower peak demand each year.

2.4 Historical Demand

National demand and peak demand for electricity in GB, as measured by National Grid⁴ has been consistently falling year on year since 2005-06. This is primarily due to customers reacting to increasing electricity tariffs, the take up of energy efficient technologies, the closure or relocation of energy consuming industry and government obligations on suppliers to undertake measures to reduce electricity consumption.

This trend in national demand (both peak and consumption) is shown in the graph⁵ below. The values used for peak and total demand exclude any embedded generation and represent the underlying trend.

² Source: DECC Digest of UK Energy Statistics (<https://www.gov.uk/government/statistics/electricity-chapter-5-digest-of-united-kingdom-energy-statistics-dukes>)

³ Highlighted within the National Grid System Operability Framework report 2015: <http://www2.nationalgrid.com/UK/Industry-information/Future-of-Energy/System-Operability-Framework/>

⁴ The measure of national demand used is the one adopted by National Grid in the Future Grid Scenarios. This measure is the raw underlying demand and excludes embedded generation, pumped storage load and interconnector load from Ireland and the continent.

⁵ Data extracted from National Grid Future Electricity Scenarios, <http://fes.nationalgrid.com/fes-document/>

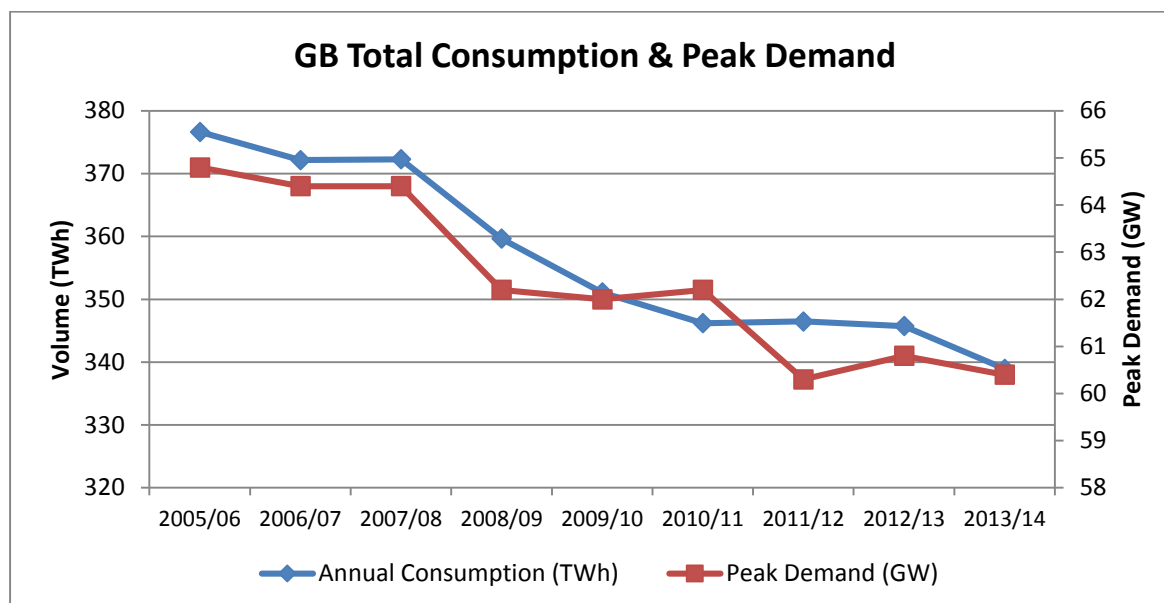


Figure 4: GB Total Consumption and Peak Demand

Although historical demand has fallen, future underlying demand (excluding any embedded generation) over the long term is generally expected to rise, particularly if there is a large take up of electric vehicles, heat pumps and electrification of heating load. National Grid has developed four scenarios of future demand to help assess the range of demand and the potential implications on the GB electricity infrastructure requirements. The peak demand under each scenario is shown in the graph below⁶:

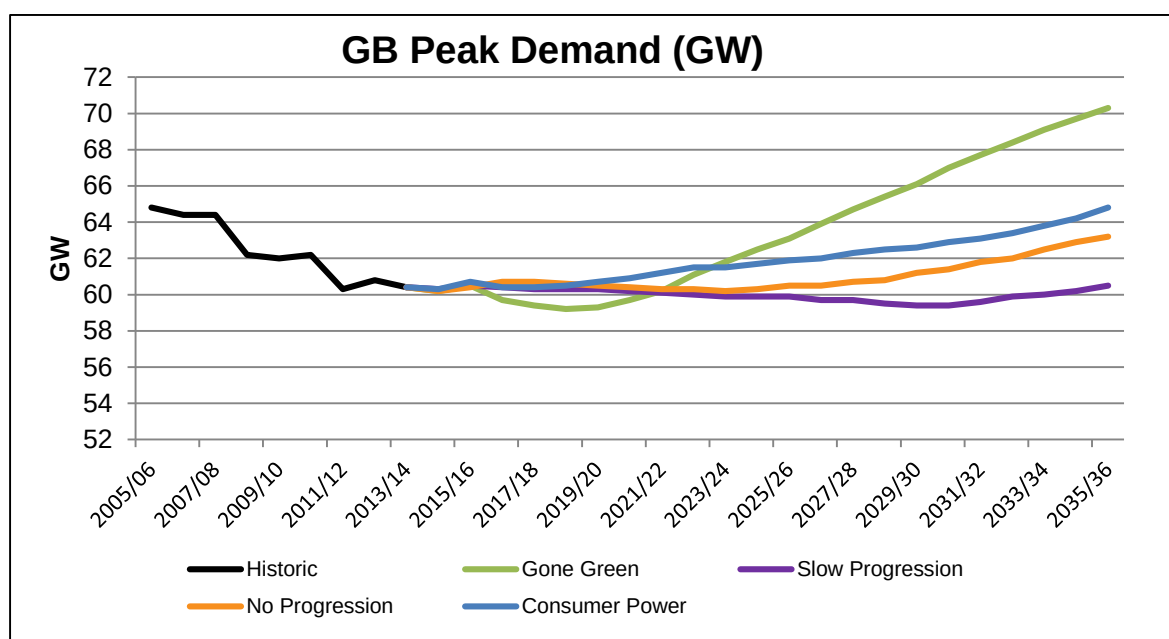


Figure 5: National Grid Future Demand Scenarios

These scenarios show that National Grid expect the trend of declining peak demand to stabilise and hold constant over the next five years. Following this, National Grid expect peak demand to increase and the rate at which this occurs is dependent on how quickly low carbon technology is adopted with GB.

⁶ National Grid Future Electricity Scenarios, <http://fes.nationalgrid.com/fes-document/>

2.5 Why are Embedded Benefits an Issue

Embedded benefits have come under close scrutiny in recent times due to the strong incentive they place on generation to connect to distribution networks and the impact, whether real or postulated, this is having on transmission and distribution network operators. In particular, the cost reflectiveness of the embedded benefits has been questioned by a number of stakeholders.

The current system that enables distribution connected generation to capture embedded benefits has been in place for a number of years. The government and Ofgem has encouraged the take up of embedded generation, particularly renewable generation, to assist towards meeting the ambitious carbon reduction targets for GB. Over the last five years, the level of embedded benefits available to distribution connected generators has increased substantially and there is concern that the current level of embedded benefits is no longer an accurate reflection of the costs avoided by generators connecting directly to distribution networks rather than transmission. If this is the case, the embedded benefits could provide a perverse price signal and distort the market for new connections going forward. The magnitude of the increase in embedded benefits is explored in section 3.

A further issue is a challenge to the concept of net charging. At present, transmission charges are applied to the net flow of electricity at the boundary of the transmission network while distribution charges are applied to individual premises. National Grid has explored the idea of moving to gross charging which effectively extends the transmission charging methodology into the distribution networks rather than at the boundary. A change to this principle could have a large impact on embedded benefits for distribution connected generation.

In March 2016, DECC issued a consultation on the capacity market and within this highlighted that the level of embedded benefits may be leading to embedded generators, particularly diesel generators, bidding into the capacity market at a level which may not reflect their true costs and that this could result in a suppressed clearing price within the capacity market. DECC are concerned that this could be preventing the connection of new Combined Cycle Gas Turbine (CCGT) plant who are unable to secure a sufficient clearing price to justify the investment. Consequently, DECC have requested Ofgem to undertake an investigation into the level of embedded benefits.

2.6 Report Scope

This report examines the scale of embedded benefits that are available to generators in GB and whether these benefits remain appropriate from both a cost reflective perspective and a principles perspective. It undertakes a reasonableness test of each embedded benefit received by generators to assess whether the reward is reflective of the avoided cost and quantifies areas where the costs may be either over or under stated within the current charging regime.

The report continues to consider potential changes to the charging regime that could impact on the level of benefits from a principles basis and the likely impact on the level of embedded benefits received by generators.

Conclusions

The government has recommended a review of embedded benefits in the context of the capacity market. Given the large amount of embedded generation that is currently connected to GB distribution networks and the growth in the benefits they are receiving, we feel it is entirely appropriate to review embedded benefits to better understand whether the current network charging regime is cost reflective. However, it is equally important that the review should take a careful, holistic and systematic approach to ensure the network charging regime is fit for the future.

3 Overview of Embedded Benefits

3.1 Review of Embedded Benefits

This section undertakes an analysis of the current level of embedded benefits available to embedded generation and any export from storage. The total benefits that are available will vary for each generator depending on a number of factors such as location, voltage of connection, capacity and the type of generation.

3.1.1 Transmission Network Use of System (TNUoS) charges

TNUoS charges are applied to suppliers in respect of the demand customers they supply for the use of the transmission network. These charges vary across the country which is split into regional zones. The charge is split between generation and demand with demand picking up approximately 73% of the charge. The demand charge is applied in one of two formats depending on whether the supplier's customer is settled on a half hourly basis or non-half hourly:

- Where the customer is settled half hourly the TNUoS charge is applied as a £/kW charge based on the average consumption in the three highest half hours of demand between November and February separated by 10 days. This is known as the triad charge.
- Where the customer is settled non-half hourly, the TNUoS cost is charged on a unit basis in p/kWh based on the total units consumed between 16:00 and 19:00 across the year.

Where a supplier contracts with a half hourly metered generator for their export, the generation within the triad half hours is offset against the supplier's triad demand within the same GSP group and reduces the supplier's TNUoS bill. Where the supplier does not have an offsetting demand, the export is treated as negative demand and the supplier receives a credit for the generation. The amount by which the triad bill is reduced by or the credit received by the supplier is termed the triad benefit.

3.1.2 Balancing Services Use of System (BSUoS)

BSUoS charges recover all the costs incurred by the system operator in balancing the system. They are split 50% between suppliers and transmission connected generation. The charge is a unit based charge in £/MWh and varies by half hour.

The application of this charge to suppliers is based on their net consumption at the GSP and consequently any contracted generation will offset the demand and reduce the BSUoS bill for the supplier by the corresponding amount in each half hour. Where a supplier does not have an offsetting demand the export is treated as negative demand and a credit is applied.

3.1.3 Transmission Losses

Transmission losses are the difference between the volumes entering the transmission system and those exiting. Losses are currently applied 45% to transmission connected generation and 55% to suppliers. Losses are derived for each half hour and the same rate is applied across GB.

Supplier's volumes at GSP are grossed up by transmission losses before settlement. The ability of suppliers to offset distributed generation export against demand results in transmission losses being applied to a smaller demand and consequently, this is a further saving that accrues to embedded generation. Where a supplier does not have demand within the GSP group, the export from the embedded generator is increased by transmission losses.

It should be noted that the current arrangements are likely to change following the CMA investigation into the electricity industry. The CMA is recommending that all transmission losses should be applied to generation and that regional transmission losses should be introduced. This will effectively remove

transmission losses as an embedded benefit in the future, although the timescales for such a change remain uncertain.

3.1.4 Capacity Market Supplier Charge

The costs of running the capacity market will be recovered from suppliers based on their market share of consumption at time of peak which is defined as between 4pm and 7pm on working days, November to February. This charge will apply to a supplier's consumption within settlements which will be offset by any exporting embedded generation within the given time band, that the supplier contracts with. Consequently, the CMSC has resulted in a new embedded benefit that can be attributable to embedded generation. It should be noted that any payments received by embedded generation under the capacity market does not exclude them from receiving the CMSC as an embedded benefit.

3.1.5 Assistance for Areas with High Distribution Costs (AAHDC)

GB customers pay a subsidy to assist customers in Scotland with the high cost of distributing electricity which arises due to the spread of the population across the area. This charge is applied as a single unit based charge that applies across the year to each supplier based on their settled consumption. As the consumption for each supplier is derived after embedded generation has been deducted, the AAHDC becomes an embedded benefit. Where the supplier does not have offsetting demand, the generation is treated as negative demand and a credit is received.

3.1.6 Residual Cashflow Reallocation Cashflow (RCRC)

RCRC charges arise from balancing the residual cashflow within the balancing mechanism once all payments to or from balancing mechanism participants within a half hour have been made. The residual is allocated to all BSC parties and is charged on a unit basis which varies by half hour. The charge can be positive or negative. As the consumption for each supplier is derived after embedded generation has been deducted, the RCRC becomes an embedded benefit when the adjustment is positive for demand. As this element switches frequently between positive and negative values and averages out at close to zero, this report does not focus further on RCRC as an embedded benefit.

3.1.7 Generator Distribution Use of System (GDUoS)

DNOs provide all Low Voltage (LV) and High Voltage (HV) connected generation with a credit based on the amount of units exported. For intermittent generation this credit is a single unit rate in p/kWh that applies to all units exported. For non-intermittent generation, the credit is split into three timebands labelled red, amber and green with the credit unit rate highest in red, lower in amber and lowest in the green timeband. The time periods for which the red, amber and green timebands apply vary by each DNO.

At Extra High Voltage (EHV), prices are locational and the amount of credit that is applicable for an individual site will be derived individually. Intermittent generation is not eligible for a credit and for those non-intermittent EHV generators that receive a credit, the credit will be a unit rate that applies to the super-red time band. The super-red timeband is normally a subset of the red timeband that applies at LV and HV but restricted to cover only the period of November to February. EHV generation do not receive a credit for any export outside of the super-red time period.

Under the supplier hub principle, the GDUoS credits are paid by the DNO to the generators supplier based on the metered export from the generation site.

3.1.8 Distribution losses

Distribution losses are applied to all metered volumes, including export units within each DNOs area to create boundary equivalent volume data at the transmission network that enters settlements. A supplier is able to offset the generation export data from their demand or, where the supplier has insufficient demand

to offset the generation, will receive a credit for the metered export after it has been increased for distribution losses.

3.2 The Value of Embedded Benefits

The value of embedded benefits to a generator will vary depending on a number of different factors which are highlighted below:

- DNO area – will affect the level of GDUoS credits, the triad benefit and the distribution losses saving.
- Voltage of connection – will affect the level of GDUoS credits and the distribution losses saving
- Type of generation (intermittent or non-intermittent) – will impact the level of GDUoS credits
- Time of export– the period during which volume is exported will impact all of the embedded benefits with the exception of AAHDC which is applied at a single unit rate and GDUoS credits for intermittent generation which also receives a single rate credit. In particular the amount of export at peak will have a large impact on GDUoS income for non-intermittent generators, triad benefit and the CMSC.

The level of embedded benefits that are currently received by embedded generation can be estimated using public domain data. In particular, the DNO's charging models for setting DUoS contain forecast data relating to all LV and HV connected generation in each year and the DNO's Long Term Development Statements (LTDS) include information about EHV connected generation. The Low Voltage (LV) and High Voltage (HV) published data is detailed and allows for an accurate picture of the level of embedded benefits. At Extra High Voltage (EHV), DNOs do not publish the pricing model as it contains confidential data and consequently, the LTDS has been used as a proxy to determine an estimate of the level of embedded benefits.

To provide a context to the level of overall embedded benefits, the table below shows the total costs for each of the areas where embedded generators can receive a credit:

	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16
Transmission System Embedded Benefits						
Transmission Network Use of System (TNUoS)	1,562	1,723	1,949	2,097	2,477	2,637
Balancing Services Use of System (BSUoS)	702	616	897	1,027	1,071	1,076
Transmission losses	262	302	286	286	299	247
Assistance for Areas with High Distribution Costs (AAHDC)	48	50	53	55	56	58
Capacity Market Supplier Charge	0	0	0	0	0	3.9
Distribution System Embedded Benefits						
Distribution Use of System (DUoS)	4,272	4,717	5,239	5,704	6,211	5,254
Distribution losses	1,448	1,341	1,459	1,468	1,592	1,297
Total	8,294	8,748	9,883	10,637	11,706	10,573

Figure 6: Total GB costs in areas where embedded benefits can be earned (£m)

The modelling work undertaken by Cornwall Energy has derived an estimate of the current value of embedded benefits in the GB market between 2011-12 and 2015-16. A summary of the analysis is shown in the table below. Appendix C contains the breakdown of this table split between intermittent and non-intermittent generation and across the LV/HV and EHV.

	2011/12	2012/13	2013/14	2014/15	2015/16
Transmission System Embedded Benefits					
Transmission Network Use of System (TNUoS)	£129.0	£162.9	£179.1	£232.1	£293.0
Balancing Services Use of System (BSUoS)	£49.2	£54.6	£66.7	£78.8	£95.3
Transmission losses	£30.9	£30.9	£32.9	£38.0	£41.1
Areas of Assistance (AAHDC)	£5.3	£6.5	£6.8	£8.4	£9.1
Capacity Market Supplier Charge	£0.0	£0.0	£0.0	£0.0	£0.1
Distribution System Embedded Benefits					
Distribution Use of System (DUoS)	£53.4	£53.7	£54.9	£53.2	£65.8
Distribution losses	£41.5	£46.1	£51.5	£55.2	£55.5
Total	£309.3	£354.7	£392.0	£465.7	£559.8

Figure 7: Estimate of total embedded benefits in GB (£m)

The estimate of historical embedded benefits has been derived from historical unit rates applied to an estimate of export volumes or export at time of peak. These estimates have been derived from the following sources of data:

- For LV and HV generation the forecast volume and generation credits by tariff has been extracted from the charging models that are published for each DNO area. An estimate of peak export has been derived from the volumes by assuming load and coincidence factors for different technologies.
- The estimates for EHV volumes are derived from the Digest of United Kingdom Energy Statistics (DUKES) for the period 2011-12 to 2014-15. The data for 2015-16 has been extracted from the long term development statements published by DNOs each year. The LV and HV data has been removed to determine the EHV volumes and any large EHV generators that pay transmission charges have also been excluded. Peak load has been derived from load factors and coincidence factors.

This analysis demonstrates how embedded benefits have increased since 2010 with the total embedded benefits rising from £309m in 2011 to £560m in 2015. This increase is across the board with all components of the embedded benefit increasing across the period. The increase is due to a combination of higher unit rates and an increase in the total capacity of generation connected to the distribution network which has doubled across the period (see figure 2). The table also shows the relative size of the embedded benefits of which TNUoS and BSUoS are currently the largest. The CMSC appears small at present but only recovers the operational cost in 2015-16. This will increase as the capacity market becomes operational.

4 Rationale for Change

4.1 Introduction

This section considers the issues and concerns that have been raised in relation to embedded benefits and the attempts to implement change. The main themes in the debates have concerned the extent to which embedded benefits are cost reflective, whether there are perverse incentives on generators to connect at distribution level rather than transmission, and what kind of enduring model would be appropriate going forwards, which focused on whether charges should be on a net or gross basis and which body, suppliers or DNOs, should be responsible for them.

Although the issues have been raised and reviewed several times since the introduction of BETTA in 2005, other more pressing matters have repeatedly taken industry attention and embedded benefits have slipped down the agenda. Both the lack of appetite for change in this area, partly reflecting the fact that many industry participants have interests that span the debate, and the lack of consensus, has meant there has been little actual change. Attention to the issues has also been prompted by the successive deadlines for the ending of the “small generator discount” which gives eligible generators in Scotland a discount on their TNUoS bills aimed at avoiding discrimination between these generators and their counterparts in England and Wales. National Grid also has a licence obligation to seek to put enduring arrangements in place. A further driver has been the rise in the overall TNUoS revenue collected by National Grid which has risen from £943mn⁷ in 2006-7 to £2,709mn for 2016-17 which has impacted on the absolute level of the embedded benefits for distributed generation and of the small generator discount.

National Grid’s most recent initiative, its informal review of embedded benefits in 2013-14 and subsequent consultation on the treatment of exporting GSPs in late 2015 has itself now been overtaken by events: DECC’s consultation on further changes to the Capacity Market in March said, in the context of considering whether diesel engines have an unfair advantage in the energy market, that Ofgem will review the charging arrangements for embedded generation and that it will set out its conclusion and a proposed way forward in the summer.

A detailed narrative of the initiatives to address the issues around embedded benefits is set out in Appendix I. Below is a high level summary of the key developments.

4.2 Transmission arrangements for embedded generation

At the start of the BETTA arrangements in April 2005 Ofgem implemented what was intended to be a temporary arrangement to prevent discrimination against generators under 100MW in Scotland and offshore that were connected to the system at 132kV. The “small generator discount” was introduced to TNUoS charges through a licence condition on National Grid (SLC C13) to reflect that 132kV is part of the transmission system in Scotland but part of the distribution system in England and Wales. Therefore the Scottish and offshore generators would pay transmission charges whereas the England and Wales generators would not. The discount was set at 25% of the combined generator and demand residual tariff and has remained calculated according to that formula throughout its existence. However, the value of the discount, which is paid for through the residual TNUoS charge on demand, has increased significantly, rising from £3.67/kW for 2005-6 to £11.46/kW for 2016-17.

Although originally set for three years, the discount has been extended five times since its introduction, first by a year to May 2009, then to March 2011, March 2013, March 2016 and, most recently by Ofgem this January, to March 2019. In each case the extension was to enable enduring arrangements for embedded generation to be developed, and Ofgem’s rationale has referred to the different initiatives underway at different times. When it extended the expiry date to 31 March 2011, Ofgem also strengthened National Grid’s obligation to use “best endeavours” to develop and implement enduring arrangements.

⁷ https://www.ofgem.gov.uk/sites/default/files/docs/2005/11/12136-253_05_0.pdf

At an early stage following the implementation of the arrangements Ofgem issued a discussion document in September 2005 which sought to highlight key issues it considered needed to be addressed. These included GSPs exporting onto the transmission system without access rights, the potential lack of cost reflectivity of the arrangements, and the potentially perverse incentives on generators when deciding where and at what voltage to locate on the network. The regulator set up a workgroup the following summer, the Transmission Arrangements for Distributed Generation, to consider the issues. This examined four models which considered in particular two dimensions of a potential solution: whether charges should be applicable on a gross or a net basis (ie whether distributed generation should be subtracted from suppliers' demand or not); and who should be liable for charges, suppliers or distribution network operators (DNOs). National Grid supported the gross supplier agency model, while the majority of the workgroup supported a net DNO agency approach.

Ofgem considered its role was to facilitate debate rather than to prescribe particular answers — that was for industry to bring forward — but it concluded there was a good case for a review of the cost reflectivity of the size of embedded benefits and that National Grid should undertake a review of the drivers of the costs associated with the residual TNUoS charge, taking into account the impact of distributed generation on such costs. It considered cost reflective charging could be applied on either a net or a gross basis, but said it did not consider that a solution based on net exports alone would be appropriate because the impact of distributed generation on transmission was not limited only to where there is net export.

The review by National Grid of the drivers of cost associated with residual TNUoS charges proposed by Ofgem was, in the event, effectively deferred by the Transmission Access Review (TAR) launched by the regulator in July 2007. TAR was led jointly by Ofgem and BERR following the publication of the energy white paper *Meeting the Energy Challenge* in May 2007. The main issue was the significant queue of generators waiting to connect and the need to meet 2020 renewable energy targets. Although the focus of the review was to be on the arrangements for generators wishing to access the transmission system it was noted that “it should also recognise the offsetting effect from the demand side together with the impact of distributed generation.” However, this issue was not considered during the review, which ended in Ofgem recommending that the secretary of state should use its powers to implement new transmission access arrangements.

The “connect and manage” regime then imposed by the government in August 2010 enabled transmission connected generation to apply for an accelerated connection based on the time taken to complete their “enabling works”, with wider network reinforcement carried out after they have been connected. The new arrangements also applied to certain distributed generation: larger generators, and smaller ones where their connection could have a significant impact on the transmission system.

National Grid took up the review of embedded generation charging arrangements again in January 2010 with the publication of its “pre-consultation” charging methodology paper GB ECM-23 *Transmission Arrangements for Embedded Generation*. It argued that the value of embedded benefits provided by the current arrangements was around £20/kW but that a cost-reflective benefit would be around £6.50-7.25/kW and presented two possible models for an enduring solution, a gross nodal supplier agency model, which it favoured, and a net DNO agency model. However, its proposals were not generally well received by industry and were again superseded by events, this time the launching of Ofgem's Project Transmit to facilitate the move to a low carbon energy sector, which was announced in June 2010. Although embedded charging arrangements were originally intended to be within its scope, it soon focused on electricity transmission connection and charging arrangements and embedded distribution arrangements fell out of scope.

Towards the conclusion of the Project Transmit process and with a further extension to the small generator discount in place National Grid held an “informal review” of embedded benefits between April 2013 and April 2014. Its analysis indicated the embedded benefit (summation of the generator and demand residual elements) could be £27.54/kW to £41.30/kW in 2013-14 depending on the location of the generator. It estimated that £215mn as the value of the benefits that would otherwise be redistributed amongst TNUoS charge payers. Most of the focus group felt there was no clear defect as proposed by National Grid in respect of the cost reflectivity of embedded benefits or on the impact of transmission charges on competition between transmission and distribution connected generation. However it agreed

the cost reflectivity of embedded benefits could be improved and a range of issues were discussed including: the extent to which embedded generation uses transmission; the de minimis level of embedded generation that could be considered to impact on the transmission system; the embedded benefit arising from TNUoS charges; whether demand should be charged net or gross; the comparison of transmission and distribution network charges paid by generation users; and exporting GSPs.

National Grid's final report concluded that the small generator discount should be allowed to lapse in 2016 as network charges faced by eligible generation without the discount are within the range faced by distributed generation. It decided not to take forward further options to charge the demand half hourly residual amount of TNUoS on a gross basis, either with or without explicitly charging embedded generation. However, it did decide to give further thought to exporting GSPs and subsequently held a consultation in autumn 2015 with a proposal to charge DNOs a local charge on the net export of a GSP.

Meanwhile Fred Olsen Renewables raised a CUSC proposal, CMP239, aiming to grandfather the small generator discount, which would otherwise expire in March 2016, with existing generators (or those connecting ahead of the expiry date) would continue to receive the discount for 25 years, whereas those connecting later would not. Ofgem rejected this proposal in August 2015 on the grounds that it would be discriminatory between existing and new generators and would distort competition. It gave no hint of its intention to consult on again extending the small generator discount, but nevertheless consulted on a further three year extension shortly afterwards. It said it was appropriate that the discount remains in place while ongoing work in developing enduring arrangements for transmission charging for embedded generation continues, noting National Grid's work on exporting GSPs. In deciding to extend the discount Ofgem cast doubt on National Grid's analysis for the informal review about the relative costs faced by eligible and non-eligible generators. However, it did say that it was aware of the growing level of embedded benefits and was looking into whether action is needed in this area.

DECC issued a consultation on 1 March 2016 on further changes to the Capacity Mechanism (CM). It considered there may be merit in concerns that diesel engines have unfair advantages in the CM due to how they are treated in the main energy market. It said Ofgem has previously expressed concerns that embedded benefits may over-reward distribution-connected generators and noted also that the impact of flows from the distribution network to the transmission network is increasing. The regulator was concerned that the charging arrangements could be having an increasing impact on the system, including distorting investment decisions and leading to inefficient outcomes in the CM. DECC said Ofgem is therefore reviewing "whether it would be consumers' interests to change the charging arrangements for distributed-connected generators" and that the regulator will set out its conclusions and a proposed way forward in the summer.

4.3 International approaches

There are a wide range of approaches to charging for transmission use of system used by countries internationally which can serve to highlight the type of choices and trade-offs to be made when considering what are appropriate arrangements in GB. Appendix 2 sets out a short survey of examples of different methodologies used in different markets.

The Investment Cost Related Pricing (ICRP) approach used in Great Britain calculates TNUoS tariffs according to the incremental cost of supplying network capacity at different locations. This is intended to provide an economic signal that allows users to consider their impact on the network when making siting decisions and therefore promotes an overall economic generation and transmission system for consumers. The proportion of TNUoS charges allocated to generation is set at 27%, as adjusted by the need to remain within the €2.5MWh average annual charging limit set by Regulation 838/2010 which will see the proportion paid by generation fall to a forecast 10% by 2020-21. This change largely reflects the increase in allowed revenue that National Grid is required to collect.

Many countries do not allocate any transmission charges to generation, for example, 21 out of the 35 European countries examined by ENTSO-E in its latest survey do not. Of those that do, some include items not included in the GB charging methodology for TNUoS, notably losses and system services. The way charges are allocated also differ in terms of methodology used, and the location and time of day/season to

which they apply. For example, Australia's National Energy Market and the Republic of Ireland and Northern Ireland use different multi-step methodologies that seek to reflect costs imposed on the network. There are also differences as to whether transmission charges are spread over the whole network (postalised), or are allocated by zone or by node. In considering the impact of these allocations, other factors, particularly the policy on connections, also needs to be taken into account. Locational signals, for example, can alternatively be provided by "deep" connection charges which include costs related to network reinforcements downstream, as opposed to the "shallow" policy, as operated in GB, which does not. (By contrast in GB connections for distributed generation are "shallowish" for generators connecting post 2005⁸ in that they cover the full cost of sole use connection assets but typically only a proportion of any reinforcements of the shared network).

Ofgem's Project Transmit (2010) considered these issues in depth, particularly in the context of the costs imposed by renewable generation on the transmission system. The same questions are relevant to the current issues around embedded generation, in particular: what aspects of cost are being reflected and how (for example time of day, short run/long run); what incentives does this create; and how the costs that are incurred are allocated. The range of international solutions indicates that any solution needs to be considered holistically and in the context of the particular circumstances of the market.

Conclusions

The issue of embedded benefits has been reviewed a number of times in recent years without any firm conclusions reached or directions issued by Ofgem. In March 2016 DECC requested Ofgem to undertake a further review citing concern that embedded benefits could be over-rewarding embedded generators. The ongoing debate around embedded benefits has led to increased uncertainty for developers looking to install embedded generation and making it more difficult to raise finance for new schemes.

⁸ https://www.ofgem.gov.uk/sites/default/files/docs/2012/02/decision-letter-on-pre-2005-exemption_0.pdf

5 Review of Transmission Charging Principles

5.1 Alternative charging basis for transmission

The current approach for charging TNUoS is for National Grid to charge suppliers based on their net demand at GSP. National Grid have explored a number of alternative charging arrangements which would potentially reduce the level of the triad benefits as follows:

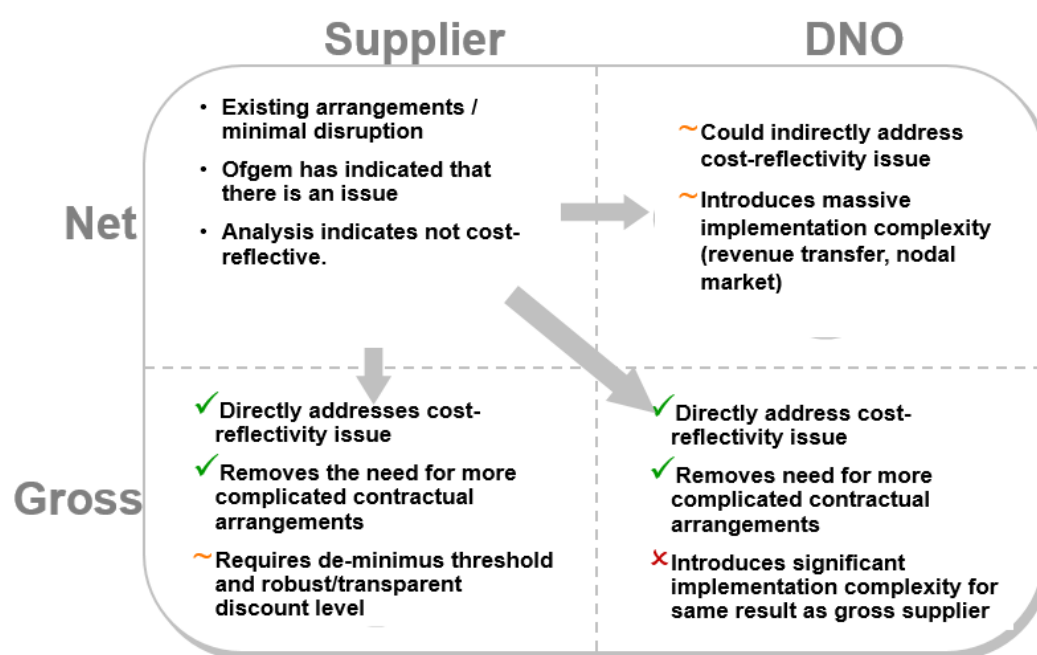


Figure 8: Potential agency agreements for TNUoS demand charging⁹

(i) Gross Supplier

A gross supplier model levy charges on suppliers based on their gross demand rather than the net demand after any offset generation has been taken into account. The impact of this is that the TNUoS charge would decrease as it would be spread over more units and embedded generators would receive a lower credit from reducing the triad charge. There are further sub options within this model that include applying a charge or credit to gross generation export that reflect the benefit or cost that they bring the transmission network. This model allows National Grid to control the level of benefits that pass through to generators. A threshold may also be implemented, below which net charging would apply.

(ii) Net DNO

A net DNO model would continue to settle demand TNUoS based on the net demand by GSP group. It would also introduce access rights for each GSP that would be managed by the DNO and embedded generators would only be able to sell to demand within the same GSP. The market at each GSP would be facilitated by the DNO who would procure entry and/ or exit rights from the system operator.

(iii) Gross DNO

A gross DNO model would be a combination of the two previous options with the DNO managing entry and exit rights at each GSP in combination with gross charging on behalf of the supplier.

All three options considered have advantages and drawbacks. The net and gross DNO options introduces additional complexity and places an additional burden on DNOs. It also raises the issue of how the costs of entry or exit requirements are recovered by DNOs and whether this will result in an improvement in cost

⁹ Source: Presentation by National Grid on embedded benefits

reflectivity for customers. A further issue is the allocation of embedded generation to individual GSPs, particularly in those areas that operate a mesh rather than radial network.

The gross supplier model allows National Grid to control the level of avoided TNUoS benefits received by embedded generators. However, the current level of avoided costs put forward by National Grid are low compared to the analysis contained with Section 4 and therefore any move to applying charges and embedded benefits on a gross basis will be likely to undervalue the costs avoided by embedded generation.

The introduction of a gross charging model would lead to a lower triad rate for demand customers as the transmission costs will be spread across a higher level of demand than at present. It would also mean that any avoided TNUoS cost for embedded generation would be set by National Grid at a different rate to that paid for by demand customers through their triad charge. This introduces a differential between the cost of a unit reduction in demand and a unit increase in generation during the triad period. However, a reduction in demand or an increase in generation has the same impact from National Grid's perspective and at an operational level, National Grid would be unable to differentiate demand reduction and a generation increase when measured at a GSP. Consequently, the introduction of a gross model can be considered as less cost reflective as it places a different value on demand reductions and generation increases.

One scenario considered by the industry is for National Grid to adopt a gross charging approach and remove the residual charge from the triad when applying the charge to embedded generation. This would result in some embedded generators receiving a charge rather than a credit depending on where they are located. This may result in generators being charged for using the transmission network when in reality they export into the local distribution network and their export is absorbed locally. It would be hard to justify a cost reflective charge for generators that are clearly not using the transmission network. This would also impact on the operating regime for storage which reacts to price signals when determining whether to import or export.

A further unintended consequence of a gross supplier model is to potentially push embedded generation from standalone to behind the meter. Embedded generators will become incentivised to lay private wires to connect to local demand and receive the full benefit from the demand customer rather than the supplier. This will lead to an inefficient allocation of resource as embedded generation lay copper in the ground simply to avoid the new charging arrangements. It will also lead to less transparency as National Grid will lose sight of the embedded generation which effectively becomes hidden behind the meter and makes the system harder to manage for National Grid and DNOs.

An alternative to netting of at GSP group level is to facilitate the netting off for demand and generation that are sited in a set locality. This may be defined by an individual GSP, substation or by postcode. This is effectively a local energy scheme that would allow local demand and generation to offset each other and removing them from settlements. The benefit of local energy schemes over the current netting arrangements is that that actual export is consumed locally rather than from a theoretical basis at GSP group level. At present the settlement arrangements are not in place to enable community energy schemes, but this option should be considered alongside the discussion on net/ gross charging at GSP level.

Conclusions

Moving to a gross system of charging would create a price differential between a decrement of demand and an increase in generation when the impact on the transmission network is identical. The introduction of this differential would potentially distort the economic signal for both generation and demand and could lead to unintended consequences such as generation moving behind the meter and less transparency for National Grid in managing the system.

An important principle that currently underlies the transmission charging methodology is that embedded generation is treated as negative demand and is rewarded in the same way. A move to gross charging would remove this fundamental principle and favour demand reductions over export from embedded generation. A more beneficial approach would be to improve the cost reflectiveness of the TNUoS demand charge so that it does not need to distinguish between demand and embedded generation and continuing to charge on a net basis. This would provide the correct economic signal for both demand and embedded generation customers.

5.2 Locational vs residual charges

The TNUoS demand charge is broken down into two components. The first is a locational charge which is calculated from a Direct Current (DC) loadflow model referred to as the Investment Cost Related Pricing (ICRP) transport and tariff model. This model determines the incremental cost on the transmission network of injecting 1MW of generation at each node on the network to determine the change in powerflows that result when compared to a baseline that represents the current network.

The locational charge produces a set of nodal charges that are grouped into zones and represent the marginal cost of taking additional demand in each area. The change in powerflow that is determined from the ICRP model is changed into a £/kW price using an expansion constant which equates to the unit cost of reinforcement.

The locational element of TNUoS creates a set of relative prices across the GB charging zones that represents the relative marginal costs in each zone. The locational element alone will not recover the total allowed revenue that National Grid is allowed to recover under its price control and a further charge is added to the locational charge to recover this shortfall. The additional charge is referred to as the residual element of TNUoS. The residual element is calculated for demand as a flat £/kW value that is applied to the locational price in each zone to make up the shortfall in revenue. The shortfall is recovered via a fixed £/kW capacity based charge to retain the relative price signals between each charging zone.

The locational element can be considered as the marginal reinforcement costs and the residual the shortfall to recover all other costs. The residual will cover items such as depreciation and return on existing assets, direct and indirect costs and business rates. These elements have been set out in section 6.

In the context of embedded generation, the appropriateness of demand based TNUoS as an embedded benefit can be assessed for the locational and residual elements. The locational element represents the relative cost of reinforcement which some commentators have suggested is the cost that is being offset by embedded generation and that they should therefore only receive the locational element of TNUoS as an embedded benefit.

The impact of this approach can be seen in the table below which shows the TNUoS demand tariff with the residual element removed:

HH Zonal Tariff (£/kW)							
Zone No.	Zone Name.	2011-12	2012-13	2013-14	2014-15	2015-16	2016-17
1	Northern Scotland	-13.13	-12.09	-14.36	-13.88	-12.16	-4.36
2	Southern Scotland	-7.94	-6.83	-8.62	-8.81	-8.84	-5.09
3	Northern	-3.99	-3.17	-3.06	-3.11	-3.01	-2.40
4	North West	-0.22	0.01	-0.23	-0.41	0.05	-2.50
5	Yorkshire	-0.09	0.35	0.08	0.20	0.66	-2.84
6	N Wales & Mersey	0.53	0.81	0.22	-0.33	-0.01	-2.65
7	East Midlands	2.54	2.62	2.80	3.05	3.44	-0.61
8	Midlands	4.14	4.53	3.79	3.73	4.00	0.41
9	Eastern	3.00	3.12	4.48	4.58	5.55	1.21
10	South Wales	3.18	2.43	2.13	2.27	1.98	-3.02
11	South East	7.07	5.42	7.42	7.61	8.11	3.87
12	London	8.27	8.34	8.67	8.50	10.61	6.54
13	Southern	7.90	7.78	8.34	8.74	9.16	4.75

14	South Western	8.74	8.23	8.14	8.65	8.35	3.25
15	Average	1.43	1.54	1.41	1.48	1.99	-0.25

Figure 9: Locational Element of demand TNUoS charge

The average values for the locational element of TNUoS are relatively small in the context of total TNUoS at less than £2/kW and the simple average is negative in 2016-17. This compares with an average TNUoS demand charge of £45.08 in 2016-17.

Residual TNUoS clearly accounts for the majority of the demand TNUoS charge and removing it as an element of the embedded benefit would have a large impact on embedded generators. The locational element of the charge is a forward looking marginal cost that looks at future reinforcement, whereas the residual is recovering the full costs of operating the transmission system in the long term.

Cornwall Energy believes it is appropriate to use a marginal locational element to set the relative cost signals between the charging zones but not to value the benefits that embedded generation bring to the transmission network. The residual element recovers the bulk of the costs that relate to the existing network such as depreciation, return, direct and indirect operating costs. Embedded generation will reduce the requirement for these costs over the longer term and the savings that will be achieved from the increase in embedded generation will be realised in future price controls. It is therefore important that the relative marginal costs derived from the ICRP model are not relied upon to provide the cost signal to embedded generators. However, as this report identified in section 6 there are some elements of the TNUoS target revenue that are not demand related and it would improve the cost reflectiveness of the triad charge if these elements were removed from the calculation and recovered in a more appropriate way such as on a unit or per customer basis.

Conclusions

The locational element of the TNUoS demand charge is appropriate for determining the regional split of the triad charge but does not fully reflect the avoided cost of embedded generation and therefore should not be used as a proxy for the TNUoS embedded benefit.

5.3 Exporting GSPs

The increase in embedded generation has led to an increasing number of GSPs starting to export. The number of GSPs that exported more than they imported in shown in the table below:

DNO	Total No. of GSPs	Max export > max import	
	14/15	13/14	14/15
WPD – W Midlands	14	0	0
WPD – E Midlands	16	0	0
UKPN - Eastern	20	0	0
UKPN - London	16	0	0
UKPN – South East	10	0	0
Electricity North West	17	1	1
Northern Powergrid - N	18	3	3
SPEN - Manweb	13	0	0
SSEPD - S England	18	0	0
WPD – South West	9	0	0
WPD – South Wales	11	0	0
Northern Powergrid - Y	20	0	0
SSEPD - N Scotland	69	32	36
SPEN – S Scotland	84	11	11

Figure 10: Number of exporting GSPs in 2013-14 and 2014-15

The increase in exporting GSPs is a particular issue in Scotland with 36 out of 69 GSPs exporting in North Scotland. As there are already constraints on the transmission system between Scotland and England as discussed earlier, embedded generation that is exporting through GSPs is exacerbating the problem and driving costs on the network.

National Grid has consulted on the issue of exporting GSPs and has suggested that any potential solutions should be applied through DNOs as National Grid has a relationship with individual DNOs for each GSP rather than suppliers. National Grid is still reviewing the responses to its latest consultation in this area and has not yet produced guidance on how it proposes to take the issue further.

In the context of embedded generators, an exporting GSP is more likely to drive additional costs on the transmission network, but this is not always the case. The additional cost or benefit that may be caused by an exporting GSP will be determined by the location, the time and duration of the export and the forecast future demand at the GSP. Cornwall Energy recommends that any solution that is adopted for exporting GSPs should recognise the individual characteristics of each GSP and determine the incremental costs driven by the export both now and in the future before determining a charging structure that is site specific for those GSPs that are causing additional costs.

Conclusions

Exporting GSPs should only be treated differently from a demand TNUoS perspective if they are creating additional costs for the transmission operator. A case by case of each GSP should be considered to determine the level of additional costs created due to the export and any solution put in place should only apply to those GSPs where there is an increase in costs as a result of the embedded generation.

5.4 Sunk Costs

A general principle adopted by Ofgem in setting the objectives of the charging methodologies is that price signals should be forward looking and take account of the incremental costs that a user is driving on the network. Consequently, the network charging methodologies treats costs that do not vary if a consumer changes their consumption as sunk and generally does not take them into account when setting the underlying price signal. Instead these costs are socialised and recovered from all customers.

Many of the costs associated with networks could be considered as sunk in the short term as they are likely to be incurred regardless of consumption patterns and the level of peak demand on the network. In section 7.3 we examine the breakdown of the allowed revenue to determine whether each element varies with demand.

The principle of classifying costs as sunk or variable should be aligned with the type of user who responds to the price signal. In the case of embedded generators, the decision to invest depends on a forecast of future revenues which includes embedded benefits. The expected life of an embedded generator can be in the region of 15 to 45 years and consequently, network costs that can be offset across this timeframe should be considered as variable, even though in the short term they may appear sunk. If this approach is not adopted, there is less of an incentive to invest in embedded generation and storage which ultimately drives down the longer term transmission costs.

Conclusions

Some of the costs incurred at transmission level may appear static in the short term, but are variable costs when considered over the typical life of an embedded generator. It is therefore, appropriate that the price signal for embedded generation should reflect the avoidance of longer term costs.

6 Impact of Reducing or Removing Embedded Benefits

The removal or reduction of embedded benefits will impact on the economics of existing embedded generators and potential investment in new embedded generation and storage. However, a reduction in embedded benefits would not only affect the revenue streams of embedded generation but would also have a wider impact on other areas of the industry. This section looks at the potential impact that reducing embedded benefits could have on the capacity market and wholesale prices.

6.1 Impact on Capacity Market of changes to Embedded Benefits

The DECC consultation on the capacity market highlighted a potential issue that embedded benefits could lead to embedded generators bidding into the capacity market auction at a level that could distort the clearing price and reduce the likelihood of new Combined Cycle Gas Turbines (CCGT) plant connecting to the transmission network. CCGT are the governments preferred technology for ensuring security of supply in the future as a result of their large scale and ability to provide baseload electricity as well as flexibility. However these schemes are expensive and are unable to find enough support in the wholesale energy market to go ahead.

6.1.1 Capacity Market Auction for 2019-20

Cornwall Energy has modelled the impact of removing the transmission embedded benefits (triad benefit and BSUoS) from embedded generation to determine the likely impact this would have on the capacity market. The analysis simulated the 2015 T-4 Capacity Market auction using estimates of costs for different technologies and regions across the GB electricity market. The operational costs have been estimated for each scheme which prequalified in the 2015 auction in 2019-20, as well as expected revenues and a bid calculated based on the difference. These bids were then ranked lowest to highest and compared to the target capacity to determine a clearing price.

In the first simulation, using an average Triad benefit of £55/kW for delivery year 2019-20 a clearing price of £18.5/kW was calculated, close to the actual clearing price of £18/kW. In this simulated auction 4GW of embedded generation cleared; 500MW higher than the actual clearing volume of small scale embedded plant.

In the second simulation the revenue from embedded benefits was removed from all embedded generators and the resulting clearing price was £23.2/kW, £4.7/kW higher than the estimate including the full embedded benefit. This difference could cost in total an estimated £214mn, representing an extra £2.3 on the annual household bill. Only 364MW of embedded generation was procured and the difference was made up by existing large scale gas fired power stations.

The results of the capacity market simulation under each scenario is shown in the two graphs below:

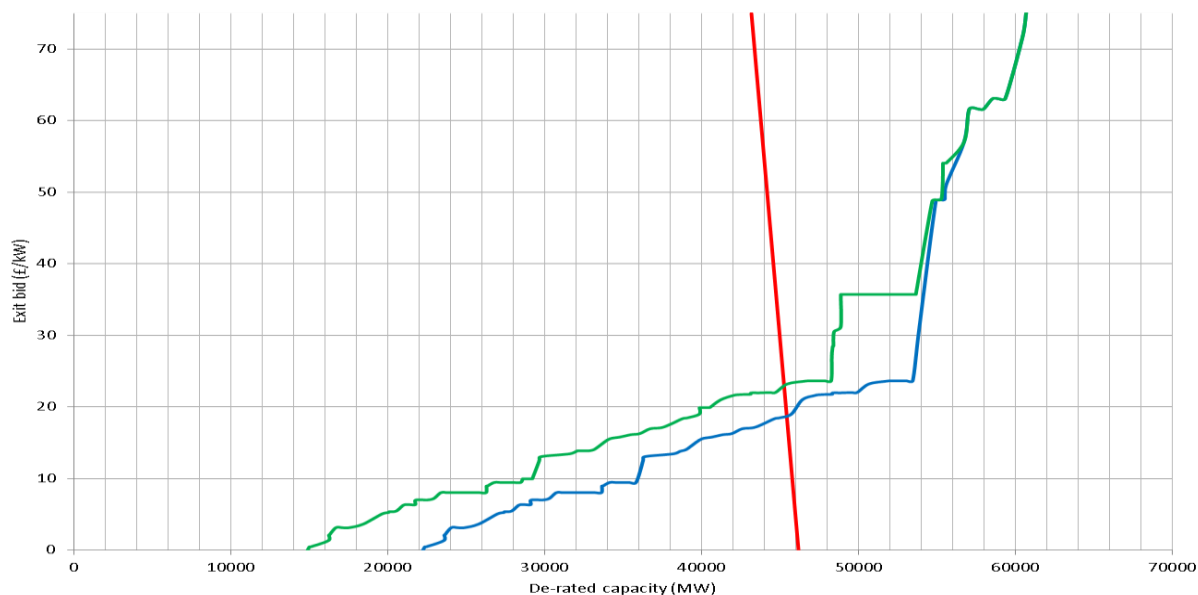


Figure 11: Comparison of the Capacity Market auction curve for 2019-20 with and without embedded benefits

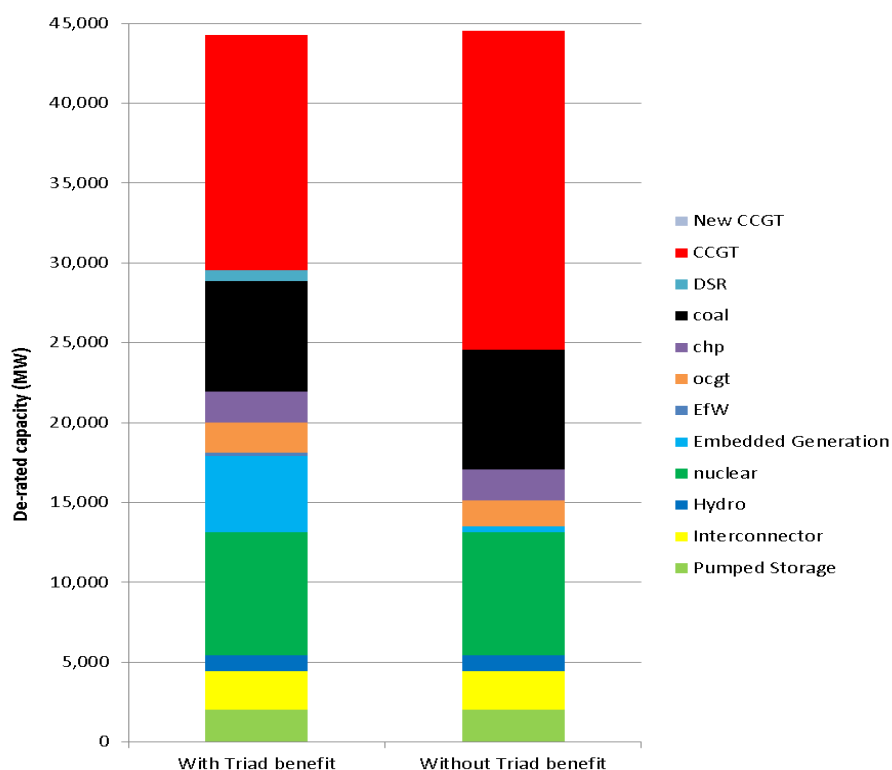


Figure 12: De-rated capacity by technology in the 2019-20 Capacity Market auction with and without embedded benefits

Based on the modelling work undertaken, no new CCGT would have cleared in the auction even with the removal of embedded benefits. This is because the real barriers to the construction of new large scale CCGT are more complex. CCGT are considerably more expensive than smaller stations such as Open Cycle Gas Turbine (OCGT). Carrington was estimated to cost £698/kW, whereas an OCGT could cost

between £300-£500/kW and IPPR estimated a reciprocating engine could be close to £150/kW¹⁰. As a result of this high cost developers need certainty that their plant will have a route to market through either a tolling agreement or a power purchase agreement, for a plant greater than 100MW and this is likely to have to come from one of the larger suppliers who would be the only participants able to offer such long-term deals. Without a route to market in place a lender is unlikely to provide the capital to develop such a project.

The largest suppliers are unlikely to offer such deals as they are vertically integrated and already have enough generation volumes to cover their market share. In order for new generators to find a place in the market older ones will have to close. Although some older coal fired generators have already proposed to close, beyond these announcements it is not clear where other capacity closures will come from. It is these existing plant which do not have capacity agreements which we believe would take up the slack from reduced competitiveness from the embedded market.

6.1.2 Capacity Market Auction for 2020-21

The simulated auction was re-run for 2020-21 to determine whether the additional 3GW of load that is to be procured in this auction would impact on the likelihood of new build CCGT clearing within the auction. The simulation was run with embedded benefits included under a Business As Usual (BAU) scenario. Three further scenarios were considered to assess the impact of possible changes on the clearing price as follows:

- BAU plus an additional 2.5GW closure of coal plant which is removed from the simulation. This is in line with the closures announced in early 2016 as referenced in the impact assessment¹¹ released by DECC as part of the government response to the consultation on further reforms to the capacity market.
- The BAU scenario with 2.5GW of coal closure removed from the simulation plus the removal of transmission embedded benefits (triad benefit and BSUoS).
- The BAU scenario with 2.5GW of coal closure removed from the simulation plus the removal of transmission embedded benefits (triad benefit and BSUoS) plus the removal of 2.07GW of embedded new-build capacity which procured a contract in the 2014 T-4 and 2016 T-4 auctions.

The results of the simulation is shown in the graph below:

¹⁰ http://www.ippr.org/files/publications/pdf/mad-maths_Dec2015.pdf?noredirect=1

¹¹ https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/521302/CM_Impact_Assessment.pdf

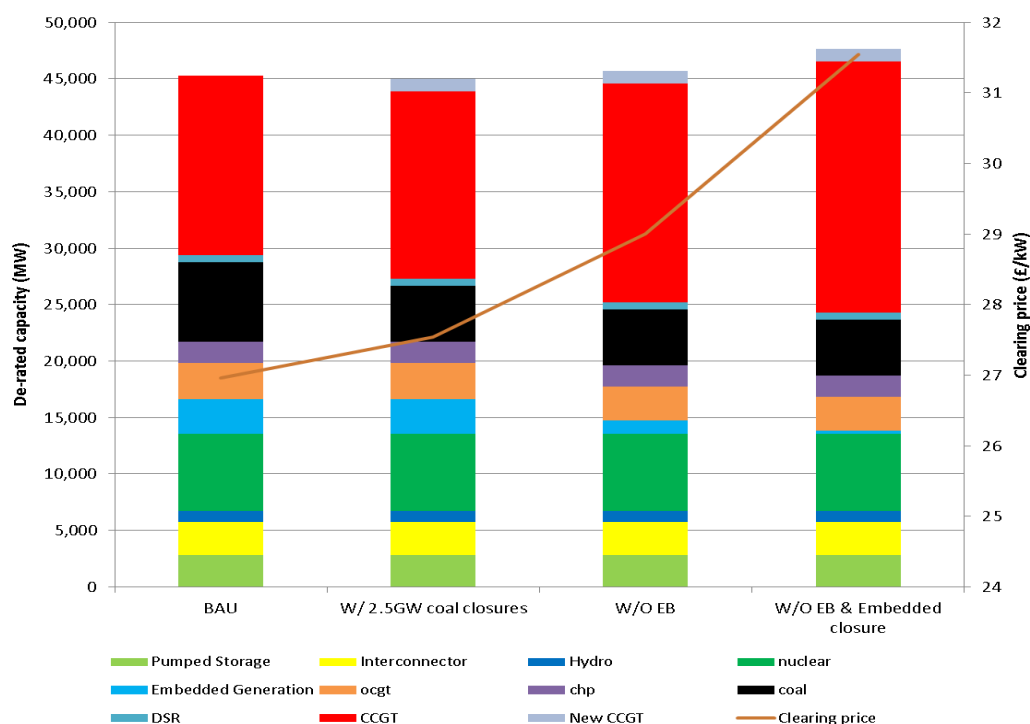


Figure 13: De-rated capacity by technology in the simulated 2020-21 Capacity Market auction

Under the “Business as Usual” scenario which includes an extra 3GW, embedded benefits and no plant closure a total of just over 45GW of capacity is procured at a clearing price of £26.9/kW. This includes no new build gas fired power stations but also includes a new generation of small scale reciprocating engines in line with the previous two auctions.

The second scenario assumes the removal of 2.5GW of coal plant and the clearing price increases to just over £27.5/kW. This includes one new CCGT; however there is no significant change in price as the station is Damhead Creek 2 which is in a negative TNUoS zone and this reduces its estimated bidding price by £6/kW in comparison to its peers.

The third scenario assumes the removal of embedded transmission benefits in addition to the 2.5GW of coal plant closure. Under this scenario, the clearing price increases to £29/kW, an increase of £2.0/kW over the BAU scenario.

The final scenario assumes the withdrawal of 2.07GW of embedded new build capacity which procured a contract in the 2014 T-4 and 2016 T-4 auctions and whose capacity needed to be procured again. In this scenario the estimated clearing price rises to £31.5/kW, an increase of £4.6/MWh compared to the BAU scenario. This is expected to cost consumers £282mn, representing £3.0 on the annual household bill.

Under all the scenarios considered, the only CCGT plant that is built is Damhead Creek 2 which has a competitive advantage due to its location in a negative TNUoS zone. In addition, end consumers face additional costs from the removal of embedded benefits in the following areas:

- A higher capacity market clearing price which is paid to all generators who are successful in the auction.
- Higher wholesale prices, reflecting an increase in the marginal cost of embedded generation and the potential closure of embedded generation in response to the removal of triad benefits.
- An increase in the cost of ancillary services as embedded generators need to make up for a shortfall in their revenue through higher contract prices.
- Higher levels of reinforcement and other costs at the transmission network level as embedded generation is replaced by transmission connected generation.

- Higher levels of reinforcement and other costs at the distribution network level as the export from embedded generation is reduced.
- Potentially higher balancing costs, as more volume enters the balancing market.
- A higher cost of capital for all generation due to the increased risk associated with industry change.

Conclusions

The analysis undertaken suggests that a reduction or even the removal of embedded benefits would not result in the development of new CCGT plant and will lead to additional costs for end consumers.

6.2 Impact on Wholesale Electricity Prices of changes to the triad benefit.

The impact of removing or reducing triad payments will have a wider impact on the wholesale market. The response of consumers and embedded parties will potentially have an effect on the fundamental drivers of supply and demand and therefore the price of wholesale electricity.

Based on an assumption that wholesale power price is driven by the marginal power station required to meet demand at any given time, if the triad response from half-hourly customers or embedded generators (who effectively operate as negative demand) is reduced, demand will be higher and more expensive power stations will need to operate to ensure supply meets demand.

There is an estimated 24.5GW of embedded generation connected to the GB system at present and it is unlikely that existing generation would reduce its export over the winter peak as it will need to recover its operating costs regardless of whether triad revenue is available. However there is likely to be a reduction in the response from half-hourly demand customers and from new build generators looking to take advantage of peak prices and Triad revenues. National Grid has estimated there is a response of between 2GW and 4GW from consumers avoiding Triads and in the 2014-15 Winter Outlook report¹² National Grid estimated customer demand management over the Triad period at 1.2GW. This response could be lost or diluted if the Triad benefit is removed.

To estimate the impact on power prices the impact of removing varying levels of Triad response from the demand has been simulated and the impact on power prices calculated. The model used builds a merit order of costs from different power stations connected to the transmission and distribution systems, and calculates which power station is required to run to meet the demand in a half hour period and assumes that this power station therefore sets the power price for that period. To estimate the impact of removing the incentive to respond to Triad periods, different levels of estimated Demand Side Response (DSR) has been removed from the model over the Triad periods (4-7pm, weekdays, November to February).

The graph below illustrates the impact of removing the incentive to respond over Triad periods to wholesale power prices. Over 2016-17 the average impact of reducing Triad response by 1GW is estimated to be £0.63/MWh rising to £2.84/MWh assuming a 4GW reduction in DSR. Based on an estimate of demand over these periods (~15TWh) the rise in power prices could cost an extra £10mn in 2016-17 for 1GW DSR loss or up to £45mn for a 4GW reduction in Triad response.

¹² <http://www2.nationalgrid.com/UK/Industry-information/Future-of-Energy/FES/Winter-Outlook/>

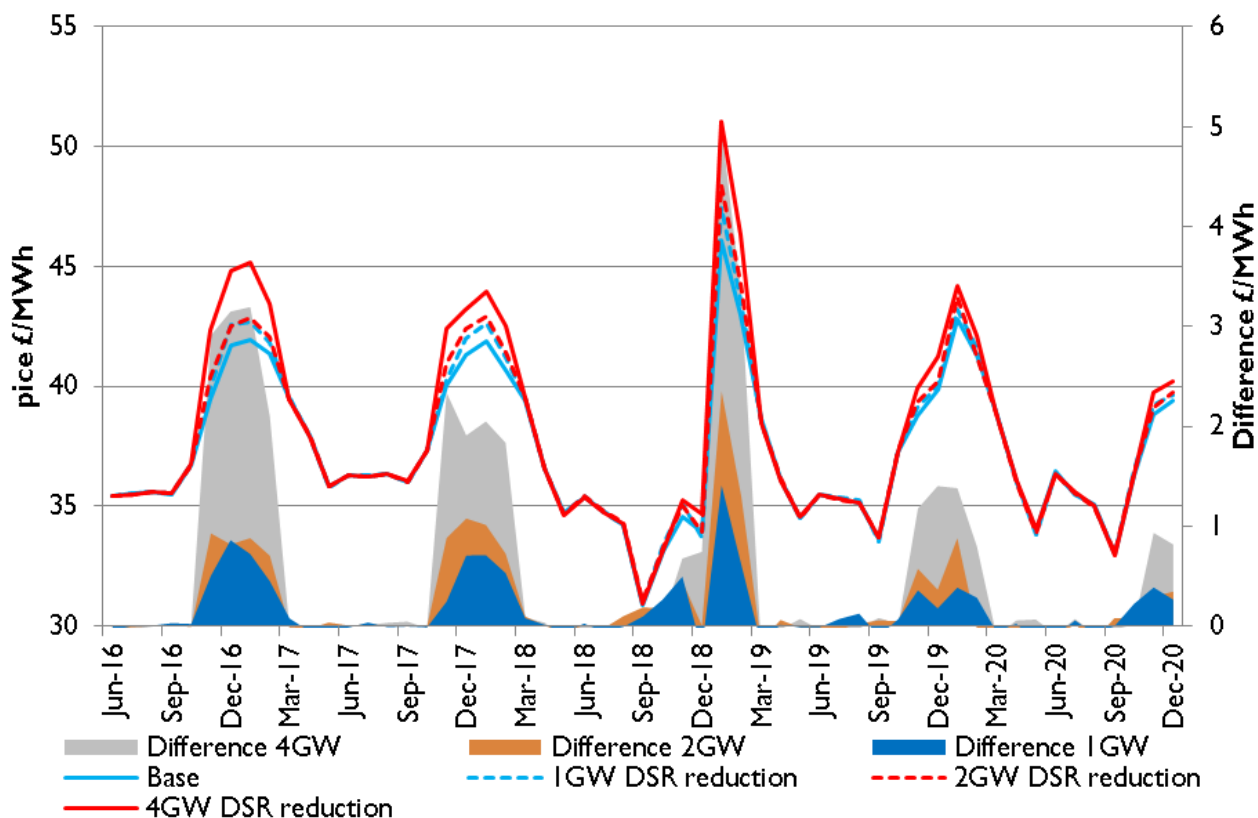


Figure 14: Average monthly forecast power prices with different levels of demand response

The impact of this change appears small on its own but needs to be considered as part of the wider impacts on the market. A £0.60/MWh increase in power prices is not enough to bring on new forms of generation, but reducing or removing the triad would impact on the Capacity Market (as outlined in 8.2) and the level of transmission infrastructure. In addition the effects of removing or reducing the triad as a time of use signal needs to be considered on new and innovative technologies, such as DSR and storage, which have the potential to transform the market going forward.

Conclusions

The modelling suggests that the direct impact on peak wholesale prices of removing the triad based on the current merit order of plant would be minimal. However, regard should be given for the wider impact this could have on the capacity market, transmission infrastructure and new technologies.

7 Transmission Charges

7.1 Overview

Transmission Use of System Charges are derived by National Grid under the methodology set out in the Connection and Use of System Code (CUSC). All generation and demand directly connected to the transmission system in England and Wales are charged TNUoS. However, in Scotland, transmission includes 132kV lines, which in England and Wales are defined as distribution. To ensure a level playing field for generation, 132kV connected generation in Scotland therefore currently receive a discount on their TNUoS. In addition, some large embedded generations that connect to distribution networks (or 132kV in Scotland) will incur TNUoS charges, even though they are not directly connected to the transmission network. This is because the generator is large enough to be likely to have an impact on the transmission system. The threshold for distribution connected generators paying TNUoS is where their Maximum Import Capacity is over 100MW or they are classified as large under the Grid Code and do not have a Bilateral Embedded Licence Exemptible Large Power Station Agreement (BELLA).

7.2 Drivers behind the Increasing Triad Charge

The triad charge has consistently increased year on year and this trend is forecast by National Grid to continue over the next five years. There are four drivers behind this increase:

- The allowed revenue that transmission companies are able to recover from TNUoS charges has increased substantially over the last two price control periods
- The triad mechanism recovers the allowed revenue across the triad demand which has consistently fallen year on year.
- The TNUoS revenue target is split between generation and demand, with 27% normally attributed to generation. There is a cap that limits the charge to generation at 2.50 euros/MWh and to avoid breaching this cap, the share of the TNUoS revenue target that is allocated to generation has fallen from 27% and is forecast to reduce to 10% in 2020-21.
- The locational element of the charge has fallen and this has resulted in more revenue recovered from the residual charge.

The graph below shows an estimate of how each of these factors is contributing to the rising triad charge. These estimates have been derived by holding each parameter constant at the 2010-11 value and updating each variable individually. The impact of the variables are inter-dependant as the impact of a lower demand peak will have a larger impact when allowed revenue is higher. These inter-dependencies have been shared equally between the peak demand and allowed revenue variables:

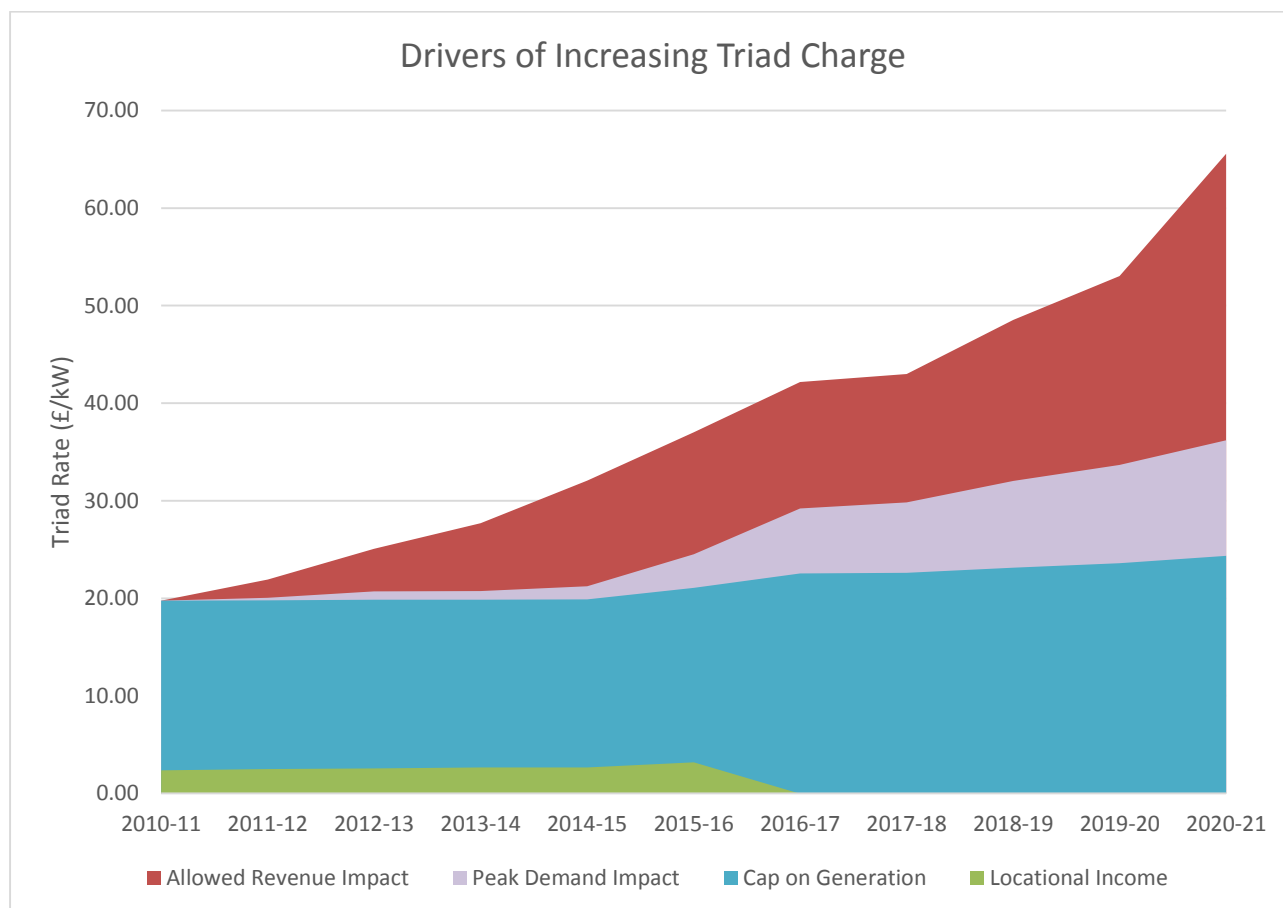


Figure 15: Breakdown of the drivers behind the increasing triad charge

The biggest driver behind the increasing triad charge is the allowed revenue. In National Grid's latest forecast of TNUoS the revenue target increases from £2,477m in 2014-15 to £3,790 in 2020-21. This increase can be broken down into the following main areas:

- Increase in base revenue (including MOD term and excluding RPI) accounts for £214m
- RPI accounts for £414m
- An increase in offshore transmission revenue accounts for £657m

The second largest driver of the increasing triad charge is the reduction in peak triad demand. When the other variables are held constant (and adjusted for 50% of the interdependency of allowed revenue), the average triad charge increases from £19.8/kW in 2010-11 to £36.2/kW in 2020-21.

The 2.50 euro/MWh cap on generation charges also impacts the level of the triad charge. From 2015-16 the allowed revenue reaches a level that risks breaching the cap and the percentage of the allowed revenue that is recovered from generation is reduced. This means that the share of the TNUoS revenue that is recovered from demand via the triad charge is increased to compensate. The current impact of this is £1.0/kW in 2015-16 and is estimated to rise to £4.6/kW in 2020-21.

The locational element of the charge has been stable between 2010-11 and 2015-16. In 2016-17, the average locational charge becomes slightly negative and is forecast to remain at close to zero until 2020-21.

7.3 Avoidable Cost of Transmission

7.3.1 National Grid Calculation of Avoided TNUoS

National Grid has undertaken a number of reviews of the level of avoided cost at transmission that can be attributed to embedded generators. In 2010, National Grid published a "pre-consultation" charging

methodology paper GB ECM-23 *Transmission Arrangements for Embedded Generation*¹³ which argued that the value of a cost-reflective benefit would be around £6.50-7.25/kW. This valued the avoided reinforcement cost due to embedded generators at between £5.00/kW and £5.75/kW with the additional value of £1.50/kW attributed to the avoided cost of connecting a generator directly to the transmission network.

The review of embedded benefits undertaken by National Grid in 2013 amended the calculation of the avoided reinforcement costs by removing the cost of the supergrid transformer and annuitised the infrastructure costs associated with demand reinforcement at a GSP. The cost of the supergrid transformer was removed from the avoided cost calculation as it tends to be fully contributed (ie paid for by the DNO) and is recovered from DNOs via transmission exit charges as outlined in section 5. This change reduced the estimated value of avoided reinforcement cost from between £5.00/kW and £5.75/kW to £1.58/kW in 2012-13 prices and £1.62/kW in 2013-14 prices. These values can be compared with the current level of TNUoS savings incurred by embedded generators which ranges from £23.47/kW to £46.24/kW in the current charging year (2015-16).

The £1.58/kW avoided cost of the embedded generation was determined across 18 schemes based on RIIO-T1 values and the summary of the results by scheme is shown below:

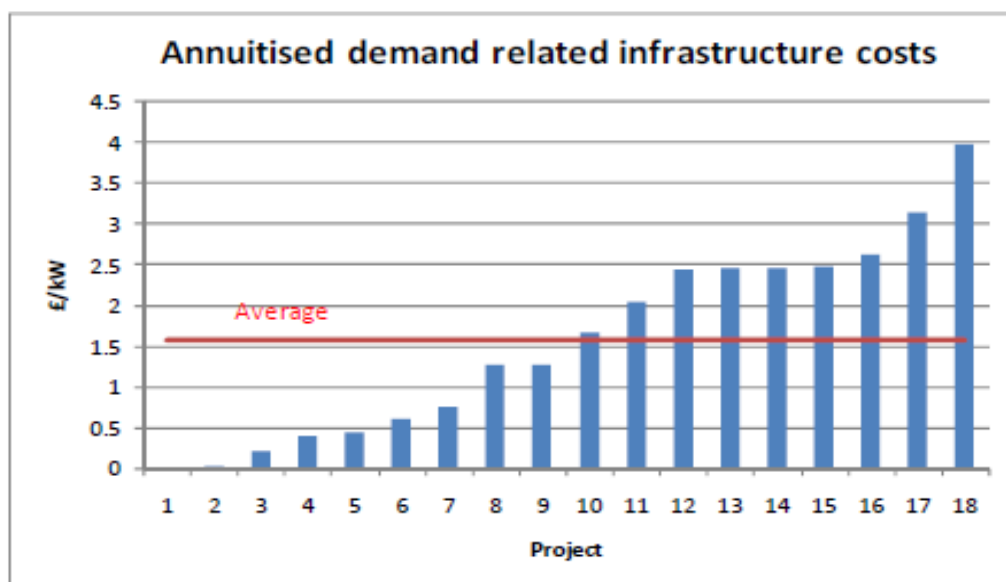


Figure 16: National Grid estimate of avoided infrastructure costs¹⁴

7.3.2 Unit Costs of National Grid Schemes

In 2012, the Energy Networks Strategy Group, which is jointly chaired by DECC and Ofgem commissioned a report¹⁵ on the potential strategic reinforcements required to facilitate connection of new generation to the GB transmission networks by 2020. This report examined the reinforcement needed to the transmission network across England, Scotland and Wales, estimated the cost and the additional generation capacity that would be accommodated for each scheme.

The schemes identified by the report can be used to determine the expected cost of future reinforcement across GB on a unit basis which provides a benchmark of the avoidable cost for embedded generation. The table below is a summary of the schemes and the capital cost estimates are on a 2008-09 price basis. The annuitised unit cost is derived across a 50 year depreciation period and an annuity factor of 5.8% as set

¹³ <http://www2.nationalgrid.com/WorkArea/DownloadAsset.aspx?id=29996>

¹⁴ GB ECM-25 Review of Intermittent Generation Charging:
<http://www2.nationalgrid.com/WorkArea/DownloadAsset.aspx?id=18776>

¹⁵ https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/48275/4264-ensg-summary.pdf

down in the National Grid April 2016 use of system charging statement¹⁶ and inflated by RPI to 2015-16 equivalent values

Region	Generation Accommodated (GW)	Estimated Cost	Annualised Unit Cost (£/kW)
Scotland	10.2	£2.5bn	18.3
Scotland-England	1.1	£3.56bn	241.1
North to Midlands and Midlands to South	3.7	-	-
North Wales	3.8	£1.12bn	22.0
Mid-Wales	0.36	£200m	41.4
South West	6	£450m	5.6
East Coast and East Anglia	10.8	£790m	5.4
London	3.3	£200m	4.5
Total (excl. North to Midlands & Midlands to South)	35.56	£8.82bn	18.5

Figure 17: Estimated cost of new transmission network. Annualised costs are on a 2015-16 price basis.

The schemes covered within the report show a large range in costs for the new schemes ranging from £4.5/kW to £241.1/kW. The average is £18.5/kW and this exceeds the estimate of the avoided reinforcement costs as calculated by National Grid but is less than the current level of avoided triad that embedded benefits currently receive.

The costs of the schemes in the table above are the capital costs of providing each scheme. They do not include any direct and indirect costs that may materialise across the life of the assets in terms of operation and maintenance costs or other costs. The costs also do not include the environmental impacts of growing the transmission network such as the impact on visual amenity. Consequently, the actual costs that are avoided by embedded generation will be higher than that stated in the table above. However, the estimated avoided cost of £18.5/kW is useful as providing a minimum avoided cost that can be assigned to embedded generation.

A further issue with the schemes assessed above is the degree to which the increase in capacity is likely to be beneficial to the system operator. The changing shape of the generation mix means that many of the new transmission connected generators are intermittent. The connection of intermittent generation at transmission requires infrastructure that enables the plant to operate at its full Transmission Entry Capacity (TEC). However, the actual output at time of peak for an intermittent generator is likely to be much lower than the TEC. This means that based on the schemes in the table above, the investment of £8.82bn to accommodate a maximum of 35.6GW, in reality only accommodates a smaller export capability at time of peak. The implication of this is that transmission companies continue to invest to connect generation, but are benefiting less from the investment. This point is illustrated in the table below which shows the value from investing £8.8bn to accommodate conventional generation compared to onshore and offshore wind generation:

¹⁶ <http://www2.nationalgrid.com/UK/Industry-information/System-charges/Electricity-transmission/Transmission-Network-Use-of-System-Charges/Statement-of-Use-of-System-Charges/>

	Conventional	Onshore Wind	Offshore Wind
Estimated Capital Cost (£bn)	8.82	8.82	8.82
Generation Accommodated (GW)	35.56	35.56	35.56
Forecast Availability at peak	90%	25%	35%
Useful Generation (GW)	32.00	8.89	12.45
Annuity Unit Cost of Investment (£/kW)	17.00	61.19	43.71

Figure 18: Unit cost of new transmission network to connect intermittent generation

This table demonstrates that the unit cost of adding new network is not just dependant on the capital cost of the scheme, but also the type of generation that is connected.

A further assessment of the reinforcement costs that are avoided by embedded generation can be derived from the depreciation costs of the transmission companies. The triad charge is set to recover the allowed revenue which incorporates the depreciation of the transmission companies existing assets and the estimated future reinforcement costs identified above can be compared to the historical depreciation costs within the allowed revenue as a reasonableness check. The table below shows the depreciation in the Regulatory Asset Value (RAV) taken from the final proposals under the RIIO-ET1 price control in nominal terms.

	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
NG Dprn	£658	£701	£743	£796	£836	£870	£891	£907
SP Dprn	£94	£105	£118	£134	£140	£144	£146	£150
SHydro Dprn	£50	£53	£69	£98	£121	£133	£139	£142
Total Dprn (£m)	£802	£859	£929	£1,029	£1,098	£1,147	£1,176	£1,200
Triad Demand (MW)	56,000	55,300	52,400	49,800	49,298	48,229	47,603	47,297
Dprn (£/kW)	£14.32	£15.54	£17.73	£20.66	£22.26	£23.78	£24.70	£25.36

Figure 19: Depreciation by transmission company (nominal)

The value of the schemes derived by the Energy Networks Strategy Group (£18.5/kW in 2015-16 price basis) align with the values as calculated by the depreciation of the RAV across the three transmission companies. On this basis the assumption within the triad that historical depreciation is representative of future reinforcement looks reasonable. This suggests that the depreciation element of the triad benefit is reflective of the avoided costs of embedded generation.

7.3.3 Other Demand Related Costs

The historical reinforcement costs estimated in the previous section is one element of the TNUoS allowed revenue that is recovered via the triad charge and our analysis shows that the historical depreciation is in line with our estimate of future reinforcement.

The allowed revenue includes a number of other items in addition to depreciation and we have reviewed these to determine whether they are demand related costs and therefore whether it is reasonable to recover these costs from a demand based charge such as the triad charge. Each element of the allowed revenue has been classified under one of the following categories:

- Short-term demand related costs: Costs which are likely to vary with the general level of demand in the short term (classified as 1-5 years).
- Long-term demand related costs: Costs that are likely to vary with the general level of demand in the long term (classified as 5-15 years).
- Non demand related costs: Costs that are likely to be incurred regardless of the level of demand.

The table below shows an estimate of the level of these costs for 2015-16. These values have been derived from the RIIO-ETI final proposal for the transmission companies and the breakdown of the TNUoS target revenue as published by National Grid. It should be noted that a number of assumptions have been used to derive these values and they should be treated as illustrative. A breakdown of these values is contained in Appendix D:

	Short-Term Demand Related	Long Term Demand Related	Non-Demand Related
Total Revenue	£189.3	£2,002.5	£303.5
TNUoS Revenue allocated to Demand (73%)	£138.2	£1,461.8	£221.6
2015-15 Triad Demand (MW)	48,726	48,726	48,726
Estimated Charge (£/kW)	2.84	30.00	4.55

Figure 20: Estimate of 2015-16 TNUoS demand revenues categorised by the degree to which they vary with demand

The majority of the costs can be categorised as demand related over the long term and of this element, just over half relates to depreciation. The other significant components of cost within this category are:

- Return
- Offshore transmission costs
- Business Rates
- Tax Allowance

These costs could be considered as fixed in the short term and therefore sunk costs. However, over a longer term horizon, they will vary with the level of infrastructure in place which depends upon the long term level of demand. The decision to invest in embedded generation is a long term one and the costs avoided by embedded generation should therefore cover the longer term cost of the transmission network not just short term costs. This analysis suggests that it is appropriate to continue to recover the majority of the TNUoS revenue target from a demand based charge such as the triad.

The elements that should not be recovered from a demand related charge are those costs identified as non-demand related in the table above. This includes indirect costs, incentive payments and the Network Innovation Competition/ Allowance (NIC/ NIA). The analysis suggests that approximately £304m of the TNUoS revenue target in 2015-16 is not demand related but is being recovered through a demand related triad charge. These costs are not avoided by embedded generation but the current structure of TNUoS charges enables distribution connected generators to avoid these costs through triad avoidance. These elements will also overstate the cost signal to demand customers as dropping demand in the triad period will not influence the level of these costs.

The avoidable cost of embedded generation applies equally to storage as to other types of generation. Storage is likely to export at times of peak demand and contribute to reducing the national demand peak thereby reducing the need for expenditure at transmission level. However, storage is only available for a limited time each day due to its capacity which is limited by its charge. Consequently, the price signal needs to be cost reflective and targeted at those half hours which are driving costs to ensure the maximum value is extracted from the ability of storage to export for short periods.

Conclusions

The cost of the National Grid planned future investments average out at £18.5/kW in 2015-16 prices which is higher than the estimated avoided cost of embedded generation put forward by National Grid and in line with the current level of depreciation that forms part of the triad charge. This represents an estimate of the

minimum avoidable cost of embedded generation as it equates to the capital cost of these schemes and does not include additional ongoing costs such as operations and maintenance.

The remaining demand related costs should not be considered as sunk even though they do not vary with demand in the short term. Investment decisions to build embedded generation are made over the long term and they avoid longer term demand related transmission costs as well as short term. It is therefore appropriate for embedded generation to benefit from offsetting these long term costs.

Some components of the TNUoS allowed revenue do not vary with demand and should therefore not be recovered from a demand based charge such as the triad. We estimate the impact of recovering indirect costs via the triad is currently overstating the avoided costs of embedded generation by around £4.6/kW per annum.

Some of the proposed future investment in transmission infrastructure is to enable intermittent generation to connect which does not bring the same level of system security as conventional plant, and the unit cost of the infrastructure is much higher when this is taken into account. Embedded generation reduce the need for transmission connected generation and its associated infrastructure and therefore the generation mix of new transmission connected generation should be included when assessing the avoidable cost of embedded generation.

7.3.4 Long Term Avoidable Costs of the Transmission Network

The current charging methodology for demand TNUoS recovers the long and short term costs of the transmission network which are set down in the RIIO-T1 prices control allowed revenues. These costs represent all elements of building and operating the transmission network and the triad calculation divides the annuitised costs by the peak triad demands in each year to determine the annual triad rate. The triad demand has been consistently decreasing year on year and is one of the drivers behind the increasing triad rate. The graph below shows how the triad demand has changed since 2007 and includes National Grid's forecast from 2016-17 onwards:

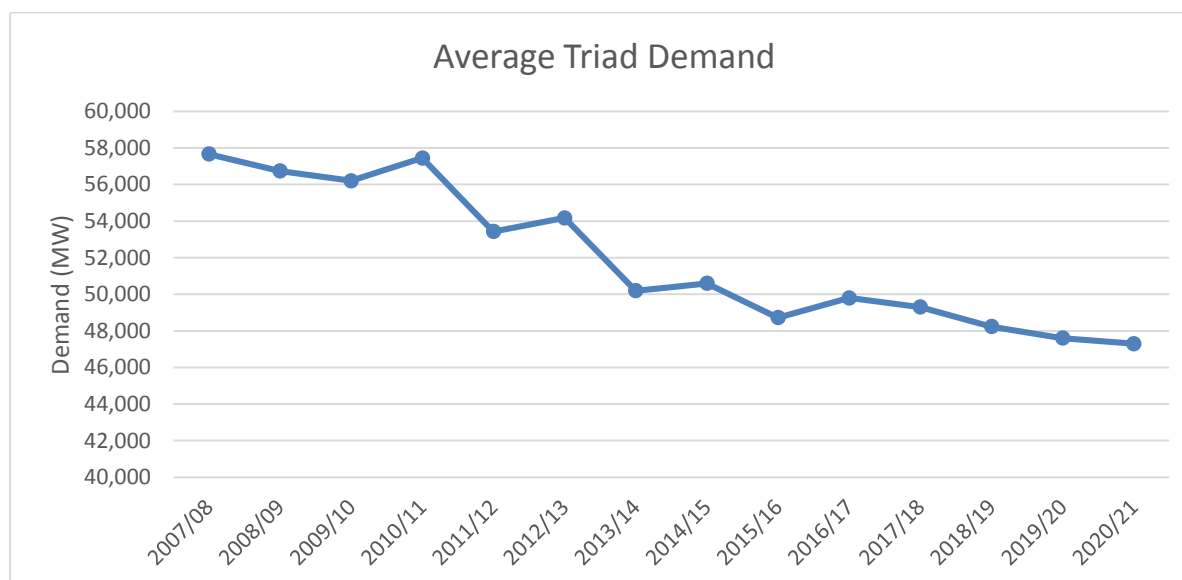


Figure 21: Historical and forecast average triad demand

This graph shows the degree to which the triad demand has decreased since 2007. It has reduced from 57.7GW in 2007-08 to 48.7GW in 2015-16 which equates to a drop of 9.0GW or 15.6%.

The triad benefit for embedded generators reflects the demand TNUoS savings achieved by exporting during the triad period. To provide embedded generation with the correct economic signal from an operational perspective and when making decisions on where a generation should connect, the triad benefit should approximate to the costs avoided on the transmission due to the embedded generation. However,

the triad benefit is not a good proxy for assessing the avoided cost of embedded generation for two reasons:

- Firstly, the triad is recovering the long term costs of setting up and operating the transmission system over a one year demand peak. This difference in timeframes between the long term costs that factor into the annuitised allowed revenue and the short term peak over which the cost is recovered distorts the cost reflectiveness of the price signal.
- Secondly, the use of maximum demand to determine the triad price does not reflect the capability of the network which exists and for which the allowed revenue has been set.

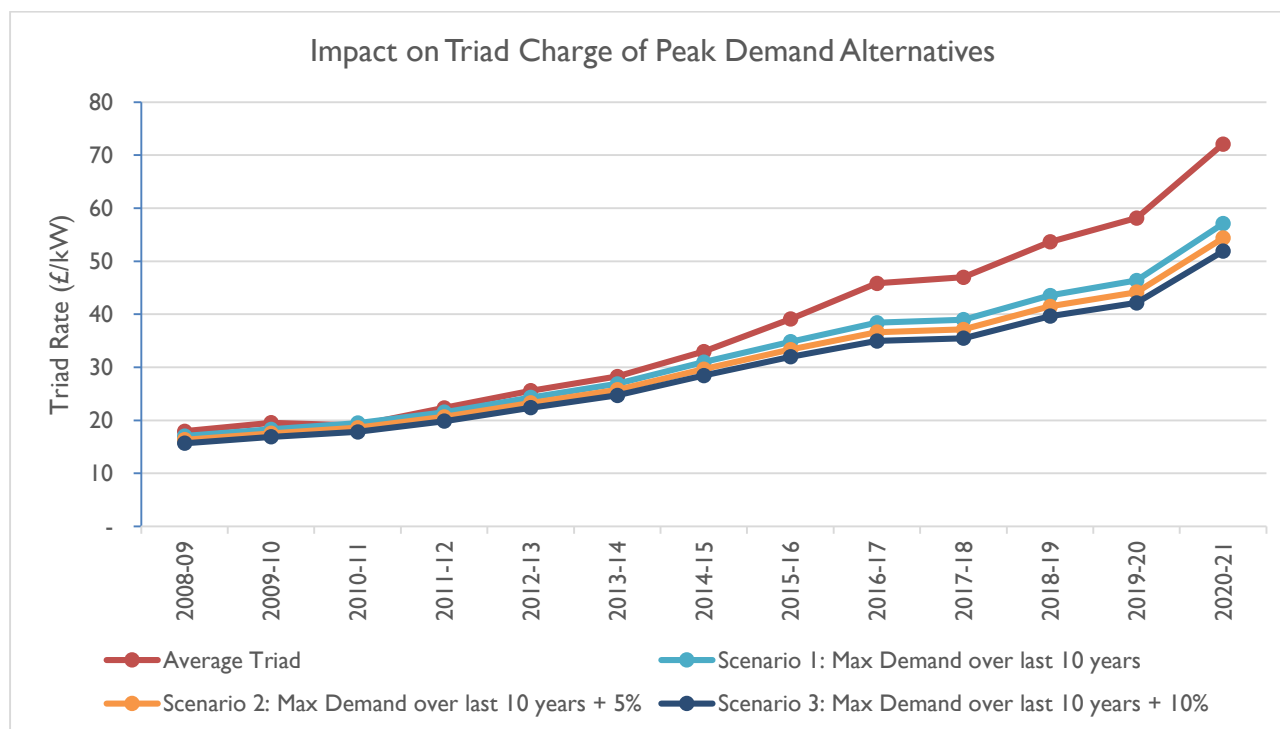
To assess the impact of these issues, Cornwall Energy has adapted the current triad calculation to reflect how distributors assess their networks. The DNOs use the 500MW model (as detailed in section 5) to determine the unit rate that is used to derive yardstick charges. The 500MW model is a fully utilised network model and is forward looking as it is based on current design standards. The benefits of using a fully utilised model from a charging perspective is that it reflects the most efficient design of a future network. This approach therefore provides a good indicator of the costs avoided by embedded generators.

When the DNO approach is compared to the triad charge calculation, the triad charge is determined based on an under-utilised network. This is apparent as peak demand has fallen (as shown in the graph above) which implies that spare capacity has been released on the transmission network. In addition, the transmission network needs to be capable of delivering more than the historical maximum demand, to take account of extreme weather scenarios. Consequently, we have replicated the triad calculation, but replaced the peak demand with a more long term measure of the capability of the network. This has been achieved by creating three scenarios where the triad charge is determined based on the maximum half hourly demand over the last ten years and then inflated by 5% and 10% to reflect any additional spare capacity within the network as follows:

- Maximum demand over the last ten years
- Maximum demand over the last ten years + 5%
- Maximum demand over the last ten years + 10%

These scenarios are more stable measures than the one year triad peak and have been selected to represent the capacity of the network. This means that the long and short term costs of building and operating the transmission system are divided by the capacity of the network which represents the long term capability of the network rather than the short term demand. An adjusted triad charge calculated based on network capacity aligns the long term revenues with the long term capacity of the network and therefore provides a more effective estimate of the avoided costs of embedded generation.

The graph below shows the average triad charge based on the existing calculation of peak demand plus the alternative calculation based on the three scenarios. The rate increases over time in line with the allowed revenue of the transmission companies as derived under the RIIO price controls.



Triad calculation based on three scenarios for measuring network capacity

This methodology calculates the avoidable cost of embedded generation at between £35.0/kW and £38.4/kW in 2016-17. This is approximately £9.2/kW below the 2016-17 triad charge and correlated embedded benefit which embedded generation can expect to achieve in the same year. The methodology used within this section is an illustrative methodology to demonstrate the level of embedded benefit for a different triad calculation. It would result in a shortfall in recovering the allowed revenue for National Grid which would need to be recovered via an alternative charge such as a volume or customer based charge.

Conclusions

The current level of TNUoS charge, and therefore the correlated triad benefit is overstated due to the misalignment of long term costs being recovered over short terms demand. Cornwall Energy has estimated the impact of this using three scenarios that better represent the long term capacity of the transmission network. The estimated avoided cost of avoided demand and embedded generation using this methodology is approximately £10/kW lower than the current level of the triad charge and correlated benefit.

7.4 Overall Level of Triad Charge

This section has looked at the triad charge from a number of perspectives. It has reviewed the level of reinforcement costs and the different components that make up the TNUoS demand revenue target and the appropriateness of the triad calculation. Our overall conclusion is that the triad benefit overstates the value of the avoided costs of embedded generation in two key areas as follows:

- The calculation of the triad charge recovers long term cost over a short term demand peak.
- The TNUoS allowed revenue contains some elements of costs which are not demand related and therefore overstate the value of the triad charge.

The table below summarises our conclusions on the overall level of the triad charge for 2016-17 and reconciles our assessment of the avoided costs of embedded generation with the triad charge:

	2016-17 (£/kW)	Comment
Reinforcement costs	18.5	Based on 8 schemes in the Energy Networks Strategy Group report (2015-16 values)
Demand related costs	13.8	Other costs that vary with demand such as direct costs, return, non-controllable opex, tax allowances.
Total	32.3	Our assessment of avoided costs
Non-Demand related costs	4.4	Propose to recover on a unit or customer basis
Maximum Demand as denominator	9.2	Alternative calculation of triad charge
Published Triad Charge	45.8	Weighted Average charge

Figure 22: Reconciliation of assessed avoidable cost and triad charge in 2016-17

Conclusions

This table, based on our analysis contained in the previous sections of this report, indicates that a reasonable level for the triad charge and correlated embedded triad benefit in 2016-17 would be in the region of £32.3/kW. The difference between this value and the published triad charge of £45.8kW leads to a revenue shortfall at transmission where the allowed revenue still needs to be recovered. However, this additional revenue is not demand related and our view is that it should not be recovered via a demand related charge such as the triad, but socialised and recovered on a volume basis.

8 Distribution Charges

8.1 Overview

Distribution Use of System (DUoS) charges are calculated using a national methodology that is set down in the Distribution and Connection Use of System Agreement (DCUSA). The national methodology is split into two areas as follows:

- Common Distribution Charging Methodology (CDCM) – The CDCM is used to set tariffs for all customers that connect at Low Voltage (LV) and High Voltage (HV).
- Extra high voltage Distribution Charging Methodology (EDCM) – The EDCM is used to calculate prices for all customers that connect at Extra High Voltage (EHV), including those customers who connect directly to a primary substation (sometimes referred to as High Voltage Substation (HVS) customers)

The CDCM methodology applies to the majority of customers and socialises DNO costs by calculating average tariffs that apply to different groups of customers. This is a different approach to the EDCM which calculates site specific tariffs for all EHV customers which vary depending on location.

8.2 CDCM

The CDCM is a forward looking methodology that calculates charges to demand customers and credits to all generation and exporting storage customers. Generation receives a credit to recognise that their export is offsetting demand and reducing the need for reinforcement on the DNO's network.

8.2.1 Generation Charges

Generation credits are calculated as a negative demand charge. They mirror the demand charge calculation with two exceptions.

- Firstly, the demand charge which is split by voltage level, is only applied as a credit for generation at voltage levels above the level of connection. This general principle was agreed when the CDCM was developed and was justified as the benefit of reduced reinforcement was perceived to be higher up the network.
- Secondly, demand tariffs do not recover the total allowed revenue that each DNO is allowed to recover under its price control. To make up for this shortfall (or surplus) scaling is applied to the charges to ensure the DNO recovers the correct revenue. This scaling element is generally positive for most DNOs, although one DNO tends to have negative scaling. The scaling element can be significant at times and is only applied to demand tariffs. This means that generation credits do not reflect this element of the demand charge.

These two issues suppress the level of credits awarded to embedded generation, notwithstanding the negative scaling in one DNO area which would reduce the credit if factored into generation charges. The application of scaling on generation was flagged up by Ofgem as an area for further development¹⁷ for DNOs to consider in more depth as part of the approval of the CDCM methodology. DNOs justified that scaling should not apply as it would distort the cost signal for generators and this was accepted by Ofgem at the time.

8.2.2 Intermittency in the CDCM

The CDCM differentiates between generation customers based on whether they are classified as intermittent or non-intermittent. Non-intermittent generators receive a credit based on their export in the red, amber and green timebands which vary by DNO. Intermittent sites receive a single unit rate credit as

¹⁷ [https://www.ofgem.gov.uk/sites/default/files/docs/2009/11/cdcm-decision-doc-201109-\(2\).pdf](https://www.ofgem.gov.uk/sites/default/files/docs/2009/11/cdcm-decision-doc-201109-(2).pdf)

they are unable to change their generation profile in response to price signals. The CDCM definition for intermittency is based on whether the fuel source can be relied upon. The current status of storage within the CDCM is not defined, but indications from DNOs are that export from storage will be treated as non-intermittent within the CDCM.

The different tariff structure for intermittent and non-intermittent generation within the CDCM impacts the cost reflectivity of the CDCM credits. For intermittent generation, a single rate credit values each half hour equally, whereas export at time of peak is more useful than export during off-peak periods.

This issue has a parallel with demand tariffs where customers are charged on either a single rate, two rate or three rate tariff. A new DCUSA change proposal (DCP 268¹⁸) proposes that all demand and generation customers should be settled on the three rate tariff, which is normally just used for half hourly tariffs. The justification for this change is that it increases cost reflectivity as the unit rate is set based on the cost to the network operator within each timeband and this should be applied irrespective of whether the demand customer is settled on a non-half hourly profile or on half hourly metered data.

Conclusion

Although an intermittent generator is unable to vary its output in response to price signals, it is appropriate to reward all generation based on the degree to which it offsets costs incurred by the network operator. Consequently, all generation, whether intermittent or non-intermittent, should receive credits that are based on the time of export and therefore reflect the degree to which they are assisting the network operator in reducing peak demand. It is not appropriate to award all intermittent generation a single rate credit and a more cost reflective approach would be to apply credits to all intermittent generators based on the red, amber and green timebands.

8.2.3 Generation Dominated Areas

Within the CDCM, all generators receive a credit regardless of where they connect or the nature of their local network. In some areas where a large number of generators connect and the level of demand is low, the export can drive reinforcement on the DNOs network. However, as the CDCM is an average methodology these generators will be receiving a credit in spite of the fact that they are causing additional costs that are picked up by demand customers.

This issue was identified by Ofgem who made it a condition that DNOs look into this area as a condition of the acceptance of the CDCM methodology¹⁹. The DNOs subsequently put forward a paper on this subject that was rejected by Ofgem who wanted a more detailed analysis. Consequently, the DNOs recruited Frontier to look into this issue who put a report together that was submitted to Ofgem. In tandem with this, the DNOs brought forward a change proposal (DCUSA change proposal 137²⁰) that sought to reduce or remove credits to generators where they were located in parts of the network defined as generation dominated.

The resultant change report that was submitted to Ofgem for approval proposed that credits would be reduced gradually as areas of the network became more generation dominated. The assessment of whether the network was generation dominated was undertaken by performing a number of tests on each primary substation. If the primary substation was deemed to be generation dominated or likely to become generation dominated, the credits would be reduced or removed for all HV connected generators depending on the degree to which the primary was judged to be generation dominated.

¹⁸ [DCUSA Change Proposal DCP268 - DUoS Charging Using HH settlement data](#)

¹⁹ [https://www.ofgem.gov.uk/sites/default/files/docs/2009/11/cdcm-decision-doc-201109-\(2\).pdf](https://www.ofgem.gov.uk/sites/default/files/docs/2009/11/cdcm-decision-doc-201109-(2).pdf)

²⁰ [DCUSA Change Proposal DCP137 - Introduction of locational tariffs for the export from HV generators in areas identified as generation dominated](#)

Ofgem rejected this change proposal in February 2015 citing “concern about the impact that the proposed change may have on further growth of renewable generation, and the balance between generation and demand growth, on distribution networks”.

Since the implementation of the CDCM in 2010, there has been a substantial increase in the amount of embedded generation connecting to the distribution networks. In many areas the capacity to connect new generation has not been available, but DNOs have developed innovative ways to enable the generation to connect without incurring reinforcement through active network management techniques and managed connections. As a consequence, a significant amount of generation has been connected without leading to the additional reinforcement that was envisaged when the generation dominated areas issue was first looked at.

Conclusion

In principle, generators connected to areas of the distribution network that are considered to be generation dominated, should not receive credits from DNOs if they are the main driver of future reinforcement costs. However, with hindsight, the issue of generator dominated areas has not led to the increase in reinforcement costs for DNOs that was originally envisaged and the development of managed connections and active network management has reduced the need for a solution to generation dominated areas. We anticipate that this has delayed the issue rather than removed it and expect generation dominated areas to return as an issue if more embedded generation continues to connect.

8.3 Cost Reflectiveness of CDCM Credits

The CDCM contains a number of data items that can be used to test the reasonableness of credits received by LV and HV generation. The relevant items are:

- The 500MW values – the £/kW cost of building new network
- Volume forecast for each generation tariff
- The total credits expected to be given by DNOs for each tariff.

This data has been modelled to create a benchmark level of avoided reinforcement costs that can be attributed to embedded generation and then compared with the actual level of credits received.

8.3.1 Reinforcement Costs using 500MW Model

One of the key building blocks of the CDCM model is the “500MW model”²¹. This model determines the assets necessary for the DNO to add a 500MW increment to their existing network. It is a hypothetical model that uses current design policies to create a forward looking cost of creating a network capable of meeting a 500MW peak. The model output is the gross modern equivalent asset value at each voltage level necessary to meet the 500MW peak.

The 500MW model provides a benchmark cost of building a new network for each DNO. This cost is turned into a £/kW value by adjusting the gross asset values by the 500MW peak and adjusting for losses and diversity.

The benefit of embedded generation connecting to a distribution network is the saving in reinforcement costs for the DNO as a result of the generation offsetting the demand. This report has used the benchmark 500MW values, converted into a £/kW value to determine whether the generation credits calculated under the CDCM are reasonable or whether there is a tendency to under or overvalue the credits within the CDCM.

A summary of the £/kW values of building new network across the DNOs is provided in the table below:

²¹ Also be referred to as the Distribution Reinforcement Model (DRM)

Voltage Level	Average	Max	Min
Assets 132kV	11.97	29.30	4.91
Assets 132kV/EHV	2.43	4.05	1.38
Assets EHV	8.76	14.18	3.96
Assets EHV/HV	4.26	7.96	2.10
Assets HV	16.58	25.10	11.85
Assets HV/LV	7.44	11.31	3.35
Assets LV circuits	11.72	18.50	5.01
Total	63.17		

Figure 23: Average 500MW Model values (£/kW/year) across DNOs in 2016-17

8.3.2 Converting Generation Credits into £/kW

The first step in assessing the level of credits awarded to LV and HV embedded generators is to use the CDCM data to convert the tariffs from unit based to capacity based, to enable comparisons with the benchmark reinforcement costs within the 500MW model. To achieve this a load factor is assumed for each tariff based on whether the generation is intermittent (23%)²² or non-intermittent (63%)²³ and the peak export is calculated from this. A further adjustment is made to the peak export to reflect coincidence with peak demand by applying a 51%²⁴ reduction for intermittent generation and 10%²⁵ reduction for non-intermittent generation to reflect that some of the generation will not be available during the winter peak (such as solar for intermittent generation). The table below shows a summary of the peak export across the DNOs for each tariff:

Tariff	Total	Average	Max	Min
LV Intermittent	145.0	10.4	51.9	1.1
LV - Non Intermittent	21.1	1.5	9.2	0.2
LVS Intermittent	5.0	0.4	2.6	0.0
LVS - Non Intermittent	3.6	0.3	1.6	-
HV Intermittent	872.6	62.3	135.0	0.3
HV - Non Intermittent	940.9	67.2	179.4	13.5
Total	1,988.2			

Figure 24: Assumed peak export (MW) within CDCM by tariff

8.3.3 CDCM Total Credits

The second step in the modelling is to extract the level of credit awarded to each tariff group and divide it by the assumed peak demand calculated in the previous step. This converts the credits to a £/kW capacity based charge that can be compared to the reinforcement costs derived from the 500MW model.

²² Average of load factors for onshore wind published by National Grid ([Draft Annual Load Factors - 2014-15](#)) and solar as published by DECC ([FITs quarterly and annual load factors](#))

²³ Load Factor for CCGT and CHP as published by National Grid ([Draft Annual Load Factors - 2014-15](#))

²⁴ Estimated based on ratio of solar to wind capacity published in DUKES ([Plant Installed Capacity, by connection: UK -DUKES 5.12](#))

²⁵ Set at the de-rating value for CHP and CCGT in the Capacity Market Auction as published by National Grid ([Capacity Market Auction Guidelines](#))

	GDUoS Income (£)	Peak (kW)	Credit (£/kW)
LV Intermittent	-£5,395,618	145.0	-£22
LV - Non Intermittent	-£1,221,732	21.1	-£58
LVS Intermittent	-£150,134	5.0	-£18
LVS - Non Intermittent	-£185,739	3.6	-£52
HV Intermittent	-£15,964,407	872.6	-£11
HV - Non Intermittent	-£26,214,491	940.9	-£28
Total	-£49,132,120	1,988.2	

Figure 25: CDCM generation credits by tariff

This analysis indicates that DNOs are paying c£49m in 2016-17 to embedded LV and HV connected embedded generation which is reducing peak demand by around 2.0GW.

8.3.4 Recovery of Supergrid transformer costs

The supergrid transformer costs do not form part of TNUoS, but are paid for by DNOs through their transmission exit charges. Exit charges are recovered from customers through DUoS. Each DNO forecasts the exit charges that will apply in the charging year and the CDCM methodology divides this value by the forecast system simultaneous maximum load to create a £/kW value that is used within the tariff calculation. This is normally in the region of between £2/kW and £5/kW.

To confirm the level of embedded benefits awarded, Cornwall Energy has calculated the annuitised cost of a £15m installed 240MW supergrid transformer at £3.25/kW based on a 4.2% cost of capital and 40 year asset life which is consistent with the values used by DNOs in the CDCM. This value is added into the benchmark reinforcement savings used by Cornwall Energy to assess the level of DUoS credits awarded to embedded generation.

8.3.5 Benchmark credits vs Credits Awarded

The level of credits awarded under the CDCM when compared to the benchmark values calculated from the CDCM 500MW model and including the cost of the supergrid transformers which is passed on to DNOs from National Grid through exit charges is shown below. The graph shows the difference between the benchmark values less the actual level of credits awarded by DNO for 2016-17. A positive value means the benchmark level is higher than the actual level of credits awarded.

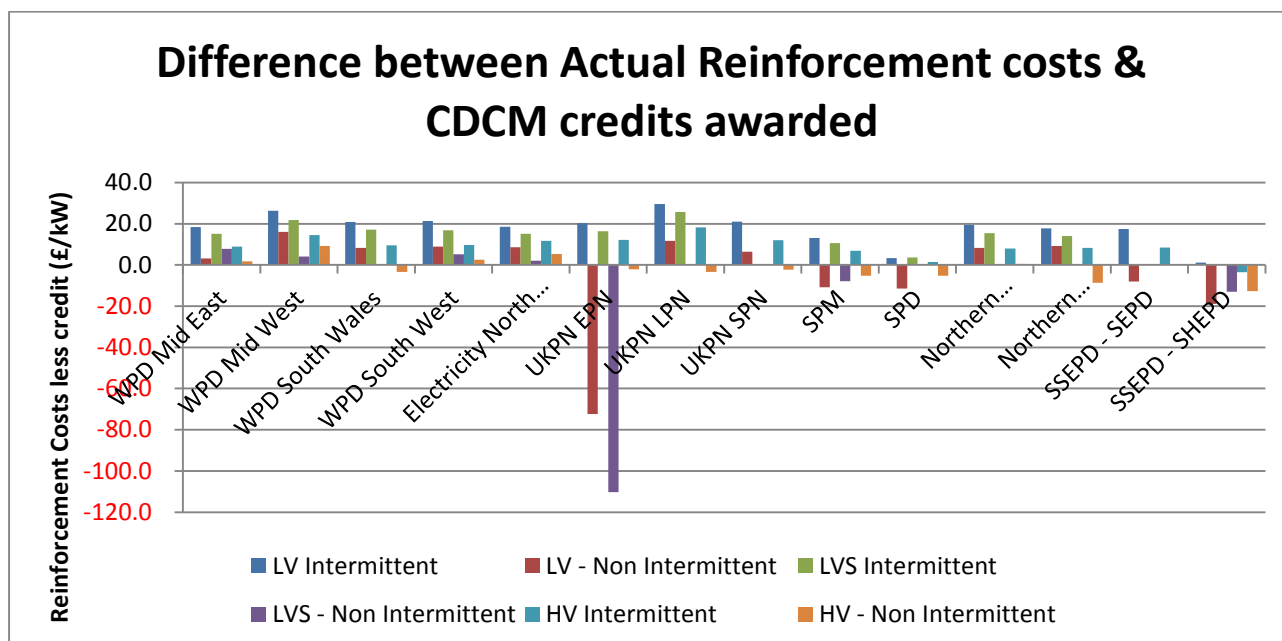


Figure 26: Actual CDCM credits in 2016-17 compared to benchmark costs (derived from 500MW model plus SGT costs)

The graph above shows a number of outliers for the UKPN Eastern network area. These values occur as the modelling uses a standard load factor for all non-intermittent generation. In some network areas there are only a small number of generators and if their load factor differs significantly from the modelling assumption, the resultant estimated peak will also be significantly different. However when the data is assessed across a range of DNOs and a large number of generators the use of standard load factor assumptions is appropriate.

The analysis has been replicated for the last three years to determine if there is a bias to the level of credits awarded. The table below is a summary of the average level of difference between the benchmark and actual credits awarded. A positive value represents a surplus (ie the benchmark is higher than the actual credits awarded):

	2014/15 (£/kW)	2015/16 (£/kW)	2016/17 (£/kW)	Average Annual Volume (MWh)
LV Intermittent	24.0	23.7	17.7	31,279
LV - Non Intermittent	1.3	-0.5	-2.9	8,136
LVS Intermittent	17.9	19.3	14.3	983
LVS - Non Intermittent	-20.6	-5.6	-16.0	1,037
HV Intermittent	12.7	12.1	9.0	205,776
HV - Non Intermittent	2.1	0.1	-1.7	398,962
Weighted Average	6.5	5.1	2.6	

Figure 27: Actual CDCM credits compared to benchmark credits averaged across all DNOs.

The results from the analysis show that over the last three years, the average level of credits received by embedded generators is less than the avoided costs when assessed using the 500MW model benchmark values. It should be noted that some of the tariffs assessed, particularly the Low Voltage Substation (LVS) tariffs, only have a small number of customers and this has been taken account of by calculating a volume weighted average to determine the overall impact. The analysis is reliant on a number of assumptions, but a prudent approach has been adopted to avoid over-stating the level of peak export for the embedded generation,

Conclusion

The analysis suggests that the CDCM is awarding an appropriate level of credits, with a bias towards undervaluing rather than overvaluing the benefit.

8.3.6 Credits at the voltage of connection

Within the CDCM, credits are awarded for offsetting demand at voltage levels above the voltage level of connection. This principle was established by Ofgem in their October 2008 decision document which stated “*The network is assumed to be demand dominated. Credit will be provided for offsetting demand on the distribution network above the voltage of connection.*”²⁶ This was justified as generators are deemed to “*impose a net benefit on DNOs networks by diverting upstream power flows and contributing to system security*”²⁷.

The benefit of embedded generation in terms of offsetting DNO reinforcement was perceived to be at higher voltage levels where the demand and generation net off. However, in a demand dominated network, the export from a generator offsets demand once the export enters the shared use network and combines with the normal flow of electricity to demand users. Whether this results in a saving to the DNO is dependent on the degree to which the DNO can rely on the generator exporting at time of peak and therefore offsetting the demand which is driving reinforcement. At higher voltage levels demand is deemed to be offset by a diverse portfolio of generation and therefore the application of credits is appropriate.

At the voltage of connection, the diverse portfolio of generation does not exist, so individual generation does not receive a credit based on its voltage of connection. However, non-intermittent can be relied on to export at time of peak and have every incentive to do so. These non-intermittent generators are bringing a benefit to the DNO as soon as their export combines with demand at the same level of connection. The offsetting nature of the export releases capacity on the existing network which can be used by other demand users and this creates an opportunity cost saving to the DNO who may have needed to reinforce the network to accommodate any increase in demand. As storage looks likely to be treated as non-intermittent within the CDCM, any amendment to apply credits at the voltage of connection would also apply to storage.

The potential impact of extending the calculation of generation credits to include benefits attributed at the voltage of connection for non-intermittent generation can be determined from the benchmark 500MW values set down in figure 9 above. On average across the DNOs factoring in the costs offset by the generator at the voltage of connection would result in an additional credit of between £7.44 and £16.58/kW.

Conclusion

The principle of awarding credits to generators for the demand that is offset at voltage levels above the level of connection was set down in an Ofgem decision document in 2008. This principle may be appropriate for intermittent generation, but non-intermittent generation that can be relied on to export at peak should also benefit from the capacity that they create for DNOs at the voltage of connection. The application of credits in this area should be re-looked at by the industry.

8.4 EDCM

The EDCM is a site specific charging methodology that calculates individual prices for each customer that is connected at EHV. This methodology only applies to the largest customers in GB and accounts for around 2,500 customers.

²⁶ https://www.ofgem.gov.uk/sites/default/files/docs/2008/10/decision-document-1-october-2008_0.pdf

²⁷ As above

8.4.1 Calculation of Locational Charges under the EDCM

The EDCM is a forward looking methodology and uses both future reinforcement and existing assets to determine the price for each customer. Under the EDCM, the DNOs are able to choose between two methodologies, Long Run Incremental Cost approach (LRIC) or Forward Cost Pricing (FCP) to determine the locational costs. DNOs use a powerflow model of their EHV network and inflate demand to determine the increased cost of bring forward future reinforcement or use a forecast of future demand growth depending on which methodology they adopt.

The LRIC or FCP methodology will calculate a price for each location on the EHV network. As a general rule, the more congested the network is at a location, the higher the demand charge that will result.

The EDCM methodology also uses Network Use Factors (NUFs) to allocate a range of costs and these are based on the actual assets used by the customer in connecting to the transmission network.

8.4.2 Generation credits under the EDCM

Under the EDCM, the criteria for applying credits refers to an “f factor” which is defined within engineering recommendation P2/6. The “f factor” is a measure of the degree to which a network operator can rely on a generator to be exporting for planning purposes. The result of this is that intermittent generation does not receive a credit within the EDCM. This is a different approach to National Grid, where all embedded generators receive a credit if exporting during the Triad periods. It should be highlighted that the EDCM is also different to the CDCM which provides intermittent generation with a credit regardless of when they generate through the single rate approach described earlier.

Non-intermittent generation is entitled to a credit within the EDCM and this is calculated as the reverse of the locational charge at voltage levels above the level of connection. This principle mirrors the CDCM approach. However, the EDCM credit is only based on the locational element of the demand charge as determined by the powerflow analysis and does not account for any other elements.

8.4.3 Intermittent Generation within the EDCM

The most recent decision regarding credits for intermittent generation was reached by Ofgem as part of their decision to approve the EDCM for generation in November 2012²⁸ which placed a condition on DNOs to remove credits for intermittent generators from the methodology. The rationale for this was that engineering recommendation P2/6 does not allow for intermittent generation to be relied upon for planning purposes by DNOs and consequently it does not offset reinforcement and save costs for the DNO. However, Ofgem acknowledged that intermittent generation may assist network operators in deferring the need for reinforcement at higher voltage levels but stated that credits can only be provided if engineering recommendation P2/6 is amended to allow DNOs to rely on the intermittent generation. The DNOs are currently reviewing Engineering Recommendation P2/6 and this review is being led by Electricity North West²⁹.

It should be noted that under the EDCM, storage is treated as intermittent generation and consequently does not receive a credit for any export. This is because of the different criteria that is applied within the CDCM and EDCM in determining whether credits should be applied.

Conclusions

Although an individual intermittent generator cannot be relied upon to export at times of peak demand, a network operator can expect that across a large portfolio of diverse intermittent generators in a variety of locations, there is likely to be some export at time of peak. Therefore it is appropriate that intermittent generation should be entitled to a credit that reflects this likelihood. The review of engineering recommendation P2/6 should provide further details in this regard.

²⁸ https://www.ofgem.gov.uk/sites/default/files/docs/2012/11/edcm-for-export---decision-letter---16nov12---final_0.pdf

²⁹ <http://www.enwl.co.uk/about-us/the-future/lcnf-tier-1-nia/nia#section12>

9 Other Embedded Benefits

9.1 Network Losses

9.1.1 Transmission losses

Transmission losses represents the difference between units entering and leaving the system. Embedded generators do not use the transmission network and therefore do not directly create losses. However, embedded generation impacts on the consumption at GSPs and therefore indirectly effects the flow of electricity and losses on the transmission network.

In some circumstances the connection of an embedded generator can increase or decrease the level of losses for transmission users. Currently, the flow of electricity across the transmission network is north to south as most generation is connected in the north of GB and most of the demand is further south. In Scotland, in particular there are a number of larger generators who produce too much power to be absorbed locally and it needs to be transported across the country. The result is much higher transmission losses applicable to those generators in the north of the country. This can be seen in the graph below:

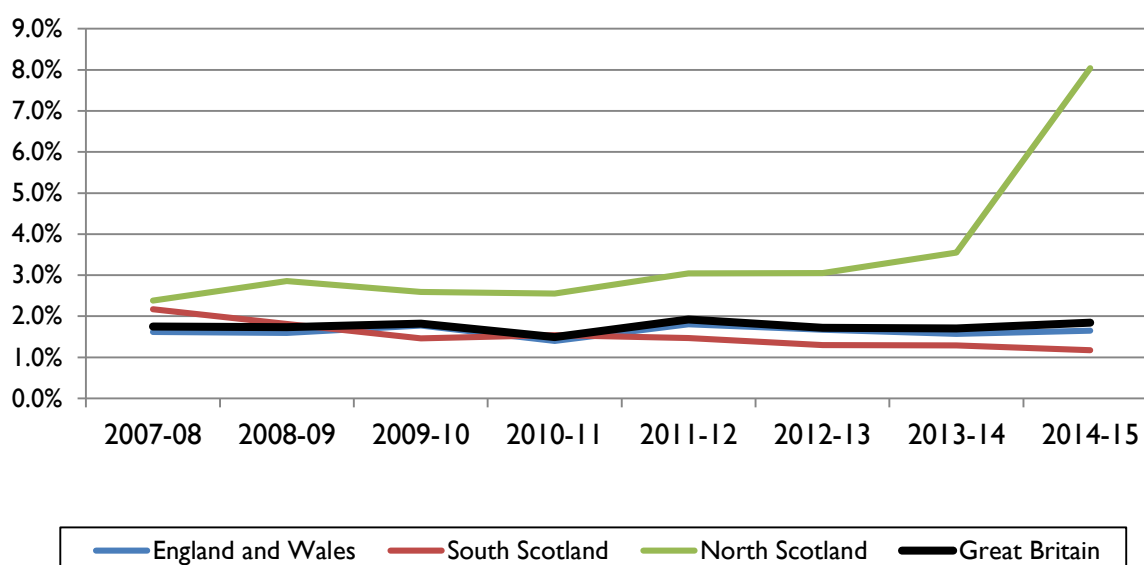


Figure 28: Regional transmission losses (%)³⁰

Transmission losses are applied evenly across GB and split 45% to generation and 55% to demand. Where an embedded generator connects in the north of the country, they offset local demand and receive the offsetting transmission losses benefit. However, at the transmission level, the impact of the embedded generator is to reduce local demand for the transmission connected generator and force more power further away from the generator which increases transmission losses. In instances such as these, the embedded generator is rewarded for reducing transmission losses when it is actually contributing to the level of losses.

The converse of this argument is that embedded generators who connect close to demand (eg in the south of the country) offset the need for power flowing a long distance along the transmission network and consequently bring a large benefit to the transmission system in terms of reducing losses.

Overall, from a principle perspective it is appropriate that embedded generation receives a transmission losses benefit where they do not use the transmission network. The indirect impact that these generators may have on the transmission network should not remove their entitlement as the transmission losses are

³⁰ Data extracted from National Grid Transmission Losses Report covering period 2014-15:
<http://www2.nationalgrid.com/WorkArea/DownloadAsset.aspx?id=43615>

mostly driven by where transmission connected generation decides to connect. These generators will connect to the transmission network based on a wide range of economic signals which are determined by the market and include transmission losses. It is the current trend to connecting generation to the periphery of the transmission network which is driving transmission losses higher. The only potential exception to this principle is where an embedded generator is connected to an exporting GSP. Under this scenario, the export from the embedded generation is using the transmission network and should therefore not be entitled to a benefit for reducing transmission losses.

The application of transmission losses is not currently cost reflective due to the flat application of losses to all demand across GB. The recent CMA enquiry has proposed that transmission losses should be applied regionally which will increase their cost reflectivity. However, the CMA also proposes the application of transmission losses just to transmission connected generation which removes transmission losses as an embedded benefit altogether.

Conclusions

The introduction of regional transmission losses is a beneficial proposal by the CMA. If regional transmission losses were applied, it would provide embedded generation with a locational signal to connect in areas that would be of most benefit. However, the CMA has also proposed that transmission losses should be fully allocated to transmission connected generators and this effectively removes transmission losses as an embedded benefit. We believe the current arrangements that split transmission losses between demand and generation provide an economic signal to embedded generation that helps reduce the overall level of transmission losses and should therefore should remain in place.

9.1.2 Distribution Losses

Distribution losses are determined by DNOs at each voltage level on their networks and are therefore regional as they vary by DNO area. The very largest customers that connect at EHV will have a site specific loss adjustment factor determined that takes account of the network assets used and the consumption pattern of the customer. The level of losses can vary substantially at different voltage levels with LV losses in the region of 8-10% and EHV losses around 1%.

Sites that generate have their metered export scaled up for distribution losses and receives the benefit of this via their supplier. A generator reduces losses on the distribution network by offsetting the local demand and reducing the need for power to flow from the transmission network. Consequently, the embedded generator is reducing losses on the DNOs network and receives the losses as an embedded benefit.

The generic distribution losses that apply at all voltage levels, with the exception of EHV, are average values determined based on the flows into and out of each voltage level. The actual losses offset by a generator will vary depending on the individual circumstances of the generator and the network to which they connect. There will be cases where the actual level of losses offset by the generator will be substantially more or less than that received and this is part of a socialised approach to charging and therefore a reasonable approach.

The exception to this is where a generator is connected to a generation dominated part of the DNOs network. In these areas the principle reverses and generators will be adding to distribution losses rather than reducing them. As set out in Section 5.2.3, Ofgem has rejected the proposal to amend distribution charges in generation dominated areas to remove credits. In addition, the emergence of managed connections and active network management systems has reduced the likelihood of generation areas becoming an issue.

Conclusions

Embedded generators reduce the level of distribution losses on DNOs networks and the current method of applying distribution losses to the export of embedded generation in the same way as they are applied to demand is both equitable and cost reflective. Therefore, the current allocation of distribution losses as an embedded benefit is appropriate.

9.2 BSUoS

9.2.1 Components of BSUoS

BSUoS recovers the cost of balancing the system within each half hour. It covers a range of services provided by National Grid from trading to the provision of ancillary services. The table below provides a breakdown of the services that make up the BSUoS charge:

Latest Projection of Scheme Outturn Cost	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Total 15/16
Energy Imbalance	-14.0	1.3	-1.6	0.0	3.1	-2.9	-0.3	6.5	-4.8	-0.8	3.8	-2.7	-12.5
Operating Reserve(Less SBR Tests)	5.5	6.7	5.5	6.7	4.8	6.6	4.8	7.0	5.6	7.1	9.9	9.5	79.6
BM Startup	0.0	0.0	0.0	0.0	0.1	0.1	0.0	0.1	0.1	0.1	0.3	0.0	0.8
STOR	3.1	4.1	3.9	4.2	4.9	4.5	4.5	4.1	3.5	4.6	4.4	7.3	53.1
Constraints - E&W	8.1	12.8	7.8	7.1	6.1	1.0	2.4	6.5	5.6	4.7			
Constraints - Cheviot	3.0	14.7	11.7	5.9	15.2	0.8	8.0	30.9	45.2	29.5	19.8	21.8	332.3
Constraints - Scotland	5.4	12.2	5.6	5.4	3.1	1.2	2.8	10.4	11.4	6.3			
Footroom	0.3	0.1	0.3	0.5	0.1	0.1	0.0	0.1	0.2	0.1	0.2	0.3	2.4
Fast Reserve	8.4	9.7	9.5	11.0	11.3	8.4	9.9	9.5	9.9	10.9	8.8	10.2	117.4
Response	15.5	19.4	16.7	14.5	12.9	13.5	13.9	14.4	15.0	12.5	12.7	15.3	176.3
Reactive	6.7	7.3	6.6	6.1	6.9	6.7	6.8	5.8	6.2	5.7	5.2	5.2	75.2
Minor Components	4.5	6.3	3.2	3.5	2.5	2.5	3.3	3.2	4.0	3.4	3.3	3.9	43.7
ROCOF (E&W)	0.9	2.8	4.6	4.6	4.8	2.9	1.0	1.5	3.0	2.3			28.4
TOTAL (inc SBR Tests)	47.6	97.4	73.8	69.4	75.7	45.4	57.2	100.4	105.3	86.7	68.4	70.8	898.1
Estimated BSUoS Vol (TWh)	41.8	40.3	38.6	39.5	39.1	40.5	45.9	46.3	45.9	50.4	53.2	53.7	535.1
Forecast NGET Profit/(Loss)							30.0						30.0
Estimated Internal BSUoS (£m)	12.2	12.6	12.2	12.6	12.6	12.2	12.6	12.2	12.6	12.6	11.4	12.6	148.0
Estimated BSUoS Charge (£/MWh)	1.49	2.79	2.29	2.14	2.33	1.48	1.57	2.48	2.62	2.02	1.54	1.60	2.01
SBR (Tests)								0.53	0.54	0.42	0.00	0.00	1.48
Total SBR &DSBR (not added)								5.36	7.55	7.26	0.00	0.00	20.17

Figure 29: Breakdown of BSUoS components³¹

The largest component of the BSUoS charge is the constraint costs which account for 37%, followed by frequency response and fast reserve which account for 20% and 13% respectively. Constraint costs are the payments made by the system operator to restrict the flow of electricity within an area which would exceed the capacity of the network. Currently, the main constraint costs are due to turning down generation in the north as the export is unable to flow to the south of England due to the restricted capacity between England and Scotland.

9.2.2 Drivers of the BSUoS Charge

The unit rate of BSUoS has shown a general increase over the last eight year. Since 2010-11, the average annual BSUoS rate has consistently increased as shown in the figure below:

³¹ National Grid BM Report, published January 2015 (<http://www2.nationalgrid.com/UK/Industry-information/Electricity-transmission-operational-data/Report-explorer/Services-Reports/>)

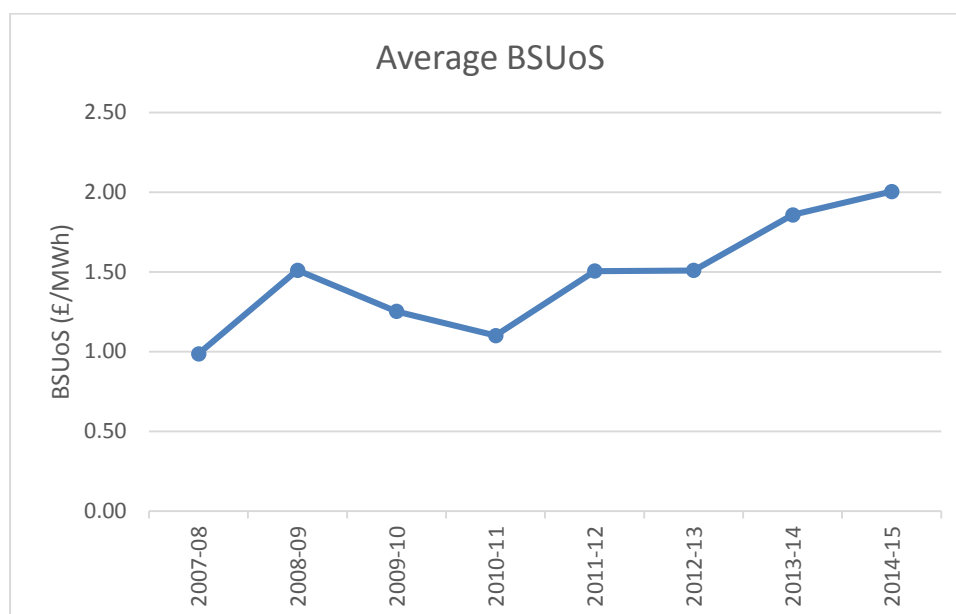


Figure 30: Average annual BSUoS rate

The primary driver behind the general increase in the BSUoS rate is the higher costs incurred by the system operator in balancing the system. This has been driven by a number of factors including more generation connecting to the periphery of the transmission network leading to additional system constraints and the increasing intermittency of the generation mix. A further factor is that BSUoS costs are recovered across demand (measured as half hourly consumption as opposed to peak demand for the triad charge), which has reduced across the period.

9.2.3 Constraint element of BSUoS

Embedded generation receives a benefit from offsetting demand and thereby avoiding BSUoS charges. BSUoS is charged as a flat unit rate in each half hour. However, the actual constraint cost element of BSUoS are regional in nature and consequently a similar situation to transmission losses occurs. Where embedded generators offset demand in the south, they ease the constraints and should receive a larger benefit than the average GB rate. Conversely those embedded generators in the northern regions offset demand, but make the constraint worse, by forcing more transmission connected generation to export through the constraint.

At present, the cost of constraints on the transmission network are socialised over all users of the transmission network. However, transmission connected generators who are subject to a constraint receive payments to reduce export and alleviate the constraint in addition to paying their share of BSUoS. Consequently, moving to charging the constraint element of BSUoS on a regional basis would result in transmission connected generation receiving constraint payments which are partly funded from embedded generators in those areas.

Conclusions

The current level of constraint costs is a cost to GB as a whole that is recovered on an average basis through BSUoS. In principle the application of a regional constraint cost would be a more cost reflective proposition, but applying constraint costs to the generators who create the constraints would be likely to impose excessive costs on those plants and could result in them becoming uneconomic. The socialisation of constraint costs via BSUoS is an equitable approach and should continue in its current format.

9.2.4 Reserve and Frequency Response

The remaining elements such as reserve and frequency response are not location specific costs, so it is sensible to socialise these into an average charge. Embedded generation receive a benefit as they offset the volumes entering the transmission system and make it easier for the system operator to balance.

The system operator has highlighted that reducing inertia is likely to become a bigger issue for them in managing frequency, particularly at times of low demand. The large increases in connected PV and wind to the distribution networks make managing the frequency potentially challenging in the summer. The system operator is looking to procure new services such as enhanced frequency response (EFR) and demand turn up to give it more tools to manage frequency in the future.

The increased need for the system operator to procure more services due to reduced inertia created by embedded generation reducing load on the transmission system raises the question of whether embedded generation should be entitled to a benefit by avoiding BSUoS through offsetting demand. It should be noted that although non-intermittent generation offset demand on the transmission network, they also slow down the rate of change of frequency which helps to stabilise the system. The overriding principle that should be applied is that if embedded generation is driving cost within the balancing mechanism, then they should not receive a credit for avoiding the application of that cost.

The potential areas of additional costs that could be due to embedded generation are in the areas of reserve and response. The system operator needs to procure more reserve and response services to make up for more intermittency in the generation mix and reduced inertia. The extent to which embedded generation is contributing to these requirements is based on the type of generation. Non-intermittent embedded generation reduces the need for reserve as it can be relied upon to export at times of system stress. It is also unlikely to add to problems with inertia in times of low demand as it will switch off in response to economic cost signals when demand is low and stabilises the system by slowing down the rate of change of system frequency.

Intermittent generation has the opposite impact on balancing costs. It is not possible to predict if intermittent generation is available at peak times and consequently, reserve requirements, particularly long term reserve, are greater. Also, the intermittent nature of the generation combined with the minimal marginal cost means they are likely to generate even at times of very low demand and reduce inertia on the network when it is already low.

Conclusions

Embedded generation is contributing to reducing inertia on the transmission system and driving National Grid to procure new services such as EFR and demand turn up. It is more likely that intermittent generation is the driver of reduced inertia as they are unlikely to reduce export at times of low demand. A potential solution would be to differentiate between intermittent and non-intermittent generation when applying these elements of BSUoS charges as an embedded benefit. However, the practicality of implementing a methodology that differentiated between different types of embedded generation would be difficult to implement and any reduction in benefits for intermittent generation will impact on investment decisions and make meeting future carbon targets more challenging. Consequently, we recommend the current method of applying BSUoS charges to net demand should continue

9.3 Assistance for Areas with High Distribution Costs (AAHDC)

AAHDC is a relatively small embedded benefit compared to the other elements available to embedded generators. This charge is a subsidy that is levied on demand customers to reduce the higher distribution costs that occur in Scotland.

This report has identified that one of the key benefits of embedded generators is that they lower the costs for DNOs of running the distribution networks. As AAHDC is a subsidy to reduce the high distribution costs incurred in Scotland, it appears reasonable to reward embedded generators that are helping to

reduce distribution network costs by allowing the application of AAHDC charges on net demand and therefore passing the benefit on to embedded generators.

Conclusions

The AAHDC is a subsidy that aims to reduce distribution costs within Scotland and it is therefore appropriate for embedded generators who contribute to reducing distribution costs to receive AAHDC as an embedded benefit.

9.4 Capacity Market Supplier Charge (CMSC)

Although the CMSC is low at present, as the capacity market is still only recovering its set up costs, the charge will grow in the future to recover the full capacity market costs. The application of this charge to net demand creates a benefit to embedded generators who can assist suppliers in offsetting this charge. However, unlike TNUoS and BSUoS, suppliers only benefit from a reduction in the CMSC if they have demand to offset the embedded generation against. In addition to this, existing embedded generators will only receive the CMSC as an embedded benefit if their existing Power Purchase Agreement (PPA) facilitates the pass through of the benefit.

To provide an illustration of the potential income from avoiding the CMSC, the table below provides a forecast of the level of CMSC in £/kW that could be achieved by a non-intermittent generator that exports at 90% of its capacity across the CMSC period.

	2016-17	2017-18	2018-19	2019-20	2020-21
CMSC Income	£0.32	£23.38	£17.46	£13.95	£24.61

Figure 31: Forecast CMSC income (£/kW) for non-intermittent generator exporting at 90% of capacity during 4pm and 7pm on weekdays, Nov to Feb.

The benefit will only accrue to generators who export between 4 and 7pm on weekdays, November to February each year. The introduction of the CMSC raises two issues from an embedded generation perspective. The first is that intermittent generator will receive the benefit if they export during the period, but will not bring any capacity certainty and therefore are not reducing the costs or need for the capacity market. Non-intermittent generation on the other hand are reducing peak demand and can be relied upon to do so.

The second issue, is that embedded generators are able to participate in the capacity market and will receive the benefit twice if they are successful. Embedded generators will receive capacity market payments plus the benefit from offsetting the CMSC. This effectively means embedded generators are being paid twice for providing the same amount of capacity. It also means that embedded generators are able to bid a lower price into the capacity market and displace transmission connected generators.

Conclusions

The potential double payment of embedded generators appears to be an anomaly that has been overlooked by the industry. It undermines the capacity market mechanism and embedded generators should not be rewarded twice for providing the same service

9.5 End to End Use of System Charging

The current industry structure splits transmission and distribution and uses separate charging methodologies set down in different codes to determine charges. Within distribution there are two further charging methodologies with the EDCM and CDCM and to further complicate matters DNOs have a choice within the EDCM to use either LRIC or FCP. It is important to have consistency across the network

charges to ensure both demand and generation connectees receive the correct cost reflective price signals and that their interests are aligned with that of the network operator.

Cornwall Energy has examined the end to end network charging across transmission and distribution as a whole and identified a number of inconsistencies between the charging methodologies which are highlighted below:

- **Scaling** – The CDCM and EDCM do not apply any scaling element to generation credits, but at transmission level the triad benefit is based on the target revenue and therefore includes full scaling.
- **Intermittent generation** – At LV and HV all intermittent generation receives a single rate credit that applies whenever they export. At EHV intermittent generation does not receive a credit and at transmission intermittent generation receives a credit based on its export during the triad period.
- **OPEX as a credit** – At LV and HV, credits are calculated for offset reinforcement and operating expenditure (opex). At EHV opex is not included within the credits and at transmission, all elements are currently included. However, the estimates of the avoided cost due to embedded generation at TNUoS that have been proposed by National Grid have not included an element of opex.
- **Peak demand** – At LV and HV, credits for reinforcement costs are determined based on the assets required to build a network with a 500MW peak demand. Consequently, the charge is based on a fully utilised network. At the transmission level the triad charge is based on the full TNUoS allowed revenue recovered across peak demand rather than network capacity and consequently is based on an under-utilised network. At EHV, the credit is determined on a site specific basis.

Conclusions

The inconsistent approaches have developed due to the separation of the network charging methodologies and their independent development. A move to establish a consistent set of charging principles that can be applied across all networks would offer a more robust approach for the industry as a whole.

I0 Report Summary

Cornwall Energy has undertaken a review of the level of embedded benefits and reached a number of conclusions which are highlighted throughout the report. These findings are summarised below.

Overall, the analysis undertaken within this report suggests that the level of distribution credits that embedded generation receive is lower than the actual benefit they bring to distribution companies. This is largely because there is no recognition of the benefit to the distribution company at the level of connection for LV and HV connected generators with credits calculated only for the voltage levels above the level of connection. In addition, at EHV, intermittent generation does not receive a credit whereas it is eligible for a credit at LV, HV and transmission.

The report also examined the issue of generation dominated areas at LV and HV and concluded that this area is no longer a material issue given the innovative ways in which DNOs have enabled embedded generation to connect without a material increase in reinforcement costs by using active network management systems and managed connections. However, the issue could return if more embedded generation continues to connect to the distribution network.

At transmission level, this report suggests that the level of triad benefit received by embedded generators is higher than the benefit they bring to the transmission network. This is primarily due to the mechanism of the triad calculation which recovers long term costs over short term demand and also includes the recovery of transmission level costs which are not demand or capacity related. However, our analysis suggests that the level of avoided costs that should accrue to embedded generators at TNUoS are higher than the values put forward by National Grid.

This report has reviewed the potential solutions put forward by National Grid such as moving to a gross method of charging and concluded that they would not be cost reflective as they assign a different value to an increment in generation and a reduction in demand where in reality there is no difference between the two from a transmission perspective. A preferred approach is to make the triad charge more cost reflective and to apply it equally to embedded demand and generation on a net basis.

This report has also considered the approach of calculating the embedded TNUoS benefit on the locational element of the TNUoS charge and concluded that this would understate the value of the avoided cost of embedded generation. However, the principle of removing some elements of the allowed revenue that are not demand related and recovering these either on a volume or customer basis would result in a more cost reflective triad charge but this should be done by reviewing the components of the TNUoS target revenue rather than assuming that the residual charge is not demand related.

A review of BSUoS has also been undertaken which has highlighted a number of issues. In particular, the socialisation of this embedded benefit means that all generators receive a benefit regardless of where they connect or the impact they may have on the network. In reality, the impact of different generators will vary depending on the type of generation and where they are connected to the distribution network. Our analysis suggests that there may be a case for making some components of BSUoS either regional for the constraint element of BSUoS or only available as an embedded benefit to non-intermittent generators for reserve and frequency response services. However, although this may be correct from a principles perspective, these changes could have a disproportionate impact on some embedded generators to the extent that they become uneconomic. It could also have the unintended impact of pushing the worse effected embedded generators to connect behind the meter or to install private wires to local demand which would enable them to capture the full level of embedded benefits and result in a significant loss of transparency for the system operator.

The remaining categories of embedded benefits have also been reviewed within this report. It concludes that distribution losses and assistance for areas of high distribution costs are currently providing an appropriate level of benefits to embedded generators and do not warrant any changes to the current system. It should be noted that under the CMA proposals transmission losses will no longer be an embedded benefit once the conclusions have been implemented.

The remaining embedded benefit reviewed is the capacity market supplier charge. A potential double benefit has been identified as embedded generators who are successful within the capacity market will receive a capacity market payment and also potentially benefit from avoiding the recovery of the capacity market charge from suppliers via the CMSC. The report concludes that this will result in embedded generation being paid twice for providing the same service which is detrimental to the capacity market mechanism and may distort the clearing price.

Appendix A - Policy and Regulatory Background

The table and narrative below chart the development and review of the transmission charging arrangements with respect to embedded generation against the backdrop of the introduction and repeated extension of the small generator discount.

Date	Event
Sept 2002-Mar 2003	P100 <i>Extension of Demand Side Trading Units in Order to Increase the Competitiveness of the Market for Embedded Benefits</i> - approved
Apr 2005	SLC13 licence condition introduces small generator discount at start of BETTA
Sept 2005	Enduring transmission charging arrangements for distributed generation - Ofgem discussion document
Jun 2006 -Apr 2007	Transmission Arrangements for Distributed Generation (TADG)
Jul 2007-Aug 2010	Transmission Access Review
Apr 2008	Small generator discount extension for one year to end Mar 2009 begins
Apr 2009	Small generator discount extension for two years to end Mar 2011 begins
Jan 2010	GB ECM-23 <i>Transmission Arrangements for Embedded Generation</i> consultation
Jun-Nov 2010	P260 <i>Extension to Data Provided to the Transmission Company in the TNUoS</i> - rejected
Sept 2010 - Jul 2014	Project Transmit and CMP213 <i>Project Transmit TNUoS Developments</i>
Apr 2011	Small generator discount extension for two years to Mar 2013 begins
Apr 2013- Apr2014	National Grid informal review of embedded generation benefits
Apr 2013	Small generator discount extension to Mar 2016 begins
Oct 2014 - Aug 2015	CMP239 <i>Grandfathering Arrangements for the Small Generator Discount</i> - rejected
Aug-Oct 2015	Informal consultation - <i>Potential Charging Arrangements at Exporting GSPs</i>
1 Mar -1 Apr 2016	DECC Consultation on Further Reforms to the Capacity Market
Apr 2016	Small generator discount extension for three years to Mar 2019 begins

Pre-BETTA developments to embedded generator arrangements

After the New Electricity Trading Arrangements were introduced in March 2001, embedded benefits could only be attained by grouping Embedded Licence Exemptible Generators (ELEGs) — generators that are connected to the distribution system and are not required to be licensed under the Electricity Act 1989 — and demand within a Trading Unit or through a netting off agreement with a supplier. As in some GSP Groups there were few suppliers it was claimed this left limited opportunity for the ELEG to obtain a competitive commercial agreement to net off.

Slough Estates raised BSC proposal P100 *Extension of Demand Side Trading Units in Order to Increase the Competitiveness of the Market for Embedded Benefits*³² in September 2002 that sought to create one default trading unit, a Base Trading Unit, for each GSP Group that would comprise all supplier Balancing Mechanism (BM) Units and all participating Export Exempt BM Units in the relevant GSP Group. Each Export Exempt BM Unit in a Base Trading Unit would be allowed to choose its Production/Consumption status independently. It would also allow for Supplier Meter Registration Service (SMRS) registered non-default supplier BMUs composed of licenced exemptable generation to be treated as exempt export BMUs.

While P100 was in the modification process, National Grid proposed a change to the transmission charging arrangements, UoSCM-M-07 *Proposed change to the TNUoS Liability rules for Embedded Licence Exemptible*

³² <https://www.elexon.co.uk/mod-proposal/p100-extension-of-demand-side-trading-units-in-order-to-increase-the-competitiveness/>

*Generations and Distribution Interconnectors*³³. This established that ELEGs that are registered in the Central Meter Registration Service will pay or be paid demand TNUoS charges on the basis of their metered volumes for the half hours used in calculating those charges. As such, ELEGs do not have to be in a Trading Unit with demand, or have a netting-off agreement with a supplier to receive TNUoS benefit. However, the generation of ELEGs whose meters are registered in the SMRS is still automatically netted off against their supplier's demand. This change was approved by Ofgem for implementation on 5 November 2003.

As a result of this change, P100 had the effect of addressing the remaining elements of embedded benefit: BSUoS, transmission losses and BSCCo costs.

Those in favour of P100 said the modification would remove certain market imperfections and create the economic conditions under which competition for embedded benefits could increase. The contracting options available to both ELEGs and those tendering for their outputs would be increased, as those parties possessing sufficient demand to permit netting off in a GSP Group would no longer be competitively advantaged over those lacking such demand.

Those against said P100 would distort the market by forcing suppliers to pay too much for transmission services and that there were already sufficient provisions in the BSC for the competitive trading of embedded benefits. Suppliers would face increased costs for contracting with ELEGs, to the extent that these contracts would become commercially unsound propositions. It was argued the proposal introduced a direct cross subsidy of ELEGs by suppliers: that ELEGs already benefit from non-usage of the transmission system through avoidance of generation TNUoS and BSUoS charges so any subsequent allocation of benefits represents a cross subsidy. Objectors said the proposal would result in higher prices to the end consumer.

Ofgem considered that P100 was likely to improve the liquidity and transparency in energy trading by ELEGs, as the extent to which embedded generators can realise the available benefits was dependent on the generator's ability to strike a contractual agreement with a supplier or suppliers in the GSP Group and as a result form a Trading Unit. P100 would mean all ELEGs will have the means to realise embedded benefits without necessarily having contractual arrangements with suppliers, through becoming a Party to the BSC and registering their meter in the Central Meter Registration Service (CMRS). The regulator said that the potential to choose to register in CMRS rather than SMRS to obtain better terms should in turn influence the contractual terms available for those generators that remain registered in SMRS.

In respect of potential cross subsidies, Ofgem said suppliers will still be subject to the same quantity of demand TNUoS and BSUoS charges as before, in line with the cost to the system operator for providing for that demand in the GSP Group, and that any ELEG that offsets that demand, thereby saving system operator costs should be rewarded accordingly, so far as the contractual relationships between the ELEG and transmission system operator allow. On the impact on consumers, Ofgem said that while those suppliers who are taking a significant proportion of embedded benefit from ELEGs they have contacts with may feel an impact, in the longer term a more cost-reflective regime should improve efficiency to the benefit of consumers.

The modification was implemented on 5 November 2003.

BETTA and transmission charging methodology

In September 2004 the secretary of state put in place amended licence conditions for transmission licensees to implement the British Electricity Transmission and Trading Agreements (BETTA) and this included new licence obligations for National Grid to establish GB transmission and charging arrangements and in March 2005 Ofgem approved National Grid's proposed methodology³⁴.

In developing its charging arrangements National Grid said it was planning to undertake further work post BETTA looking at the wider implications of distributed generation. This reflected that the Renewables Obligation had provided strong incentives to develop new renewable generation projects creating a step change in the demand for connections to both the transmission and distribution networks. National Grid

³³ https://www.elexon.co.uk/wp-content/uploads/2012/02/p100_ofgem_decision.pdf

³⁴ https://www.ofgem.gov.uk/sites/default/files/docs/2005/03/10033-8005_0.pdf

noted that this was leading to a larger number of GSPs exporting onto the transmission system and it was concerned that the existing charging methodology and wider contractual framework were not sufficiently robust to address this change.

Given the timescales for developing the BETTA trading arrangements National Grid said it did not intend to address these concerns within the initial GB charging methodologies but that it may become necessary to consider the charging methodologies and contractual framework in the short to medium term.

Introduction of and extensions to the “small generator discount”

One consequence of these considerations was that in the interim Ofgem implemented the “small generator discount” from April 2005, a rebate to transmission use of system charges for generators less than 100MW that are transmission connected in Scotland but would have been distribution-connected in England and Wales³⁵. The aim of the discount, set out in Standard Licence Condition (SLC) C13 was to avoid discrimination and create a level playing field between under 100MW 132kV transmission connected generators in Scotland and offshore and those that are distribution connected at 132kV in England and Wales. The discount was set for three years starting in 2005, with a view to reviewing the charging arrangements and developing enduring arrangements for charging distributed generators. The level of the discount was set at 25% of the combined generator and demand residual tariff and has remained calculated according to that formula throughout its existence. It is paid for through a non-locational charge on demand – the demand residual. The discount was first extended to 31 May 2009 (the original term of the discount was for three years falling to zero for the fourth year) Ofgem maintained the fourth year at the original discount. The discount was then further extended to 31 March 2011. In addition to extending the expiry date for the discount from 31 May 2009 to 31 March 2011, this amendment to SLC C13 strengthened National Grid’s obligation to use “best endeavours” to develop and implement enduring arrangements. The discount was further extended to 31 March 2013, to 31 March 2016 and most recently to 31 March 2019³⁶. In each case the discount was extended to enable enduring arrangements for embedded generation to be developed, and have referred to the different initiatives underway at different times.

In its most recent extension Ofgem said that, in respect of analysis by National Grid for its informal review of embedded benefits (see below) it did not consider that the evidence allowed it to reach a view on whether letting the discount expire is more cost reflective than continuing with the discount.

The discount was expected to be worth £3.67/kW for the first year starting 1 April 2005 and will be worth £11.46/kW for 2016-17.

Enduring transmission charging arrangements for distributed generation - Ofgem discussion document

Ofgem considered that the charging arrangements should be reviewed at an early stage after the introduction of BETTA and issued a discussion document in September 2005³⁷. The regulator said that its role was to facilitate debate in a coordinated manner, not to prescribe particular answers to the issues raised - it was for licensees in tandem with industry to develop any proposals through the appropriate consultation and modification channels. However, it was difficult for an individual licensee to adequately consider the full range of issues in the round.

The regulator identified the following issues as needing to be addressed in developing enduring charging arrangements for distributed generators:

³⁵ *Interim discount for small transmission connected generators- decision letter*
https://www.ofgem.gov.uk/sites/default/files/docs/2005/02/9798-5905_0.pdf

³⁶ https://www.ofgem.gov.uk/system/files/docs/2016/01/c13_stat_con_decision_letter_final.pdf

³⁷ *Enduring transmission charging arrangements for distributed generation - a discussion document*
https://www.ofgem.gov.uk/sites/default/files/docs/2005/09/11679-211_05.pdf

- **exporting GSPs without access rights.** It noted that CUSC proposal CAP093 *Enabling the Flow of Electricity from Distribution Systems into the Transmission System at Grid Supply Points*³⁸ had been raised to clarify that GSPs may export power onto the transmission system. Ofgem said there were two aspects to this issue:
 - the operational concerns of National Grid in relation to its rights to collect information about, and lack of control over, the amount of power flowing onto the transmission system from a distribution connection. Ofgem said such operational concerns may be expected to increase the total level of balancing costs which are met by all BSC Parties but are unlikely to be faced by the parties causing these costs; and
 - some parties do not pay for the use that they are making of the transmission network and the costs of this “free riding” are paid for by other parties, for example directly connected generation and the demand charging base that has contractual relationships with National Grid and whose charges are consequently likely to be higher than the cost-reflective or economically efficient level.

Ofgem said it is worth considering whether the fact that a GSP may export power to a transmission network is a directly relevant issue in considering charging arrangements. It said the impact of a single incremental MW on flows across the transmission network is the same, regardless of the voltage at which the generator that produces the power contracts. The regulator said “If the distributed generator locates in the south of the country, where demand charges are highest and generation charges are negative, it should receive a benefit for reducing excess demand. If a distributed generator connects in the north of the country it will reduce demand, and increase flows down the transmission system, imposing an increased cost which, in a cost reflective charging system, it should face. A directly connected power station of the same size locating at the same point will increase power flows by the same amount”.

- **cost reflectivity** - that where a user has an impact on the transmission network for which it does not pay, those parties that do pay transmission charges will be paying charges that are higher than the efficient level. This may not facilitate competition in generation and could be seen as discriminatory;
- **perverse incentives - voltage, location and size** - that the differential charging arrangements for distribution and transmission connected generators can lead to perverse incentives when deciding where and at which voltage to connect. Given the size definitions relevant to the liability for TNUoS charges, any absolute threshold would provide incentives to size plant marginally below them - the presence of 99MW generation schemes indicated this effect was real; and
- **interaction with access issues** - Ofgem noted that there could be an interaction between access issues on the transmission network and on the distribution network.

In May 2006 following two industry workshops in the winter Ofgem published a “further thoughts” document that summarised respondents’ views and sought to focus debate on the future direction of developments. It said that one of the key views that emerged out of the consultation process was the complexity of the issues to be addressed and the fact that those issues potentially cut across a number of different industry costs and documents. Respondents argued that this would mean the governance and consultation processes for any of the individual costs or documents would be insufficient to develop a holistic solution to the existing problems and therefore Ofgem needed to have a central role in the process.

Transmission Arrangements for Distributed Generation (TADG) - Review

³⁸ This proposal, raised by Central Networks, was rejected by Ofgem in January 2006
<https://www.ofgem.gov.uk/sites/default/files/docs/2006/01/12669-cap093-d.pdf>

In June 2006 Ofgem established a working group, to be tasked with developing specific options for change through developing “straw-men” for the form of enduring arrangements³⁹. The workgroup had 27 full members drawn from a broad range of industry parties and its objective was to identify options for change that should: minimise implementation costs; reflect the costs and benefits that industry participants impose on the system; and encourage efficient network development. The scope was to include:

- the development of appropriate transmission charging arrangements, removing any perverse incentives;
- the interaction with issues of transmission access, including the treatment of exporting GSPs without access rights to the transmission system, the contractual arrangements and nature of access rights appropriate to distributed generation and any interactions with the work of the Access Reform Options Development Group⁴⁰;
- the impact of distributed generation, as compared to transmission connected generation and demand, on the operation and planning of the transmission system, including issues around the need for direct interfaces between distributed generation and the system operator; and
- the ease of implementation and implementation costs (one-off and ongoing) associated with any solution and associated interactions with other policy areas.

Other key areas the workgroup was charged to consider were: to what extent is the impact of distributed generation on the transmission system, individually or in aggregate, the same as transmission connected generation; whether the existing transmission access products are appropriate to distributed generation; and, if distributed generation does not have firm transmission access rights then how can its export onto the transmission system be controlled if necessary.

The workgroup met eight times between July 2006 and April 2007. In July 2007 Ofgem issued the workgroup’s report and an update on the regulator’s thinking⁴¹.

In its report the workgroup said a majority of the group agreed that the existence of a gap in the contractual framework with respect to exports to the transmission system is a “material issue” and that there is a need to minimise contractual burden.

The group developed four models and assessed them against minimising implementation costs, being cost reflective, and facilitating efficient development and use of the networks. The models were:

- a DNO agency model with charges applicable to net exports at individual GSPs and charged out to distributed generation on the basis of connection voltage, proposed by Scottish Power Transmission and Distribution;
- a DNO agency model with charges applicable to net exports at individual GSPs and charges out to all distributed generators contributing to export proposed by Airtricity;
- a supplier agency model with charges applicable to net exports from suppliers over each GSP Group proposed by CE Electric; and
- a supplier agency model with charges applicable to gross generation exports from suppliers at individual GSPs proposed by National Grid Electricity Transmission.

The workgroup noted that by applying transmission charges for exports associated with distributed generation any of the models could impact, to varying extents on the existing embedded benefits received

³⁹ *Transmission Arrangements for Distributed Generation (TADG) Working Group: Invitation and draft terms of reference* https://www.ofgem.gov.uk/sites/default/files/docs/2006/06/14425-ofgem102_1.pdf

⁴⁰ This was a workgroup that met six times in spring 2006 to examine transmission access arrangements and was a forerunner of the Transmission Access Review. Its report is here: <https://www.ofgem.gov.uk/publications-and-updates/framework-considering-reforms-how-generators-gain-access-gb-electricity-transmission-system-report-access-reform-options-development-group-april-2006>

⁴¹ *TADG workgroup report and next steps* <https://www.ofgem.gov.uk/publications-and-updates/19407-transmission-arrangements-distributed-generation-working-group-report-and-next-steps>

by it, but they differ in the way in which those exports are defined and charged depending on the party acting as agent and the scope of the agency model. Each model would also confer transmission access rights to the distributed generator via the respective agency without requiring it to contract directly with National Grid.

The workgroup agreed that either a supplier or DNO agency model could theoretically form a suitable basis for an agency model, but were unable to agree on an individual strawman in terms of cost-reflectivity and facilitating efficient network development. It considered that “the primary source of this division of views was the use of a gross or net model for access and charging which was perceived as the main driver of the commercial impacts on industry parties”. Overall the report said a majority of the workgroup favoured a net DNO agency approach while a small minority supported a gross supplier agency approach.

The majority of the workgroup considered that the operation and planning issues identified were not a primary driver for change. The workgroup was split on the issue of the cost reflectivity of the current treatment of distributed generation: some questioned the appropriateness of embedded benefits and argued that distributed generation should pay transmission charges, with mixed views on whether such charges should be applied to gross generation exports or based on net exports to the transmission system, at a GSP or GSP Group level.

Ofgem said it believed there was case for change in the treatment of distributed generation in the transmission arrangements. In respect of TNUoS charging it said that through negative demand TNUoS charges distributed generation sees broadly the same impact from locational charges as transmission connected generation, and there is no proposal to change this. However, it said the question is whether distributed generation should a) be paid the demand residual and b) avoid the generation residual element of the charge. National Grid estimated that the embedded benefit for annual TNUoS charges was of the order of £17/kW, at the time.

The regulator considered there was a good case for a review of the cost-reflectivity of the size of the embedded benefits and that National Grid should undertake a review of the drivers of the costs associated with the residual TNUoS charge, taking into account the impact of distributed generation on such costs. It said in particular the review should address the treatment of generation under 100MW and connected at 132kV across GB and develop a consistent and cost-reflective arrangement that replaces the interim small generator discount in Scotland.

Ofgem said it did not consider the distinction between gross and net was particularly useful to achieving cost-reflective charging - cost reflective charging could be applied through variants of either a gross or net basis. However, it did not consider that a solution based on net export alone would be appropriate because the impact of distributed generation on transmission is not limited only to where there is net export.

The regulator noted the point that some generation, for example on a private network, will be considered net. It was therefore important to recognise that changes to charges which reduce the distortion in cost-reflectivity between transmission and distribution may well increase the distortion elsewhere. The appropriate approach then depended on the materiality of the distortions likely to be caused. It said for practical reasons there may be merit in considering an appropriate threshold below which distributed generation is treated net.

It continued to believe that agency models may be an appropriate way for smaller distributed generation to deal with transmission issues and it noted that **CAP097** (see below) provided for DNOs to have a role in dealing with transmission issues for DG without the latter having direct contractual relationships with transmission, but there was scope to clarify or further develop relevant obligations.

Transmission Access Review (TAR)

The review by National Grid of the drivers of cost associated with residual TNUoS charges proposed by Ofgem was in the event effectively deferred by the Transmission Access Review⁴² that was launched in July

⁴² <https://www.ofgem.gov.uk/electricity/transmission-networks/transmission-access-review>

2007. It was taken up again with the pre-consultation on GB ECM23 *Transmission Arrangements for Distributed Generation* in January 2010 (see below).

TAR was led jointly by Ofgem and BERR following the publication of the energy white paper in May 2007 *Meeting the Energy Challenge*⁴³. The purpose was to review the present technical, commercial and regulatory framework for the delivery of new transmission infrastructure and the management of the grid to ensure they remain fit for purpose as the proportion of renewable generation grows. The main issue was the significant queue of generators waiting to connect and the need to meet 2020 renewable energy targets.

The terms of reference for the review said that while the focus of the review would be on the arrangements for generators wishing to access the transmission system “it should also recognise the offsetting effect from the demand side together with the impact of distributed generation.” However, this is not reflected in any of the subsequent work including Ofgem’s report⁴⁴ in June 2009 in which it recommends the secretary of state uses its powers to implement new transmission access arrangements as it did not consider the industry was capable of delivery reform.

This resulted in the connect and manage regime for transmission connected generation imposed by DECC through legislation. Under this model all new generation is able to apply for an accelerated connection based on the time taken to complete their “enabling works”, with wider network reinforcement carried out after they have been connected.

The connect and manage regime was also applicable for those generators that are large enough to have, or are deemed to have, a significant impact on the transmission system⁴⁵. This covered: distributed generation directly contracted with National Grid for transmission access; medium-sized distributed generation as defined by the Grid Code (generation between 50MW and 100MW in National Grid Electricity Transmission’s (NGET’s) area); and small distributed generation as defined in the Grid Code (than 50 MW in NGET’s area, less than 30MW in SPT’s area and less than 10MW in SHETL’s area) where the DNO believes the connection may have a significant impact on the transmission system, and a request for a Statement of Works is therefore made by the DNO to National Grid.

The amount of user commitment each generator must give to remain on the network was increased by one year. All constraint costs, including those arising from the advanced connection are socialised among all generators and suppliers on a per-MWh basis. The new regime was introduced in August 2010.

Transmission charging consultation on embedded generation - National Grid

In January 2010 National Grid issued a “pre-consultation,” for a transmission charging proposal GB ECM-23 *Transmission Arrangements for Embedded Generation*⁴⁶ which took forward the review proposed by Ofgem at the end of the TADG work and invited views on a range of related issues.

At that time all changes to the TNUoS charging methodology were proposed and consulted upon by National Grid before being submitted to Ofgem for determination. National Grid was also under a licence obligation, following the extension of the small generator discount to March 2011, to use “best endeavours” to develop and implement enduring arrangements for distributed generation.

As discussed at the transmission charging methodology forum in September 2009, National Grid’s proposed process following the pre-consultation was to develop proposals in spring 2010, consult on the proposals and consider consequential changes in the summer, with a report to Ofgem in the autumn and

⁴³ DTI White Paper *Meeting the Energy Challenge*

https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/243268/7124.pdf

⁴⁴ *Enduring Transmission Access Reform* <https://www.ofgem.gov.uk/sites/default/files/docs/2009/06/enduring-transmission-access-reform-final-published.pdf>

⁴⁵ *Government response to the technical consultation on the model for improving grid access*

https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/42979/251-govt-response-grid-access.pdf

⁴⁶ <http://www2.nationalgrid.com/UK/Industry-information/System-charges/Electricity-transmission/Transmission-Network-Use-of-System-Charges/Historical-Use-of-System-charges-consultations/>

the new arrangements to be implemented by April 2011 when the small generator discount arrangement was due to expire⁴⁷.

In GB ECM-23 National Grid first considered the current arrangements against Ofgem's principles for change, as set out for TADG. It presented analysis on defining the embedded benefit and considered the potential effects of the commoditisation (charged on a KWh basis rather than a kW basis) of the residual tariffs. National Grid then set out two potential enduring solutions, saying that it broadly favoured one of them, the gross nodal supplier agency model, as being the more cost reflective. These discussions are considered in turn below.

In respect of Ofgem's principles for charging National Grid considered:

▪ **Cost reflectivity**

National Grid identified that unlicensed distributed generation is treated as negative demand in TNUoS charging and therefore both avoids the TNUoS generation tariff and, subject to negotiation between the generator and the associated supplier, is paid the TNUoS demand tariff. It said that if tariffs were purely locational this would result in an arrangement that is much more cost effective: directly connected generators would pay the locational generation tariff, and embedded generators would be paid the locational demand tariff. Provided the locational generation and demand tariffs are equal and opposite, this would lead to a consistent treatment.

However, in order for transmission companies to recover their allowed revenue an additional flat residual charge is applied to the TNUoS tariffs. Due to the non-locational nature of this residual element, coupled with its relative size (around 85% of total revenue collected at that time), distributed generation gains a net TNUoS benefit over transmission connected generation. Whilst distributed generation does offset local demand, the current embedded benefit results in a net TNUoS benefit to distributed generation over.

Based on historic and planned future levels of investment as well as historic and forecast levels of demand growth, National Grid estimated that a cost-reflective embedded benefit would be in the region of between £6.50/kW and £7.25/kW⁴⁸ while the current embedded benefit provided by the existing transmission charging arrangements is in the order of £20/kW.

▪ **Access allocation**

National Grid said that DECC's application of the connect and manage regime meant that the playing field of network connection dates between transmission and distribution connected generation would be levelled somewhat in respect of connection dates. It also noted that DECC's proposal that the connect and manage regime should apply to distributed generation. It said a knock-on effect of the regime could be an increase in the cost of operating the system and that a review of the allocation of BSUoS charges is also required (with the unstated possible implication that distributed generation should pay BSUoS charges). It said that if contractual arrangements are not developed in parallel, this has the potential to exacerbate existing difficulties with investment planning, demand forecasting, timing of operational outages and fault level planning. Whilst not insurmountable, it said the transmission issues caused by increased volumes of distributed generation connecting to the distribution networks in shorter timescales are significant in practice.

▪ **Proportionality**

Noting Ofgem's concern to have an appropriate administrative and regulatory burden for smaller market participants and that implementation costs should be minimised. It said agency models, where generators do not have a direct contractual relationship with the system operator were favoured by the TADG workgroup for their perceived proportionality. National Grid considered that the gross nodal supplier agency arrangements would maximise the use of the existing commercial frameworks but also that with the

⁴⁷ Presentation to TCMF September 2009 <http://www.nationalgrid.com/NR/rdonlyres/5E8C42F8-AA1F-43BD-9941-F253EF91A53B/37271/EmbeddedNG.pdf>

⁴⁸ Presentation to TCMF October 2007 <http://www.nationalgrid.com/NR/rdonlyres/3F26A596-B935-41CA-9405-74429133D3E5/20852/EmbeddedGenerationOct2007TCMFfinal.pdf>

emergence of smart grid technology and the potential for more centralised control for DNOs, that it might be prudent to pursue a net DNO model.

Analysis

Subject to zoning, the locational elements of TNUoS demand and generation tariffs are the equal and opposite of each other in the same location. Where a transmission connected generator pays the locational TNUoS generation tariff determined by its location, a generator connected to the distribution system is effectively paid the demand tariff dependent on location by its relevant supplier (subject to negotiation) which nets the distributed generator from that supplier's demand. Assuming 100% pass-through of the avoided demand tariff by the supplier National Grid calculated that locational TNUoS tariffs result in an average, inherent embedded benefit of ~£2/kW, this being the result of the use of differing "relevant" nodes when calculating the flow-weighted marginal km for demand and generation zones respectively.

This locational element amounted to around £550mn in 2007-08, whereas the additional residual element, around £1.05bn, was recovered on a split of 27:73 demand: generation at tariffs of £3.78/kW and £14.06/kW respectively. The sum of these plus the "inherent" embedded benefit is around £20/kW.

National Grid said many of the misconceptions over the impact of connecting generation to either the transmission or distribution network arises from seeing them as two separate networks instead of two contiguous electrical systems. For a given network capability between two parts of the transmission system - the boundary - the amount of generation that can be accommodated on the exporting side is a function of the demand in that areas of the network. So an increase in the amount of distributed generation, reducing local demand behind the boundary, has the same impact on that boundary as generation connected directly to the transmission network. This remained the case regardless of whether the amount of distributed generation exceeds the demand within a particular GSP for the distributed generation simply has the net effect of reducing demand.

However, it acknowledged there were avoided costs from distributed generation in investment required at the interface point between the transmission and distribution networks, estimated to be £5.00-5.75/kW (2010 prices), and the costs associated with connecting a generator to the transmission system, estimated at £1.50/kW on an annuitised basis.

National Grid also considered commoditisation of the residual element of TNUoS charges but concluded this was not in itself a solution to the issue of embedded benefit. This would mean charging the residual (non locational) elements of TNUoS charges on a kWh basis instead of on a per kW basis as is currently the case for generation and half hourly demand (with all non-half hourly charges made on a p/kWh basis). National Grid identified that the load factor of the generation plant would then be a key determinant of charge. It said for low load factor plant, such as wind and hydro (assumed load factor 27% and 37% respectively), the embedded benefit is reduced to what could be considered more cost reflective levels (around £9.20/kW and £12.80/kW respectively). However, for average load factor plant (assumed at 56%) it said the embedded benefit remained largely at those levels provided by the existing transmission charging arrangements (around £18.30/kW). It concluded that commoditisation in itself is not a solution to the issue of embedded benefits but did not preclude it as part of a wider solution to charging issues.

Potential Enduring Solutions

National Grid presented two possible solutions to stimulate debate and invited industry views on the pros and cons of each:

- **the gross nodal supplier agency model.** This would treat all generation, both directly connected and embedded, equally for transmission charging purposes, except for a cost reflective discount (which National Grid said would be in the order of £6.50-£7.25) applied to the generation tariff levied on distributed generation, reflecting the avoided investment in the transmission network. For Supplier Volume Allocated embedded generation TNUoS and BSUoS would be levied on the supplier in respect of all generation in excess of a predetermined threshold based on transmission entry capacity (TEC) or "DGTEC" (TEC obtained by distributed generation). TNUoS demand tariffs would be levied on gross demand. The residual element of TNUoS generation tariff could remain TEC/ triad-based or be

commoditised and the residual element of demand tariff could remain triad based or be commoditised; and

- **the net DNO agency model.** This would treat embedded generation as negative demand and would require users, via the DNO, to book firm exit products in the form of transmission offtake capacity (TOC) for demand and distributed generation transmission entry capacity (DGTEC) for distributed generation (both SVA and CVA registered). National Grid would levy TNUoS and BSUoS generation and demand tariffs on DNOs and directly connected demand and generation on a net basis. The locational element of TNUoS would be calculated and charged based on TEC, DGTEC and TOC.

Consultation responses and workgroup

The consultation received responses from a range of market participants and in general it was not well received. Several did not believe that the case for change had been made and/or that the consultation was poorly timed, including RES, Good Energy, Statkraft, Fred Olsen Renewables and Scottish Power. EON UK said it was concerned that such proposals would have a significant and detrimental effect on past and planned investment in distributed generation. It also believed that the timescales for such fundamental reforms were too tight, particularly in light of their questionable benefits. RWE Npower highlighted that a simple change to the charging methodology while part of any solution may not be sufficient to deliver robust and enduring transmission arrangements for distributed generation. It said given the range and extent of the issues any proposals to address transmission arrangements for distributed generation will impact on a number of different codes, licences and regulatory arrangements. First Hydro said key issues that needed to be examined as part of the review included the benefits and the costs associated with distributed generation and a methodology for charging those costs. The Renewable Energy Association stressed that the gross/net issue was by far the most important issue that ought to be decided on “as a matter of principle”. Several respondents highlighted the need for a minimum generation threshold limit for the proposed arrangements.

A workgroup was set up by National Grid which met four times, the last time in June 2010. The workgroup considered the strawman models and associated issues. The final workgroup presentation by National Grid set out an indicative timetable for changes and timescales for some form of gross supplier agency model, which would see a BSC and CUSC modification raised in June/July 2010 with implementation of an enduring solution from 1 April 2011.

P260 Extension to Data Provided to the Transmission Company in the TNUoS

National Grid raised this BSC proposal⁴⁹ in June 2010 which sought to ensure that the data sent to it by the Supplier Volume Administration Agency in the daily transmission use of system (TUoS) report would also include gross allocated volume data for half hourly demand and generation for each supplier Balancing Mechanism Unit in every Grid Supply Point Group, in addition to the net demand allocated volume data already provided. During assessment by the modification group, the original proposal was further developed so that gross allocated volume data for non-half hourly demand and generation would also be provided. An alternative proposal was also developed that would give wider access to the TUoS report

In its decision⁵⁰ in November 2010 Ofgem said that “there is broad consensus within industry that the current embedded benefit available to exemptible [distributed generation] DG is disproportionately higher than any potential savings from deferred transmission investment”. However, it rejected the proposal on the grounds that National Grid had indicated that it could not utilise this data in the charge setting process for the year from April 2011 and therefore the benefits of obtaining the additional data were difficult to quantify in relation to the TNUoS charging methodology and did not outweigh the costs of implementation.

Run up to Project Transmit

In June 2010 Ofgem announced its plans to undertake a review of the existing transmission charging arrangements — Project Transmit (see below). In the light of this announcement National Grid decided to

⁴⁹ <https://www.elexon.co.uk/mod-proposal/p260-extension-to-data-provided-to-the-transmission-company-in-the-tuos-report/>

⁵⁰ https://www.elexon.co.uk/wp-content/uploads/2012/02/p260_d_rejected.pdf

delay a further consultation on GB ECM-23 until further clarity on the review was available⁵¹. In October National Grid wrote to Ofgem informing it that it considered it was no longer possible to implement an enduring charging arrangement from 1 April 2011, partly due to the interaction with the scope and timeline for Project Transmit, and also because there was still a substantial amount of work required to develop the distributed generation charging solution along with other associated changes. The regulator consulted on further extending the small generator discount by two years from 31 March 2011 to 31 March 2013⁵². It said that it had established with National Grid that Project Transmit represented the “best vehicle” for the continuation of the work started through the development of GB ECM-23.

Project Transmit

Ofgem launched this project in September 2010 with a call for evidence⁵³. The objective of the review was to ensure that there were arrangements in place that facilitate a timely move to a low carbon energy sector and it initially was set to consider, for both electricity and gas transmission, charging and related connection issues as well as the way that charging would need to accommodate cross-European and other market and regulatory developments.

In January 2011 the regulator set out the confirmed scope of Project Transmit and a summary of responses to the call for evidence⁵⁴. It said that in relation to the treatment of distributed generators that a few respondents considered there was no evidence to support a move away from current treatment of distributed generation in the charging methodology, some criticising the policy direction of National Grid’s TNUoS charging consultations. Ofgem determined that the Project Transmit would focus on electricity connections and electricity transmission charging, and it did not include the treatment of distributed generation

In July 2011 Ofgem launched a Significant Code Review (SCR) on transmission charging⁵⁵. It noted that some respondents to its consultation on this considered that the SCR should be expanded to consider the treatment of distributed generation under the TNUoS methodology. However, while Ofgem said it recognised the need to develop appropriate arrangements that recognised the increasing deployment of distributed generation, it considered the resolution of this issue was not deliverable within the timeframes of the proposed TNUoS charging SCR process. It considered that it would be sensible to defer the development of an enduring solution until the outcome of the review work to establish the TNUoS methodology upon which appropriate embedded benefits would be based. Therefore this area was not to be progressed as part of the SCR process.

At the conclusion of the SCR in July 2012 National Grid was directed to raise a CUSC modification, *CMP213 Project Transmit TNUoS Developments* that sought to: better reflect the costs and benefits imposed by different types of generators on the transmission network; take into account the potential Scottish island links being considered; and take into account the development of the HVDC “bootstrap” links. This went through the CUSC modification process, including an impact assessment and a further consultation by the regulator before one of options under the proposal was approved by Ofgem in July 2014 for implementation in April 2016.

National Grid letter and further extension to small generator discount

In March 2012 National Grid wrote a letter⁵⁶ to the regulator which sought to avoid parallel development of the TNUoS charging arrangements and fundamental changes to the charging arrangements for embedded

⁵¹ Letter on *Interim approach to charging modifications* http://www.nationalgrid.com/NR/rdonlyres/44201E6D-B4A1-4D94-BF50-342350ED3D69/43170/IndustryLetter_final_review.pdf

⁵² https://www.ofgem.gov.uk/sites/default/files/docs/2010/10/101810_small-gen-open-letter-publisheda_0.pdf

⁵³ https://www.ofgem.gov.uk/sites/default/files/docs/2010/09/transmit_call_for_evidence_letter_0.pdf

⁵⁴ https://www.ofgem.gov.uk/sites/default/files/docs/2011/01/110125_transmit_scope_letter_final_0.pdf

⁵⁵ https://www.ofgem.gov.uk/sites/default/files/docs/2011/07/110707_final-launch-scr-statement_0.pdf

⁵⁶ https://www.ofgem.gov.uk/sites/default/files/docs/2012/07/nget-letter-relating-to-the-review-of-cl3_5-3-12_0.pdf

generation. It presented a possible timetable for the progression of embedded generation charging arrangements which included extending the small generator discount from March 2013 to March 2016.

National Grid said it had initially suggested this area for a Significant Code Review but had since recognised the limitations of this approach in addressing this issue and agreed that National Grid would be best placed to lead the industry debate. At this stage it was expected that CMP213 would be implemented in April 2013 or April 2014, meaning that there would be insufficient time to progress the embedded charging arrangements. National Grid said that to implement its preferred model, in addition to CUSC modifications, there would also be a need to raise a BSC modification to replicate the effects of P260 (see above) as well as potential DCUSA consequential changes.

Ofgem took account of this letter in its decision to extend the small generator discount again by three years to 31 March 2016. In its consultation⁵⁷ Ofgem considered that a further extension of the discount was not a desirable option but that the fundamental changes to the charging arrangements being progressed under the banner of Project Transmit and the impact this may have on the enduring charging baseline presented unique circumstances. It considered the extension would allow an enduring embedded generation solution to be developed that could build upon any new transmission charging baseline arising from CMP213.

Review of Embedded Generation Benefits - National Grid

This informal review was conducted by National Grid from April 2013 to April 2014⁵⁸ with a “focus group” of members from different sections of industry, with twelve members and Ofgem as an observer.

The scope of the work was envisaged to be: to review the GB ECM 23 and whether there were other options that can be pragmatically implemented; review the impact of Project TransmiT/CMP213 on the proposals; consider whether there is any interaction with the DNO charging methodologies; consider the potential proposals against the applicable CUSC objectives, (facilitating competition, cost-reflective charging and accounting for developments in the transmission businesses); and identify potential consequential changes, for example to licences, the BSC and distribution codes. It was initially expected that a CUSC proposal would be raised in October/November 2013.

Consultation and responses

The focus group met five times between May and October 2013 and in December National Grid issued a consultation on its work. This included analysis by National Grid, reflecting input by the group, followed by a report on the discussions of the focus group.

National Grid’s analysis looked at the scale of embedded benefits related to TNUoS and BSUoS charges and transmission losses. Its analysis indicated the embedded benefit (summation of the generator and demand residual elements) could be £27.54/kW to £41.30/kW in 2013-14 depending on the location of the generator. It estimated that £215mn was the value of the benefits that would otherwise be redistributed amongst TNUoS charge payers.

It analysed the costs faced by those generators eligible for the small generator discount compared with the costs faced by sub 100MW generators connected at distribution level in England and Wales, including TNUoS charges and connection charges.

National Grid looked at the costs of avoided transmission infrastructure investment at GSPs from embedded generation and concluded the average annuitised cost was £1.58/kW in 2012-13 prices. Finally it examined exporting GSPs, the rationale being that these GSPs are more likely to trigger network reinforcements in order to cope with the increasing levels of embedded generation. It found that 37% of GSPs in Scotland and 22% in England and Wales were exporting at some point in 2012-13.

Initial focus group discussions considered that there were two potential areas of defect in the arrangements: the cost reflectivity of transmission charges on distribution connected generation; and the

⁵⁷ https://www.ofgem.gov.uk/sites/default/files/docs/2012/07/final_small_generator_c13_open_letter_24-7-12_published_0.pdf

⁵⁸ <http://www2.nationalgrid.com/UK/Industry-information/System-charges/Electricity-transmission/Transmission-Network-Use-of-System-Charges/Embedded-Benefit-Review/>

impact of transmission charges on competition between transmission and distribution connected generation. Most of the focus group “felt there was no clear defect or impact on the embedded benefit within the two apparent defects presented”, but that the review should focus on cost reflectivity as the cost reflectivity of embedded benefits could be improved. Discussion in the focus group included:

- the extent to which embedded generation uses transmission;
- the de minimis level of embedded generation that could be considered to impact on the transmission system;
- the embedded benefit arising from TNUoS charges;
- whether demand should be charged net or gross;
- the comparison of transmission and distribution network charges paid by generation users; and
- exporting GSPs.

The focus group considered options for change. There was a level of support for developing options to better reflect the impact of exporting GSPs on the transmission system in the TNUoS charging methodology. There was a view that 132kV system in Scotland should be re-designated distribution, but the Chair said this would be a more fundamental reform. In respect of the agency models, there was acceptance that charges and payments via DNOs could be more cost reflective but would “likely require more industry reform”.

The group also considered options for resolution of the need to address the small generator discount, which included removing it in April 2016 or some other justifiable date, enshrining it in the TNUoS methodology, tapering it to a fixed value that would decline in real terms over time or retaining it for existing projects but closing it to new ones.

Responses to the consultation, of which there were 33, were in general in favour of retaining levying charges on a net rather than a gross basis, including E.ON UK, Good Energy, Scottish Power, SmartestEnergy and RWE Npower. Ecotricity, while also supporting the net basis, suggested that net charging at a nodal level rather than a distribution zonal level would be a more accurate method of establishing a supplier’s actual demand on the transmission network. It said the net DNO model would be most suitable to realise this. However, EDF Energy supported charging on a gross basis, with explicit generator charging. It did not attach special importance to the point when a GSP becomes a net exporter as all embedded generation influences flows across the entire transmission system.

A joint response from six trade associations comprising Energy UK, Renewable UK, the Combined Heat and Power Association, the Renewable Energy Association, the Solar Trade Association, Scottish Renewables and Community Energy Scotland said the review should focus on addressing the C13 licence condition where it recommended that the discount should remain for existing connected generation but be discontinued for generation connecting from 1 April 2016. It considered net flows should be the quantity on which transmission charges are levied, with all tariff components based on the net flows at each location. It agreed that current charging arrangements do not charge effectively for exports from distribution networks onto the transmission system and supported work to introduce appropriate charges for such exports.

Conclusions and Next Steps

National Grid issued the review’s final report in April 2014. It concluded that the small generator discount should be allowed to lapse in 2016 as network charges faced by eligible generation without the discount are within the range faced by distributed generation. It said further information provided through the consultation had enabled a more informed comparison. National Grid noted that if SLC13 were allowed to lapse, any grandfathering arrangements to continue the discount would require a CUSC modification. One was subsequently raised by Fred Olsen Renewables (see below).

On the issue of better reflecting the impact of exporting GSPs on transmission investment National Grid said many respondents considered this is an area of increasing significance that could be better reflected in

the TNUoS charging arrangements and it would continue to develop its thoughts. It subsequently issued a consultation on this element of the arrangements (see below).

It decided not to take forward further options to charge the demand half hourly residual amount of TNUoS on a gross basis, either with or without explicitly charging embedded generation. This would prevent suppliers netting either the demand residual or both the demand residual and the locational element of the charge. Reasons included: waiting for change proposals that will improve the level of information on embedded generation (GC0042 *Information on Small Embedded Power Stations and Impact on Demand* - approved by Ofgem in August 2014)⁵⁹; the volume of industry reforms at that time, including the Electricity Market Reforms and the Electricity Balancing Significant Code Review; the need to ensure there is no discriminatory treatment of demand response, demand management and onsite generation; and that the change could have a “disproportionate impact on a significant number of industry parties when considered alongside any benefits it may provide”.

Potential Charging Arrangements at Exporting GSPs - National Grid informal consultation

National Grid held a consultation⁶⁰ between August and October 2015 on options for better reflecting the impact that exporting GSPs have on the transmission system. There were 47 of these GSPs in 2013-14 and 51 in 2014-15 (which included all of those in 2013-14).

This proposed charging DNOs for a local charge on the net export of a GSP. National Grid proposed that DNOs were the appropriate parties to be liable to pay a TNUoS local charge, as it has a contractual relationship with the DNO at the GSP and because the DNO has responsibility for coordinating net power flows at the GSP. These local charges would be treated in a similar manner to local connection charges. National Grid said an alternative could be a commercial framework developed directly between it and an increasing number of DGs.

It proposed that only those GSPs with a higher maximum export than their maximum import would be liable for the charge and put forward two options:

- **Option 1 - Local substation charges.** Transmission connected generators pay local substation charges based on a tariff reflecting the nature of the substation they connect to. This option would extend the relationship to exporting GSPs and would be based on the high voltage (HV) i.e. transmission side of the GSP. GSPs with HV double busbars would be considered to have “redundancy” while those with HV single busbars would have “no redundancy”; or
- **Option 2 - Local circuit and substation charges.** Transmission connected generators pay a local circuit charge if they are deemed to have local circuits connecting them to the main interconnected transmission system (MITS). Additionally all transmission connected generators pay local substation charges. This option would extend these relationships to exporting GSPs and would also include a “local transformer tariff” at shared exporting GSPs. Not all exporting GSPs would qualify for a local circuit charge as some would connect directly into MITS nodes. The size of the local circuit tariff would depend on the nature and length of the local circuits.

The consultation also considered longer term commercial arrangements, including noting that embedded generation is remunerated for balancing services but does not pay BSUoS and that GSPs that spill onto the transmission system do not pay access rights.

In the consultation responses there was majority support supporting focusing only on exporting GSPs where the maximum export is higher than the maximum import and that the charges should be passed on to DNOs who would need to put in place arrangements to recover the costs from generators. National Grid also received feedback that it should undertake further work to determine how exporting GSPs drive investment. It said there was no consensus on whether the identification of exporting GSPs should be based

⁵⁹ GC0042 sought that DNOs provide certain additional pieces of information to National Grid about power stations over IMW to enable it to more accurately plan and operate the transmission system. <http://www2.nationalgrid.com/UK/Industry-information/Electricity-codes/Grid-code/Modifications/GC0042/>

⁶⁰ <http://www2.nationalgrid.com/UK/Industry-information/System-charges/Electricity-transmission/Transmission-Network-Use-of-System-Charges/Transmission-Charges-Open-Letters/>

on historical data, changes to main interconnected transmission system (MITS) node definitions, and the potential to align local charging with longer term requirements.

Following the consultation, National Grid is considering how the issue of exporting GSPs should be progressed.

Proposal to grandfather small generator discount and further extension

Fred Olsen Renewables raised CMP239 *Grandfathering Arrangements for the Small Generator Discount*⁶¹ in October 2014. The original proposal sought an end date of 25 years from 1 April 2016 for new generators connecting ahead of this date. For existing generators the end date would be 25 years from their commissioning date. Three alternative proposals were also developed, which included reflecting the timing of significant investment decisions and the instance where 132kV is re-classified as distribution in Scotland.

Ofgem rejected the proposal in August 2015. It said the licence condition was time limited and therefore parties should expect it to expire at some point, albeit that there had been a number of extensions. It also considered that grandfathering the small generator discount for some generators only would be discriminatory. It said CMP239 would therefore lead to the distortion of competition, which could lead to inefficient outcomes and may increase the cost of generation, which would impact bills in the medium to long term.

In January 2016 Ofgem issued its decision⁶² following a consultation to further extend the small generator discount to 31 March 2019. It said it was appropriate that the discount remains in place while ongoing work in developing enduring arrangements for transmission charging for embedded generation continues, noting National Grid's work on exporting GSPs.

Ofgem received 16 responses to its consultation: ten in favour, five against and one neutral. It noted some respondents had referenced National Grid's analysis on the costs faced by those eligible for the discount and sub 100MW distributed generators in England and Wales. Ofgem said it did not consider the evidence considered allowed it to reach a view on whether letting the discount expire is more cost reflective than continuing with the discount.

In support of its position, the regulator noted that the evidence available to National Grid in respect of connection charges was limited. In particular, it said the bottom-up estimate of connection charges for distribution connected generators that National Grid used to reach this conclusion relied on a small and self-selecting sample of connection charges and varied significantly from its top-down estimate carried out earlier in the review process. Ofgem also noted that the analysis did not fully take account of embedded benefits for sub-100 MW embedded generators and that it did not consider balancing service use of system charges or transmission losses.

Several respondents considered that this and previous decisions to extend the discount created a legitimate expectation that if changes to charging arrangements for embedded generation are not developed by 31 March 2019, then the discount will be extended again. Ofgem denied this and said that any future decision on extending the discount will be made based on the evidence available to it at that time. However, it said it is aware of the growing level of embedded benefit and National Grid's ongoing work on exporting GSPs. It was also aware that small-scale generators bring a range of benefits, including for security of supply as they can help to meet peak demand by producing electricity when it is most needed. The regulator said it is "looking into whether action is needed in this area".

Further Reforms to the Capacity Market - DECC consultation

DECC issued this consultation⁶³ on 1 March 2016 (closed 1 April) which set out proposed reforms to the Capacity Market (CM) following its review of the mechanism. In relation to the growth of diesel engines DECC said:

⁶¹ <http://www2.nationalgrid.com/UK/Industry-information/Electricity-codes/CUSC/Modifications/CMP239/>

⁶² https://www.ofgem.gov.uk/system/files/docs/2016/01/c13_stat_con_decision_letter_final.pdf

⁶³ https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/504217/March_2016_Consultation_Document.pdf

“Small distribution-connected generators are receiving increasing revenues from “embedded benefits” which include avoided transmission network charges. Some of this is justified because they offer system benefits such as avoided network reinforcement costs. However Ofgem has previously expressed concerns that these arrangements are not fully cost reflective; and hence “embedded benefits” may over-reward distribution-connected generators such as diesel reciprocating engines. Moreover, the proportion of generation connected at distribution level is increasing and so is the impact of flows from the distribution network on the transmission network.

Ofgem is therefore concerned that these charging arrangements could be having an increasing impact on the system, including distorting investment decisions and leading to inefficient outcomes in the CM. Ofgem is therefore reviewing whether it would be in consumers’ interests to change the charging arrangements for distribution-connected generators. Ofgem will set out their conclusions and a proposed way forward on this matter, potentially including initiating changes to the charging regime, in the summer. Ofgem will need to consider carefully how and when any changes should be implemented, including whether any transitional arrangements are required, and will aim to provide clarity on their direction of travel before prequalification for the next CM auction.”

Appendix B - International Models of Transmission Charging Arrangements

This section considers international models of transmission charging arrangements and draws on reports produced for Project Transmit and the annual survey of transmission tariffs produced by ENTSO-E. This focuses particularly on countries where there are generator charges and where these are not postalised. Where a country is considered by more than one report the most detailed is set out, and supplemented by further material where available.

Many countries do not allocate any transmission charges to generation, for example, 21 out of the 35 European countries surveyed by ENTSO-E do not. Of those that do, some of these charges relate to items not included in the GB charging methodology for TNUoS, notably losses and system services.

CEPA's study highlighted two key dimensions to network charges: whether they were postage stamp (for example Netherlands and Spain) versus zonal (for example GB) network charges; and the allocation of charges between generation and demand. It also noted different approaches taken to connection charges, which is relevant for the overall cost-reflectivity of charges. These can be "shallow", usually based on the simply recovering the costs related to the physical connection assets between the connected party and (usually) the nearest network connection point, an approach used in the UK, Australia, New Zealand and elsewhere; or "deep". These are based on a combination of shallow charges plus the costs related to any additional "downstream" network reinforcement required to support the load of the connected party. This approach is used in PJM in the US, and for load (not generation) in Germany. CEPA noted that it is possible, depending on the details of application, that a combination of "deep" connection charging and postalised use of network charges might achieve more or less the same type of cost reflectivity as a combination of "shallow" connection charging and locationally differentiated use of network charges.

Poyry's survey also highlights some important differences, for example, in the GB system charges are based on two different sets of zones, for generation and demand, while in some other markets, for example Ireland, Norway and the PMJ, charges are based on nodes. There is also variation in the basis of charges with respect to whether they are based on production/consumption at system peak or in aggregate over the course of a year. Poyry set out some of the key differentiators between the markets it chose to study (see chart below), the "building blocks" that can be combined to form viable end-to-end transmission charging solutions.

International markets transmission use of system

Building block	Country							
	GB (TNUoS)	Germany	Ireland	Norway	Sweden	PJM	Texas	NEM
Generation or demand	G: 27% D: 73%	G: 0% D: 100%	G: 25% D: 75%	G: ~25-35% D: ~65-75%	G: 25% D: 75%	G: 0% D: 100%	G: 0% D: 100%	G: 0% D: 100%
Short-term or long-term pricing	Long-term	Long-term	Long-term	Short-term mainly	Mixed	Mixed	Mixed	Mixed
Locational or non-locational	Locational	Non-locational	Locational	Locational	Locational	Locational	Non-locational	Locational
Zonal or nodal	Zonal	n/a	Nodal	Nodal	Nodal	Nodal	Zonal*	Zonal
Capacity or commodity	Capacity	Commodity	Mixed	Commodity mainly	Commodity mainly	Mixed	Commodity	Mixed
Peak or annual	Peak	Annual	Mixed	Mixed	Mixed	Mixed	Peak	Mixed
Single or multiple system conditions	Single	n/a	Single	Multiple	Multiple	Mixed	Single: system peak	Mixed
Dynamic or static	Static	Static	Static	Mixed	Mixed	Mixed	Static	Mixed
Ex-post or ex-ante	Ex-ante	Ex-ante	Ex-ante	Ex-post	Ex-post	Mixed	Ex-ante	Ex-ante
Shallow or deep connection	Shallow	Mixed	Shallow	Shallow	Deep	Deep	Shallow	Shallow

* Moving towards a nodal structure at the end of 2010

Source: Poyry

Australia - National Energy Market

In a report⁶⁴ produced for Ofgem for Project Transmit in February 2011 CEPA identified the differences between the Australia National Electricity Market (NEM) approach of cost reflective network pricing (CRNP) and National Grid's incremental cost reflective pricing approach (ICPR).

In the NEM charges are computed on a state by state basis and all the charge is assigned to demand. In general within each stage the net revenue requirement ascribed to transmission use of system is apportioned so that 50% is used to form a non-locational charge within each state charged to all load, and 50% is allocated to individual offtake points via a load-flow simulation process.

Drawing on the CEPA research, the CRNP approach is set out in the National Electricity Rules⁶⁵. There are two possible methodologies, the CRNP methodology and the modified CRNP methodology.

The CRNP has the following steps:

“(1) Attributing network ‘costs’ to *transmission system assets*: the locational component of the ASRR allocated to *prescribed TUOS services* is allocated to each asset used to provide *prescribed TUOS services* based on the ratio of the optimised replacement cost of that asset, to the optimised replacement cost of all *transmission system assets* used to provide *prescribed use of system services*. The allocation to each *transmission system asset* is the ‘locational network asset cost’.

(2) Determining the baseline allocation of *generation to loads* using a ‘fault contribution matrix’.

(3) Determining the allocation of dispatched *generation to loads* over a range of actual operating conditions from the previous *financial year*. The range of operating scenarios is chosen so as to include the conditions that result in most stress on the *transmission network* and for which *network investment* may be contemplated. For each operating scenario selected:

- (i) a constrained allocation of *generation to loads* matrix must be developed, in which *generation* is allocated to serving *loads* on the basis of the fault contribution matrix;
- (ii) load flow analysis techniques are used to solve for *network flows* and to calculate the sensitivity of flows on each *network element* resulting from incremental changes in each *load*;
- (iii) the sensitivities are weighted by *load* to derive a ‘flow component’ magnitude in each *network element* due to each *load* for that hour;
- (iv) the relative utilisation of each *network element* by each *load* is calculated from the ‘flow component’ magnitudes, using only the flow components in the direction of the prevailing line flow.

(4) When all the selected operating scenarios have been assessed, allocating the individual locational *network asset costs* to *loads* on a pro rata basis using the maximum ‘flow component’ that each *load* has imposed on each *network asset* across the range of operating conditions considered.

(5) Summing the individual locational *network asset costs* allocated to each *load* to give the total amounts allocated to that *load*.”

There are also rules for permissible postage stamp pricing structures⁶⁶.

Sweden

As part of Project Transmit Poyry produced a report for EDF Energy in November 2010: *Electricity Transmission Use of System Charging: Theory and International Experience*⁶⁷.

Historically generators have paid 25% while demand has paid 75%, although these values are not fixed. The Swedish market is geographically divided between north and south, with most generation in the north and

⁶⁴ https://www.ofgem.gov.uk/sites/default/files/docs/2011/02/project_transmit_-_cepa_report_0.pdf

⁶⁵ Version 79, Chapter 6A, p127 <http://www.aemc.gov.au/getattachment/c8ab497d-86ce-4555-996e-1d2ebd52ca1a/National-Electricity-Rules-Version-79.aspx>

⁶⁶ *Electricity transmission network service providers Pricing methodology guidelines* p11, http://www.aer.gov.au/system/files/AER%20-%20Transmission%20pricing%20methodology%20guidelines%20-%2017%20July%202014_3.pdf

⁶⁷ <http://www.poyry.com/sites/default/files/electricitytransmissionsystemcharging-nov2010-energy.pdf>

demand in the south. As such the transmission pricing regime imposes relatively high charges on generation in the north and demand in the south with nodally varying charges. There are two main charges:

- an energy charge, based on the extent to which a party increases or reduces losses at a given node; and
- a capacity charge depending on the capacity at each connection point. The charge for injections is highest in the north and reduces linearly with latitude in the south, with the opposite for withdrawals.

Pennsylvania Jersey Maryland (PJM)

Demand pays 100% of the charge through three different mechanisms:

- usage charges aimed at reflecting the impact of congestion and losses;
- network integration transmission services charges, which are locationally differentiated commodity charges levied on daily peak demand. Charges differ between zones providing a location signal; and
- point to point transmission service charges, which are postage stamp, capacity charges.

ENTSO-E survey of transmission tariffs 2015

This annual survey⁶⁸ was issued in June 2015. Of the 35 countries looked at, apart from GB, only Ireland and Northern Ireland (for generation only), Romania and Sweden have any locational signals in transmission tariffs. 14 of the 35 allocate some proportion of the costs to generation, with Austria the highest at 43%. 13 of the countries operate at least one time differentiation in their charges.

Romania

In Romania both generation and load users pay location-based grid input/offtake charges. Differences across the location-based transmission price list are based on the impact the incremental input/off-take of energy in the connection point has on the amount of losses incurred at the transmission grid level. Losses are included in the transmission use of system charge.

Ireland

The GTUoS capacity charge is calculated individually for each generator based on the location of its connection to the system. This GTUoS charge is capacity based (i.e. based on MEC of generator), there is no energy (MWh) component for GTUoS. The GTUoS tariff has a locational element; which is calculated considering the usage of current generation on future network using a “reverse MW mile” methodology.

This methodology was explained by the CER⁶⁹:

“The methodology for calculating locational TUoS charges for generators is based on the Reverse MW-mile approach. This approach allocates a share of the fixed costs of the network to the generator based on its usage of the transmission system, reflecting the fact that cost depends on the distance and direction that power is being transmitted as well as the level of power being transmitted. The methodology rewards generators which offset network flows and averages the cost of spare capacity that exists in the network across all users. There are three main steps involved in deriving transmission tariffs using the reverse MW-mile approach:

1. Load flow analysis is first conducted to determine the use of each circuit by each generator, based on peak load conditions. Usage is then divided into: flows that add to overall system flow (dominant flows); and those that counter the overall flows (reverse flows). Generators producing dominant flows will pay for their usage whilst those producing reverse flows will be credited for reducing overall transmission flows;

⁶⁸ https://www.entsoe.eu/publications/market-reports/Documents/ENTSO-E%20Overview%20of%20Transmission%20tariffs%202015_FINAL.pdf

⁶⁹ <http://www.cer.ie/docs/000830/cer03298.pdf>

2. The annual replacement costs of overall transmission assets are then broken down on a cost per circuit basis; and
3. The charge to each generator is made on their proportional usage of each circuit multiplied by the cost of each circuit. This delivers a generator circuit charge. Per circuit charges are aggregated across all circuits to derive the generator's aggregate locational use-of-system charge.

Due to inherent spare capacity on the intact network (as it is designed to withstand certain contingencies) the aggregate locational charges do not recover all generator related revenue requirements. The remainder of the charge is recovered on a postage stamp basis."

Northern Ireland also uses the "reverse MW mile" methodology.

Appendix C – Breakdown of Total Embedded Benefits

(i) Embedded Benefits LV/HV

Estimated Value of Embedded Benefits - Non-Intermittent Generation (£)

	2011/12	2012/13	2013/14	2014/15	2015/16
Transmission System Embedded Benefits					
Transmission Network Use of System	14,539,581	17,586,158	21,868,315	27,213,464	33,089,758
Balancing Services Use of System	6,642,153	7,617,650	10,314,761	11,114,197	12,885,305
Transmission losses	4,393,242	3,830,655	5,081,668	5,357,137	5,552,726
Areas of Assistance (AAHDC)	717,083	902,583	1,053,588	1,181,737	1,231,472
Capacity Market Supplier Charge	0	0	0	0	92,726
Distribution System Embedded Benefits					
Generator Distribution Use of System	23,869,898	23,869,898	26,643,264	26,811,105	31,106,556
Distribution losses	15,750,510	18,063,701	20,976,208	23,163,957	19,345,395
Total	£65,912,468	£71,870,645	£85,937,804	£94,841,597	£103,303,939

Estimated Value of Embedded Benefits - Intermittent Generation (£)

	2011/12	2012/13	2013/14	2014/15	2015/16
Transmission System Embedded Benefits					
Transmission Network Use of System	13,811,383	16,837,768	21,991,210	21,495,810	44,702,578
Balancing Services Use of System	3,268,770	3,127,929	4,693,895	4,212,809	7,751,309
Transmission losses	1,885,161	1,803,935	2,312,493	2,030,610	3,340,309
Areas of Assistance (AAHDC)	352,895	370,615	479,452	447,935	740,807
Capacity Market Supplier Charge	0	0	0	0	55,780
Distribution System Embedded Benefits					
Generator Distribution Use of System	8,871,792	8,871,792	11,136,692	9,730,566	18,195,242
Distribution losses	7,751,221	7,417,245	9,545,554	8,780,242	11,637,453
Total	£35,941,223	£38,429,284	£50,159,296	£46,697,971	£86,423,478

Estimated Total Value of Embedded Benefits (£) at LV/HV

	2011/12	2012/13	2013/14	2014/15	2015/16
Transmission System Embedded Benefits					
Transmission Network Use of System	£28,350,965	£34,423,925	£43,859,525	£48,709,274	£77,792,336
Balancing Services Use of System	£9,910,923	£10,745,579	£15,008,656	£15,327,006	£20,636,614
Transmission losses	£6,278,403	£5,634,590	£7,394,161	£7,387,746	£8,893,035
Areas of Assistance (AAHDC)	£1,069,978	£1,273,198	£1,533,040	£1,629,672	£1,972,279
Capacity Market Supplier Charge	£0	£0	£0	£0	£148,506
Distribution System Embedded Benefits					
Generator Distribution Use of System	£32,741,690	£32,741,690	£37,779,956	£36,541,671	£49,301,798
Distribution losses	£23,501,732	£25,480,947	£30,521,762	£31,944,199	£30,982,848
Total	£101,853,691	£110,299,929	£136,097,100	£141,539,568	£189,727,417

(ii) Embedded Benefits at EHV

Estimated Total Value of Embedded Benefits (£) at EHV

	2011/12	2012/13	2013/14	2014/15	2015/16
Transmission System Embedded Benefits					
Transmission Network Use of System	£100,655,784	£128,474,917	£135,261,981	£183,423,264	£215,216,340
Balancing Services Use of System	£39,257,312	£43,872,064	£51,706,408	£63,469,132	£74,625,478
Transmission losses	£24,656,682	£25,301,843	£25,473,667	£30,592,659	£32,158,717
Areas of Assistance (AAHDC)	£4,251,243	£5,198,214	£5,281,483	£6,748,471	£7,132,095
Capacity Market Supplier Charge	£0	£0	£0	£0	£0
Distribution System Embedded Benefits					
Generator Distribution Use of System	£20,624,101	£20,919,286	£17,154,553	£16,625,420	£16,519,509
Distribution losses	£17,978,831	£20,594,524	£20,978,314	£23,277,023	£24,468,589
Total	£207,423,953	£244,360,849	£255,856,406	£324,135,969	£370,120,728

Appendix D – Categorisation of TNUoS Allowed Revenue for 2015-16

	Short-Term Demand Related	Long Term Demand Related	Non-Demand Related	Comments
BASE REVENUE				
Direct opex	£208.6			Direct costs tend to vary with short term demand
Business Support and Closely Associated Indirects			£124.3	Indirect costs tend to be fixed and do not vary with the general level of demand
Non-controllable opex		£153.5		Mainly business rates that will vary with the level of assets installed
RAV depreciation		£929.0		Depreciation varies with the level of installed assets and therefore long term demand
Return		£670.9		Return varies with the level of installed assets and therefore long term demand
Additional income			£28.3	Relates to IQI income
Core Direct Allowed Revenue Terms (DARTs)	-£83.3	-£83.3	£78.5	Pension adjustments are not demand related. Excluded services are related to either long term or short term demand.
Tax allowance	£64.0	£64.0		
Offshore Transmission		£261.4		
FURTHER ADJUSTMENTS				
Pass through items		£7.0		
Incentive revenue,			£13.9	Incentive income is dependent on quality of service and is not directly demand related
Network Innovation Allowance/ Competition			£55.5	
Scottish Site Specific Adjustment			£2.9	
Total Revenue	£189.3	£2,002.5	£303.5	

Glossary

Acronym	Definition
AAHDC	Assistance for Areas of High Distribution Costs
BELLA	Bilateral Embedded Licence Exemptible Large Power Station Agreement
BERR	Business, Enterprise and Regulatory Reform
BETTA	British Electricity Trading Transmission Arrangements
BSUoS	Balancing Services Use of System Charge
CCGT	Combined Cycle Gas Turbine
CDCM	Common Distribution Charging Methodology
CM	Capacity Market
CMA	Competition Markets Authority
CMSC	Capacity Market Supplier Charge
CUSC	Connection and Use of System Code
DC	Direct Current
DCUSA	Distribution, Connection and Use of System Agreement
DCP	DCUSA Change Proposal
DECC	Department of Energy and Climate Change
DNO	Distribution Network Operator
DRM	Distribution Reinforcement Model
DSR	Demand Side Response
DUKES	Digest of UK Energy Statistics
DUoS	Distribution Use of System
EFR	Enhanced Frequency Response
EHV	Extra High Voltage
ELEGs	Embedded Licence Exemptible Generators
ENTSO	European Network of Transmission System Operators
FCP	Forward Cost Pricing
GDUoS	Generation Distribution Use of System
GSP	Grid Supply Point
HV	High Voltage
ICRP	Investment Cost Related Pricing
LRIC	Long Run Incremental Cost
LTDS	Long Term Development Statement
LV	Low Voltage
MOD	Modification term
NIA	Network Innovation Allowance
NIC	Network Innovation Competition

NUF	Network Use Factor
OCGT	Open Cycle Gas Turbine
OPEX	Operating Expenditure
PPA	Power Purchase Agreement
RAV	Regulatory Asset Value
RCRC	Residual Cashflow Reallocation Cashflow
RIIO-ETI	Revenue = Incentives+ Innovation+ Outputs - Electricity Transmission I
RPI	Retail Price Index
SLC	Standard Licence Condition
TAR	Transmission Access Review
TEC	Transmission Entry Capacity
TNUoS	Transmission Network Use of System