Meeting 112

4 March 2021

Transmission Charging Methodologies Forum and CUSC Issues Steering Group

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Agenda

1	Introduction, meeting objectives **Mark Herring - NGESO**	10:30 - 10:35
2	Code administrator update **Joseph Henry – Code Administrator NGESO**	10:35 - 10:45
3	Codes update: Planning for RIIO2 **David Wildash - NGESO**	10:45 - 11:05
4	CUSC roadmap to 2025 **Mark Herring - NGESO**	11:05 - 11:30
5	SSEN Transmission – Transmission Charges Paper **David Boyland - SSEN**	11:30 - 11:45
6	Break	11:45 - 11:55
7	Modelling of three-terminal HVDC in TNUoS **Jo Zhou - NGESO**	11:55 - 12:10
8	Expansion Constant Update **Grahame Neale - NGESO**	12:10 - 12:20
9	'Pre-existing' assets as part of the CMP317/327 follow on Mods **James Stone - NGESO**	12:20 - 13:05
10	Queue Management and Interactivity **Rashmi Radhakrishnan - NGESO / Peter Turner - NPg**	13:05 - 13:20
11	Update on BSUoS Reform: billing frequency review mod **Katharina Birkner - NGESO**	13:20 - 13:25
12	AOB and Meeting Close **Mark Herring - NGESO**	13:25 - 13:30

Code Administrator Update

Paul Mullen / Joseph Henry, Code Administrator

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Authority Decisions Summary (as at 3 March 2021)

No Authority decisions since last TCMF

Awaiting Authority Decisions

Modification	Decision Date / Anticipated Decision Date
CMP335/336 and CMP343/340	Minded to decision expected on CMP343 ~ end March 2021 with the decisions on CMP340 and CMP335/CMP336 to follow this.
CMP344	Ofgem confirmed receipt of CMP344 on 12 January 2021 and noted the Proposer's request for a decision date by 25 January 2021 to allow an implementation of 1 April 2021. However, they do not expect to make a decision until ~ end March 2021.
CMP300	Ofgem at January 2021 Panel indicated that a decision would be made ~ mid February 2021 but at February 2021 Panel advised that a decision would now not be until ~ end March 2021 due to high workload on Capacity Market issues.
CMP280	Update on CMP280 was provided on 2 October 2020. Ofgem will consider whether or not CMP280 is needed after they have decided on the other Transmission Demand Residual Modifications but do not expect to make a decision on CMP280 in the near future.
CMP292	CMP292 decision was expected 20 September 2019; however, this remains de-prioritised due to Ofgem's focus on the TCR modifications.

Implementations Summary (as at 3 March 2021)

Implementations

- **CMP351** on 11 February 2021
  - ***CMP351*** *relaxes the timescales for cash deposits for Financial Securities from 45 calendar days to 21 calendar days*
- 16 Modifications being implemented on 1 April 2021

Withdrawals

- None since last TCMF

Panels since last TCMF

26 February 2021

- 4 New Modifications:
  - Fixed BSUoS Modification **(CMP361)** and associated definitions **(CMP362)** – to be progressed via a joint Workgroup with nominations open until 5pm on 22 March 2021. 1st Workgroup 23 March 2021; and
  - TNUoS Demand Residual charges for transmission connected sites with a mix of Final and non-Final Demand **(CMP363)** and associated definitions **(CMP364)** - to be progressed via a joint Workgroup with nominations open until 5pm on 22 March 2021. 1st Workgroup 1 April 2021.
- Deep dive of prioritisation stack – no movements though.

2 March 2021

- CMP360 proposes changes required to Section 14 BSUoS calculations to reflect updated special licence conditions. The CUSC Panel recommended unanimously that the CMP360 Original better facilitated the CUSC Objectives than the current CUSC.

Next Panel

26 March 2021

- New Modifications:
  - Minor Governance changes (largely mirror GC0131)
  - Housekeeping change re: 1 April 2021 Implementations
- Panel to determine whether or not the **CMP326** Workgroup has met its Terms of Reference
  - ***CMP326*** *seeks to introduce a 'Turbine Availability Factor' for use in Frequency Response Capacity Calculation for Power Park Modules (PPMs)) Clarity on the EBGL process at each stage gate*
- Clarity on the EBGL process at each stage gate

In Flight Modification Updates

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In flight Modifications (as at 3 March 2021)

1 open Workgroup Consultation

- **CMP328 –** closes 12 March 2021

0 open Code Administrator Consultations

4 CUSC Workgroups held in February 2021

- 9 held across CUSC, Grid Code, STC and SQSS
- 11 to be held across CUSC (8 CUSC), Grid Code, SQSS and STC in March 2021

For updates on all “live” Modifications please visit “Modification Tracker” at:
https://www.nationalgrideso.com/industry-information/codes

Introduction to Code Change

FREE WEBINAR: Introduction to code change

Are you new to code change, or in need of a refresher?

Would you or someone you know benefit from a walk-through of the change process and how it works?

What you'll get from this webinar:

- An easy-to-understand overview of code change
- Learn more about our role as Code Administrator
- Find out how the code change modification process works for the codes we administer
- Discover how you can get involved in code change
- The opportunity to ask any questions

Event Dates:

You can attend the free webinar on either of these dates:

Friday 19 February 2021, 10am-11am

Register now >

Thursday 18 March 2021, 1pm-2pm

Register now >

2021 Dates

CUSC 2021 - Panel dates

CUSC	(TCMF) CUSC Development Forum	Modification Submission Date	Papers Day	Panel Dates
January	7	14	21	29
February	4	11	18	26
March	4	11	18	26
April	8	15	22	30
May	6	13	20	28
June	3	10	17	25
July	8	15	22	30
August	5	12	19	27
September	2	9	16	24
October	7	14	21	29
November	4	11	18	26
December	25/11	2	9	17

Codes update: Planning for RIIO2

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Introduction and context

David Wildash

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Purpose of the session

- ESO Codes teams; who we are, current structure & funding model
- Preparing for the future post April 2021 (Code Admin survey results & what's next)
- What we will deliver in RIIO2 from April 2021 (Strategic Roadmap, Digitalisation)

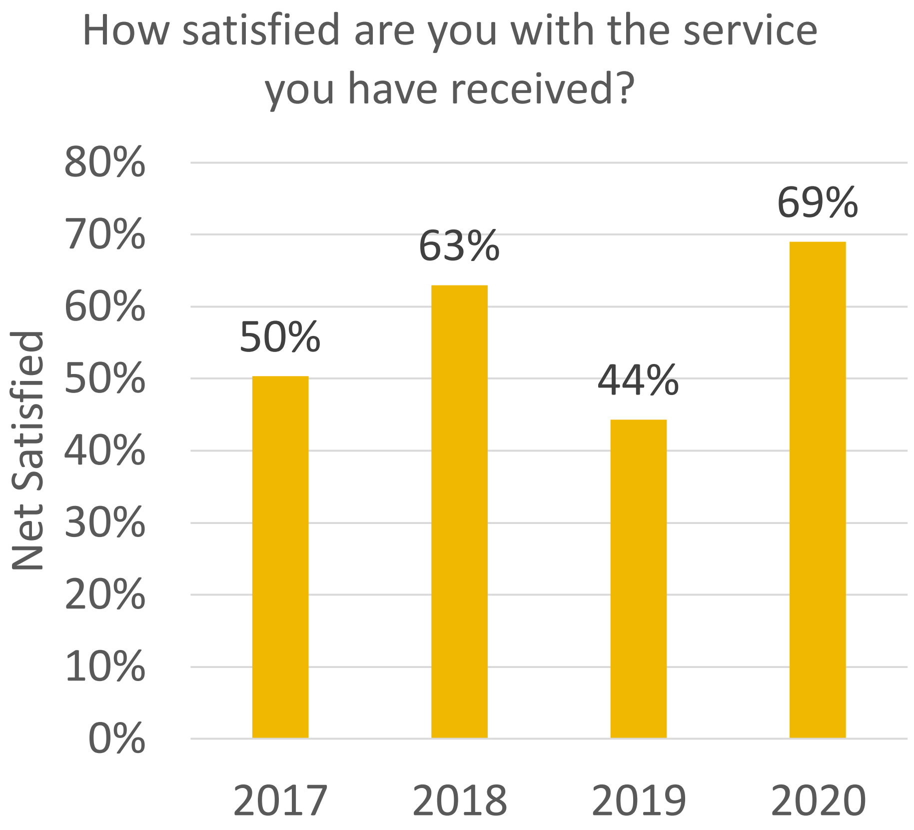
Our funding model and set up: today vs April 2021 and beyond

5.4.1. Costs

Develop code and charging arrangements that are fit for the future	Five-year strategy					
	Two-year Business Plan					
	RIIO-1 average	2021/ 22	2022/ 23	2023/ 24	2024/ 25	2025/ 26
Capex (£m)	8.6	15.5	10.8	11.0	11.9	12.6
Opex (£m)	6.7	13.2	14.0	14.8	15.6	15.6
FTE	50	70	74	76	80	79

- RIIO2 is supported by stakeholders
- Pass through model; there is a requirement to clearly evidence the uptick in value for consumers that can be created by increasing cost base.
- FTE is the biggest driver of workgroups
- Holistic solution must also continue to enhance our processes so that all parties across industry are able to easily take part in an increase in code change

ESO Code Administrator Survey 2020



The 2020 survey results give us a foundation for incremental change and areas we need to focus on

69% of the **59 stakeholders** surveyed in 2020 were satisfied with our service. This is an increase of **25 percentage** points on the previous year.

While we know that direct comparison across Codes isn't possible due their differences and set up, if we'd have scored this in 2019, we'd have been in **joint 4th position**.

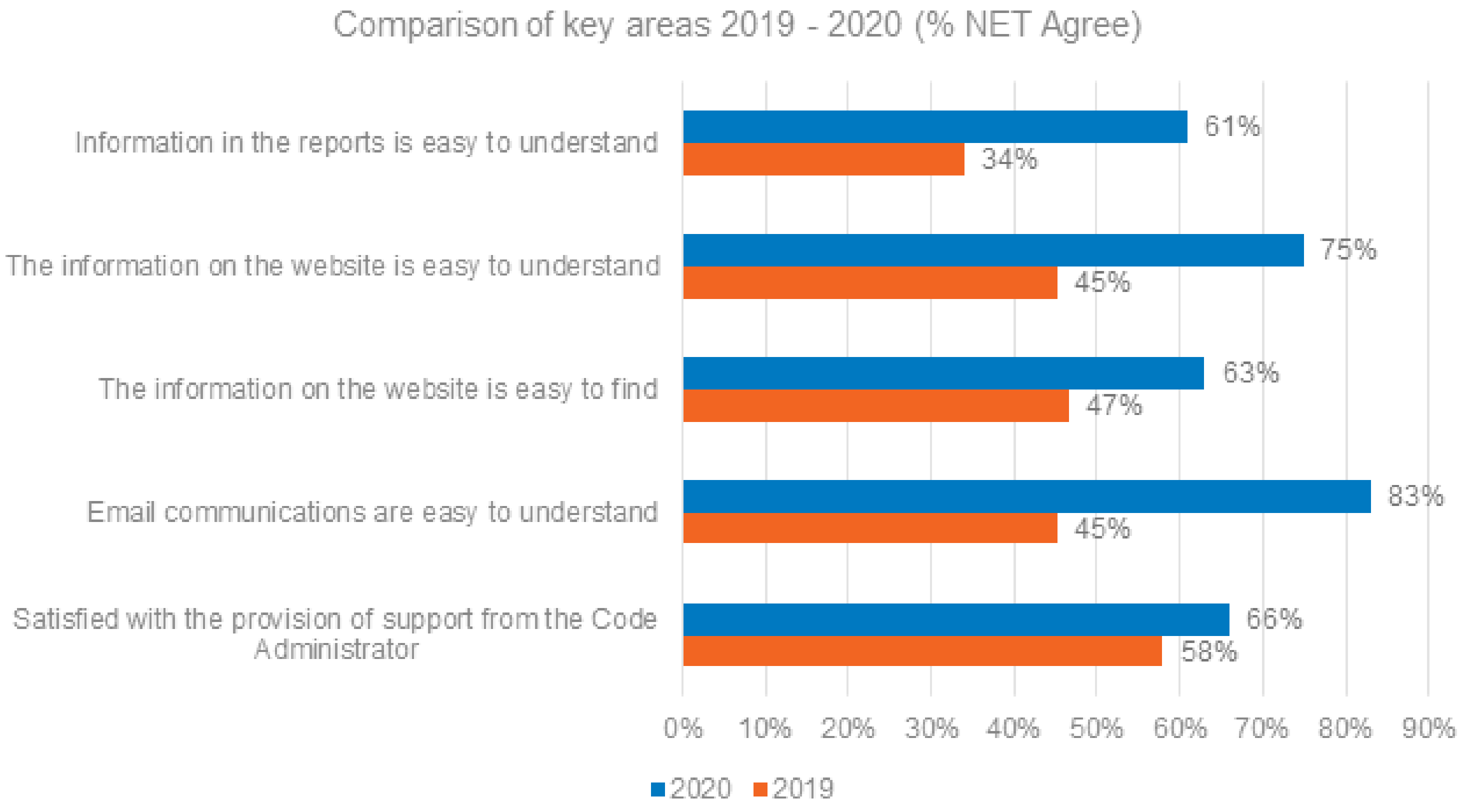
66% of respondents in 2020 agreed that our **service had improved**.

2020 Survey: key improvement areas

Website: *Some of the items are easier to find whereas before you had to dig for it. It is more structured now and find things even when you don't know where to look*

Reports/Templates: *They are shorter and more concise, which is a lot easier to read and understand.*

Communications: *Sent out in a timely manner and containing all relevant information I need to do my job. The quality seems to be at a higher level than it was.*



Survey 2020: continuous improvement

The feedback from our Code Administrator 2020 survey has identified some areas in which we still need to improve.

We will use the feedback to build the deliverables we will commit to for 2021-22 and also address the level of future change in specific ways, such as;

- Increase **resource** (as outlined in the RIIO2 Business Plan) across all Codes teams
- Recognising that increased resource is not the full solution to delivering higher volumes; we will build on **Chairing capability**, **project management** of each modification & making our processes **more accessible** across industry
- **Visibility and planning are key** (while also having the **flexibility** to deal with urgent industry changes that have **maximum consumer benefit**)
- Work with other teams to produce larger scale change projects such as **digitalisation of the Grid Code**
- In the shorter term we're also taking part in a week long event hosted by the ESO '<u>Road to net zero – electricity markets change</u>' via a series of webinars, that will provide a view of market change as the industry continues towards a zero carbon grid.

April 2021 onwards

Mark Herring

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Enabling net zero and driving change for the benefit of consumers

Industry codes and charging are seen as lagging industry change, and in some places creating barriers to innovation and net zero

1. Whole System

By 2030 we could see:

- Decentralised generation providing 73-89% of peak demand
- 4.5x increase in interconnector capacity

2. Competition everywhere for consumer benefit

- 10x increase in ESO ancillary service market participants
- Over a third of consumers could be providing flexibility services by 2030, increasing to over 80% by 2050

3. Carbon free operation

- The ESO aims to be able to operate the system carbon free by 2025
- Annual renewable generation could increase from 41% today, to 80% by 2030 and 96% by 2050

4. Scaling up low carbon infrastructure for net zero

Trends such as the electrification of transport and heat are expected to drive:

- increase in total GB generation capacity by 30-60% in 2030, and 150-200% by 2050
- increase in offshore wind to 40 GW by 2030 and over 80GW by 2050

A more strategic approach to code change is required

The energy industry must anticipate and adapt codes and charging arrangements in a coordinated way

1. Whole System

- Coordination and consistency across the electricity system: transmission / distribution, onshore / offshore, GB / cross border
- Visibility and engagement of distributed assets at a national level
- Potential links to other systems (eg interactions with gas / potentially hydrogen networks)

2. Competition everywhere for consumer benefit

- Reducing barriers to entry
- Enabling market access for more participants
- Improving access to information

3. Carbon free operation

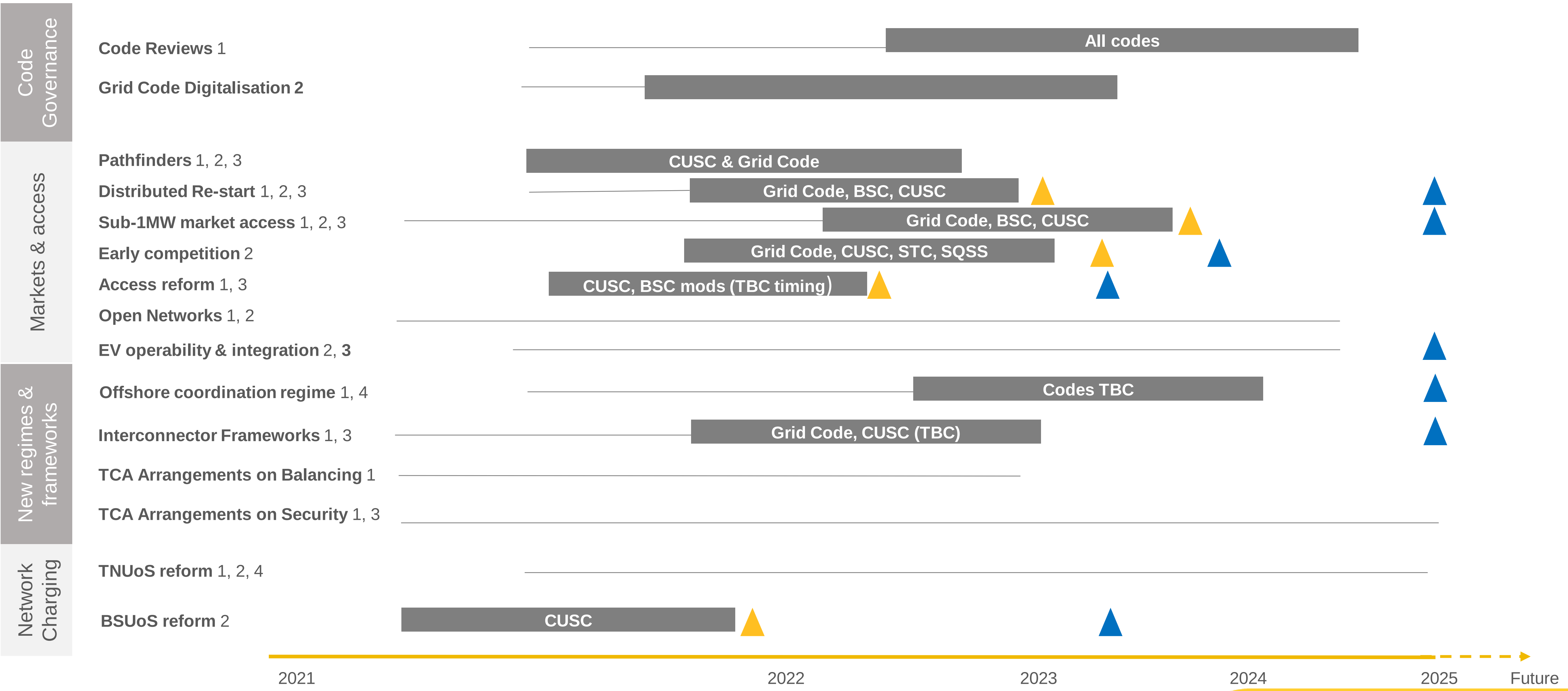
- Supporting new markets and services for operating the system without carbon
- Enable increased system flexibility e.g. increase in EVs
- Enable increased interconnection with Europe

4. Scaling up low carbon infrastructure for net zero

- New connections & infrastructure arrangements to support net zero ambitions
- Efficient commercial signals in network charging as the electricity system scales up for net zero

Strategic programmes will require increasing levels of code change

DRAFT FOR INPUT



Key

Industry engagement

Code mod process

Ofgem decision on mod

Go live

Drivers

1. Whole System
2. Competition everywhere
3. Carbon Free Operation
4. Scaling up of low carbon infrastructure for net zero

Discussion: next steps

Input on the roadmap content

- What programmes of work are planned but missing?
- What programmes are not yet planned, but should be?
- Are the categories the right ones?
- Initial reactions to seeing this on one page?

Some suggested additions so far…

- Review of locational charging signals
- Review of codes for potential barriers to policy (e.g. net zero)

How could a strategic perspective add value to industry?

Without code reform

- What can this be used for immediately?

For future code reform

- What needs to change in roles, governance?

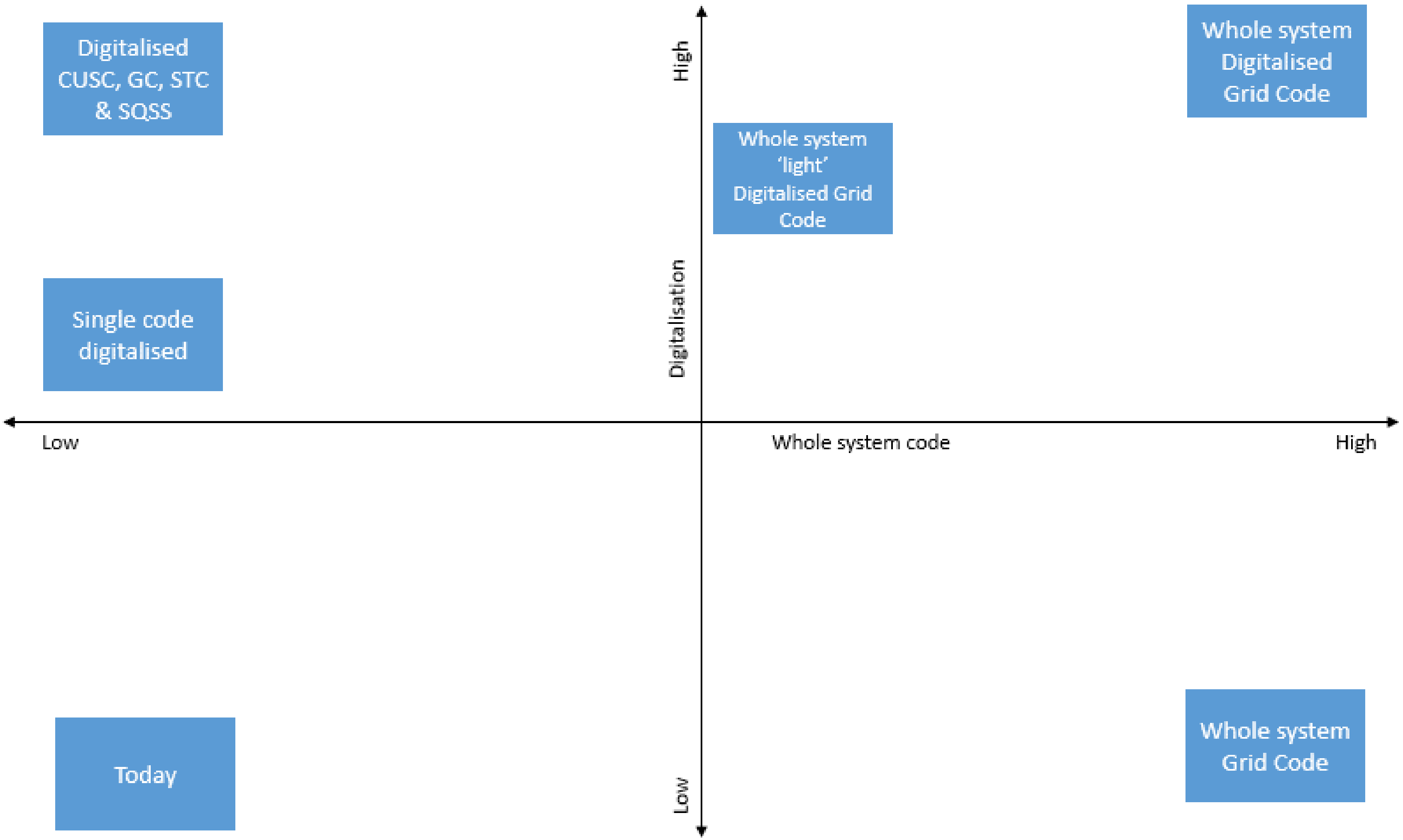
Some suggested additions so far…

- Assist industry to plan their decisions and resourcing of code change
- Support govt & regulator to prioritise and coordinate change

Join for discussion of the next iteration on 24th March
Register for *The Road to Net Zero Electricity Markets* here

Enabling faster change through Digitalisation

Whole system digitalised Grid Code – Speed/ambition of delivery



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The road to net zero electricity markets: 23rd – 25th March

Are you interested in finding out about how the electricity market is changing and progressing to a zero carbon grid?

The Markets team in the ESO are running a series of interactive, online events in March, where you will be able to take part in focused sessions with subject matter experts on different aspect of electricity market change.

Click here to find out more and register for the event.

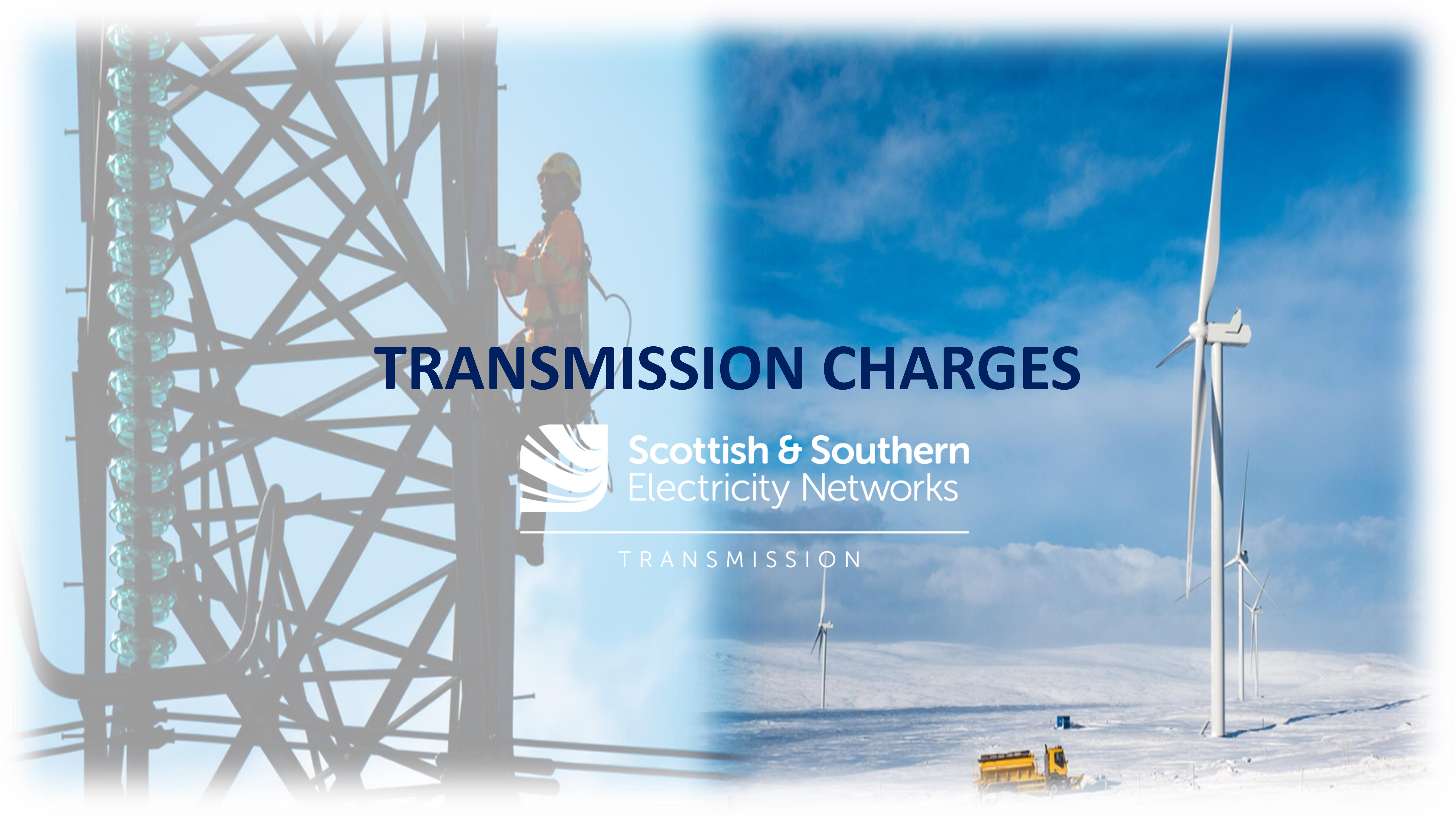
	Tuesday 23rd March	*Wednesday 24th March*	*Thursday 25th March*
10am	**The road to net zero electricity markets launch** *A strategic overview of how various ESO reforms come together to deliver carbon free operation by 2025.*	**Code change roadmap to 2025** *Discuss and contribute to the view of how net zero will drive reform in network codes and charging, and how the ESO will facilitate this.*	**Net zero market design** *An interactive discussion of the challenges in redesigning GB electricity markets for net zero.*
1pm	**Market reform insights** *Join our experts as they answer questions on how we are developing and delivering our market initiatives to meet future operability challenges*	**Electricity Market Reform: Capacity Market and Contracts for Difference** *An overview of potential medium term developments in policy and the market and how the ESO will respond and deliver.*	**DSO markets** *A deep dive into the ESO strategy for facilitating DSO markets across the whole electricity system.*

Thank you

Questions

SSEN Transmission – Transmission Charges Paper

David Boyland, SSEN Transmission



TRANSMISSION CHARGES

Scottish & Southern Electricity Networks

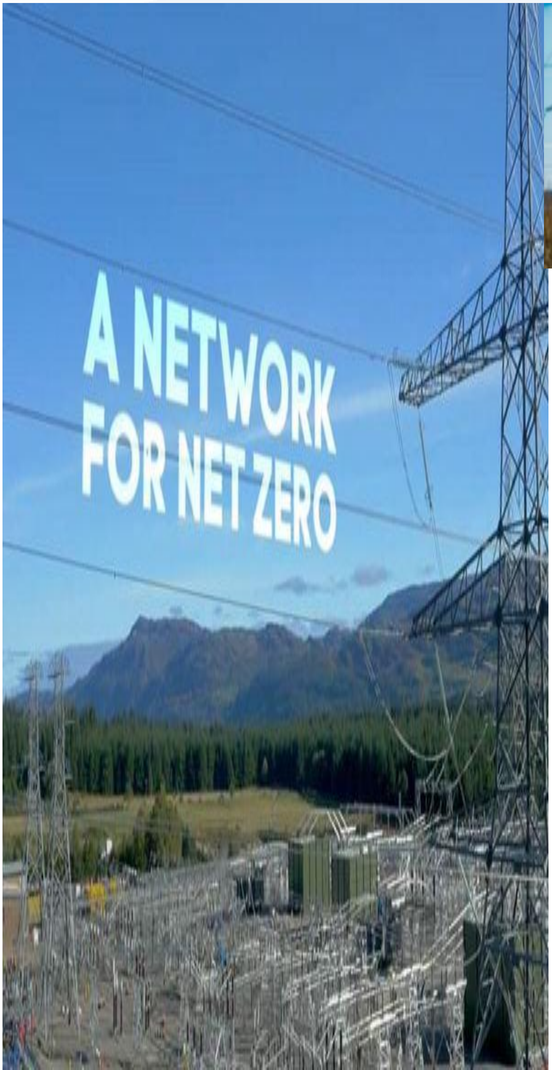
TRANSMISSION

Scottish Government targets.

- Net zero emissions by 2045.
- 75% emissions reduction from 1990 by 2030.
- 11GW of offshore wind by 2030.
- Operation of unabated fossil fuel power stations to end in Scotland by 2030.

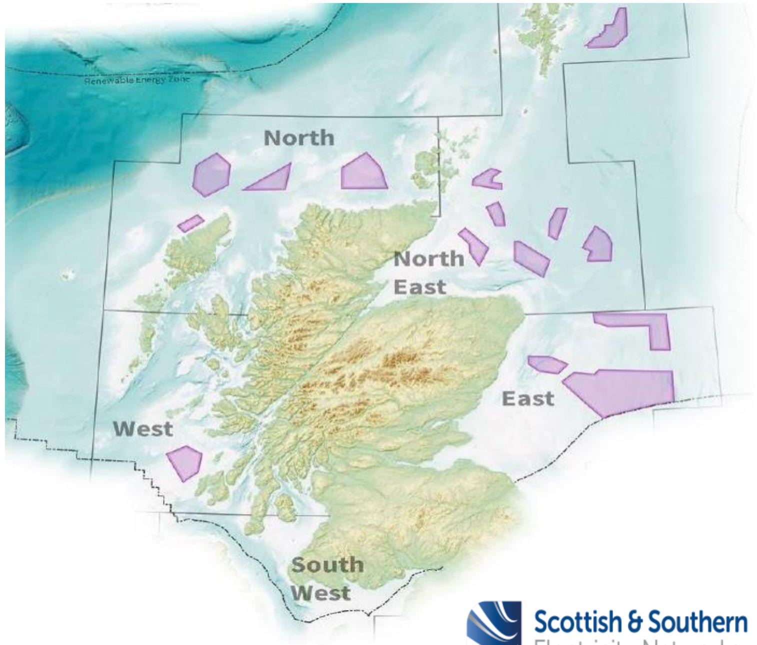
UK Government targets.

- Net Zero by 2050.
- Reduce greenhouse gas emissions by at least 68% on 1990 levels by 2030
- 40GW of offshore wind by 2030.
- AR4 to deliver 12GW of renewable energy.



Our Contribution to Net Zero

- So far agreed **a total expenditure to £2.16bn**. to deliver a Network for Net Zero.
- Certain View **capital investment of £814 million in generation connections, regional and strategic infrastructure**
- Deliver the **capacity and flexibility to accommodate 10 GW renewable generation** in the north of Scotland by 2026
- Our NoS FES shows **c.20-23GW by 2030 and c.33-37GW by 2050** of renewable generation is required from the north of Scotland to help GB reach Net Zero.



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Our stakeholders have told us…

- The cost of wider TNUoS could effect the sustainability of the project.
- Wider TNUoS is far more expensive in the north of Scotland than anywhere else in GB.
- Wider TNUoS is a barrier to entry, costs are volatile and unpredictable.

How does this effect us?

‘Put simply, timing and sizing uncertainty for generation developers translates to timing and sizing uncertainty for network investment.’

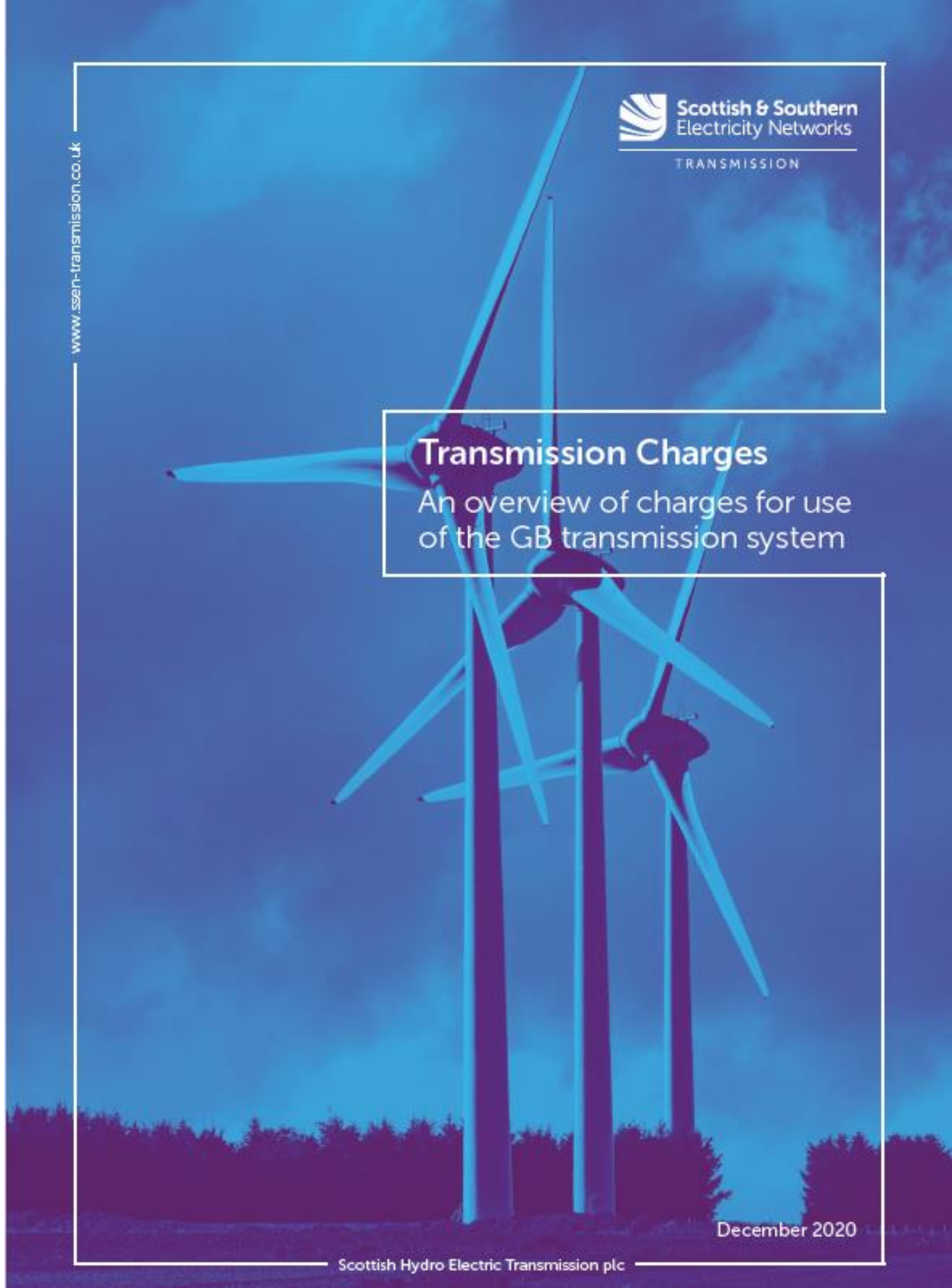
Transmission Charges Paper

The paper will be used as a tool to gain the views of industry and to show that we are;

- Listening to our stakeholders
- Advocating for reform
- Serious about removing barriers to Net Zero

The paper includes;

- Investigating stakeholders’ concerns about high charges in north of Scotland, volatility and unpredictability – evidences these concerns are valid.
- Baringa assured our analysis.
- Focus on wider charge and concludes in favour of reform.



Where we are now

Stage 1

Build advocacy with all impacted stakeholders groups.

Our Next Steps

Stage 2

Develop position and key asks including reform options and our recommendations.

Stage 3

Agree reform options and next phase of engagement

OUR ANALYSIS

1.

We identified representative generators of 3 different technologies (onshore wind, offshore wind and CCGT) similar installed capacity located in the north of Scotland, south of Scotland and in England and Wales (Figure 5).

2.

Using ESO publicly available data we;

1) Compared the absolute charge paid.

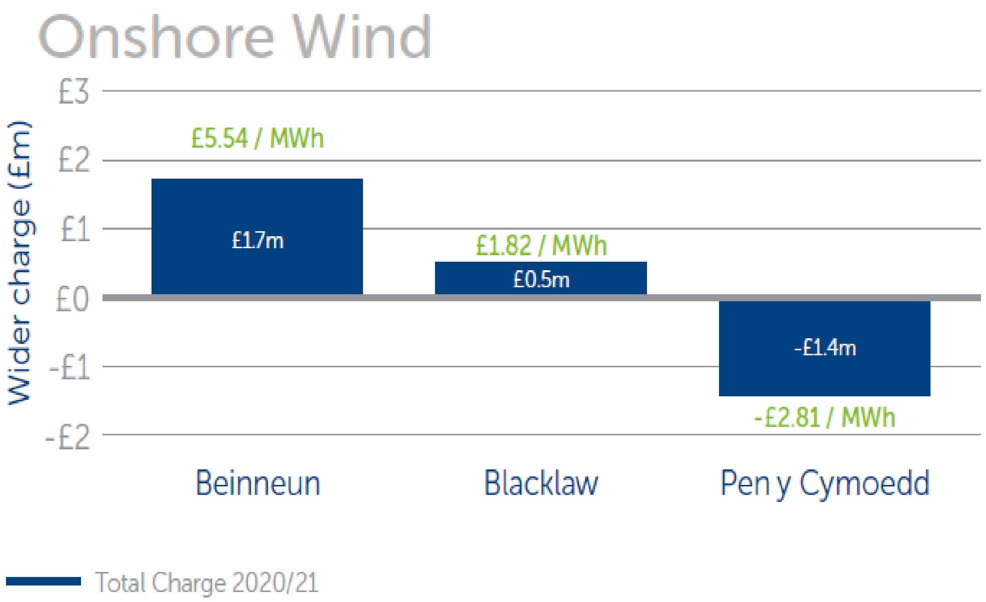
2) Measured year-on-year variation in the absolute charge paid.

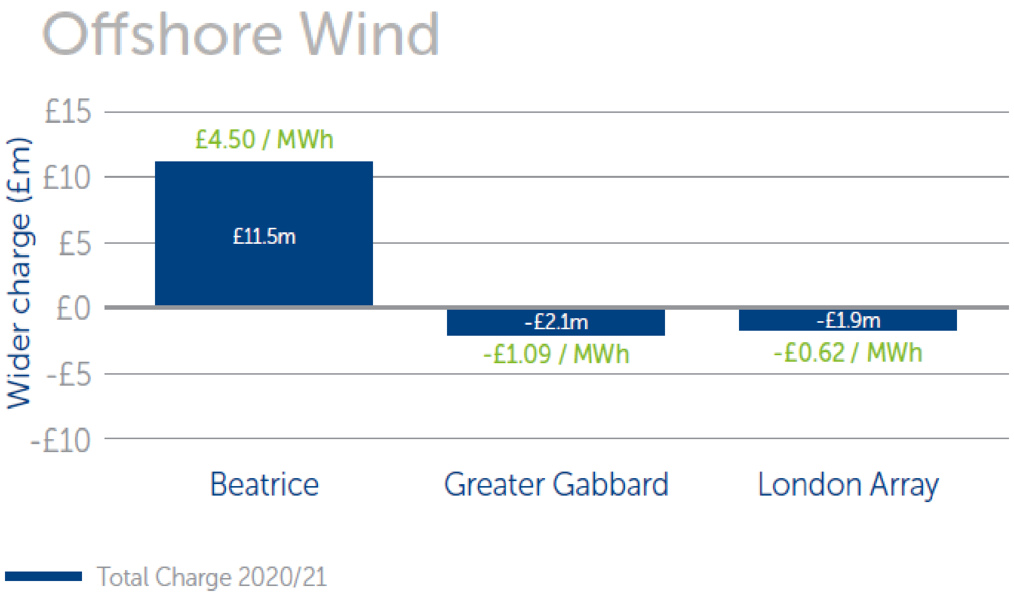
3) Measured the difference between the forecast TNUoS charge and the actual charge.

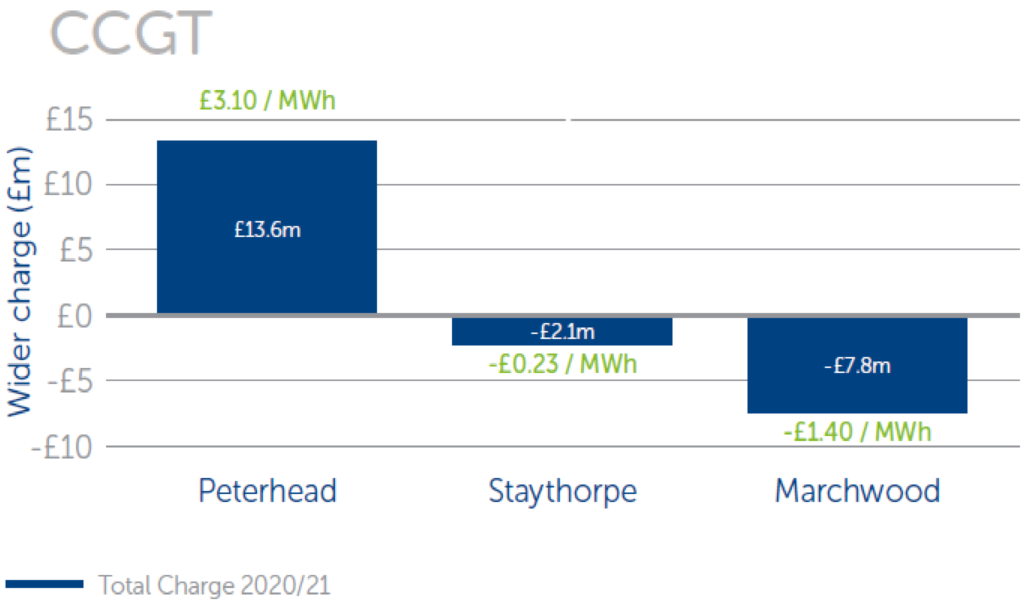
3.

Using these results, we sought to understand the underlying reasons and drivers for variability between, and annual changes in, the TNUoS charges paid by different generators

CHARGES BY LOCATION







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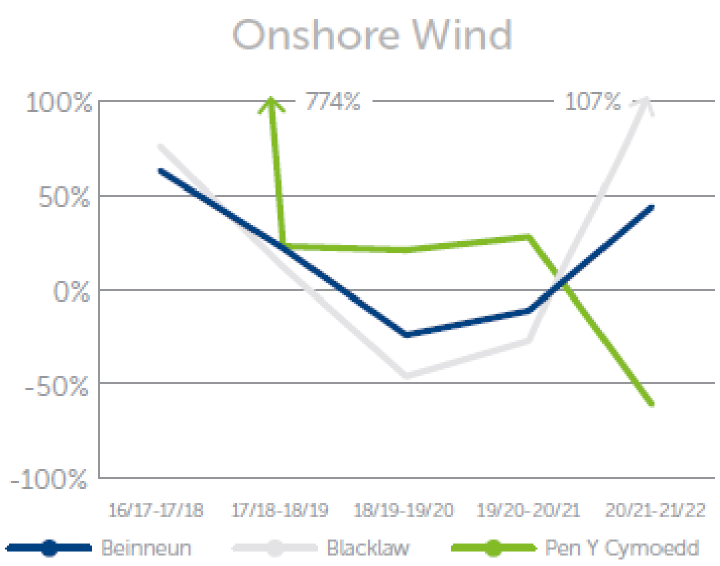
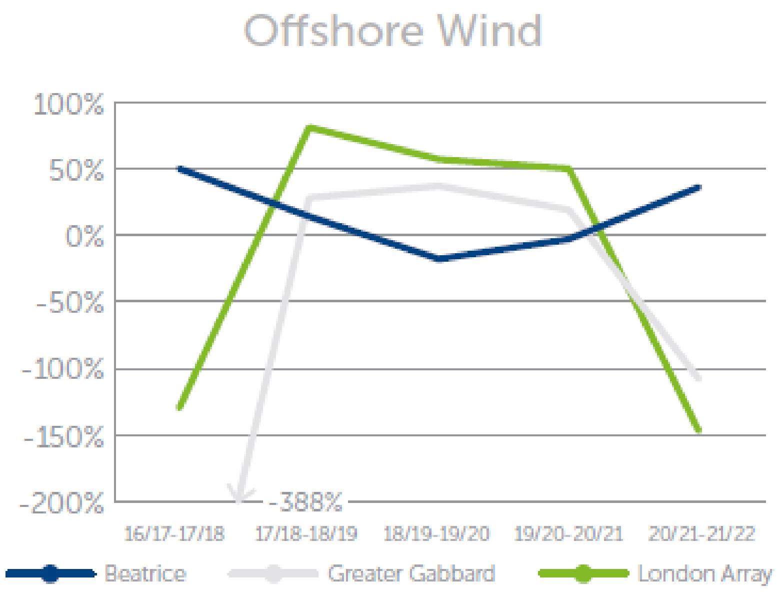
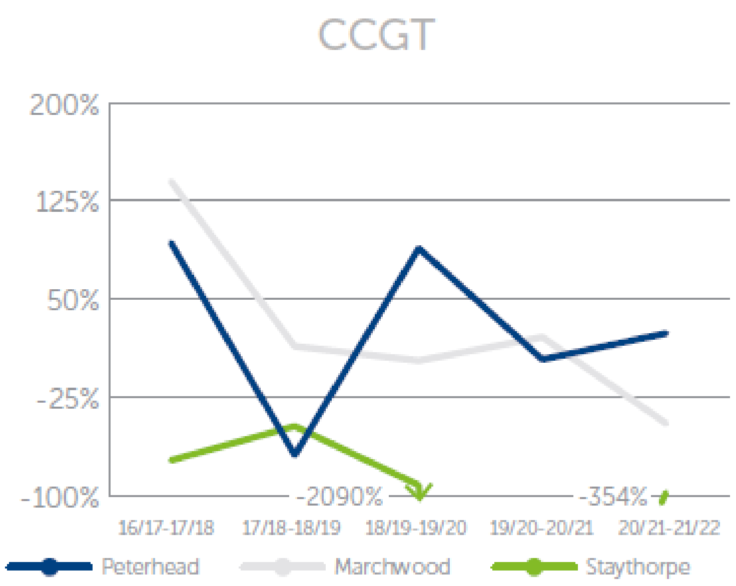
VOLATILITY







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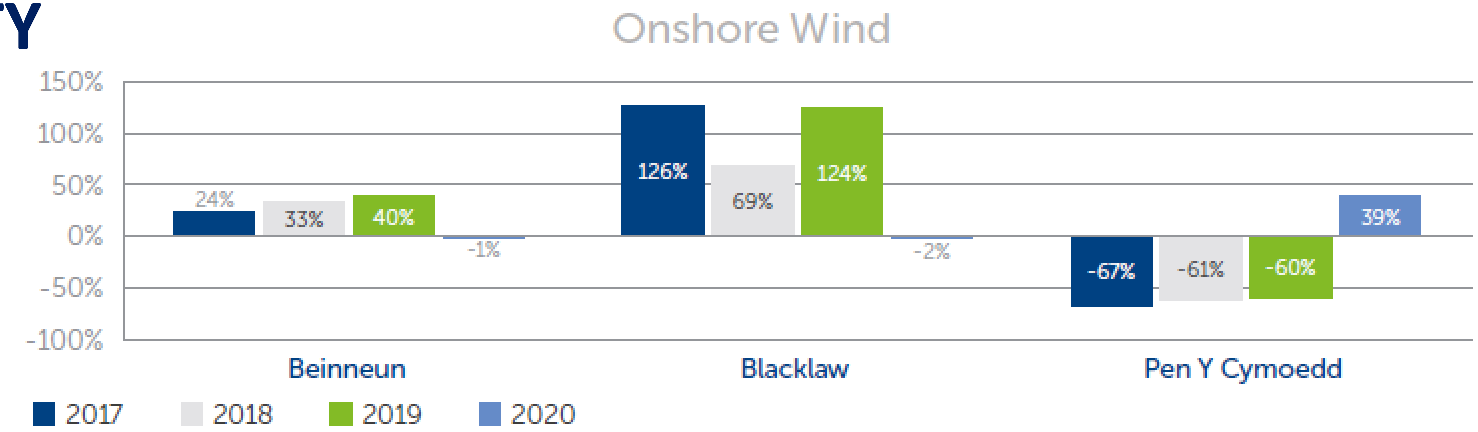
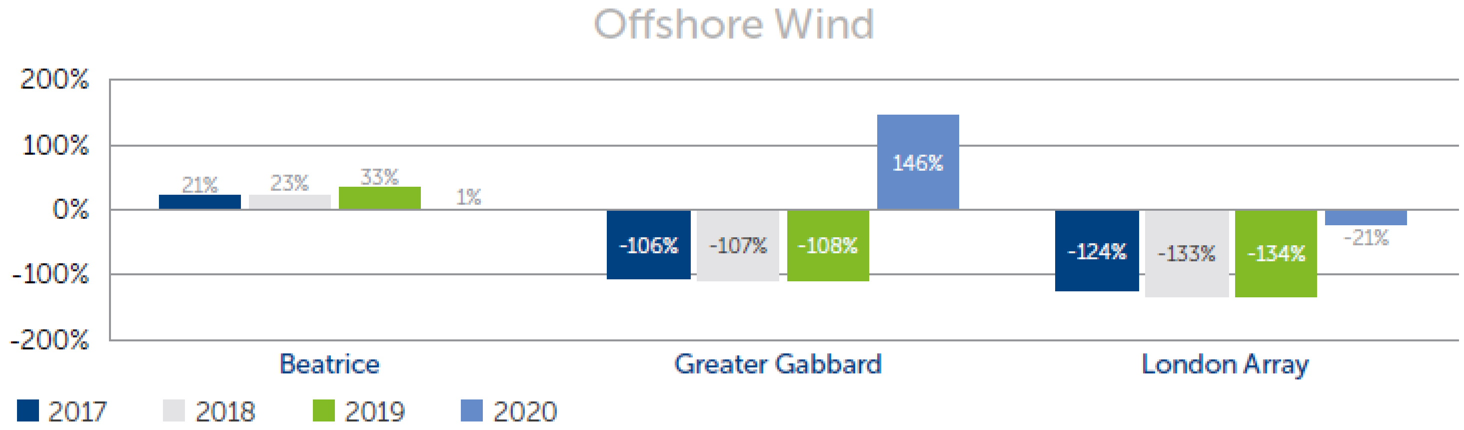
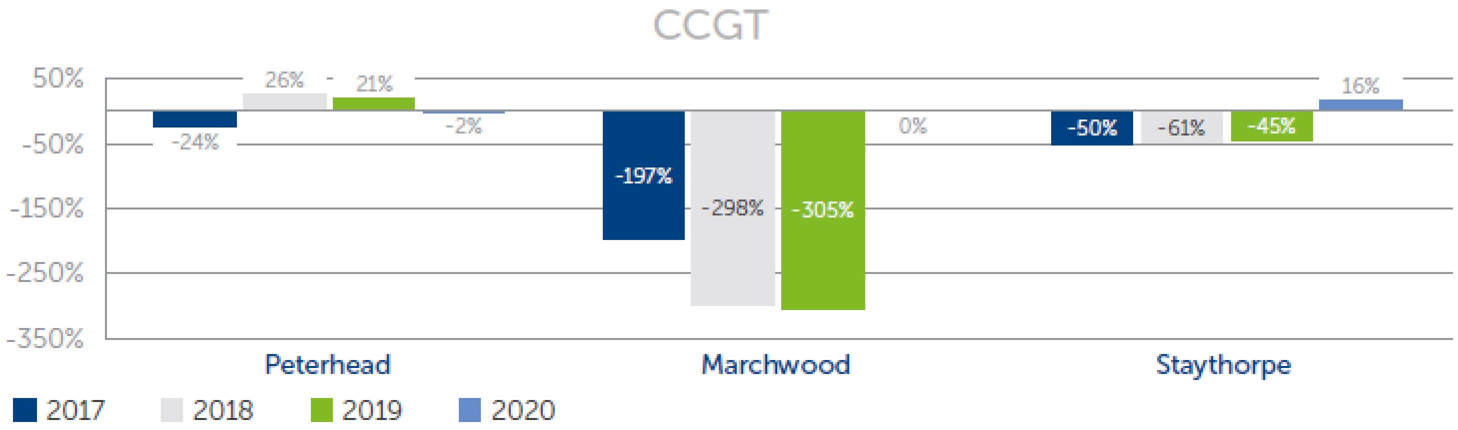
UNPREDICTABILITY







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SUMMARY OF OUR FINDINGS

We support the views and concerns of our stakeholders. TNUoS costs are high, volatile and unpredictable.

The current locational 'signal' penalises existing renewable generators and acts as a barrier to decarbonisation.

Volatility is exacerbated by uncertainty during the energy transition and in in part, due to spurious accuracy in the modelling.

Unpredictability is due to uncertainty about future modelling variables and changes to the modelling methodology.

We expect the risk of unpredictable and volatile generation TNUoS feeds through to increase the cost of energy to end consumers


QUESTIONS?
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Modelling of three-terminal HVDCs in TNUoS

Jo Zhou, NGESO

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Modelling of three-terminal HVDC in TNUoS

- **Purpose**
  - To clarify different categories of HVDC circuits in TNUoS modelling
    - “Parallel” vs “radial” HVDC circuits
    - Three-terminal “hybrid” HVDC circuits
  - To discuss our assumptions and approach to modelling the Caithness – Moray – Shetland three-terminal HVDC in the TNUoS model

- **Background**
  - Project TransmiT(CMP213) introduced HVDC circuits into the TNUoS model
  - HVDC circuits affect locational tariffs
  - However there are limitations on where the rules apply

- **“Parallel” HVDC circuits and “radial” HVDC circuits**

- **Three-terminal “hybrid” HVDC circuits**
  - The equivalent circuits in the TNUoS model

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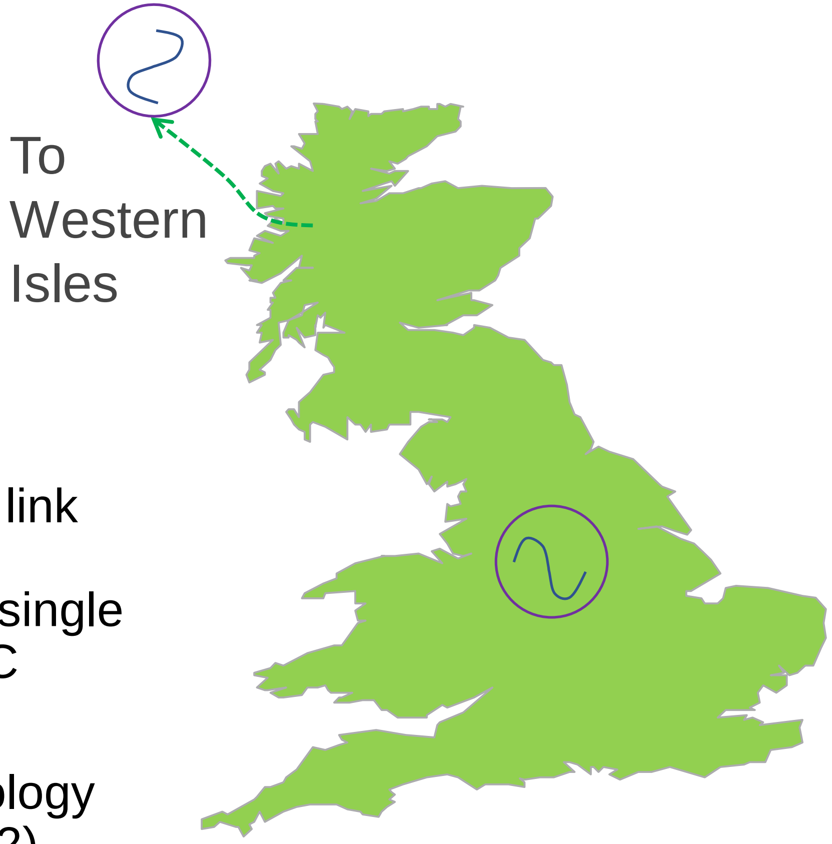
“Parallel” vs “radial” HVDC circuits

The Western "bootstrap" HVDC

Parallel - a DC link with two ends connected to a single synchronous AC network

CUSC methodology (CUSC 14.15.12) specifies how a parallel HVDC should be modelled when calculating TNUoS

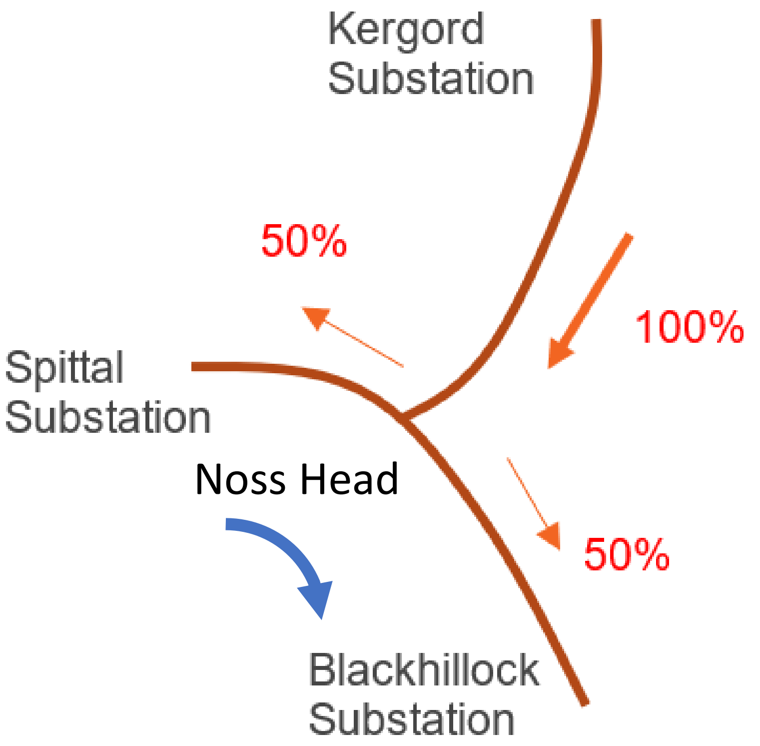


The planned Western Isles HVDC

Radial - a radial circuit connecting two separate HVAC grids, with no AC circuits or transmission network boundaries running in parallel

A radial HVDC circuit is modelled as a “cable” or “overhead line” in the TNUoS model

The three-terminal “hybrid” HVDC circuit



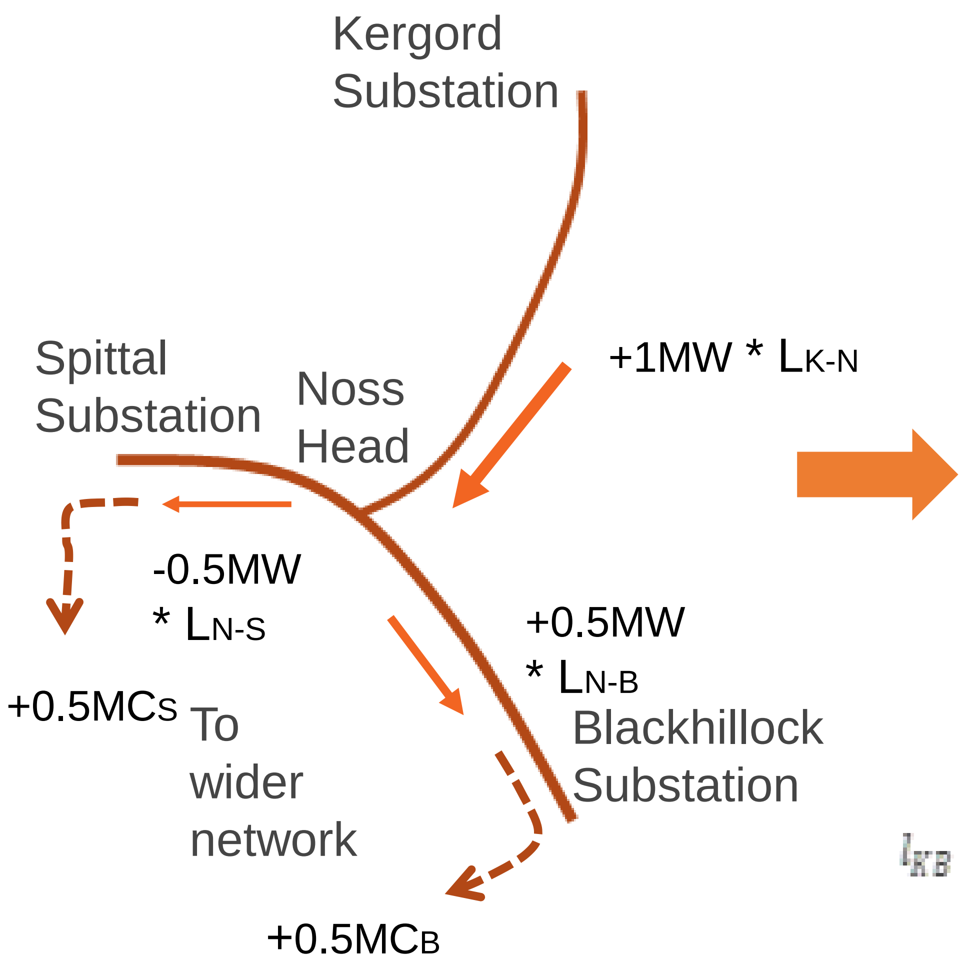
Our assumptions and approach

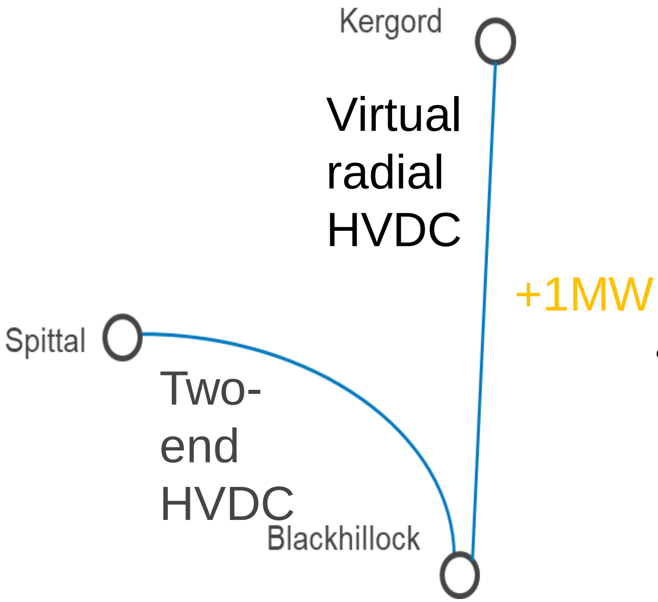
- Excessive Shetland generation flows across Kergord – Noss Head
- Then split evenly across Noss Head – Spittal and Noss Head – Blackhillock
- The predominant flow on Caithness –Moray is North → South, therefore the Noss Head – Spittal flow offsets the predominant background flow
- The Noss Head → Blackhillock flow increases the predominant background flow

Issues to be considered

- HVDCs are highly flexible at controlling the flows to each of its three ends
- The TNUoS model, however, is aimed at deriving predictable and stable tariffs
- Rules are needed to specify how the MW flows on a three-terminal HVDC link are distributed, in TNUoS scenarios

How to separate the “radial” link and the “parallel” link





- The TNUoS local circuit tariff for Shetland generators, is set by the “incremental” MWkm over the three-terminal HVDC
- By comparing the marginal costs at Kergord and at Blackhillock, we can get the equivalent length of the virtual “radial” circuit

$$
\begin{aligned}
l_{KB} &= MC_K - MC_B \\
&= l_{KN} - 0.5l_{NS} + 0.5l_{NB} + 0.5MC_s + 0.5MC_B - MC_B \\
&= l_{KN} - 0.5l_{NS} + 0.5l_{NB} + 0.5MC_s - 0.5MC_B
\end{aligned}
$$

Any questions?

We will publish a guidance note on this topic by 31st March

https://www.nationalgrideso.com/industry-information/charging/charging-guidance

We welcome your comments (our contact details are given here), and will incorporate them in the guidance note where applicable

Email: TNUoS.queries@nationalgrideso.com

Do you think the CUSC needs to be updated?

Expansion Constant

Grahame Neale, NGESO

Reinforcement types

Broadly, all works on the transmission system achieve one or more of the following;

1. Increase network capacity
2. Increase utilisation of existing capacity
3. Extend life of existing capacity

The current Expansion Constant only focuses on a subset of (1) (i.e. not all works have a km value such as substation works) and uses the following data from Transmission Owners;

- The cost of construction per route km
- The amount of route km’s installed over the last 10 years
- Average asset life

Looking for industry thoughts on the following slides

Current Ambition/Thoughts

Broadly, all works on the transmission system achieve one or more of the following;

1. Increase network capacity
2. Increase utilisation of existing capacity
3. Extend life of existing capacity

Looking to enhance the Expansion Constant to capture as many of the above work types as possible – if we can create a suitable methodology… Also looking to;

a) Revise 10 years of historic data to 5 years of historic and 5 years prospective
b) Keep the current frequency of updating the Expansion Constant (i.e. start of each price control and annual index-linked revisions within a price control)
c) Keep/review approach for assets that can be upgraded

Challenges

To capture these other types works in the Expansion Constant, the following challenges need to be overcome;

a) Methodology – should the Expansion Constant account for the above works equally or be weighted in some way?

b) ‘Zero values’ and proxies – Some works don’t provide all the variables needed unless secondary effects or proxies are considered. For example, substation works have no length unless circuits connected to that substation are considered

c) Data availability – Data to apply this retrospectively may not exist and so it may only be possible to apply to current/future works.

d) STCP 14-1 changes – Section 3.5 of STCP14.1 lists the data NGESO will receive from Transmission Owners. This will need to be considered in full alongside any CUSC changes.

Next Steps

Still a lot of to do…

1. Keep engaging with industry via TCMF & bilaterally (Grahame.Neale@nationalgrideso.com)
2. Discussions with Transmission Owners to understand data possibilities
3. Understand linkages to CMP315 (may deliver part of this?)
4. Develop some options for methodologies
5. Write and raise CUSC/STC mods.

No change to timeline from Jan’s TCMF;

- Raise modification in spring 21 for a decision in September 2022
- April 2023 implementation

Updating the ‘Connection Exclusion’ & Assigning ‘Pre-Existing’ Assets

James Stone, NGESO

Ofgem's CMP317/327 Decision

- As part of Ofgem's CMP317/327 decision they expected NGESO to undertake further work and bring forward a CUSC modification to: ***Include, in the assessment of compliance with the €0-2.50/MWh Limiting Regulation range those local charges in respect of local assets (i.e. Local Substations & Local Circuits) to the extent that such assets were 'pre-existing' at the time the generator paying those charges wished to connect to the NETS***

- In order to facilitate this direction, a definition of 'pre-existing' local charges in respect of local assets in relation to Physical Assets Required for Connection (the 'Connection Exclusion') is required

- Since the last TCMF, NGESO has been developing the modification proposal form considering both the definition of Physical Assets Required for Connection and the different scenarios and the rules to in order to assign what would be considered 'pre-existing' assets

- Following stakeholder feedback, this update is to provide our initial view on how pre-existing assets may be assigned and gain feedback on our latest thinking ahead of any modification being raised

Connection Exclusion - Ofgem's Interpretation

- Within the CMP317/327 decision letter Ofgem considered that;
    - The Connection Exclusion includes all charges paid by generators in respect of local assets (whether shared / shareable or otherwise) that were required to connect the generator(s) in question to the NETS and;
    - Those charges paid by generators in relation to local assets which existed at the point at which such generator(s) wished to connect to the NETS do not fall within the Connection Exclusion and;
    - Those assets which should be regarded as 'pre-existing' could be determined by reference to what assets existed as at the dates the relevant BCA for those generators were executed
- An update to the current definition of charges related to Physical Assets Required for Connection will be required to reflect Ofgem's interpretation of the Connection Exclusion and that pre-existing assets do not fall within it

Updating the ‘Connection Exclusion’ Definition

- Using the current definition of Physical Assets Required for Connection and Ofgem’s interpretation as a starting point we propose to update Section 11 of the CUSC as follows:

  Charges for Physical Assets Required for Connection: Connection Charges and charges in respect of an Onshore local circuit, Onshore local substation, Offshore local circuit and Offshore local substation (whether shared / shareable or otherwise) that were required to connect the Generator in question to the NETS excluding charges paid by generators relating to pre-existing assets in respect of a Generator Onshore local circuit and/or Onshore local substation and/or Offshore local circuit and/or Offshore local substation that existed prior to the connection of that Generator to the NETS determined by reference to what assets existed as at the dates the relevant Bilateral Connection Agreements for those generators were executed with The Company.

- In addition to the definition update, we also believe it would be beneficial to provide visibility to industry, by including within the CUSC detail around the rules/process by which to assign charges in relation to pre-existing local assets

Connection Exclusion - Principles

- NGESO have been considering the rules/processes/charging arrangements required to translate Ofgem's interpretation of the Connection Exclusion

- Some of the over-arching principles in terms of what will fall within the Connection Exclusion and how the charges are calculated include:

  - **Infrastructure Assets:** TNUoS local charges with respect to such assets built or upgraded under "enabling works" for the relevant generator will fall within the Connection Exclusion
  - **Onshore Local Charges:** relevant onshore local charges under the Connection Exclusion to be based on the capacity that the generator "triggered" the new asset/or upgrade - this will be either TEC value of the single generator that pays the specific onshore local charge; or TEC value of the generator with the highest TEC among multiple generators that pay the same onshore local charges
  - **Negative Onshore Tariffs:** should a onshore local circuit tariff be negative the relevant Connection Exclusion for the specific charging year is zero - as a negative tariff means the generator is also offsetting system costs so the asset is not just required for connection
  - **Offshore Local Charges**: the calculation of offshore local charges under the Connection Exclusion to be based on offshore local charges, minus a portion of the OFTO revenue associated with an offshore interlink (where applicable)

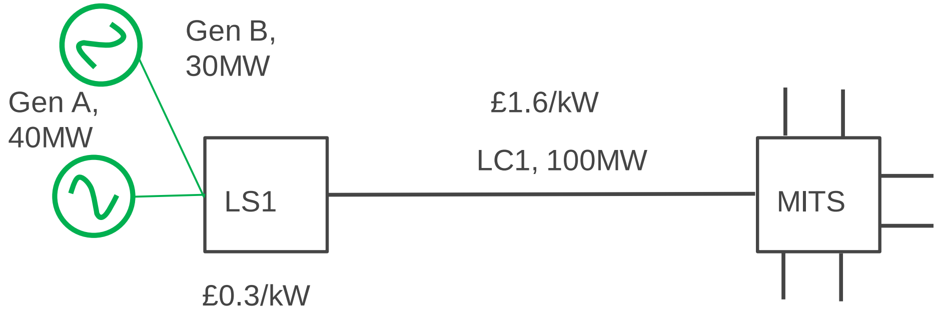
Connection Exclusion & Pre-Existing Scenarios

- Ofgem's CMP317/327 decision stipulates that charges relating to pre-existing assets do not fall within the Connection Exclusion and the expectation is that pre-existing assets could be determined by reference to the assets which existed at the date the relevant BCA for those generators were executed

- To facilitate the decision, NGESO has been considering various scenarios that may arise, the rules around how pre-existing local assets may be assigned and how the associated charges would be allocated (some examples of which are detailed below)

Event	Scenario Description	Within Connection Exclusion or Pre-Existing
Increase in TEC	• First 50MW connection doesn't require a new line • Additional 100MW in phase two triggers a new line	• Local charge associated with the generator falls within Connection Exclusion until the year when the new line becomes part of the MITS
Reduction in TEC or Closure	• After connection (and building of the new assets) the "trigger" generator reduces their TEC	• Local charge associated with the generator if it is the sole generator within exclusion, in the case of a "cluster" of multiple generators, local charges associated with the TEC value of the generator with the highest TEC
Onshore generator "split" **Offshore generator "split"**	• Part of the generator (i.e. one of two BMUs) is sold/transferred to another party and a new connection agreement with the ESO is required	• There will now be multiple generators - local charges associated with the TEC value of the generator with the highest TEC fall within the Connection Exclusion • No Change
Offshore Interlink	• Generator A is connected to an offshore interlink while generator B is still under construction	• The portion of OFTO revenue associated with the interlink and paid by generator B via its local charge, will not count towards the Connection Exclusion, as the interlink is the pre-existing asset to generator B

Illustrative Examples - Potential Scenarios



Local substation charge (£k) : Gen A = 40*0.3=12
Local circuit charge (£k): Gen A = 40*1.6=64

Local substation charge (£k) : Gen A = 40*0.3=12
Gen B = 30*0.3=9

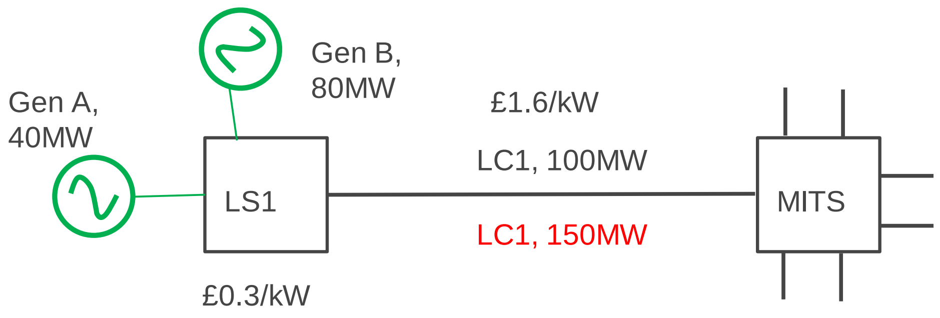
Local circuit charge (£k): Gen A = 40*1.6=64
Gen B=30*1.6=48

Connection Exclusion
Pre-existing asset charge

Onshore local substation charge –
local sub charges relating to "pre-existing" assets rarely exist;
However, an example could include two generators, each connects to the transmission network at 33kV, with each having 33/132kV transformer as its connection asset, and the two transformers share the same 132kV disconnector at the connection/infrastructure boundary point

Onshore local circuit charge –
local circuit charges relating to "pre-existing" assets are more common;
Examples include two generators, each connects to the same substation and share the same local circuit.

Illustrative Examples - Continued



Local substation charge (£k) : Gen A = 40*0.3=12
Local circuit charge (£k): Gen A = 40*1.6=64

Local substation charge (£k) : Gen A = 40*0.3=12
Gen B = 80*0.3=24

Local circuit charge (£k): Gen A = 40*1.6=64
Gen B=80*1.6=128

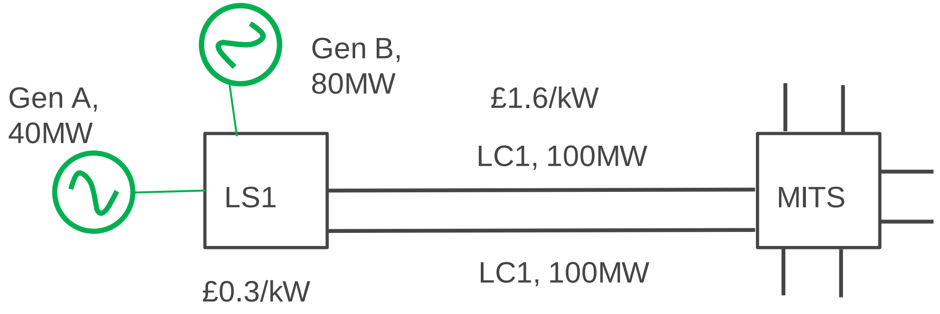
Connection Exclusion
Pre-existing asset charge

Local circuit reinforcement options –

(1) Thermal uprating from 100MW to 150MW.

Gen B is now the "trigger generator" of the asset reinforcements.

Illustrative Examples - Continued



Local substation charge (£k) : Gen A = 40*0.3=12
Local circuit charge (£k): Gen A = 40*1.6=64

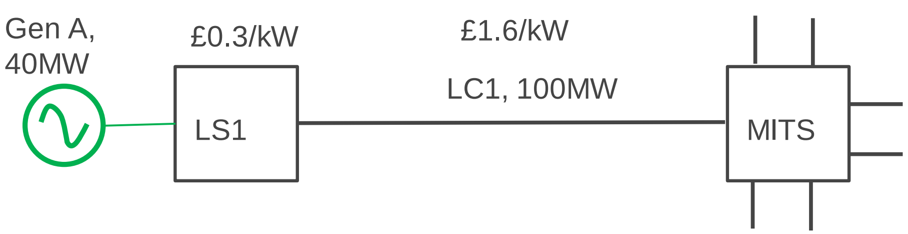
Local substation charge (£k) : Gen A = 40*0.3=12
Gen B = 80*0.3=24

Local circuit charge (£k): Gen A = 40*1.6*1.76=113
Gen B=80*1.6*1.76=225

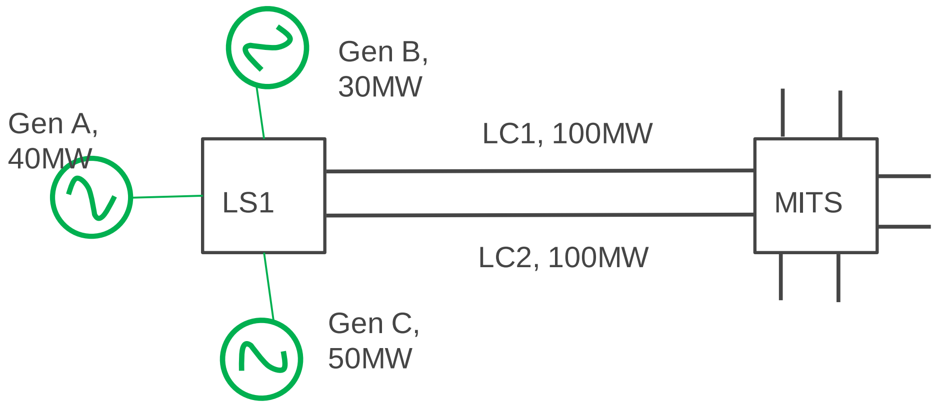
Connection Exclusion
Pre-existing asset charge

Local circuit reinforcement options –
(2) Adding a second 100MW local circuit (security factor of 1.76 applies).
Gen B is now the “trigger generator” of the asset reinforcements.

Various additional scenarios



- Gen A increases its TEC from 40MW to 120MW, triggering LC1 uprating to 120MW
  - Local circuit charge relating to 120MW of TEC falls within Connection Exclusion, as Gen A is the sole user triggering the work;



- After connection (and building of the new assets) the "trigger" generator reduces their TEC – for example, Gen C reduces its TEC from 50MW to 20MW
  - Local charges associated with the Gen A falls within connection exclusion,

Discussion points:
How far back should data set go?
Is there anything else we need to consider e.g. How de-energised/redundant assets are dealt with?

Next Steps

- We will continue to develop based on feedback today
- Happy to discuss bilaterally after TCMF (James.Stone@nationalgrideso.com)
- We plan to;

1. Engage further and refine
2. Raise urgent modification following the outcome of SSE's CMA Appeal (end of Mar21)
3. April 2022 implementation aligned with Ofgem decision/expectations

Queue Management
Managing network capacity efficiently, effectively and economically

Rashmi Radhakrishnan, NGESO / Peter Turner, NPg

nationalgridESO

Queue Management roadmap:

Queue management arrangements is been developed through the Energy Network Association as part of the Open Networks Project. The Open network project is a major industry initiative to transform the way our energy network operate to facilitate the transition to a smart flexible energy system.

- **2018 consultation** – providing stakeholders with a review of network companies' approach to queue management and seeking views on the approach for 2019 here
- **2019 consultation** – set out a Queue Management policy framework here
- **2020 consultation -** sought stakeholder comments on the User Guide based on previous consultations and our 'minded to' policy here
- **In Dec 2020**, the final Queue Management User Guide and implementation plan was published by ENA here

A CUSC modification is identified as part of this new QM arrangement and would like to seek your views.

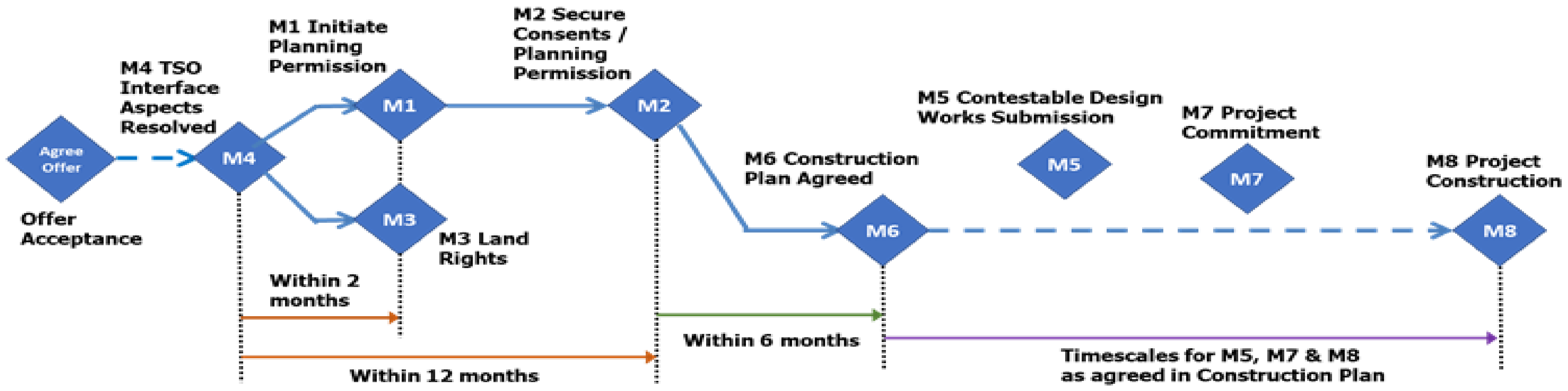
Introduction to Queue Management:

Queue management is the process which manages contracted connections and enables:

- Effective management of contracted projects which are not progressing against agreed milestones;
- Avoid stalled or slow-moving projects from affecting other projects in queues; and
- Utilise flexible resources in connection queues to better utilise the available capacity.

The main components in respect of applying queue management are:

- Milestones: benchmarks agreed between network companies and customers to measure and track project progress towards a contracted connection date.
- Tolerance: provides some flexibility which recognises that some delays can lead to milestones not being achieved and provides customers with an opportunity to get their project back on track.



Pic Courtesy : ENA published document

Issues outside of the customer's control:

- Queue Management recognises that there may be exceptional issues that customers cannot control and which may lead to project delay and these include, but are not limited to:
  - Force Majeure: a contract provision that excuses a party from not performing its contractual obligations that becomes impossible or impracticable, due to an event or effect that the parties could not have anticipated or controlled.
  - Planning appeals and third party challenges: Where a planning decision by the determining authority is challenged through a formal appeal process by the developer or a third party to that decision.
  - Any delay which is caused by the network company, e.g. the customer is awaiting a required input from the network operator.
- Project experiencing delays of this nature can be placed on hold and the customer's connection terms maintained providing the customer complies with the following conditions:
  - they discuss the specifics of the delay with the network company at the earliest opportunity; and
  - they provide reasonable evidence to justify the specific delay.
- For the avoidance of doubt, a failure to comply with any of these conditions can result in a failure of a milestone and a change in the project status.

Benefits of Queue Management:

- Better facilitate competition
- Ensure electricity connections rights allocated are managed efficiently
- Enables fair and effective use of available capacity
- Help promote the adoption of flexible energy sources
- Ensure consistent treatment of users across the Whole System
- Helps to implement Britain's Net Zero target
- Formed this approach by consulting the wider industry

What we improved after July 2020 consultation:

What you have asked	What we have done to improve
Simpler approach	A simpler approach has been adopted. If milestone tolerances are exceeded, there is no intermediate stage ahead of contract termination whereby projects are moved to the end of the connection queue.
Additional clarity to milestones & cumulative delays	Additional clarity is included in the guide to ensure customers have a clearer understanding • Changes made to the later milestones to provide greater leniency. • Cumulative delay will only applies to earlier milestones.
Applicability	Additional clarity on the scope of QM and its applicability has added to the guide. QM principle will be applied to new and modification application from 1st of July.
Governance	Clarity was sought on the governance process would work however, Stakeholders can raise issues with ENA directly. A minor change to the CUSC is identified and CUSC modification will give transparency and governance at Transmission level.
Customer and Stakeholder engagement	• Open letter and Implementation plan have been published here • Webinar is planned for all interested industry parties and stakeholders in May 2021 . • A CUSC change proposal will be initiated.

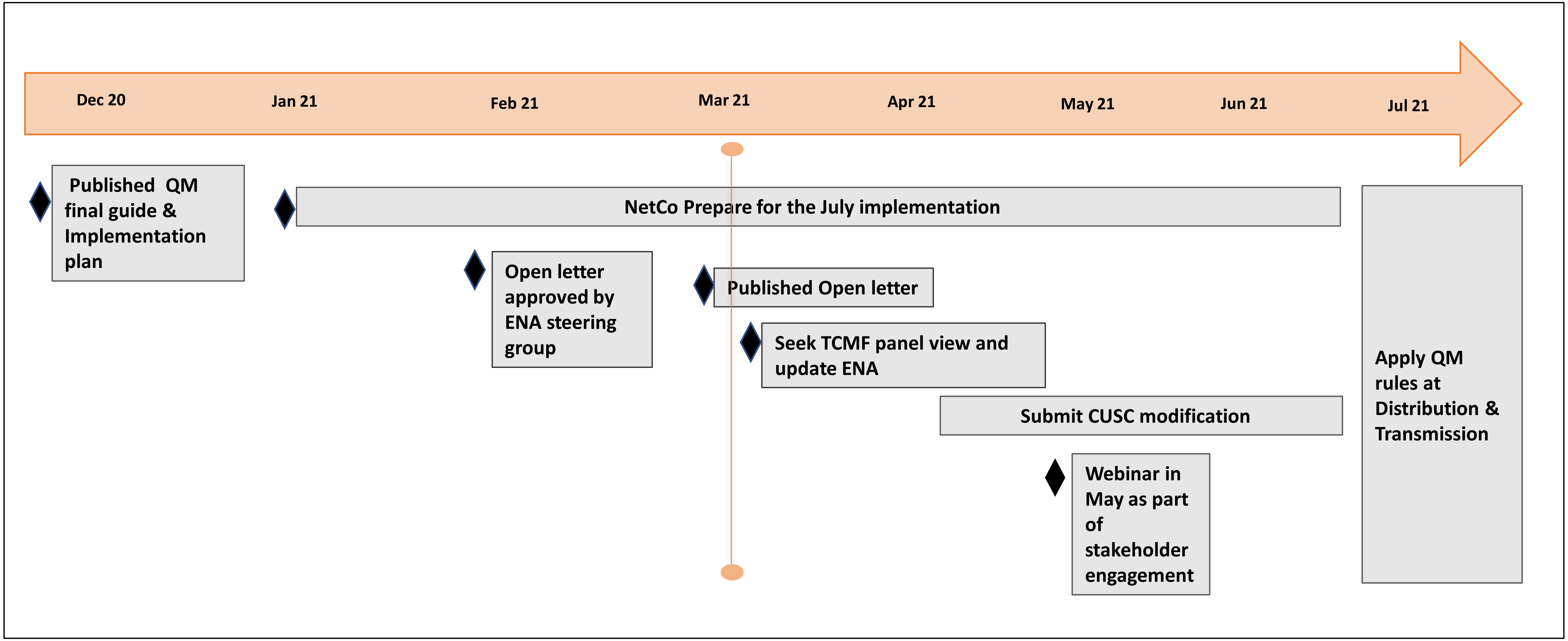
CUSC modification:

- It is proposed to initiate a CUSC change proposal to introduce a clause covering project progression that allows contract termination where milestones are not met.
- Subject to the agreement of the CUSC Panel , this proposal would be considered asap and will run in parallel with implementation of the new QM arrangements.
- We sought Ofgem's decision on this matter and they were supportive of implementing QM arrangements in July and process the CUSC modification in parallel.

Benefits of progressing this through CUSC modification quickly

- Addresses concerns raised through the consultation and we also think this industry developed rules should go through appropriate legal governance. Modification to CUSC ensures stakeholder engagement, customer experience and sign off from Ofgem.
- It will also ensure transparency and governance.

Implementation plan:



Any Questions ?

Final Queue management guide:
https://www.energynetworks.org/assets/images/ON20-WS2-P2%20Queue%20Management%20User%20Guide-PUBLISHED.23.12.20.pdf

We welcome your comments for our published open letter:
https://www.energynetworks.org/assets/images/Resource%20library/ON21-WS2-P2%20Queue%20Management%20Open%20Letter%20(01%20Mar%202021).pdf

Implementation plan covering next steps.
https://www.energynetworks.org/industry-hub/resource-library/on21-ws2-p2-queue-management-implementation-plan-(01-mar-2021).pdf

We welcome your comments. If you have any questions please contact us on

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Update on BSUoS Reform: billing frequency review mod

Katharina Birkner, NGESO

AOB & Close