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Transmission Charging Methodologies Forum

11th May 2016

Introduction, Welcome and Agenda

- 11:00 Introduction – Wayne Mullins, National Grid
- 11:05 CUSC Modifications Update (Charging) – Juliette Richards, National Grid
- 11:15 Discussion on potential CUSC modification to look at GAV calculation in connection charges – Nigel McManus, Eneco – *via dial in*
- 11:35 Generation zones for TNUoS – Lewis Elder, RWE
- 11.50 GC0079 (ROCOF setting) and impact on BSUoS – Graham Stein, National Grid
- 12.15 Timing of offshore expansion factor – Jo Zhou, National Grid
- *12.30 Lunch*
- 13.00 HH Elective metering and TNUoS – Damian Clough, National Grid
- 13.25 AOB (charging) and close

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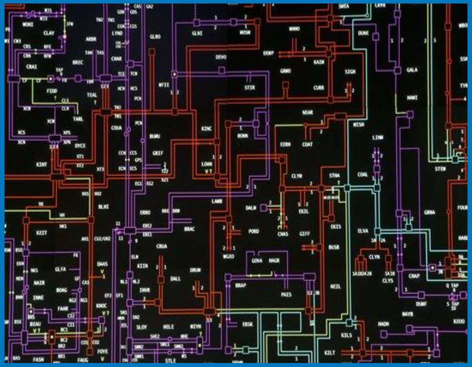
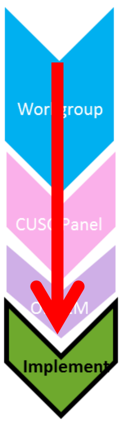
Ongoing charging modification proposals



Juliette Richards

New modification proposals: charging - page 1 of 2

- **CMP263 - Housekeeping changes to Section 14 Legal text as a result of the implementation of CMP213, CMP242 and CMP248 on 1st April 2016**
  - This was raised by National Grid correcting incorrect references / numbering within Section 14 of the CUSC to account for new modifications. This has now been implemented via fast track.



- **CMP262 ‘Removal of SBR / DSBR Costs from BSUoS into a ‘Demand Security charge’**
  - This proposal was raised by VPI Immingham and was discussed in brief at the March TCMF meeting. The proposal aims to create a new cost recovery mechanism, a ‘Demand Security charge’ specifically for the recovery of all SBR / DSBR costs, which would only be levied on demand side balancing mechanism units (BMUs).
  - The proposer requested urgency so that this issue could be considered ahead of 16/17 winter, and Ofgem have granted this request. The Workgroup will be going out to consultation in May.

New modification proposals: charging - page 2 of 2

- **CMP261 ‘Ensuring the TNUoS paid by generators in GB in charging year 2015/16 is in compliance with the €2.5/MWh annual average limit set in EU regulation 838/2010 part B (3)’**
  - This proposal was raised by SSE and was discussed in brief at the March TCMF meeting.
  - The modification proposes an ex post reconciliation of generator charges for the 15/16 charging year, where these are deemed to have exceeded the €2.5 / MWh annual average cap. This would take place via a negative generator residual levied on all GB generators who paid TNUoS during the period 1st April 2015 to 31st March 2016.
  - The proposer requested urgency – Ofgem did not grant this but the proposal is progressing to an accelerated timetable. The Workgroup met for the 2nd time on 28th April 2016. There are some links to the analysis already undertaken for CMP251 so these Workgroups are working in parallel where possible.

Ongoing modification proposals: charging - page 1 of 5

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- **CMP260 'TNUoS demand charges for 2016/17 during the implementation of P272 following approval of P322 and CMP247'**
  - This proposal was raised by RWE npower and proposes that Suppliers should have the option for those metering Systems that are registered on Measurement Class E-G on or before 1/4/2016 to be treated as HH for the purposes of calculating the actual annual liability up until the full charging year after the Implementation date of P272.
  - The proposer requested urgency – Ofgem did not grant this but the proposal is progressing to an accelerated timetable and the 5 day Workgroup consultation took place in March.
  - The Workgroup reported to the CUSC Panel in April and the Code Administrator consultation opened on 4th May for 10 days.

Ongoing modification proposals: charging - page 2 of 5

- **CMP255: ‘Revised definition of the upper limit of Generation Charges in the charging methodology with removal of the reference to the 27% charging cap’**
  - This proposal was raised by RWE in November and seeks to clarify what would happen if the limit detailed in EU regulation 838/2010 (€2.5/MWh average) were removed in line with the recent ACER recommendation.
  - The Original proposal suggested keeping the €2.5/MWh average limit. There were three workgroup alternative CUSC modifications: WACM1 would fix the generation percentage at the level last used to set transmission tariffs; WACM2 would see a phased return to 27%; and WACM3 would set the generation percentages as forecast in the latest five year forecast, quarterly updated, and fix at the last one.
  - The Workgroup voted by majority for the Original proposal. The Workgroup reported to the CUSC Panel in April and the Code Administrator consultation opened on 3rd May.

Ongoing modification proposals: charging - page 3 of 5

- **CMP251: Removing the error margin in the cap on total TNUoS recovered by generation and introducing a new charging element to TNUoS to ensure compliance with European Commission Regulation 838/2010**
  - This proposal was raised by British Gas and seeks to set generation charges to €2.5/MWh, followed by post event reconciliation as necessary.
  - There are some links to the analysis and legal work being undertaken for CMP261. The Workgroup reported to the CUSC Panel in April, but will report again in May when the legal opinion for CMP261 has been considered.

Ongoing modification proposals: charging - page 4 of 5

- **CMP250: Stabilising BSUoS with at least a twelve month notification period**
  - This modification seeks to fix the BSUoS price ahead of time to reduce volatility.
  - The Workgroup consultation closed on 14th April and the Workgroup will report to the CUSC panel in May.

- **CMP249: Clarification of other charges (CUSC 14.4) Charging arrangements for customer requested delay and backfeed**
  - This modification aims to include the principles underpinning the CEC before TEC policy within Section 14 of the CUSC, state the methodology for calculation and clarify in which situations this will be applied.
  - The Workgroup consultation closed on 18th March and the Workgroup is currently due to report back to the CUSC Panel in May.

Ongoing modification proposals: charging - page 5 of 5

- **CMP248: Enabling capital contributions for transmission connection assets during commercial operation**
  - This proposal was raised by Eneco UK to enable users that have existing arrangements to pay annual charges for transmission connection assets the opportunity to make capital contributions against the transmission connection assets.
  - CMP248 was implemented on 1st April 2016.

- **CMP244: Set final TNUoS tariffs at least 15 months ahead of each charging year**
  - The Workgroup has voted on a revised Original looking at a TNUoS tariff notice period of *200 calendar days* rather than 15 months. No alternatives were raised.
  - The Code Administrator consultation closed on 27th April, and the CUSC Panel will vote on this modification, in parallel with CMP256 (Consequential changes to the CUSC arising from CMP244), in May.

All for sustainability

CUSC Mod proposal

By Eneco UK on behalf of LZN Ltd

Weds 11 May 2016

Background

- Lochluichart is a transmission-connected wind farm, wholly owned by Eneco UK
- It enjoys the use of a transmission asset - a 132kV transformer at Corriemoillie substation - and has been in operation since 2013
- The connection agreement was signed in 2010
- Eneco intends to reduce the capital component by making a capital contribution under CMP248
- The capital contribution is approximately £1m more as a result of the annual RPI rebasing of the GAV – the inflation re-basing is equivalent to 25% over 7 years (equivalent to 3.8% pa)
- This note briefly sets out the rationale for a possible CUSC defect

GAV, NAV & MEA

All for sustainability

- Each transmission connection incurs non capital costs (maintenance and operating costs) and **capital costs (**for construction, engineering, Interest During Construction and return on capital). The capital component consists of a rate of return element and a depreciation element (the asset is depreciated over 40 years as standard)
- The Gross Asset Value, **GAV** represents the total initial cost of constructing the connection assets
- The Net Asset Value, **NAV** represents the mid year depreciated GAV of the asset
- The connection charge is re-calculated annually and the GAV is rebased to account for inflation (CUSC 14.3.4, 14.3.6).

Customer can request an alternative revaluation methodology under the CUSC (14.3.5) and the Modern Equivalent Asset (MEA) can be used which references the prevailing price level for an asset that performs the same function as the original asset.

Suggested CUSC defect

Why is the GAV rebased for inflation? A transmission connection asset is depreciated and should be financed on that basis. The RPI indexation on the GAV appears to be like an insurance policy or a financing premium because the customer is actually paying for a replacement asset value whilst using a depreciating asset.

Eneco believes this RPI re-basing is inappropriate for financing a depreciating asset and that the replacement value could be retained in the case of termination. A modification in the CUSC to remove this indexation – except for termination events – would better facilitate effective competition by removing a financial hurdle and thus deliver a more balanced choice of financing option to the User.

The MEA alternative does not in our opinion alter the principle that customer should be paying off capital linked to the current value of an asset and not the replacement value.

Eneco would be interested in the views of the members of the TCMF.

Appendix – simplified example

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Eneco

Asset inflation +RPI

Year	Inflation	GAV	NAV
		£5,000,000	
	3.00%	£5,150,000	
1	3.00%	£5,304,500	£5,105,581
2	3.00%	£5,463,635	£5,122,158
3	3.00%	£5,627,544	£5,135,134
4	3.00%	£5,796,370	£5,144,279
5	3.00%	£5,970,261	£5,149,351

No asset inflation

Year	Inflation	GAV	NAV
		£5,000,000	
	0.00%	£5,000,000	
1	0.00%	£5,000,000	£4,812,500
2	0.00%	£5,000,000	£4,687,500
3	0.00%	£5,000,000	£4,562,500
4	0.00%	£5,000,000	£4,437,500
5	0.00%	£5,000,000	£4,312,500

In this simple example, the asset has increased in “replacement” value by almost £1m over the period since commissioning as compared to a scenario with no inflation. If the user of this asset chose to make a 100% capital contribution, they would be paying off a NAV greater by £0.8m than if inflation were not applied.

In this example the depreciation period is 40 years, the NAV recalculates in mid year and the project takes 2 years to commission.

Zonal Transmission Charges

Prepared by
Lewis Elder
(with support from Paul Wakeley and Dave Corby)

The energy to lead

The zoning process

Nodal marginal costs from transport model are applied onto substation line diagram

These are then grouped into initial zones using the +/-£1.00/kW range

All nodes within each zone are then checked to ensure they are geographically and electrically proximate

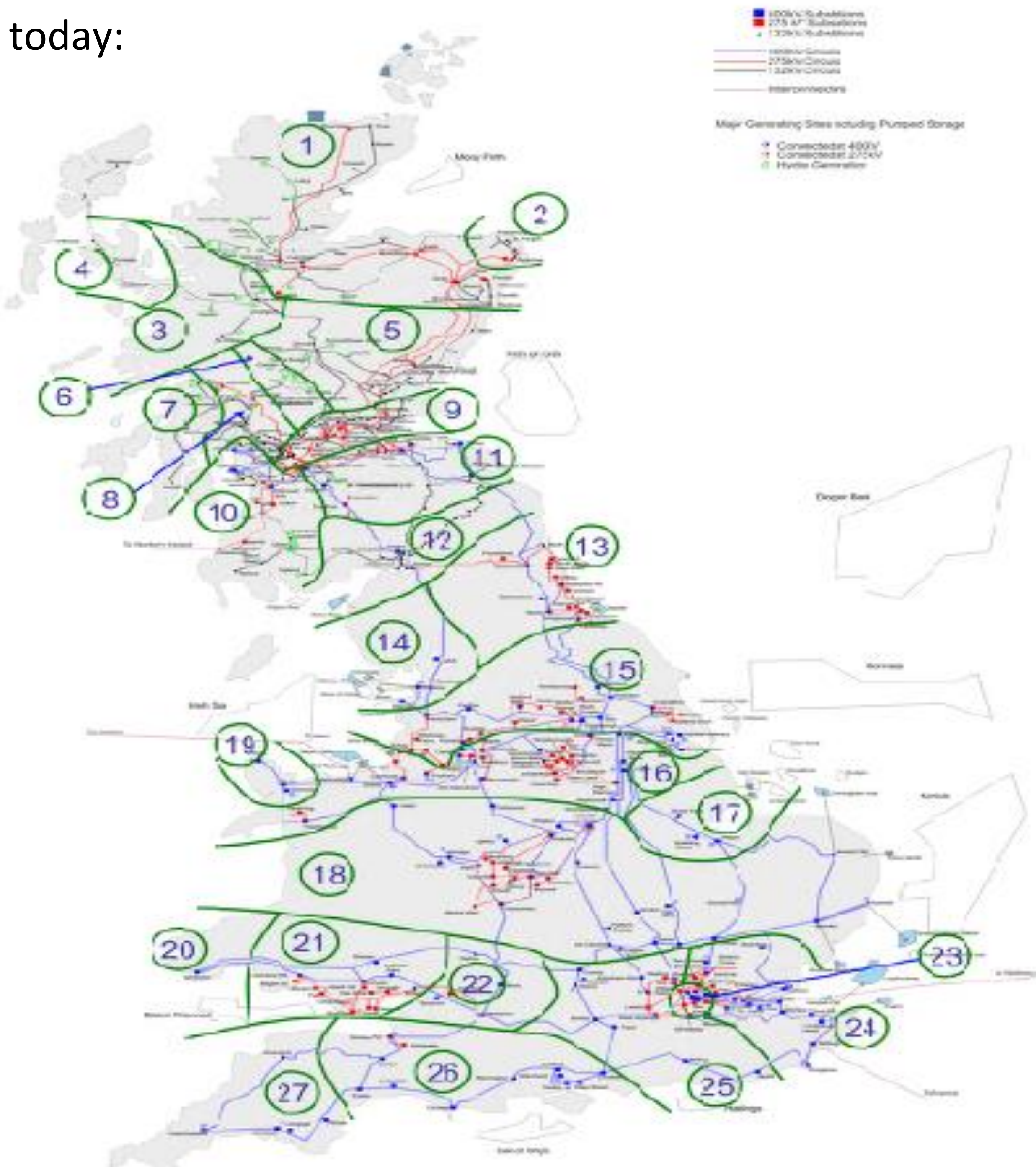
Established zones are inspected to ensure the least number of zones are used with minimal change to existing zones.

Finally, zonal boundaries are confirmed using the demand nodal costs for guidance.

Other points:

- Zoning criteria are applied to a reasonable range of transport model scenarios.
- Minimum number of zones, which meet the stated criteria, are used.

Where we are today:



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14.28 Stability & Predictability of TNUoS tariffs

"The Transmission Network Use of System Charging Methodology has a number of elements to enhance the stability of the tariffs, which is an important aspect of facilitating competition in the generation and supply of electricity"

"Each node of the transmission network is assigned to a zone. ***The result of this is to dampen fluctuations*** *that would otherwise be observed at a given node caused by changes in generation, demand, and network parameters"*

…HOWEVER..!

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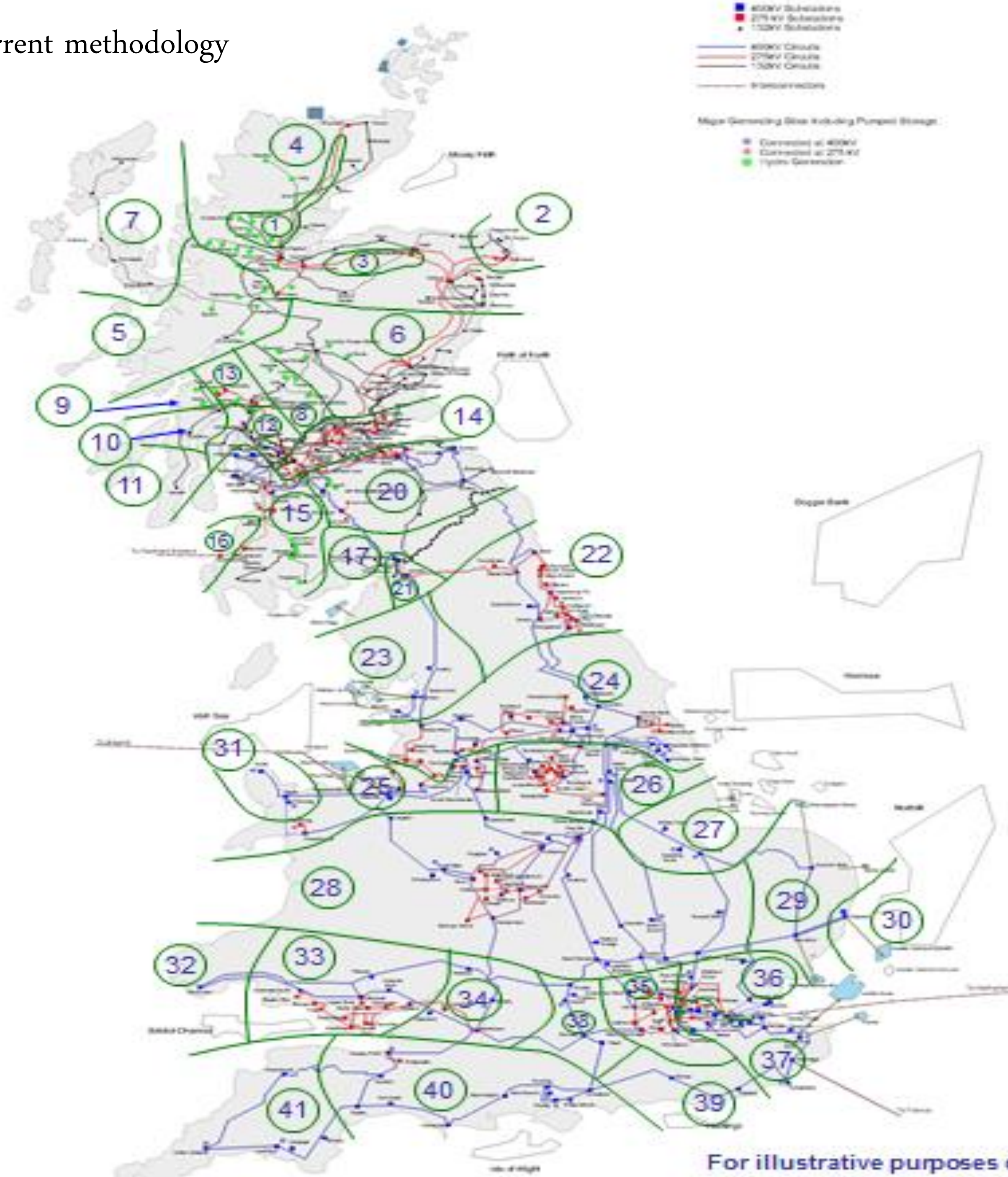
Continuation of current methodology



For illustrative purposes only

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The defect?

14.15.35 A number of criteria are used to determine the definition of the generation zones. Whilst it is the intention of The Company that zones are fixed for the duration of a price control period, it may become necessary in exceptional circumstances to review the boundaries having been set. In both circumstances, the following criteria are used to determine the zonal boundaries:

i.) Zones should contain relevant nodes whose wider marginal costs (as determined from the output from the transport model, the relevant expansion constant and the locational security factor, see below) are all within ***<u>+/-£1.00/kW (nominal prices)</u>*** *across the zone. This means a maximum spread of £2.00/kW in nominal prices across the zone.* [Emphasis added]

i.e. The +/-£1/kW nodal difference is not RPI linked

How can we address this defect?

Index-link from a specific date?

Mirror Demand zones?

Agree an arbitrary number of zones?

Other?

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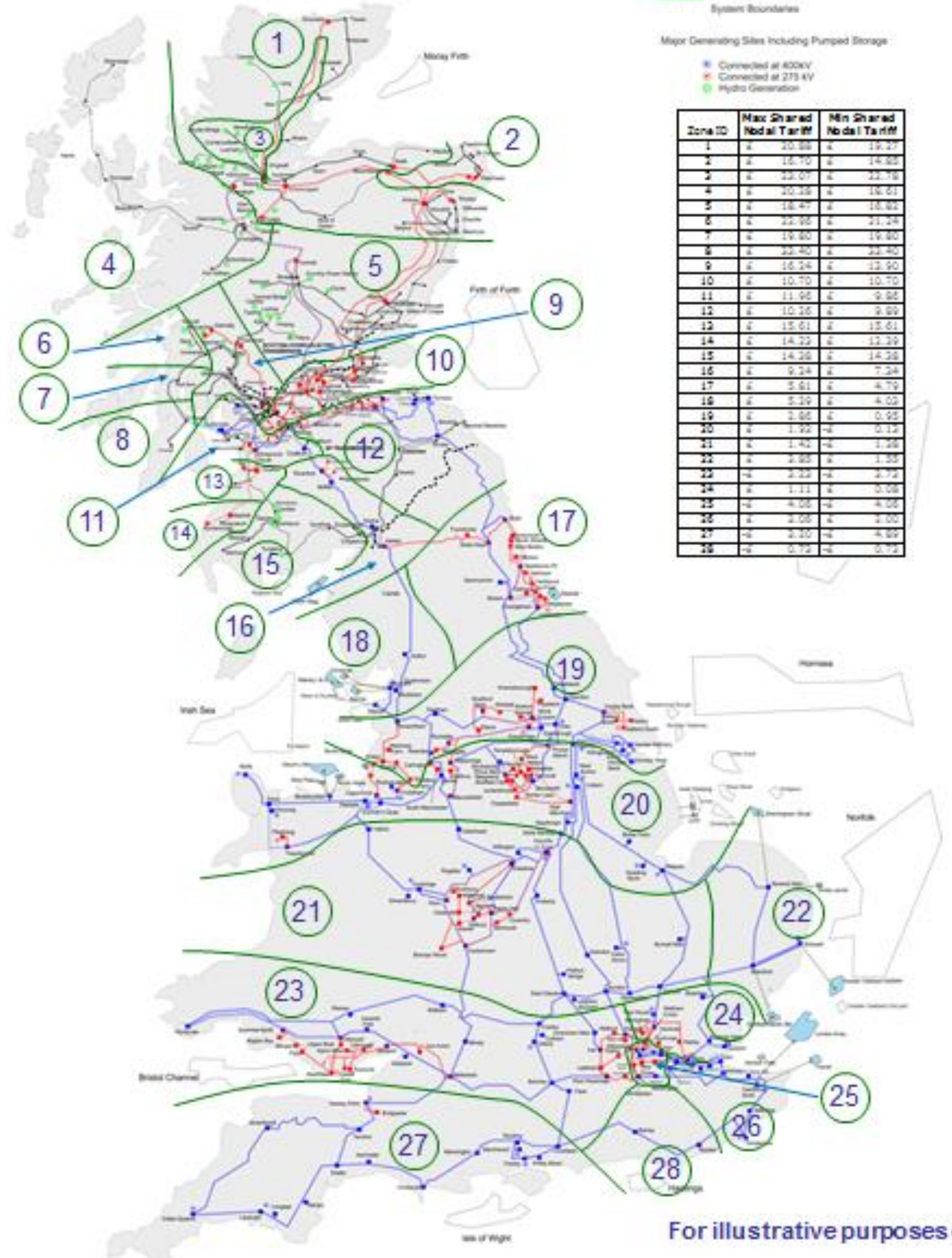
Index link from a specific date?

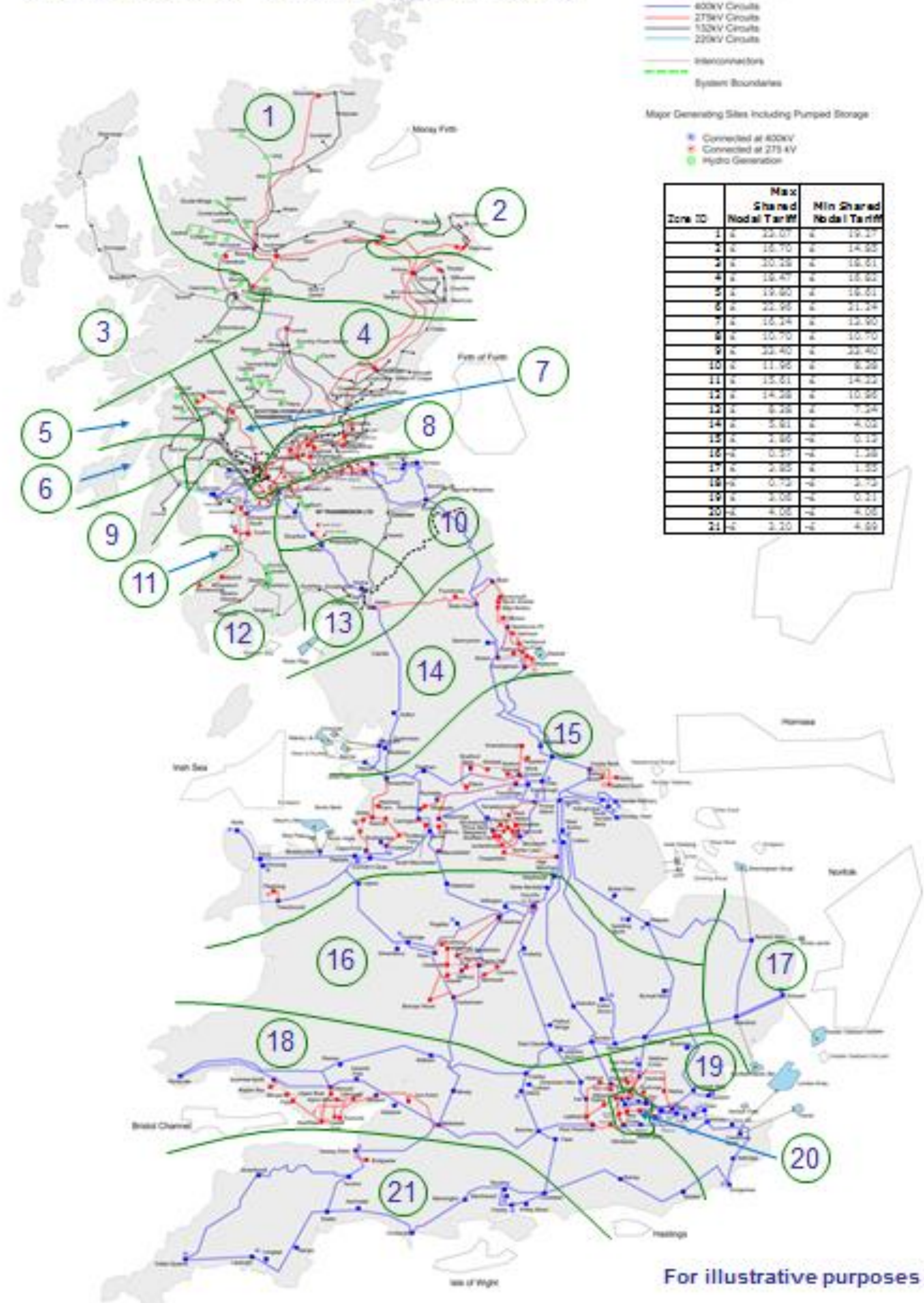
Zoning based on 2017/18 model using Inflated since ICRP +/-£1+RPI (spread £2.88)



Zone ID	Max Shared Nodal Tariff		Min Shared Nodal Tariff	
1	£	20.88	£	19.27
2	£	16.70	£	14.85
3	£	22.07	£	22.78
4	£	20.38	£	16.61
5	£	18.47	£	16.82
6	£	22.98	£	21.24
7	£	19.80	£	19.80
8	£	22.40	£	22.40
9	£	16.24	£	12.90
10	£	10.70	£	10.70
11	£	11.98	£	9.88
12	£	10.38	£	9.89
13	£	15.61	£	15.61
14	£	14.22	£	12.39
15	£	14.38	£	14.38
16	£	9.24	£	7.24
17	£	5.61	£	4.79
18	£	5.39	£	4.02
19	£	2.88	£	0.95
20	£	1.92	-£	0.12
21	£	1.42	-£	1.38
22	£	2.85	£	1.55
23	-£	2.22	-£	2.72
24	£	1.11	£	0.08
25	-£	4.08	-£	4.08
26	£	2.08	£	2.00
27	-£	2.20	-£	4.89
28	-£	0.72	-£	0.72

For illustrative purposes only

Zoning based on 2017/18 model using Inflated since privatisation +/-£1+RPI (spread £4.15)



Zone ID	Max Shared Nodal Tariff		Min Shared Nodal Tariff	
1	£	23.07	£	19.17
2	£	16.70	£	14.93
3	£	20.28	£	18.61
4	£	19.47	£	15.93
5	£	19.80	£	16.61
6	£	22.95	£	21.24
7	£	16.24	£	12.90
8	£	10.70	£	10.70
9	£	22.40	£	22.40
10	£	11.95	£	8.28
11	£	15.61	£	14.22
12	£	14.28	£	10.95
13	£	8.28	£	7.24
14	£	5.61	£	4.02
15	£	2.86	-£	0.12
16	-£	0.57	-£	1.38
17	£	2.85	£	1.55
18	-£	0.72	-£	2.72
19	£	3.08	-£	0.21
20	-£	4.08	-£	4.08
21	-£	3.20	-£	4.89

For illustrative purposes only

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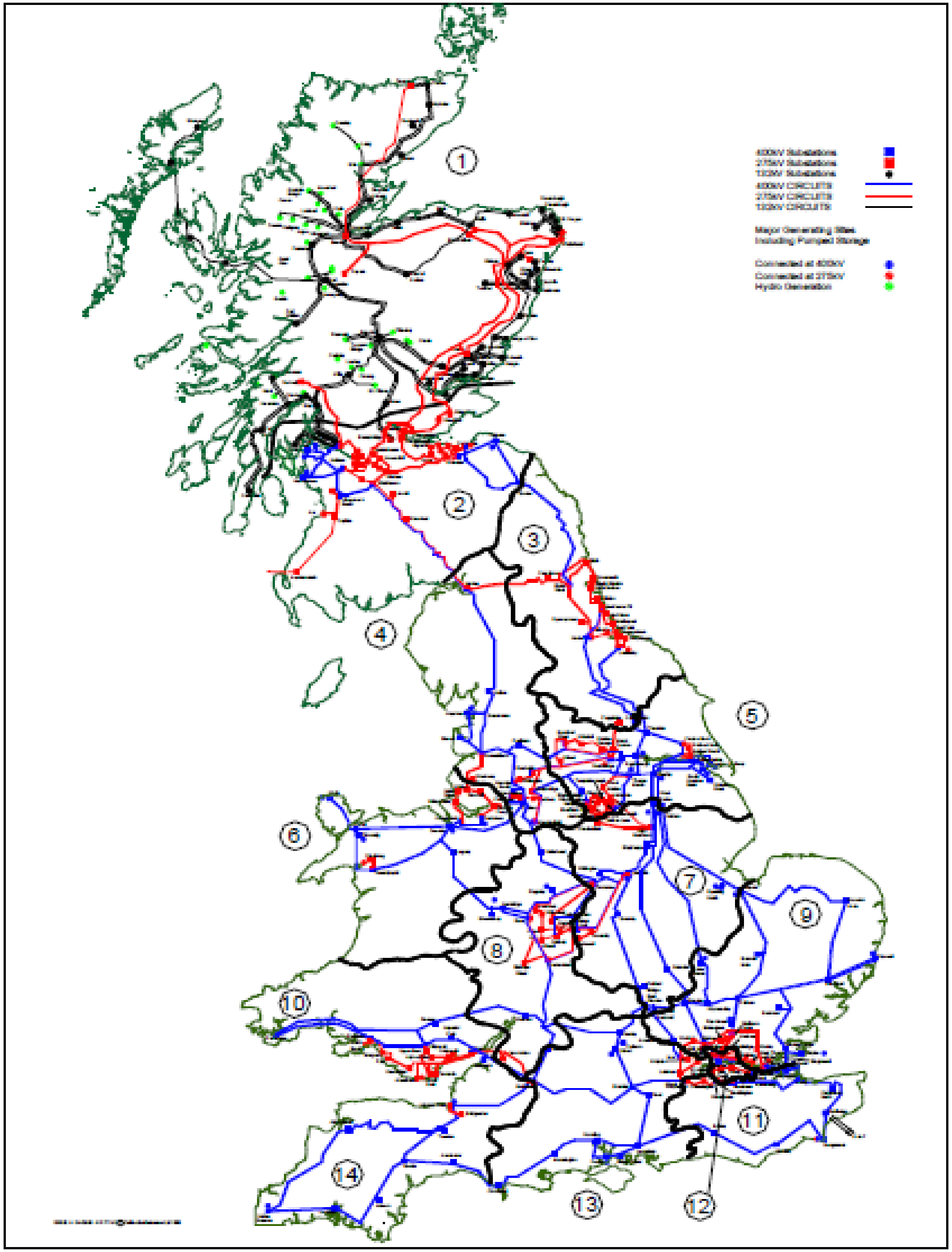
Mirror demand zones?


400kV Substations
275kV Substations
132kV Substations
400kV CIRCUITS
275kV CIRCUITS
132kV CIRCUITS
Major Generating Sites Including Pumped Storage
Connected at 400kV
Connected at 275kV
Hydro Generation
1
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11
12
13
14

Agree an arbitrary number of zones?

Other?

Zone fixing

Zone fixing - These zones are themselves fixed for the duration of the price control period. The methodology does, however, allow these to be revisited in exceptional circumstances to ensure that the charges remain reasonably cost reflective or to accommodate changes to the network.

"14.15.38 Zones will typically not be reviewed more frequently than once every price control period to provide some stability. However, in exceptional circumstances, it may be necessary to review zoning more frequently to maintain appropriate, cost reflective, locational cost signals."

Should this be addressed now? Are these "exceptional circumstances"?

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Questions for the audience

- Do we agree there is a defect?
- Any support or objections to potential solutions? (Or a new solution?)
- Should this be amended now? Or in the next price control period?

Thank you

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GC0079 (ROCOF setting): impact on BSUoS

Graham Stein

Outline

- GC0079: what it's aiming to do
- Why is a view being sought from TCMF?
- Options under discussion
- Points considered by GC0079
- Next Steps

GC0079: what it's aiming to do

- GC0079 is a joint GCRP and DCRP workgroup
  - Current focus is Loss of Mains protection settings at stations of less than 5MW
  - Its recommendation is likely to be a change to protection settings similar to that recommended by GC0035 for stations of 5MW and above because
    - the workgroup's estimates of the costs of making a change are significantly less than the Balancing Service cost incurred if no change is made
    - Network and User safety risks are manageable

Why bring GC0079 to TCMF?

- As with GC0035, the proposals are likely to affect existing distributed generators
- Ofgem's decision letter for GC0035 highlighted that the GC0079 Workgroup would need to examine how its proposals could be implemented, including how the work is funded
- DNO's experience implementing GC0035 has also highlighted some of the challenges in implementing retrospective changes
- GC0079 needs to capture its thinking within its report to the DCRP and GCRP and the workgroup feel this would be better informed with TCMF's input

Options under Discussion

Option 1

Do nothing: costs are borne by the parties that need to do the work, in this case small generators

Option 2

DNOs contract appropriate specialists to undertake all the necessary changes, and provide assistance, for affected generation owners, funded from BSUoS

Points Considered by the GC0079 WG

- Connectees are obliged to comply with all relevant, including D Code, requirements
  - the costs of compliance fall on connectees
- The costs to connectees need to be considered in relation to any government or other policy decisions
- Larger commercial organizations are generally in a better position to manage the risks of such costs than smaller players or domestic customers
- The proposed changes are to maintain a secure system and reduce balancing costs.
  - initially borne by NGET, but are funded by Generators and Suppliers, and in turn by customers in general.

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Points Considered by the GC0079 WG

- Is it more efficient to manage compliance with the change centrally (option 2)?
  - Perceived benefits
    - no cash payment to a user
    - economies of scale in a small number of expert contractors undertaking all the work
    - potential to incentivise progress and deadlines for completion.
    - central information gathering
  - Variations on option 2 could also be considered e.g. generators undertake own work but receive a central compensation payment or similar.

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Table of cost/benefit – Option 1

Sub-5MW generators obligated to change settings at their own cost

Party	BSUoS Payer?	Costs	Benefits	Reputational
NGET		-	Less balancing actions required; Grid Stability	+VE (if successful)
DNOs		-	Grid stability	+VE (if successful)
Large Generators	Y	Negligable opportunity cost for not being called so often for Balancing Services?	Reduced BSUoS charge; Grid stability	-
Distributed Generators	If commercial arrangements dictate	-	Reduced BSUoS charge (if applicable); Grid Stability	-
Sub-5MW Generators	N	Incur full costs for making changes	Grid stability	+VE (if successful)
Suppliers	Y	Increased PPA cost with small generators?	Reduced BSUoS; Grid stability	+VE for reducing bills
End Consumer	(Indirectly)	Negligable increase if affected generators increase cost to buy their power?	Lower bills; Grid stability	-
Manufacturers	N	Potential costs for reconfiguring equipment…	…which can be recouped by increasing charges	+VE for selling compliant equipment
Interconnectors	N			

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Table of cost/benefit – Option 2

Fully-costed administration activity to manage settings change:

Party	BSUoS Payer?	Costs	Benefits	Reputational
NGET		Administration burden if undertaking the change management activity	Funding for admin work?; Less balancing actions required; Grid Stability	+VE (if successful)
DNOs		Administration burden if undertaking the change management activity	Funding for admin work?; Grid stability	+VE (if successful)
Large Generators	Y	If work funded through BSUoS then in short-term no charge cost saving; Negligible opportunity cost for not being called so often for Balancing Services?	Longer-term reduced BSUoS; grid stability	-
Distributed Generators	If commercial arrangements dictate	If work funded through BSUoS then in short-term no charge cost-saving (if applicable);	Longer-term reduced BSUoS (if applicable); Grid Stability	
Sub-5MW Generators	N	There is a cost for doing this, but this is recovered in full	Are fully compensated for any cost to change settings (potential for up-side too?); Grid Stability	+VE (if successful)
End Consumer	(Indirectly)		Lower bills; Grid stability	-
Suppliers	Y	Administration burden if undertaking the change management activity	Reduced BSUoS; grid stability	+VE for reducing bills
Manufacturers	N	Potential costs for reconfiguring equipment…	…which can be recouped by increasing charges (even more so in this example?)	+VE for selling compliant equipment
Interconnectors	N			

Next Steps

- Feedback desired on
  - Are there other costs and benefits?
  - Are the descriptions/allocations accurate?
  - Are there other options which are useful to explore?
  - Any other considerations?

- Incorporation into GC0079 Workgroup Report

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Offshore Generator Local TNUoS Tariff

Jo Zhou

Content

- Background
- The “gap” due to potential revenue adjustments to OFTOs
- The pros and cons of the existing local offshore TNUoS methodology
- Next Steps
- Q & A

Background

- **The current state**
  - SO collect revenue for OFTOs (and onshore TOs) through TNUoS charge
  - Any over/under forecast by the TOs are adjusted in the following financial year
  - The adjustment is recovered via non-locational wider elements of the generation/demand TNUoS tariffs
- **Who pay for the OFTOs' revenue**
  - Majority are paid by the local offshore generators through local TNUoS Tariff
  - The remaining costs are recovered through wider TNUoS, including locational and non-locational wider tariffs
  - Average generation TNUoS charge are capped at €2.5Euro/MWh, and demand customers pick up the remaining charges

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The “Gap”
– revenue adjustments that OFTOs may not be able to forecast

- Pass Through Adjustment Items
  - Temporary Physical Disconnection Payment
  - Refinancing Gain
  - Income Adjustment Events
  - Other items including tender fee adjustment, decommissioning cost adjustment etc
- OFTO Performance Incentives
  - Transmission System Availability Incentive
  - Incremental Capacity Adjustments, including Incremental Capacity Utilisation Adjustment and Incremental Capacity Investment Adjustment
- Correction (K) Factor Incentive Adjustment

The pros and cons of the existing offshore local TNUoS methodology

- **Existing local TNUoS Charge**
  - Offshore generators' local TNUoS charge is "fixed" (only inflated by RPI) during each onshore price control period
  - Unforeseen adjustment to OFTO's annual revenue (e.g. performance incentives) are not seen by the local offshore generators
  - These unforeseen adjustments are picked up through wider residual tariffs, and affect other network users

The pros and cons of the existing offshore local TNUoS methodology

- **Pros**
  - Stability of TNUoS tariff, particularly stable local tariffs for local generators
  - Wider users may benefit from OFTOs' refinancing gain or other cost savings through wider residual tariffs
- **Cons**
  - Cost-reflectivity: e.g. offshore network's availability is not reflected in the local offshore generator's local TNUoS charge
  - The revenue adjustments may add up to a significant figure within 8-years' onshore price control period (e.g. a contingent event adjustment on Sheringham Shoal, resulted in circa £61k additional charge per year; the TR2 tender fee adjustment was around -£330k across four TR2 OFTOs)

Next Steps

- Is the concern need addressing?
- If the answer is yes, by when would you like to see the change to the local charging methodology?
- Is there any wider issue that may have impacts on this topic?

Any Questions?

Lunch

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HH Elective Metering and TNUoS

Damian Clough

HH Elective Metering

- Post April 2017 any meter moving from NHH to HH will currently pick up both the NHH and HH charge
- The above issue arose as part of the implementation of P272
  - CMP241 was raised to prevent Suppliers being ‘overcharged’
  - All meters migrating on or after 1st April 2015 are treated as NHH up until the implementation date of April 2017
- The workaround for P272 in terms of TNUoS charging is detailed in Appendix A
- To remove the potential blocker for customers electing to be settled HH, a change to how TNUoS demand charges are levied will need to be made
- This presentation details at a high level the potential solutions ahead of a formal modification

HH Elective Metering

- To prevent double charging a meter electing to be settled as HH mid year needs to be charged based on the NHH methodology for the whole charging year
  - National Grid will use **actual** metering data for the period 4pm to 7pm but not charge as per the HH methodology i.e. Triad
  - NHH profiled data will **not** be used so consumers **will** be HH settled
- The various options revolve about how the above process will work in practice and over what timescales

HH Elective Metering

- **Option 1**: All meters in Measurement Classes E-G are charged as per the NHH methodology up until HH settlement is mandatory
  - Meters previously charged as HH will be charged NHH from April 2017 onwards
  - Change in expectations
  - Minimal industry change and impact on billing systems and forecasting
- **Option 2**: Meters which were classed as Profile Classes 1-4 are charged as per the NHH methodology up until HH settlement is mandatory. Old Profile Classes 5-8 are charged under the HH methodology from April 2016 onwards
  - To prevent double charging under P272, National Grid treated all demand in Measurement Classes E-G as NHH
  - Option 2 will require the need to separate the demand in Measurement Classes E-G based on old profile classes

HH Elective Metering and Options not supported by National Grid

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- There are other potential Options but from National Grid’s perspective we do not support them
  - **Option 3**: Customers can choose which methodology to be charged under
  - **Option 4**: Meters are charged under the HH methodology for the first full charging year after electing to be HH settled
- Option 3: National Grid and Elexon systems are set up to deal with aggregated data so any option which involves treating customers differently within a class will involve significant system changes, even before consideration is made whether it is right for customers to choose the most beneficial methodology from a liability perspective

HH Elective Metering and Options not supported by National Grid

- Option 4: The NHH methodology was introduced in 2001/02 following the opening up of competition for sub 100kW meters
- New Suppliers argued at the time that Triad charging was a barrier to switching as for similar reasons to the issue regarding double charging, they would pick up a full years worth of Triad liability but would not cover this through revenue recovered from the end consumer if a customer switched mid year
- Therefore consumers who are able to switch at any time throughout the year, by being charged under the HH methodology will reduce when they can switch
- For Profiles 5-8 they are currently restricted from switching as the majority sign fixed term contracts

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System Changes

- P272 workarounds were only designed as a temporary solution as P272 was initially meant to take one year
- To enable HH Elective over a period of 4 years this would necessitate a more robust and permanent solution to be designed
- Similar changes as per TransmiT cost ~£1m. However those changes were made to internal calculations, whereas this could involve changes to how the systems handles files and data as well as calculations
- If amendments are made to the P210 file before National Grid receive the file then there will be minimal impact on our internal billing systems
  - However this may necessitate a Change Proposal or Modification to the BSC

Questions

- Could any of the changes to demand data be more efficiently undertaken by the Data Aggregators?
  - National Grid/Elexon will therefore receive amended HH and NHH demand data per settlement period?
- Will being charged under the HH methodology, prevent switching?

Appendix A TNUoS charges and P272

Background

- BSC Modification P272 was raised to make it mandatory that meters within Profile Classes 5-8 must be Half Hourly (HH) settled by April 2016
- If meters migrate mid year then they will be charged both NHH and HH TNUoS charges
- CMP241 was raised to prevent Suppliers being ‘overcharged’ for the charging year (2015/16) up until the implementation date of April 2016 by treating meters which migrate mid year as being NHH settled for the whole charging year.
- Following P322 which extended the implementation date from April 16 to April 17 CMP247 was raised so meters migrating were charged based on the NHH methodology up until April 17

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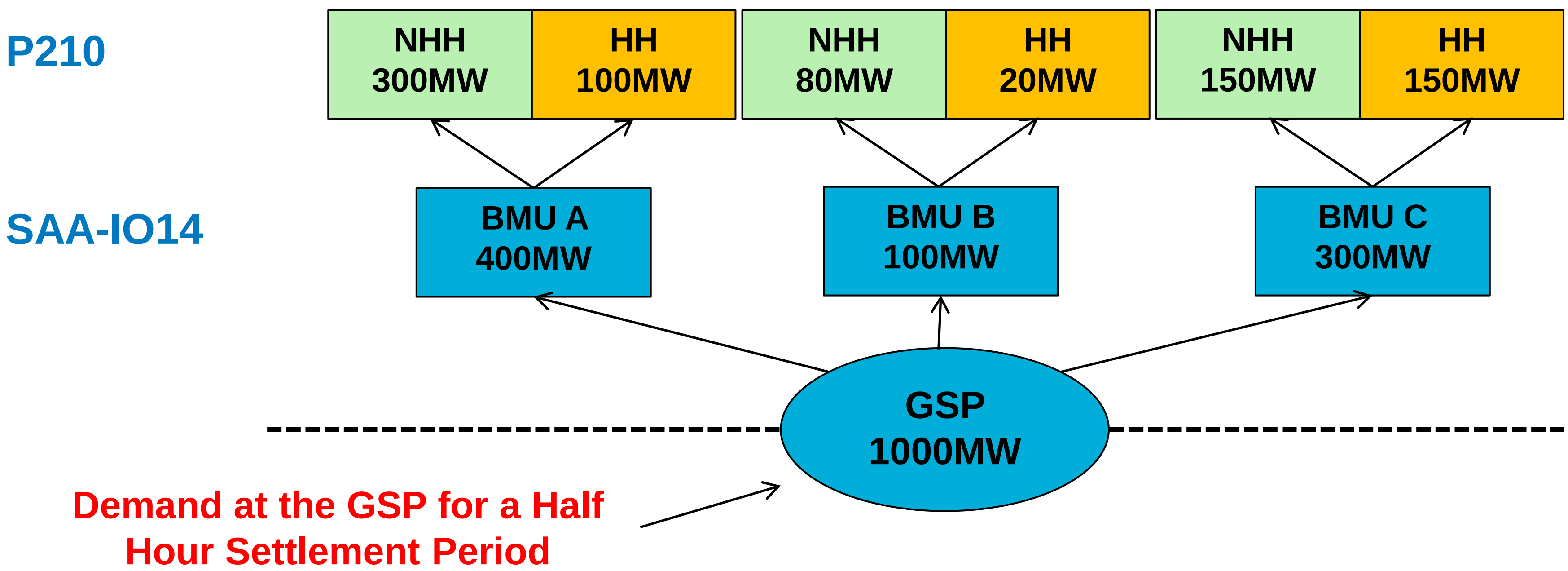
TNUoS Charging <2014/15

Elexon Files

National Grid invoice Suppliers based on the aggregated demand data in the BMU. The P210 file splits this aggregated demand into NHH and HH demand



TNUoS Charging P272

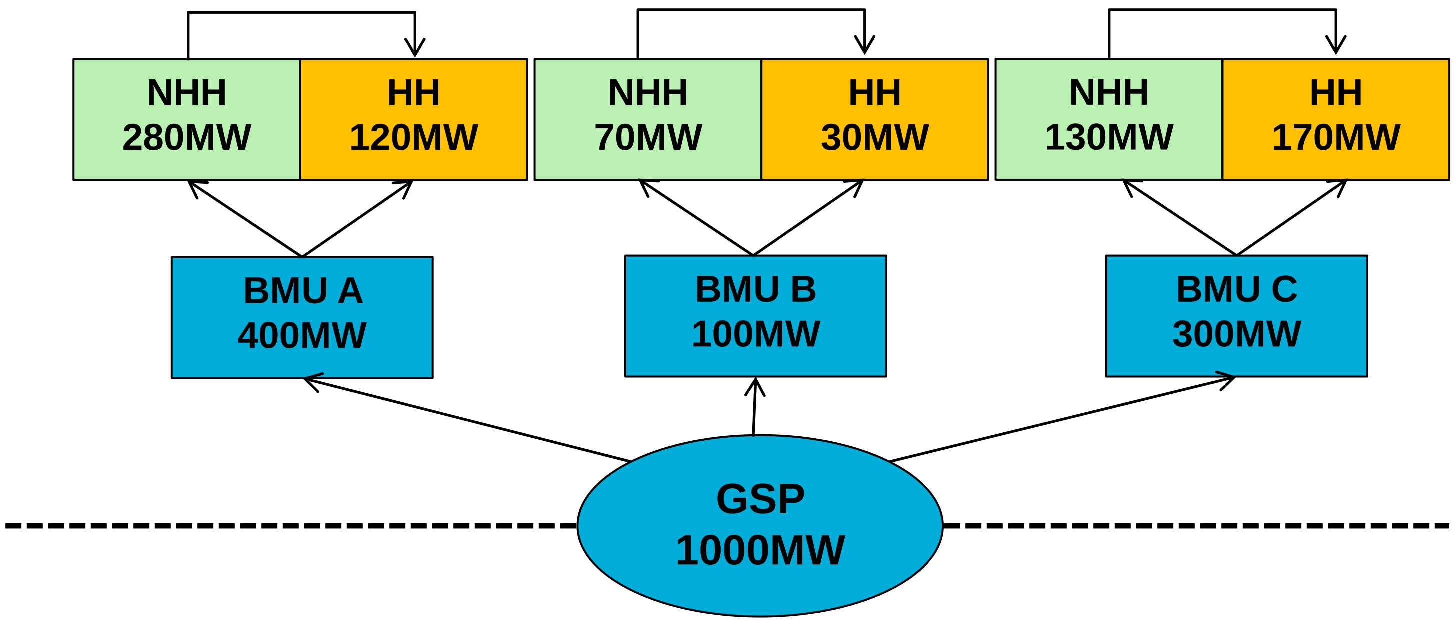
Elexon Files

As meters move from Profile Classes 5-8 to Measurement Classes E-G the aggregate demand for these meters moves from the NHH pot to the HH pot

National Grid have sight of the total aggregated amounts in each pot, and can see the amounts changing but have no sight of the demand changes due to Migration

P210

SAA-IO14



TNUoS Charging P272

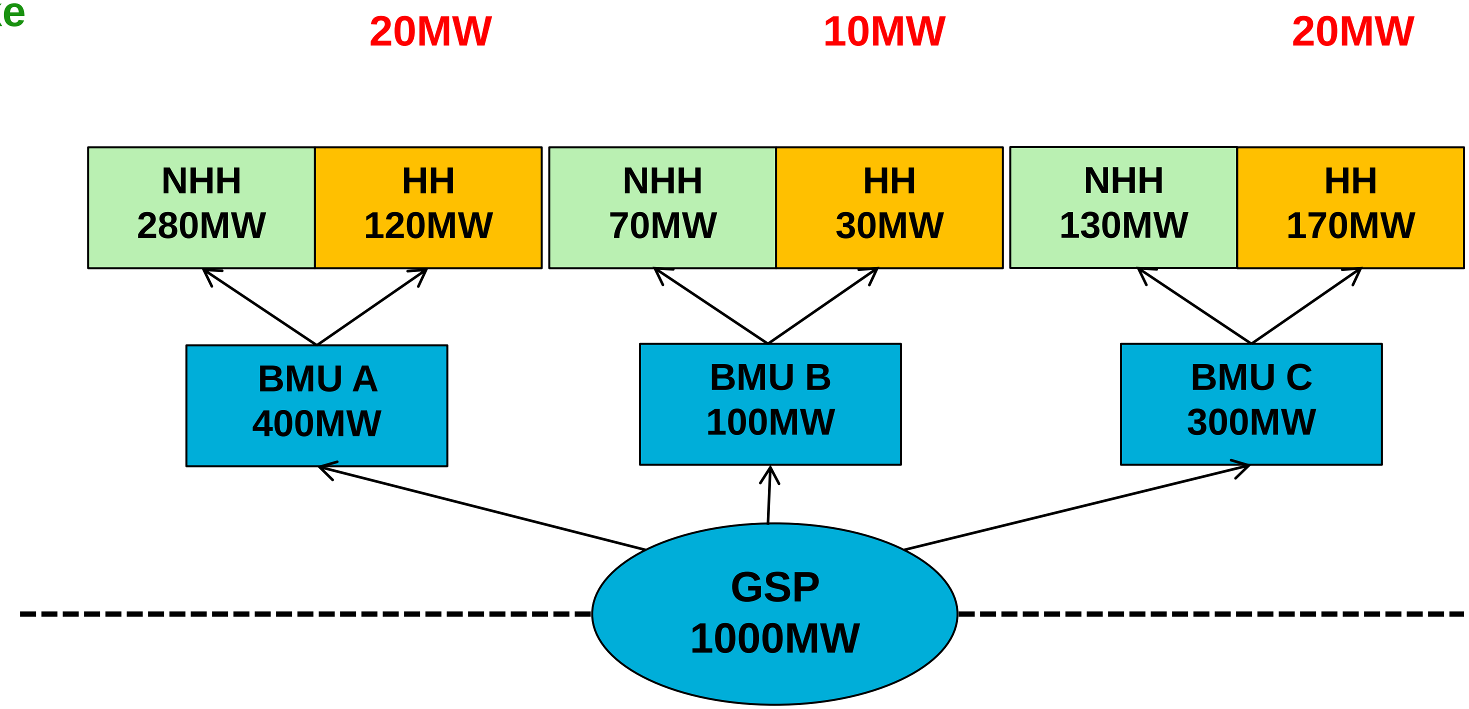
Elexon Files

The bespoke file details the HH demand for Measurement Classes E-G. This demand makes up part of the total aggregated HH demand shown in the P210 file

NEW Bespoke <100KW file

P210

SAA-IO14



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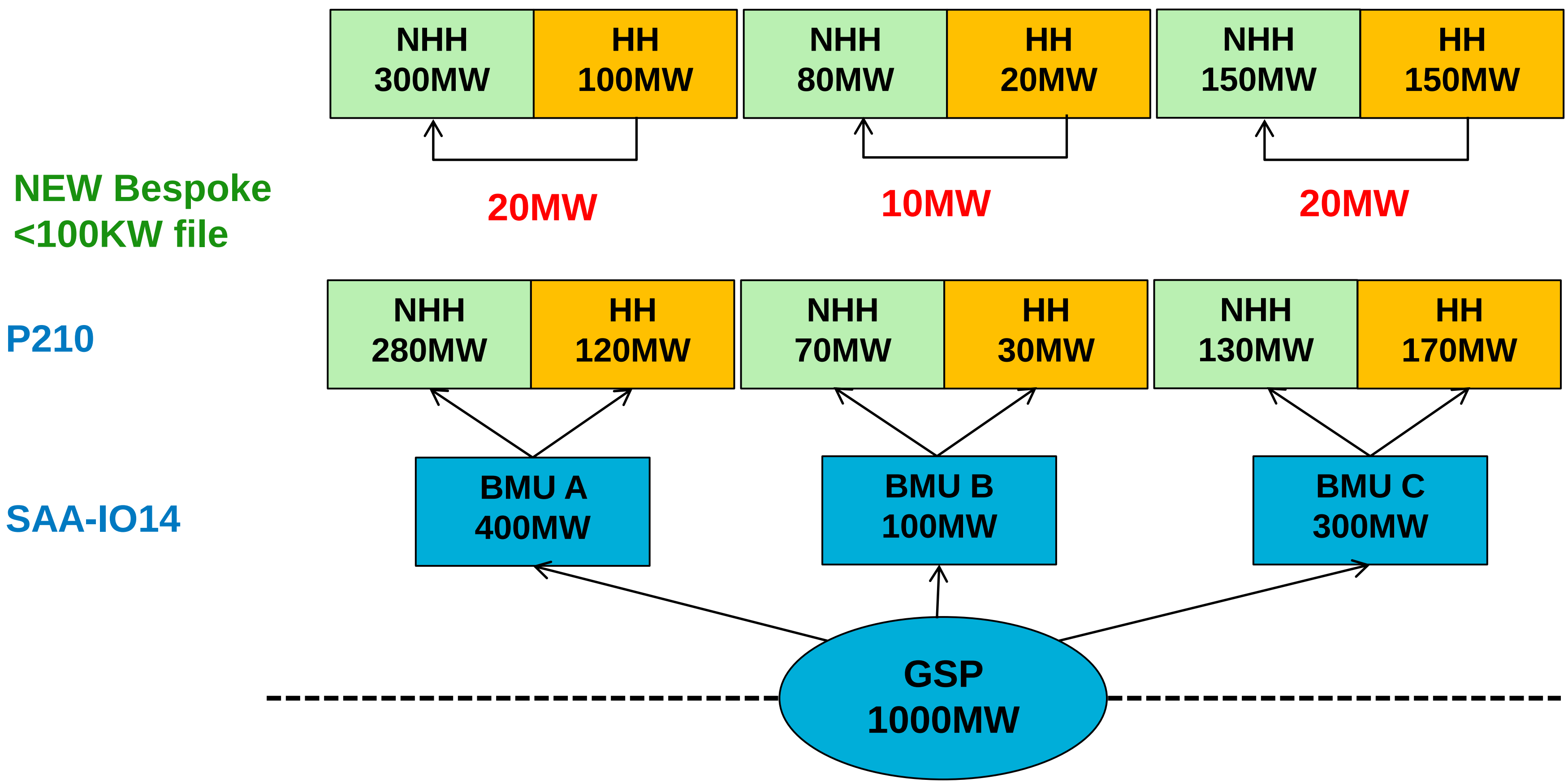
TNUoS Charging P272

The bespoke file enables National Grid to shift the demand for <100kW from the HH pot into the NHH pot preventing double charging

Elexon Files



TNUoS Charging P272 for HH meters <1st April 2015

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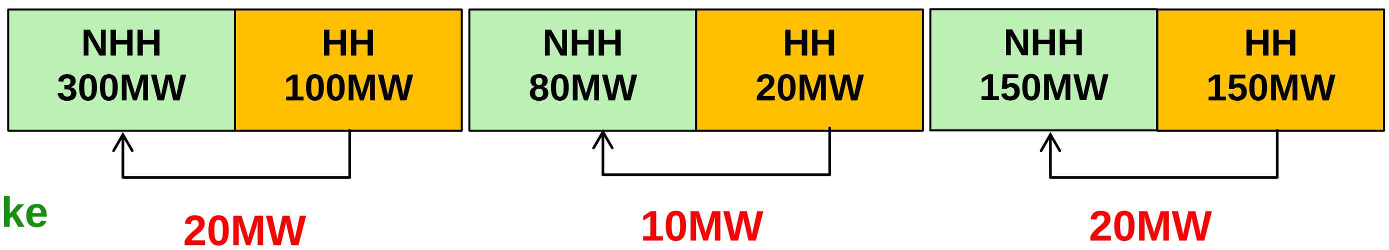
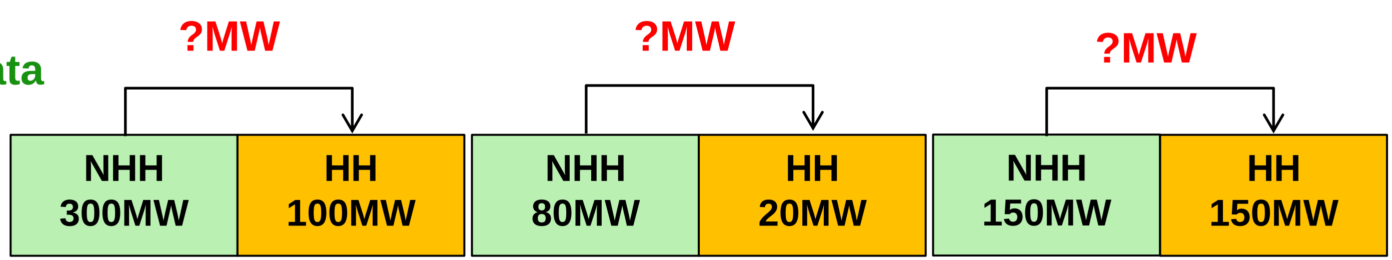
We move all demand for <100kW from the HH pot to the NHH Pot. However within this demand is a set of customers who were HH settled < 1st April 2015



NEW Bespoke <100KW file

If Suppliers provide metering data for these customers we can reverse the process above meaning that their demand is charged under the HH methodology

Individual Supplier Data



Any other business (Charging)

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CUSC Issues Standing Group

Introduction, Welcome and Agenda

13:30 Introduction and meeting objectives – John Brookes, National Grid

13:35 Ongoing non-charging modification proposals – Jo Zhou, National Grid

13:45 Update on the Transmission Works Register – John Brookes, National Grid

13:55 AOB (non-charging) and close – John Brookes, National Grid

Ongoing non-charging modification proposals

Jo Zhou

Ongoing modification proposals: non charging – page 1 of 3

- **CMP259: Clarification of decrease in TEC as a Modification**
  - This proposal was raised by RWE in January to enable a User to request both a TEC reduction and a subsequent TEC increase in the form of a single modification application to National Grid.
  - Workgroup consultation closed on the 3rd May, and workgroup to submit report to CUSC panel by the 19th May.

- **CMP258: Rewording of the legal text to align the CUSC with the intentions of CMP235/6**
  - This proposal was raised by National Grid to complete the implementation of CMP235/6 by modifying some minor points in the relevant legal text. The CUSC Panel agreed that it should be classed as Self-Governance.
  - CMP258 was implemented on the 22nd March 2016.

Ongoing modification proposals: non charging – page 2 of 3

- **CMP257: Enabling the electronic (email) issue of ‘offers’ to customers**
  - This proposal was raised by National Grid in November 2015 to seek to allow for the electronic issue of offers and other formal documents (where agreed) and to remove the obligation to provide hard copies of documentation once elected.
  - CMP257 was implemented on the 12th April 2016.

- **CMP254: Addressing Discrepancies in Disconnection / De-energisation Remedies**
  - This proposal was raised by EDF in October 2015 and seeks to enable Suppliers to instruct National Grid to disconnect customers in accordance with their rights under the Electricity Act.
  - The Authority approved CMP254 WACM3 and it was implemented on the 18th March 2016.

Ongoing modification proposals: non charging – page 3 of 3

- **CMP243 & CMP237: A fixed response energy payment option for all generating technologies / Response Energy Payment for Low Fuel Cost Generation**
  - CMP243 seeks to allow all generators the option of choosing between the current methodology, or a fixed value of £0/MWh, for their Response Energy Payment (REP).
  - CMP237 seeks to set the Response Energy Payment at £0/MWh for those generators with low or negative energy costs.
  - The Workgroup Report was accepted by the CUSC Panel at the February 2016 meeting.
  - The Code Administrator Consultation closed on the 4th April 2016, and CUSC panel voted in April. Authority to make decision when the Final Modification Report is received.

Update on Transmission Works Register

John Brookes

Transmission Works Register

- We understood that the importance of the transmission works register had reduced post ‘connect and manage’ implementation.
- We’re continually listening and responding to your feedback; updating our product and service offerings where relevant to better meet your needs.
- You have recently been telling us that some form of register would be helpful going forward.
- As a result we’ve embarked on the process of updating our processes and systems to be able to provide a register of Enabling Works, which we plan to make available this summer.

Any other business (Non-charging)

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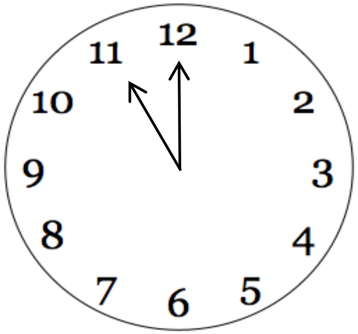
Future TCMF and CISG dates: 2016

July	September	November
6	7	9
Wednesday	Wednesday	Wednesday



All 11 am starts unless otherwise notified

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We value your feedback and comments

If you have any ***questions*** or would like to give us ***feedback*** or share ***ideas***, please email us at:

cusc.team@nationalgrid.com

Also, from time to time, we may ask you to participate in surveys to help us to improve our forum – *please look out for these requests*

Close