Stage 02: Workgroup Consultation

At what stage is this document in the process?

01	Initial Written Assessment
02	Workgroup Consultation
03	Workgroup Report
04	Code Administrator Consultation
05	Draft CUSC Modification
06	Final CUSC Modification Report

CMP280: 'Creation of a New Generator TNUoS Demand Tariff which Removes Liability for TNUoS Demand Residual Charges from Generation and Storage Users'

Purpose of Modification: CMP280 seeks to remove liability from Generator and Storage Parties for the Demand Residual element of the TNUoS tariff.

This document contains the discussion of the Workgroup which formed in July2017 to develop and assess the proposal. Any interested party is able to make a response in line with the guidance set out in Section 6 of this document.

Published on: 19 June 2018

Length of Consultation: 15 Working days

Responses by: 10 July 2018

LOW Impact:

Suppliers: Any reduction in TNUoS Demand Residual charges paid by generators and storage operators will be recovered from the balance of parties liable to Demand TNUoS. However, the demand from generators and storage operators is small as a proportion of the total and most such parties can currently avoid Demand TNUoS charges by avoiding import at Triad; the impact is therefore expected to be minimal.

Generator: Due to the €2.50/MWh cap applied by ER 838/2010 there should be no impact on Generator parties. National Grid. Changes will be required to the TNUoS billing systems to ensure that the new Generator TNUoS Demand tariff is applied to generator and storage parties.

Contents

Timetable

The CUSC Panel agreed the following timetable:

Workgroup Consultation Issued to Industry (15WD)	**19 June 2018**
CUSC Panel Meeting to discuss Workgroup Report	**29 July 2018**
Code Administrator Consultation Report to be Issued to Industry (15WD)	**Early September 2018**
Draft Final Modification Report presented to Panel	**22 November 2018**
Modification Panel Recommendation Vote	**30 November 2018**
Final Modification Report issued to the Authority	**06 December 2019**
Indicative Decision for the Authority*	**January/February 2019**
Decision implemented to CUSC	**1 April 2019/1 April 2020**

* Note to allow for system changes to be made a decision by Summer 2018 is required for change to be applied to Charging Year 2019

Any questions?

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1 Format of this report and Terms of Reference

This report contains the discussion of the Workgroup which formed in July 2017 to develop and assess the proposal.

Section 2 (Original Proposal) and Section 3 (Proposer's solution) are sourced directly from the Proposer and any statements or assertions have not been altered or substantiated/supported or refuted by the Workgroup. Section 5 of the Workgroup contains the discussion by the Workgroup on the Proposal and the potential solution.

The CUSC Panel detailed in the Terms of Reference the scope of work for the CMP280 Workgroup and the specific areas that the Workgroup should consider.

The table below details these specific areas and where the Workgroup have covered them or will cover post Workgroup Consultation.

The full Terms of Reference can be found in Annex 1.

Table 1: CMP280 ToR

Specific Area	Location in the report
a) Consider interactions (if any) with the Ofgem's TCR (Panel noting the timelines associated with the TCR).	Sections 3, 25
b) Consider the practical implications of solution e.g. that all metered data is available to National Grid to support the proposed solution.	Sections 18, 19
c) Consider what the interaction with other participants (e.g. Distribution storage).	Sections 16, 21

2 Original Proposal

Section 2 (Original Proposal) are sourced directly from the Proposer and any statements or assertions have not been altered or substantiated/supported or refuted by the Workgroup. Section 5 of the Workgroup contains the discussion by the Workgroup on the Proposal and the potential solution.

Defect

Under the current Charging Methodology, generator and storage parties contribute to both the Generation and Demand TNUoS Residual tariff elements; these parties are therefore contributing more towards the residual cost of the network when compared with other users. Storage users in particular, who compete with generators in the provision of ancillary services, may therefore be at a competitive disadvantage due to their much higher exposure to TNUoS Demand Residual tariff elements.[1]

Generators and electricity storage operators generally should be able to avoid exposure to Demand TNUoS charges by minimising demand at times of peak system demand (Triad) through generating at these times in order to help balance the system. However, should they import over the Triad (e.g. due to plant outage or instruction to store energy from the System Operator) or should changes in the charging of Demand Residual make it harder to avoid incurring the costs, they would be exposed to potentially significant Demand TNUoS charges.

What

CUSC 14.17 states that Parties with a Bilateral Connection Agreement (BCA) shall be liable for demand charges. CUSC 14.17.10 states that The Chargeable Demand Capacity for a Power Station with a Bilateral Connection Agreement (BCA) or Licensable Generation with a Bilateral Embedded Generation Agreement (BEGA) will be based on the average of the net import over each Triad leg of the BM Units associated with the Power station (in Appendix C of its BCA or BEGA, including metered additional load) during the Triad. CUSC 14.17.11 states that the Chargeable Demand for Exemptible generation and Derogated Distributed interconnectors with a BEGA will be based on the average of the metered volume of each BM Unit specified in Appendix C of the BEGA during the Triad. It is proposed to amend the TNUoS Charging methodology (CUSC Section 14) so that parties who hold TEC during the charging year (generator parties and storage operators) and who import over the Triad periods would be liable for the proposed Generator Demand TNUoS tariff. The Generator Demand TNUoS tariff would be defined as the locational element of the Demand TNUoS tariff as currently calculated, subject to flooring at zero. The locational element of demand TNUoS would be retained as this element is cost-reflective and reflects the marginal impact of increasing demand at times of system peak demand. The locational element would be floored at zero to prevent a perverse incentive on generators or storage

[1] Because in the case of storage, imports typically exceed exports, whereas for generators imports are typically a small proportion of exports

parties in locations with a negative demand locational tariff charge to import during periods of peak demand.

Why

The locational element of the Demand TNUoS tariff provides a cost reflective signal of the impact on the transmission system of increasing demand at a particular location of the transmission system. The TNUoS Demand Residual tariff element is not intended to be cost-reflective and serves to ensure that the Total Allowed Revenue is recovered from parties. As outlined in Ofgem's Targeted Charging Review consultation[2] , Residual charges should be recovered on a basis which: reduces distortions, is fair and is proportional and practical in its application. Requiring generators and storage parties to contribute to both the Generation and Demand TNUoS Residual tariff elements gives an unfair advantage to generators (whose imports are typically a small proportion of exports) compared to storage (whose imports typically exceed exports). The solution is to remove the liability to the TNUoS Demand Residual tariff element from these parties. Failure to do so will perpetuate the above distortion.

How

As identified above, changes are required to the TNUoS Charging Methodology within section 14 of the CUSC to reflect the fact that Generator parties and storage operators should not be liable for the TNUoS Demand Residual element of the tariff. This will require the definition of a new tariff charge for these parties, the Generator TNUoS Demand Tariff.

Detail on why change

Generators and storage operators are both liable to TNUoS Demand Residual charges. However, storage operators are potentially much more exposed to these charges because their imports typically exceed exports, whereas for generators imports are typically a small proportion of exports. This may create a competitive distortion between generators and storage, who compete with each other in the provision of ancillary services.

The TNUoS Demand Residual tariff element is not intended to be cost-reflective and serves to ensure that the Total Allowed Revenue is recovered from parties. As outlined in Ofgem's Targeted Charging Review consultation[3] , residual charges should be recovered on a basis which: reduces distortions, is fair and is proportional and practical in its application. Given that storage and generators are not end users of electricity, and are connected to the network primarily for the purposes of providing flexibility and energy services, there is no rationale for them to contribute to both the generator and demand residual recovery mechanisms.

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[2] Ofgem, Targeted Charging Review: a consultation, 13 March 2017, 5.9

[3] Ofgem, Targeted Charging Review: a consultation, 13 March 2017, 5.9

The solution is to remove the liability to the TNUoS Demand Residual tariff element from these parties. For the avoidance of doubt, both generator and storage parties would remain liable for the cost-reflective locational element of demand TNUoS to reflect the marginal impact of increasing demand at times of system peak demand.

Failure to address this issue will perpetuate a distortion to competition between generators (whose imports are typically a small proportion of exports) and storage (whose imports typically exceed exports).

3 Proposer's solution

Section 3 (Proposer's solution) are sourced directly from the Proposer and any statements or assertions have not been altered or substantiated/supported or refuted by the Workgroup. Section 5 of the Workgroup contains the discussion by the Workgroup on the Proposal and the potential solution.

The CUSC definition of those parties liable to TNUoS Demand charges should be amended to remove the reference to generator parties. A new Generator Demand TNUoS tariff consisting of only the locational elements of the Demand TNUoS tariff as calculated from the TNUoS charging model (and floored at zero) should be defined within the Charging Methodology. The Charging methodology should define those parties liable to the Generator Demand TNUoS tariff.

Details of any potential cross-code, consumer or environmental impacts and attach or reference any other, related work.

We do not believe that there are any cross-code impacts from this Proposal.

Does this modification impact a Significant Code Review (SCR) or other significant industry change projects, if so, how?

On 4 August 2017 Ofgem published the Targeted Charging Review – Significant Code Review launch statement to consider:

- "Reform of residual charging for transmission and distribution, for both generation and demand, to ensure it meets the interests of consumers, both now and in the future; and
- Keep the other 'embedded benefits' that may be distorting investment or dispatch decisions under review."

"The scope of the SCR excludes (amongst other things)

- charging arrangements for storage. Our current thinking is that industry is best placed to bring forward modification proposals to make changes within the current charging framework. We note that at the time of this letter, two code modifications have been raised to address BSUoS (CMP281) and TNUoS (CMP280) charging for storage. We reserve the option, if necessary, of bringing storage charges back into the SCR, and issuing a direction to one or more industry parties to raise modifications."

- In their November 2017 update on the TCR[4], Ofgem stated "Our initial work , however, indicates that it may be in consumers' longer-term interests to recover residual charges from suppliers only, as they ultimately pay all system costs. As such, this is a more transparent approach."
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It is therefore concluded that CMP280 is at present specifically excluded from the scope of the current SCR. As Ofgem have not exercised the option to bring storage charging back within the scope of the SCR it is the view of the Proposer that CMP280 remains out of the scope of the SCR.

Consumer Impacts

Removal of a distortion to competition should result in fairer allocation of the costs of the transmission system and stronger competition, which should in turn drive lower costs in the wholesale electricity market.

4 Workgroup Discussions

The proposer presented the defect that they had identified in the CMP280 proposal and highlighted:

- Generators (including storage) pay network charges both as demand (based on imports at Triad peak and generation (based on TEC).
- Residual charges are not intended to be cost reflective and should serve only to recover TNUoS revenue
- Generators may potentially contribute towards residual charges twice if they import over the Triad peak

The Workgroup explored a number of aspects in its meetings to understand the implications of the proposed defect and solutions The discussions and views of the Workgroup are outlined below.

1. Clarification of the scope of CMP280

Although the defect identified by the Proposer was primarily aimed at storage parties whose potential exposure to TNUoS Demand Residual charges is greater than other generator parties (due to the potential to import significant volumes of energy at the Triad for storage), the proposed solution would address all CVA registered generator parties.

[4] Targeted Charging Review: update on approach to reviewing residual charging arrangements 2.7; Ofgem 6 Nov 2017

2. Proposer's view on why CMP280 would level the playing field

The Working Group noted that this proposed modification was intended to resolve a defect as the defect is present now. Whilst the group recognised that the SCR/TCR may consider this area and that industry needs to consider impacts post CMP280, the WG can only change the current CUSC baseline, while trying to remain aligned to the direction of travel being highlighted by Ofgem.

Under the current charging methodology there are instances where generators (including storage) may pay more towards the residual cost of the transmission network. This would arise where a generator imported over the Triad periods and became liable to the TNUOS Demand Residual charge in addition to the Generation Residual Charge. Certainly there is the potential for generator parties (including storage) to be contributing twice towards TNUoS residual charges.

CMP280 seeks to address this defect by removing liability for the TNUoS Demand Residual tariff element from all generator parties.

The Proposer believes that the Demand Residual tariff is a cost recovery mechanism which is not intended to be cost reflective and is not intended to signal a particular behaviour to parties. This is in accordance with the view expressed in the Targeted Charging Review - Significant Code Review launch statement[5] that "Residual charges are 'top up' charges set to ensure that the network's efficient costs, as determined through price controls, can be covered after other charges have been levied" and "the current framework for residual charging may result in inefficient use of the networks. They may drive actions from some network users that result in adverse impacts on other network users"

The Proposer believes that by retaining the demand locational tariff elements in the proposed Generator Demand TNUoS charge, that a signal reflective of the generator's impact on the transmission system under both the Peak and Year Round scenarios will continue to be applied.

3. Counter views of WG member on why the defect would not level the playing field

A workgroup member raised a concern that if CMP280 is implemented then the deterrent for storage importing at triad is removed. This behaviour might not regularly be employed by storage operators, but the lack of deterrent means that it could be without penalty and such behaviour would add to system stress. Storage units can represent very significant demand loads in comparison to other forms of generation which also contract for import (on the basis of auxiliary demand). The import triad tariff is a significant determinant of the operation of batteries and pumped storage. Therefore it would be incorrect to assume that removing the deterrent for generating at triad will not lead to storage units adding to system stress.

[5] Targeted Charging Review – Significant Code Review launch statement; Ofgem 4 August 2017

The workgroup member commented that the proposer identified in the meeting on 4th August that if a storage unit was to import during times of system stress that this would surely be because National Grid require a service from that unit – however they question under what circumstances this would occur. Does this happen and what are the system benefits of instructing storage to add to peak demand load? One would assume that if this does occur the costs of triad would already be then covered for the storage operator? For the network to operate efficiently and effectively we should be confident that forms of flexibility will always be incentivised to act as reducers of system stress, not unintentional amplifiers of it. Some analysis/modelling could be done to assess the potential impact (or lack thereof).

The Member also added that this Mod is a 'sticking plaster' which does not address fundamental issues, but seems to recognise at least one without identifying that it is the true defect. In the identification of the defect for CMP280 it says that generators and storage operators 'avoid exposure to Demand TNUoS by minimising demand at Triad' and 'potential changes in the charging of Demand Residual [could] make it harder to avoid incurring costs [in the future]'. Effectively the defect identified as justification for CMP280 is being supported by the existence of a much greater defect – that where the Residual is driving behaviour, contrary to its purpose. Surely storage should pay both the demand and generation residual when it imports/exports, but those charges should be made fit for purpose (via the TCR SCR). This reiterates the point that triad is not suitable for the smart, flexible charging regime of the future (and present!!), and jumps the gun ahead of the SCR making more fundamental decisions.

4. Proposer's response to the counter views

In response to these concerns, the Proposer suggested that the major factors determining whether a storage operator would import over the Triad period would be the energy price and the Balancing Mechanism price at that time. In most circumstances these price mechanisms would be likely to act as a disincentive to importing energy at the Triad. However, there may be circumstances when in particular locations or at particular times operational requirements dictate otherwise. If the System Operator should decide that, at a particular location and/or time, accepting a Balancing Mechanism bid is beneficial to the operation of the transmission system at Triad then the TNUoS Demand Residual tariff should not be used as a disincentive to taking this action. Any ancillary service offered to the System Operator at the Triad would have to factor in both the market price and any potential TNUoS charge.

The Proposer believes that the solution proposed will not only rectify the existing defect identified but by removing the liability to demand residual charges from generator parties (including storage) will be "future proof" to any potential changes in the treatment of the TNUoS demand residual tariff arising from the SCR process.

5. Current charging arrangements for transmission-connected and both large and small distribution-connected generation and storage

In their November 2017 update on the TCR[6], Ofgem provided the following analysis and summary:

"We have set out concerns with how residual charges are levied at present, which we think may be distorting competition between different network users and leading to unfair outcomes. This is illustrated in figure 1 below which outlines which network users currently pay residual and cost recovery charges."*Figure1 Network users' current exposure to residual/cost recovery charges*

		T Final Demand	T Generation	T Storage†	D Larger EG**	D Larger Storage**†	D Smaller EG*	D Smaller Storage*†	D Demand
Transmission residual	Generation		✓	✓	✓	✓			
	Demand	✓	✓	✓	✓	✓	Paid††	Paid††	✓
Distribution residual	Generation				Only EHV pay#	Only EHV pay#	Only EHV pay#	Only EHV pay#	
	Demand				✓	✓	✓	✓	✓
Balancing	Generation		✓	✓	✓	✓			
	Demand	✓	✓	✓	✓	✓	Paid	Paid	✓

✓ - Pay the charge Paid – can get paid the inverse of the charge when generating
* <100MW EG **>100MW EG
† - may be affected by ongoing storage modifications CMP280 & CMP281
†† - will be replaced by dedicated embedded export tariff following CMP264/5 WACM4 implementation
# - only those connected at HEV level pay distribution demand residuals. All other are exempted

6. Impact on Demand Residual Charging

A Workgroup Member confirmed that CVA generation licensees including storage parties would not be liable for demand residual.

The Workgroup discussed how this could be work in practice as this would need policing and the only way to do so would be for Ofgem's licensing to show that only those generating stations that are licensed would be applicable.

It was the view of Workgroup Members that if you are being supplied by a Supplier then the Supplier would have to know you are a Licensed Generator and then would have to be able to net off imports for the purpose of the levies. This would also require an information flow from the BSC to National Grid to net it off or deducted volumes.

[6] Targeted Charging Review: update on approach to reviewing residual charging arrangements 2.7; Ofgem 6 Nov 2017

This indicated that for any SVA solution (using either the Licence or netting route) would likely require a BSC Modification to do the relevant charging/forecasting.

7. Impacts of Ofgem's consultation on amendment of the Generation Licence to include Electricity Storage Facilities

On 29 September 2017, Ofgem published a consultation on "Clarifying the regulatory framework for electricity storage licensing".[7]

The consultation seeks views on proposals to modify the electricity generation licence to clarify the regulatory position of storage in the regulatory framework and to ensure consistency between both storage and electricity generation. This will help ensure that a level playing field exists so that storage can compete fairly with other sources of flexibility.

The proposals seek to:

- Include a definition of electricity storage in the electricity generation licence
- Clarify expectations with regard to compliance by storage with the standard licence conditions in the electricity generation licence
- Introduce a new licence condition that, by definition electricity storage providers do not have self-consumption as the primary function when operating the storage facility

The consultation anticipates that storage providers operating under a generation licence:

- Will be expected to sign up to relevant industry codes only insofar as these are applicable to them and/or depending on the capacity of the storage facility; and
- Not be subject to the payment of final consumption levies

The proposed changes to the Electricity Generation Licence Standard Conditions include the following changes:

"generating station" means an electricity generating station or an electricity storage facility which:

i. has, or will have when its construction or extension is completed, a capacity of not less than 50 MW or such other capacity as may be specified in relation thereto by order of the Secretary of state under section 36(3) of the Act;
ii. Is, or will be when its extension or construction is completed, operated by or for the licensee;

SECTION E: Supplementary Standard Conditions for electricity storage

Condition E1: Requirement to export

[7] Ofgem: Clarifying the regulatory framework for electricity storage licensing; https://www.ofgem.gov.uk/system/files/docs/2017/10/electricity_storage_licence_consultation_final.pdf

1 The licensee shall not have self-consumption as the primary function when operating its storage facility.
2 If at any time the licensee knows or reasonably should know of any event or circumstance that has occurred or is likely to occur that may affect its ability to comply with paragraph 1, the licensee shall as soon as reasonably practicable notify the Authority in writing of the event or circumstance.
3 In this Section:

"Export"	Has the meaning given to it in Section K of the Balancing and settlement Code.

Note new SLC E1 will apply to both existing and future licensees.

By scoping the proposed solution to include all current generator parties (including storage) there should be minimal impact on the solution from the extension of the generation licence to include electricity storage facilities.

It is anticipated that the proposed extension of the generation licence to include certain electricity storage facilities will likely result in storage parties entering into a form of Bilateral Agreement with National Grid. Therefore, depending on the agreement type, they will be liable for TNUoS charges (if applicable to them) and so any changes to TNUoS charges will apply also.

8. Will there be a requirement under CMP280 solution for a separate bi-lateral agreement for licensable generation for storage

The Proposer of CMP280 does not believe that a separate bilateral agreement will be required to implement the Original Proposal. At present CVA registered generation, including storage facilities, are subject to one of the existing forms of Bilateral Agreement under the CUSC:

- Bilateral Connection Agreement (BCA) – for transmission connected generators
- Bilateral Embedded Generation Agreement (BEGA) – for embedded generators

As existing transmission connected pumped-storage facilities are already connected under BCA contracts there would not appear to be any requirement for a new form of bilateral contract.

The Workgroup also discussed whether for storage technologies to benefit from the levies they would want/need to sign up to the BSC. It was clarified by Workgroup Members that if you are a Licensed Generator as such you do not have to sign up to the BSC if you construct or operate a generating station(s), each of which are less than 50 MW (please see Condition 14 of the licence. The same interpretation applies to the CUSC under Condition 19 also). If you are licensed for storage you are classed as a licenced operator and the generating party would sign up to the BSC on your behalf.

A challenge was raised around whether the Supplier would be aware that the other party is a Licenced Generator since the storage provider could be unlicensed and exempted for being below 50MW and in being so there would be no requirement to sign up to the CUSC.

9. Cost reflectivity

The Proposer believes that the Demand Residual tariff is a cost recovery mechanism and is not cost reflective or intended to signal a particular behaviour to parties. This is in accordance with the view expressed in the Targeted Charging Review - Significant Code Review launch statement[8] that “Residual charges are ’top up’ charges set to ensure that the network’s efficient costs, as determined through price controls, can be covered after other charges have been levied” and “the current framework for residual charging may result in inefficient use of the networks. They may drive actions from some network users that result in adverse impacts on other network users”

The Proposer believes that by retaining the demand locational tariff elements in the proposed Generator Demand TNUoS charge, that a signal reflective of the generator’s impact on the transmission system under both the Peak and Year Round scenarios will continue to be applied.

10. Impacts on the Generation/Demand (G/D) split and charges/tariffs should CMP280 be implemented

At present generator parties and storage facility operators are largely able to avoid incurring Demand TNUoS charges by avoiding import at Triad. This is reflected in the Transport and Tariff model where currently no additional demand is modelled for generator or storage parties. Therefore, should there be any Chargeable Demand in a charging year, this could constitute an over-recovery in TNUoS in that charging year. It was noted that over/under recoveries of Allowed Revenue are recovered in subsequent year’s TNUoS charges through the k factor.

The G/D split and the €2.50/MWh cap under EU Regulation 838/2010 is implemented within the Charging Methodology at CUSC 14.14.5 (v). The key inputs are as follows:

- The upper limit in Regulation 838/2010 (currently €2.50/MWh)
- The error margin – determined on previous year’s difference between forecast and out-turn values
- Forecast Generation Output
- Forecast TO Allowed Revenue
- Forecast €/£ exchange rate (OBR rate in year prior year)

Although none of the above forecast factors are affected (materially or otherwise) by Chargeable Demand from Generator parties; there may be an impact on the forecast which is used in the calculation due to technology such as storage coming online in future.

[8] Targeted Charging Review – Significant Code Review launch statement; Ofgem 4 August 2017

11. System changes and the impact on setting tariffs and publishing them.

CMP280 is looking to create a completely new tariff to apply to a certain category of users which is conceptually relatively easy to understand. From a system perspective the impact to National Grid is twofold: firstly, the systems and processes around setting TNUoS tariffs, and secondly to the systems and processes for billing customers. These impacts are not felt by National Grid alone, and similar system changes to billing processes would be required for generators and/or suppliers, and also potentially to end consumer billing systems.

To set tariffs under the new structure, the Transport and Tariff model would need to be updated to reflect the CUSC. The particular challenge in setting the tariffs is having sufficiently robust data to enable tariffs to be set as it ensures the allowed revenue is recovered. This data requirement has two aspects: having new data about the particular categories of users, and understanding the impact of the new data on existing data such as the demand forecast. Errors in the forecasting could lead to a notable over or under recovery of revenues through TNUoS tariffs, and may in the extreme require a mid-year tariff change.

The more complex changes are to National Grid's's Charging and Billing System. An entire new category of tariffs would need to be created in the system, which applies to certain groups of users. These users would need to be flagged – which may require a BSC modification to ensure the P0210 and IO14 files that are provided to National Grid contain data with the correct granularity. The will be explored further following Workgroup Consultation. Depending on the option chosen, this may increase the complexity of the solution e.g. if this was taken to SVA level. This is because the data National Grid will receive as part of CMP264/265 will not identify what type of units volumes are coming from and so these will need to be flagged.

An indicative cost for the changes to National Grid's Charging and Billing System is around £1-2million. This is because this modification will lead to significant changes within our Charging and Billing System to allow applicable parties to be billed correctly and flagged within our systems. However, we will be exploring this further including any alternatives raised and is dependent on the solution chosen, and whether other system changes (arising from other Mods) can be progressed at the same time.

National Grid requires at least 9 month lead time of a decision to implement this modification to make the necessary changes to the billing systems. In addition, historic data, to allow forecasting of new tariffs, is also required in a timely manner ahead of tariff setting and forecasting (Feb, June, Oct, December and final tariffs in January).

12. Rationale for solution flooring to zero

Cost-reflective locational demand charges are intended to reflect the cost to the transmission system of a User's decision to site their demand at a particular location on the transmission system and are derived from the DCLF ICRP Charging Model. This produces a range of locational charges are outlined below ((2017/18 Final TNUoS Charges) :

Table 24 - Demand Tariffs with breakdown of peak security and year round elements

Zone	Zone Name	Peak Security Tariff	Year Round Tariff	Residual	Small Generators Discount	HH Demand Tariff (£/kW)
1	Northern Scotland	1.87	-20.11	47.26	0.55	29.58
2	Southern Scotland	0.02	-17.35	47.26	0.55	30.48
3	Northern	-2.67	-5.92	47.26	0.55	39.22
4	North West	-0.71	-1.85	47.26	0.55	45.25
5	Yorkshire	-2.58	-0.27	47.26	0.55	44.97
6	N Wales & Mersey	-1.82	0.79	47.26	0.55	46.79
7	East Midlands	-2.13	2.21	47.26	0.55	47.89
8	Midlands	-1.41	3.05	47.26	0.55	49.46
9	Eastern	1.04	0.76	47.26	0.55	49.62
10	South Wales	-6.19	3.92	47.26	0.55	45.55
11	South East	3.86	0.87	47.26	0.55	52.54
12	London	5.04	2.11	47.26	0.55	54.97
13	Southern	1.68	3.91	47.26	0.55	53.41
14	South Western	-0.93	5.08	47.26	0.55	51.96

The proposed Generator Demand TNUoS tariff will consist of the sum of the Peak Security Tariff and the Year Round Tariff. In a number of zones (Zones 1-6 & 10 above) the generator Demand TNUoS Tariff would be negative (-£18.24/kW to -£1.02/kW).

The effect of a negative Generator Demand TNUoS tariff would be that Users would be paid the negative tariff element if they used energy at times of maximum system demand. This would potentially encourage Users to increase demand at this time to maximise the payment received thus increasing the strain on the system at this time and potentially increasing the cost of balancing the system. Any increased costs would ultimately be passed through to consumers through BSUoS costs.

To avoid this detrimental impact on system costs it is proposed that the Generator Demand TNUoS tariff is floored at zero. Although this may result in some reduction in cost-reflectivity, it is believed that this is outweighed by preventing the potentially detrimental impact of incentivising consumers in some TNUoS charging zones to increase demand at times of system stress.

Retaining the TNUoS demand locational signal, subject to flooring at zero, would continue to provide a cost reflective signal for the siting of demand on the transmission network. Relieving generators from the non-cost reflective residual element of the demand TNUoS tariff would have no impact upon the cost reflectivity of the demand TNUoS charge.

Indicative Generator TNUoS Demand Tariffs are shown in Annexe 3.

13. Potential alternatives

Ofgem recommended in the Targeted Charging Review consultation that changes to charging for storage should be taken forward ahead of any wider changes to residual charging.

While CMP280 is primarily aimed at addressing the defect affecting storage parties, it also proposes to adopt the same approach for generator parties.

At present, generator parties, like storage parties, are potentially liable for the demand TNUoS cost recovery element should they import over the Triad periods. Generators' demand is likely to be a significantly lower proportion of their generation output compared to storage parties, where maximum demand is often similar to or in excess of maximum generation capacity. This means that the issue of recovery of the demand residual is potentially less material for generator parties than for storage. However, neither generator nor storage parties import energy from the transmission system as an end user.

Removing the liability for generator parties would ensure a level playing field with storage in terms of the costs faced by two competing providers of ancillary services. CMP280 therefore proposes to remove the liability for the cost recovery element of the Demand TNUoS charge from both Storage and Generator parties.

It would also be simpler to implement a solution to the defect which removed the liability for the residual element of the demand TNUoS charge from all generator parties, including storage, The definition in CUSC 14.17.1 of parties liable to demand charges includes Power Stations with a Bilateral Connection Agreement (BCA) and Parties with a Bilateral Embedded Agreement (BEGA). Both the BCA and BEGA require the party to be Generator i.e. a person who generates electricity under licence or exemption under the Electricity Act 1989 (as amended by the Utilities Act 2000 and the Energy Act 2004).

If the Working Group wished to put forward a proposal which only removed the liability from storage parties this could be progressed as an Alternative. Such an alternative would require the development of a separate definition of Storage BM Unit (a definition, which may potentially be appropriate, is proposed in CMP 281).

The current version of CMP280 does not apply to SVA storage or generation units. Utilising the definition of parties liable to demand charges in CUSC 14.17.1 restricts the liability to the Generator Demand TNUoS Charge to those generator parties subject to a BCA or BEGA which would require the parties to be registered in CVA.

This is also an area for possible alternatives (see discussion below at paragraph 5).

	Storage only	Storage & Generation
CVA only	Option 1	Option 2
CVA & SVA	Option 3	Option 4

Option No	Option	Pro	Con
1	CVA Storage only	Addresses the identified defect and levels playing field with generation	Does not address SVA connected storage. Requires definition, identification and recording/flagging of storage parties for TNUoS billing purposes
2	CVA Storage and Generation	Provides a level playing field between generator and storage parties – nether exposed to TNUoS Demand Residual tariff element	Does not address SVA Storage and Generation sites.
3	CVA and SVA Storage only	Avoids discrimination between CVA and SVA connected storage sites	Increased complexity of solution and need for metering to prevent exempting end use. Requires definition, identification and recording/flagging of storage parties for TNUoS billing purposes
4	CVA and SVA Storage and Generation	Avoids discrimination between parties through equivalent treatment.	Increased complexity of solution and need for metering to prevent exempting end use . Need to ensure that exempting SVA generation does not create risk of end use consumption being excluded

Following discussion and for the reasons outline above, the majority of the Workgroup had a preference to progress Option 2 (the original proposal). – The new Generator Demand TNUoS charge based on CVA imports based on plant and apparatus would apply to all CVA registered generator parties (including storage).

14. Impact on other Mods (CMP271/274/276)

There are currently three CUSC Modifications in process with which CMP280 could potentially interact should the Authority direct that one or more of these modifications are implemented:

- CMP271 'Improving the cost reflectivity of demand transmission charges'

- CMP274 'Winter TNUoS Time of Use Tariff (TToUT) for Demand TNUoS'
- CMP276 ‘Socialising TO costs associated with "green policies’

Each of these modifications deals primarily with the method of recovery of the Residual or cost recovery element of Demand TNUoS charges. In addition, CMP271 also considers the appropriate charging base for the Peak and Year Round tariff elements and CMP276 seeks to adjust the amounts recovered from Transmission connected generation.

While each of these modifications would result in changes to the calculation of the cost recovery (Residual) element of the Demand TNUoS tariff it is not believed that this has a significant bearing upon CMP280 which proposes that Generator and Storage parties should be exempt from the demand cost recovery element regardless of its calculation.

Proposals that seeks to recover the Demand Residual tariff element over a greater time period, or indeed to commoditise it (£/MWh), would increase the potential liability of generator or storage parties to the demand TNUoS cost recovery element. If such proposals were implemented, this would increase the defect which CMP280 seeks to address and increase the justification for implementation of CMP280.At the CUSC Panel meeting on 29 September 2017, it was decided, with the working groups’ agreement, that further development of CMP271/4/6 by the working groups be suspended until further guidance on the direction of travel of Ofgem’s Targeted Charging Review becomes available. It is therefore likely that CMP280 will be presented to the Authority for decision before CMP271/4/6.

15. Scope of CMP280: all Generators or just storage?

The Proposer confirmed that the scope of CMP280 would extend to all Generators and as such by default include storage units.

16. Scope of CMP280: CVA and/or SVA BMUs or new class of BMU?

In the Proposer’s opinion, the scope of CMP280 is currently limited to generators (including storage) registered in **Central Volume Allocation (CVA)** and party to a valid Bilateral Connection Agreement (BCA) or Bilateral Embedded Generation Agreement (BEGA) with National Grid. These are the only categories of user under the current CUSC Baseline (CUSC 14.17.10 and 14.17.11) which are potentially subject to a Demand TNUoS liability (including the cost recovery element) should they import over the Triad periods.

Embedded storage sites, if importing over the Triad periods, potentially increase their associated Supplier’s Demand TNUoS liability. This liability may, in turn, be passed through to the storage site depending on the nature of the contract with the Supplier (“pass-through” contract”).

When exporting, embedded generation sites registered in Supplier Volume Allocation (SVA) and without a Bilateral Agreement may (if connected at 11kV or above) be liable to Distribution Use of System (DUoS) charges but will not in any event pay Generation TNUoS charges as they do not possess Transmission Entry Capacity (TEC). Storage sites with either a BCA or BEGA will be liable to Generation TNUoS charges and will contribute towards TNUoS cost recovery in this manner.

During the implementation period of CMP264, SVA storage sites are likely to be in a significantly better position than CVA storage because of the availability of full or partial embedded benefits if the energy store is discharging at triad. It is the view of some workgroup member that it may therefore not be necessary to address SVA storage at this stage.

If it was decided that an alternative should be raised to include SVA storage sites into CMP280 at this stage, this could be done in cases where there was appropriate metering (ensuring that the meter did not also measure any end user load). It would be necessary to create a register of such meter points so that their imports could be tagged out from the calculation of the relevant supplier's demand in setting the TNUoS residual payment.

The Proposer does not advocate extending the proposed solution to SVA sites at this stage as SVA storage sites will benefit from additional revenues during the CMP264/265 transitional period. It may be appropriate to revisit this at a later stage. The Proposer has also indicated that the associated practicalities may also be an issue,

The Proposer would be interested in any analysis that workgroup members who support an Alternative which includes an SVA solution, could provide around the additional systems requirements.

17. How would the CMP280 Proposal identify those parties not liable for the TNUoS Demand Residual Charge?

It was the view of the Proposer that the CMP280 Original Proposal would exclude all CVA Generators including storage facilities with a Generation Licence from paying the TNUoS Demand Residual charge.

As all CVA generators and licenced storage facilities would be required to accede to the CUSC, the Grid Code and the BSC and that as CVA sites they would be registered as BM Units and would be separately identifiable in the data flows provided to National Grid for TNUoS billing purposes. These Generation sites, including storage facilities, would use the existing BM Unit identifying prefixes:

- T_ for transmission connected generators or;
- E_ for embedded generators

It was the view of some Workgroup Members that data flows must already exist from the BSC to National Grid, to enable the measurement of any Chargeable Demand for Generator parties under the existing charging arrangements and therefore it would not be expected that any changes would be required to the BSC to facilitate CMP280.

18. Would a BSC Change be required to support the implementation of CMP280

It was the view of the Proposer that data flows must already exist from ELEXON to National Grid to enable the measurement of any Chargeable Demand for generator parties under the existing charging arrangements and therefore it would not be expected that any changes would be required to the BSC to facilitate CMP280.

The Proposer confirmed that if you wanted to avoid the TNUoS demand residual charge you would enter into a bilateral agreement with National Grid and so the Proposal was restricted to CVA generators including storage.

The Workgroup further discussed that if you have a new embedded storage entrant to the market they are not exempt and would not benefit from the exemption in the Modification. Otherwise they would have to apply for a licence to benefit from this Modification. Adding that the licensee will have the responsibility to nominate the sites and be the customer of the sites and then provide this data to the supplier who would then have to submit this information to the BSC.

Currently, the process in the BSC for those who are licensed gives an obligation to submit data for the metered readings therefore this would require a BSC Modification as there would be a requirement to be able to net off volumes through ELEXON’s settlement process thus a change would be required to change this process.

19. Metering requirements

The CMP280 solution requires appropriate metering. The Workgroup discussed what was meant by metering and whether this would be Settlement metering.

In the Proposer’s opinion, the scope of CMP280 is currently limited to generator (including storage) Power Stations with a BCA and Parties with a BEGA both of which categories would be registered in Central Volume Allocation (CVA). As each of these parties is required to provide half-hourly metering data through CVA to the Settlements Administration Agent, (SAA) and this data is currently provided to National Grid for TNUoS billing purposes, it is not envisaged that the original solution would require any additional data flows or changes to the BSC. At present National Grid receives metering data for all generators for TNUoS billing purposes. It should not be necessary to design a separate metering data flow for billing generators on the Generator Demand TNUoS tariff.

20. Impacts on behind the meter issue

The scope of CMP280 is currently limited to generators (including storage) registered in Central Volume Allocation (CVA) and party to a valid Bilateral Connection Agreement (BCA) or Bilateral Embedded Generation Agreement (BEGA) with National Grid and therefore will have no impact on behind the meter (BTM) generation or storage. If extended to SVA units, it is likely that separate metering would be required to be mandatory in order to avoid abuse (e.g. using a small storage unit to shield a large end user load).

As outlined in Sections 9 and 11 above the Working Group did not feel it was necessary to extend the solution to SVA generation at this time.

CMP280 does not address the issues with BTM generation and storage benefiting from avoidance of Triad charges. After the implementation of CMP280, BTM generation and storage will still be able to avoid making contribution to common costs, providing them with a relative advantage over other storage and generation, and therefore the issue still needs to be addressed.

21. Impact on DCUSA and DUoS

There should be no direct impact upon the Distribution Connection Use of System Agreement (DCUSA) or Distribution Use of System (DUoS) charges from CMP280.

It is not proposed that CMP280 would impact SVA storage sites therefore there should be no impact upon the DCUSA.

The DCUSA specifies the DUoS charges payable by parties connected to a Distribution System. These are calculated under either the EHV Distribution Charging Methodology (EDCM) or Common Distribution Charging Methodology (CDCM) depending on the connection voltage.

The new Generator Demand TNUoS charge, as envisaged under CMP280, will not be levied upon Distribution Network Owners (DNOs) and therefore will not require to be recovered from Distribution connected parties through the DUoS charges.

22. Materiality of the proposed defect?

It is important to address the defect as CVA storage parties remain at risk of being instructed to operate in a manner which might incur a liability for demand TNUoS; even if this is mitigated by setting very high BM prices, this is not a satisfactory outcome reflecting actual costs. Other generator parties are only likely to import at the Triad peak if the site is on outage. If future changes to the method of recovering the demand residual charge increase the potential liability of generator parties to the demand TNUoS cost recovery element, this would increase the scale of the defect that CMP280 addresses.

It is understood that generator and storage parties have generally been successful in avoiding a liability for demand TNUoS . Demand is forecasted at peak and so generators (including storage) will be assumed to be generating over peak. Please note that within the T&T model, demand is not forecasted on a site by site basis, therefore a specific storage sites demand would not be modelled but demand overall forecasted.CMP280 is therefore not expected to have a material impact on any other parties.

23. Table of Historic Data Costs

Charging Year	Chargeable Triad Demand, from Generators (kW)	Demand TNUoS charged to Generators based on final published tariffs (£)	Indicative Demand TNUoS charged to Generator if only liable for Demand Locational floored at zero (£)
13/14	139,812	£ 3,548,098.56	£ 147,339.38
14/15	31,988	£ 1,002,325.87	£ 106,800.53
15/16	42,791	£ 1,560,631.13	£ 116,258.21

16/17	44,974	£ 2,068,361.64	£ 90,658.14
17/18	68,683	£ 3,134,924.98	£ 116,066.10

24. Transitional Arrangements

The implementation of CMP280 is not expected to have a material impact on other parties and as such, it is proposed that there would be no requirement for any transitional arrangements.

The Proposal, if approved, should be implemented to coincide with the start of a Charging Year (i.e. 1 April) and should be implemented in the first practical Charging Year following a decision by the Authority. If an Authority decision is available in time, the change should be implemented in April 2019.

25. Unintended consequences

The proposer has not identified any unintended consequences that could arise should CMP280 be approved and implemented

In the current CUSC Baseline there is not a separate definition of a storage BM unit type and storage units are treated in the same manner as generators for Demand TNUOs charging.

Under CMP280, it is intended to treat both generator and storage sites in the same manner and therefore there is no requirement for a separate definition of storage sites and the change could be effected by removing the liability to Demand Charges under sections 14.17.10 and 14.17.11 and replacing these with a liability to the new Generator Demand TNUoS tariff.

Should an alternative modification be proposed with the intention of treating storage sites on a different basis from generators then a separate definition of storage sites would be required. If there is a need to define storage sites, the proposer suggests that the definition of storage sites being proposed under CMP281 would be an appropriate starting point. Indeed, a single definition for storage should be used for both TNUoS and BSUoS charging purposes.

26. Interactions with Ofgem's Targeted Charging Review

The most recent statement from the Government and Ofgem is set out on pages 11 and 12 of the Government and Ofgem Smart Systems and Flexibility Plan (July 2017)[9]. The relevant text says:

It is important that network charges do not prevent a level playing field between different providers of flexibility. It is clear from responses to the CFE and from our engagement with stakeholders that the current network charging arrangements can create a relative disadvantage for storage when competing to provide services.

Ofgem's Targeted Charging Review (TCR) consultation re-asserted its view that while storage should pay forward-looking network charges for both import and export, there are instances where storage may currently pay more towards the residual cost of the network than other network users. The consultation sets out a number of proposals to address this. The proposals include removing demand residual charges at transmission and distribution level and reducing BSUoS charges for storage. The proposed changes would apply to standalone storage and storage co-located with generation.

Ofgem believes that the relative disadvantage for storage under the current network charging arrangements is sufficiently material that it should be addressed ahead of any wider changes that may take place as result of the TCR. Ofgem therefore proposes storage charges should be taken forward directly by industry through the code governance process, rather than forming part of a wider significant code review. Ofgem is currently reviewing responses to the TCR, which closed on 5 May, and will publish a response in the summer.

In their November 2017 update on the TCR[10], Ofgem stated "Our initial work , however, indicates that it may be in consumers' longer-term interests to recover residual charges from suppliers only, as they ultimately pay all system costs. As such, this is a more transparent approach."

It is therefore concluded that CMP280 is at present specifically excluded from the scope of the current SCR. As Ofgem have not exercised the option to bring storage charging back within the scope of the SCR it is the view of the Proposer that CMP280 remains out of the scope of the SCR.

27. Impacts on consumers

Storage providers may pay more towards the residual cost of the network when compared with other network users placing them at a competitive disadvantage.

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[9] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/631656/smart-energy-systems-summaries-responses.pdf

[10] Targeted Charging Review: update on approach to reviewing residual charging arrangements 2.7; Ofgem 6 Nov 2017

Removal of this distortion will place generator and storage users, who compete with each other in the provision of ancillary services and in the energy market, on a more level playing-field, better facilitating competition which will ultimately be to the benefit of the consumer. Increased competition in the provision of ancillary services will potentially put downwards pressure on costs for end consumer. It can be seen that there are a range of inconsistencies in how residual and cost recovery charges are currently levied.

28. Legal text changes

The CMP280 Workgroup discussed whether the associated legal text for the CMP280 original proposal would have to explicitly mention both CVA and SVA generators?

The view of the CMP280 Proposer was that CUSC 14.17.1 States that the following parties are liable for demand charges:

- The Lead Party of a Supplier BM Unit
- Power Stations with a Bilateral Connection Agreement (BCA)
- Parties with a Bilateral Embedded Generation Agreement (BEGA)

Embedded generators and storage parties who **do not hold a BCA or BEGA** are therefore not liable to demand charges under the existing CUSC wording and therefore SVA registered generator parties do not need a specific exemption from demand charges to be included in the proposed CMP280 draft legal text.

The CMP280 Proposer provided a draft of the legal text changes to Section 14 of the CUSC:

14.17 Demand Charges
Parties Liable for Demand Charges
14.17.1(a) The following parties shall be liable for demand locational charges:

• The Lead Party of a Supplier BM Unit;

• Power Stations with a Bilateral Connection Agreement;

• Parties with a Bilateral Embedded Generation Agreement

14.17.1(b) The following parties shall be liable for demand residual charges:

• The Lead Party of a Supplier BM Unit

14.17.2 Classification of parties for charging purposes provides an illustration of how a party is classified in the context of Use of System charging and refers to the paragraphs most pertinent to each party.

Basis of Demand Charges
14.17.3 Demand charges are based on a de-minimus £0/kW charge for Half Hourly and £0/kWh for Non Half Hourly metered demand.

14.17.4 Chargeable Demand Capacity is the value of Triad demand (kW). Chargeable Energy Capacity is the energy consumption (kWh). The definition of both these terms is set out below.

14.17.5 If there is a single set of demand tariffs within a charging year, the Chargeable Demand Capacity is multiplied by the relevant demand tariff, for the calculation of demand charges.

14.17.6 If there is a single set of energy tariffs within a charging year, the Chargeable Energy Capacity is multiplied by the relevant energy consumption tariff for the calculation of energy charges..

14.17.7 If multiple sets of demand tariffs are applicable within a single charging year, demand charges will be calculated by multiplying the Chargeable Demand Capacity by the relevant tariffs pro rated across the months that they are applicable for, as below,

where:
Tariff 1 = Original tariff,
Tariff 2 = Revised tariff,
a = Number of months over which the original tariff is applicable,
b = Number of months over which the revised tariff is applicable.
14.17.8 If multiple sets of energy tariffs are applicable within a single charging year, energy charges will be calculated by multiplying relevant Tariffs by the Chargeable Energy Capacity over the period that that the tariffs are applicable for and summing over the year.

Where:
T1 S = Start date for the period for which the original tariff is applicable,
T1 E = End date for the period for which the original tariff is applicable,
T2 S = Start date for the period for which the revised tariff is applicable,
T2E = End date for the period for which the revised tariff is applicable.

Supplier BM Unit
14.17.9 A Supplier BM Unit charges will be the sum of its energy and demand liabilities where:

- The Chargeable Demand Capacity will be the average of the Supplier BM Unit's half-hourly metered demand during the Triad (and the £/kW tariff), *and*

- The Chargeable Energy Capacity will be the Supplier BM Unit's non half-hourly metered energy consumption over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year (and the p/kWh tariff).

Power Stations with a Bilateral Connection Agreement and Licensable Generation with a Bilateral Embedded Generation Agreement

14.17.10 The Chargeable Demand Capacity for a Power Station with a Bilateral Connection Agreement or Licensable Generation with a Bilateral Embedded Generation Agreement will be based on the average of the net import over each Triad leg of the BM Units associated with the Power Station (in Appendix C of its Bilateral Connection Agreement or Bilateral Embedded Generation Agreement, including metered additional load) during the Triad.

14.17.10 (a) The locational charge applied to a Power Station with a Bilateral Connection Agreement or Licensable Generation with a Bilateral Embedded Generation Agreement will be calculated as follows:

$$GDL_{Di} = \min_0 \left[\frac{ITTD_{iPS} + ITTD_{iYR}}{1000}\right]$$

Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement

14.17.11 The Chargeable Demand Capacity for Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement will be based on the average of the metered volume of each BM Unit specified in Appendix C of the Bilateral Embedded Generation Agreement during the Triad.

14.17.11 (a) The locational charge applied to Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement will be calculated as follows:

$$GDL_{Di} = \min_0 \left[\frac{ITTD_{iPS} + ITTD_{iYR}}{1000}\right]$$

29. Consideration of ELEXON discussion paper

ELEXON shared a discussion paper (see annex 4) with the workgroup for consideration at its 6th meeting.

ELEXON's discussion paper argued that the CMP280 and CMP281 workgroups raise a Workgroup Alternative CUSC Modifications (WACMs). Specifically that a WACM proposes a solution that applies to all licensed generation, irrespective of whether it is connected to a transmission or distribution system, or whether the Metering System(s) for the site are registered in the Central Volume Allocation or Supplier Volume Allocation arrangements. The paper argued that changes to network charging and Final Consumption Levy charging arrangements should converge on the approach set out in Ofgem and BEIS' Smart Systems and Flexibility Plan (SSFP) so they are as simple and consistent as possible. In particular, that:

- Imports to storage (and other generation) operated by a generation licensee should be excluded from the calculation of FCLs, network charges and other charges levied on demand, irrespective of whether the generation is 'exemptible', or whether it is registered in Supplier Volume Allocation (SVA) or CVA); but
- Imports to storage (and other generation) that is operated by an unlicensed person should be treated like an ordinary 'supply' and included in the calculation of FCLs, network charges and other charges levied on demand.

ELEXON's paper set out its understanding of how imported electricity used for different purposes should be charged for FCLs and that this approach should also apply to charging for TNUoS and BSUOS. In particular, ELEXON believe that Ofgem and BEIS' policy intent is that only electricity imported for the specific purpose of operating a generating asset operated by a licensee ('a licensed activity') should be exempt from FCLs and other charges.

As well as facilitating fair treatment, ELEXON believes common or at least consistent arrangements would likely keep the costs of changes to central and parties' processes and systems to a minimum, rather than requiring the design of solutions that differ from code to code and between participants.

The CMP280 workgroup welcomed ELEXON's paper. They acknowledged that in principle, and where appropriate, the CUSC should treat all types of generator consistently, irrespective of whether connected to a transmission or distribution system, or whether related metering was registered in CVA or SVA arrangements.

The workgroup noted ELEXON's interpretation of Ofgem and BEIS' policy regarding the treatment of imports used for different purposes – that is, the difference in treatment of imports to generating plant operated by licensed and unlicensed persons and the difference in treatment of imports for licensable [generator] activities and for end-use consumption. One workgroup member noted that the explanation was helpful and the level of detail was more than had been published to date.

Bearing in mind ELEXON's argument that changes to charging arrangements ought to converge and deliver the intent of Ofgem and BEIS' SSFP, the workgroup considered whether to raise a WACM that ensures imports to SVA and distribution connected generators are also excluded from the calculation of TNUOS demand residual charges. The workgroup also considered how the current proposal and any WACM would differentiate between electricity imported for different purposes.

National Grid currently calculates network charges for a Supplier based on the aggregated sum of the Supplier's customers' SVA metered imports. This aggregated metered volume is determined in accordance with the BSC and relies on Settlement boundary metering. The registration details and processes for aggregating metered data for Settlement do not differentiate between imports used by different types of customer or for different purposes. The workgroup acknowledged that the challenge of excluding imports to SVA registered generators is that any solution would need to identify these sites, specifically collect their metered data and subtract their metered imports from the related Suppliers' overall imports.

The workgroup considered the practical implications of identifying and excluding imports to SVA registered generators. On the one hand, a workgroup member argued that rather than define a detailed solution in the BSC for collecting and excluding import data for SVA generators, each Supplier could be responsible for identifying and reporting eligible metered volumes to National Grid, which National Grid would exclude from its calculation of network charges. On the other hand, the ELEXON representative argued that rather than developing individual supplier solutions, a centralised system for identifying, collecting, aggregating and reporting metered data for eligible generators would be far more efficient, controlled and cost effective.

The ELEXON representative noted that the BSC Modification P344 workgroup is developing a solution for identifying and aggregating metered volumes for metering systems that belonged to a Virtual BM Unit. This solution could be easily adapted to support a CMP280 WACM for SVA Metering Systems. Furthermore, he noted that ELEXON was considering adapting the P344 solution to facilitate changes to how ELEXON reports Supplier imports to EMRS Ltd for calculating EMR Charges (an FCL). He noted that it was likely that a solution to support EMR charging would aggregate metered imports using the same or similar rules as would be necessary for TNUOS charging - assuming the principles (described in ELEXON's discussion paper) are applied consistently across EMR and network charging. The ELEXON representative noted that the opportunity to use common, centralised systems to support multiple initiatives would deliver a more cost effective and efficient outcome for industry and consumers.

The workgroup also considered the implications of differentiating between imports used for different purposes – i.e. imports for carrying out 'a licensed activity' and imports for end-use consumption. The workgroup noted that as it stands National Grid calculates network charges based on metered data from meters registered for Settlement purposes and that the BSC does not specifically require Settlement meters to differentiate between electricity used for different purposes or different 'behind-the-meter' activities. The ELEXON representative noted that Settlement metering was likely sufficient where a site has a single purpose (i.e. generation or end use only) but his paper summarised options for differentiating between imports at mixed purpose sites: rely on existing Settlement metering only; register additional Settlement meters to differentiate between different imports; install additional operational (non-Settlement) metering; or expand the BSC to cover 'behind-the-meter' activities. The ELEXON representative noted that ELEXON had already presented a paper to the P344 workgroup illustrating how the BSC's metering and registration requirements could be expanded to allow 'behind-the-meter' activities to be recorded and used for Settlement purposes, and that it was preparing to establish a BSC Issue Group to consider the issue further.

The workgroup noted that suppliers and generators would make a commercial decision weighing up the cost of installing additional metering (whether or not covered by the BSC arrangements) versus the potential savings from having metered volumes excluded from the calculation of certain network charges and FCLs.

The National Grid workgroup member noted that even if the Proposer's Solution focused on CVA registered generators only, National Grid might not be able to differentiate between imports used for different purposes. That is, whilst National Grid receives raw metered data for CVA registered sites, this metered data is not reported in such a way as to identify how the electricity is used. The ELEXON representative noted that there are a growing number of non-standard BM Units that combine generator assets and end-use consumption (i.e. mixed purpose). The National Grid workgroup member took an action to confirm whether National Grid has enough information to identify and differentiate between imports. The workgroup noted that even if the Proposed Solution focused on CVA generators, a BSC modification may be necessary to enable National Grid to differentiate between imports used for different purposes.

Despite agreeing with the overall principle of treating all generators consistently, the workgroup considered that developing a solution that excluded SVA imports to generators from the calculation of network charges would likely require considerable effort and time to define and implement. They believed that it would be pragmatic to focus on delivering a pragmatic solution, limited to CVA registered sites. They considered that focusing on a CVA only solution would be cheaper and could be delivered in a more timely manner. They noted that this approach did not preclude a workgroup member raising a WACM, a respondent to the Workgroup's forthcoming consultation recommending that a WACM be raised or an entirely new CUSC modification that extended the CMP280 proposed solution to SVA metered volumes.

ELEXON acknowledged that its discussion paper did not specify a detailed solution that a workgroup member could easily adopt as a WACM but that it planned to republish its paper, setting out in more detail how a centralised solution could be delivered by ELEXON to support FCL and network charging.

None of the workgroup members decided to formally propose a WACM.

5. Workgroup Consultation questions

The CMP280 Workgroup is seeking the views of CUSC Parties and other interested parties in relation to the issues noted in this document and specifically in response to the questions highlighted in the report and summarised below:

Standard Workgroup Consultation questions:

Q1: Do you believe that CMP280 Original proposal better facilitate the Applicable CUSC Objectives?

Q2: Do you support the proposed implementation approach as detailed in Section 7 of this report?

Q3: Do you have any other comments?

Q4: Do you wish to raise a Workgroup Consultation Alternative request for the Workgroup to consider?

Specific CMP280 Workgroup Consultations:

Q5: Can you confirm how CMP280 will impact CUSC Parties (for example, operations, billing, contractual, tariff stability, processes and information flows)?

Q6: Do you believe CMP280 original proposal would level the playing field in the way that Ofgem and Government have intended in recent publications?

Please send your response using the response proforma which can be found on the National Grid website via the following link: http://www2.nationalgrid.com/UK/Industry-information/Electricity-codes/CUSC/Modifications/CMP280/

In accordance with Section 8 of the CUSC, CUSC Parties, BSC Parties, the Citizens Advice and the Citizens Advice Scotland may also raise a Workgroup Consultation Alternative Request. If you wish to raise such a request, please use the relevant form available at the weblink below:

http://www.nationalgrid.com/uk/Electricity/Codes/systemcode/amendments/forms_guidance/

Views are invited upon the proposals outlined in this report, which should be received by **5pm** on **10 July 2018**. Your formal responses may be emailed to: cusc.team@nationalgrid.com

If you wish to submit a confidential response, please note that information provided in response to this consultation will be published on National Grid's website unless the response is clearly marked "Private & Confidential", we will contact you to establish the extent of the confidentiality. A response market "Private & Confidential" will be disclosed to the Authority in full but, unless agreed otherwise, will not be shared with the CUSC Modifications Panel or the industry and may therefore not influence the debate to the same extent as a non-confidential response.

Please note an automatic confidentiality disclaimer generated by your IT System will not in itself, mean that your response is treated as if it had been marked "Private and Confidential"

6. Relevant Objectives

Impact of the modification on the Applicable CUSC Objectives (Charging):	
Relevant Objective	Identified impact
(a) That compliance with the use of system charging methodology facilitates effective competition in the generation and supply of electricity and (so far as is consistent therewith) facilitates competition in the sale, distribution and purchase of electricity;	Positive. Removing a distortion in competition will better facilitate competition.
(b) That compliance with the use of system charging methodology results in charges which reflect, as far as is reasonably practicable, the costs (excluding any payments between transmission licensees which are made under and accordance with the STC) incurred by transmission licensees in their transmission businesses and which are compatible with standard licence condition C26 requirements of a connect and manage connection);	Positive/None As Residual charges are not intended to be cost reflective, this proposal will have little impact on cost reflectivity other than removing a distortion whereby some users pay a disproportionate amount of the costs.
(c) That, so far as is consistent with sub-paragraphs (a) and (b), the use of system charging methodology, as far as is reasonably practicable, properly takes account of the developments in transmission licensees' transmission businesses;	Positive The large increase in the Allowed Revenues due to investment in the transmission system and consequential growth in the value of the TNUoS Demand Residual element of the tariff has increased the

	urgency of addressing this distortion. Addressing this issue will reflect these changes in the transmission licensees' businesses.
(d) Compliance with the Electricity Regulation and any relevant legally binding decision of the European Commission and/or the Agency. These are defined within the National Grid Electricity Transmission plc Licence under Standard Condition C10, paragraph 1*; and	None
(e) Promoting efficiency in the implementation and administration of the CUSC arrangements.	None
*Objective (d) refers specifically to European Regulation 2009/714/EC. Reference to the Agency is to the Agency for the Cooperation of Energy Regulators (ACER).	

7. Implementation

Proposer's initial view:

The Proposal should be implemented to coincide with the start of a Charging Year (i.e. 1 April) and should be implemented in the first practical Charging Year following a decision by the Authority. Given the importance of promoting storage, we believe that, if at all possible, the change should be implemented in April 2020 and should be expedited accordingly.

8. Legal Text

The draft legal text changes are detailed in the above workgroup discussion section, and the proposer welcomes any feedback around the legal text in the Workgroup Consultation process

Annex 1 – Terms of Reference

Workgroup Terms of Reference and Membership

TERMS OF REFERENCE FOR CMP280 WORKGROUP

CMP280 aims to remove liability from Generator and Storage Parties for the Demand Residual element of the TNUoS tariff.

Responsibilities

1. The Workgroup is responsible for assisting the CUSC Modifications Panel in the evaluation of CUSC Modification Proposal **CMP280 Creation of a New Generator TNUoS Demand Tariff which Removes Liability for TNUoS Demand Residual Charges from Generation and Storage Users'** raised by **Scottish Power** at the Modifications Panel meeting on 30 June 2017.

2. The proposal must be evaluated to consider whether it better facilitates achievement of the Applicable CUSC Objectives. These can be summarised as follows:

   Charging Applicable Objectives

   (a) That compliance with the use of system charging methodology facilitates effective competition in the generation and supply of electricity and (so far as is consistent therewith) facilitates competition in the sale, distribution and purchase of electricity;

   (b) That compliance with the use of system charging methodology results in charges which reflect, as far as is reasonably practicable, the costs (excluding any payments between transmission licensees which are made under and accordance with the STC) incurred by transmission licensees in their transmission businesses and which are compatible with standard license condition C26 requirements of a connect and manage connection);

   (c) That, so far as is consistent with sub-paragraphs (a) and (b), the use of system charging methodology, as far as is reasonably practicable, properly takes account of the developments in transmission licensees' transmission businesses;

   (d) Compliance with the Electricity Regulation and any relevant legally binding decision of the European Commission and/or the Agency. These are defined within the National Grid Electricity Transmission plc. License under Standard Condition C10, paragraph 1; and

   (e) Promoting efficiency in the implementation and administration of the system charging methodology.

3. It should be noted that additional provisions apply where it is proposed to modify the CUSC Modification provisions, and generally reference should be made to the Transmission Licence for the full definition of the term.

Scope of work

4. The Workgroup must consider the issues raised by the Modification Proposal and consider if the proposal identified better facilitates achievement of the Applicable CUSC Objectives.

5. In addition to the overriding requirement of paragraph 4, the Workgroup shall consider and report on the following specific issues:

   a) Consider interactions (if any) with the Ofgem's TCR (Panel noting the timelines associated with the TCR)
   b) Consider the practical implications of solution e.g. that all metered data is available to National Grid to support the proposed solution
   c) Consider what the interaction with other participants (e.g. Distribution storage)

6. The Workgroup is responsible for the formulation and evaluation of any Workgroup Alternative CUSC Modifications (WACMs) arising from Group discussions which would, as compared with the Modification Proposal or the current version of the CUSC, better facilitate achieving the Applicable CUSC Objectives in relation to the issue or defect identified.

7. The Workgroup should become conversant with the definition of Workgroup Alternative CUSC Modification which appears in Section 11 (Interpretation and Definitions) of the CUSC. The definition entitles the Group and/or an individual member of the Workgroup to put forward a WACM if the member(s) genuinely believes the WACM would better facilitate the achievement of the Applicable CUSC Objectives, as compared with the Modification Proposal or the current version of the CUSC. The extent of the support for the Modification Proposal or any WACM arising from the Workgroup's discussions should be clearly described in the final Workgroup Report to the CUSC Modifications Panel.

8. Workgroup members should be mindful of efficiency and propose the fewest number of WACMs possible.

9. All proposed WACMs should include the Proposer(s)'s details within the final Workgroup report, for the avoidance of doubt this includes WACMs which are proposed by the entire Workgroup or subset of members.

10. There is an obligation on the Workgroup to undertake a period of Consultation in accordance with CUSC 8.20. The Workgroup Consultation period shall be for a period of **15 working days** as determined by the Modifications Panel.

11. Following the Consultation period the Workgroup is required to consider all responses including any WG Consultation Alternative Requests. In undertaking an assessment of any WG Consultation Alternative Request, the Workgroup should consider whether it better facilitates the Applicable CUSC Objectives than the current version of the CUSC.

    As appropriate, the Workgroup will be required to undertake any further analysis and update the original Modification Proposal and/or WACMs. All responses including any WG Consultation Alternative Requests shall be included within the final report including a summary of the Workgroup's deliberations and conclusions. The report should make it clear where and why the Workgroup chairman has exercised his right under the CUSC to progress a WG Consultation Alternative Request or a WACM against the majority views of Workgroup members. It should also be explicitly stated where, under these circumstances, the Workgroup chairman is employed by the same organisation who submitted the WG Consultation Alternative Request.

12. The Workgroup is to submit its final report to the Modifications Panel Secretary on **7 December 2017** for circulation to Panel Members. The final report conclusions will be presented to the CUSC Modifications Panel meeting on **15 December 2017**.

Membership

13. It is recommended that the Workgroup has the following members:

Role	Name	Representing
Chairman	Caroline Wright	Code Administrator
National Grid Representative	Urmi Mistry	National Grid
Industry Representatives	Rupert Steele James Anderson Bill Reed Robert Longden Libby Glazebrook Paul Mott Andrew Colley Paul Youngman Fruzina Kemenes	Scottish Power (Proposer) Scottish Power RWE Cornwall Energy Engie EDF Energy SSE Drax Innogy
Authority Representatives	Judith Ross	OFGEM
Technical secretary	Heena Chauhan	Code Administrator
Observers	Nicholas Rubin	ELEXON

NB: A Workgroup must comprise at least 5 members (who may be Panel Members). The roles identified with an asterisk in the table above contribute toward the required quorum, determined in accordance with paragraph 14 below.

14. The chairman of the Workgroup and the Modifications Panel Chairman must agree a number that will be quorum for each Workgroup meeting. The agreed figure for CMP280 is that at least 5 Workgroup members must participate in a meeting for quorum to be met.

15. A vote is to take place by all eligible Workgroup members on the Modification Proposal and each WACM. The vote shall be decided by simple majority of those present at the meeting at which the vote takes place (whether in person or by teleconference). The Workgroup chairman shall not have a vote, casting or otherwise]. There may be up to three rounds of voting, as follows:

- Vote 1: whether each proposal better facilitates the Applicable CUSC Objectives;

- Vote 2: where one or more WACMs exist, whether each WACM better facilitates the Applicable CUSC Objectives than the original Modification Proposal*;*
- Vote 3: which option is considered to BEST facilitate achievement of the Applicable CUSC Objectives. For the avoidance of doubt, this vote should include the existing CUSC baseline as an option.

The results from the vote and the reasons for such voting shall be recorded in the Workgroup report in as much detail as practicable.

16. It is expected that Workgroup members would only abstain from voting under limited circumstances, for example where a member feels that a proposal has been insufficiently developed. Where a member has such concerns, they should raise these with the Workgroup chairman at the earliest possible opportunity and certainly before the Workgroup vote takes place. Where abstention occurs, the reason should be recorded in the Workgroup report.

17. Workgroup members or their appointed alternate are required to attend a minimum of 50% of the Workgroup meetings to be eligible to participate in the Workgroup vote.

18. The Technical Secretary shall keep an Attendance Record for the Workgroup meetings and circulate the Attendance Record with the Action Notes after each meeting. This will be attached to the final Workgroup report.

19. The Workgroup membership can be amended from time to time by the CUSC Modifications Panel.

Appendix 1 – Updated Timetable

Workgroup Stage

22 June 2017	CUSC Modification Proposal submitted
30 June 2017	Modification Presented to the Panel
30 June 2017	Request for Workgroup Members (10 working days)
w/c 31 July 2017	Meeting 1 via WebEx to ensure Workgroup members have a fully understanding of the context of the modification
w/c 18 September 2017	Circulate draft Workgroup Report
September to May 2018	Workgroup Meetings – Develop Proposal
June 2018	Workgroup Consultation issued to the Industry (15WD)
July 2018	Workgroup Meeting - Workgroup review consultation responses, agree options, finalise legal text and WG vote
August 2018	Workgroup Report issued to CUSC Panel
August 2018	CUSC Panel meeting to discuss Workgroup Report

Code Administrator Stage

September 2018	Code Administration Consultation Report issued to the Industry (15 WD)
October 2018	Draft FMR published for industry comment (3 Working days)
November 2018	Draft Final Modification Report presented to Panel
November 2018	CUSC Panel Recommendation vote
December 2018	Final Modification Report issued the Authority
January/February 2019 *	Indicative Decision for the Authority
1 April 2019 or 1 April 2020	Decision implemented in CUSC

* Note to allow for system changes to be made a decision by Summer 2018 is required for change to be applied to Charging Year 2019

Annex 2: Attendance Log

A – Attended

X – Absent

O – Alternate

D – Dial-in

Name	Organisation	Role	2 August 2017	7 September 2017	16 October 2017	19 December 2017	29 January 2018	10 May 2018
Caroline Wright	Code Administration	Chair	A/D	A	A	A	A	X
Heena Chauhan	Code Administration	Tec Sec	X	A	A	X	A	X
Lurrentia Walker	Code Administration	Tec Sec	X	X	A	A	A	X
Urmi Mistry	National Grid	WG Member	A/D	A	A	A	A	A
Rupert Steele (Proposer)	Scottish Power	WG Alternate	A/D	X	X	X	X	X
James Anderson	Scottish Power	WG Member	X	A	A	A	A	A
Bill Reed	RWE	WG Member	X	A	A	A	A	A
Tim Ellingham	RWE	WG Alternate	A/D	X	X	X	A	A
Robert Longden	Cornwall Energy	WG Member	A/D	A	X	A	A/D	A

Name	Organisation	Role	2 August 2017	7 September 2017	16 October 2017	19 December 2017	29 January 2018	10 May 2018
Libby Glazebrook	Engie	WG Member	X	A	A	A		A/D
Lee Taylor	Engie	WG Alternate	A/D	X	X	X	X	X
Paul Mott	EDF Energy	WG Member	X	X	A	A	X	X
Binoy Dharsi	EDF Energy	WG Alternate	A/D	A	X	X	A	A
Andrew Colley	SSE	WG Member	A/D	A	A/D	A	X	A
Nicola Pervical	Innogy	WG Member	A/D	A	A	A/D	A	A/D
Paul Youngman	Drax	WG Member	A/D	A/D	X	X	A	A
Andrew McKenna	Drax	WG Alternate	X	X	A	A	X	X
Judith Ross	Ofgem	Observer	X	A/D	X	X	A	X
Chiara Redaelli	Ofgem	Observer	X	X	A	A/D	A	A
Christine Brown	National Grid	Chair	X	X	X	X	X	A
Joseph Henry	National Grid	Tec Sec	X	X	X	X	X	A
Shazia Akhtar	National Grid	Observer	X	X	X	X	X	A

Annex 3 – Tariff Breakdown Tables

These tariffs are derived from National Grid's 5 Year Forecast of TNUoS Tariffs (Table 50)

Table 50 - Breakdown of HH Demand Tariffs, and CMP264/265 Calculator*							
Zone	**Zone Name**	**18/19 Demand Peak Security HH (£/kW)**	**18/19 Demand Year Round HH (£/kW)**	**18/19 Demand Residual HH (£/kW)**	**18/19 Demand Total HH (£/kW)**		**Indicative Generator Demand TNUoS Tariff**
1	Northern Scotland	2.09	- 7.14	52.24	47.20		-
2	Southern Scotland	- 1.60	- 18.58	52.24	32.07		-
3	Northern	- 3.22	- 5.97	52.24	43.06		-
4	North West	- 0.86	- 1.42	52.24	49.96		-
5	Yorkshire	- 2.59	0.19	52.24	49.84		-
6	N Wales & Mersey	- 2.19	1.24	52.24	51.29		-
7	East Midlands	- 1.70	2.64	52.24	53.18		0.94
8	Midlands	- 1.45	3.70	52.24	54.49		2.25
9	Eastern	1.67	1.03	52.24	54.95		2.71

10	South Wales	-6.17	4.54	52.24	50.61		-
11	South East	3.81	1.26	52.24	57.31		5.06
12	London	5.55	2.36	52.24	60.16		7.91
13	Southern	1.89	4.31	52.24	58.44		6.20
14	South Western	-0.87	5.51	52.24	56.89		4.64
Zone	**Zone Name**	**19/20 Demand Peak Security HH (£/kW)**	**19/20 Demand Year Round HH (£/kW)**	**19/20 Demand Residual HH (£/kW)**	**19/20 Demand Total HH (£/kW)**		**Indicative Generator or Demand TNUoS Tariff**
1	Northern Scotland	2.23	-6.51	58.24	53.96		-
2	Southern Scotland	-2.37	-18.67	58.24	37.20		-
3	Northern	-3.63	-5.91	58.24	48.70		-
4	North West	-1.48	-0.91	58.24	55.84		-
5	Yorkshire	-2.92	0.38	58.24	55.70		-
6	N Wales & Mersey	-2.93	1.87	58.24	57.18		-
7	East Midlands	-1.68	2.65	58.24	59.20		0.97
8	Midlands	-1.89	4.15	58.24	60.49		2.25

9	Eastern	1.94	0.49	58.24	60.66		2.43
10	South Wales	-6.05	4.18	58.24	56.36		-
11	South East	4.27	0.64	58.24	63.15		4.92
12	London	6.00	1.78	58.24	66.02		7.78
13	Southern	2.16	3.45	58.24	63.85		5.62
14	South Western	0.07	5.20	58.24	63.51		5.27

Zone	**Zone Name**	**20/21 Demand Peak Security HH (£/kW)**	**20/21 Demand Year Round HH (£/kW)**	**20/21 Demand Residual HH (£/kW)**	**20/21 Demand Total HH (£/kW)**		**Indicative Generator or Demand TNUoS Tariff**
1	Northern Scotland	3.52	-8.29	64.60	59.83		-
2	Southern Scotland	-1.19	-19.91	64.60	43.50		-
3	Northern	-3.47	-7.52	64.60	53.61		-
4	North West	-0.99	-1.98	64.60	61.64		-
5	Yorkshire	-2.81	-0.62	64.60	61.17		-
6	N Wales & Mersey	-2.17	0.80	64.60	63.24		-
7	East Midlands	-2.22	2.59	64.60	64.97		0.37

8	Midlands	- 1.65	3.48	64.60	66.43		1.83
9	Eastern	1.51	0.37	64.60	66.49		1.89
10	South Wales	- 5.91	3.88	64.60	62.58		-
11	South East	4.09	0.44	64.60	69.14		4.53
12	London	5.79	1.69	64.60	72.09		7.49
13	Southern	2.11	3.28	64.60	70.00		5.39
14	South Western	- 0.98	3.82	64.60	67.44		2.84
Zone	**Zone Name**	**21/22 Demand Peak Security HH (£/kW)**	**21/22 Demand Year Round HH (£/kW)**	**21/22 Demand Residual HH (£/kW)**	**21/22 Demand Total HH (£/kW)**		**Indicative Generator or Demand TNUoS Tariff**
1	Northern Scotland	4.33	- 9.09	69.54	64.78		-
2	Southern Scotland	- 1.65	- 20.89	69.54	47.00		-
3	Northern	- 3.56	- 7.38	69.54	58.60		-
4	North West	- 0.98	- 1.62	69.54	66.94		-
5	Yorkshire	- 2.97	- 0.14	69.54	66.43		-
6	N Wales & Mersey	- 1.19	0.74	69.54	69.08		-

7	East Midlands	- 2.27	3.23	69.54	70.50		0.97
8	Midlands	- 1.07	3.94	69.54	72.41		2.87
9	Eastern	1.10	1.69	69.54	72.33		2.79
10	South Wales	- 4.69	7.12	69.54	71.97		2.43
11	South East	3.63	2.04	69.54	75.21		5.67
12	London	5.43	3.14	69.54	78.11		8.57
13	Southern	1.92	4.92	69.54	76.38		6.84
14	South Western	- 0.58	5.82	69.54	74.78		5.24

Annex 4: Elexon Paper – Consistent Treatment of Generation

ELEXON

CMP280/281 - CONSISTENT TREATMENT OF GENERATION – DISCUSSION PAPER

Ofgem and BEIS set out actions in their [Smart Systems and Flexibility Plan](#) (SSFP)[1] to clarify the arrangements for charging electricity storage for Final Consumption Levies (FCLs) and network charges. To give effect to the actions in the SSFP, Ofgem consulted on changes to the standard conditions of the Generation Licence. Additionally, Scottish Power proposed changes to how the Transmission Company calculates network charges in accordance with the Connection and Use of System Code (CUSC).

These changes need to be made in a coordinated way, or it will further increase the complexity of the industry codes and regulations. Furthermore, if uncoordinated it will result in more costly and inefficient operations as industry participants manage inconsistencies. We believe it would be better to implement changes that adopt a consistent approach to defining and identifying affected sites, and collecting, aggregating and sharing metered data for calculating FCLs and network charges. This will enable innovation from new business models, new technologies and new services, which is in the interests of consumers.

We believe that industry should adopt a common approach to FCL and network charging based on that outlined in the Ofgem/BEIS Smart Systems and Flexibility Plan. We have developed a proposed approach and will discuss this with industry and interested parties. Furthermore, we propose that this approach can be supported by ELEXON's new systems architecture.

Charging electricity storage providers is changing: FCLs and network charges

In July 2017, Ofgem and BEIS jointly published the SSFP. In it they explained how they expected the industry arrangements to change to better facilitate the participation of electricity storage. Amongst other things, the SSFP covered the following issues:

- Network charges (Transmission Use of System (TNUOS), Balancing Services Use of System (BSUOS) and Distribution Use of System (DUOS)) put electricity storage at a disadvantage compared to other forms of generation; and
- Electricity storage operated by a generation licence holder ought to be exempt from paying Final Consumption Levies (such as for the Renewables Obligation (RO), and Capacity Market (CM)/Contract for Difference (CFD) arrangements).

In the SSFP, Ofgem and BEIS set out their view that any electricity supplied by a licensed Supplier to storage facilities operated by a Generation Licence holder should not be subject to Final Consumption Levies (FCLs):

'Electricity supplied to generation licence holders is excluded from the supply volumes used to calculate the costs of the Renewables Obligation (RO), Contracts for Difference (CFD), Feed in Tariffs (FITs) and Capacity Market auctions. Holders of either a generation licence or the new storage licence to be consulted on by Ofgem will, as a result, not be liable for such levies.'

In September 2017, Ofgem reinforced this point when it consulted on changes to the standard conditions of the Generation Licence[2]. However, in practice there are currently inconsistencies between the way certain FCLs are charged, and the approach set out by BEIS and Ofgem in the SSFP. In particular, the CFD and CM charges levied on Suppliers do include imports to plant that are exemptible[3] but operated by a licensee[4]. Therefore, in order to give

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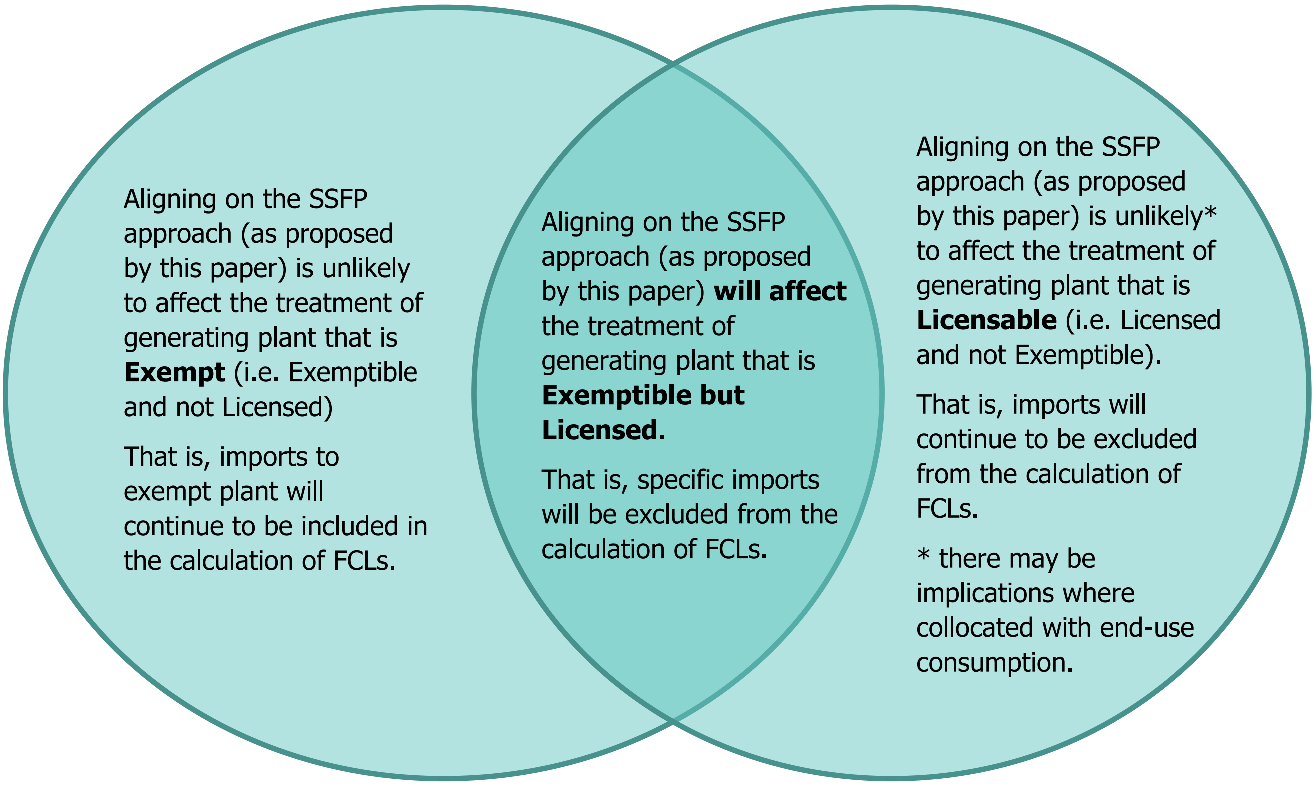
[1] Ofgem and BEIS, ['Upgrading our Energy System – smart systems and flexibility plan'](#) (July 2017)
[2] Ofgem, ['Clarifying the regulatory framework for electricity storage: Licensing'](#) (September 2017).
[3] The CM and CFD arrangements rely on the BSC defined term 'Exemptable Generating Plant', which means 'Generating Plant where the person generating electricity at that Generating Plant is, or would (if it generated electricity at no other Generating Plant and/or did not hold a

full effect to Ofgem and BEIS' policy intent, we believe the CM and CFD arrangements will need to change, so that imports for the explicit operation[5] of any plant operated by a generation licensee are excluded from the calculation of CM and CFD charges. This represents a change to charging arrangements primarily for storage (and other generating plant) that is exemptible[6] but licensed (as illustrated in the Venn diagram in Figure 1).



Exemptible Generating Plant

This is generating plant (including storage) that could be operated under an Exemption (even if it is not Exempt, because the person operating it holds a Generation Licence). It therefore includes generating stations providing less than 50MW (and hence falling under the 'Class A' exemption for small generators).

Licensed Generating Plant

This is generating plant (including storage) operated by the holder of a Generation Licence, irrespective of whether they could otherwise operate without a licence, i.e. be exempt.

Figure 1

Generation Licence) be, exempt from the requirement to hold a Generation Licence'. The terms 'exemptible' and 'Exemptable Generating Plant' do not have an explicit basis in relevant legislation, e.g. the Electricity Act 1989.

[4] LCCC and Electricity Settlements Company, 'G2 – Calculation of Supplier Demand for EMR Charging - EMRS Guidance' (March 2018) – paragraph 6.4

[5] For a more detailed explanation, please see the subsection entitled 'Scope of revised charging arrangements' below.

[6] The Connection and Use of System Code (CUSC) uses the term 'Exemptible', while the BSC uses the term 'Exemptible', but the meaning is the same.

In June 2017, Scottish Power raised CUSC Modifications CMP280[7] and CMP281[8] in response to Ofgem and BEIS' views on how storage providers are charged network charges. CMP280 currently seeks to create a new Generator Demand TNUoS tariff consisting of only the locational elements of the Demand TNUoS tariff, thereby excluding all imports by Central Volume Allocation[9] (CVA) registered generators (including storage) from the calculation of the Demand Residual Charge. CMP281 currently seeks to exclude the imports to 'exemptible storage BM [Balancing Mechanism] Units' from the calculation of BSUOS charges. As it stands, CMP281 proposes to define 'exemptible storage BM Units' as a BMU that consists of only plant and apparatus capable of storing energy from electricity imported from the Transmission System and wholly or mainly converting stored energy back to electricity for the purpose of exporting it back to the Transmission System, i.e. CVA registered.

Ofgem and BEIS' SSFP and consultation on changes to the Generation Licence are based on the idea that electricity storage constitutes a form of generation and so should be subject to the same industry arrangements where these are appropriate. We are concerned that the FCL and CUSC arrangements are heading in different directions. Our understanding is that in practice Ofgem and BEIS' policy means imports for the explicit operation[10] of any generating plant operated by a licensee should be excluded from FCLs – regardless of whether the site is connected to a Transmission System or Distribution System, and whether the site's meters are registered in the BSC's Supplier Volume Allocation (SVA) or CVA arrangements. However, both CUSC modifications seek a more limited effect. That is, CMP280 applies to all generation registered in the BSC's CVA arrangement, and CMP281 applies to 'Exemptible Storage BM Units' only, which would also only apply to plant connected to the Transmission System and registered in the BSC's CVA arrangements.

One of the key issues raised by respondents to the SSFP Call for Evidence[11] was that complexity and lack of consistency in charging arrangements is a barrier to investment in storage. In order to improve rather than worsen this situation, we propose that parties, code administrators and others involved in the development of charging arrangements should seek to converge on the approach outlined in the SSFP. In particular that:

- Imports to storage (and other generation) operated by a generation licensee should be excluded from the calculation of FCLs, network charges and other charges levied on demand, irrespective of whether the generation is 'exemptible', or whether it is registered in Supplier Volume Allocation (SVA) or CVA); but
- Imports to storage (and other generation) that is operated by an unlicensed person should be treated like an ordinary 'supply' and included in the calculation of FCLs, network charges and other charges levied on demand.

For example, we believe the CMP280 and 281 workgroups should consider Workgroup Alternative CUSC Modifications (WACMs) that are consistent with Ofgem and BEIS' approach. In particular, that changes to the rules for charging TNUOS and BSUOS are, as far as possible, implemented so they apply to all licensed storage providers (and possibly generators) whether or not they are connected to the Transmission System and registered in CVA.

As well as facilitating fair treatment, we believe common or at least consistent industry arrangements would likely keep the cost of changes to central and individual parties' processes and systems to a minimum, rather than requiring the design of solutions that substantively differ from code to code, agreement to agreement.

[7] CMP280 'Creation of a New Generator TNUoS Demand Tariff which Removes Liability for TNUoS Demand Residual Charges from Generation and Storage Users'
[8] CMP281 'Removal of BSUoS Charges From Energy Taken From the National Grid System by Storage Facilities'
[9] The terms Central Volume Allocation (CVA) and Supplier Volume Allocation (SVA) refer to different sets of BSC rules for registering metering systems and collecting and aggregating corresponding metered data for Settlement purposes. SVA arrangements apply to metering systems registered by Suppliers, where metered data is collected and aggregated by Supplier Agents. The CVA arrangements apply to larger and individual sites registered by a BSC Party (typically generators), where metered data is collected and aggregated by central agents managed by ELEXON.
[10] For a more detailed explanation, please see the subsection entitled 'Scope of revised charging arrangements' below.
[11] The issues raised by respondents are summarised in the SSFP 'Call for Evidence question summaries and response from the Government and Ofgem' (July 2017)

Detailed implementation issues

In order for market participants to benefit from a consistent approach to charging, it is important that different codes and charging arrangements adopt a consistent approach not just to principles, but to the details of implementation. In the context of aligning charging arrangements on the approach outlined in the SSFP, these important details include clear and consistent definitions of the following (which are discussed in more detail in the remainder of this paper):

1. The **scope of revised charging arrangements**, e.g. the extent to which imports to other loads associated/co-located with the licensed storage (or generation) can be excluded from the supply volumes used to calculate FCLs and network charges;
2. The **metering arrangements** necessary to collect metered volumes for such storage or generation; and
3. The industry processes for licensed generators (or other parties acting on their behalf) to **register which Metering Systems** should be excluded from the calculation of import charges, and for data from those Metering Systems to be **collected and aggregated** for charging purposes.

Scope of revised charging arrangements

Although the principle of not charging for imports to storage (and other generation) operated by licence holders seems clear, consideration is needed of what happens when generating units are co-located with end-use consumption. Imports to the end-use consumption should still be charged for (on grounds of fairness, and to avoid creating perverse incentives for all consumers to install storage or other generation as a way of avoiding charges).

In October 2017, Ofgem recognised this point in its consultation on changes to the generation licence. They proposed a licence condition that licensees operating a storage facility must primarily export back to the system, thereby limiting the types of electricity storage provider that could hold a licence. However, this does not entirely solve the problem, as licensees operating other forms of generation would not be subject to the same constraint.

Earlier this year ELEXON discussed these points of definition with Ofgem and BEIS. Our understanding is that Ofgem and BEIS had meant only electricity imported for the specific purpose of operating a generating asset operated by a licensee should be exempt from FCLs and other charges. In other words, it is only imports to licensed storage units and generating units (and any directly associated load) for the eventual purpose of exporting electricity back to a Transmission or Distribution System that should be excluded from import charges.

In order to implement the above, industry would need to agree a clear definition of what load can be treated as directly associated with a generating unit. We suggest that it may be appropriate to follow existing Low Carbon Contracts Company (LCCC) guidance on what load should be included in the registration of a CFD Facility i.e. the licensed generating unit(s) and any auxiliary equipment required to operate the generating unit(s) for a sustained period of time safely and efficiently at the maximum capacity possible and without causing damage to it.

Metering Arrangements

The majority of FCLs and network charges are calculated using data from Settlement metering installed in accordance with the provisions of the BSC. The approach outlined above therefore implies that licensed generators wishing to avoid charges on imports to their generating units will need to ensure that those generating units (and any directly associated load) is metered separately to any other on-site load.

- Single purpose sites - existing Settlement metering may be sufficient for collecting and reporting metered data for straightforward sites where the imports are explicitly for the operation of the generating unit(s).
- Mixed purpose sites - however, a party may need to install additional metering where a site is complex, so the metering differentiates between electricity imported for operating licensed generating unit(s) and for other purposes.

- Rely on existing Settlement metering – that is, because existing Settlement metering may not differentiate between how the electricity is used on site, the metered data for mixed purpose sites cannot be used to exclude the site from the calculation of FCLs or network charges;
- Register additional Settlement meters – parties could use existing BSC provisions to register additional Metering Systems in Settlement that explicitly record the different imports at a mixed purpose site; or
- Operational metering - a party might install non-Settlement metering 'behind-the-meter', to record the different sub-flows of electricity use. However, the metered data from these non-Settlement meters is not currently collected and aggregated for Settlement purposes and reported by ELEXON to Network Businesses, Suppliers and EMRS Ltd. Therefore, parties would need to collect this metered data themselves and report it directly to whomever is responsible for calculating FCLs or network charges. Furthermore, the charging arrangements would need to change to allow this alternative source of metered data to be used in the calculation of charges.
- Incorporate 'behind-the-meter' activities into the BSC - ELEXON recognises that future charging and market arrangements, e.g. Peer to Peer trading and market aggregation services, require greater visibility and control of 'behind-the-meter' activities. As such we are already exploring how the industry arrangements might be modified to enable the registration, assurance and aggregation or differencing of sub-metering, which traditionally has not been necessary for Settlement purposes. By extending the BSC to cover non-Settlement meters, metered data could be collected, aggregated and reported using existing or amended BSC provisions.

Industry processes for registration, data collection and data aggregation

The processes for calculating network charges and FCLs are specified in industry codes (CUSC, DCUSA and BSC) for network charging, and secondary legislation for FCLs (such as RO, CM and CFD charges). In general, all these processes rely on BSC registration, data collection and data aggregation processes to obtain the aggregated metered data needed for charging purposes.

As a result, changing the charging arrangements to differentiate between licensed storage and generation and exempt storage and generation will require changes to BSC processes (including in particular the development of processes for licensed generators, or parties acting on their behalf, to identify Metering Systems associated with licensed generating plant).

We believe that a BSC Modification to deliver these changes would be relatively straightforward, as it would build on the solution we are delivering next year for Modification Proposal P344 ('Project TERRE implementation into GB market arrangements'). The P344 solution includes processes for registering information about individual Metering Systems, and aggregating metered data related to them. These processes are being delivered on a new data platform, implemented on the public cloud using micro-services and Software as a Service (SAAS) solutions. This architecture gives us the ability to adapt our business processes flexibly and quickly, and would therefore facilitate re-purposing the P344 solution to also collect and aggregate data related to licensed generation for network charging and FCL purposes.

Possible wider implications – remove the distinction between exemptible and licensable plant?

Ofgem and BEIS' intent is to differentiate between generating units that are operated by parties that either hold a licence or not. They have told us that they do not differentiate between exemptible and licensable plant.

As stated above, we believe it is in the interest of parties and consumers that changes to the arrangements for FCLs and network charges should be implemented as consistently as possible across the industry codes. With this in mind we believe that Ofgem and BEIS' policy intent could require further consideration of how the wider industry arrangements apply to generators.

For example, the BSC differentiates between exemptible and licensable plant. The purpose of this distinction is to enable exemptible plant to be registered by a Supplier in the SVA arrangements, who then accrues embedded benefits (for example reduced BSUOS charges), which they may share with the generator.

Ofgem and BEIS' policy intent in relation to FCLs suggest that we should differentiate between plant operated by a licensee or not, rather than between exemptible and licensable plant. In order that the overall treatment of generators is consistent, it may be appropriate to modify the BSC and other industry codes to align with this treatment. Whilst such a change might enable consistency and simplify the treatment of generators, it could have considerable practical and financial implications for generators and suppliers.

Summary and Next Steps

In summary, we propose that parties, code administrators and others involved in the development of charging arrangements should seek to converge on the following approach, which is based on that outlined in the SSFP:

- Imports to generation (including storage) operated by a generation licensee should **not** be subject to FCLs or demand charges, provided that there is dedicated Settlement Metering of the imports to licensed generating units (and any auxiliary equipment required to operate them for a sustained period of time safely and efficiently at the maximum capacity possible and without causing damage to them) separately from any other on-site demand; and
- Imports to generation (including storage) operated by an unlicensed person should be treated like normal demand for the purposes of FCLs and charging.

In the first instance, we intend to work towards this by:

- Discussing with the CMP280/281 Workgroups the possibility of raising WACMs consistent with the above approach; and
- Discussing with BSC Parties (and LCCC) the possibility of raising a BSC Modification Proposal that would put in place the registration and aggregation processes necessary to fully implement the above approach.

Want to know more?
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