AESO 2025
Reliability Requirements Roadmap

AUGUST 2025

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Abbreviations

Abbreviation	Term
2024 LTO	AESO 2024 Long-Term Outlook
AC	Alternating Current
ACE	Area Control Error
AESO	Alberta Electric System Operator
AGC	Automatic Generation Control
AIES	Alberta Interconnected Electric System
AIL	Alberta Internal Load
AIR	Alberta Intertie Restoration
ARS	Alberta Reliability Standard
ATC	Available Transfer Capability
AVR	Automatic Voltage Regulator
BA	Balancing Authority
BESS	Battery Energy Storage System
CBW	Cassils/Newell–Bowmanton–Whitla
CR	Contingency Reserve
CRPC	Chapel Rock to Pincher Creek
DC	Direct Current
DER	Distributed Energy Resource
d-FFR	discrete Fast Frequency Response
EATL	Eastern Alberta Transmission Line
EMS	Energy Management System
EMT	Electromagnetic Transient
ESR	Energy Storage Resource
EUE	Expected Unserved Energy
EV	Electric Vehicle
FACTS	Flexible Alternating Current Transmission System
FFR	Fast Frequency Response
FNDR	Fast Net Demand Response
GFO	Generation Facility Owner
GVA	Giga Volt Ampere
GW	Gigawatt
HVDC	High Voltage Direct-Current
Hz	Hertz

Abbreviation	Term
IBR	Inverter-Based Resource
IEEE	Institute of Electrical and Electronics Engineers
ISD	Industrial System Designation
LCC	Line Commutated Converter
LSSi	Load Shed Service for imports
LTO	Long-Term Outlook
LTP	Long-Term Transmission Plan
MATL	Montana–Alberta Tie Line
MMS	Market Management System
MSDC	Most Severe Single Demand Contingency
MSSC	Most Severe Single Supply Contingency
MW	Megawatt
NERC	North American Electric Reliability Corporation
PFR	Primary Frequency Response
PLL	Phase-Locked Loop
PPC	Power Plant Controller
PV	Photovoltaic
RAS	Remedial Action Scheme
RC	Reliability Coordinator
Roadmap	Reliability Requirements Roadmap (defined as either 2023 or 2025 Roadmap)
ROCOF	Rate of Change of Frequency
SCED	Security Constrained Economic Dispatch
SCL	Short Circuit Level
SCR	Short Circuit Ratio
STATCOM	Static Synchronous Compensator
TFO	Transmission Facility Owner
TFR	Transferred Frequency Response
TSAT	Transient Stability Assessment Tool
TTC	Total Transfer Capability
UFLS	Under-Frequency Load Shedding
WECC	Western Electricity Coordinating Council
WSCR	Weighted Short Circuit Ratio

Foreword: AESO Reliability Requirements Roadmap at a Glance

The *2025 Reliability Requirements Roadmap* (Roadmap) outlines the path forward to ensure Alberta's electricity system remains reliable and ready for the future. From new procurement initiatives and technical requirements to grid infrastructure investments and enhanced forecasting, the Alberta Electric System Operator (AESO) is taking a proactive, data-driven approach to managing grid reliability challenges.

Challenging Grid Conditions

Alberta's electricity system continues to evolve. We are seeing:

- More wind and solar generation with different capabilities and characteristics from synchronous dispatchable generation
- Increased interest in connecting large loads, especially data centres
- More dynamic, less predictable conditions on the power grid

Understanding the Reliability Challenges We Are Facing

System Strength and Stability

Wind and solar generators and batteries are examples of inverter-based resources (IBRs). Most IBRs are "grid-following" and rely on synchronous generators to provide stabilizing support. However, some IBRs are "grid-forming" and contribute to grid stability. The wind and solar generators in Alberta are grid-following.

Some areas of the grid with fewer synchronous generators and relatively high grid-following IBR capacity from wind and solar lack the system strength necessary for stability. Low system strength contributes to reliability risks, including voltage fluctuations, poor fault recovery, and generator tripping.

The Medicine Hat, Brooks–North Lethbridge, and Pincher Creek regions have low system strength, making them more vulnerable to reliability risks.

Flexibility and Balancing

The electricity system must always have balanced supply and demand. Intermittent generation resources (like wind and solar) and fast-ramping loads make this harder. The grid needs flexibility to quickly adjust to changing supply and demand conditions. Flexibility can be provided by dispatchable generators or storage when they have adequate ramp rates and available capacity to adjust their output.

Frequency Response and Stability

When large generators or loads suddenly disconnect, the difference in net demand can show up as incremental interchange (when Alberta is connected with the Western Interconnection) or large changes in system frequency (when Alberta is not interconnected).

Sudden disconnection of the interties can also cause large frequency changes. If the frequency becomes too high or too low, it can trigger protection systems, causing loss of load or generation.

The shift in the supply mix, including the retirement of coal-fired synchronous generators, has resulted in lower system inertia and primary frequency response. This change has made the system more vulnerable to large frequency changes.

What the AESO Is Doing Today To Maintain Operational Reliability

System Strength and Stability

Since 2023, the AESO has:

- Developed IBR connection requirements to ensure generators and storage are designed to operate reliably, given the system strength available at their points of connection
- Worked with generator owners to implement mitigations for specific performance problems with individual generators
- Implemented operational limits to maintain reliability where system strength is lacking

The AESO is currently:

- Implementing real-time stability assessment and oscillation detection capabilities
- Working with generators to identify opportunities to enhance the stability of their control systems

Flexibility and Balancing

Since 2023, the AESO has:

- Increased our regulating reserve procurement

The AESO is currently:

- Piloting a new ancillary service called Fast Regulating Reserve (FRR) to enhance balancing capabilities
- Developing a new ancillary service for ramping (a 30-minute ramping product called R30) and implementing security-constrained economic dispatch (SCED) as part of our implementation of the Restructured Energy Market (REM)
- Implementing reliability unit commitment (RUC) to ensure enough generation is online when self-commitment alone may not meet reliability needs

Frequency Response and Stability

Since 2023, the AESO has:

- Calibrated intertie transfer limits to system frequency response
- Transitioned from load-only Load Shed Service for imports (LSSi) to technology-neutral fast frequency response (FFR), which supplements the frequency response available from generators and load, and allows for higher intertie transfers (when interconnected) and generator contingencies (when islanded)
- Procured technology-neutral FFR
- Procured transferred FFR to ensure Alberta complies with reliability standards and meets its obligations to the Western Interconnection

The AESO is currently:

- Implementing a system to dynamically calculate the needed amount of FFR, with the goal of accommodating higher intertie transfers when reliability allows
- Engaging with industry to develop an enhanced fast frequency response service (FFR+), which will improve on existing FFR by being highly available and offering additional capabilities

What the AESO Is Doing To Minimize Reliability Challenges Associated with New Projects

System Strength and Stability

- New IBR projects are required to meet *AESO Connection Requirements for Inverter-Based Resources*
  - IBR projects connecting in weak areas must conduct electromagnetic transient (EMT) studies to ensure their facilities will perform reliably; this may also influence equipment choices and require projects to enhance controls and protection systems
- The AESO is planning to transition the IBR connection requirements into rules and standards
  - Our standards will be aligned with North American Electric Reliability Corporation (NERC) standards being developed under Federal Energy Regulatory Commission (FERC) Order 901, and we will plan our schedule to align with NERC timelines where reasonable
- The AESO is assessing the efficacy and economics of an infrastructure solution, such as a synchronous condenser or grid-forming battery, for enhancing system strength in the Medicine Hat area (the Cassils–Bowmanton–Whitla transmission corridor)

Flexibility and Balancing

- The new ancillary service for ramping (R30) will provide a new incentive for generator and storage projects to provide flexibility

Frequency Response and Stability

- The AESO is planning to propose performance-based rules for frequency response, which will help ensure system performance is predictable
- The AESO will apply limits on supply loss and load loss (in a single contingency) to new generator and load facilities through their functional specifications
- The AESO is investigating a fast net demand response (FNDR), triggered by supply loss and potentially load loss, to allow for larger contingencies (it may be part of the additional capabilities provided by FFR+)

How the AESO Is Managing Reliability Risks From Large Loads

Large loads can create power quality issues, voltage fluctuations, and balancing challenges.

- Inverter-based loads like data centres can contribute to instabilities when system strength is lacking, much like inverter-based generators. Therefore, the AESO is developing Transmission-Connected Data Centre Technical Requirements, to be finalized in late 2025, which will address:
  - Voltage stability
  - Fault ride-through
  - Harmonics
  - Power quality
- The Data Centre Technical Requirements will limit data centre ramp rates to make balancing the system more manageable
- The AESO expects to limit the maximum load loss from a single contingency to 200 MW, which will prevent excessive inadvertent interchange and intertie overloads
- While a single load facility may be larger than 200 MW, its facility design operations must respect this limit

What Project Developers and Existing Generators Need to Know, at a Glance

For Project Developers

- **Design for weak-grid conditions:** In areas with low system strength, be prepared to invest in grid-friendly technology and controls
- **Start technical studies early:** Even though some studies are required late in the connection process, early modelling helps avoid costly redesigns
- **Engage in AESO service procurements:** Opportunities will be available to earn revenue by supporting grid reliability for facilities that can be flexible or provide frequency response

For Existing Generators

- **Follow connection requirements and system limits:** Facilities that cause instability or fail to respond properly during disturbances may be curtailed
- **Expect new performance-based rules:** The AESO is shifting from equipment-based rules to performance-based rules that ensure facilities behave predictably in real-world conditions
- **Be prepared to adapt:** As the grid changes, generators may need control system setting changes or enhancements to continue operating reliably

Executive Summary

Purpose and Scope

The *2025 Reliability Requirements Roadmap* (2025 Roadmap) outlines how the AESO plans to sustain and improve the operational reliability of Alberta's electric system. This 2025 Roadmap explains the reliability challenges posed by the system's evolution on both the supply side and the demand side, and what we will do to ensure compliance with reliability standards and maintain grid stability as the system evolves. It sets out plans addressing three critical areas:

- **System Strength and Stability:** Ability of the electric system to maintain stable voltages and support the secure operation of generators, storage, and load during disturbances
- **Flexibility and Balancing:** Ability of the electric system to adapt to dynamic and changing conditions while maintaining balance between supply and demand
- **Frequency Response and Stability:** Ability of the electric system to maintain an acceptable frequency level and to recover from supply-demand imbalance accompanied by frequency error in a timely manner, especially when caused by contingencies

Reliability Key Actions

The AESO is taking decisive action to address growing reliability challenges across Alberta's power system. These efforts are essential to ensure the grid remains reliable and capable of supporting the evolving energy landscape. Our work identifies the following key actions:

- **FFR+ procurement:** This will supplement primary frequency response, system inertia, and fast regulating reserve—enabling higher intertie transfers and improving balancing performance. FFR+ may offer system strength and voltage stability benefits depending on asset location
- **R30:** Through the REM initiative, the 30-minute ramping product (R30) will ensure needed energy market ramping capability is available, a growing concern as intermittent generation increases
- **SCED:** Through the REM initiative, security-constrained economic dispatch (SCED) will automate the process of dispatching energy and R30 products to minimize costs while respecting transmission capacity, stability, and balancing constraints
- **Data Centre Requirements and Connection Studies:** These will proactively ensure new facilities are connected to the Alberta grid in a reliable manner

Significant progress has already been made. In 2024, the AESO proactively introduced new IBR requirements and improved connection study processes. In 2025, we will establish analogous requirements for data centres to address potential impacts on grid dynamics.

The design and development of FFR+, R30, and SCED are underway and remain top strategic priorities for the AESO. These initiatives are essential to maintaining a reliable, efficient, and future-ready electricity system.

The following sections detail our findings as studied using the *AESO 2024 Long-term Outlook* (2024 LTO).

System Strength and Stability

System strength is the grid's ability to maintain acceptable voltages and ensure stable operation of generators, storage, and load during disturbances. While wind and solar generators are increasingly contributing to Alberta's electric energy supply, they do not inherently[1] contribute to system strength. Weak systems with low short-circuit levels are prone to adverse behaviours, control instabilities, and protection system failures, potentially leading to voltage oscillations and poor fault recovery. These risks are greater in areas with high wind and solar concentrations and low synchronous generation.

The AESO studies show that system strength in the Medicine Hat, Brooks–North Lethbridge, and Pincher Creek areas may be insufficient to support the connection of additional wind and solar generators, which are not designed for weak systems. This is primarily due to the high volume of wind and solar generators already connected. Additional wind and solar generators in these areas must have appropriate risk mitigations.

New wind and solar projects in these areas:

- Will require EMT studies to assess risks and mitigations
- Must be designed to meet *AESO Connection Requirements for Inverter-Based Resources* (IBR connection requirements) and operate reliably with the system strength available at their point of connection. Facility design could include:
  - Simple protection and control system adjustments
  - Selection of different equipment
  - Addition of equipment such as synchronous condensers or grid-forming battery energy storage systems (BESS)

We have also collaborated with existing facility owners on the following EMT studies to assess risks and mitigations:

- **EATL South Terminal:** Initial studies indicate stable operation
  - Ongoing studies are evaluating potential interactions with nearby wind and solar generators
  - Connections of wind and solar generators near the EATL South Terminal will need to mitigate any adverse control interactions that they may introduce
- **Stavely Area:** Studies reproduced real-time voltage oscillations observed in 2021 at a solar facility in this area and helped inform mitigations
  - Adjustments to power plant controllers have been completed, and any further oscillations during transmission outages will be managed by curtailment

[1] Modern control strategies, such as "grid forming" controls, can enhance system strength. Legacy control strategies, such as "grid following" controls, can be more susceptible to instability in weak system conditions.

- **Southeast (Medicine Hat) Area:** Real-time voltage oscillations in the Medicine Hat area have been linked to wind generator control instabilities where low system strength was a contributing factor
  - Studies identified an outflow limit to prevent instability
  - In the short term, the AESO and generator owners are enhancing control systems within facility capabilities
  - Long-term solutions, such as adding a synchronous condenser or grid-forming BESS, are being explored through the Southeast System Strength Project and the FFR+ procurement

To address system strength shortfalls, we have developed IBR connection requirements and implemented system operating limits. The *AESO 2025 Long-Term Transmission Plan* highlights opportunities for system enhancements, including the potential use of synchronous condensers when required to address system strength reliability issues. We are also engaging with stakeholders on bundling system strength services in the procurement of FFR+.

Large non-conforming loads, such as data centres, can worsen system strength issues by impacting voltage profiles. To address this, Transmission-Connected Data Centre Technical Requirements will mitigate impacts on voltage profile and resulting issues, such as voltage stability, fault ride-through, voltage fluctuations, power quality, control interactions, harmonics, and resonance.

A summary of our plan for mitigating system strength concerns includes:

- **Real-time tools:** Implementing online transient stability assessment and oscillation detection to improve situational awareness
- **IBR control system enhancements:** In collaboration with facility owners
- **IBR connection requirements:** Enforcing the requirements to ensure that new IBRs operate reliably within the system strength available at their point of connection, and transitioning the requirements into rules and standards
- **Transmission-connected data centre technical requirements:** We will finalize connection requirements for transmission-connected data centres in late 2025. These requirements will initially be applied in functional specifications similar to *AESO Connection Requirements for Inverter-Based Resources*
- **Ongoing evaluation:** Assessing system strength and evaluating mitigations as new projects connect. We will consider solutions for areas where low system strength is exhibiting or expected to exhibit reliability issues, including:
  - **Southeast System Strength Project**: We are considering a synchronous condenser or grid-forming battery in the Medicine Hat area
  - Alternatively, the FFR+ engagement and following procurement could introduce a grid-forming battery in the area that may reduce or eliminate the need for a system project
  - No other enhancements associated with system strength needs have been identified

Flexibility and Balancing

System flexibility refers to the electric system's ability to maintain balance between supply and demand in dynamic conditions. The ability of the system and system controllers to balance dispatched net-supply with net-demand[2] is affected by:

- The volume and characteristics of flexibility services, such as regulating and ramping reserves
- The composition of the generation fleet
- Asset commitment and responsiveness to dispatches
- Forecast quality, such as forecasts for non-controllable supply and non-controllable demand, including intermittent distributed energy resources (DERs) and non-conforming load

Balancing the system was challenging for the AESO in 2024 and is expected to remain complex over the next several years due to industry's ongoing, gradual shift towards intermittent generation. We must adapt our ancillary services and operational tools to align with the changing supply mix.

As an outcome of the *2023 Reliability Requirements Roadmap*, the AESO is working towards adding ramping products (R30) and security-constrained economic dispatch (SCED) through the REM. We are also piloting FRR to complement the existing wind and solar power ramp-up management and regulating reserve products.

Our analysis finds that:

- By 2030, an average of 481 MW of R30 will be needed in an interval to reserve ramping capability for the following two hours
- Energy market ramping will still result in residual imbalances, primarily due to forecast error
- These imbalances can be managed by limiting wind and solar output to their forecasted level (average reduction of 51 MW in 2030), along with a combination of regulating reserve (RR) and FRR (approximately 170 MW of RR and 180 MW of FRR in 2030) to respond when output is below their dispatch

Large, non-conforming loads (such as data centres) can impact balancing due to significant and unforeseen changes in demand. Transmission-connected data centre technical requirements will limit the allowed ramp rate of data centres to a manageable level to avoid balancing issues.

Our strategy for maintaining acceptable balancing performance includes:

- Adjusting regulating reserve based on system performance
- Piloting and evaluating FRR as part of the FFR+ engagement
- Introducing R30 ramping product
- Limiting the ramp rate of data centres within system capabilities through the introduction of Transmission-Connected Data Centre Technical Requirements

[2] See Section 4 for definitions on net-supply and net-demand.

- Implementing Reliability Unit Commitment (RUC) to backstop self-commitment based on reliability constraints
- Implementing a new Market Management System (MMS) to automate dispatch issuance and obeyance and apply security constraints
- Improving forecasting capabilities

Frequency Response and Stability

Frequency response from generators corrects system frequency deviations caused by changes in supply or demand. The system needs frequency response to:

- Avoid under-frequency load shedding (UFLS) during large supply loss events
- Prevent generator frequency protection activation during frequency excursions
- Comply with reliability standard BAL-003, which requires Alberta to have a minimum level of frequency response for the Western Interconnection

Several risk scenarios related to the lack of frequency response are further described below.

Loss of AC Interties[3] While Importing

- Supply loss events cause frequency to drop, risking load shedding
- The AESO limits Available Transfer Capability (ATC) and uses FFR services to enable imports while mitigating the load-shedding risk
- Import ATC is frequently restricted to levels below intertie transfer capability due to limited FFR availability

Loss of AC Interties While Exporting

- Demand loss events cause frequency to rise, risking generator tripping
  - Risk increases as exports increase; however, the risk is relatively small compared to the load-shedding risk when importing
- Primary frequency response is stronger for over-frequency events relative to under-frequency events, as fully loaded generators can decrease output in response to over-frequency

Loss of Generation or Load While Islanded

- Events cause a frequency excursion, risking load shedding or generator tripping
- The AESO uses FFR services to maintain the Most Severe Single Supply Contingency (MSSC) limit while mitigating the load-shedding risk
- No additional services are required to maintain the Most Severe Single Demand Contingency (MSDC) limit

[3] All AC interties can be opened in a single contingency.

Loss of Generation or Load While Synchronously Interconnected

- Causes an in-rush or out-rush over the AC interties
  - Risk is potential overload leading to intertie tripping

MSSC and MSDC Limitations

- The MSSC is limited to 466 MW to respect the reserved in-rush margin and to mitigate the risk of tripping the AC interties
- Conversely, the MSDC is limited to 200 MW to respect the reserved out-rush margin

Limiting Sudden Loss of Demand from Data Centres

- Transmission-connected data centre technical requirements will limit the sudden loss of demand from a single contingency to 200 MW
- Without this limit, a single contingency could cause an out-rush larger than the out-rush margin, which risks disconnecting the interties
- While a single data centre site may be larger than 200 MW, its facility design and operations must ensure a single contingency does not violate this 200 MW limit

Decline in Inertia and Primary Frequency Response

- **Expected trend:** Primary frequency response is projected to continue declining over the next several years due to increasing intermittent generation
- **Impact:** The system will become less capable of quickly stabilizing from frequency drops over time
- **Assumptions:** Trends are subject to the wind and solar development, unit commitment, and energy market dispatches assumed in the 2024 LTO Reference Case
- **Recent observation:** Wind and solar capacity may be lower than originally forecasted; therefore, the decline in primary frequency response may be overstated

Increasing Import Transfer Capability

- **Government directive**: The Alberta government directed the AESO to increase the availability of import transfer capability on the interties
- **Strategy for improving frequency response and increasing ATC:**
  - Procuring up to 834 MW of high-availability FFR to address under-frequency risks and restore the import ATC to the existing import transfer capability
  - Implementing a new tool to dynamically determine FFR arming requirements
  - Implementing mitigations for over-frequency risks, including bi-directional proportional FFR
  - Proposing outcome-based frequency response rules and evaluating generator performance
  - Enabling primary frequency response on new DERs

These actions will enable the AIES to be self-reliant in meeting BAL003 requirements, replacing the need for procuring transferred frequency response (TFR).

Action Items

The following table provides a summary of action items and their status. Section 9 provides a retrospective on action items from the 2023 Roadmap with status updates.

System Strength Actions	Status
Continuously/Periodically	
Apply and enforce the IBR connection requirements	Ongoing
Collaborate with facility owners to improve IBR control systems	Ongoing
Assess system strength and evaluate infrastructure-based enhancements	Ongoing
Monitor the development of NERC's IBR standards	Ongoing
Near-Term (<2 years)	
Improve real-time tools with Online Transient Stability Analysis Tool (TSAT) and Oscillation Detection	In progress
Develop Transmission-Connected Data Centre Technical Requirements with system strength-related requirements	In progress
Transition the IBR connection requirements into rules and standards	Not started
Long-term (>2 years)	
Increase system strength in the southeast using a synchronous condenser or other effective technology	In progress
Flexibility and Balancing Actions	**Status**
Continuously/Periodically	
Monitor balancing performance and adjust regulating reserve volumes as needed	Ongoing
Improve forecasting capabilities	Ongoing
Near-Term (<2 years)	
Develop Transmission-Connected Data Centre Technical Requirements with ramping-related requirements	In progress
Long-Term (>2 years)	
Introduce the R30 ramping product	In progress
Develop and procure FRR (evaluating as part of the FFR+ engagement)	In progress
Implement Reliability Unit Commitment (RUC)	In progress
Implement Market Management System (MMS) with Security Constrained Economic Dispatch (SCED)	In progress

Frequency Stability Actions	Status
Continuously/Periodically	
Participate in the Western Frequency Response Sharing Group (WFRSG)	Ongoing
Purchase transferred frequency response (TFR)	Ongoing
Monitor and evaluate generator responses to frequency events	Ongoing
Near-Term (<2 years)	
Implement a new tool to dynamically determine FFR arming requirements	In progress
Enable primary frequency response on new distributed energy resources	In progress
Develop Transmission-Connected Data Centre Technical Requirements with MSDC- related requirements	In progress
TTC validation study	In progress
Propose outcome-based frequency response rules	Not started
Long-Term (>2 years)	
Procure up to 834 MW of high availability FFR to restore import ATC	In progress
Procure a subset of high availability FFR as bi-direction proportional FFR to reduce dependence of TFR and mitigate over-frequency risks	In progress
Evaluate increasing the MSSC and MSDC limits through FNDR	In progress

Need for Ancillary Services

The AESO estimates that the system will need the following quantities of ancillary services for frequency response and balancing in the future:

Service	Quantity (2030)		Function
Fast frequency response	692 MW to 834 MW		Enable imports and improve frequency stability
Subgroup 1 (always active) Proportional FFR	Minimum 250 MW		Maintain 466 MW MSSC limit during islanded conditions Replace transferred frequency response
Subgroup 2 (as required) FFR & fast net demand response	Minimum 250 MW		Increase the MSSC limit to 716 MW while synchronously interconnected without reducing import ATC
Subgroup 3 (when not providing fast frequency response) Fast regulating reserve	Minimum 0 MW	Maximum[4] 178 MW	Provide energy for large unforeseen down-ramps in wind and solar production
Regulating reserve	Minimum 170 MW	Maximum 285 MW	Provide continuous responses to maintain system balance
Ramping reserve: R30	481 MW[5]		Ensure ramping capability is available for each interval over the following two hours

[4] Maximum FRR is based on a 25 per cent cost ratio to RR.

[5] Average R30 requirement for expected and unexpected ramping in 2030.

Sections 4 through 6 further explain the purpose of these services and how we determined these quantities. The need for services will be dynamic and dependent on factors including weather volatility and interchange offers. The required quantities of regulating reserve and fast regulating reserve are related, and procurement of each may be adjusted based on the price and availability of the other.

We are engaging with stakeholders on FFR+ and the potential bundling of other services as part of this procurement. The procurement of FFR+ will increase import transfer capability and improve reliability.

1. Background

The *2025 Reliability Requirements Roadmap* (Roadmap) presents our plan for sustaining and improving the operational reliability of the Alberta grid.

Achieving and enhancing operational reliability encompasses:

- Reducing the probability of load loss and unserved load
- Avoiding cascading events
- Reducing the probability of inadvertent activation of protection systems
- Managing system constraints efficiently
- Meeting reliability standards and performance targets when balancing the grid
- Maintaining grid stability
- Meeting power quality goals

The Roadmap explains how operational reliability can be sustained and improved using:

- Ancillary services
- Rules and standards
- Operations systems and processes
- Market mechanisms

The Roadmap is a counterpart to the *AESO Long-Term Transmission Plan* (LTP), which presents our plans for increasing grid capacity and improving reliability using transmission infrastructure. When transmission infrastructure is the best solution for an operational reliability problem, we will point to the LTP.

This Roadmap is focused on our top areas of concern in 2025:

- System strength
- Balancing and flexibility
- Frequency stability

Each section covers a specific topic, outlining reliability challenges and corresponding action plans. Studies use the *AESO 2024 Long-Term Outlook* (2024 LTO) Reference Case as an input. The 2024 LTO highlights Alberta's expected electricity demand over the next 20 years, and the expected generation capacity needed to meet that demand. Therefore, the findings presented here are subject to the forecasted conditions, including:

- Wind and solar development
- Unit commitment
- Energy market dispatches modelled in the 2024 LTO Reference Case

2. Operational Experience

In this section, we review our operational experience since the release of the *AESO 2023 Reliability Requirements Roadmap*, including:

- Operational events observed during this period
- Insights gained from event analysis
- Actions, planned and taken, that relate to these events

2.1 System Strength and Voltage Stability

Over the past two years, an increasing number of operational challenges have arisen from system strength shortfalls and the complex dynamics of IBRs in the Alberta Interconnected Electric System (AIES). As more IBRs connect to the grid, these challenges have become more pronounced in weak areas of the system.

Weak grid conditions have led to vulnerabilities in:

- Maintaining voltage stability
- Ensuring the reliable operation of control and protection systems
- Disturbance and fault ride-through and recovery

These vulnerabilities have manifested in operational events as further described below.

2.1.1 Voltage Oscillations

A voltage oscillation event occurs when there is a periodic fluctuation of three per cent or more in system voltage that is undamped and lasts for minutes or longer. Voltage oscillations can indicate IBR control instability due to lack of system strength.

- Nearly 20 voltage oscillation events have occurred in the Alberta system since 2022—a phenomenon that has historically been rare
- All events apparently originated with IBRs
- Ten different generating facilities were involved in one or more events
- Voltage oscillations can be observed as flicker and can damage customer equipment

In real-time, we have stopped some oscillations by curtailing IBRs, while other events naturally resolved. The AESO will continue to manage the risk of voltage oscillations by applying operating limits and curtailing generation. In the short term, the AESO and generator owners are working to implement control system enhancements within facility capabilities to reduce oscillations. In the longer term, a synchronous condenser or a grid-forming battery can mitigate oscillatory behaviour.

2.1.2 IBR Disturbance Ride-Through

Changes in real power flows, caused by generator re-dispatch and intermittent generator ramping in turn cause the system voltage profile to change. These changes should generally be benign.

Two IBR facilities were observed to trip from time to time because changes to the system voltage profile, which the AESO expected to be benign, activated their overvoltage protections.

- The trips did not violate any rules, standards, or functional requirements imposed on the facilities by the AESO
- The AESO and the facility owners are managing the situation through the facilities' voltage set points and adjustments to target operating voltages in the grid
- We have reviewed the functional specifications of other facilities to adjust voltage ride-through capabilities
- The IBR connection requirements, if applied to the facilities that tripped, would ensure ride-through capabilities are more aligned with the AESO's expectations

2.1.3 Action Plan

- Improve real-time monitoring tools with Online Transient Stability Analysis Tool (TSAT) and Oscillation Detection (See Section 3.4.1)
- Increase system strength in the southeast using a synchronous condenser or other effective technology (See Section 3.4.1)
- Periodically review and update system operating limits using the appropriate study methods to identify system strength risks
- Continue to apply and enforce the IBR connection requirements

2.2 Flexibility and Balancing

2.2.1 Performance Monitoring

The AESO monitors balancing performance monthly using two key metrics:

- CPS1 as defined in ARS BAL-001-AB-2
- CPS2 as defined in BAL-001-AB-0a

We adjust regulating reserve empirically based on the results, with the goal of maintaining CPS2 near 95 per cent. We have generally been successful. As more intermittent generation has been integrated into the system, we have increased the regulating reserve over time to maintain optimal performance.

2.2.2 Action Plan

- Continue to monitor performance and adjust regulating reserve volumes as needed
- Develop and procure the R30 ramping product to complement regulating reserve (See Section 5.5.2)
- Develop and procure FRR to complement regulating reserve

2.3 Frequency Response and Stability

2.3.1 Performance Monitoring

- Monitoring Compliance:
  - We monitor the Alberta system's response to frequency disturbances in the Western Interconnection as part of compliance with BAL-003-AB1-1.1
  - Each balancing authority (BA) evaluates performance on a pass/fail basis
  - Performance is acceptable if the median MW/Hz response for NERC-selected events (within a rolling time window) exceeds the threshold assigned by NERC
- AIES Performance:
  - AIES frequency response has been gradually declining, as predicted by AESO simulations
  - In summer 2023, AIES performance fell below the BAL-003 compliance threshold as a standalone BA, requiring AESO intervention
- Western Frequency Response Sharing Group Membership:
  - The AESO is part of the Western Frequency Response Sharing Group (WFRSG), where BAs collaborate for compliance
  - In 2023, we remained compliant with BAL-003 due to WFRSG membership, but must address performance issues to retain membership
- Transferred Frequency Response:
  - In fall 2023, the AESO procured Transferred Frequency Response (TFR) to meet compliance requirements and maintain WFRSG membership
  - TFR is a contractual arrangement where a transferor BA provides frequency response on behalf of a transferee BA
  - TFR does not change the physical performance of the transferee's system or affect AIES operating limits (e.g., import ATC)
  - We continue to procure TFR as needed and are confident that AIES frequency response will exceed NERC requirements

2.3.2 Islanded Performance

- Frequency Response Challenges:
  - In 2023, the system's frequency response was inadequate to withstand the MSSC without under-frequency load shedding (UFLS) while islanded
  - We developed an islanded FFR product to avoid UFLS
- Temporary MSSC Restriction:
  - MSSC was temporarily restricted until we secured adequate islanded FFR
  - Currently, there is sufficient FFR under contract to support an MSSC of 466 MW while islanded
- Frequency Volatility:
  - Stakeholders observed increased frequency volatility during islanded operation (e.g., MSA's 2024 Q4 Quarterly Report following an extended intertie outage)
  - We are confident that contracted FFR during intertie outages will prevent UFLS despite increased frequency volatility

2.3.3 Action Plan

- Continue to participate in the Western Frequency Response Sharing Group (WFRSG)
- Continue to purchase TFR as needed for compliance with BAL-003
- Physically improve the frequency performance of the AIES by procuring proportional FFR, enabling reduced dependence on TFR

3. System Strength and Stability

System strength is the system's ability to maintain stable voltages and support the secure operation of generators, storage and load during disturbances. Weak systems are prone to instability and protection system mis-operation, particularly where generators are primarily inverter-based.

- System Strength Challenges:
  - Alberta's supply mix continues to evolve with increasing wind and solar generators using grid-following inverters
  - These technologies do not enhance system strength, leading to stability risks
- Areas of Concern:
  - Specific concerns exist in southern Alberta, particularly in the Medicine Hat area, due to a high concentration of IBRs and relatively little synchronous generation
  - Without sufficient system strength, minor disturbances can lead to significant and widespread instability

The AESO has implemented measures to improve reliability when projects are connecting to weak areas of the system:

- The IBR connection requirements ensure projects assess risks adequately and are designed to operate reliably with the system strength available at their points of connection
- Screening studies are used in the connection process to identify high-risk projects and require their owners to do detailed EMT studies
- Operating limits are applied to improve system stability

However, further actions are required to improve and maintain stability.

In this section, we elaborate on the risks of system strength shortfall in the Alberta system, explain the results of system studies we have recently performed, and outline our action plan.

3.1 Reliability Risks in Weak Systems

Weak systems present risks to system stability and performance. They have less ability to support voltage control and fault recovery, which are critical for maintaining stability. Low short-circuit levels in weak areas limit the grid's capacity to absorb and recover from disturbances, increasing the likelihood of system instability, adverse control interactions, and protection failures.

Challenges with IBRs

IBRs rely on strong system voltage for synchronization. Weak systems can distort voltage, leading to:

- Loss of synchronization
- Inability to ride through faults

- Tripping during disturbances
- Reduced output and undamped oscillations
- Momentary cessation of operation

Such events have been observed in Alberta (See Section 2).

Cascading Disturbances | Impact on Surrounding Facilities

- Adverse behaviours in one facility can increase instability risks for others, creating risk of cascading[6] disturbances
- Potential for voltage oscillations due to negative interactions among IBRs

Challenges with Protection Systems

- Low short-circuit levels (characteristic of weak systems by definition) can prevent traditional protection schemes from effectively detecting and isolating faults
- Delayed fault clearing is one potential outcome. Delayed clearing increases the risk of equipment damage, protection system mis-operation, and transient stability issues

Mitigation Options

Both long-term (equipment and infrastructure-based) and operational (tools-based) solutions apply to mitigating these risks:

- **Long-term solutions**: The AESO can use technologies like synchronous condensers or grid-forming batteries to reinforce system strength. Owners can enhance IBR control systems to improve their performance under weak grid conditions.
- **Operational solutions**: Tools such as online stability assessments can provide operators with greater visibility into stability risks, enabling the efficient determination and rapid application of stability-based operating limits.

3.2 Screening Study

We have assessed system strength adequacy using a screening method[7]. The results are provided in Table 1 and presented on a map in Figure 1. A system strength assessment was first presented in the 2023 Roadmap. In our 2025 Roadmap, we have refreshed our assessment based on more recent data, including:

- The *AESO 2024 Long-Term Outlook* (2024 LTO)
- Grid topology changes, including customer and system projects
- The latest customer project list

[6] Loosely, cascading occurs when a disturbance that should be isolated to one facility extends to others.
[7] Screening methods are suggestive of the need for further study using more accurate detailed methods. In this context, a project that fails screening because the grid is too weak (WSCR < 3) should be studied further using EMT methods to determine whether and how it can be made to perform reliably.

We use a metric called weighted short circuit ratio (WSCR) for screening. The WSCR applies to a group of inverters and is defined as the ratio of the representative three-phase fault level (in MVA at nominal voltage) to the total capacity of inverters nearby (in MW). The representative fault level is a weighted average of the fault level at the point of connection of each IBR facility included in the calculation (where the weight is normalized project size).

- WSCR < 3 means the system is weak
  - Grid-following IBRs may not operate properly
- There is a moderate level of risk when 3 < WCSR < 5
  - Most IBRs are probably within design parameters, but the system has a limited capacity for hosting new projects
- WSCR > 5 means the system is strong

The WSCR numbers predicted for a given year include the customer projects expected to be operating by that year, based on the customer project list and customers' financial commitments.

Our analysis included the years 2025 and 2030. We are uncertain which customer projects might happen after 2030, and WSCR heavily relies on which generator projects progress to energization. The scope of assessment was limited to south and central east Alberta, where developers are most interested in connecting wind and solar generators. The WSCR values in Table 1 apply when the system has no transmission outages.

Table 1: System Strength Screening Results

Location	2025		2030	
	WSCR	IBR Capacity (MW)	WSCR	IBR Capacity (MW)
Southeast – Medicine Hat (CBW) (240 kV)	0.55	2,098	0.43	2,935
Hanna east (240 kV)	3.17	457	2.65	557
Hanna west (144 kV)	2.61	223	2.58	227
Brooks – EATL terminal	2.54	1,400	2.41	1,400
Milo to North Lethbridge (240 kV)	2.06	1,292	1.56	1,792
Stavely (138 KV)	2.40	239	2.36	239
Southwest – Pincher Creek	2.20	914	1.56	1,464

Key Areas of Concern

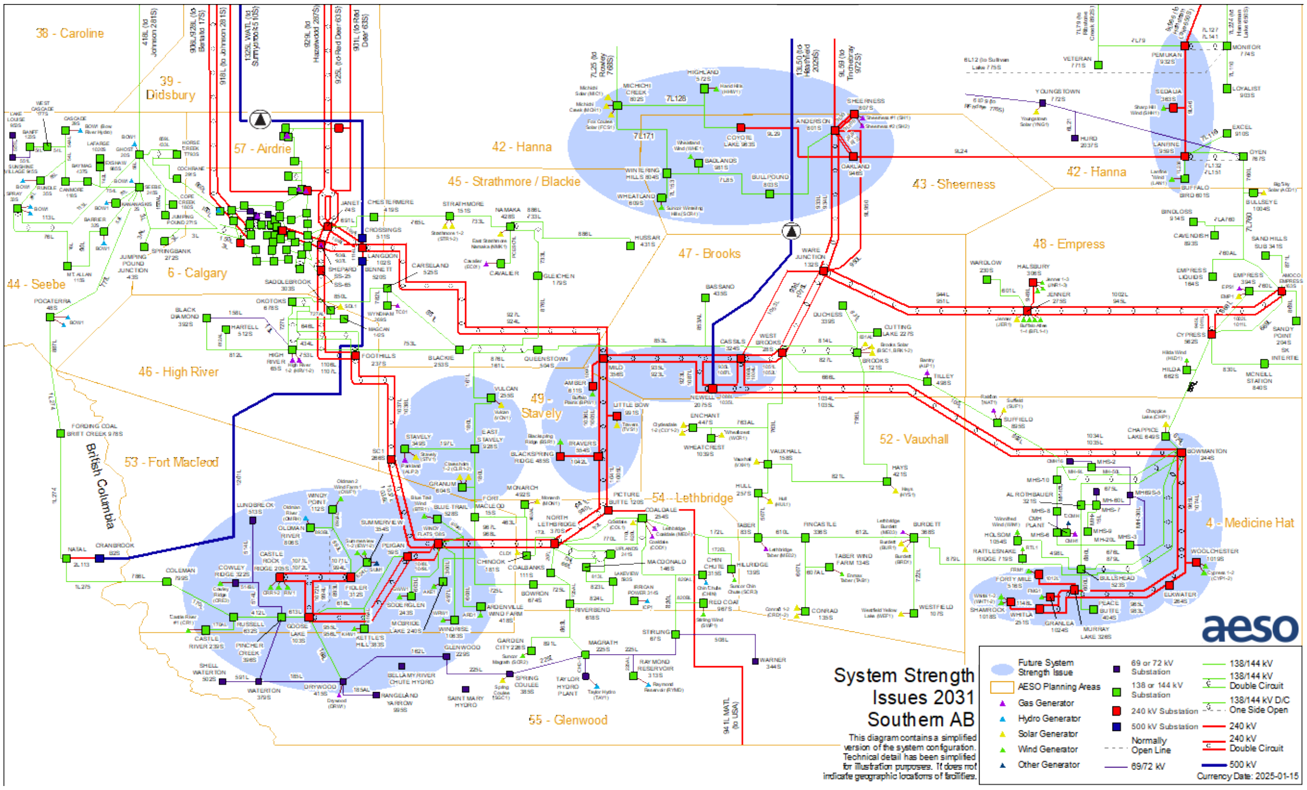
This system strength assessment reaffirms the findings of our previous studies: system strength in south and central east Alberta may not be adequate to support the IBR projects planned by market participants, and stability risks are present. Risks have increased in specific areas compared to our previous assessment:

- Milo to North Lethbridge:
  - Significant decline in system strength in area due to increased IBR capacity
  - Heightened risks:
    - Voltage instabilities
    - Adverse control interactions
    - Failures to ride through faults
- Brooks – EATL South Terminal:
  - No material increase in risk compared to the 2023 assessment
- Southwest – Pincher Creek:
  - Significant reductions in system strength adequacy at the following locations because of increased IBR capacity:
    - 240 kV connection points
    - 138 kV connection points
- Southeast – Medicine Hat:
  - Cassills–Bowmanton–Whitla 240 kV transmission corridor
    - System strength deficit already causing real operational reliability issues (See Section 2)
  - Proposed solutions include infrastructure enhancements, including synchronous condensers or grid-forming batteries and transmission lines for this area
  - Projects that are new or in early development should choose equipment designed to operate in weak grid conditions
- Hanna area:
  - 144 kV network: decline in system strength adequacy

The system strength map in Figure 1 illustrates the geographical areas and substations corresponding to the IBR groups listed in Table 1:

- Developers can use this map to determine if their points of connection have system strength shortfalls
- We will use this map to prioritize system studies focused on specific areas and the mitigations that may follow from them

Figure 1: System Strength Map



Proactive Measures for System Strength and Reliability

- The next five years are critical for the AESO to proactively manage risks related to system strength adequacy
- Projects identified as "at risk" based on these assessments will be required to conduct electromagnetic transient (EMT) studies, which may require:
  - Adjusting control measures
  - Selecting different equipment
- This approach aims to safeguard the system from reliability risks associated with system strength

3.3 System Studies

The AESO identified areas at risk for system strength shortfall in the 2023 Roadmap by performing screening studies. Where the screening studies showed risks, we followed up with EMT studies to verify the screening results and investigate mitigations.

Four EMT studies were performed:

- EATL uses line-commutated converter (LCC) technology, which relies on a minimum level of system strength for stable operation

- The declining trend in system strength at the EATL South Terminal at Newell/Cassils raised concerns that EATL might experience instability caused by faults or system disturbances

- We observed a specific generating facility in the Stavely area that appeared to cause local voltage oscillations during transmission outages when the short circuit ratio was low
- In the Cassils–Bowmanton–Whitla 240 kV transmission corridor, a group of IBRs has a WSCR < 3
  - Voltage oscillations in the area during operations were noticed; new projects planning to connect in the area would increase the risk
- A specific generating facility near Whitla also appeared to cause voltage oscillations in this area during operations.

EMT Studies Purpose

- Use a detailed and accurate model to predict instability
- Reproduce the same behaviour that was observed operationally
- Determine whether control system modifications could plausibly restore stability, where applicable
- Determine whether transmission system operating procedures or infrastructure enhancements could mitigate problems that cannot be solved through control system modifications

The following sub-sections elaborate on the results of these EMT studies.

3.3.1 EATL South Terminal

Studies

- Screening study:
  - EATL South Terminal (Newell 2075S substation) showed risks of instability due to short circuit ratio and minimum fault level below design values
- EMT study:
  - Conducted detailed EMT simulations using the manufacturer's model
  - Simulated credible contingencies (N-1, N-2, and N-1-1) and scenarios with:
    - Hypothetical retiring or mothballing of synchronous generators at Sheerness and Battle River
    - Variation in wind and solar output to capture the minimum system strength conditions that might manifest at the EATL South Terminal in the future

Findings

- Simulations suggest EATL can maintain stable operation in the studied scenarios

- No control system modifications, enhancements, or operational restrictions are needed

Ongoing Monitoring and Updates

- Monitoring of the situation will continue
- Studies are being refreshed using detailed site-specific models of nearby IBR facilities that were previously unavailable
- Potential risks of interactions with IBRs will be assessed
- Studies will evaluate the risk of interactions with IBRs that could adversely affect system dynamics and stability.

3.3.2 Stavely Area

Observation

- Operational Instability:
  - Observed at a solar facility during a transmission outage
  - Occurred when the facility was radially connected to the grid
  - Voltage oscillations were linked to low system strength caused by the outage

Studies

- Screening study:
  - Revealed low WSCR in the Stavely area
- EMT study:
  - Conducted to investigate the root cause of the instability
  - Utilized high-fidelity models of the solar facility and the grid
  - Simulated the transmission outage conditions present during the instability
  - Explored potential mitigation strategies

Findings

- Low-frequency oscillations:
  - EMT simulations replicated the oscillations observed in the real event:
  - Study confirmed that the power plant controller (PPC) was responsible for low-frequency oscillations
  - Adjusting the PPC control parameters eliminated low-frequency oscillations
  - Solution was discovered in simulation and validated by a test conducted at the site
- High-frequency oscillations:
  - Cause of high-frequency oscillations traced to:
  - Inverter controls

- Weak grid conditions during the transmission outage were outside the inverter design parameters
- Tuning the inverter controls to eliminate high-frequency oscillations was deemed not feasible

Mitigation Strategy

- Control system enhancements were found to be ineffective in mitigating high-frequency oscillations
- We will curtail the unstable facility during the relevant transmission outage
  - Curtailment is not required when the system is intact

3.3.3 System Strength Assessment in the Southeast

Observation

- Voltage and reactive power oscillations were observed operationally on multiple occasions in 2022 and 2023 (referenced in Section 2)
- The earliest oscillations were linked to transmission line outages in the Cassils–Bowmanton–Whitla corridor
- As more IBR projects energized, oscillations were observed even when the transmission system was intact
- The southeast region has a high concentration of generation connected:
  - Over 1,400 MW of IBR-based generation is already connected
  - Expected to increase to 2,100 MW by the end of 2025

Studies

- Screening study:
  - Showed a system strength shortfall in the 240-kV grid
- An AESO EMT study was conducted to:
  - Determine the maximum hosting capability of IBRs in the CBW area and investigate options for increasing this capacity
  - Identify ways to mitigate stability constraints, enabling the full use of the 1,200 MW thermal capacity of the CBW transmission lines, if feasible
- A generator owner EMT study was conducted in collaboration with the AESO to:
  - Assess facility performance to identify the root cause of observed oscillations
  - Investigate possible mitigations

Findings

- AESO EMT study:
  - Several contingencies can lead to unstable operation of IBRs
  - Limiting the total output of IBRs in the CBW area can prevent the instability
  - The stability limit on outflow is approximately 800 MW. The limit applies when the system is intact and being operated in preparation for first contingencies
  - Achieving the outflow limit is contingent on a remedial action scheme (RAS) that trips generators when transmission contingencies occur
  - The addition of synchronous condenser capacity can increase the outflow limit, e.g., adding 100 MVA of synchronous condenser capacity may enable an increase in the outflow limit to approximately 1,000 MW
- A generator-owner EMT study:
  - A simple system equivalent representative of the level of system strength available operationally. The study found that:
    - Simulations could reproduce oscillations like those observed operationally
    - The oscillations were not just the result of an adverse interaction between facilities, because they could occur when no other IBR facilities were online
    - Control system adjustments could improve stability
  - Therefore, the facility owner is implementing control system adjustments

Future Plans

- AESO EMT study:
  - Generic models were used for several facilities because detailed site-specific models[8] were not available at the time; therefore, we do not have a high degree of confidence in the results
  - The study will be repeated in 2025 when better models become available to refine transfer limits and further investigate mitigation options
  - Findings will be used to inform the "Southeast System Strength Project"

Mitigation Strategy

- We prefer to reduce stability constraints by having generator owners implement control system enhancements because control-based solutions generally cost much less than infrastructure
- Other generators in the Medicine Hat area may be able to enhance system stability by improving their controls
- We will continue to pursue control system enhancements implemented by facility owners

[8] i.e., models provided by the vendor representing as-built firmware, protection and control settings.

- A synchronous condenser in the Medicine Hat area is likely to enable incremental CBW outflow capability, even after generator owners make reasonable efforts to improve control systems
- Grid-forming storage resources can theoretically offer similar stability benefits to synchronous condensers

We need further system studies to:

- Improve model quality for some CBW generators
- Investigate the efficacy of grid-forming storage (as opposed to synchronous condenser capacity) at increasing the CBW outflow limit
- Refine our estimate of the relationship between outflow capability and synchronous condenser or battery capacity
- Help us identify further opportunities for control system enhancements in CBW generators, using site-specific models

If the studies show control system enhancements allow transmission to be used up to thermal limits, then no infrastructure solutions will be required. Otherwise, we will consider implementing either a synchronous condenser or grid-forming battery in the Medicine Hat area.

Until other mitigations are implemented, we will achieve stable system operation through a system operating limit on CBW outflow. Generators will be curtailed based on the efficacy of curtailment at improving system stability.

3.4 Action Plan

3.4.1 AESO Actions

Our strategy for operating a stable grid as more IBRs connect to the grid includes:

- **Implementing new tools and procedures to predict, prevent, and mitigate instability in real time:** An online transient stability assessment tool (TSAT) coming online in 2026 will allow us to set more efficient limits on the outputs of groups of generators based on system stability limits determined in real time. Operating limits are currently determined based on conservative offline studies. The online TSAT tool will enable us to set more efficient limits. A real-time oscillation detection tool, planned for implementation and enhancement in 2026, will enable us to immediately identify generators causing or participating in oscillations, allowing us to curtail or direct them offline.
- **Working with IBR owners to improve stability so they can avoid stability-based curtailment:** Generator owners are responsible for designing and operating stable and reliable facilities. Instabilities may be observed operationally despite reasonable efforts to avoid them when facilities are designed. When this happens, our role is to help owners scope studies that can identify stability risks and control system improvements and validate proposed improvements using system models that have sufficient detail to predict adverse control interactions. The owner's role is to design and implement the improvements. For example, see the case studies in Sections 3.3.2 and 3.3.3.

- **Continuing to apply and enforce the IBR connection requirements:** We published the connection requirements in early 2024. They protect both the system and facility owners from the risk that generators will be constrained or unable to operate because of instability. We will continue to apply the requirements in functional specifications until they are replaced with rules and standards. We will also continue to administer an exemption process for facilities that are unable to comply with elements of the requirements for acceptable reasons.

- **Transitioning the IBR connection requirements into rules and standards:** While our current approach accomplishes the high-level goal of mitigating the risks posed by IBRs connecting to a weak grid, a rules and standards-based approach has several advantages:

  - Introducing consistency with other jurisdictions
  - Adding regulatory oversight
  - Enhancing enforceability

  Therefore, we will expediently review, modify, and adopt the NERC standards for IBRs, and develop ISO Rules to complement the reliability standards. We plan to draft and consult industry on these rules and standards in winter 2025/2026. Some rules developed through this process may result in new requirements for existing IBR assets. We will work with these assets to ensure reasonable implementation to improve system stability.

- **Evaluating infrastructure-based system strength enhancements:** We will consider solutions if we anticipate or observe reliability issues associated with low system strength, including:

  - **Southeast System Strength Project:** Outflow from the Cassills–Bowmanton–Whitla (CBW) transmission corridor is constrained because of instability risks arising from a system strength deficit
  - We believe either a synchronous condenser or grid-forming battery will make incremental outflow capability available; additionally, we are engaging on bundling system strength services in the procurement of Fast Frequency Response Plus (FFR+)
  - We plan to choose one of these solutions based on the results of system studies and, if applicable, an FFR+ procurement following the engagement
  - At this time, no other enhancements associated with system strength needs have been identified

3.4.2 Advice for Market Participants

Meeting the IBR Connection Requirements is Your Responsibility

- Each new generating or storage facility should be designed for stable operation based on the characteristics of its point of connection, including the fault level and short circuit ratio.

- If the facility does not meet the IBR connection requirements, the owner is responsible for modifying the facility design to enable compliance.

- Modifications could include anything from simple protection and control system adjustments to selecting different equipment or adding a synchronous condenser

- Meeting the requirements in the functional specification is a necessary condition for system access
- If you design a facility that will not function reliably, we will not connect it
- Project developers should work with their AESO project managers to ensure they understand the requirements and seek exemptions as needed to be able to comply

When to Do EMT Studies

- The IBR connection requirements do not tell you when to do electromagnetic transient (EMT) studies
- We require EMT studies late in the connection process, and projects may be exempt based on high-level screening. However, we believe many projects would benefit from a first round of studies prior to equipment selection, followed by a second round of studies using realistic models after detailed design (including control and protection systems). In this way we hope you can discover problems that would influence your major equipment selection before it is too late

Comply With Functional Specifications

- Compliance with functional specifications is a condition for system access
- We may limit system access for facilities that do not comply with the requirements in their functional specifications

Unstable Facilities Will Be Constrained

- Some inverter-based resources that pre-date the IBR connection requirements exhibit intermittent instability or other deficiencies
- Our top priority is ensuring the system is stable and reliable
- We will apply operating limits and curtail generators as needed to prevent instability, power quality problems, or cascading outage risks
- Targeted curtailment of unstable facilities is the most efficient and effective way to restore stability
- Facility owners may be able to avoid or reduce curtailment by adjusting controls or implementing other upgrades to improve stability

Facilities May Have to Be Re-Tuned

- The system strength available to a facility at its point of connection may change over time
  - Consequently, the facility may have to be re-tuned, within the facility’s capability, to maintain stable operation
  - We will consider system strength enhancements when re-tuning does not mitigate reliability concerns

4. Supply and Demand Balance

In this section we provide background information supporting a clear understanding of reliability challenges related to frequency response and balancing, but do not discuss our plans.

The AESO's Role

We are the Balancing Authority (BA) and Reliability Coordinator (RC) for the AIES and are responsible for the reliable operation of the electric system, including maintaining supply and demand balance in normal and abnormal grid operation.

The Interties

Alberta has two alternating current (AC) interties:

- Path 1 (the BC intertie), comprising a high-capacity 500 kV transmission line (called 1201L) between the Calgary area and Cranbrook, BC, and two low-capacity 138 kV transmission lines in Peter Lougheed Provincial Park and the Municipality of Crowsnest Pass.
- Path 83 (the Montana–Alberta Tie Line, or MATL), a merchant-owned 230 kV transmission line between the Lethbridge area and Great Falls, Montana, with series compensation and a phase-shifting transformer.

Direct current (DC) interties, including Path 2 (the Saskatchewan intertie, called McNeill), do not respond to imbalances unless responses are explicitly designed in their control systems.

Supply-demand imbalance has different consequences depending on the status of the AC interties. Table 2 provides the names and descriptions of different operating states. We use these names throughout the Roadmap.

Table 2: Intertie Operating States

Operating State	BC intertie		Montana Intertie	Saskatchewan intertie
	500 kV	138 kV		
Islanded	Disconnected	Disconnected	Disconnected	Either[9]
Weakly connected	Disconnected	Connected	Disconnected	Either
Strongly connected	Connected	Either	Either	Either
Not allowed	Disconnected	Either	Connected	Either

Area Control Error

Area Control Error (ACE) is the instantaneous difference between actual and scheduled interchange, accounting for the effects of frequency bias and frequency error[10]. In practical terms, ACE measures the degree to which supply and demand are out of balance within a balancing area:

[9] i.e., either open or connected.

[10] See the Consolidated Authoritative Document Glossary for a definition.

- A positive ACE indicates supply is larger than demand
- A negative ACE indicates supply is smaller than demand

Large area control error (in either direction) poses physical and compliance risks including:

- Equipment overloads
- Intertie trips
- Load shedding

4.1 Responses to Imbalance

Throughout the Roadmap, when we refer to a *supply-demand imbalance*, we mean an imbalance between aggregate generator *input power* and *electrical load* inclusive of losses.

Generator Technologies and Power Conversion

- Most generator technologies, e.g., gas, coal, nuclear, and wind, convert *mechanical input power* to electrical power
- Solar photovoltaic generators have electrical input power
- Battery storage facilities convert stored chemical energy to electricity (no mechanical input)

Instantaneous Power Balance and Conservation of Energy

- Instantaneous power balance is always maintained in any power system
- Conservation of energy during a supply-demand imbalance is achieved through:
  - Inertial response
  - Minor contributions from stored energy in inductors and capacitors

Frequency Error and System Response

- Inertial response is accompanied by a frequency error, which is the difference between system frequency and nominal frequency (i.e., 60 Hz)
- Frequency error initiates a series of responses to restore balance

The system's inertial response and subsequent responses to frequency error are discussed as follows in chronological order.

4.1.1 Inertial Response

System Frequency and Synchronous Machines

- System frequency is directly proportional to the rotational frequency of each synchronous machine connected to the system
- Synchronous machines store kinetic energy in their rotating mass

Response to Supply–Demand Imbalance

- When supply and demand are not balanced:
  - Kinetic energy is stored or released over time as electric power
  - Machines accelerate (speed up) or decelerate (slow down)
  - The system settles at a new synchronous frequency when mechanical input power equals electrical load
- This process is described by a system of differential equations:
  - Swing equation: the speed of each machine factoring in an inertia constant that represents the amount of energy stored in the machine's rotating mass at nominal frequency
  - Power flow equations: link the swing equations for each machine by determining voltages and currents in the power grid, considering topology and impedances

System Inertia

- Definition: System inertia, stated in units of [GVA·s], is the total inertia of all synchronous machines in the system
  - Primarily contributed by generators
  - Synchronous motors also contribute

Inertial Response

- Definition: The process by which synchronous machines store or release kinetic energy during frequency changes
- Buffers imbalances between generator input power and electrical load
- Continues until acceleration is arrested through primary, secondary and tertiary frequency control

Rate of Change of Frequency (ROCOF)

- Definition: The derivative of system frequency with respect to time
- Impact of system inertia:
  - High inertia: Frequency changes slowly during disturbances (making the system more stable)
  - Low inertia: Frequency changes quickly during disturbances (increasing the risk of instability)

4.1.2 Primary Frequency Response

Supply-Demand Imbalance and System Frequency

- Any imbalance between supply and demand causes:
  - An inertial response

- A deviation in system frequency

Primary Frequency Response (PFR)

- The change in a generator's input power proportional to the frequency error
  - Frequency drops (demand > supply): Generators increase their input power
  - Frequency rises (supply > demand): Generators decrease their input power
- Some loads naturally adjust power consumption based on frequency. For example, synchronous motors consume less power when frequency drops (due to lower spinning), depending on control systems

Role of the Governor

- Control system: The governor manages the PFR of a generator
- Droop:
  - The governor adjusts the generator's mechanical power input in proportion to the frequency deviation
  - Adjustments occur only when the frequency is outside the "deadband"
- Delay in response depends on generator technology: For example, steam turbine generators take more time to burn more fuel to produce additional steam for power

Purpose and Limitations of PFR

- Purpose: Provides proportional changes in active power output to:
  - Reduce inertial response
  - Arrest frequency excursions
- Limitations:
  - PFR cannot restore frequency to nominal levels
  - It begins immediately when frequency error occurs but:
    - Delivery of incremental electric power may be delayed
    - PFR persists until frequency is returned to nominal by other means

4.1.3 Intertie Response

Intertie Response

- Applicable when interconnected with the Western Interconnection via the AC interties
- Frequency changes: Imbalance in the AIES affects the frequency of the Western Interconnection, triggering inertial and primary frequency response
- AIES contribution: Provides a fraction (close to 10 per cent) of the total inertia and PFR of the Western Interconnection

- Western Interconnection contribution: The remaining balance of the response (close to 90 per cent) is provided by the rest of the interconnection
  - AIES supply loss: Causes an inflow of power nearly equal to the supply loss
  - AIES demand loss: Causes an outflow of power that is nearly equal in magnitude

Compliance and Mitigation

- Inertia and PFR are inherently shared within the Western Interconnection
- AIES requirements: Must maintain sufficient inertial response, PFR, and other mitigations to be compliant with BAL-003-AB1-1.1 (see Section 4.4.3)

Intertie Transfer Capability

- Purpose: Reserved to facilitate the intertie response without overloading the interties (See Section 4.5)
- Risks of large imbalances:
  - If the imbalance exceeds the intertie margins, reliability limits may be breached
  - Overloading could trigger a trip by a RAS

4.1.4 Secondary Frequency Control

- Provided by regulating reserve (RR)
- Responds to ACE

Area Control Error (ACE)

- ACE is the sum of the intertie response and the approximate PFR (calculated as frequency deviation x constant representative of PFR)
- Automatic generation control (AGC) uses ACE as an input to adjust RR resources

Automatic Generation Control (AGC)

- AGC typically starts to respond to an imbalance event within 30 seconds and RR can take up to ten minutes to fully respond to AGC control
- When ACE reaches zero or regulating reserve output reaches its limits, RR will hold its output until there is a change in supply-demand balance
- When an imbalance event causes ACE to be larger than available RR, some level of PFR, intertie response, and frequency deviation will persist until subsequent control actions correct the remaining imbalance

Tertiary Frequency Control

- Secondary frequency control is typically followed by directives or dispatches of tertiary frequency control that displace it
- RR is automatically withdrawn as these directives or dispatches impact ACE

Regulating Reserve

- RR is designed for natural supply and demand variations, not contingencies, and is not procured in sufficient quantities to mitigate them
- Imbalances outside the AIES may trigger inertial and primary frequency response, but do not cause a large secondary frequency response[11]

4.1.5 Tertiary Frequency Control

Tertiary frequency control includes actions taken to displace any remaining PFR, intertie response, or secondary frequency control.

- Tertiary frequency response is provided by:
  - Contingency reserve (CR), which is capacity reserved through spinning and supplemental reserves for responding to contingencies according to the requirements set out by BAL-002-WECC-AB1-2, is directed by system controllers following a supply loss contingency to quickly return area control error to zero and displace any prior frequency response and/or control
  - System controller dispatch of assets in the energy market to return ACE to zero or to displace any prior frequency response and/or control while maintaining supply and demand balance
- Net supply provides the ramping capability to match the size, speed, and frequency of net demand ramps beyond what RR can manage
  - Without adequate ramping capability, the system could have large power imbalances sustained over long durations
- Proactive dispatching using system forecasts can better align the energy market dispatch with underlying natural variations in net demand and can reduce the balancing contribution from the preceding responses

4.2 Imbalance Scenarios

Imbalances can occur due to:

- Contingencies (loss of generation, load, or interties)

[11] External imbalances have a negative intertie response (i.e., the AIES providing inertial and PFR to external imbalances over the interties). When calculating ACE, the negative intertie response counteracts the PFR, reducing ACE to approximately zero. Therefore, external imbalances do not translate to secondary frequency control actions.

- Natural variations between net-supply (controllable supply[12] minus controllable demand[13]) and net-demand (non-controllable demand[14] plus system losses and interchange minus non-controllable supply[15])

Table 3 outlines imbalance scenarios by cause and operating state, with explanations on how each is corrected.

Table 3: Imbalance Scenarios

Reason for Imbalance	Strongly Connected	Islanded or Weakly Connected
Negative ACE (excess demand)		
Loss of generation	Scenario 1	Scenario 2
Loss of interconnection (1201L contingency), importing	Scenario 2	n/a
Loss of MATL, McNeill, or 138 kV BC tie elements, importing	Scenario 1	n/a
Natural variations	Scenario 3	Scenario 4
Positive ACE (excess supply)		
Loss of load	Scenario 5	Scenario 6
Loss of interconnection (1201L contingency), exporting	Scenario 6	n/a
Loss of MATL, McNeill, or 138 kV BC tie elements, exporting	Scenario 5	n/a
Natural variations	Scenario 7	Scenario 8

Scenario 1: Loss of supply while strongly connected

- Supply loss is primarily balanced by intertie response, and inertia and PFR responses are relatively small
- Power in-rush (i.e., the intertie response) risks overloading the AC interties
- **Reliability challenge:** Maintain intertie flows within ratings, operating limits and compliance limits, rather than maintaining system frequency stability (see Section 4.5.1.)
- Intertie response is displaced by CR directives, which are displaced by energy market dispatches

[12] Controllable supply is the energy production from controllable resources (i.e., supply resources that can control production to a specified power under normal operating conditions) that are dispatched in the energy market.
[13] Controllable demand is the energy consumption of controllable resources (i.e., demand resources that can control consumption to a specified power under normal operation conditions) that are dispatched in the energy market.
[14] Non-controllable demand is energy consumption of non-controllable resources (i.e., demand resources that are not able to control consumption to a specified power), which is net of DER production not offered in the energy market plus energy consumption of controllable resources that are not dispatched in the energy market.
[15] Non-controllable supply is energy production from non-controllable resources (i.e., supply resources that are not able to control production to a specified power) plus energy production from resources within an ISD that are exclusively used for self-supply and energy production serving onsite load within a net-to-grid dispatched ISD.

Scenario 2: Loss of interconnection while importing; Loss of supply while islanded or weakly connected

- Large supply loss will cause an intertie in-rush that is expected to activate a RAS that trips the remaining tie lines
- Supply loss is balanced by inertial response and PFR, whether islanded or weakly connected
- Loss of interconnection while importing mirrors islanded supply loss, as the AIES becomes an island with a supply deficit
- **Reliability challenge**: Contain frequency above UFLS thresholds (see Section 4.4.1)
- PFR is displaced by CR directives which are displaced by energy market dispatches

Scenarios 3 and 7: Natural variations in supply and demand while interconnected

- Primarily balanced by intertie response, accompanied by a positive or negative ACE
- Intertie response is typically replaced by RR, in turn, which is subsequently displaced by energy market dispatches
- **Reliability challenge**: Manage intertie flows within ratings, operating limits, and compliance limits (see sections 4.5.1 and 4.5.2)

Scenarios 4 and 8: Natural variations in supply and demand while islanded

- Primarily balanced by inertial response and PFR.
- PFR is typically displaced by RR response which, in turn, is displaced by energy market dispatches.
- Large imbalance events can drive a large PFR prior to RR and energy market dispatches correcting the imbalance.
- **Reliability challenge**: Containing frequency within an acceptable envelope (see sections 4.4.1 and 4.4.2)

Scenario 5: Loss of demand while strongly connected

- Similar to Scenario 1, but with intertie out-rush instead of in-rush
- CR is not usable, so intertie response is only replaced by energy market

Scenario 6: Loss of interconnection while exporting; Loss of demand while islanded or weakly connected

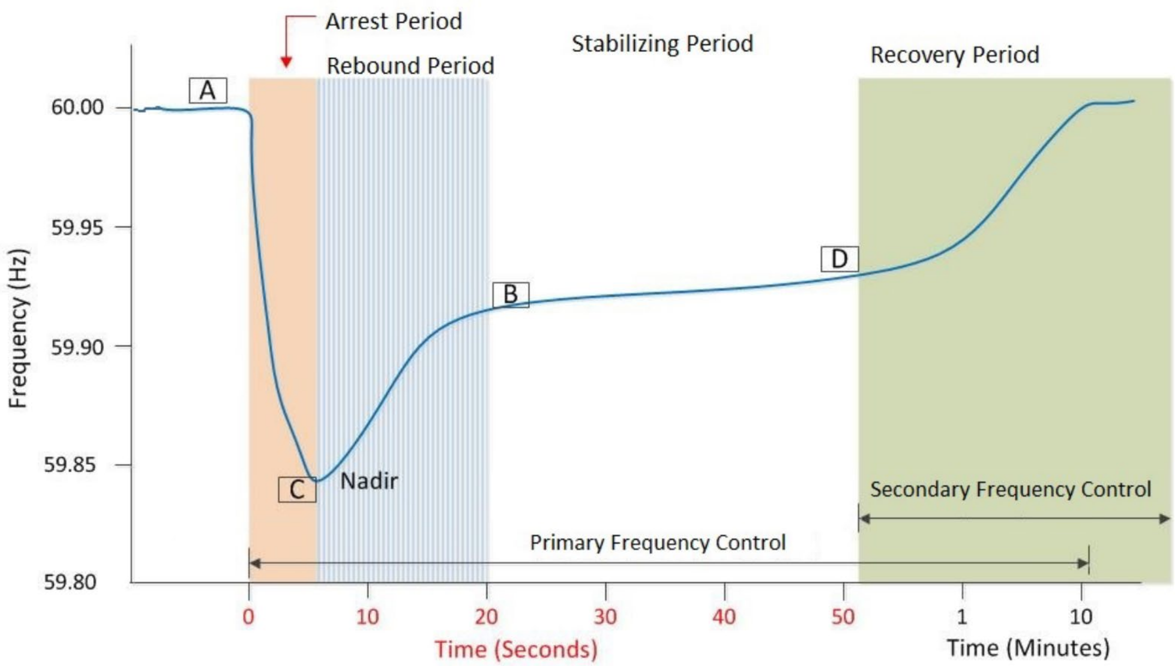
- Similar to Scenario 2, but the focus is on containing frequency within the over-frequency ride-through envelope for generators
- CR is not usable, so PFR is only replaced by energy market dispatches

4.3 Imbalance Examples

4.3.1 Contingencies While Islanded

Figure 2 illustrates a typical frequency excursion caused by a supply loss contingency.

Figure 2: Typical Frequency Excursion[16]



- The frequency excursion is separated into the arresting period, the rebound/stabilizing period, and the recovery period
- The following explains how the responses from Section 4.1 function within each region (intertie response is excluded in this example because the AIES is islanded)
- The arrest period begins when a contingency occurs and ends when ROCOF first equals zero (Hz/s), typically within 10 seconds of the contingency
  - The latter time is called the frequency nadir for under-frequency events and the frequency zenith for over-frequency events
  - The ROCOF immediately after the contingency depends on the size of the contingency and the system inertia (ROCOF decreases as PFR increases)
  - When PFR first equals the size of the contingency, ROCOF is zero (Hz/s), marking the frequency nadir or zenith
- The rebound/stabilizing period is between the frequency nadir or zenith and the time when the frequency stabilizes (i.e., the ROCOF settles around zero (Hz/s)), typically within 30 seconds of the contingency

[16] From Balancing and Frequency Control Reference Document, prepared by the NERC Resources Subcommittee, May 11, 2021.

- At the frequency nadir/zenith, PFR is equal to the size of the contingency, but continues to increase because of hysteresis
- The imbalance switches polarity, and the frequency rebounds
- When the resulting power swings have subsided, ROCOF settles around zero (Hz/s), marking the stabilization frequency

- The recovery period spans from frequency stabilization to its restoration to nominal, typically within 15 minutes
- At the stabilization frequency:
  - PFR is sustained at the size of the contingency due to the sustained frequency deviation
  - Replacing PFR with other responses restores frequency to nominal
  - The recovery period's length depends on the contingency size, available secondary frequency control (RR), and the speed of tertiary frequency control (CR and replacement energy) deployment

4.3.2 Natural Variations in Supply and Demand

Managing natural supply and demand variations is similar to contingency recovery (Section 4.3.1), but the imbalance stems from continuous processes rather than a single event. Key differences in the system's response include:

- The accumulation of variability over time can lead to a large imbalance, but the imbalance forms over a period of minutes or longer (instead of instantaneously).
- As in a contingency, inertial response and PFR act to contain the accumulated imbalance. However, inertial response is minimal and PFR is limited or minimal. When interconnected, intertie response mostly replaces PFR. The slow accumulation of an imbalance (compared to a contingency) allows for secondary frequency response to play a much larger role than PFR while islanded and intertie response while interconnected.
- Secondary frequency control continuously works to reduce ACE and the need for PFR. This is the main purpose of RR. We determine the amount of RR we procure based on the expected size of imbalances due to natural variations in supply and demand.
- Tertiary frequency control is limited to energy market dispatches because CR is not used for variability. Dispatches are made based on accumulated imbalance with the objective of restoring regulating reserve to neutral output and can also be made proactively based on forecasts to reduce the response from secondary frequency control.

4.4 ISO Rules and Alberta Reliability Standards

The following sections identify the ISO Rules and Alberta Reliability Standards (ARS) that control how supply and demand balance is to be managed.

4.4.1 ARS PRC-006-AB-3

ARS PRC-006-AB-3, *Automatic Underfrequency Load Shedding,* requires the AESO to adopt an automatic under-frequency load shedding (UFLS) program, which is specified in ID #2021-002, *Alberta Underfrequency Load Shedding Program*. If frequency were to deviate below the specified envelope, load enrolled in the UFLS program would trip.

- ARS TPL-002-AB1-0 disallows non-consequential load shedding following loss of a single system element (including UFLS activation due to contingencies)
- ARS TPL-001-AB-0 disallows load shedding under normal conditions (including UFLS activation due to natural variations)

Table 4: Imbalance Scenario Mitigations | Scenarios 1–4

Table 4 indicates which mitigations the system relies on in relevant imbalance scenarios.

Scenario	Mitigation Needed				
	Inertial Response	PFR	Intertie Response	Intertie Margin	RR
Scenario 1	Yes[1]	No[2]	Yes	No[3]	No[4]
Scenario 2	Yes	Yes	No	No	No[4]
Scenario 3	No	No[2]	Yes	No[3]	No[5]
Scenario 4	Yes	Yes	No	No	Yes

1. Inertia dampens the imbalance while the intertie response materializes, helping the AIES remain synchronized with the Western Interconnection.
2. PFR is ignored as the intertie response is much larger in magnitude. PFR is still required per BAL-003.
3. Intertie response, rather than intertie margin, helps to contain frequency.
4. While RR will respond to contingencies, it is designed to manage natural variations in supply and demand.
5. RR does not help contain frequency, but rather, helps to contain the intertie response within the intertie margins (see TPL-001-AB-0).

4.4.2 ISO Rule 503.6

ISO Rule 503.6, *Frequency & Speed Governing,* imposes frequency ride-through requirements on generating units, aggregated facilities, and energy storage resources. If frequency were to deviate outside the allowed envelope, generators might trip.

- ARS TPL-002-AB1-0 requires a single contingency, including loss of a load or generator, and must not cause cascading events such as generator tripping

While frequency ride-through requirements apply to both over- and under-frequency excursions, the binding constraint on under-frequency excursions is always UFLS. Therefore, frequency ride-through requirements are only relevant to over-frequency excursions when determining which mitigations are needed.

Table 5: Imbalance Scenario Mitigations | Scenarios 5–8

Table 5 indicates which mitigations the system relies on in relevant imbalance scenarios.

Scenario	Mitigation Needed				
	Inertial Response	PFR	Intertie Response	Intertie Margin	RR
Scenario 5	Yes[1]	No[2]	Yes	No[3]	No[4]
Scenario 6	Yes	Yes	No	No	No[4]
Scenario 7	No	No[2]	Yes	No[3]	No[5]
Scenario 8	Yes	Yes	No	No	Yes

1. Inertia dampens the imbalance while the intertie response materializes, helping the AIES remain synchronized with the Western Interconnection.
2. PFR is ignored as the intertie response is much larger in magnitude. PFR is still required based on BAL-003.
3. Intertie response, rather than intertie margin, helps to contain frequency.
4. While RR will respond to contingencies, it is designed to manage natural variations in supply and demand.
5. RR does not help contain frequency, but rather, helps to contain the intertie response within the intertie margins (see TPL-001-AB-0).

- ISO Rule 503.6 does not contain ROCOF ride-through requirements
- Generators may monitor and incorporate ROCOF into their real-time protection schemes because a high ROCOF may cause mechanical damage to their rotating shaft
- Generators may also monitor ROCOF to identify when they are operating within an island and should trip the generation. Overall, high ROCOF may unexpectedly trip generation
- We conducted a “Rate of Change of Frequency Stakeholder Survey” and will propose changes to ISO rules to establish a ROCOF ride-through requirement. If approved by the AUC, we will use the ROCOF ride-through requirement to determine a minimum operating value for system inertia

4.4.3 ARS BAL-003-AB1-1.1

ARS BAL-003-AB1-1.1, *Frequency Response and Frequency Bias Setting,* is applicable when the AIES is strongly or weakly connected with the Western Interconnection.

- BAL-003-AB1-1.1 requires the AESO to maintain a level of PFR determined by NERC to help regulate the frequency of the Western Interconnection
- Compliance is assessed by measuring the AIES response to frequency excursions that occur within the Western Interconnection (as it manifests in incremental outflow following supply loss contingencies) and comparing the median response against the AIES frequency response obligation

4.4.4 ARS TPL-001-AB-0

ARS TPL-001-AB-0, *System Performance Under Normal Conditions,* requires the AESO to demonstrate through a planning assessment that the transmission system can be operated to accommodate forecasted supply and demand, including natural variation thereof, without exceeding equipment ratings or shedding load.

Table 6: Imbalance Scenario Mitigations | Scenarios 3, 4, 7 & 8

Table 6 indicates which mitigations the system relies on in relevant imbalance scenarios.

Scenario	Mitigation Needed				
	Inertial Response	PFR	Intertie Response	Intertie Margin	RR
Scenario 3	No	No	Yes	No[3]	Yes
Scenario 4	No	See PRC-006[1]	No	No	See PRC-006[1]
Scenario 7	No	No	Yes	No[3]	Yes
Scenario 8	No	See Rule 503.6[2]	No	No	See Rule 503.6[2]

1. The joint application of TPL-001-AB-0 and PRC-006-AB-3 means natural variation in supply and demand while islanded must not activate UFLS, so the system must have adequate PFR and RR to avoid it.
2. The joint application of TPL-001-AB-0 and ISO Rule 503.6 means natural variation in supply and demand while islanded must not activate generator over-frequency protections, so the system must have adequate PFR and RR to maintain frequency within the ride-through envelope.
3. RR should be capable of maintaining ACE within TRM; but if not, incremental margin would be required.

4.4.5 ARS TPL-002-AB1-0

ARS TPL-002-AB1-0, *System Performance Following Loss of a Single BES Element,* requires the AESO to demonstrate through a planning assessment that a single contingency (with normal fault clearing) does not cause non-consequential load loss or cascading outages.

Table 7: Imbalance Scenario Mitigations | Scenarios 1, 2, 5 & 6

Table 7 indicates which mitigations the system relies on in relevant imbalance scenarios.

Scenario	Mitigation Needed				
	Inertial Response	PFR	Intertie Response	Intertie Margin	RR
Scenario 1	No	No	Yes	Yes	No[3]
Scenario 2	Yes	See PRC-006[1]	No	No	No[3]
Scenario 5	No	No	Yes	Yes	No[3]
Scenario 6	Yes	See Rule 503.6[2]	No	No	No[3]

1. The joint application of TPL-001-AB-0 and PRC-006-AB-3 means islanding while importing and supply loss contingencies must not activate UFLS, so the system must have adequate PFR and inertia to avoid it.

2. The joint application of TPL-001-AB-0 and ISO Rule 503.6 means islanding while exporting and load loss contingencies must not activate generator over-frequency protections, so the system must have adequate PFR and inertia to maintain frequency within the ride-through envelope.
3. While RR will respond to contingencies, this is not its intended purpose.

4.4.6 ARS BAL-001-AB-2

- ARS BAL-001-AB-2, *Real Power Balancing Control Performance,* imposes certain balancing performance requirements on the AESO, as further explained in the standard
- We must maintain adequate secondary frequency control capability (e.g., RR) to meet the performance requirements

4.4.7 ARS BAL-002-AB-3 and BAL-002-WECC-AB1-2

- ARS BAL-002-AB-3, *Contingency Reserve for Recovery from a Balancing Contingency Event,* requires the AESO to recover ACE within 15 minutes and have an amount of CR equal to or greater than the most severe supply contingency
- ARS BAL-002-WECC-AB1-2, *Contingency Reserve,* requires the AESO to have an amount of CR equal to or greater than whichever is larger:
  - The most severe single contingency
  - 6 per cent of net generation delivered to the grid minus 3 per cent of the net interchange

4.4.8 Summary

The previous sections outline the ISO Rules, ARS and required mitigations applicable to balancing (including responses described in Section 4.1). Table 8 summarizes these details.

Table 8: Matrix of Mitigations Needed for Compliance

ARS/Rule	PRC-006	Rule 503.6[2]	TPL-001	TPL-002	BAL-001	BAL-002
Scenario 1	Inertia, In-rush[1]			Margin		CR
Scenario 2	Inertia, PFR					CR
Scenario 3	Inertia, In-rush[1]		Margin, RR		RR	
Scenario 4	Inertia, PFR, RR				RR (weakly connected)	
Scenario 5		Inertia, Out-rush[1]		Margin		
Scenario 6		Inertia, PFR				
Scenario 7		Inertia, Out-rush[1]	Margin, RR		RR	
Scenario 8		Inertia, PFR, RR			RR (weakly connected)	

1. PFR is ignored as the intertie response is much larger in magnitude. PFR is still required based on BAL-003.
2. ROCOF ride-through requirements may introduce additional inertia constraints.

4.5 Intertie Margins

Intertie margins facilitate intertie response (Section 4.1.3), which is only applicable when the AIES is connected with the Western Interconnection via the AC interties. Intertie margins are reserved on each intertie to prevent the tie lines from being overloaded due to in-rush or out-rush of power. These may occur for the following reasons:

- In-rush:
  - Loss of generation
  - Loss of another tie line while importing
  - Rising net demand
- Out-rush:
  - Loss of load
  - Loss of another tie line while exporting
  - Lowering net demand

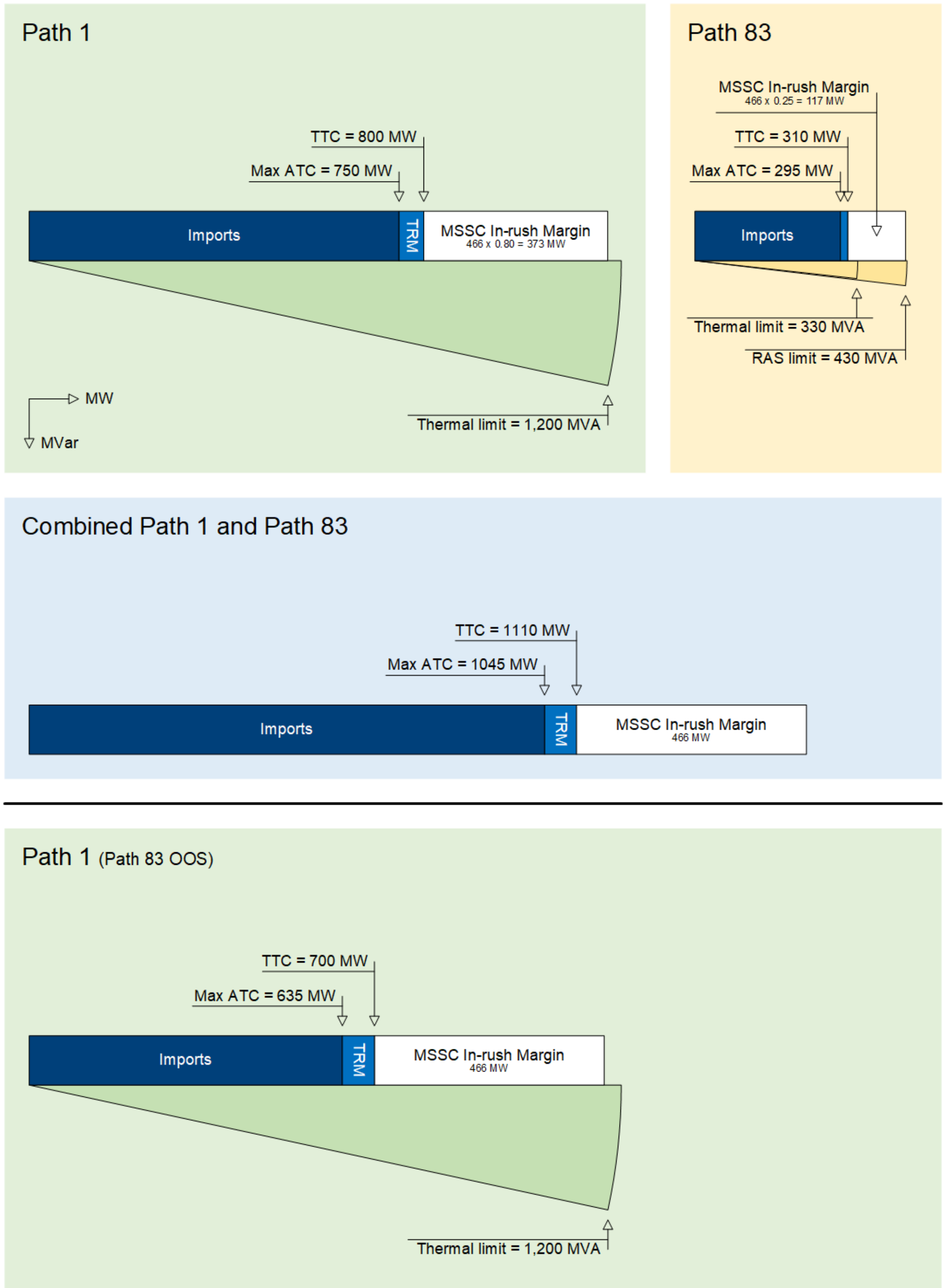
Intertie margins and transfer limits must be coordinated between adjacent jurisdictions to ensure the demand for intertie response can be physically realized.

4.5.1 Import Limits

Figure 3 shows the import scenario with both 1201L and MATL in-service and the import scenario with 1201L in-service and MATL out-of-service. It shows how the summer operating limits are allocated between imports, transmission reliability margin (TRM), MSSC in-rush margin, and allowance for reactive power consumption.

- **Transmission Reliability Margin:** TRM is defined as transmission capacity reserved to ensure the reliable operation of the interconnected electric system, taking into account uncertainties in system conditions and the need for operating flexibility. Natural variation in supply and demand causes an intertie response, described in Section 4.1.3. In practice, TRM is transmission capacity allocated to the intertie response caused by natural variability.
- **MSSC In-rush Margin:** As described in Section 4.1.3, supply loss within the AIES causes an intertie response approximately the same size as the contingency. The MSSC in-rush margin reserves transmission capacity for intertie response caused by supply loss contingencies. Enough capacity is reserved to accommodate the MSSC, which is limited to 466 MW. Each path’s MSSC in-rush margin reflects its share of this 466 MW in-rush. As shown in Figure 3, the loss of Path 83 while importing at its limit of 310 MW would result in a power in-rush on Path 1 that is below its in-rush margin.
- **Reactive Power Consumption:** Both tie lines and transformers consume and transfer reactive power. Reactive power flow is a function of real power flow and system voltages and can only be controlled indirectly (by adjusting the system voltage profile). The active power transfer capability of an intertie (in MW) must be set below the equipment ratings (in MVA) to allow for both real and reactive power to flow.

Figure 3: Import Margin

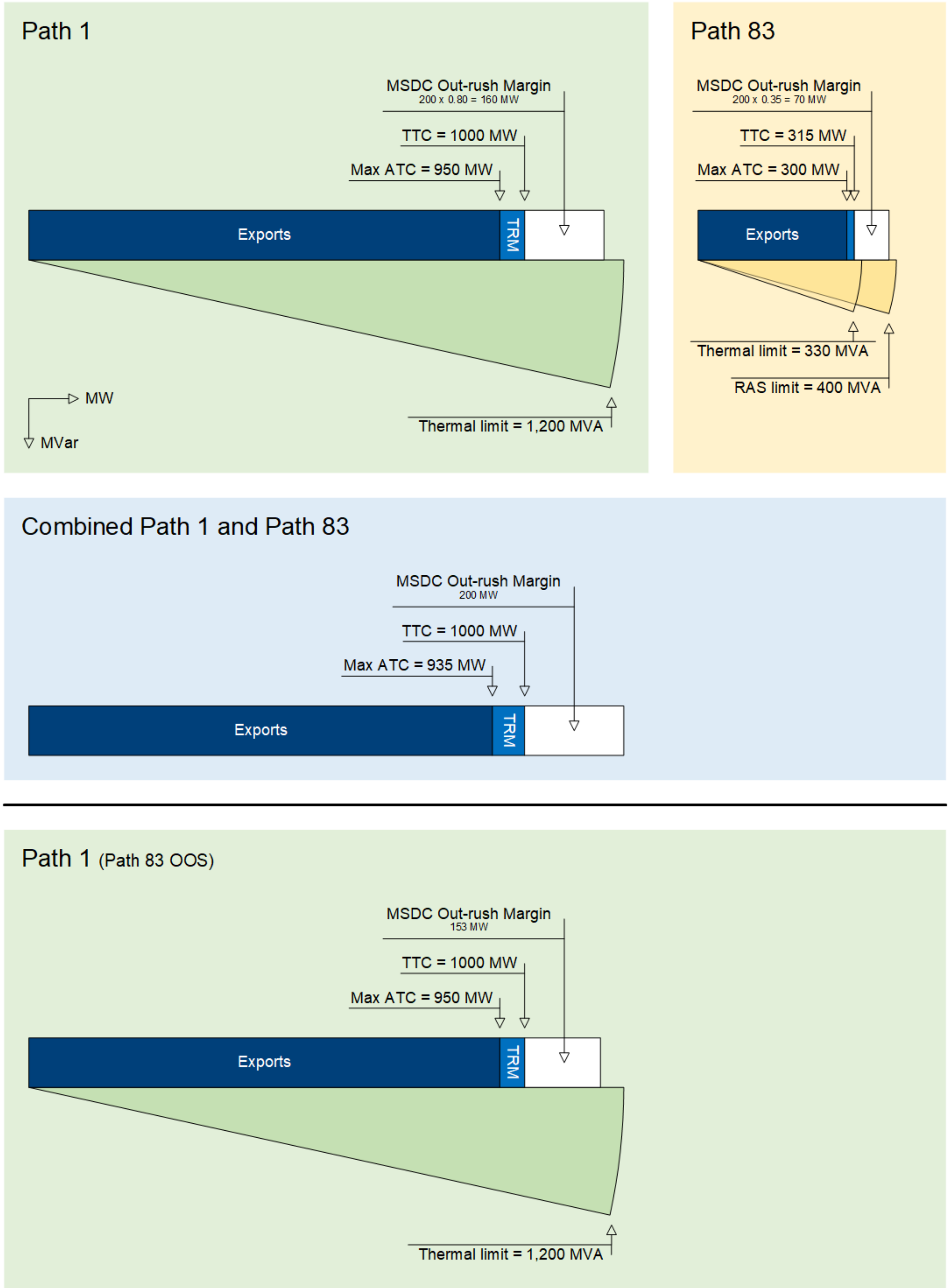


4.5.2 Export Limit

Figure 4 shows the export scenario with both 1201L and MATL in-service and the export scenario with 1201L in-service and MATL out-of-service. The figure shows how the summer operating limits are allocated between exports, TRM, MSDC out-rush margin, and allowance for reactive power consumption:

- **Reactive Power Consumption:** see reactive power consumption under Section 4.5.1.
- **MSDC Out-rush Margin:** as discussed in Section 4.1.3, loss of load within the AIES causes an intertie response approximately equal in size to the contingency
  - The MSDC out-rush margin is transmission capacity reserved for the intertie response caused by load loss contingencies
- Appendix B provides a historical measure of the available MSDC out-rush margin on Path 1 based on the current export total transfer capability (TTC) of Path 1
  - A 200 MW MSDC limit is applied to large load connections to limit the potential out-rush within each path's MSDC out-rush margin
  - Note that, as shown in Figure 4, the loss of MATL while exporting at its limit of 315 MW would result in a power out-rush on Path 1 above its out-rush margin
  - Consequently, the combined Path 1 and Path 83 ATC is limited such that the loss of Path 83 does not overload 1201L
  - For example, if Path 1 is loaded at 635 MW and Path 83 is at 300 MW, the combined export would be 935 MW
  - On the loss of MATL, the intertie response on Path 1 would load Path 1 up to 935 MW
- **Transmission Reliability Margin:** see TRM under Section 4.5.1.

Figure 4: Export Margin



5. Flexibility and Balancing

System flexibility refers broadly to the ability of the electric system to adapt to dynamic and changing conditions while maintaining balance between supply and demand. The electric system's ability to balance net supply with net demand[17] is impacted by the:

- Composition of its generation fleet
- Commitment of assets and their dispatch characteristics
- Quality of forecasts
- Volume and characteristics of its flexibility products

In this section, we outline key challenges that impact balancing performance and our action plan for maintaining system flexibility.

5.1 Existing Balancing Tools

We currently rely on three primary approaches to balance net supply and net demand:

1. Energy market dispatches up or down the merit order (i.e., dispatching net supply) to address changes in net demand and merit order. Proactive dispatching relies on the short-term net-demand forecast, which is approximated by the Alberta internal load (AIL)[18] forecast plus the interchange forecast minus the wind and solar forecasts minus non-dispatched ISD generation serving ISD load[19].
2. Regulating reserve ramp-up or down, via automatic generation control, to address minute-by-minute changes in supply and demand balance.
3. Using a power ramp management (PRM) system, as enabled by ISO Rule 304.3, *Wind and Solar Power Ramp Up Management*, which limits wind and solar generation ramping in fast and large ramp-up events.

Under normal system operation, these approaches do not entirely balance supply and demand. Any residual imbalance manifests as intertie response when interconnected (Section 4.1.3) or PFR while islanded or weakly connected (Section 4.1.2).

5.2 Physical and Compliance Risks

Balancing refers to managing natural variations in net demand through secondary and tertiary frequency control. If the system ramping capability, regulating reserve capability, and other balancing mitigations are not enough to maintain balance, then various operating scenarios (as described in Section 4.2) pose risks of:

- Failing to meet BAL-001 performance obligations when interconnected (Section 4.4.6)
- Tripping the intertie when interconnected (Section 4.4.4)

[17] See Section 4 for definitions on net supply and net demand.

[18] AIL is equal to non-controllable demand plus controllable demand plus system losses.

[19] Approximation assumes there is no controllable demand and non-dispatched ISD generation doesn't change.

- Frequency deviating outside of the acceptable envelope when islanded or weakly connected, causing UFLS or generators to trip (Sections 4.4.1 and 4.4.2)

5.3 Changing Balancing Needs

The installed capacity of wind and solar facilities is expected to increase. Since their output depends on weather, changes in weather are observed as net demand variability. Also, forecasting net demand will become more difficult as wind and solar expand across transmission and distribution systems.

The PRM system handles large increases in wind and solar production, but there's no solution yet for managing large drops in production. These drops are mainly caused by:

- Natural variations in weather conditions:
  - Correlated conditions, e.g., sunset for solar or wind fronts affecting nearby wind facilities
  - Uncorrelated conditions, e.g., cumulus clouds passing over solar facilities
- Weather events:
  - Hailstorms or high winds that cause solar panels to stow or wind turbines to shut down
  - While individual facility shutdowns are manageable (see scenarios 3 and 4 in Section 4.2), the system cannot handle drops exceeding 466 MW
  - Larger decreases may be possible in real-time, but this depends on import limits (Section 4.5.1), which are based on the largest electrical contingency, not weather

Non-conforming load is also expected to increase (see Large Non-Conforming LoadsLarge Non-Conforming Loads). Forecasting consumption is challenging since it depends on unique factors such as real-time computing capacity. If the non-conforming load participates as controllable demand, forecasting isn't needed. Otherwise, increasing unpredictable non-conforming loads will make forecasting net demand harder. To reduce the impact of sudden load changes, the ramp rate of large non-conforming loads should stay within system capabilities.

5.4 Future Balancing Tools

Products in the Restructured Energy Market

The REM is introducing a suite of products to manage issues related to substantial intermittent generation, including solutions to address flexibility and balancing.

- **R30 Ramping Product:** The 30-minute ramping product (R30) is used to schedule and compensate for pre-positioning assets in the current dispatch interval to ensure ramp-up capability is available in subsequent dispatch intervals. The volume of R30 is the sum of the expected ramp (i.e., forecasted ramping) and the unexpected ramp (i.e., forecast error).
- **Security-Constrained Economic Dispatch (SCED):** SCED is an algorithm that co-optimizes real-time dispatches for the energy market and R30 while adhering to system constraints such as supply and demand balance and ramping limitations. Automating the dispatching processes provides a deterministic outcome with consistency in the dispatch calculation and asset response times.

Fast Regulating Reserve

Outside of REM, we are piloting FRR as a complementary product to the existing wind and solar power ramp-up management and regulating reserve products. FRR is used in fast and large ramp-down events to counteract wind and solar generation ramping. FRR provides a power injection equal to the reduction in wind and solar output until the system can transition the response onto regulating reserves and the energy market or the response is no longer needed.

5.5 Assessment of Exposure to Net Demand Ramps

5.5.1 Real-Time Dispatch Simulation

Flexibility and Balancing Assessment

- In this section, the assessment evaluates ramping and balancing requirements following the introduction of REM
- Simulations use the basic inputs available to SCED, and assumptions are made about how SCED operates and how assets respond to dispatches

SCED Dispatch Process

- Dispatch interval: SCED will run on a 5-minute dispatch interval to produce asset dispatches for a rolling delivery interval
- Forecast and Optimization: Following we show how a 5-minute dispatch schedule could progress over three delivery intervals:
  - 1) Forecasts for the delivery interval and the following 23 intervals are provided 10 minutes before the delivery interval begins
  - 2) SCED runs its optimization over the next 5 minutes to produce dispatches based on the forecasts
- Dispatch communication: Dispatches are communicated to assets, which then ramp during the delivery period to meet their dispatch target by the end of the interval
- Continuous process: Prior to the end of the current delivery period, assets receive their dispatch for the next delivery period
  - This ensures delivery periods are seamlessly connected, providing assets with clear expectations for their output and associated ramping

Table 9: SCED 5-Minute Dispatch Process

Step	Time Range (minutes) $t-15$ to $t-10$	$t-10$ to $t-5$	$t-5$ to $t+0$	$t+0$ to $t+5$	$t+5$ to $t+10$	$t+10$ to $t+15$	$t+15$ to $t+20$
Delivery interval starting at $t+0$							
Forecast	Running *available at* $t-10$			Forecast for Energy Dispatch	Forecast for R30 Dispatch	Forecast for R30 Dispatch	Forecast for R30 Dispatch
SCED Calculation		Running *available at* $t-5$					
Asset Ramping			Instruction & Delay[1]	Ramping *at setpoint by* $t+5$			
Delivery interval starting at $t+5$							
Forecast		Running *available at* $t-5$			Forecast for Energy Dispatch	Forecast for R30 Dispatch	Forecast for R30 Dispatch
SCED Calculation			Running *available at* $t+0$				
Asset Ramping				Instruction & Delay[1]	Ramping *at setpoint by* $t+10$		
Delivery interval starting at $t+10$							
Forecast			Running *available at* $t+0$			Forecast for Energy Dispatch	Forecast for R30 Dispatch
SCED Calculation				Running *available at* $t+5$			
Asset Ramping					Instruction & Delay[1]	Ramping *at setpoint by* $t+15$	

1. Delay could be reduced to 2.5 minutes, allowing ramping to reach the target by the middle of the forecast period.

SCED Dispatch Interval and Historical Forecast Data

- **Dispatch interval:** SCED operates on a 5-minute dispatch interval
- **Data limitation:** Historical forecast data used in this analysis is only available in 10-minute intervals

Approximating a 5-Minute Interval with 10-Minute Data

Following, we show how a 10-minute interval can be used to approximate a 5-minute interval.

- Combining intervals:
  - Two 5-minute delivery intervals are combined into a single 10-minute delivery interval

- The historical forecast for this delivery interval is available 10 minutes prior, which aligns with the timing of the 5-minute dispatch interval

- Ramping period:
  - Instead of a 5-minute delay and 5-minute ramping period, a single 10-minute ramping period is applied
  - This ensures the dispatch is achieved by the middle of the 10-minute delivery interval

Key Comparisons Between 5-Minute and 10-Minute Intervals

- Timing consistency: Both intervals have the same duration between the forecast availability and completion of ramping
- Exclusion of midpoints: The 10-minute dispatch interval excludes the “midpoints” provided by the 5-minute dispatch interval
- Impact on variability: The 10-minute dispatch interval has lower variability in asset ramping simulations compared to a 5-minute interval

Table 10: 10-Minute Dispatch Interval Comparison

<table>
<tr><th rowspan="2">Step</th><th colspan="7">Time Range (minutes)</th></tr>
<tr><th>$t-15$ to $t-10$</th><th>$t-10$ to $t-5$</th><th>$t-5$ to $t+0$</th><th>$t+0$ to $t+5$</th><th>$t+5$ to $t+10$</th><th>$t+10$ to $t+15$</th><th>$t+15$ to $t+20$</th></tr>
<tr><td colspan="8">Delivery interval starting at $t+0$</td></tr>
<tr><td>Forecast</td><td>Running
available at $t-10$</td><td></td><td></td><td colspan="2">Forecast for Energy Dispatch</td><td colspan="2">Forecast for R30 Dispatch</td></tr>
<tr><td>SCED Calculation</td><td></td><td>Running
available at $t-5$</td><td></td><td></td><td></td><td></td><td></td></tr>
<tr><td>Asset Ramping</td><td></td><td></td><td colspan="2">Ramping
at setpoint by $t+5$</td><td></td><td></td><td></td></tr>
<tr><td colspan="8">Delivery interval starting at $t+10$</td></tr>
<tr><td>Forecast</td><td></td><td></td><td>Running
available at $t+0$</td><td></td><td></td><td colspan="2">Forecast for Energy Dispatch</td></tr>
<tr><td>SCED Calculation</td><td></td><td></td><td></td><td>Running
available at $t+5$</td><td></td><td></td><td></td></tr>
<tr><td>Asset Ramping</td><td></td><td></td><td></td><td></td><td colspan="2">Ramping
at setpoint by $t+15$</td><td></td></tr>
</table>

Appendix A provides an example of the 10-minute dispatch process for the energy market and R30 over seven intervals, including how the intervals are strung together.

The dispatch simulation requires the net demand forecast as an input. The net demand forecast used in the simulation is constructed from the AIL forecast, wind forecast, and solar forecast[20]. The data source for each of these inputs is as indicated in Table 11.

Forecasted wind and solar generation capacity was sourced from the *AESO 2024 Long-Term Outlook* (2024 LTO). Since the release of the 2024 LTO, trends in wind and solar development suggest that projected wind and solar capacity will be lower than originally forecasted. Therefore, the results included herein are overstating the flexibility needs relative to the latest trends.

Table 11: Input Data for Ramping Simulation

Input	Assumption
AIL Forecasts	Historical 10-minute AIL forecasts from 2023/24 scaled by study year to reflect the forecasted AIL values in the 2024 LTO
Wind Forecasts	Historical 10-minute wind forecast data from 2023/2024 scaled by study year to reflect the forecasted wind generation capacity in the 2024 LTO, using moving averages multiplied by a temporal scaling factor
Solar Forecasts	Historical 10-minute solar forecast data from 2023/2024 scaled by study year to reflect the forecasted solar generation capacity in the 2024 LTO, using moving averages multiplied by a temporal scaling factor

5.5.2 Real-Time Ramping Requirement

Ramping products are procured to ensure enough ramp-up capability is available to SCED when dispatching for a delivery interval; SCED utilizes net demand forecasts for dispatching, and therefore, the ramping requirement is solely based on forecasts instead of observed net demand.

Ramping products will not be procured for ramp-down capability. A ramp down in net demand often coincides with a ramp up of wind and solar production. If the system does not have enough ramp-down capability, SCED can slow down the wind and solar ramp through dispatches.

5.5.2.1 30-Minute Ramping Product

The AESO determines the need for R30 each interval based on the forecasted net demand profile over a 2-hour outlook[21] with an additional volume based on the statistical forecast error. These factors determine the R30 demand curve. Market participants submit offers based on opportunity costs, and the procured amount is determined by where the market clears.

The anticipated volume of R30 for each study year is calculated as follows.

R30 Expected Ramp

- Delivery interval definition:
  - For a forecast at time[22] $t - 10$, the delivery interval is t to $t + 10$
  - The 2-hour outlook period is divided into 10-minute intervals after the delivery interval

[20] Simulation assumes there is no controllable demand, the interchange schedule is zero, and non-dispatched ISD generation doesn't change.

[21] The "30" in R30 is in reference to qualification rather than the outlook period.

[22] When reading times in this section, assume they are in minutes. For example, $t + 5$ means five minutes after time t.

- Ramping capability calculation:
  - For each interval “n” in the outlook period:
    - R30 required to ramp from interval $n-1$ to n = forecasted change in net demand between intervals, adjusted to a 30-minute ramp rate (e.g., multiply by 3 for a 10-minute dispatch interval)
    - Total R30 required to ramp to interval “n” =
      - R30 spent to reach n-1 +
      - R30 required to ramp from interval n-1 to n
    - R30 spent to reach interval n-1 = change in net demand between the delivery interval and interval n-1
- Procurement of Ramping Capability:
  - The expected ramping capability to be procured in the delivery interval is the maximum total R30 required for all intervals "n" over the 2-hour outlook period
- Example: Appendix A provides an example of this calculation

R30 Unexpected Ramp

- Forecast error at time t-10 is the difference between:
  - Dispatched energy market ramping over a 2-hour outlook period
  - Expected ramping requirement
- Dispatched energy market ramping is calculated similarly to the expected ramp, but uses energy market dispatch instead of a forecast
- Energy market dispatch for each interval is set to the forecast made 10 minutes prior

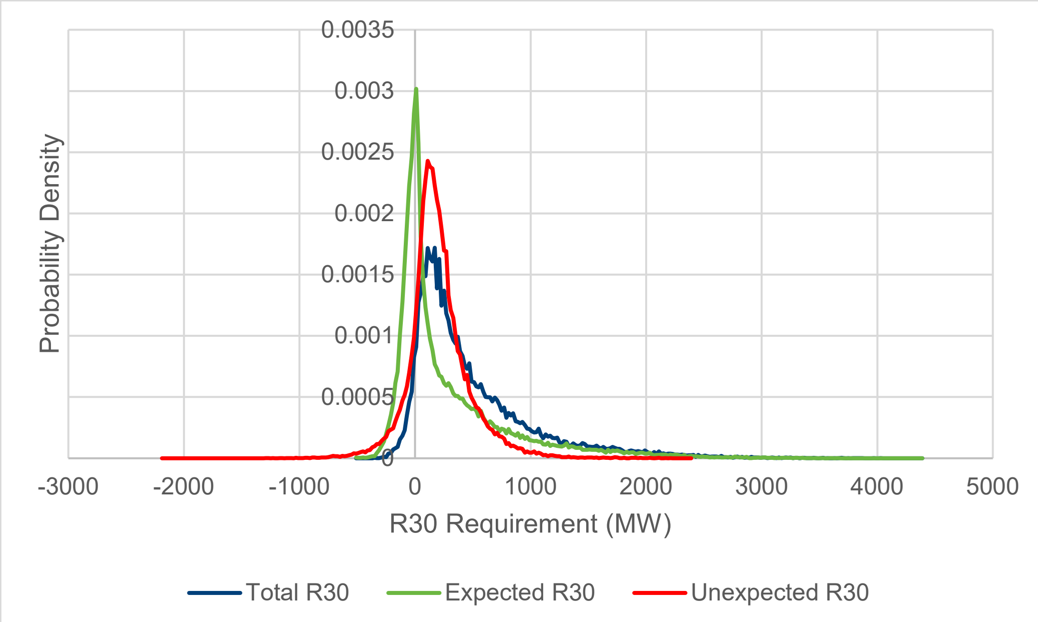
Purpose of Unexpected Ramp Calculation

- Measures the magnitude of forecast error relative to the R30 expected ramp
- Used to derive the ramping reserve demand curve

Figure 4 shows the distribution of R30 expected and unexpected ramp for each 10-minute interval in 2030:

- Includes the total R30 ramp (expected + unexpected) distribution across intervals
- Provides insights into ramping capability required at any interval.
- Practical Application:
  - R30 expected ramp rate is procured based on forecasted ramping
  - Unexpected ramp is procured using a ramping reserve demand curve derived from forecast error distribution

Figure 4: R30 for 2030 (2-hour outlook)



R30 allows the energy market to be dispatched up over a 2-hour duration with the ability to follow forecasted net demand ramps across intervals. Any forecast error observed within a delivery period is managed by regulating reserve (RR), fast regulating reserve (FRR), and/or limiting wind and solar to their dispatch (Section 5.5.3).

Key Findings

- The R30 requirements are based on net demand forecasts[23] and how the forecasts evolve
  - How these forecasts align with the observed net demand impacts the required RR, FRR, and limiting wind and solar to their dispatch (see Section 5.5.3)
- While the procurement of R30 in real-time is dependent on several factors, the volumes identified in an interval to reserve ramping capability for the following two hours are provided in Table 12
- The sum of the 95th percentile for expected and unexpected volumes is larger than the total ramping requirement, as ramping uncertainty doesn't necessarily correlate to ramping magnitude

Table 12: R30 Volumes

Year	Measure	Average	95th Percentile
2030	R30 Expected Ramp	315 MW	1,420 MW
	R30 Unexpected Ramp	162 MW	664 MW
	Total Ramp	481 MW	1,599 MW

[23] Assuming no controllable demand, no interchange, and non-dispatched ISD generation doesn't change.

In the REM Technical Design Finalization Week 4, we provided an estimate that approximately 950 MW of R30 will be required on average in 2030. This number was calculated as the sum of the average R30 expected ramp plus the 95th percentile of the R30 unexpected ramp. As the unexpected ramp is procured based on a ramping reserve demand curve, a single number is not representative of the required volume; the 95th percentile was selected to represent the volumes, assuming R30 is not limited.

The REM derivation of the ramping reserve demand curve focuses on the forecast error over a 30-minute outlook using a simplified approach. As a result, the average R30 unexpected ramp is reduced to 75 MW while the 95th percentile is 323 MW[24]. The selection of a 30-minute outlook materially reduces the R30 unexpected volumes.

5.5.3 Wind and Solar Dispatches

The difference between net supply (i.e., the dispatch simulation results) and the observed net demand is the residual imbalance, which is managed by RR, FRR, and/or limiting wind and solar to their dispatch. While the dispatch simulation only required 10-minute forecast data, the residual imbalance is simulated at a 1-minute granularity and is dependent on the net demand, which is assumed as the AIL minus wind and solar production limited to dispatches. Table 13 explains the data sources for each input.

Table 13: Input Data for Wind and Solar Dispatch Simulation

Input	Assumption
AIL Profiles	Historical 1-minute AIL time series from 2023/24 scaled by study year to reflect the forecasted AIL values (scaling process matches that of AIL Forecasts in Table 11)
Wind Profiles	Historical 1-minute wind production time series from 2023/24 scaled by study year to reflect the forecasted wind generation capacity using moving averages multiplied by a temporal scaling factor (scaling process matches that of Wind Forecasts in Table 11)
Solar Profiles	Historical 1-minute solar production time series from 2023/24 scaled by study year to reflect the forecasted solar generation capacity using moving averages multiplied by a temporal scaling factor (scaling process matches that of Solar Forecasts in Table 11)

Dispatch Simulation Overview

- Wind and solar facilities receive a dispatch based on their forecast
- Dispatch represents the facility’s expected contribution to maintaining supply–demand balance
- Dispatches are converted to 1-minute granularity by interpolating between mid-interval dispatch values

Production vs. Dispatch

- When actual production is **less than** dispatch, the facility cannot correct the error

[24] Numbers are approximate and may change as the REM ramping reserve demand curve is finalized. The average value represents the negative forecast error rather than the expected procurement volume as procurement volumes are subject to the ramping reserve demand curve and supply of R30.

- When potential production **exceeds** dispatch, facilities may need to limit production to the dispatched level to avoid system imbalances

1-Minute Wind and Solar Profiles

- Profiles are limited to the lesser of:
  - 1-minute dispatch
  - 1-minute potential production
- This adjustment helps:
  - Shift net demand closer to the forecasted level
  - Reduce residual imbalances

Practical Implications

- Wind and solar facilities are held back at their dispatch if potential production exceeds the forecast
- Facilities can ramp up quickly to match updated forecasts in subsequent intervals
- This ramping capability helps balance output when other facilities decrease production

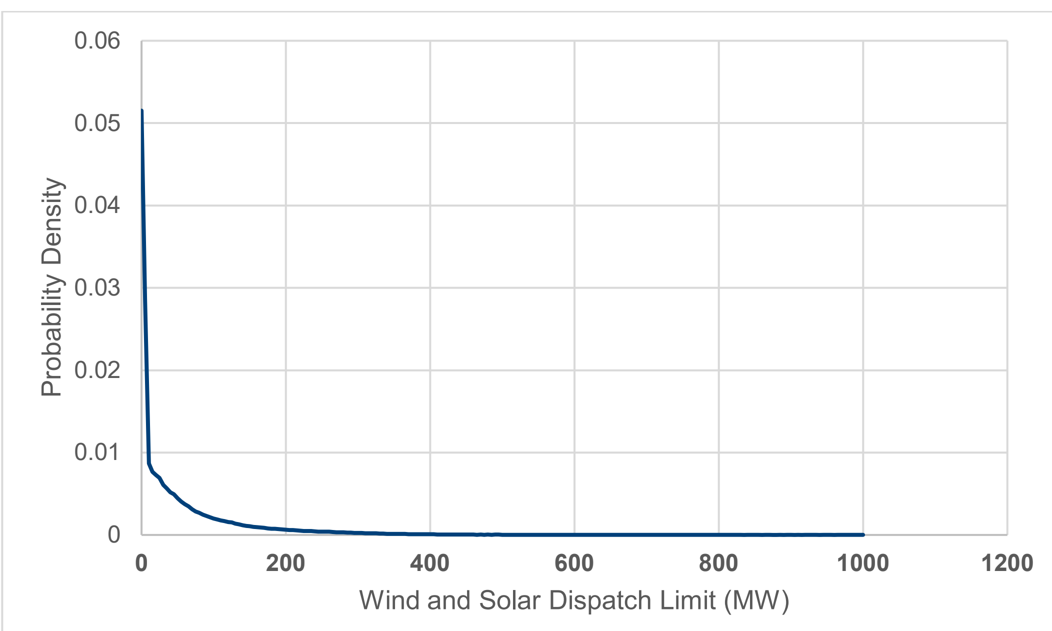
Aggregate-Level Analysis

- For this analysis, dispatch limits are applied at an aggregate level, facilities producing above their forecast offset those producing below

The following

Figure 5 provides a distribution of the 1-minute aggregate wind and solar potential power minus the aggregate dispatch for 2030.

Figure 5: Wind and Solar Dispatch Limit for 2030



Key Findings

- Wind and solar dispatches limit the potential power output above the forecast, which results in lower net demand variability within the dispatch interval
- Dispatch limits reduce energy by an average of 1,217 MWh per day for the purpose of balancing
- Allowing some level of production above the forecast could be manageable without negatively impacting balancing
- With a 100 MW allowance, the reduced energy could decrease to an average of 798 MWh per day (35 per cent reduction)

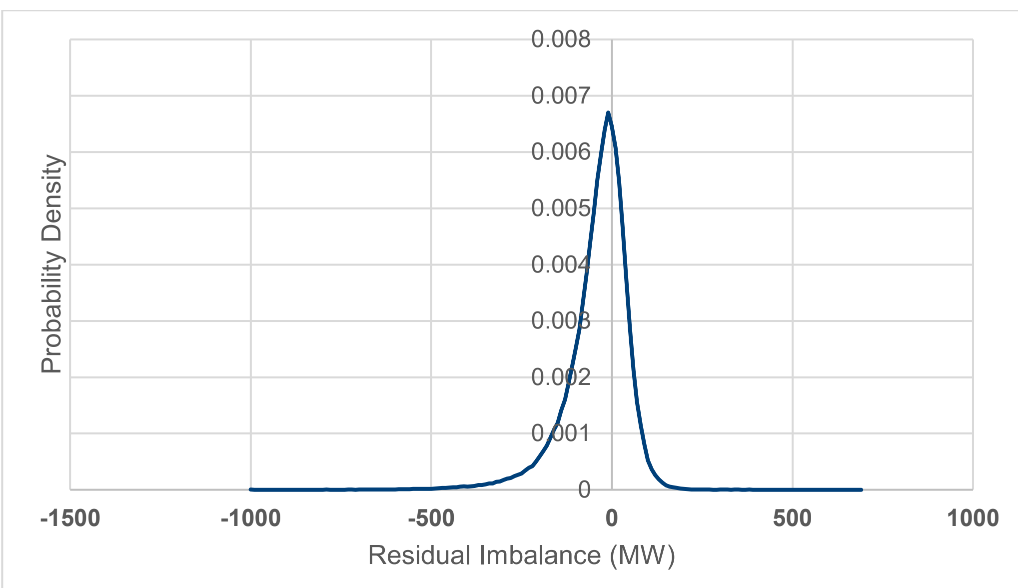
5.5.4 Regulating Reserve Simulation

The regulating reserve (RR) simulation quantifies the need for fast regulating reserve (FRR) and RR based on the residual imbalance from energy market dispatch, including wind and solar being limited to their dispatch. As the residual imbalance is simulated at a 1-minute granularity, the net supply also needs to be converted to a 1-minute granularity. The following assumptions are made about the ramping profile:

- Between R30 and the residual ramp-up capability in the energy market, ramping of net supply can always match the forecasted net demand on a 10-minute interval
- Net-supply ramps linearly between dispatch levels (as illustrated in the figures in Appendix A) at exactly the minute-by-minute dispatched level

With both the net demand profiles and net supply profiles defined, the residual imbalance is the difference between net supply and net demand. Figure 6 provides a distribution of the residual imbalance for 2030, assuming RR is at its midpoint.

Figure 6: Residual Imbalance



The histogram shows that large, undersupplied conditions are more frequent than oversupplied conditions. Limiting wind and solar output to the forecasted values reduces the probability of oversupplied conditions. However, undersupplied conditions do not have an equivalent preventative measure, which allows for much larger deviations.

RR and FRR are, together, designed to manage the residual imbalance:

- FRR is designed as the complementary service to limiting wind and solar production. FRR monitors for when reductions in wind and solar production cause an undersupplied condition and takes corrective action faster than RR
- RR is designed to continuously monitor the system balance and take corrective action. This is after the effects of FRR and dispatches for wind and solar. However, the design of FRR still allows for a transfer of an imbalance from FRR onto RR

The RR simulation considers the impact of FRR and RR on mitigating the residual imbalance. Area control error is simulated as the residual imbalance plus the response from FRR and RR. FRR is simulated with the following assumptions:

- The entire FRR volume can be ramped within one minute
- FRR does not provide energy unless responding to an imbalance (i.e., it only responds to undersupplied conditions)
- FRR responds to firm wind and solar production when ACE is below -50 MW, followed by a 40 MW decrease in wind and solar production
- The FRR response is withdrawn as either wind and solar production return to the pre-imbalance level or area control error recovers above -50 MW (due to a RR or energy market response); the FRR response is withdrawn even quicker if area control error recovers above zero MWs

RR is simulated with the following assumptions:

- The RR volume can be ramped within 10 minutes
- RR sits at the middle of its range under normal conditions (i.e., it responds equally to oversupplied and undersupplied conditions)
- RR integrates the previous ACE to calculate its response

As FRR is controlled to manage wind and solar imbalances, FRR cannot be exclusively used to manage ACE. While RR is controlled to manage ACE, it can also manage wind and solar imbalances. However, FRR is more effective at managing the speed of wind and solar variability and the asymmetrical nature of their imbalances.

Figure 7 provides simulation results for different combinations of RR and FRR in 2030. The contour lines provide the boundaries between different levels of CPS2 performance. The coloured bands provide the average energy requirement from FRR per day relative to the volume of FRR being tested. Table 14 summarizes specific points from Figure 7.

Figure 7: Regulating Reserve Versus Fast Regulating Reserve

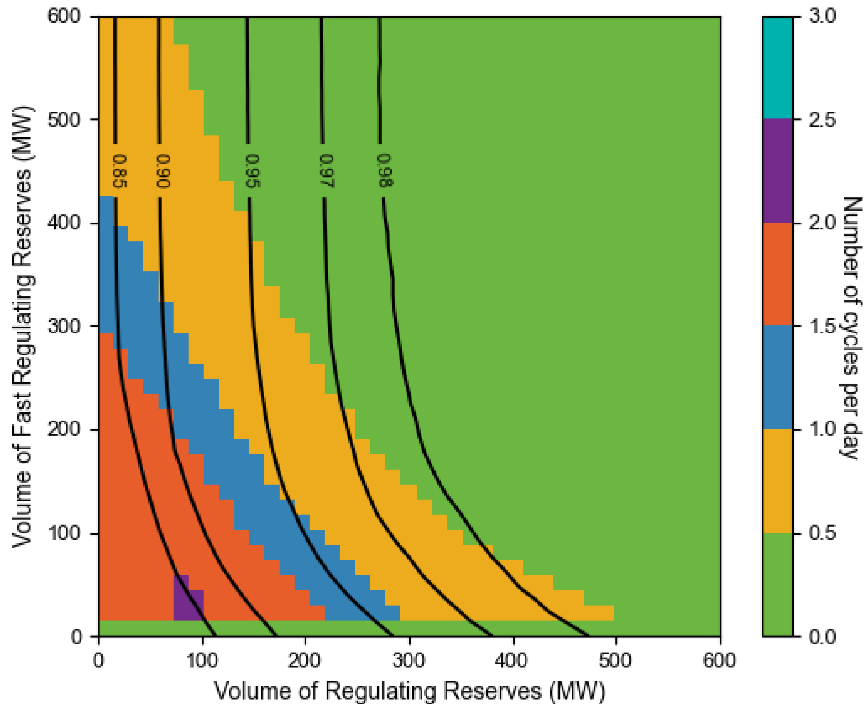


Table 14: Regulating Reserve Versus Fast Regulating Reserve

Year	Case[1]	90% CPS2 Performance		95% CPS2 Performance	
		RR Volume	FRR Volume	RR Volume	FRR Volume
2030	No FRR	173 MW	0 MW	285 MW	0 MW
	100% Cost Optimization	173 MW	0 MW	248 MW	34 MW
	50% Cost Optimization	112 MW	83 MW	198 MW	103 MW
	25% Cost Optimization	75 MW	180 MW	170 MW	178 MW

1. Assuming the per-unit cost of FRR is X% of RR

Key Findings

- Despite the increasing installed capability of wind and solar facilities, current RR volumes are expected to hold due to:
  - Utilization of SCED and ramping products, which increases the responsiveness of the energy market to variability and, therefore, reduces the residual imbalances
  - Limiting wind and solar to their dispatch, which reduces the residual imbalances that RR needs to manage
  - The introduction of FRR (assuming a successful pilot) is complementary to limiting wind and solar, and reduces the need for RR
- About 170 MW of RR and 180 MW of FRR can:
  - Maintain a 95 per cent CPS2 performance in 2030
  - Limit FRR energy to below one hour per day.

5.6 Action Plan

Our strategy for maintaining acceptable balancing performance includes:

- **Adjusting regulating reserve volumes as needed:** At present, regulating reserve is the primary tool used to supplement energy market dispatch when balancing the system. We will continue to regularly assess balancing performance and adjust regulating reserve volume as needed to achieve performance targets. As new services become available, we will optimize between them and use each as appropriate to balance the system efficiently.
- **Implementing Fast Regulating Reserve:** We started designing and implementing FRR in winter 2024/2025. We are working on a pilot with our commercial partner, and it is expected to conclude in the fall of 2025. We are engaging on procuring FRR as a service bundled with FFR+ (discussed in Section 6.6).
- **Introducing a ramping product called R30:** When we purchase this service, which is designed to manage ramping operations, the headroom needed to cover anticipated increases in net demand will be allocated to generators up to their qualified volume (i.e., their ramping capability over the interval) based on their offers co-optimized with energy. Sellers will receive a market-determined price for the flexibility of their assets. In return, we will have the capacity needed for ramping reserved on flexible machines. R30 will be introduced as part of the REM.
- **Implementing Reliability Unit Commitment (RUC):** We need to ensure that large swings in the output of wind and solar generators, such as might happen over periods of several hours on days with volatile weather, can be balanced with dispatchable generation. RUC is used to backstop the self-commitment of units based on reliability constraints.
- **Implementing a new Market Management System (MMS) as part of REM:** An enhanced MMS offers several flexibility benefits. Automated issuance and obeyance of dispatches will eliminate human compliance and reaction time delays. SCED will enable generators to be constrained in an economically efficient way based on physical limitations, including transmission capacity and ramping capability.
- **Improving forecasting capabilities.** Good forecasts are important for committing generation and buying the right amounts of flexibility services. We are looking for opportunities to improve our forecasting capabilities, including market participants' submissions of available capacity data.

6. Frequency Stability

Frequency stability is the ability of the system to maintain an acceptable frequency level and to recover from supply-demand imbalance, especially when caused by contingencies, in a timely manner.

The system's frequency response is primarily determined by the composition of its generation fleet, the strength of its interconnections with adjacent systems, and the volume and characteristics of its reliability support services. The system needs the frequency response to:

- Avoid under-frequency load shedding (UFLS) or generator tripping when large supply loss events occur
- Prevent generator frequency protection activation during frequency excursions
- Comply with reliability standard BAL-003, which requires Alberta to have a minimum level of frequency response for the benefit of the Western Interconnection

The availability of intertie transfer capability depends on the frequency response:

- Loss of the interties while importing is a supply loss event that causes frequency to drop, risking load shedding, as discussed in Section 4.2 (Scenario 2). To enable imports while mitigating the load-shedding risk, the AESO:
  - Limits ATC
  - Uses Fast Frequency Response (FFR) services
- Loss of the interties while exporting causes frequency to rise, risking generator tripping, as discussed in Section 4.2 (Scenario 6)
  - The risk is relatively small compared to the load-shedding risk when importing, due to the system's asymmetrical frequency response
  - Total export is currently limited to 935 MW because of frequency response

The Alberta government directed the AESO to increase the availability of transfer capability on the interties. We must improve on the system's base level of frequency response to carry out the direction.

In this section, we:

- Explain the responses and services we rely on to manage frequency
- Present studies determining the system's base level of frequency response
- Present studies determining the quantity of services required to accommodate large supply or load loss contingencies, including intertie trips

6.1 Frequency Management Tools

The system responds to frequency excursions with:

- Inertial response from synchronous machines (Section 4.1.1)
- PFR that must be provided by generating units, aggregated facilities, and energy storage resources when they have capacity to do so, per ISO Rule 503.6, *Frequency & Speed Governing*
- Load frequency response[25]
- Intertie response (Section 4.1.3), which amounts to inertial response and PFR provided by other balancing areas within the Western Interconnection

The system primarily[26] relies on intertie response and intertie margins (Section 4.5) to recover from loss of supply or demand when interconnected.

For loss of interties (i.e., islanding) and for loss or supply or demand while islanded, the AESO relies on two approaches to manage frequency stability when system responses are insufficient:

- Contracted discrete Fast Frequency Response (d-FFR) services that provide a rapid power injection or load shed when frequency drops below a threshold
- Setting ATC limits, the MSSC limit, and the MSDC limit to ensure contingencies do not require more frequency response than the system can deliver

The above responses and approaches act to contain a frequency excursion, whereas tertiary frequency control is used to restore frequency (Section 4.1.5).

6.2 Physical and Compliance Risks

Frequency stability is achieved by maintaining an acceptable frequency following a contingency. If inertial response, PFR, intertie margins, and other frequency mitigations are not enough to maintain frequency stability, as categorized in Section 4.2 there is risk of:

- Failing to meet BAL-003 performance obligations when interconnected (Section 4.4.6)
- Tripping the intertie when interconnected (Section 4.4.4)
- Frequency deviating outside of the acceptable envelope when islanded or weakly connected, causing UFLS or generator tripping (Sections 4.4.1 and 4.4.2).

6.3 Changing System Performance

The installed capacity of wind and solar facilities and batteries is anticipated to increase in the coming years.

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[25] There are no requirements for load to be frequency responsive, but some loads naturally reduce when frequency goes down or increase when frequency goes up.

[26] Internal frequency response also occurs (See Section 4.1.3).

Wind and solar generators typically have some limitations in their frequency response. They typically output at their maximum potential generation based on prevailing weather conditions. This leaves limited capability to:

- Increase active power output in response to under-frequency conditions (i.e., PFR)
  - Note that wind and solar facilities equipped with a governor system, as per ISO Rule 503.6, *Frequency & Speed Governing*, are to respond to both under-frequency and over-frequency events within their capability
  - Therefore, when wind and solar facilities are supplying active power to the system, they should decrease active power in response to over-frequency conditions and increase active power in response to under-frequency conditions when they are supplying active power below their potential power
- Increase active power output in response to declining frequency (i.e., inertial response)
  - Note that a wind turbine generator can provide a synthetic inertial response by temporarily converting the kinetic energy stored within the turbine into active power
  - However, the turbine speed is slower after the response is provided, reducing the efficiency with which wind is converted to electricity (and therefore reducing the power output)
  - Additionally, the wind facility would also temporarily further reduce active power output to restore the turbine speed. This reduction in active power creates a larger need for PFR, and therefore, creates an unfavourable trade-off when the system is constrained by PFR

Existing wind, solar and storage resources typically use grid-following inverters. Grid-following inverters have some theoretical drawbacks in the way they provide synthetic inertia. The time required to measure ROCOF and respond appropriately reduces the value of synthetic inertia. This limitation can be mitigated by using grid-forming controls, which limit the ROCOF of the voltage waveform synthesized by the inverter instead of following a voltage reference and adjusting voltage angle based on its ROCOF.

6.4 Future Frequency Management Tools

Proportional FFR

Proportional FFR (p-FFR) is a conceptualized service that has similarities with PFR. The notable differences are that the magnitude of response would be much larger for a given frequency deviation, and the response time would be in line with d-FFR. As with PFR, p-FFR would be able to respond to both under-frequency and over-frequency events.

Fast Net Demand Response

Fast Net Demand Response (FNDR) is a conceptualized service that has similarities with d-FFR. The notable difference is that FNDR would respond to event-based triggers in addition to monitoring frequency, allowing FNDR to respond in scenarios where frequency is an unreliable indication of a contingency. Particularly, FNDR could respond to the loss of generation while interconnected and reduce the level of intertie response provided by the Western Interconnection; therefore, the required MSSC in-rush margin could be maintained while increasing the MSSC limit.

6.5 Assessment of Frequency Stability

We evaluated the system's current and anticipated frequency performance for generation profile scenarios representing 2024, 2025, and 2030, with the following objectives per scenario:

- Find the statistical distribution of system inertia and PFR (Section 6.5.1)
- By simulating system dynamics (Section 6.5.2), find the relationships between:
  - The level of supply or demand loss the system can accommodate
  - The level of inertial response and PFR provided by the system
  - The amount of mitigation services in action (i.e., d-FFR or p-FFR)
- Estimate the risk that the system will not meet reliability criteria as a function of contingency size and mitigation services in action (Section 6.5.2)

6.5.1 Inertia and PFR Statistics

The inertia and PFR statistics were calculated based on the following inputs.

Input	Data Source
Generation Profile (Year & Scenario)	2024 – Historical generation profile 2025 (half year) – Historical generation profile 2025 – 2024 Long-Term Outlook Reference Case generation profile 2030 – 2024 Long-Term Outlook Reference Case generation profile
Unit Inertia	Existing Units – Inertia from unit models Future Units – Weighted average of existing units with the same fuel type
Unit PFR	Existing Units – Measured from historical observations Future Units – Per-unit PFR weighted average of existing units based on fuel type

1. Wind and solar units without historical observations are assumed to have a 5 per cent droop.

Each generation profile includes hourly status, output, and available capacity for each unit. Units that are online contribute to the system inertia if synchronous and PFR headroom or foot-room[27] is available.

Table 15 summarizes how the aggregate inertia and PFR are changing over time.

Key Findings

- While the 10th percentile of system inertia is anticipated to marginally decrease from 2024 to 2025 and then meaningfully increase from 2025 to 2030, the increase is subject to assumptions made in the 2024 LTO
- While the 10th percentile of PFR (for under frequency) is declining between 2024 to 2030, these declines are most prominent between 2024 and 2025 and are a result of anticipated unit commitment and headroom from the 2024 LTO compared to 2024 actuals

[27] Minimum stable generation limits were disregarded when calculating the foot-room in historical data sets.

- Historical data from the first half of 2025 suggests that the decline in PFR is much less than the 2024 LTO Reference Case anticipates

- Over-frequency response is much stronger than under-frequency response due to the contribution from wind and solar facilities.

  The over-frequency response could be overstated if new and recently built wind and solar facilities do not provide the assumed five per cent droop.

Table 15: System PFR and Inertia Statistics

Source	Year	Group	Hours	System Inertia (GVA·s)		Under-Frequency PFR (MW/-0.1Hz)		Over-Frequency PFR (MW/-0.1Hz)	
				Median	P10	Median	P10	Median	P10
Historical	2024	Import	2,592	54.8	49.9	85.1	68.8	-	-
		Export	5,908	55.1	49.7	-	-	176.0	143.9
	2025[1]	Import	980	59.9	55.8	77.7	66.1	-	-
		Export	3345	60.7	54.0	-	-	193.8	157.2
2024 LTO Reference Case	2025	Import	2,135	61.3	46.7	49.3	37.4[4]	-	-
		Export	4,944	55.7	40.9	-	-	199.6	150.7
	2030	Import	1,412	65.6	60.3[2,3]	40.4	29.3	-	-
		Export	6,811	64.4	57.1[2,3]	-	-	197.6	141.9

1. Half-year of data (January 1 to June 30).
2. New cogeneration installations in the 2024 LTO Reference Case introduce ~7.4 GVA·s of inertia in 2028 and 2029.
3. The 2024 LTO Reference Case anticipates the implementation of CCS, which results in less cycling and, therefore, inertial generators remaining online in more hours.
4. The 2024 LTO Reference Case anticipates gas-fired steam being offline more often and cogeneration facilities having less headroom than in the 2024 historical data, which results in less PFR.

6.5.2 Effect of Mitigations

Simulation Assumptions

- **Generator inertia:** Generator inertial response was modelled using the swing equation and the instantaneous power imbalance for the simulated inertia level

- **Generator PFR:** Generator response was modelled using a combination of three first-order responses with gains and time constants that mimic the system response for the simulated PFR level

- **Load inertia:** Inertial response from synchronous motors was not modelled

- **Load response:** Load response was assumed to be 14.2 MW/0.1Hz, which corresponds to 8,500 MW of AIL and a 1.0 load-damping constant

  - This assumption was selected to simplify the presentation of results. In real time, load response would be estimated based on AIL at the time

- **ROCOF limit:** No ROCOF limit was applied when calculating risk percentages based on mitigation volumes
  - A ROCOF limit of 0.5 Hz/s and 1.0 Hz/s was assumed for calculating risk percentages that ROCOF will exceed a future ROCOF ride-through requirement
- **Discrete FFR settings:** FFR was assumed to trigger at 59.5 Hz and respond within 200 ms
- **Proportional FFR settings:** Proportional FFR is assumed to have the following power response to frequency within 200 milliseconds
  - Note that resources providing proportional FFR are still required to provide PFR, if applicable

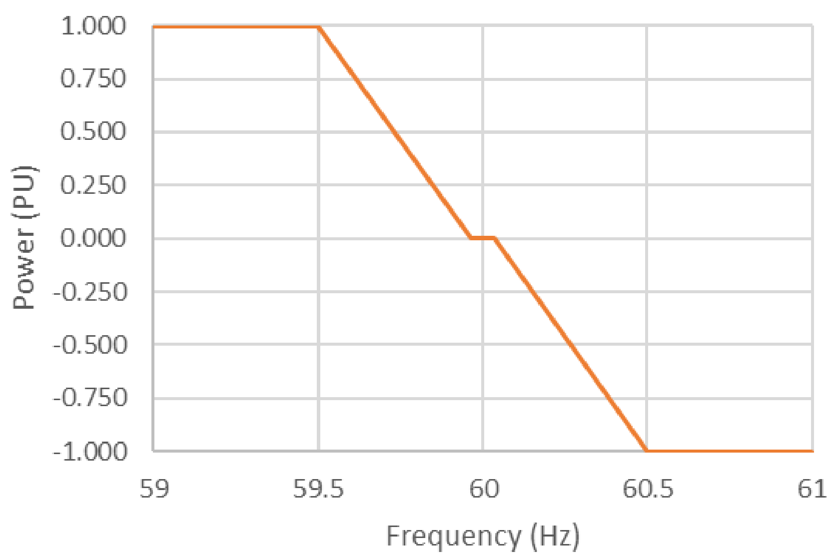


Table 16: Contingency List

Table 16 lists the contingencies we simulated and where they appear in the figures.

Location in Figure (Row, Column)	Contingency[1] (MW)	Contingency Description
1, 1	- 466	Loss of supply at the current MSSC limit while islanded
1, 2	- 716	Loss of supply at an expanded MSSC limit while islanded
1, 3	+ 153	Loss of demand at the reduced MSDC limit while islanded
1, 4	+ 200	Loss of demand at the current MSDC limit while islanded
2, 1	- 1,045	Loss of AC interties at present-day maximum import ATC
2, 2	- 1,245	Loss of AC interties with import ATC increased by 200 MW
2, 3	- 1,445	Loss of AC interties with import ATC increased by 400 MW
2, 4	+ 935	Loss of AC interties at the current maximum export ATC

1. Positive indicates loss of demand, while negative indicates loss of supply.

Simulation Results: d-FFR

- Figures 22–25 in Appendix C provide simulation results for the years 2024 historical, 2025 historical, 2025 forecast and 2030 forecast, respectively, when using d-FFR as a mitigation
- The d-FFR service does not respond in over-frequency events; therefore, only a single 0-MW mitigation line is provided in loss-of-demand scenarios

Key Findings

- The consequences of different ROCOF ride-through limits are as follows for all study years:
  - A 0.5 Hz/s limit would require significant increases in inertia to facilitate existing contingencies and much larger increases in inertia for intertie restoration
  - A 1.0 Hz/s limit would effectively mitigate ROCOF concerns over most operating conditions
- Primary frequency response is the limiting factor for remaining within the allowable frequency envelope (ignoring ROCOF limits)
- Depending on the scenario, there is some level of PFR improvement that could be made prior to the system becoming inertia constrained (i.e., moving the operating points upwards towards the corner line in Appendix C)
  - However, these levels are relatively small and d-FFR remains a good solution compared to increasing both inertia and PFR
- All else being equal, an additional one MW of loss of supply requires an additional one MW of d-FFR up to the point where inertia becomes the limiting constraint
  - Beyond this point, an additional one MW of loss of supply requires more than one MW of d-FFR
- Table 17 provides the volume of d-FFR required for supply loss scenarios and the confidence in maintaining frequency stability for demand loss scenarios

Table 17: Contingency Scenarios

Scenario	Size of Contingency	Historical Data		2024 LTO Reference Case	
		2024	2025	2025	2030
Supply Loss					
Volume of d-FFR required for a 90% confidence in avoiding UFLS operation	466 MW	56 MW	70 MW	213 MW	254 MW
	1,045 MW	636 MW	650 MW	792 MW	834 MW
Demand Loss					
Confidence of frequency remaining within the generator ride-through requirements	200 MW	100%	100%	100%	100%
	935 MW	93%	97%	98%	91%

Simulation Results: p-FFR

Figure 20, Figure 21, Figure 22, and Figure 23 in Appendix C provide simulation results for the years 2024 historical, 2025 historical, 2025 forecast and 2030 forecast, respectively, when using proportional FFR as a mitigation.

Proportional FFR has generally the same findings with some minor variations to the mitigation lines. However, p-FFR can also manage over-frequency events and, therefore, additional mitigation lines are provided.

6.6 Action Plan

6.6.1 AESO Actions

Our strategy for improving frequency response and increasing intertie ATC includes:

- **Procuring high availability FFR:** There is uncertainty as to the required volume of FFR over the next five years. To achieve a 90 per cent confidence of avoiding UFLS at a maximum ATC of 1,045 MW:
  - The FFR needed in 2030 could be as low as 692 MW (650 MW from the 2025 historical data plus the 42 MW increase in FFR observed in the 2024 LTO Reference Case between 2025 and 2030)
  - The FFR needed in 2030 could be as high as 834 MW

  To meet this requirement, we are engaging on the procurement of a new ancillary service called Fast Frequency Response Plus (FFR+). Additionally, we are considering the potential bundling of other services that are not procured through the market to use assets efficiently.
- **Implementing a new tool for determining import ATC:** We are creating a dynamic FFR arming tool that will look ahead two hours to determine the expected level of frequency response, considering the effects of the energy market dispatch and unit commitment
  - It will determine import ATC based on an approximation of actual system state, replacing the conservative offline studies we currently use

- The tool will enable us to increase import ATC most of the time without compromising reliability—it will be operational in Q4 2025

- **Implementing mitigations for over-frequency risks:** We will enhance the dynamic FFR arming tool to monitor over-frequency risk in 2026
  - Some of the new high-availability FFR will regulate frequency in both directions. Until it becomes available, we will use interim mitigations, which may include:
    - Generation shedding or down-ramp RAS or services
    - Operationally restricting export when there is a high risk of generator tripping
    - Asking generator owners to investigate increased ride-through capabilities

- **Proposing new rules:** We want an outcome-based frequency response rule to get predictable and uniform frequency response from all generation and storage technologies
  - We will propose a rule to require this when we transition the IBR connection requirements into the ISO Rules
  - We are also requesting distributed energy resources (DERs) larger than five MW to provide PFR, as defined in the *DERS Primary Frequency Response Guideline*

- **Monitor and evaluate generator responses to frequency events:** We will continue to monitor and evaluate generator primary frequency response to both under-frequency and over-frequency events

- **Increasing the MSSC and MSDC limits:** We are consulting on the FFR+ service (or a subset thereof) to also provide fast response to supply and demand loss contingencies other than intertie trips, where technically feasible (Section 6.4)
  - Provided we find capable providers, FNDR will enable us to increase the MSSC (and potentially the MSDC) limit
  - Feasibility will be tested in detailed engineering studies, followed by a pilot, which will focus on demonstrating that we can meet challenging response time requirements

- **TTC validation study:** We will validate the existing import and export TTC under different operating states
  - An MSDC of 200 MW will be considered for all operating states when determining the export TTC

6.6.2 Advice for Market Participants

Outcome-Based Rules are Coming

- We will propose outcome-based rules that require generators and storage to deliver stable, predictable, and uniform frequency and voltage regulation

- These rules may apply to existing generators, as the existing equipment-based rules were always intended to deliver these outcomes

- Outcome-based rules will be technology-neutral and not limited to IBRs
  - If your facility has the required equipment but is not delivering a reliable outcome, we want you to upgrade it

FFR-Capable Assets Are Needed

- We are engaging on the procurement of FFR+
- Assets with high availability and that are technically capable will be needed for this service

7. Large Non-Conforming Loads

Non-conforming load refers to load that does not follow a typical load pattern.

Economic growth in the 21st century has increased the demand for computing capacity, which is primarily provided by data centres for applications like artificial intelligence, cloud computing, and data storage. These data centres consume significant amounts of electricity and present planning and operational challenges for grid operators, such as the AESO. Their energy consumption is deemed non-conforming, as it is driven by the need for computing power rather than factors related to time or weather.

We are advancing plans to enable data centres to connect in Alberta. Doing so requires that we address certain reliability and grid stability challenges, described below.

7.1 Reliability and Grid Stability Challenges

Data centres and other large loads may create the following risks and challenges:

- **Supply risk:** If data centre load growth outpaces generation growth, or peak production capacity does not coincide with peak load, the system may be unable to serve all load.
- **Congestion:** Data centres, especially hyperscale data centres (sized 100 MW and larger), can be challenging to locate because of transmission capacity constraints. Unlike generators, the AESO does not generally consider using RAS for curtailment to allow loads to connect in places where transmission capacity would otherwise be inadequate. Therefore, it can be relatively difficult to find an acceptable point of connection.
- **Voltage stability:** Data centres can pose voltage stability challenges, particularly when located in electrically weak areas. These facilities typically involve highly concentrated loads that are large relative to the local system demand, which can result in substantial voltage drops under both normal and contingency conditions. This challenge is further amplified in larger data centres, where high active power demand increases reactive power requirements in the surrounding network—potentially straining local voltage support and degrading voltage stability. Additionally, fast load dynamics associated with data centres can cause sharp and sudden voltage deviations.
- **Demand loss contingencies:** As discussed in Section 4.5, we must manage out-rush margin and the MSDC so that the MSDC does not cause intertie overloads.
- **Balancing challenges:** Data centre load can exhibit rapid fluctuations due to changing computation load, cooling systems, or price sensitivity. Abrupt load changes can increase balancing challenges as discussed in Section 4.2.
- **Fault ride-through and resilience:** Data centres can affect the grid's ability to recover from faults. Their sensitivity to voltage and frequency deviations can cause them to trip offline or transfer to backup supply during disturbances, potentially leading to cascading outages. Weak system areas, as discussed in Section 3, are more prone to these problems.

- **Voltage fluctuations and transient stability:** Large variable loads can cause voltage fluctuations (because real power consumption affects the system voltage profile), especially in weak system conditions. Frequency fluctuations are also possible while the system is islanded. Sufficiently large voltage and frequency fluctuations pose ride-through risks for other loads and generators. In extreme cases, they can pose voltage stability risks for the grid.
- **Power quality:** The power electronics used in data centres introduce harmonic distortions that can degrade power quality. Nonlinear loads, such as power supplies for IT equipment, can result in significant harmonic injection into the grid, leading to rapid voltage fluctuations, equipment overheating, and resonance issues. Degradation of power quality can be exacerbated in weak system conditions.
- **Control interactions:** IBRs can have adverse interactions with data centre electronics, which can be exacerbated in weak system conditions. Detailed EMT studies may be required to assess risk and find solutions (such as control system adjustments or filters).
- **Harmonics and resonances:** Large data centre loads can contribute to forced oscillations at low frequencies, particularly under weak system conditions or in areas with low damping. These forced oscillations can propagate across the grid, potentially destabilizing nearby generators or inverter-based resources. Data centre operations can excite torsional modes of nearby rotating machinery, such as synchronous generators or motors. These interactions can lead to resonance stability issues, resulting in mechanical stress on equipment, operational instability, and potential equipment failure if not mitigated.

7.2 Action Plan

7.2.1 AESO Actions

Our strategy for maintaining system reliability as data centres and other large loads connect to the grid includes:

- **Supply risk management:** We need to ensure growth in data centre load does not exceed growth in generation capacity to the extent that the system is unable to supply all customers with power at times. We are managing this risk through an interim large load connection limit for phase one of the large load integration framework.
- **Developing Transmission-Connected Data Centre Technical Requirements:** We will be releasing connection requirements for transmission-connected data centres in Q3/Q4 2025. These requirements will initially be applied in functional specifications like the IBR connection requirements.
- **Taking a standards-based approach:** We will monitor interconnection requirements and reliability standards in other jurisdictions and may adopt additional requirements and standards as North America converges on a common set of requirements. The pace will be driven by developments in other jurisdictions (and our influence on the electricity industry at large).

- **Investigating bi-directional FNDR:** We recognize there could be value in creating symmetrical FNDR capable of responding to both load and generation loss contingencies, to enable a larger MSDC. However, we are uncertain whether or when we will find capable providers for this service. Project owners should assume that this service will not be available until further notice.

7.2.2 Advice for Market Participants

Contribute to Supply Risk Management

The biggest risk to a hyperscale data centre project pertaining to grid access in Alberta is that the system may not have adequate supply for the project. However, data centre owners can partner with (or become) generator owners to mitigate this risk.

8. Rules, Standards, and Requirements

The *2023 Reliability Requirements Roadmap* marked the start of a comprehensive effort to improve reliability rules, standards, and requirements, beginning with a gap analysis focused on IBR requirements. This effort led to the introduction of *AESO Connection Requirements for Inverter-Based Resources*, aligning Alberta's requirements with industry-leading standardization efforts such as IEEE 2800. These requirements addressed important design parameters and capabilities including fault ride-through capabilities, reactive power support, and voltage regulation in weak system conditions.

Subsequently, we have continued to assess potential areas for improvement in the reliability requirements framework, informed by:

- Real-time operating experience
- Market participant feedback
- Evolving grid uses and needs

The scope of assessment was not limited to IBRs, but also extended to standards impacting conventional generation, system operators, and grid performance metrics.

8.1 Opportunities for Improvement

We found the following opportunities for improvement:

- **System Strength**
  - Revised reactive power capability requirements, including provision of VARs at zero or low active power output and updated Q-V characteristics for all generation technologies
  - Improvements in voltage regulation requirements, including regulating on the high-voltage side of step-up transformers and aligning with updated VAR-002 requirements
  - More broadly applicable transient over-voltage, phase angle jump, and ride-through response requirements for abnormal voltage and frequency conditions
- **Frequency Response and Stability**
  - Updated technical characteristics for frequency regulating systems, including synthetic inertia and fast frequency response capabilities for applicable asset types
  - Enhanced ride-through requirements
- **Operational and Technical Standards**
  - Operator training and competency requirements addressing gaps identified in real-time scenarios where operator training and facility control knowledge were insufficient
  - Clarification and expansion of facility monitoring and testing standards, including updates to SCADA, reactive power verification, and model revalidation testing

- **Performance-Based Standards**
  - Introduction of explicit frequency, voltage, and reactive power performance standards to provide clarity and reduce ambiguity in technical rules
  - Proposals for new performance metrics to ensure facilities meet expected operational capabilities under varying system conditions

8.2 Action Plan

To address the identified gaps, we are planning a phased approach to rule development and implementation. We will propose the rules and standards most critical for grid stability in the first phase, such as system strength enhancements and frequency response improvements.

As part of our reliability standards sync-up project, we are reviewing the proposed Milestone 2 IBR standards filed with FERC. The review will:

- Identify whether unique features of the Alberta legislative and regulatory framework require variances from NERC standards
- Identify which parts of the Milestone 2 IBR standards are new content and which parts overlap with the IBR connection requirements and existing ISO Rules and ARS
- Plan for changes to other rules, standards, and requirements to simplify them and remove redundancies

Throughout 2025, we will monitor the development of NERC's Milestone 3 IBR standards ahead of their filing with FERC on November 4, 2025. We will also use this time to:

- Review the Milestone 3 IBR standards (with the same objectives as the Milestone 2 review)
- Draft ARS covering the FERC Milestone 2 and 3 IBR content
- Draft ISO Rules covering IBR connection requirements that will not be part of the ARS
- Revise other ISO Rules and ARS as needed per our review
- Make further adjustments to rules and standards as described in Section 8.2

Upon the completion of Milestone 3, we will consult with stakeholders regarding the adoption of both Milestone 2 and Milestone 3 IBR ARS, as well as any required ISO rules. Engagement with stakeholders on the complete IBR package is anticipated to commence in the first half of 2026, with implementation timelines initially aligned with NERC but subject to consultation.

9. Retrospective

The *2023 Reliability Requirements Roadmap* listed some near- and long-term actions the AESO planned to improve grid reliability. The following tables outline our 2023 plans, and the actions taken to implement them.

9.1 System Strength and Stability

Table 18: Status of System Strength Actions

Action	Status
Near-Term	
Perform detailed Electromagnetic Transient (EMT) studies in weak areas and investigate mitigations	Studied a facility in the southeast as discussed in Section 3.3.1 Studied EATL reliability as discussed in Section 3.3.1
Investigate whether market-based or wires-based solutions for improving system strength are warranted in areas where IBRs are at risk	Determined system enhancement, such as a synchronous condenser, is needed in the southeast
Collaborate with the owners of at-risk facilities to retune controls	Studied a facility in the southeast as discussed in Section 3.3.1 Studied a facility in the Stavely area as discussed in Section 3.3.2 We are coordinating studies for a group of generators in the southeast
Establish requirements for owners to provide EMT models of IBR facilities to the AESO	Implemented mandatory EMT modelling requirements in spring 2024
Require screening assessments in connection studies	Connection and planning studies now require screening for system strength adequacy
Implement real-time system monitoring to improve operational awareness of stability risks	A real-time transient stability assessment tool is currently being tested and will be operationalized in 2026
Regularly conduct studies to identify upcoming operational concerns related to system strength	Each project is subject to screening followed by detailed EMT studies when warranted Operations planning studies determine limits based on system strength The Reliability Requirements Roadmap includes a system-wide screening study

Action	Status
Long-Term	
Integrate EMT studies into outage coordination studies	EMT studies have been used for some scenarios[28]
Build a tool to detect oscillations and instability in real time	Implementation is planned for 2026
Build a tool to predict near-term stability risks based on forecasted conditions	SCED will be capable of applying proxy stability constraints (such as stability-based system operating limits).
Implement a process for improving models based on real-time operational data	Not started
Clearly articulate model requirements for various study types	Developing a series of comprehensive study guidelines to enable analysis and assessment of emerging reliability issues Each guideline provides modelling and data requirements for each study phenomenon
Augment screening studies with detailed EMT simulations in areas that are at risk	Implemented EMT modelling and study requirements Owners must perform studies and show that facilities are expected to perform reliably
Work with facility owners and IBR manufacturers to ensure each facility is studied and performance is verified for credible system conditions	
Develop an integrated generator interconnection and long-term transmission planning process	Implementing an optimal transmission planning process at the direction of Government
Review existing IBR requirements, identify gaps, determine appropriate actions, and implement changes	Implemented comprehensive *AESO Connection Requirements for Inverter-Based Resources* in spring 2024
Develop performance requirements for emerging IBR technologies (e.g., grid forming)	Not started
Monitor impact of IBR proliferation on protection systems and mitigate any reliability risks that arise	No adverse impacts to date

9.2 Flexibility and Balancing

Table 19: Status of Flexibility Actions

Action	Status
Near-Term	
Improve simulation and modelling	Developed new simulation methods as discussed in Section 5.5
Improve wind and solar power ramp management (PRM)	Implemented improvements in 2023

[28] Such as Cascade transformer energization.

Action	Status
Near-Term	
Improve short-term wind and solar forecasts	Added a second forecast vendor in 2024 to improve our understanding of forecast uncertainty and add redundancy Supplementing the solar forecast with cloud tracking based on computer vision in 2025
Update regulating reserve procurement volume as needed	Using an empirical approach to adjust regulating reserve amounts as needed RR procurement was adjusted several times since 2023
Investigate dynamic procurement of regulating reserve	Deferred, pending introduction of new regulating and ramping products and a new Market Management System (MMS)
Improve dispatch certainty during supply surplus events	Planning a new MMS that will improve supply surplus management
Evaluate process, market-based, and rule-based options for improving flexibility	Proposing new balancing products, including ramping reserve, through the Restructured Energy Market FRR is under development and a pilot is currently underway
Long-Term	
Improve system controller tools to enhance situational awareness	Planning a new MMS to enhance balancing capability in various ways
Monitor balancing error and adjust regulating reserve procurement as needed	We are monitoring balancing performance RR procurement was adjusted several times since 2023

9.3 Frequency Response and Stability

Table 20: Status of Frequency Response Actions

Action	Status
Near-Term	
Revise the Fast Frequency Response (FFR) Arming Table (ID #2011-001R Table 7a/b)	Updated in March 2023
Procure FFR for islanded operation	Procured in 2023
Survey industry on the capability of their equipment for ROCOF ride-through.	Survey completed in February 2025
Complete a technical assessment of Fast Net Demand Response (FNDR)	FNDR technical studies are in progress The AESO is planning to include

Action	Status
Near-Term	
Review *Evaluation of the Most Severe Single Contingency Options Paper* responses and make a recommendation	In 2023, the AESO decided to maintain the MSSC limit at 466 MW until further notice
Evaluate responses to the Supply Loss RFI and communicate next steps	Transitioned from Load Shed Service for imports (LSSi) product to technology-neutral FFR
Develop a real-time monitoring tool for frequency response	The AESO has developed a system for determining the required volume of FFR in real time The system is currently being tested, and the AESO is planning to operationalize it in late 2025
Assess the system's capability to meet frequency regulation requirements per BAL-003	The Alberta system is not independently able to reliably meet its BAL-003 FRO Procured transferred frequency response from another Balancing Authority
Long-Term	
Investigate rules-based and market-based options for improving frequency performance	Increased maximum FFR availability to 600 MW in the summer 2024 procurement The AESO is currently engaging in a procurement for high-availability FFR+ (up to 750 MW)

9.4 Additional Actions

We've implemented some improvements that were not included in the 2023 Roadmap, and others are currently in progress. These include:

- Improving our supply adequacy assessment tools
- Published a *Distributed Energy Resources Primary Frequency Response Guideline* in April 2025, suggesting that distribution facility owners should require distribution-connected generators to provide frequency response

Appendix A

The following figures provide a time-lapse example of how SCED could dispatch energy and the 30-minute ramping product (R30) over a 70-minute period. This example is built with the following assumptions:

1. A 10-minute dispatch interval to align with the flexibility analysis (Section 5.5.1)
2. A 1-hour outlook instead of the 2-hour outlook used in the flexibility analysis (Section 5.5.2)
3. No ramping available for energy market dispatch other than R30
4. No R30 procured for unexpected ramp

Each figure represents a delivery interval (n) from $t = n \cdot 10\ minutes$ to $(n+1) \cdot 10\ minutes$. As described in Section 5.5.1:

1. The average net demand forecast for the delivery interval is available at $t - 10\ minutes$
2. The SCED calculation for the delivery interval is run from $t - 10\ minutes$ to $t - 5\ minutes$
3. The resulting ramp in net supply occurs from $t - 5\ minutes$ to $t + 5\ minutes$ and, therefore, the dispatch is achieved at the middle of the delivery interval

The SCED calculation for each delivery interval, which starts at $t - 10\ minutes$, is aware of:

1. The "Projected Net Supply" based on the energy market dispatch from the $n - 1$ interval, which ramps from $t - 15\ minutes$ to $t - 5\ minutes$
2. The "Ramp Up Capability" between $t - 5\ minutes$ to $t + 25\ minutes$ is the "R30 Dispatch" from the $n - 1$ interval
3. The net demand forecast ("T$[t - 10\ minutes]$ Net Demand Forecast") in the six 10-minute intervals following the delivery interval

The SCED calculation provides two dispatches:

1. The energy market is dispatched to the "T$[t - 10\ minutes]$ Net Demand Forecast" for the delivery interval which results in the "Projected Net Supply" ramping from $t - 5\ minutes$ to $t + 5\ minutes$
2. The "R30 Dispatch" is calculated from the "T$[t - 10\ minutes]$ Net Demand Forecast" across the six 10-minute intervals following the delivery interval. First, the R30 requirement for each interval ("R30 Segment") is calculated as the change in the "T$[t - 10\ minutes]$ Net Demand Forecast" from the previous interval adjusted to a 30-minute ramp (e.g., x3 for a 10-minute dispatch interval) plus the R30 used to reach the previous interval. Then, the "R30 Dispatch" is the maximum of the "R30 Segments". The "R30 Dispatch" provides "Ramp Up Capability" available at $t + 5\ minutes$. This process is expressed as:

$$R_{30}(t+5) = \max_{n=1,2,3,4,5,6} [3 \cdot F_{t-10}(t + 10n + 5) - 2 \cdot F_{t-10}(t + 10n - 5) - F_{t-10}(t+5)]$$

Where:

- R_{30} is the R30 dispatch
- F_{t-10} is the net demand forecast 10 minutes before the delivery interval

Finally, error can exist between the "Net Supply" and the "Net Demand" due to:

1. Forecast error (e.g., the "T$[t - 10\ minutes]$ Net Demand Forecast" was incorrect resulting in net supply deviating from net demand), which should self-correct over the following intervals
2. Limited ramping capability (e.g., the available ramp up capability is less than the expected increase in net demand), which will take time for dispatches to catch up
3. Interval duration (i.e., net supply is controlled on a 10-minute dispatch interval and SCED cannot dispatch for net demand variation within the interval)
4. Generation ramping, which is not shown in this example (e.g., power deviation from a generator's expected ramp)

These errors are referred to as natural variations between net supply and net demand (see Section 4.2) which is primarily managed by regulating reserve, fast regulating reserve, and limiting wind and solar to their dispatch.

Figures 8 through 14 provide a time slice for seven intervals and illustrates how past SCED dispatches and forecasts are used to make dispatches for the delivery interval. There are several observations to note:

- Figure 9 illustrates how negative forecast error is managed. The increase from the "T00 Net Demand Forecast" to the "T10 Net Demand Forecast" in interval 2 (+25 MW) results in additional ramping need that was not planned for when R30 was dispatched in interval 1. This additional ramping need pulls forward ramping capability reserved for later intervals, forcing the spent R30 to be replaced by new R30.
- Figure 10 illustrates how positive forecast error is managed. The decrease from the "T10 Net Demand Forecast" to the "T20 Net Demand Forecast" in interval 3 (-120 MW) results in less ramping need than what was planned for when R30 was dispatched in interval 2. This lower ramping need pushes back ramping capability and makes it available for later intervals. In this case, the pushed back ramping capability is retained as the "T20 Net Demand Forecast" still anticipates similar ramping.
- Figure 14 illustrates how forecast error can result in a ramping requirement larger than the ramping capability procured through R30. In interval 6, 335 MW of R30 was dispatched based on the "T50 Net Demand Forecast" providing 112 MW of "Ramping Up Capability" between interval 6 and 7. In interval 7, the "T60 Net Demand Forecast" updated to have a 175 MW ramp up between interval 6 and 7, which is 63 MW above the available ramping capability. Therefore, the energy market dispatch is limited to the available ramping capability of 112 MW. Without other sources of ramping, the resulting error is managed by regulating reserve and R30 demand spikes to catch up. Additional R30 procured for uncertainty would reduce the spike and need for regulating reserve.

Figure 8: Interval 1

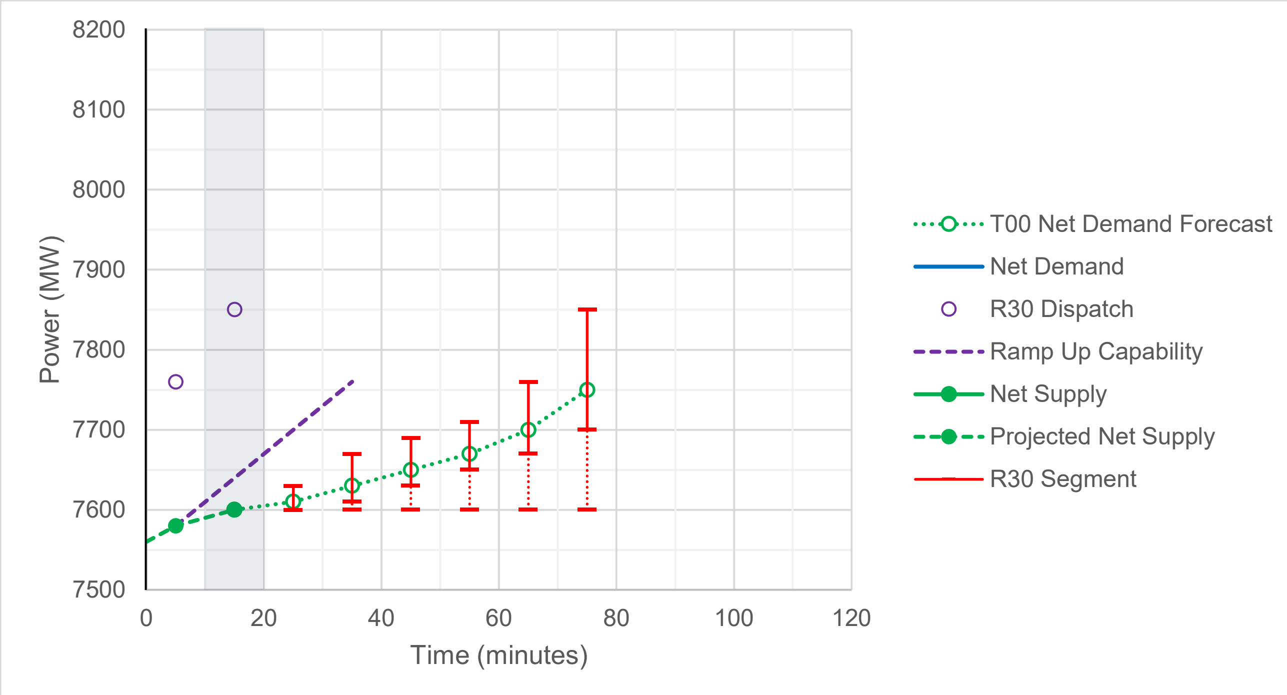


Figure 9: Interval 2

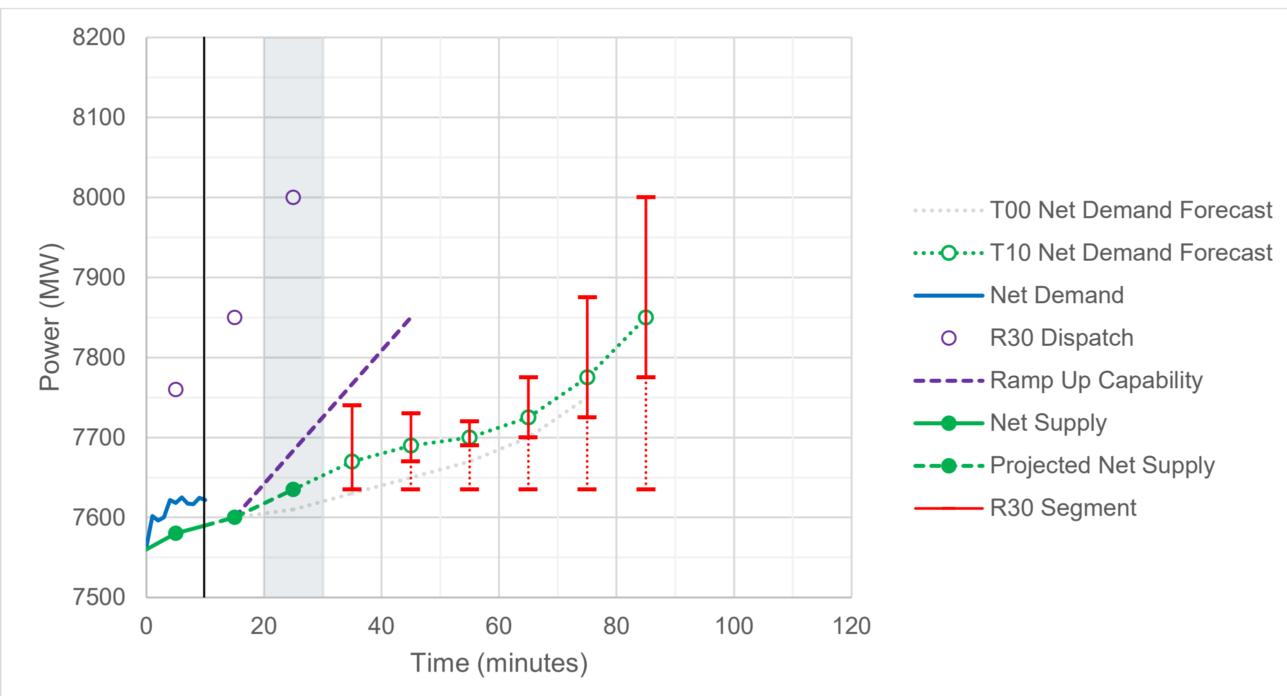


Figure 10: Interval 3

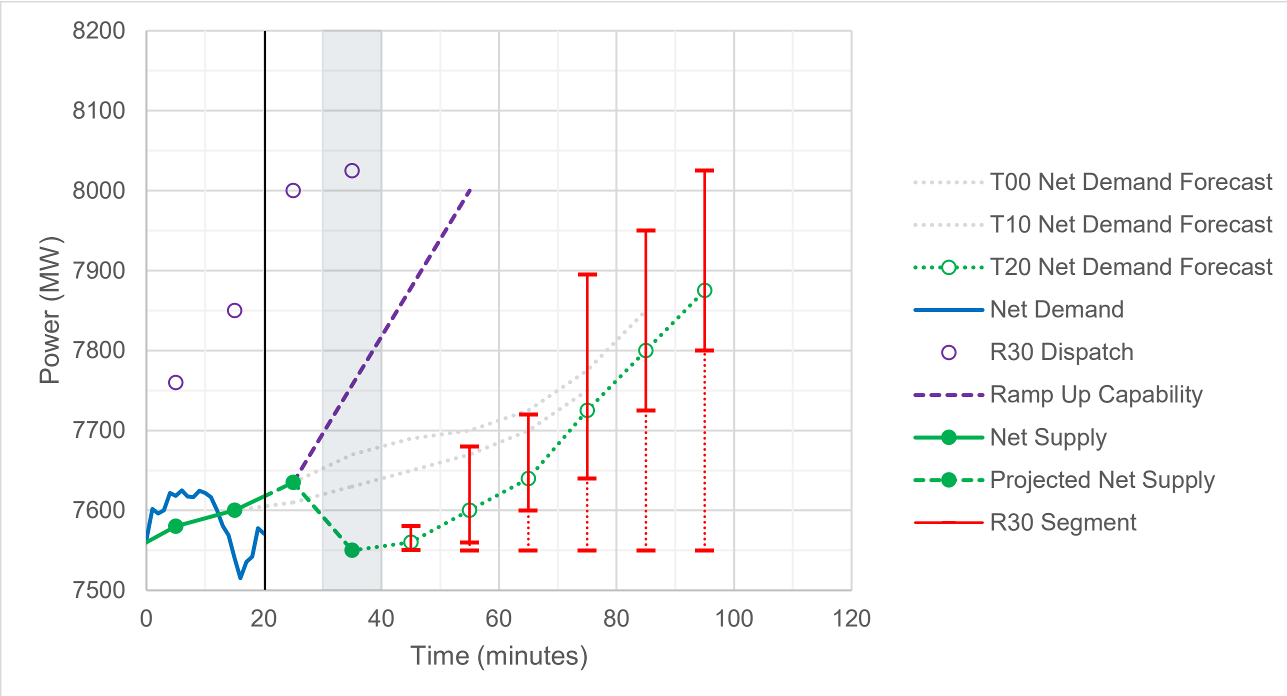


Figure 11: Interval 4

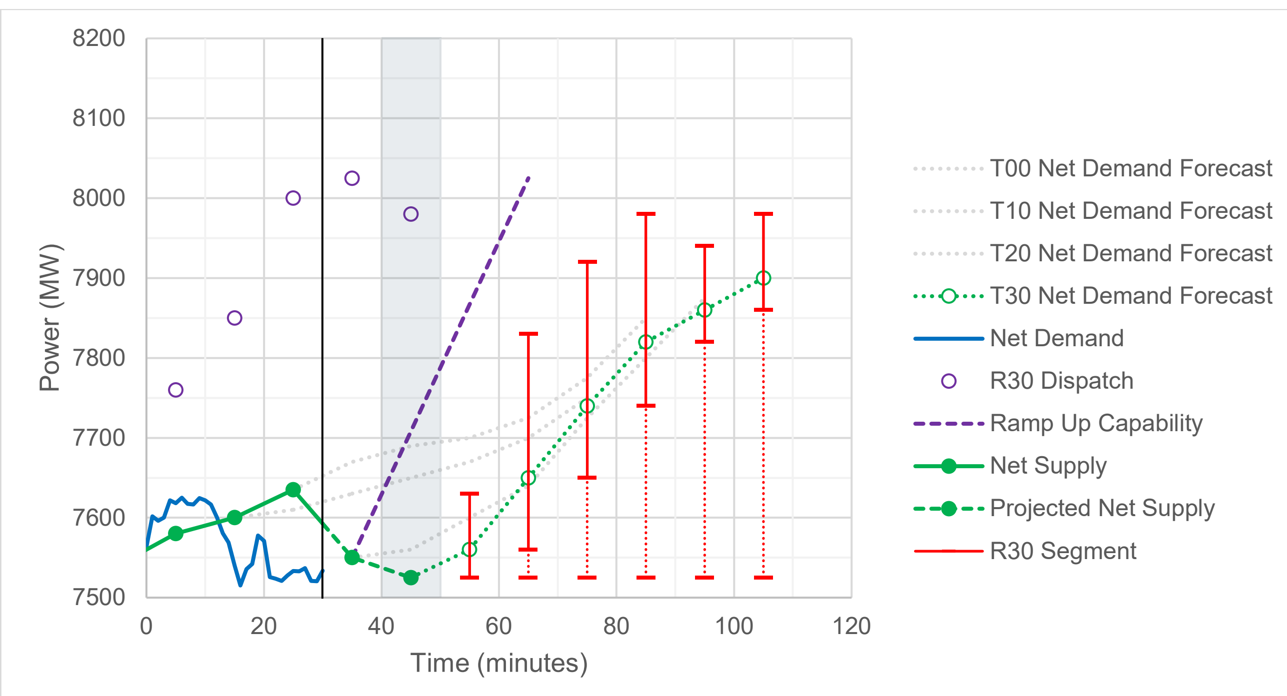


Figure 12: Interval 5

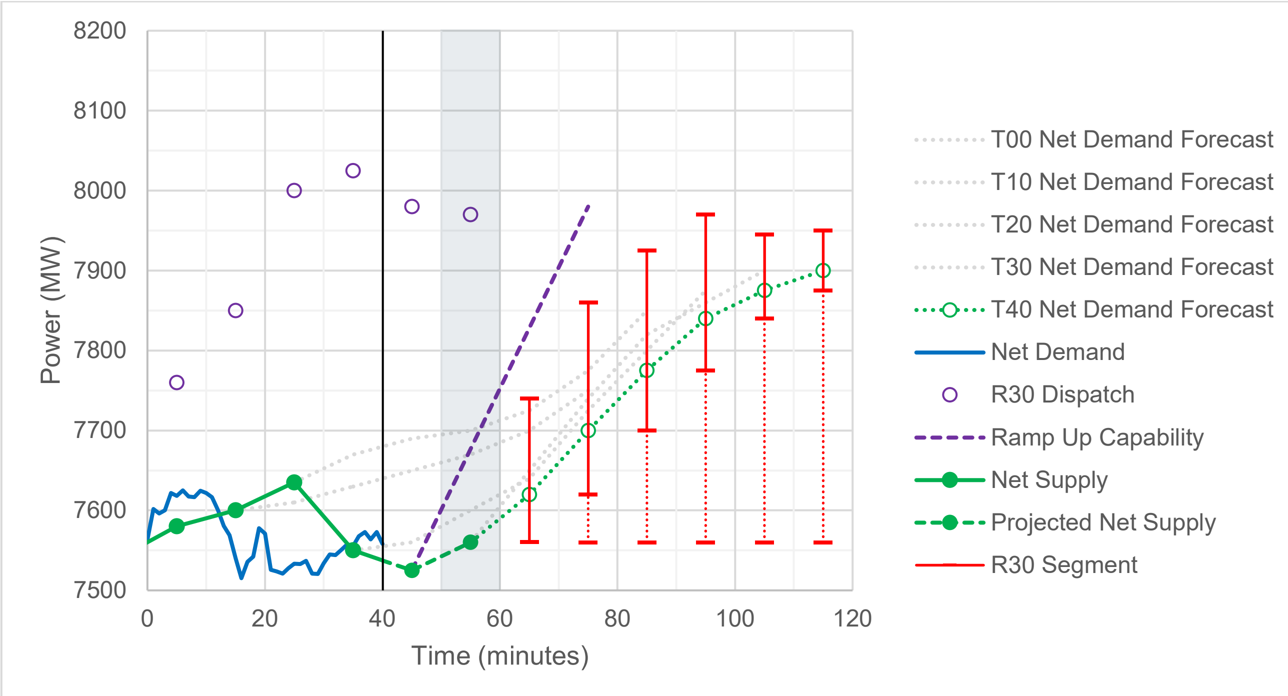


Figure 13: Interval 6

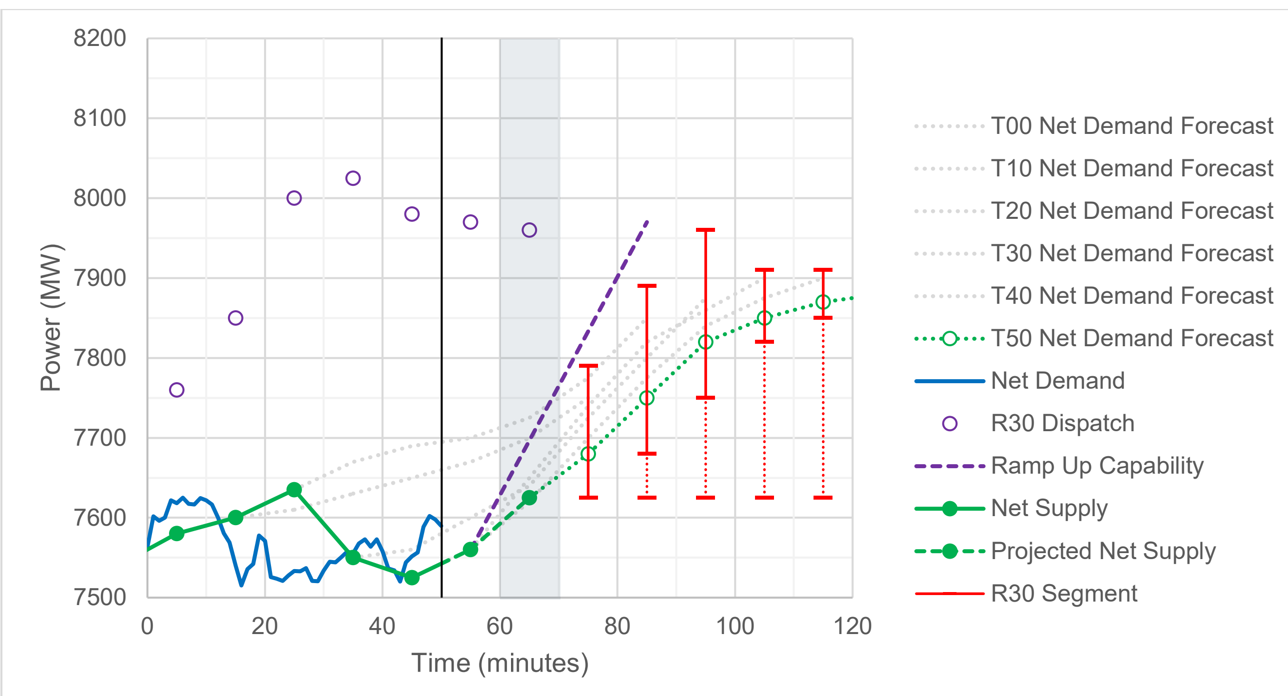
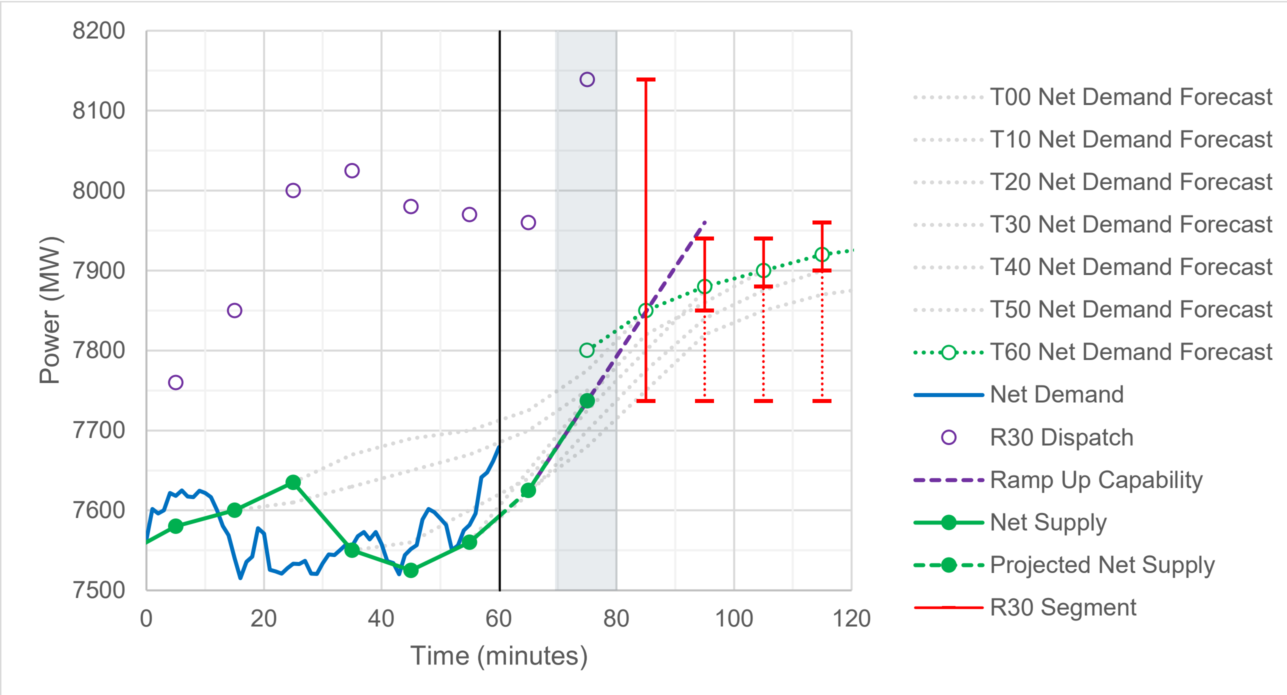


Figure 14: Interval 7



This example is summarized in Table 21, including the ramp-up capability available for dispatch, the change in energy market dispatch, and the incremental R30 that needs to be sourced (i.e., replacing R30 used for ramping in the previous interval and adjusting for changes in the expected ramp).

Table 21: SCED Dispatching Example

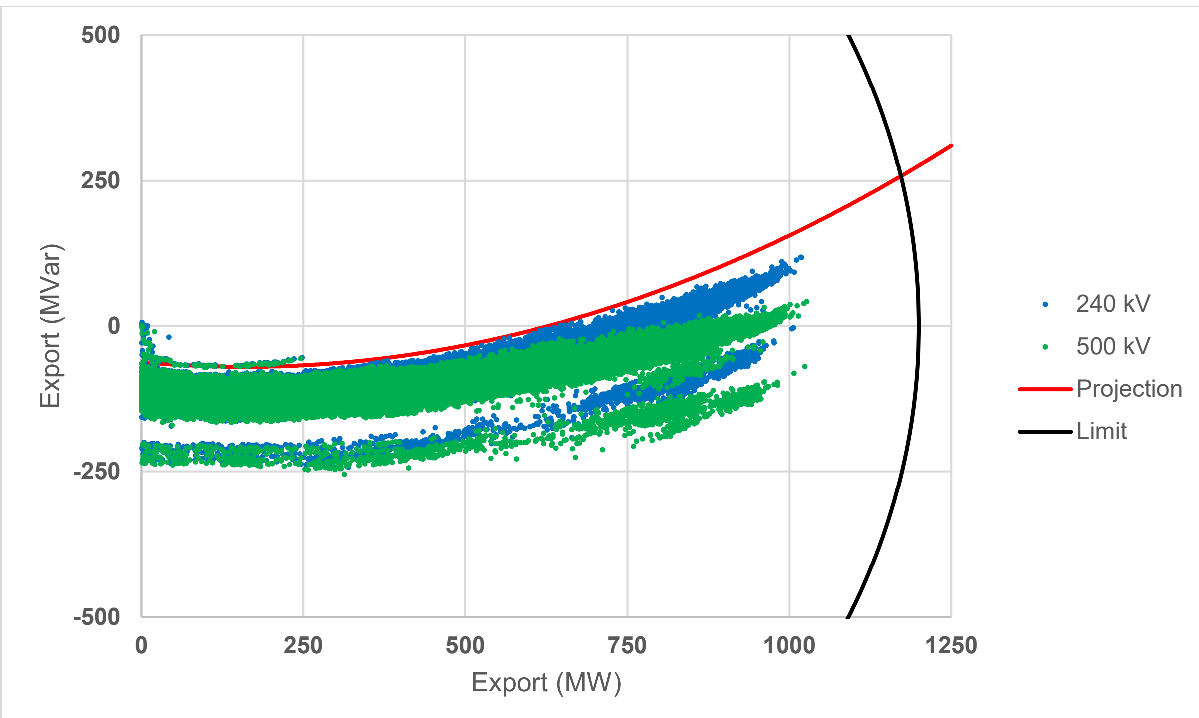
Dispatch Interval	Previous R30 Dispatch (MW)	10-minute Ramp Up Capability (MW)	Energy Market Ramp (MW)	Dispatched R30 (MW)	Incremental R30 (MW)
1	180	60	20	250	90
2	250	83	35	365	150
3	365	122	-85	475	25
4	475	158	-25	455	-45
5	455	152	35	410	-10
6	410	137	65	335	-10
7	335	112	112	402	179

Appendix B

Figure 15 provides five years of historical power flows for Bennett transformer from 2020 through 2024, which captures the relationship between real and reactive power.

- Blue points are the 10-minute average active power vs reactive power measured on the 240 kV winding of the transformer, while the green points are measured on the 500 kV winding.
- The red “projection” line is a P-Q relationship fit to the operational data from the 240 kV winding. The P-Q relationship accounts for typical operating voltages at Bennett and Cranbrook because it is fit to the conservative end of the historical measurements.
- The black “limit” line represents the 1,200 MVA rating of the Bennett transformer.

Figure 15: Bennett Transformer Historical 10-minute Average Export



Bennett Transformer and MSDC Limits

- Key operating conditions:
  - Maximum Temporary Rating $S = 1{,}200\ MVA$:
  - Transformer capacity: 1,200 MVA
  - Power flow (approximate): $P = 1{,}172\ MW$ and $Q = 257\ MVar$
  - Based on the P-Q projection (intersection of “projection” and “limit” lines)
  - Export Total Transfer Capacity (TTC):
  - 1,000 MW

- Residual Capability for MSDC Out-Rush Margin:
  - Minimum residual capability:
  - 172 MW $(1{,}172\ MW\ -\ 1{,}000\ MW)$
- Impact of MATL
  - When MATL is in-service:
  - Approximately 80 per cent of demand loss appears on the Bennett transformer
  - Allowable MSDC 215 MW $(172\ MW/0.8)$ under typical operating conditions
  - MSDC limit set to 200 MW to provide some margin
  - When MATL is out of service:
    - Allowable MSDC 172 MW, unless export TTC is reduced to reserve more capability for MSDC out-rush margin
    - MSDC limit set to 153 MW until a TTC validation study is completed

Appendix C

We've presented the results of our evaluation of system frequency response in Figure 16 to Figure 23. Each figure comprises several diagrams showing different contingencies, arranged per Table 21.

For each diagram:

- The X axis is the system inertia and the Y axis is the generator PFR
- The solid lines, referred to as mitigation lines, represent the minimum inertia and PFR required to contain the frequency within the acceptable envelope (Sections 4.4.1 and 4.4.2) based on a specified amount of FFR
- The highest mitigation line represents 0 MW of FFR, and each successive mitigation line (moving down the Y axis) represents a 100 MW increase in FFR
- The colour of the mitigation lines indicates the calculated ROCOF for that operating point.
  - The ROCOF is calculated as the maximum absolute change in frequency measured over a 500 ms window
- The densely dotted line, referred to as the corner line, connects the mitigation lines where the mitigation transitions from being limited by the frequency nadir/zenith (left of the corner line) to being limited by the stabilization frequency (right of the corner line)
- A hexagonal lattice is overlaid, where each hexagon is used as a bin for displaying a 2-dimensional histogram of the system inertia and generator PFR
- Each annual generation profile contains hourly operating points that are binned into the hexagons. The total count of points within each bin is indicated by the colour of the hexagon
- The sparsely dotted lines, referred to as the inertia lines, represent the minimum inertia required for different assumed ROCOF limits such that the ROCOF immediately following the contingency (when it is highest) is within the limit
  - The percentage of operating points to the right of each inertia line is used to quantify the probability that the available inertia can maintain the ROCOF within the assumed ROCOF limit. The calculated probability is reported within the label for each inertia line
- The percentage of operating points above each mitigation line is used to quantify the probability that the available inertia and generator PFR can maintain the frequency ride-through requirement without considering any future ROCOF limit
  - Each mitigation line with a greater than zero per cent probability is labelled with the volume of the mitigation and the probability. In the bottom left of each figure, an additional label is provided for the mitigation volume that achieves a 90 per cent confidence, if applicable
  - Figure 16, Figure 17 and Figure 18 provide simulation results for years 2024 historical, 2025 historical, 2025 forecast, and 2030 forecast, respectively, when using d-FFR as a mitigation. Figure 19, Figure 20 and Figure 21 provide the same information but with p-FFR as a mitigation.

Figure 16: d-FFR Simulation Results for 2024 (Historical Generation Profile)

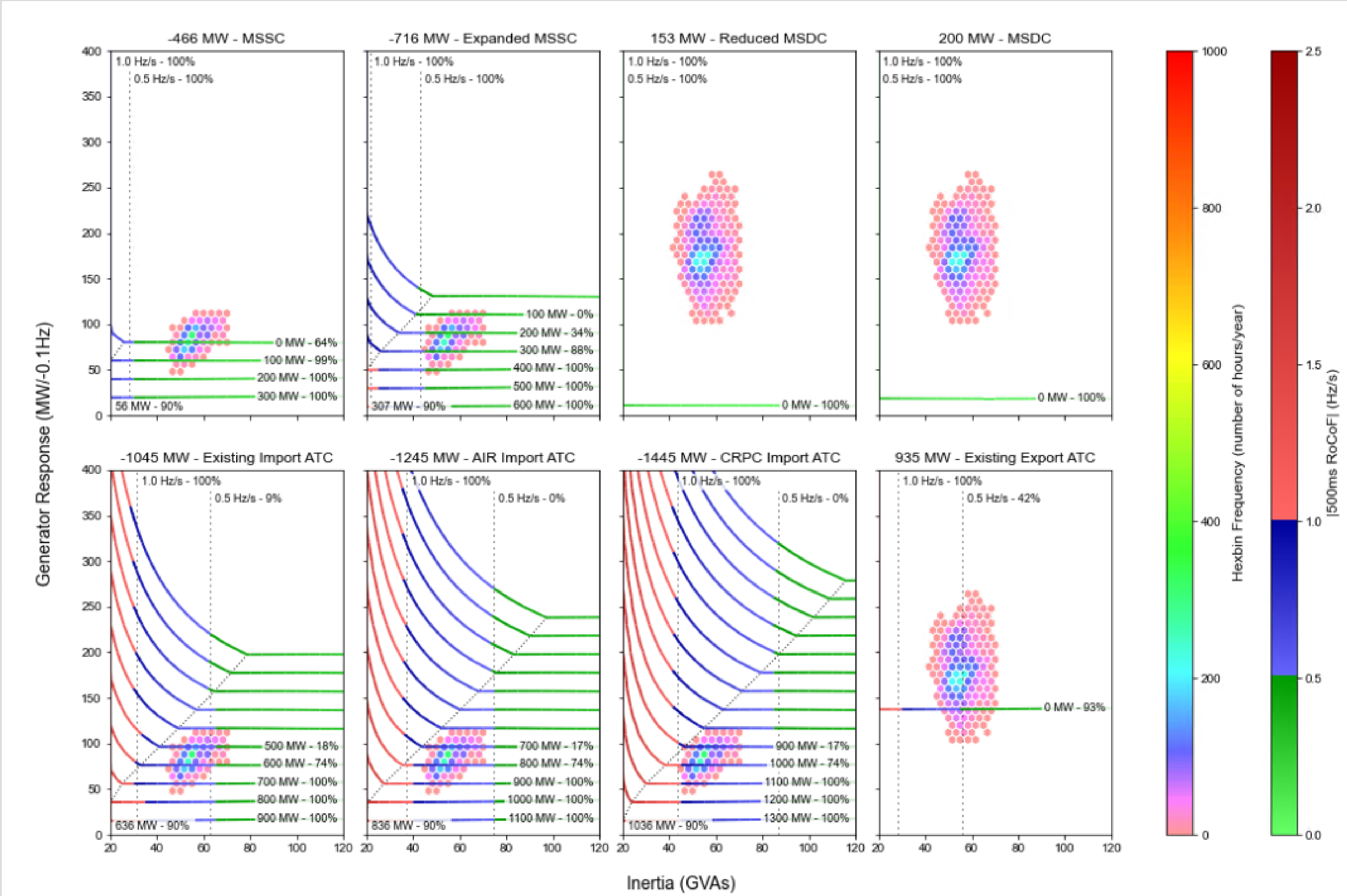


Figure 17: d-FFR Simulation Results for the First Half of 2025 (Historical Generation Profile)

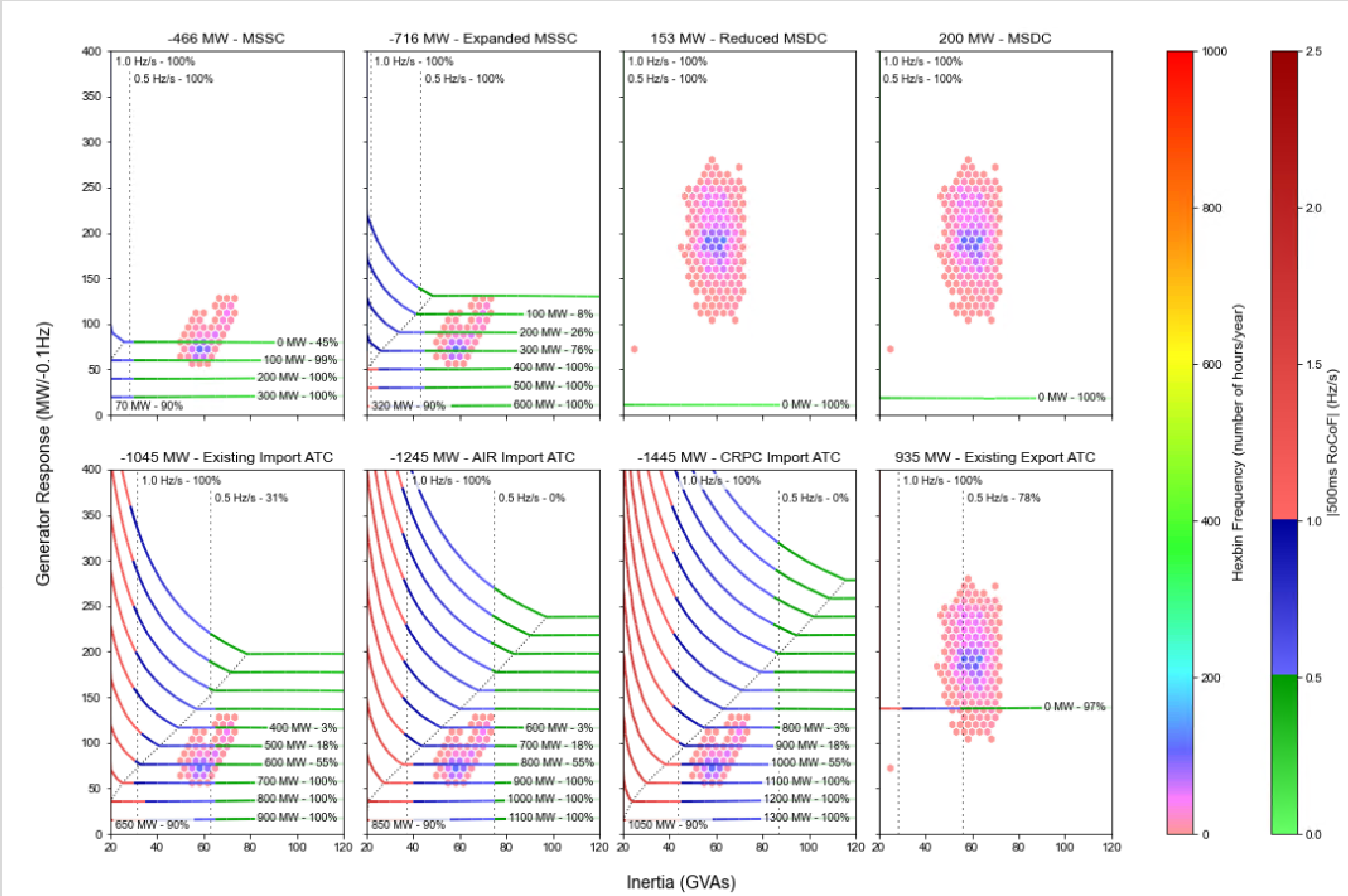


Figure 18: d-FFR Simulation Results for 2025 (2024 LTO Reference Case)

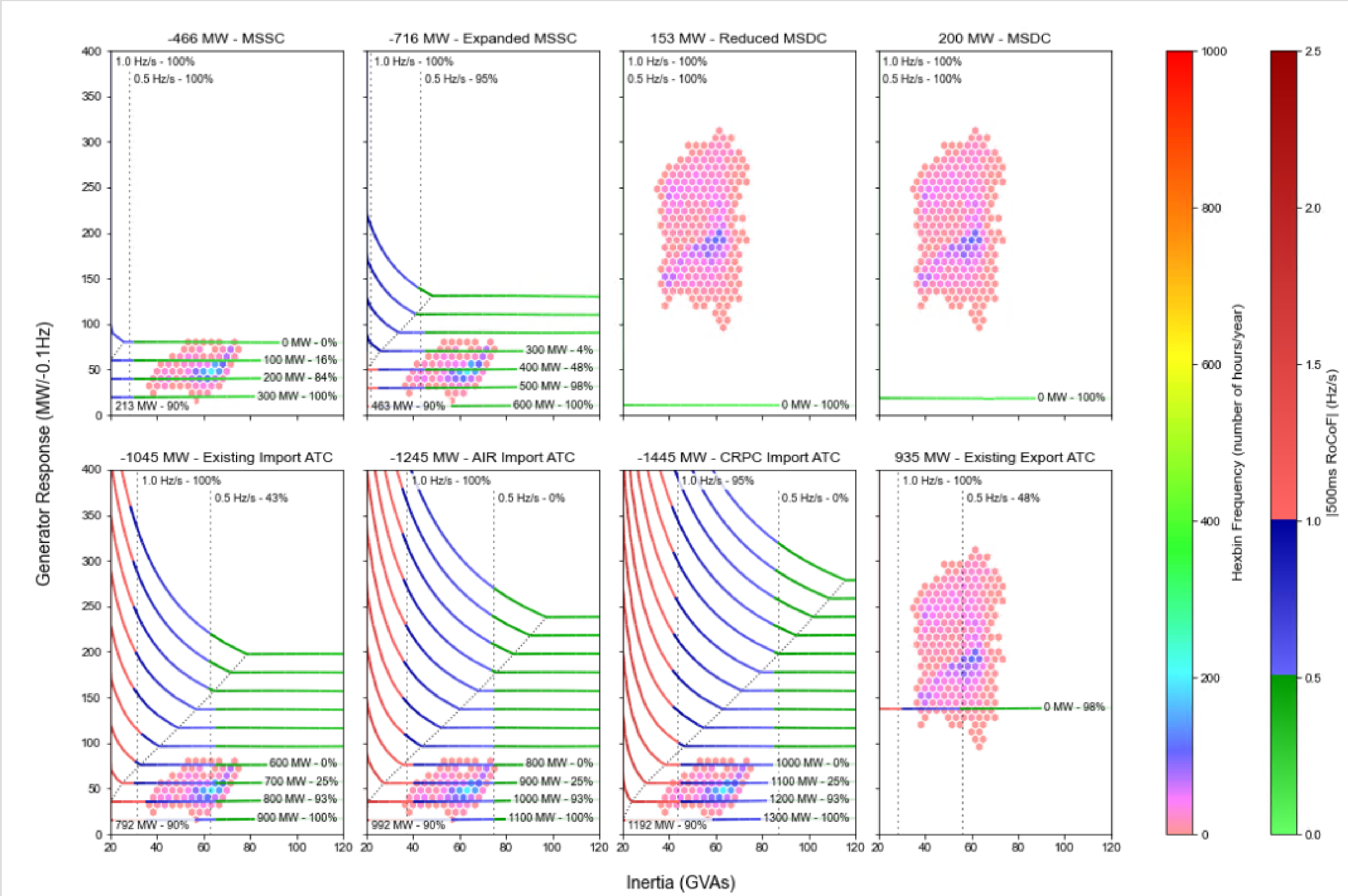


Figure 19: d-FFR Simulation Results for 2030 (2024 LTO Reference Case)

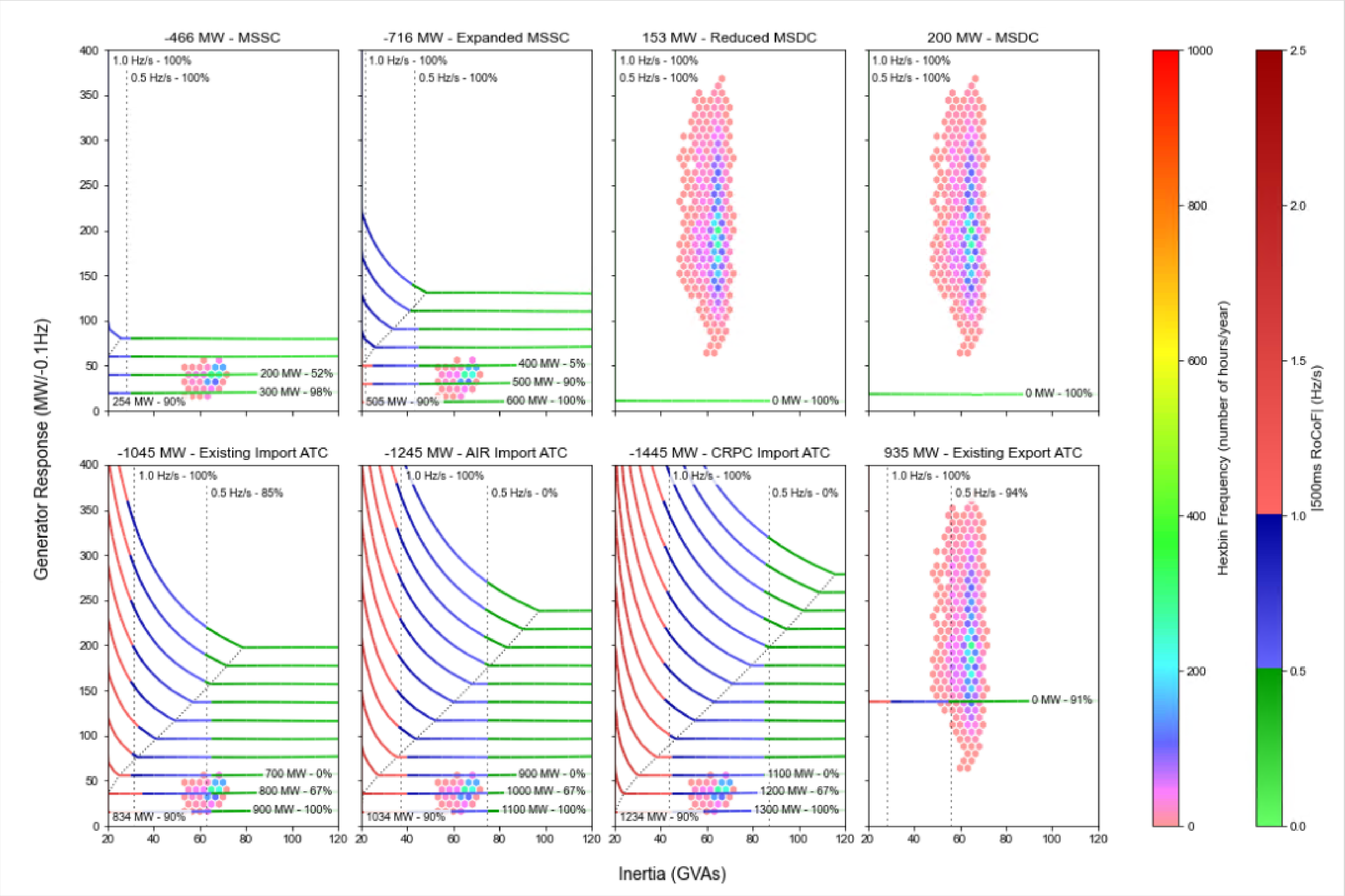


Figure 20: p-FFR Simulation Results for 2024 (Historical Generation Profile)

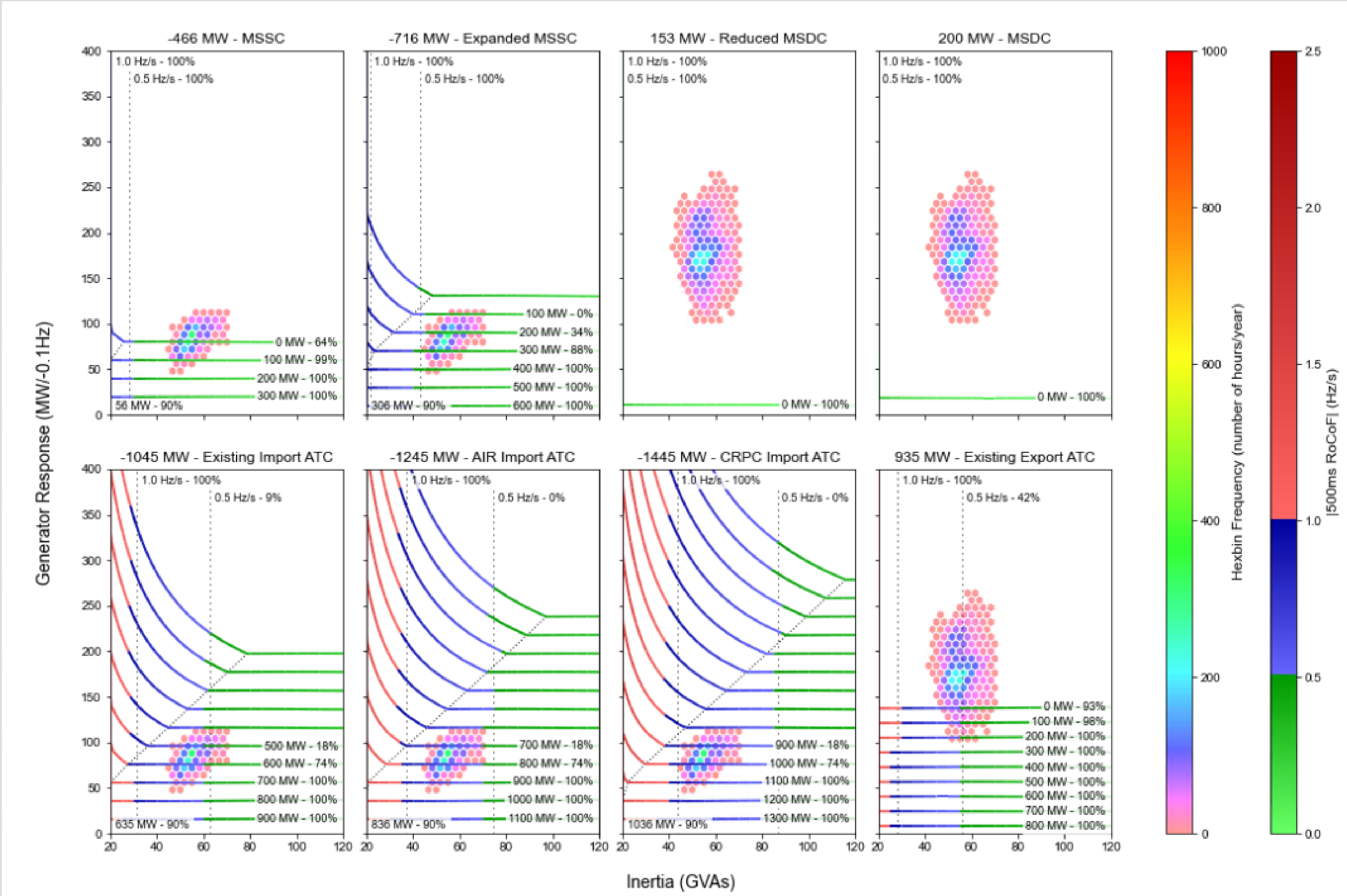


Figure 21: p-FFR Simulation Results for the First Half of 2025 (Historical Generation Profile)

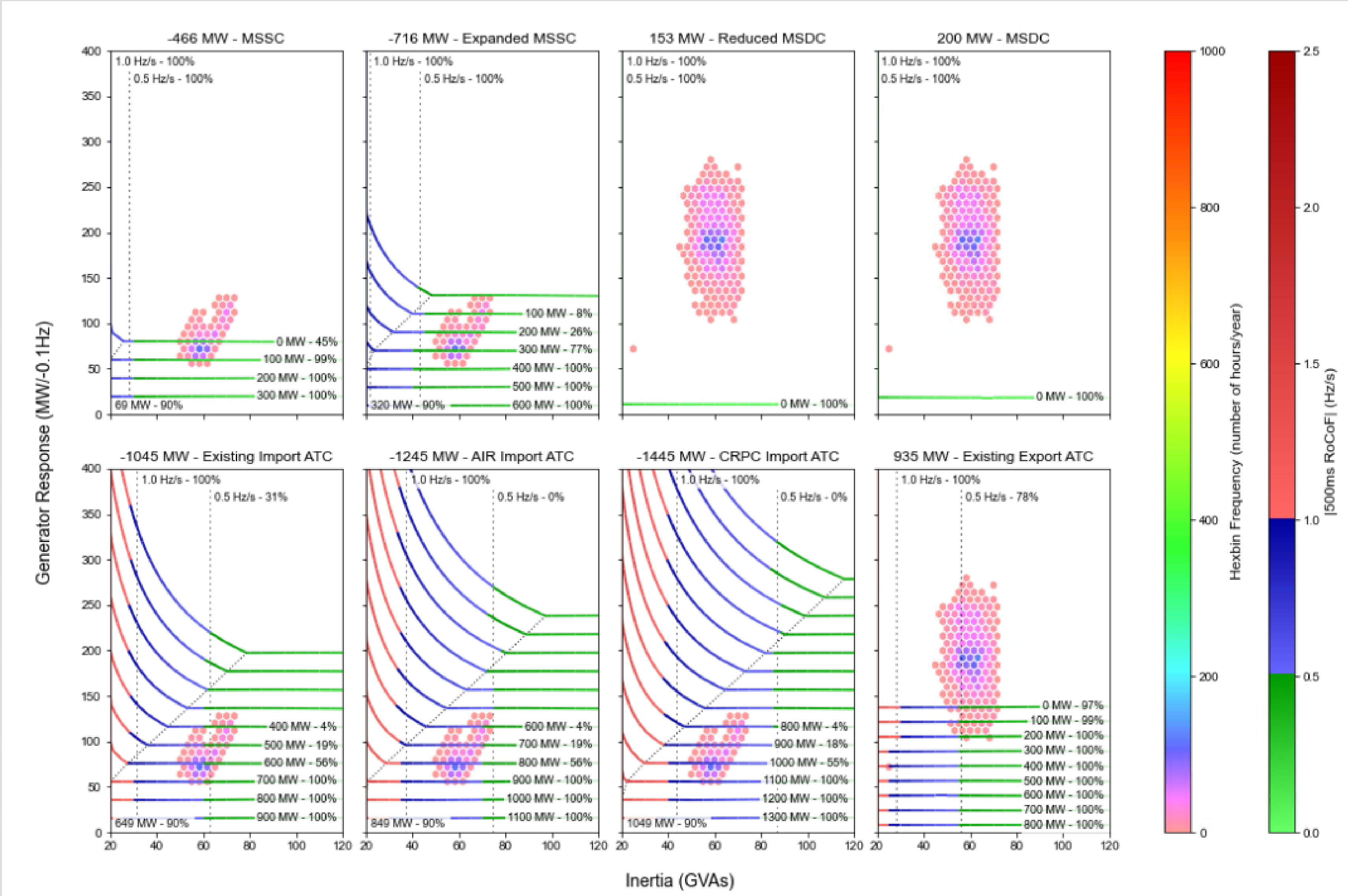


Figure 22: p-FFR Simulation Results for 2025 (2024 LTO Reference Case)

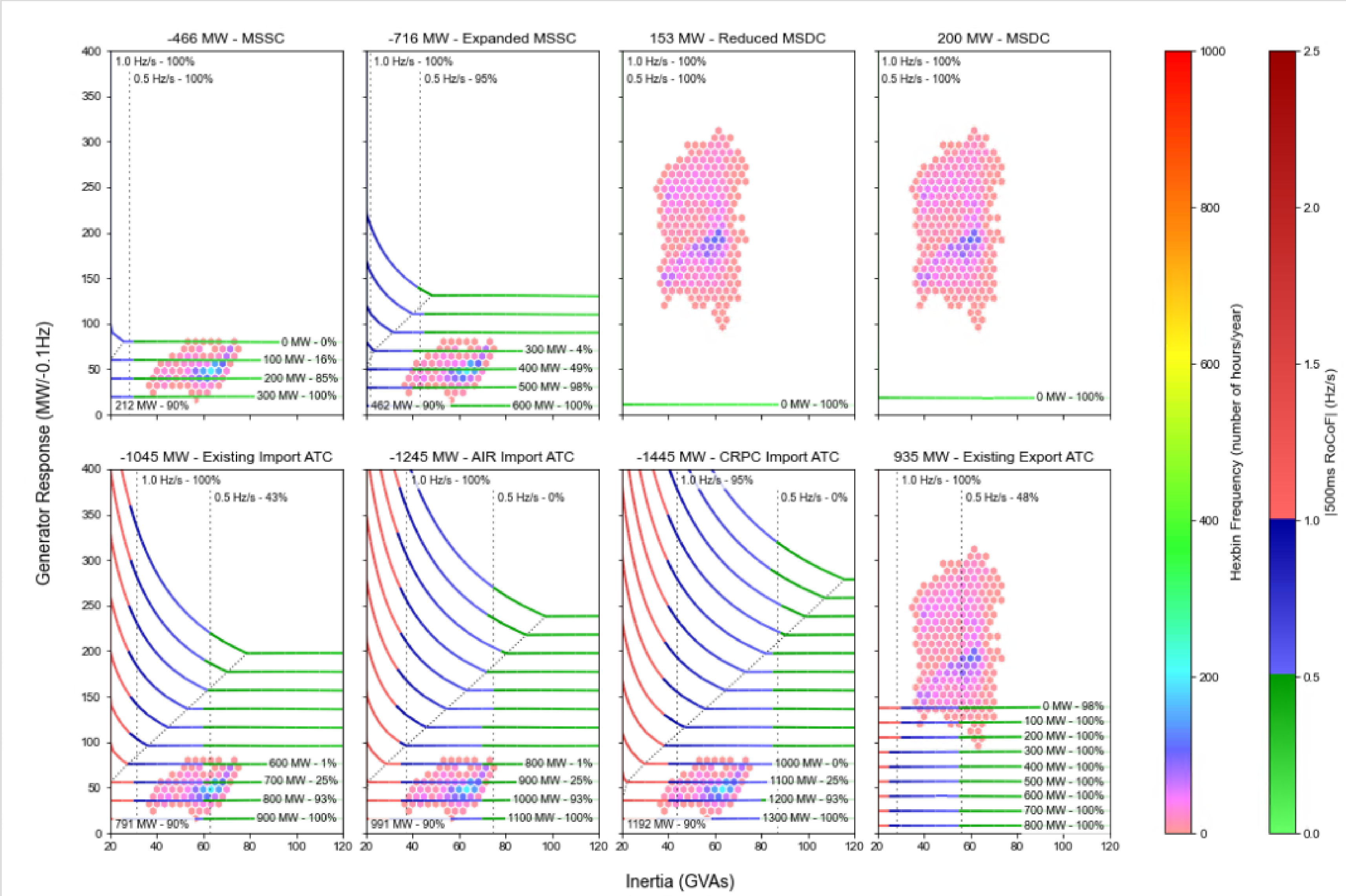
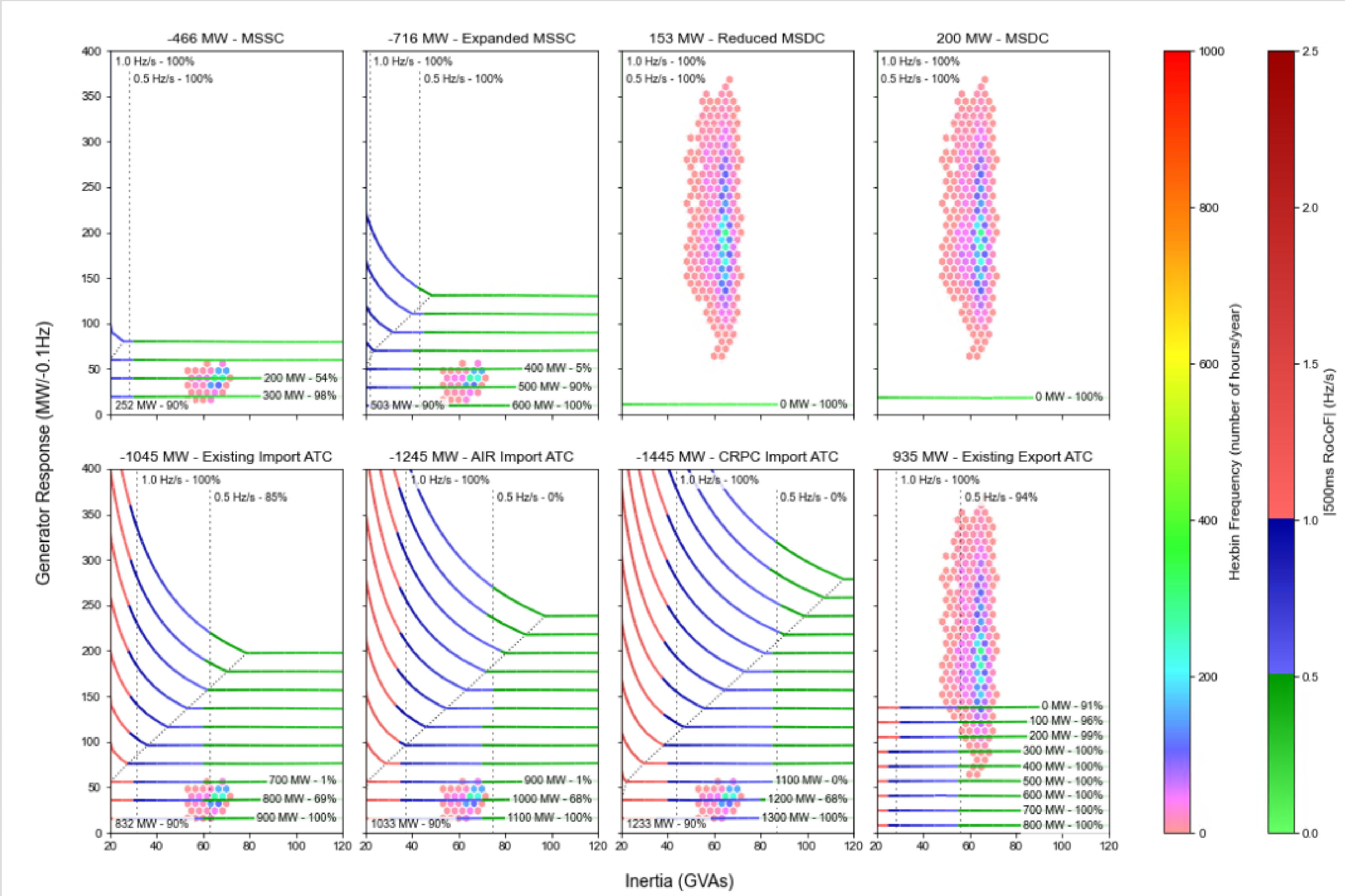


Figure 23: p-FFR Simulation Results for 2030 (2024 LTO Reference Case)



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