Public

Ref: FOI/25/040

National Energy System Operator
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www.neso.energy

30 June 2025

Dear requester

Request for Information

Thank you for your Freedom of Information request which we received on 2 June 2025.

The National Grid Electricity System Operator (NG ESO) was part of the National Grid PLC group of companies until 30 September 2024 and was not subject to the Freedom of Information Act 2000 (FOIA). On 1 October 2024 ('Day 1') we became the National Energy System Operator (NESO) under government ownership (the Independent System Operator and Planner as designated in the Energy Act 2023). Regulation 14 of the Energy Act 2023 (Consequential Amendments) Regulations 2024 (SI 2024/706) amended Part 6 of Schedule 1 (other public bodies and offices: general) of the FOIA, inserting the following: "The Independent System Operator and Planner designated in accordance with section 162 of the Energy Act 2023 in respect of information held by it as a result of the exercise of its functions under, or as a consequence of, that Act." NESO has therefore been subject to the FOIA since 1 October 2024 and our response relates only to information collected, received, or created since Day 1.

Request

You asked us:

Please provide the following information for each calendar month from January 2022 to the latest available month:

1. *The total cost incurred by NG ESO / NESO in procuring frequency control services, including but not limited to:*
    - *Dynamic Containment / Dynamic Moderation / Dynamic Regulation*
    - *Legacy frequency response services (FFR etc)*
    - *Other related reserve services explicitly used to support frequency control.*

2. *The volume (MW) procured per month for each of the above service types.*

3. *Any internal reports or communications detailing changes in frequency management policy, and the anticipated cost implications of these changes, particularly those related to any changes to the reserve holding.*

Please also confirm whether any of the above costs are re-allocated to non-frequency budget lines in BSUoS or other categories.

Our response

We confirm that we hold information in scope of your request. The information related to the cost/volume of procuring response in the system, whether through dynamic services (Dynamic Containment / Dynamic Moderation / Dynamic Regulation), Firm Frequency Response (FFR), or Reserve services are published on the Data Portal via the following links:

- Static Firm Frequency Response auction results | National Energy System Operator
- Enduring Auction Capability (EAC) auction results | National Energy System Operator
- Static Firm Frequency Response Requirement | National Energy System Operator
- Long-Term Forecasts for DC, DM and DR Requirements | National Energy System Operator

These datasets are publicly accessible and are updated as new data is released. In relation to the published information, please note the following points:

- We have two ways of considering costs. One is what can be called the 'Action Cost'. This is the cost paid to BMUs for direct turn-up/turn-down actions. This view of costs is useful to understand the cashflow of balancing costs to regions across GB.
- The other is the 'Whole System Cost', this is NESO's method of allocating second order actions with an initial action. This accommodates all costs associated with an action,

including replacement energy costs and imbalance costs. This view of costs is useful from the perspective of system operations to understand the original cause of costs.
- By way of illustration, please refer to slide 12 of our Yearly Balancing Cost Report.

These costs are allocated under "Balancing Cost" Components within BSUoS and a forecast of these are used to form the BSUoS Fixed Tariff. As a further breakdown, the costs mentioned above could be placed in "Frequency Control", "Negative Reserve", and "Positive Reserve" categories within "Balancing Cost".

We have identified 7 internal reports relating to change in frequency management policy, which are attached. This does not include the FRCR and service design documents which are published on our website. Whenever any of these FRCR or service design documents are updated the changes are presented at the Operational Transparency Forum and a consultation process is put in place for major changes.

We have included information relating to changes in volumes of frequency management and implementation of FRCR24. As you will see from this attached information we have assessed the frequency deviations taking place compared to historical standards and introduced new demand response measures which brings them back to historical levels. It is also important to note that the deviations that have taken place do not risk security of supply, and steps are being taken through an abundance of caution and good practice to maintain our overall reliability of supply in 2023-24 at 99.9999%.

Some sections of the 7 internal documents have been redacted. These redactions are for commercially sensitive information, where there is a security risk, or for personal data.

Section 43 of the FOIA allows us to withhold information where disclosure would prejudice the commercial interests of any party. Disclosure of this information would be likely to provide some market participants with a competitive advantage and therefore disadvantage others. Although this information would theoretically be available to any market participant via our FOI disclosure log, it could not be guaranteed that all potential participants would have access and some could gain an unfair advantage. Section 43 of the FOIA is a qualified exemption which requires a public interest test. There is always a public interest argument for disclosure bringing greater transparency to the decision-making processes in the public sector and government and for public corporations to be accountable for their advice and actions. NESO acknowledges that information about Great Britain's energy system is very much a subject of public interest and debate at the current time, as is the approach to clean power and there is a public interest in furthering public understanding of issues and decisions which impact on members of the public and organisations. NESO has a public duty under our licence to facilitate competition within the energy market and there is a recognised public interest in allowing competition in the energy industry. There is a public interest in ensuring that the market operates fairly and that market participants can compete fairly. Failure to operate in this way would be likely to impact negatively on public confidence in NESO and would potentially have cost implications for consumers. In this case we believe that the public interest in refusing the exemption outweighs the public interest in disclosing the further information. We have, therefore, applied redactions to the commercially sensitive sections of the attached documents.

Section 31(1)(a) of the FOIA allows us to withhold information where disclosure would prejudice the prevention or detection of crime. This additional information could be used by malicious actors to attack physical critical national infrastructure. Section 31 of the FOIA is a qualified exemption with requires us to conduct a public interest test. NESO recognises that there is a general public interest in disclosure of information that would promote transparency of the requested information. This includes information about the vulnerabilities and risks relating to the security of supply and resilience of the network.   NESO must balance its transparency obligations with protecting the resilience of the network and the security of supply. In this case, NESO does not consider that the public interest in transparency is sufficiently strong enough to outweigh the substantial interest in maintaining the integrity of the network. We have, therefore, redacted these sections of the attached documents.

The names of our employees have also been redacted under the exemption at Section 40(2) of the FOIA which allows us to refuse to provide information which is personal data. The employees in question are not members of the Executive Leadership Team and did not have the expectation that their names would be disclosed into the public domain. We do not, therefore, believe that we have a lawful basis for the disclosure of their personal data and have redacted names.

This concludes our response to your request.

Advice and assistance

We note that in your email of 2 June in which you sent your five FOI/EIR requests, of which this is one, you raised concerns about data on the NESO Data Portal and BMRS. If those concerns relate to this FOI request and any of the data provided above, please provide further detail and we will endeavour to provide further information or explanation.

Next steps

If you are dissatisfied with our handling of your request, you can ask us to review our response. If you want us to carry out a review, please let us know within 40 working days and quote the reference number at the top of this letter. You can find our procedure here: Freedom of Information and Environmental Information Regulations | National Energy System Operator. The

ICO's website also provides guidance on the internal review process: What to do if you are dissatisfied with the response | ICO.

If you are still dissatisfied after our internal review, you can complain to the Information Commissioner's Office (ICO). You should make complaints to the ICO within six weeks of receiving the outcome of an internal review. The easiest way to lodge a complaint is through their website: www.ico.org.uk/foicomplaints. Alternatively, they can be contacted at: Wycliffe House, Water Lane, Wilmslow, SK9 5AF.

Thank you for your interest in the work of the National Energy System Operator (NESO).

Regards,

The Information Rights Team, National Energy System Operator (NESO

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RAPID – Lift DR Cap to 500 MW

#	Date	Author	Reviewer	Draft/Final	Change since previous version
1	04/10/2024	REDACTED		Draft	
2	11/10/2024	REDACTED		V1	

Executive owner: [NAME REDACTED] (Frequency Risk and Modelling team)

RAPID

- **Recommend:** REDACTED
- **Agree:** REDACTED
- **Perform:** REDACTED
- **Input:** REDACTED
- **Decide:** REDACTED

Aim

- Introduce and review the Dynamic Regulation (DR) cap, methodology and assumptions.
- Propose to lift the DR cap from current 350 MW to 500 MW to remove blockers to future policies.

Background

In the past year, the GB system frequency has been deviated further away from 50 Hz. It has been more than 5% instances where we observed frequency outside the $\pm$0.15 Hz pre-fault assumption. To deal with the more volatile frequency performance, more Mandatory Frequency Response (MFR) has been procured. As the deadline of MFR derogation is approaching, it is important to reduce the use of MFR and to find a secured and efficient approach to manage the pre-fault frequency.

DR is the response service mainly designed to smooth the pre-fault frequency and to maintain the frequency within operational limits ($\pm$0.2 Hz). Currently DR is capped at 350 MW based on analysis performed back in 2021. The analysis was running in parallel by both internal colleagues using OLTA models and external consultancy using MATLAB models. Both studies adopted conservative assumptions as the worst case scenarios, i.e. 10 GW demand, 110 GVA.s inertia and all DC DM DR centralised in one small area.

By checking the DCDMDR procurements and system conditions in the past year, it is clear that the above assumptions do not represent the realistic situation. Therefore, it has been proposed to review the methodology and assumptions to reflect realistic worst case scenarios, so that the DR cap can be lifted while maintaining the system stability.

Methodology

The analysis adopts [REDACTED] as the study model. DCDMDR models have been developed by Operability Innovation team and have been inserted into the GB master model. The methodology can be summarised as below:

1. Look at historical system conditions and pick up a low demand low inertia settlement period, this represents a weak system thus is considered as the worst case scenario.

   By looking at the year between 2023.04 and 2024.07, the SP 2024-04-07 04:30 am is selected. Transmission demand was 21.3 GW and inertia was manually tuned to 120 GVA.s.

2. Pick up the relevant Transmission Analysis Engineer (TAE) project for best illustration of network configuration, generator patterns and demand configurations.

3. Set up the OLTA project with DCDMDR models.

   Volumes of DC and DM are determined based on the peak procurements in the past one year, which are 1400 MW for DC and 200 MW for DM. Two levels of DR volume are considered in the analysis: 500 MW and 700 MW.

   Locations of DCDMDR are determined based on historical procurements and are simplified to three areas only: Scotland, E&W North and E&W South. [REDACTED]

   The response delay of DR is also considered due to the deployment of EAC, which allows providers to stack the DR with fast DC and DM. In such cases providers are obliged to deliver fast DR services. Therefore, in the analysis, different combinations of scenarios regarding the regional procurements of DCDMDR, along with the technical parameters of DR, have been tested.

4. Trip generation/demand to stimulate DCDMDR responses.

   [REDACTED] To focus on the DR product, small MW trips are considered ranging from $\pm$300 MW to $\pm$500 MW, followed by a ramping of $\pm$150 MW in 10 seconds to represent system demand ramping.

5. Observe the frequency traces as well as the DCDMDR response curves. Conclude if the system is stable under the studied scenarios.

   Overall the study extended the base case to consider more slow DR percentage and more procurement in Scotland, as shown below.

<table>
<tr><th>Case name</th><th colspan="2">Base case</th><th>More slow DR</th><th>More in Scotland</th></tr>
<tr><td>DC volume</td><td colspan="2">1400 MW</td><td>1400 MW</td><td>1400 MW</td></tr>
<tr><td>DM volume</td><td colspan="2">200 MW</td><td>200 MW</td><td>200 MW</td></tr>
<tr><td>DR volume</td><td colspan="2">500 MW</td><td>500 MW</td><td>500 MW</td></tr>
<tr><td>Scotland volume [REDACTED]</td><td colspan="2">300 MW DC + 50 MW DM + 125 MW DR (25%)</td><td>300 MW DC + 50 MW DM + 125 MW DR (25%)</td><td>600 MW DC + 100 MW DM + 250 MW DR (50%)</td></tr>
<tr><td>E&W North volume [REDACTED]</td><td>300 MW DC +50 MW DM + 125 MW DR (25%)</td><td>300 MW DC + 50 MW DM + 125 MW DR (25%)</td><td colspan="2">0</td></tr>
</table>

E&W South volume [REDACTED]	600 MW DC + 100 MW DM + 250 MW DR (50%)	600 MW DC + 100 MW DM + 250 MW DR (50%)	600 MW DC + 100 MW DM + 250 MW DR (50%)
Slow DR percentage (2 second delay + 8 second ramping)	100 MW slow DR (20%)	250 MW slow DR 50%	100 MW slow DR (20%)

For each study case, 12 scenarios are simulated to reflect different combinations of instantaneous gen/demand trip and slow ramping gen/demand, as shown in the table below.

Scenario	Loss level (MW) +tive for gen loss -tive for demand loss	Base case oscillating?	More slow DR case oscillating?	More in Scotland case oscillating?
1	500 MW followed with 150 MW ramping in 10 second	N	N	N
2	400 MW followed by 150 MW ramping in 10 second	N	N	N
3	300 MW followed by 150 MW ramping in 10 second	N	N	N
4	500 MW followed by -150 MW ramping in 10 second	N	N	N
5	400 MW followed by -150 MW ramping in 10 second	N	N	N
6	300 MW followed by -150 MW ramping in 10 second	N	N	N
7	-500 MW followed by 150 MW ramping in 10 second	N	N	N
8	-400 MW followed by 150 MW ramping in 10 second	N	N	N
9	-300 MW followed by 150 MW ramping in 10 second	N	N	N
10	-500 MW followed by -150 MW ramping in 10 second	N	N	N
11	-400 MW followed by -150 MW ramping in 10 second	N	N	N
12	-300 MW followed by -150 MW ramping in 10 second	N	N	N

Based on the results, none of the scenarios or cases demonstrated instability. Therefore, the conclusion is that the system remains stable with power imbalances or disturbances when having no more than 500 MW DR, without the risk of leading to any operational issues.

Results

Results and more details are provided in the attached slides.

RAPID - increase DR cap to 500 MW.pptx

Future work

- Set up regional procurement monitoring process, for Dx units, to assure the assumptions made in the study are valid. Triggering point could be if >25% of Dx volumes are observed in Scotland.
- Set up a DR standalone/stacked contract monitoring process, to assure the assumptions are valid. At the moment, the 100% slow DR as the worst case has been verified for 500 MW with no issues.

Appendix - Additional thoughts and reflections

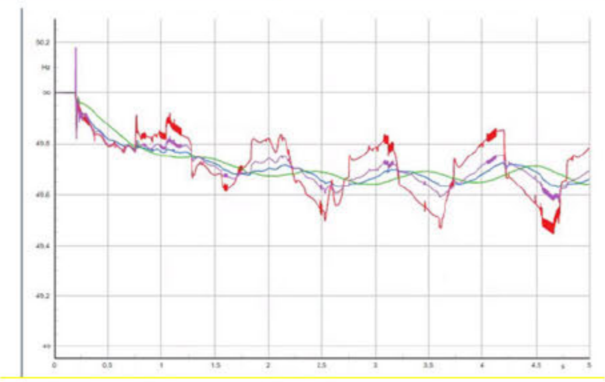
This section is used to log comments and feedback, to help better illustrate the concept of this paper.

What are the observations so far?

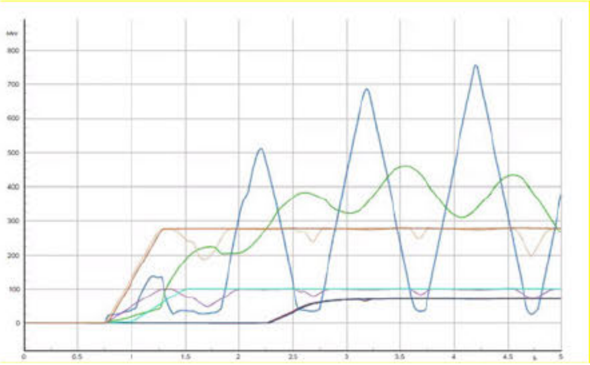
When a system experiences a disturbance, such as a sudden loss of generation or demand, the system frequency deviates from its nominal value. In such cases, the power system relies on the frequency response products to help restore and stabilise the system frequency.

If the frequency response is slow, such as DR with 2 seconds delay and 8 seconds ramping time, it takes more time for that unit to adjust its power output in response to the frequency deviations. The delay in response can lead to imbalances between generation and load, cause the frequency to oscillate.

[REDACTED SECTION]



[LEGENDS FOR CHARTS REDACTED – Frequency Traces]



[LEGENDS FOR CHARTS REDACTED – Dx responses]

[REDACTED SECTION]

How is the base case derived, and why consider 500/700 MW DR as the new target cap?

The aim of this review is not only to lift DR cap to a new level but also to gain acknowledgement across NESO, ensuring ongoing evaluations of DR, DM and DC.

The derived base case is to assume that DC and DM requirements would stay solid as where they are in the recent market, so that we can focus on the DR impacts. The daily DC procurements can vary depending on system conditions so we select the peak volume to represent the worst case. DM requirements have been lifted to 200 MW recently and we do not foresee any plans to change DM requirements in near future.

Regarding DR, the current cap stands at 350 MW, which matches daily requirements. Considering the planned implementation, it is recommended to increase the DR cap incrementally by 150 to 200 MW. Therefore, in this study, the target DR cap levels are set at 500 MW and 700 MW. Due to the time-consuming nature of OLTA simulations, it was agreed to limit the analysis to these levels, avoiding intermediate values (e.g., 550 MW or 600 MW). These intermediate levels can be explored further once there is a more comprehensive understanding of the stability issues related to DR response.

Simulation results thus far indicate that oscillations were observed when 700 MW of DR was included in the system, while no oscillations occurred at 500 MW. Based on these findings, it is recommended to set the new DR cap at 500 MW. When higher DR requirements are implemented, system behavior can be closely monitored to ensure that the study's assumptions remain valid, allowing for future cap revisions as necessary.

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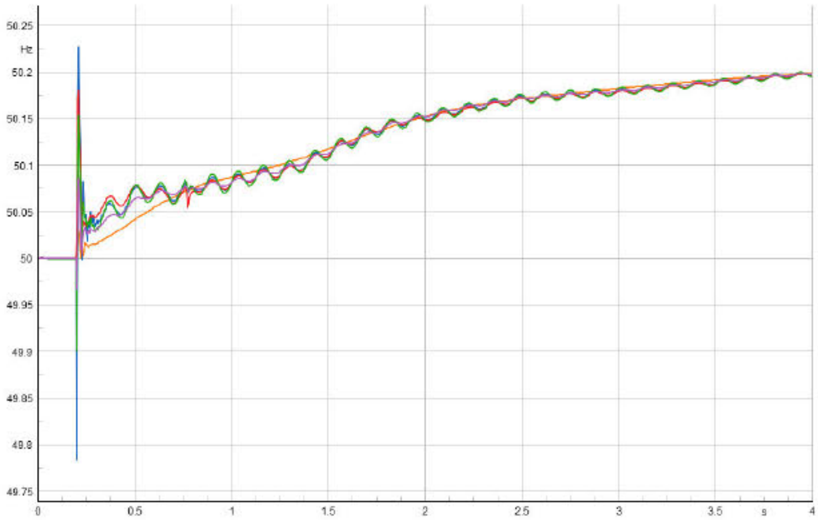
What are the limitations of OLTA and can we ignore them?

In the past analysis, two types of models were used: a swing equation based single-mass model and the OLTA model.

The swing equation-based model, developed by an external agency using MATLAB, offers the advantage of incorporating the system state matrix and transfer functions for frequency response products. This model allows for the rapid analysis of a large set of scenarios to identify potential instability issues. However, its primary limitation is the lack of regional specificity, which prevents it from accurately simulating events occurring in areas like Scotland.

In contrast, the OLTA model, while not perfect, is currently the most robust model available for this analysis. Nonetheless, several erroneous behaviours have been observed during simulations:

[REDACTED SECTION]



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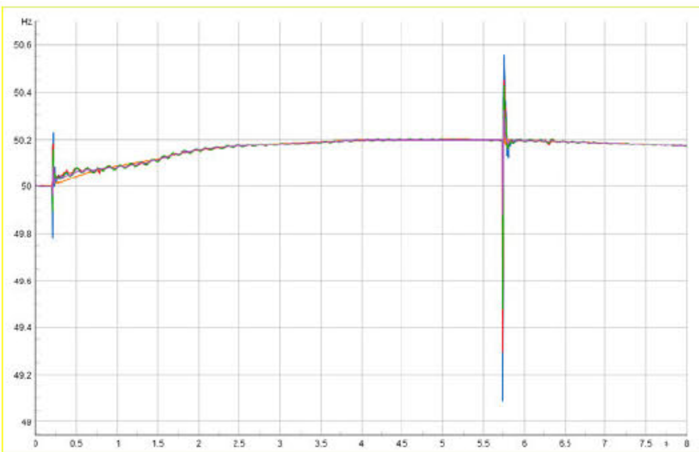
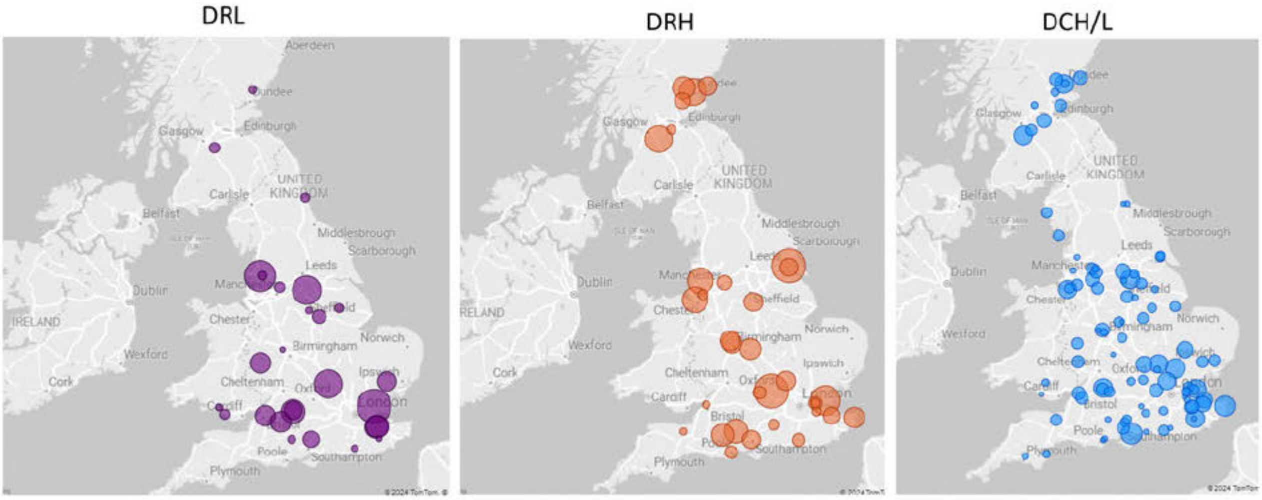


[REDACTED SECTION]

Why we assume 25% of Dx volume in Scotland and E&W North, while 50% in E&W South?

The allocation of DR, DM and DC volumes across regions is based on an analysis of historical Dx procurement data. The figure below summarizes the regional distribution of Dx procurement for the months of July 2024 and August 2024, highlighting that the majority of DR and DC volumes were procured in England & Wales (E&W), particularly in the E&W South region.



A summary of the average Dx procurement by location is provided in the table below. It reveals that the maximum percentage of all Dx units procured in Scotland is 17.94%. To incorporate a margin of safety, we assume that 25% of total Dx volumes will be procured in Scotland for the base case scenario.

Sum of DCH avg (MW)	Sum of DCL avg (MW)	Sum of DMH avg (MW)	Sum of DML avg (MW)	Sum of DRH avg (MW)	Sum of DRL avg (MW)	Max percentage of Dx	Region
1168	996	179	152	340	283		All Regions
149	127	26	20	61	30	17.94%	Scotland
233	205	52	57	68	39	37.5%	England North
786	653	100	74	210	213	75.2%	England South

Based on this data, we assume that 25% of Dx volumes are procured in Scotland, accounting for a conservative margin above the historical maximum of 17.94%. For England & Wales (E&W), the analysis shows that a significant proportion of Dx volumes—especially in DR and DC—are concentrated in the southern region. Consequently, we assume that 50% of Dx volumes will be procured in the E&W South region, which aligns with the historical trend of high procurement in this area.

This regional allocation is essential for accurately simulating system behaviour and stability, ensuring that the assumed distribution reflects realistic operational scenarios.

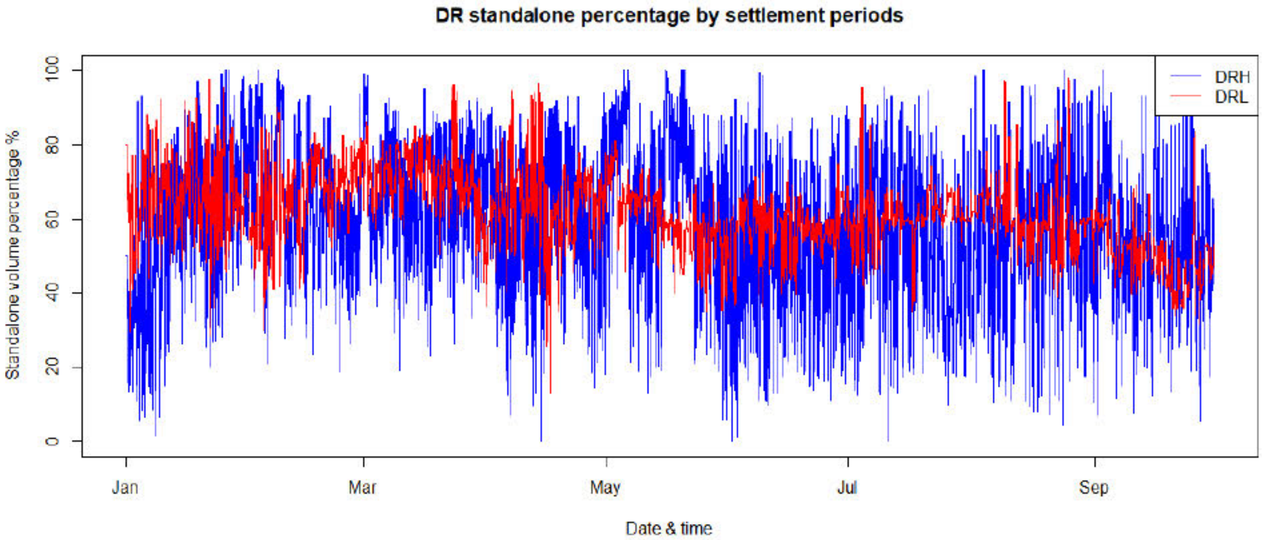
How we consider response speed for DX, especially for DR?

For Dx units, the technical requirements specify the maximum allowable delays and ramping times that a provider must meet. While providers may choose to configure their response times to be faster than these specified limits, the general assumption is that slower response times are more likely to induce oscillations in the power system. Consequently, for DC and DM, a 0.5-second delay and 0.5-second ramping time are used as the standard.

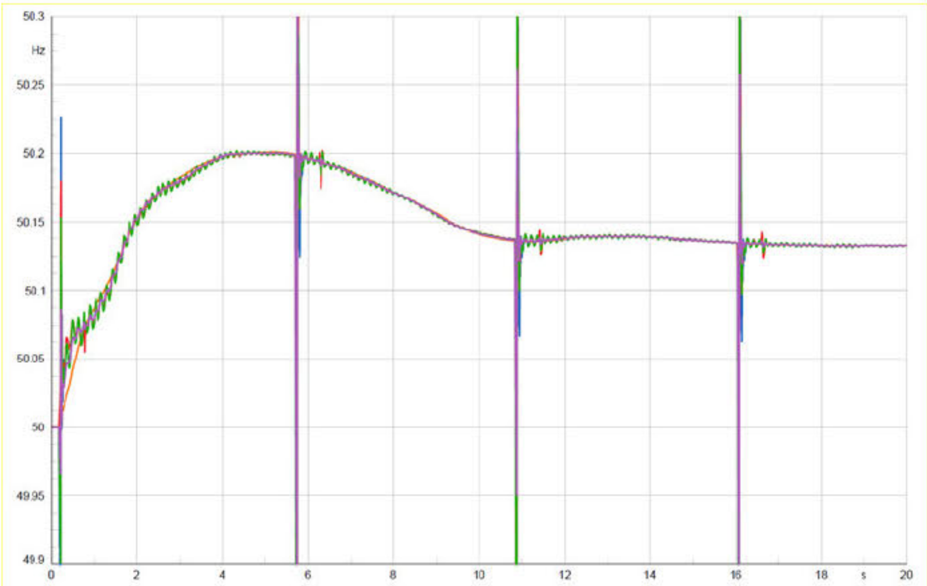
For DR, the requirements differ following the introduction of the Enhanced Ancillary Services (EAC) platform with its stacking functionality. The technical requirements for DR are derived as follows:

- For stacked DR services (i.e., when DR is provided alongside DC/DM by a same unit), the delay and ramping time must match those of DC/DM, meaning fast response parameters.
- For standalone DR services, the delay can be up to 2 seconds, with an 8-second ramping time, representing slow response parameters.

[REDACTED SECTION]

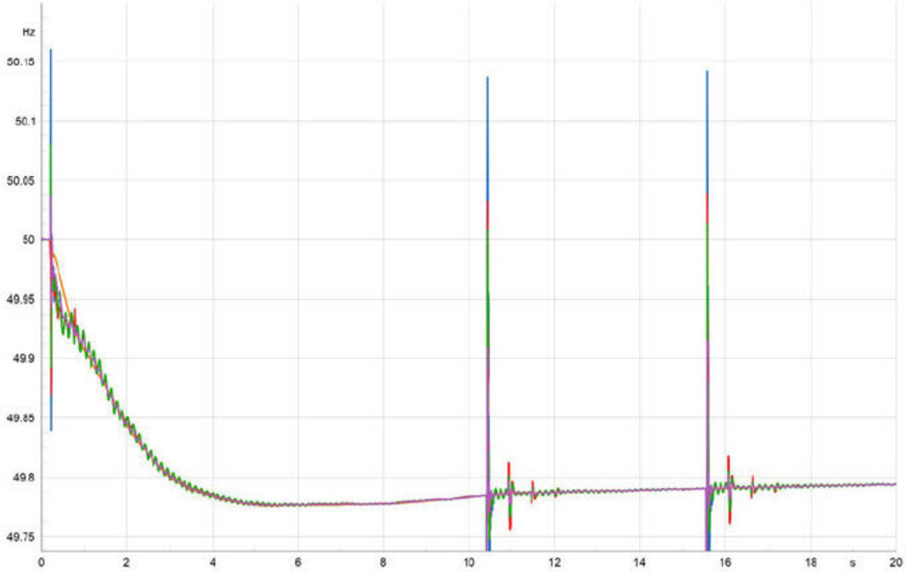


[REDACTED SECTION]



[LEGEND REDACTED]

[REDACTION]



[LEGEND REDACTED]

FRCR 2024 Implementation – additional 100MW DC-L procurement

Date Issued:	14/10/2024	Last Updated:	
Status:	NEW		
Contact(s):	[NAME REDACTED], Frequency Risk and Modelling		

Background

FRCR 2024 policy recommend to:

- Maintain the minimum inertia requirement at 120 GVA.s.
- Secure all BMU-only risks as baseline.
- **Apply additional Dynamic Containment - Low (DC-L) requirement to further reduce residual risks.**

Ofgem approved FRCR 2024 policy recommendations on Friday 27th September 2024.

More details on FRCR can be found in BP1882. QMS - BP1882 - Frequency Risk and Control Report (FRCR) – Policy.pdf

Implementation of FRCR 2024

- Implementation is planned on the procurement date of **Wednesday 16th October 2024** for the delivery on **17th of October 2024.**
- There are **no changes / impacts** to ENCC process from this implementation. The additional DC-L will be procured from the day-ahead auction.
- There are **no tools update needed** for frequency-related process, [REDACTED]

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RAPID – Increase DR Cap to 500 MW

20/11/2024

[NAME REDACTED]

Frequency Risk and Modelling

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RAPID

- **Recommend:** [ALL NAMES REDACTED FROM SLIDE]
- **Agree:**
- **Perform:**
- **Input:**
- **Decide:**

Objectives

- **Introduce and review the Dynamic Regulation (DR) cap review process, methodology and assumptions**
- **Propose to lift the DR cap from current 330 MW to 500 MW to remove the blockers to future policies**

Background

- More violent frequency trends forced CR to procure more MFR
- Current DR capped at 330 MW due to analysis performed back in 2021 – adopted very conservative and unrealistic assumptions, i.e. 10 GW demand, 110 GVA.s inertia and all DR in one substation in Scotland

Can we trust OLTA as the tool?

- It has been raised that there are some oscillating interactions (1 – 5 ms cycle time) among controllers within the OLTA master model. These have been assessed by Network Operability team and is irrelevant to Dx services.
- There are also frequency spike issues which are caused by non-convergent load-flow calculations. These are also irrelevant to Dx services so can be ignored.
- For any types of issues we observe within the study, we can tell if it is linked to Dx services by:
  - They appear and get worse with larger Dx capacities
  - They disappear with no Dx service

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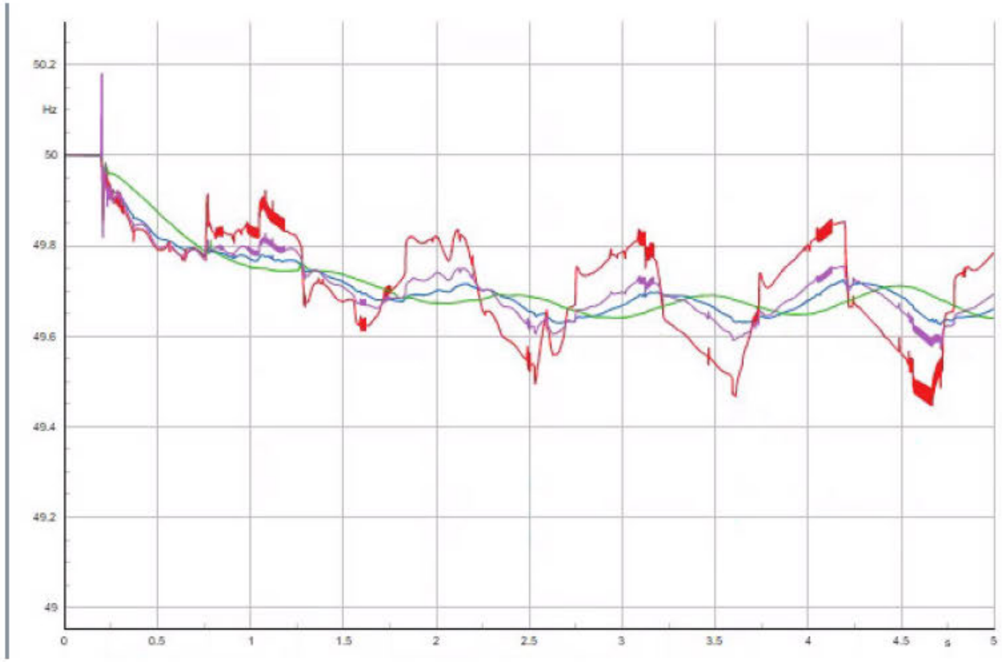
Why we need a DR cap?

- Two main concerns over DR:
  - By design DR is slow service with up to 2 seconds delay – more likely to cause overshooting and oscillations
  - Without regional procurement rules, large amount of DR centralised in a small area can cause oscillations



Frequency traces measured in E&W and Scotland

What methodology?

- In the previous study, swing equation based model and OLTA model were both used
- After consulting Network Operability team, the OLTA master model is selected in the study
- The same methodology is used but assumptions are updated
- [REDACTED BULLET POINTS]

What methodology?

- **The methodology can be summarised as below flowchart**

Choose TAE model for system configuration, system conditions and generation patterns

Setup the OLTA project with DCDMDR model

Trip a generation/demand to stimulate dynamic responses

Observe the frequency trends and tell if stable or not

Why consider 500 MW as the new DR cap?

- We do not have the mathematical model to work out the theoretical cap
- The study is based on one basic assumption:
  - If 500 MW is assessed to be stable in all scenarios, then any DR volumes below 500 MW will be safe
- This is a try & error study, we considered 500 MW and 700 MW. 700 MW sometimes can cause oscillations in some scenarios

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How to define study scenarios

- We want to choose scenarios to reflect realistic worst case scenarios
- Things to be defined in a scenario:
  - System conditions: inertia level, demand level, network topologies, generation patterns
  - Volumes of DCDMDR
  - Location of DCDMDR
  - Technical parameters of DCDMDR
  - Trips of BMU/demand

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System conditions

- No demand inertia or demand damping considered
- Scotland inertia tuned to around 10%, 12 GVA.s

Selected date: 2024-04-07 04:30 am

Import generation & demand from relevant TAE project

TSD = 21,397 MW

LSLC inertia tuned to 120 GVA.s

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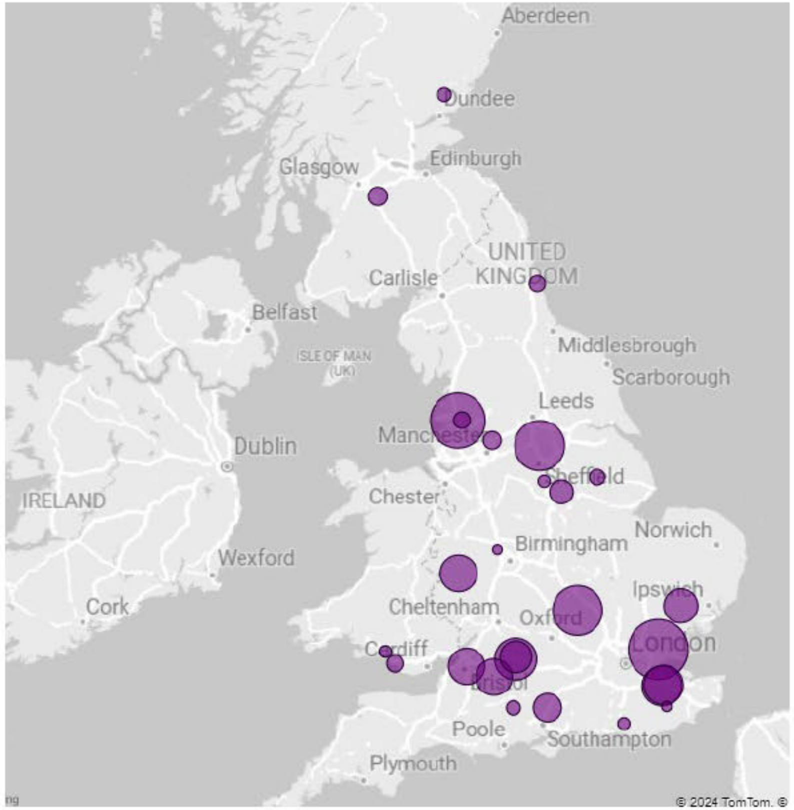
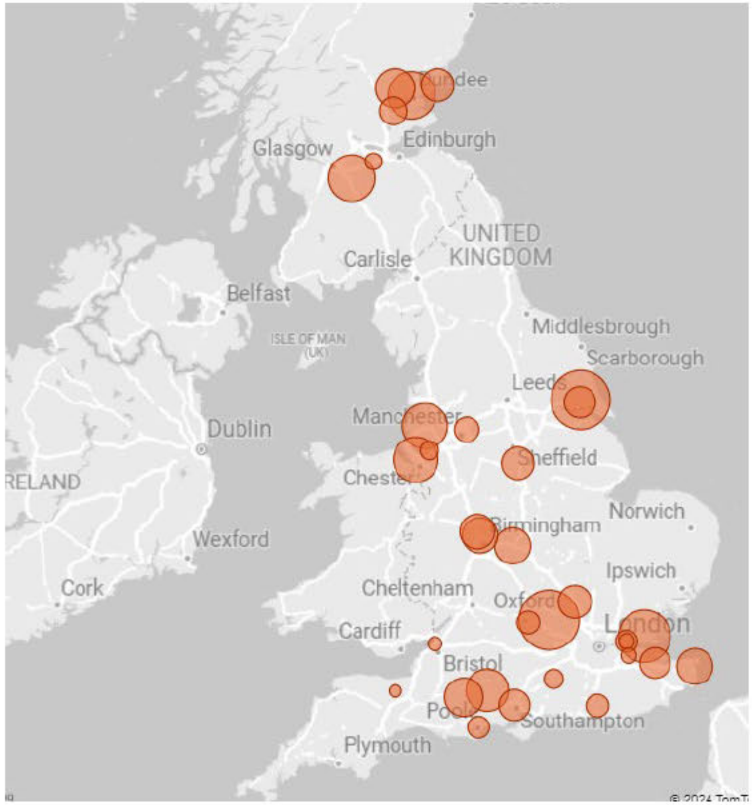
Historical location for DR & DC

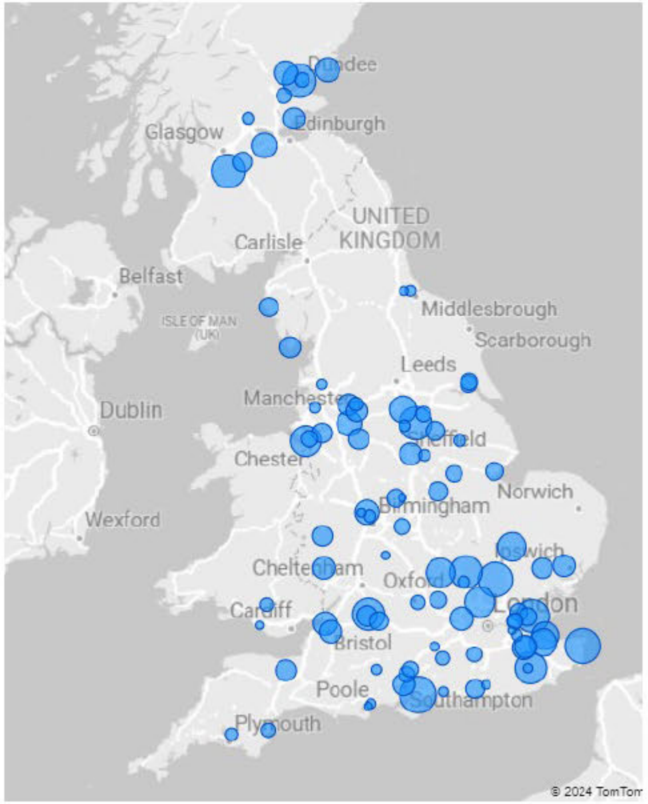
DRL



DRH



DCH/L



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Historical facts for DRDMDC

- Historical data shows only up to 18% DCDMDR procured in Scotland
- Procurements are distributed in multiple substations, no obvious centralisations
- All DR providers are battery units, in theory they can provide fast DR service with 0.5 second delay and 0.5 second ramping time
- Currently DM requirement is 200 MW, DC requirements are varying on day-to-day basis but peak volume hit 1400 MW

[CONTENT REDACTED]

Extended cases

Scenario name	Base case	More slow DR	More in Scotland
DC volume	1400 MW	1400 MW	1400 MW
DM volume	200 MW	200 MW	200 MW
DR volume	500 MW	500 MW	500 MW
Scotland volume [REDACTED]	25%	25%	50%
E&W North volume [REDACTED]	25%	25%	0
E&W South volume [REDACTED]	50%	50%	50%
Slow DR percentage (2 second delay + 8 second ramping)	20%	50%	20%

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Trigger of frequency deviation

- In the previous study, trips of I/C with high/low flows and [REDACTED] were used to trigger frequency deviation
- However, in this review we only consider small MW trips due to:
  - Since we are focusing on DR cap review so consider smaller MW trips between 300 MW and 500 MW
  - [REDACTED] trip is not considered as it does not cause active power imbalance.
- [REDACTED]

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List of test scenarios

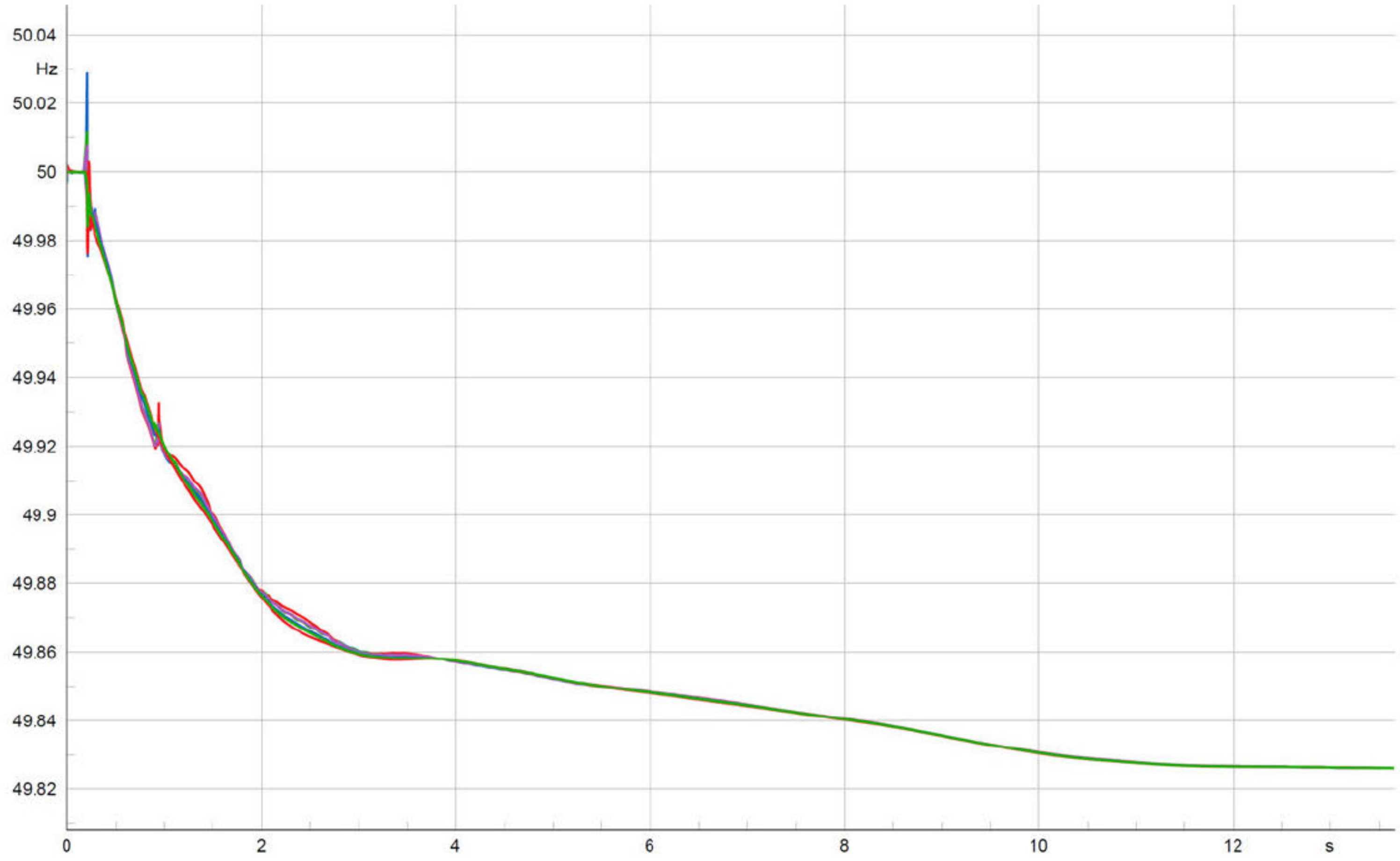
Scenario	Loss level (MW) +tive for gen loss -tive for demand loss	Oscillating?
1	500 MW followed with 150 MW ramping in 10 second	N
2	400 MW followed by 150 MW ramping in 10 second	N
3	300 MW followed by 150 MW ramping in 10 second	N
4	500 MW followed by -150 MW ramping in 10 second	N
5	400 MW followed by -150 MW ramping in 10 second	N
6	300 MW followed by -150 MW ramping in 10 second	N
7	-500 MW followed by 150 MW ramping in 10 second	N
8	-400 MW followed by 150 MW ramping in 10 second	N
9	-300 MW followed by 150 MW ramping in 10 second	N
10	-500 MW followed by -150 MW ramping in 10 second	N
11	-400 MW followed by -150 MW ramping in 10 second	N
12	-300 MW followed by -150 MW ramping in 10 second	N

Conclusion

- The study results are attached in the appendix
- Results indicate that if we lift DR volume to 500 MW, it will not cause stability issues in the system
- Therefore, it is recommended to lift the DR cap to 500 MW.

Results – scenario 1: stable

500 MW followed with 150 MW ramping in 10 second



[LEGENDS REDACTED ON THIS AND SUBSEQUENT SLIDES]

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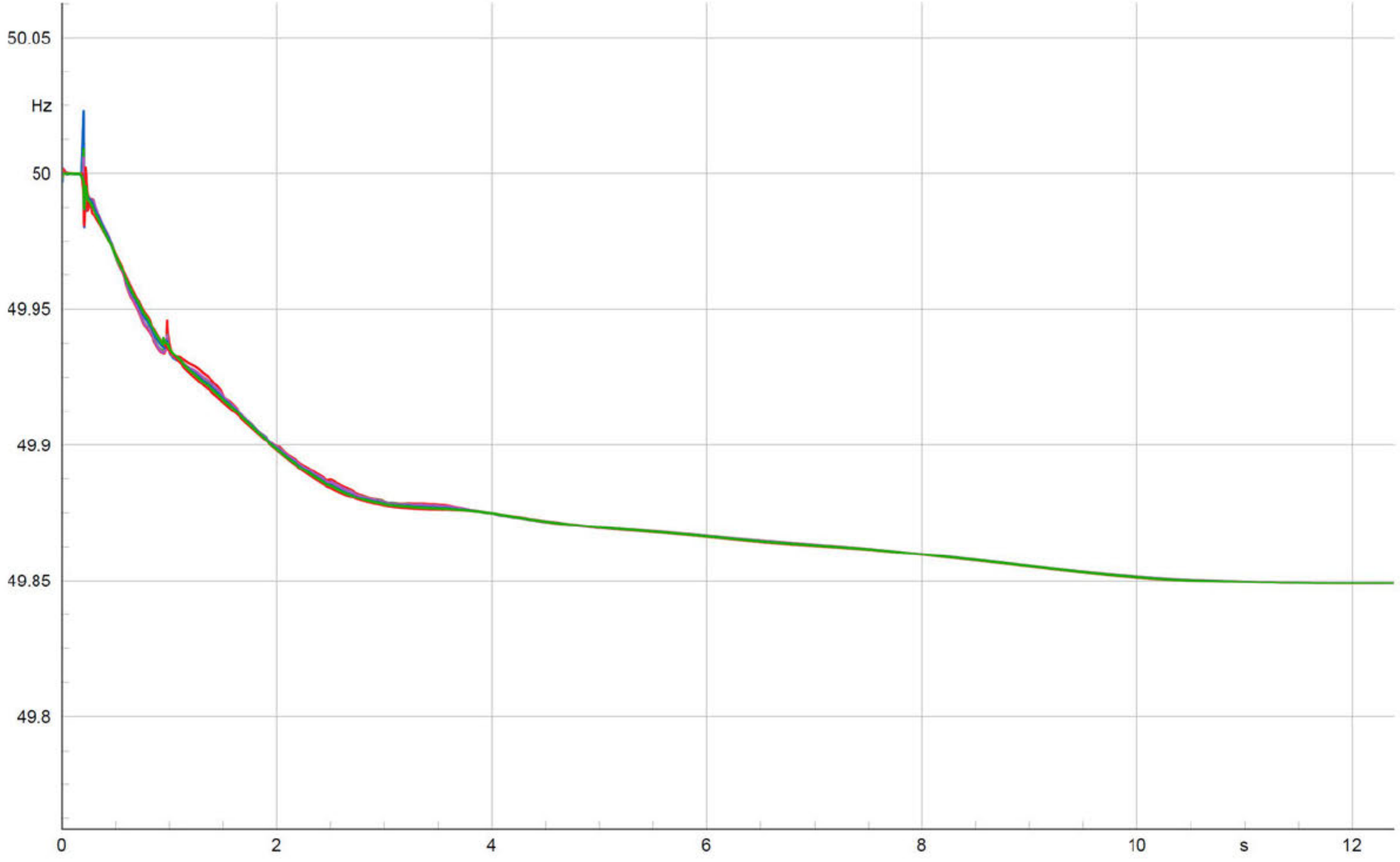
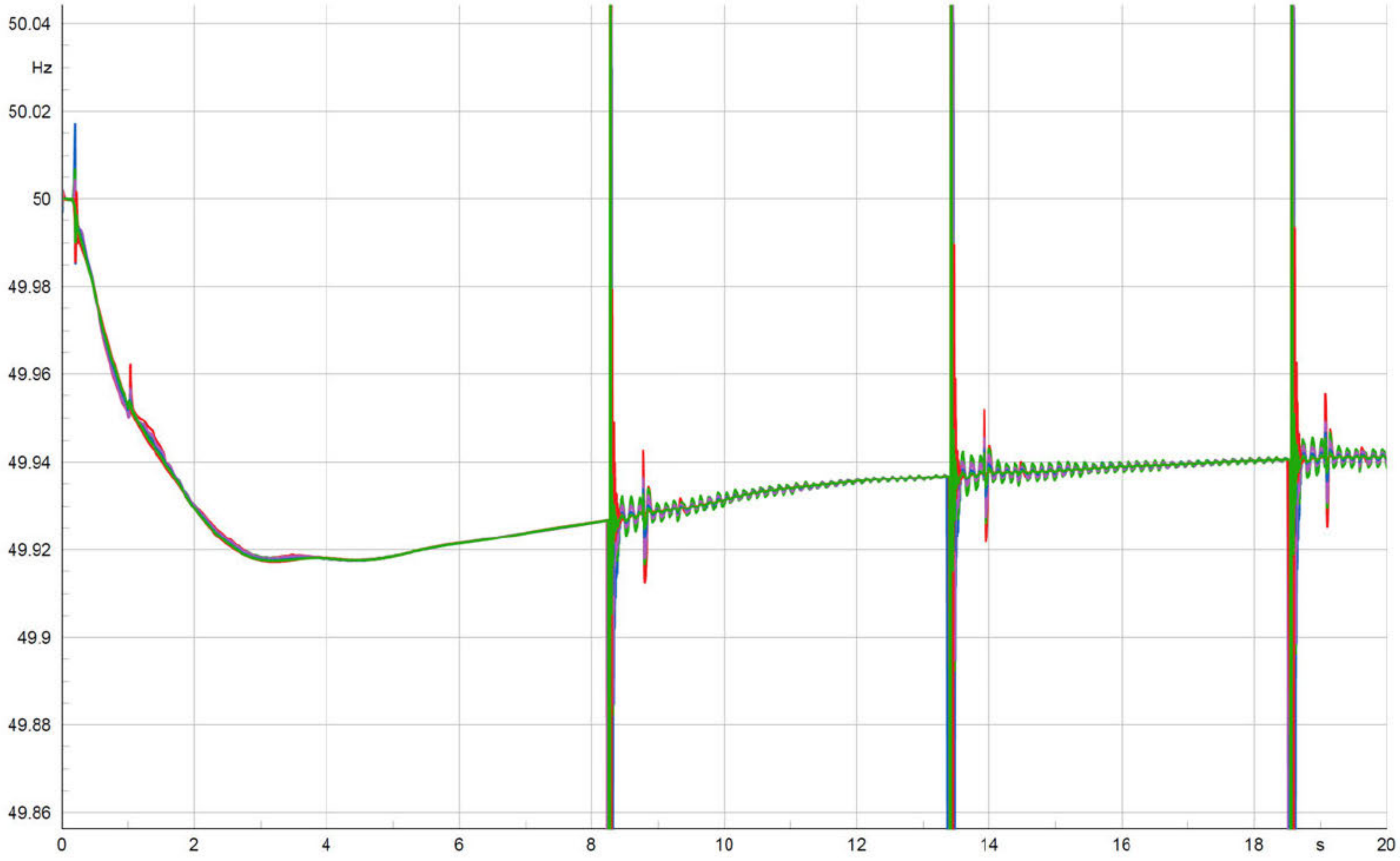
Results – scenario 2: stable

400 MW followed with 150 MW ramping in 10 second



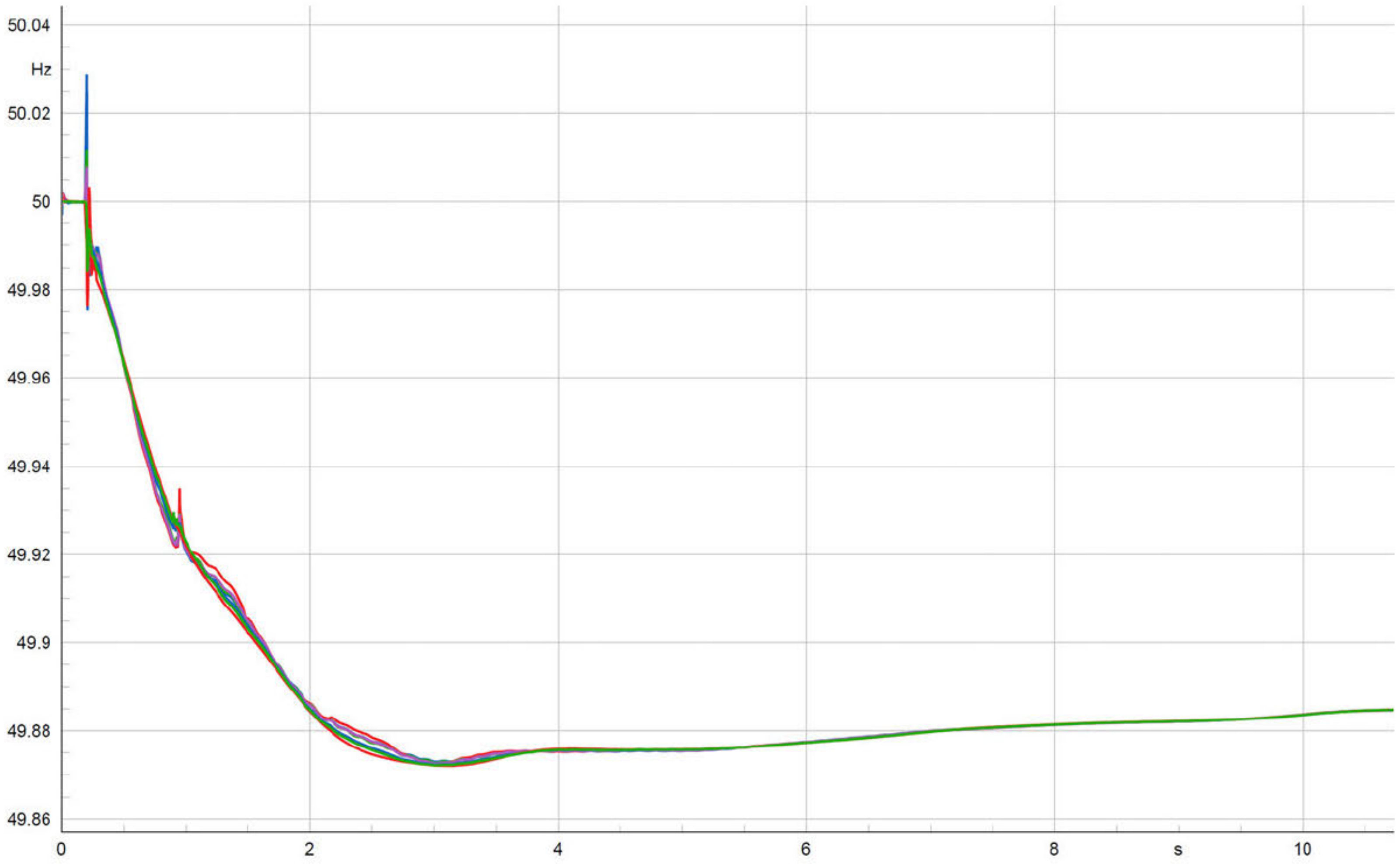
Results – scenario 3: stable

300 MW followed with 150 MW ramping in 10 second



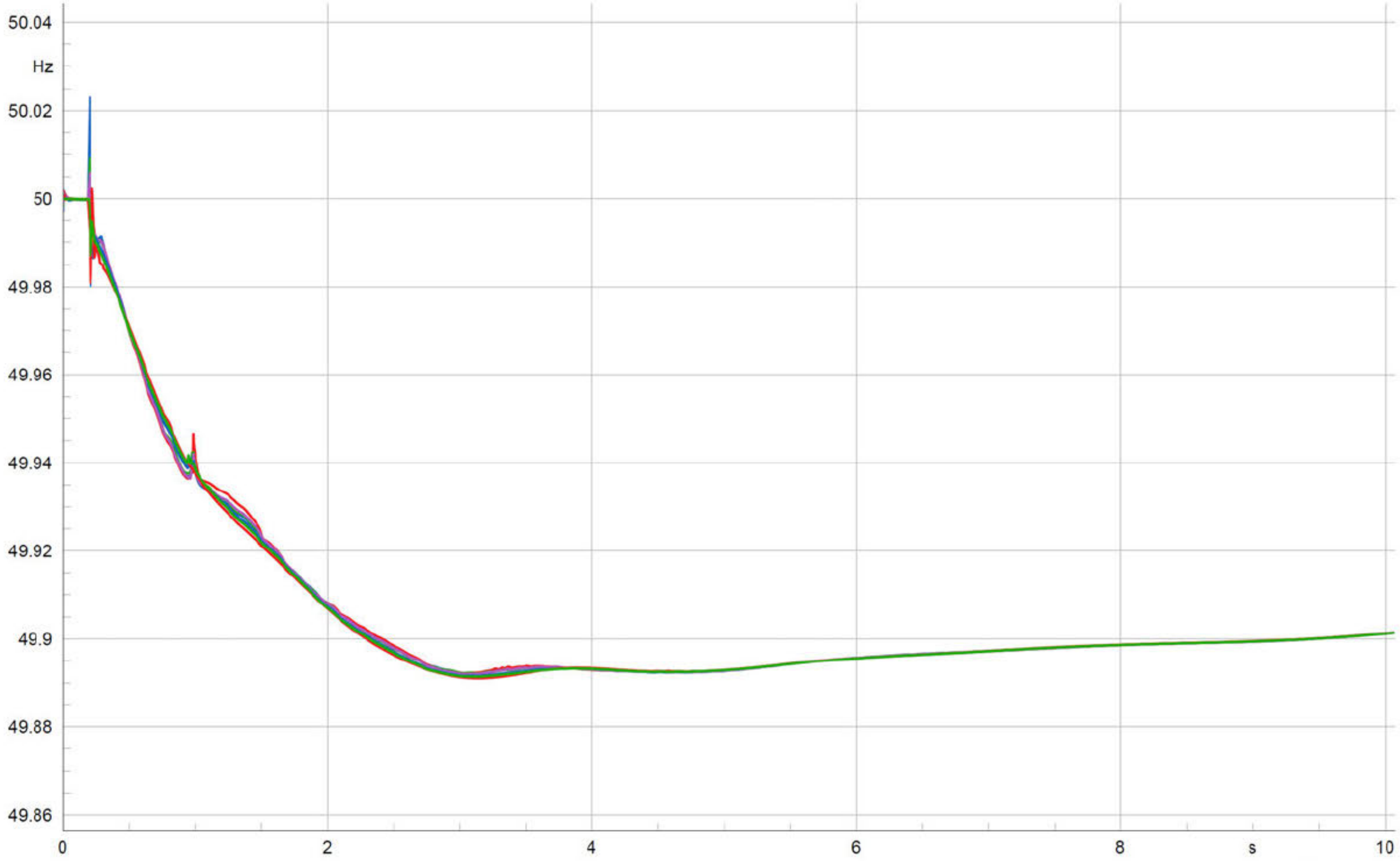
Results – scenario 4: stable

500 MW followed with - 150 MW ramping in 10 second



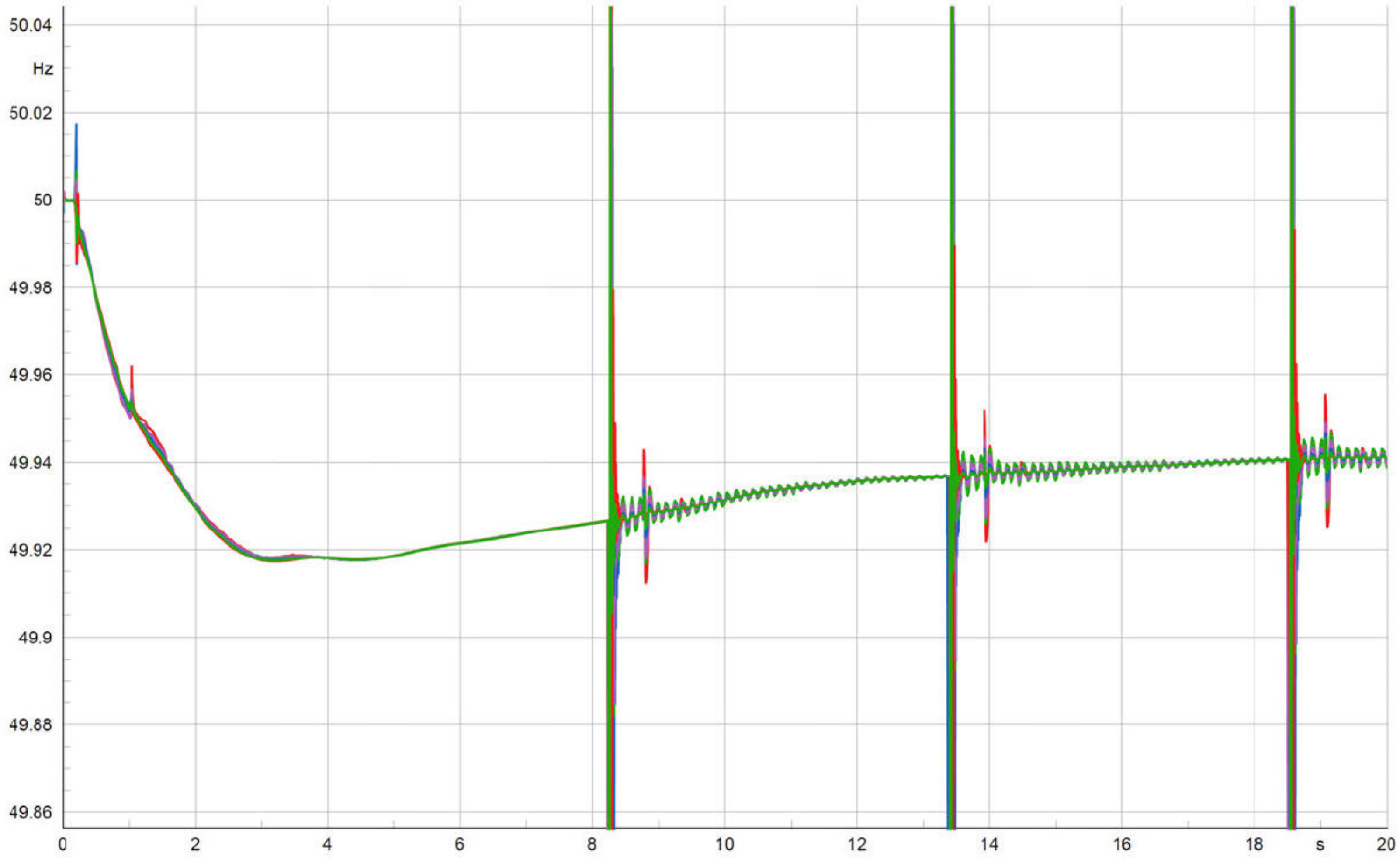
Results – scenario 5: stable

400 MW followed with -150 MW ramping in 10 second



Results – scenario 6: stable

300 MW followed with -150 MW ramping in 10 second



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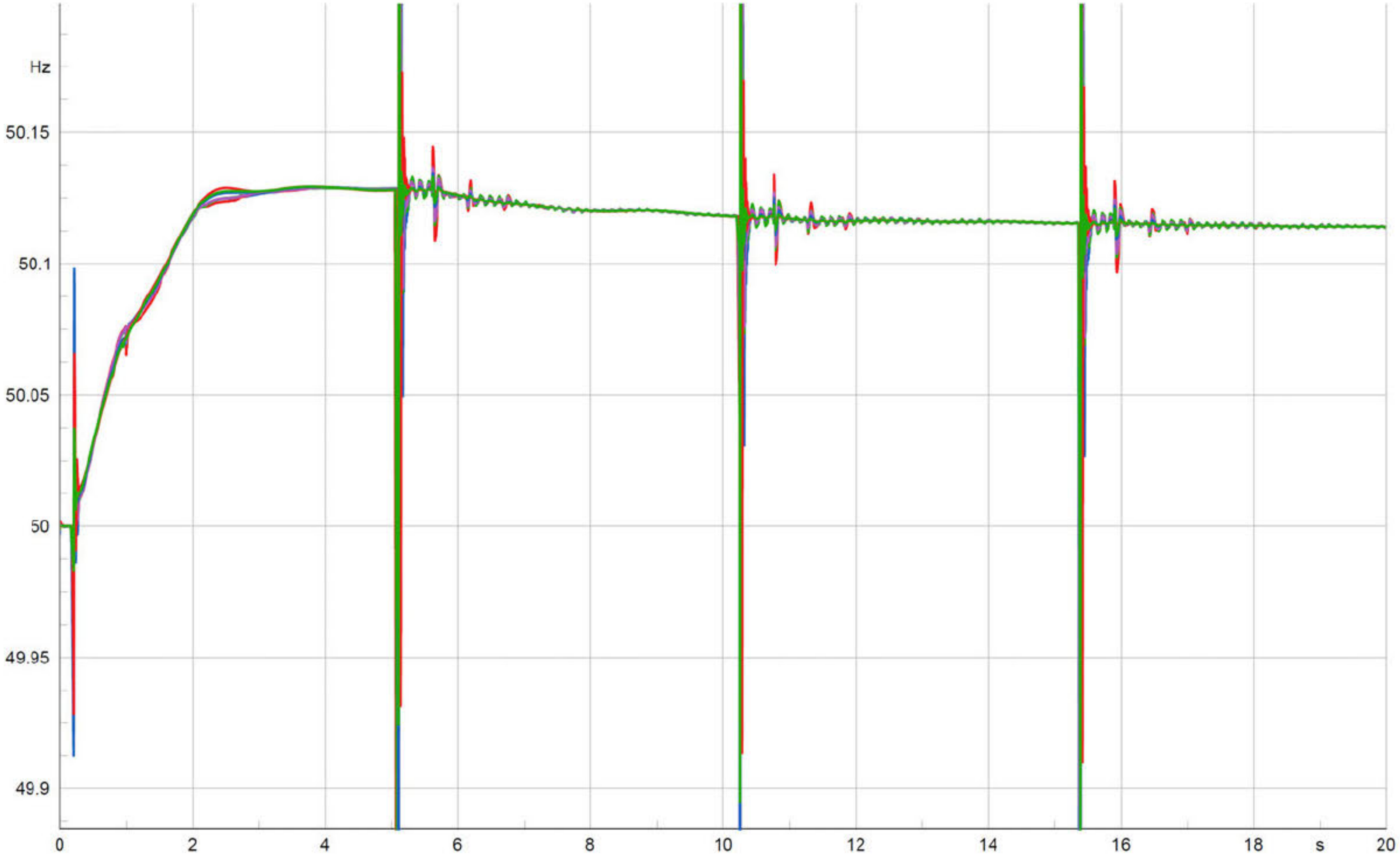
Results – scenario 7: stable

−500 MW followed with 150 MW ramping in 10 second



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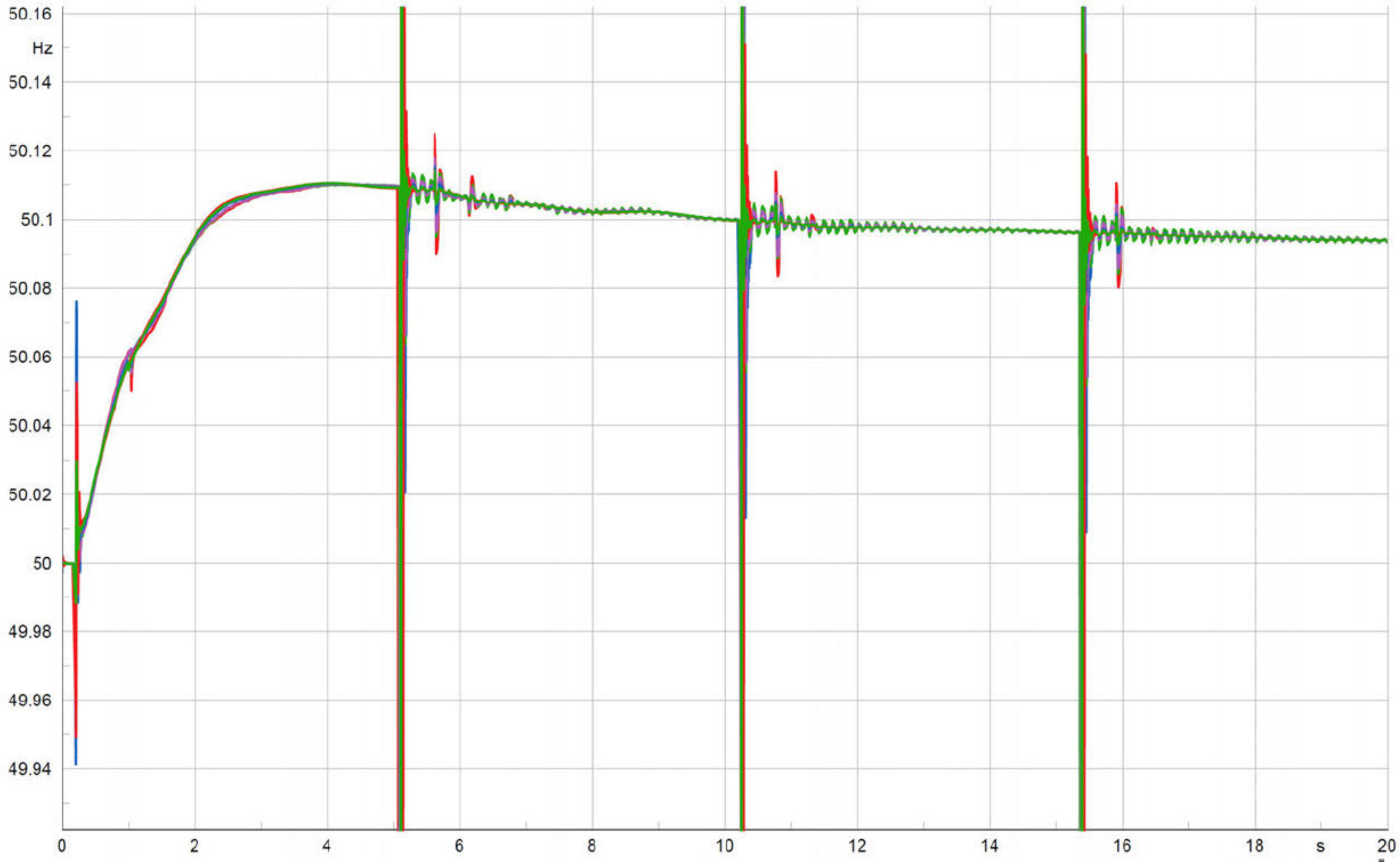
Results – scenario 8: stable

-400 MW followed with 150 MW ramping in 10 second



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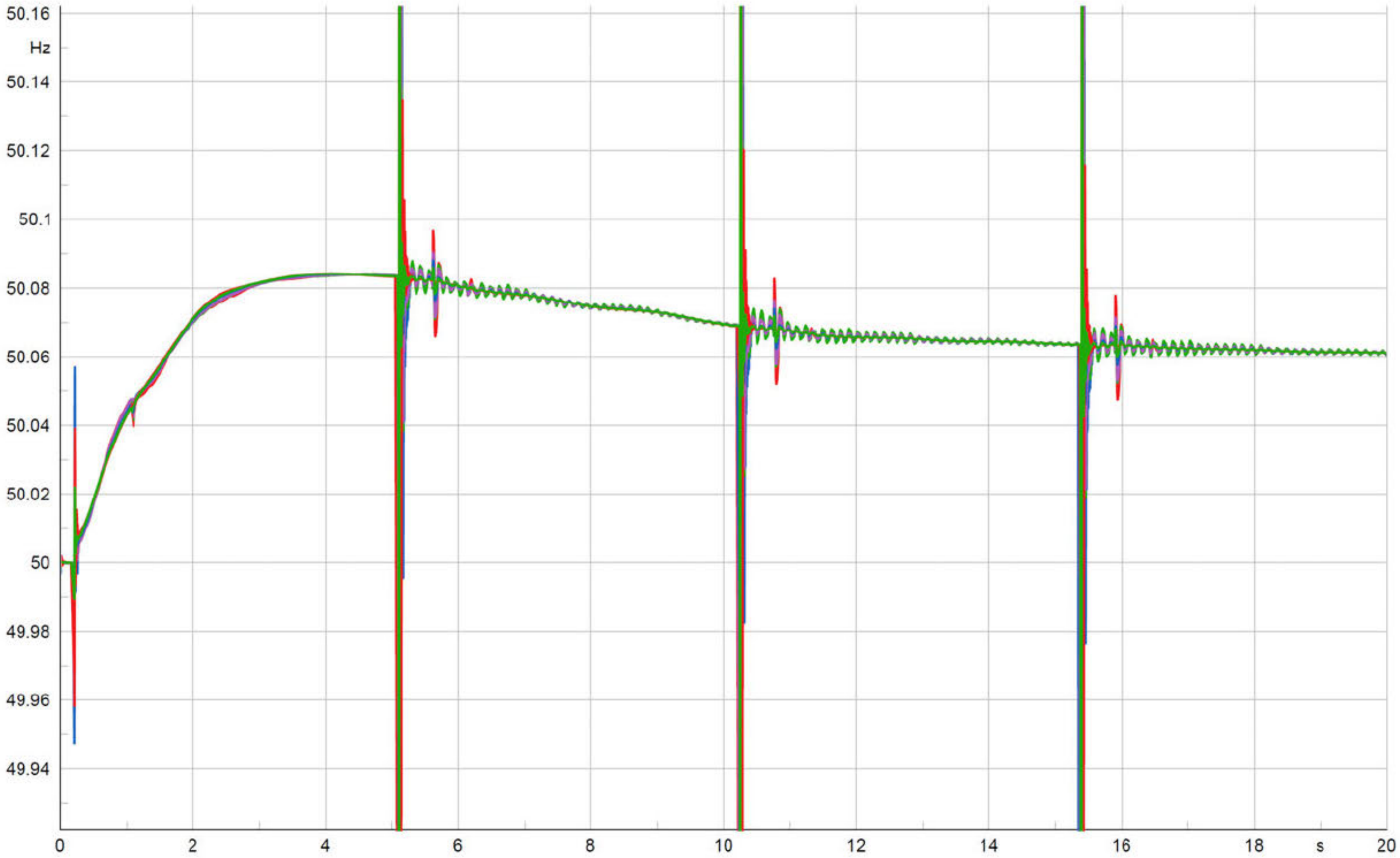
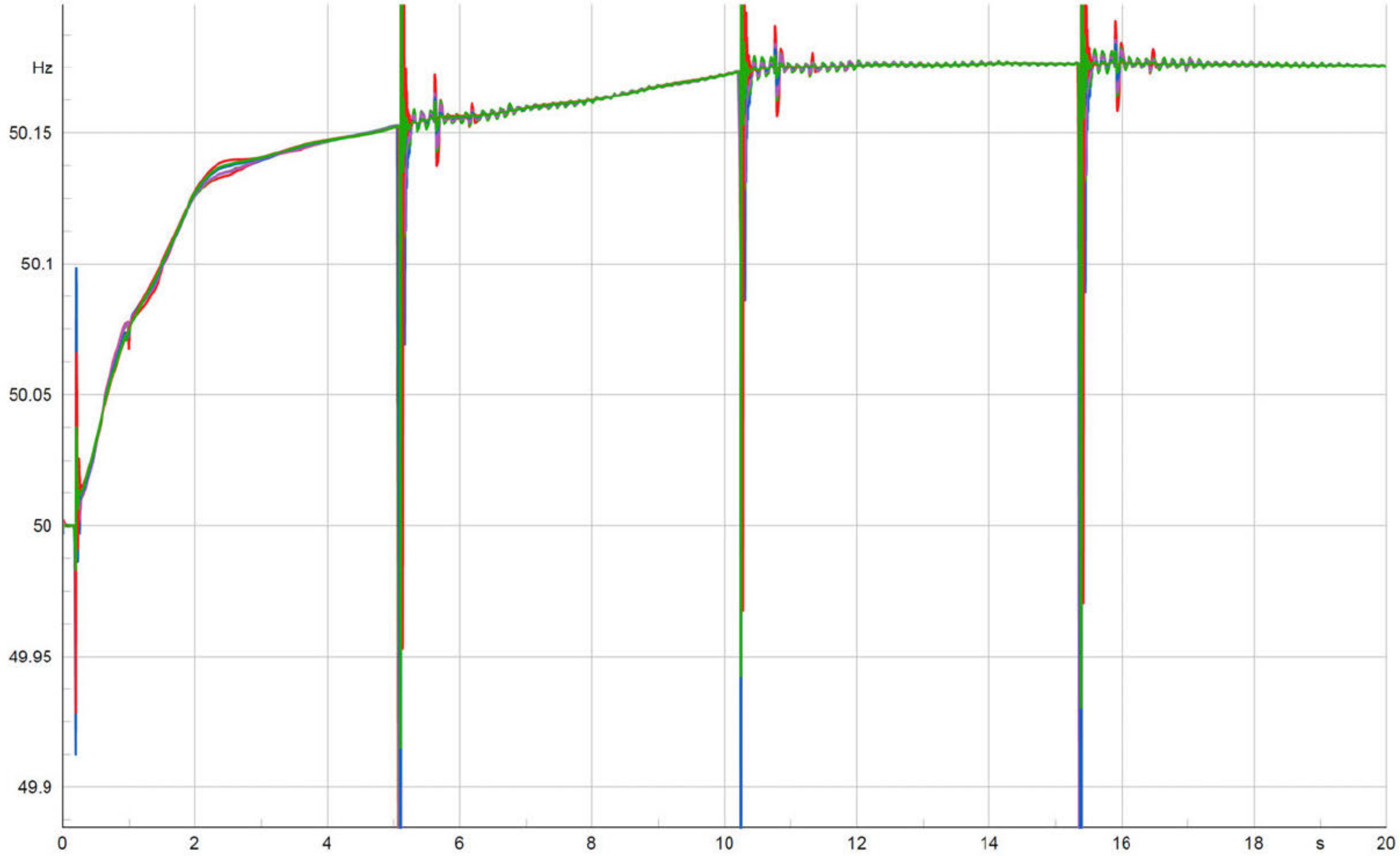
Results – scenario 9: stable

−300 MW followed with 150 MW ramping in 10 second



Results – scenario 10: stable

−500 MW followed with -150 MW ramping in 10 second



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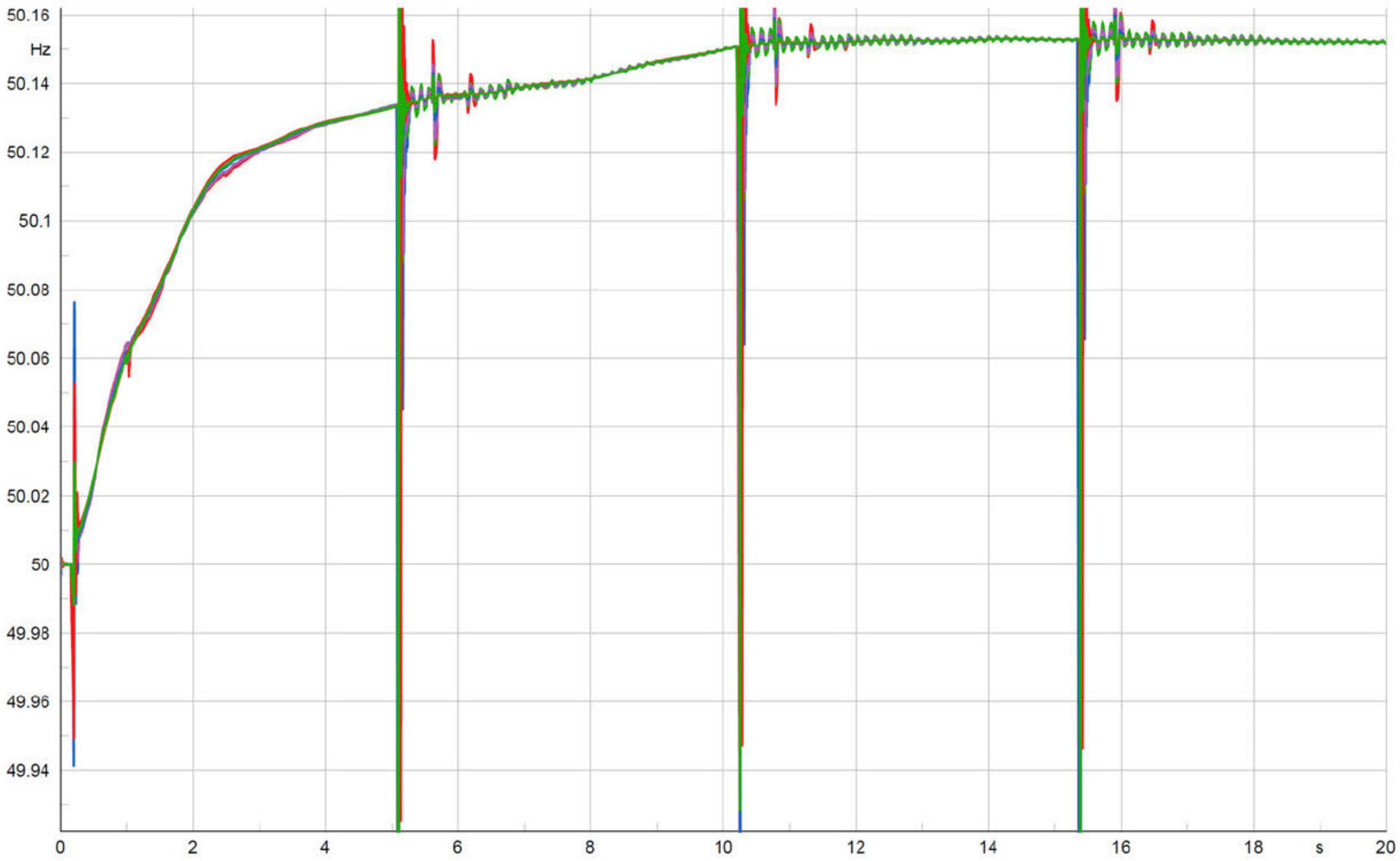
Results – scenario 11: stable

−400 MW followed with -150 MW ramping in 10 second



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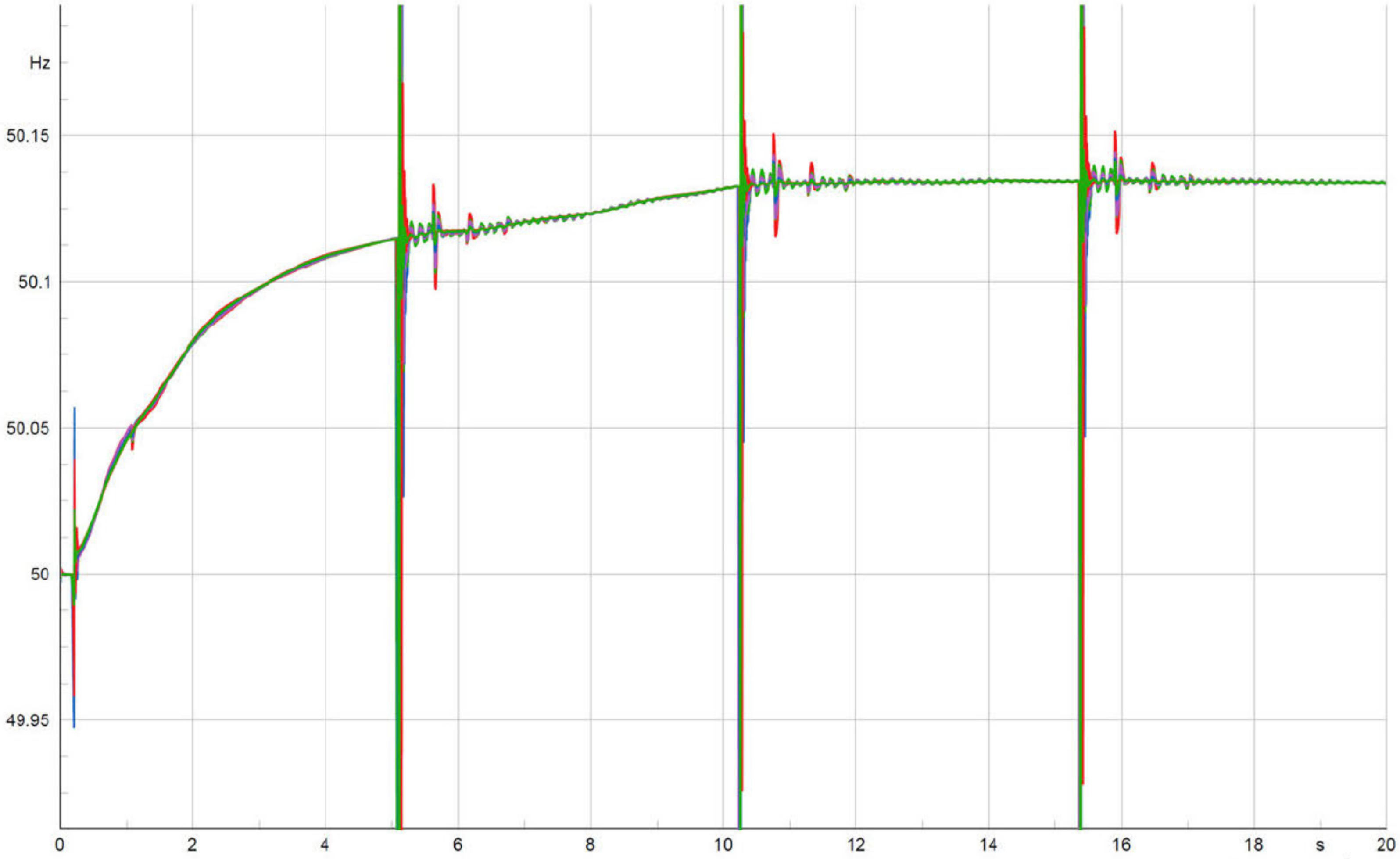
Results – scenario 12: stable

−300 MW followed with -150 MW ramping in 10 second



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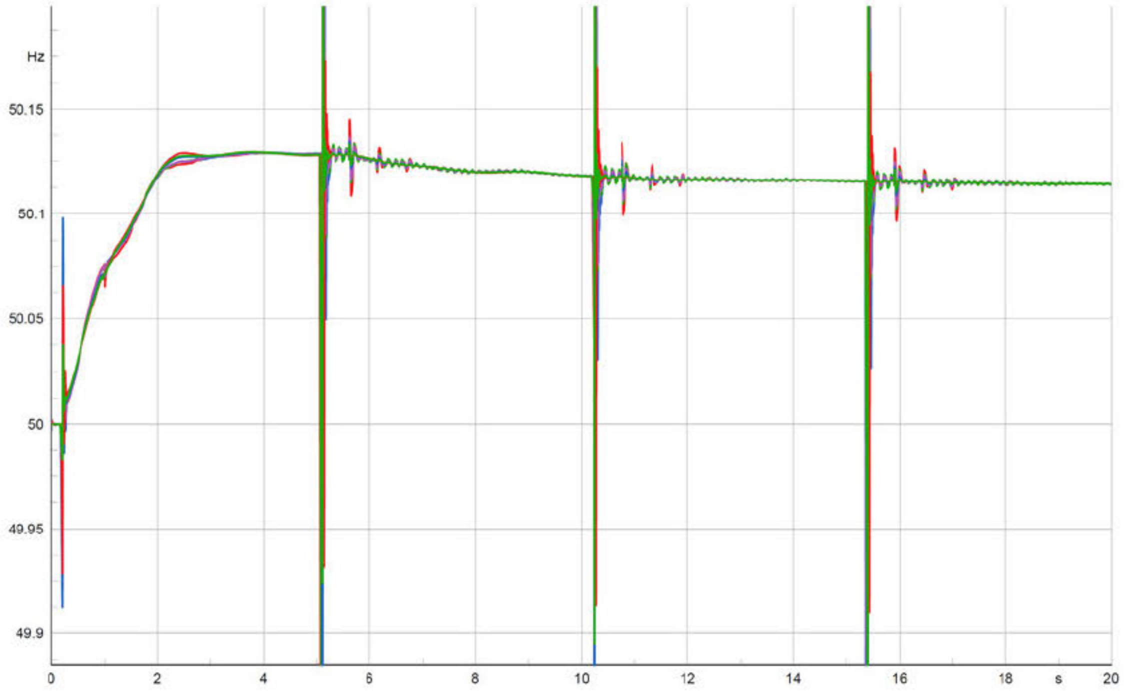
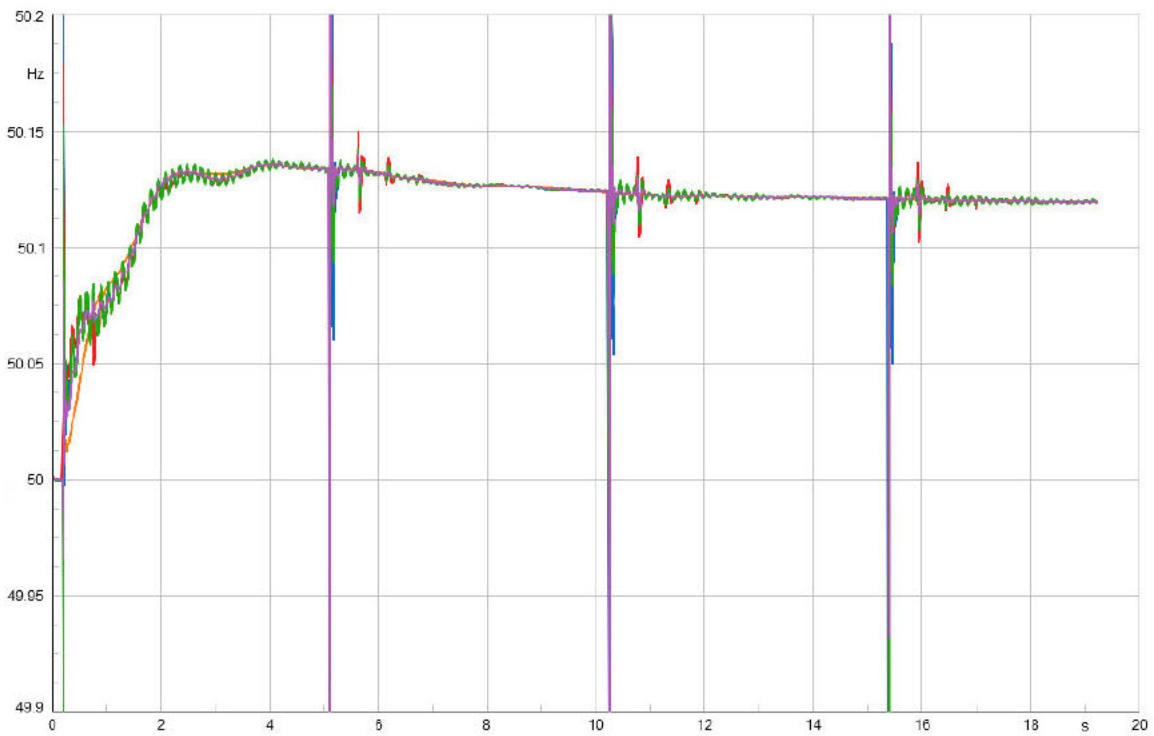
−500 MW followed with 150 MW ramping in 10 second



[REDACTION]



[REDACTION]

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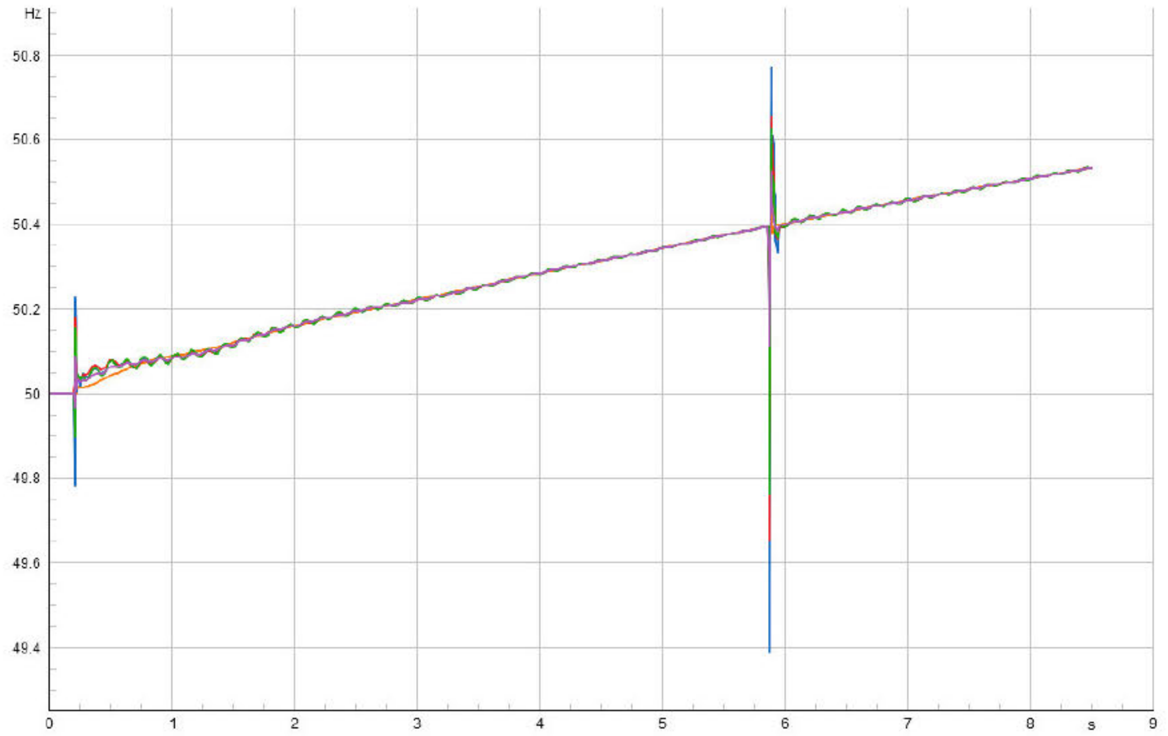
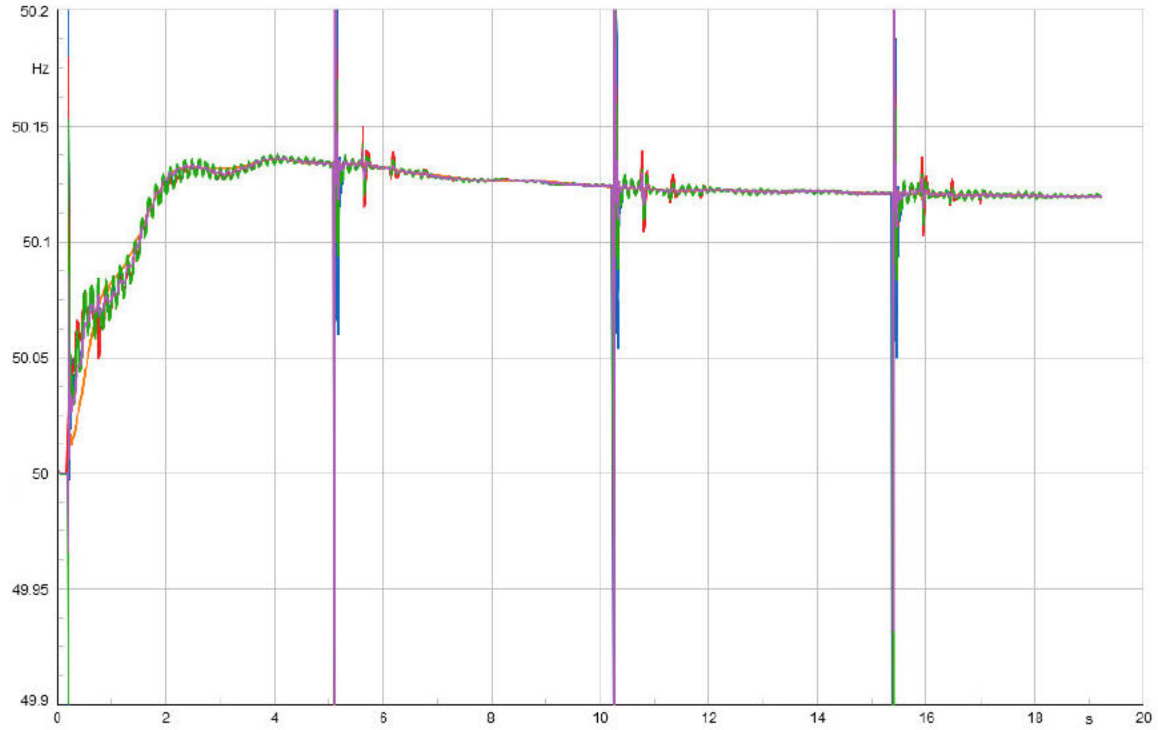
−500 MW followed with 150 MW ramping in 10 second



[REDACTION]



[REDACTION]

This comparison illustrates that the sub-synchronous oscillation at the start and the spikes are not related to the Dx units.

Internal Use Only

RAPID – Lift DM Requirements To 300 MW

RAPID

- Recommend: [REDACTED]
- Agree: [REDACTED]
- Perform: [REDACTED]
- Input: [REDACTED]
- Decide: [REDACTED]

Please note that due to operational needs, the proposal Dynamic Moderation lift has been brought forward to 3rd Feb, Monday. The auction will occur on 2nd Feb, Sunday.

The impacted tools will be updated on 6th Feb, Thursday. No operational impacts are expected due to the delayed tool updates as the plan to increase dynamic frequency response volumes are relevant to pre-fault services only.

Aim

- Obtain approval for the implementation of 300 MW Dynamic Moderation (DM) requirements from 3th of February (auction happening on 2nd of February), and operational tools to be updated on 6th of February.

What is the problem?

ENNC has expressed their concerns regarding system volatility and uncertainties within operational limits, highlighting the necessity for increased volumes of dynamic frequency response to prevent potential frequency events that could exceed operational limits. Operational requirements demand an immediate enhancement of pre-fault frequency response services, thereby prioritising the increase of frequency response volumes of Dynamic Moderation and Regulation.

What is the decision?

To increase the frequency response requirements for DM to 300 MW for Low and High in parallel to the pre-approved DR requirements increase from 3th of February (auction happening on 2nd of February), and operational tools to be updated on 6th of February.

RAPID – Lift DR Requirements To 480 MW

#	Date	Author	Reviewer	Draft/Final	Change since previous version
1	14/01/2025	REDACTED		Draft	
2	22/01/2025	REDACTED	REDACTED	V1	Include implementation plan and cost analysis.
3	31/01/2025	REDACTED		Final	Reflect new implementation date due to operational needs

RAPID

- Recommend: REDACTED
- Agree: REDACTED
- Perform: REDACTED
- Input: REDACTED
- Decide: REDACTED

Please note that due to operational needs, the proposal DR lift has been brought forward to 3rd Feb, Monday. The auction will occur on 2nd Feb, Sunday.

Communication with industries will commence on 5th Feb, Wednesday.

The impacted tools will be updated on 6th Feb, Thursday. The delayed updates in relevant tools will not have any impacts on system security. The existing tools will continue to work while system security will be improved as we are over-procuring both pre-fault and post-fault responses.

Aim

- Obtain approval for the implementation of 480 MW DR requirements from 13th February, Thursday (auction happening on 12th February, Wednesday, tools to be updated at around 11 am, on 12th February).

Background

In recent years, the GB frequency performance has increasingly deviated from the standard 50 Hz, resulting in more volatile performance. The frequency deviations exceeding ± 0.1 Hz have risen from 5% in 2018 to approximately 10% in 2024. This reduces CR's confidence in containing the frequency within operational range and will result in higher MFR procurements due to lack of confidence. Dynamic Regulation (DR) is a service primarily designed to smooth pre-fault frequency and maintain it within operational limits of ± 0.2 Hz.

Internal Use Only

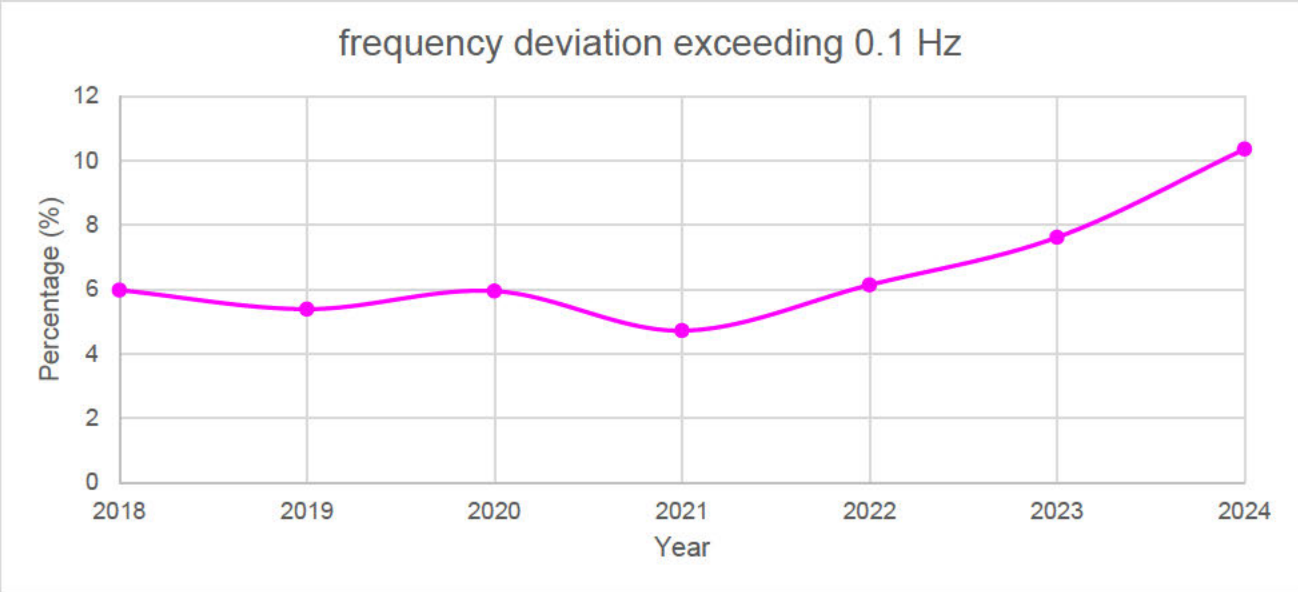
Currently, DR is capped at 350 MW based on an analysis conducted in 2021. Since January 2024, the daily DR requirements have been fixed at 330 MW.

A recent study on the DR cap concluded that the cap can be increased to 500 MW without compromising stability. The FRM team has developed a methodology to simulate system frequency behaviour considering varying system conditions and response holdings. Simulation results indicate that increasing the DR volume can enhance frequency performance by reducing instances of deviations beyond $\pm$0.1 Hz to around 6%, similar to the levels seen in 2018. To achieve this objective, an additional 150 MW of DR is required. On 9th Jan 2025, this methodology and proposal for additional 150 MW DR have been presented to ESG. ESG has agreed to the proposal.

Therefore, this paper seeks approval to increase the DR requirements from the current 330 MW to 480 MW for both DR-High and DR-Low.

What is the problem

The analysis examines the frequency deviations from 2018 to 2024. The figure below shows that frequency deviation exceeding $\pm$0.1 Hz was stable at around 5-6% between 2018 and 2022. However, this worsened from 2023, reaching above 10% in 2024. Consequently, the Control Room sees more volatile frequency behaviour. [REDACTED]



How the proposal is derived

FRM has adopted a methodology to evaluate the effectiveness of the proposal, which has been presented to ESG with their concurrence. The methodology can be summarized as follows:

- Employ the Frequency Simulation Engine (FSE) to estimate historical imbalances based on past system conditions (such as demand and inertia levels), actual response holdings (DCDMDR and MFR), and historical frequency measurements.
- Simulate the new frequency trend using a revised set of response holdings, while maintaining the same system conditions.
- Evaluate the improvement of the new frequency trend in comparison to the historical frequency trend.

Using this methodology, simulations conducted for data from January 2024 to December 2024. The primary reason for selecting this timeframe is that FFR was fully phased out by December 2023, and the DR requirement has been established from January 2024 onwards.

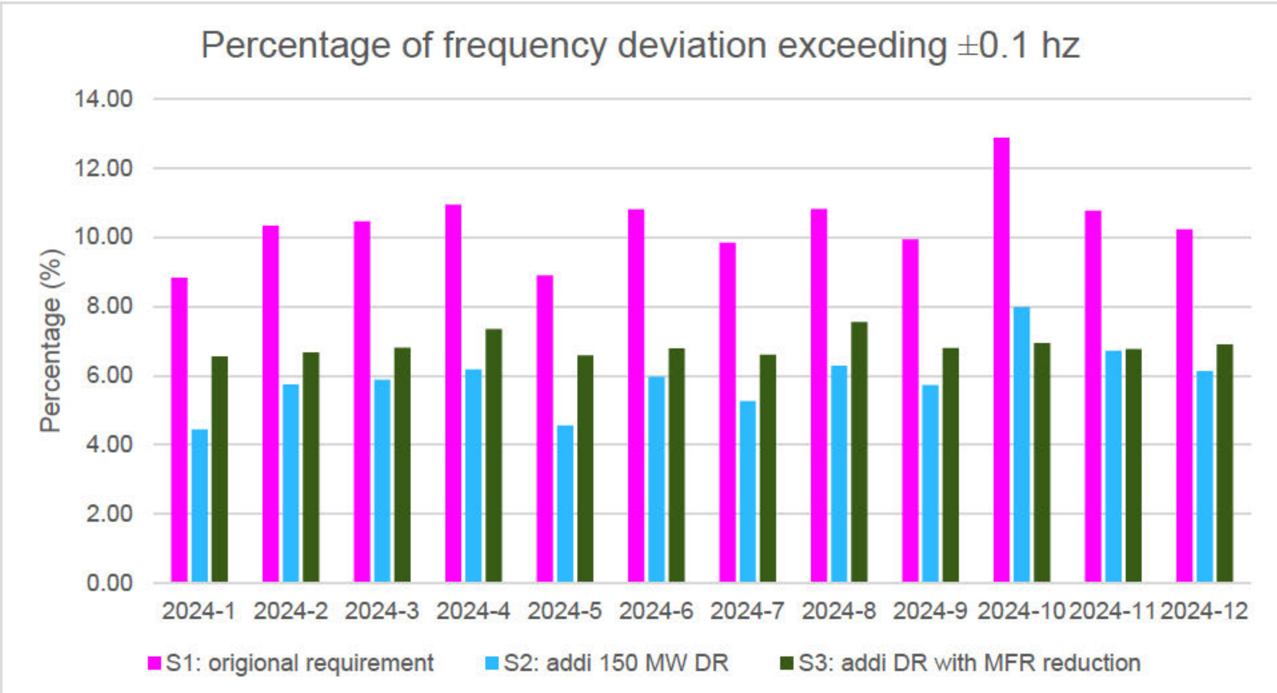
Internal Use Only

In order to bring the frequency performance back to the 2018 level, the study analysed monthly frequency performance from January to December 2024. It compared frequency deviations exceeding ± 0.1 Hz under different scenarios, as defined in below table. Scenario 1 is the base case where historical response holdings were adopted. Scenario 2 is used to assess if additional 150 MW DR is employed. Scenario 3 is derived from scenario 2 but considers the removal of excessive MFR. The excessive MFR is defined as any MFR procured on top of the 550 MW minimum dynamic requirements, which will be offset by DR first.

Scenario	DR	DM	DC	MFR
1	historical procurements	historical procurements	historical procurements	historical procurements
2	historical procurements + Additional 150 MW	historical procurements	historical procurements	historical procurements
3	historical procurements + Additional 150 MW	historical procurements	historical procurements	historical procurements – excessive MFR

The figure below presents the simulated frequency performance measuring the percentage of instances where the frequency deviation could exceed ± 0.1 Hz. S1 is the base case showing the frequency performance with historical response holdings including MFR procurements. With S2, an additional 150 MW DR is procured on top of the historical response holdings. By comparing the S1 and S2, the average percentage of instances where frequency deviation exceeding ±0.1 Hz drops from 10.39% to 5.90%, with a 43.2% reduction.

In S3, the excessive MFR is removed from historical response holding, while the additional 150 MW DR is still procured. The excessive MFR is determined by checking if MFR is procured exceeding the minimum dynamic requirements of 550 MW. This scenario is used to assess the potential impacts of implementing 480 MW DR requirements when MFR is less utilised. The simulation results indicate that there is very minor reduction in the performance comparing S2 and S3, leaving the percentage of instances where frequency deviation exceeding ±0.1 Hz drops from 5.90% to 6.86%, increased by 16.2%. This indicates that with the implementation of 480 MW DR, the Control Room should see a improved frequency performance and the removal of MFR should not cause the performance to differ too much.



What is the saving

The saving is estimated with the current market status and is based on historical MFR procurements. With the implementation of 480 MW DR, the estimated cost is:

$$Cost_{DR} = 150\ MW * \left(Price_{DR-Low} + Price_{DR-High}\right) * 24h * 365\ days$$
$$= 150MW * (£8.33/MWh - £4.63/MWh) * 24h * 365days = £4.68m$$

The price of DR used in the above equation is from FRCR 2025 model.

[REDACTED SECTION]

The potential saving is estimated as the excessive MFR being replaced by additional 150 MW DR. The saving is estimated as:

$$Saving_{MFR} = (Average\_Primary\_Volume * Price_{MFR-Low} + Average\_High\_Volume * Price_{MFR-High}) * 24h$$
$$* 365days = (80.5MW * £26.35/MWh + 209MW * £9.65/MWh) * 24h * 365days = £36.25m$$

The MFR-Low/High price is inline with the FRCR 2025 model.

The projected savings based on 2024 data, assuming the increased DR requirement is implemented and the CR does not procure excessive MFR, are as follows:

$$Saving = Saving_{MFR} - Cost_{DR} = £36.25m - £4.68m = £31.57m$$

Which tools will be impacted

This update will involve the response table which will be used in multiple tools, as listed below.

[REDACTED SECTION]

Once approved, will pick the nearest OTF to communicate with industries about the new DR requirement, to allow industry to react to the new requirements. Normally we tend to notice the industry 1 week ahead of the implementation, i.e. on Wednesday, 29th Jan.

Backlogs

1. Shall we increase the minimum dynamic requirements?

There have been discussions on whether the minimum dynamic requirements should be increased from the current 550 MW to 800 MW, which is equivalent to the 480 MW DR. The conclusion is that the minimum dynamic requirements should remain at 550 MW.

[REDACTED SECTION]

Temporary Minimum Dynamic Frequency Response Advice

Date Issued:	31/01/2025	Last Updated:	
Status:	NEW		
Contact(s):	[redacted] ENCC		

Following the frequency events in the last two days and the frequency performance over previous weeks, it is advised that the minimum dynamic response levels are revised to 950MW for Primary, Secondary and High.

This will remain in effect until notified otherwise.

These values should be entered into Delphi and FFRIC. The Minimum Dynamic level in SPICE should remain at 550MW.

Response	Standing Advice level (MW)	**Recommended level (MW)**
Primary	550	**950**
Secondary	550	**950**
High	550	**950**

As referenced in the Standing Advice, *Minimum Dynamic Frequency Response Advice*, it remains at the discretion of the Operational Energy Manager to deviate from these recommended levels, by considering the prevailing conditions, including:

- Variability and uncertainty in generation and demand
- Availability and cost of additional response that the minimum dynamic response requirement is/would be driving
- Availability and cost of alternative measures

Minimum Dynamic Frequency Response Advice

Date Issued:	19/12/2019	Last Updated:	11/02/2025
Status:	UPDATE		
Contact(s):	[NAME REDACTED] (Frequency Risk and Modelling Team)		

1. Overall and Dynamic Response Requirements

The overall requirements for frequency response to secure infeed and demand losses are satisfied by a variety of frequency response available to ENCC.

In addition to this overall requirement, there is a sub-requirement for 'dynamic' response to account for continuous imbalances between demand and generation. The requirement is specified as being the amount of dynamic response that is delivered at 0.5 Hz deviation. Note that this is distinct from some SORT screens which refer to response delivered at other points, for example 0.2 Hz.

Dynamic response for this purpose needs to be proportional and sensitive to frequency variations close to 50 Hz. Dynamic response (Mandatory, Commercial or Firm), held on BM and Non-BM units contributes to meeting the 'Minimum Dynamic' requirement. Varieties of 'static' frequency response and Enhanced Frequency Response do **not** count towards this requirement.

2. Advice

The default levels of minimum dynamic response are:

Response	MW
Primary	950
Secondary	950
High	950

Variations from these levels (increasing or decreasing) may be taken at the discretion of the Operational Energy Manager, by considering the prevailing conditions, including:

- Variability and uncertainty in generation and demand
- Availability and cost of additional response that the minimum dynamic response requirement is/would be driving
- Availability and cost of alternative measures