Uniform GFM Performance Metrics (minimum requirements)

WECC MVS

May 8, 2025

Jan 30, 2025 Discussion Review

- GFM control is viewed as a beneficial method of IBR power conversion.
- One of the challenges in requiring GFM (or the capability to switch to GFM at little or no cost) is lack of clear GFM specifications.
- This has been noted in different publications such as the Australian Energy Market Operator (AEMO) May 2023 Voluntary Specification for Grid-forming Inverters.
- ***Ultimately, clear GFM specifications will allow developers to specify requirements from Original Equipment Manufacturers (OEMs), and for OEMs to design their GFM offerings.***
- **Goal:** Investigate the current work and draft a GFM capability minimum requirements document.

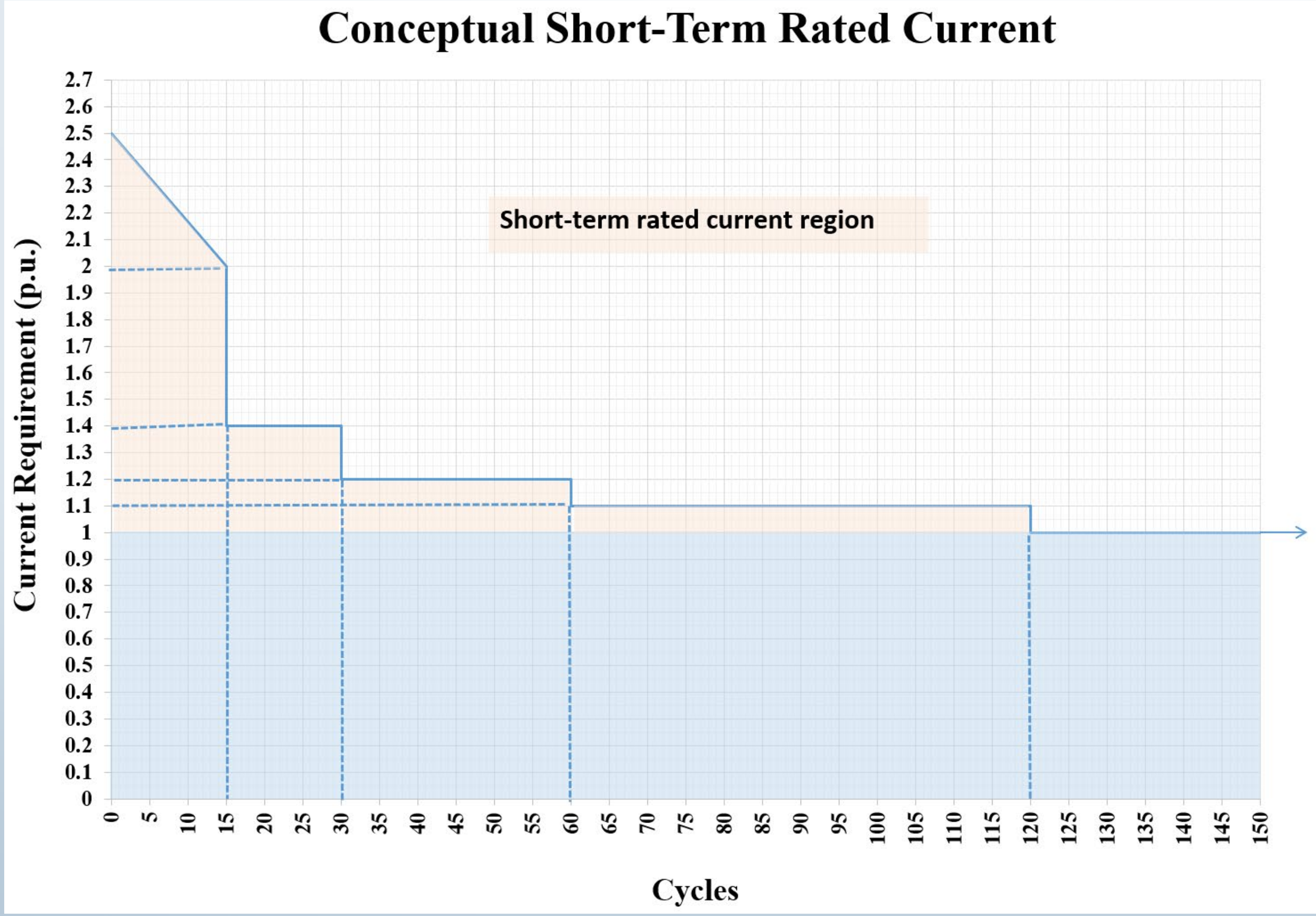
Example GFM Requirement Specifics

- Voltage angle step change response
  - AEMO/ERCOT example: for each 10-degree voltage phase angle jump a plant's power change of at least 0.2 pu on rated active powerbase with a response time of 15 ms (AEMO) or 1 cycle (ERCOT).
- Equivalent Inertia Response
  - ERCOT example: equivalent inertia constant greater than 2.5 s
- Weak System Operation, e.g. down to a SCR of 1.2 (ERCOT)
- Small Voltage Disturbance (capability to resist change in voltage magnitude)
- Loss of last Synchronous Machine or preferably stated last GFM resource? – Is the intent to prove IBR provides independent and stable control of an internal voltage phasor?

IEEE 2800 Annex C.4
Gird-Forming Inverters

- Sufficient current and energy headroom should be available for the inverter *all the time it is operated as grid forming*.
- It is expected that the inverter protects itself from overcurrent. Once the current limit is reached, inverter cannot operate as grid forming and has to switch to a different mode of operation to respect the hardware limits.
- Out of Scope: Changes to the control loops to help ensure stable and reliable operation under fast varying system conditions.
- Out of Scope: Impacts to protection and relaying resulting from IBR fault current capability.

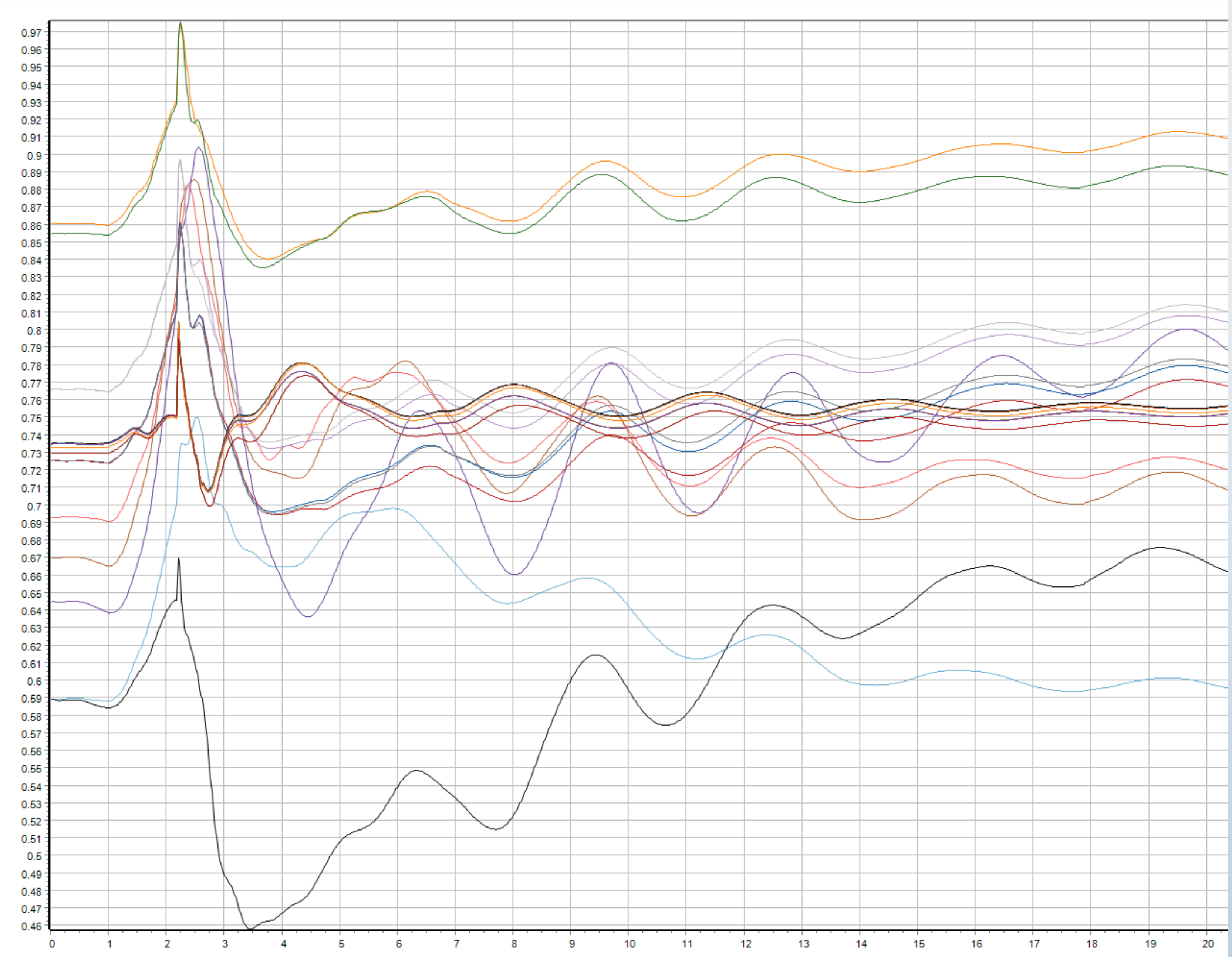
Exploration: IBR Short-Term Rated Current (ISRC)



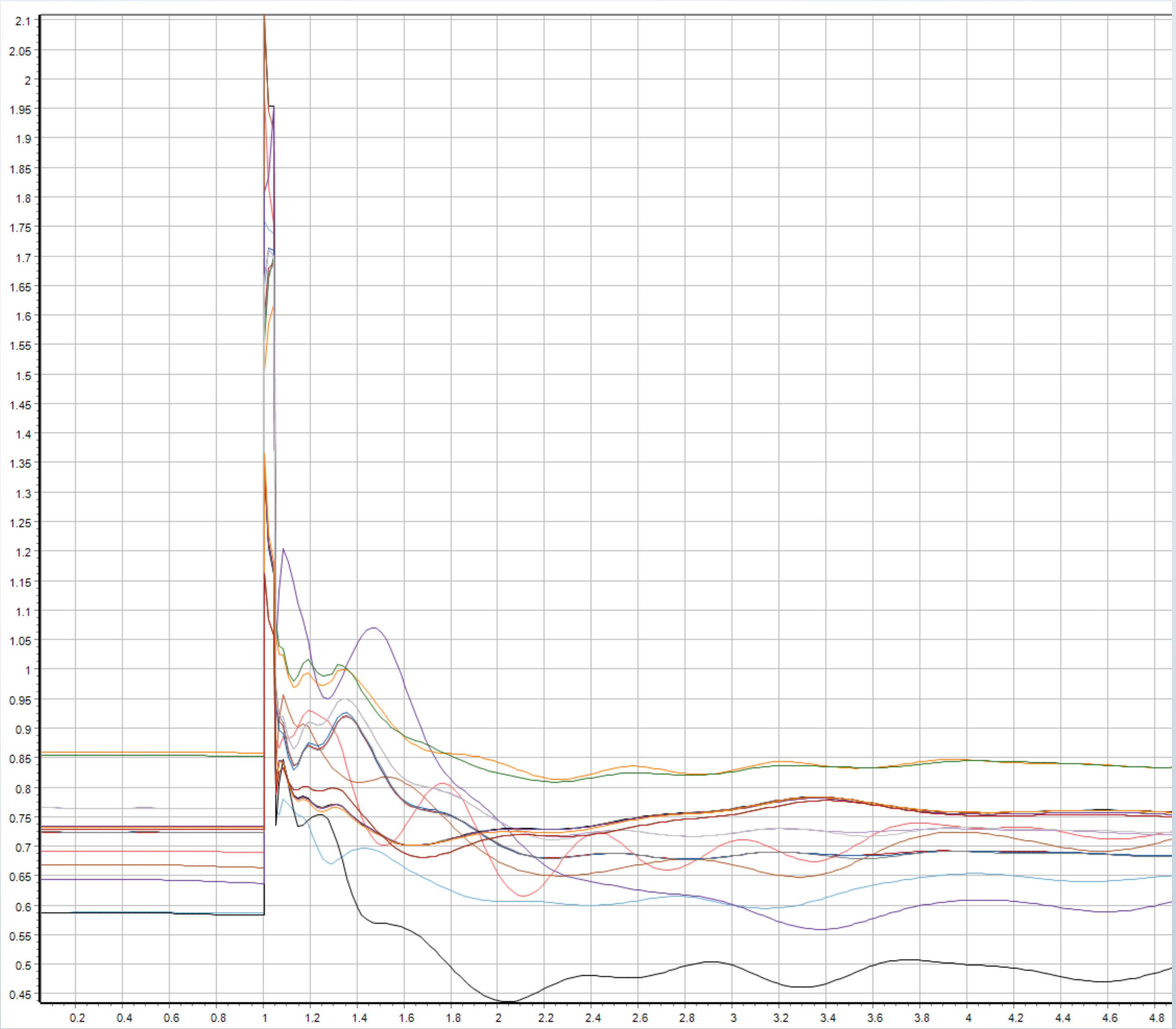
Example Generator Current (p.u.) McNary, John Day, Lower Snake Hydro Units

Displayed on the Next Slides

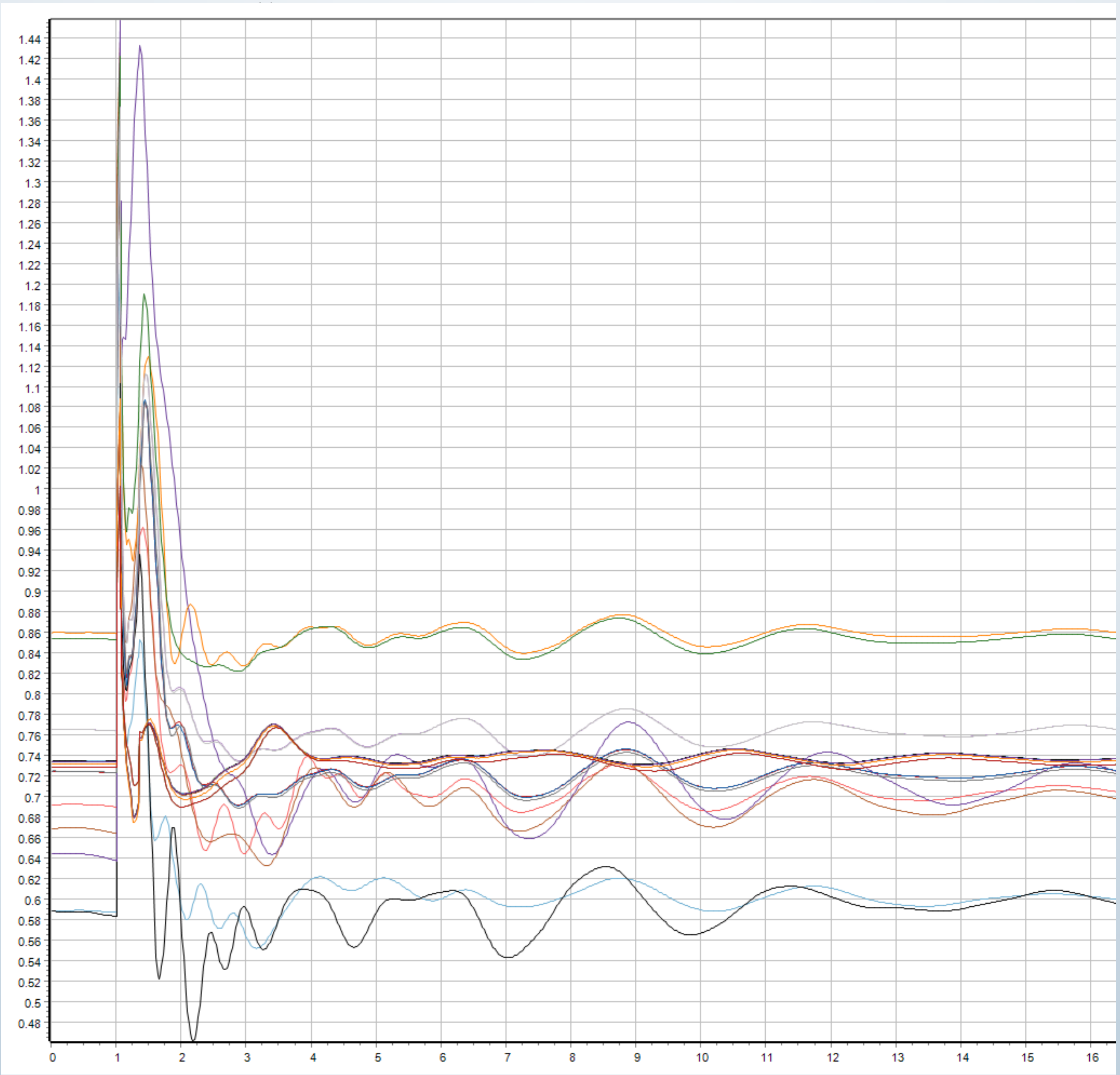
No Fault
Gen. Loss
~2800 MW



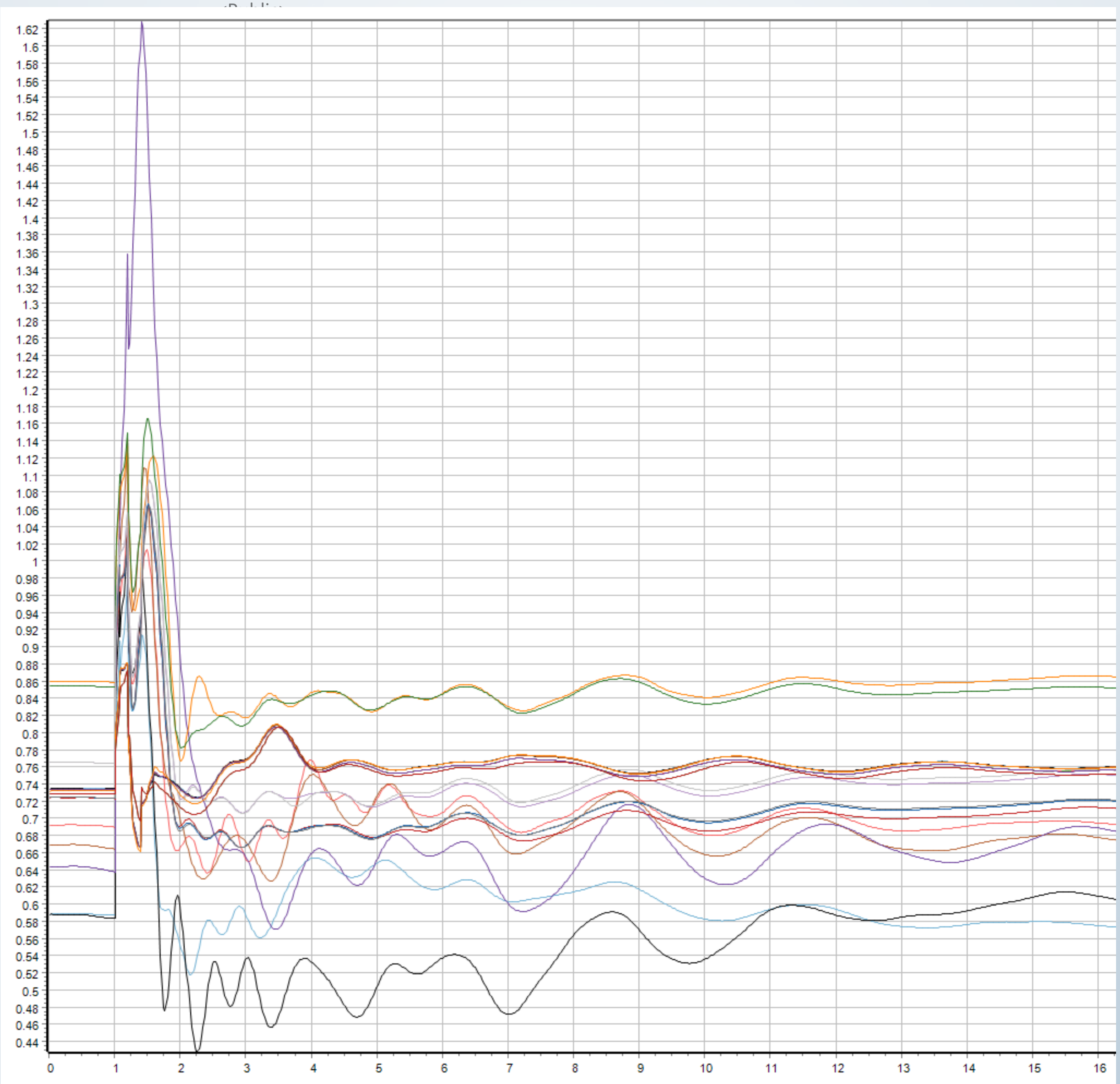
P1-1 Columbia Generating Station, 3-ph fault, 4 cycle clear

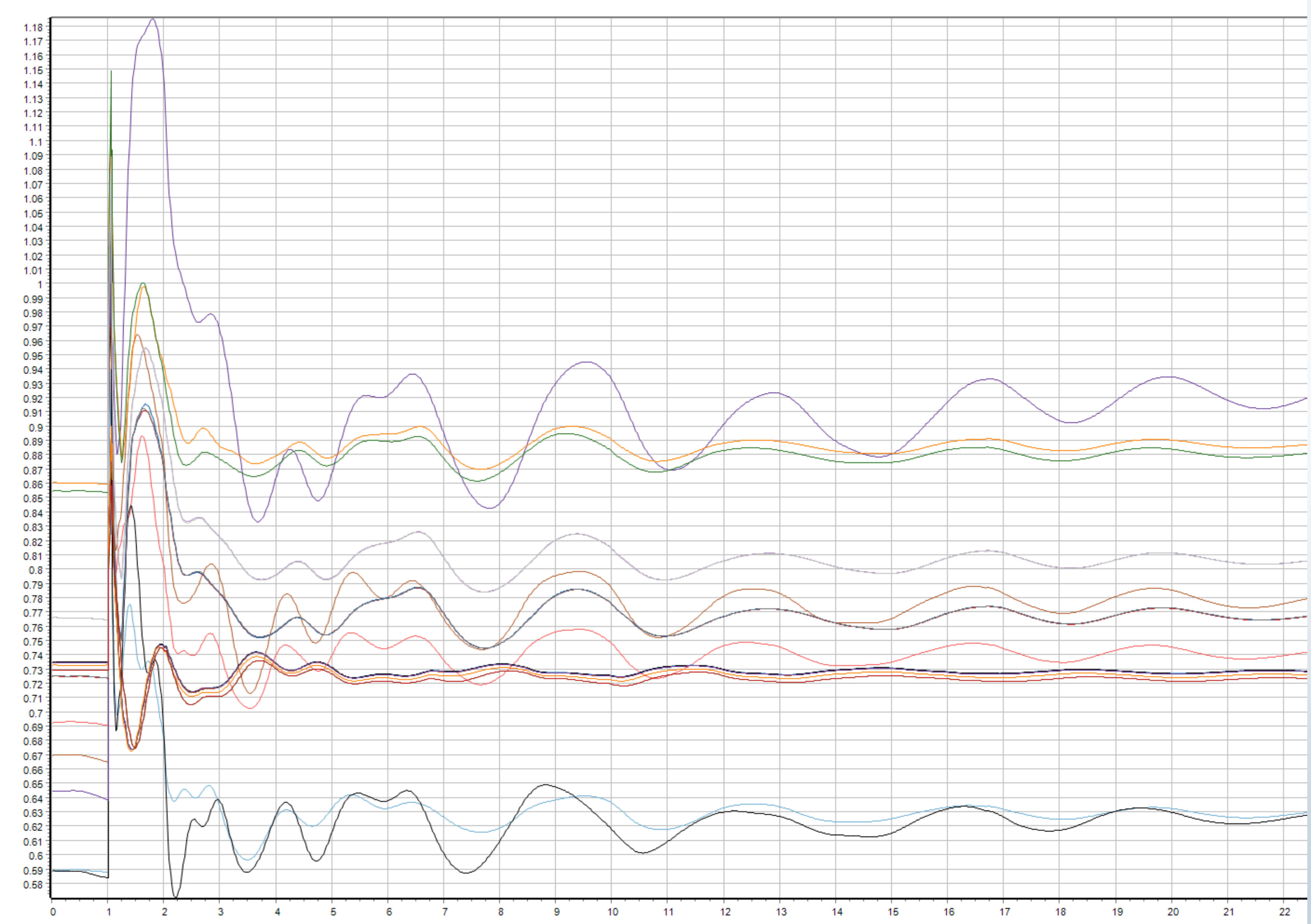


P1-2 Grand Coulee-Schultz #1 500 kV, 3-ph fault, 4 cycle clear

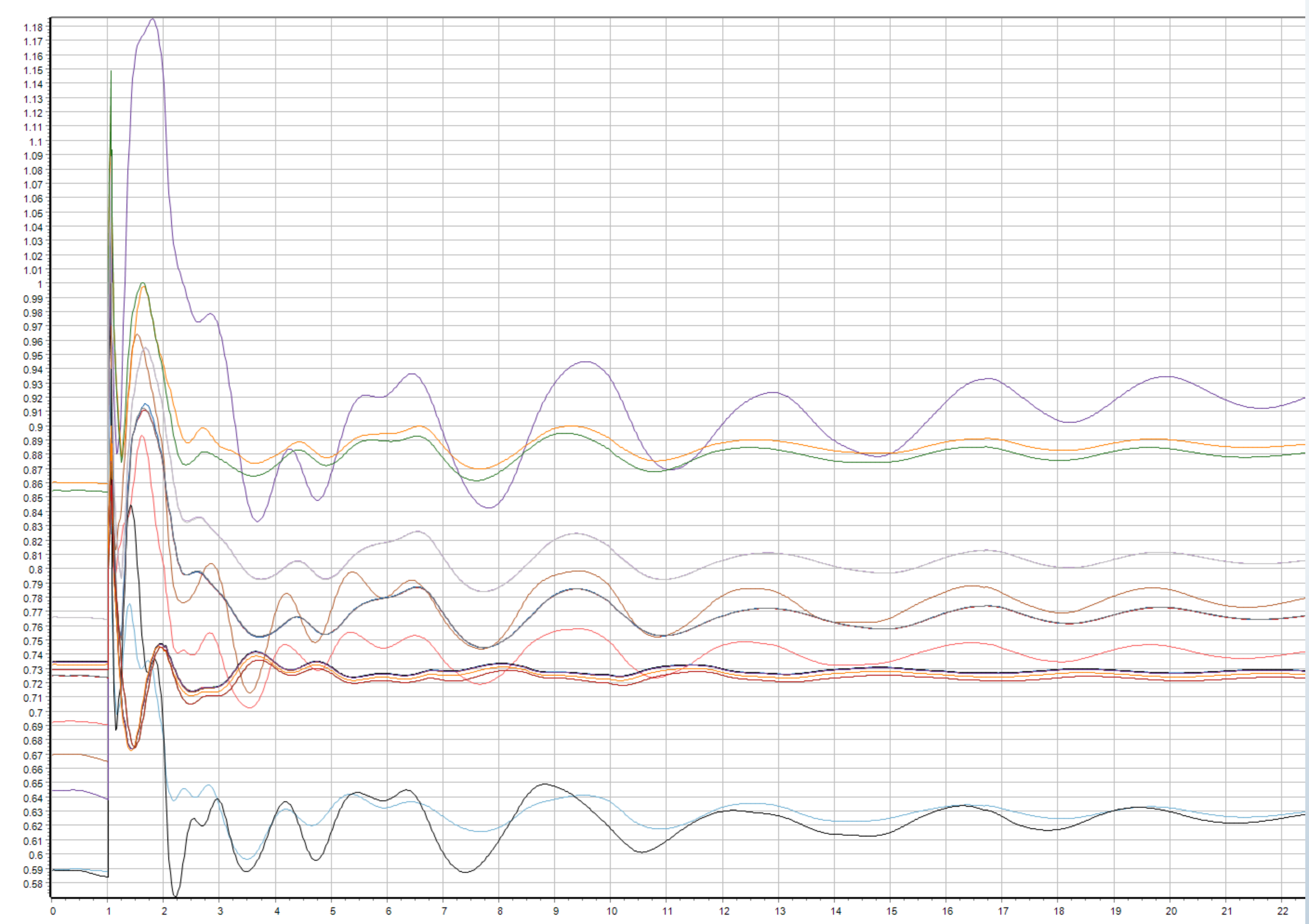


P2-3 Grand Coulee BKF 8792 Hanford 500 kV, 1-ph fault, 12 cycle clear





P7-1 Grand Coulee-Schultz #1 & #2 500 kV (bypass sc), 1-ph fault, 4 cycle clear



P7-1 Grand Coulee-Schultz #1 & #2 500 kV (bypass sc), 1-ph fault, 4 cycle clear

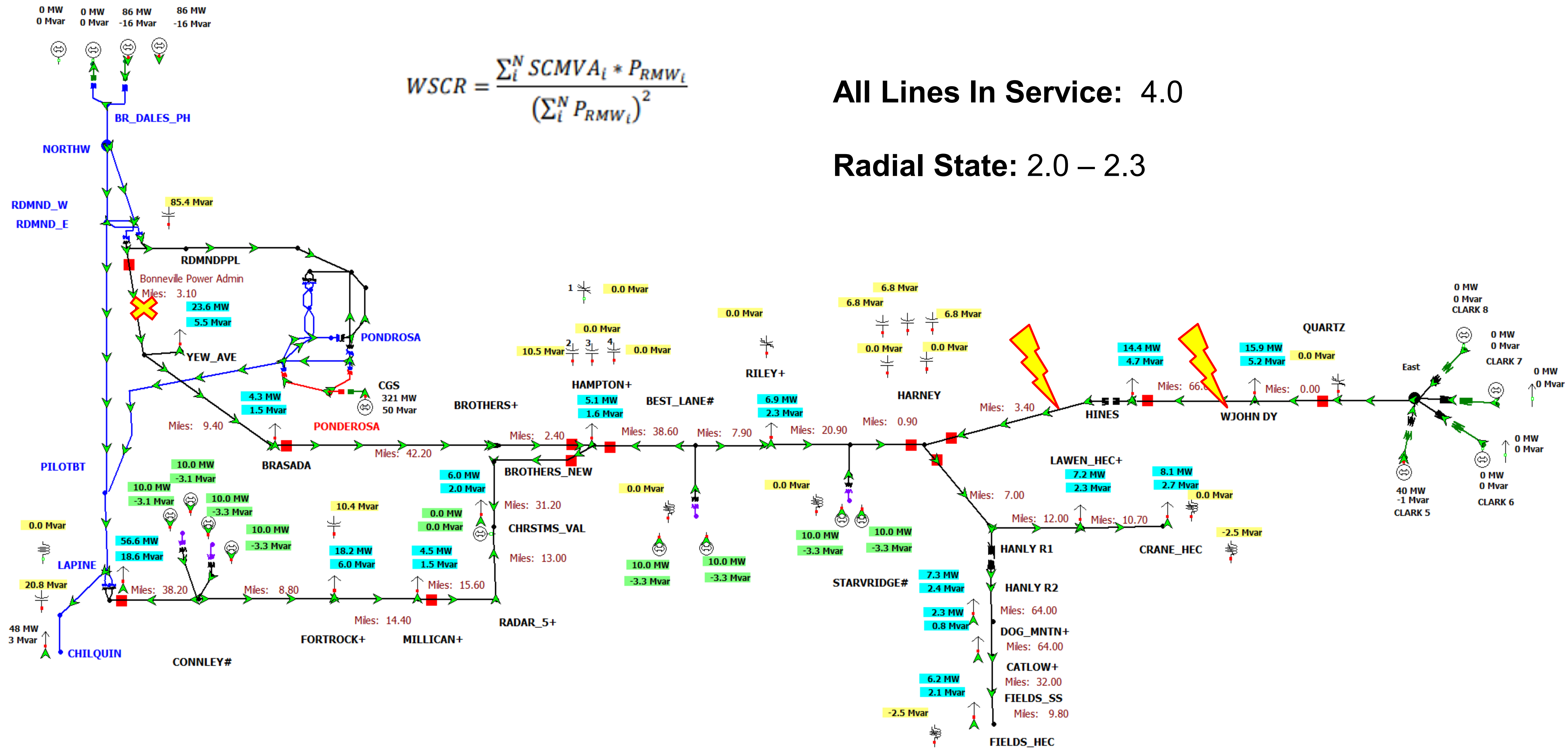
Exploration Study: Minimum IBR Short-Term Rated Current (ISRC)

- Can a required minimum short-term rated current be established from a study?
- A small system model with weak grid conditions (WSRC ~ 2.0), and fault induced delayed voltage recover (FIDVR) is considered.
- IBR Model being used: REGFM_B1 with varying Ifaultmax
- Preliminary results are not providing a clear determination for a minimum IBR ISRC.
- Work is ongoing.

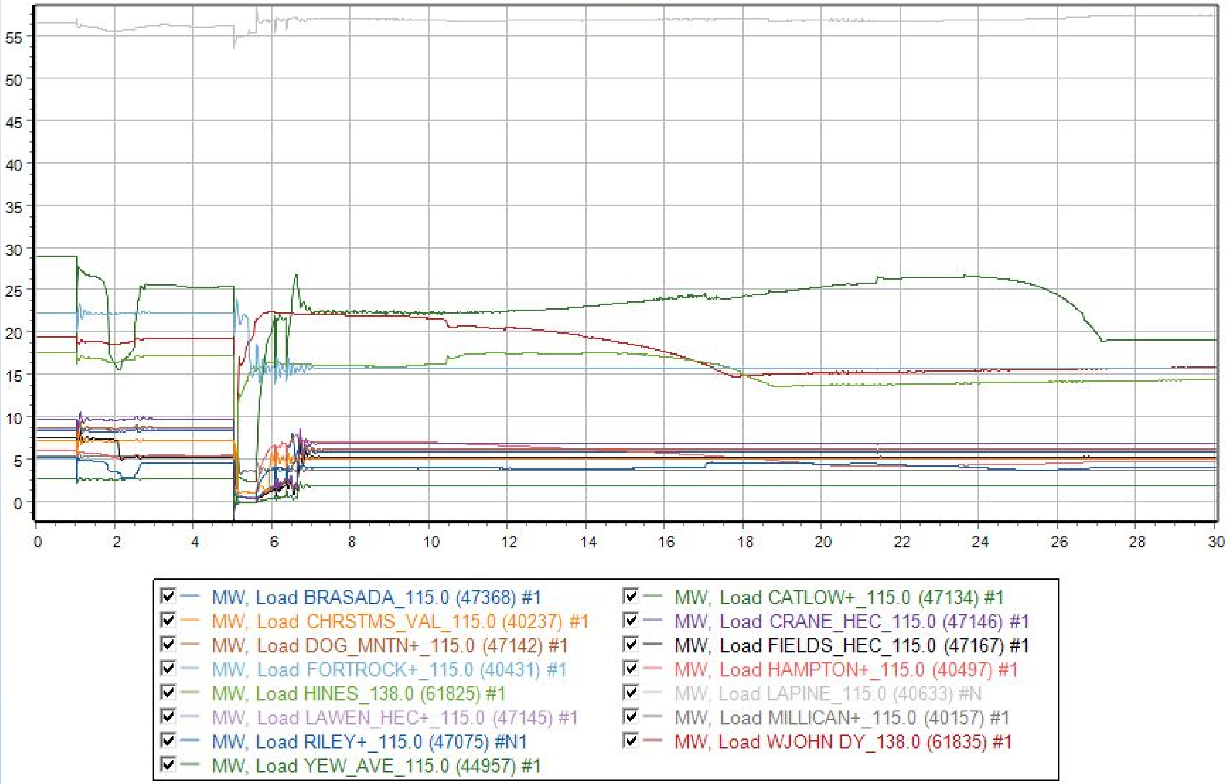
$$WSCR = \frac{\sum_i^N SCMVA_i * P_{RMW_i}}{\left(\sum_i^N P_{RMW_i}\right)^2}$$

All Lines In Service: 4.0

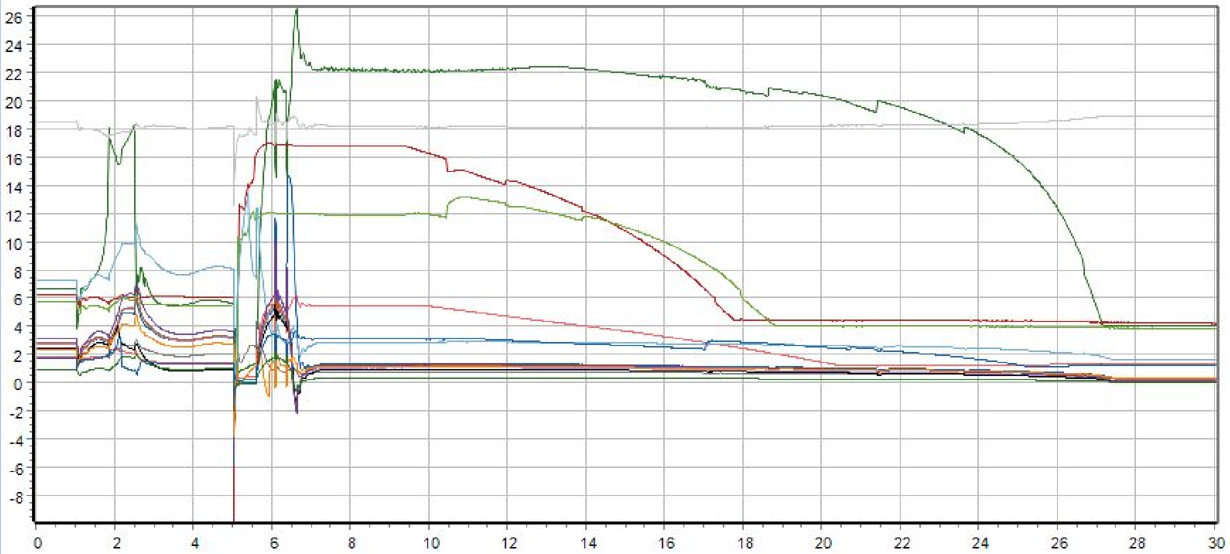
Radial State: 2.0 – 2.3



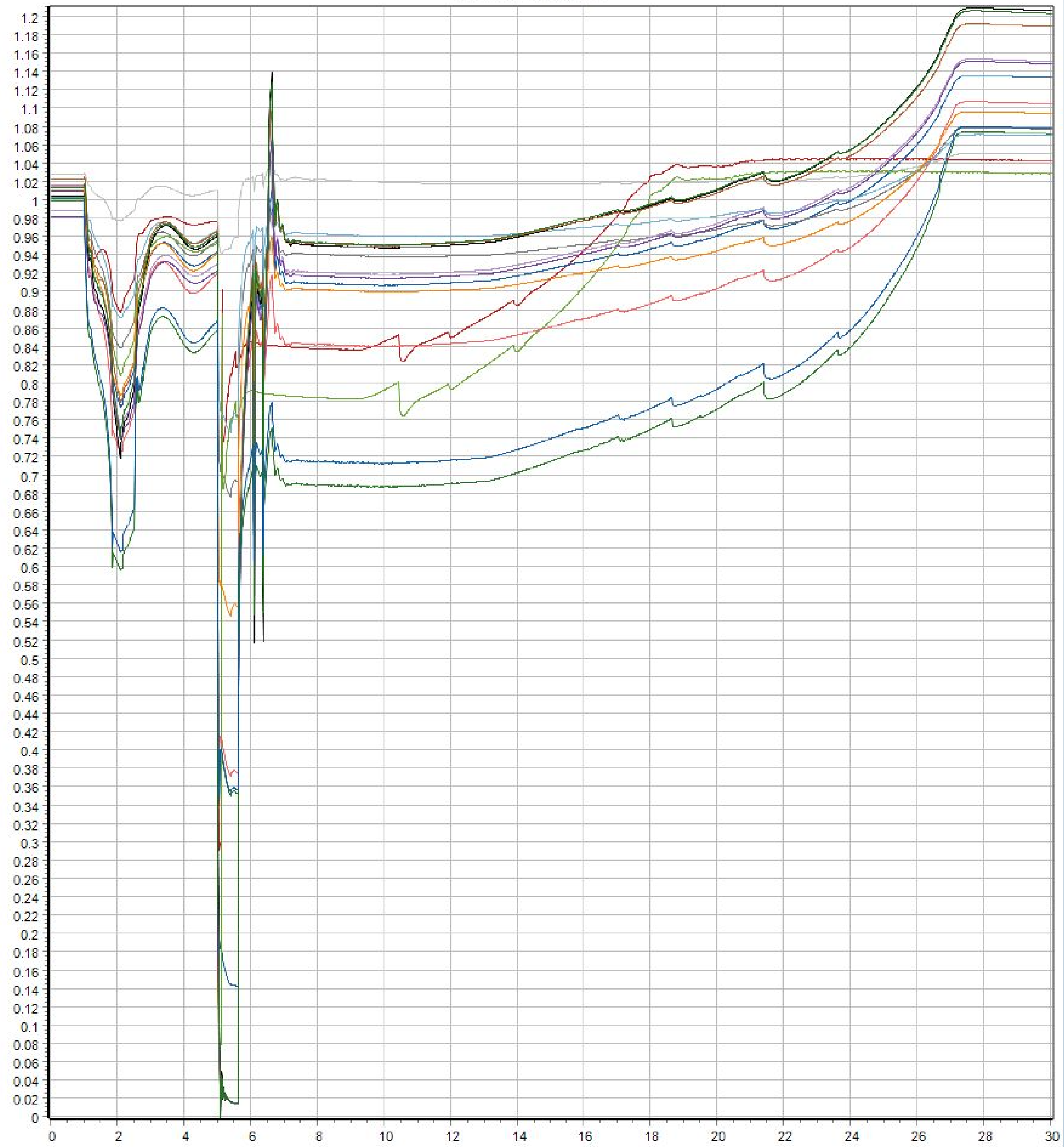
Load (MW)

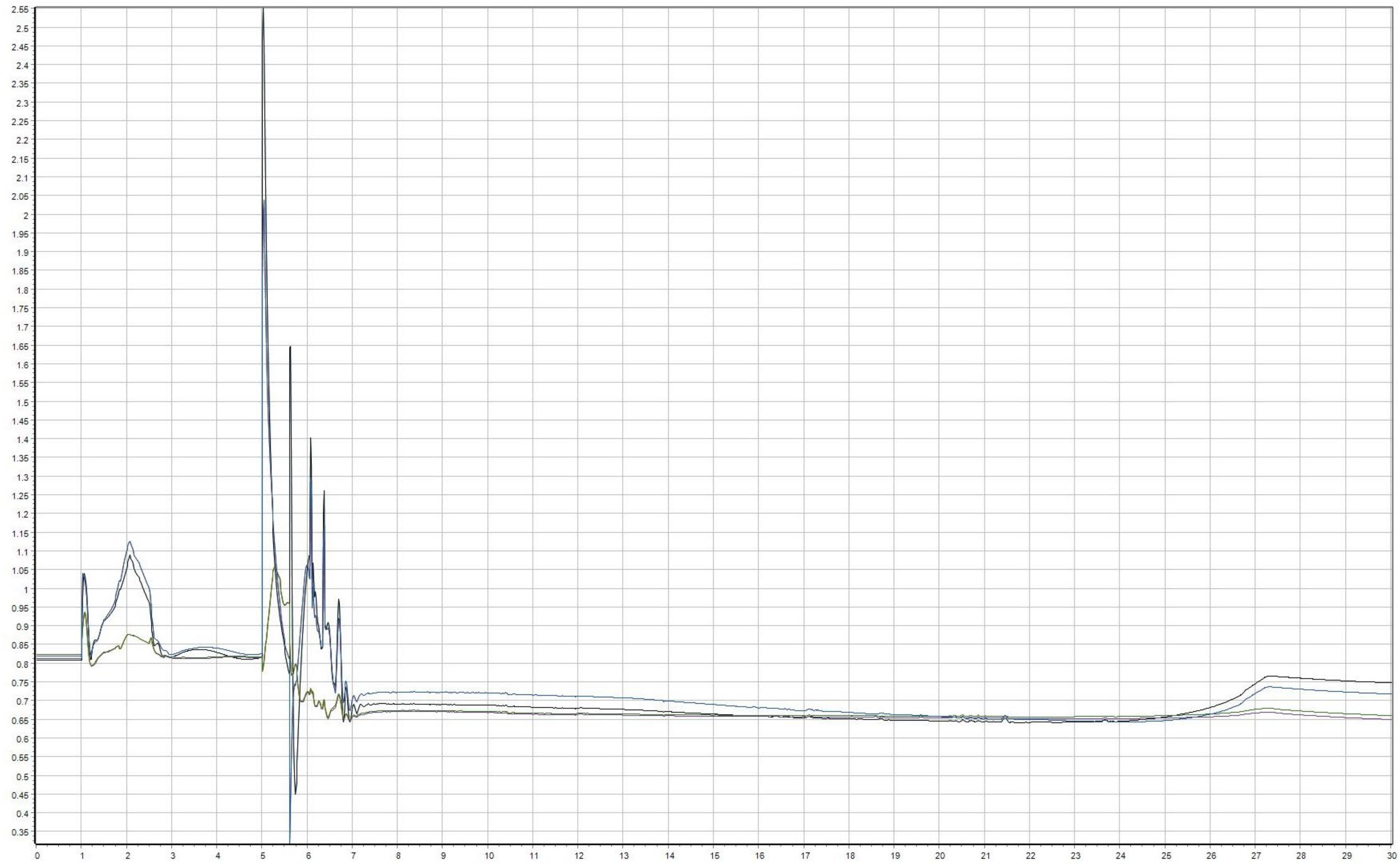


Load (MVAR)



Load (Voltage pu)





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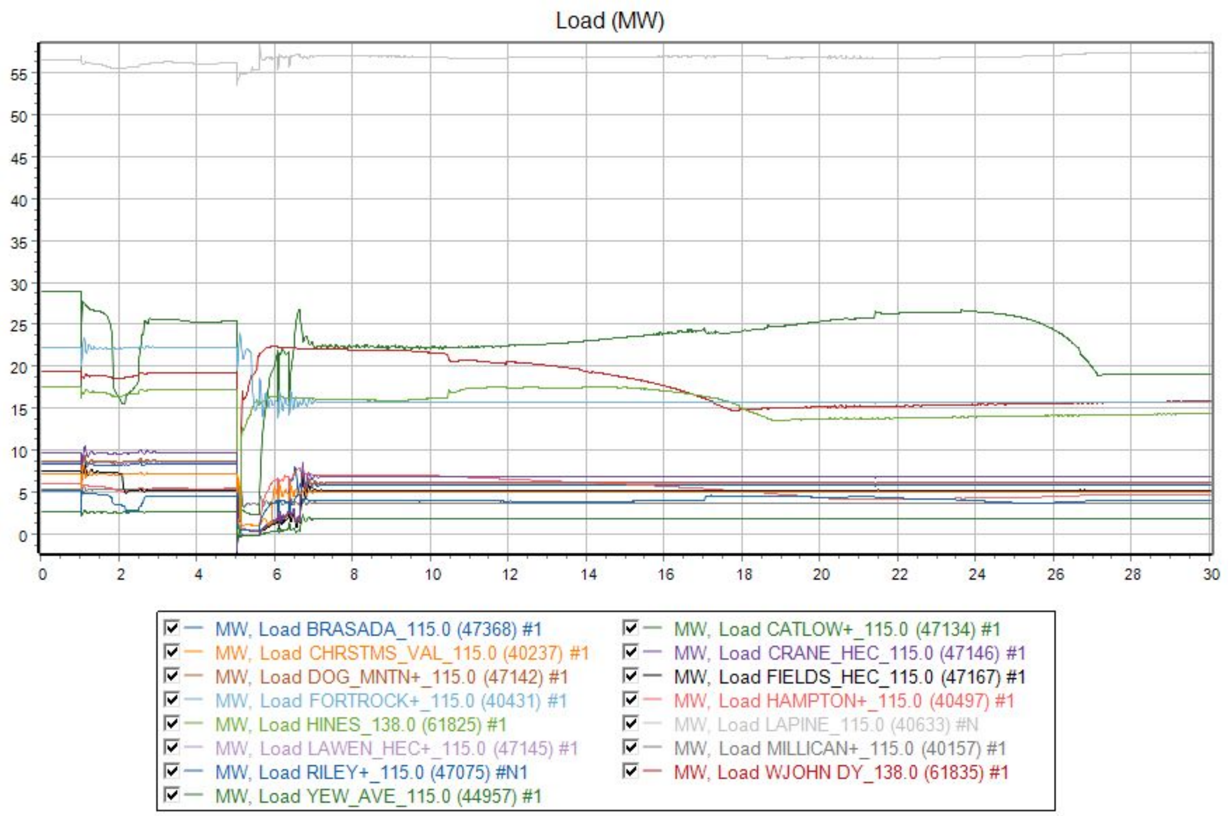
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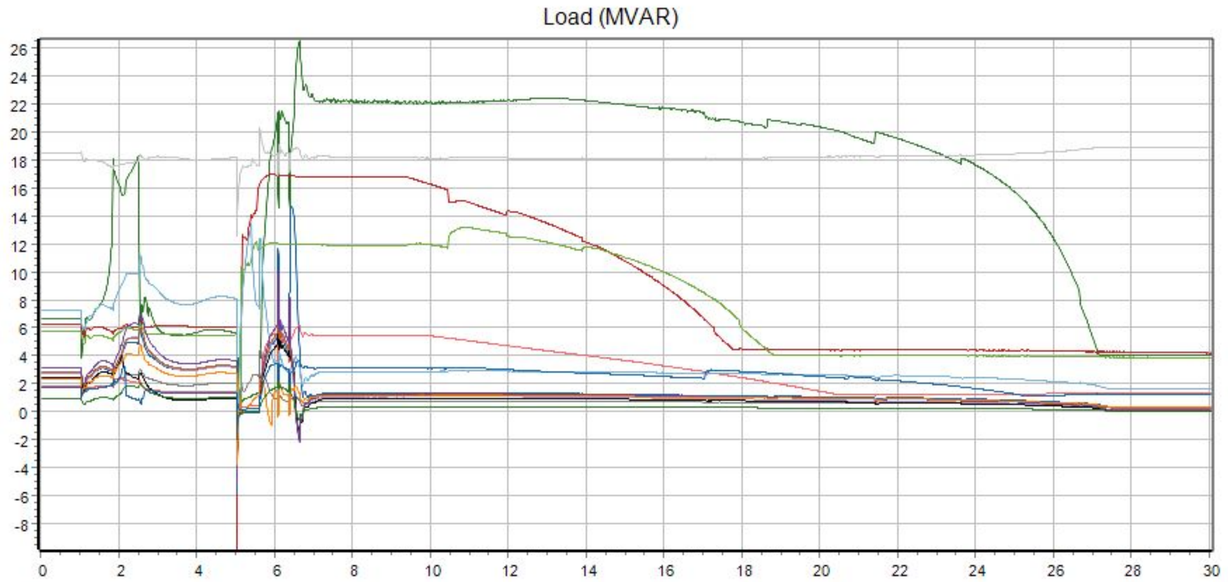
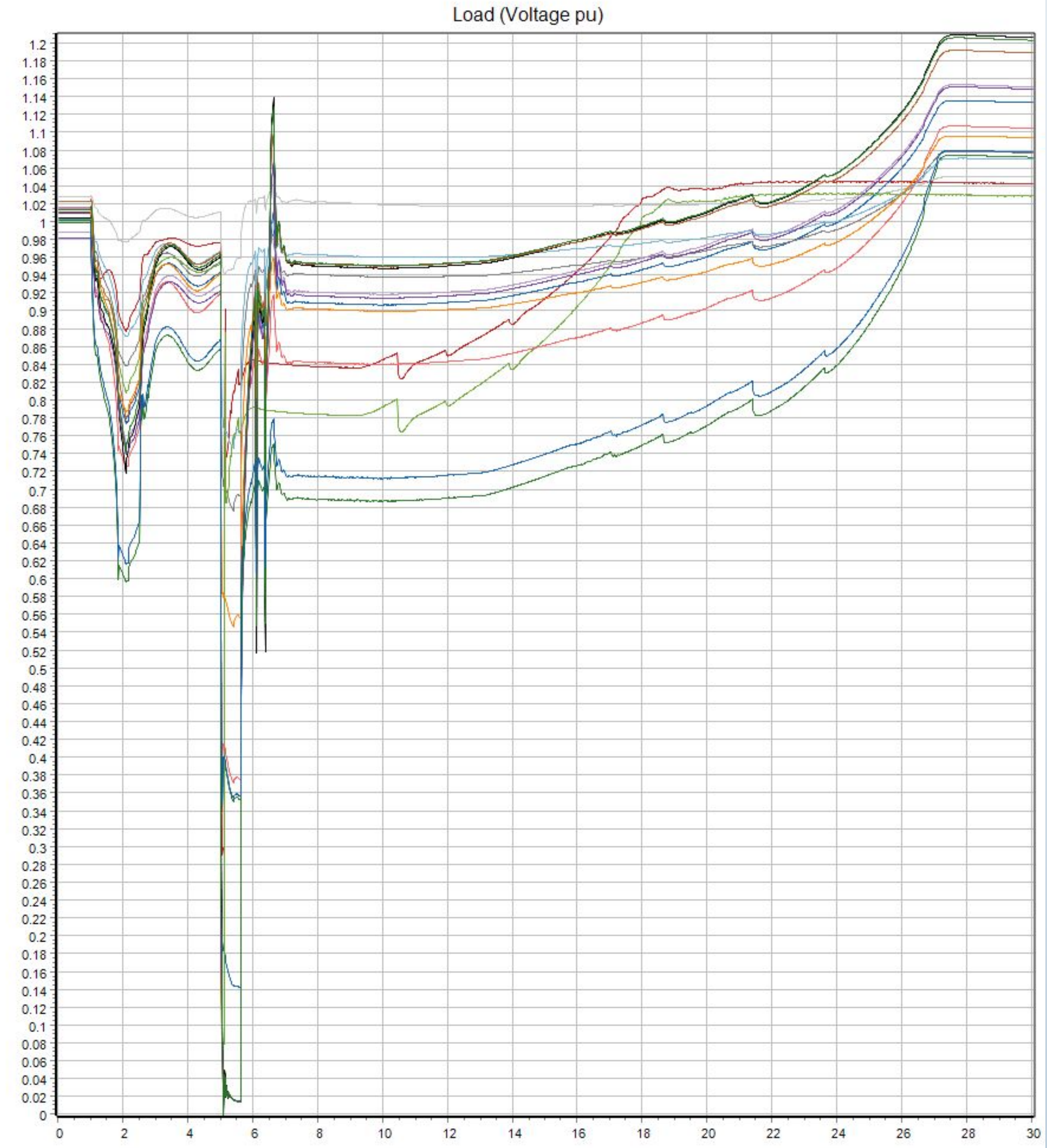
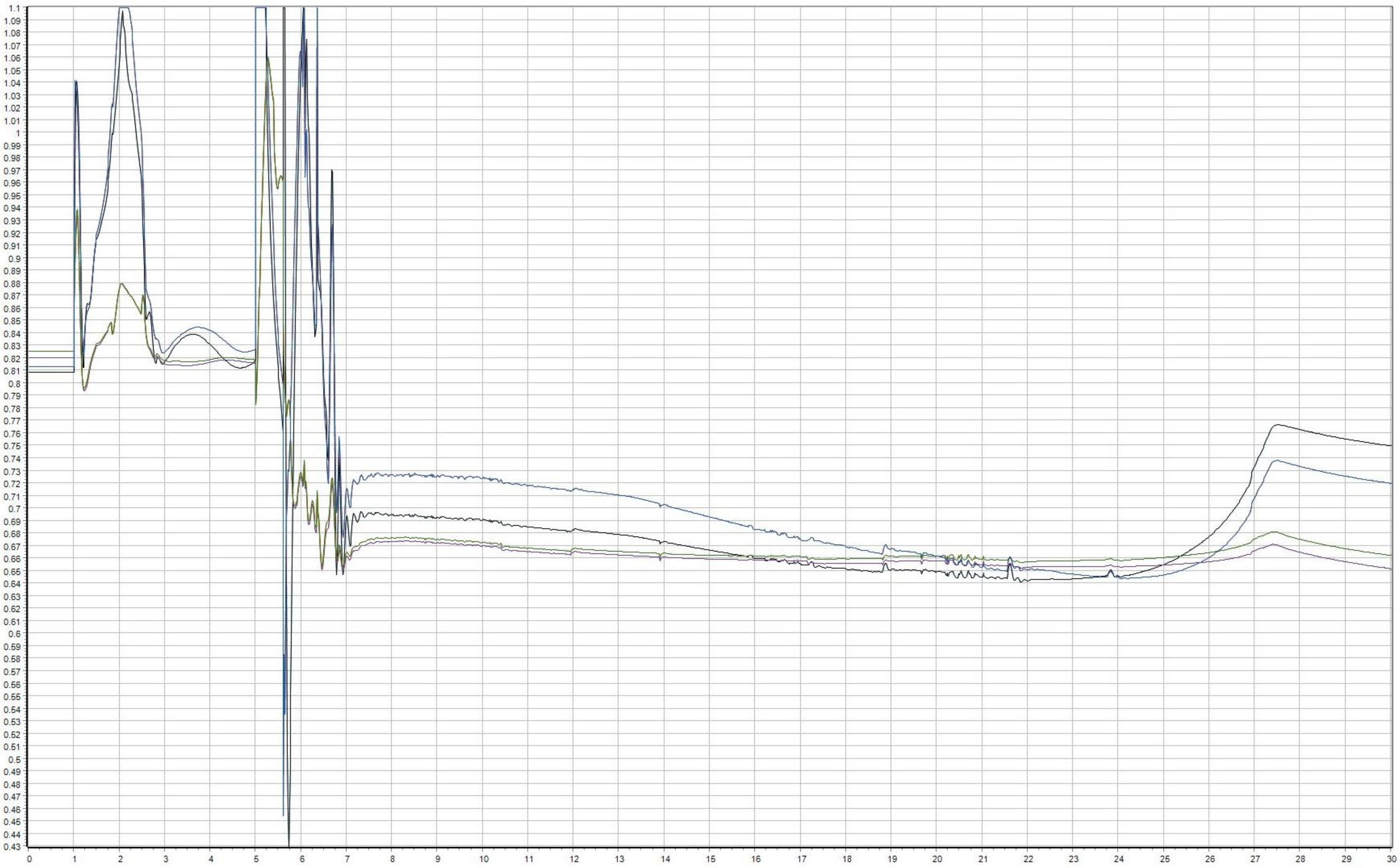
MW, Load HINES_138.0 (61825) #1
MW, Load LAWEN_HEC+_115.0 (47145) #1
MW, Load RILEY+_115.0 (47075) #N1
MW, Load YEW_AVE_115.0 (44957) #1
MW, Load CATLOW+_115.0 (47134) #1
MW, Load CRANE_HEC_115.0 (47146) #1
MW, Load FIELDS_HEC_115.0 (47167) #1
MW, Load HAMPTON+_115.0 (40497) #1
MW, Load LAPINE_115.0 (40633) #N
MW, Load MILLICAN+_115.0 (40157) #1
MW, Load WJOHN DY_138.0 (61835) #1


Load (MVAR)


Load (Voltage pu)



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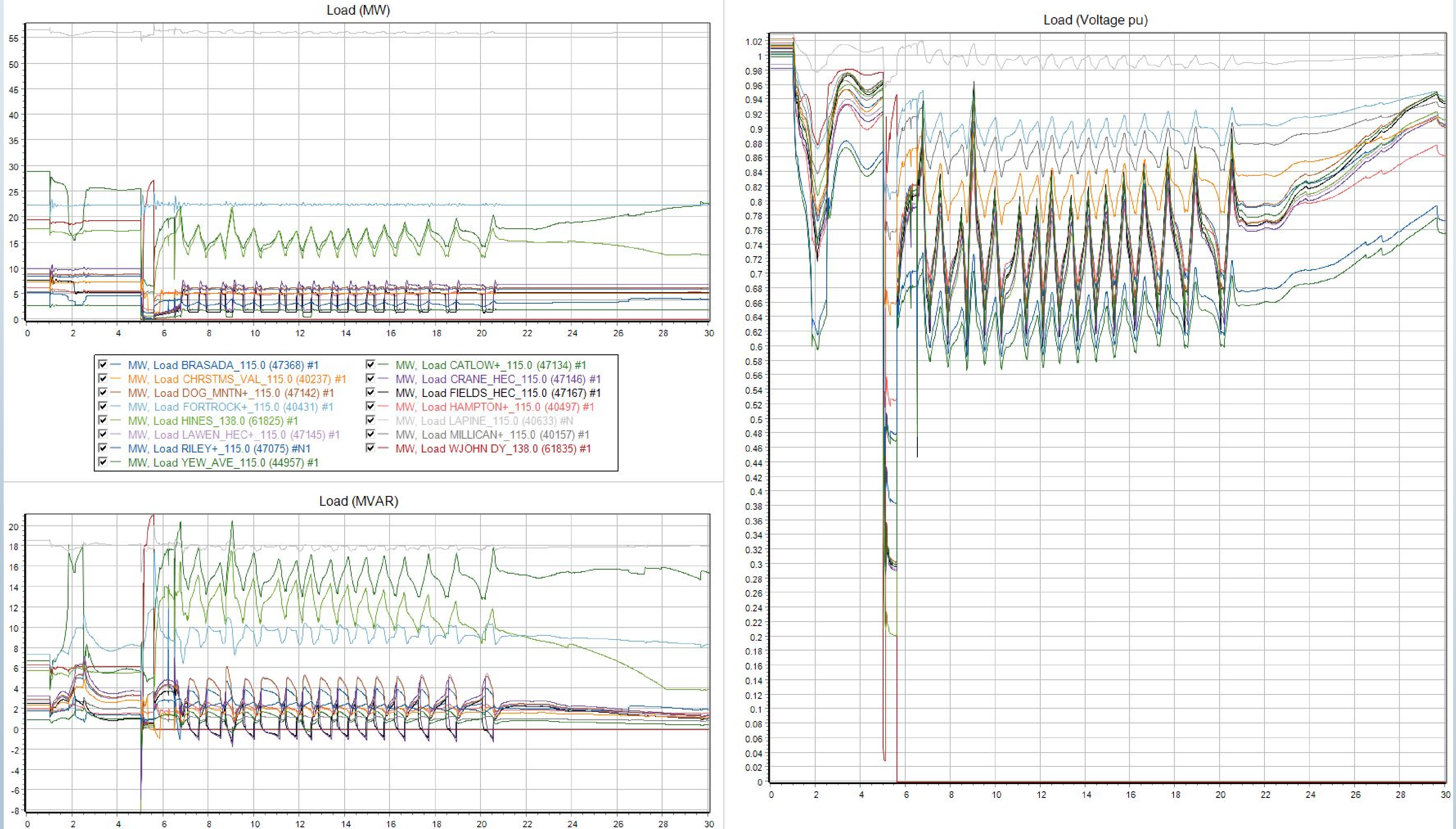
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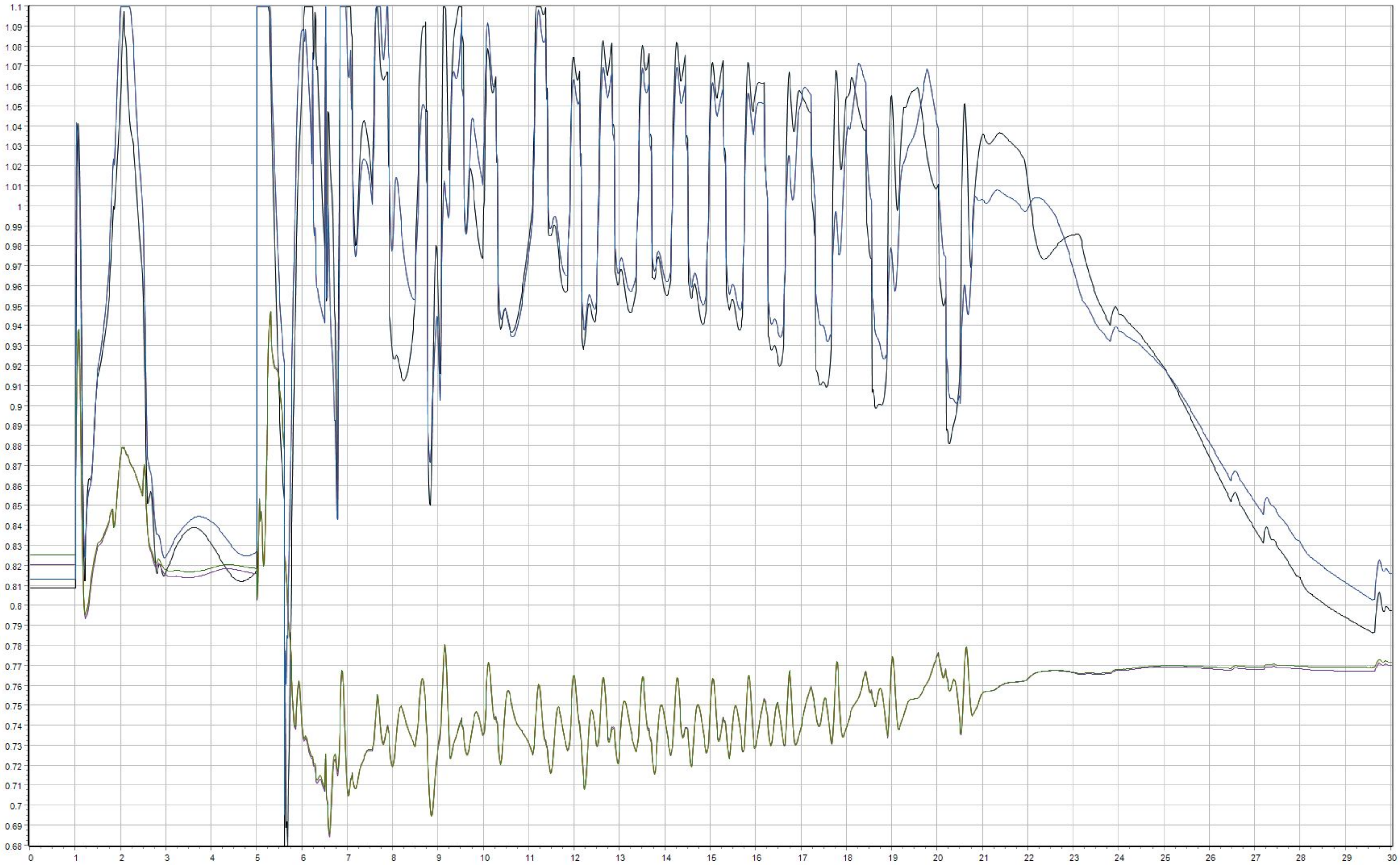
MW, Load WJOHN DY_138.0 (61835) #1
Load (MVAR)
Load (Voltage pu)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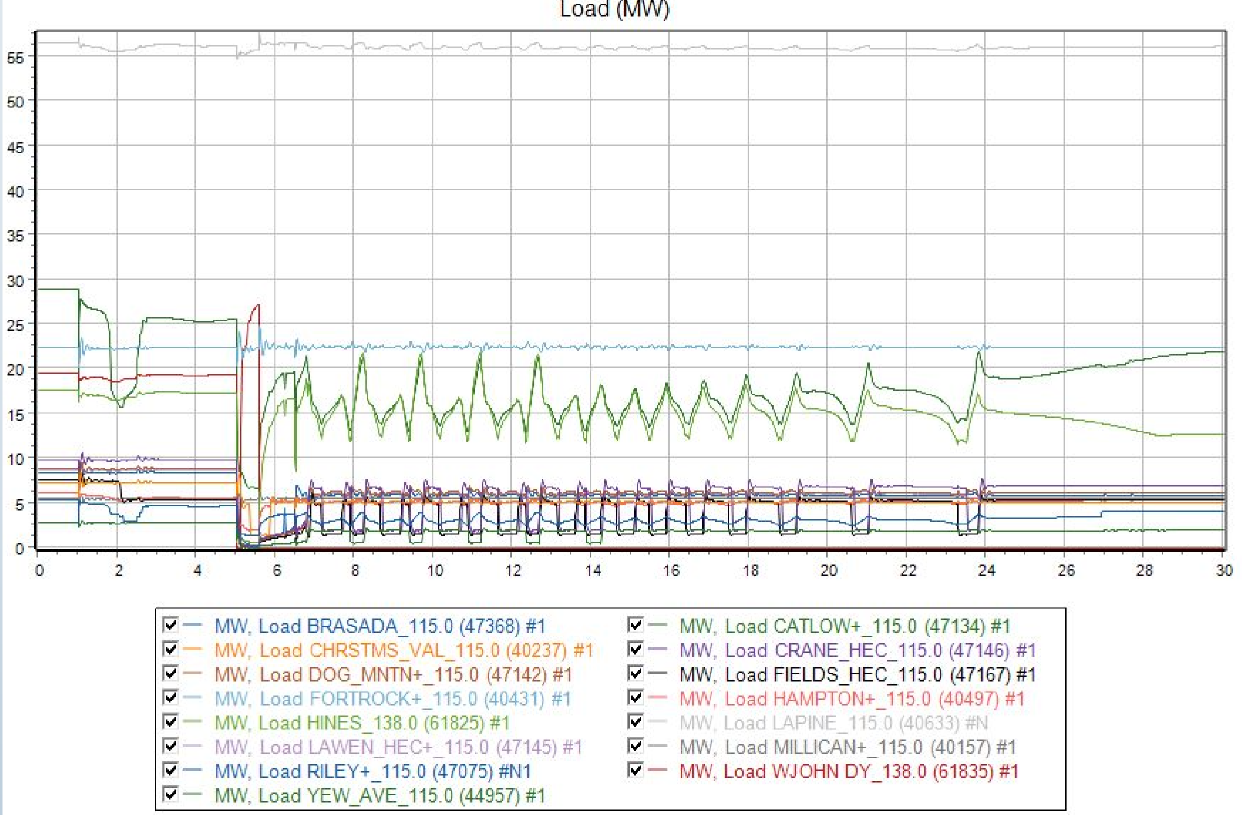
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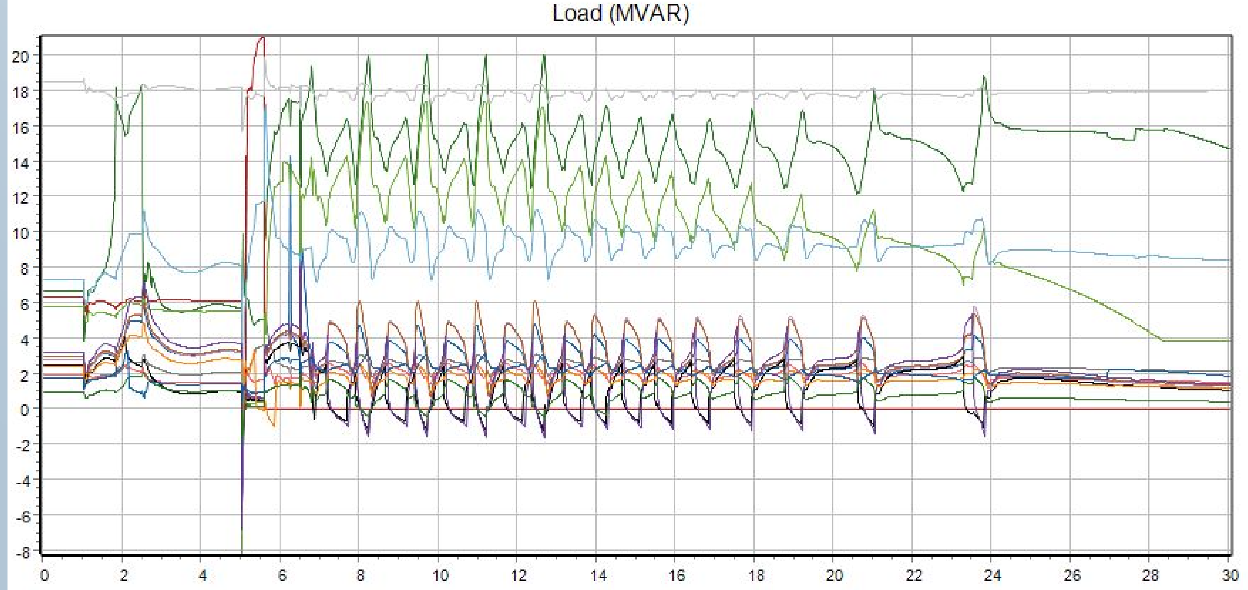
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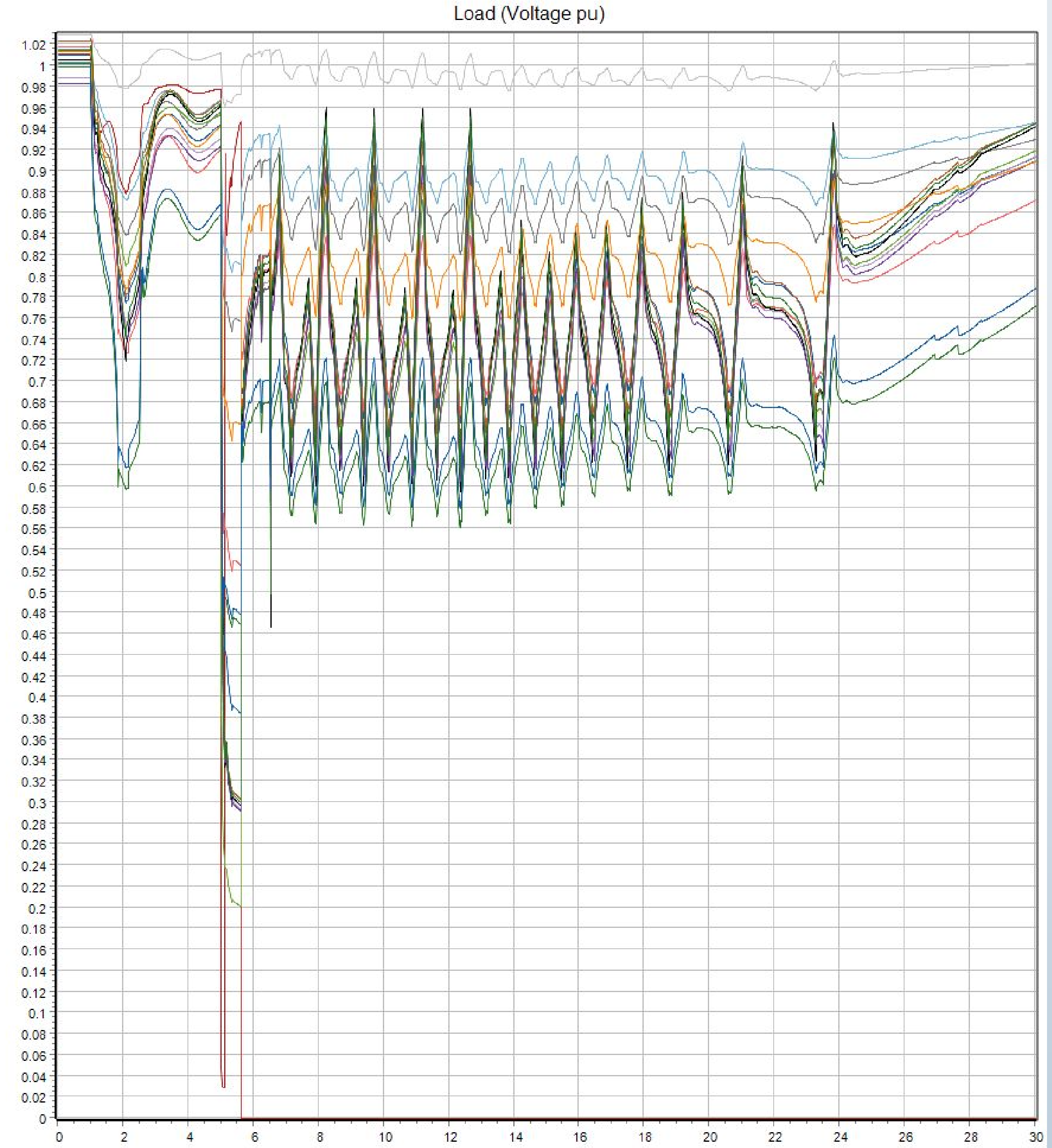
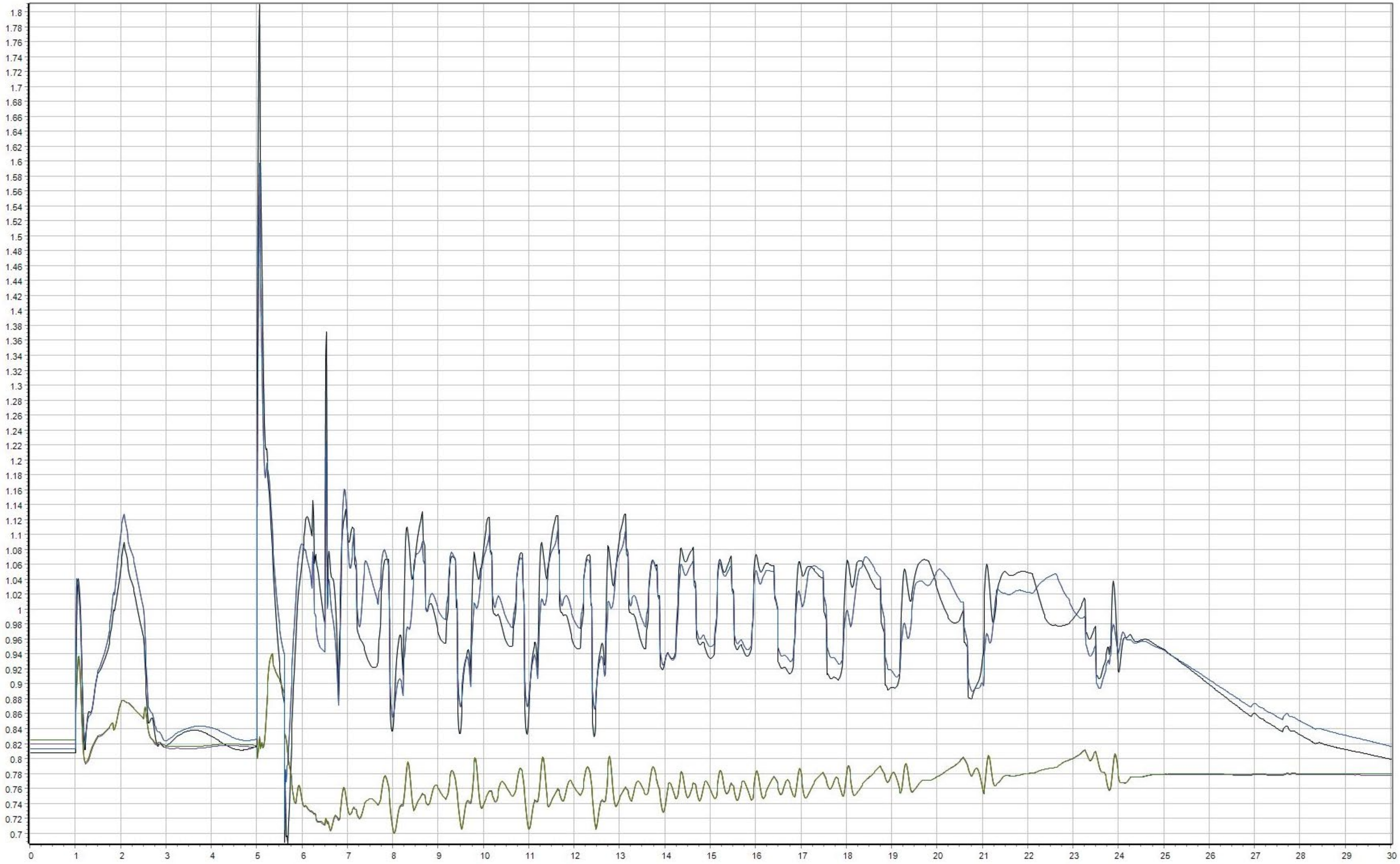

Load (Voltage pu)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Ongoing Work

- Determine the necessary GFM specifications required for GFM resource design.
- Compile the necessary GFM specifications with numerical definitions of performance (magnitudes, droops, timeframe)
- Investigate the exemptions and modifications of IEEE 2800-2022 that are needed for GFM operation

Summary of IEEE 2800-2022 Exemptions/Modifications

MISO Grid-Forming Battery Energy Storage Capabilities, Performance, and Simulation Test Requirements Proposal

20240723 IPWG Item 04b DRAFT GFM BESS Performance Requirements Whitepaper (PAC-2024-2)_REDLINE639677.pdf

IEEE 2800	Subclause name	Potential issue	Recommended action
4.7	Prioritization of IBR responses	Incompatibility with GFM fundamental operation (e.g., prioritization between ridethrough and current responses).	GFM exemption
7.2.2.1	Voltage ride-through – General	Definition of permissive operation region in Table 11 and Table 12	Only allow current blocking or tripping for self-protection in permissive operation region.
7.2.2.3.2	Low and high voltage ride-through capability	Refers to performance in Table 13. Defaults to reactive current priority mode.	Exempt Table 13. Exempt reactive current priority, if affecting GFM operation
7.2.2.3.3	Low and high voltage ride-through performance	Permissive operation region allows current blocking	Only allow current blocking or tripping for self-protection in permissive operation region.
7.2.2.3.4	Current injection during voltage ride-through	Specifies type and amount of current injection. References 7.2.2.3.5 performance. Mentions "automatic voltage control"	GFM exemption
7.2.2.3.5	Performance specification [during voltage ridethrough]	Specific step response time	GFM exemption
7.2.2.6	Restore output after ride-through	Specific active power recovery time and rate	GFM clarification that rate should not constrain natural response
7.3.2.1	Frequency disturbance ride-through requirements – general	References 7.3.2.3.2 and 7.3.2.3.4	Only allow current blocking or tripping for self-protection in permissive operation region.

Table 2. Summary of IEEE 2800-2022 exemptions or modification for IBR GFM

Resources Links

- GFM Landscape - Specifications and Interconnection Requirements – ESIG

- UNIFI Specifications for Grid-Forming Inverter-Based Resources: Version 2

IEEE 2800 - Reactive Power

Item	IEEE 2800 (summarized)
Minimum reactive power capability, capability to inject and absorb reactive power.	|Qmin| ≥ (0.3287) (Plant Active Power Rating) Adjustable for voltage at the reference point of applicability Adjustable for real power output less than 10% for type III WTGs
Voltage and reactive power control modes	Voltage control (capable of reactive power droop set by TS Operator (0 to 0.3 pu voltage change for 1.0 per unit reactive power) Power factor control Reactive power control
Reaction time	< 200 ms (12 cycles)
Maximum step response time (0-90%)	Determined by TS Operator Typical range 1 to 30 seconds Overshoot limits can be applied, for example overshoot < 10%
Damping	0.3 or higher

IEEE 2800 – Active Power Freq. Control

Item	Requirement
Primary Frequency Response	All new interconnecting generating facilities (large and small) shall install and enable primary frequency response capability as a condition of interconnection.
Frequency and real power control	Droop should be set between 2% and 5% The default droop is 5% Under/Over frequency dead band 0.025% to 1.6% The default deadband 0.06% of 60HZ (+/-36 mHZ), (59.964, 60.036)
Reaction time	0.2 (0.5 for WTG) to 1 seconds 0.5 default value
Rise time (10-90%)	2 (4 for WTG) to 20 seconds 4.0 default value
Settling time	10 to 30 seconds 10 default value
Settling band	1 to 5% Maximum (2.5% of change or 0.5% of ICR)
Damping	0.2 to 1.0 0.3 default value

IEEE 2800 – Active Power Freq. Control

Fast Frequency Response (FFR1, proportional to frequency deviation)	
Under frequency trigger	99.17% to 99.94% of nominal, default 99.4% of nominal 59.502 Hz to 59.965 Hz, default 59.64 Hz
Droop	1% to 5%, default is 1% per unit change in frequency corresponding to 1 per unit change in power output.
Step response time	No greater than 1 second
Damping	0.3 or better (dampened response shall take precedence over response time)
Other FFR Methods, IEEE Std 2800-2022, Annex K: FFR2 – proportional to df/dt FFR3 – fixed magnitude with frequency trigger FFR4 – fixed magnitude with df/dt trigger	

IEEE Std 2800-2022

IEEE Standard for Interconnection and Interoperability of Inverter-Based Resources (IBRs) Interconnecting with Associated Transmission Electric Power Systems

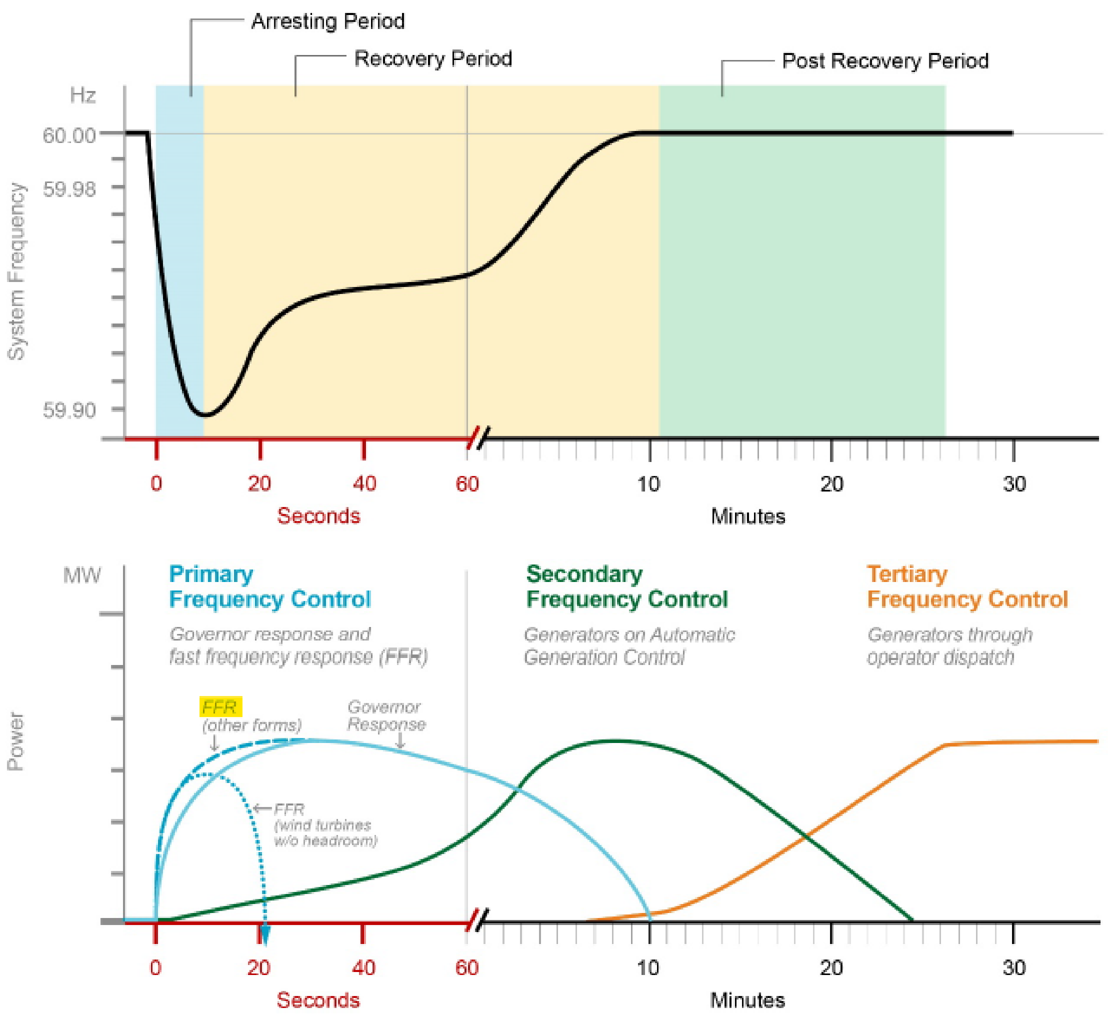

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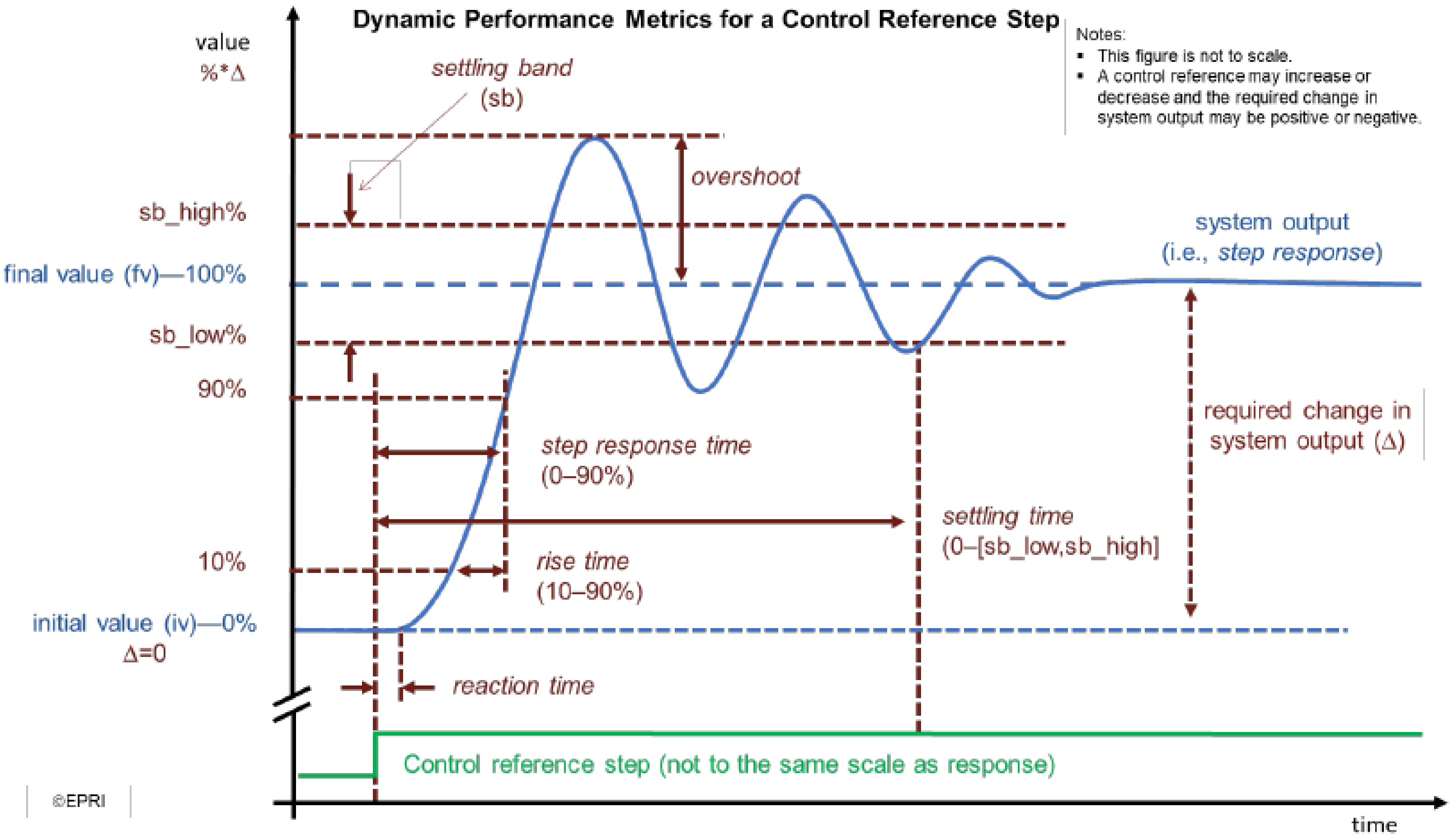
Figure 10—BPS frequency control time frames

IEEE Std 2800-2022

IEEE Standard for Interconnection and Interoperability of Inverter-Based Resources (IBRs) Interconnecting with Associated Transmission Electric Power Systems



(a) Dynamic performance metrics for a control reference step (e.g., frequency response, current injection during fault); the figure illustrates a case where the required final value and final settled value are equal.