Grid Forming Inverters

EPRI Tutorial (2021)

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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 capacity. As 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 and why is it needed?
- What are its performance requirements?
- How to model grid-forming inverters in EMT and RMS domain?
- Can grid-forming inverters be the first black start resource?

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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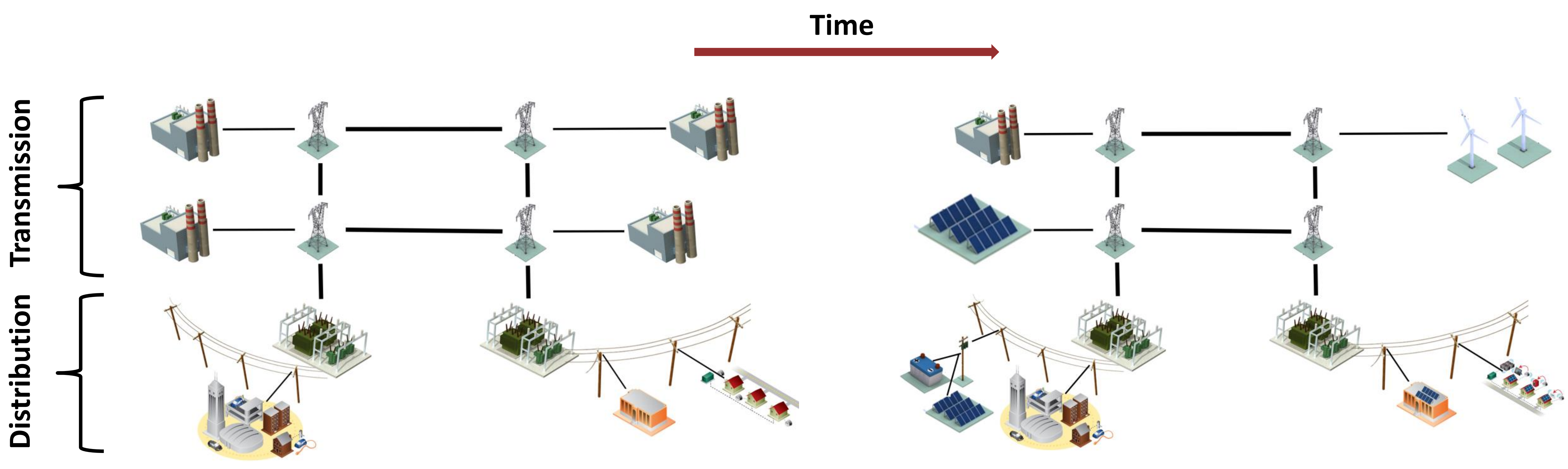
Introduction

Transforming power system



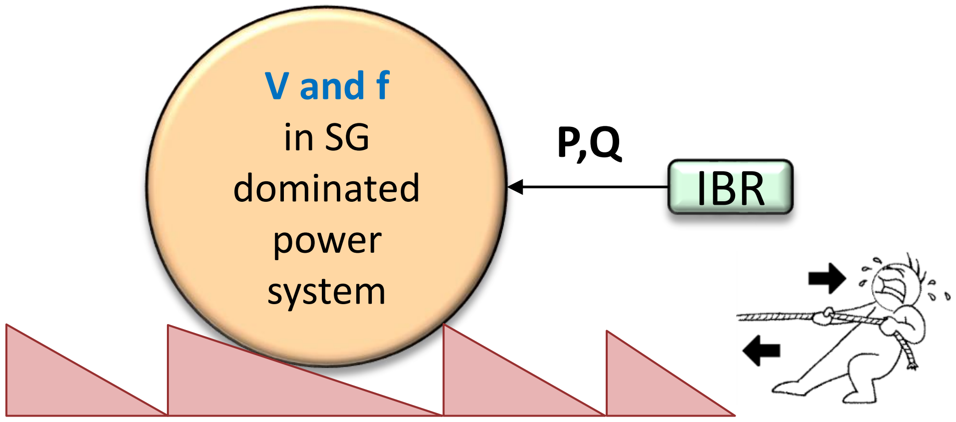
Central synchronous generators (SGs) are being replaced by transmission and distribution connected inverter-based resources (IBR), primarily wind and solar PV.

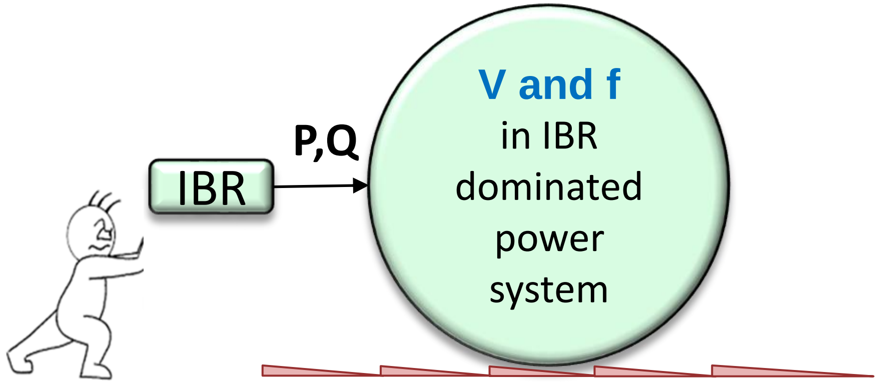
Evolving system needs expected from Inverter Based Resources (IBRs)

Power System	System needs from IBR
Past: SG dominated system	Unity power factor, minimal fault ride-through …
Present: Increased penetration of IBRs	Automatic voltage control, frequency response, V/F ride-through …
Future: IBR dominated system	Without relying on SGs, provide the above services and more (fast frequency response, maintain system stability…)

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

Challenges for IBRs to provide grid services





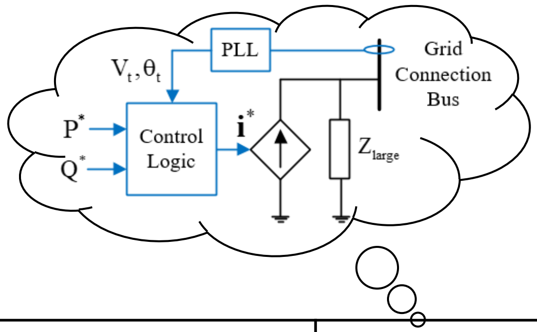
- Majority of today's IBR control is designed to work in a stiff system
  - Changes in IBR injected current do not 'move' the stiff system
  - Changes in system cause IBR to 'move' in tandem
- This behavior has recently been labeled as grid following (GFL)

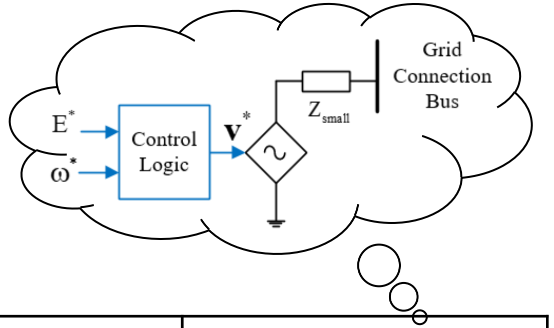
- In IBR dominated power system:
  - Increased elasticity in the grid
  - Changes in IBR injected current will 'move' the system
  - This movement in system will itself cause IBR to 'move' in tandem
- This increased interaction is to be stabilized for IBR to deliver expected needs

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

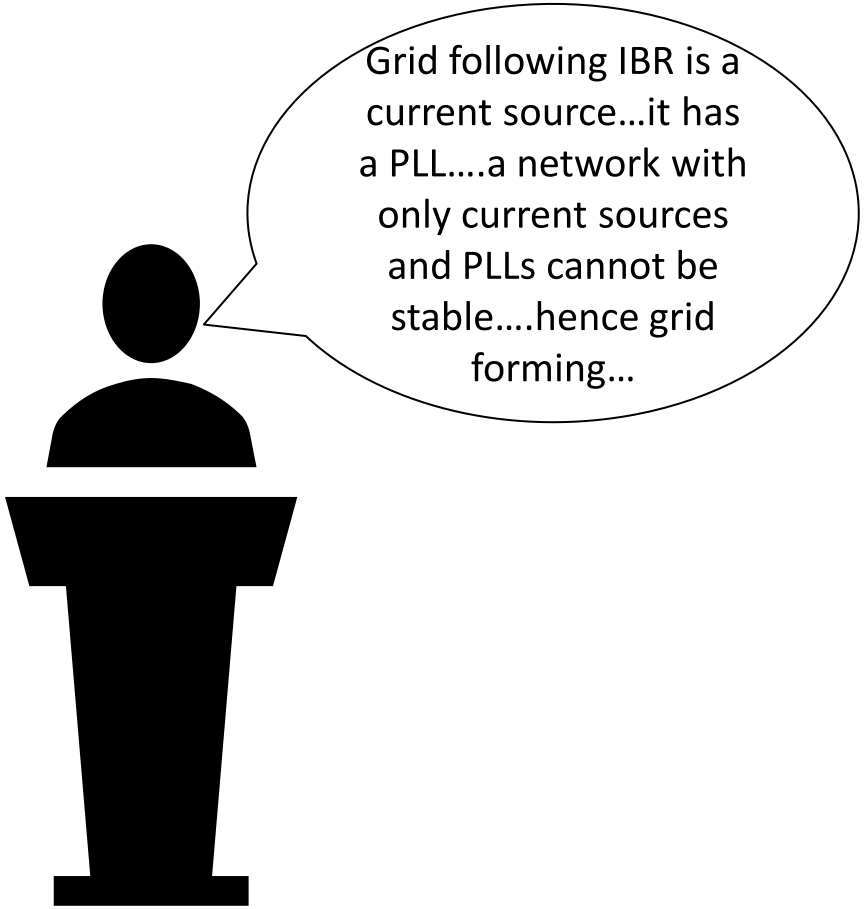
High level definition based on specific control design



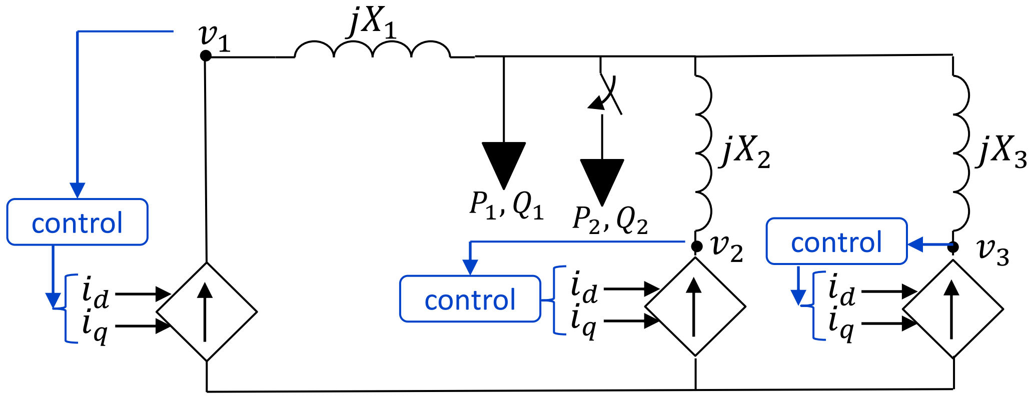


	Grid-following inverter	Grid-forming inverter
Basic control objectives	Deliver a specified amount of power to an energized grid	Set up grid voltage and frequency
Output quantity controlled	ac current magnitude and phase angle	ac voltage magnitude and frequency
Require a stiff and stable voltage at the 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



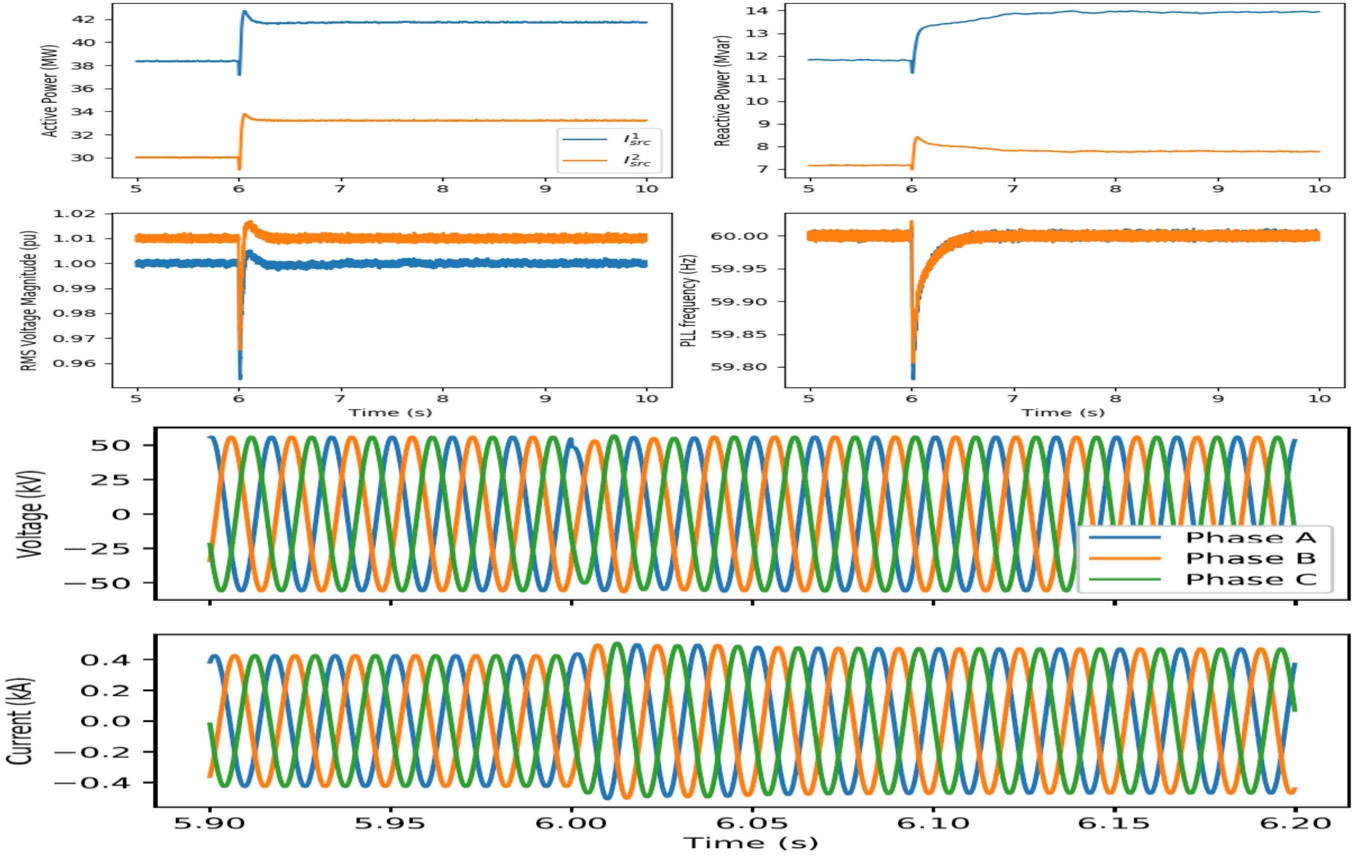
But Kirchhoff's Laws still apply in a 100% current source network



» 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

10% increase in constant power load

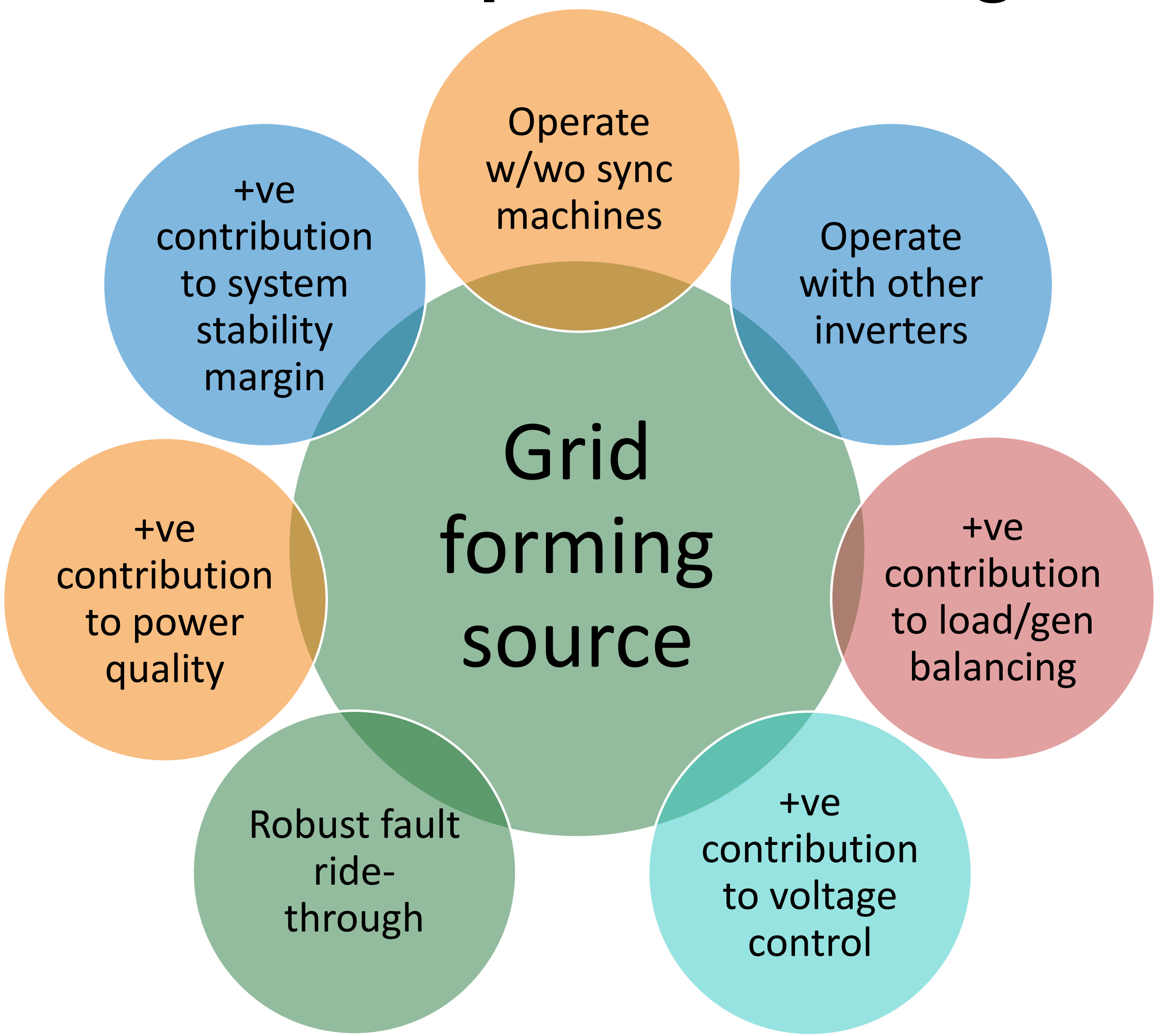
What does this have to do with grid forming behavior?

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

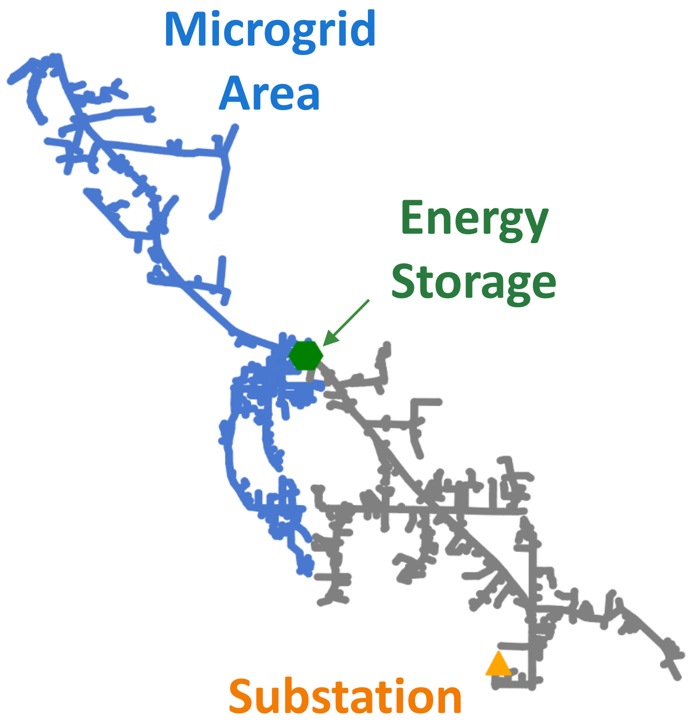


Illustration of a utility-level microgrid containing a section of a distribution feeder

- 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
- National Grid microgrid, 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 (in process)
  - 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

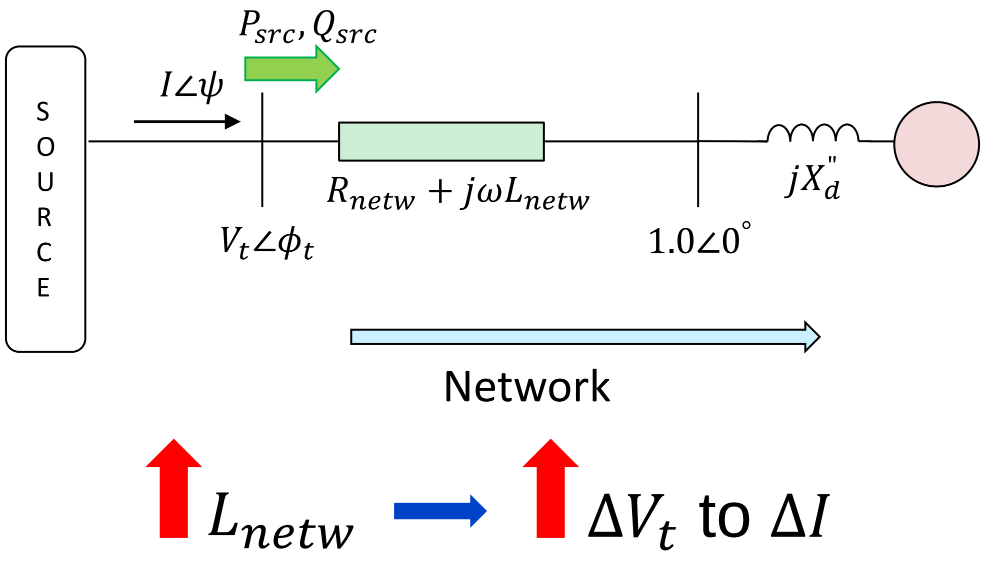
Few examples of GFM installations around the world

- BESS in St. Eustatius Island
  - 2.3 MW peak load, 100% (Solar + storage) operation mode during daytime
  - 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/
- Dersalloch Wind Farm in Scotland
  - 69 MW of wind turbines operated in GFM mode for 6 weeks
  - 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: A. Roscoe, et. al. "Practical Experience of Providing Enhanced Grid Forming Services from an Onshore Wind Park," 19^{th} Wind Integration Workshop, 2020
- 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/

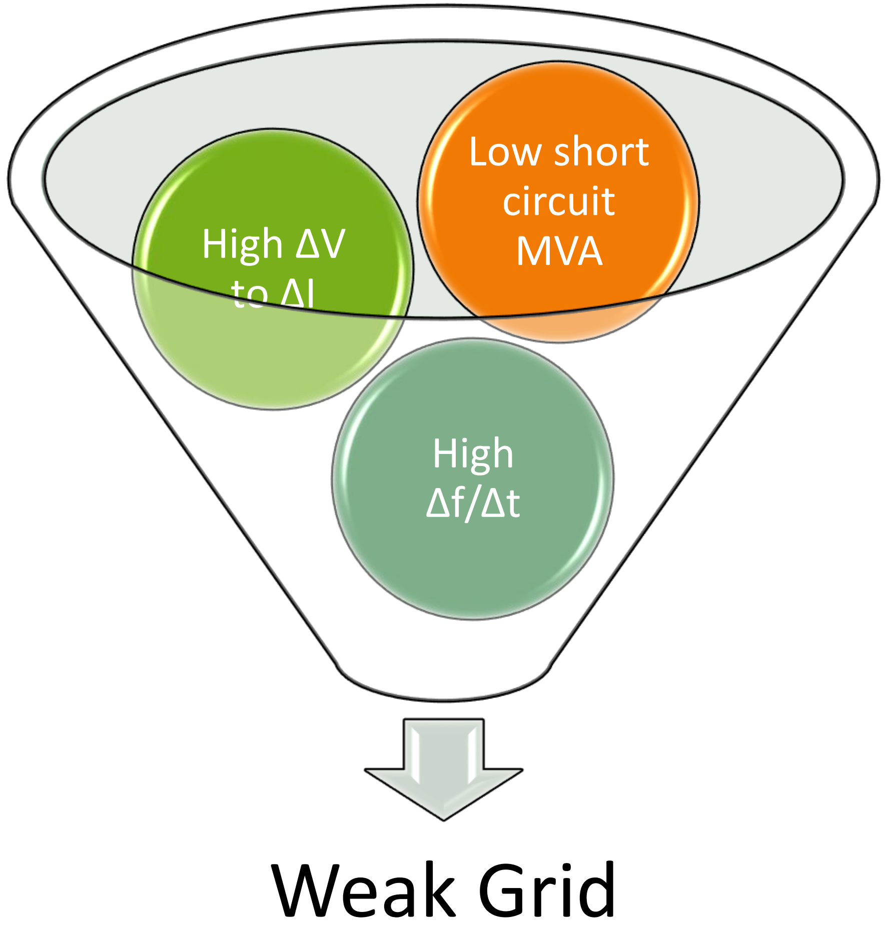
More examples available at: Julia Matevosyan, "Survey of Grid-Forming Inverter Applications," G-PST/ESIG Webinar Series, June 2020 (link)

Weak Grid Operation of IBR

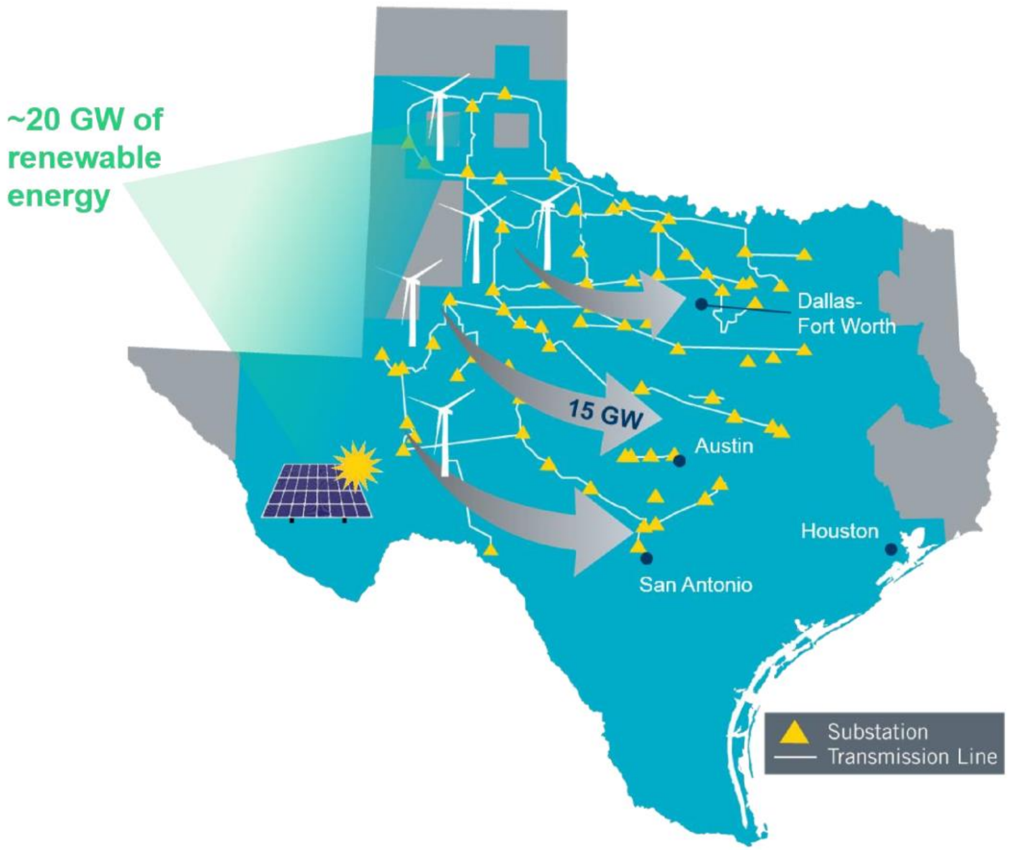
Defining, evaluating, and stability in weak grids…



- 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…



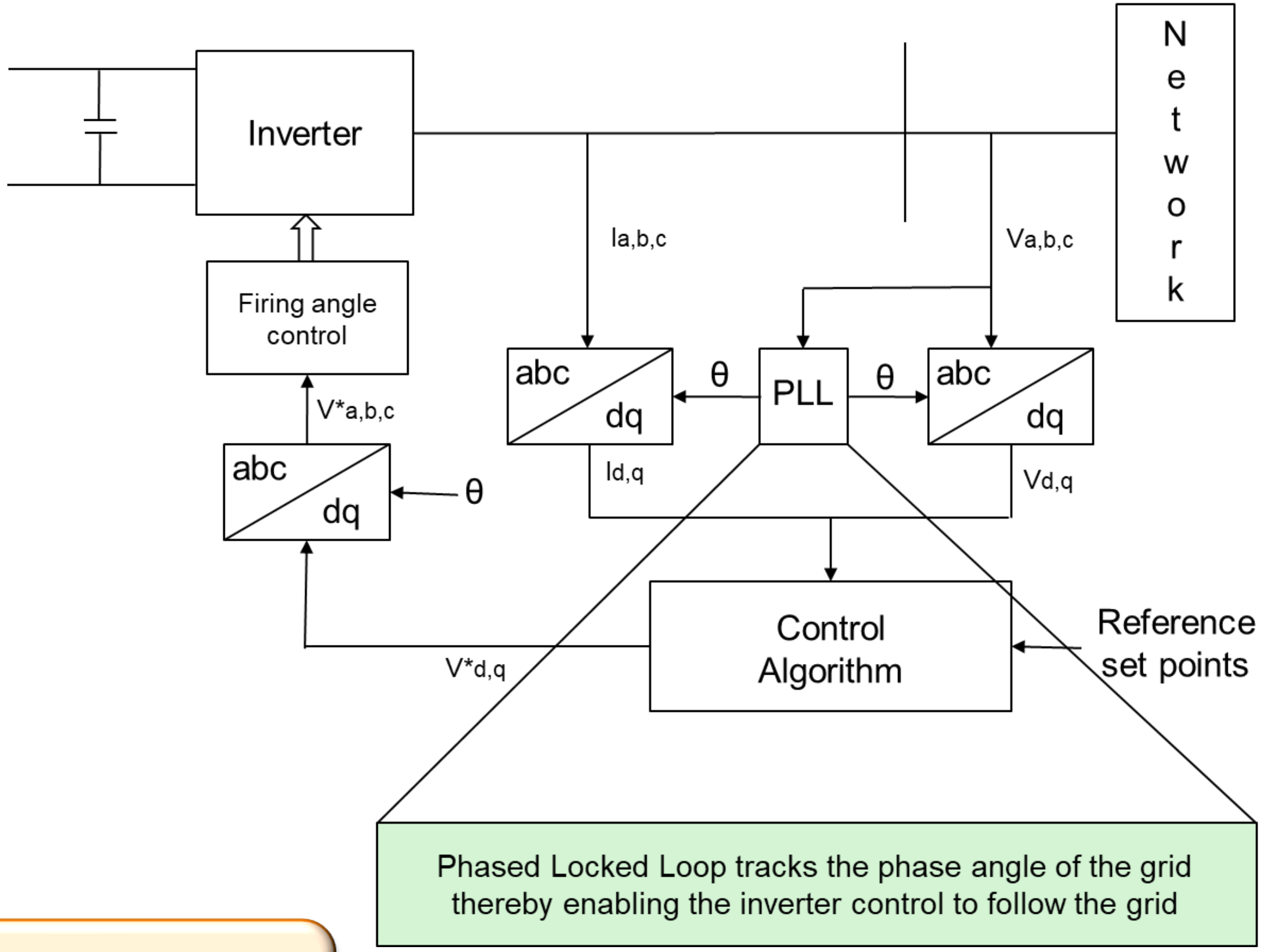
- Operational issues and control instability of IBRs connected to weak transmission grids have been reported by several transmission system operators around the world, (e.g. ERCOT*, AEMO).
- **This is one of the key drivers for looking into GFM inverters in the transmission system.**
- Similar challenges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

*Figure source: Dynamic Stability Assessment of High Penetration of Renewable Generation in the ERCOT 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.

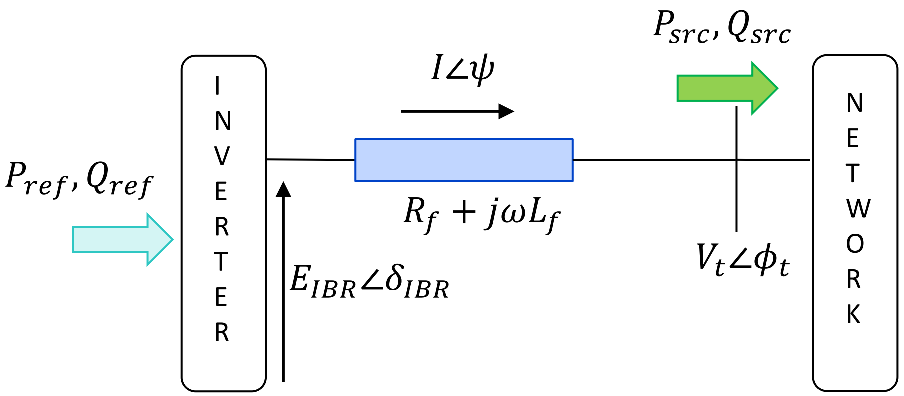
- All controls within an IBR treat this evaluated PLL phase angle as a reference
  - Subsequently used to evaluate amount of current to be injected by IBR



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…



$$\frac{P_{ref} - jQ_{ref}}{V_t\angle -\phi_{PLL}} = (I\angle\psi)_{ref} \approx I\angle\psi = \frac{E_{IBR}\angle\delta_{IBR} - V_t\angle\phi_t}{R_f + j\omega L_f}$$

Decided by controller — Decided by KVL and network

- 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

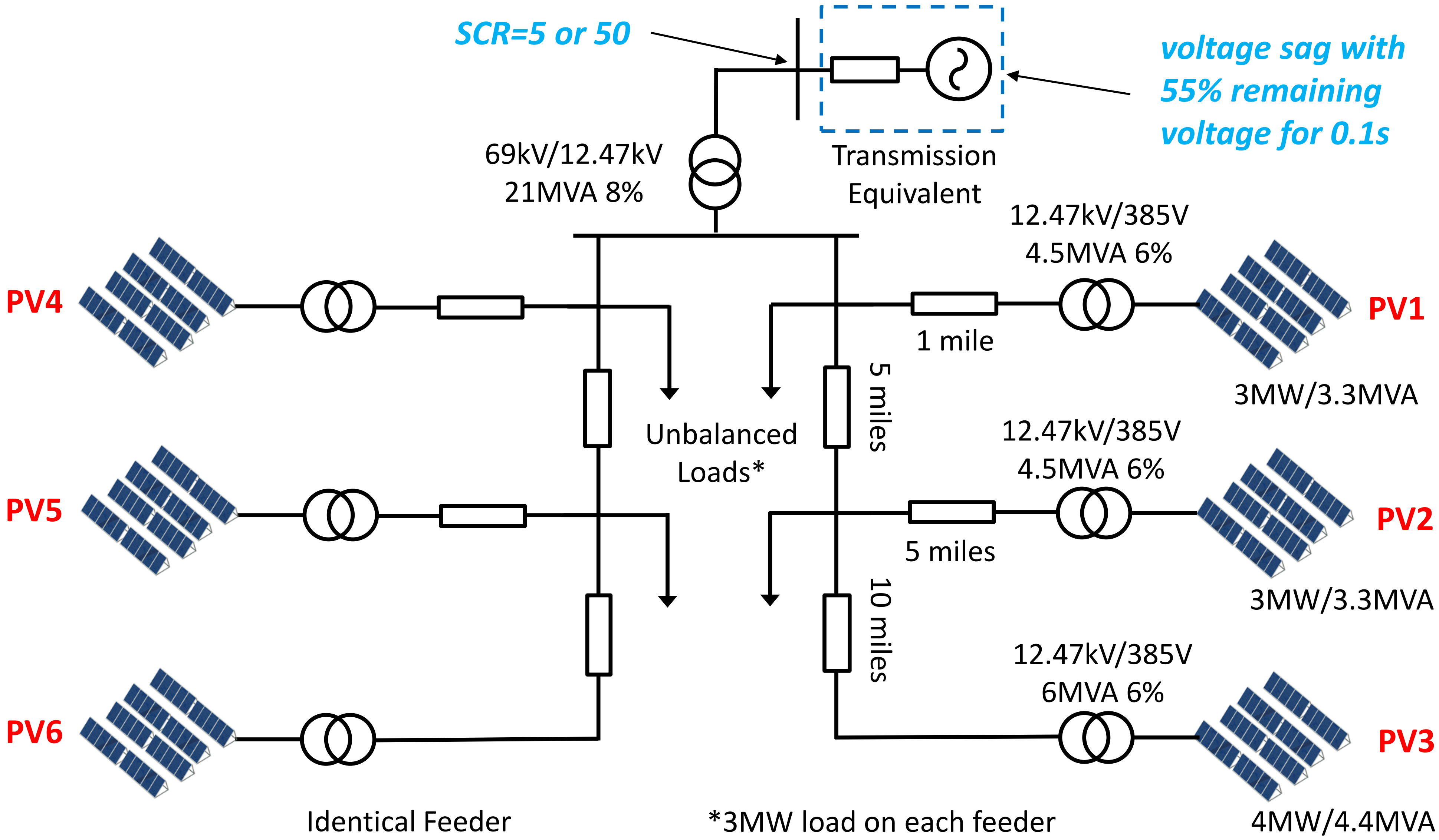
⇩

- 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

⇩

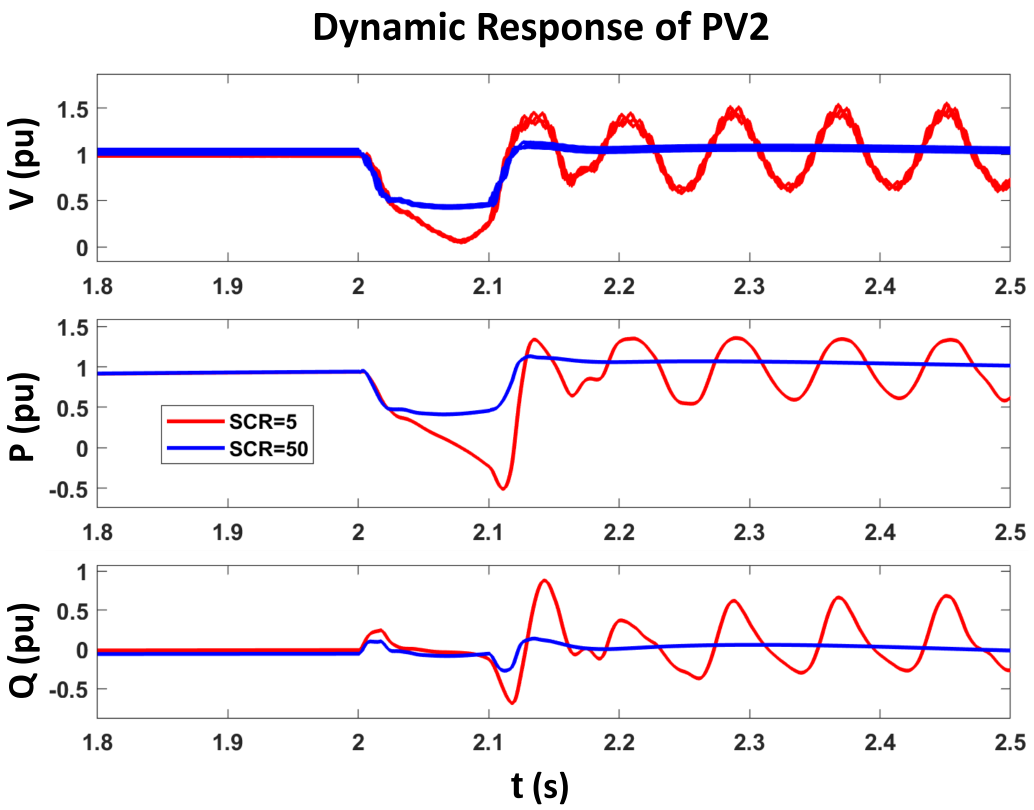
Fast control loops of IBRs that help $E_{IBR}\angle\delta_{IBR}$ change rapidly can become unstable

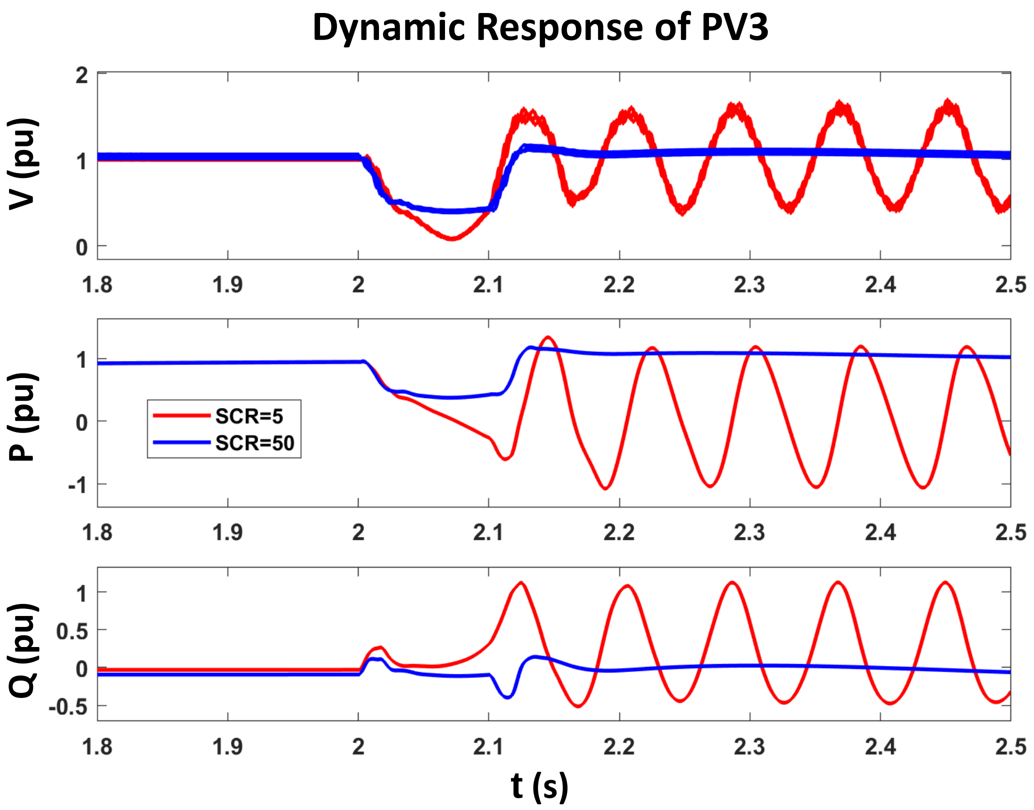
Simulation case study: weak grid operation of DER



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

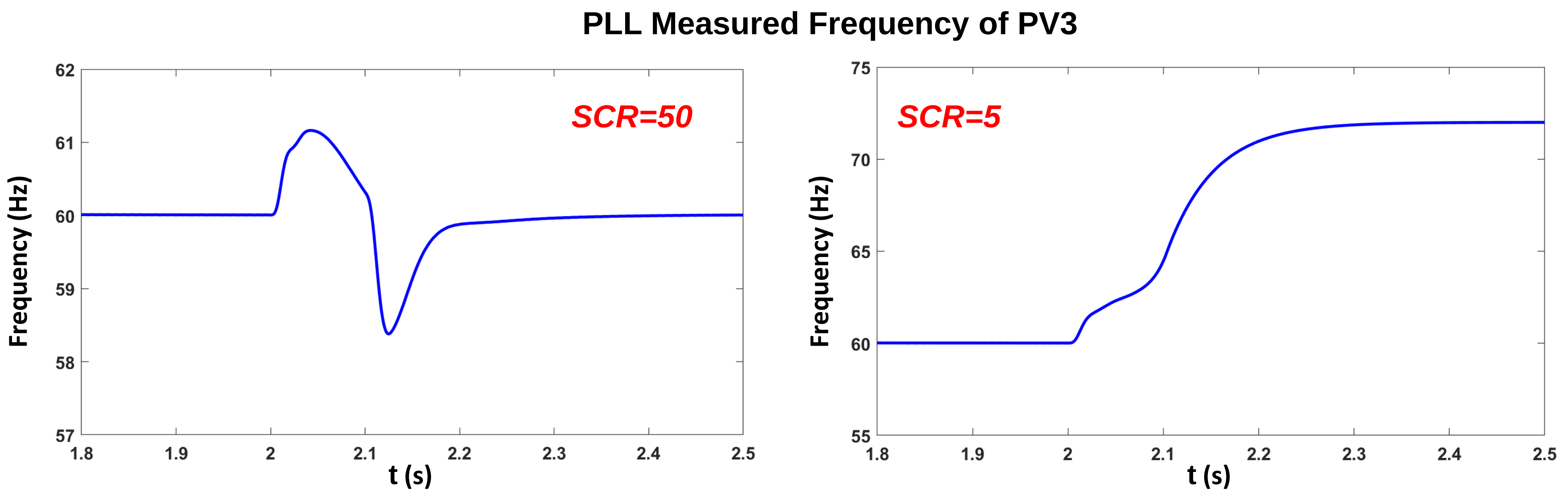
Disturbance ride-through with varying SCRs





- 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…

Strengthen the transmission system to increase short circuit strength

Caveat: There could be significant constraints to build more lines

Re-tune the fast control loops to recognize a low short circuit condition

Caveat: May not provide desired performance under all conditions

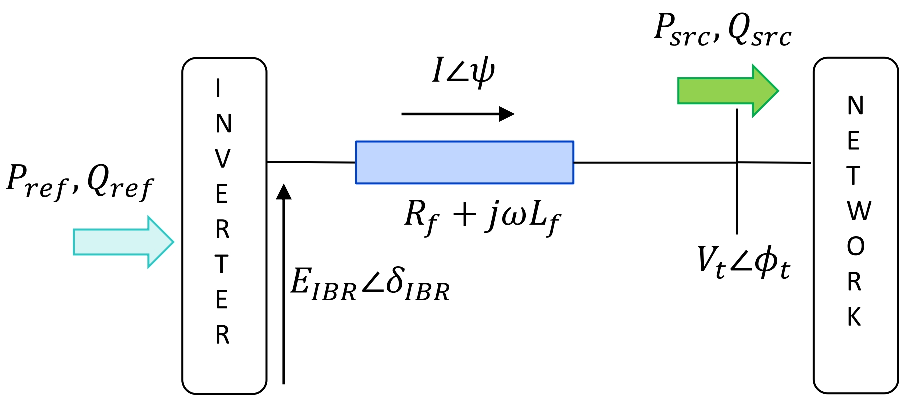
Re-imagine IBR controls to introduce additional flexibility in operation

Caveat: May require standardization to ensure consistent performance

Addition of synchronous condensers

Caveat: There could be techno – economic constraints

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

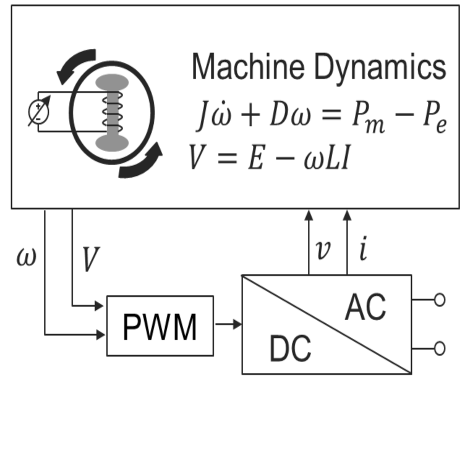
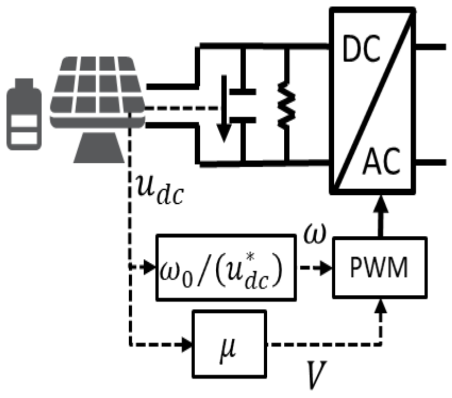
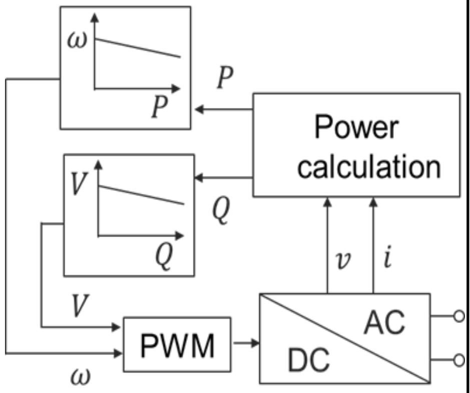
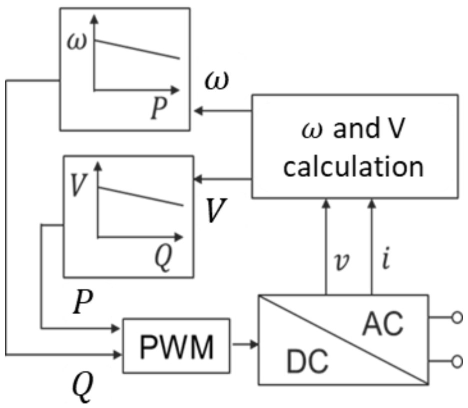
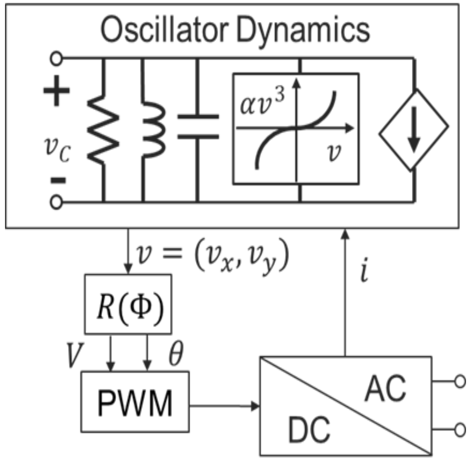
High ΔV to ΔI

- GFM IBRs can contribute through improvements in control methods

High Δf/Δt

- GFM IBRs can contribute through participation in frequency response

Several GFM inverter controls from the literature

Virtual synchronous machine [2]	Matching control [3]	Droop based control [4]	FERC Orders 842 and 827 based control [5]	Virtual oscillator control [6]
				

Emulate Synchronous Machine Dynamic Behavior (Virtual synchronous machine, Matching control)

P-f and Q-V Droop (Droop based control, FERC Orders 842 and 827 based control)

Nonlinear Control (Virtual oscillator control)

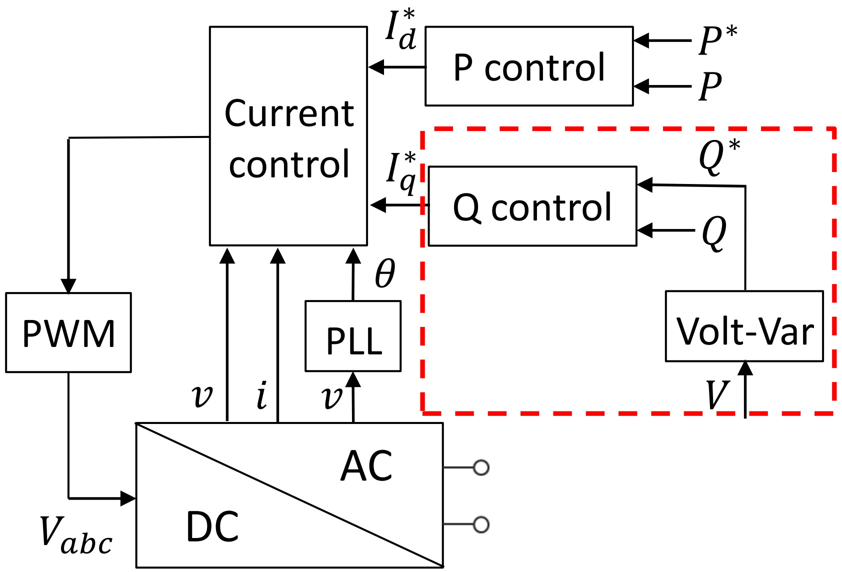
Phasor-Domain Controller

Time-Domain Controller (Faster Dynamics)

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

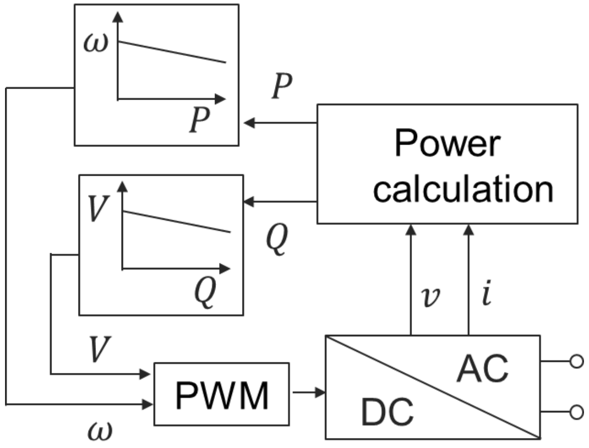
Example case to illustrate improved inverter operation in low short circuit scenario with GFM control

Two forms of GFM inverter control compared for improved system behavior

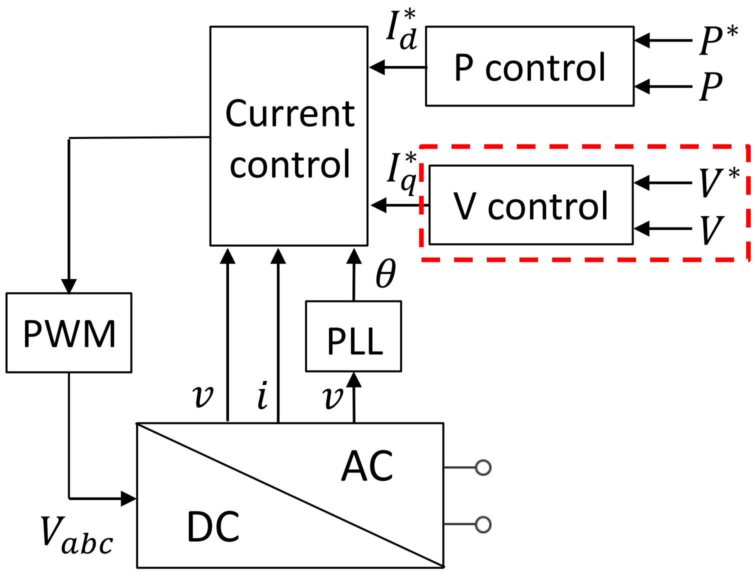


Conventional inverter control with slow volt-var

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



Droop-based inverter control



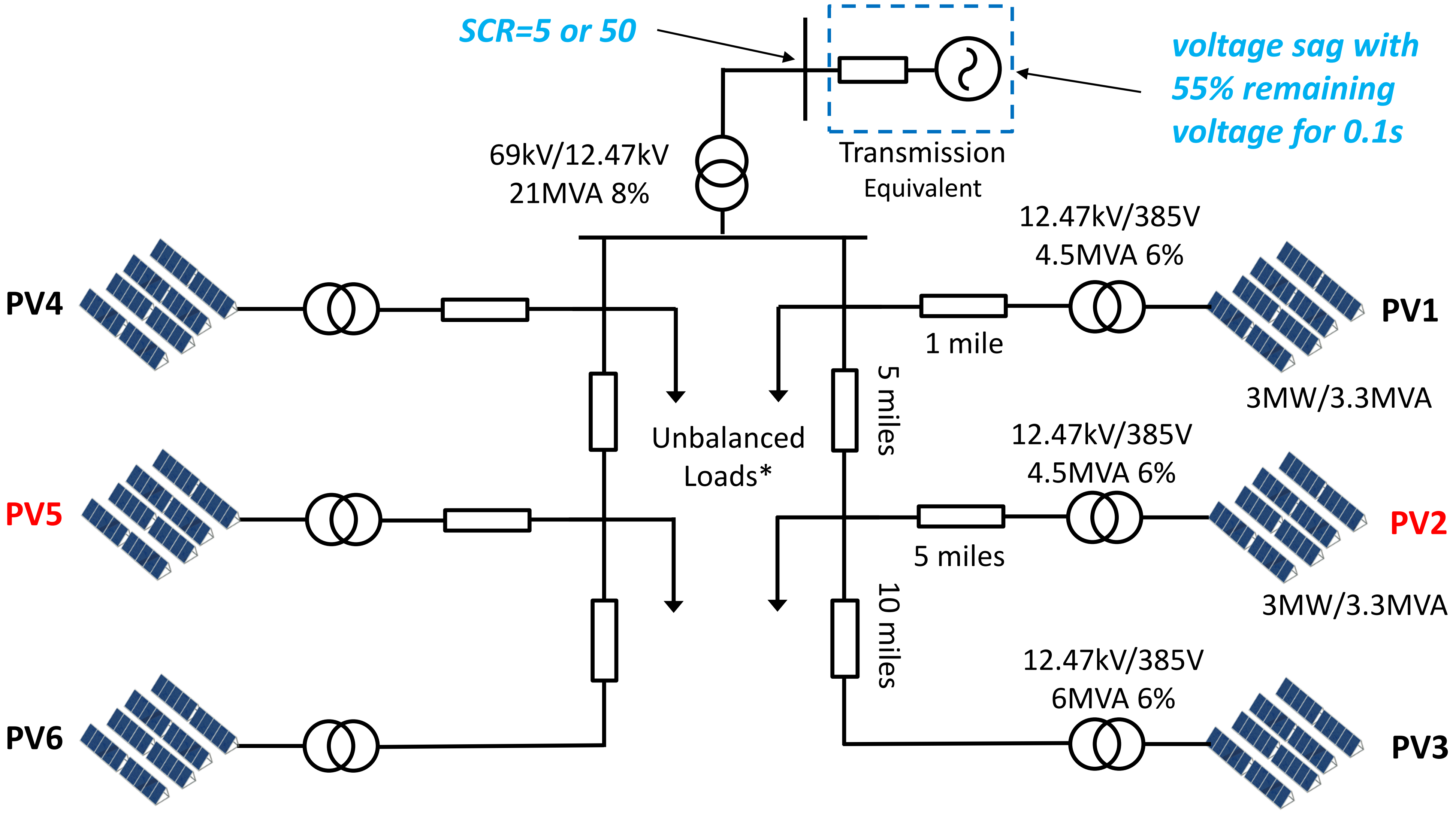
Inverter control with fast reactive current injection (labeled as DVS)

GFM control for two PV plants in the system

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

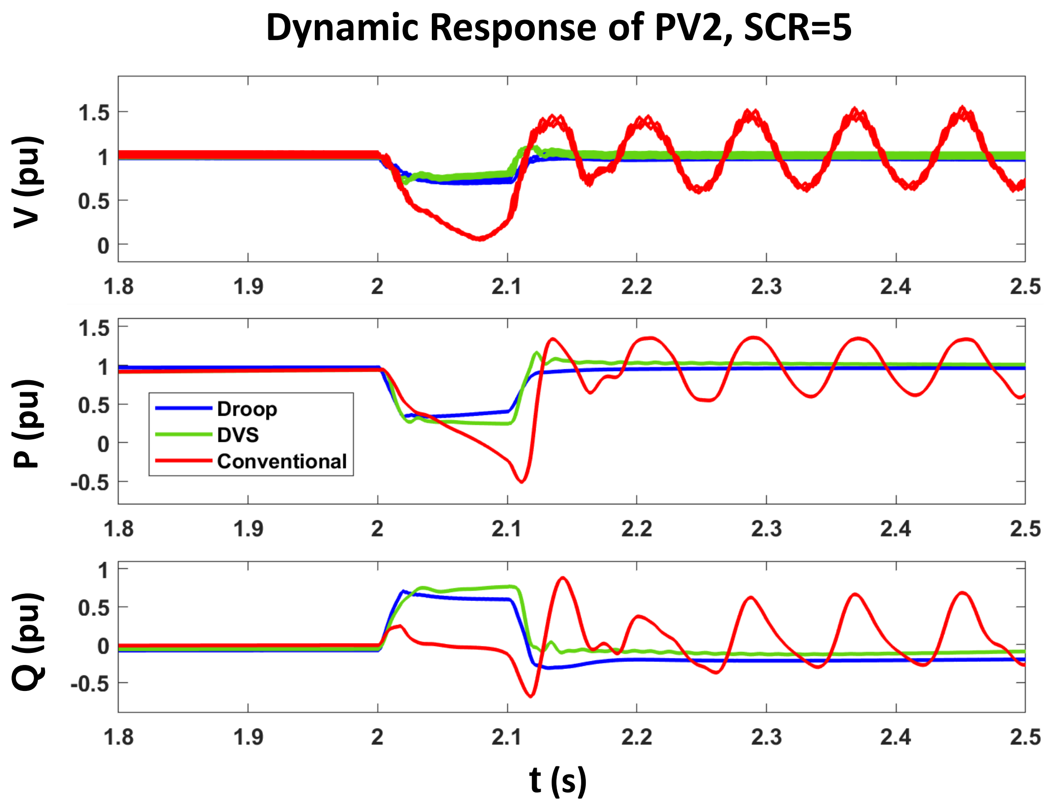
Conventional, DVS or droop-based control for PV2 and PV5

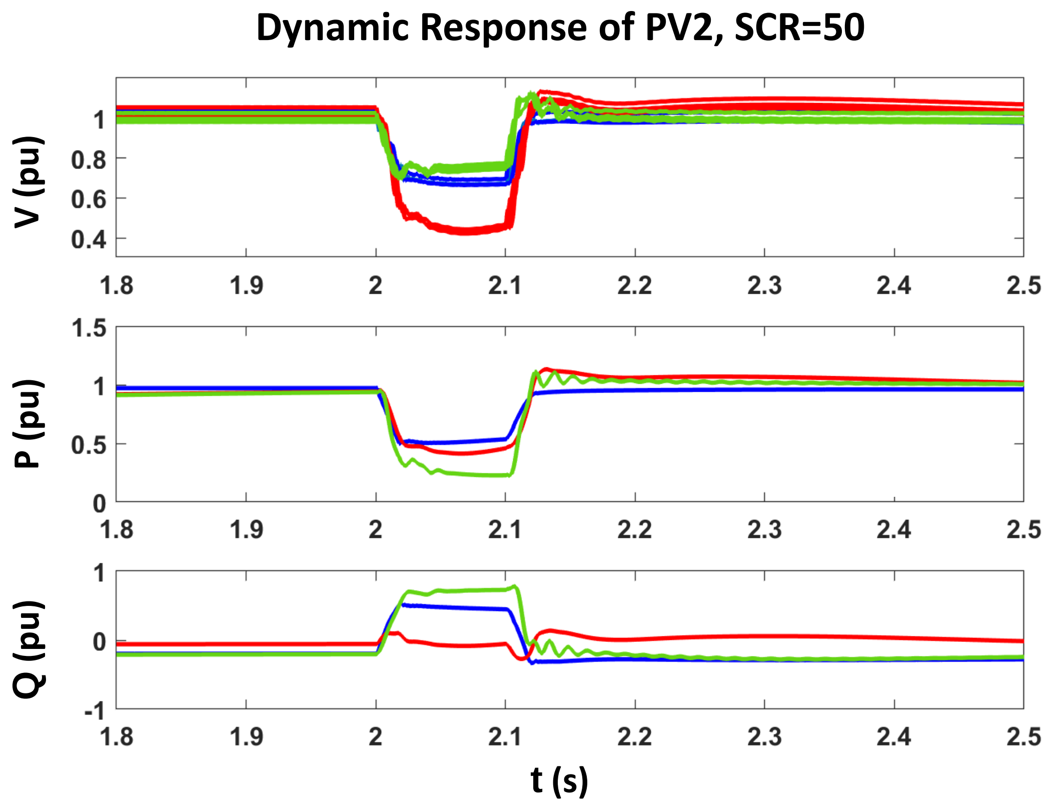
Other system parameters and settings remain the same as in previous analysis



*3MW load on each feeder

Performance comparison – conventional, DVS and droop

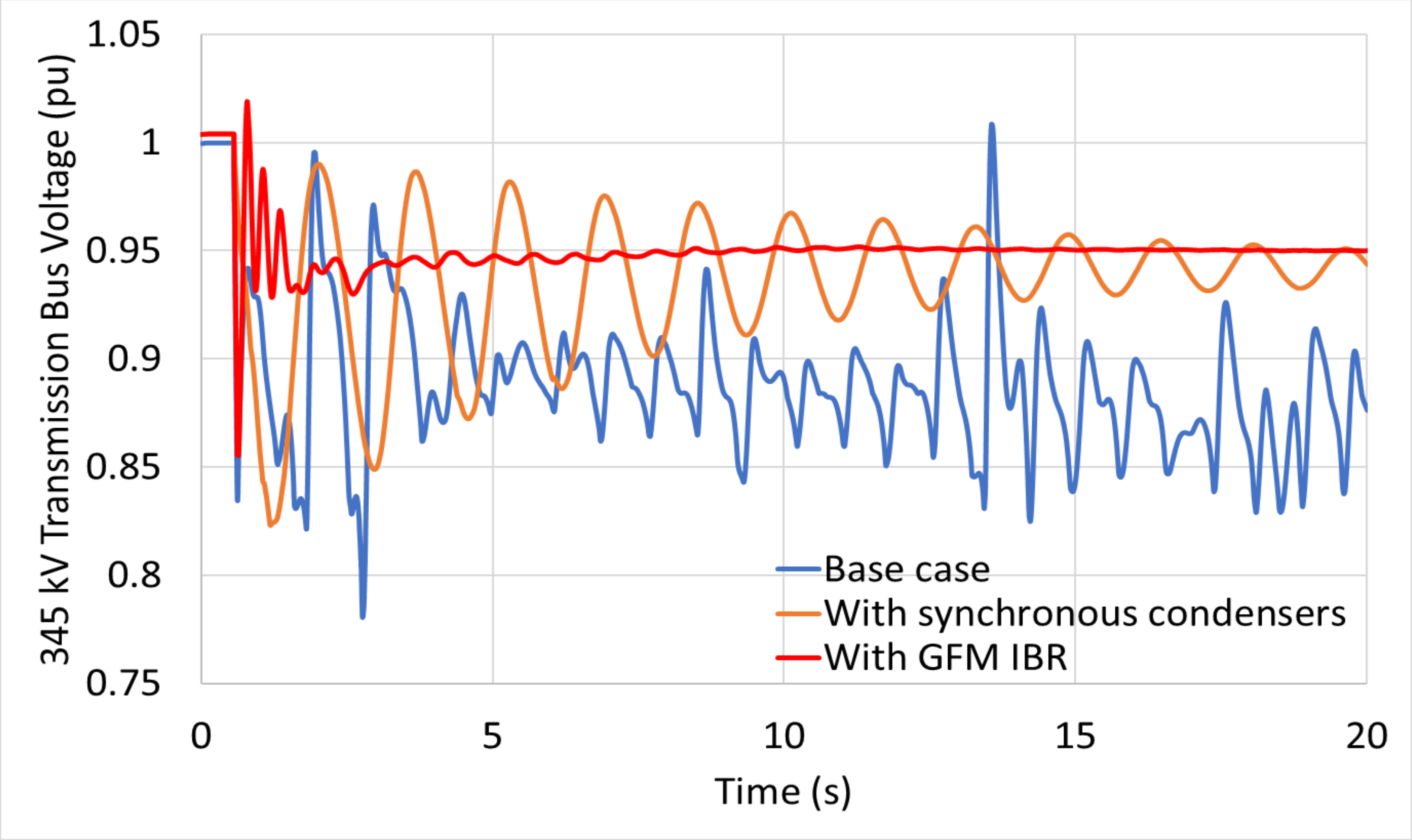




- DVS and droop-based control can both stabilize the inverters following the fault ride-through.
- The DVS and droop-based control show similar dynamic response: the reactive power increases fast to boost the feeder voltage during the disturbance.
- By using DVS or droop-based control for two PV plants,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

GFM IBR vs synchronous condenser to increase wind farm percentage…

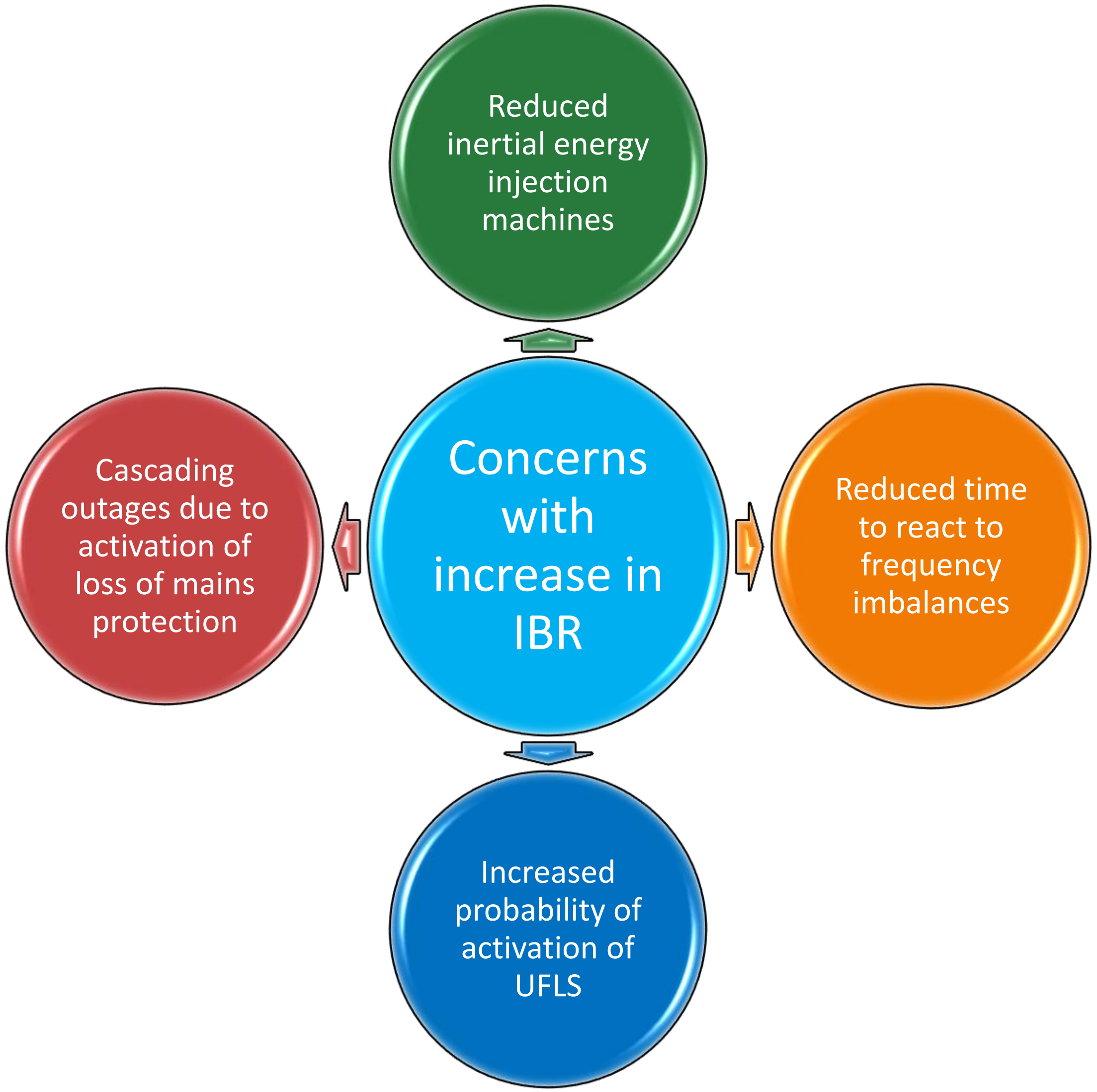
- With increase in MW generation from wind turbines
  - Voltage oscillations observed in 345kV network for N – 1 outage

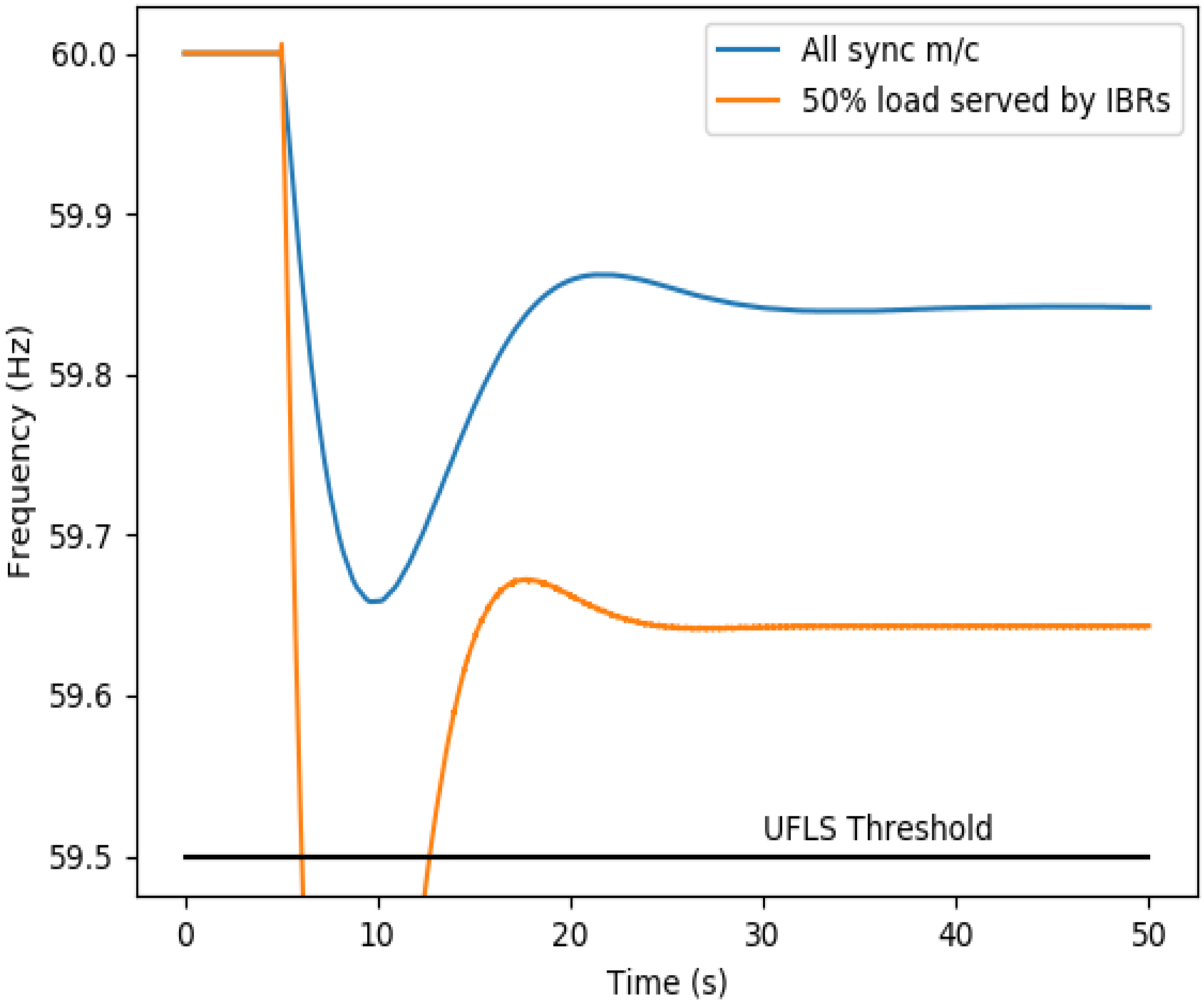


GFM IBR of similar rating as synchronous condenser can provide possible increased improvement in stability

IBR Control and Frequency Response in Low Inertia System

IBRs and frequency response…

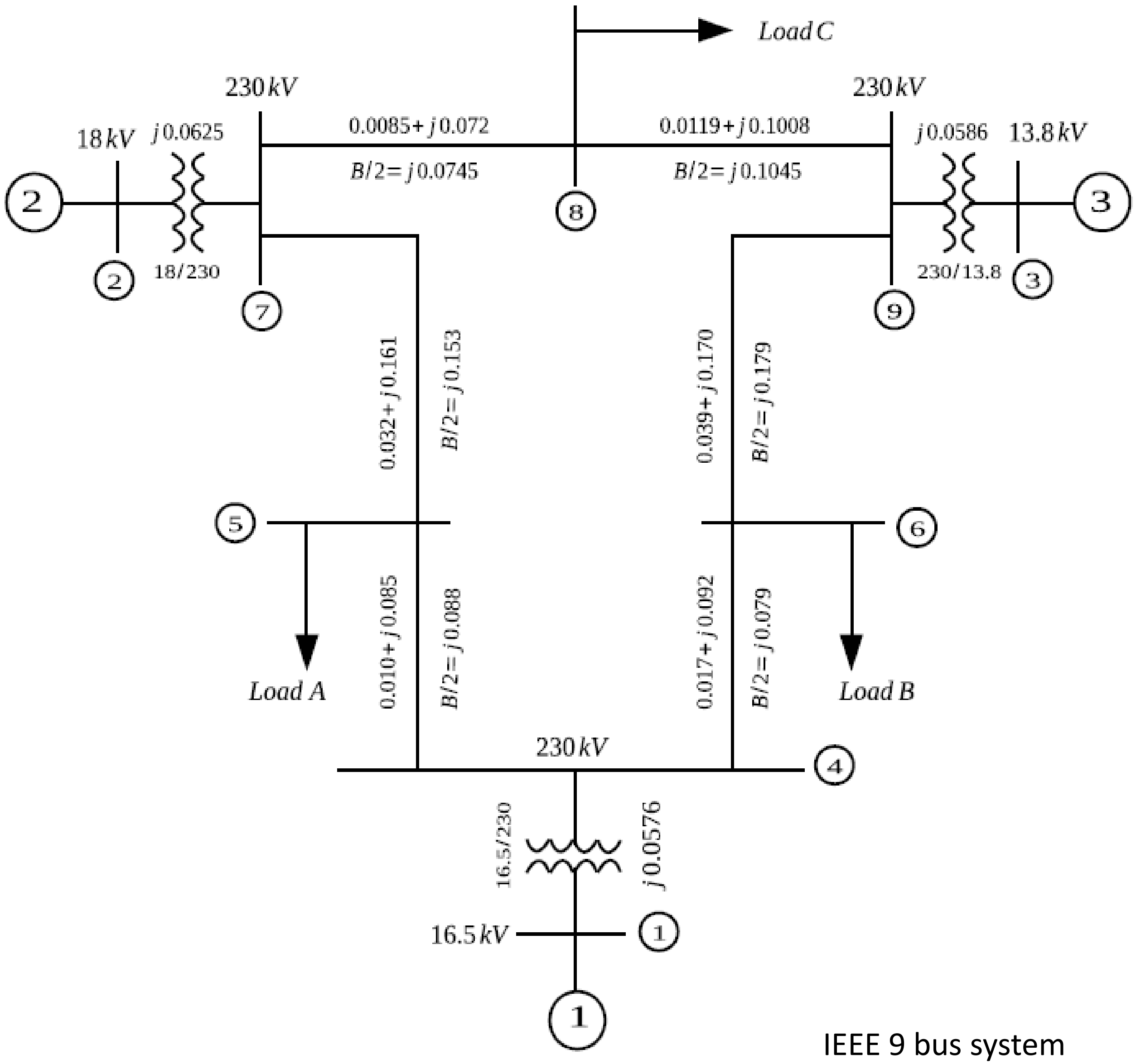




Frequency response in the bulk power system

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

What would happen if IBRs replace the generation sources?

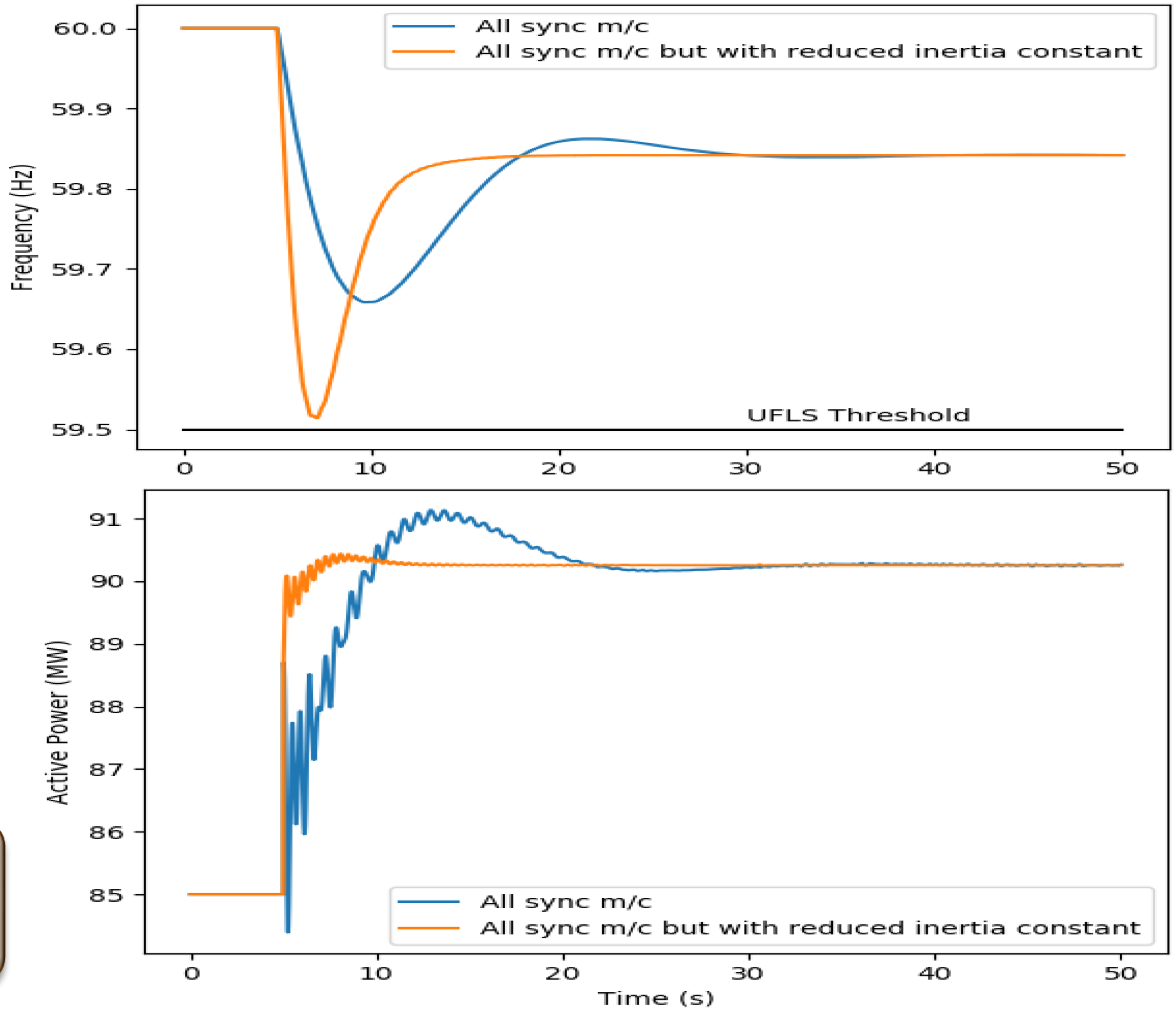


IEEE 9 bus system

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

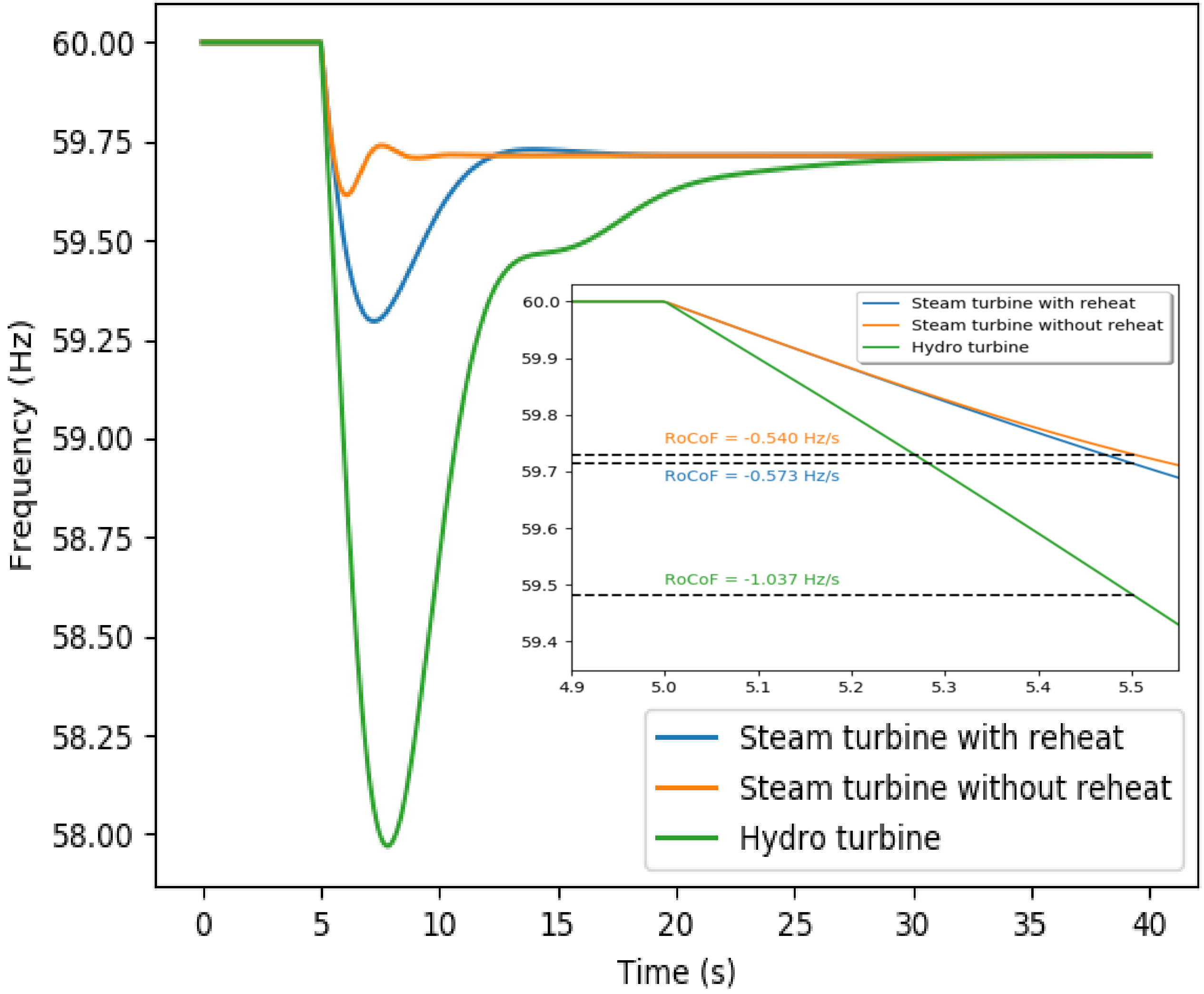
Value of nadir depends on inertia and time constants in active power control loop



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

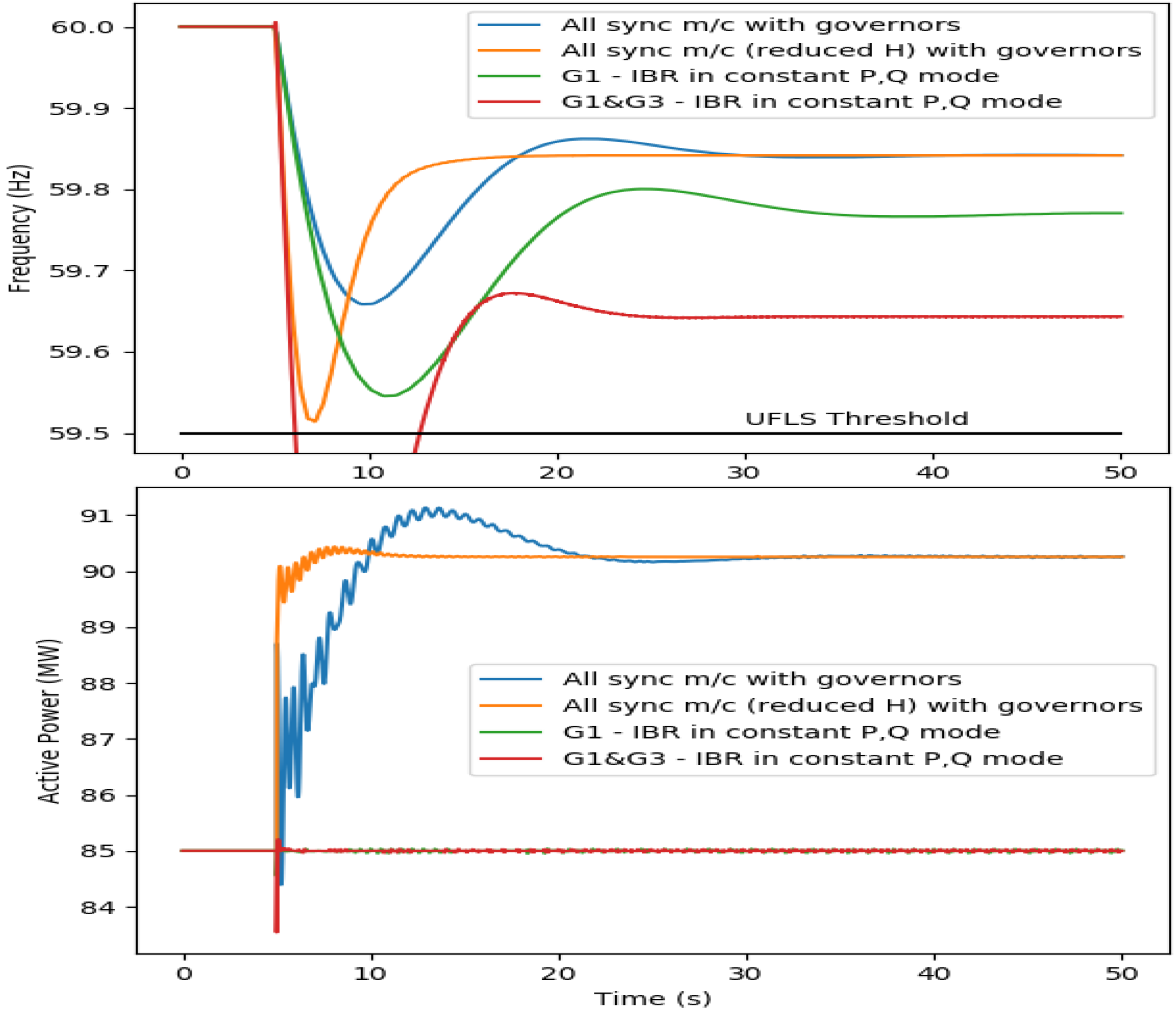


Adapted from frequency response plots in Chapter 11, Power System Stability and Control, Prabha Kundur

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

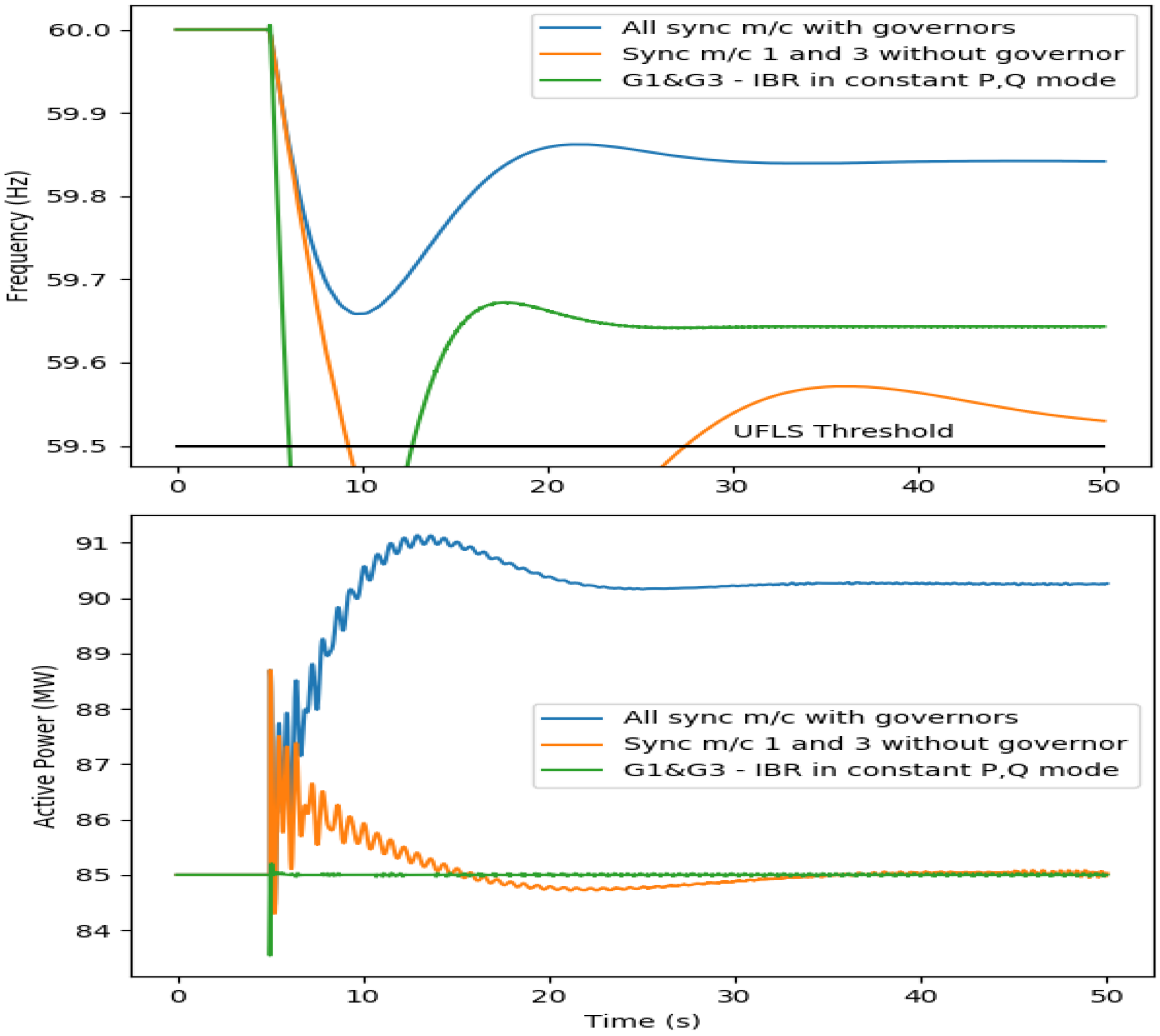
Is this because of IBRs or because of reduced amount of response?



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!

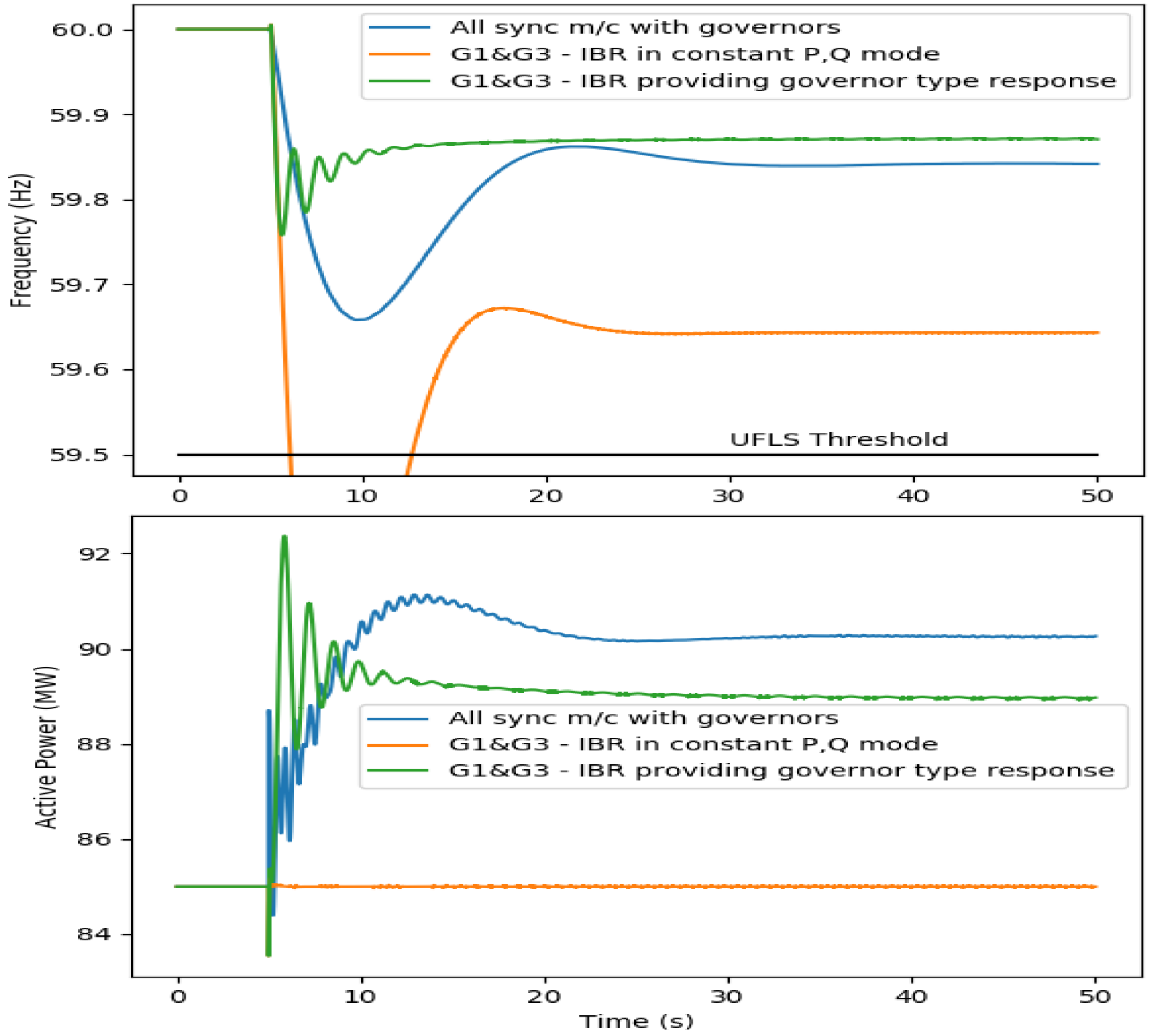


Can conventional IBRs provide frequency response…?

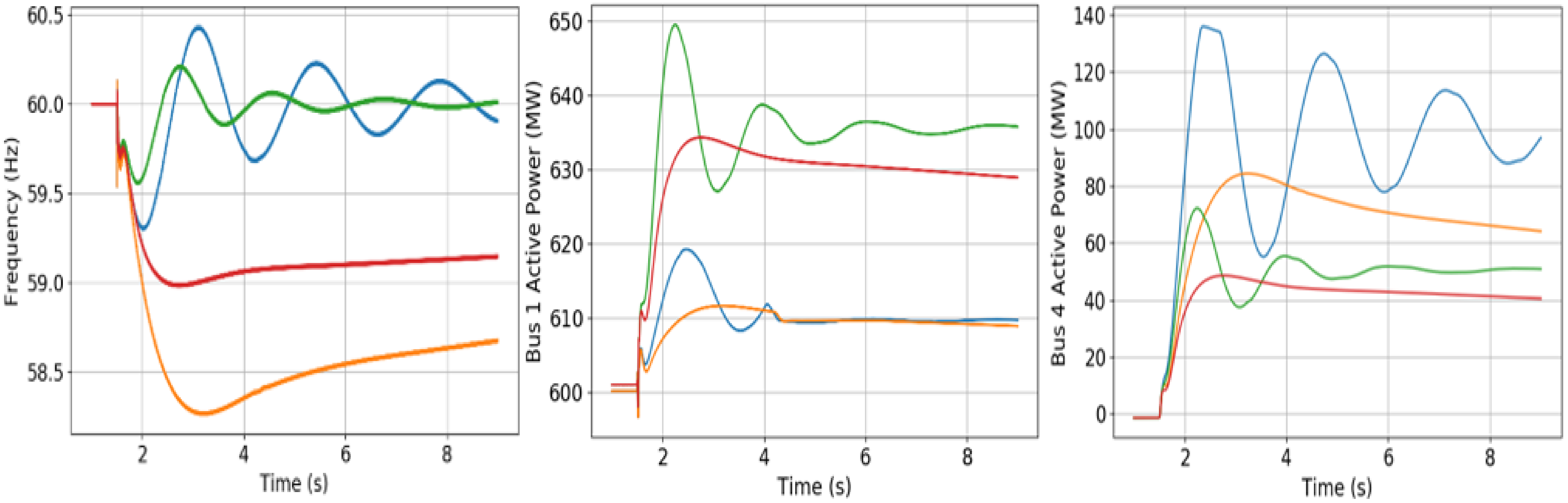
- Both IBRs at G1 and G3 have governor – like capability enabled:
  - 750ms time lag in IBR control
  - Inherent fast primary response due to lack of mechanical components and low inertia
- If IBR controls need a measure of electrical frequency, robust measurement techniques should be implemented

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…

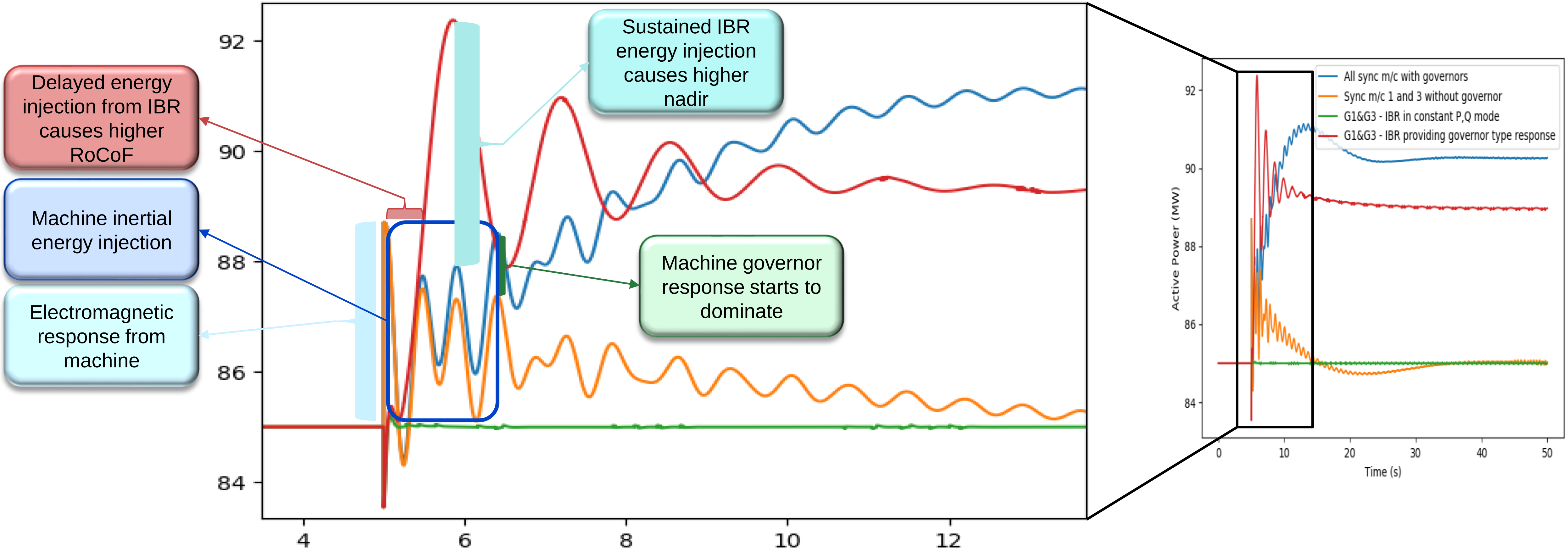


- 20 MVA storage, distributed slack power sharing
- 20 MVA storage, conventional frequency droop
- 100 MVA storage, distributed slack power sharing
- 100 MVA storage, conventional frequency droop

Proper sizing of energy storage and tuning of controls is essential

Different flavors of GFM IBR controls have different responses

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 draft IEEE P2800 standard say about primary frequency response?

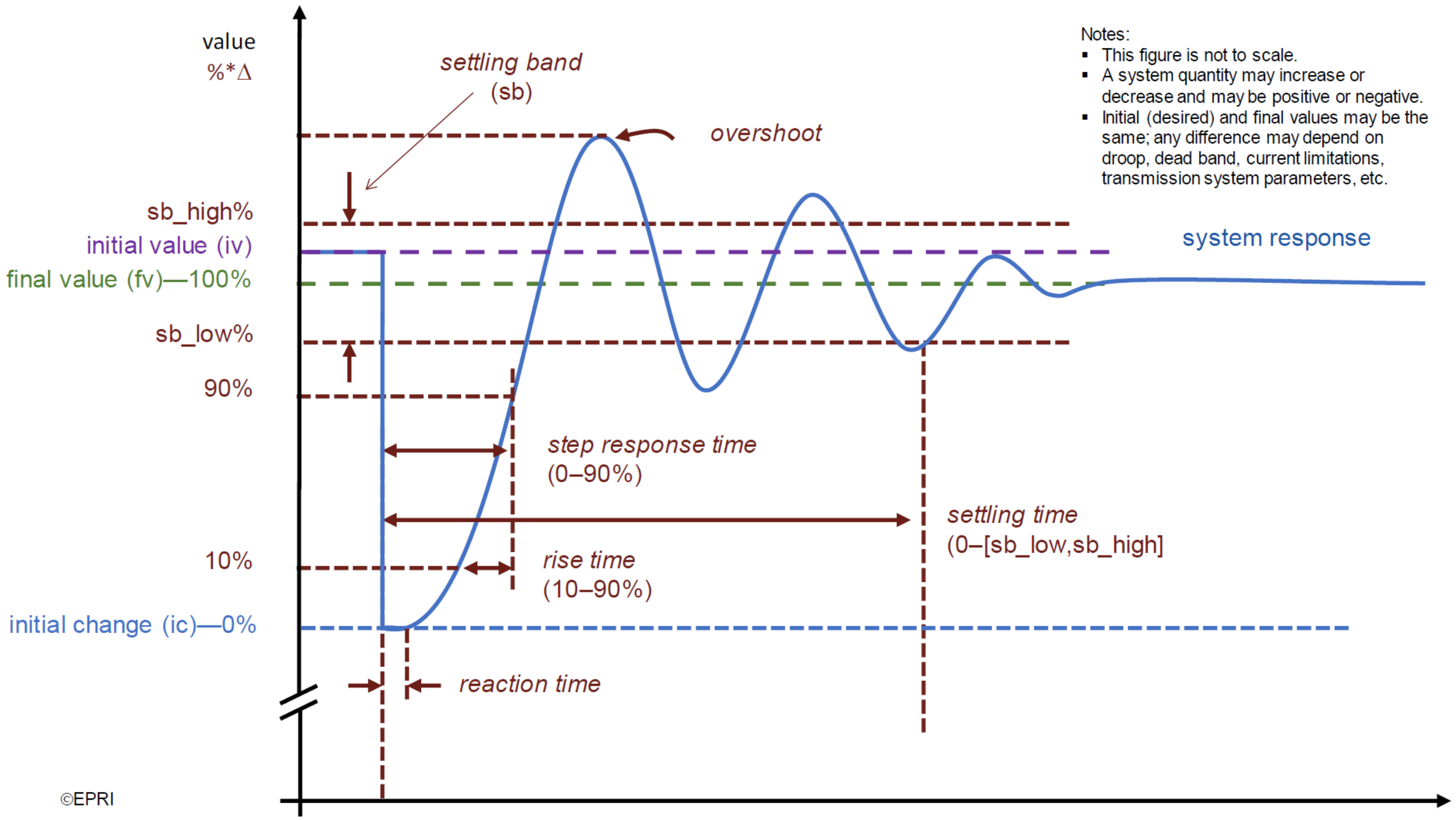


Figure 5(b) from Draft 5.1 of IEEE P2800 Draft Standard

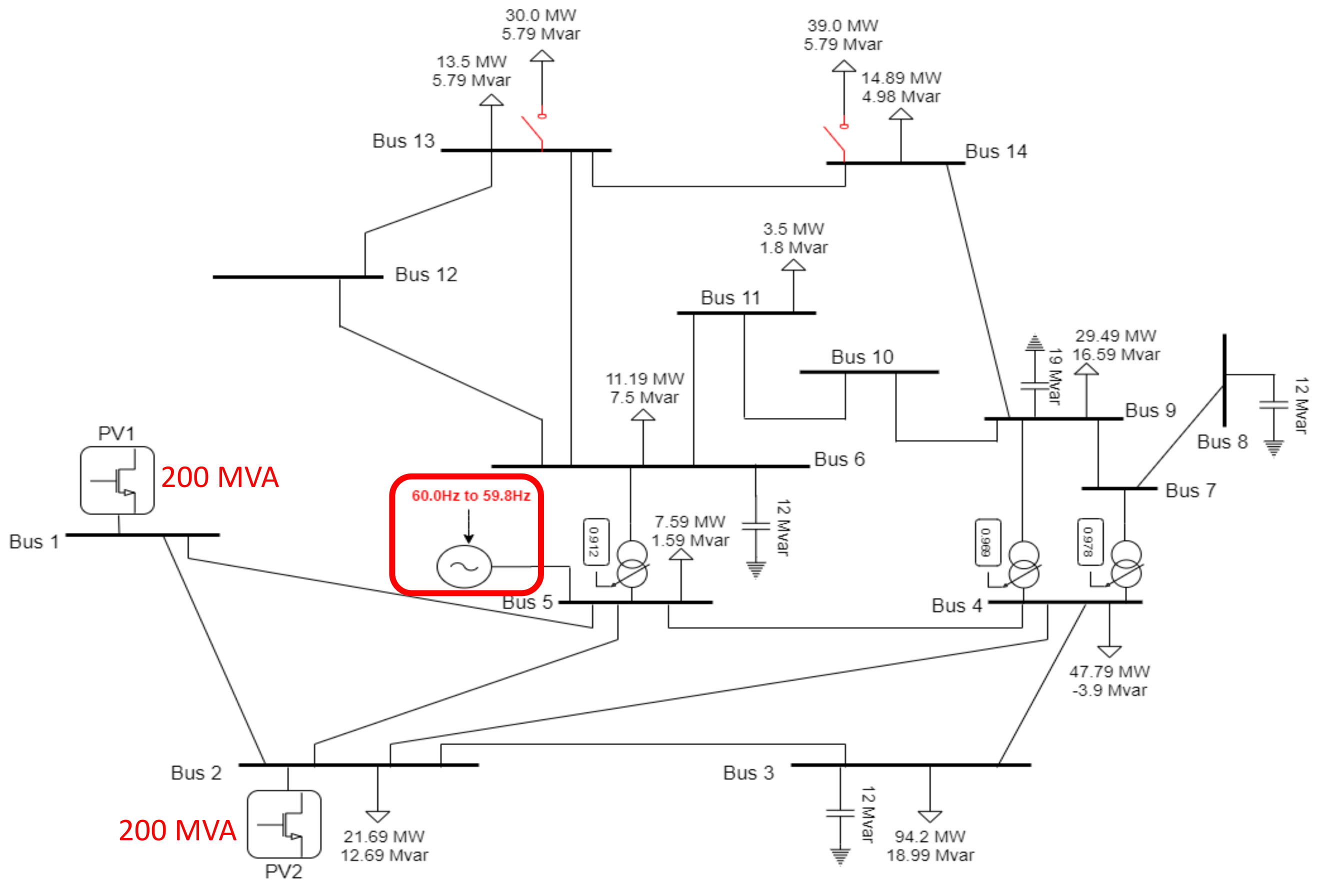
	Units	Default Value	Minimum	Maximum
Reaction time	seconds	0.50	0.20 (0.5 for WTG)	1
Rise time	seconds	4.0	2.0 (4.0 for WTG)	20
Settling time	seconds	10.0	10	30
Damping Ratio	% of Change	0.3	0.2	1.0
Settling band	% of Change	Max (2.5% of change or 0.5% of ICR)	1	5

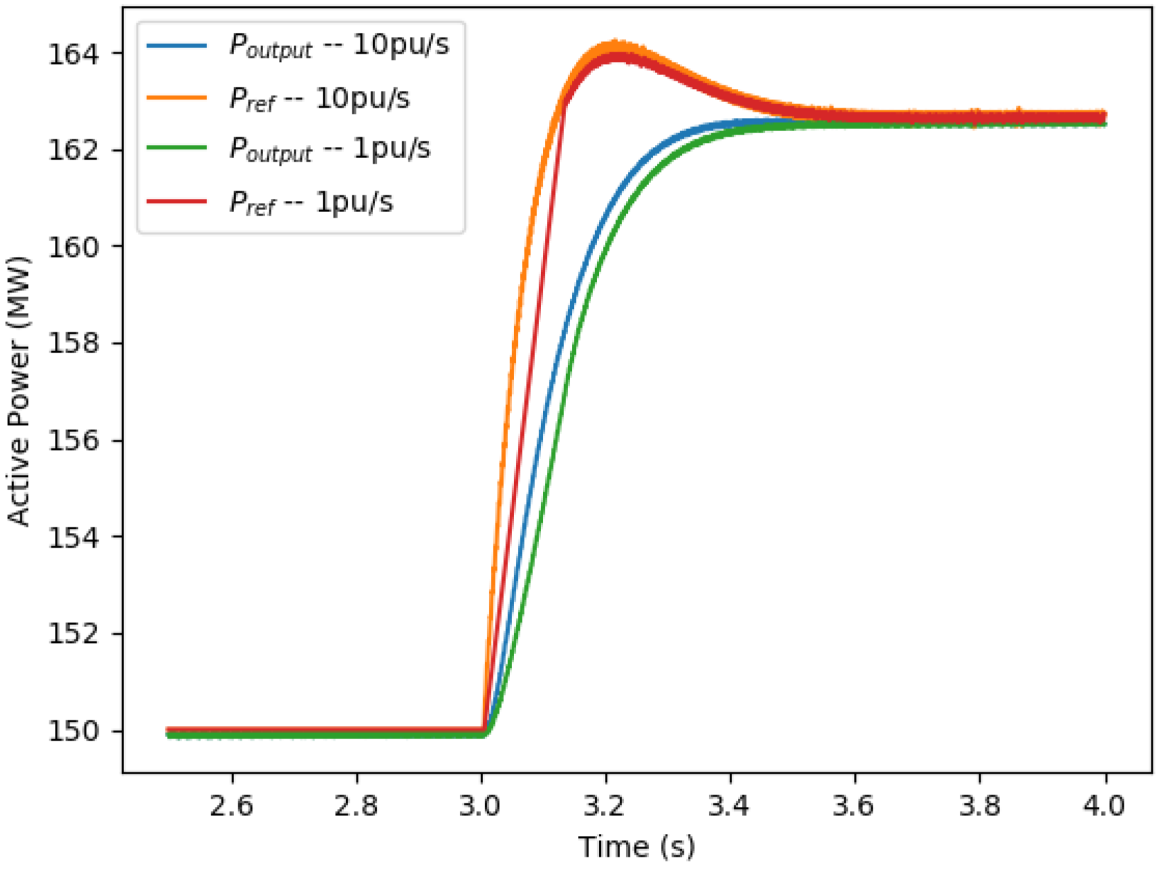
Table 10 from Draft 5.1 of IEEE P2800 Draft Standard

- 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

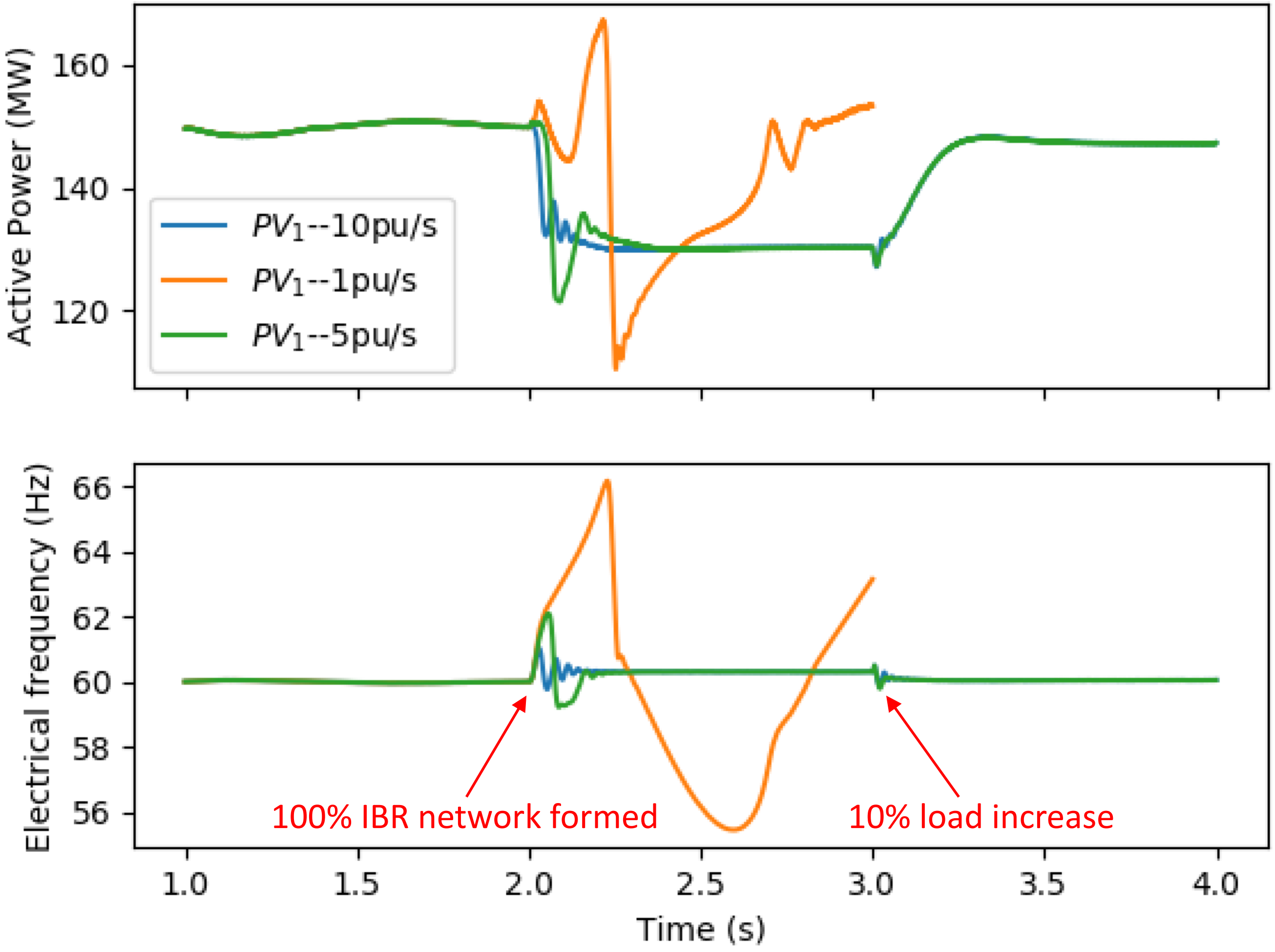
[1]https://www.pscad.com/knowledge-base/article/521

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

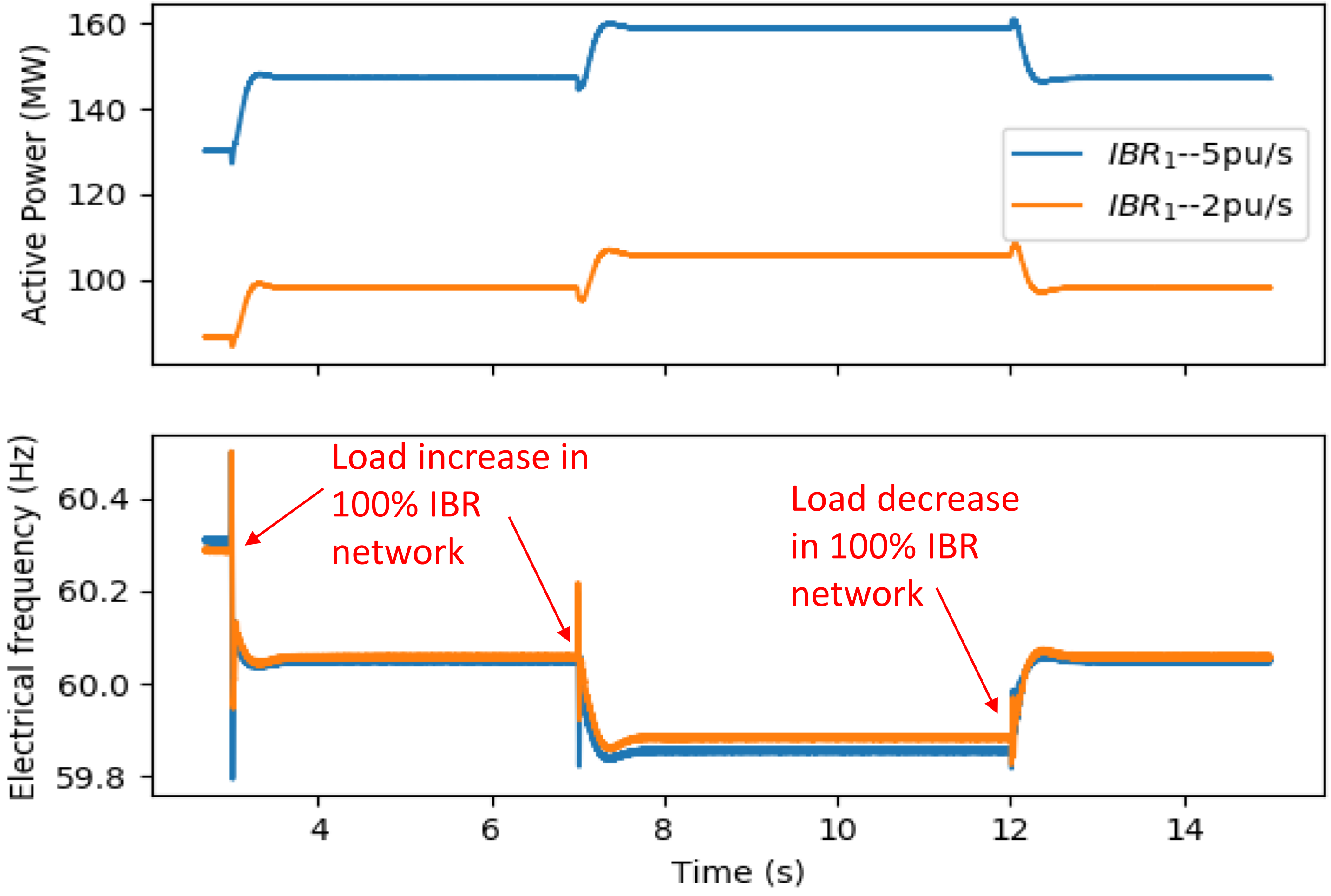


- 100% IBR network created at t=2.0s
- Load increase at t=3.0s

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

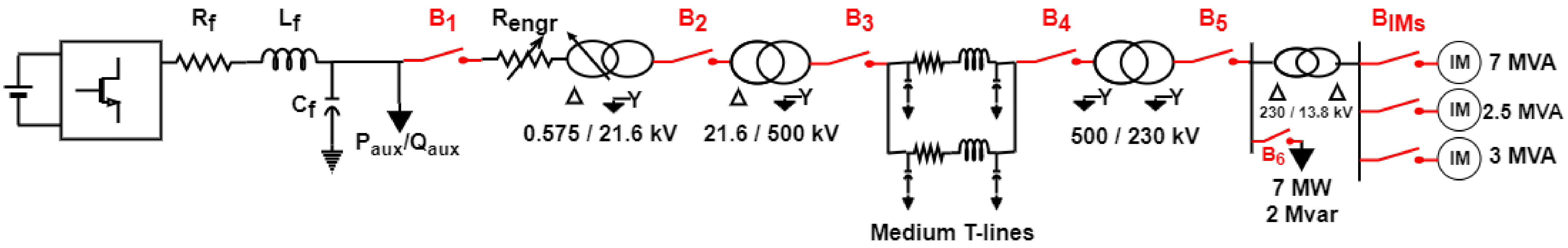
Blackstart of a system with IBRs – A grid forming service

- 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

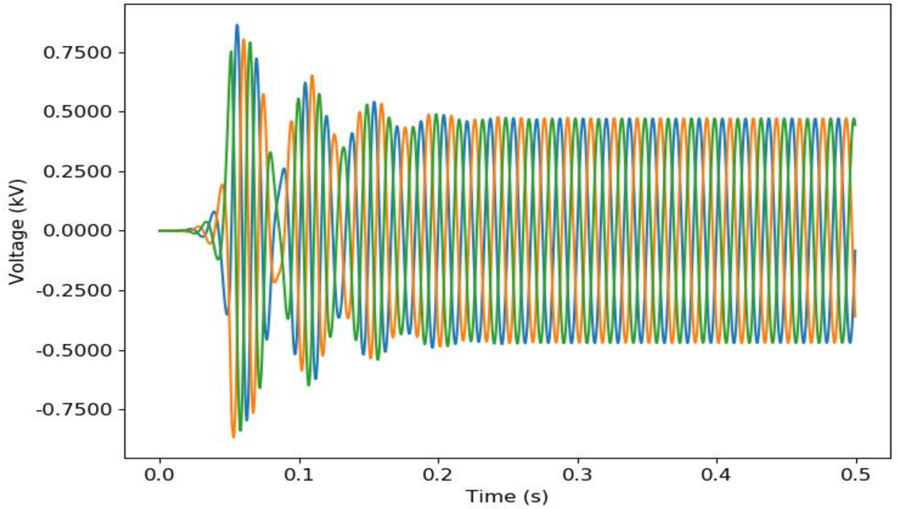
- A GFM IBR can be this first black start resource
  - Not all GFM IBRs need to be capable of providing such services

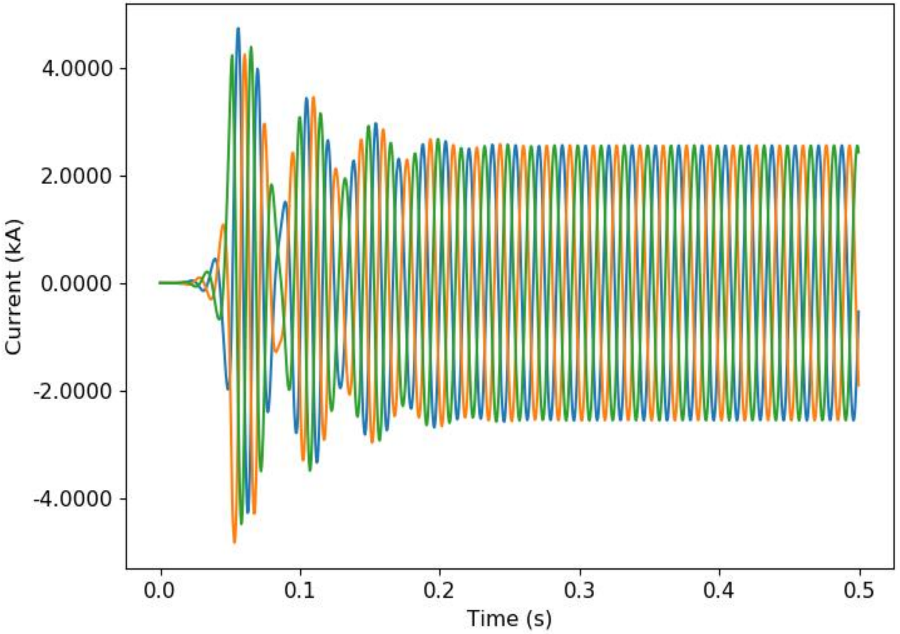
Conducting black start using grid forming inverters

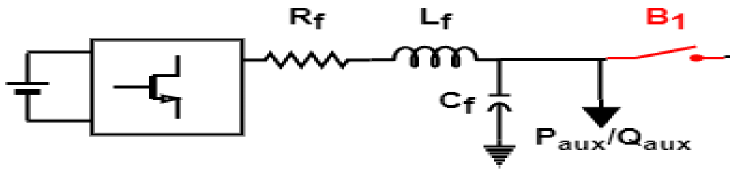


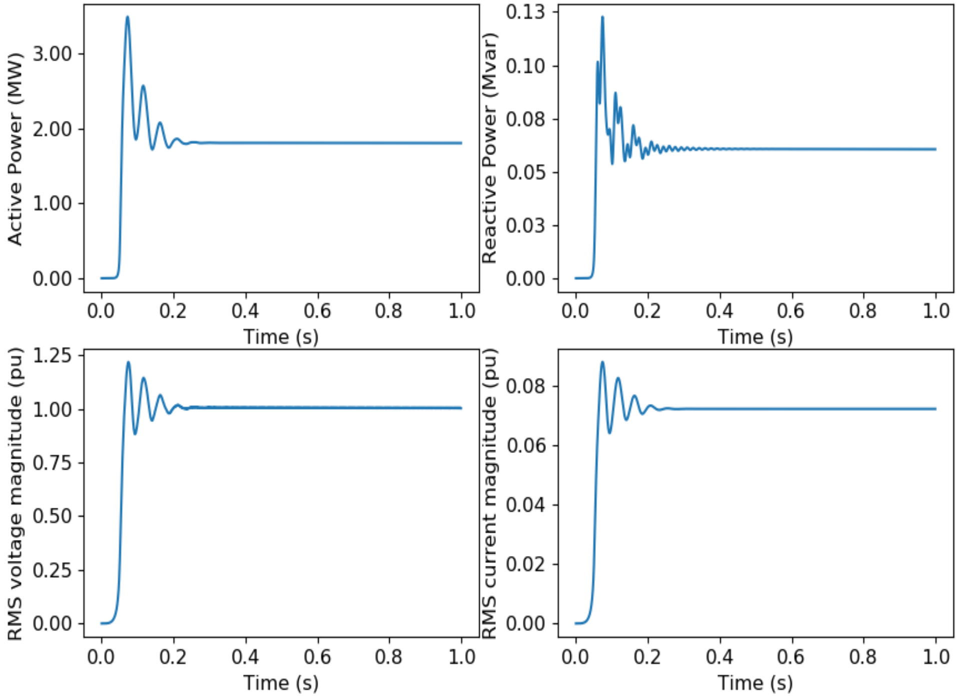
- A 25 MVA grid forming inverter control developed at EPRI conceptually based upon FERC Orders Nos 827 and 842.
- All transformers have saturation represented:
  - Leakage reactance of 0.08pu on self MVA base
  - Magnetization current of 0.3%
  - Inrush decay time constant of 1.0s
  - Knee voltage of 1.15pu
- R_{engr} is a transformer energization variable resistance used for soft energization
- The three induction motors (IM) (7 MVA, 2.5 MVA, 3.0 MVA) have a soft starting mechanism

Start up of inverter – at t = 0.0s





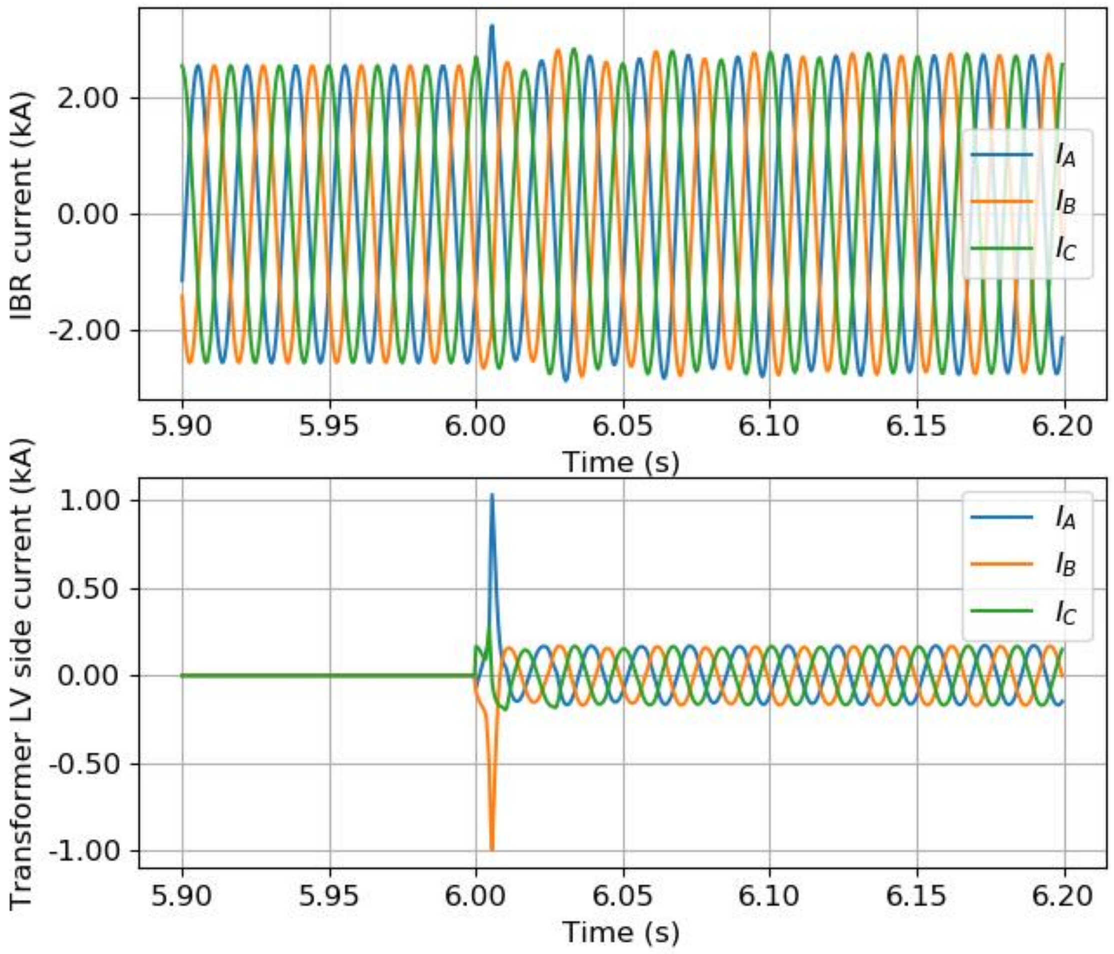


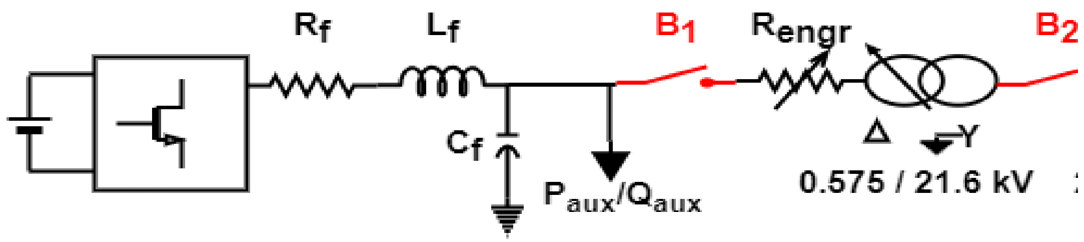


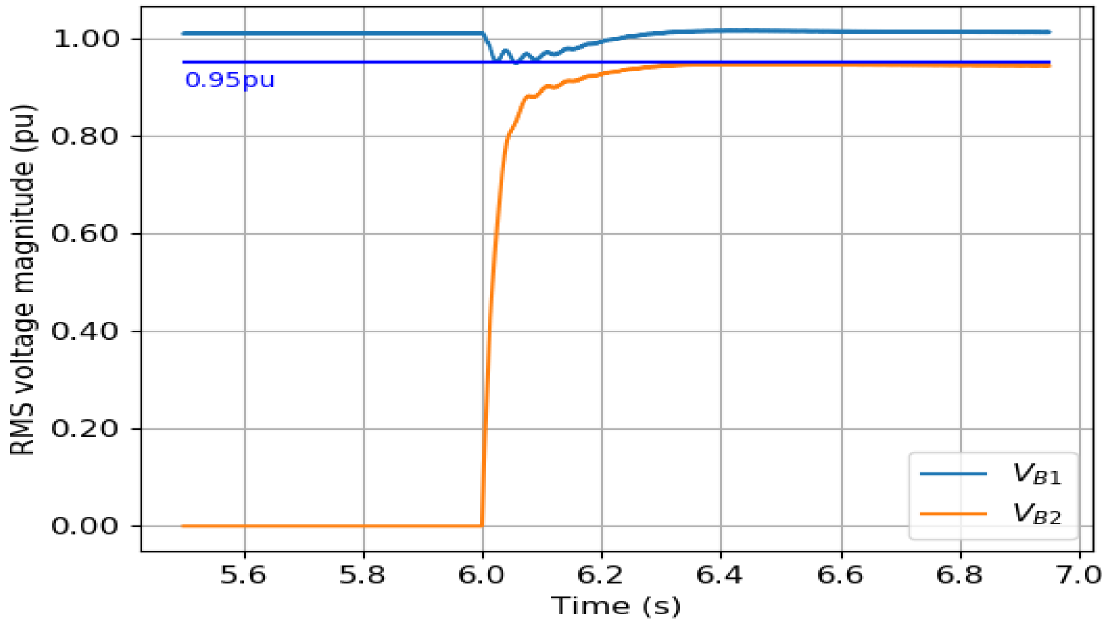
1. Inverter starts at t = 0.0s
2. Constant current control enabled at 1ms
3. Outer voltage and frequency control disabled until 1.5s

Successful inverter start up

Energizing 0.575/21.6kV 25 MVA transformer – at t = 6.0s by closing B_1

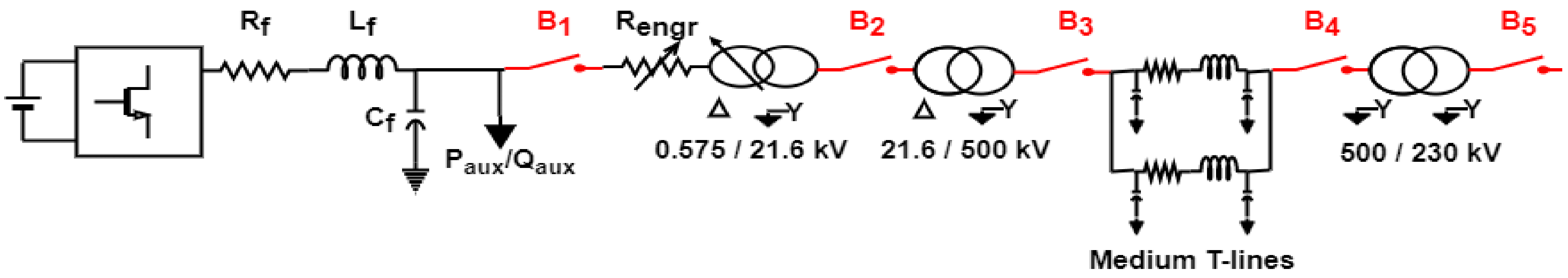


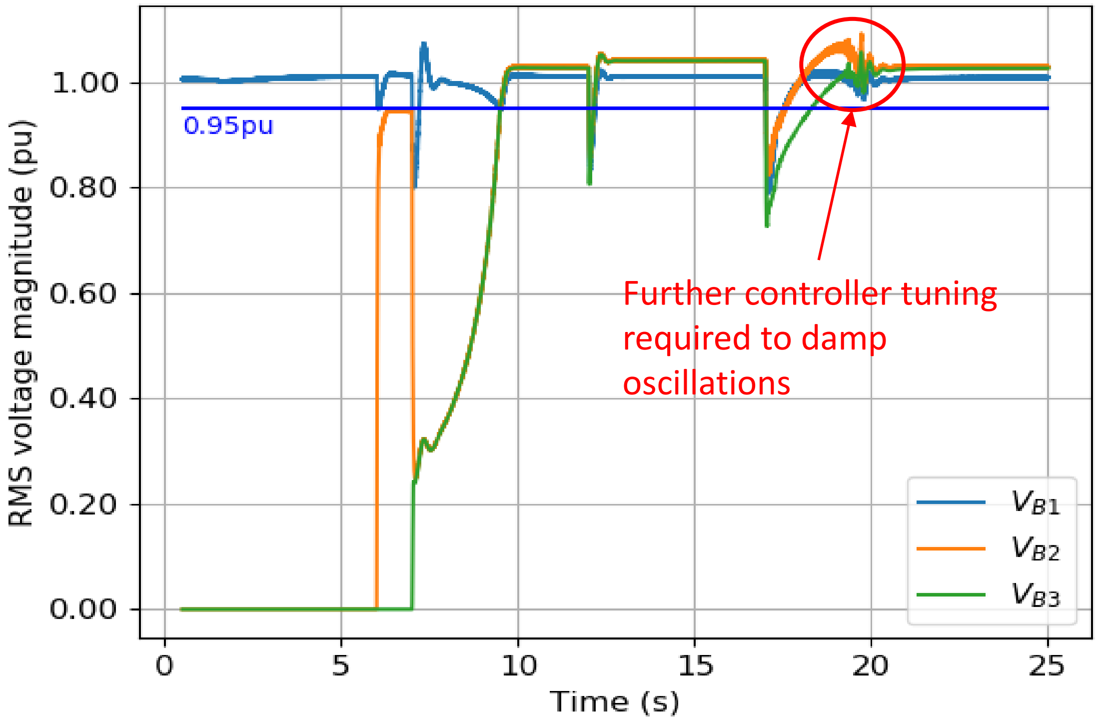


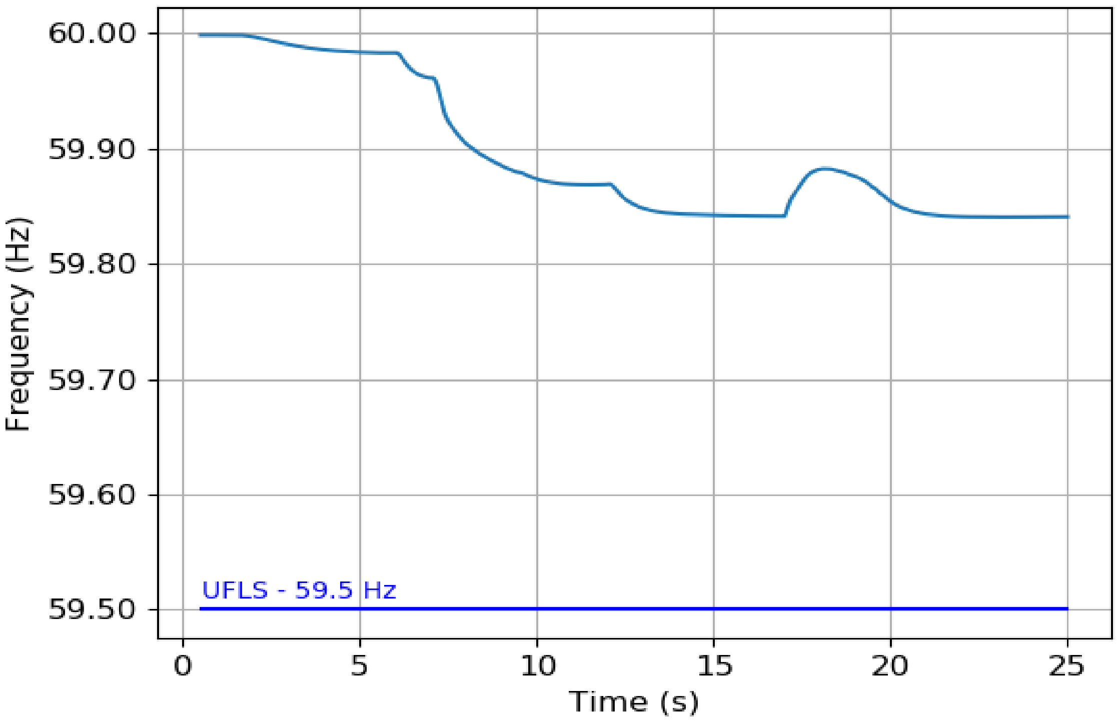


1. Transformer is energized using resistance based soft energization
2. Resistance is reduced gradually
3. There are numerous other methods of transformer energization that can be applied

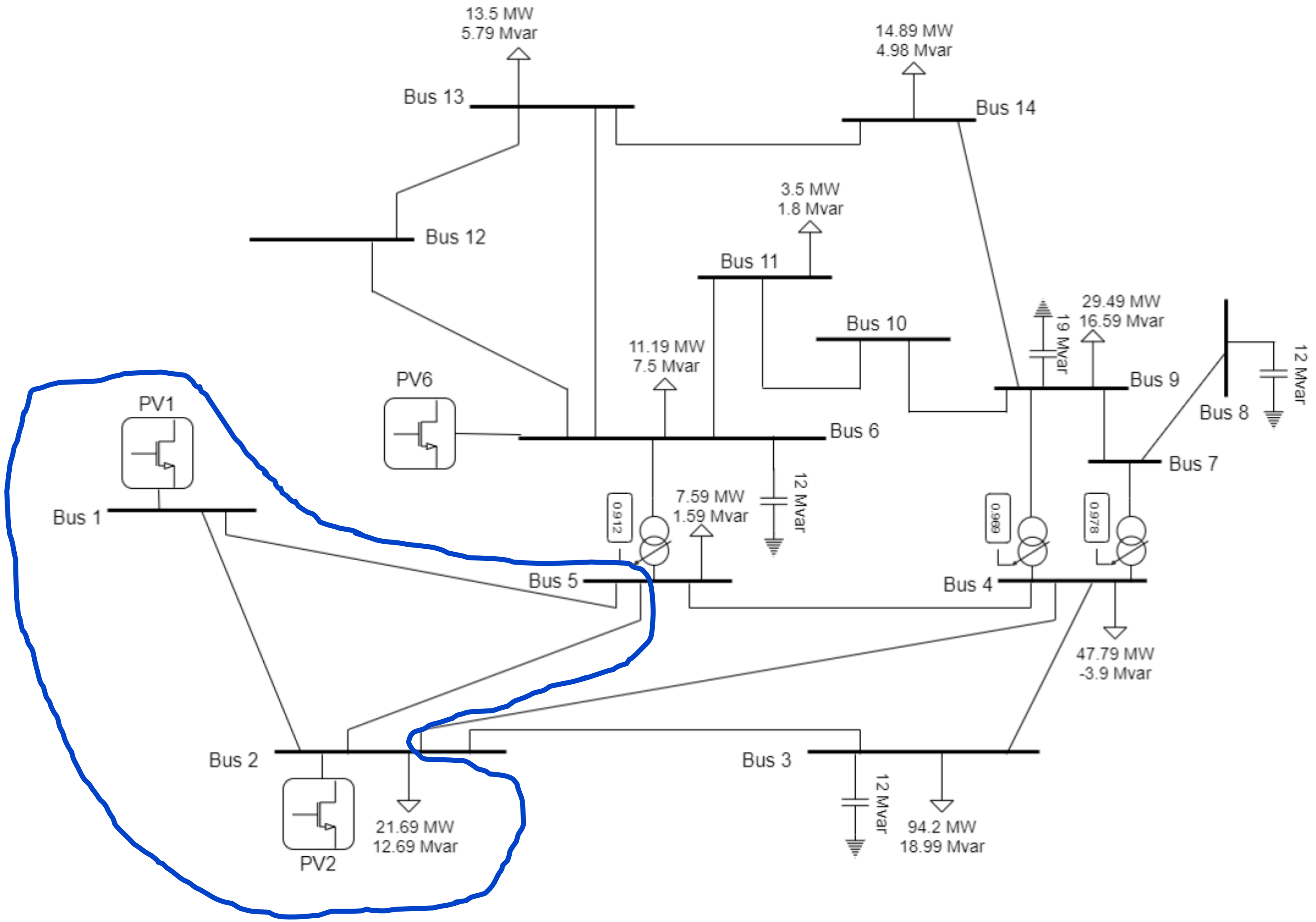
Energization of complete cranking path up to load bus





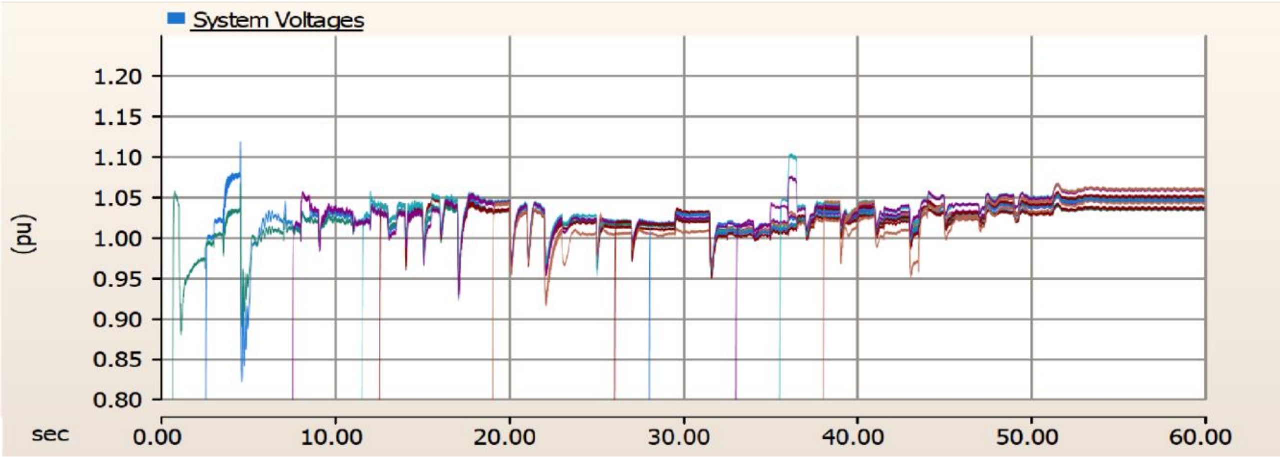


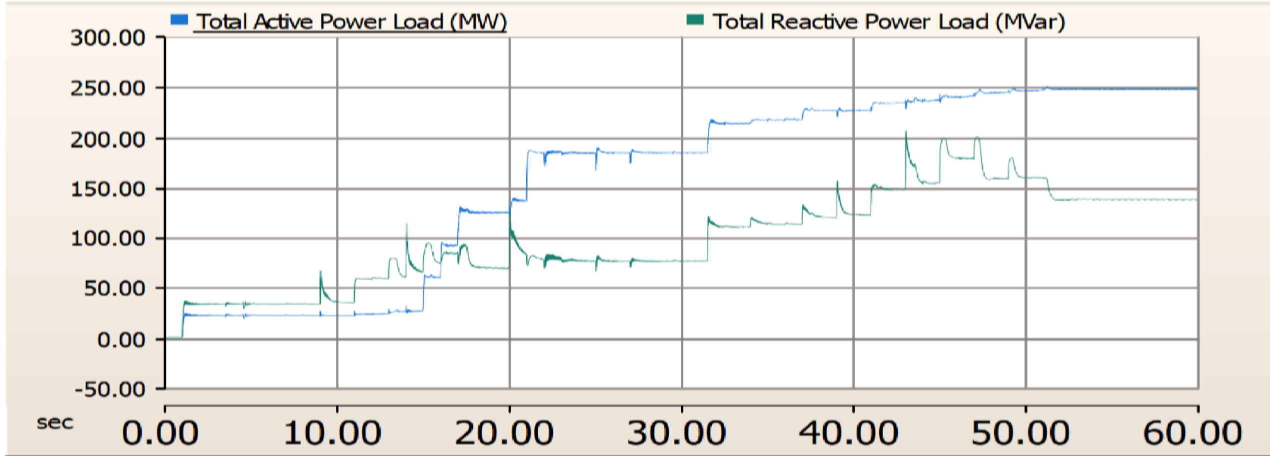
Black start of IEEE 14 bus test system

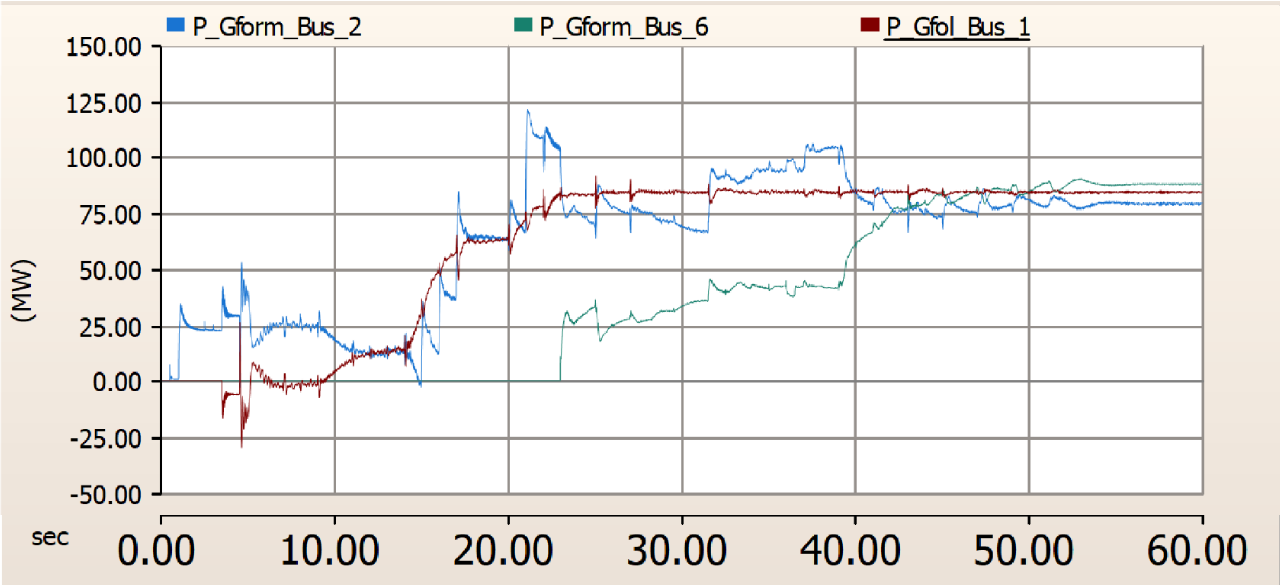


- PV at bus 2 and 6 are grid forming
- PV at bus 1 is grid following
- First black start bottom portion of the network
- Then bring PV6 online
- Then restore rest of the network

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 design process

Design → **Review and Test** → **Operation**

Design

- Protection
- Grounding
- Location and size of GFM plant(s)
- Functional requirements of GFM plants

…

⇩

RFP for GFM plants

Review and Test

- Verify that the microgrid design can satisfy system level performance criteria

…

Operation

- 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
- Developing functional requirements of GFM plants is a critical part of microgrid design to satisfy the system criteria

GFM performance requirements needed

- Reactive power capability
- Steady state and dynamic voltage requirement
- Steady state and dynamic frequency requirement
- Frequency and voltage ride-through
- Requirement on voltage harmonics
- Grounding of the GFM plant
- Temporary overload/overcurrent capability (for providing inrush current, cold load pick up, etc.)
- Black start capability
- Fault contribution levels

… …

More details available at: Grid Forming Inverter Performance Requirement for Microgrid Applications, August 30, 2021

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

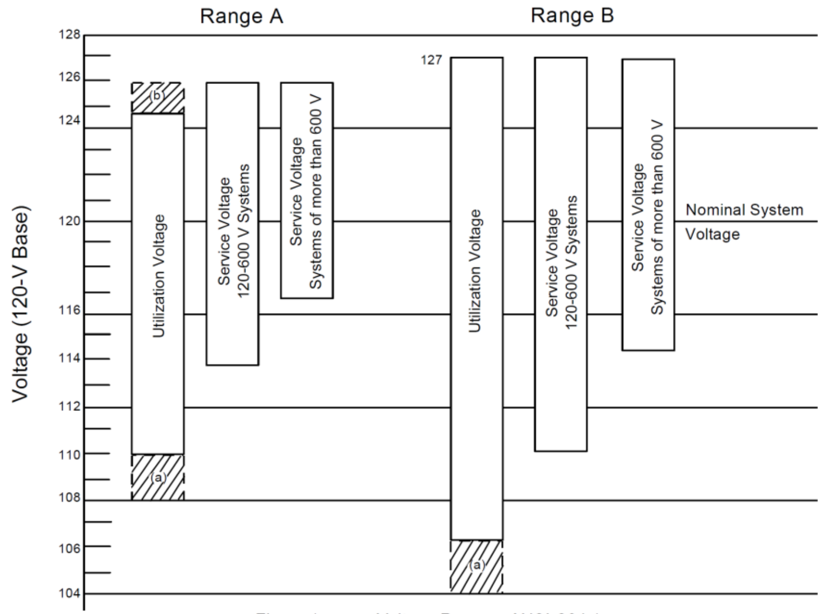


Figure 1. Voltage Ranges, ANSI C84.1

- 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%

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

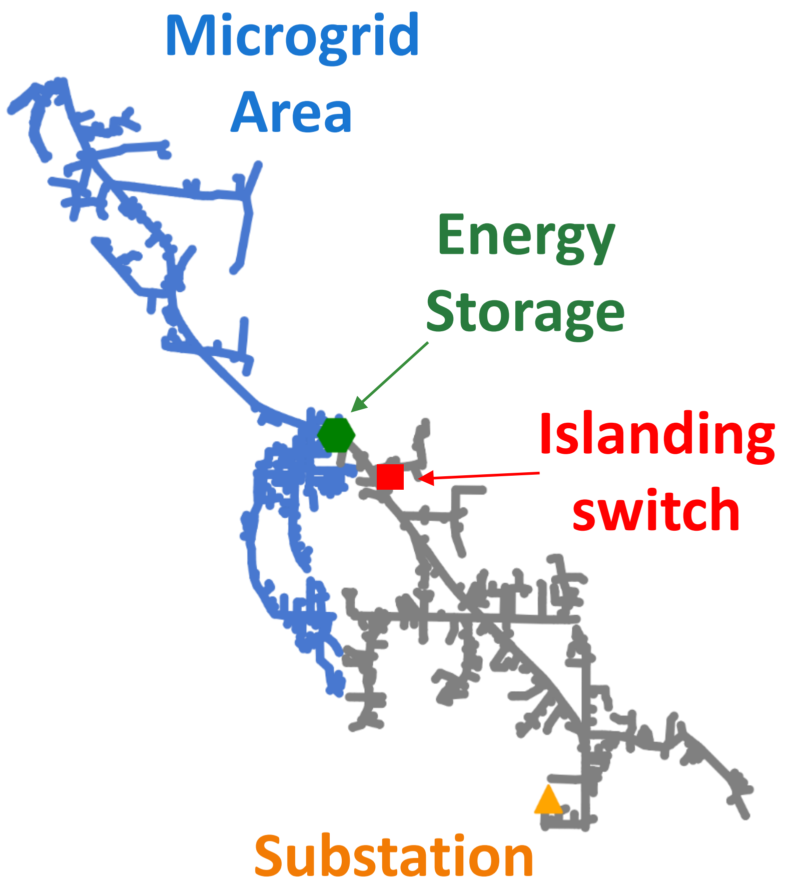
- IEC 61000-3-x recommends that the voltage unbalance factor (VUF) should be less than 2%

$$VUF = \frac{|V_2|}{|V_1|} \times 100\%$$

$|V_1|$ positive sequence voltage

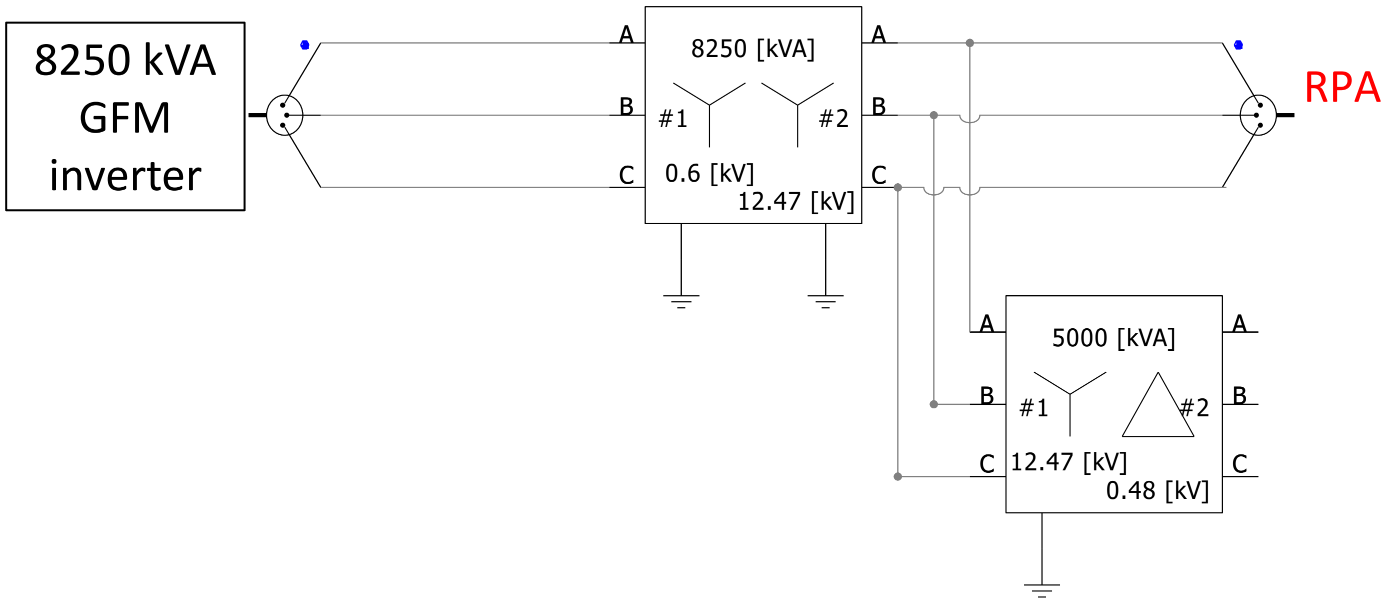
$|V_2|$ negative sequence voltage

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.

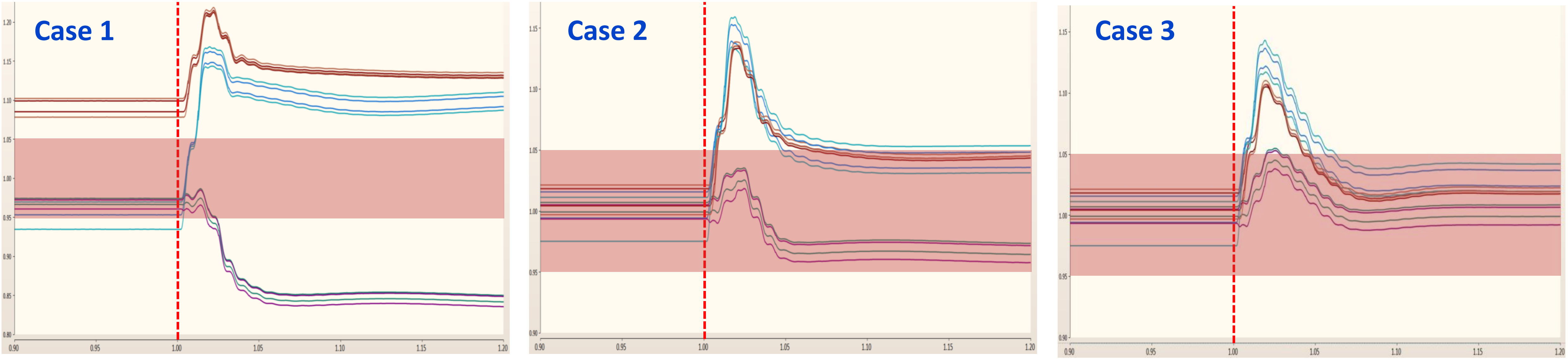
Case studies on GFM negative sequence voltage control

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)



Time(s)

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. For the microgrid circuit studied, 0.1 pu is found to be satisfactory based on the scenarios considered

*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

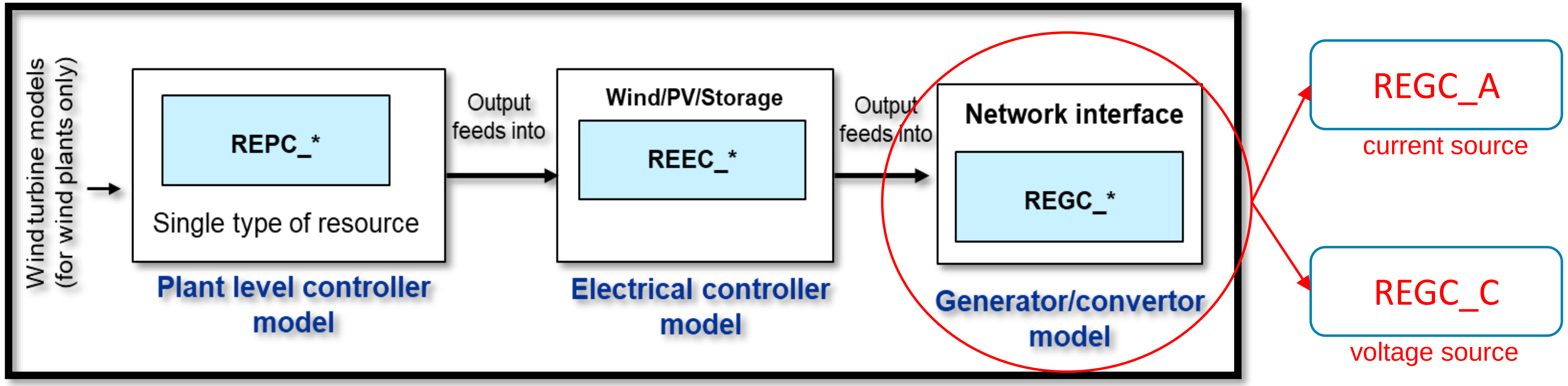
- Planning studies conducted at a time frame when exact models of inverter equipment may not be available

- 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.

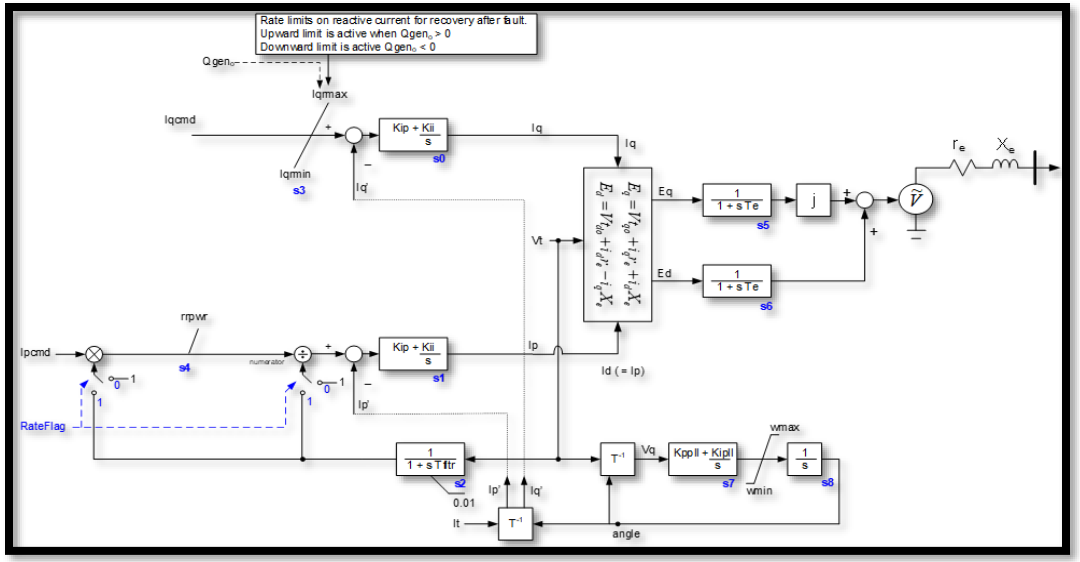
- But with different grid forming control methods, would there be a need for many different generic models?
  - Also would positive sequence modeling techniques remain to be valid?

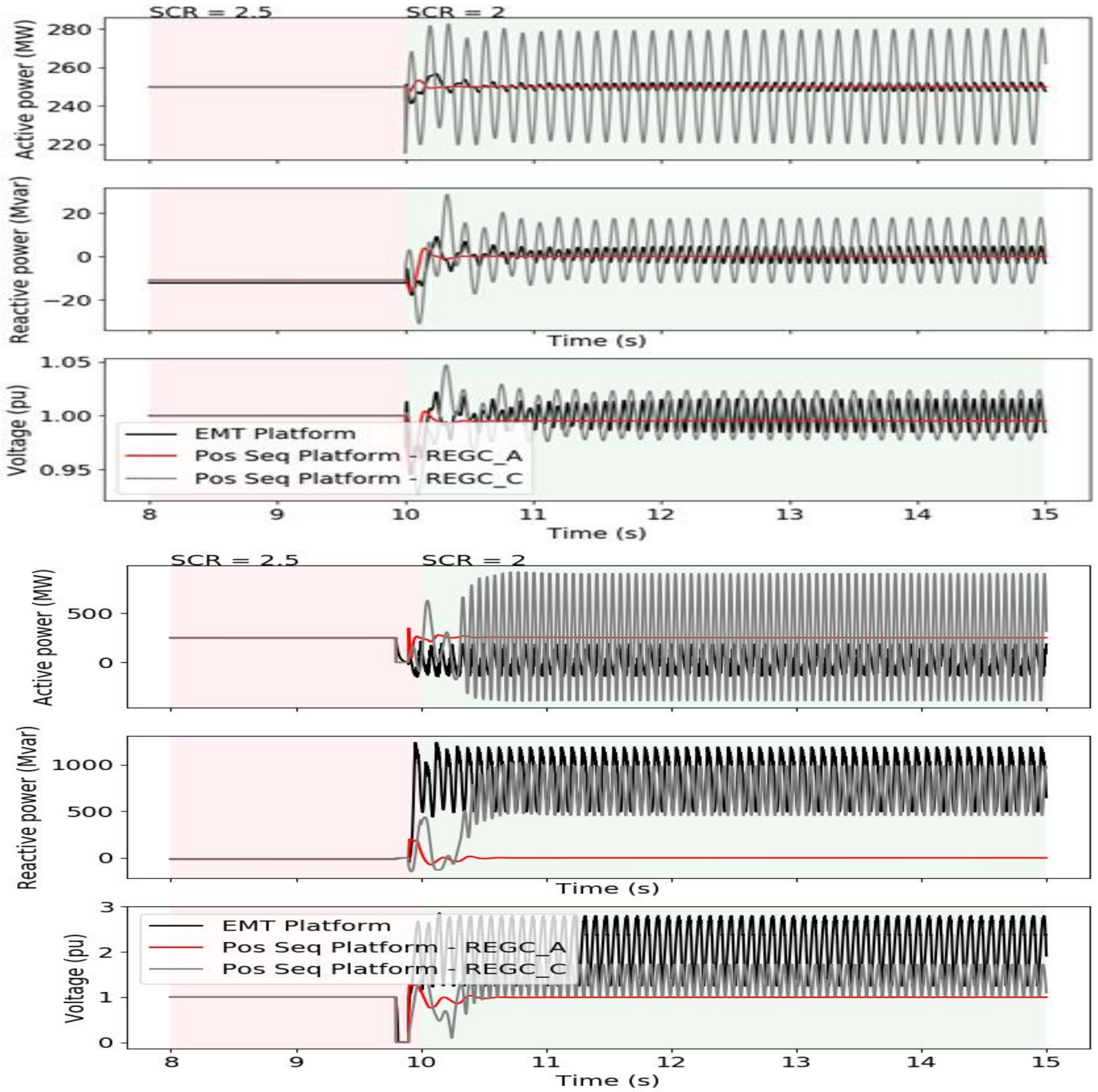
Positive sequence generic models



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.

The REGC_C generic model for low short circuit grids

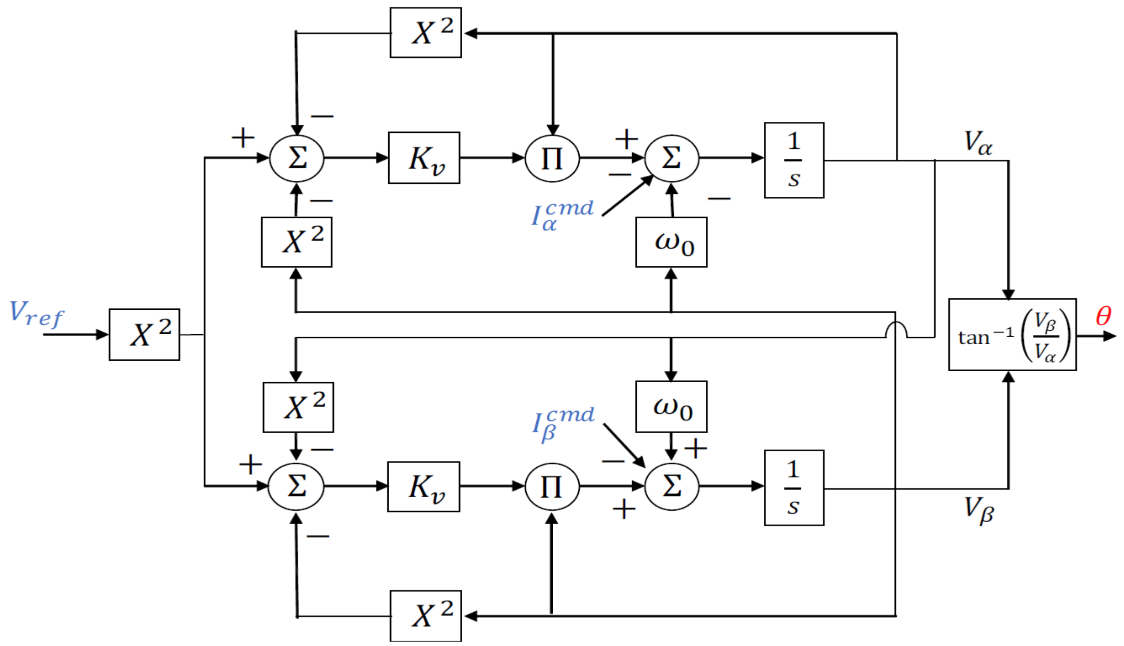




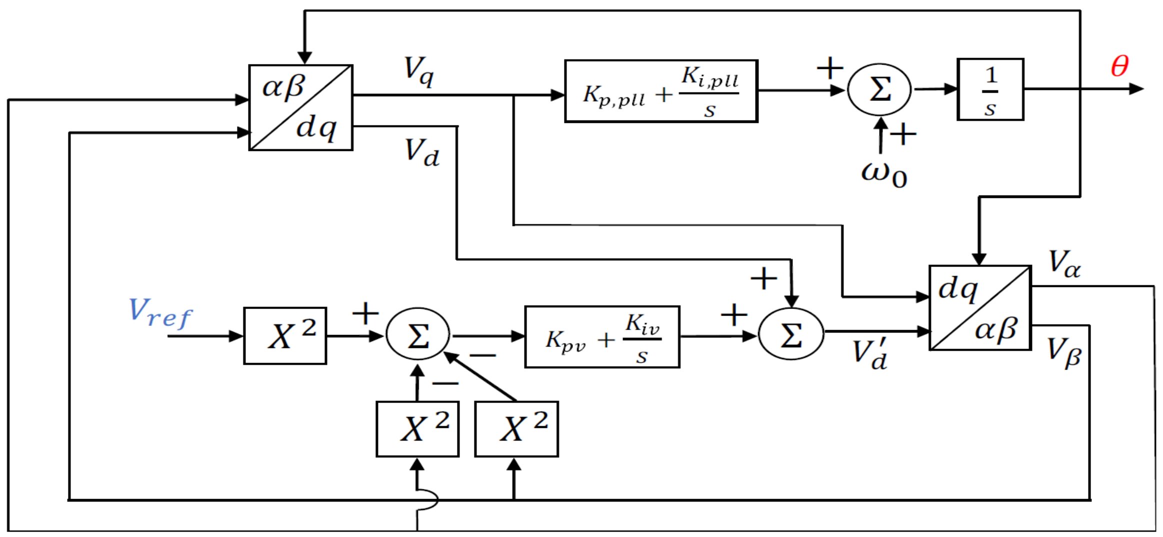
- Approximate representation of dynamic behavior of
  - Inverter's inner current control loop.
  - Inverter's phase locked loop (PLL)
- Current commands are translated into voltage reference commands behind an impedance

More details can be found in reference [7]

Conceptual operational similarities exist with PLL behavior



Virtual Oscillator

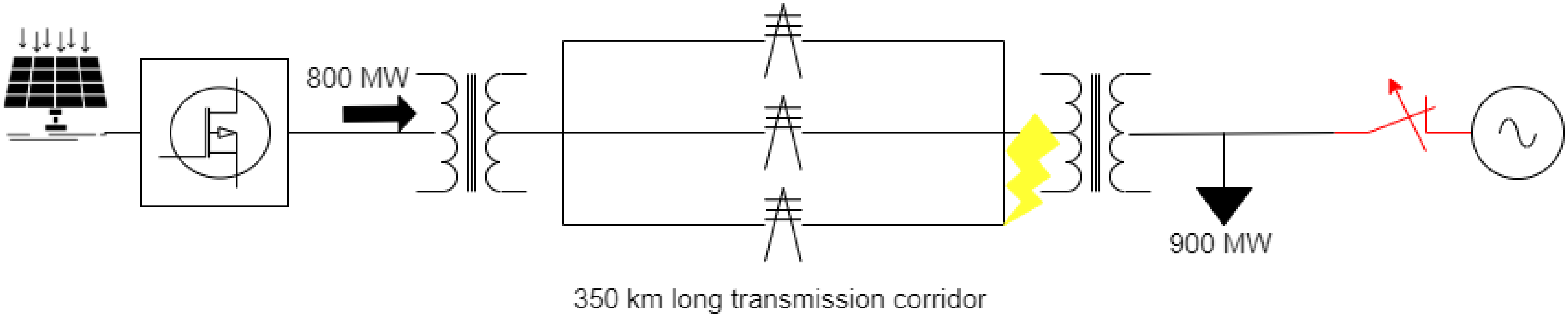


PLL – Voltage controlled oscillator

- 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

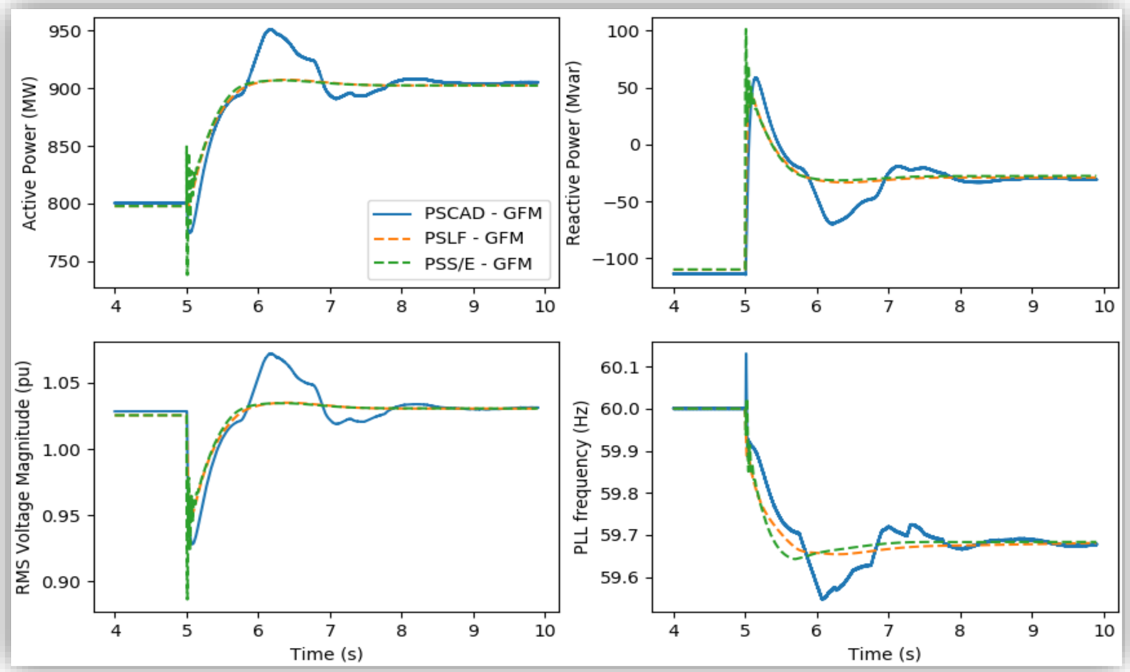


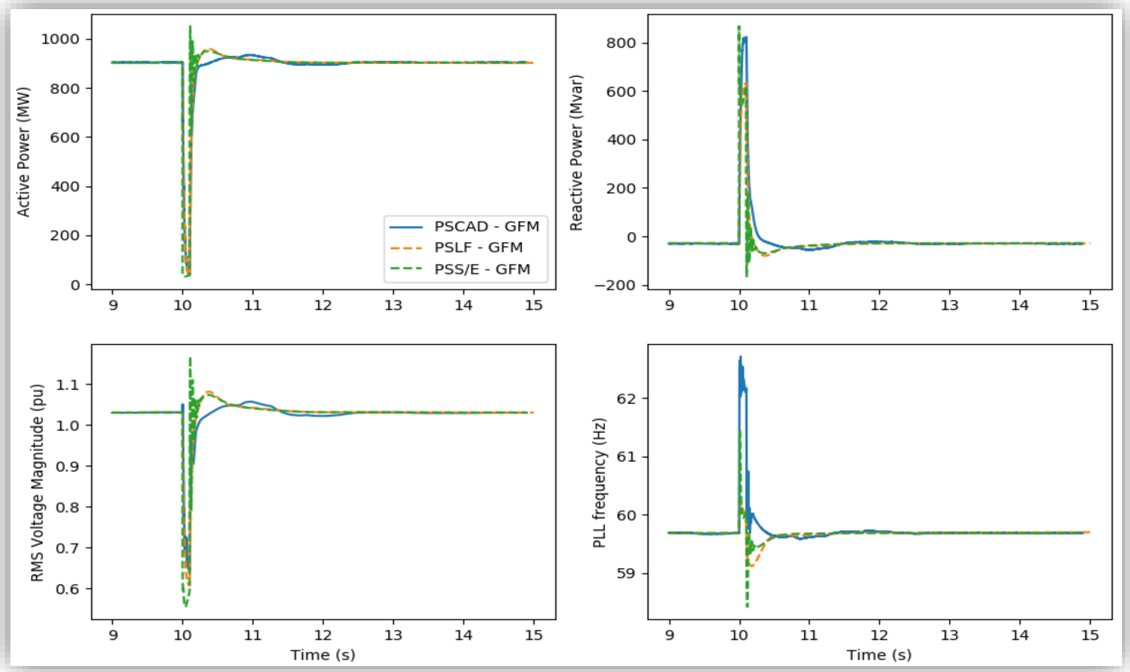
- Voltage at PV plant point of interconnection to be controlled
- Frequency control is implemented at device level
  - 10pu/s ramp rate limit

» 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

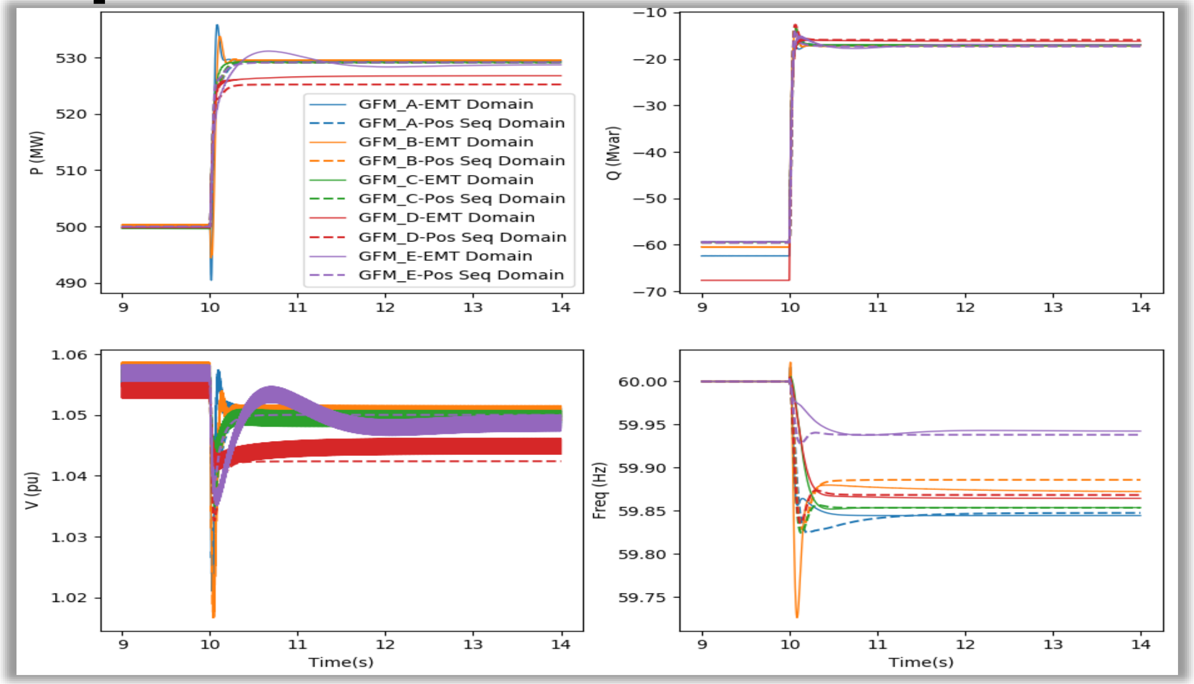


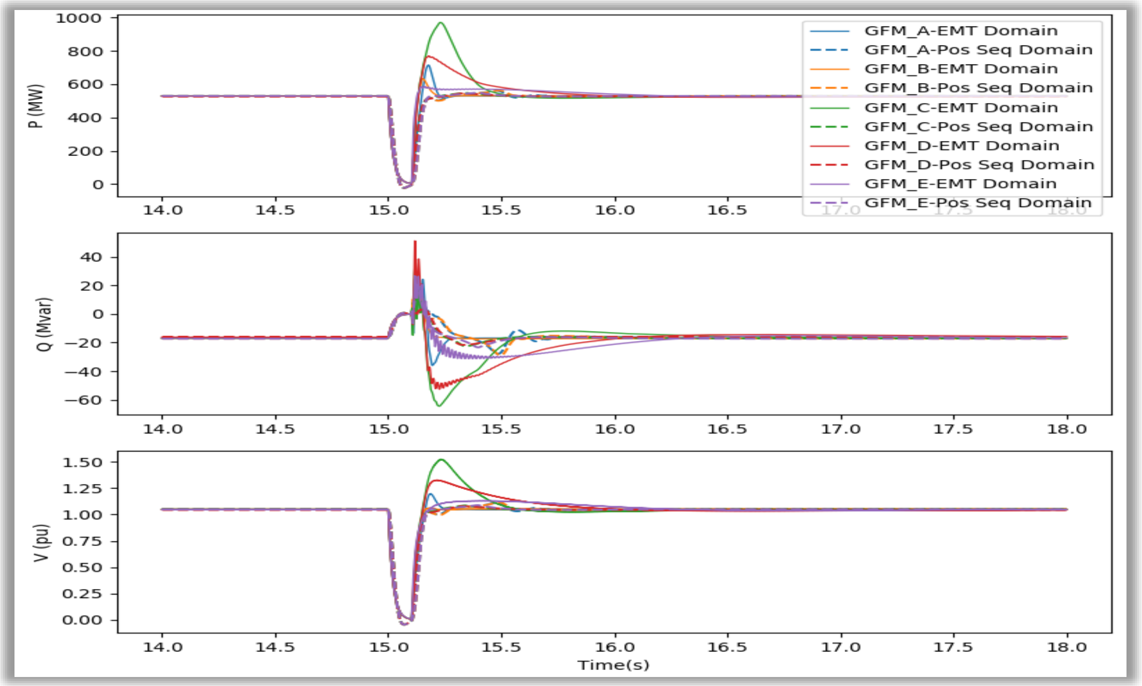


- Positive sequence response obtained using approved generic models
  - REGC_C + REEC_D + REPC_A
- Models should be parameterized with diligence and thoroughness

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

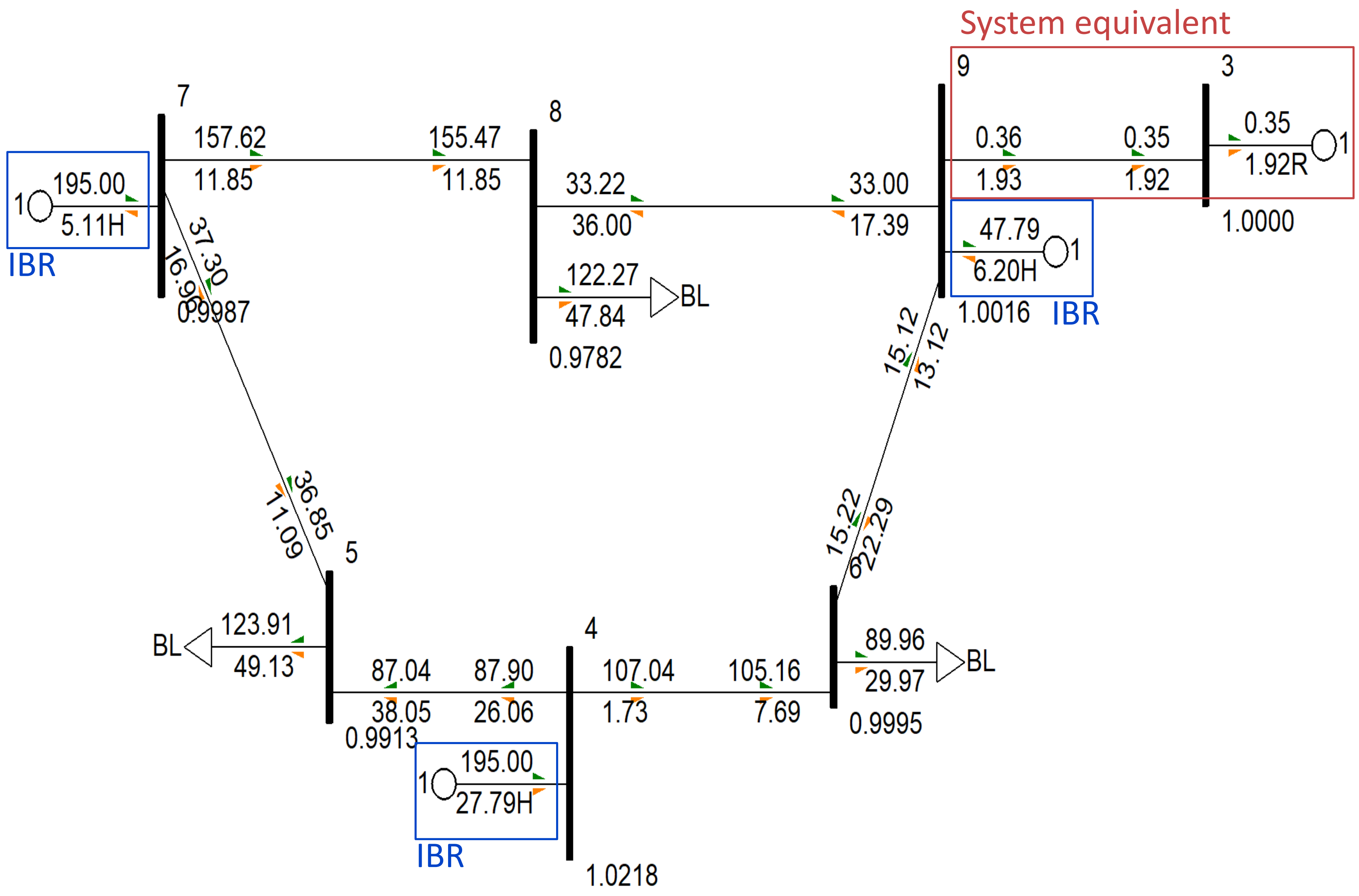
- These generic models in-turn allow for determination of grid forming capacity in future grids

- Both time domain and small signal stability concerns can exist

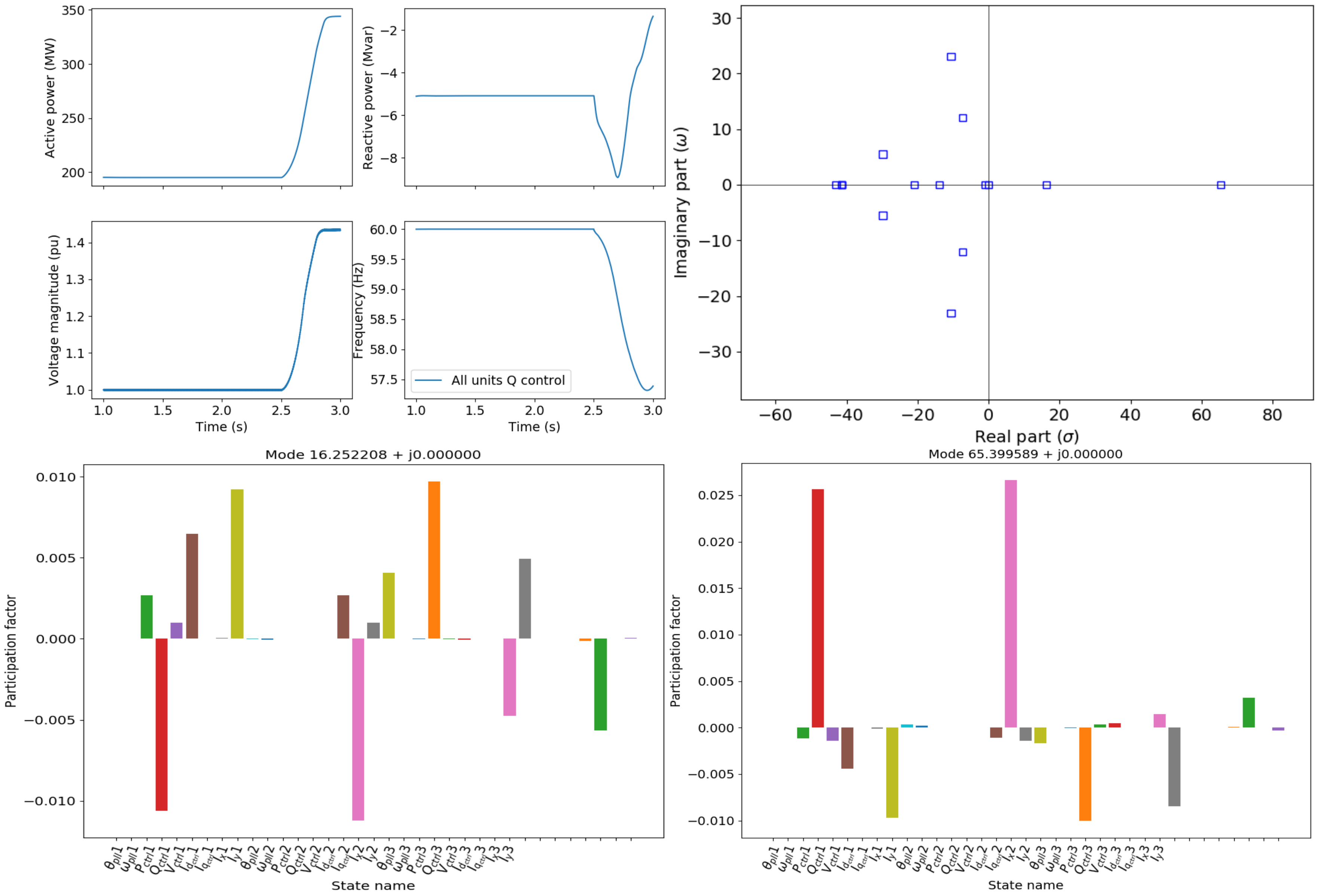
- Size of required grid forming inverters is not readily intuitive

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

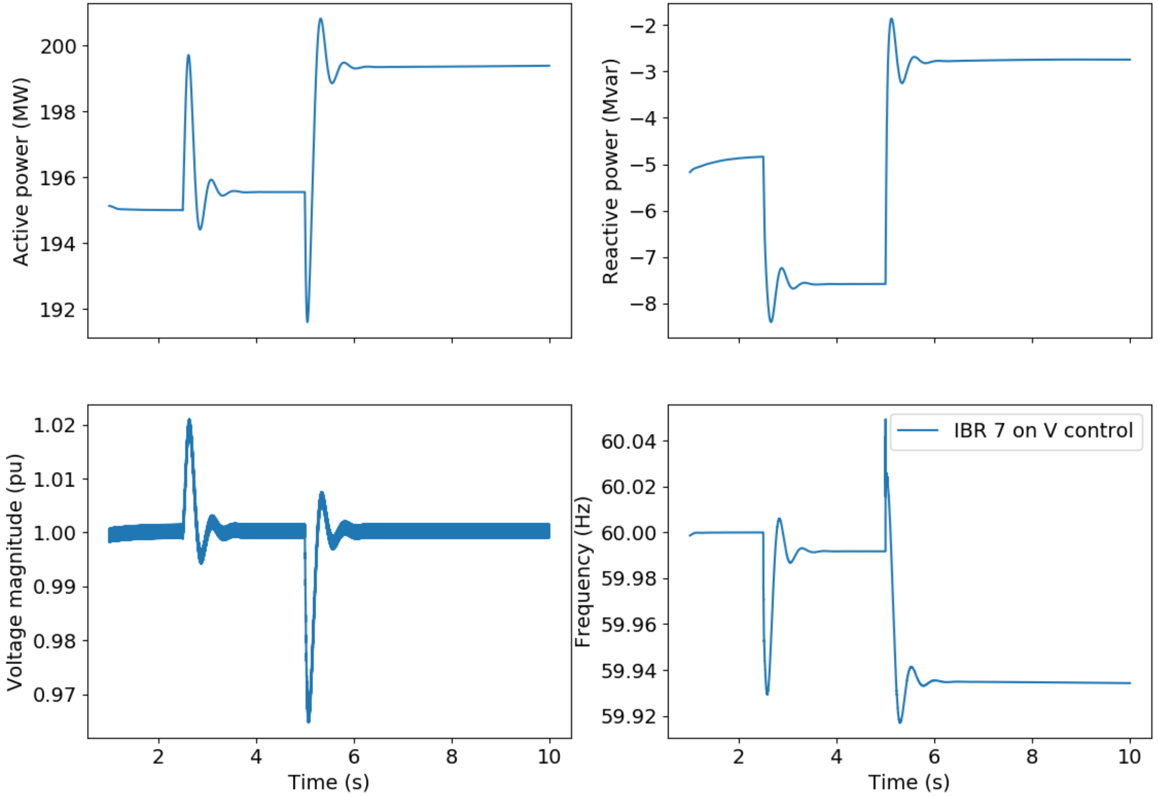


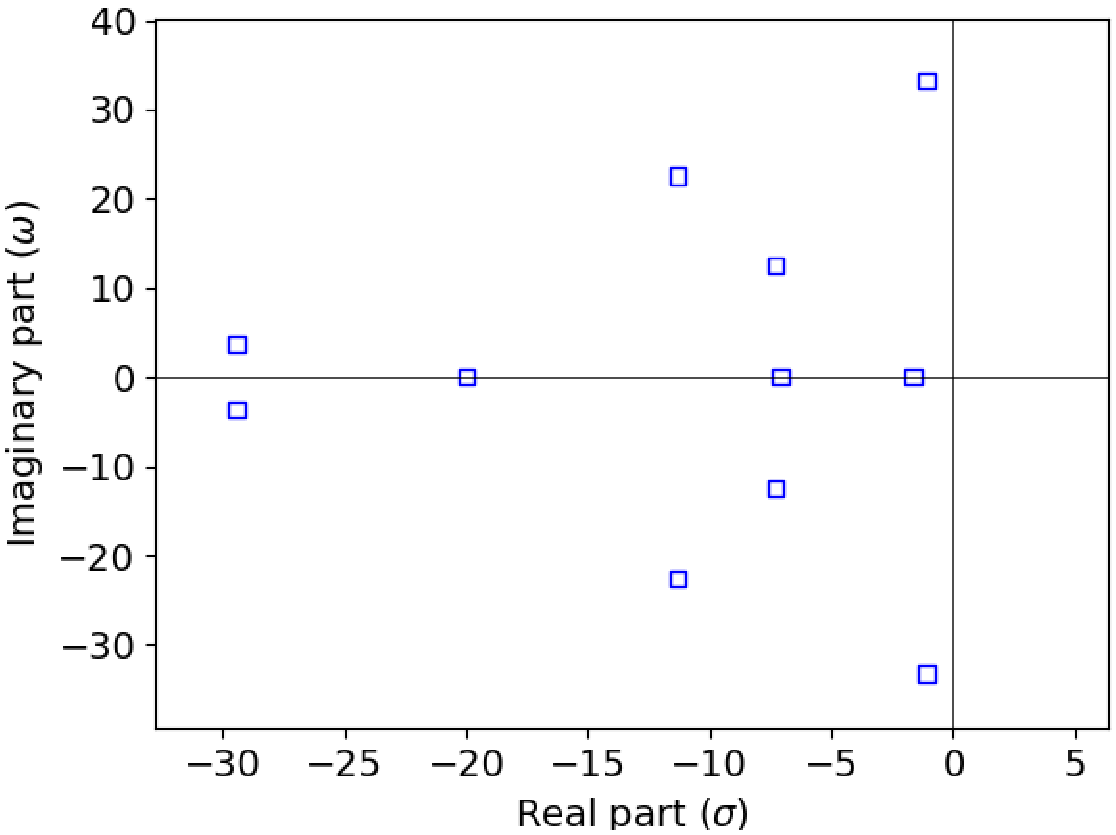
When all IBRs are grid following



- 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

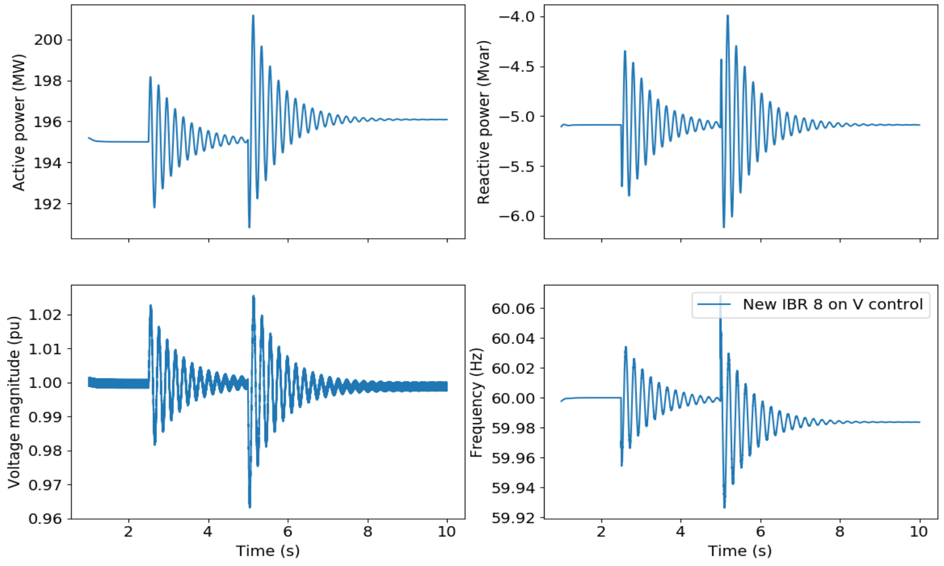


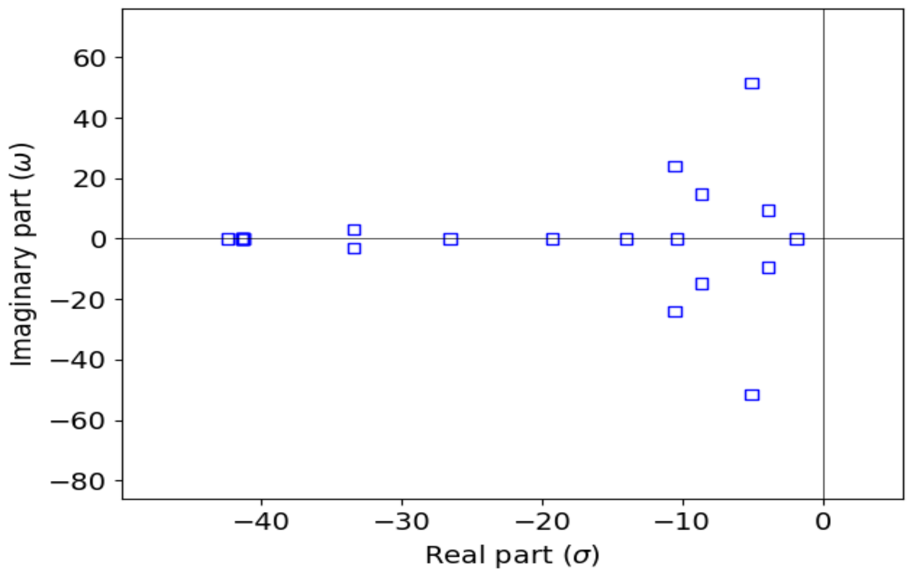


- Maximum settling time for performance of voltage control is 3.0s.
  - Within the specifications of draft IEEE P2800 standard!

- 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



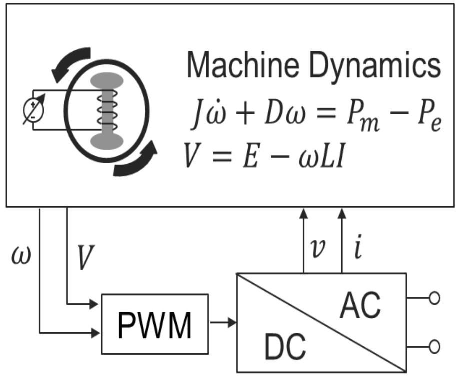
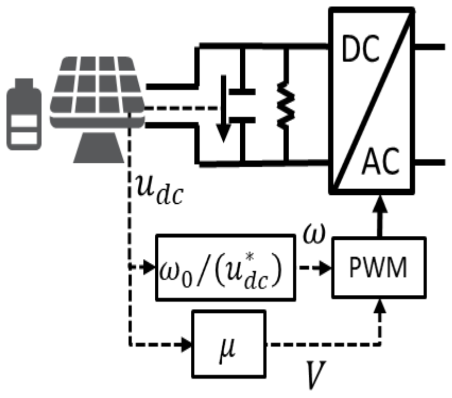
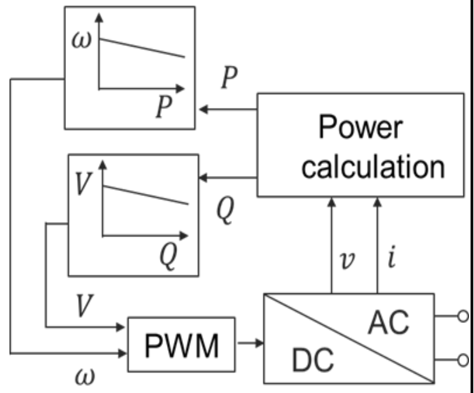
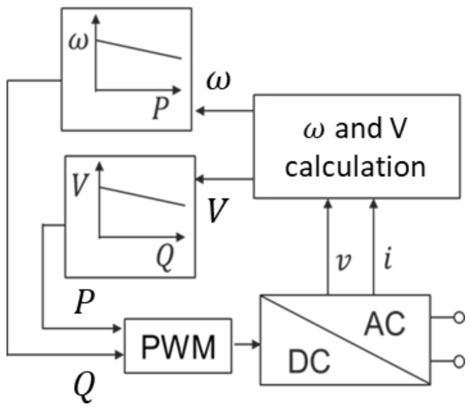
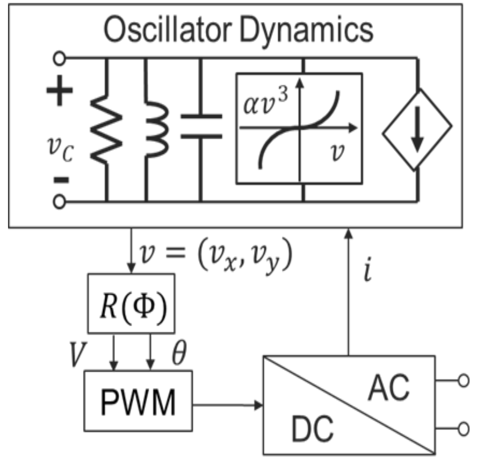


- A new 150 MVA inverter is required to maintain stability

- Installation of new/additional equipment could have economic considerations

Survey of Few GFM Control Methods

Several GFM Inverter Controls from the Literature

Virtual synchronous machine [2]	Matching control [3]	Droop based control [4]	FERC Orders 842 and 827 based control [5]	Virtual oscillator control [6]
				

Emulate Synchronous Machine Dynamic Behavior

P-f and Q-V Droop

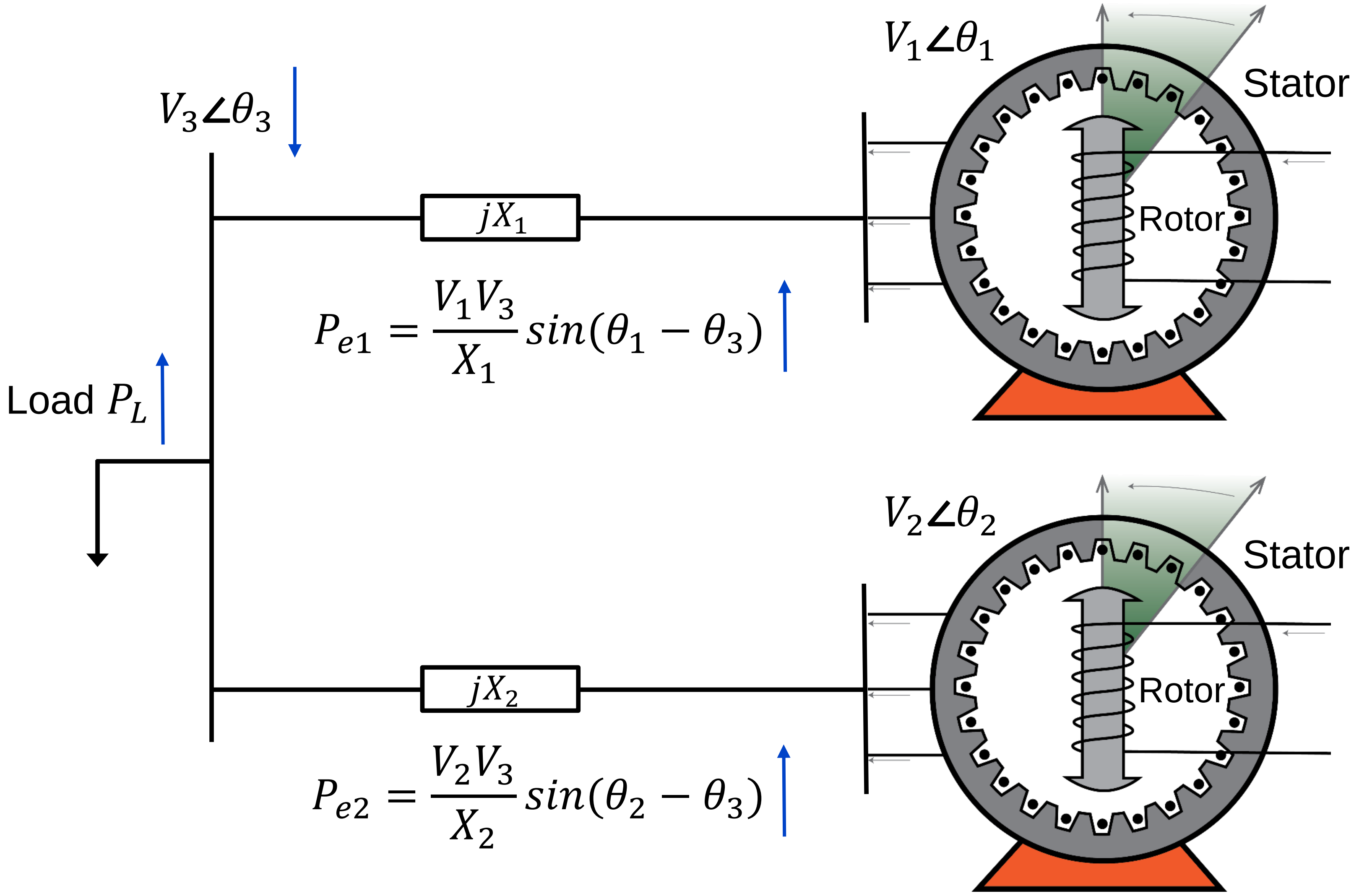
Nonlinear Control

Phasor-Domain Controller

Time-Domain Controller (Faster Dynamics)

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

Operation Principle of Synchronous Generators



$$P_{e1} = \frac{V_1 V_3}{X_1} sin(\theta_1 - \theta_3) \uparrow$$

$$P_{e2} = \frac{V_2 V_3}{X_2} sin(\theta_2 - \theta_3) \uparrow$$

SG swing equation

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

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

Governor Control

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

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

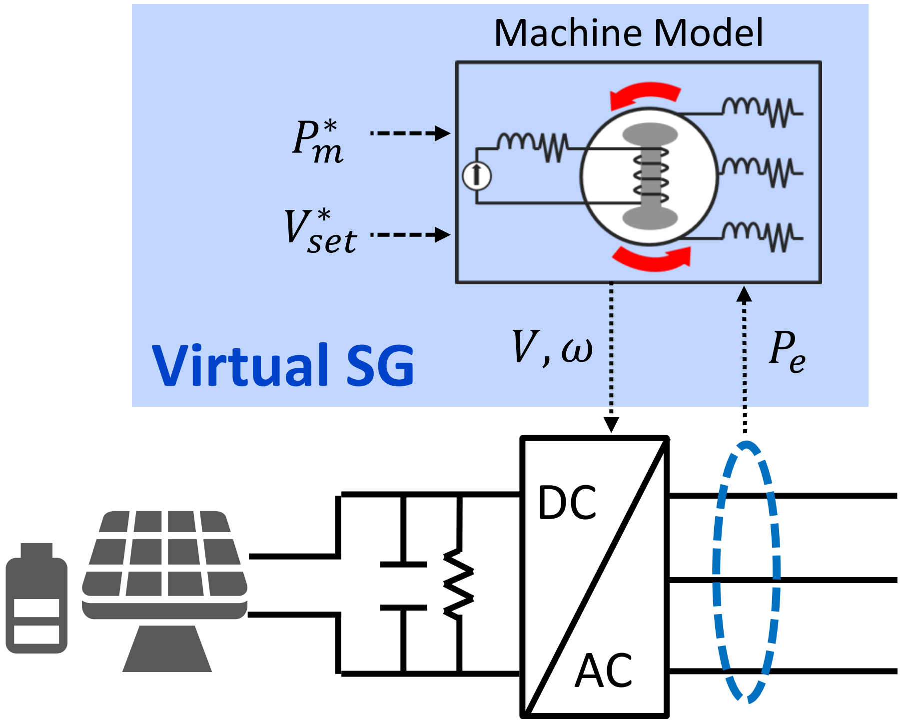
At the new steady state: $\omega_1 = \omega_2$

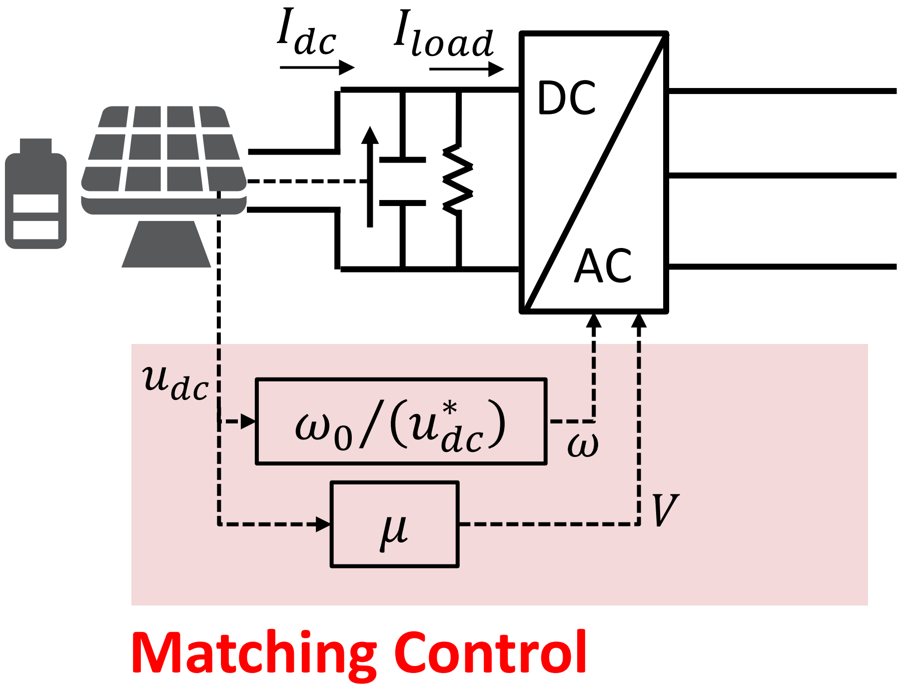
The load increase is shared by the two SG based on the governor droops:

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

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

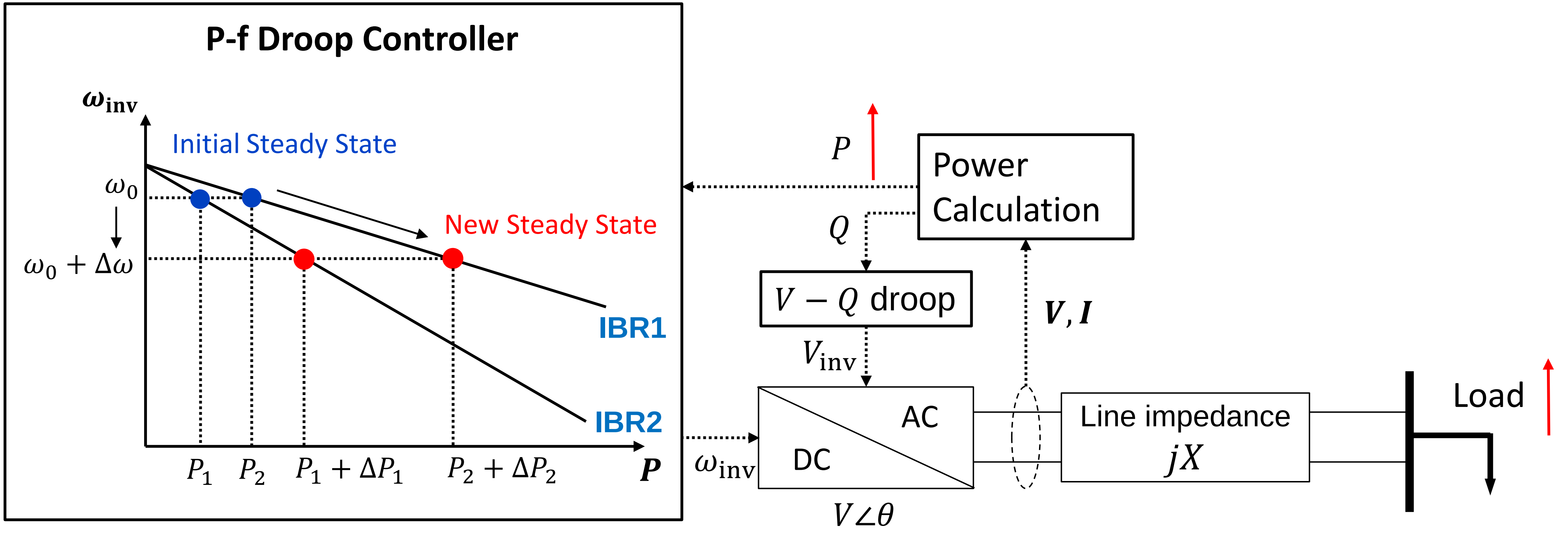
Operation Principle of Virtual SG and Matching Control





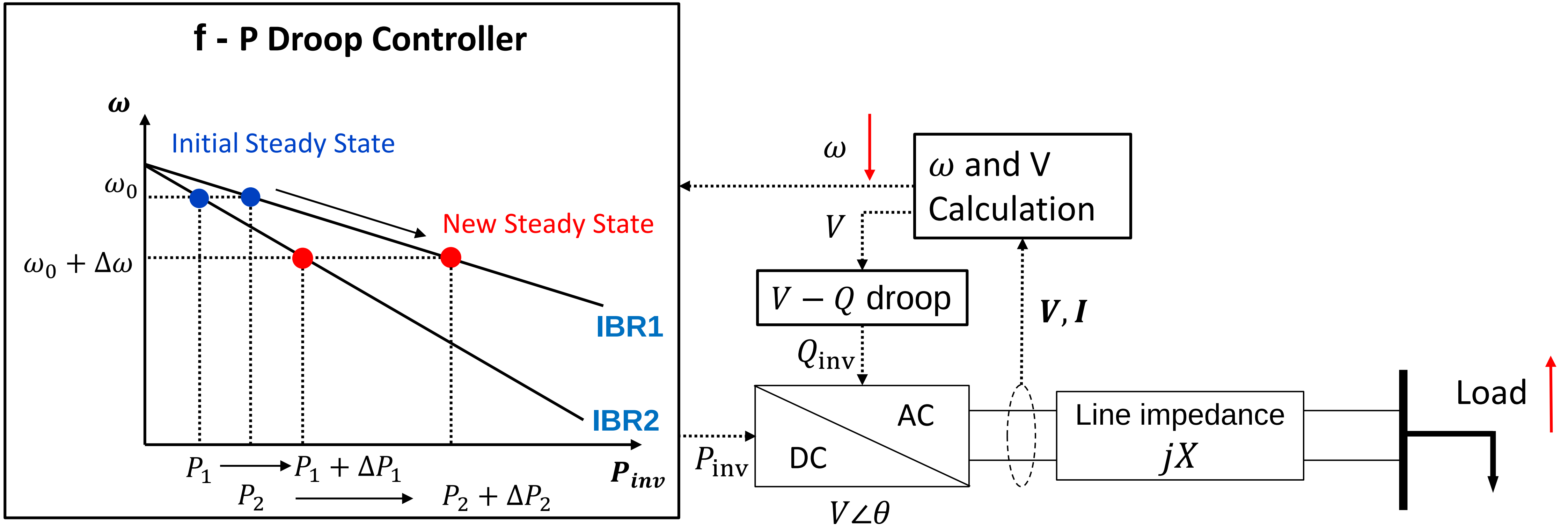
- Virtual SG and matching control both implement the SG swing equation and the droop characteristics in the inverter control loop.
- The difference is that virtual SG measures ac side voltage and current while matching control mainly measures dc side voltage.
- These method will provide inertial response 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

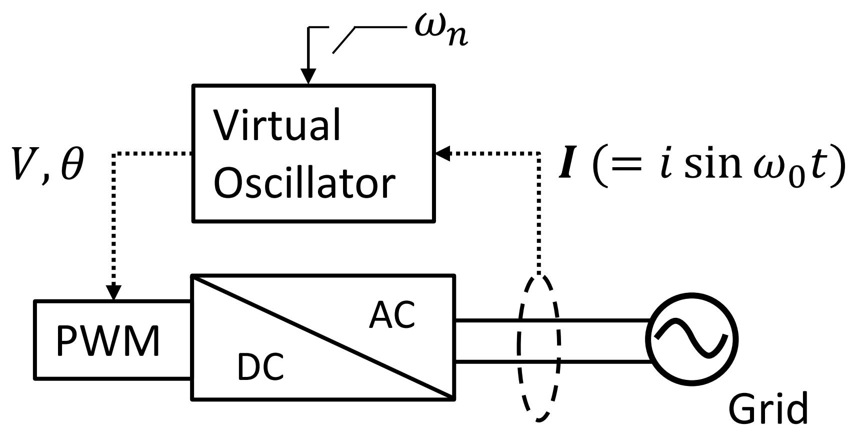


Load change is shared by IBRs with f-P droop

Operation Principle of Virtual oscillator Control (VOC)

Liénard type VOC

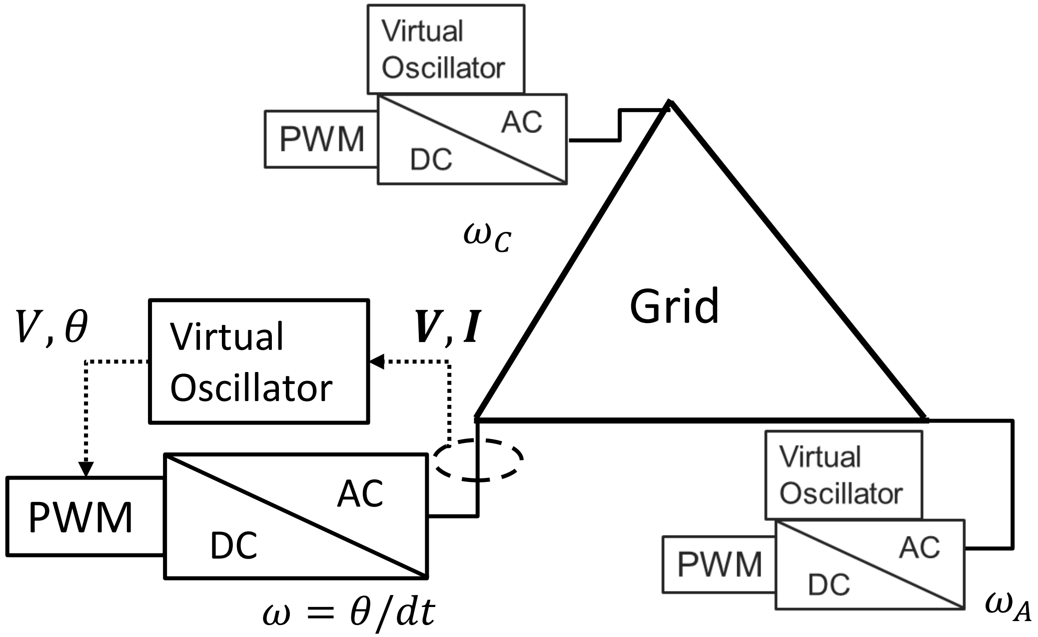
- Determines frequency as neighborhood value of current input
- Cannot specify a signal of P and Q setpoints



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

Dispatchable VOC (dVOC)

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



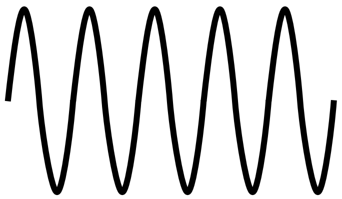
$$\boldsymbol{\omega_A = \omega_B = \omega_C = \omega_0 \text{ at } t \to \infty}$$

Liénard type VOC

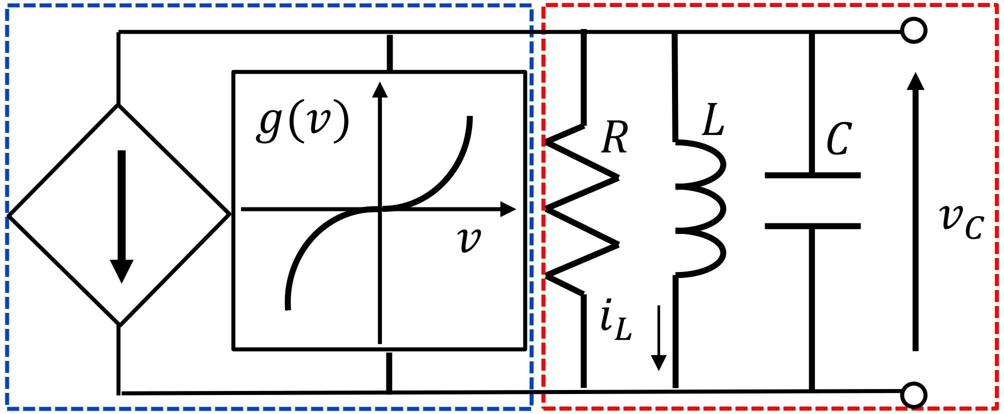
LC Resonant Circuit

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

Input



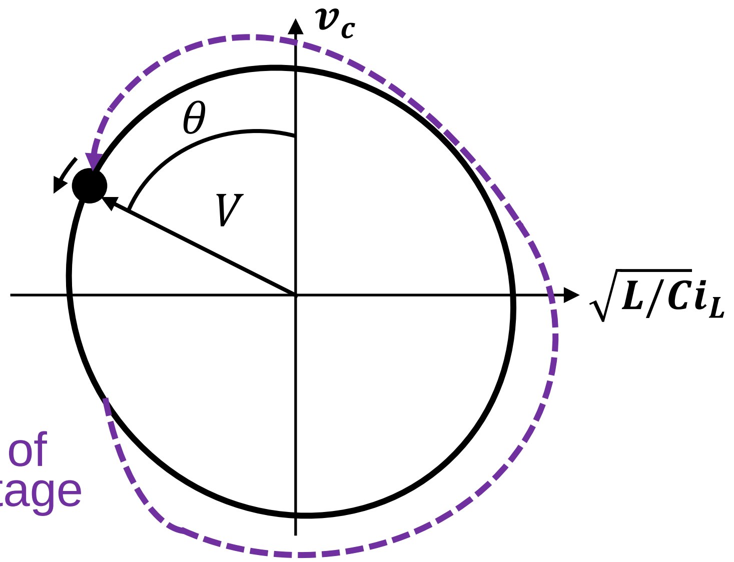
Load current



Output

v_C, i_L →

$$V = \sqrt{v_c^2 + \left(\sqrt{L/C}\, i_L\right)^2},$$
$$\theta = \tan^{-1} v_c / \sqrt{L/C}\, i_L$$



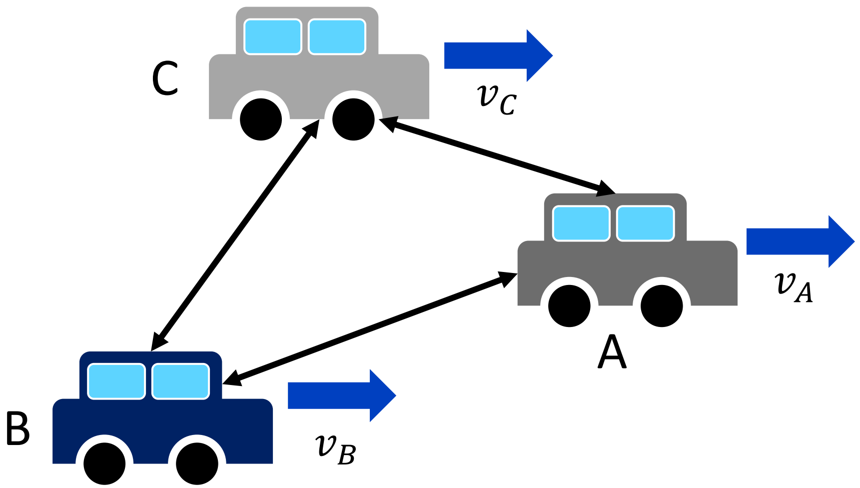
Nonlinear Damping

- 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

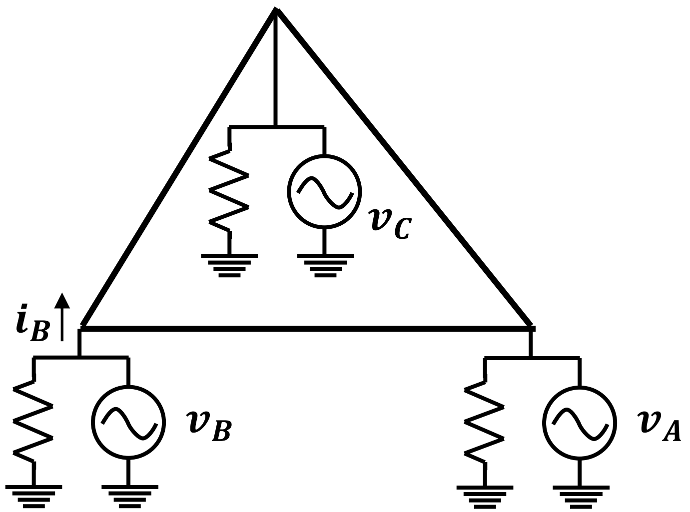


$$\frac{d}{dt}v_A(t) = \frac{1}{2}\big(v_C(t) - v_A(t)\big)$$
$$\frac{d}{dt}v_B(t) = \frac{1}{2}\big(v_A(t) - v_B(t)\big)$$
$$\frac{d}{dt}v_C(t) = \frac{1}{2}\big(v_B(t) - v_C(t)\big)$$

$\boldsymbol{v_A = v_B = v_C}$ **at** $\boldsymbol{t} \to \infty$

Key factors: Same control policy, Other's state

dVOC for inverter-based network



$$\boldsymbol{v_i} = [V_i cos\theta, V_i sin\theta]$$
$$\frac{d}{dt}\boldsymbol{v_i} = \underbrace{\omega_0 J \boldsymbol{v_i}}_{\text{rotation at } \omega_0} + \underbrace{error_\theta(\boldsymbol{i_i^*}, \boldsymbol{i_i})}_{\text{phase error}} + \underbrace{error_v(|\boldsymbol{v_i^*}|, |\boldsymbol{v_i}|)}_{\text{voltage error}}$$
$$\boldsymbol{i_i^*} = \frac{(p_i^* + jq_i^*)}{\bar{\boldsymbol{v_i}}}, \boldsymbol{i_i} = \sum_j \boldsymbol{Y_{ij}}(\boldsymbol{v_i} - R(\theta_{ij})\boldsymbol{v_j})$$

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 can have stability limits beyond which synchronization with the grid can be lost or other types of instability can occur.

Conducting collaborative industry-wide research in grid forming technology will be critical in the near future

U.S. DEPARTMENT OF ENERGY

unifi is co-led by NREL, University of Washington, and EPRI

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

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Appendix

Answer to questions submitted via webinar chat

1. To make a distribution system truly mimic the "current source network" wouldn't the distribution system components also have to have current controls, and not voltage controls (tap changers, etc.) like they do today?

The illustration was mainly to show the concept that even a system with only current sources can work if the current injection is controlled properly. It is true that power system will have equipment behaving as voltage sources. In this case properly controlled current source can work along with voltage sources in the system as well, while collaboratively establish system voltage and frequency.

2. It makes sense to focus on performance. However, does it not ultimately come down to controls?

Performance is what matters to system planners/operators. Once the performance requirements are clearly defined, inverter manufacturers can design control accordingly to meet the requirements. In other words, properly defining the performance requirements can help drive the control design of grid forming inverters. As an example, system planner needs to define requirement on grid forming inverter fault current levels considering protection coordination, following which the inverter control can be designed to satisfy the requirement. This is from the perspective that there can be many different control structures that can meet the same performance requirements.

3. What is the typical response time for a grid forming inverter to reach full output power? Is the response time of a battery critical for a grid forming inverter to provide system stability? Any rule of thumb on the required response time for batteries?

Typical response time of an inverter will depend on the response characteristics of the source behind the inverter. For example, the same inverter may be applied to both a battery and a wind turbine. However, the response time of the inverter when connected to the wind turbine can be slower than the response time when connected to the battery due to additional constraints from the wind turbine. Response time of the source is critical to be considered when evaluating system stability as it will influence the decision-making process related to how many sources should be available to provide response.

4. PLL (phase locked loop) assumes you're using PI controllers, right? Alternatively, you may use FLL (frequency locker) with resonant controllers. If there's no PLL nor FLL, how to synchronize GFM inverters with the remaining grid for non-islanding application?

PLL and FLL are synchronization blocks and they both can work with either PI controllers or resonant controllers for inner loop current control. Without PLL or FLL, an inverter can still synchronize with the grid by other mechanisms. One way is to control the inverter as a voltage source and emulate the swing equation of a synchronous machine. In this case, the frequency and angle of the inverter will swing until the frequency settles down to the grid frequency and the angle settles down to a fixed value.

5. In systems with synchronous generators remaining, at present can grid forming sources provide black-start power to pick up large loads such as draught groups (maybe pumps), mills, etc. for large fossil fuel generating units?

Yes, they can. There are few example systems where grid forming batteries have been used to blackstart diesel and gas turbines. Grid forming batteries can also be used to start auxiliary loads for fossil fuel units. Here, it is important to design the inverter in a manner that it will be able to provide the starting current that large induction motors may draw. Additionally, if any transformers are present, the inverter should be able to provide transformer energization currents.

6. Are grid forming inverters commercially available?

In limited scale, grid forming inverter are commercially available, especially for battery energy storage system for microgrid applications. In most cases, commercially available BESS inverters will operate in grid following mode when grid connected and transition to grid forming mode when islanded. Larger scale grid forming offerings are also becoming available. There are a few utility scale transmission connected grid forming projects under trial and construction in Australia and Europe.

7. How would grid forming inverters perform under low inertia scenarios and areas with high industrial motor load types where inertia becomes critical?

The interaction between grid forming inverters, grid following inverters, and motor loads is crucial to be studied. In a local region of the network, industrial motor load can be impacted not only from inertial energy reaction perspective but also from a voltage/reactive power perspective. The total current rating of the inverters has to be considered when evaluating the behavior of the inverters with industrial motor loads.

8. Would grid-forming be an application for residential rooftop solar without BESS to operate when the grid is down?

To our knowledge there are few commercial PV residential inverters (like SMA Sunny Boy) that can provide limited power (up to 15A at 120V) in off-grid mode if enough sunlight is available. Residential Inverter will be disconnected from the grid and will not inject any current to grid during outage. However, the SMA inverter provide an option to connect to its 120V outlet (separate from its 240AC terminal), where it can support loads up to 15A if enough DC power is available.

9. Power oscillation dampers can be made available even from grid following inverters, correct?

Yes, that is correct. Power oscillation dampers can be designed and made available even in grid following inverters.

10. What is the maximum angle deviation that could be ridden through by a PLL? Any lab test results on this?

The maximum angle deviation that an inverter can ride through depends on its control design, including but not limited to the PLL design. It also depends on the characteristics of the system that the inverter is connected to (e.g., weak or strong grid) and its operating condition (e.g., level of power generation). We will have lab test results on this and many other aspects later through a supplemental project: Inverter-Based DER Dynamic Response Characterization for Protection, Planning, and Power Quality (https://www.epri.com/research/products/000000003002014731)

We also have further research work which can enable system planners understand and evaluate the maximum angle deviation for inverters depending on the system condition. If interested, please reach out to us to learn more regarding this research effort.

11. What are the consequences we need to be aware of, especially from a reliability point of view, for not having a stiff IBR (inverter-based resource) system?

Here, the concept of stiffness will first have to evaluated. A stiff system as per conventional synchronous machine norms may be different from the perspective of a stiff system from an IBR system perspective. However, once the definition of a stiff system has been identified, and is in-line with IBR behavior, then the consequences of not having a stiff system remain the same as today's network i.e., not having a stiff IBR network (where again stiff has been defined based on IBR behavior and not based on synchronous machine behavior) can result in loss of load and stability.

12. Do any of the inverters tested in EPRI labs have negative sequence current control during unbalanced transients? Or do they only have positive sequence control?

We have tested two commercial three-phase string inverters (each around 30 kW) to investigate their negative sequence behavior. Both have limited negative sequence current output (or equivalently high negative sequence impedance) when the terminal voltage is unbalanced. This suggests that the inverters have negative sequence current control to limit the negative sequence current output. We will be investigating on this for all the inverters (10+) that will be tested in the inverter dynamic characterization supplemental project (https://www.epri.com/research/products/000000003002014731).

13. I wonder if these controls would interact with each other for multi-infeed IBRs at the same point of interconnection (POI)?

There will be some interaction between the inverter controls. However, the controls should be designed/tuned properly such that negative interaction is avoided.

14. You have control of the SCR (short circuit ratio) in your studies, but in the real-world, wouldn't the SCR value be dependent on the planner's setups of big transmission circuits accounting for faults/system protection

Presently the SCR at distribution substations is relatively high. However, as renewable penetration increases in the transmission system, distribution substations at certain locations may have decreased SCR. The study shows that if this is the case, then present-day IEEE 1547-2018 compliant inverters can have instability issues. It is true that in transmission planning, measures can be taken (e.g., add/upgrade transmission lines, require sufficient grid forming capability from the transmission connected IBRs) such that the SCR at the distribution substations remain sufficiently high. The purpose of the study is to show that by utilizing grid forming control, DERs can work with lower SCR therefore reducing the need to strengthen the transmission system. Additionally, this work aims to understand how DERs/IBRs would behave when an SCR value is reached. However, the concepts and dynamic behavior can be extended to scenarios even when exact value of SCR is not known.

15. Are there any adverse impacts to tuning a PLL for a weak grid and then operating it on a stronger grid (e.g., varying levels of generation commitment)?

In tuning the PLL control, if the IBR is expected to work under different grid strength, then it needs to ensure that the PLL works adequately in all conditions. Tuning a PLL may also include improving the control design (e.g., adding additional control loops), besides tuning the parameters of existing PLL control. There can be situations where a PLL that is tuned for weak grids may result in sub-optimal performance in strong grids. This has to be considered while carrying out the tuning exercise.

16. Does the instability due during low short circuit conditions have implications for ride through?

Based on this study, due to the slow response of volt-var, DERs with present-day inverter control do not inject sufficient reactive power following the voltage dip. As a result, the DER terminal voltage becomes very low which will trip the DER (notice the DER tripping was not simulated since the DER protection was not considered). On the other hand, if the DERs have grid forming control to fast inject reactive power right after the voltage dip, the voltage at the DER terminal is improved and the DER can successfully ride through the disturbance.

17. Since the synchronous condenser in this study is used without a power system stabilizer (PSS), does that mean grid forming IBR used here has a PSS?

The grid forming IBR has a fast and robust voltage control loop, but it did not have an explicit PSS. Because there are no mechanical time constants involved in the grid forming IBR, the behavior of the system is more robust.

18. To relate the droop type controls simulated in previous slides to current IEEE 1547-2018 standards, which have both volt-var and frequency droop control functions, would you characterize the simulated units as simply having much shorter open loop response times for reactive current droop (and perhaps higher gain) or are there other major changes in control topology that make these units fundamentally different from today's grid following inverters?

We have some encouraging results (including the results presented here) showing that by having faster voltage and frequency response from today's grid following inverters, it can provide some grid forming capabilities. However, research is ongoing at EPRI to investigate whether this type of control can meet all the grid forming requirements in different system conditions. Please refer to the references below for more information and do contact us if we can help provide more information.

1) 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.

2) IBR Modeling Guidelines for Weak Grid Studies and Case Studies, EPRI Palo Alto, CA: 2020, 3002018719 (https://www.epri.com/research/products/000000003002018719)

19. The green curve with IBRs providing governor like capability: is that what is also referred to as synthetic inertia?

Not really. Since the IBRs considered in this study do not have any mechanical time constant (as there is no turbine or governor), traditional governor response by default is faster. As a result, the IBR is able to inject current without being hindered by mechanical time constant. This manifests as a fast frequency response on the network side. It is governor like response, not inertial type response because the active power output is adjusted based on frequency deviation, rather than the rate of change of frequency.

20. Not related to the calculations, but would you include the latency of the communication in your overall time response?

Yes. Any communication latency within the plant, such as between plant controller and inverters, would have to be considered when evaluating overall time response. This is one of the reasons why for responses such as fast frequency and voltage control, it can be recommended to have this response at the inverter level and not at the plant level.

21. How do you define and determine the droop coefficient for IBR providing governor type response? Can it be tunable as needed?

In the study considered, the value of the droop coefficient for the IBR was the same value as droop coefficient in the synchronous machine that was replaced. And this value of droop gain can be tuned as needed.

22. Any EPRI documentation on calculating the sizing requirement for the energy storage?

Sizing of energy storage system depends on many factors, including use cases. https://www.der-vet.com/ might be a good resource to explore. Please do contact us for further information.

23. At EPRI labs, have you tested any commercially available controllers for Synchroconverters (Inverters that mimic synchronous generators)? If so, how do they stack up against the performance/response of conventional synchronous machines?

We have not yet tested commercial grid forming inverters at our lab. We do have plan to test different types of grid forming inverters as more commercial products start becoming available in coming years.

24. What would be the fault current (estimate) contribution at bus 5 from the 200MVA PV1 plant?

The PV plant has a maximum current limit of 1.2 pu and it was set to operate in reactive current priority mode. As a result, it contributes 1.2 pu of fault current.

25. Can we just mandate controls that can tell the difference between frequency response and ordinary work, and have no ramp rate limit (or a faster limit) for the former?

It would be possible to have adaptive controls that can change the ramp rate limit. However, based on the characteristics of the energy source behind the inverter there can be a certain ramp rate limit which cannot be overcome.

26. How do these ramp rate limits compare with IEEE 1547-2018 maximum requirement? Would these ramp rate limits be dependent on the size of the IBR?

Both IEEE 1547-2018 and IEEE P2800 mentions that the maximum available power ramp rate shall be as fast as technically feasible and the DER/IBR shall not be required to change its active power output at a rate greater than its ramping capability. For an IBR, the ramp rate in terms of active power change (per unit based on IBR rating) per second is mostly affected by the source behind the inverter (e.g., battery can provide higher ramp rates compared to wind turbines) rather than the size of the IBR. The ramp rate is usually defined in per unit of the size of the IBR and the energy source behind the IBR. Hence, the kVA/MVA rating of the IBR should not impact the ramp rate.

27. Can you upgrade existing grid following Inverter to grid forming by updating firmware?

Some newer designs of grid following inverters might be able to behave as grid forming by firmware update. However, it also depends on the performance requirements for grid forming inverter and whether the existing hardware of the grid following inverter is sufficient to meet the requirements. For instance, if black start is required for grid forming inverter, the inverter needs to have back up power to start the inverter control board and communication, which may not be there for the grid following inverter. Similarly, if high fault current level is required, capacity of the inverter may need to be increased.

28. This is not a typical transformer energizing means and would not likely be a standard for energizing Distribution transformers. How can this be tackled for blackstart studies?

Use of a soft energization resistor may not be a typical means of energizing transformers. There are other energizations schemes available such as slow voltage ramp. For each blackstart path to be evaluated, the energization mechanism that can be used should be based upon the type of equipment in the cranking path and with consideration of its capabilities.

29. Was the blackstart simulation exclusively performed in an EMT simulation software?

A combination of both EMT and RMS/positive sequence software were used. The positive sequence software was used to determine the cranking path and the energization sequence. Following this, the time domain simulation of the cranking path and the energization steps were carried out in EMT software.

30. What does "startup of induction loads needs to be coordinated" refer to?

If a lot of induction motors start up at the same time, the amount of starting current that they draw might exceed the total current rating of the inverters. Hence while carrying out a blackstart sequence, the start up of motors should be coordinated to avoid low voltages across the path.

31. Is any of this testing/simulation being presented done at EPRI labs using HIL systems such as Typhoon HIL

We have tested grid following inverter anti-islanding, open phase detection and negative sequence behavior with Typhoon HIL at our lab. We have not tested any grid forming control with HIL, although it is on our agenda as future work.

32. Are there any practical examples of using IBR to black-start under test conditions?

There is a wind farm in Scotland where black start trials have been carried out. There is a link on slide 16 to more details regarding this test.

33. Am I right to say that in an island of renewable generation, only one of the stations need to be grid-forming and the others can simply be black-started from here?

Not necessarily. It depends on the size of the grid forming inverter and how much burden it can support. If other inverters do not provide any form of system support, the burden on the grid forming inverter can be quite high. It is recommended to have many inverters sharing the burden. Here, grid forming doesn't automatically imply black start. Black start is treated as an additional service from grid forming inverters.

34. What would have been the difference if you modeled the load as constant KVA on slide 61?

If the load is modeled as constant power load instead of constant impedance load, the degree of voltage unbalance in the system would probably change some, especially after the load drop event. The conclusion that the grid forming plant should regulate voltage unbalance with sufficient negative sequence current capability will not be affected. In practice, when a microgrid is analyzed, the load model should represent the load behavior as close as possible and dynamic motor models (if any) should be included in transient/dynamic study of the microgrid.

35. If you didn't provide the grounding transformer what are other alternatives that can be used to have an efficient grounding in the microgrid?

Besides grounding transformer, Y-grounded/Delta DER interconnection transformer (Delta on the MV side) can also serve as a grounding source. For a substation microgrid, if the distribution substation transformer is inside the microgrid and the transformer has Y-grounded/Delta (Delta on the high voltage side) connection, it can also serve as a grounding source. Some inverter manufacturers also offer four-legged inverter (compared to traditional three-legged inverter) which has the capability to provide zero sequence current. This type of inverter together with Y-grounded/Y-grounded interconnection transformer can also provide grounding in a microgrid.

36. Can the negative sequence current provided by grid forming inverters be used to control phase unbalance directly rather than setting the negative sequence contribution at a constant value?

In the case study shown on slides 64 and 65, the negative sequence current capability indicates the limit of negative sequence current. For instance, if the capability is 0.1 pu, it means the maximum negative sequence current from the inverter is 0.1 pu. However, it does not mean the inverter should constantly output 0.1 pu negative sequence current in all conditions. Instead, the inverter control that regulates the voltage unbalance will determine the amount of negative sequence current generated.

37. Any comparison on EMT simulation results between PSCAD and Power Factory? Are the results in good agreement?

We have not carried out comparison tests between two EMT simulation software products.

38. Is there a formula or rule of thumb to determine the amount of negative sequence current for different microgrid scenarios?

This is under investigation. One way to have a rough estimation is to measure the negative sequence current provided by the main grid when the microgrid is connected to the main grid and the generation sources inside the microgrid is not regulating the voltage unbalance.

39. For Grid Forming PV plant, how does system protection conventionally protect the transmission lines with weak current sources?

There can be many forms of protection applied for transmission lines in a high inverter penetration system. These protection schemes can include differential protection and/or distance protection in addition to over current protection. The exact impact of grid forming IBRs on these protection schemes is an active area of research.

40. Are the newer positive sequence models still current-source models? Can these new models capture grid forming contribution to system Short Circuit Ratio?

The new positive sequence models such as REGC_C are developed with a voltage source interface structure. These models do have the ability to capture short circuit current contribution of the inverters. The impact of the short circuit contribution on the short circuit ratio is to be evaluated from a system wide analysis.

41. Are these new positive sequence models available in software such as PSLF, PSS(R)E, TSAT, Power Factory and PowerWorld ? If so, can you share typical data with us to run sensitivity studies?

Yes, these models are either already available in the software mentioned or are going to be soon released. Some of the models which are to be soon released are presently going through benchmark testing. More details regarding parameterization of these models in positive sequence software can be found at https://www.epri.com/research/products/000000003002021787 .

42. Were simulations run at a time step of 1 ms?

The positive sequence simulations using the REGC_C model were run using a 1 ms time step. Most of the EMT simulations were run using 5 μs time step.

43. Regarding typical data for REGC_C, have you identified critical control parameters which will aid in stabilizing the system?

Yes. In the REGC_C model, both the phase locked loop and the inner current control loop parameters can play a role in stabilizing the system. Lowering the phase locked loop integral gain and increasing the current control loop proportional gain has shown to be beneficial in stabilizing the system. However, this is not to considered as a general conclusion and should be verified with sensitivity studies.

44. Is grid forming synonymous with "high penetration"?

No. Not necessarily. It depends on how high penetration is defined, and whether there is high penetration in a local pocket of the network or over the wide network. Additionally, high penetration of renewable generation does not directly imply high penetration of inverters (e.g., hydro plant and Type I and II wind turbines do not utilize inverters). The more important aspect is to consider the services that can be provided by these inverters in the system.

45. Will this render SCO's unnecessary?

If SCO is meant to indicate Security Constrained Optimization, then grid forming inverters will not render SCO unnecessary. This will be a part of planning process that need to be considered in addition to existing procedures. Please do reach out to us if SCO was meant to indicate some other process.

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