Inverter-Based Operation of Maui: Electromagnetic Transient Simulations

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Inverter-Based Resource Performance Working Group (IRPWG)

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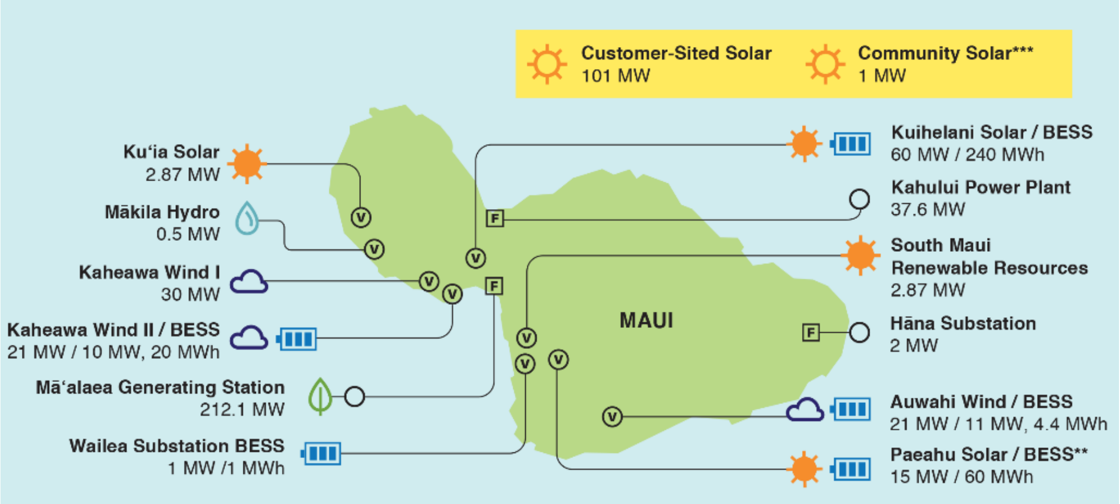
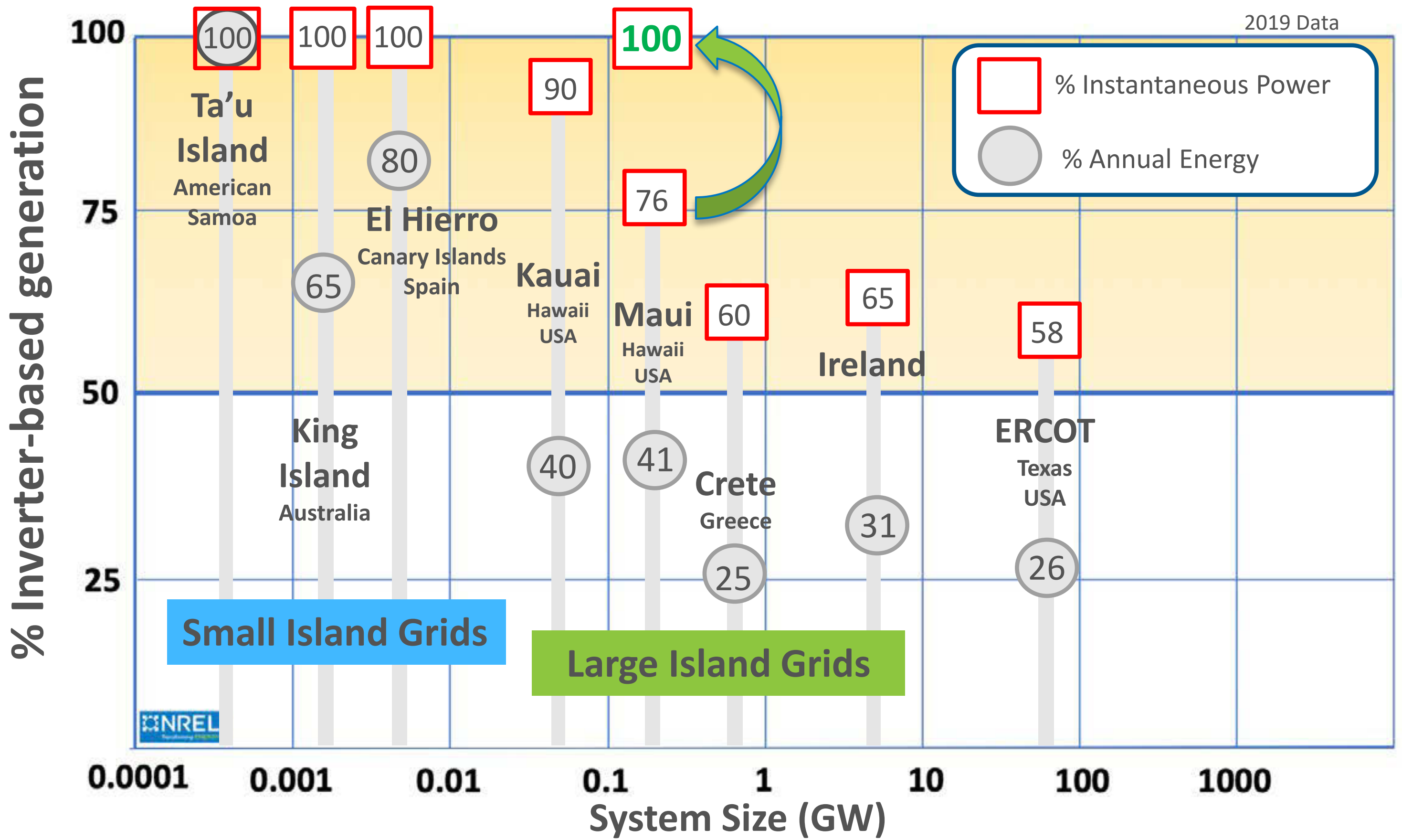
Background

- Hawaiian Electric expects Maui to be the first large island to be capable of operating with 100% inverter-based power resources
  - 2020 peak: ~89.5% IBR (DER and wind)
  - 100% IBR expected to possible for certain hours by 2023, *from an energy balance perspective*
- Maui would be the first interconnected power system of its size (~200 MW peak) with highly distributed utility-scale generation and 69 kV voltage levels to reach this milestone
- Grid-forming control capability required for Stage 2 PV-BESS plants (~2023 interconnection)
- Technical hurdles need to be overcome to ensure grid stability on the shortest time scales
- NREL currently performing EMT study (PSCAD)
- Electranix performing system impact study



- These studies are just steps in a complex due-diligence process working towards operating Maui in an unprecedented way

Wind and Solar in Synchronous AC Power Systems as a Percentage of Instantaneous Power and Annual Energy

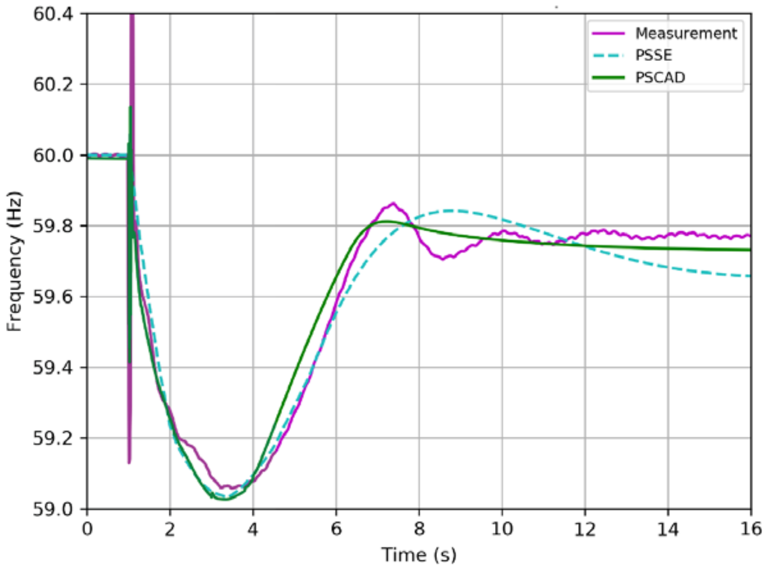


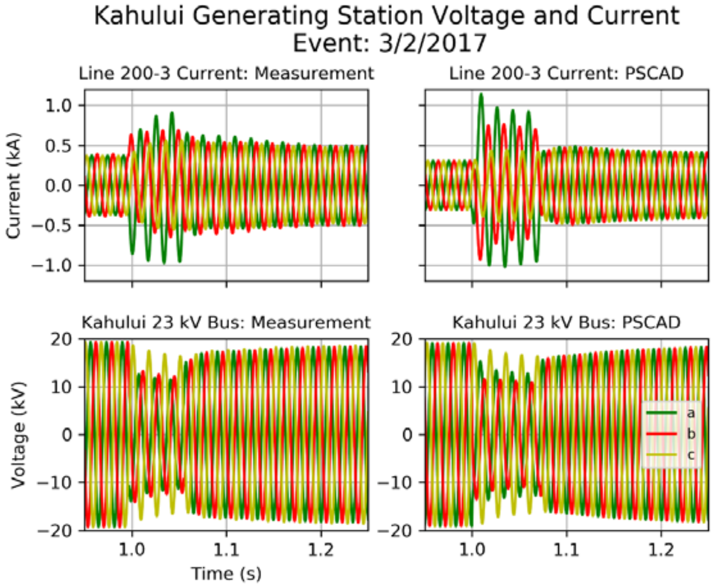
PSCAD model development/validation

- Developed EMT (PSCAD) model of Maui, parallelized on 30 cores*
- Validated against HECO field event data and PSSE model [1]
- Simulating faults, contingencies under various grid and IBR configurations

3/2/2017 Event:

Line-ground fault induces generation trip



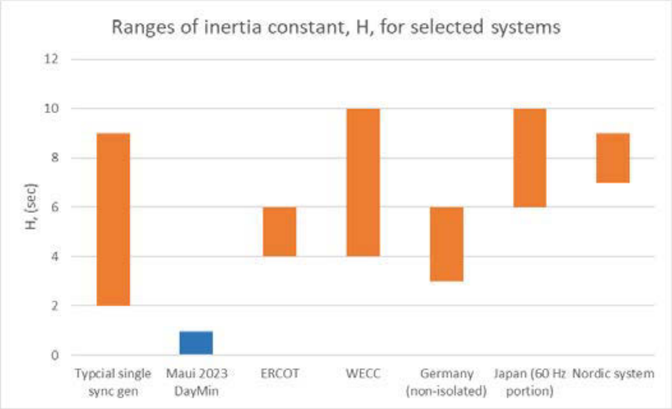


*Thank you to Electranix for providing E-TRAN Plus

[1] R. W. Kenyon, B. Wang, A. Hoke, J. Tan, B. Hodge, “Validation of Maui PSCAD Model: Motivation, Methodology, and Lessons Learned,” IEEE NAPS, April 2021.

EMT Simulation Base Case: “Scenario S1”

S1: 2023 DayMin (pre Stage II RFP)



2023 DayMin case: ~96% IBR

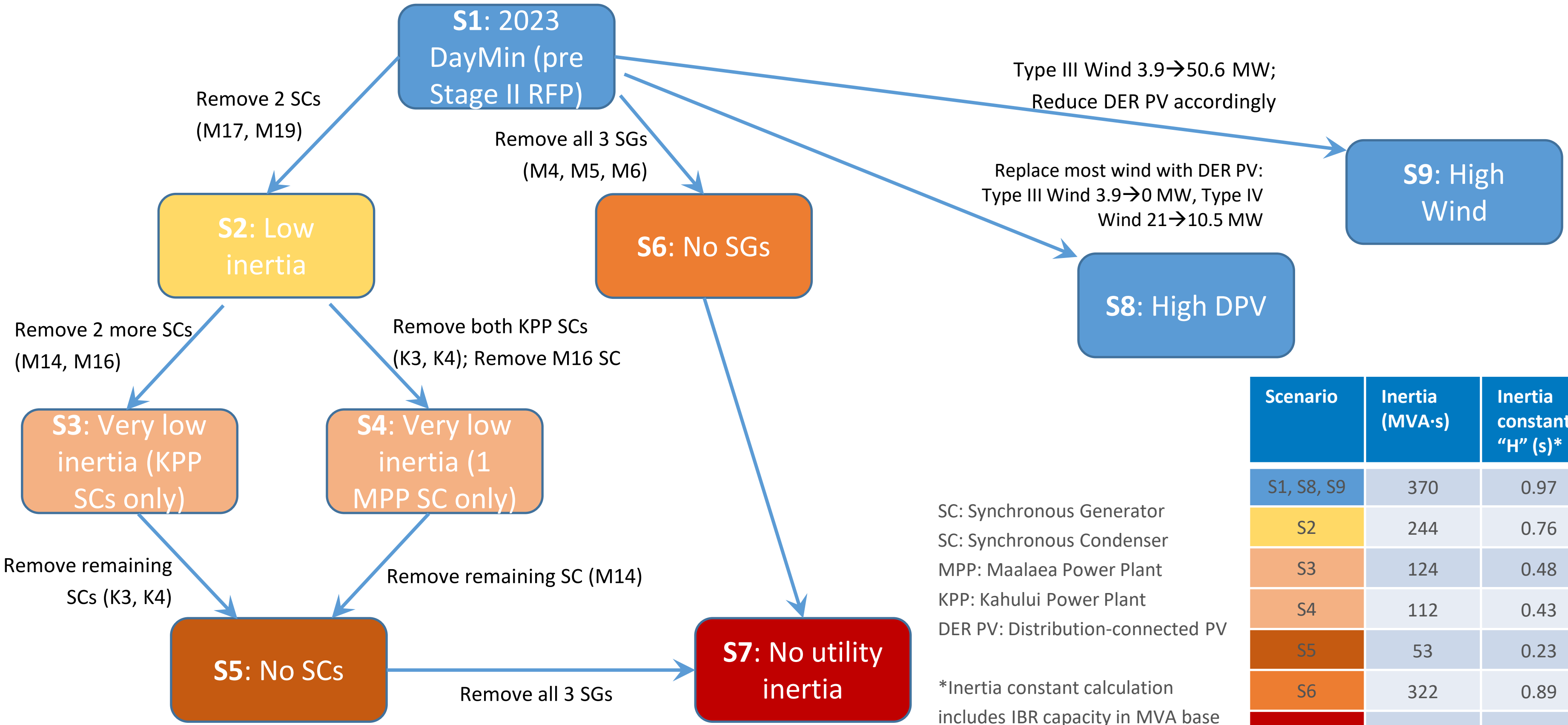
- Two “Stage 1” HPPs online:
  - Kuihelani (60 MW)
  - Paeahu (15 MW)
  - GFM capability not required (but may be available?)
- “Stage 2” HPPs not yet online (expected later in 2023). GFM capability required.
- Inertia: 370 MVA·s; Inertia constant H = 0.97 s (~1 order of magnitude below typical systems)

Note: We use “inertia” as a proxy metric for online synchronous machines

Capacities, MW

Total Load	Total Gen	Dist. PV “rooftop”	Existing large PV 2 plants	Wind 4 plants	Paeahu PV-BESS HPP	Kuihelani PV-BESS HPP	Sync Gens 3 generators
144.6	146.0	104.3	5.3	24.9	0	5.7	5.7

EMT Simulation Scenarios



SC: Synchronous Generator
SC: Synchronous Condenser
MPP: Maalaea Power Plant
KPP: Kahului Power Plant
DER PV: Distribution-connected PV

*Inertia constant calculation includes IBR capacity in MVA base

Scenario	Inertia (MVA·s)	Inertia constant “H” (s)*
S1, S8, S9	370	0.97
S2	244	0.76
S3	124	0.48
S4	112	0.43
S5	53	0.23
S6	322	0.89
S7	5.3	0.03

Simulated Events

Event	Contingency	Notes
E1	A three-phase fault on bus 97 (KWP) and cleared in 5 cycles.	Fault at a low short-circuit ratio (SCR) bus
E2	A three-phase fault on bus 1203 (AWP) and cleared in 5 cycles.	Fault at a low SCR bus
E3	A three-phase fault on bus 35 (Kihei) and cleared in 5 cycles.	Fault at a low critical-clearing-time (CCT) bus
E4	A three-phase fault on bus 39 (Maalaea) and cleared in 5 cycles.	Fault at a low CCT bus
E5	A three-phase fault on bus 401 (Puunene) and cleared in 5 cycles.	Fault at a low CCT bus
E6	A three-phase fault on bus 823 (Puuk B) and cleared in 5 cycles.	Fault at a low CCT bus
E7	A three-phase fault on bus 850 (Mahina A) and cleared in 5 cycles.	Fault at a low CCT bus
E8	Loss of the largest generator (21 MW wind plant)	
E9	Loss of line 39-35 (Maalaea-Kihei)	A critical contingency for Maui system which may lead to voltage instability
E10	Loss of 4 BTM hydro units	Reduces inertia (to zero in S7)
E11	Loss of synchronous condenser (SC)	K4 is lost upon fault in S3; M14 is lost for all other scenarios except for S5 and S7 where there is no SC

Note: Events simulated with UFLS and DER trip settings disabled. Intent is to focus on system transient and dynamic stability.

PSSE-PSCAD Comparison Summary

Scenarios

Events	S1		S2		S3		S4		S5		S6		S7		S8		S9	
E1	Y	Y	Y	Y	N	Y	N	N	N	N	Y	Y	X	N	Y	Y	Y	Y
E2	Y	Y	Y	Y	N	Y	N	N	N	N	Y	Y	X	N	Y	Y	Y	Y
E3	Y	Y	Y	Y	N	Y	N	N	N	N	Y	Y	X	N	N	Y	N	Y
E4	Y	Y	Y	Y	N	Y	N	N	N	N	Y	Y	X	N	Y	Y	Y	Y
E5	Y	Y	Y	Y	N	Y	N	N	N	N	Y	Y	X	N	Y	Y	Y	Y
E6	Y	Y	Y	Y	N	Y	N	N	N	N	Y	Y	X	N	Y	Y	N	Y
E7	Y	Y	Y	Y	N	Y	N	N	N	N	Y	Y	X	N	Y	Y	Y	Y
E8	Y	Y	Y	Y	N	Y	Y	N	N	N	Y	Y	X	N	Y	Y	Y	Y
E9	Y	Y	Y	Y	Y	Y	Y	N	Y	N	Y	Y	X	N	Y	Y	Y	Y
E10	Y	Y	Y	Y	Y	Y	Y	N	N	N	Y	Y	X	N	Y	Y	Y	Y
E11	Y	Y	Y	Y	Y	Y	N	N	n/a	n/a	Y	Y	n/a	n/a	Y	Y	Y	Y

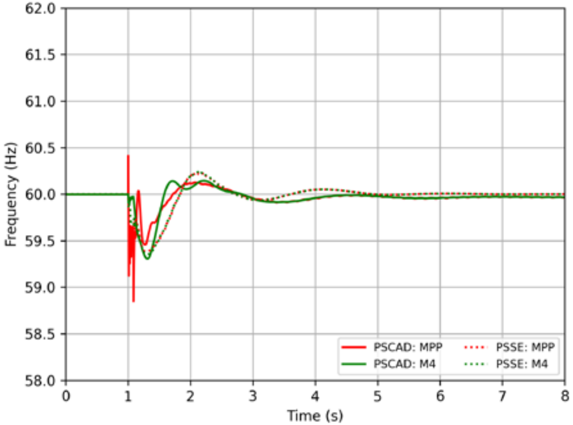
	Key
Y	PSSE sim successful
N	PSSE sim cannot be completed
X	PSSE sim cannot be run
Y	PSCAD sim successful
N	PSCAD steady state is unstable

**successful implies computational success only; in some cases, substantial UFLS/protective action would have occurred*

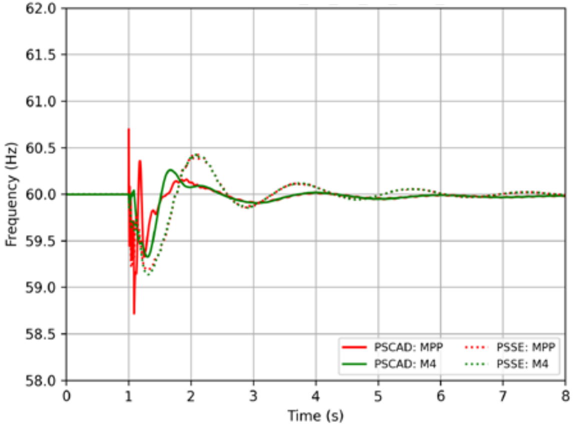
- In some very high IBR scenarios, PSSE either didn't start (S7), didn't complete (S3-5, S8-9), or missed key control interactions (S4-5)
- Some very high IBR, low SC scenarios (S4, S5, S7) are fundamentally unstable, at least with conventional grid-following inverters
- Zero sync gen scenario (S6) is numerically stable in PSSE and physically stable in PSCAD. (Significant level of SCs present)

Event E1 (Fault at low SCR bus): Frequency

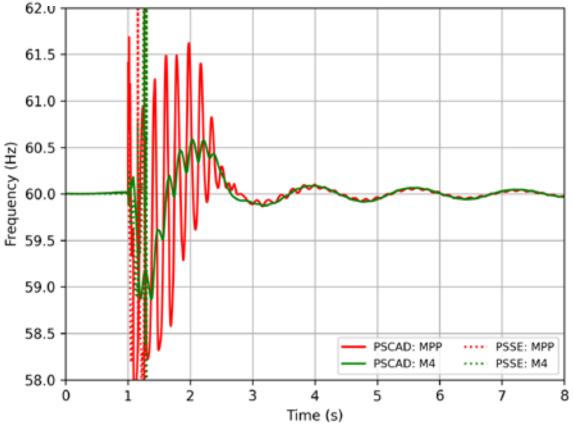
Scenario S1 (Base DayMin)



Scenario S2 (Low Inertia)



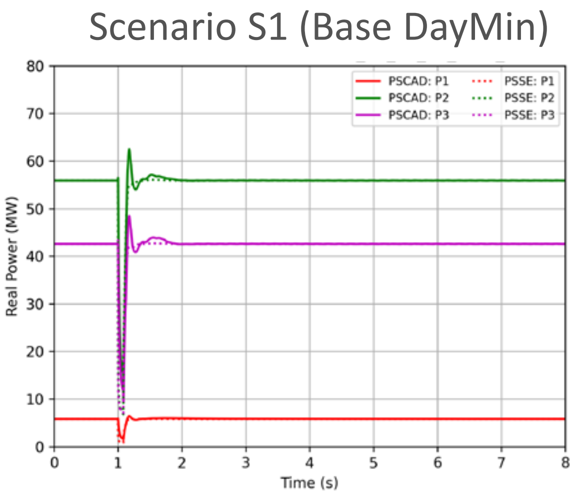
Scenario 3 (Very Low Inertia)

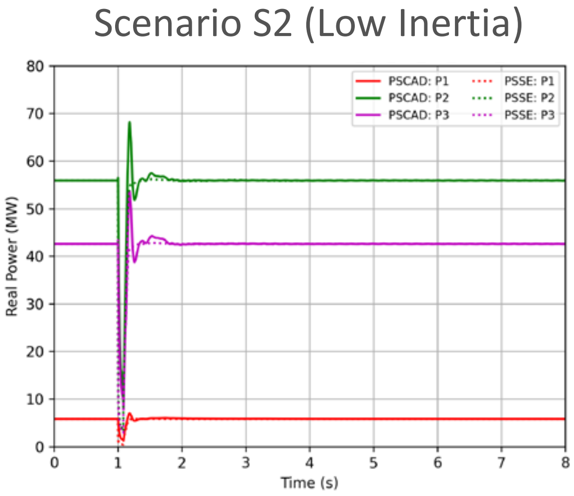


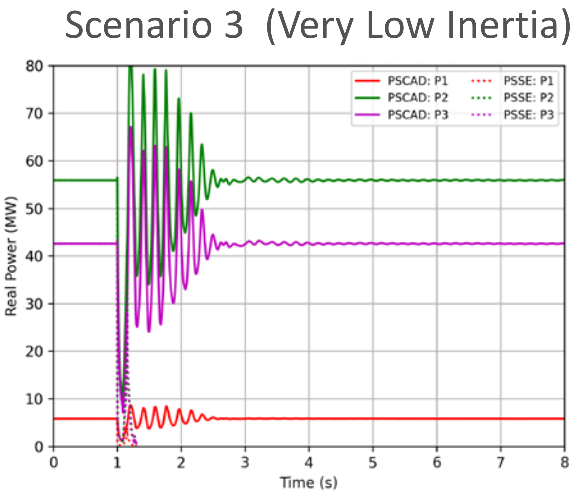
PSCAD: MPP is a PLL-measured frequency. PSCAD: M4 is a generator shaft rotation speed-derived frequency

- Scenario 1 --> Scenario 3: reduced inertia and fewer voltage sources
    - Exacerbated oscillatory modes in S3, both in damping and quantity of modes
- PSSE simulation for Scenario 3 is numerically unstable shortly after the fault

E1: Aggregate Distributed Generation Output



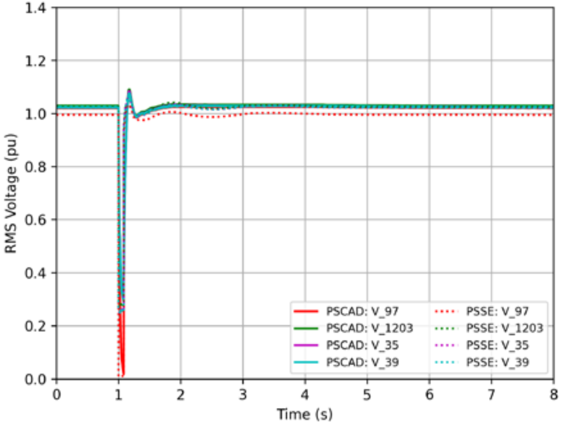




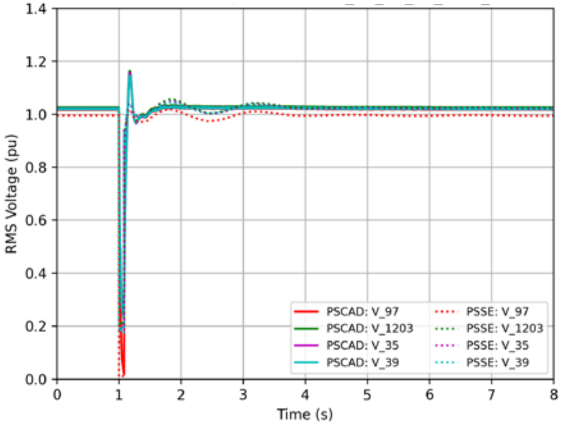
- Scenario 1 --> Scenario 3: reduced inertia and fewer voltage sources
  - Increased magnitude and duration of active power output oscillations of DG
  - Appears to be phase-locked loop or inner P/Q/I control loop instability, due to fewer voltage sources on network

E1: Selected 69 kV RMS Voltages

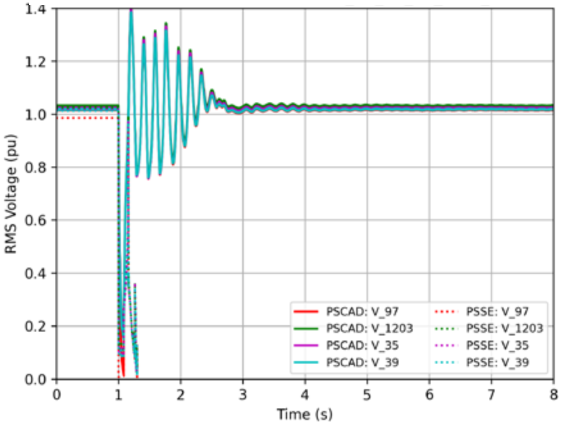
Scenario S1 (Base DayMin)



Scenario S2 (Low Inertia)



Scenario 3 (Very Low Inertia)

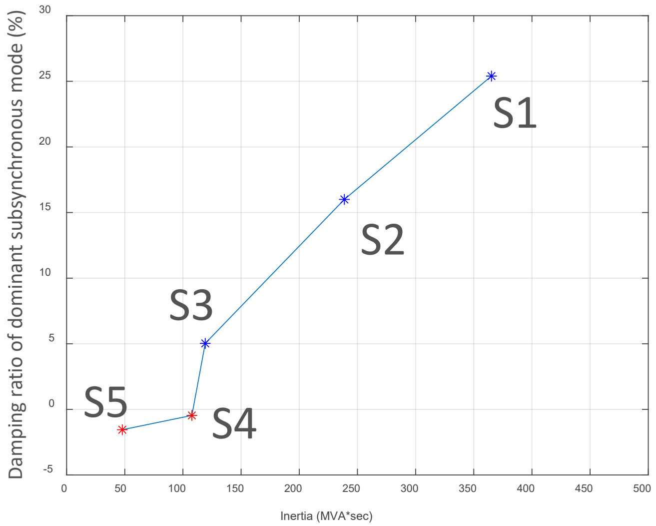


- Scenario 1 --> Scenario 3: reduced inertia and fewer voltage sources
  - Clear increase in voltage instability with fewer voltage sources on the system
  - Substantial tripping of DG would have occurred in S3, but this functionality was disabled to enable an analytic comparison between scenarios

Damping ratio: A metric for grid stability

- Damping ratios of oscillatory modes estimated for E1 in scenarios S1-S5.
- Inertia calculated based on online SGs and SCs; proxy for total voltage sources online

	S1	S2	S3	S4	S5
Low freq mode	0.44 Hz (25.4%)	0.50 Hz (16.0%)	0.64 Hz (5.03%)	0.65 Hz (-0.46%)	1.77 Hz (-1.55%)
Med freq mode	5.82 Hz (0.33%)	5.94 Hz (0.04%)	6.00 Hz (0.21%)	5.67 Hz (0.45%)	N/A
Inertia (MVA·s)	365	239	119	108	48

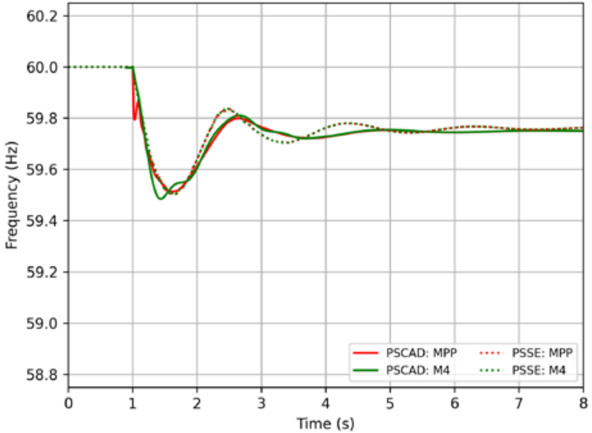


- Reduced inertia → reduced damping (less stable)
- S3 and S4 have almost same inertia but in different locations → location matters

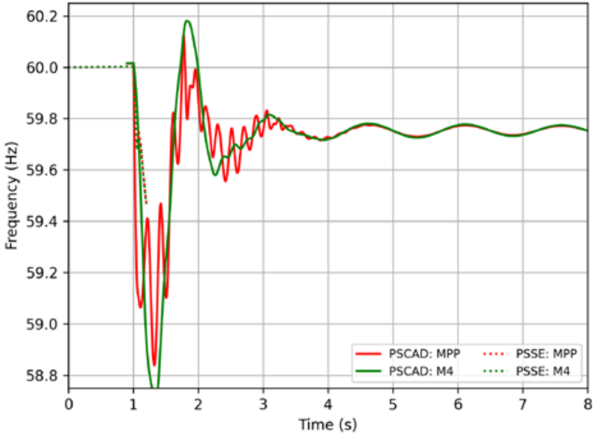
- But, see later simulations with GFM controls….

Event E8 – Loss of Generation: Frequency

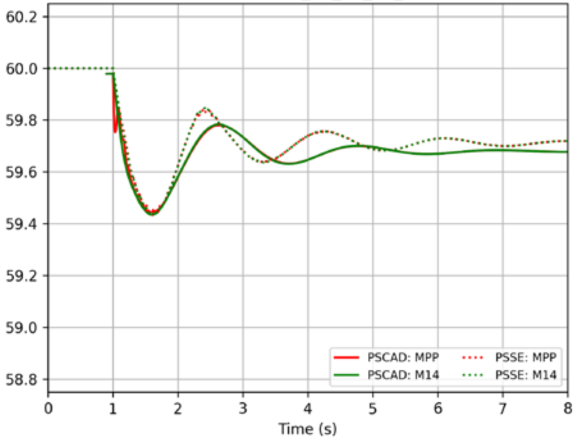
Scenario S1 (Base DayMin)



Scenario S3 (Very Low Inertia)



Scenario S6: No SGs

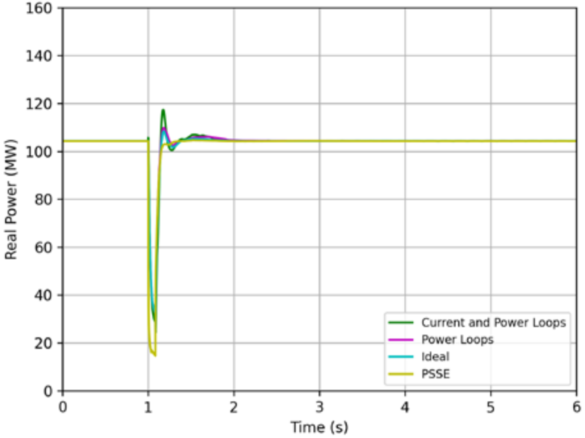


PSCAD: MPP is a PLL-measured frequency. PSCAD: M4 is a generator shaft rotation speed derived frequency

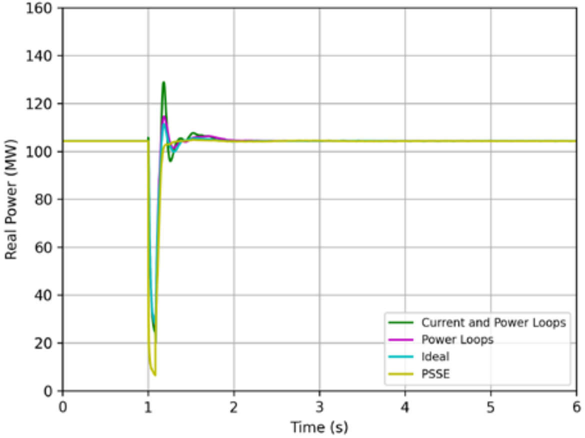
- Scenario S1 versus Scenario S3: reduced inertia and fewer voltage sources
  - Lower nadir, larger ROCOF, as expected
  - No voltage perturbation, yet large oscillations still present in PLL-derived frequency
- Scenario S6: all (3) synchronous generators taken offline
  - *Successful operation with all primary response from GFL devices*

Influence of Inner Control Loops: Active Power

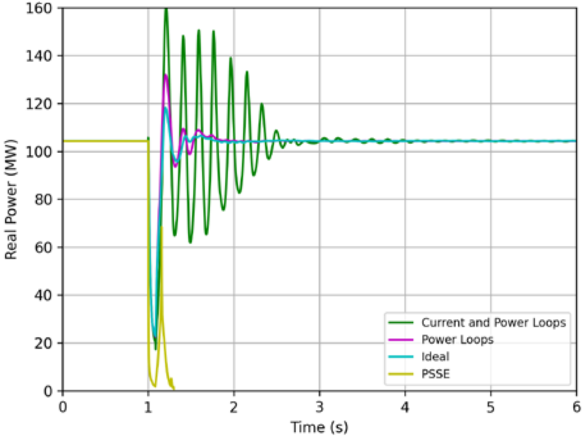
Scenario S1 (Base DayMin)



Scenario S2 (Low Inertia)



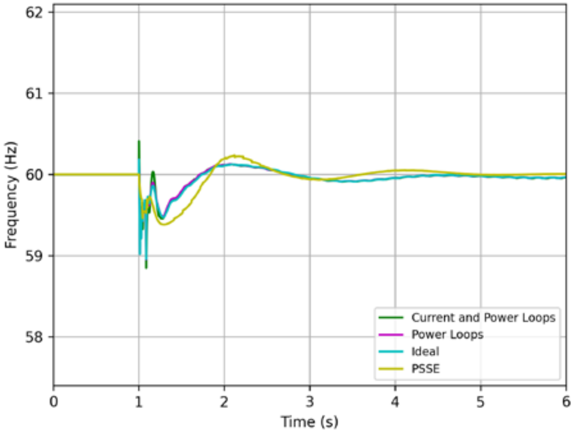
Scenario 3 (Very Low Inertia)



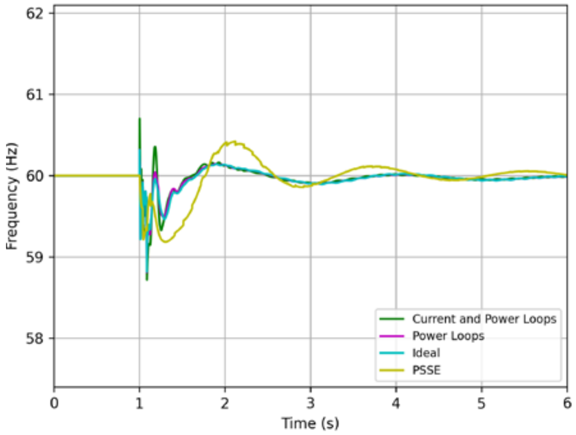
- DER totals (104 MW, of 146 MW). 180 aggregate units. Comparing three levels of control detail:
  - Ideal current source implementation (similar to PSSE control)
  - Power loops modeled (current loops ideal, no output filter)
  - Full model with power and current loops
  - Other GFL devices maintain inner loops/output filter
- Conclusion: Modeling of inner loops is critical for understanding high-IBR stability issues

Influence of Inner Control Loops: Frequency

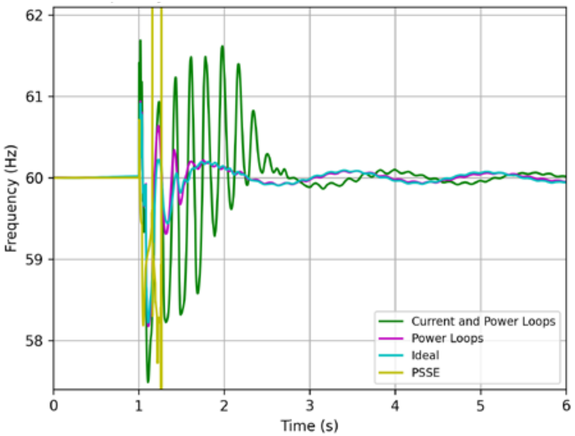
Scenario 1



Scenario 2



Scenario 3



- As expected from large swings in DER active power, large swings in frequency

Stabilizing with Grid Forming (GFM) Inverters

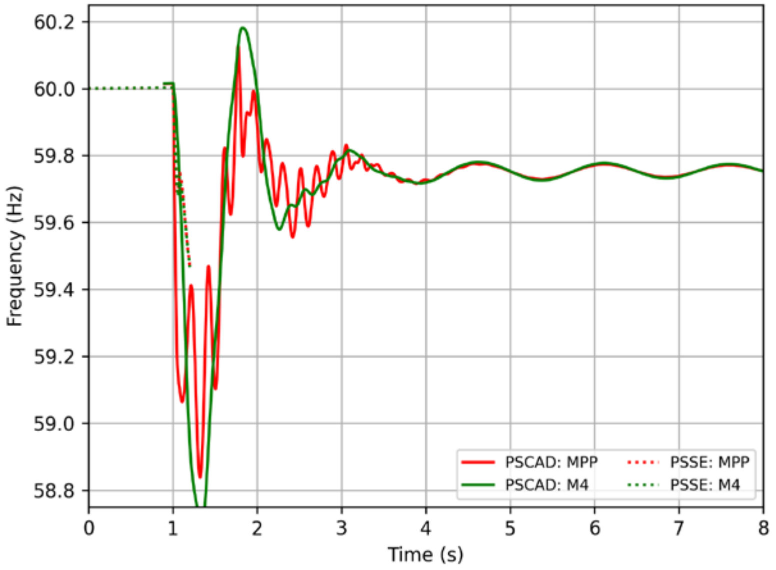
- Multi-loop droop control inverter model developed in PSCAD
  - PSCAD models are available to public (https://github.com/NREL/PyPSCAD)
  - DC side dynamics are not included, under the assumption of a BESS input source with response dynamics fast enough not to influence power system dynamics

- Substituted GFM inverter for some IBRs in previously unstable cases:
  - Replaced G2 (30 MVA) of the Kuihelani HPP (leaving G4 as a GFL)
    - Significant improvement in S3 system response
    - Stabilizes S4 and S5 as well
  - S7 (no synchronous machines) is stable with two GFMs (G2 and G4, 60 MVA total)

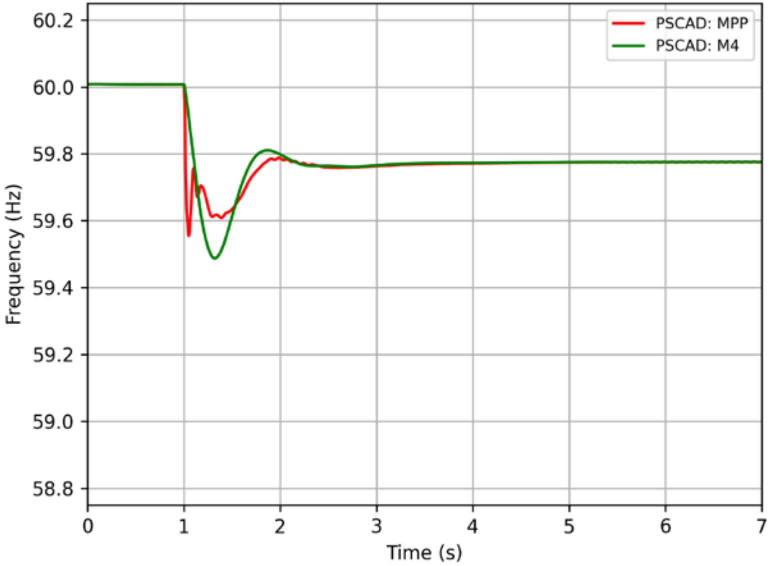
- Only looked at generation loss; comparing Scenario S3 results
  - Simulations of fault scenarios with GFMs in progress

S3 E8 (Loss of largest generator) - Frequency

G2 as a GFL



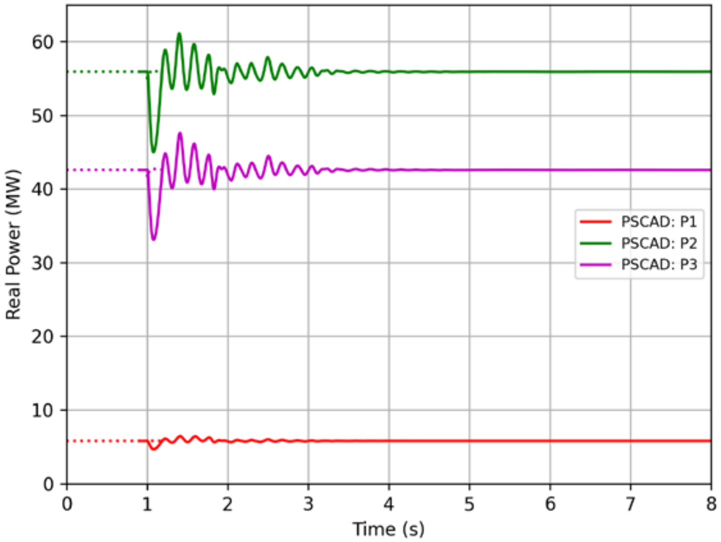
G2 as a GFM



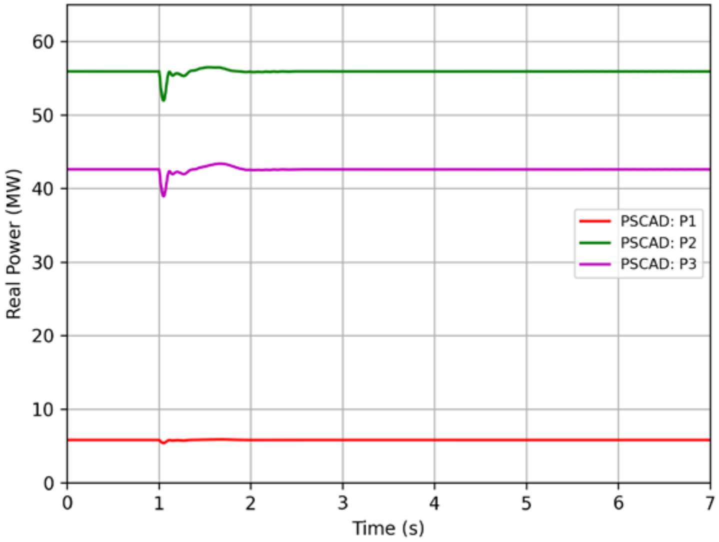
- Substantial increase in primary damping; major reduction in faster modes
- Nadir is raised significantly (58.7 to 59.5 Hz), and ROCOF improved (despite no increase in inertia

S3 E8: Aggregate DER PV Output

G2 as a GFL



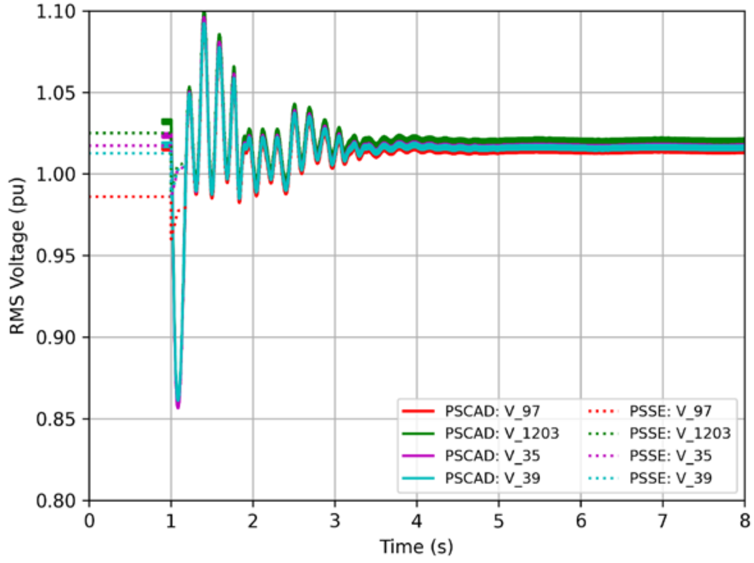
G2 as a GFM



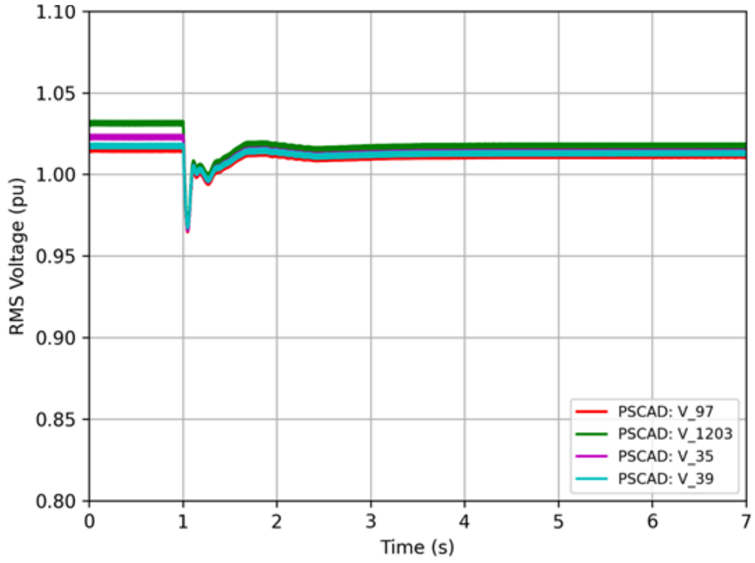
- Substantial increase in DER output stability (with no change in DER controls)
- GFM control doesn't add to system inertia → the presence of voltage sources is the primary driver in increased stability

S3 E8: Selected Voltages

G2 as a GFL



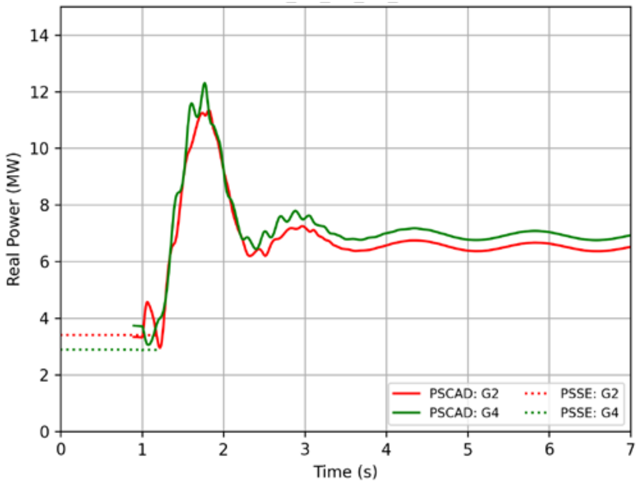
G2 as a GFM



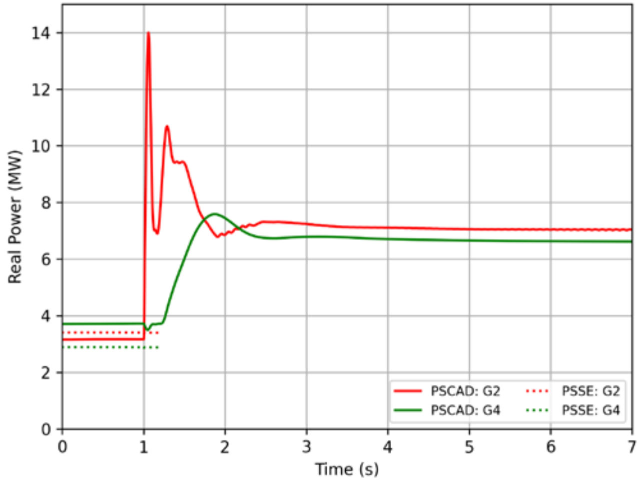
- Single GFM mitigates severe voltage oscillations throughout system

S3 E8: Kuihelani HPP Output Power

All IBRs as GFL



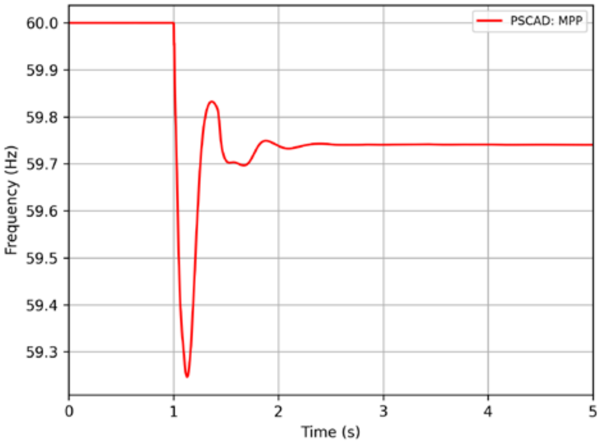
G2 as a GFM; all others GFL



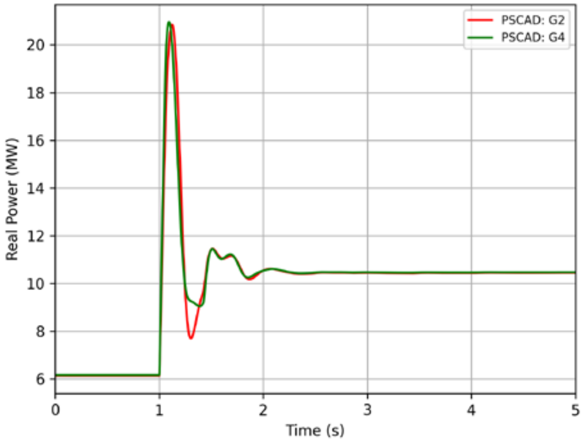
- GFL (green) device requires a change in frequency as a signal to adjust power export. Note that the power injection is itself a type of disturbance
- As a GFM (red), active power is extracted by the network from the device due to the operation as a voltage source maintaining phase angle and hence frequency. (Power isn't *injected*, it's *extracted*). GFM control inherently provides FFR (among other things).

S7 E8: No Synchronous Resources Online

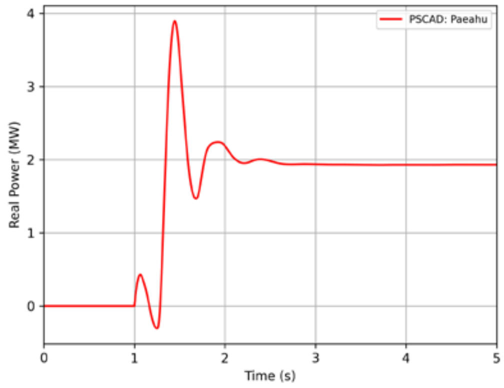
Frequency



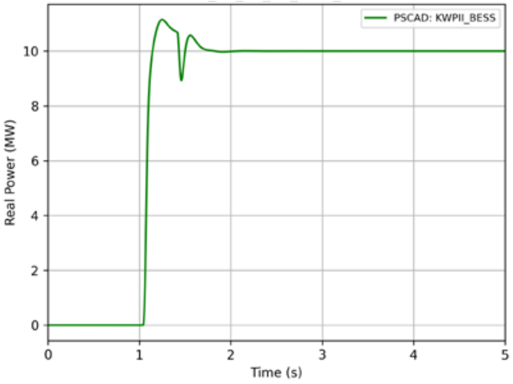
GFMs: G2 and G4



Paeahu HPP: FFR



Wind BESS: FFR



- System is stable with only two GFM; no other voltage sources
- Faster oscillation modes are absent
- Frequency reaches steady state sooner than with synchronous resources present
- Large ROCOF, very short. How are DERs measuring?

Summary of Maui EMT findings to date

- Phasor-domain simulations face numerical instability and miss key system dynamics in some low-inertia scenarios
- Modeling inverter control loops (power and current) of GFL devices is required to detect faster modes in the system response under very weak grid conditions
- Study indicates that the presence of synchronous generators is not necessary for stability; system is stable with GFL and synchronous condensers
- Presence of a single GFM (30 MVA) at Kuihelani greatly increases damping, ROCOF, and nadir of primary frequency mode
    - Stabilizes faster modes
    - Mitigates instability of remaining GFLs
    - Presumably need two GFMs for N-1 reliability
- Presence of two GFMs (60 MVA total) stabilizes zero-inertia system

- <u>Note</u>: These simulations focus on transient stability and do not consider other topics necessary for 100% IBR operation, e.g. protection, reserves, resource adequacy…

Questions and hypotheses

- Can we predict (without EMT simulation) where stability boundaries lie? Existing metrics don't adequately capture stability concerns because they don't account for synchronous condensers or GFM contributions. Perhaps a new system-wide metric can capture this?
    - SNSP or "% IBR" neglect SC and GFM
    - Inertia constant, *H*, neglects GFM IBR. (And for high IBR systems, *H* should include IBR capacity in denominator, not just total machine MVA; or just use total load as denominator?)
- Hypotheses:
    - The stabilizing effect of a GFM depends on its *capacity*, not its dispatch level. (Could even be in charging mode)
    - SC and SG are roughly equal in transient stabilizing effects
    - A GFL IBR providing FFR has some stabilizing effect: > 0, but << GFM
- Are equal capacities of GFM IBR and SC roughly equal in stabilizing effect?
- Are all GFM IBR variations equal in their stabilizing effects? (Probably not)

More Questions

- These simulations used generic GFL and GFM models. Will the results hold for vendor-specific models? What about actual inverter hardware?
- What levels of current, power, and energy headroom are needed for GFMs to stabilize a given system?
- What do the models miss that will be seen in field operational experience?

Next steps

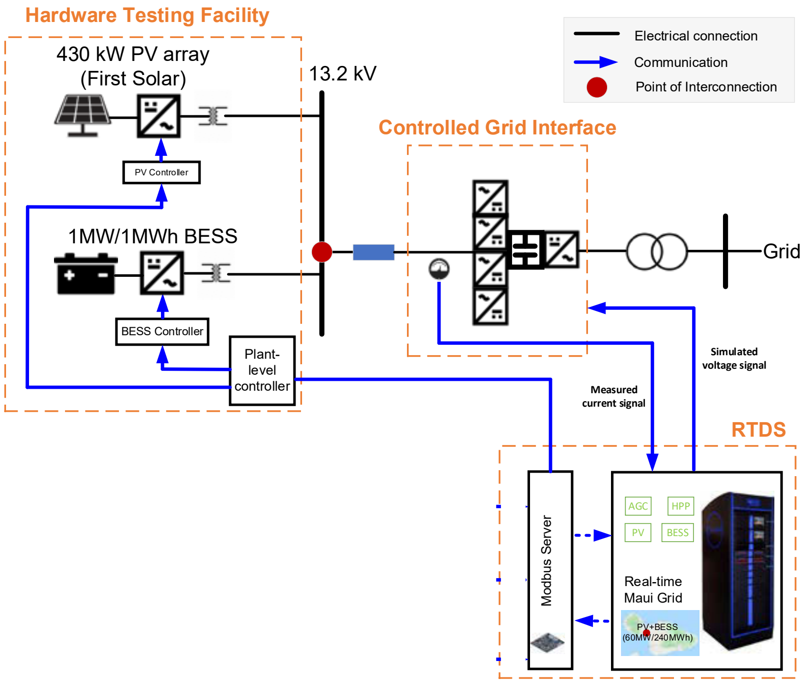
Verify with actual HPP models

- Where possible, check simulation results using plant developers' model

Add distribution model

- Add single reduced distribution feeder to PSCAD model
- Include single-phase inverter models
- Investigate any changes in dynamics relative to substation-level aggregation

Validate in PHIL



Questions?

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