Transmission Charging Methodologies Forum and CUSC Issues Steering Group

Meeting 147 - 9 July 2024

Agenda

1	Introduction, meeting objectives and review of previous actions **Dan Arrowsmith, ESO**	10:30 - 10:40
2	ESO Connections update **Alex Curtis, ESO**	10:40 - 10:50
3	CMP419 and CMP426 next steps **Martin Cahill, ESO**	10:50 - 11:00
4	Market-wide Half- Hourly Settlement (MHHS) update **Keren Kelly and Neil Dewar, ESO**	11:00 - 11:10
5	Does Embedded Generation need a BEGA **Nick Sillito, Innovergy**	11:10 - 11:20
6	Ofgem verbal update **Ofgem**	11:20 - 11:30
7	Code Administrator update **Catia Gomes, Code Administrator ESO**	11:30 - 11:35
8	Comfort Break	11:35 - 11:45
9	Location Demand signals **Lauren Jauss, RWE, TNUoS Task Force member**	11:45 - 12:45
10	AOB and Meeting Close **Dan Arrowsmith, ESO**	12:45 - 13:00

TCMF Objective and Expectations

Objective
Develop ideas, understand impacts to industry and modification content discussion, related to the Charging and Connection matters.
Anyone can bring an agenda item (not just the ESO!)

Expectations
Explain acronyms and context of the update or change
Be respectful of each other’s opinions and polite when providing feedback and asking questions
Contribute to the discussion
Language and Conduct to be consistent with the values of equality and diversity
Keep to agreed scope

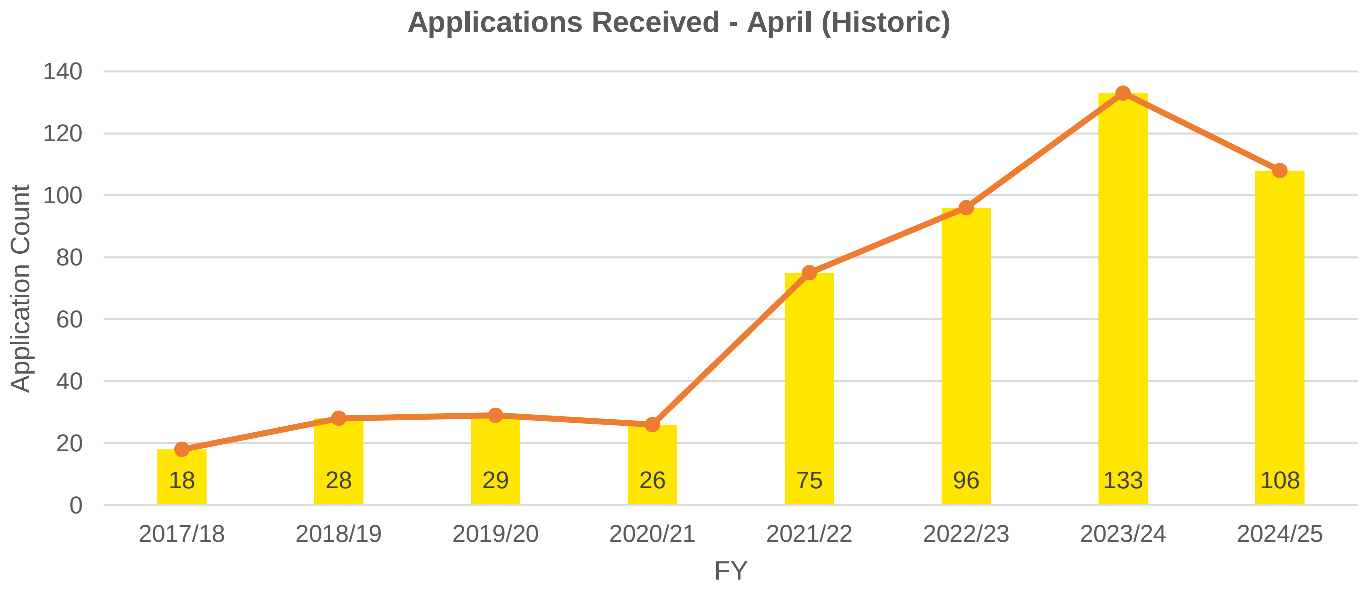
Review of previous actions

ID	Month	Description	Owner	Notes	Target Date	Status
24-6	Feb 29	Update TCMF with progress on potential CUSC defect on double counting of Cancellation Liability and Security presented by Tony Cotton at TCMF 1 February 2024.	CG	MC detailed that a few conversations with ESO Connections Team and with TO's have taken place. The consensus is the defect doesn't have a big impact currently as opportunities for double counting are very rare. Going forward the defect would be best addressed in CMP417. TC broadly concurred with this but expressed, there is still a problem with the CUSC as written currently as the ESO has confirmed double counting does occur. TC requested that the materiality be assessed, especially in the light of the working group "hiatus". TC and MC agreed to take offline. Action to remain open with further update to be presented at TCMF when appropriate.	May 24	Open
24-10	May	CMP328 update.	AC	CMP328, which proposed to introduce a Distribution Impact Assessment (DIA) process, was initially withdrawn by the original Proposer (SSE) on 16th April 2024. SPEN has subsequently requested to become the new Proposer of CMP328 on 23rd April 2024, which will require the modification to address previous send-back comments from Ofgem. A modification cannot be raised with 'substantially the same effect' while CMP328 is ongoing. ESO is now actively engaging DNOs and other stakeholders to explore how a DIA process could be implemented in alignment with connections reform. This is in parallel with our ongoing work on tactical actions to address issues in the Third Party Works process faced by transmission connections customers.	June 24	To be Closed

ESO Connections update

Alex Curtis - ESO

Connection Applications



Record Type	Licensed Applications Received (Count)	Licensed Applications Received (TEC)
ESO New Connection Application	**32**	**6,677MW**
ESO Modification Application	**53**	**10,584MW**
ESO Project Progression Application	**21**	**2,533MW**
ESO Statement of Work (SOW)	**2**	**0.203MW**
Total	108	19,794MW

Connections Queue [733GW]

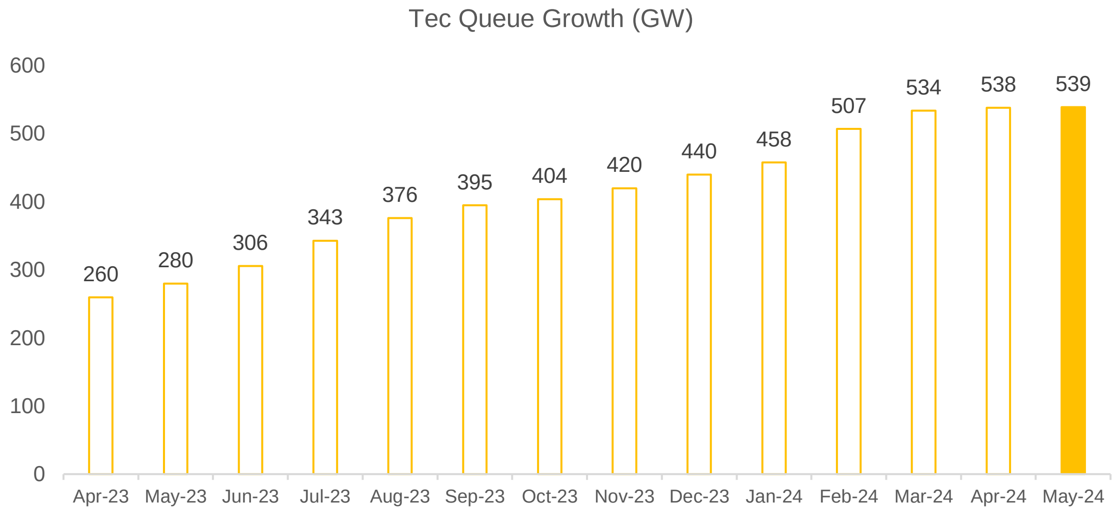
Transmission Queue

539GW
Queue Size

1
Final Operational Notices Issued*

1557
Contracted Projects

1
Terminations*



Directly Connected Demand

26GW
Queue Size

87
Contracted Projects

Distribution Queue

168GW
Queue Size

7153
Contracted Projects

Queue Figures as of 15th June 2024 [Excluding Distribution Queue]
*Terminations & Connections during May 2024

CMP419 and CMP426 next steps

Martin Cahill - ESO

Overview of Modifications

CMP419: Generation Zoning Methodology Review

Contains 3 main elements

- Updating the methodology for creating onshore zones
- Updating the TNUoS methodology for offshore generators connected to the HND by non-radial transmission
- Consider the approach to modelling meshed Direct Current (DC) circuits in HND

CMP426 TNUoS charges for transmission circuits identified for the HND as onshore transmission

- Clarifying cost recovery for Onshore transmission circuits classed as boundary reinforcement in the HND
- Updating the current methodology (where these would go into local circuit charges for generators) with a more cost reflective approach

Overview of Modifications

CMP419: Generation Zoning Methodology Review

Contains 3 main elements

- Updating the methodology for creating onshore zones
- Updating the TNUoS methodology for offshore generators connected to the HND by non-radial transmission
- Consider the approach to modelling meshed Direct Current (DC) circuits in HND

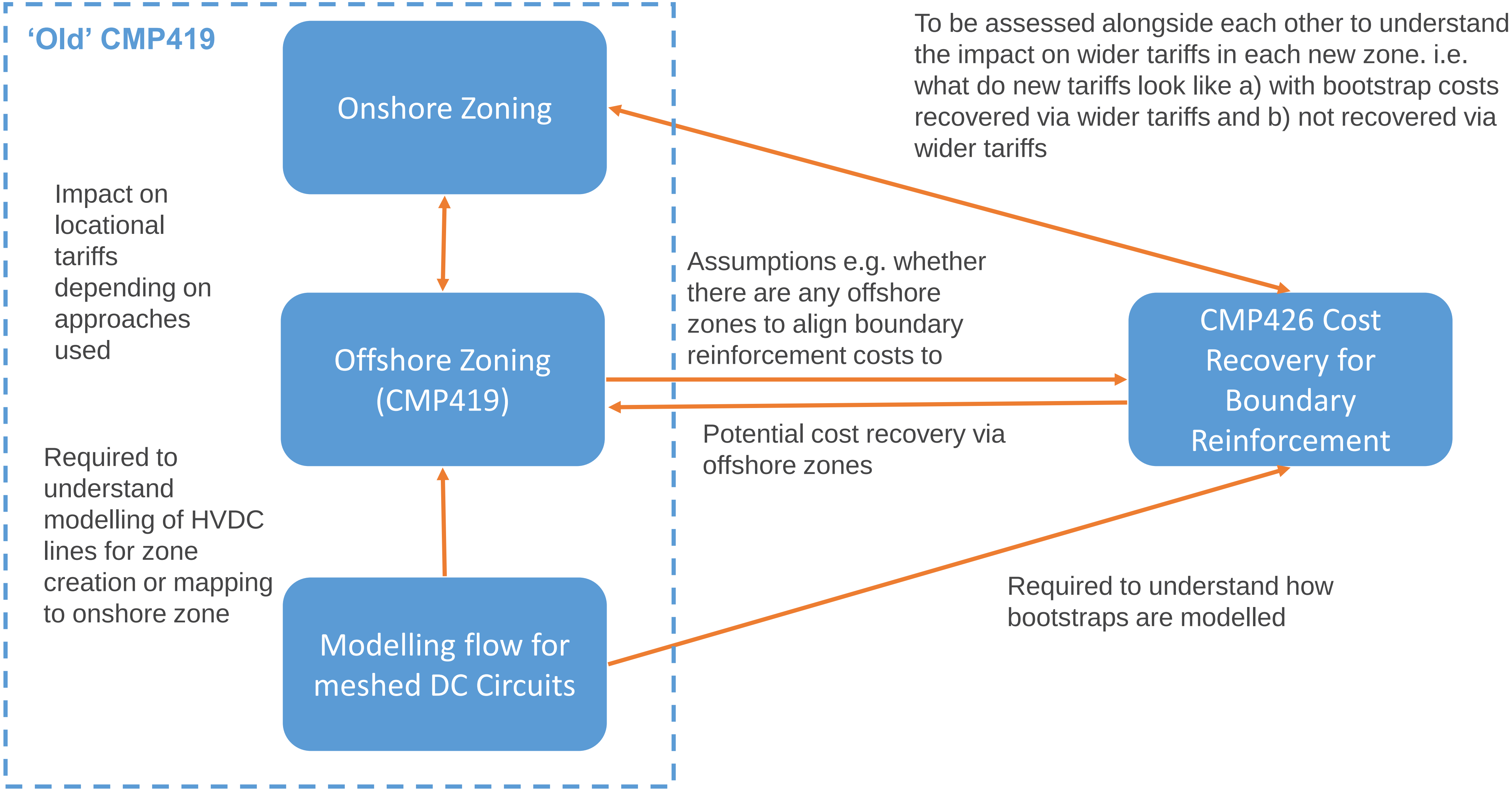
New onshore mod

Continue under CMP419

CMP426 TNUoS charges for transmission circuits identified for the HND as onshore transmission

- Clarifying cost recovery for Onshore transmission circuits classed as boundary reinforcement in the HND
- Updating the current methodology (where these would go into local circuit charges for generators) with a more cost reflective approach

Relationship between Onshore, Offshore and CMP426



New Modification – Onshore Zoning

This modification intends to update the onshore generation zones following the expectations set out as part of the Authority decision on CMP324/325, building on discussion in CMP419. This will include a proposal for the zones to use now, and a methodology for updating in the future.

This modification proposes to align charging zones to those created in ETYS, and subsequently CSNP. This would mean initially reducing from 27 zones to 18.

The advantages of this approach are:

- Stability: ETYS zones change roughly every 5 years, while lower no of zones reduces volatility
- Zones are linked to ETYS boundaries which help to identify constraints on the network. Consistent and long-term constraints in specific locations could provide long term investment signals through TNUoS charges
- More nodes falling within a generation zone will increase tariff stability
- Retains principles of geographic investment signal

Will also include a process for updating zones in future years, realigning to any changes to ETYS/CSNP

CMP419 – Offshore and DC Circuits Approach

•We are not expecting Offshore MITS nodes until early-mid 2030s at the earliest, later than thought when this modification was originally raised

•Recognize that onshore zoning part of the mod is more time sensitive, and do not want to risk implementation for 2026, also ensuring a significant amount of lead time between potential approval and implementation

•Further clarity on HND designs is expected next year, which will need to feed into workgroup considerations for the offshore charging approach

•We don't yet know what a suitable offshore zoning approach would be

On this basis we believe there is benefit in holding an out of workgroup meeting to gather views from Industry and develop options further

- Aiming to hold end of July
- If you would like to be involved please get in touch with martin.cahill1@nationalgrideso.com

Key Questions for Offshore session

- Implementing sooner vs developing a long term solution
- What are the alternative options if we do not create offshore zones?
- What should the key principles be for zoning?
- Temporary vs longer term solutions
- Onshore vs Offshore alignment
- Assumptions for CMP426

CMP426

- Existing solution to progress alongside a similar timeline to the new onshore zoning mod
- Will need to agree some key assumptions from offshore approach, though recognising that there is a risk that some of these could change
- Implementation still targeted for 2026
- We will also discuss alignment to CMP419 during out of workgroup session

Market-wide Half- Hourly Settlement (MHHS) update

Keren Kelly and Neil Dewar - ESO

CMP430 Update

Legal Text Update

- Final Legal Text agreed by Workgroup on Friday 5th July for introduction of text to CUSC to support the implementation of the MHHS Programme
- Minor amendments to clauses contained in 14.17.40
- Full review of Section 14 undertaken by Workgroup and also ESO in conjunction with ESO Revenue and ESO Legal:
    - No further legal text changes to be made within the scope of CMP430
    - Clauses identified that could be changed at the end of the MHHS Migration period or superseded by Modification proposals driven by TNUoS TF
    - Workgroup agreed this was the best solution.

Next steps

Next workgroup is on 11th July to:

- Conduct Workgroup Vote
- Discuss Workgroup Report
- Finalise all documents to ensure readiness for CUSC Panel submission
- Back up of one last Workgroup date of 16th July in diary to sign off Workgroup Report

Important Milestone and relevance for industry

- Code Administrator Consultation due between 31st July and 8th August
- Important to stress to industry that we as a Workgroup have not eliminated the risk of double charging of MPANs during the Transition phase of the MHHS Programme completely

CMP431 Update

<u>Legal Text Update</u>

- As part of a full Non-Charging CUSC review, it was determined that:
- No amendments were required to Section 3 as a result of the legal text being introduced in CMP430
- Only 1 possible term “BSCCo” could be introduced to Section 11, but Workgroup felt this was already defined in the legal text of CMP430 and question appropriateness of including as part of CMP431.
- Workgroup recommended Withdrawal of CMP431 based on above
- ESO took action away to discuss with Code Administration on consequences of withdrawal and next steps will be agreed at the upcoming Workgroup meeting

Timeline for CMP430 – Updated after Workgroup 11 (24 May 2024) Agreed by Authority

Milestone	Date	Milestone	Date
Modification presented to Panel	23 February 2024	Code Administrator Consultation (6 Business Days)	31 July 2024 to 08 August 2024
Workgroup Nominations (4 Working Days)	23 February 2024 to 29 February 2024	Draft Final Modification Report (DFMR) issued to Panel (4 working days)	16 August 2024
Ofgem grant Urgency	29 February 2024 (5pm)	Panel undertake DFMR recommendation vote	23 August 2024
Workgroup 1 to 7 (assuming Ofgem have granted Urgency)	06 March 2024 11 March 2024 13 March 2024 Cancelled 19 March 2024 28 March 2024 05 April 2024 15 April 2024	Final Modification Report issued to Panel to check votes recorded correctly	23 August 2024
Workgroup Consultation (5 working days)	17 April 2024 – 24 April 2024	Final Modification Report issued to Ofgem	23 August 2024
Workgroup 8 to 14 - Assess Workgroup Consultation Responses and Workgroup Vote	29 April 2024 03 May 2024 – Cancelled 08 May 2024 13 May 2024 – Cancelled 20 May 2024 24 May 2024 06 June 2024 – Cancelled 13 June 2024 21 June 2024 05 July 2024 11 July 2024 16 July 2024	Ofgem decision	30 September 2024
Workgroup Report issued to CUSC dot box Workgroup Report presented to Panel (Panel agree Workgroup report has met its Terms of Reference)	18 July 2024 26 July 2024	Implementation Date	01 April 2025

Does Embedded Generation need a BEGA

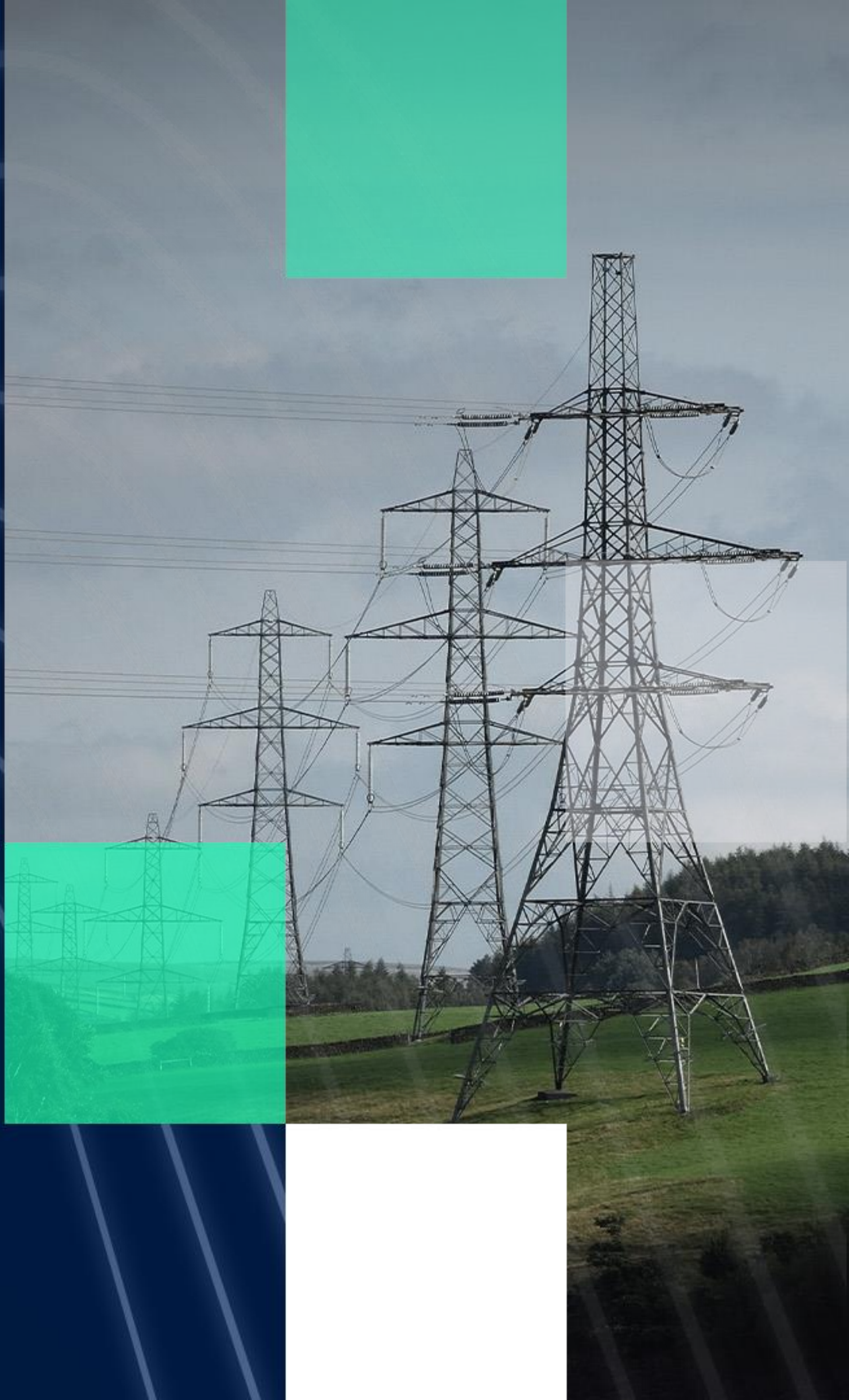
Nick Sillito - Innovergy

ESO

innovergy

Does an embedded generator need a BEGA?

Nick Sillito, TCMF July 2024



Value and innovation for energy

What is a BEGA?

- A BEGA is a **Bilateral Embedded Generation Agreement**
- The BEGA provides TEC (transmission entry capacity) required by large (≥100 MW) embedded. Smaller Generators do not require TEC
- The BEGA is a contract between NGESO and an embedded (distribution connected) generator where the settlement meter registrant is not a licenced supplier
- To enter a BEGA, the generator applies for a connection agreement to NGESO
  - As part of the BEGA process, the generator accedes to the CUSC
  - There is no obligation on the generator to have a BEGA with NGESO (the generator applies for a connection with the DNO)
  - Cost of a BEGA application is c.£17k (depends on size and location) for a standard agreement

What are the obligations on an embedded gen?

- To comply with the Grid Code if the generator is licenced
- To comply with the BSC (obligation is on the party who registers the settlement meter – this may not be the embedded generator)
- To comply with the DCUSA (and pay DUOS). Obligation is on the meter registrant who must be a DCUSA party before they can register the settlement meter
- To pay TNUoS and BSUoS (if applicable)
  - Only applies if the generator is a CUSC signatory*

*LC19 requires that a licensee with a generating station must be a CUSC party. However, a generating station is defined as being over 50 MW

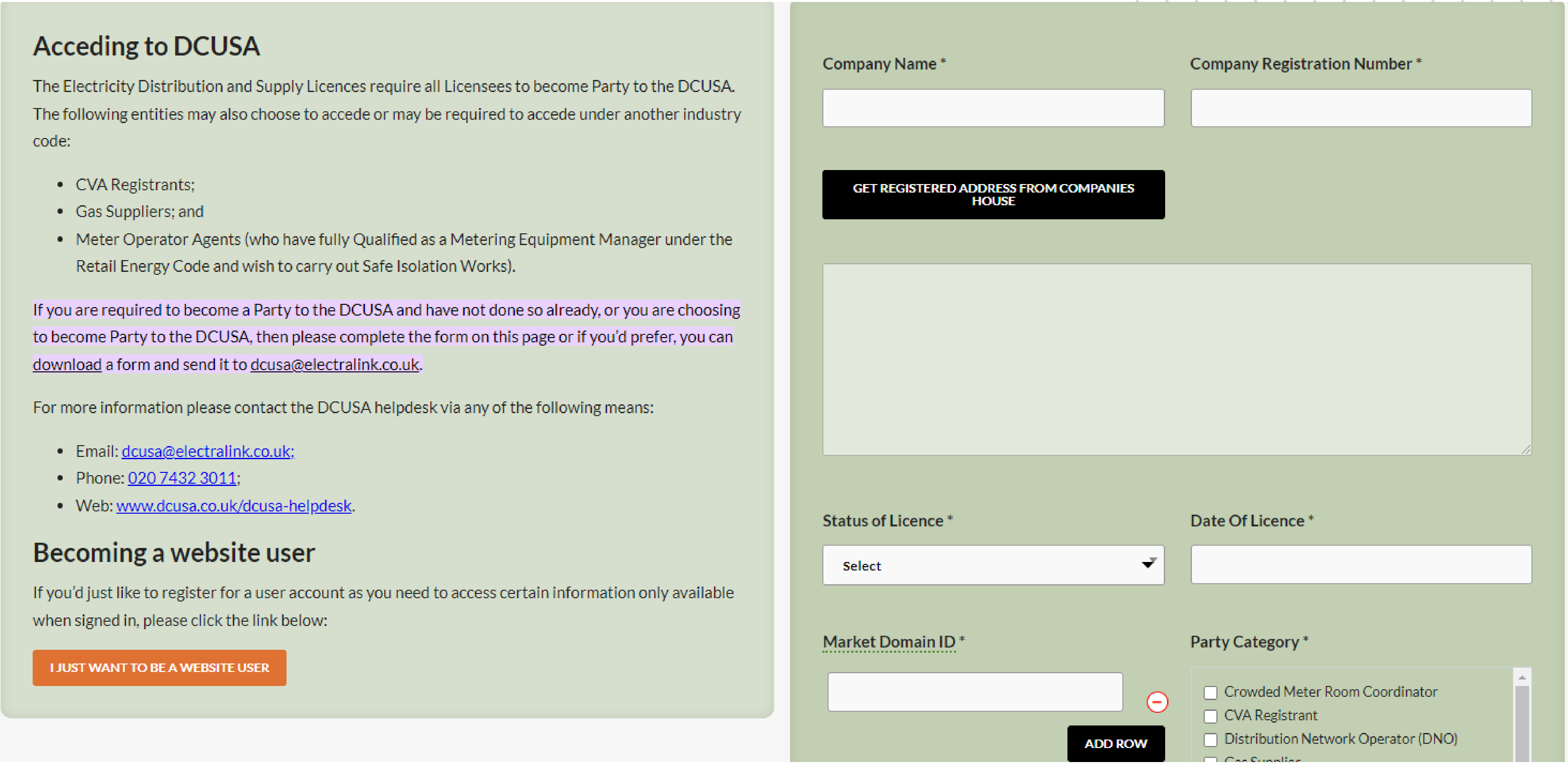
What about Balancing Mechanism participation?

- NGESO requires an embedded generator to have a BEGA before registering in the Balancing Mechanism
- Why?
  - Obligations on submitting PNs, dynamic parameters and following instructions are covered by Grid Code (BC1 and BC2)
  - Technical connection obligations are covered by DNO agreement
  - Settlement of Bids and Offers in the Balancing Mechanism is covered by the BSC
  - NGESO requires operational metering as part of the Balancing Mechanism activation process*
- Conclusion: If an embedded generator is licenced, has a connection agreement with the DNO, and its settlement meter registered by a BSC party then a BEGA is not required.

*The Grid Code requires medium and large power stations, but not small power stations, to have operational metering

What about TNUoS?

- If an embedded generator does not have a BEGA, and the generator is not a CUSC signatory, then there is no contract for the payment of TNUoS and BSUoS
- A generator can apply for a BEGA to put the obligation in place
  - BEGA process is expensive and slow
- Could create a process where a potential generator can simply apply to become a CUSC party like the DCUSA process



Acceding to DCUSA

The Electricity Distribution and Supply Licences require all Licensees to become Party to the DCUSA. The following entities may also choose to accede or may be required to accede under another industry code:

- CVA Registrants;
- Gas Suppliers; and
- Meter Operator Agents (who have fully Qualified as a Metering Equipment Manager under the Retail Energy Code and wish to carry out Safe Isolation Works).

If you are required to become a Party to the DCUSA and have not done so already, or you are choosing to become Party to the DCUSA, then please complete the form on this page or if you'd prefer, you can download a form and send it to dcusa@electralink.co.uk.

For more information please contact the DCUSA helpdesk via any of the following means:

- Email: dcusa@electralink.co.uk;
- Phone: 020 7432 3011;
- Web: www.dcusa.co.uk/dcusa-helpdesk.

Becoming a website user

If you'd just like to register for a user account as you need to access certain information only available when signed in, please click the link below:

I JUST WANT TO BE A WEBSITE USER

Company Name *

Company Registration Number *

GET REGISTERED ADDRESS FROM COMPANIES HOUSE

Status of Licence *

Select

Date Of Licence *

Market Domain ID *

ADD ROW

Party Category *

- Crowded Meter Room Coordinator
- CVA Registrant
- Distribution Network Operator (DNO)

See https://www.dcusa.co.uk/accede-to-the-code-party-registration/

Conclusion and Next Steps

- A licenced embedded generator is already subject to the Grid Code and the BSC hence does not require a BEGA to participate in the BM
- The requirement for an embedded generator to have a BEGA before participating in the Balancing Mechanism adds to the generator’s costs and forms a barrier to entry
- An embedded generator needs to accede to the CUSC (for TNUoS and BSUoS charges). The connection application process is cumbersome (if a BEGA is not required)
- Proposal: **Modify the CUSC to allow potential embedded generators to accede without a connection application**

innovergy

Value and innovation for energy

Nick Sillito

nsillito@peakgen.com

innovergy.energy

Ofgem verbal update

Ofgem

Code Administrator Update

Catia Gomes - Code Administrator ESO

Key Updates since last TCMF

New Modifications / Nominations

- CMP436 ‘Update CUSC arrangements to replace the Electricity Arbitration Association (EAA) with the London Court of International Arbitration (LCIA) (Non-Charging’
- CMP437 ‘Update CUSC arrangements to replace the Electricity Arbitration Association (EAA) with the London Court of International Arbitration (LCIA) (Charging’)
- CMP438 ‘Clarification of Illustrative Example of a TNUoS Demand Reconciliation’

Decisions

- CMP428 ‘User Commitment liabilities for Onshore Transmission (reinforcement) in the Holistic Network Design’

Original approved

Implementations

- CMP428 ‘User Commitment liabilities for Onshore Transmission (reinforcement) in the Holistic Network Design’

Authority Expected Decision Date

Modification	FMR Received	Expected Decision Date
CMP315 'TNUoS Review of the expansion constant and the elements of the transmission system charged for' and CMP375 'Enduring Expansion Constant & Expansion Factor Review'	07/02/2024	30/09/2024
CMP316 TNUoS Arrangements for Co-located Generation Sites	12/06/2024	TBC
CMP330&CMP374 'Allowing new Transmission Connected parties to build Connection Assets greater than 2km in length and Extending contestability for Transmission Connections'	10/08/2023	08/07/2024 (Previously 08/05/2024)
CMP393 Using Imports and Exports to Calculate Annual Load Factor for Electricity Storage	17/06/2024	TBC
CMP396 'Re-introduction Of BSUoS on Interconnector Lead Parties'	05/01/2024	31/05/2024
CMP397 Consequential changes required to CUSC Exhibits B and D to reflect CMP316 (Co-Located Generation Sites)	12/06/2024	TBC
CMP403 Introducing Competitively Appointed Transmission Owners & Transmission Service Providers (Section 14)	11/06/2024	TBC
CMP404 Introducing Competitively Appointed Transmission Owners & Transmission Service Providers (Section 11)	11/06/2024	TBC
CMP408 'Allowing consideration of a different notice period for BSUoS tariff settings'	13/10/2023	09/09/2024 (Previously TBC)
CMP414 'CMP330/CMP374 Consequential Modification'	10/08/2023	31/07/2024 (Previously 08/05/2024)
CMP415 'Amending the Fixed Price Period from 6 to 12 months'	13/10/2023	09/09/2024 (Previously TBC)

The Authority's publication on decisions can be found on their website below:
https://www.ofgem.gov.uk/publications/code-modificationmodification-proposals-ofgem-decision-expected-publication-dates-timetable

* Dates moved since last update

Key Updates ahead of the next TCMF

July Consultations

- CMP424 (Amendments to Scaling Factors used for Year Round TNUoS Charges) Code Administrator Consultation **open until 5pm 22 May 2024**

- CMP430 (Adjustments to TNUoS Charging from 2025 to support the market wide half-hourly settlement (MHHS) Programme) and CMP431 (Adjustments to TNUoS Charging from 2025 to support the Market Half Hourly Settlement (MHHS) Programme (Non-Charging) Code Administrator Consultation **opens 31 July 2024 until 5pm 08 August 2024**

- CMP436 (Update CUSC arrangements to replace the Electricity Arbitration Association (EAA) with the London Court of International Arbitration (LCIA) (Non-Charging) Code Administrator Consultation **open until 5pm 10 July 2024**

- CMP438 (Clarification of Illustrative Example of a TNUoS Demand Reconciliation) Code Administrator Consultation **opens 09 July 2024 until 5pm 30 July 2024**

Useful Links

Updates on all Modifications are available on the Modification Tracker here

Ofgem’s expected decision dates/ date they intend to publish an impact assessment or consultation, for code modifications that are with them for decision are available here

The latest CUSC Panel Headline Report and prioritisation stack are available here

If you would like to receive updates from the Code Administrator on CUSC modifications please join the distribution list here

CUSC 2024 - Panel dates

	Panel Dates	Papers Day	Modification Submission Date	(TCMF) CUSC Development Forum
November	24	16	9	2
December	15	7	30 November	23 November
January	26	18	11	4
February	23 (Face to Face Meeting)	15	8	1
March	22	14	7	29 February (Face to Face Meeting)
April	26	18	11	4
May	31(Face to Face Meeting)	23	16	9
June	28	20	13	Cancelled
July	26	18	11	9
August	23	15	8	1
September	27	19	12	5 (Face to Face Meeting)
October	25 (Face to Face Meeting)	17	10	3
November	29	21	14	7 (Face to Face Meeting)
December	13	5	28 November	21 November

Comfort Break

Location Demand signals

Lauren Jauss – RWE, TNUoS Task Force member

RWE

TNUoS Taskforce:

Re-introduction of Demand TNUoS locational signals by removal of the zero-price floor

9 July 2024

Context

- Taskforce were asked to consider:
  - Is it appropriate to have negative locational charges for demand?
  - Should the floor at zero be reviewed?
  - What signals should demand TNUoS send, and how?

- Taskforce agreed on the following high-level principles:
  - Demand and generation negative locational charges are appropriate, but there should not be a negative total cost of final demand to a consumer to incentivise them to waste energy in a specific time period
  - Ideally, generation and demand locational signals would be approximately equal and opposite
  - TNUoS should not send operational signals, as this can be better achieved through other mechanisms.
  - TNUoS should reflect the long-run incremental investment cost impact on the transmission system from <u>long-term user investment decisions</u>

- Frontier were commissioned for several TNUoS studies including consideration of the design principles that should underpin locational demand charges, and the extent to which the current design of demand charges remains fit for purpose. The following slides are selected from Frontier's presentations to the Taskforce

Peak and Year Round type backgrounds are important but their representation potentially can be improved with changes to the assumed generation mix (2025)

Cost reflectivity

Technology	Current backgrounds: Peak	Current backgrounds: Year-round	Most representative backgrounds (2025, NGESO FES ST scenario): Round 1	Round 2	Round 3
Biomass	88%	27%	68%	68%	3%
OCGT	88%	0%	0%	77%	0%
CCGT	88%	27%	21%	95%	0%
Hydro	88%	27%	64%	64%	0%
Interconnectors	0%	100%	48%	59%	-80%
Nuclear	88%	85%	100%	100%	100%
Wind Offshore	0%	70%	87%	4%	87%
Wind Onshore	0%	70%	81%	4%	77%
Pump Storage	88%	50%	0%	58%	-61%
Demand (MW)	52,417	52,417	50,547	50,770	26,508
Individual % represented	32%	33%	59%	27%	15%
Cumulative % represented	32%	43%	59%	67%	76%

Current Peak and YR scenarios do not provide a very good representation for over half of the network.

Similar to YR

Similar to peak

Representative backgrounds identified (2025)

- In the identified representative backgrounds, the percentage shown is the average load factor observed for the particular technology in that scenario from LCP's dispatch modelling.
- The most representative background observed, shown as "Round 1", gives a 'good' representation of 59% of circuits.
- The "Round 1" background is somewhat similar to the year-round background, with high wind, biomass and nuclear load factors, and lower gas generation.
- "Round 2" gives the greatest increase to representation of circuits when combined with Round 1. Round 2 is somewhat similar to peak, but with variation in load factors across the fleet and interconnectors importing.
- "Round 3" has lower demand and high wind load factors leading to demand from pump storage and export via interconnectors.

…our analysis suggests that updates to the current backgrounds could be appropriate in order to improve cost reflectivity

Cost reflectivity

- The analysis suggests that Year Round and Peak Security type backgrounds are likely to remain relevant, though their representativeness can be improved with changes to specific assumptions.
- If a single background was favoured, a Year Round type scenario could be most appropriate going forward, although this could entail a small reduction in cost reflectivity, relative to two backgrounds. For example, charges would be expected to increase for wind as circuits previously tagged to Peak Security are now tagged as Year Round.
- The marginal benefit of adding a third background is much reduced compared to adding a second background, particularly in 2035.
- Irrespective of whether this analysis is considered to support a change, an update to the backgrounds is likely to be required in future e.g. due to "fixed" generation exceeding demand.

Level of charges

- The impact of using more representative backgrounds appears to be relatively limited, either using two alternative backgrounds or a single alternative.
- This suggests that without a change to the fundamental flow from North to South, changes to backgrounds may only have a limited impact on final charges.
- In addition, if the €2.50/MWh cap is binding then the adjustment tariff may also reduce the impact of changes further.

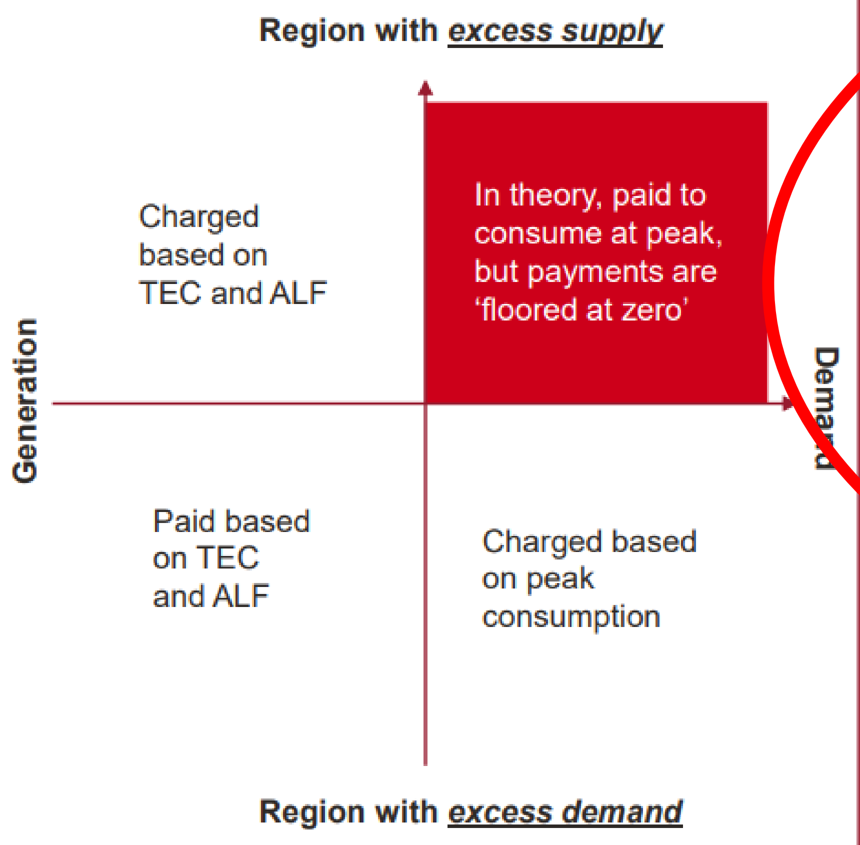
Predictability of charges

- The predictability analysis suggests that there are no clear implications for year to year volatility from applying one (Year Round) or two backgrounds, which may suggest no material change in predictability of the tariffs.
- Although moving to a single background would remove one area of uncertainty in the tariff calculations (i.e. the tagging of circuits to a particular background).
- There appear to be volatility implications if adopting only a peak background, however, this would be inconsistent with the cost reflectivity analysis.

…however, our initial view is that the implications of change for the level and volatility of charges may be relatively limited

Concerns that led to "floored at zero" are less relevant if the operational signal is much diluted

Charges are currently "floored at zero"

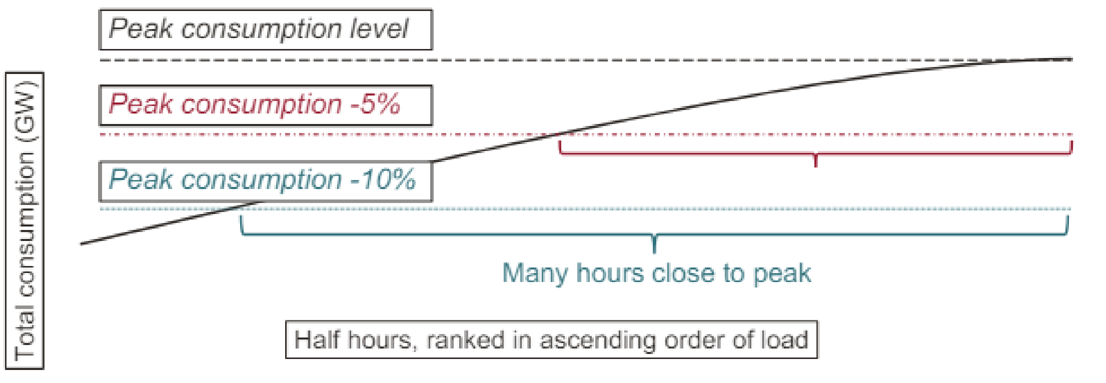


Removing floored at zero would restore important investment signal

- Charges currently floored at zero, to avoid incentivising increased peak consumption, which Ofgem worries will impact on security of supply.
- It leads to **inefficient investment signals** – Demand is insufficiently incentivised to locate close to sources of supply.
- If significantly reducing / removing operational signals then floored at zero is much less of a concern.
  - If setting charges based on a broad base of hours, incentive to increase demand remains but it is much diluted so less likely to be of concern
  - If setting charges based on deemed consumption/banding then operational signal removed
- From an efficiency perspective, removing floored at zero is beneficial.

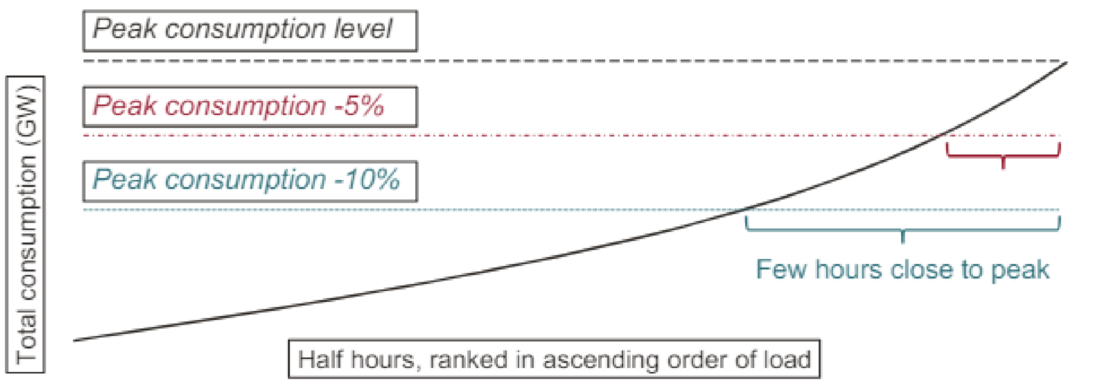
When choosing appropriate Peak Security charging methodology, it is important to consider the gradient of the load duration curve

Shallow load duration curve:



- Broad base of hours where consumption is close to peak i.e. consumption across many hours is important potential drivers of future Peak Security costs.
- This suggests that **demand should be charged** (penalised/rewarded) on the basis of **consumption across a broad base of peak hours.**

Steep load duration curve

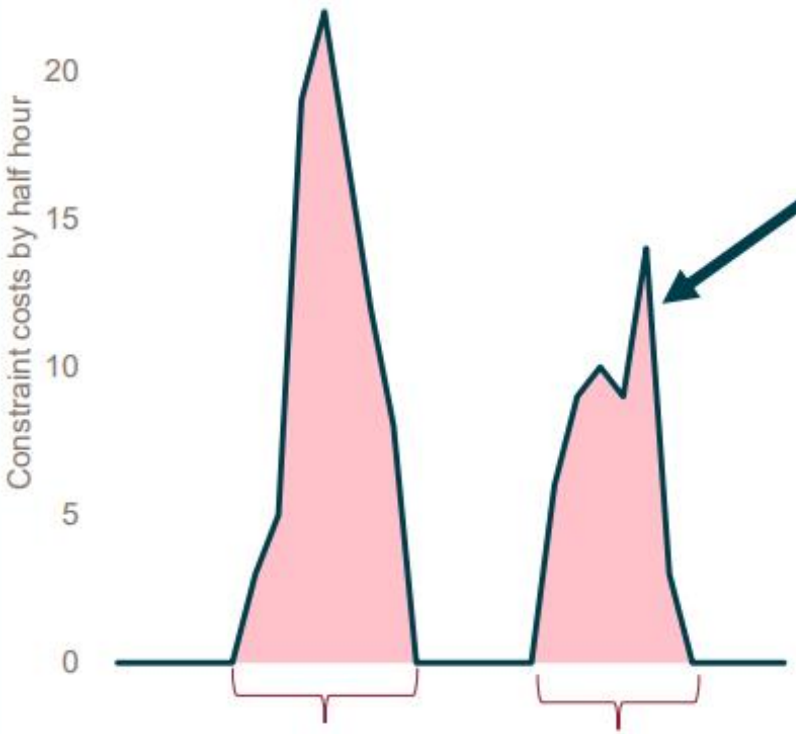


- Relatively few hours where consumption is close to peak i.e. consumption across only a few hours is important potential driver of Peak Security costs.
- This suggests that **demand should be charged** (penalised/rewarded) on the basis of **consumption in only a few peak hours**

Ultimately, the shape of demand is an empirical question which could be investigated further (see slide 30)

All constrained hours are relevant for year-round costs, rather than just hours of maximum constraint

Hypothetical constraint costs over time



Periods that contribute to constraint costs

Year-round costs relate to the sum of constraint costs

- Year-round costs relate to the optimal network investment required to efficiently alleviate constraint costs.
- Constraint costs vary over time, as represented by the line in the graph.
- Network investment to alleviate constraint costs is **not driven by the peak level** of constraint costs, rather it is driven by the total of constraint costs across all periods, as represented by the pink shaded area.

All constrained hours are relevant but not equally

- A 1MW increase in demand will have an impact on constraint costs in **all hours that the network is constrained.**
- However, the marginal cost of alleviating constraints in each constrained hour will vary depending on the actions the ESO must take to resolve the constraint.
- It is likely that when constraints are larger overall (deeper), the marginal cost to resolve the constraint will be larger because the ESO will have already exhausted the cheaper options for alleviating constraint

Basic options for charging year round identifying which hours and allocating year-round costs

1 Average demand in all hours

- Simple to implement
- Easy to understand
- Sends minimal (very diluted) operational signal
- Likely more cost reflective than charging based on peak demand
- Abstracts from the distinction between consumption during constrained hours (which affects required network investment), and consumption in other hours (which does not)

Analogous to a Load Factor style approach

Average demand in constrained hours only

2 Unweighted

- Charges based on average consumption during all constrained hours.
- Would send only a small operational signal (assuming there are many constrained hours in a year)
- Sends more targeted cost reflective investment signal but not fully cost reflective.

Analogous to a "Constrained Load Factor" style approach

3 Weighted by a metric

- Charges based on weighted average consumption in constrained hours.
  - Options for weighting approach discussed in slide 26
- May send a modest operational signal in most periods but may send stronger incentives when constraints are higher.
- In principle sends a more targeted and cost reflective investment signal.

Analogous to a "Constrained Load Factor" style approach with further adjustment

We assess each of these options in the following slides

Taskforce’s Conclusions
Objective is to agree key principles and identify any case for change

- Agree the zero-floor removes important investment incentives
- Charges based on actual consumption over a broader base of hours for both Peak and Year-Round Tariffs would reduce the operational signal which would in turn reduce the rationale for the floor.
- For Year-Round Tariffs in particular, Taskforce considered Frontier’s Option 1 to be the best solution:
  - Option 1 appears most consistent with the approach used for generation charging, which also considers consumption across the whole year and does not weight charges by generation during periods of constraints
  - Options 2 & 3 would make Demand TNUoS charges less predictable as they would be dependent on constraints for which Users have limited data and no control. The definition and identification of “constrained hours” is very complex
- There is a case for change, and given the importance of locational demand investment signals as cited in the REMA consultations and ESO Beyond 2030 report, it would seem of relatively high priority
- Further analysis expected to be relatively detailed and could be conducted during the CUSC change process

Taskforce recommended scope for a CUSC modification

- Taskforce recommend a modification to apply to Final Demand only:
  - Transmission connected/large generators are also currently liable for Demand TNUoS if they consume over the charging period. If this is widened, the current arrangements would start to capture generator consumption, but this is unlikely to be appropriate
  - Distribution connected generators are to be considered separately by Ofgem with recommendations from the Distributed Generation Sub-group of the TNUoS Taskforce. Hence the Embedded Export Tariff is similarly out of scope.
  - Storage demand is to be considered by the new Storage TNUoS Sub-group.
- Electrolysers are an important future source of demand that expected to be able to respond to long term locational cost signals to some extent. It is not clear at this stage whether electrolyser demand will be included in the definition of Final Demand. If excluded, the scope of changes under this mod should be revisited so as to include electrolysers

Converting the £/kW Tariff to p/kwh for Half-Hourly customers

Outstanding Issue & Problem Statement

- If we intend to levy charges over a wider period of consumption, we need a p/kwh tariff
- The transport model outputs £/kW - how do we convert this to p/kwh? What are the principles?
- The current approach for NHH customers is to consider, by GSP Group, the forecast income from those customers if the £/kW tariffs were levied at triad. The p/kwh tariff is set so it recovers the same income from energy consumption over the charging period (4-7pm all year)
- There is an inherent assumption that everyone has the same profile. This is not currently a significant issue for NHH customers because they are already deemed to consume in a standard profile (although there are slightly different ratios of chargeable kWh to peak MW consumption across different profile classes)

- **If a standard rate is used to convert the kwh consumption of an HH customer over a wider chargeable period to a deemed peak consumption level, this will be much less accurate than the current peak consumption measure at triad**

Converting the £/kW Tariff to p/kwh for Half-Hourly customers

Proposed Principles (not necessarily endorsed by Taskforce)

- The current concept is to charge customers based on their ACS Peak consumption/maximum required capacity
- The Economy Criterion allows for a degree of constraints to the extent it would not be economically optimal to build transmission to alleviate them.
- The Year Round Background scenario represents the Economy Criterion, and uses demand at ACS Peak.
- <u>Backgrounds</u> merely establish the prevailing power flows across each circuit, and the Year Round allows for an optimal level of constraints
- <u>Tariffs</u> are derived from an incremental MW of generation/demand at ACS Peak and are intended to reflect the marginal cost of <u>*firm capacity access i.e. constraints do not feature*</u>
- A consumer's ACS Peak consumption is similar to generator TEC where tariffs are derived to be levied on generator Transmission Entry <u>Capacity</u>, not generation output at peak, or indeed across the year
- Intermittent and dispatchable generation is deemed to <u>*share network capacity in order to meet demand*</u> – this is why the Sharing methodology reduces different amount of the generation tariff by a factor equal to ALF

- **Hence, it is proposed that maximum/ACS Peak demand remains the basis for Wider Tariff charges because the tariff is reflective of firm capacity access. An equivalent network sharing approach for demand users might consider the extent to which periods of high/ peak demand occur at different times**

Draft Mod Proposal

- The zero price floor be removed for **Final Demand for negative Peak Tariffs** and those negative charges levied on HH and NHH metered energy consumption over the period **16:00 hrs to 19:00 hrs inclusive every day** over the Financial Year i.e. in the same way as NHH consumption is currently charged.
- The zero price floor be removed for **Final Demand for negative Year Round Tariffs** and those negative charges levied on HH and NHH **total annual metered energy consumption.**
- The corresponding negative tariffs in p/kWh are arrived at by scaling the corresponding £/kW Demand Locational Tariff by the ratio of forecast metered consumption over the relevant period **assuming a baseload consumption profile**, so that the negative charge will always be based on an underestimate of ACS Peak consumption (it would not appear to be correct for a user's annual £ charge divided by their typical kW maximum demand, to exceed the £/kW Tariff.

Current

	Positive Charges		Negative Charges	
	HH	**NHH**	**HH**	**NHH**
Peak	Triad	4-7pm all year	Zero	Zero
Year Round	Triad	4-7pm all year	Zero	Zero

Proposed

	Positive Charges		Negative Charges	
	HH	**NHH**	**HH**	**NHH**
Peak	Triad	4-7pm all year	4-7pm all year	4-7pm all year
Year Round	Triad	4-7pm all year	All year	All year

Questions for TCMF

- Do you agree that demand charges should be based on ACS Peak (with a potential sharing approach)?
- Do you have any ideas for the approaches for:
  - sharing
  - £/kW to p/kWh conversion
- Do you agree that a broader consumption period measure should be used for levying negative tariffs?
  - If yes, what would you suggest?
  - Would it be best to make the period as short as possible whilst maintaining positive prices for consumption at all times?
  - How would we do this calculation/what should be included?
- Should we abolish triads altogether? If yes:
  - Should they be in scope or a separate mod?
  - How should we define a £/kW to p/kWh conversion for positive demand tariffs?

AOB & Close

ESO