

Grid Forming Inverters

EPRI Tutorial (2022)

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Abstract

With the increasing penetration of renewable energy, inverter-based resources (IBRs) are gradually replacing synchronous generators as the new generation resources. As the present-day IBR control methodology may not be sufficient to ensure grid security in a future inverter dominated system, grid-forming inverter control technology has been discussed in recent years as a potential solution.

Considering perspectives from both transmission and distribution systems, this tutorial discusses fundamental questions such as:

- What is grid-forming inverter?
- What are the challenges operating IBRs in weak grid? Why is grid-forming inverter needed?
- Can grid-forming inverters be the first black start resource?
- What are the performance requirements of a grid-forming inverter?
- How to model grid-forming inverters in EMT and RMS domain?

EPRI research results and example real-world use cases are included to facilitate the understanding of concepts. A survey of representative grid-forming inverter control techniques is also covered with their operational principles explained and compared.

Keywords

Grid forming inverter, Weak grid, Low inertia system, 100% renewable, Inverter dominated grid

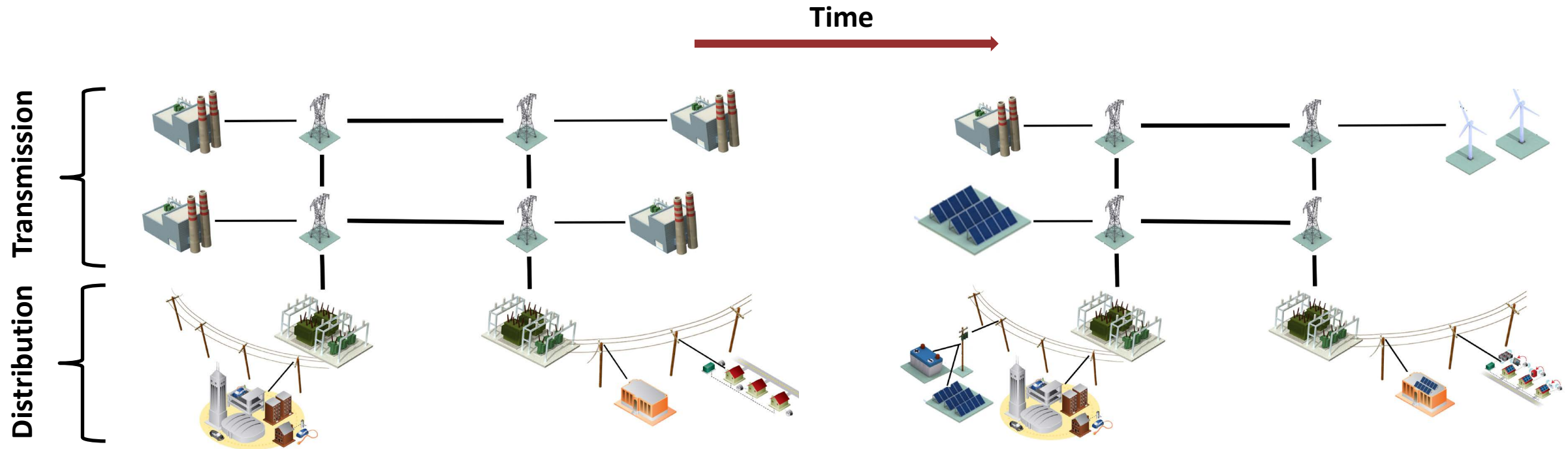
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Introduction

Transforming power system



Central synchronous generators (SGs) are being replaced by transmission and distribution connected inverter-based resources (IBR), primarily wind and solar PV.

Evolving system needs expected from Inverter Based Resources (IBRs)

Power System

Past:
SG dominated system

Present:
Increased penetration of
IBRs

Future:
IBR dominated system

System needs from IBR

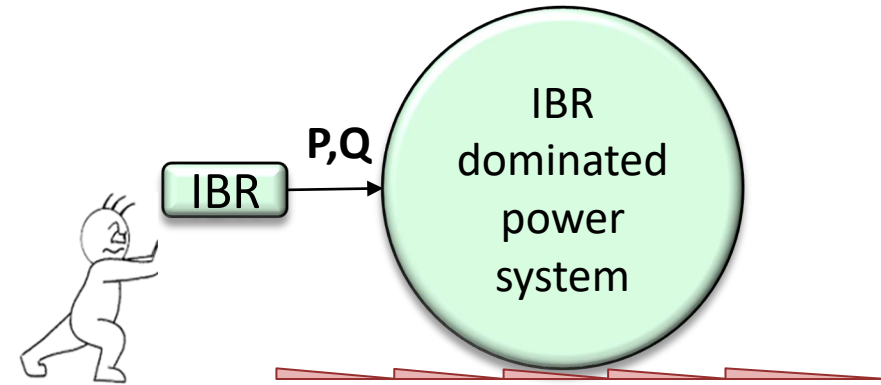
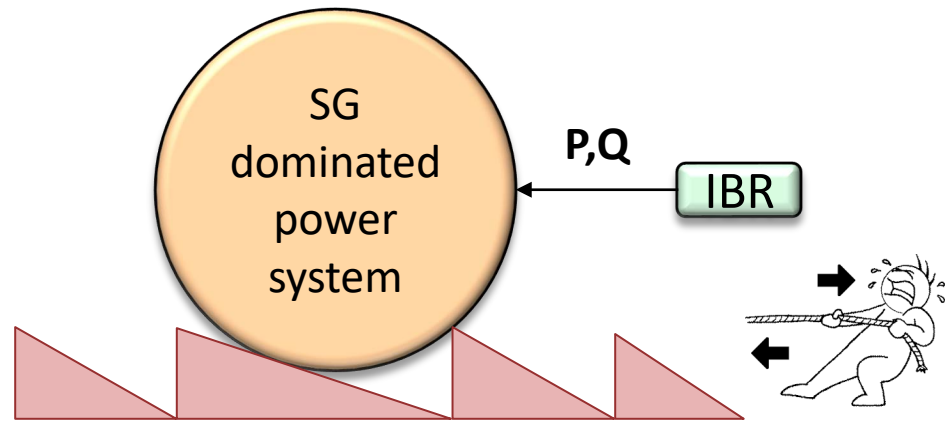
Unity power factor, minimal fault
ride-through ...

Automatic voltage control,
frequency response, V/F ride-
through ...

Without relying on SGs, provide the
above services and more
(fast frequency response, maintain
system stability...)

Moving toward an inverter dominated power system, IBRs will gradually substitute SGs in providing grid services and ensuring grid reliability

Challenges for IBRs to provide grid services

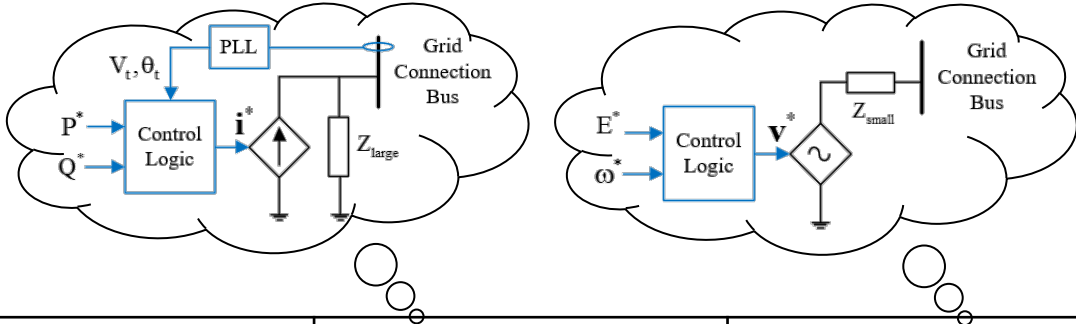


- Majority of today's IBR control is designed to work in a stiff system
 - Changes in IBR injected current **do not** 'move' the stiff system
 - Changes in system cause IBR to 'move' in tandem
- This behavior has **recently** been labeled as grid following (GFL)
- In IBR dominated power system:
 - Increased elasticity in the grid
 - Changes in IBR injected current **will** 'move' the system
 - This movement in system will itself cause IBR to 'move' in tandem
- This increased interaction is to be stabilized for IBR to deliver expected needs

Could grid forming (GFM) IBRs be the solution to provide services in an inverter dominated grid?

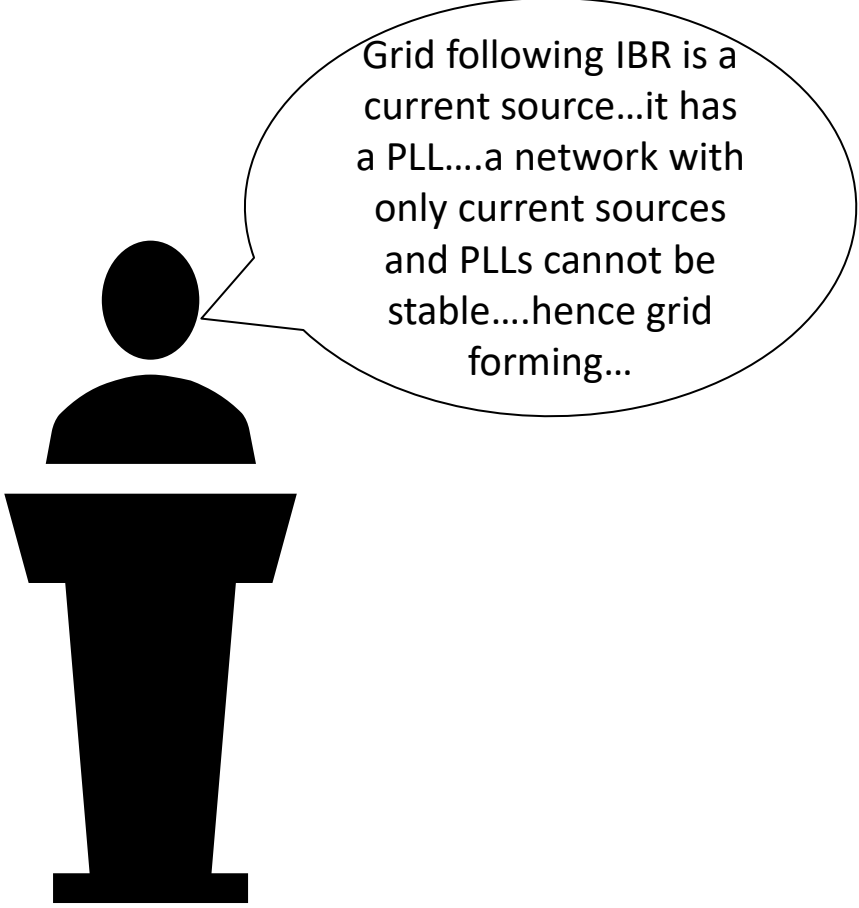
You may have heard this regarding grid following (GFL) and grid forming (GFM) inverters

High level definition based on specific control design

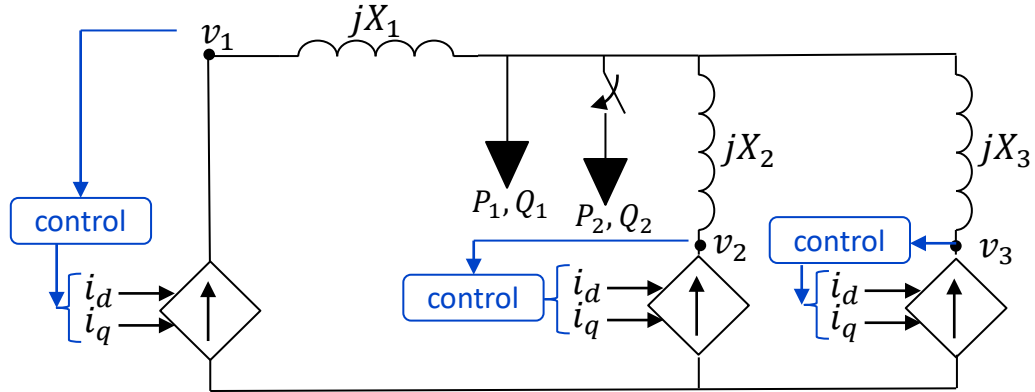


	Grid-following inverter	Grid-forming inverter
Basic control objectives	Deliver a specified amount of power to an energized grid	Set up grid voltage and frequency
Output quantity controlled	ac current magnitude and phase angle	ac voltage magnitude and frequency
Require a stiff and stable voltage at the terminal?	Yes	No
Control elements present	Compulsorily has a PLL	Compulsorily does not have a PLL

There are many nuances within each statement above that may blur the line between grid following and grid forming



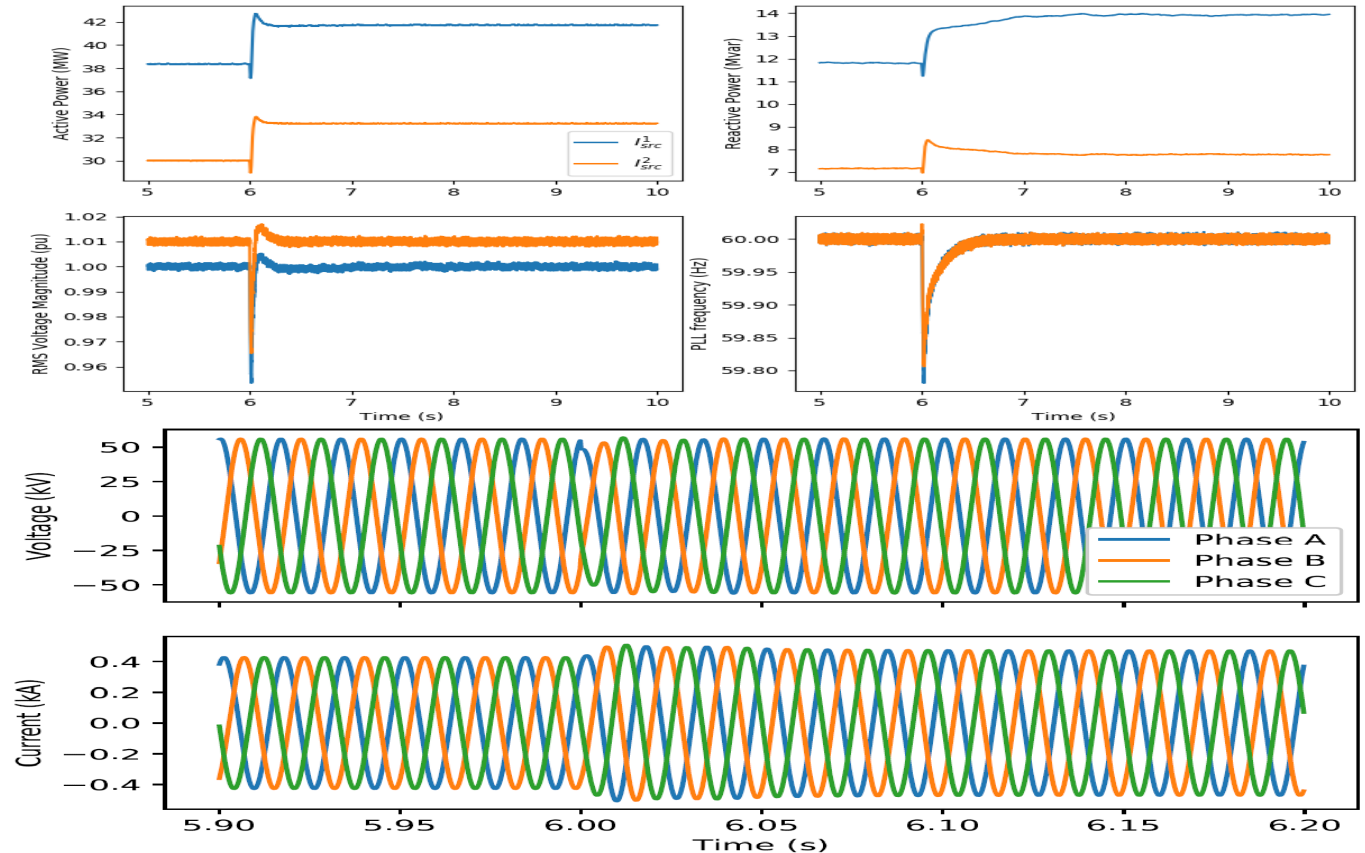
But Kirchhoff's Laws still apply in a 100% current source network



- » Voltage levels in network decided by current and impedance
- » Network will collapse if i_d and i_q do not change when load changes
- » But from circuit theory, this network has a stable/viable solution

Values of injected current to be controlled in a timely manner for network to be stable

What does this have to do with grid forming behavior?



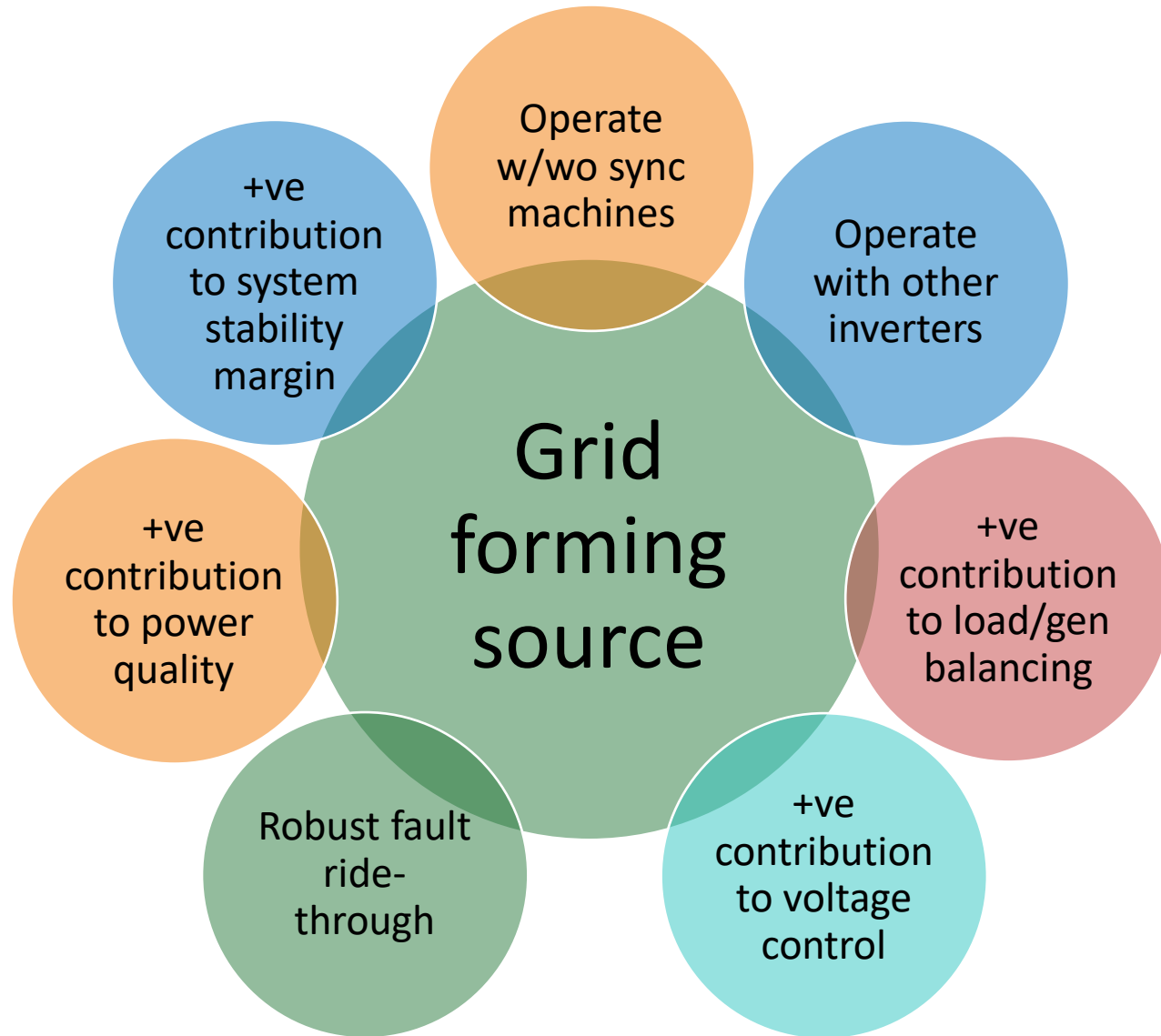
10% increase in constant power load

Defining grid forming behavior from system planner perspective

- Continued operation of 100% current source network is possible
- Today's inverter may have issues operating in weak grid simply because the control is **designed and tuned for strong grid operation**
 - PLL is just part of the control architecture to obtain synchronization
 - It is **not the sole cause of instability** in weak grids
- This does not mean inverter control with PLL cannot be developed to work in weak or even 100% IBR grids

Can be beneficial to define grid forming using a performance based approach

Performance requirement for grid forming source



- GFM inverter can be defined based on its capability and the grid services it provides
- These services should be provided while *meeting standard acceptable metrics* associated with reliability, security, and stability of the power system and *within equipment limits*
- *Few GFM sources* can also be designated as blackstart resources

Potential application of grid forming inverters

- In the near term, GFM inverters are primarily considered in
 - Inverter-based microgrid design
 - Transmission systems with low fault current and rotational inertia
- In the future, thousands of GFM inverters may be deployed in both transmission and distribution grids to support reliable operation with low grid strength
- Stable and reliable coordination between numerous GFM inverters, and with other devices in grid-connected mode, is a major challenge and the focus of on-going research at EPRI

Few examples of GFM installations in Utility-Level Microgrids

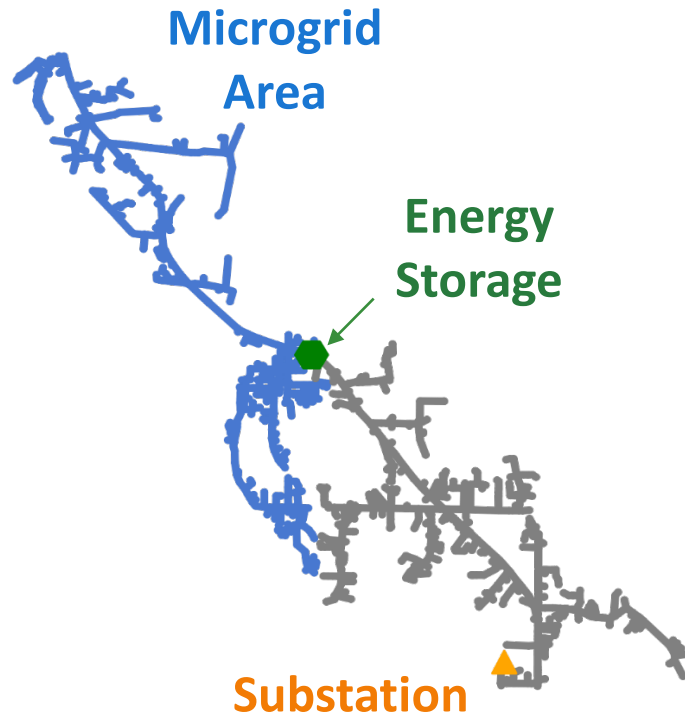


Illustration of a utility-level microgrid containing a section of a distribution feeder

- BESS with GFM capability has been deployed in a growing number of inverter-based microgrids
- Micanopy microgrid, FL
 - Section of a MV feeder with 8.25 MW BESS to support the town of Micanopy and nearby neighbors during grid outage
 - Source: <https://news.duke-energy.com/releases/duke-energy-florida-announces-three-new-battery-storage-sites-including-special-needs-shelter-and-first-pairing-with-utility-solar>
- Central Adirondack Microgrid Project (CAMP), NY (in process)
 - BESS requirements are 20 MW, 40 MWh, 75 MVA short circuit current
 - The system includes 5 substations, 46 kV sub-transmission line, and 10 feeders, which can separate to form an island supplied by the battery
 - Source: <https://www.nationalgridus.com/media/pdfs/bulk-energy-storage-request-for-proposals/appendix-e-locations-usecases.pdf>
- Waterton microgrid, AB
 - Section of a MV feeder with a 1.6 MW, 5.2 MWh BESS and a 200 kW PV site at different locations
 - Source: <https://www.pc.gc.ca/en/pn-np/ab/waterton/visit/infrastructure/solaire-solar>

Few examples of GFM installations around the world

- BESS in St. Eustatius Island
 - 2.3 MW peak load, 100% (Solar + storage) operation mode during daytime
 - Diesel free daytime electricity supply
 - Savings of 1.7 million liters of diesel fuel / year
 - Load distribution across several parallel GFM units (no communication)
 - Seamless and immediate load transfer after simultaneous loss of all gensets at peak load
 - Source: <https://www.sma-sunny.com/en/st-eustatius-100-solar-power-in-the-caribbean/>

More examples available at: Julia Matevosyan, “Survey of Grid-Forming Inverter Applications,” G-PST/ESIG Webinar Series, June 2020 ([link](#))

Few examples of GFM installations around the world (cont'd)

- Dersalloch Wind Farm in Scotland
 - 69 MW of wind turbines operated in GFM mode for 6 weeks
 - Virtual synchronous machine mode used
 - Wind farm responded to both large underfrequency events and phase steps.
 - Island operation (7 MW load) and blackstart capability of wind turbines to energize wind farm and re-synchronize with the grid
 - Source: <https://renewablesnow.com/news/scottishpower-completes-black-start-project-using-69-mw-wind-farm-719904/>

More examples available at: Julia Matevosyan, “Survey of Grid-Forming Inverter Applications,” G-PST/ESIG Webinar Series, June 2020 ([link](#))

Few examples of GFM installations around the world (cont'd)

- Dalrymple BESS in South Australia
 - 30 MVA and 8 MWh battery connected close to 91 MW wind farm and 8 MW load
 - In first six months of operation, reduced loss of supply in area from 8 hours to 30 min
 - Source: <https://go.hitachi-powergrids.com/grid-forming-webinar-2020>

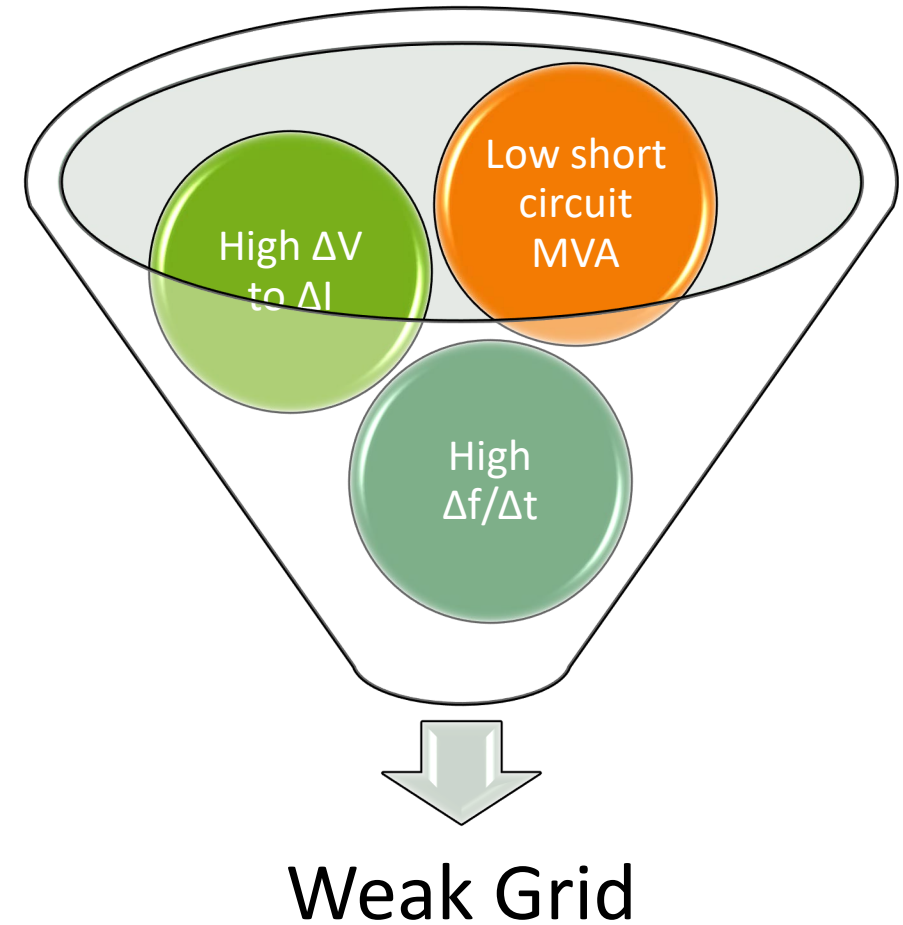
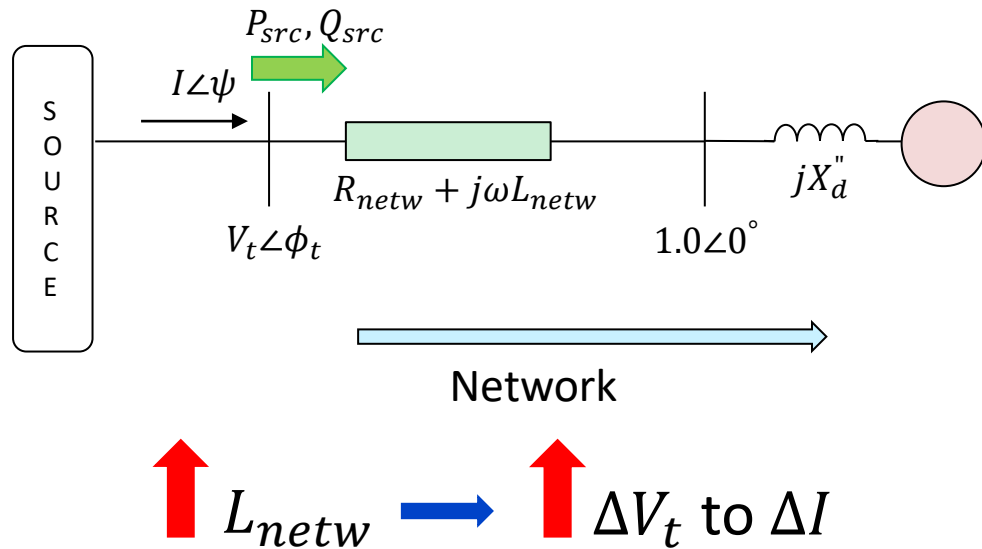
- Hornsdale BESS in South Australia
 - 150 MW/ 194 MWh BESS co-located with wind farm
 - Recently in 2020, provided response during a large grid disconnection event
 - Source: <https://arena.gov.au/knowledge-bank/presentation-arena-insights-webinar-advanced-inverters/>

More examples available at: Julia Matevosyan, “Survey of Grid-Forming Inverter Applications,” G-PST/ESIG Webinar Series, June 2020 ([link](#))



Weak Grid Operation of IBR

Defining, evaluating, and stability in weak grids...



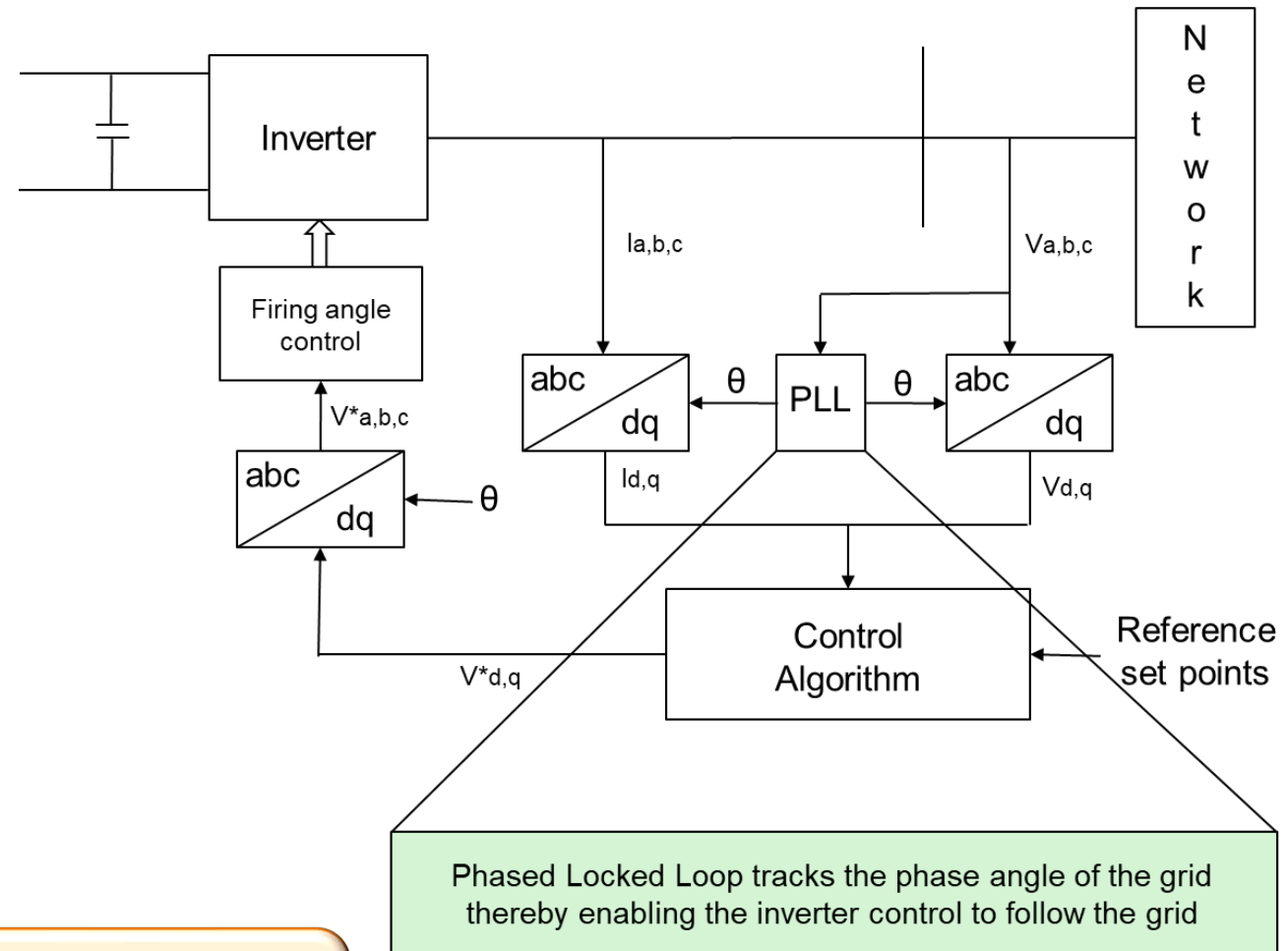
- Previously studied in context of synchronous machines connected through long lines
 - Power System Stabilizers (PSS) subsequently developed
- Similar approach can be utilized for future IBRs
 - Through power oscillation dampers (POD)

Reality of reduced grid strength and inverter operation...

- Operational issues and control instability of IBRs connected to weak transmission grids have been reported by several transmission system operators around the world, (e.g., ERCOT, AEMO)
- **This is one of the key drivers for looking into GFM inverters in the transmission system**
- Similar challenges may also occur in the distribution grid

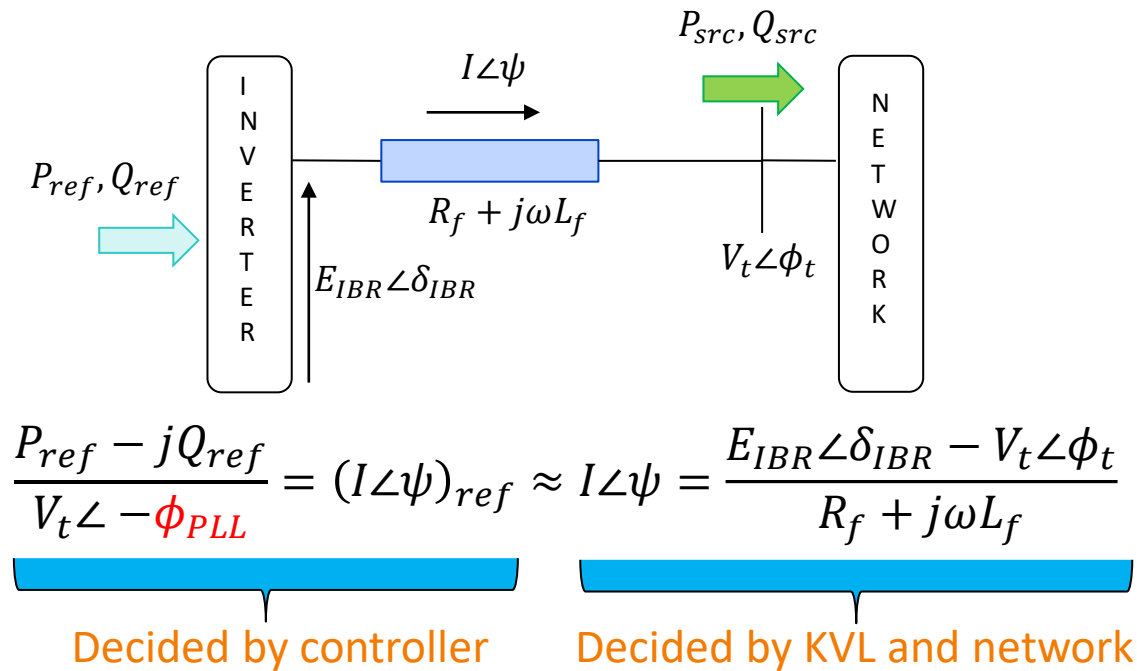
Basics of present-day IBR – grid interaction...

- Unlike synchronous machine, IBR does not have electromagnetic coupling with the grid
 - Conventional IBR uses a Phase Locked Loop (PLL) to remain synchronized and locked to the network.
- All controls within an IBR treat this evaluated PLL phase angle as a **reference**
 - Subsequently used to evaluate amount of current to be injected by IBR



In synchronous machine, laws of electromagnetics provide grid phase angle
In conventional IBR, specific control loops calculate grid phase angle

Present-day IBR current generation and weak grids...



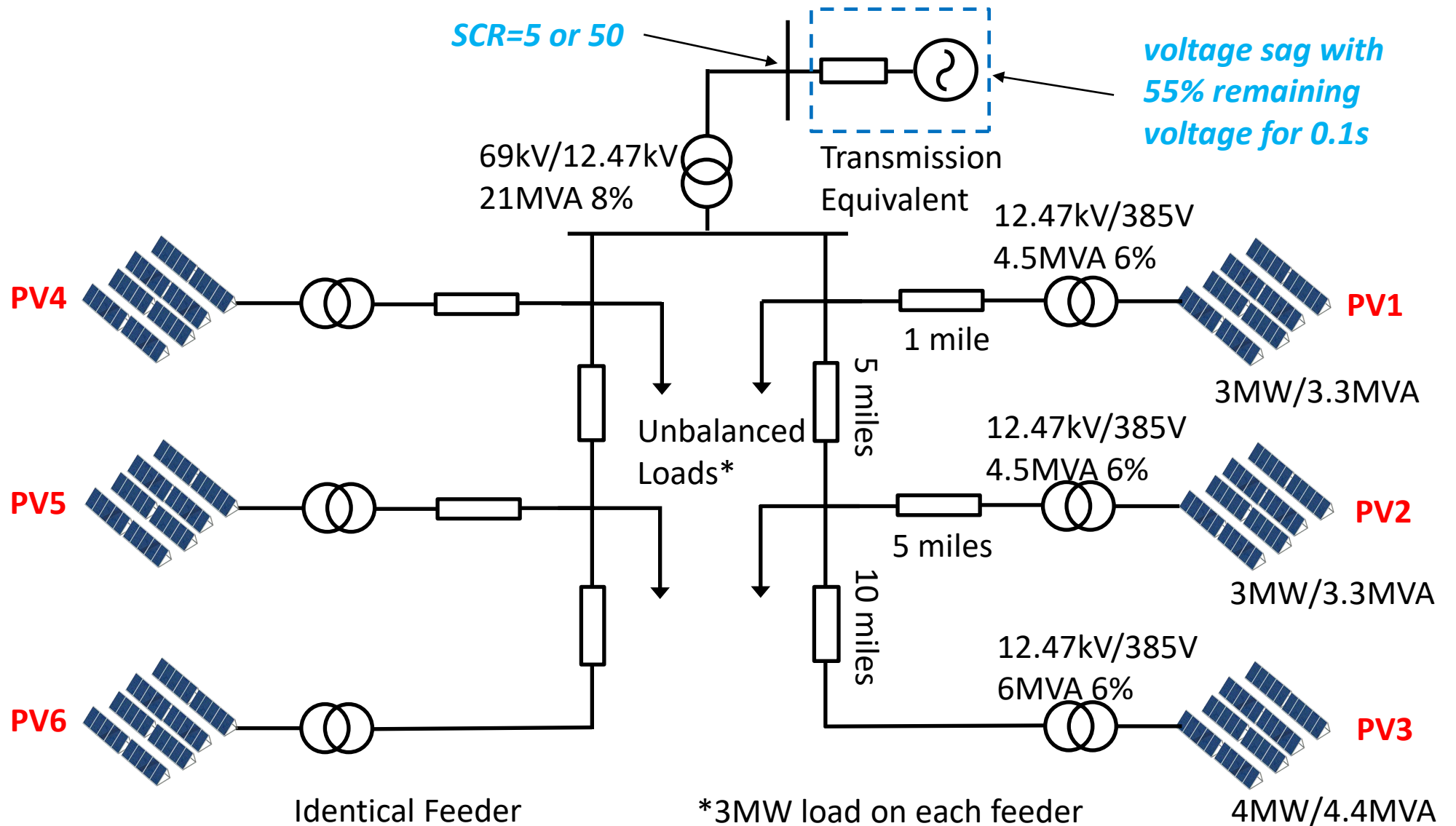
- To ensure $I \angle \psi \approx (I \angle \psi)_{ref}$
 - $E_{IBR} \angle \delta_{IBR}$ must change rapidly when $V_t \angle \phi_t$ changes
- To enable a rapid change in $E_{IBR} \angle \delta_{IBR}$
 - **Accurate and fast** estimation of $\phi_{PLL} \approx \phi_t$
 - **Accurate and fast** current controller to generate $E_{IBR} \angle \delta_{IBR}$

An IBR injects controlled current

- In weak grids, for small $\Delta(I \angle \psi)$, high $\Delta(V_t \angle \phi_t)$:
 - magnitude of change can be large
 - rate of change occurs can be large
 - frequency of change can be high

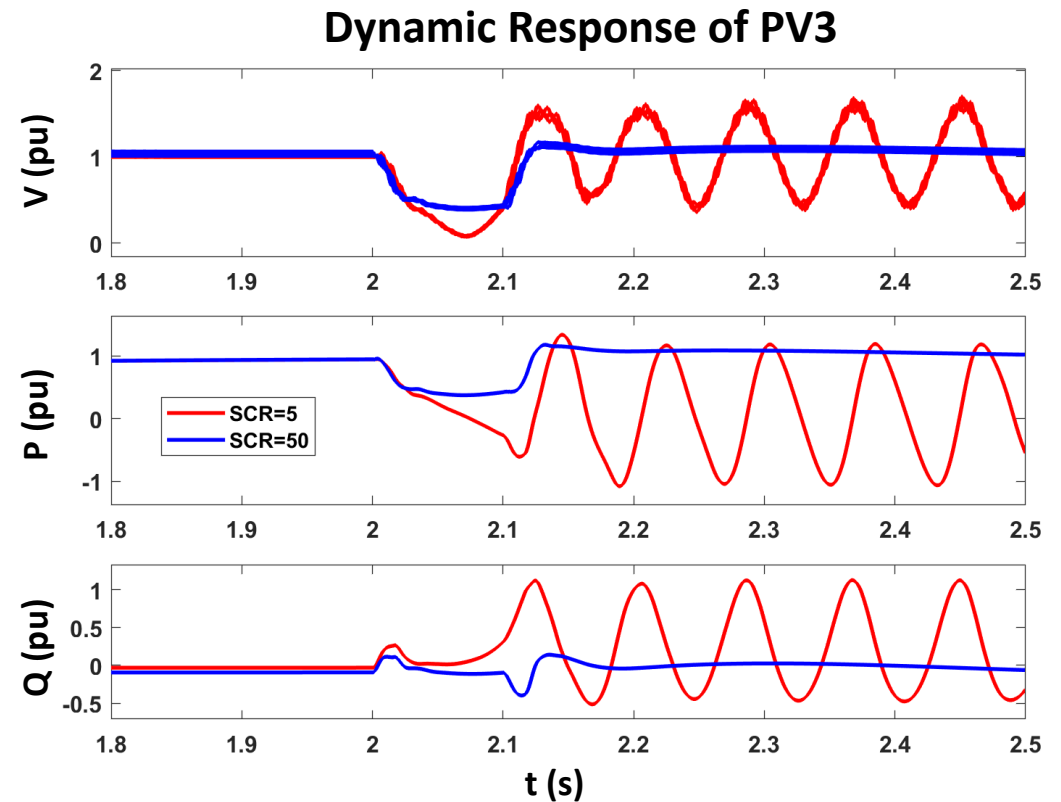
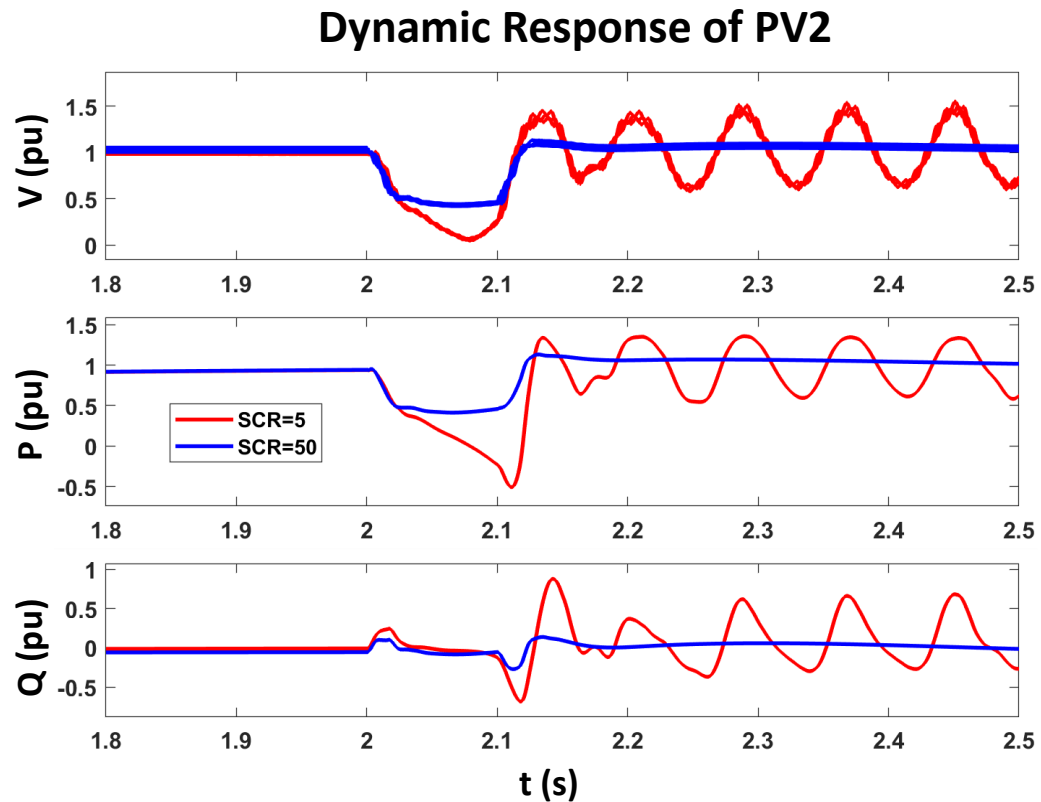
Fast control loops of IBRs that help $E_{IBR} \angle \delta_{IBR}$ change rapidly can become unstable

Simulation case study: weak grid operation of DER



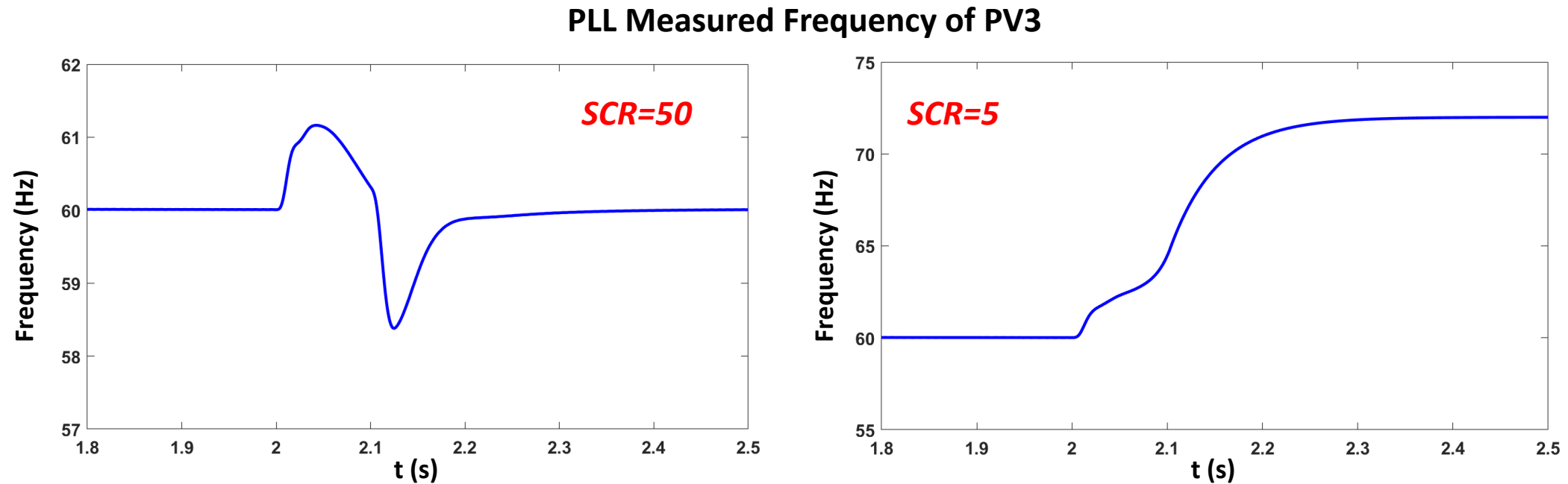
*Inverter with
volt-var control
(IEEE 1547-2018
Category B
default settings)*

Disturbance ride-through with varying SCRs



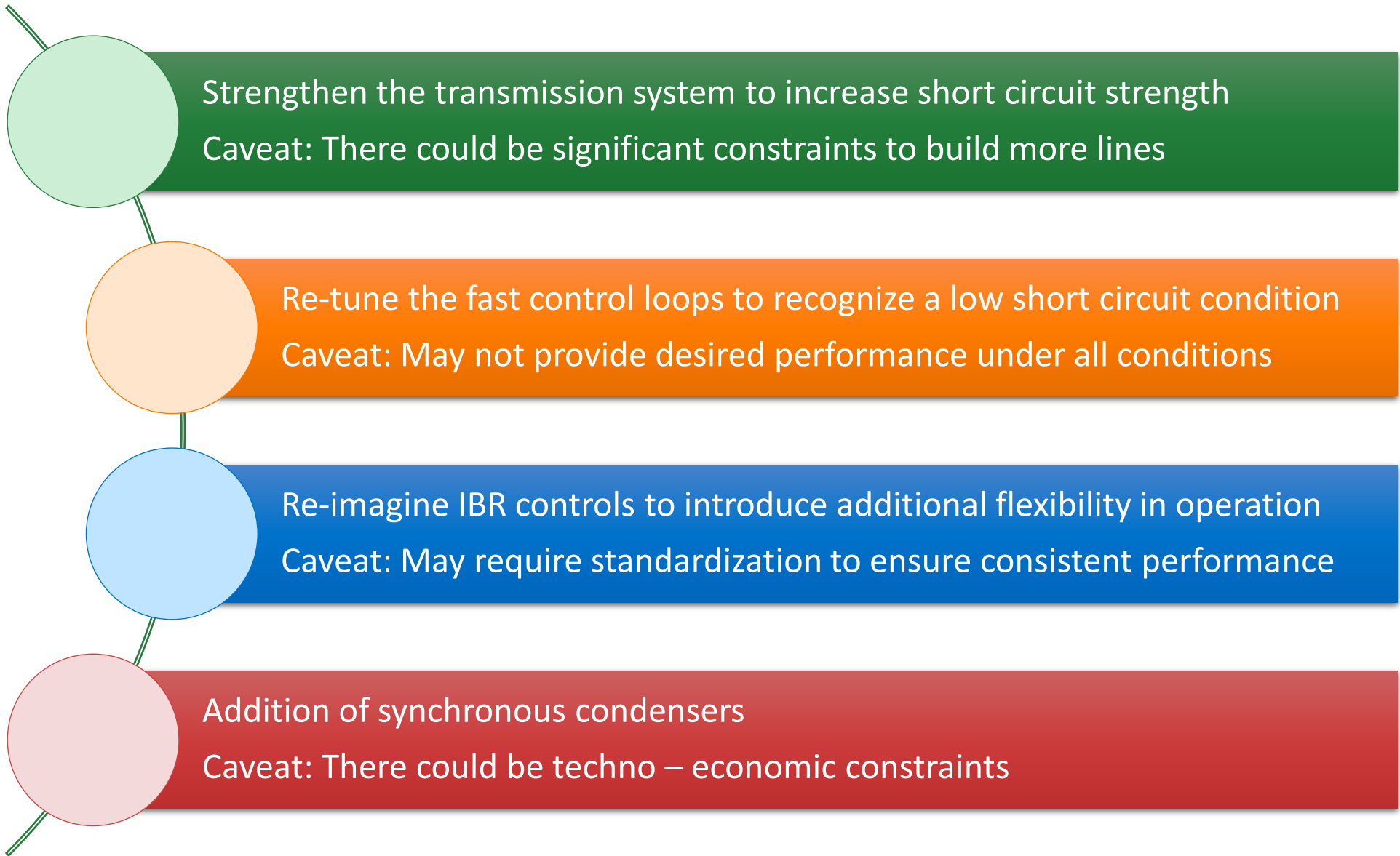
- With $SCR=5$, the inverters become unstable and have significant oscillations in the power output and voltage if they ride through the fault
- Inverter trip settings are not activated in these simulations to better observe the inverter dynamic behavior

What's causing the inverter instability?

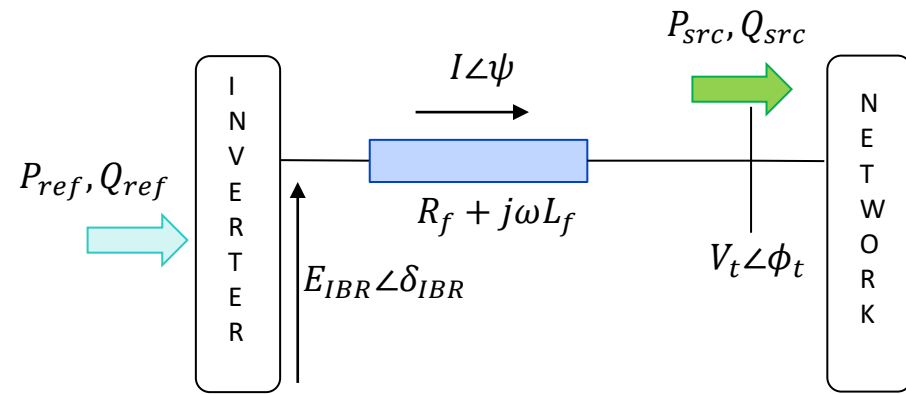


- For most present-day inverters, the PLL is designed to work properly when the grid voltage is insensitive to inverter current injection
- In a low short circuit system, the PLL may fail to lock onto the grid frequency following a disturbance [1]
- The inverter will inject current at incorrect phase and the power output is no longer controlled
- Again, inverter trip settings are not activated in these simulations to better observe the inverter dynamic behavior

Few combinations of options for mitigation...



Two possible methods to **conceptually** re-imagine IBR controls – could be called GFM IBRs



- Slowly vary $E_{IBR} \angle \delta_{IBR}$ directly as a function of change in V_t and P_{src}
- Only control current if it hits limit

- Vary P_{ref} and Q_{ref} directly as a function of change in V_t and ϕ_{PLL}
- Control current continuously

There are important nuances involved

Potential to contribute to increase system strength

Low short circuit MVA

- GFM IBRs can contribute only if the hardware rating is increased

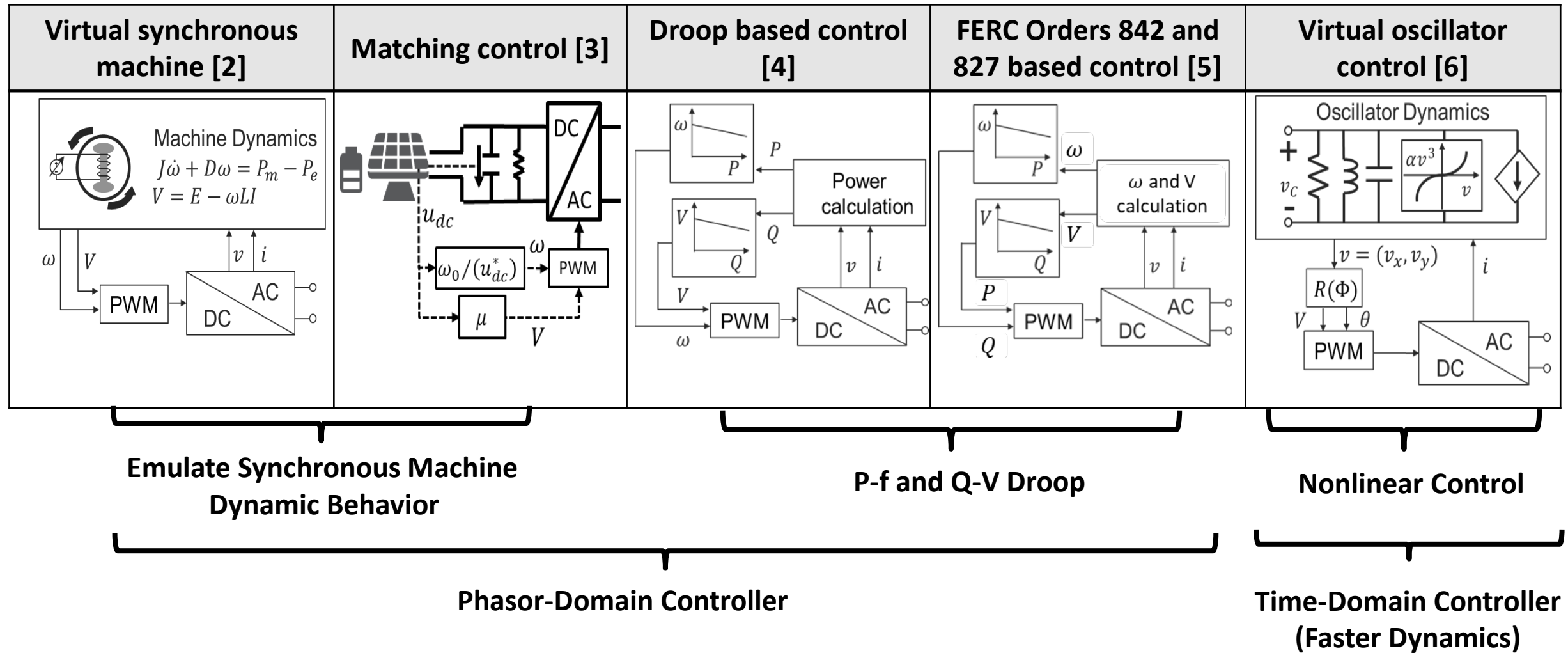
High ΔV to ΔI

- GFM IBRs can contribute through improvements in control methods

High $\Delta f / \Delta t$

- GFM IBRs can contribute through participation in frequency response

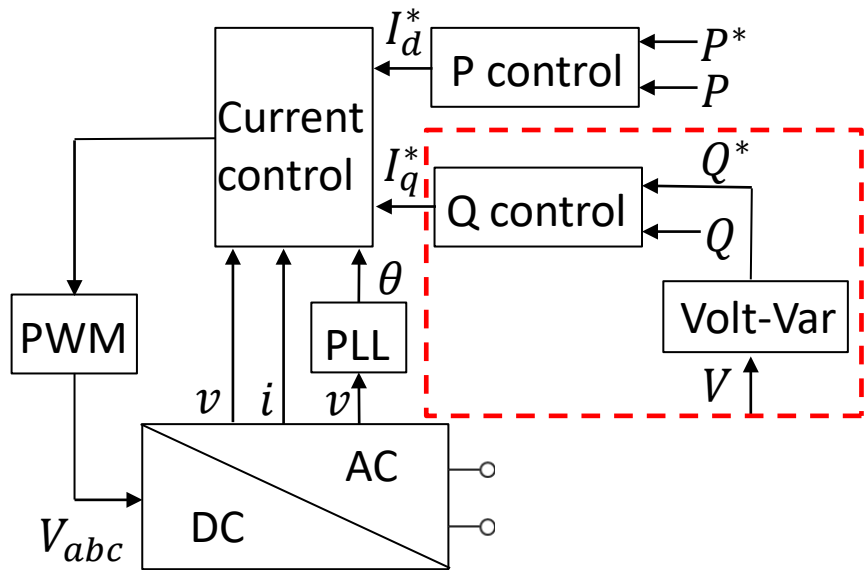
Several GFM inverter controls from the literature



This is not a comprehensive list of GFM inverter control. More controls are being proposed in the literature.

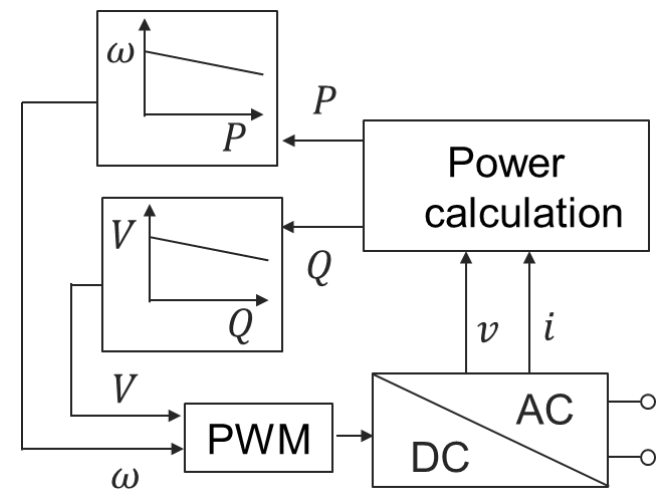
Example case to illustrate improved inverter operation in low short circuit scenario with GFM control

Two forms of GFM inverter control compared for improved system behavior

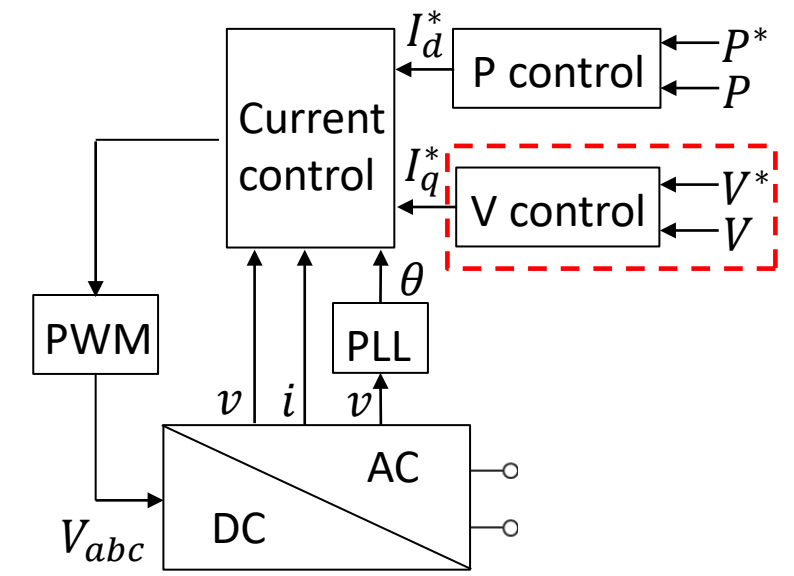


Conventional inverter control with **slow** volt-var

Use of this control was previously shown to be unstable with SCR = 5



Droop-based inverter control



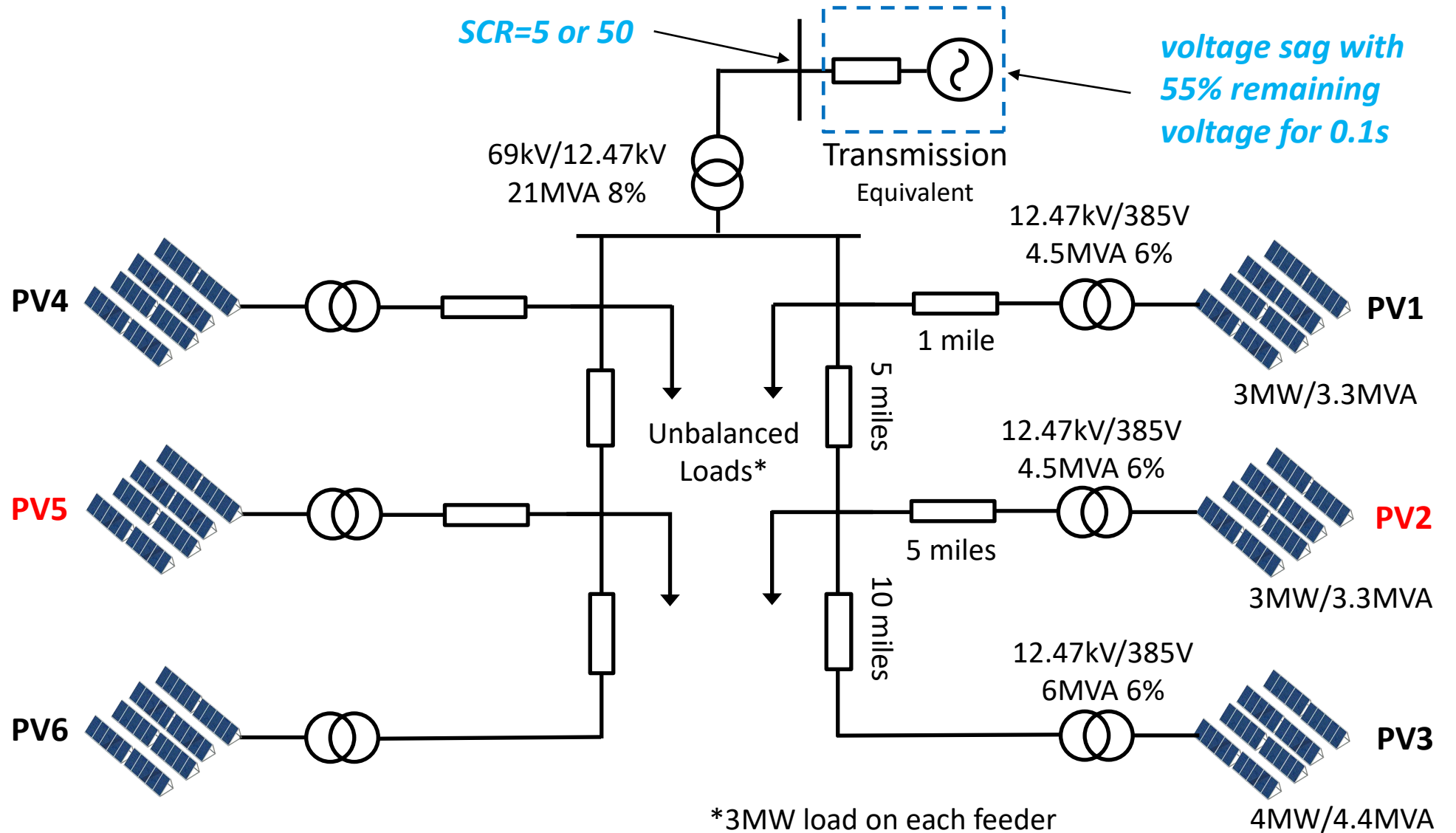
Inverter control with fast reactive current injection (labeled as DVS)

GFM control for two PV plants in the system

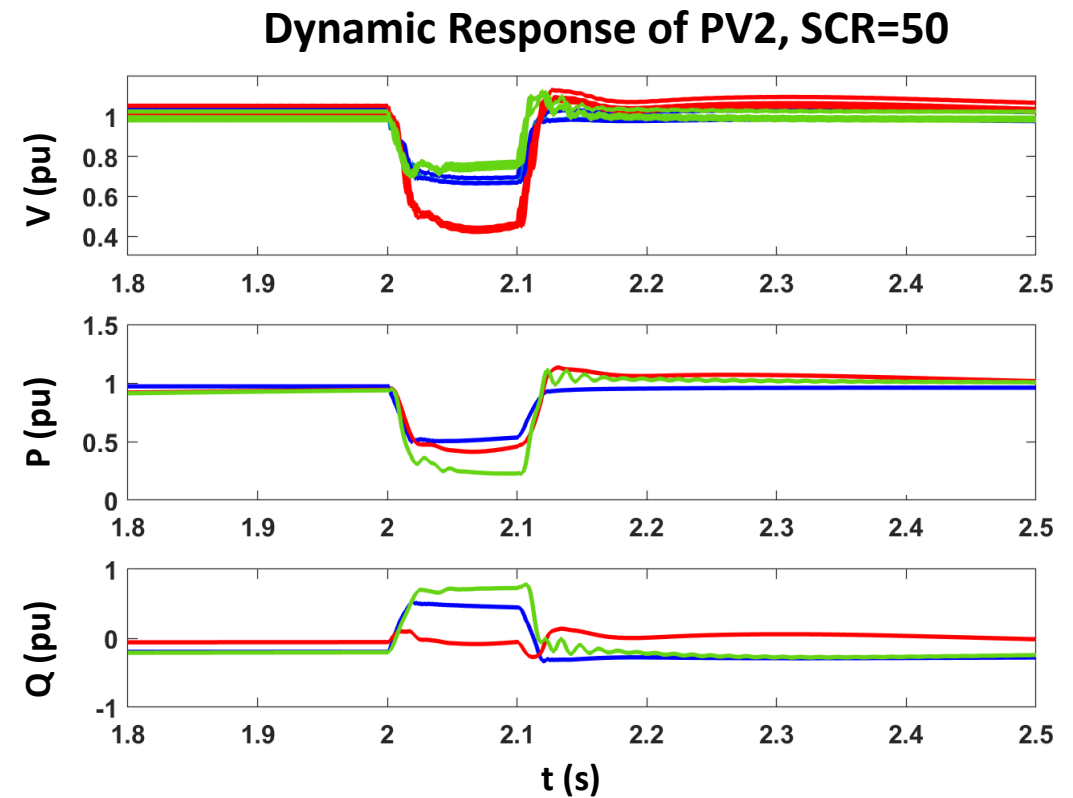
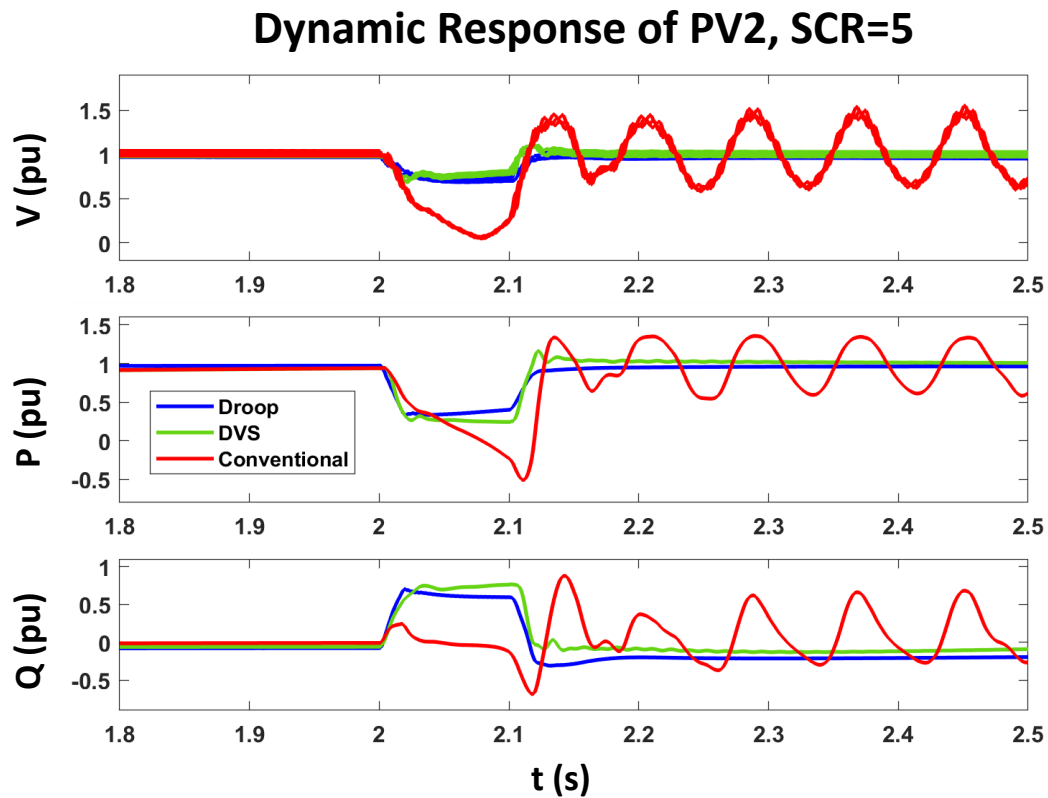
conventional inverter with volt-var control (Category B default settings)

Conventional, DVS or droop-based control for PV2 and PV5

Other system parameters and settings remain the same as in previous analysis



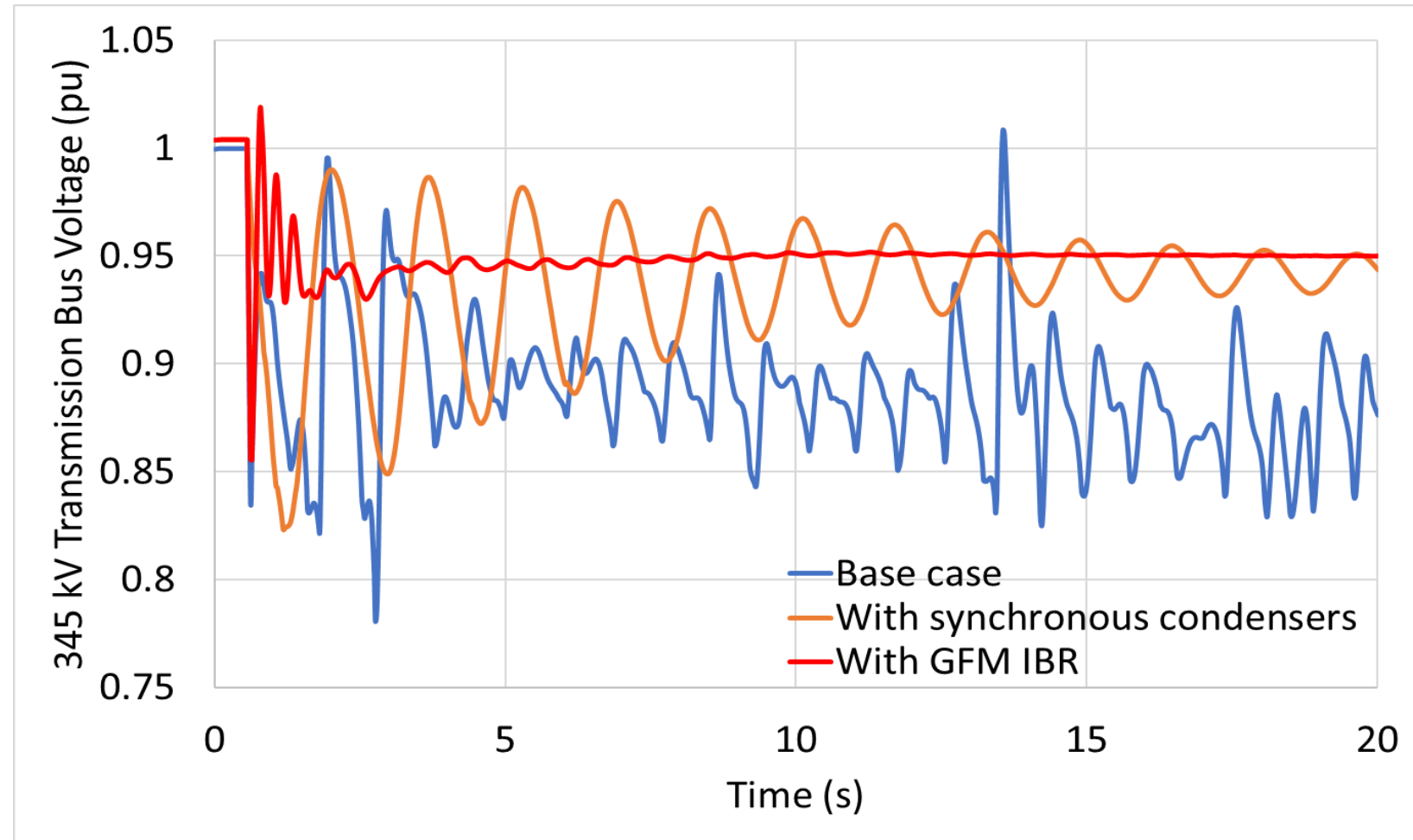
Performance comparison – conventional, DVS and droop



- DVS and droop-based control can both stabilize the inverters following the fault ride-through
- The DVS and droop-based control show similar dynamic response: the reactive power increases fast to boost the feeder voltage during the disturbance
- By using DVS or droop-based control for two PV plants, all the six PV plants in the system are stabilized

GFM IBR vs synchronous condenser to increase wind farm percentage...

- With increase in MW generation from wind turbines
 - Voltage oscillations observed in 345kV network for N – 1 outage

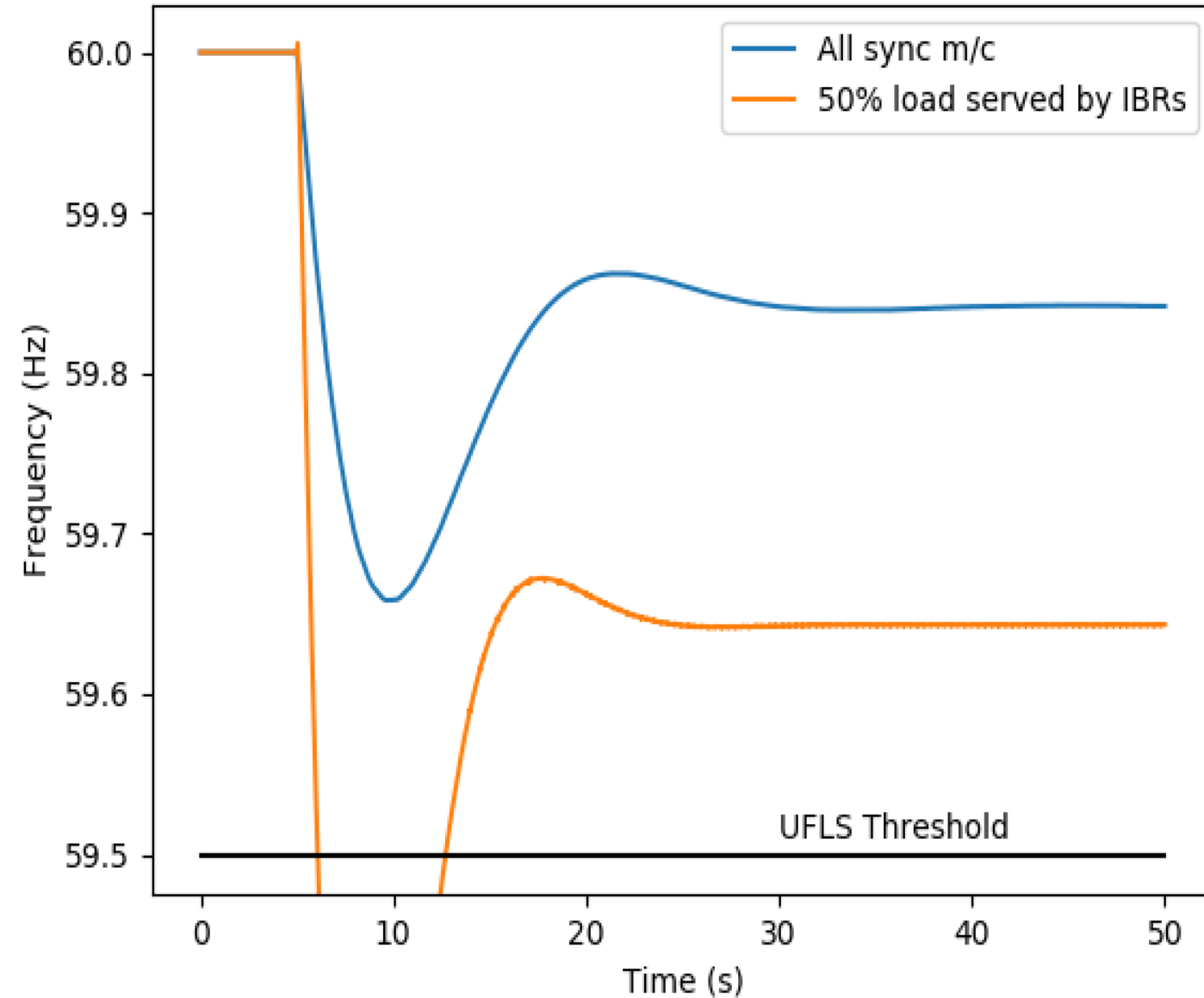
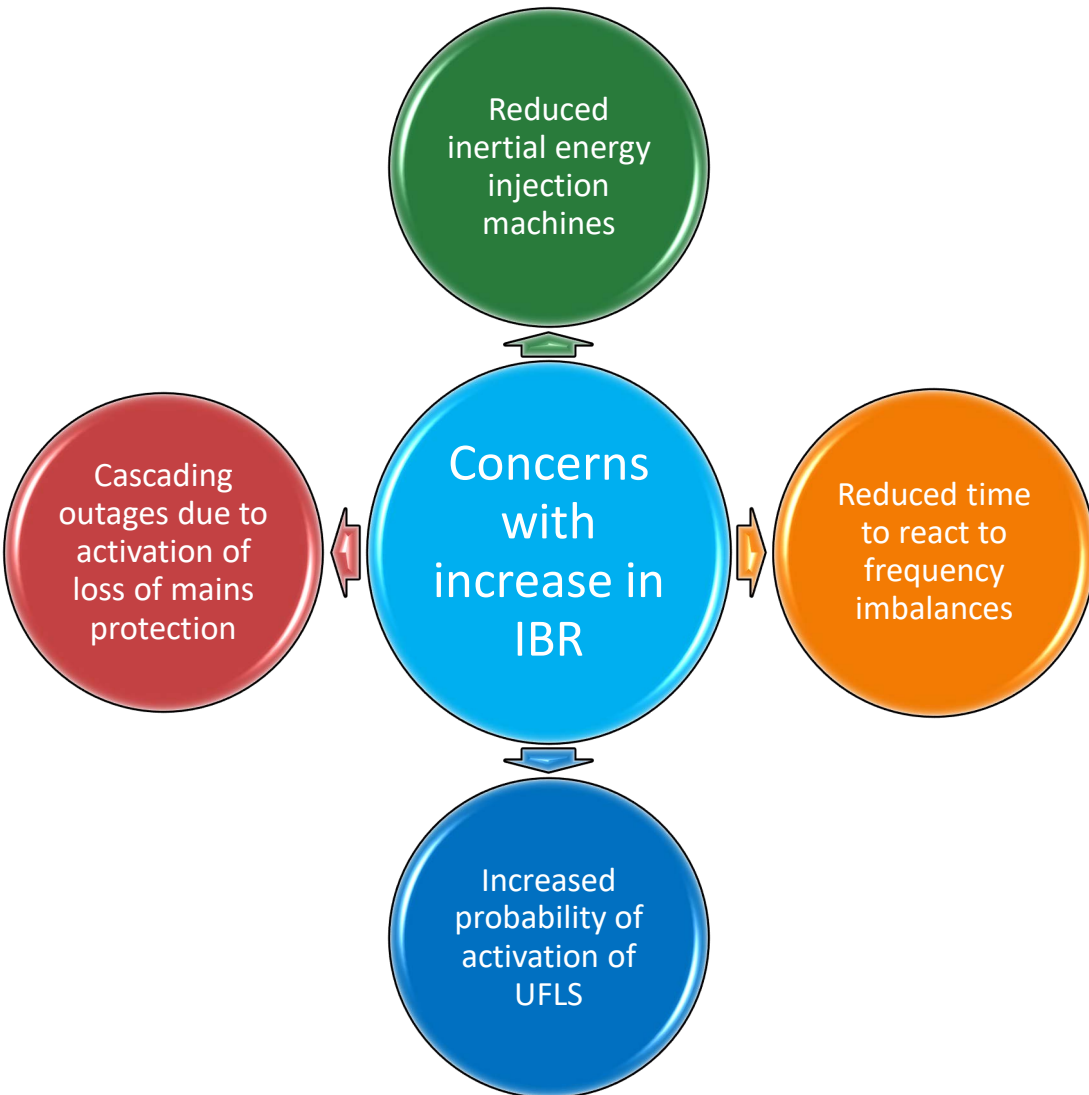


GFM IBR of similar rating as synchronous condenser can provide possible increased improvement in stability



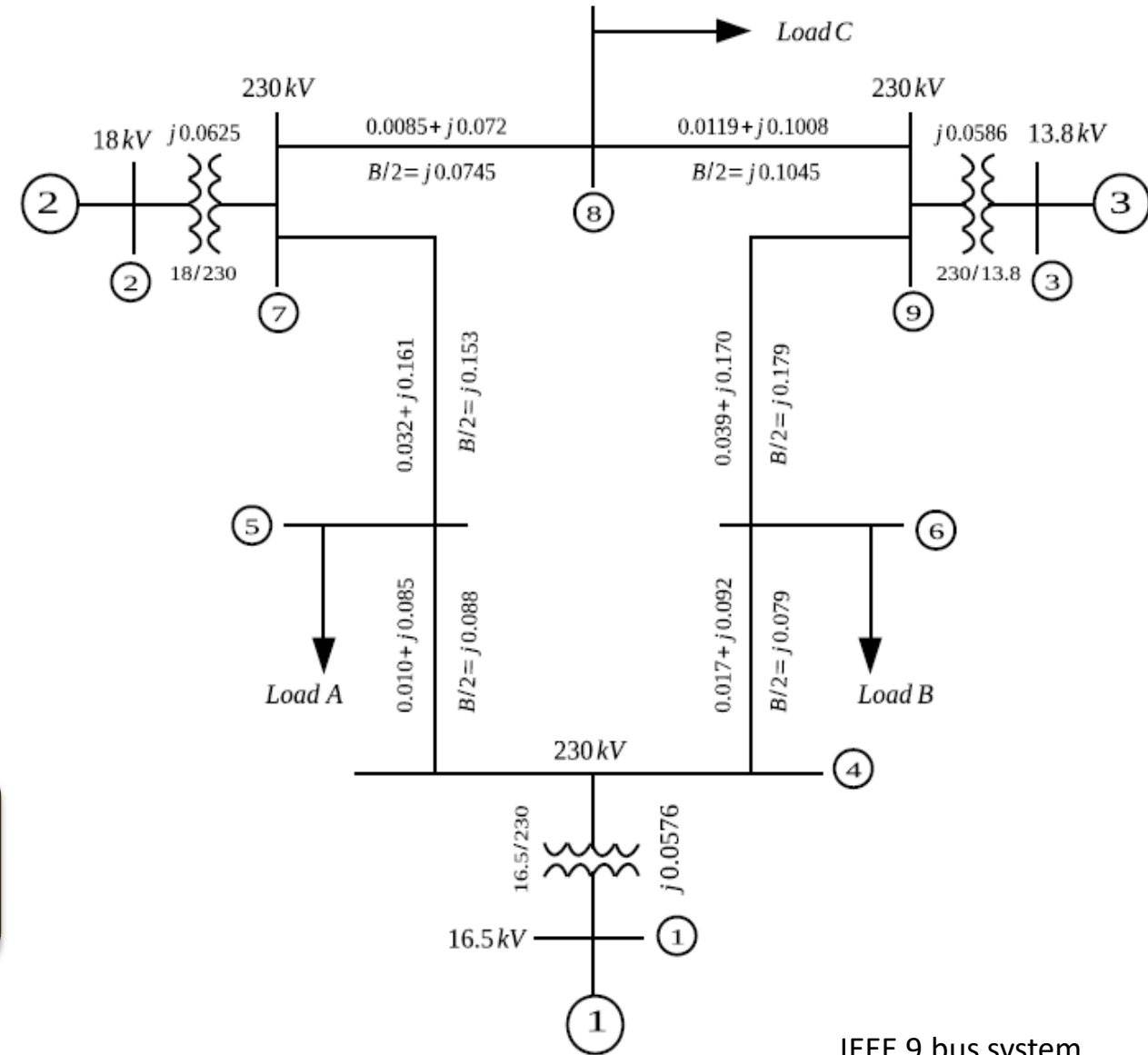
IBR Control and Frequency Response in Low Inertia System

IBRs and frequency response...



Frequency response in the bulk power system

- Sufficient spinning reserve is available on all sources
- Response for a 5% load increase is discussed



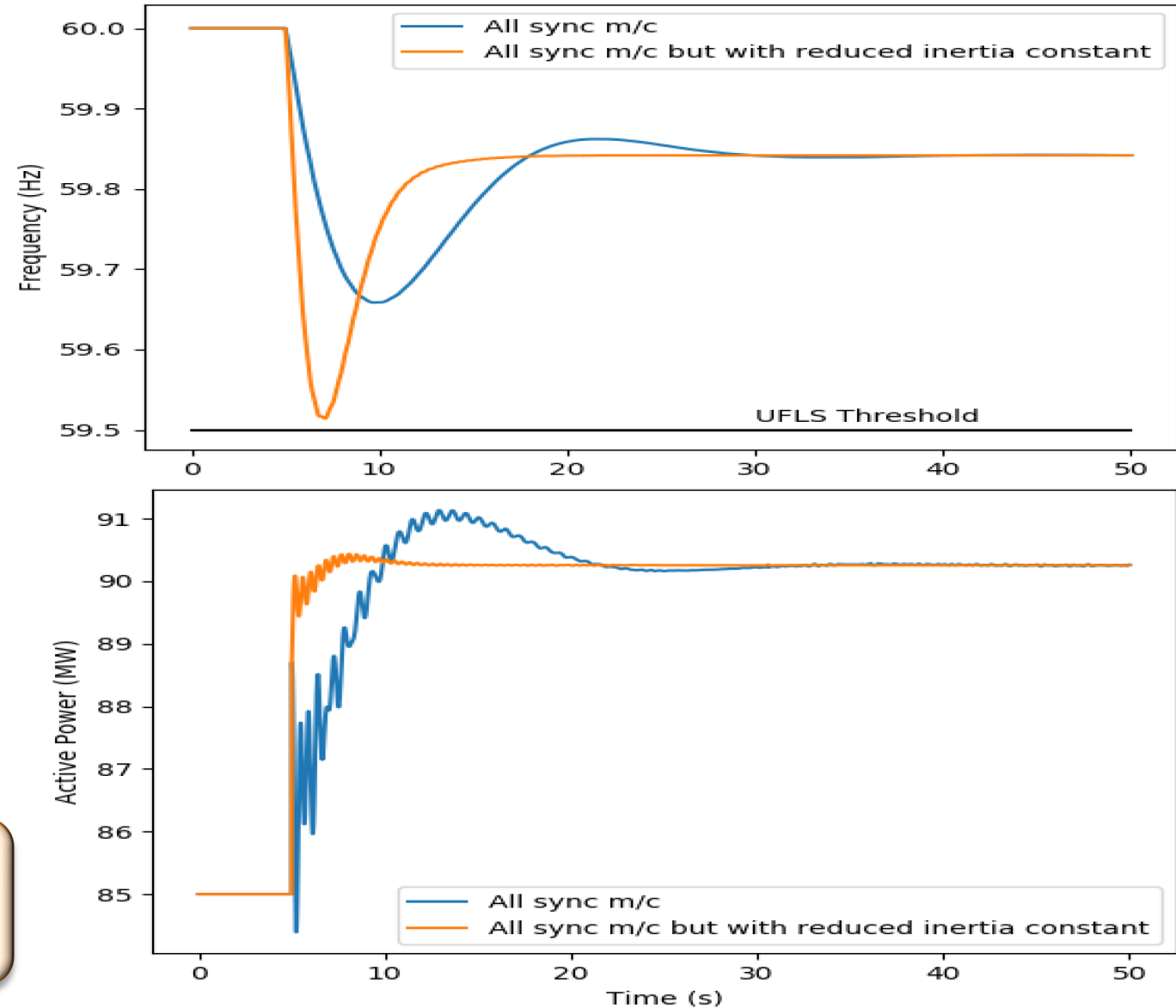
IEEE 9 bus system

What would happen if IBRs replace the generation sources?

First, when all sources are synchronous machines...

- With large generation/load change:
 - Frequency drop and fall needs to be arrested
 - Needs fast energy injection in the arresting period
 - Frequency should stabilize within 60s (usually at an off-nominal value)
 - Needs controlled and coordinated energy injection in the recovery
- With smaller inertia constant
 - Larger RoCoF
 - -0.4082 Hz/s compared to a value of -0.1302 Hz/s

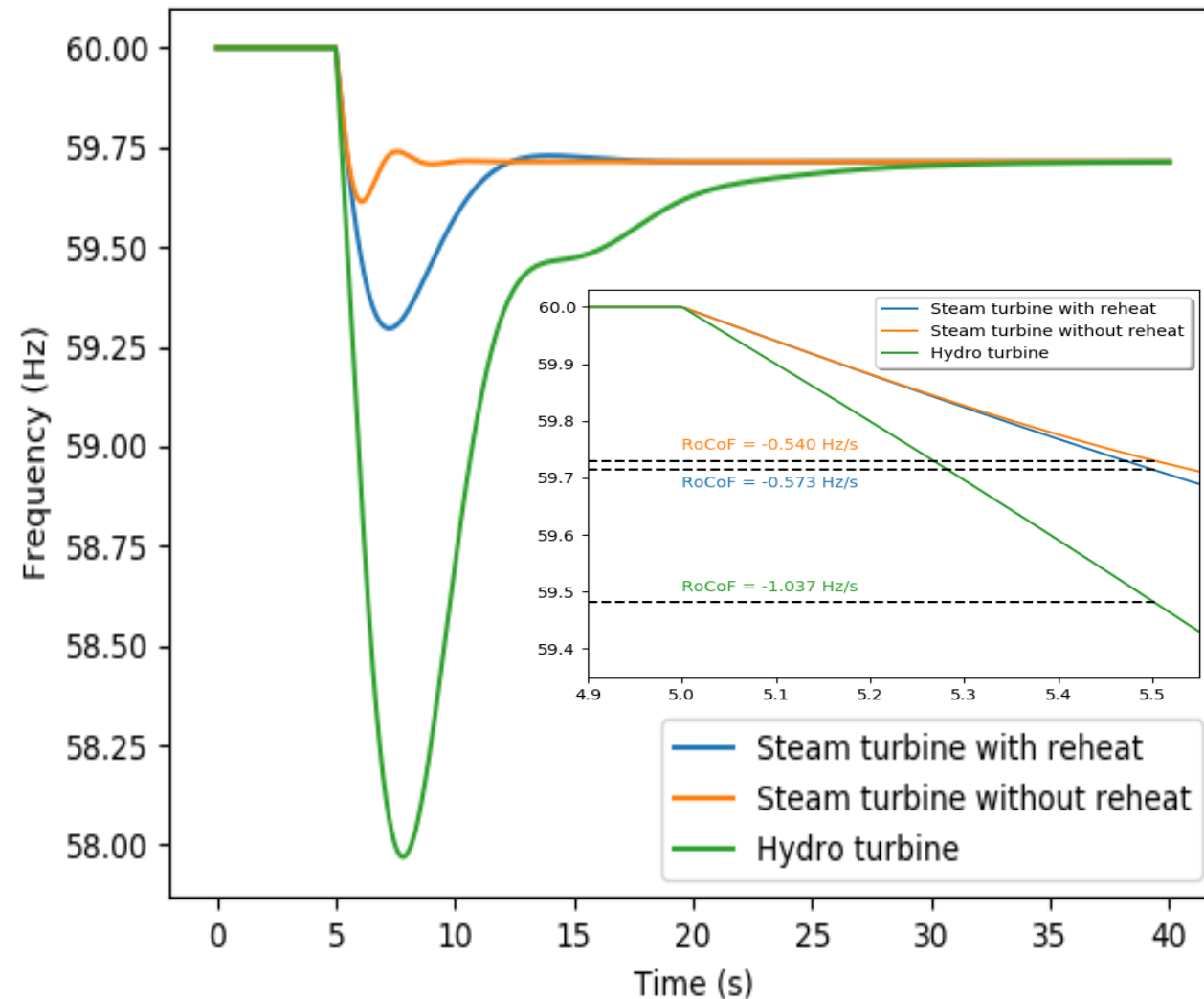
Value of nadir depends on inertia and time constants in active power control loop



Why is RoCoF such an important factor...?

- Large value of RoCoF can result in:
 - Reduced time to deploy frequency response reserves to prevent activation of UFLS
 - Can result in wide-spread load shedding

Rotating machines can tolerate larger RoCoF – designed to tolerate bolted fault at terminals

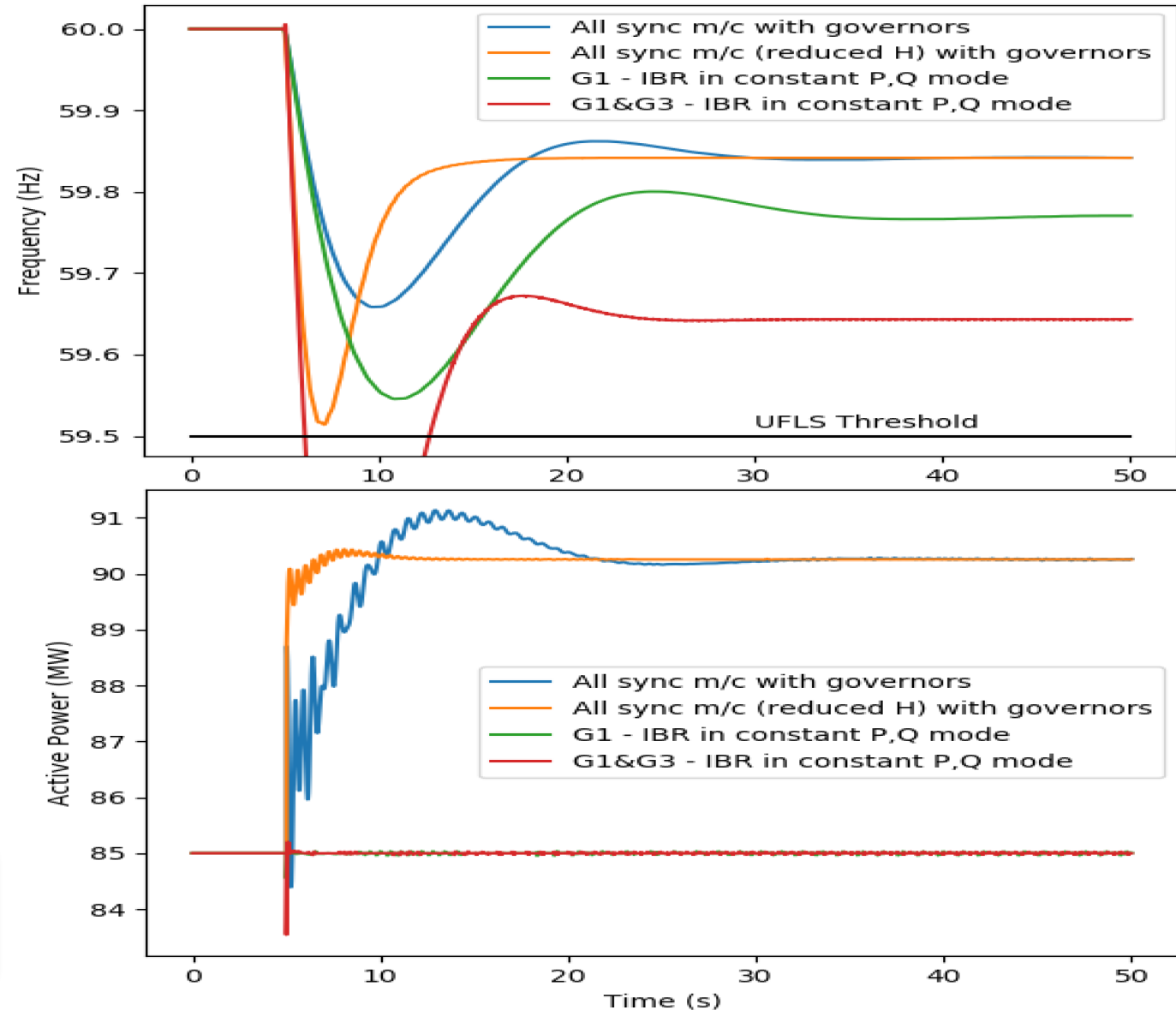


Adapted from frequency response plots in Chapter 11, Power System Stability and Control, Prabha Kundur

Impact of replacing machines with IBR...

- Replacing synchronous machines with IBRs:
 - IBRs operate in constant P,Q mode
 - Similar RoCoF as with smaller synchronous machines
 - **UFLS triggered because of fewer number of resources providing frequency response**
 - **Only G2 provides response**

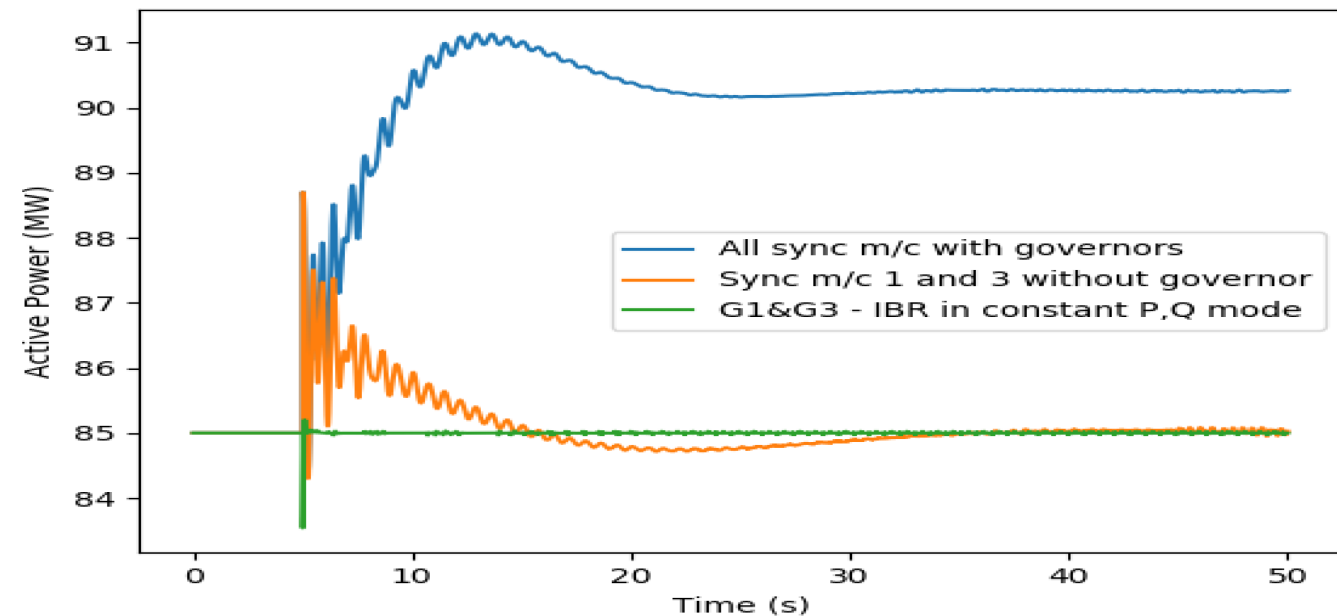
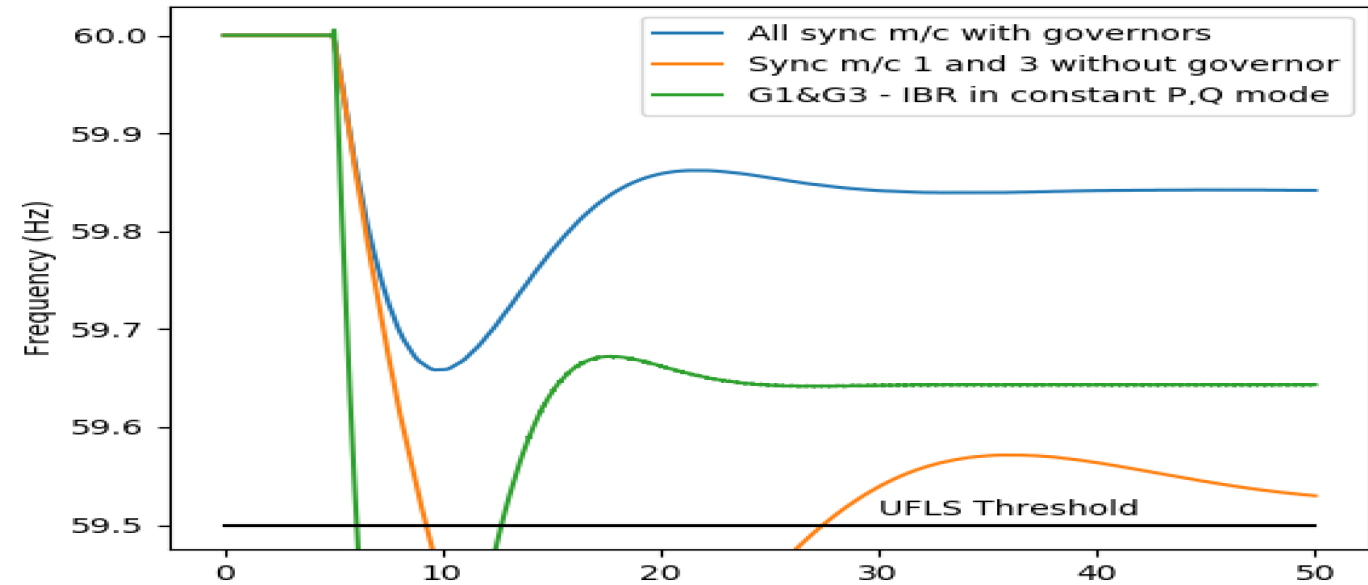
Is this because of IBRs or because of reduced amount of response?



Can it happen with synchronous machines too...?

- With all synchronous machines, governors on G1 and G3 are switched off:
 - UFLS triggered because of fewer number of resources providing frequency response
 - Again only G2 providing response

Number of resources providing response matters!

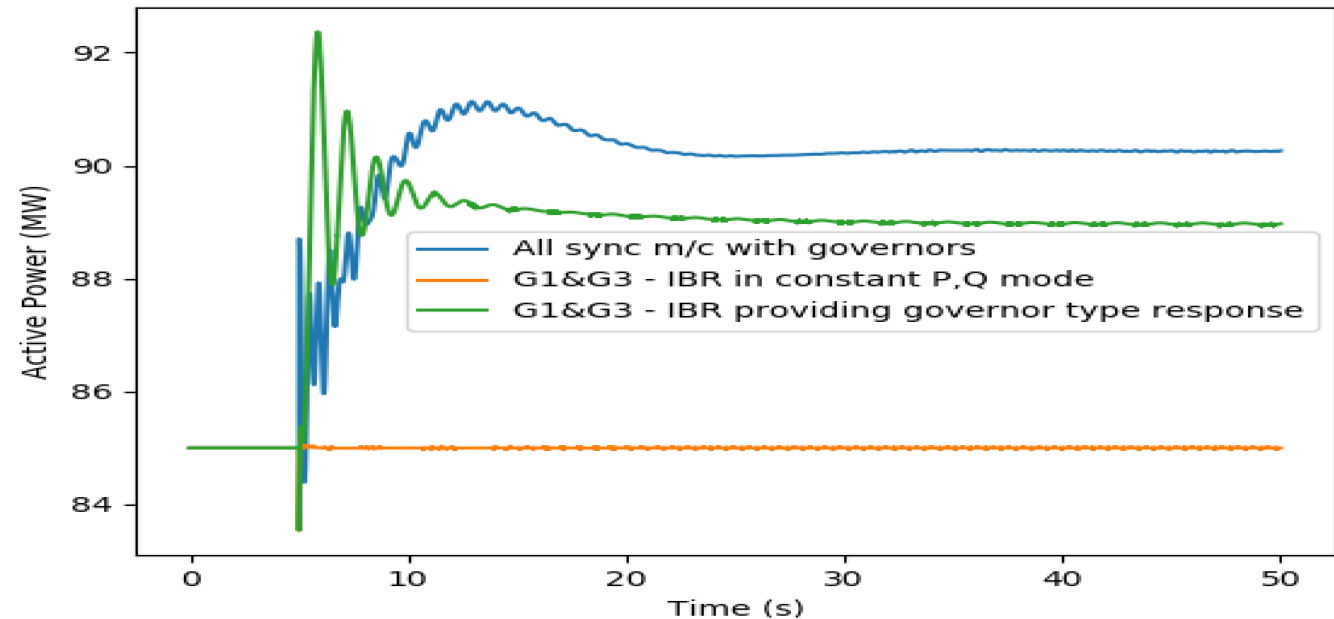
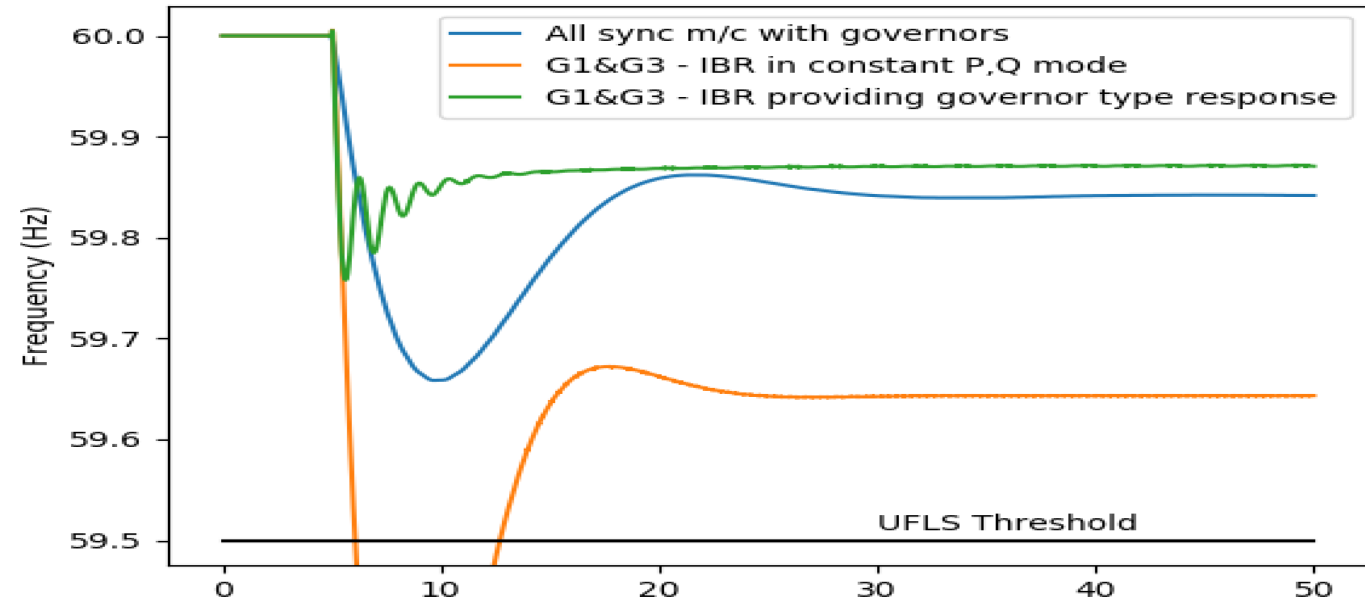


Can conventional IBRs provide frequency response...?

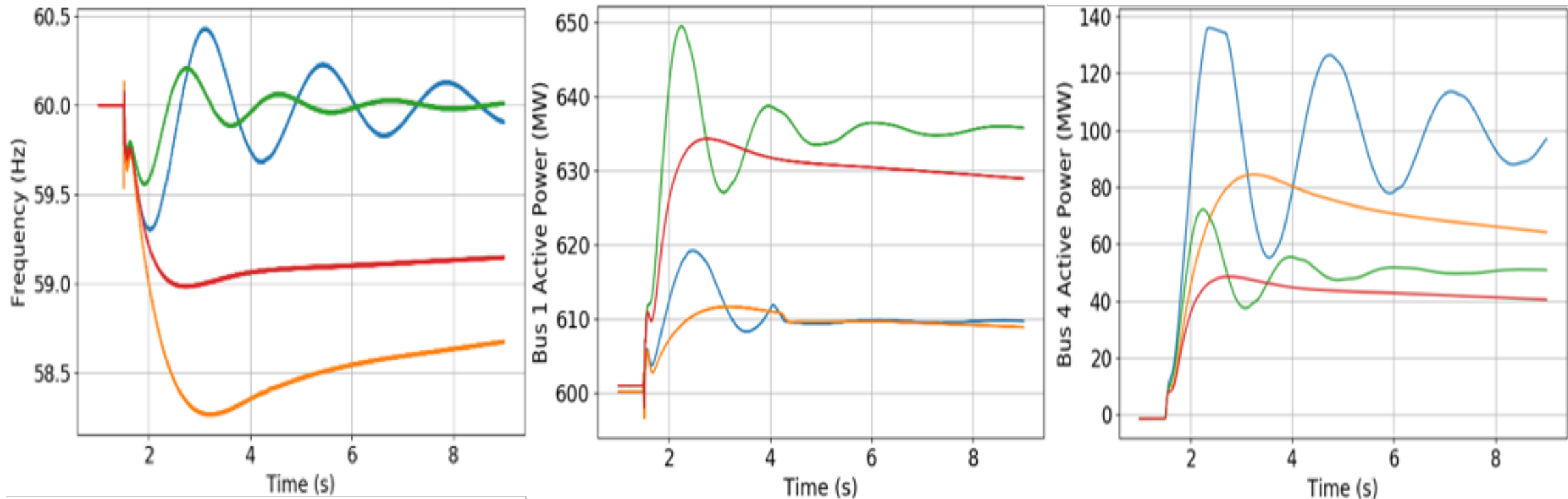
- Both IBRs at G1 and G3 have governor – like capability enabled:
 - 750ms time lag in IBR control
 - Inherent fast primary response due to lack of mechanical components **and** low inertia
- If IBR controls need a measure of electrical frequency, robust measurement techniques should be implemented

FERC Order 842 presently mandates this governor – like capability in IBRs

Provision of such a functionality can make an IBR grid forming?



Response for 10% load increase in a 100% IBR system...

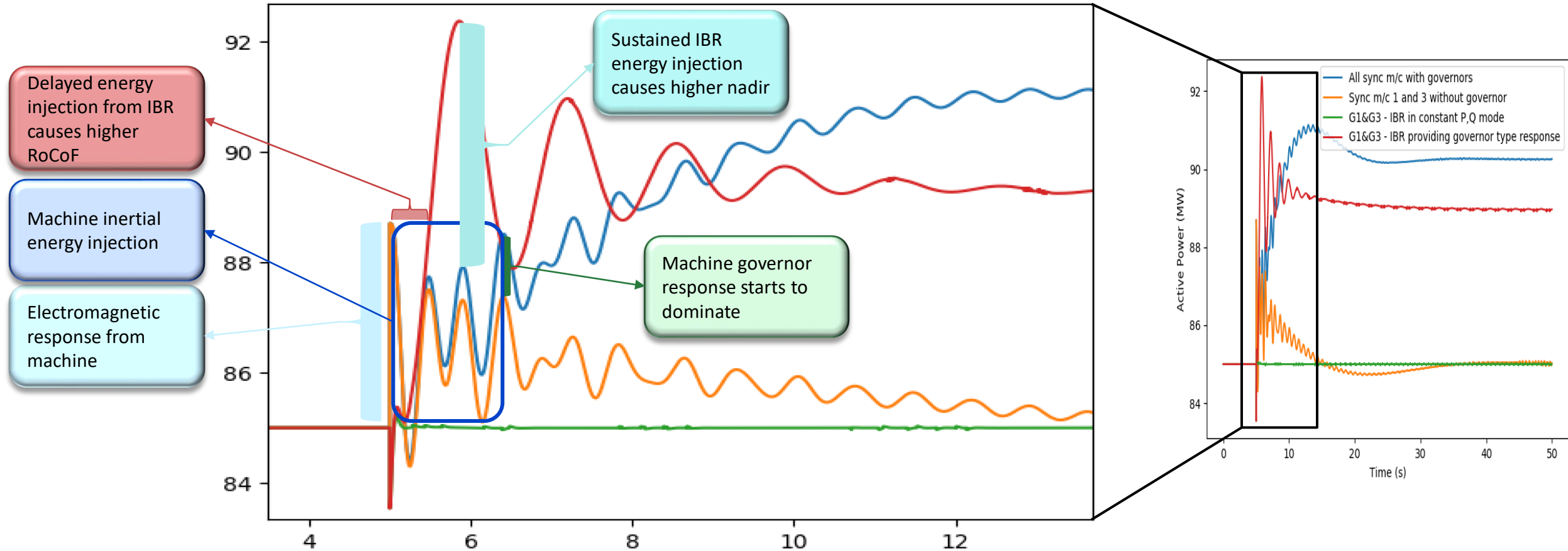


- 20 MVA storage, distributed slack power sharing
- 20 MVA storage, conventional frequency droop
- 100 MVA storage, distributed slack power sharing
- 100 MVA storage, conventional frequency droop

Different flavors of GFM IBR controls have different responses

Proper sizing of energy storage and tuning of controls is essential

Inertial energy injection from synchronous machine compared to energy injection from IBR



- IBR energy injection delayed by around 500ms
- But subsequent continued energy injection from IBR results in higher nadir

Reference: Frequency Response Primer: A Review of Frequency Response with Increased Deployment of Variable Energy Resources, EPRI Palo Alto 2018 3002014361

Can all types of energy sources be used for grid forming behavior?

- Providing grid forming behavior can be impacted by natural characteristics of battery technology, solar, and wind sources
- While voltage/reactive power response is handled solely by the inverter, active power response depends on availability of energy behind the inverter
- Care should be taken to consider these limitations while requiring frequency response from grid forming devices

What does present IEEE 2800-2022 standard say about primary frequency response?

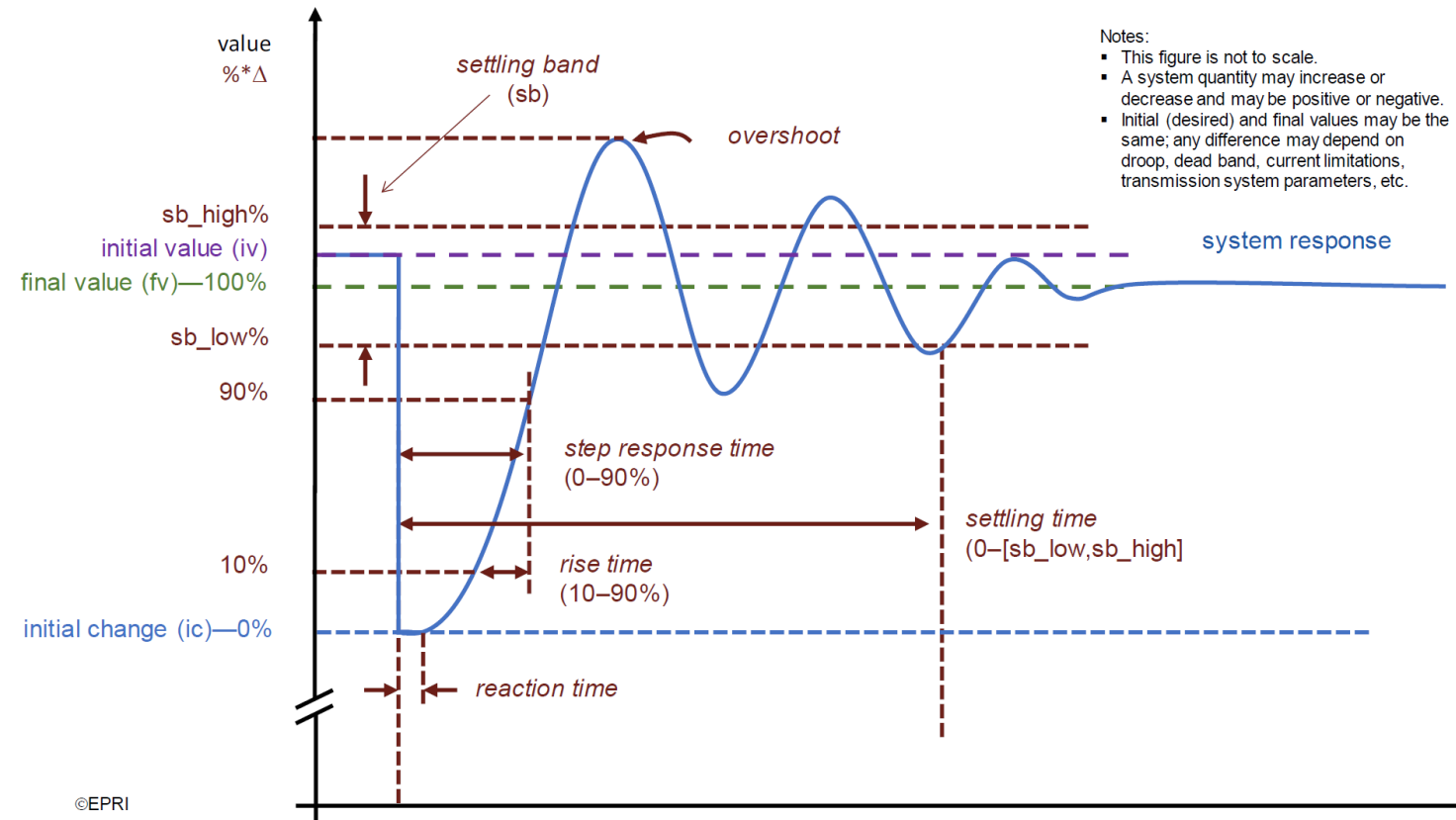


Figure 5(b) from IEEE 2800-2022 Standard

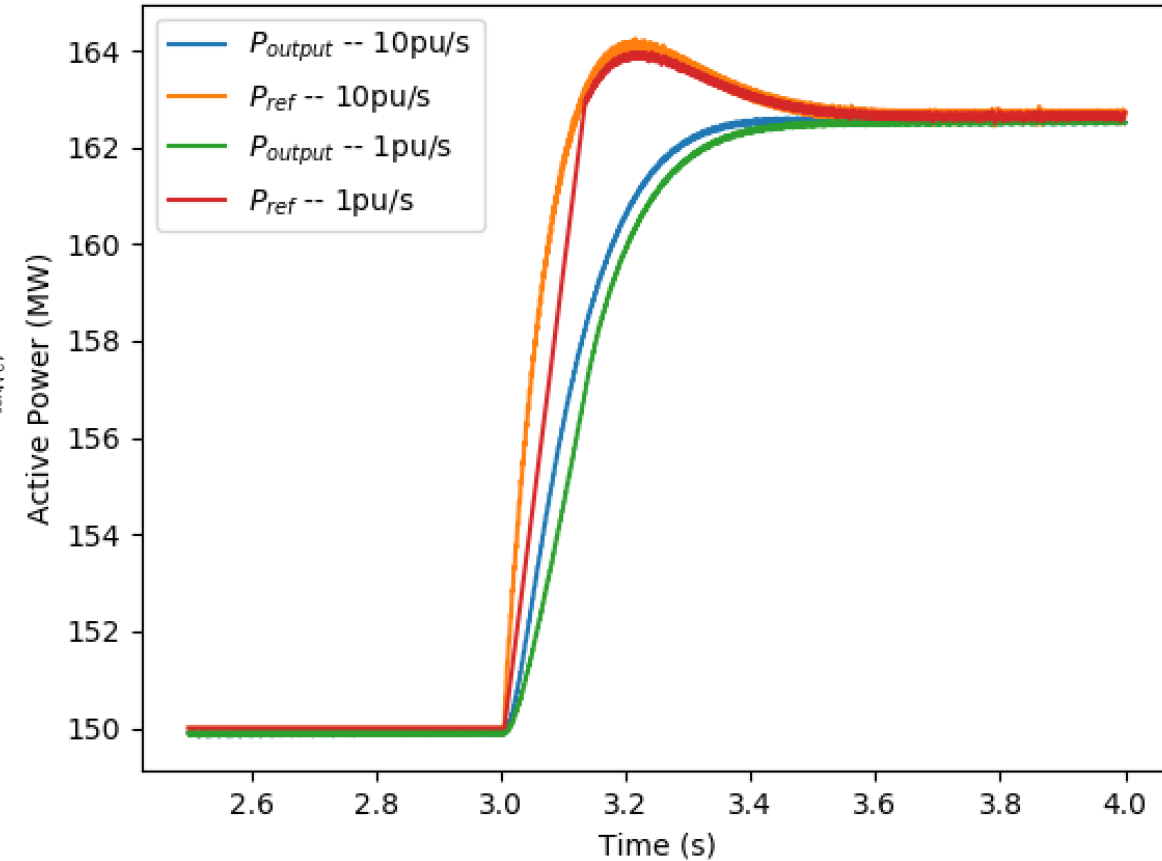
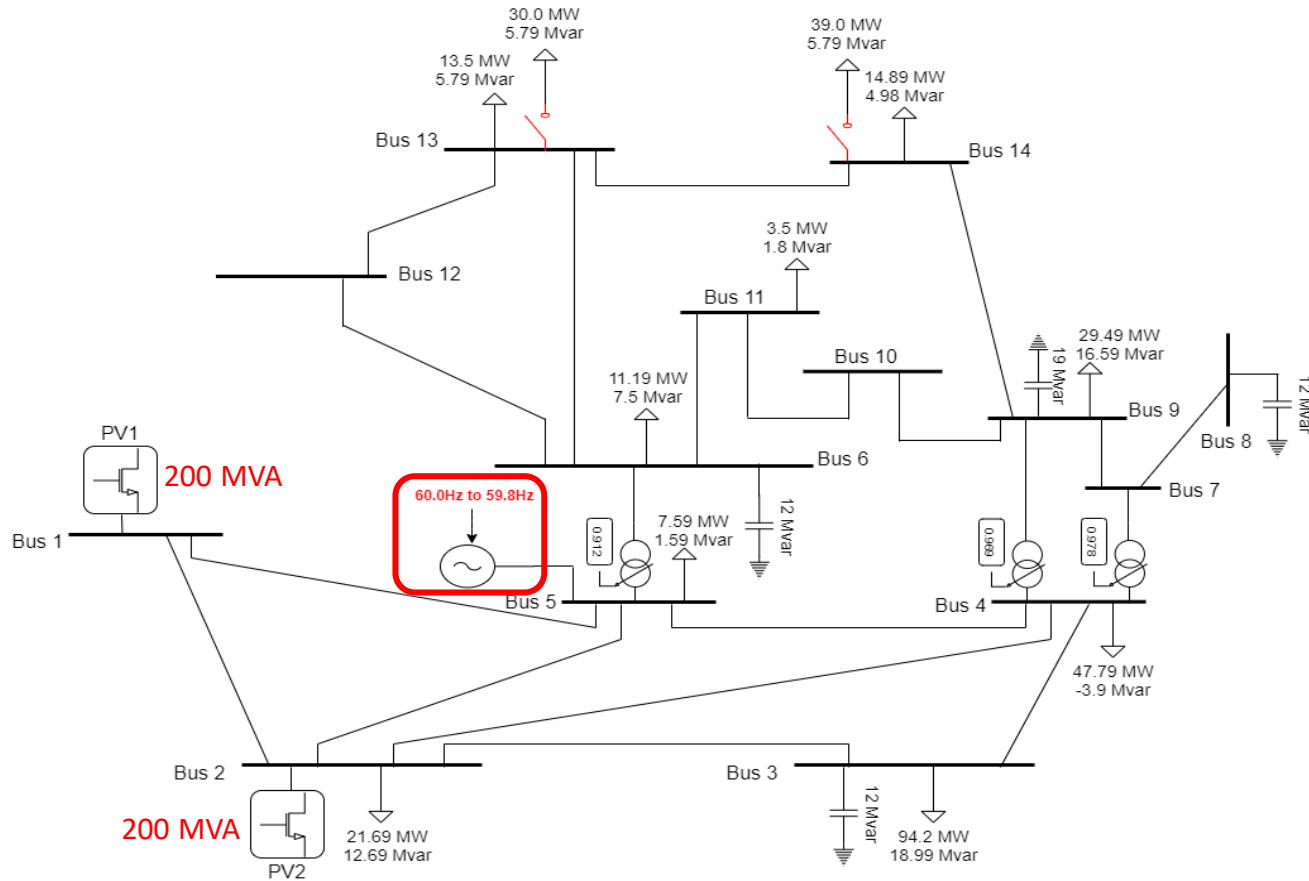
	Units	Default Value	Minimum	Maximum
Reaction time	seconds	0.50	0.20 (0.5 for WTG)	1
Rise time	seconds	4.0	2.0 (4.0 for WTG)	20
Settling time	seconds	10.0	10	30
Damping Ratio	% of Change	0.3	0.2	1.0
Settling band	% of Change	Max (2.5% of change or 0.5% of ICR)	1	5

Table 10 from IEEE 2800-2022 Standard

- Table 10 specifies minimum capability to be met
- Change in IBR plant power output may not be required to be greater than maximum ramp rate of plant
 - Should be as fast as technically feasible
- 15mHz - 36mHz deadband with 2% - 5% droop

Will this capability ever be sufficient for 100% IBR grids?

Example: Two PV plants in an existing **strong** network



- Each 200 MVA PV plant is a **full switching model**¹
- Frequency control with 17mHz dead band and 5% droop at inverter level
- Comparison with 1pu/s and 10pu/s ramp rate on **active power command**

Both ramp rates meet requirements mentioned in IEEE P2800 Draft Standard

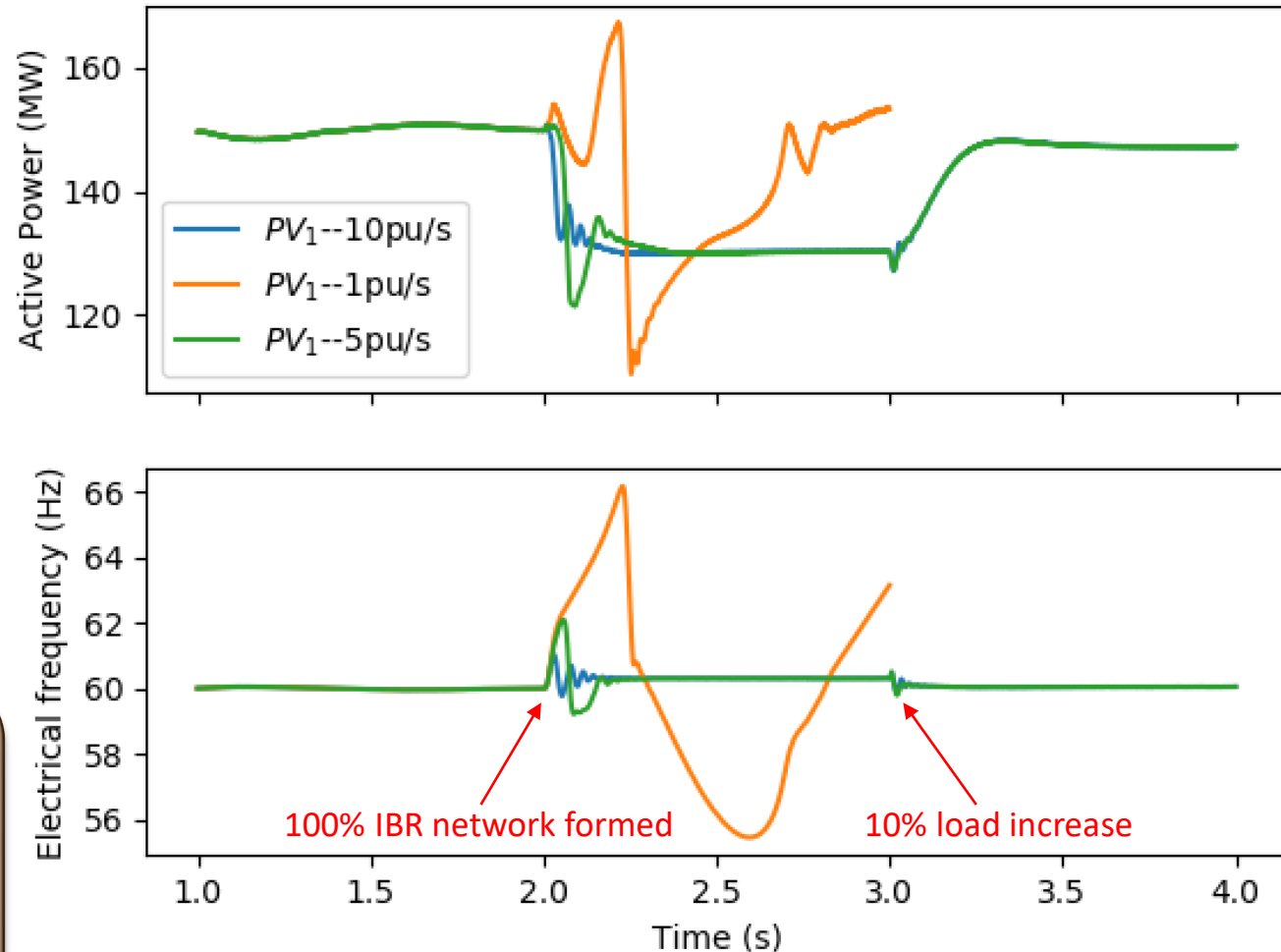
¹<https://www.pscad.com/knowledge-base/article/521>

Lower ramp rates may not work in a 100% IBR system

- A low inertia power network needs **fast injection** of current to mitigate imbalances
- Suitable **choice of ramp rate limit** can bring about a **stable response**

Maximum ramp rate influenced by source behind the inverter

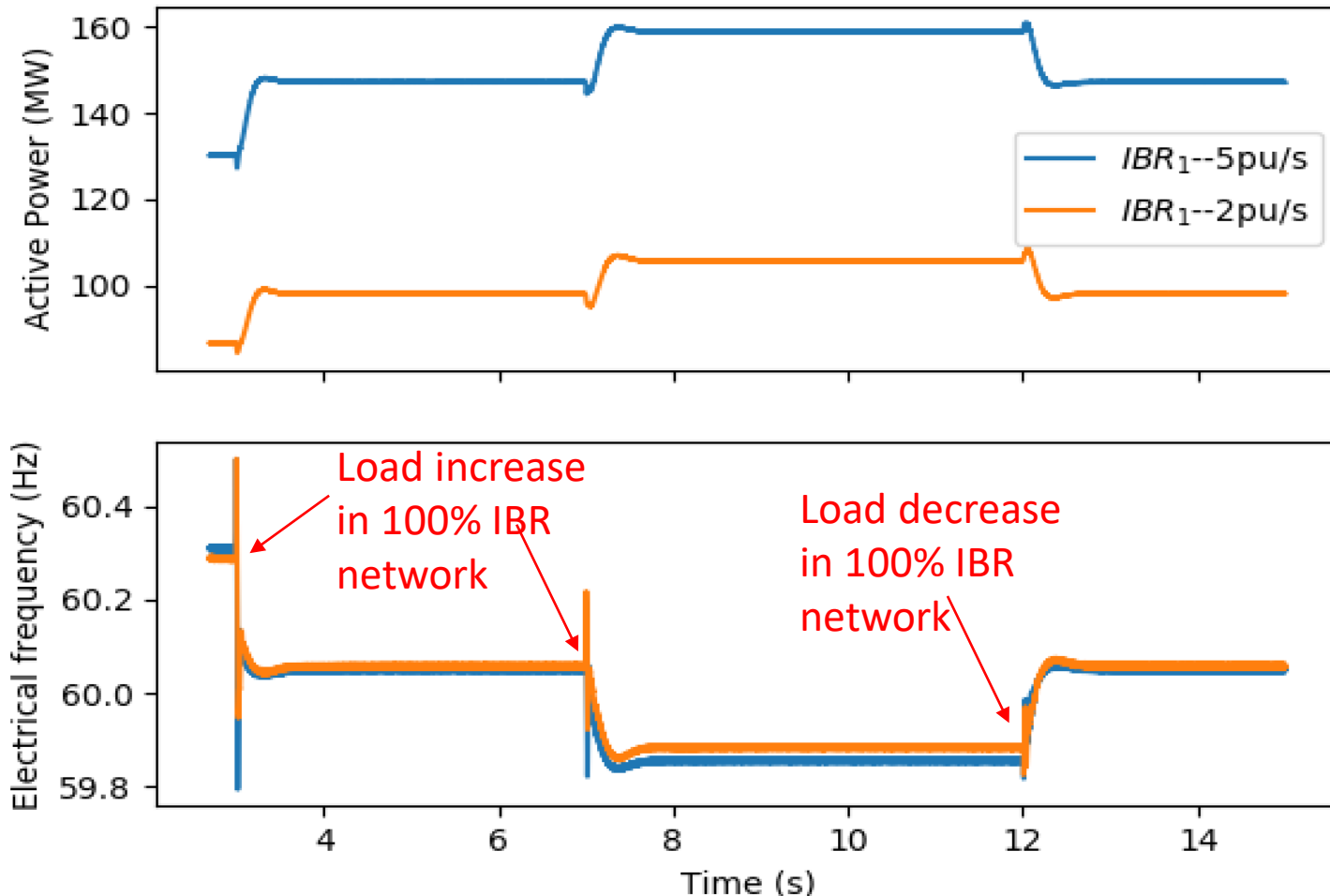
Batteries can tolerate higher ramp rates as opposed to wind turbines



- 100% IBR network created at $t = 2.0$ s
- Load increase at $t = 3.0$ s

Lower ramp rate requires more responsive resources

- Possible to obtain stable frequency control in a 100% IBR network, with lower ramp rates
- Requires more resources to share the change in energy burden
- Any form of IBR device/control can have inherent ramp rate limits



Important to recognize this if newer IBRs have to additionally support older IBRs

5pu/s – Two PV plants of 200 MVA each
2pu/s – Three PV plants of 100 MVA each

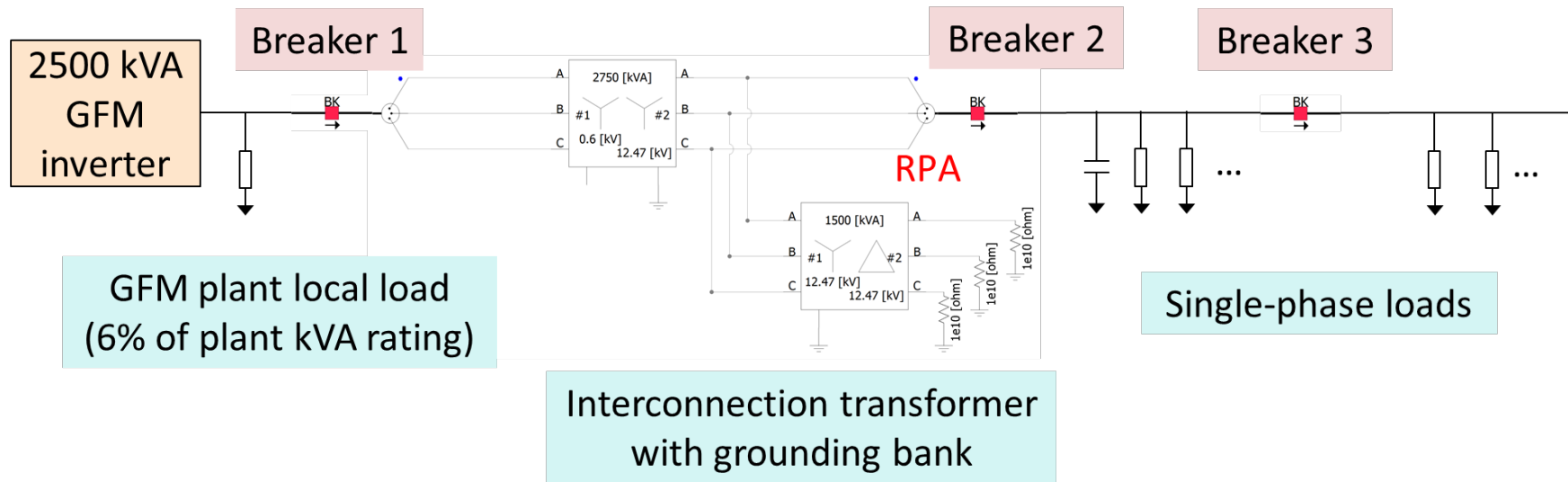


Black Start with GFM IBR

Black start of a system with IBRs – A grid forming service

- A cranking path should be identified for system restoration
- The first black start resource needs to form the voltage and frequency
 - It should be capable of providing transformer in-rush current
 - It should be capable of handling line charging currents
 - It should be capable of handling induction motor starting currents
- A GFM IBR can be this first black start resource
 - Not all GFM IBRs need to be capable of providing such services

Black start of a microgrid with GFM DER



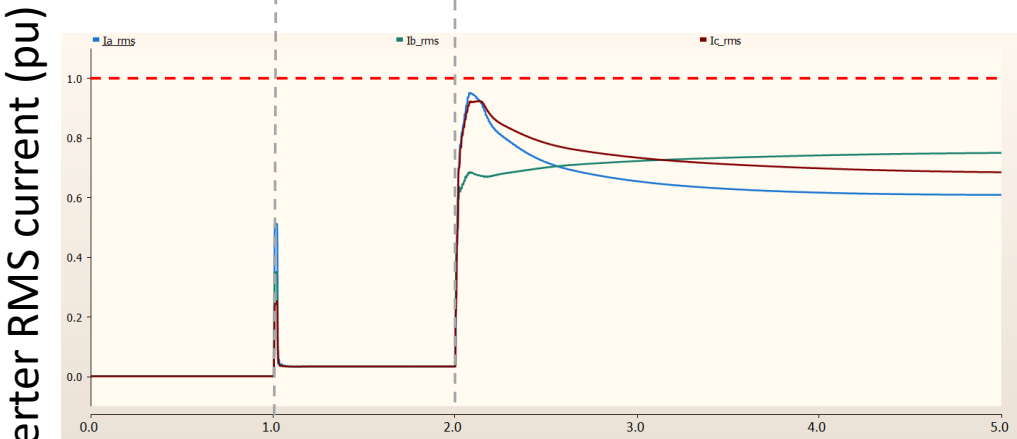
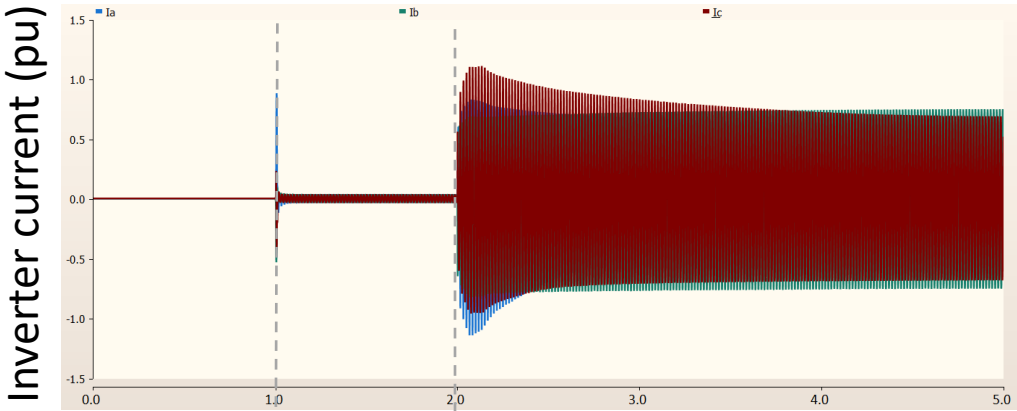
Black start sequence:

- $t=0$ GFM inverter black start
- $t=1s$ close breaker 1
- $t=2s$ close breaker 2&3

- Utilizing the GFM plant to black start the microgrid is investigated with different percentage of motor load and different short-term overcurrent capability of the GFM inverter
- Transformer saturation is modeled for all the transformers in the system (interconnection transformer, grounding bank, and load service transformers)

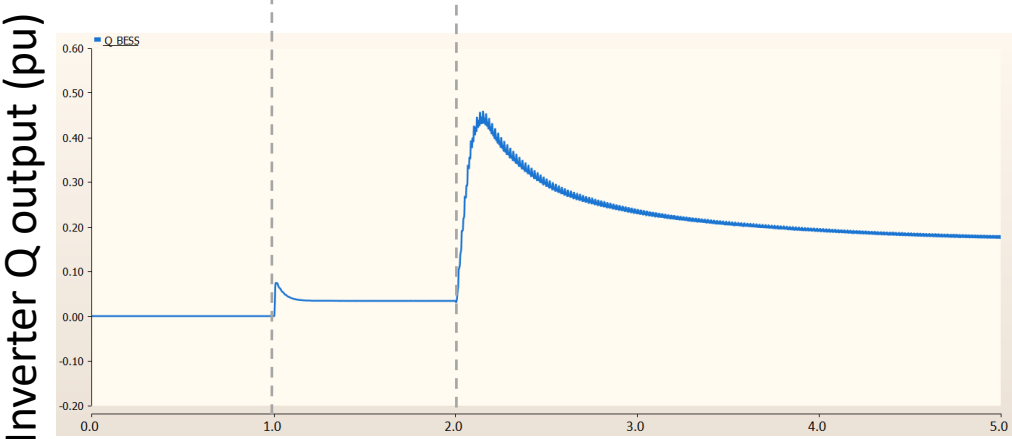
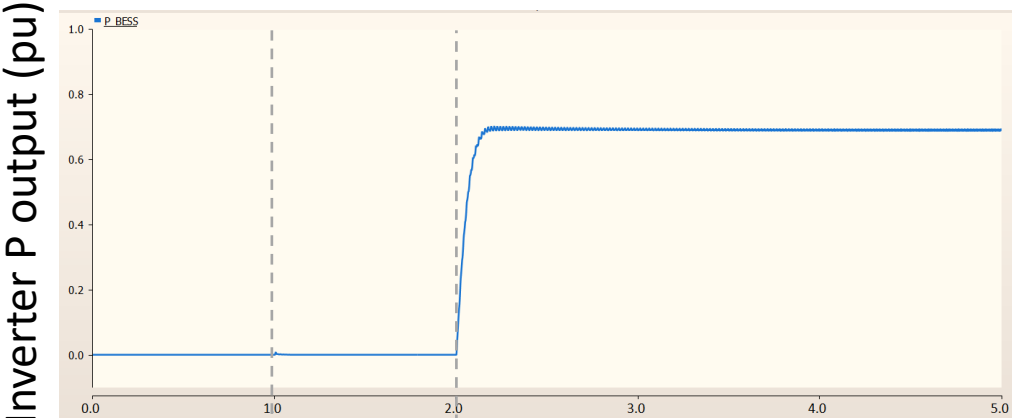
Successful black start with constant impedance load

Transformer inrush Cold load pick up (entire microgrid)



Time (s)

Transformer inrush Cold load pick up (entire microgrid)



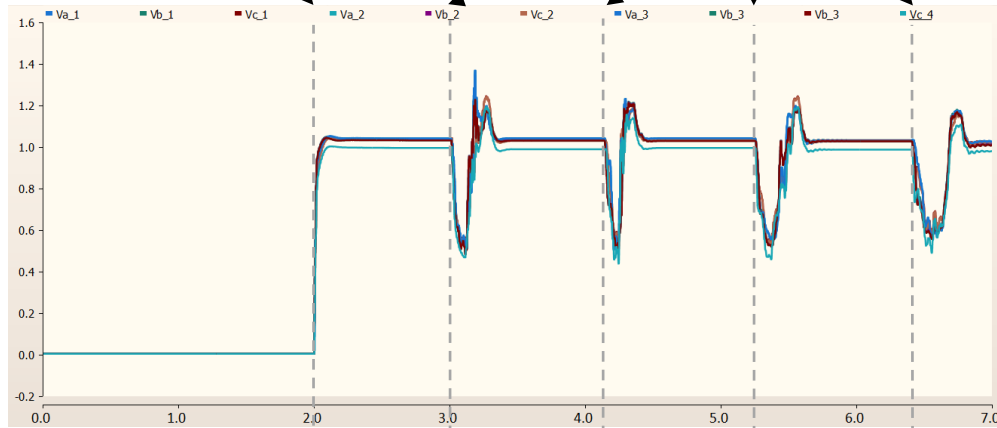
Time (s)

Impact of 35% induction motor load on microgrid black start

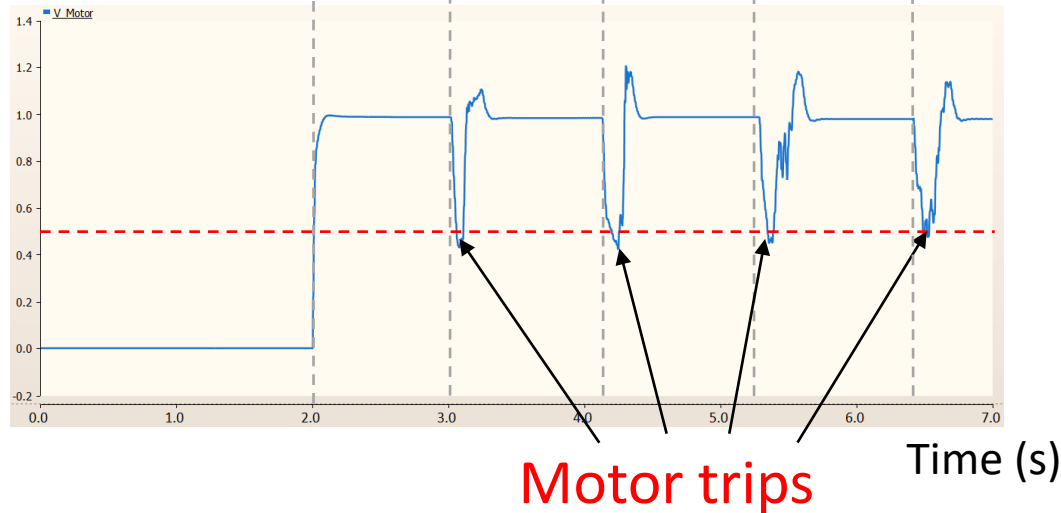
Pick up constant impedance load

Motor starts up

MV feeder voltages (pu)



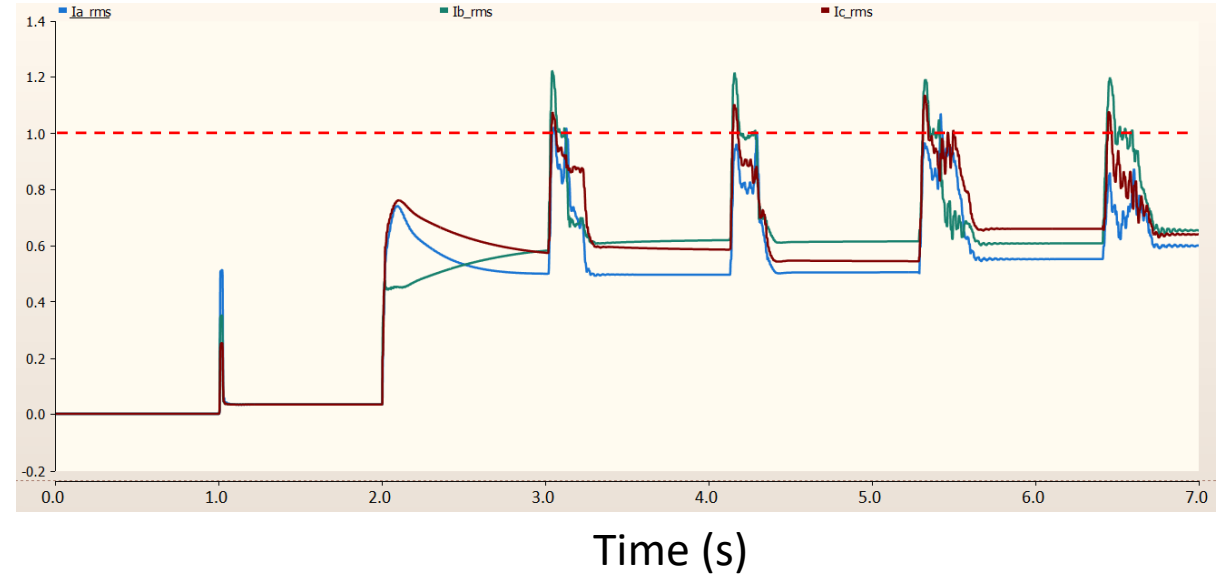
Voltage at one motor (pu)



Motor trips

Time (s)

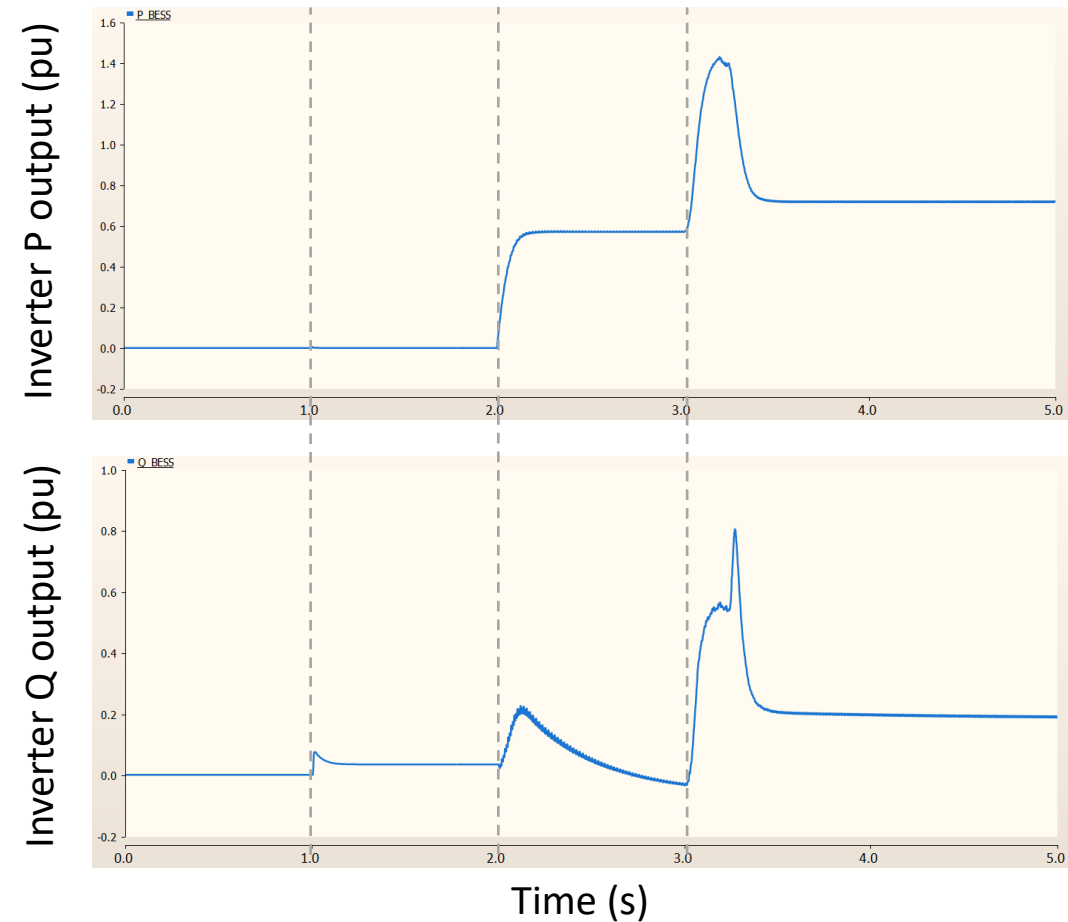
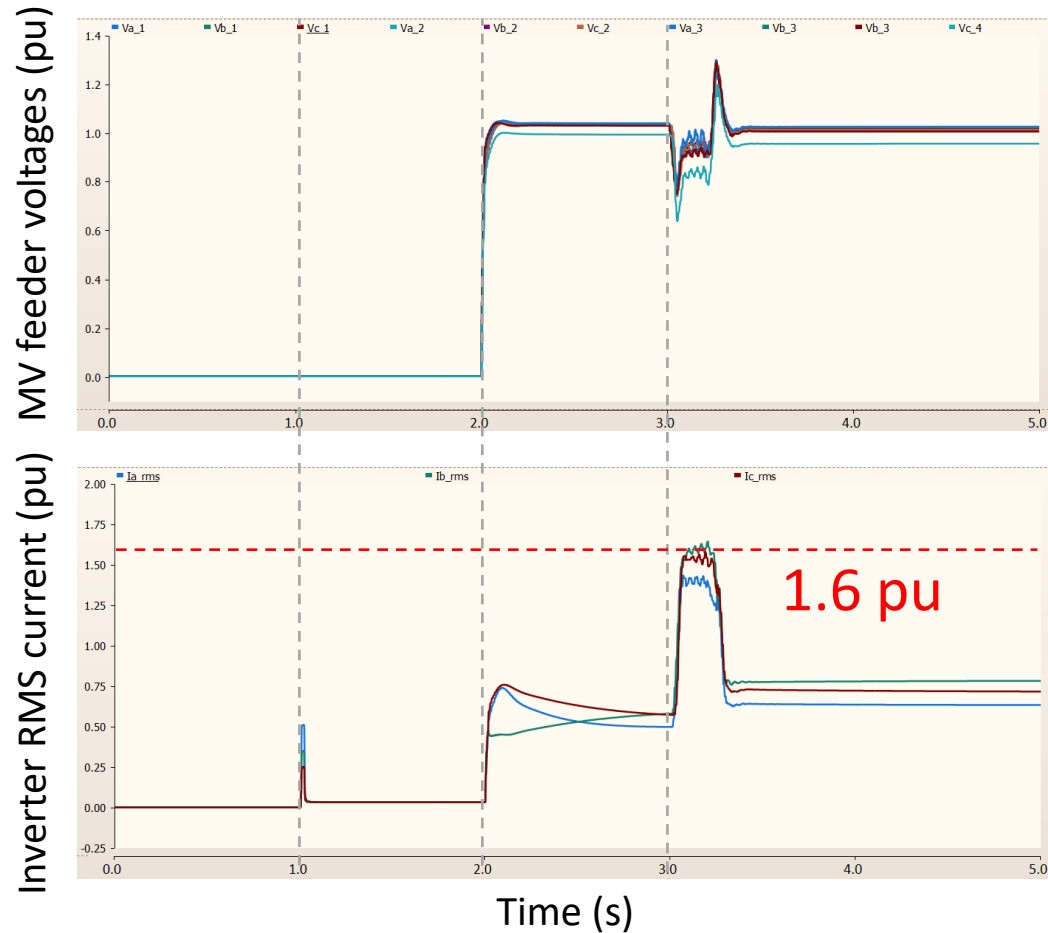
Inverter RMS current (pu)



- Since motor start requires much higher active and reactive power than its normal rating, the GFM inverter cannot provide the high temporary overload when its current is capped at 1pu, resulting in motor start up failure

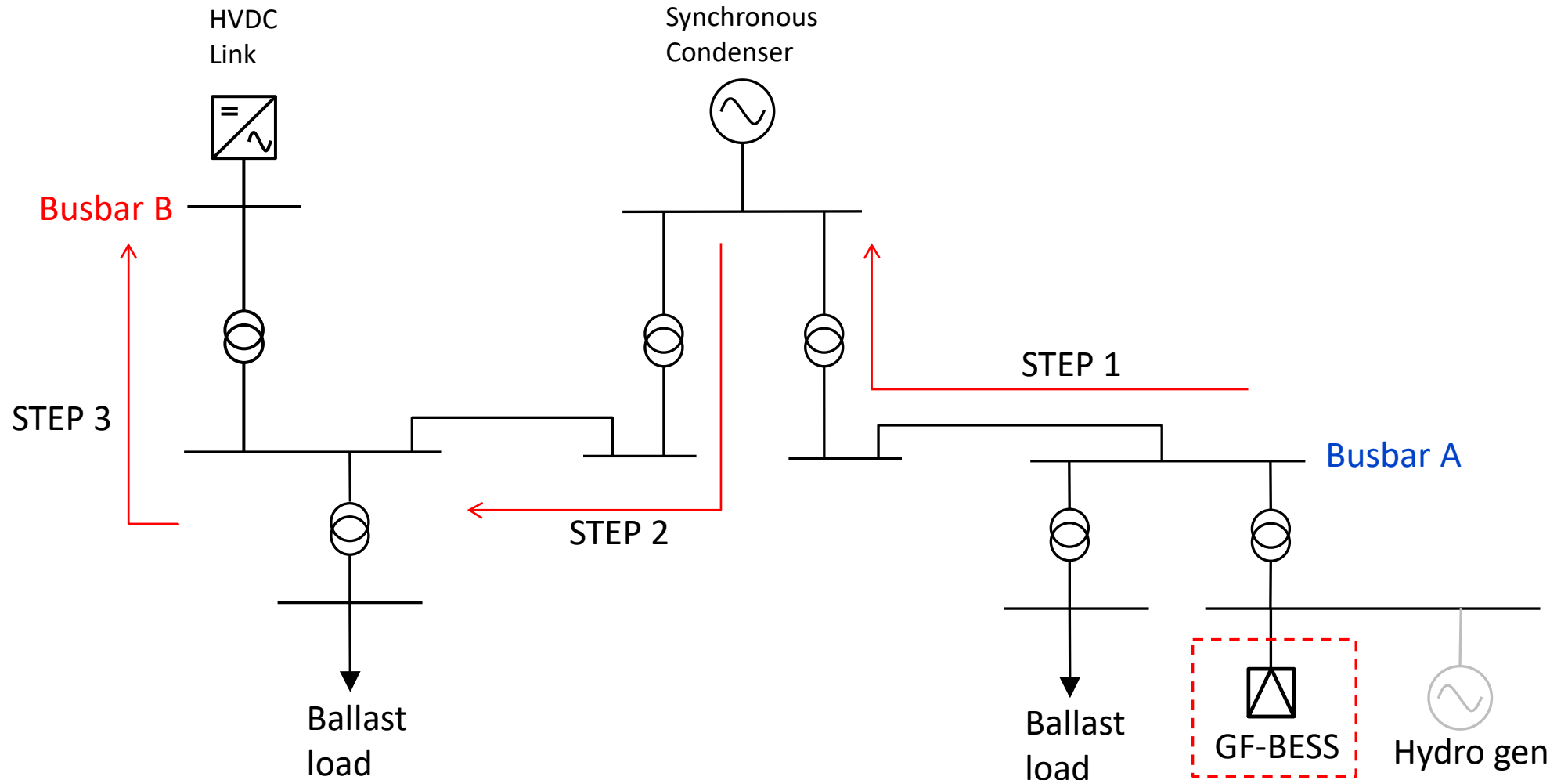
Higher short-term power rating from the GFM DER

- For the studied scenario, if the GFM plant has short-term power rating that is 1.6 times higher than the continuous rating for 1s, it can black start the microgrid with the induction motor loads successfully



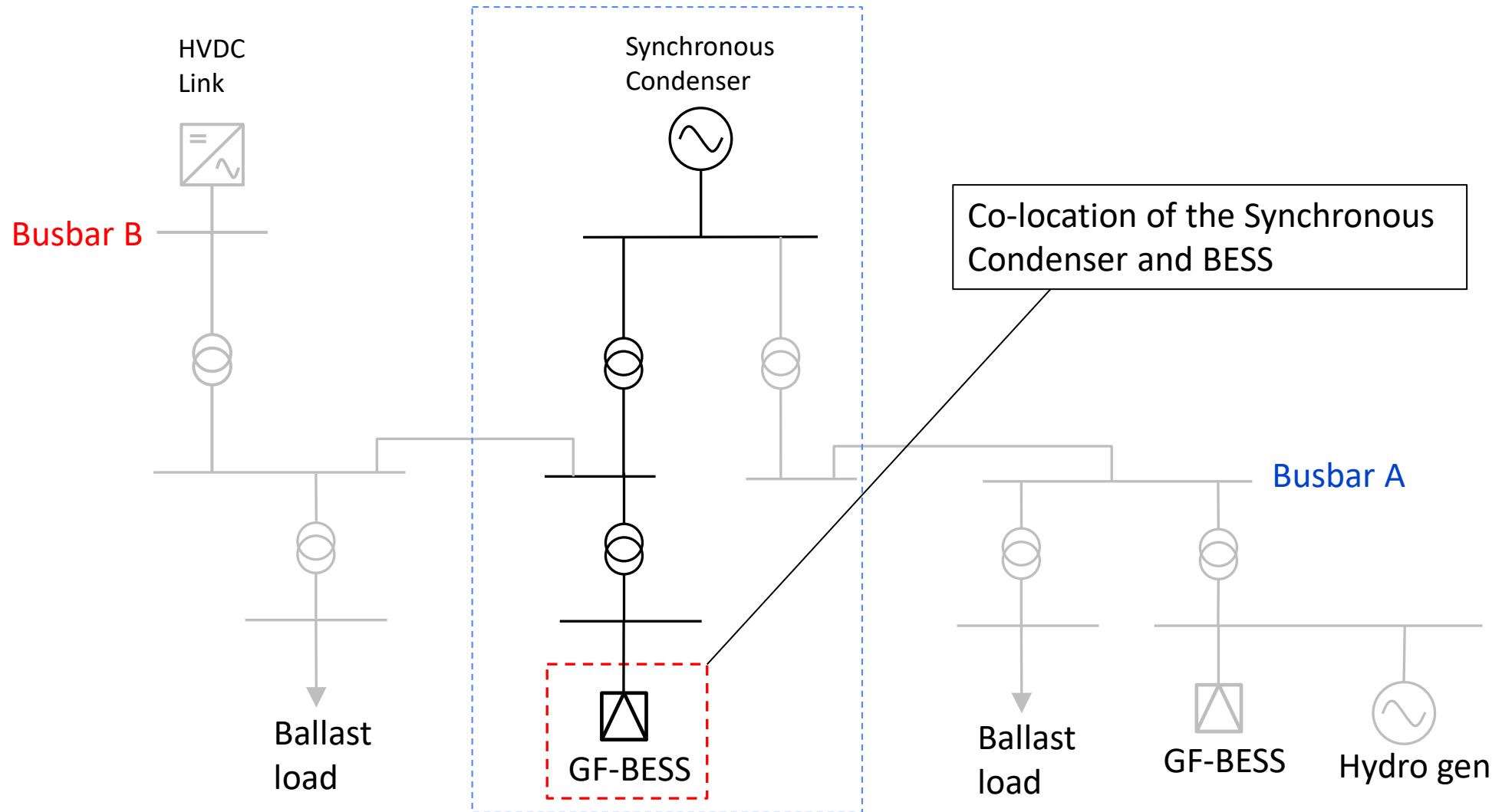
Single line diagram : Transmission restoration path analysis

Energization Path **Busbar A** – **Busbar B**



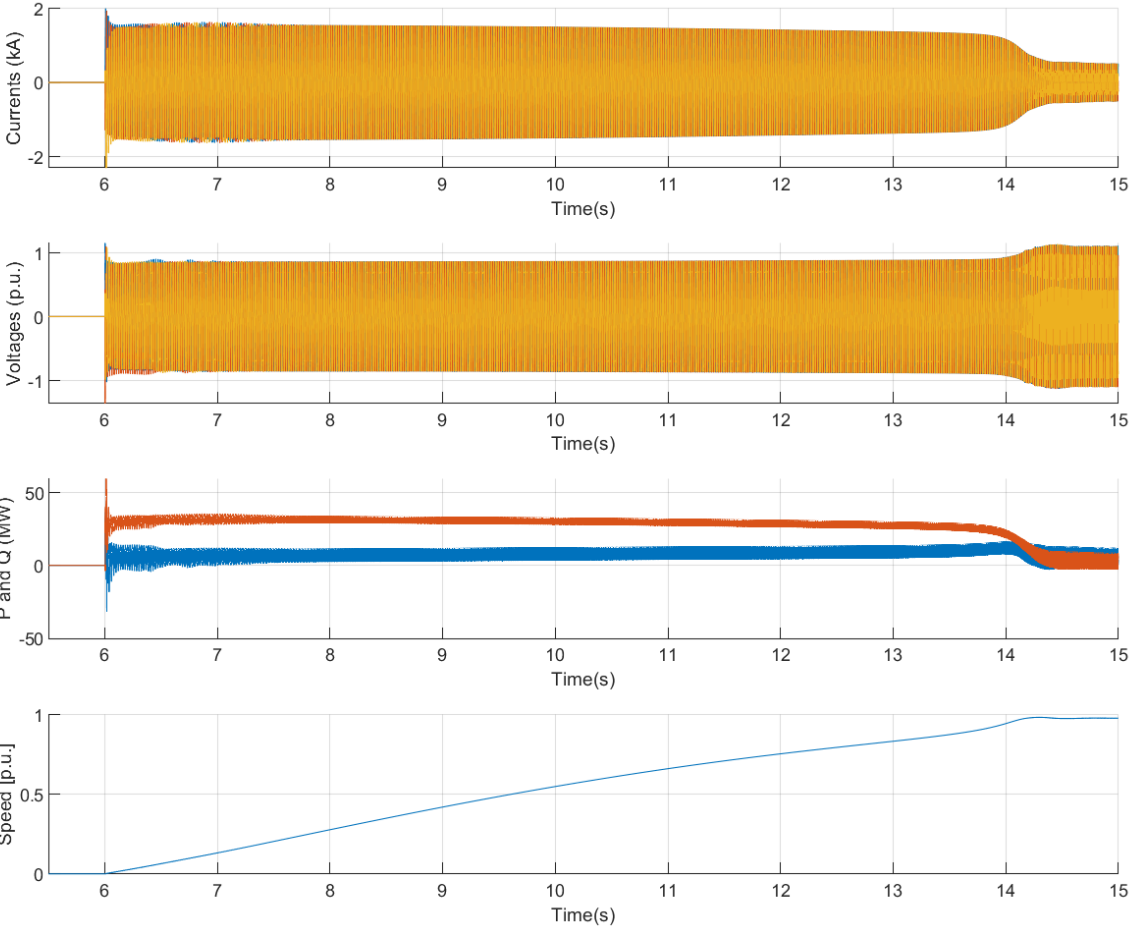
Single line diagram : energizing synchronous condenser

Energization Path **Busbar A** – **Busbar B**



Synchronous condenser startup

- Energization of pony motor at T=6.0 seconds

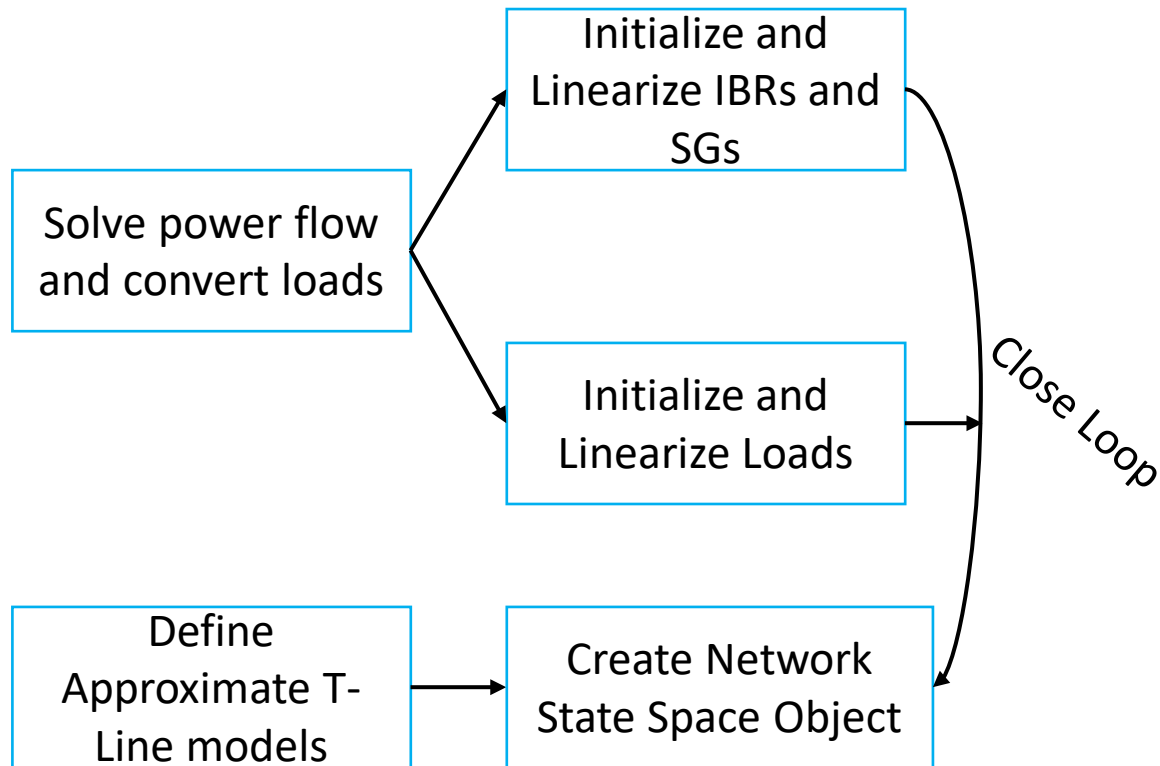


- The BESS is co-located at the same compound of the synchronous condenser
- BESS energizes the path up to the synchronous condenser transformer
- Then the pony motor is energized
- Simulations show that BESS can energize the Synchronous condenser of 5x BESS Pnom without issues
- Once synchronous condenser reaches rated speed its circuit breakers can be close and synchronize to the grid

Stability analysis during restoration with IBRs

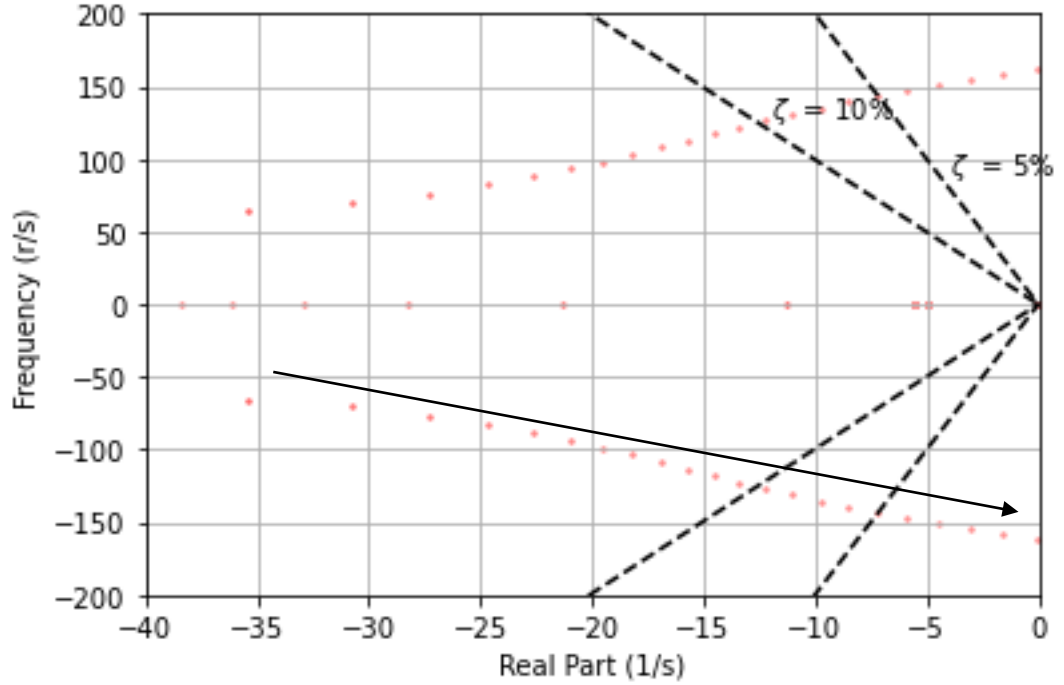
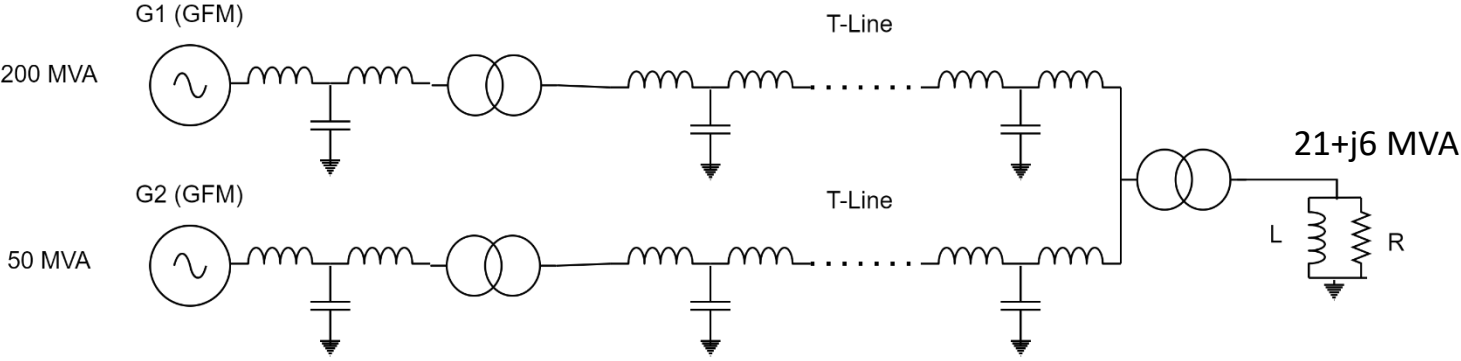
- Grids don't have a mesh structure during initial stages of restoration and thus have different dynamic characteristics
- IBRs can present control and network interactions
- When an operator establishes a BS plan, studies regarding the stability of the IBRS should be carried out
- EMT simulations are extremely computationally intensive
- Small-Signal (SS) analysis can be carried out in each stage to identify issues and provide guidance for the retuning of controllers
- Eigenvalue-based SS analysis can be utilized for this purpose

Network construction and analysis



- SS Analysis via state space requires power flow (estimated connected load and topology)
- Transmission network can be comprised of Π sections or distributed T-line models and transformers
- Generators can be either Synchronous Generators (SG), GFM and GFL IBRs
- Loads can be either constant impedance or induction motor loads
- Network construction slightly more involved than construction of a single frequency Y (or Z) matrix
- Once the model is interfaced, eigenvalue, participation factor, control design and frequency response analysis can be carried out

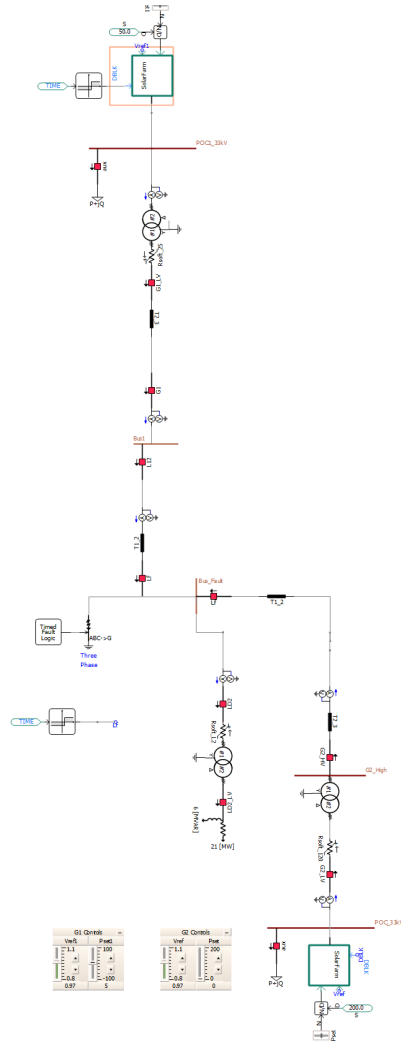
Example analysis with two remote GFM plants



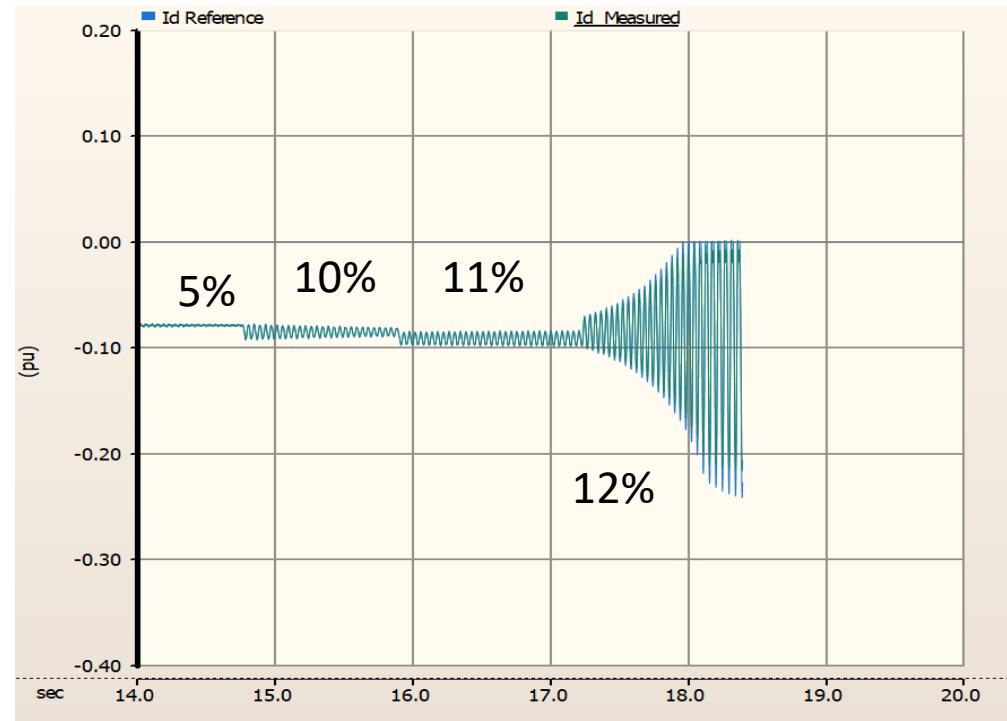
Droop Mode for Increasing Droop Gain

- Case of 2 GFM converters during light system loading
- Droop gains varied from 0.001 to 0.2 for a time constant of 5 ms
- The critical droop gain was 12%
- Due to proper tuning the critical gain seems to have small sensitivity towards loading level

Small signal analysis verification with PSCAD

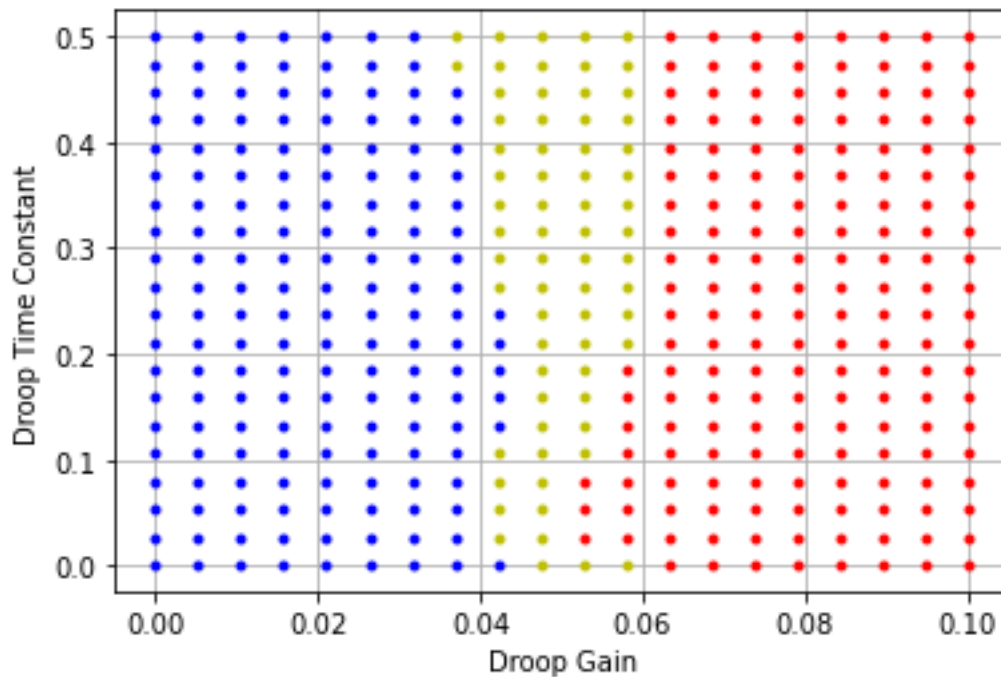
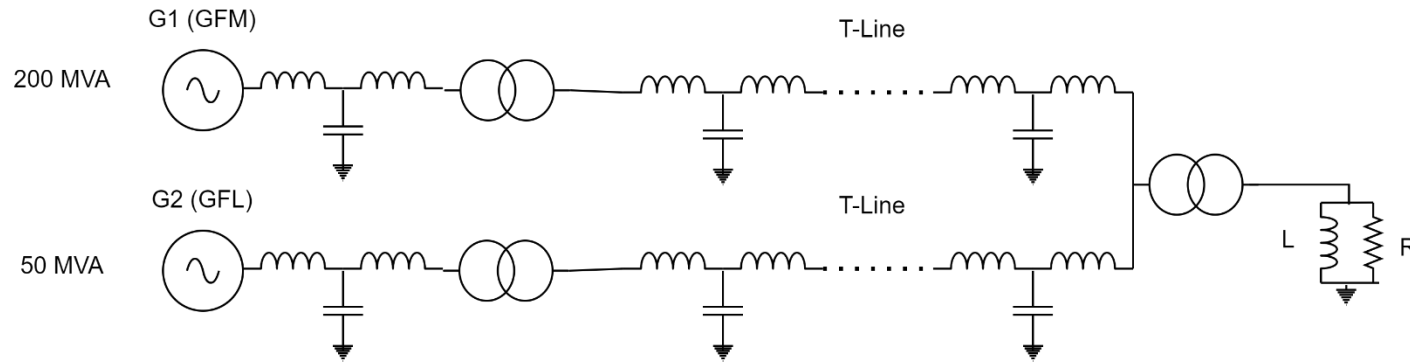


2 GFM System in PSCAD



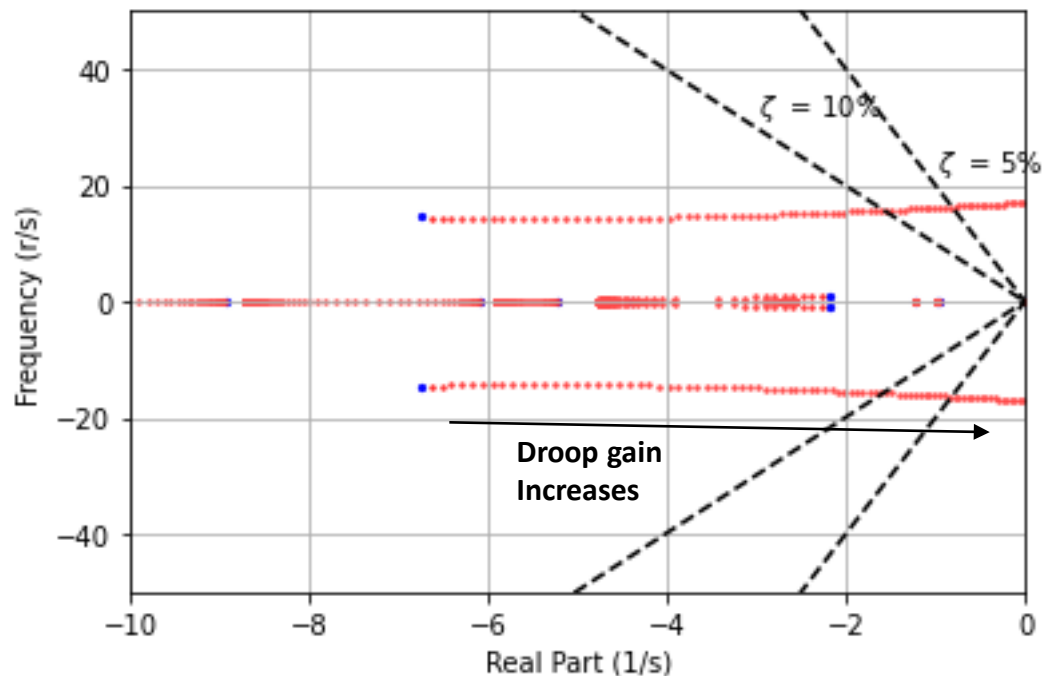
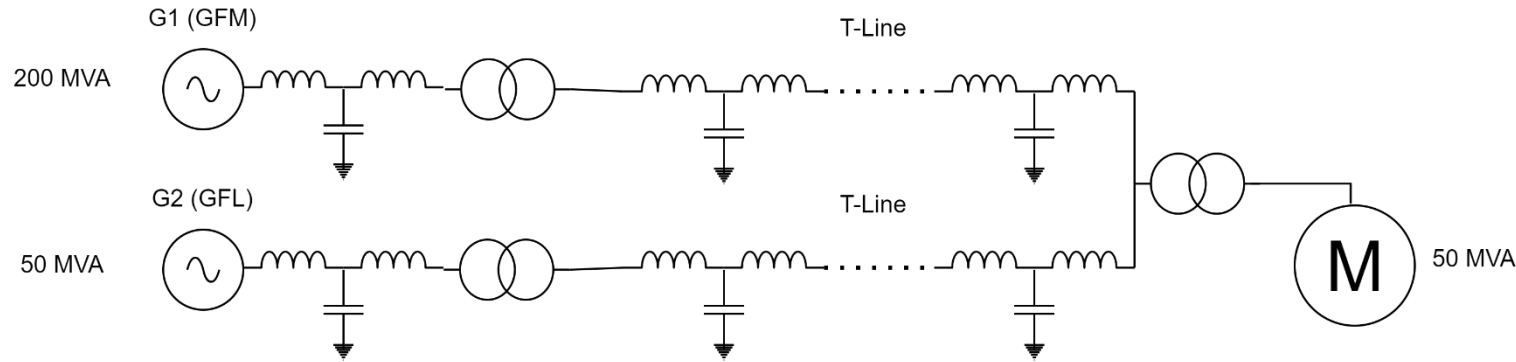
- Previous analysis predicted an unstable mode for droop of 12%
- The predicted mode had a frequency of 25.9 Hz
- In simulation the unstable droop gain was 12% with an oscillatory response at 25 Hz
- This small signal analytical tool would be able to predict such instability and pinpoint the relevant IBR as the cause of instability

Example stability margin with remote GFM and GFL plants



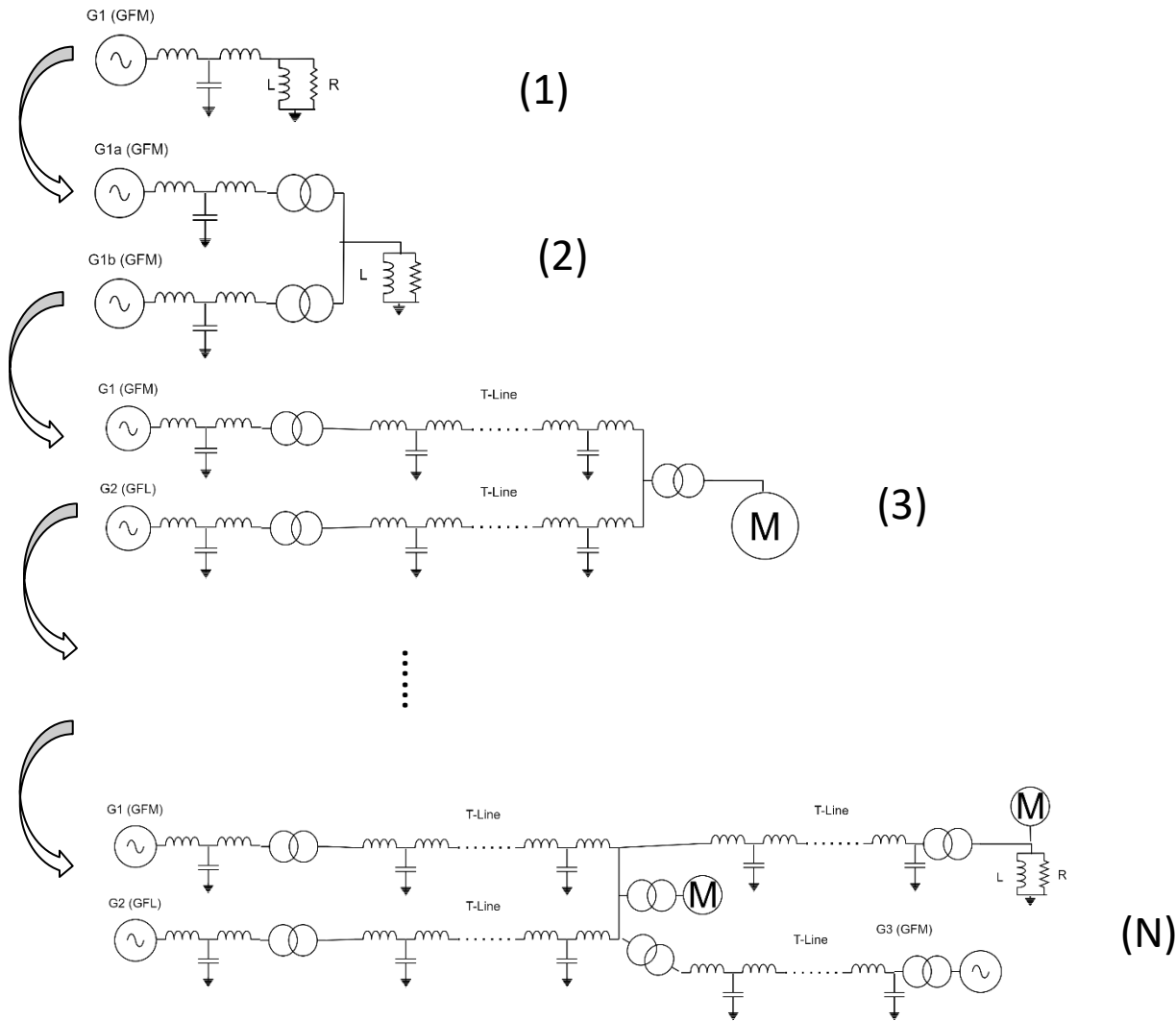
- Once the 2nd GFM converter is replaced with GFL, the stable droop region changes.
- The boundary for that value appears to be 5% for this radial network.
- These values can change slightly once voltage/current controls are retuned.
- The mode that destabilizes is identified to have strong participation between the droop loop and the voltage controllers of the GFL/GFM plants.

Remote GFM and GFL plants with induction motor



- 50 MVA load comprising of induction motors replaces the RL load.
- 2 flux motor model is assumed.
- Critical droop of 8.5% for stability for 5ms droop time constant.
- For 5% droop 14% damping is achieved.
- Mode that loses stability involves
 - Droop loop
 - GFL voltage controller
- At 9% droop the motor has increased participation in the unstable mode.

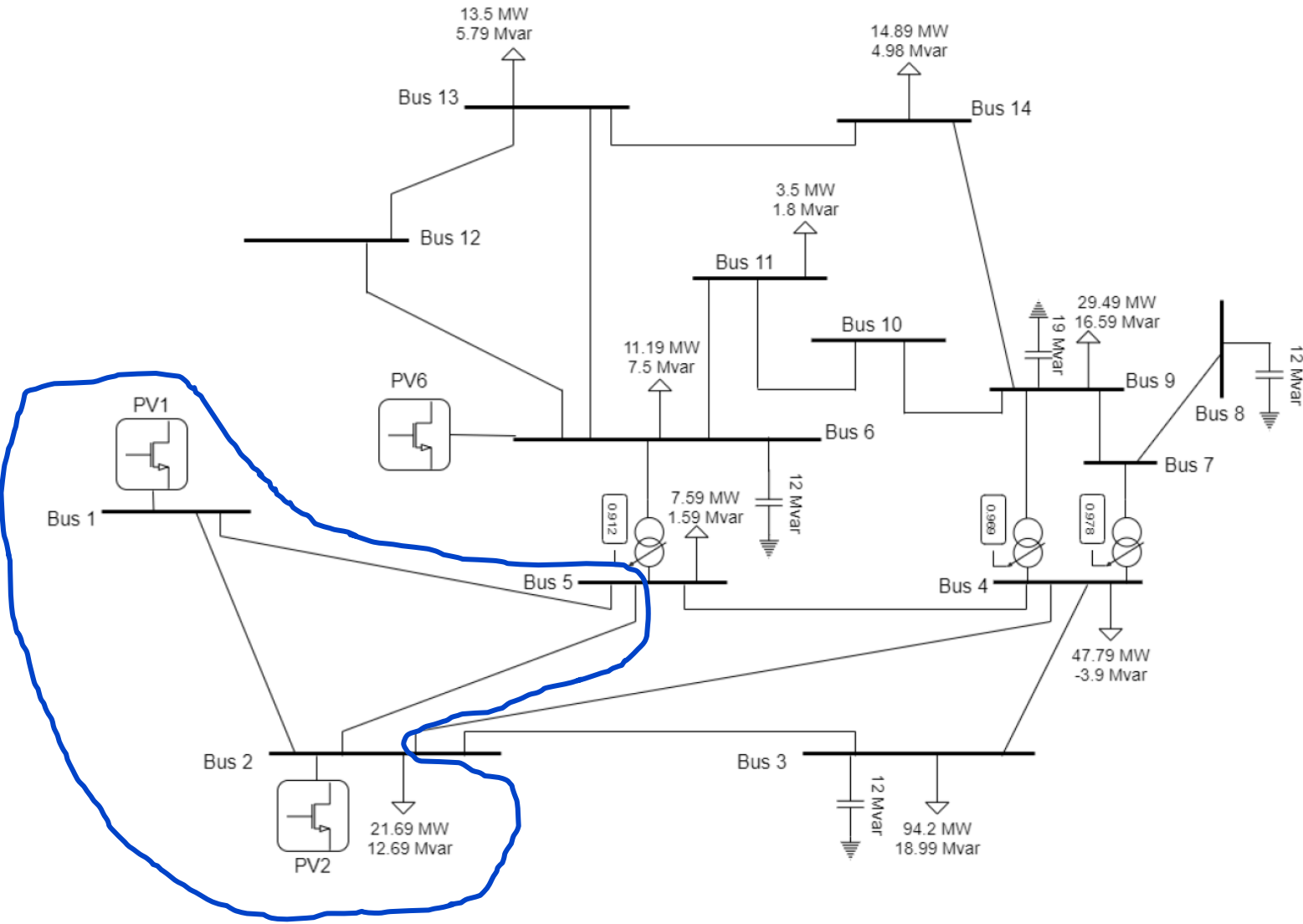
Small-Signal Procedure during Restoration



Example restoration process

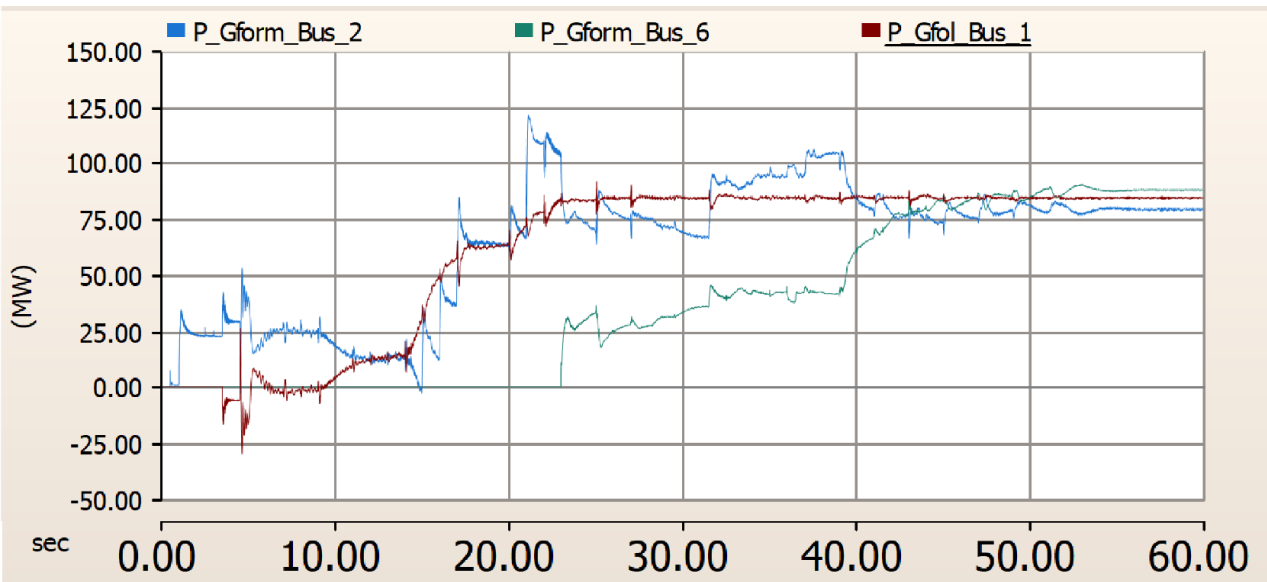
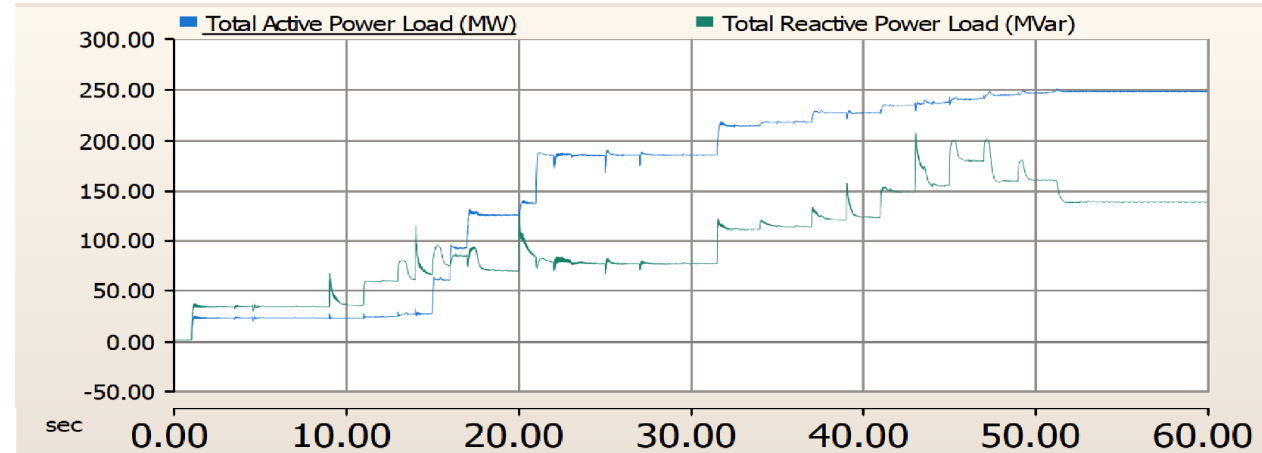
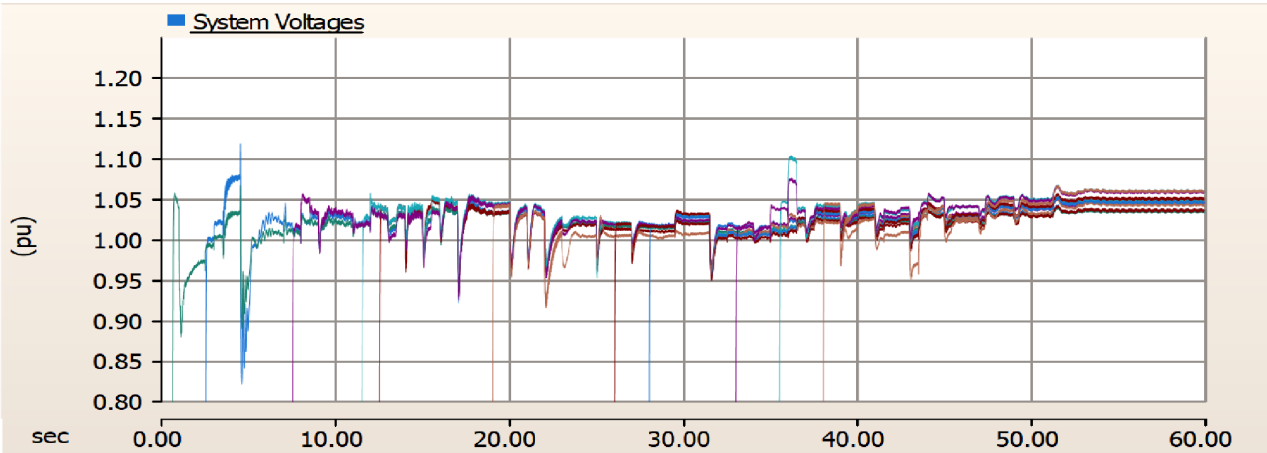
- Small-signal analysis can be carried out for each new component energization, to assess the small-signal behavior of the “live” system.
- If issues are observed, participation factor analysis can identify responsible plants and controllers.
- While screening across stages of the process, control parameter ranges for safe operation can be identified.
- If no parameter set can satisfy this requirement across stages, re-tuning can be carried out based on the analysis.
- Requirements for this process are the topology, estimated loads to be connected and their type.
- This procedure can alleviate significant computational burden since reduced EMT simulation can be required.

Black start of IEEE 14 bus test system



- PV at bus 2 and 6 are grid forming
- PV at bus 1 is grid following
- First black start bottom portion of the network
- Then bring PV6 online
- Then restore rest of the network

If controllers are tuned well, it is possible to energize the entire network



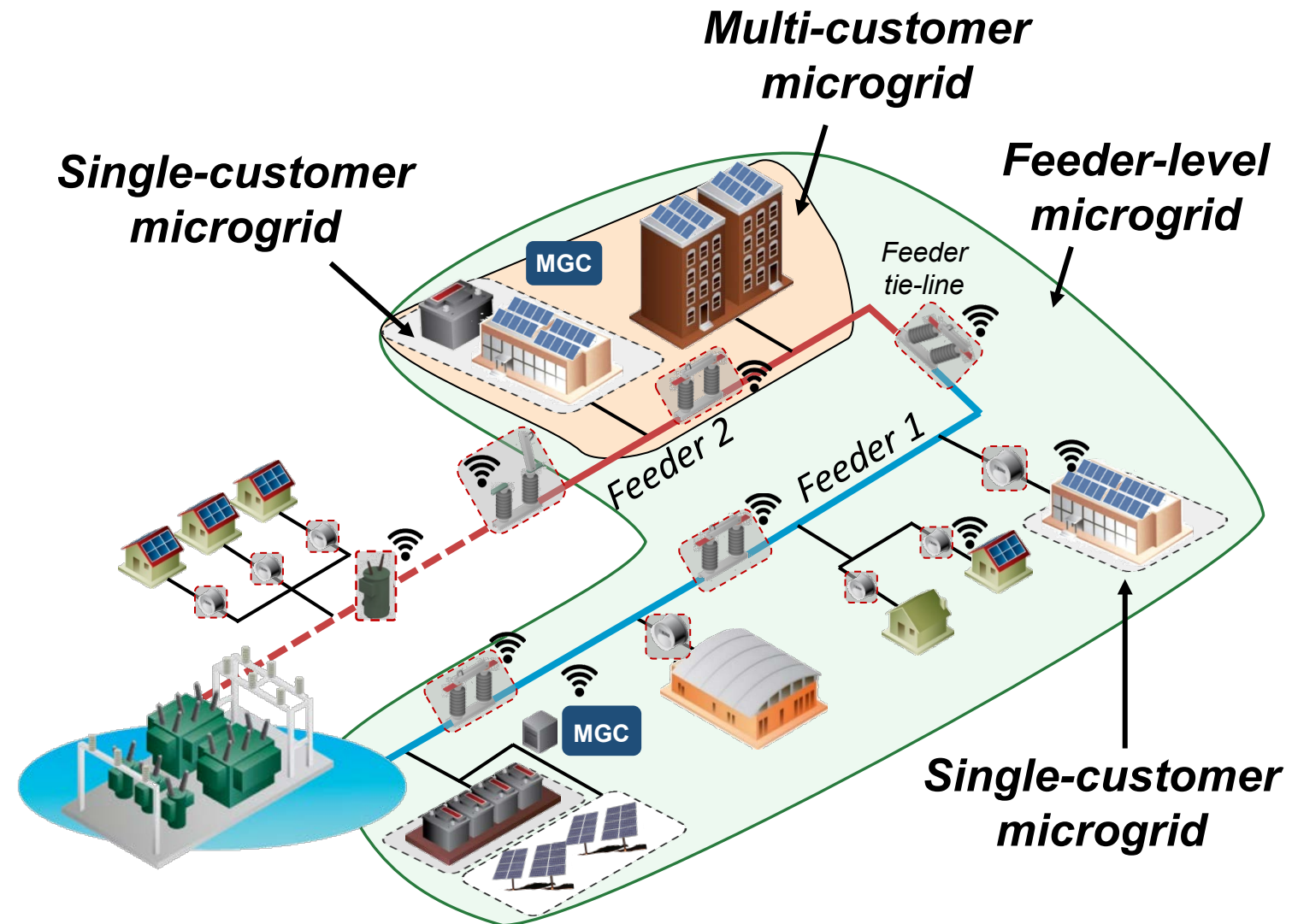
- Second GFM synchronizes at 22s
- Large variety of induction motor load present
- Start up of induction motors have to be coordinated



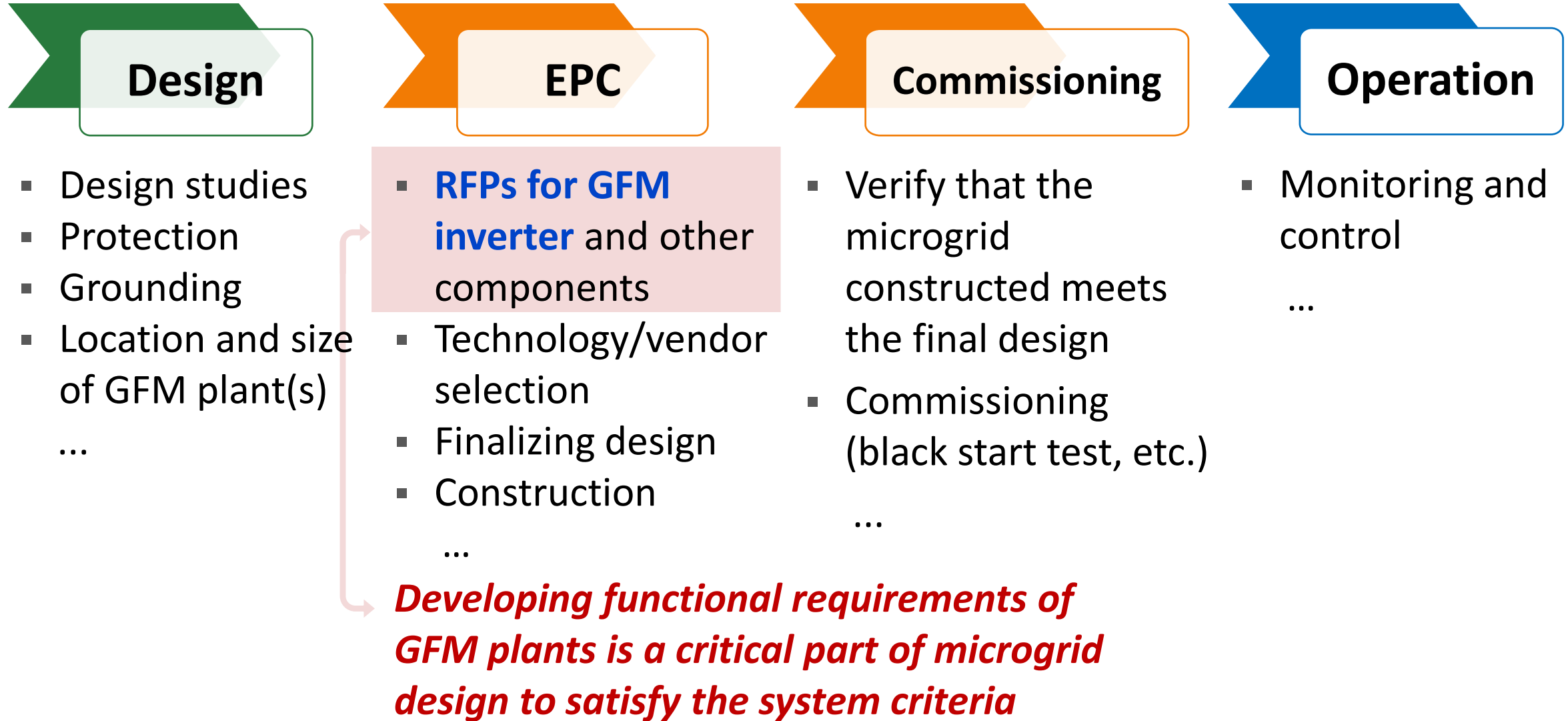
Performance Requirements for GFM Inverter in Microgrid Applications

Utility-level microgrid and the system level performance requirements

- Utility-level microgrid involves utility medium voltage feeder and loads/generations at different locations
- To ensure adequate power quality and reliability, a utility-scale microgrid must satisfy some **system level performance criteria** such as proper voltage and frequency regulation within certain ranges



Utility-level microgrid design process



Overview of GFM performance requirements needed

Single GFM plant

- Specification of power and energy ratings
- Steady state voltage requirement
 - Voltage range
 - Voltage unbalance
 - Voltage harmonics
- Steady state frequency requirement
- Black start related requirements
 - Short-term power and current capability
 - Voltage and frequency regulation during black start
- Dynamic/transient voltage and frequency
- Ride through
- Fault current
- In-rush current

Multiple GFM plants

- Applicability of single plant requirements
- Load sharing
- GFM/GFL interaction
- Microgrid stability

Developed¹

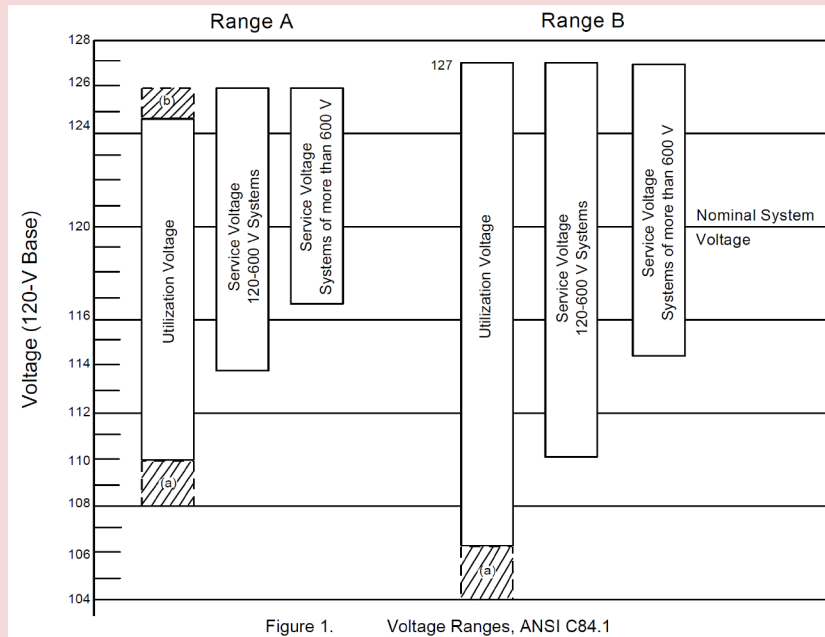
Ongoing²

¹*Performance Requirements for Grid Forming Inverter Based Power Plant in Microgrid Applications: First Edition*. EPRI, Palo Alto, CA: 2021. [3002020571](#).

²An updated version of the tech update will be published in 2022 to include additional requirements

Microgrid steady state voltage requirements

- The steady state voltage of any phase should be within a specific range (e.g., ANSI C84.1 range A) across the feeder
- The steady state voltage range should be designed considering load characteristics in the microgrid



- Load unbalance in a microgrid can lead to voltage unbalance/imbalance even during normal steady state operation
- Voltage unbalance should be restrained to prevent damage or derating to three-phase induction motor loads
- ANSI C84.1 recommends that the maximum voltage unbalance to **3%**

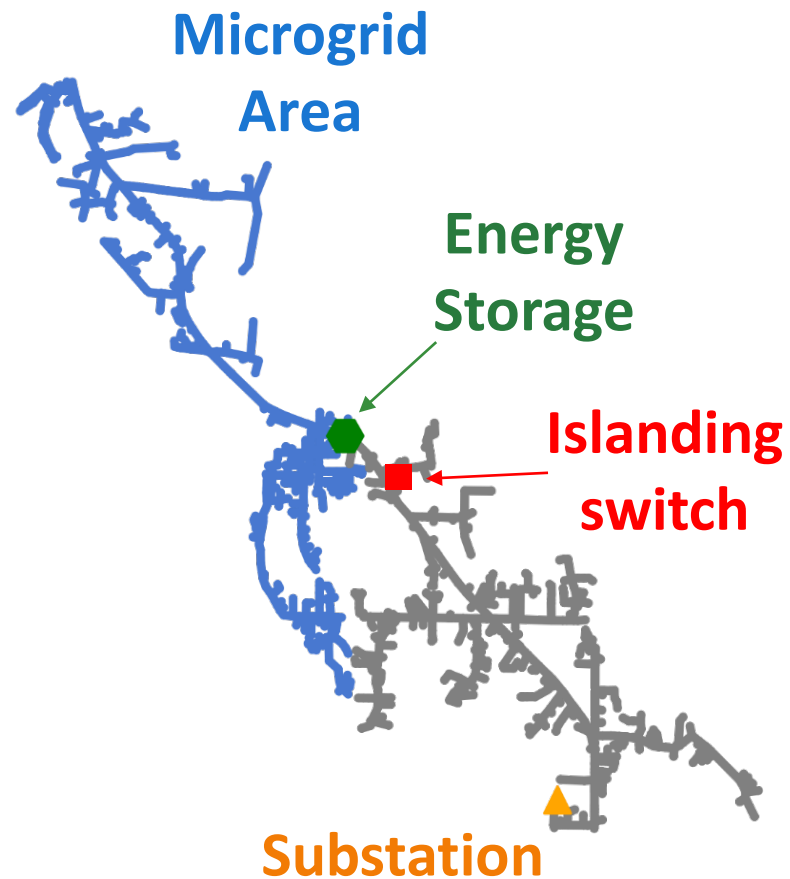
$$\text{voltage unbalance} = \frac{\text{max deviation from average } V}{\text{average voltage}} \times 100\%$$

- IEC 61000-3-x recommends that the voltage unbalance factor (VUF) should be less than 2%

$$VUF = \frac{|V_2|}{|V_1|} \times 100\% \quad \begin{array}{l} |V_1| \text{ positive sequence voltage} \\ |V_2| \text{ negative sequence voltage} \end{array}$$

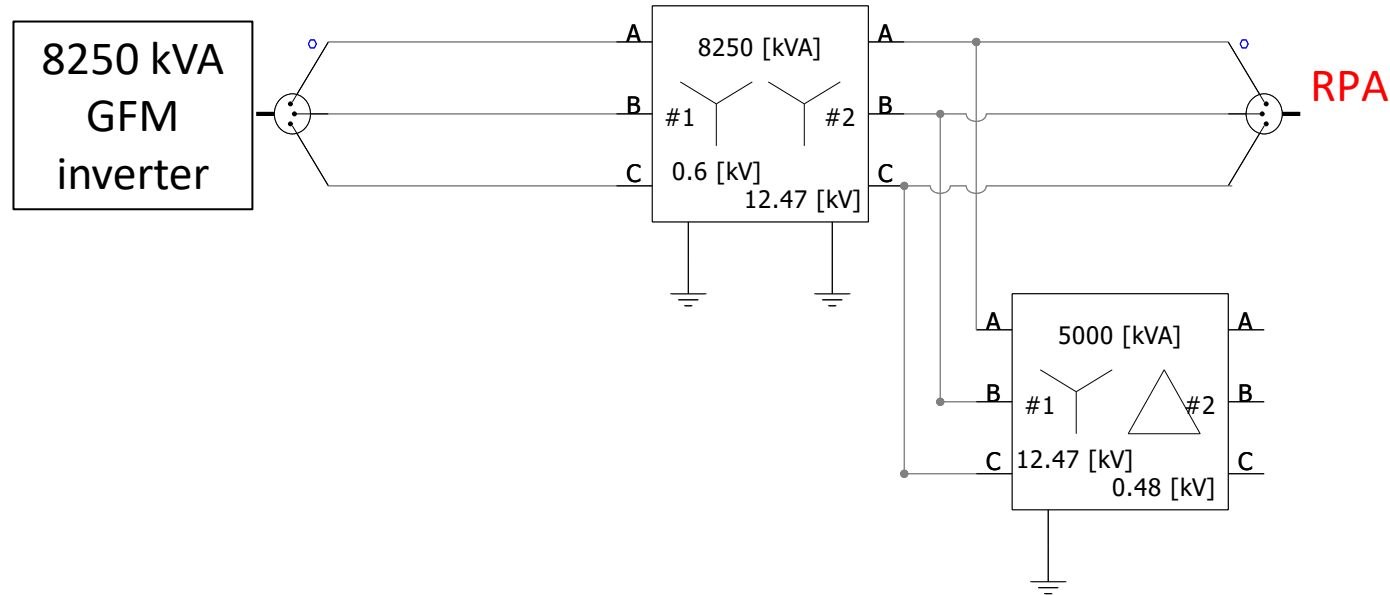
Deriving GFM requirements from microgrid requirements

— study based on a real-world microgrid circuit



- Peak load of the microgrid is around 3000 kW with an average power factor of 0.88
- An energy storage site with 8250 kVA is the only power source inside the microgrid
- For this study, the microgrid circuit is modeled in PSCAD with constant impedance load
- The circuit was reduced (from 1973 nodes to 52 nodes) and converted from an original model in CYME

Model of the GFM energy storage plant



- A GFM inverter model is developed in PSCAD with both positive and negative sequence control
- Inverter is working at isochronous mode with a frequency reference of 60 Hz and positive sequence voltage reference of 1.03 pu at the RPA
- A three-leg inverter is considered which has no grounding path
- A grounding transformer is connected to provide grounding to the microgrid

Isochronous vs frequency droop modes

- Isochronous mode refers to the case where only one generating unit is balancing the load and regulating the frequency tightly at the nominal value
- Droop mode allows some amount of frequency deviation and uses it as a feedback signal to adjust the real power generation of all the units to balance the load change
- For power system operation with multiple inverters, droop mode is preferable to achieve desirable load sharing among them

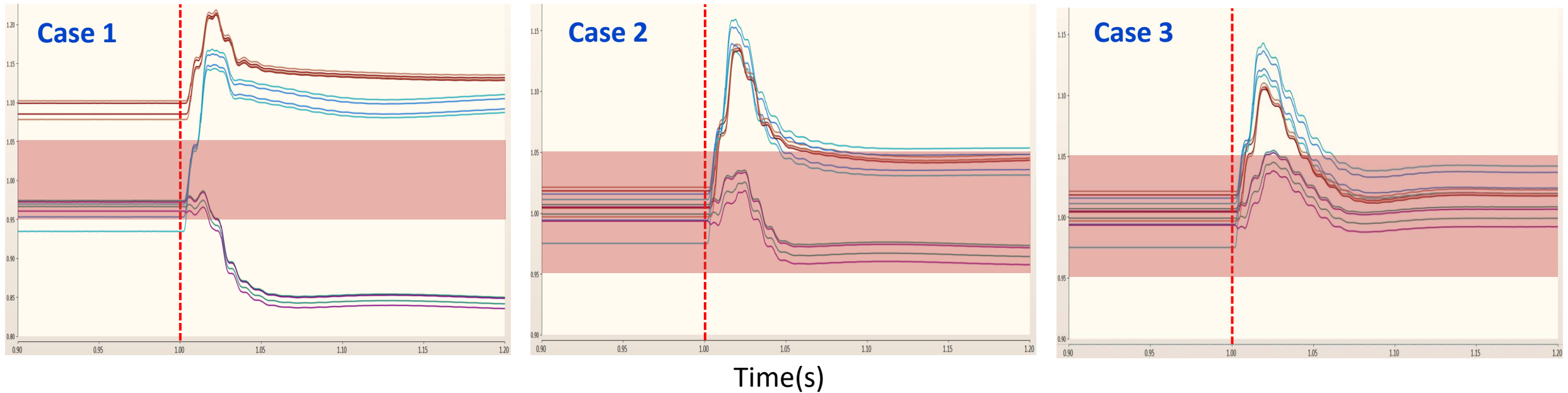
Case studies on GFM negative sequence voltage control

Case #	Negative Sequence Control Objective	Negative Sequence Current Capability
1	Regulate negative sequence current to zero	None
2	Regulate negative sequence voltage at RPA to zero	0.05 pu
3	Regulate negative sequence voltage at RPA to zero	0.1 pu

- The goal is to investigate the need for negative sequence voltage control from GFM inverter and the required negative sequence current capability in the particular microgrid
- The microgrid is initially operating at the peak load condition. At $t=1s$, a section of the feeder is disconnected from the microgrid to simulate a load drop event

Voltage magnitude across the MV feeder

Phase voltage magnitudes at different feeder locations (pu)



Analysis Case #	Negative Sequence Current Capability	Highest Feeder Voltage Unbalance per ANSI Definition	
		Before load drop	After load drop
1	None	9.11%	19.14%
2	0.05 pu	2.48%	6.21%
3	0.1 pu	2.48%	2.52%

Key results from the study

- Severe voltage unbalance can occur in the microgrid if the GFM inverter is not regulating negative sequence voltage in the system
- Effective negative sequence voltage regulation requires sufficient negative sequence current capability from GFM inverter
- Providing negative sequence current may increase the amount of power ripple on the dc capacitor and may require larger dc capacitor to be used
- **A GFM inverter may not provide negative sequence voltage regulation capability unless the requirement is clearly stated**

Steady state voltage requirement

- A GFM power plant should be able to regulate its RPA voltage to be within ANSI C84.1 range A (or other ranges as appropriate for the load inside the microgrid), when the GFM plant output is within its power and current capability*
- A GFM power plant should maintain balanced voltage at its RPA when it operates within the negative sequence current capability and total current capability
- Negative sequence current capability should be defined based on microgrid loading condition and possible contingency scenarios

*Power and current capability of a GFM power plant needs to be carefully selected based on peak load of the microgrid, inrush current and other considerations

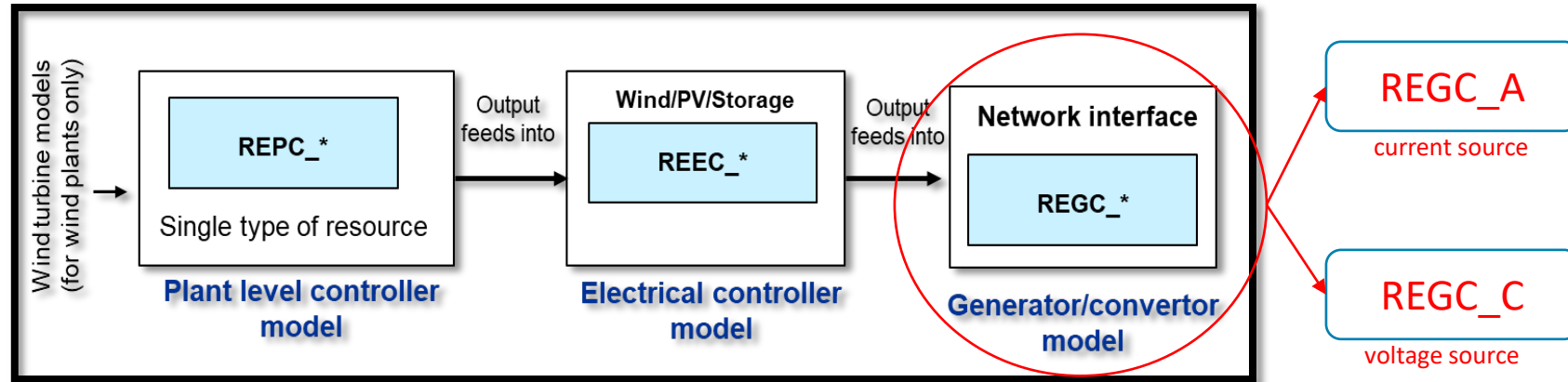


Generic Modeling of GFM Behavior

Generic modeling of grid forming behavior

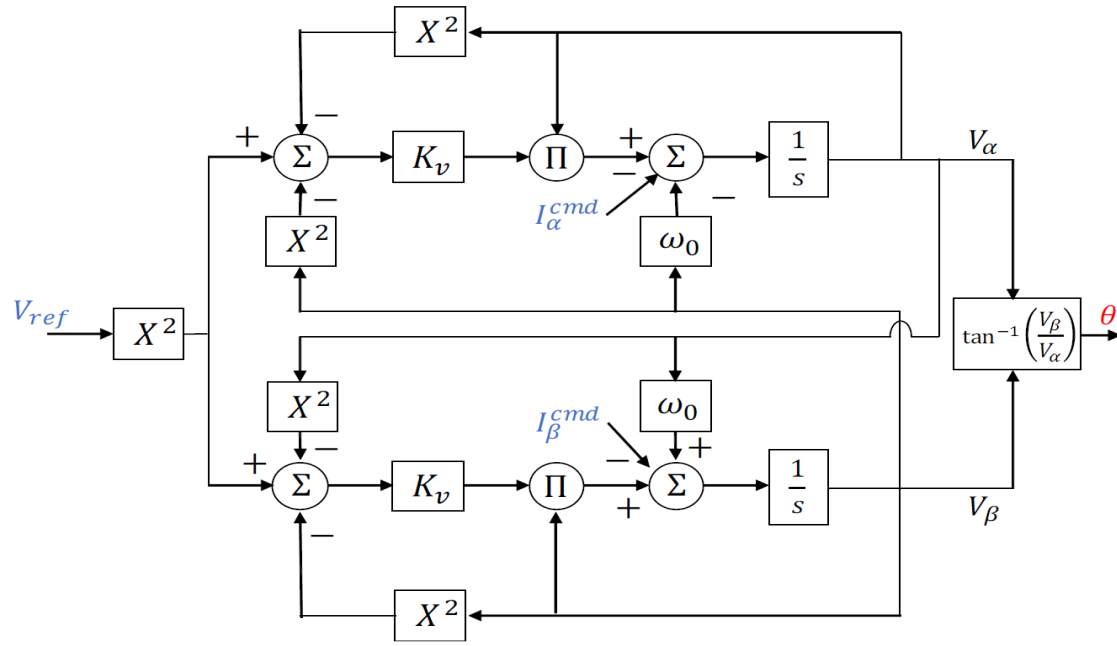
- Planning studies conducted at a time frame when exact models of inverter equipment may not be available
- If studies are carried out only after exact models are available, it might be too late to implement any system upgrades
- Here, generic models play a role in enabling planning studies to be carried out
- But with different grid forming control methods, would there be a need for many different generic models?
 - Also would positive sequence modeling techniques remain to be valid?

Positive sequence generic models

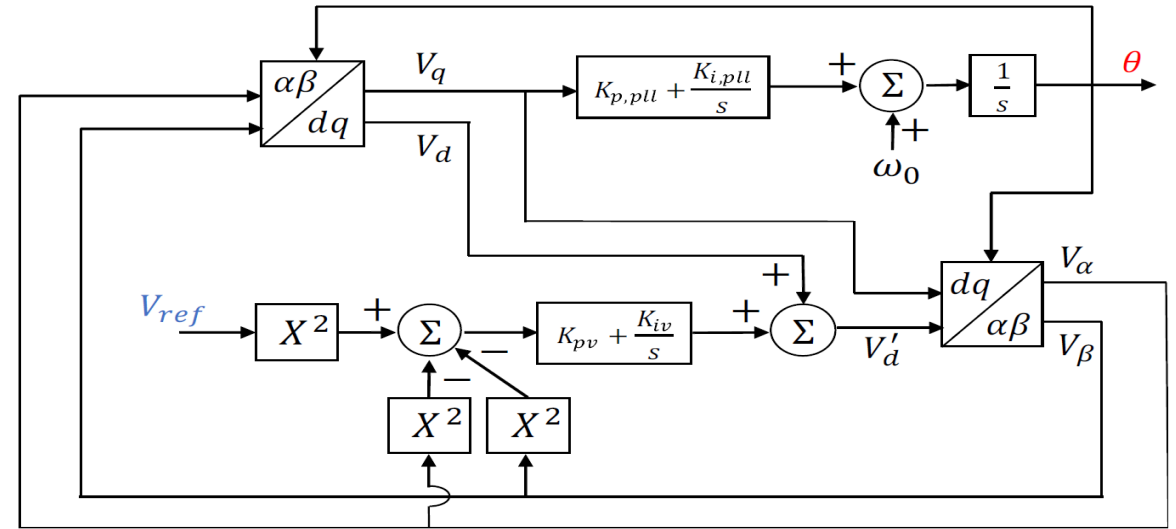


Generic models are vendor-agnostic models that do not necessarily represent the exact control algorithm of any particular IBR vendor. When appropriately parameterized, these models can subsequently provide the trend of dynamic behavior expected from IBR plants.

Conceptual operational similarities exist with PLL behavior



Virtual Oscillator

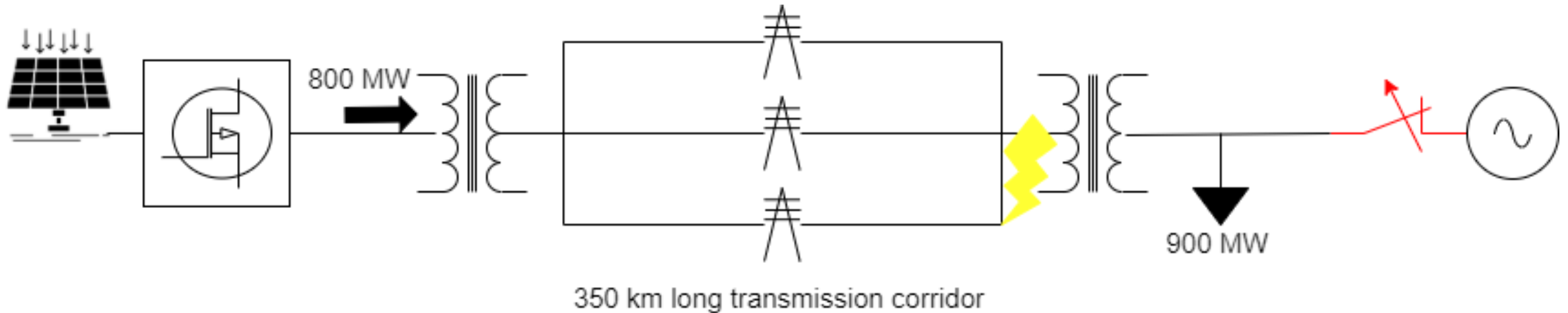


PLL – Voltage controlled oscillator

- A virtual oscillator uses internal state variable feedback to generate a sine wave
- A PLL with an additional voltage control loop uses external output variable feedback to generate a sine wave

More details can be found in reference [8]

Use of REGC_C to represent grid forming behavior

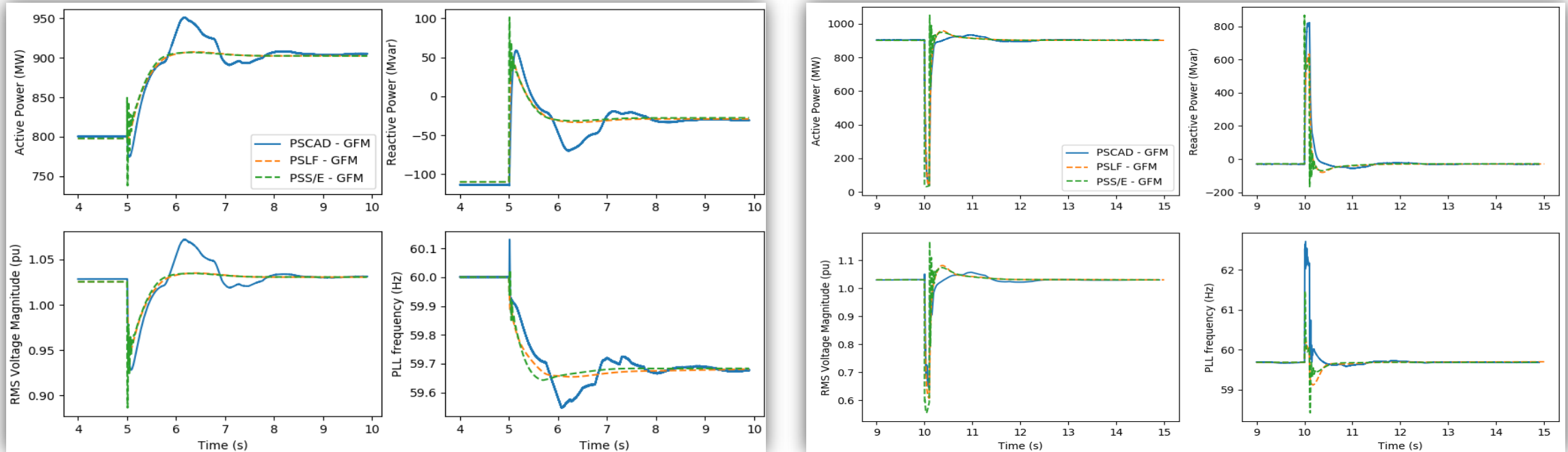


- Voltage at PV plant point of interconnection to be controlled
- Frequency control is implemented at device level
 - 10pu/s ramp rate limit

- » Voltage control at inverter and plant level:
 - 500ms sampling time – conservative
 - 500ms dead time delay between plant and inverter

More details can be found in reference [9]

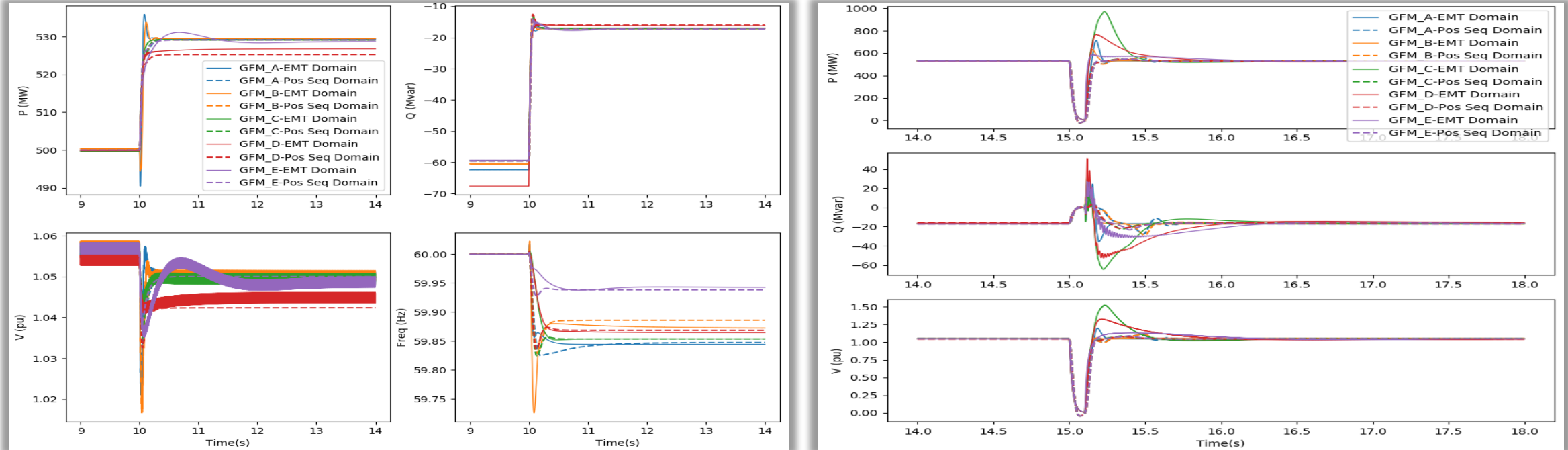
Use of the REGC_C model to represent grid forming behavior



- Positive sequence response obtained using approved generic models
 - REGC_C + REEC_D + REPC_A
- Models should be parameterized with diligence and thoroughness

EMT and Positive Sequence Domain Model of Grid Forming PV Plant (GFM-PV), EPRI, Palo Alto, CA, 2021, 3002021787 ([link](#))

Resulting in similarity in response across different GFM implementations



EMT domain GFM implementations include virtual oscillator based, droop based, PLL based, and unknown implementations

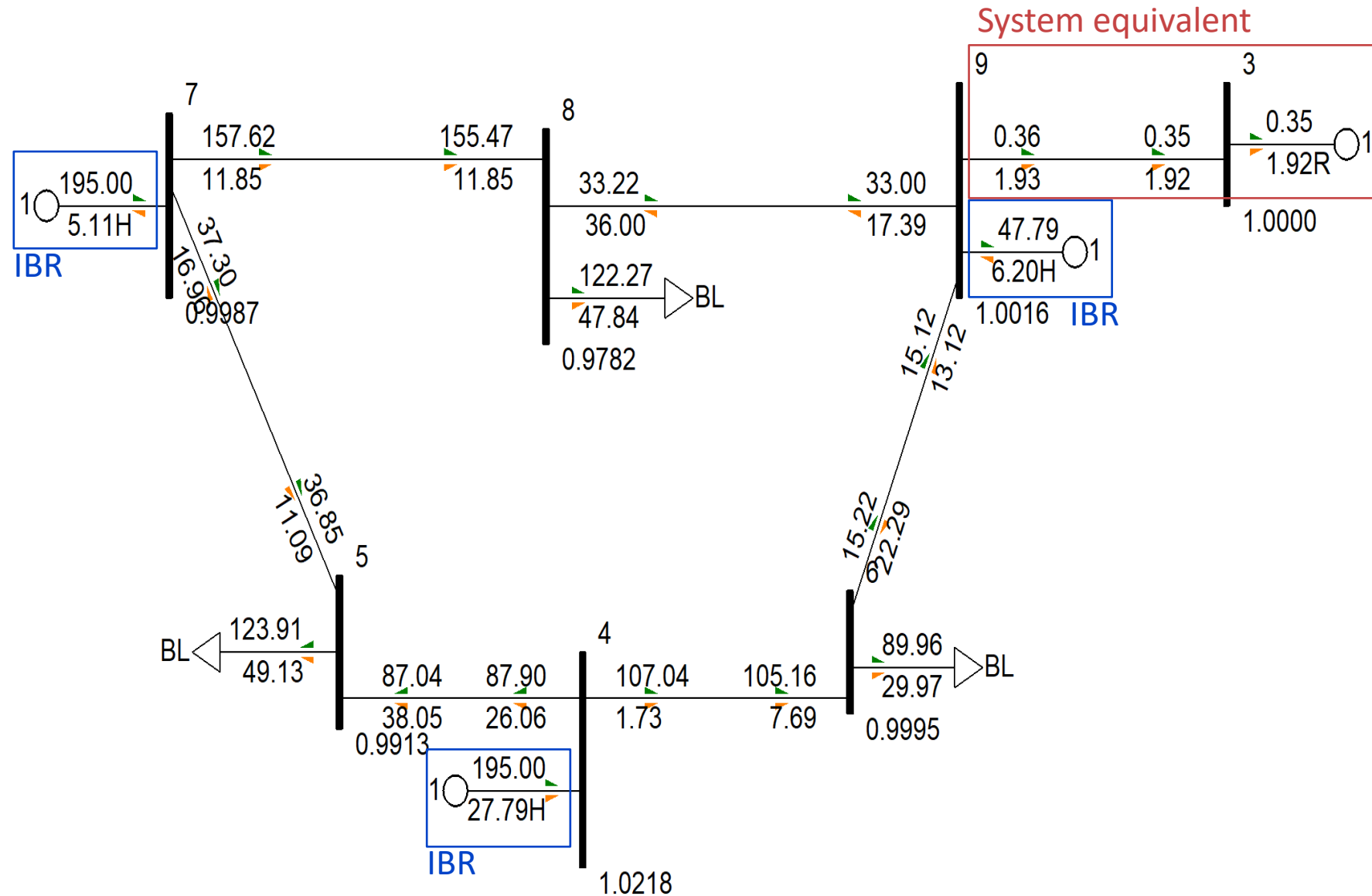
- Different GFM implementations, without additional tuning, can have slightly different transient behavior
- Complete tuning of generic positive sequence model is yet to be completed
 - But results are encouraging!

Determination of grid forming inverter capacity

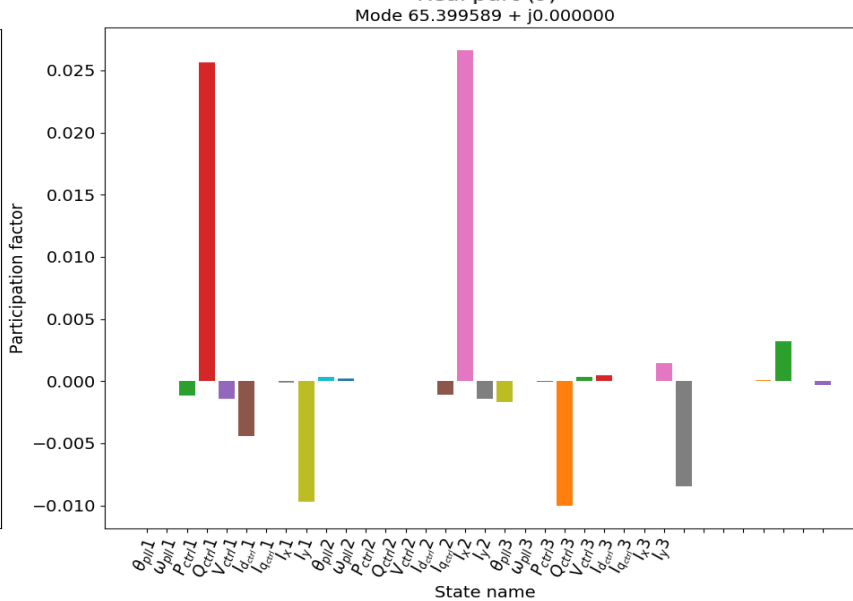
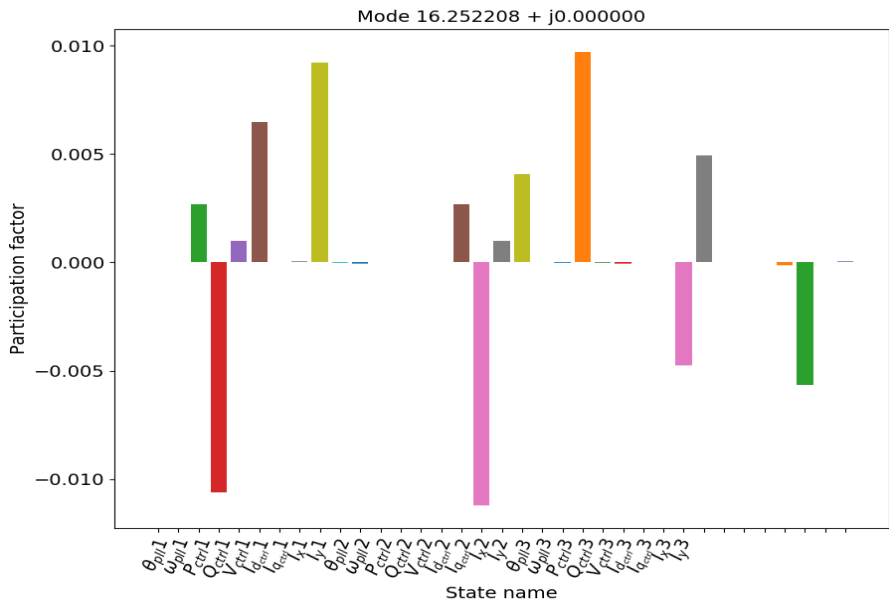
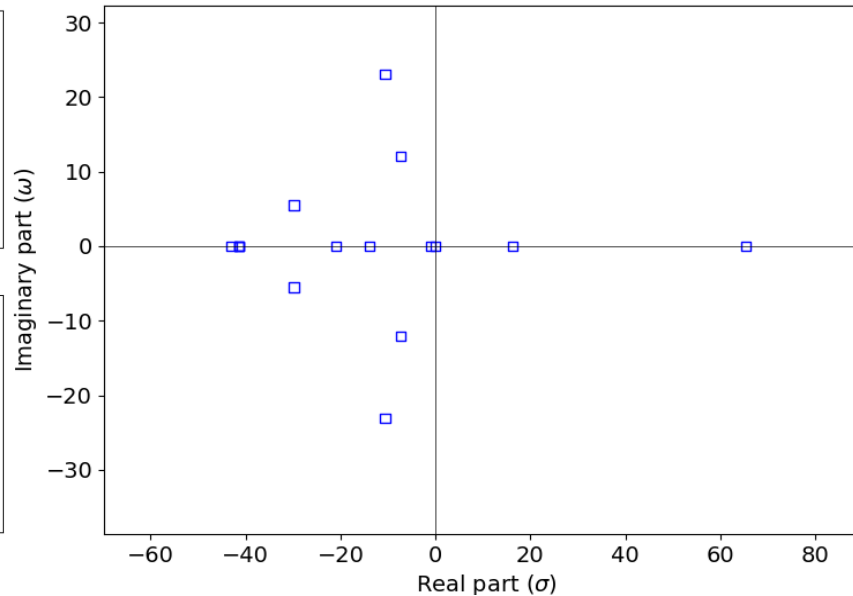
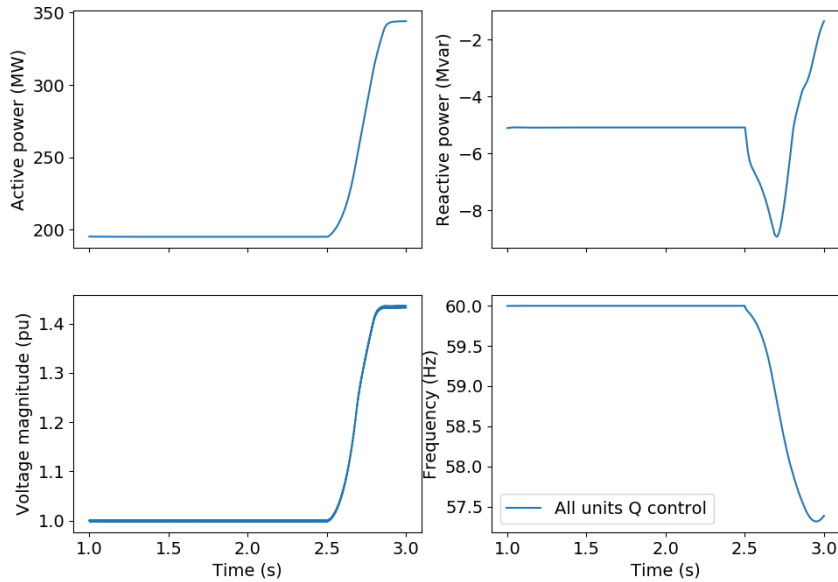
- Similar behavior across multiple grid forming control structures allows for development of generic characteristics/models
- These generic models in-turn allow for determination of grid forming capacity in future grids
- Both time domain and small signal stability concerns can exist
- Size of required grid forming inverters is not readily intuitive

Consider an example network

- Three legacy IBRs
 - Two IBRs with GFL P/Q control
 - 200 MVA each
 - One IBR with GFL current control
 - 50 MVA
- Power transfer to external network intentionally kept minimal

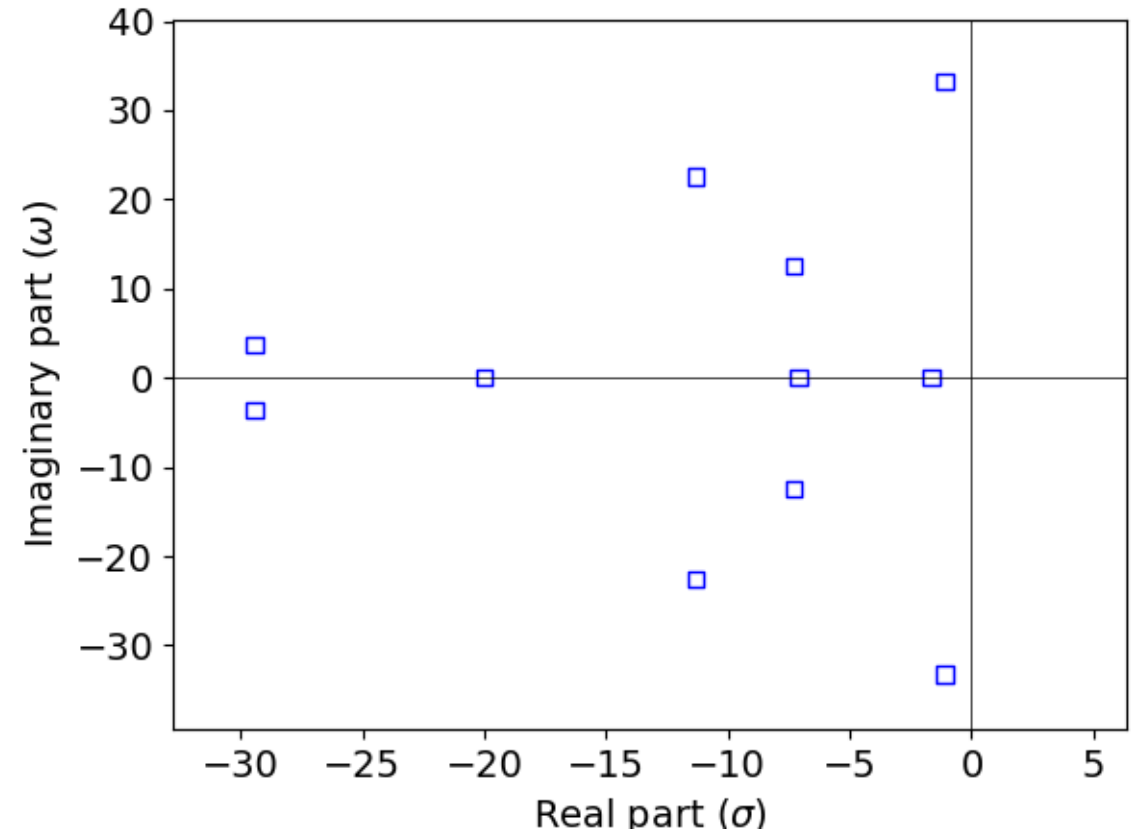
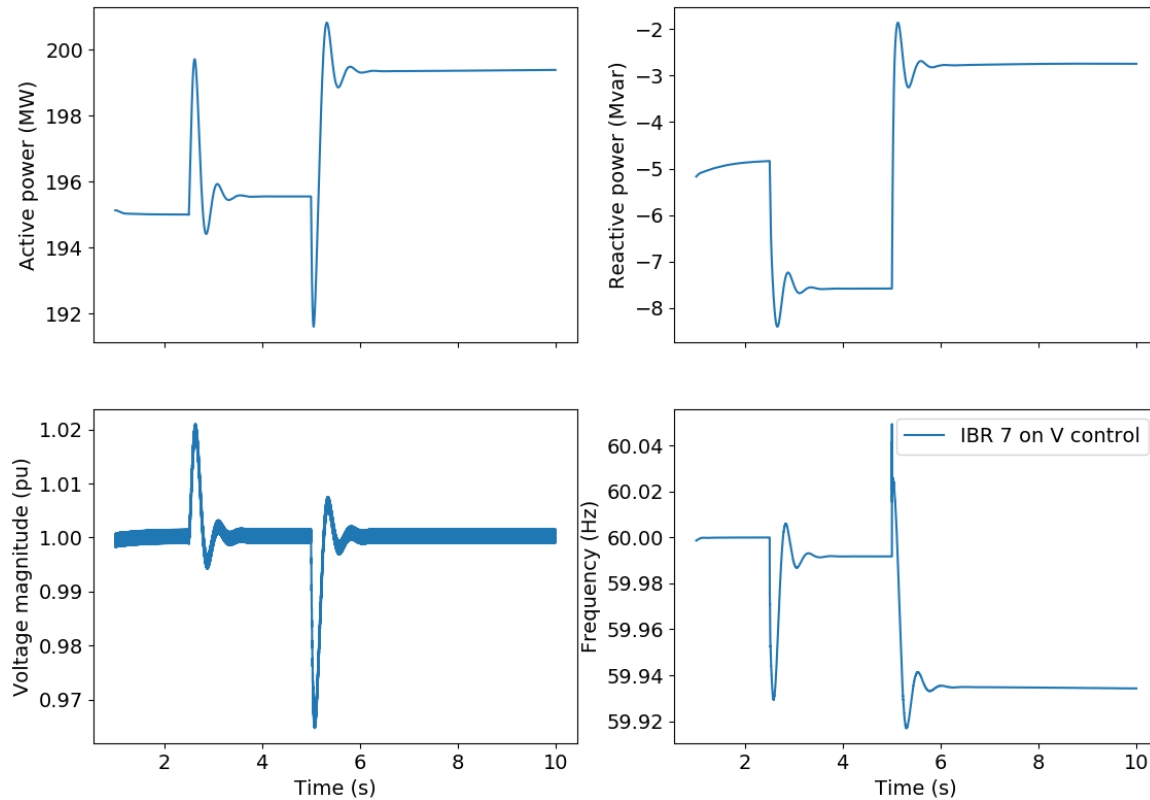


When all IBRs are grid following



- Trip of system equivalent at $t=2.5s$
- Two unstable modes observed
- Large participation of Q-control loop in each unstable mode

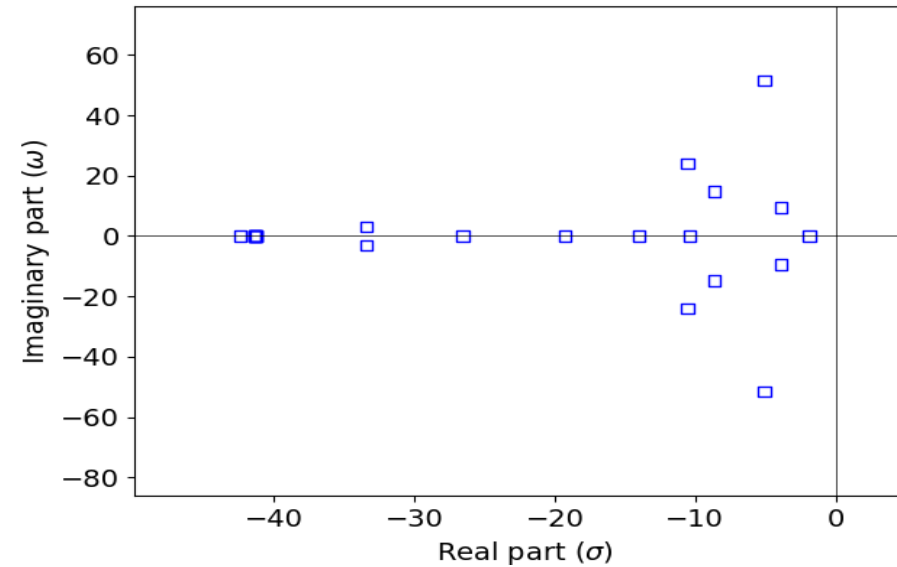
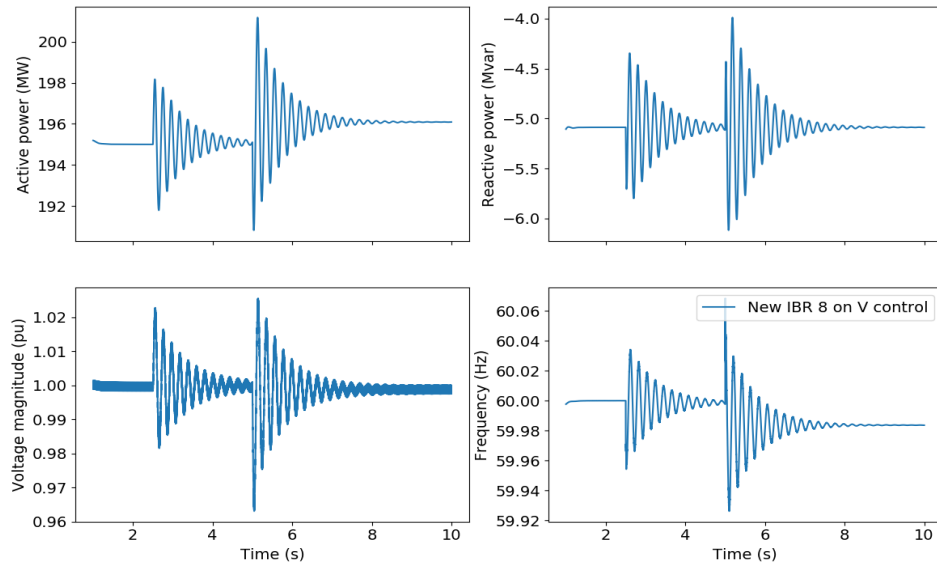
When one 200 MVA IBR is transformed to GFM Control



- Maximum settling time for performance of voltage control is 3.0s.
 - Within the specifications of IEEE 2800-2022 standard!

- Robust performance immediately delivered
 - For grid islanding at $t = 2.5s$
 - Subsequent load increase at $t = 5.0s$

Suppose no scope to change existing inverters from GFL to GFM



- A new 150 MVA inverter is required to maintain stability

- Installation of new/additional equipment could have economic considerations



Planning a Transmission Network with GFM IBR



unifi

consortium

universal interoperability
for grid-forming inverters

*Bringing the industry together to unify
the integration and operation of
inverter-based resources and
synchronous machines*

Project Team

National Labs and Research Institutes



Universities



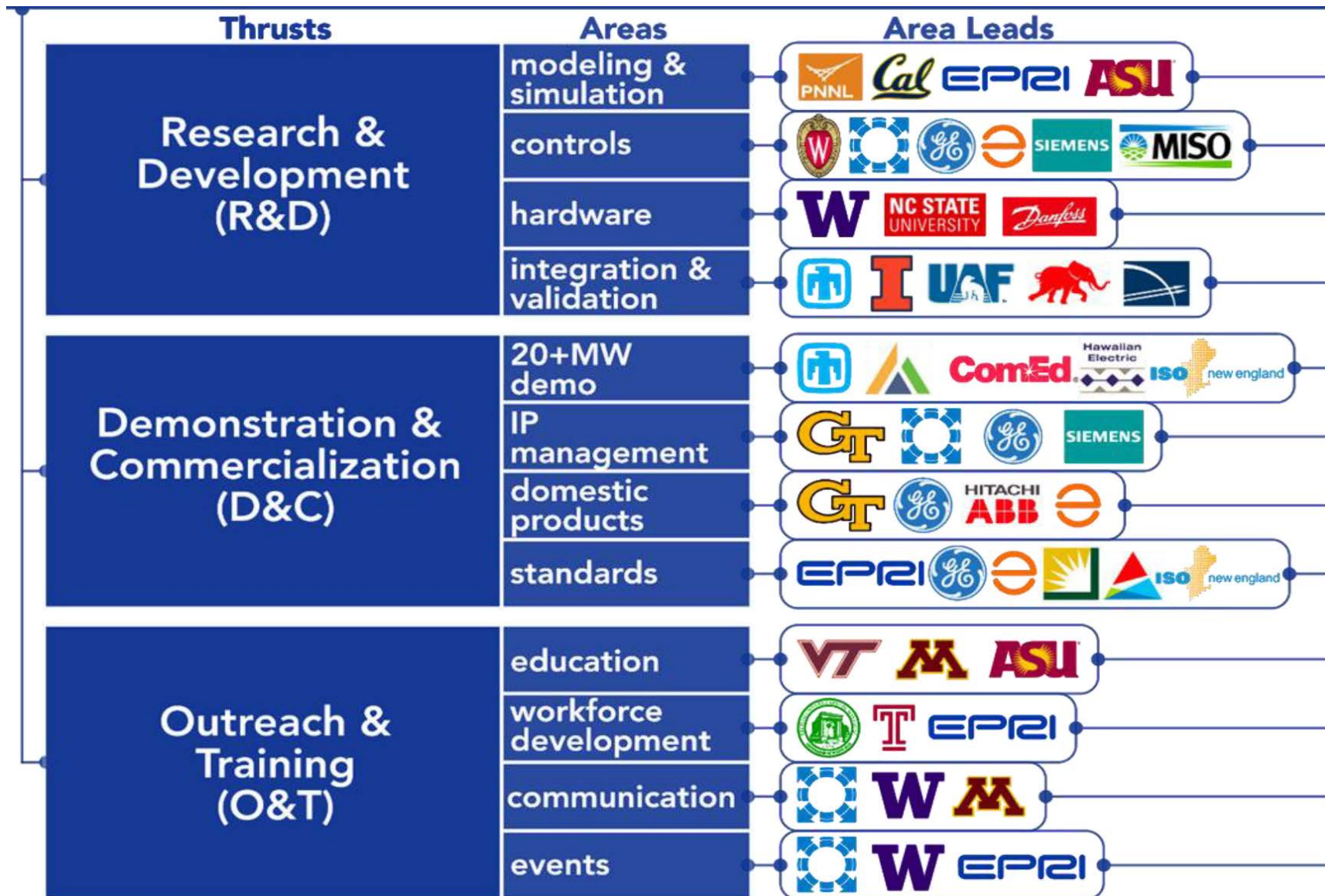
Industry



Utilities and System Operators

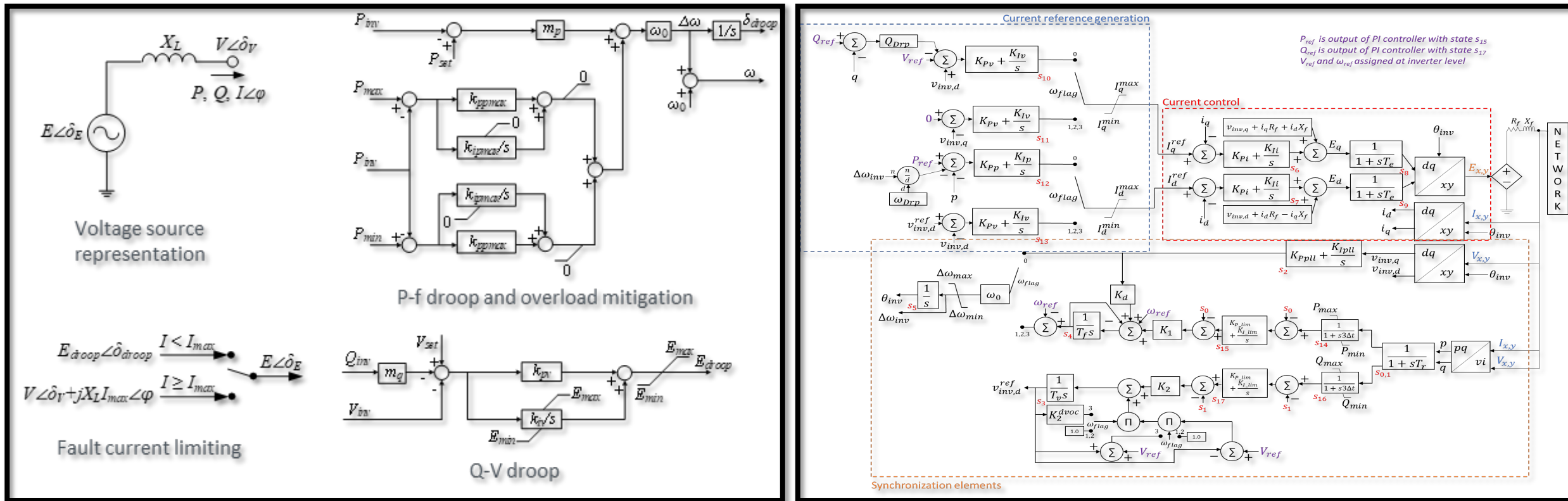


Overview of UNIFI project



Generic positive sequence models to aid in carrying out a study

- Single-loop and multi-loop structures allow for representation of wide variety of GFM behavior (developed through UNIFI Consortium)



1. https://www.wecc.org/Reliability/Model%20Specification%20of%20Droop-Controlled%20Grid-Forming%20Inverters_PNNL.pdf
 2. https://www.wecc.org/_layouts/15/WopiFrame.aspx?sourcedoc=/Administrative/Memo%20on%20Proposal%20for%20Generic%20GFM%20Model_v2.pdf&action=default&DefaultItemOpen=1

Availability of generic GFM models (to-date)

Positive sequence/RMS balanced domain			RMS unbalanced domain			
Siemens PTI PSS/E	GE – PSLF	DigSILENT PowerFactory	OpenDSS	DigSILENT PowerFactory	CYME	Synergi
✓	✓	✓	✓	✓	x	x
Type A Droop Type B Droop VSM dVOC	Type A Droop Type B Droop VSM dVOC	dVOC	dVOC	dVOC		

EMT domain ^{+,^}					Real-time domain
PSCAD ⁺	EMTP*	DigSILENT PowerFactory	SIMULINK	PLECS	RTDS/Opal-RT/RSCAD/HYPERSIM*
✓	✓	✓	✓	✓	✓
Type A Droop Type B Droop VSM dVOC				Type A Droop VSM dVOC	Type A Droop Type B Droop VSM dVOC

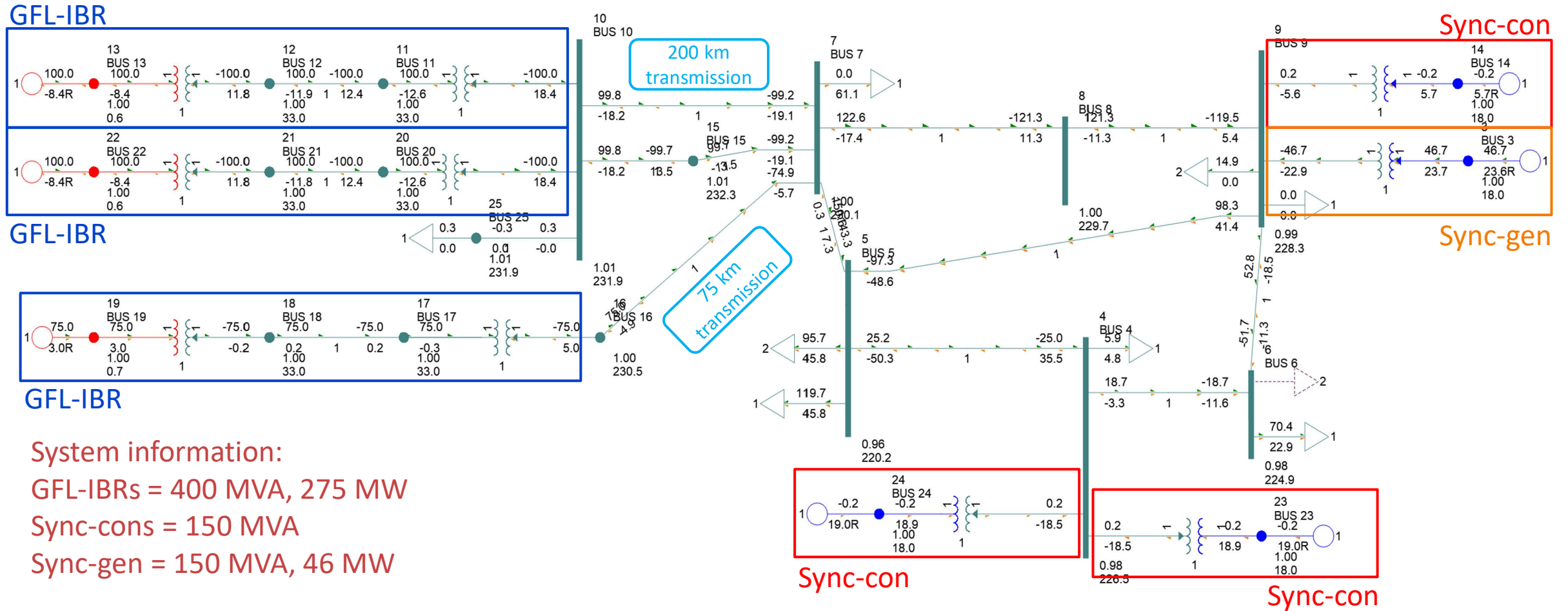
*implemented by software developer

+certain model versions also have negative sequence control implemented

^certain model versions are also implemented at switching level

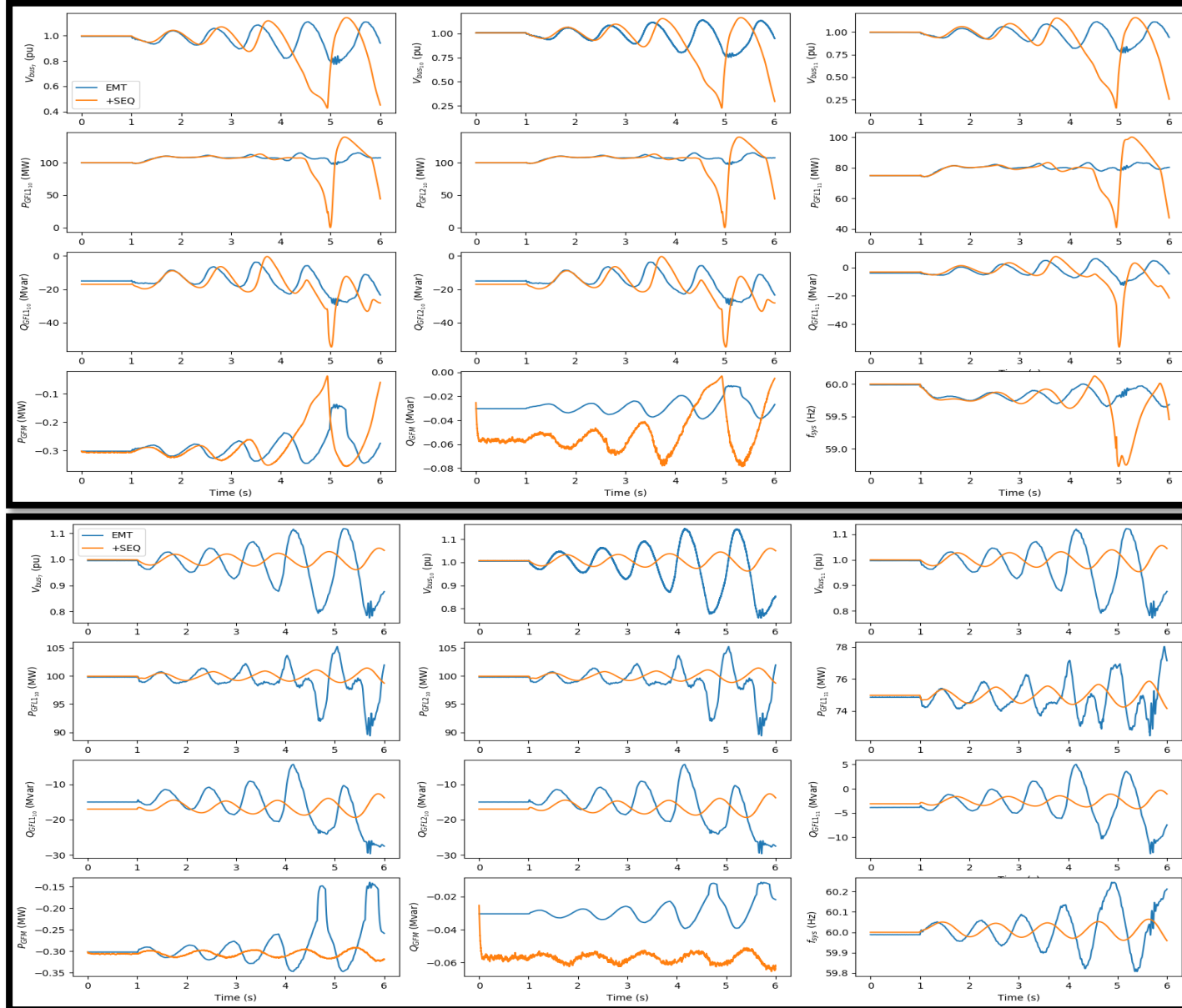
+C-code based model in addition to GUI block-based model

Locating and sizing of grid forming resources using generic models



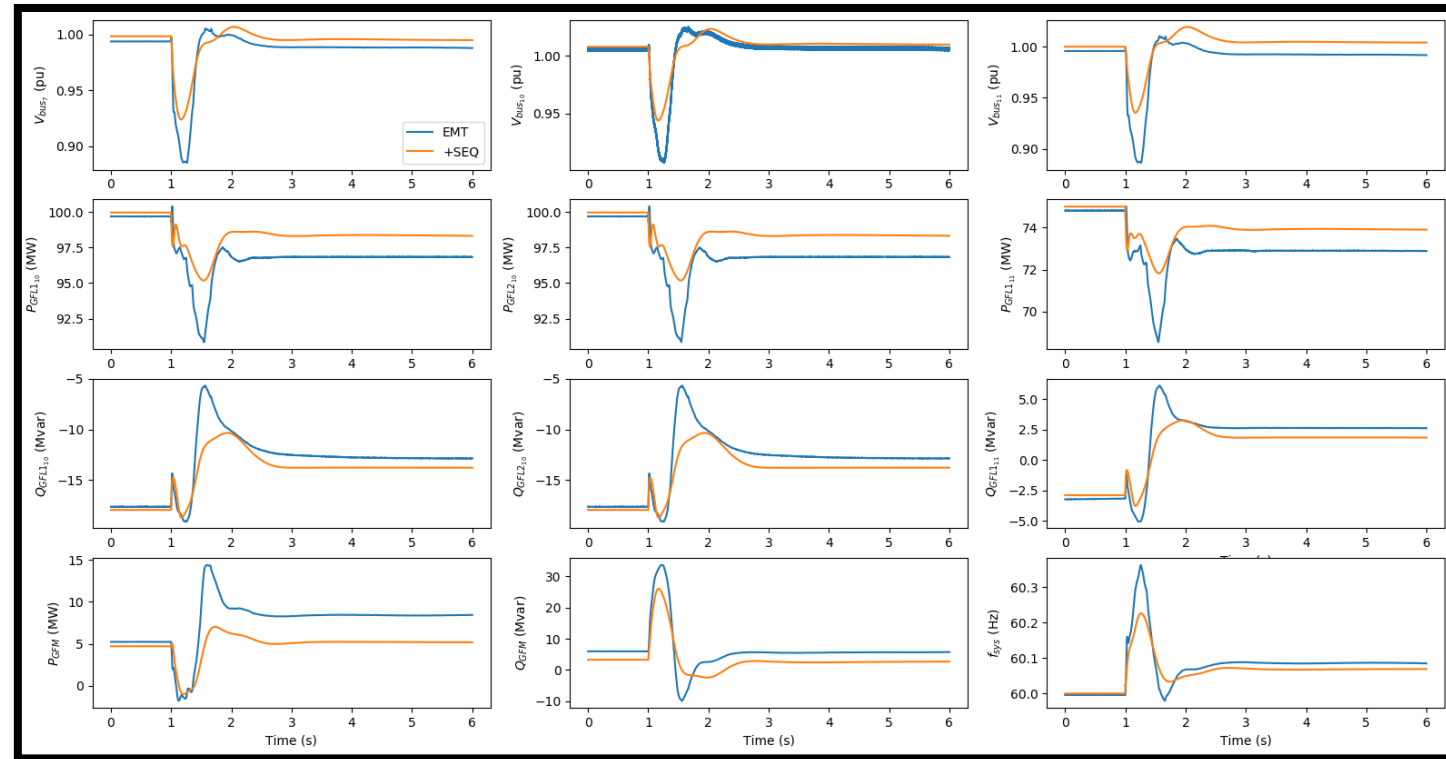
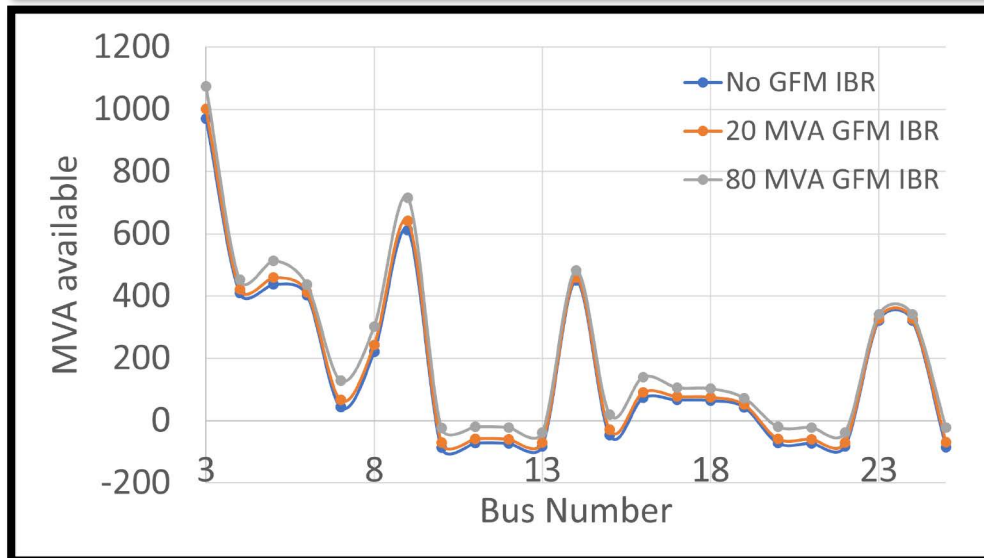
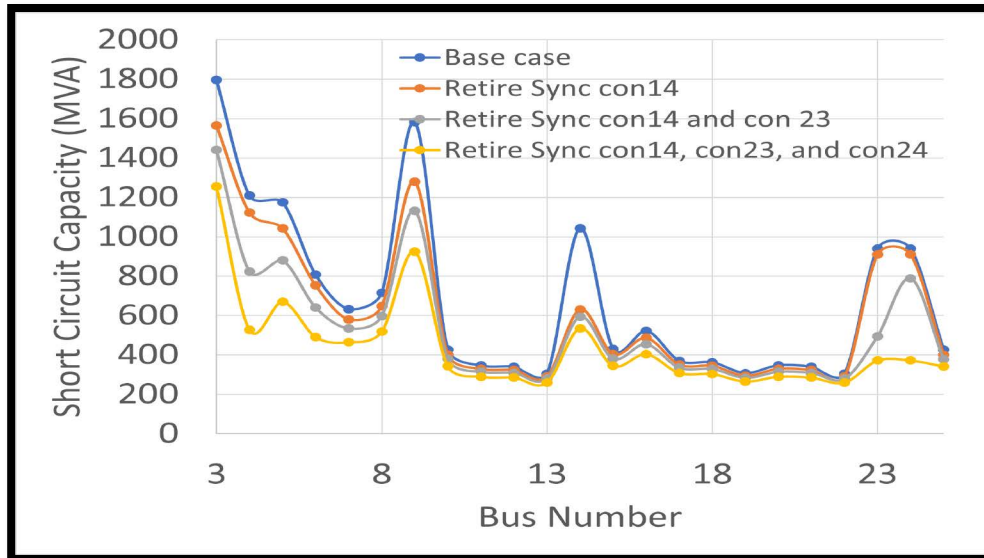
- Study objective: To allow retirement of synchronous condensers and generator from the load centers, where to place a GFM device and what should be its rating?

Locating and sizing of grid forming resources



- Events shown:
 - Top: Load increase 10%
 - Bottom: Trip of one synchronous
- Even with synchronous resources (without power system stabilizers) system is on verge of instability
 - diligently parameterized models across both simulation domains

Locating and sizing of grid forming resources (cont'd)



- Determined size and location of GFM using steady metrics of short circuit strength and remaining MVA available
- Trip of all 150 MVA of sync-con could be stabilized with 80 MVA of GFM

UNIFI consortium support supplemental project

Need

- Grid forming inverters development needs an ecosystem of R&D, demonstration and training leading to vendor- and technology-agnostic interoperability guidelines and functional requirements

Goal

- Support deployment of grid forming inverters by conducting research and development, demo concepts at scale, authoring best practices and standards, training next-generation workforce

Value

- Provides a venue for inverter manufacturers, system operators, utilities and researchers to collaborate and coordinate on grid forming R&D
- Utility/ISO participation ensures a seat at the table to participate in important discussions

Scope

- R&D Thrust: modeling and simulation, controls, integration and validation
- Demo Thrust: 1 MW and 20 MW demos, commercialization and standards
- Outreach and Training: Education, Workforce Dev, Comms, Events

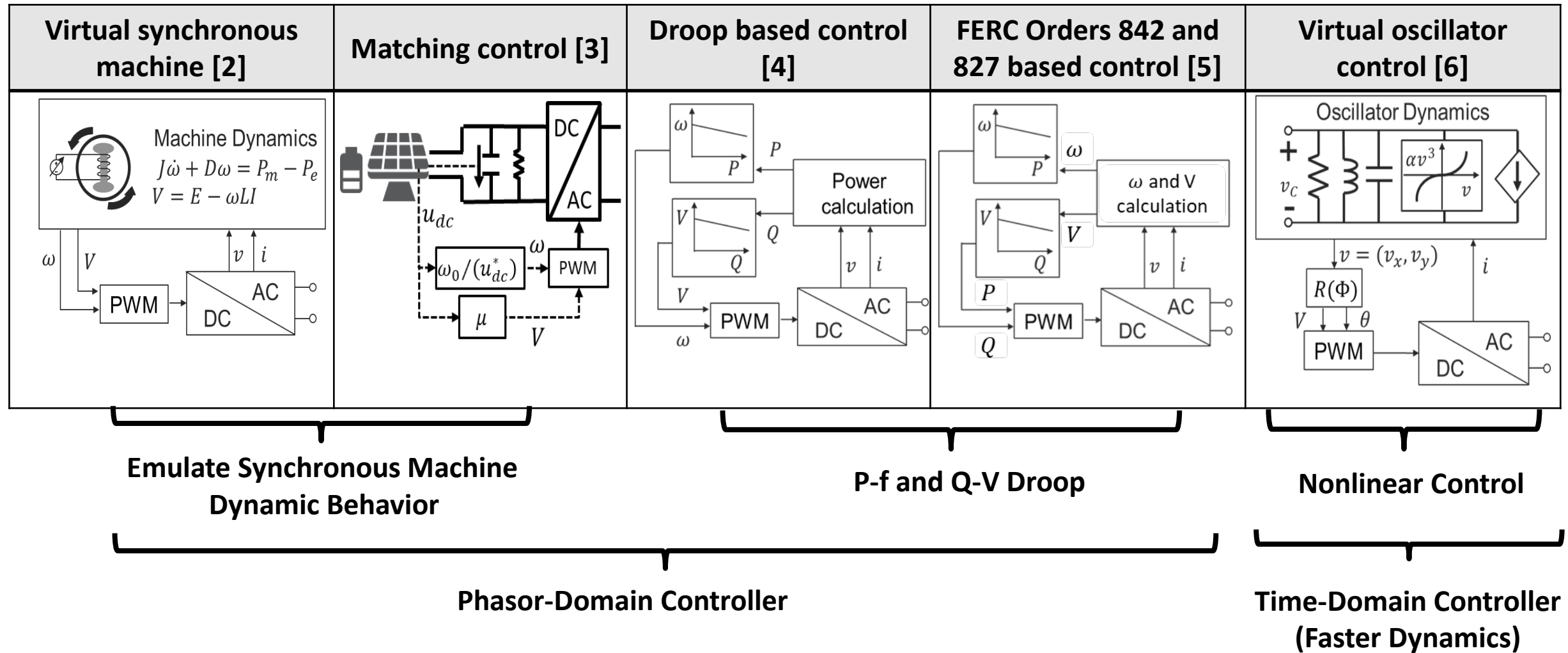


- Contact [Deepak Ramasubramanian](#)
- Contact [Wenzong Wang](#)
- Contact [Aminul Huque](#)
- Contact [Aidan Tuohy](#)



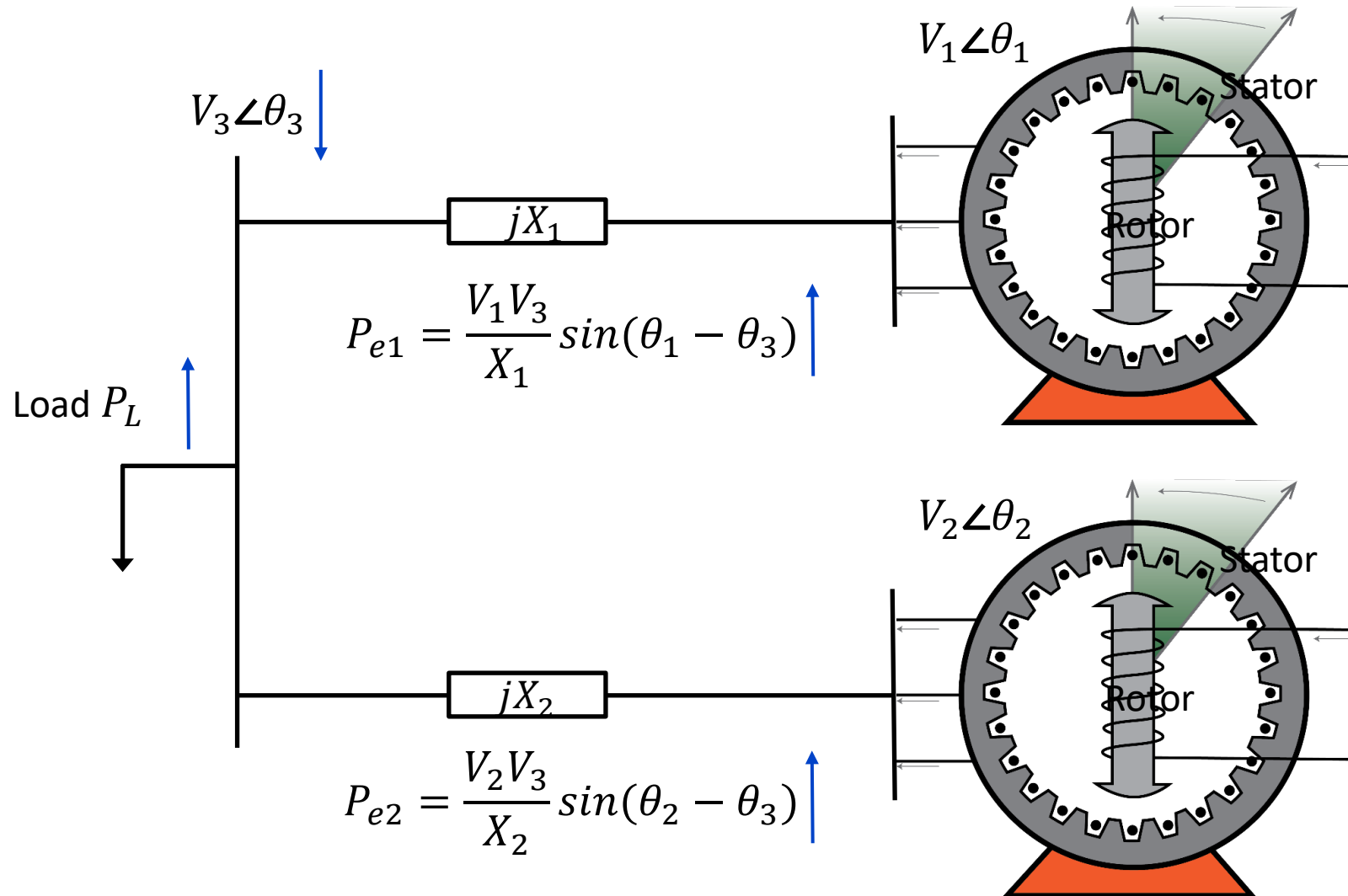
Survey of Few GFM Control Methods

Several GFM Inverter Controls from the Literature



This is not a comprehensive list of GFM inverter control. More controls are being proposed in the literature.

Operation Principle of Synchronous Generators



SG swing equation

$$2H_1 \dot{\omega}_1 = P_{m1} - P_{e1} \quad \omega_1 \downarrow$$

$$2H_2 \dot{\omega}_2 = P_{m2} - P_{e2} \quad \omega_2 \downarrow$$

Governor Control

$$P_{m1} = P_{m1}^* - K_{G1}(\omega_1 - \omega_{ref}) \quad \uparrow$$

$$P_{m2} = P_{m2}^* - K_{G2}(\omega_2 - \omega_{ref}) \quad \uparrow$$

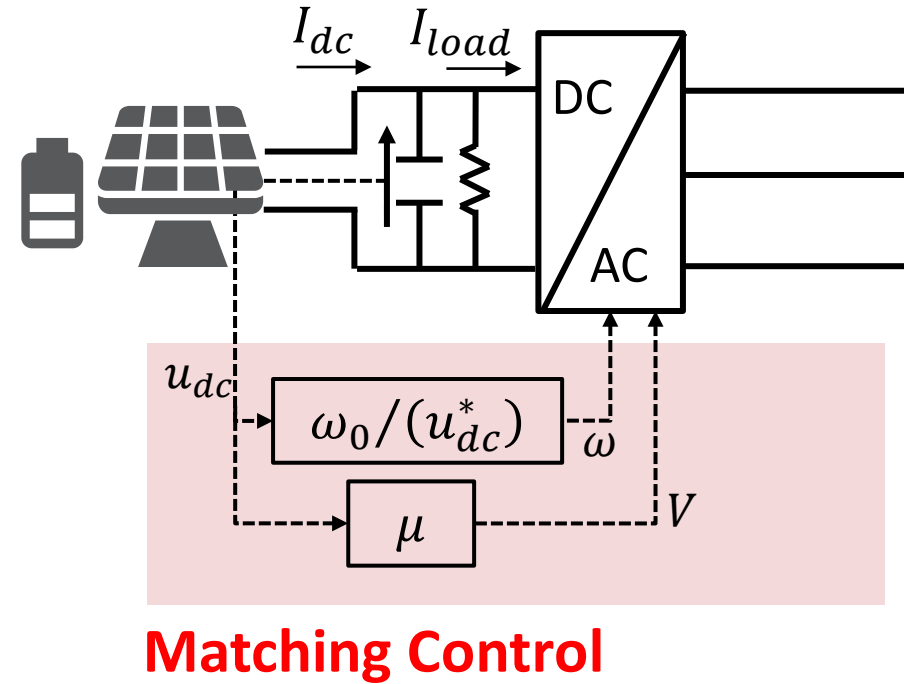
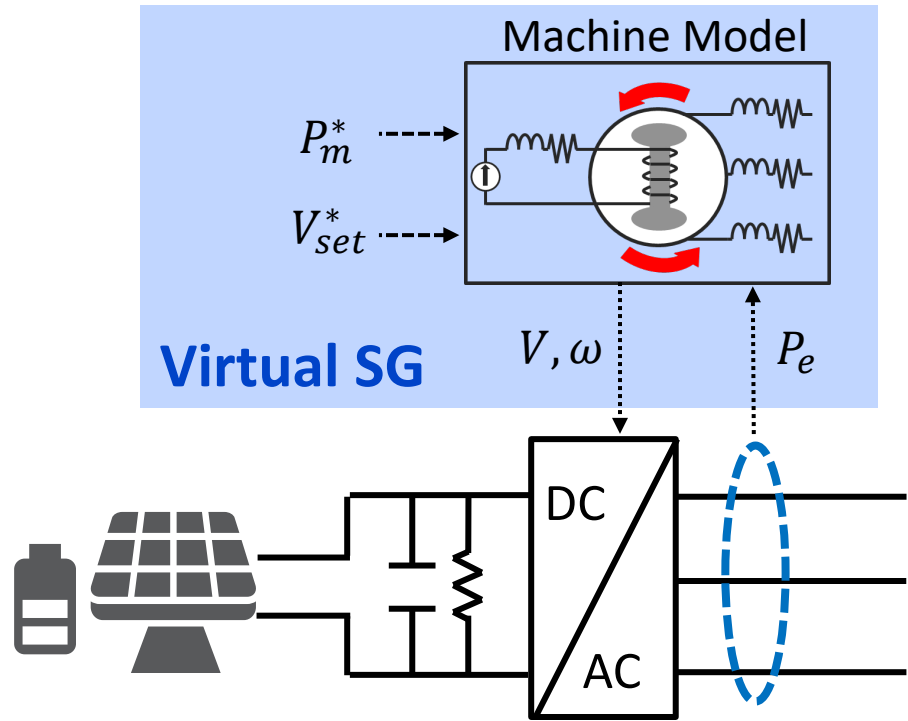
At the new steady state: $\omega_1 = \omega_2$

The load increase is shared by the two SG based on the governor droops:

$$\Delta P_{m1} = \frac{K_{G1}}{K_{G1} + K_{G2}} \Delta P_L$$

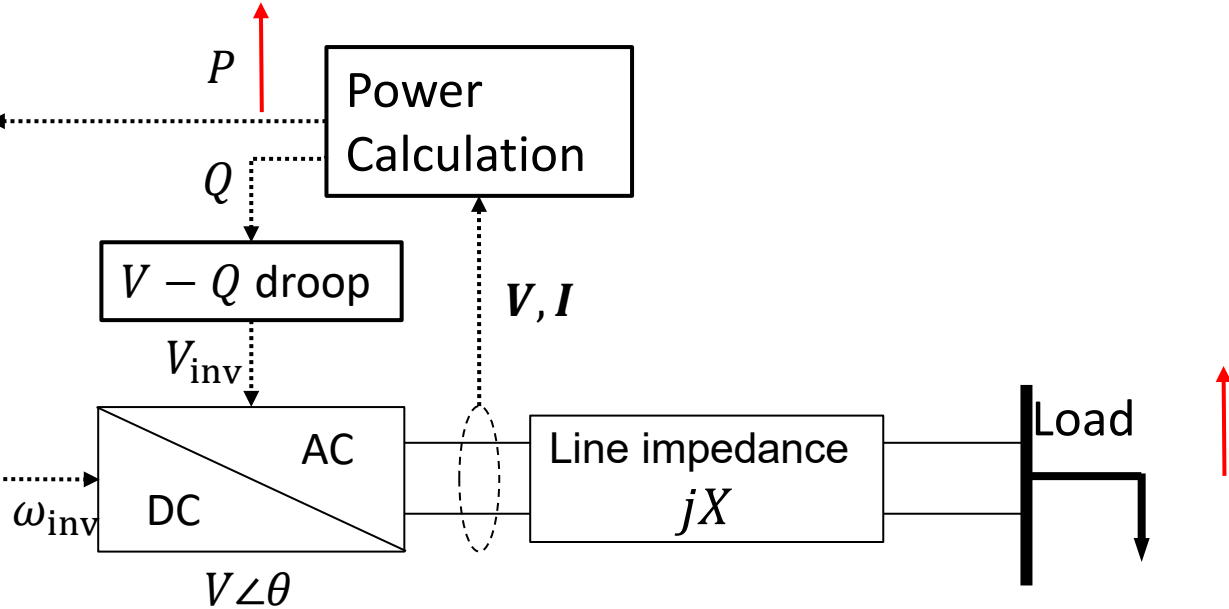
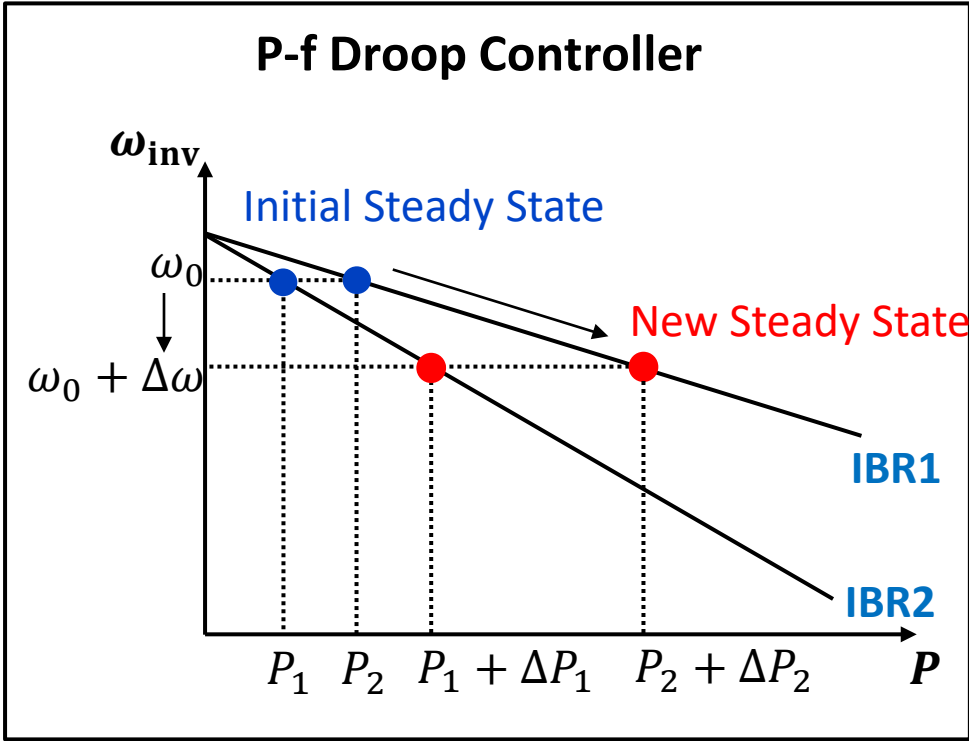
$$\Delta P_{m2} = \frac{K_{G2}}{K_{G1} + K_{G2}} \Delta P_L$$

Operation Principle of Virtual SG and Matching Control



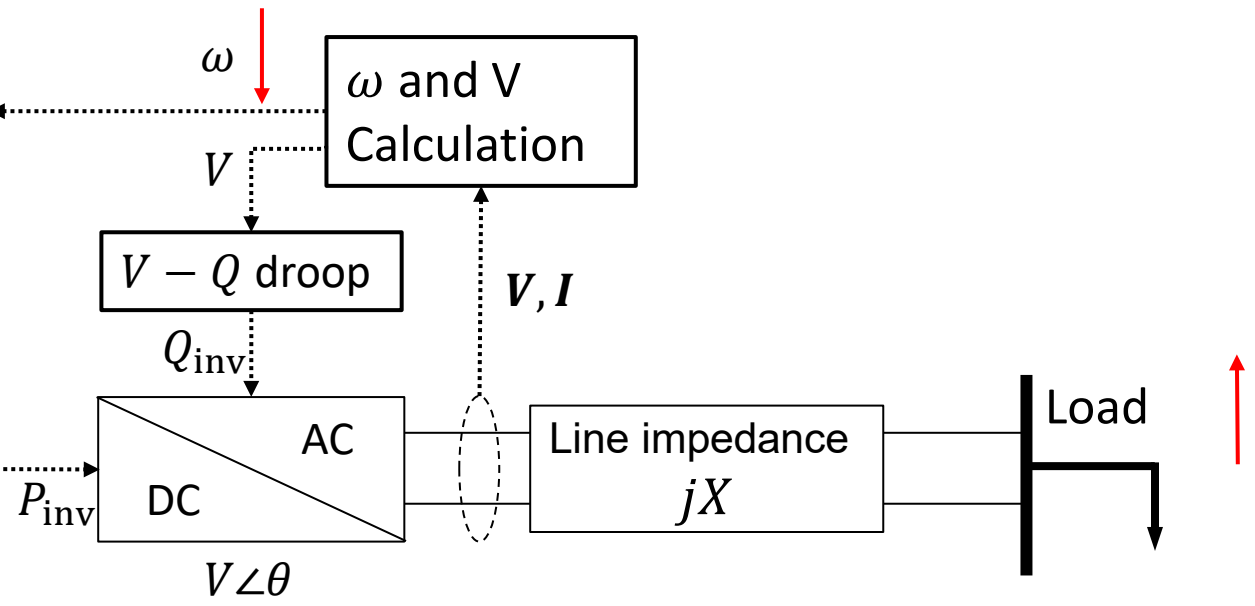
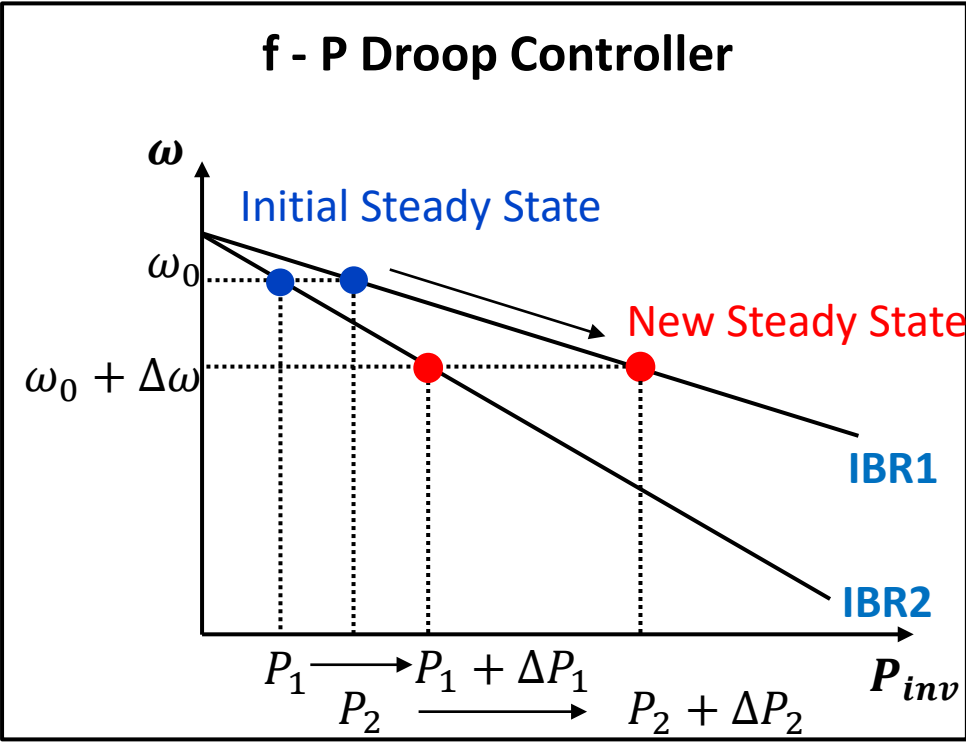
- Virtual SG and matching control both implement the SG swing equation and the droop characteristics in the inverter control loop.
- The difference is that virtual SG measures ac side voltage and current while matching control mainly measures dc side voltage.
- These method will provide inertial response similar to SGs. The inertia time constant is a control parameter and can be tuned to improve system performance, within the inverter capability.

Operation Principle of Droop Control



Load change is shared by IBRs with P-f droop

Operation Principle of FERC Order 842 and 827 Control

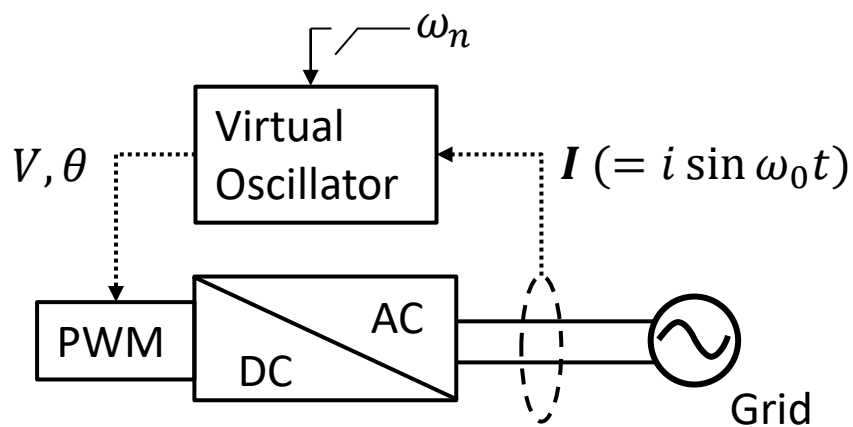


Load change is shared by IBRs with f-P droop

Operation Principle of Virtual oscillator Control (VOC)

Liénard type VOC

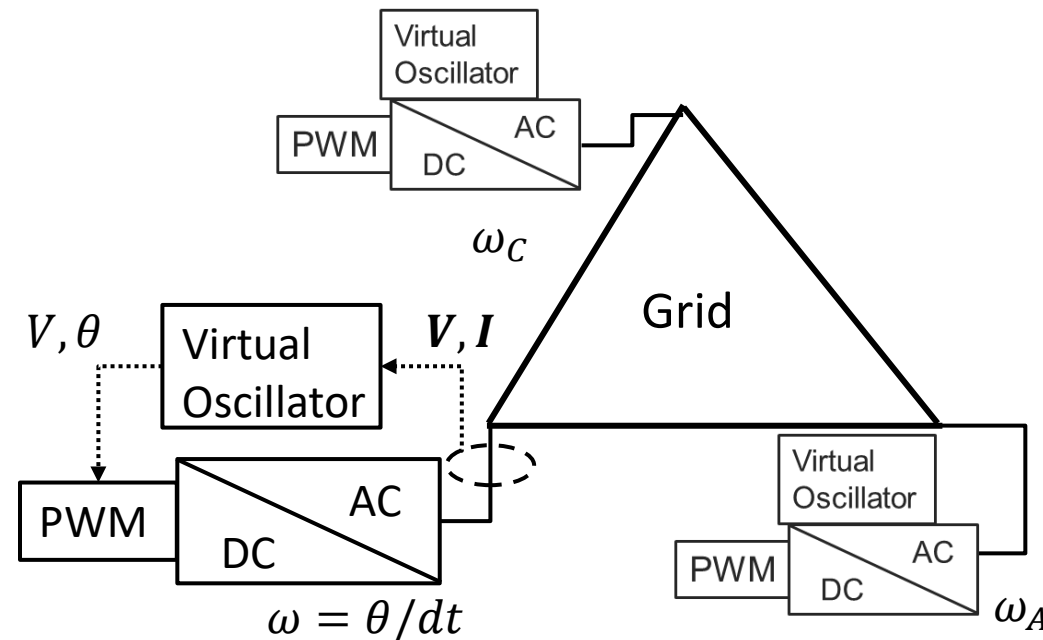
- Determines frequency as neighborhood value of current input
- Cannot specify a signal of P and Q setpoints



$$\omega \approx \omega_0 \text{ or } \omega_n \text{ at } t \rightarrow \infty$$

Dispatchable VOC (dVOC)

- Assumes that all inverters adopt same control logic
- Can specify a signal of P and Q setpoints

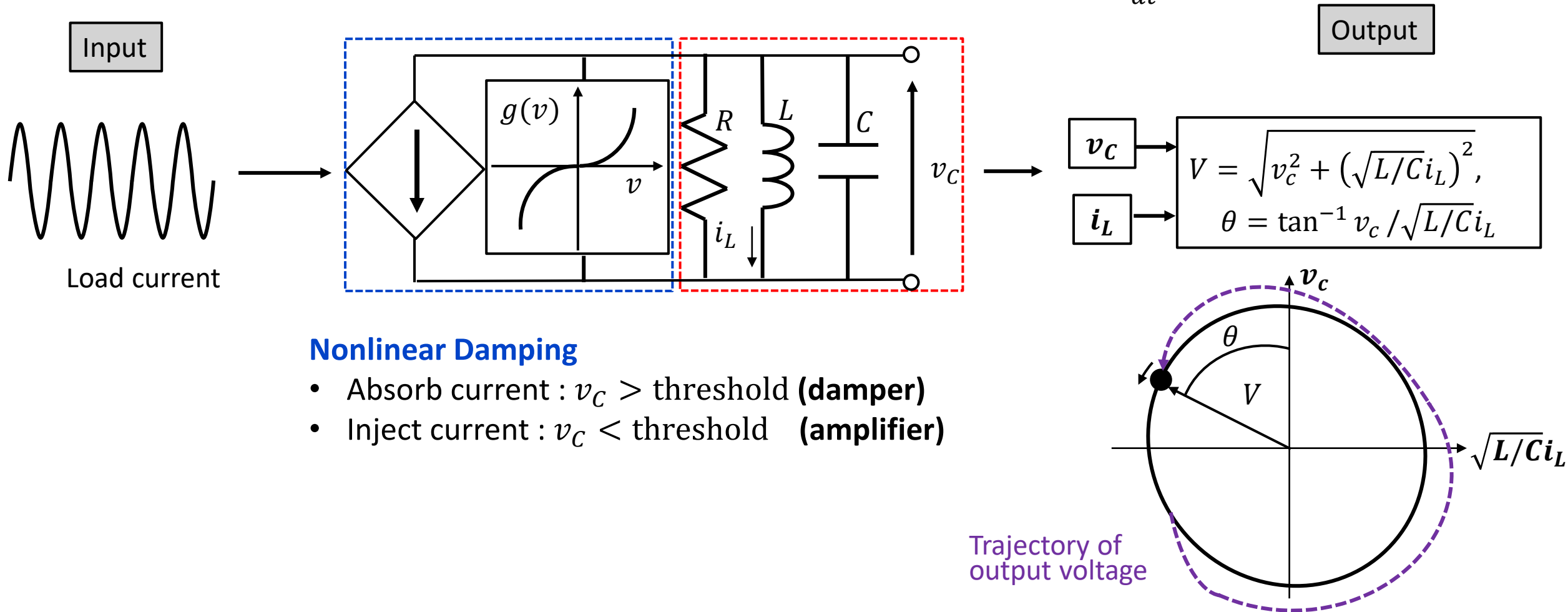


$$\omega_A = \omega_B = \omega_C = \omega_0 \text{ at } t \rightarrow \infty$$

Liénard type VOC

LC Resonant Circuit

- Natural-frequency-pass filter
- v_C and i_L are orthogonal ($v_C = L \frac{di_L}{dt}$)



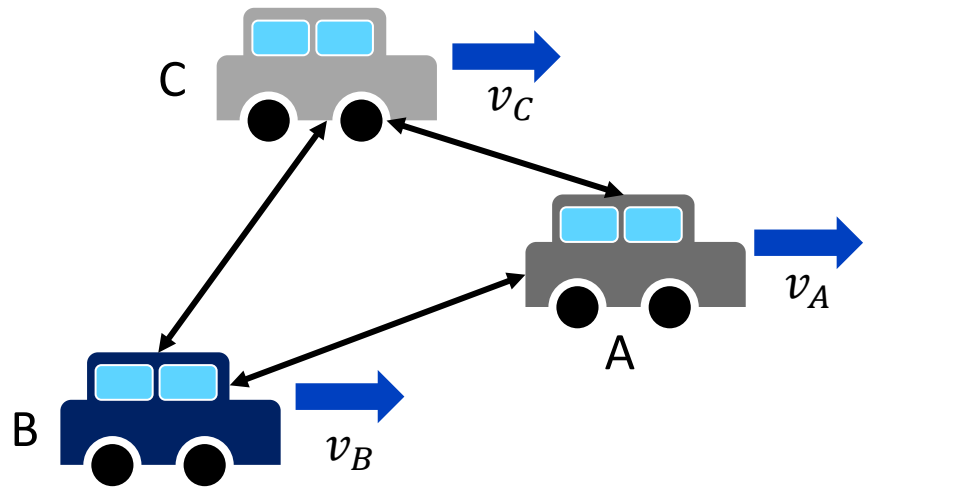
Nonlinear Damping

- Absorb current : $v_C >$ threshold (**damper**)
- Inject current : $v_C <$ threshold (**amplifier**)

Dispatchable VOC

- Build consensus on grid frequency and relative phase difference

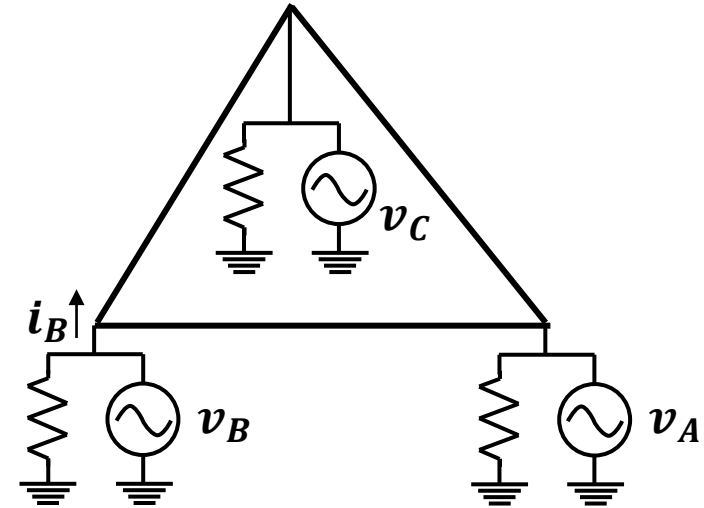
Consensus control of cars



$$\begin{cases} \frac{d}{dt} v_A(t) = \frac{1}{2} (v_C(t) - v_A(t)) \\ \frac{d}{dt} v_B(t) = \frac{1}{2} (v_A(t) - v_B(t)) \\ \frac{d}{dt} v_C(t) = \frac{1}{2} (v_B(t) - v_C(t)) \end{cases} \quad \left. \vphantom{\begin{cases} \frac{d}{dt} v_A(t) = \frac{1}{2} (v_C(t) - v_A(t)) \\ \frac{d}{dt} v_B(t) = \frac{1}{2} (v_A(t) - v_B(t)) \\ \frac{d}{dt} v_C(t) = \frac{1}{2} (v_B(t) - v_C(t)) \end{cases}} \right\} v_A = v_B = v_C \text{ at } t \rightarrow \infty$$

Key factors: Same control policy,
Other's state

dVOC for inverter-based network



$$\begin{cases} \mathbf{v}_i = [V_i \cos \theta, V_i \sin \theta] \\ \frac{d}{dt} \mathbf{v}_i = \underbrace{\omega_0 \mathbf{v}_i}_{\text{rotation at } \omega_0} + \underbrace{\text{error}_\theta(\mathbf{i}_i^*, \mathbf{i}_i)}_{\text{phase error}} + \underbrace{\text{error}_v(|\mathbf{v}_i^*|, |\mathbf{v}_i|)}_{\text{voltage error}} \\ \mathbf{i}_i^* = \frac{(p_i^* + jq_i^*)}{\bar{v}_i}, \mathbf{i}_i = \sum_j \mathbf{Y}_{ij} (\mathbf{v}_i - R(\theta_{ij}) \mathbf{v}_j) \end{cases}$$

Synchronization and operation at setpoint of P and V

Summary...

- There are numerous ways of controlling an IBR to achieve the same desired result
 - Newer forms of control continue to be proposed and developed
- From a system planner perspective, it could be more beneficial to define desired IBR performance rather than specific form of IBR control topology



What does all this imply?

Toward technology-agnostic requirements for GFM capabilities

- Instead of focusing on how GFM control can be implemented and which type of GFM control should be used, the ultimate goal is to set up technology-agnostic **performance requirements** and ensure the grid has enough GFM capability to support its reliable operation.
- However, incorporating new and perhaps different types of GFM control could change the overall system dynamic behavior and alter the failure mode of the system.
- Understanding the dynamics and stability limit with parallel operation of multiple GFM (different types) and GFL inverters is required in order to set up the requirements.
- Development of good GFM models along with appropriate parameterization techniques is crucial for being able to formulate and verify performance requirements.

GFM may not be a “Silver Bullet”

- Even though GFM control provides improvements on inverter stability and dynamic performance in weak grid operations, it is not a single/unique magical solution.
- GFM is simply another way to control the sinusoidal voltage output of the inverter.
- Physical limits of the inverter and the system still apply.
- Like every other control, GFM control have stability limits beyond which synchronization with the grid can be lost or other types of instability can occur.

References

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- [2] J. Liu, Y. Miura, H. Bevrani and T. Ise, "Enhanced Virtual Synchronous Generator Control for Parallel Inverters in Microgrids," in IEEE Transactions on Smart Grid, vol. 8, no. 5, pp. 2268-2277, Sept. 2017, doi: 10.1109/TSG.2016.2521405.
- [3] C. Arghir and F. Dörfler, "The Electronic Realization of Synchronous Machines: Model Matching, Angle Tracking, and Energy Shaping Techniques," in IEEE Transactions on Power Electronics, vol. 35, no. 4, pp. 4398-4410, April 2020, doi: 10.1109/TPEL.2019.2939710.
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- [5] D. Ramasubramanian, W. Baker, and E. Farantatos, "Operation of an All Inverter Bulk Power System with Conventional Grid Following Controls," CIGRE Science & Engineering, vol. 18, pp. 62-76, June 2020.
- [6] G. Seo, M. Colombino, I. Subotic, B. Johnson, D. Groß and F. Dörfler, "Dispatchable Virtual Oscillator Control for Decentralized Inverter-dominated Power Systems: Analysis and Experiments," 2019 IEEE Applied Power Electronics Conference and Exposition (APEC), Anaheim, CA, USA, 2019, pp. 561-566, doi: 10.1109/APEC.2019.8722028.
- [7] D. Ramasubramanian, W. Wang, P. Pourbeik, E. Farantatos, A. Gaikwad, S. Soni, and V. Chadliev, "Positive Sequence Voltage Source Converter Mathematical Model for Use in Low Short Circuit Systems," IET Generation, Transmission & Distribution, vol. 14, no. 1, pp. 87-97, Jan 2020
- [8] D. Ramasubramanian and E. Farantatos, "Representation of Grid Forming Virtual Oscillator Controller Dynamics with WECC Generic Models," 2021 IEEE PES General Meeting, Washington D.C. USA, July 2021
- [9] D. Ramasubramanian, "Importance of Considering Plant Ramp Rate Limits for Frequency Control in Zero Inertia Power Systems," 2021 IEEE Green Technologies Conference (GreenTech), Denver, CO, USA, 2021, pp. 320-322



Appendix

Answers to questions submitted via webinar chat

1. Is there an ideal ratio for inverter-based resources (IBR) vs synchronous generators (SG) with regards to maintaining an acceptable level of inertia on the power system?

There is unfortunately no ideal ratio. It depends on many factors and dynamic characteristics. 100% IBR is possible, if IBR/DER can provide the necessary services. This is an area of active research to understand the minimum value of SG that may be needed.

2. How can a grid forming inverter see what's going on upstream in the grid?

A grid-forming (GFM) IBR has primary control that responds to system events based on the local P, Q, V, f measurements. There can be secondary and tertiary control that dispatch the GFM IBR as well (a GFM IBR can receive AGC signals from secondary control to balance the load and receive economic dispatch from tertiary control).

3. What is the biggest challenge that is encountered for a grid forming source when operating alongside the synchronous resource and how is that overcome by controls? Can the controls cause instability if the ratio of synchronous resource to grid forming resource change dynamically in real time?

One of the challenges will be to maintain stability between grid forming and the synchronous resource. Research has shown that a grid forming resource may have oscillatory instability in strong grids. As a result, the grid forming resource may interact with the excitation system of the synchronous resource. Control can certainly cause instability as ratio of devices in the network changes. In this regard, every resource that has a control system, including grid forming resources, should be tuned appropriately.

4. On slide 15, how was 75MVA short circuit current achieved on a 20MW capacity IBR?

The short circuit current requirement (75MVA) was taken from the initial request for proposal (RFP). The requirement might have changed with additional studies conducted. We have seen commercial GFM inverters providing short-term overcurrent capability of 2pu for a couple of seconds, which can be utilized during a fault. 3~4pu fault current, even though high, can be provided by upgrading the hardware of the inverter.

5. Are GFM inverters certified differently from UL? Should UL 1741 incorporate EPRI's research to standardize GFM inverter?

To the best of our knowledge, as of now, there is no certification like UL exist specifically for GFM inverter. It may go through the typical UL 1741 and other energy storage certification tests followed by additional witness/commissioning tests performed as per utility requirements. EPRI's research, together with other research on GFM inverter around the world, will contribute to standardize performance requirements of GFM inverters. After the industry establishes that, UL can publish certification standard and the GFM inverters can be certified accordingly.

6. Can GFM technology make renewables be controlled as centralized generators like conventional SGs in near future? Is it possible that system operators can control frequency and voltage of IBR system? If so, 100% IBRs system could be possible in bulky power systems as well as island systems.

Even today, IBR resources can be controlled as centralized generators. Given a forecast of wind or solar conditions, it is possible to dispatch and schedule IBR resources even today. With GFM technology, one of the challenges is to ensure that this ability to dispatch is retained together with the ability to regulate system voltage and frequency. GFM technology with energy storage may allow for more instances of IBRs being dispatched and this can help bring about 100% IBR operation.

7. What are the factors that can lead to instability from PLL inverter based generation?

Note that there are PLL based IBR that are designed for weak grid operation, and we have demonstrated the improved stability performance of a PLL based GFM control in the tutorial. For a PLL based IBR that is not properly designed and tuned for weak grid operation, when connected to a weak system location, it can lose stability under small or large disturbances due to the high voltage sensitivity w.r.t the IBR current/power injection. Often times, the reactive power control loop of the inverter can be the cause for instability as it prevents the reactive current from changing to support the grid during an event. The PLL itself could also become unstable if it is not designed well, or not tuned appropriately.

8. On slide 25, if the inverters were on fixed power factor, would it be more stable?

As shown by the simulation results on slides 25 and 32, slow reactive power response contributes to the instability of the inverter based DER. With fixed power factor, the DER still cannot increase its reactive power injection quickly following the voltage sag, hence it will not improve the stability.

9. Even if GFM IBRs has good performance in weak systems (low SCR), if grid following (GFL) IBRs are included even a little, isn't it practically difficult to operate the combination GFL+GFM from a power system perspective? Because of GFL?

From the results on slides 31 and 32, replacing two out of the six PV DERs to GFM control, it manages to stabilize the system with the remaining 4 PV DERs still being GFL. On a high level, we don't need every resource to improve grid strength. Having the services from a certain number of them will enable stability of the whole system. As a real-world example, during a live trial performed at Dersalloch WF in Scotland, at the ratio 5:1 (WTGs in GFL to WTGs in GFM) stable operation was achieved.

10. How does the overload capability of an IBR compare to a synchronous machine?

Short circuit current from synchronous generators can be up to 5 pu. Depending on the magnitude, synchronous generators can continue to contribute short circuit current for hundreds of milliseconds to a few seconds before they lose stability or are tripped by undervoltage or overcurrent protection. Inverter overcurrent capability varies a lot among manufacturers and inverter models. For example, some GFM inverters claim to supply up to 2pu overcurrent for a few seconds. Moreover, inverter hardware including the power electronic switches can be customized to tolerate higher overcurrent when needed, even though it will add costs to the product.

11. In a 100% IBR system, is the frequency decline rate too fast for IBR to be able to control the frequency?

IBRs have been successfully tested for provision of inertial response, so frequency decline does not have to be very fast in 100% IBR systems. Again, using the example of Dersalloch WF where inertia (H) of 4-8s has been tested. The control of frequency in a network can be determined based on the amount of active current that is injected, and the speed at which this active current is injected. IBRs can inject active current at a very fast rate. Further, the rate at which frequency changes varies from one area of the network to another area.

12. How is the MW headroom calculated? Is there any default value for the minimum headroom that needs to be available for IBR to provide frequency response during underfrequency events?

The minimum headroom for frequency response will depend on the largest size of disturbance that is expected and also the droop and frequency nadir. Additionally, the location from which frequency response is delivered also plays a role.

13. On severely unbalanced networks (perhaps due to traction systems) or poor phase balancing on distribution networks, there will be a need for "per phase" control. Does the IBR technology make provision for independent phase control? If so can it also aid in improving voltage unbalance by injecting independent quantities of P and Q (perhaps absorbing Q also)?

Three phase IBR technology can balance voltage at its terminal, and this can cause in injection of unbalanced current. This can however result in reduced active current that can be supported as some of the current capacity of the IBR will go into phase balancing. Moreover, providing unbalanced current can increase the 120Hz power ripple on the dc side of the inverter which may cause negative impacts on the dc source and dc side components. Therefore, an IBR may not provide this capability or service if not required. This capability in the microgrid setting is discussed in detail in the performance requirements section of the tutorial.

14. What is the gap between the EMT model and the RMS model? Is the developed RMS model sufficient for GFM application in terms of planning? If there is no suitable RMS model, how should it be applied during system planning?

We have developed generic RMS model of GFM inverter and compared its response with EMT. This doesn't imply that EMT studies will not be required. However, the RMS model can be used to identify scenarios for EMT studies. This topic is discussed in detail in the generic modeling and transmission planning sections of the tutorial.

15. How are microgrids protected with only 1.6 pu max current capability from the GFM plant?

The 1.6 pu current capability was derived for providing the inrush transformer and load current during black start, without considering the protection need. The 1.6 pu current capability may also be sufficient for overcurrent relay if the GFM plant is sized sufficiently larger than the peak load in the microgrid (which is the case for quite a few real-world microgrids). There are also microgrid designs that switch to other protection logics (e.g., undervoltage protection) to deal with the low fault current contribution from inverters.

16. Is there additional cost for inverters to be able to provide negative sequence voltage regulation capability since the capability has to be specified upfront during the design phase?

First of all, some commercial GFM inverters already claim to have the phase balancing capability. For those that do not have this capability, additional cost may come from 1) engineering and tuning the negative sequence control (considering the interaction with positive sequence control as well), and 2) hardware change to deal with the power ripple on the dc side, for example.

17. On slide 78, how much longer does the voltage imbalance for the lower negative sequence injection case hold in comparison to the higher injection case?

The voltage imbalance is caused by load unbalance which is a steady state condition. In the case we analyzed, without the negative sequence current injection from the GFM DER, the voltage unbalance can cause severe voltage swell/sag on different phases which will likely cause GFL DERs to trip or other protection to operate which can cause a more severe consequence.

18. Do you still need a 1 ms time step for REGC_C?

No. The REGC_C model can be run with a standard 4.1ms time step that is used in North American positive sequence transient simulations. Note that due to numerical integration methods, where the value of time step plays a role in determining the error during integration, values of certain control parameters within the REGC_C model (and other associated models) may have to be changed when changing the time step of integration.

19. Will the existing IBR models used in commercial fault simulation software i.e., Aspen and Cape, need to be modified for GFM IBR's?

Preliminary research indicates that such a change is required. We should have more to report in the subsequent years.

20. Any changes to the PLL model in REGC_C to make it work with 4 ms timestep?

No changes have been made to the REGC_C control structure. As noted above, due to the process by which numerical integration is carried out in simulation software, values of certain control parameters within the REGC_C model (and other associated models) may have to be changed when changing the time step of integration.

21. As GFM evolves do you see this technology shifting to smaller scale, residential-type solar inverters as well? Thinking about blackouts/storm restoration, etc.

The technology for residential DER to operate as an uninterrupted power supply (UPS) has existed for some time. Most residential energy storage (ES) and PV plus ES hybrid inverters in US, offer the capability to provide backup power and serve load during grid outage by switching control mode from GFL to GFM. For PV only inverters, to the best of our knowledge, there are very few products in market that can switch to GFM mode to support load during grid outage. However, these DERs, when connected back to the main grid, will switch back to GFL control. EPRI is actively looking into potential use cases for inverter-based DERs to operate in GFM mode when grid-connected and will include result in our future tutorials.

22. Can you have too many GFM inverters in close proximity where they fight each other and cause instability?

Yes, this is possible. Research has shown that GFM can become unstable in strong grids. Further, if the droop coefficients in GFM are not tuned appropriately, then the various resources can fight with each other.

23. Are there any disadvantages of GFM over GFL, if not, why not go for GFM for all future IBR?

GFM IBR itself is not a silver bullet that resolves every challenge of future grids. Take distribution system for example, the impact of GFM DERs on system protection, grounding design and other operational practices has to be carefully studied and may need to be co-designed with GFM DER to ensure proper system operation. These studies and modifications are necessary before GFM DERs can be widely deployed. Further, the response of GFM to faults is still not fully characterized or defined. In order to widely deploy GFM more research work is to be carried out to ensure that GFM would behave as required when faults occur on the network.

24. Since IEEE 2800 stayed quiet on GFM technology, what is the need of GFM in North America in general?

Pockets of many networks in the large interconnected systems, and certain island networks may already require GFM capability in the upcoming years and the absence of requirements in a standard such as IEEE 2800 doesn't imply that GFM may not be needed. In fact, through the UNIFI consortium, one area of work is to evaluate whether IEEE 2800 would serve as an inadvertent barrier to GFM, and if gaps exist, how they can be overcome.

25. With large scale deployment of GFM inverters do you see a need for restructure and need for additional training for our system operators?

Yes. Inverter based resources can offer capabilities that far exceed the capabilities offered by synchronous machines. If these superior capabilities are to be leveraged, then it could impact the manner in which the power system is operated. Workforce training and development should go hand-in-hand with new technology. Further, more detailed simulation tools may be required in future power networks and being able to leverage the capabilities of such tools would also be important.

26. Does one need to employ an alternative to increase the short circuit contribution of IBRs in all IBR based microgrid environment in order to design current based protection system or current based protection system is impossible?

Some commercial GFM inverters already offer 2 pu or even higher overcurrent capability for a few seconds which can be leveraged for protection purposes. Moreover, it is not uncommon for today's microgrid design to have a GFM plant whose power rating is much larger than the peak load in the microgrid (considering load growth, providing inrush current, etc.), which also helps the overcurrent protection. Therefore, overcurrent protection is possible in certain microgrids. As a matter of fact, it has been applied in some real-world microgrids. However, it is not to say that overcurrent protection is doable in every microgrid design, nor to say it is the most economic option. Other protection options such as undervoltage relay can be considered instead of or in conjunction with overcurrent relay.

27. Does the GFM inverter have sub-synchronous oscillation (SSO) problem when interacting with series capacitor?

Yes, it can interact with series capacitors. Here again, the GFM should be designed and tuned well to avoid resonant interactions.

28. You mentioned briefly that EPRI was considering the ability of the protection system to detect and clear faults when using GFM inverters for black start. What types of scenarios are you considering? Often, small amounts of load are added to the cranking path to stabilize it. These typically are substations with distribution load connected to it. The distribution system is normally protected by overcurrent devices. Would the GFM inverters be able to provide enough current to RELIABLY operate overcurrent devices?

In the black start analysis we are carrying out, we are looking at transmission faults with the ability to see if the relays on the transmission network can detect and open. It is correct that many a time small amount of load would be added to the cranking path in order to stabilize the operation. So far we have seen that unless specifically designed to provide large amount of over current, a GFM inverter has the same limitation as a GFL inverter with regard to its current limit. The provided current can then be lower than the current threshold needed by the relay to operate.

29. Droop, VSM, and dVOC were mentioned in the GFM topology. Which topology do you think is the best solution?

At the moment our research has shown that different types of GFM control can behave in a similar manner. We have looked at a total of 4-5 different topologies of GFM and they exhibit similar operational characteristics. Further, our recommendation is to look at performance requirements for grid forming devices rather than control specifications, as mentioned in the tutorial.

30. It was mentioned that batteries have a higher ramp rate of current injection than wind turbines. How does a PV system similarly sized compare to those in ramp rate?

A PV system's ramp rate can be assumed to be between a battery and wind resource. The battery is able to maintain a high ramp rate due to the presence of a stiff dc voltage. A PV plant on the other hand, while not having mechanical components (which can allow it to be faster than wind) may not have a stiff dc voltage source. This can subsequently introduce constraints in the speed of response that can be provided.

31. What does it take for GFM to emulate inertia?

Many GFM control topologies can inject fast active current in response to a system frequency disturbance. This response can be near instantaneous and sustained if the dc voltage source is stiff (as in a battery energy storage system).

A blue-tinted photograph of four diverse professionals standing together. From left to right: a woman with curly hair and glasses wearing a white lab coat; a man with glasses and a tie wearing a white lab coat; a woman wearing a white hard hat and a dark polo shirt; and a man with glasses and a beard wearing a light-colored button-down shirt. They are all looking towards the right side of the frame.

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