
WELCOME
SQSS Panel
Wednesday 11 May 2022
Microsoft Teams
nationalgridESO

Introductions & Apologies for absence

Apologies

Alternates

Observers/Presenters

Approval of Panel Minutes

Approval of Panel Minutes from the Meeting held on:

11 May 2022

Actions Log

Review of the actions log

Authority Update

- **Energy Code Reform/Future System Operator**
- **Decisions**
  - GSR028 decision pending

Standing Items / impacts from other work

- Review of Modification Tracker
  Link

New modifications submitted

Standard Governance

SQSS Modification GSR029

P2/7 Alignment

Can Li/Bieshoy Awad
NGESO

Contents

Defects

This modification is proposed to review the demand connection criteria in Section 3 of the NETS SQSS to ensure alignment with EREC P2/7.

There are three main areas to address:

- Group demand definition: The NETS SQSS defines the size of a demand group based on the net transmission system demand. EREC P2/7, on the other hand, defines that size based on the total gross demand.
- NETS SQSS Section 3 does not allow the use of commercial contracts and only takes the output of embedded small power stations to the extent that it reduces the group demand.
- Assumptions for demand security contribution from large power station are different in NETS SQSS Section 3 and EREP 130.

Note: The CBA option in EREC P2/7 will not be replicated in SQSS as this option should only be exercised under specific circumstances. While in EREC P2/7 this may apply to demand groups, the number of transmission connected GSPs is manageable through the normal derogation process in similar circumstances.

Proposed Solutions

- Change the **definition of *Group Demand*** in clause 3.5 to either the gross demand or net demand plus the output of small, medium and large power stations and flexible demand;
- Introduce a definition of ***Flexible Demand***;
- Revise the background conditions specified in 3.7.3 and 3.7.4 to make it clear that the demand security contribution from embedded small and medium power stations, Demand Side Response, Energy Storage and Active Network Management scheme need to be considered;
- Remove Table 3.2 and replace with the reference to **EREP 130 as guidance** to assess the effective contribution of embedded large power stations to demand group;
- Potentially, introduce a definition of ***Electricity Storage Plant***, which should be a subset of power stations, and clarify that it can contribute to *Group Demand* and demand security.

What's changed since the draft proposal?

- Highlighted that the CBA option will not be adopted in SQSS.
- Clarified that the reference to EREP130 will act as a guidance only and created the unified requirements on all three transmission areas.
- Revised the definition of *Electricity Storage Plant* to align with Grid Code and CUSC.

  Electricity storage plant

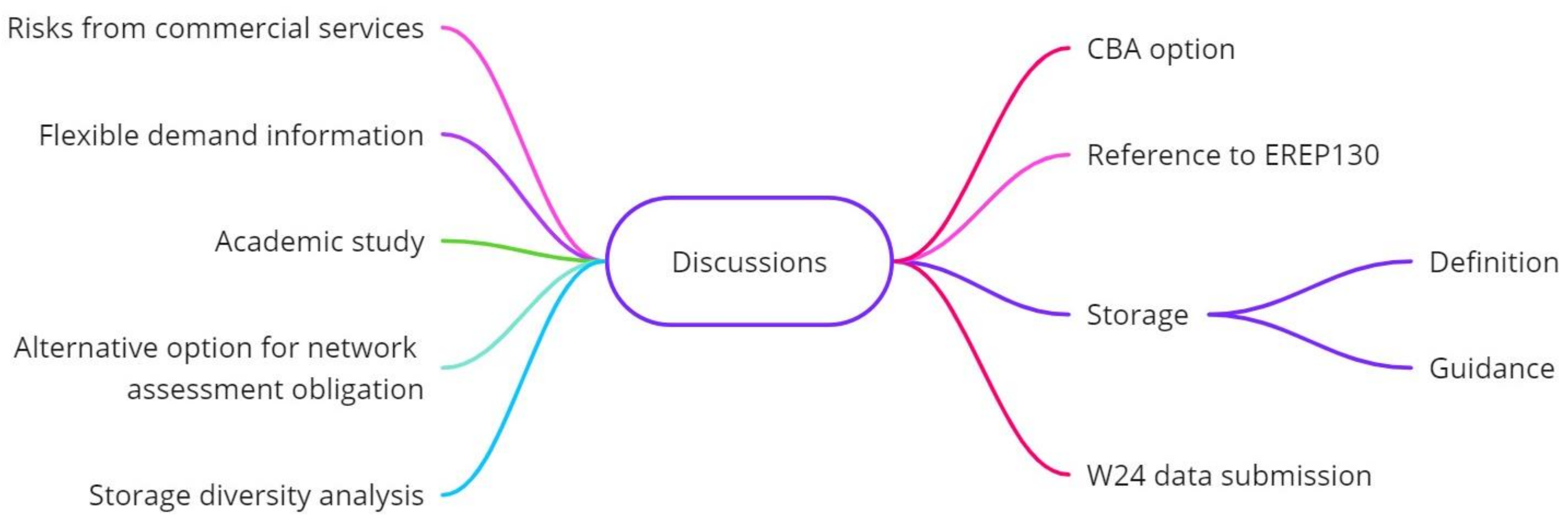
  - A *power station* which converts electrical energy into a form of energy which can be stored, stores that energy, and subsequently reconverts that energy back into electrical energy.

- Provided 3 options on Week 24 data submission on demand security contribution from small and medium power stations.

  Options subject to Grid Code modification (not the focus of this SQSS mod):

  - Request the DNO to submit the data for the GSPs where such assessment has been carried out;
  - Request the DNO to establish the demand security contribution for all GSPs;
  - Or set up a process for TOs to workout network deficiency at certain GSPs and request the DNO to submit the relevant data.

Workshop discussions summary



Next steps

July 2022
- Proposal formally submitted to panel

August 2022
- Workgroup formed

August - September 2022
- Workgroup meetings

September – October 2022
- Workgroup consultation

Oct – Nov 2022
- Workgroup meetings

Nov – Dec 2022
- Workgroup report submission

Note: the suggested timeline is subject to availability and support from the industry and may vary in practice.

Critical Friend Feedback

Code Administrator comments	Amendments made by the Proposer
Minor grammatical changes	Proposer accepted all amendments made by the Code Administrator

Timeline for GSR029 – Proposed Timeline - *Workgroup*

Milestone	Date	Milestone	Date
Modification presented to Panel	13 July 2022	Code Administrator Consultation	14 November – 12 December 2022
Workgroup Nominations (15 Working Days)	18 July – 5 August 2022	Draft Final Modification Report (DFMR) issued to Panel (5 working days)	16 January 2023
Workgroup 1 - Proposer's presentation, check Terms of Reference, initial review of legal text Workgroup 2 – Refine Solution Workgroup 3 - Finalise Workgroup Consultation document	8 August 2022 19 August 2022 1 September 2022	Panel undertake DFMR recommendation vote	24 January 2023
Workgroup Consultation (15 working days)	9 September – 30 September 2022	Final Modification Report issued to Panel to check votes recorded correctly	26 January 2023
Workgroup 4 - Discuss consultation responses, refine solution and legal text Workgroup 5 - Hold Workgroup vote, Finalise Workgroup Report and Legal text	10 October 2022 21 October 2022	Final Modification Report issued to Ofgem	6 February 2023
Workgroup report issued to Panel (5 working days)	1 November 2022	Ofgem decision	TBC
Panel sign off that Workgroup Report has met its Terms of Reference	9 November 2022	Implementation Date	TBC – in accordance with Authority timeline

GSR029 – the asks of Panel

- **AGREE** that this Modification should follow Standard Governance (Ofgem decision) rather than the Self-Governance Criteria (Panel decision)
- **AGREE** that this Modification should proceed to Workgroup
- **AGREE** Workgroup Terms of Reference
- **NOTE** the proposed timeline

DRAFT Proposal:

SQSS Infeed Loss Risk Change Proposal

Bieshoy Awad

July 2022

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Content

- Why Change?
- How?
- Changes since last review
- Risks
- Work in Progress

Why Change?

- Current limit restricts to current normal loss of infeed risk of 1320MW leading to potential sub-optimal investment

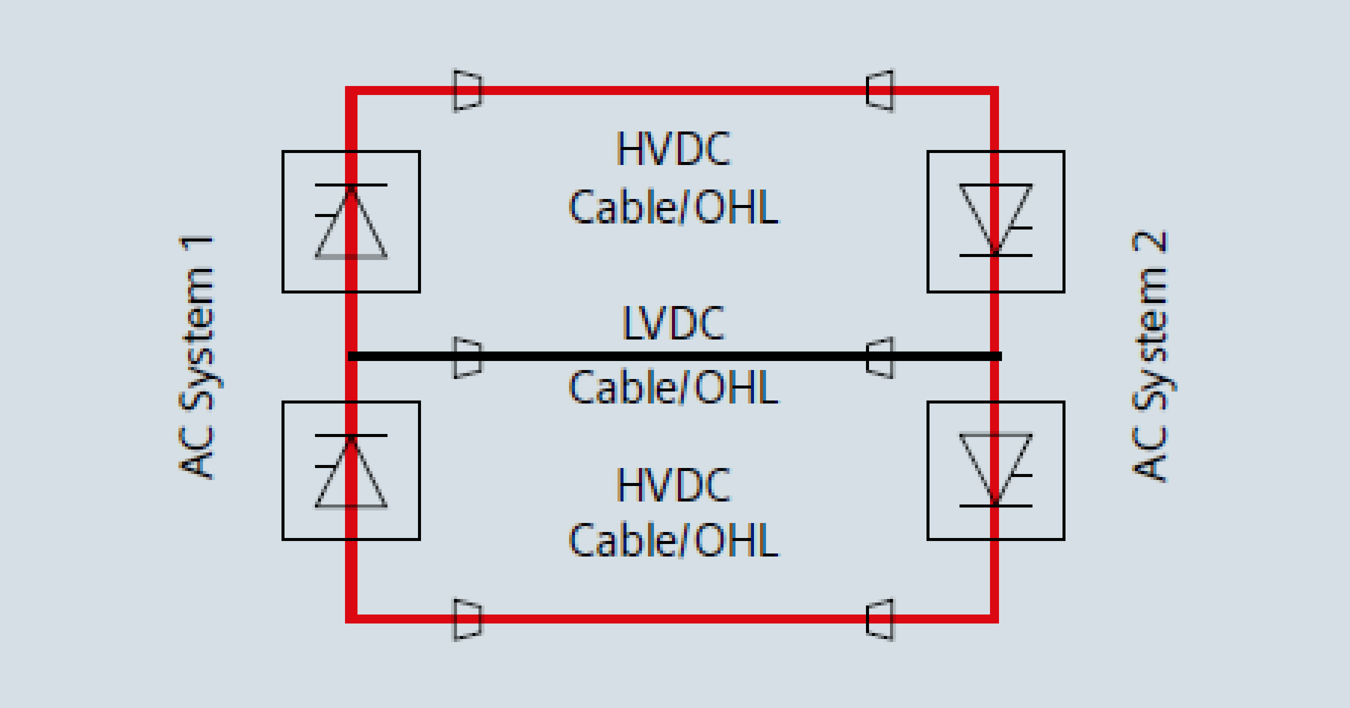
- Currently no differentiation between monopole and bipole which could lead to unnecessary restriction on the use of certain technologies

2 Issues

1. Treat a bipole with no common modes of failure as 2 separate DC converters
2. Review the restrictions of the loss if infeed risk associated with the loss of a single converter

Issue 1

Bipole with metallic return



How?

- allow DC converters using a bipolar configuration with no common mode of failure to be treated as two separate converters
- Revise the definition of an offshore transmission circuit to avoid restricting DC bipolar configurations
- Potentially restrict 2 cables running too close
- Potentially revise N-1-1

Revised Definitions:

DC converter:

Any apparatus used as part of the national electricity transmission system to convert alternating current electricity to direct current electricity, or vice-versa. A DC Converter is a standalone operative configuration at a single site comprising one or more converter bridges, together with one or more converter transformers, converter control equipment, essential protective and switching devices and auxiliaries, if any, used for conversion. In a bipolar arrangement, where there is a common mode of failure that would cause a fault outage on either of the two poles to affect the other pole or where there are operational requirements that would mean that a planned outage on either of the two poles would require the other pole to be unavailable, a DC Converter represents the bipolar configuration. Otherwise, each of the two poles is a separate DC converter.

Offshore Transmission Circuit:

Part of an offshore transmission system between two or more circuit-breakers which includes, for example, transformers, reactors, cables, overhead lines and DC converters but excludes busbars and onshore transmission circuits. Elements of an offshore DC system within an *offshore transmission circuit* which can be isolated by means of a control system action in response to a *secured event* without affecting the rest of the circuit shall be treated as an independent *offshore transmission circuit* when applying the said *secured event.*

Address the risk associated with anchor dragging

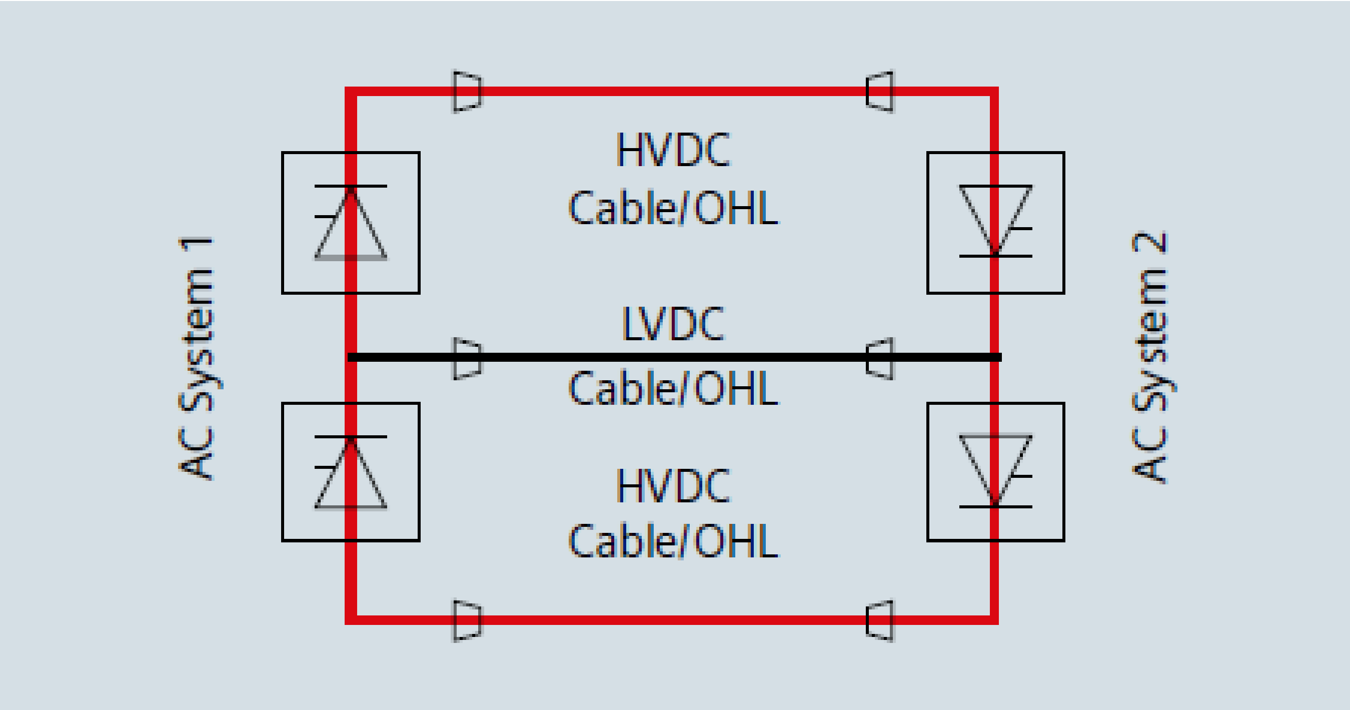
Offshore Cable Circuits Sharing the Same Route:

Two or more cable *offshore transmission circuits* that run within a distance of 250 meters from each other for a distance of 1000 meters or more.

7.8.3 following the concurrent fault outage of any two cable *offshore transmission circuits sharing the same route*, the loss of power infeed shall not exceed the infrequent infeed loss risk;

Is the N-1-1 sufficiently robust to ensure faults on metallic returns are addressed

7.8.2 following a *fault outage* of a single cable *offshore transmission circuit* during a *planned outage* of another cable *offshore transmission circuit* the further *loss of power infeed* shall not exceed the *infrequent infeed loss risk*.



Issue 2 – change to infeed loss risk

Why?

Assumption made during HND project, facilitates better use of offshore routes and landing points and better optimization of offshore transmission assets

How?

- Change “normal” to “infrequent” in 7.7.2.1 and 7.7.12.1

Issue 2 – change to infeed loss risk

Issues to consider:

- Will it lead to increase in number of excursions below 49.5Hz
- Whether there will be any costs associated with restricting this increase of frequency excursions
- Whether the costs outweigh the benefits delivered by facilitating recommendations of HND.

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Frequency Risk & Control Report v2023

NGESO – SQSS Panel

11th July 2022

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Contents

Contents

- Background
- Scope of FRCR 2023
    - Minimum Inertia policy
    - ALoMCP closure
    - Policy review (FRCR 2021 policy)

- Policy recommendations that may be delivered through FRCR 2023
- Consumer value through implementing FRCR 2023
- Timeline to deliver FRCR 2023

Background

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Background and scope of FRCR

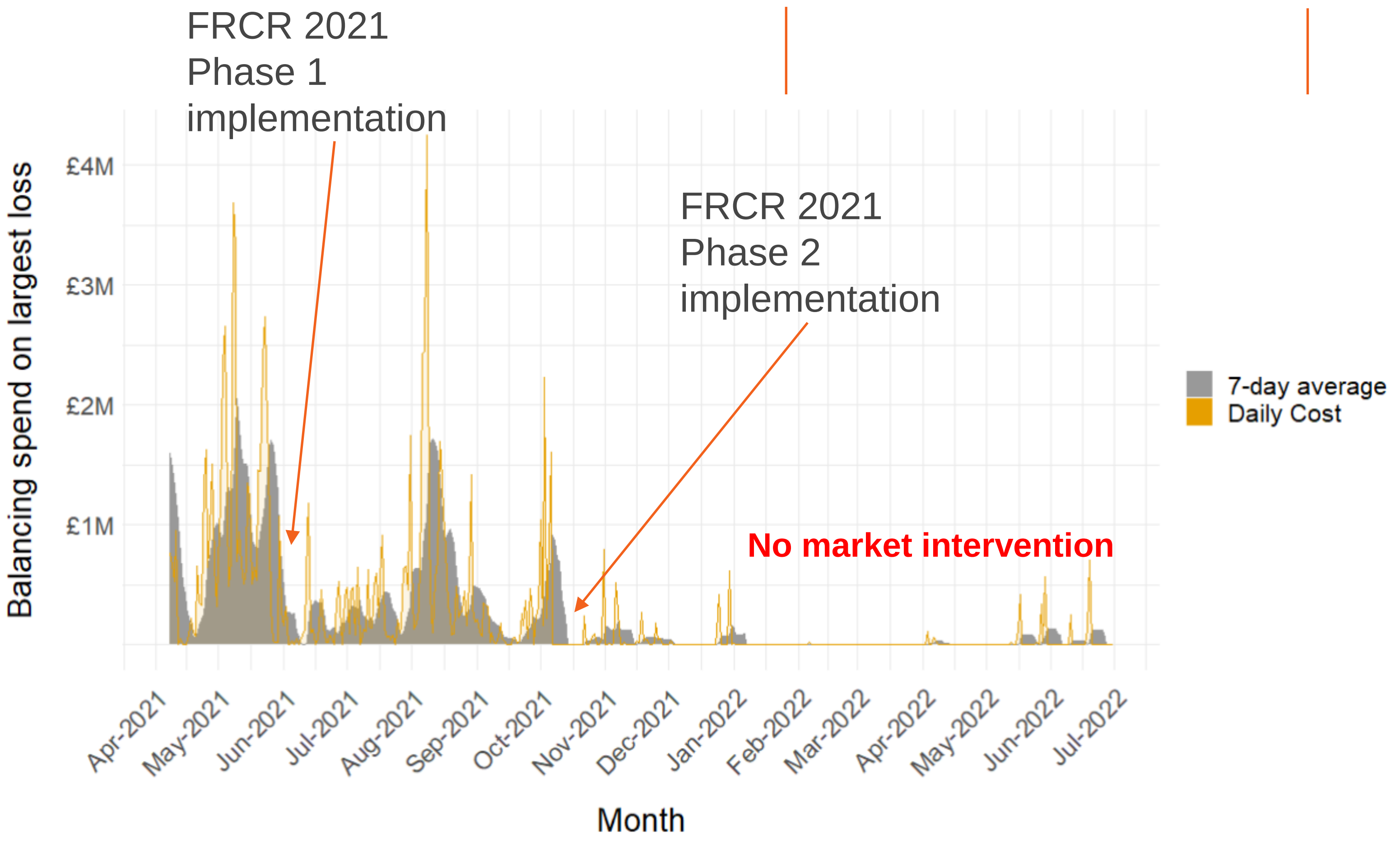
Background

- ESO raised SQSS modification GSR027 following the 09 August 2019 power cuts
- This introduced the new Frequency Risk and Control Report (FRCR)

Scope

- The first edition of the FRCR (2021) focused on establishing the FRCR process to deliver a clear, objective, transparent process for assessing reliability vs cost to ensure the best outcome for consumers
- It assessed the cost vs. risk from the inadvertent operation of Loss of Mains protection, delivery of Dynamic Containment and Accelerated Loss of Mains Change Program, the frequency standard that various size loss risks are held to, and the impact of transmission network outages on radial connection loss risks
- FRCR (2022) assessed the value in taking additional actions to secure simultaneous losses noting the role this event category played during the 09 August 2019 power cuts
- FRCR (2023) will assess the value in relaxing minimum inertia policy and investigate the enduring costs the ESO may be exposed to in relation to the LoM risks left after the closure of the ALoMCP
- A policy review (using FRCR 2021 policy as a baseline) will be undertaken to ensure FRCR 2023 policy gives the ESO the flexibility to manage the system as we approach 2025

Impact FRCR v2021 Phase 1 - Reduced Costs From June 2021



May 2021:

- Relaxing the smaller infeed loss <=1000MW to 49.5Hz
- Re-categorising certain loss events from BMU-only to BMU+VS and not taking additional action to secure them

Oct 2021:

- Allowing consequential RoCoF events to occur of the total loss could be secured to 49.2Hz
  - Which meant no longer taking targeted actions to reduce loss size

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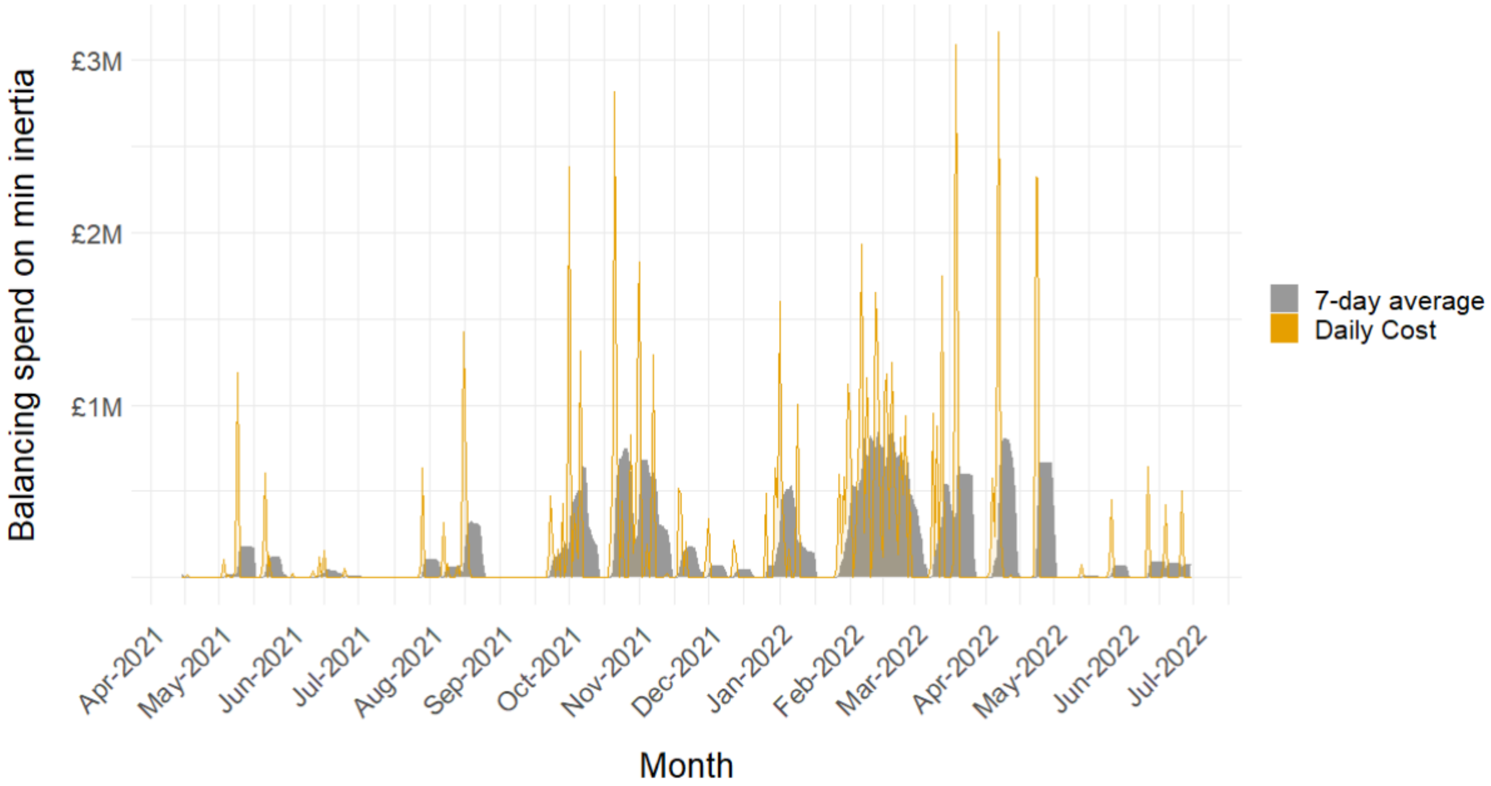
FRCR 2023 Scope

Scope (1) Relaxing Minimum Inertia

Cost associated with offering units on access their inertia (and bidding units to create footroom)



Minimum Inertia policy:

- Recent increase in spend to meet minimum inertia level of 140 GVA.s through offering conventional units (to access inertia through their MW's) and bidding (to create footroom for these units)

  - Approximately **£100m** in the last year in offer-bid costs to access inertia in the BM

  - Set to increase due to more low inertia periods and higher renewable penetration meaning more periods where inertia needs to be managed against potential expensive wind bids

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Scope (2) Enduring ALoMCP cost vs. risk

- The ALoMCP will end on 01 September 2022. The program to date has already reduced the peak LoM risk by over 60% compared to the pre-ALoMCP risk
- This reduction and risk has delivered large cost reduction compared to the counterfactual of managing the largest losses (through BOA's and trades) and increasing frequency response holdings
- There remains a risk that the projected level of compliance with not be met by September 2022
- FRCR 2023 will investigate the enduring cost vs. risk profiles of the GB system based on a range of ALoMCP scenarios noting that across 2023/24 the ESO will likely have to procure Dynamic Containment to secure any remaining RoCoF MW's

Scope (3) FRCR 2021 Policy Review

- FRCR 2021 delivered the last policy update which was implemented by October 2021
- That policy can be summarised as;
  - Ensure **BMU-only** loss risks do not cause a frequency deviation 49.2Hz < f < 50.5Hz, noting that the total loss may also include RoCoF losses
  - Do not take additional actions to secure BMU+VS and simultaneous event loss risks
  - Typically secure a 1260MW loss using conventional response and use fast acting Dynamic Containment to secure additional (RoCoF) losses
- Changes to frequency response volumes (reduced EFR and static), and potential relaxation of minimum inertia policy, means a more flexible policy is required to secure the largest losses with the most efficient mix of response products
- FRCR 2023 will seek to quantify and optimise the cost vs. risk balance with the latest data to ensure the policy is fit for purpose for operating the system in 2023

Policy

FRCR 2023 Policy draft

Minimum Inertia Policy

Minimum inertia policy set to sub-140GVA.s value e.g. 120GVA.s or as low as the Stability Pathfinder limit of 102GVA.s if there is confidence that the largest losses can be secured with fast-acting response

Loss risk controls (Response and reducing BMU loss size)

Apply loss risk controls to BMU+VS events (as well as BMU-only events) to keep resulting frequency deviations within 49.2Hz and 50.5Hz e.g. procure enough DC to mitigate **some** of the BMU+VS category and reduce overall system risk

Updating policy to remove the requirement to secure a 1260MW loss without DC e.g. cover BMU-only and some BMU+VS risks with the most efficient mix of response delivered via our daily auctions

System risk profile

Updated set of “1-in-x year” likelihoods for each frequency impact 48.8Hz, 49.2Hz, 49.5Hz, 50.5Hz based on recommended policy

Consumer Value

Consumer Value

Minimum Inertia Policy

Meeting minimum inertia cost is projected to be £100m across 2022. This will increase in 2023 as more renewables meets demand and more inertia is displaced.

ALoMCP ==> LoM Compliance Plan

FRCR 2023 will help shape the future LoM compliance and save the end consumer an enduring cost of £m's per month to secure RoCoF and VS losses

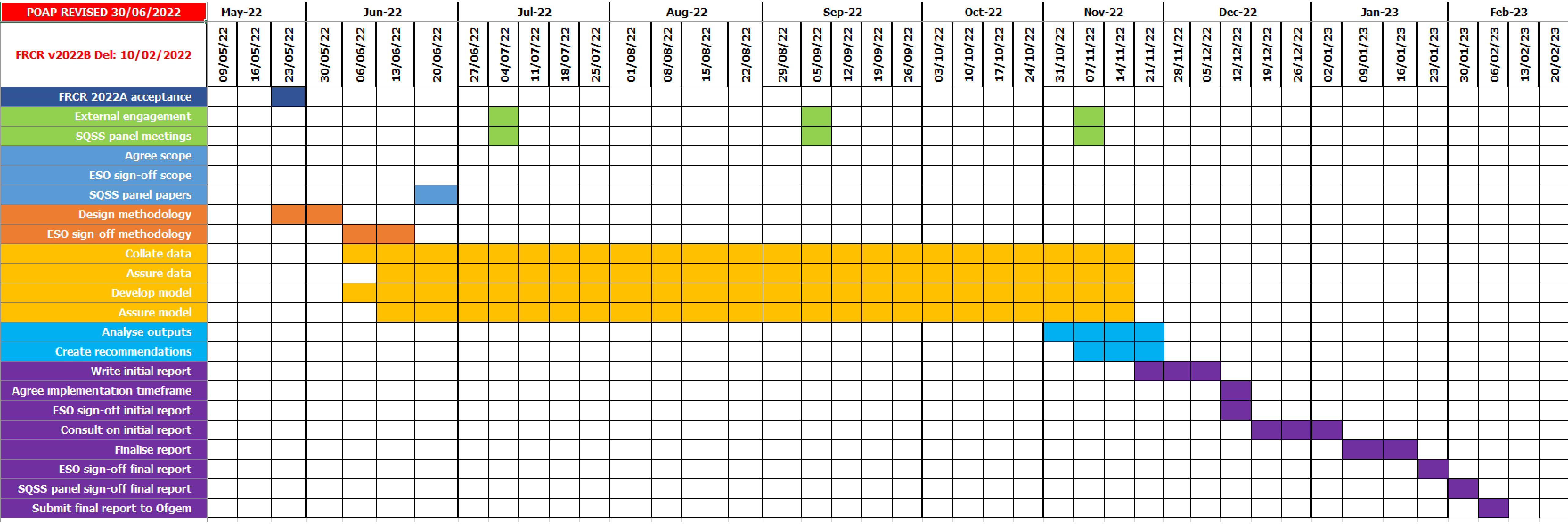
FRCR will quantify the immediate and future benefit that would be delivered through DNOs enforcing LoM compliance after ALoMCP closure.

Policy review

Reduced risk in the system through potentially securing some BMU+VS events and using the most efficient mix of response to secure the largest losses.

Timeline

Timeline



Key Project Milestones

December 2022: Consults on Methodology & Report
January 2022: Submit final report to SQSS panel for approval
February 2022: Submit final report to Ofgem

AOB

- None

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Date of next meeting

Wednesday – 14 September 2022

Panel Papers Day – 06 September 2022

Modification Submission date – 30 August 2022

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Close