Reliability Barriers to Enhanced Solar PV Deployment: Selected Research Findings - State Outreach Technical Sessions

Brady Cowiestoll, Elaine Hale, Jennie Jorgenson, Richard 'Wallace' Kenyon, Barry Mather and Gord Stephen

Western Interstate Energy Board - State Outreach Technical Sessions

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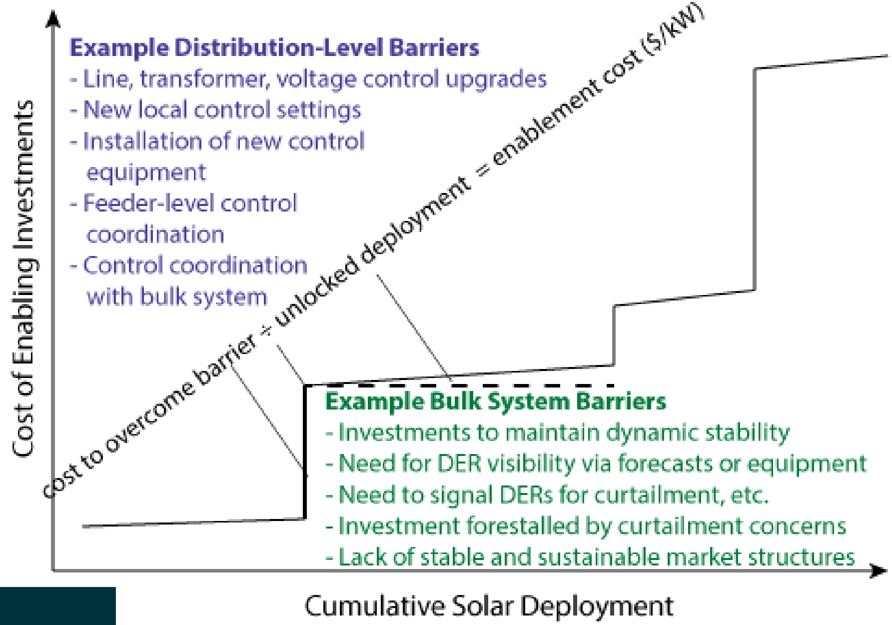
Enhanced Distributed Solar Photovoltaic Deployment via Barrier Mitigation or Removal in the Western Interconnection

WIEB-NREL-LBNL **Solar Energy Evolution and Diffusion Studies 2 – State Energy Strategies (SEEDS2-SES)** project in which we proposed to address three categories of barriers:

- Interconnection
- Net Metering
- **Reliability**



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Reliability Barriers Screening

Photo by Dennis Schroeder, NREL 45218

NREL Internal Experts Brainstorm → Perceived Reliability Barriers to PV Deployment → Internal & External[1] Screening → Research Plan

Research focused on reducing uncertainty

- Importance of perceived barrier
- Potential mitigation strategies
- Ability of state-of-the-art modeling tools to represent the issue

Photo by Jamie Keller, NREL 19697

[1]Technical Advisory Committee (TAC)

Studied high penetration PV through the lens of three Western Interconnection regions

Contents

Technical presentations covering three selected reports:

- Power System Flexibility and Supply
- Resource Adequacy Considerations
- Simulating Distributed Energy Resource Responses to Transmission System-Level Faults Considering IEEE 1547 Performance Categories on Three Major WECC Transmission Paths

Additional reports and other information are available from the project website

Power System Flexibility Requirements and Supply

Assessment of net load ramping needs and what resources are available to provide ramping at different timescales

https://www.nrel.gov/docs/fy21osti/72471.pdf

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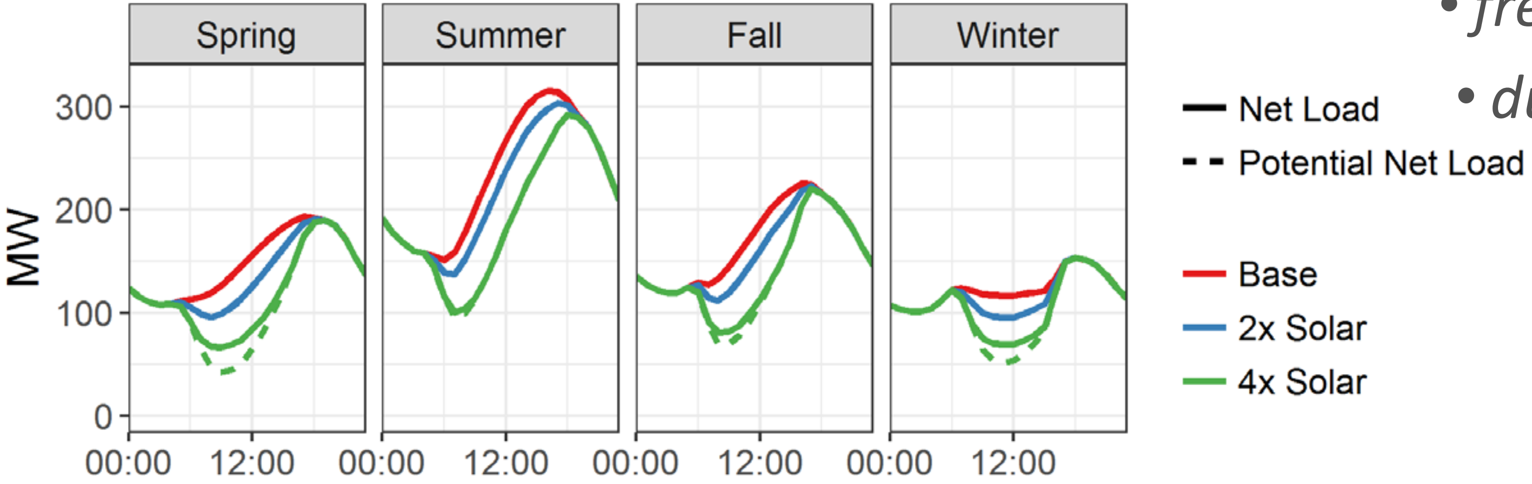
Flexibility Demand

Increasing solar leads to …

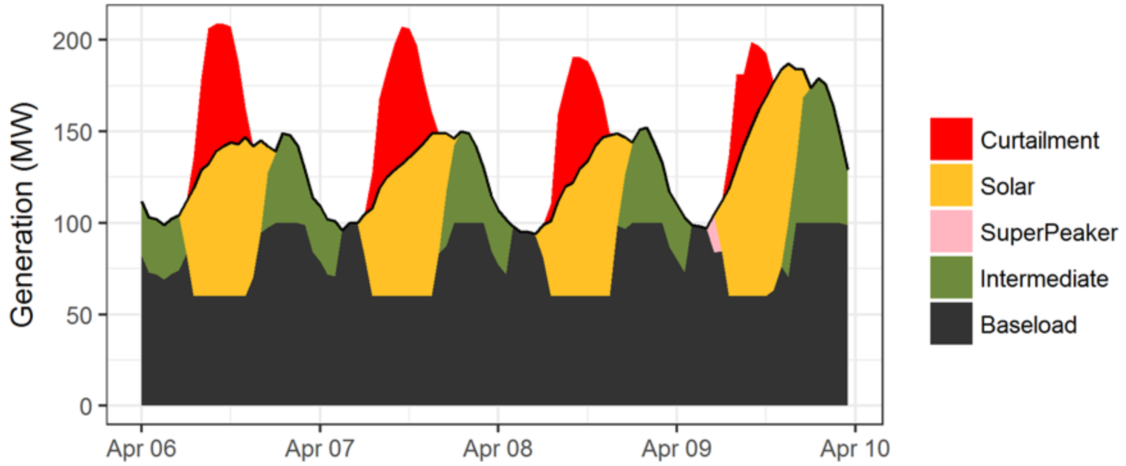


… increased

- *magnitude*
- *frequency*
- *duration*

of ramps

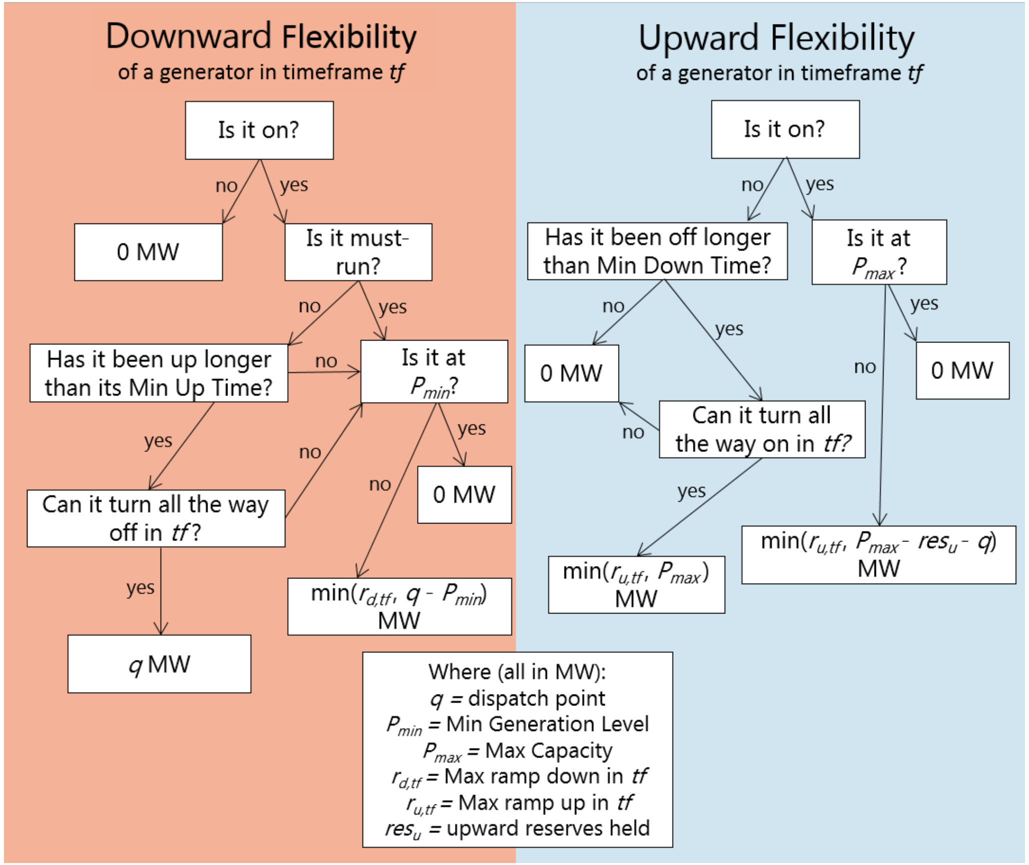
Flexibility Supply



Flexibility Sources

- Commitment and dispatch of the generator fleet, including:
  - Thermal generators
  - Hydropower
  - Storage
  - Demand Response
- Imports and exports
- Waste of "free" energy → Renewable Curtailment
- Not great → Unserved Reserves
- **BAD** → Load shedding

Supply Inventory Logic

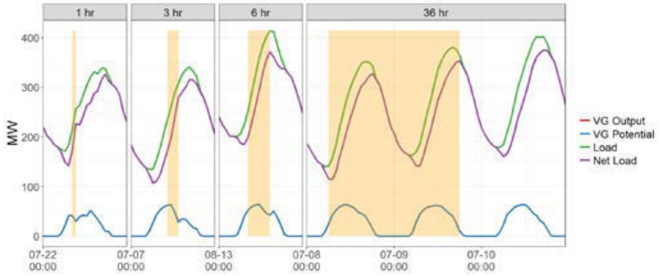


Three-Step Flexibility Inventory

1. Quantify flexibility needs

Analyze net load (demand minus wind/PV) and ramps

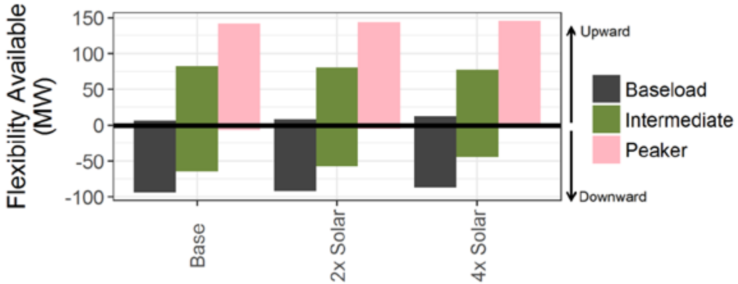
Largest ramps over various timescales



2. Quantify flexibility supply

Analyze generator fleet dispatch (PLEXOS results)

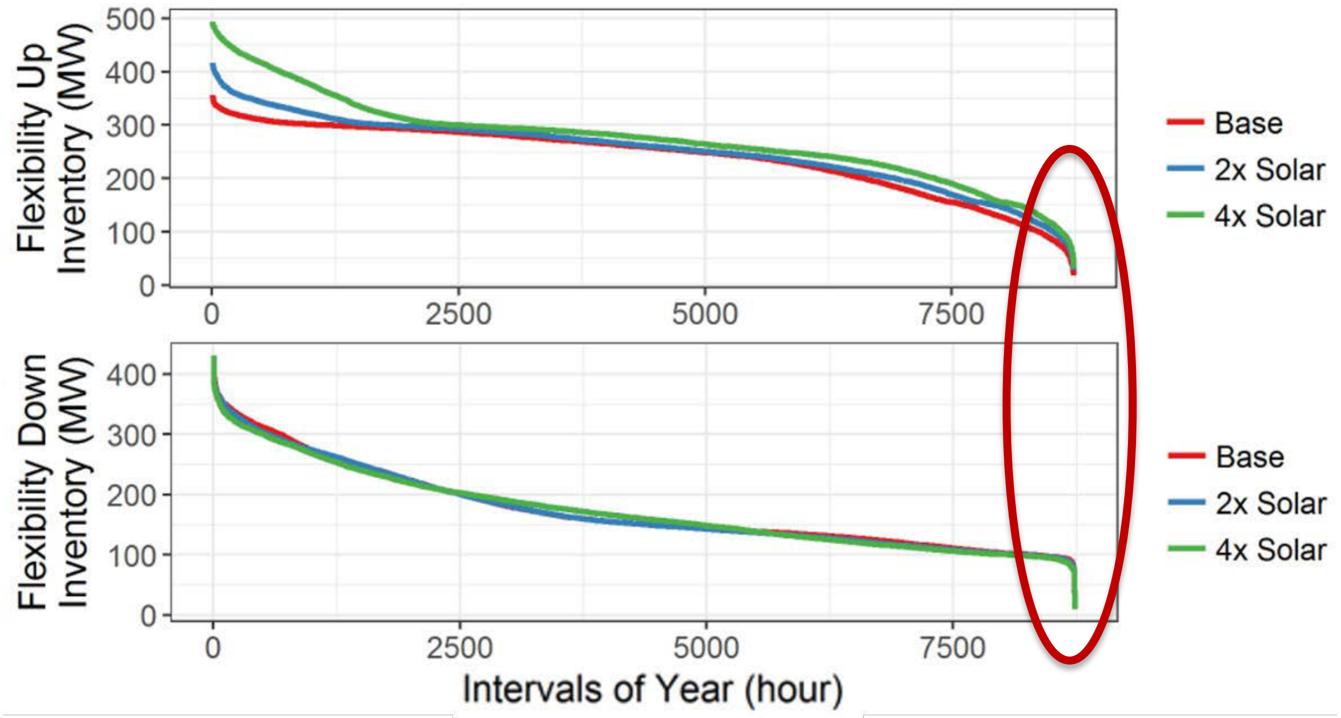
Sources of flexibility under average conditions and at specific times



3. Compare flexibility supply and demand

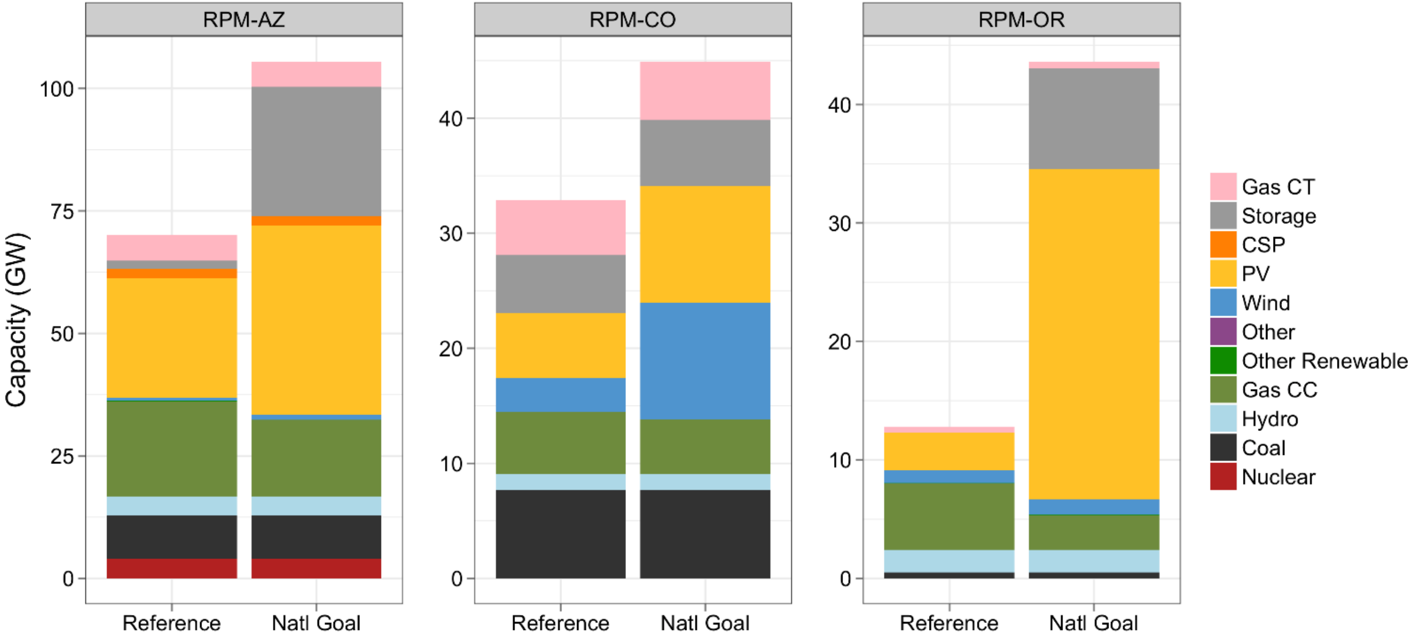
Times when flexibility is the most constrained

Three-Step Flexibility Inventory



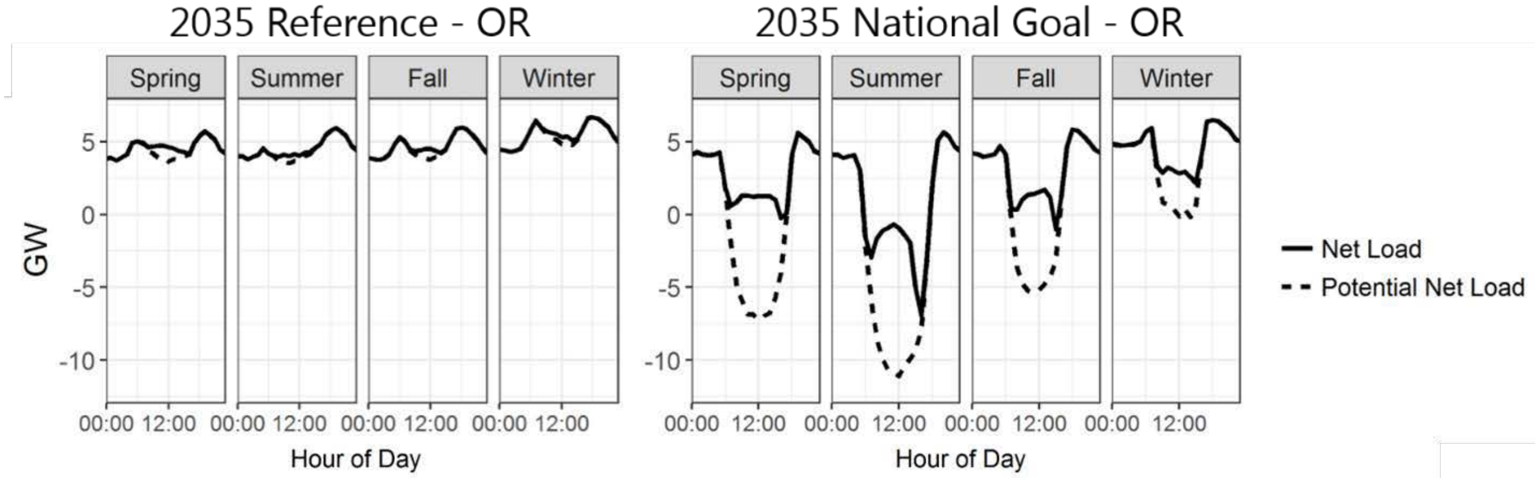
3. Compare flexibility supply and demand → **Identify when flexibility is the most constrained**

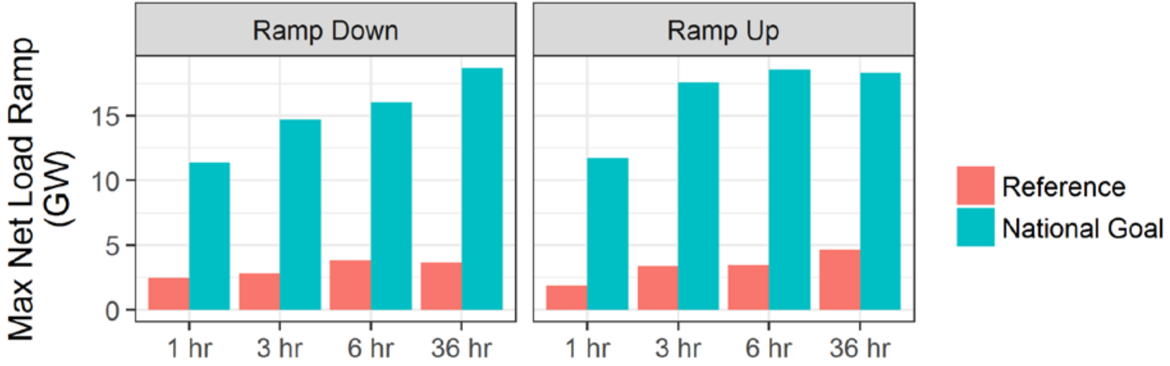
Power System Capacity for Three Regions, Two Scenarios Each



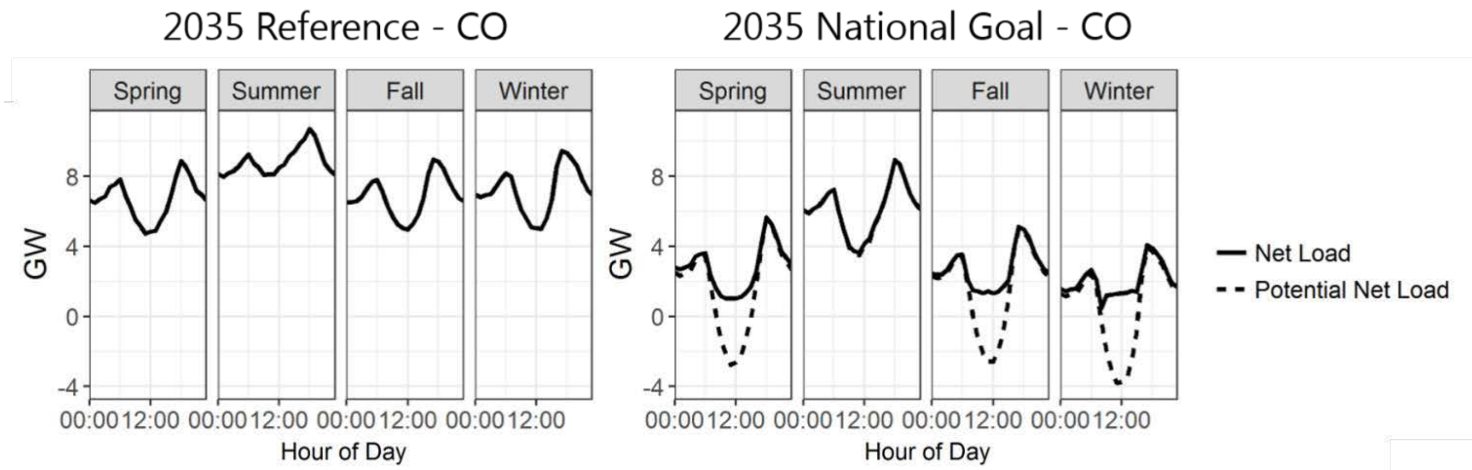
- Comparing two cases: Reference and National Goal
- National Goal has more PV, often more storage
- More capacity in general

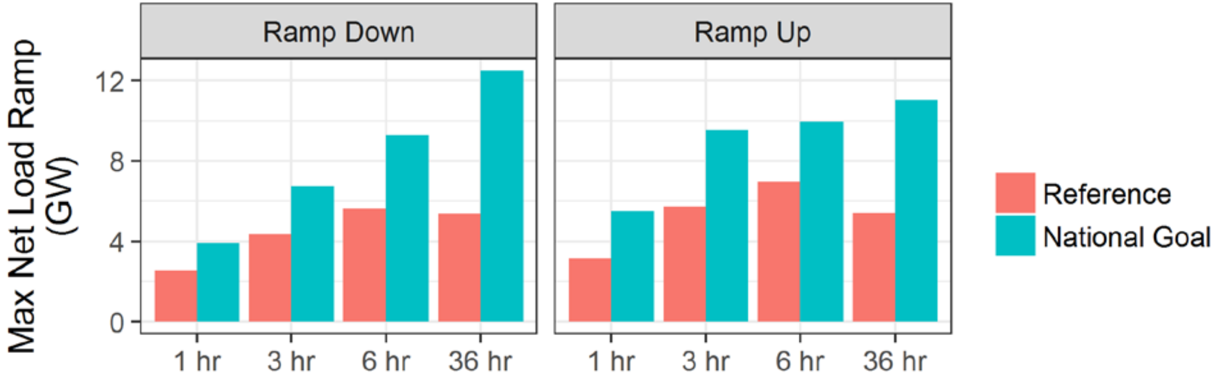
Flexibility Demand Results: RPM-OR



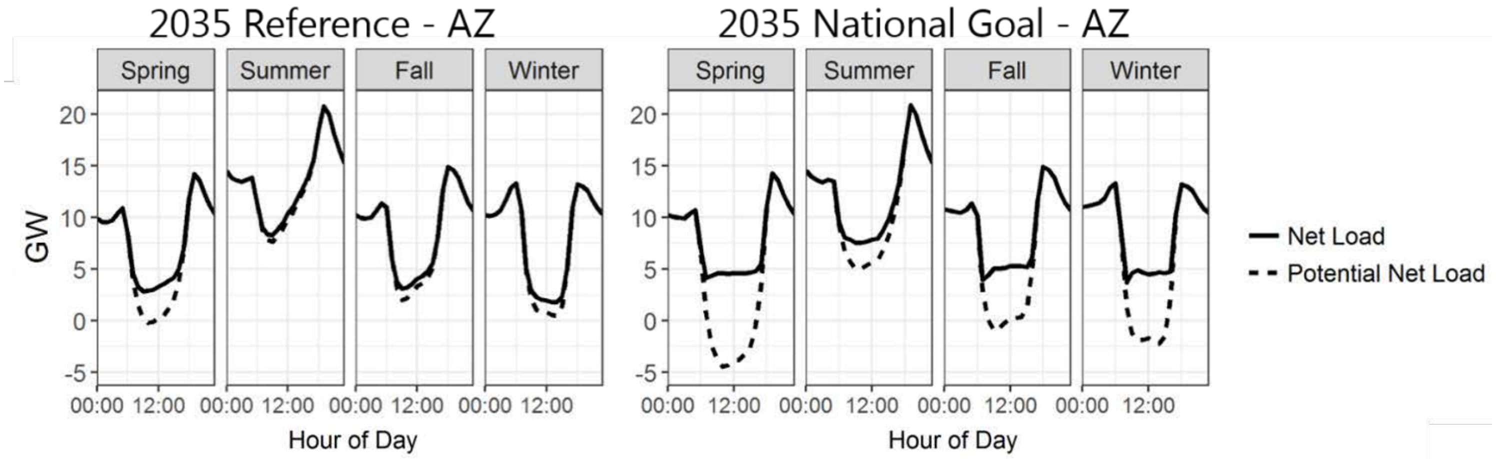


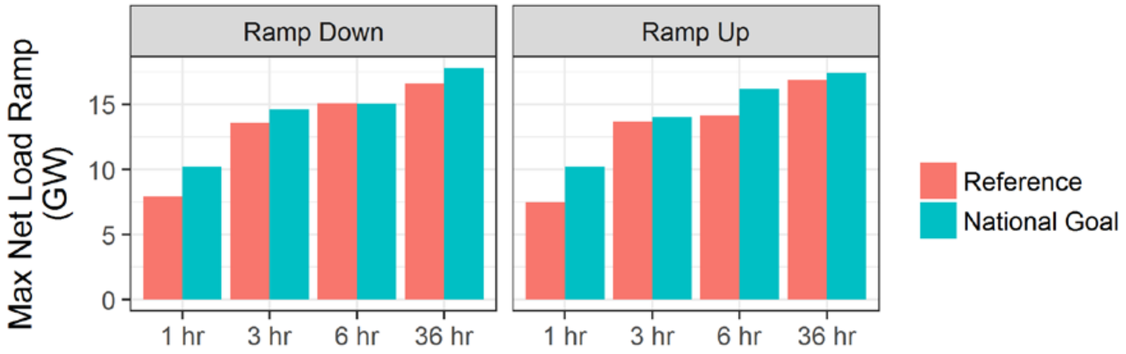
Flexibility Demand Results: RPM-CO





Flexibility Demand Results: RPM-AZ





Power System Flexibility Results

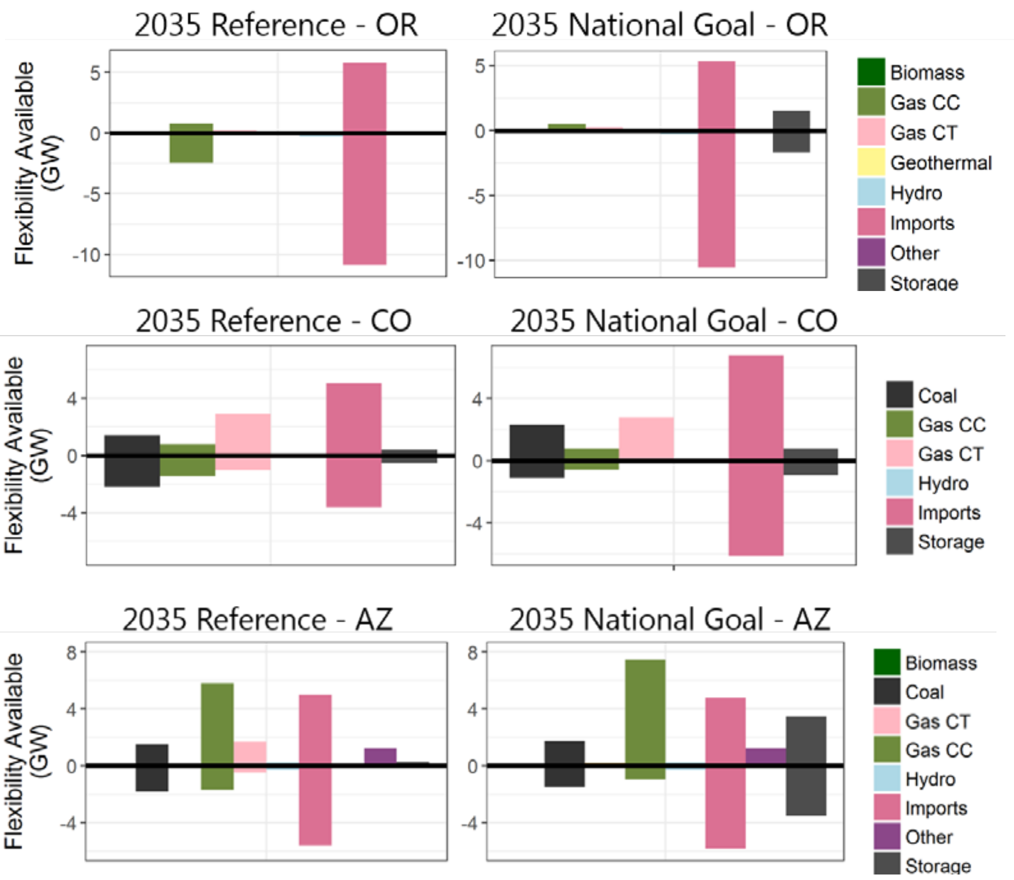
Themes

- No major flexibility shortages, even under high PV penetrations
- Each region has different sources of flexibility, but
- All regions use imports and exports as a large source of flexibility

Complications

- Regions are not likely to deploy PV in isolation, as we have modeled here
- Markets/utilities may not be able to exchange energy as modeled
- Increased PV deployment may result in economic generator retirement, which we do not fully capture

Average Hourly Flexibility per Region



Resource Adequacy and the Capacity Credit of Solar

Comparison of methods for assessing resource adequacy under high solar penetrations, including approaches to PV capacity credit estimation

https://www.nrel.gov/docs/fy21osti/72472.pdf

Gord Stephen*, Elaine Hale, and Brady Cowiestoll

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Resource Adequacy:

Is there enough power available (in the right place, at the right time) for my system to serve load with acceptably low shortfall risk?

Capacity Credit:

What portion of nameplate capacity is “firm” in the sense that it increases the amount of load that can be served with acceptably low shortfall risk?

How do we assess resource adequacy?

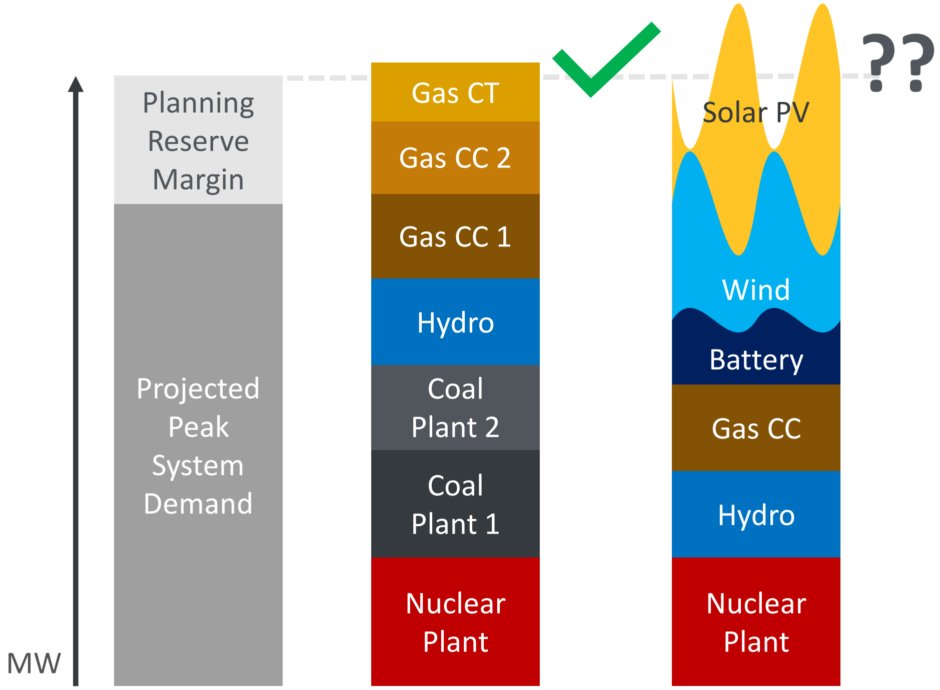
1. Planning reserve margin
2. Probabilistic Methods

Planning Reserve Margin Proxy

Installed capacity, peak load and planning reserve margins are commonly used together as a proxy for resource adequacy requirements (e.g., I consider my system resource adequate **if installed capacity exceeds expected peak load by 15%**)

Easy to calculate (historically) and transparent to communicate

Doesn't directly consider uncertainties or redundancy benefits (e.g., peak load forecast uncertainty, variable generation, serving load with one 100 MW generator vs two 50 MW generators)

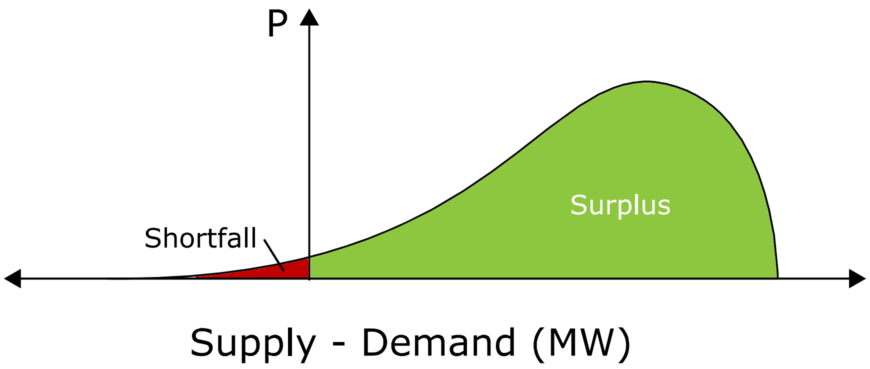


Probabilistic Resource Adequacy

Probabilistic resource adequacy assessment provides a more rigorous quantification of shortfall risk using more detailed system representations and probabilistic metrics:

- Loss-of-Load Expectation (LOLE)
  expected number of hours with shortfall during analysis period
- Expected Unserved Energy (EUE)
  expected amount of unserved energy during analysis period
- Normalized Expected Unserved Energy (NEUE)
  expected fraction of demand unserved during analysis period (ratio of EUE to total demand)

Probabilistic assessment (single-region, single-period)



Can specify resource adequacy criteria in terms of these metrics (e.g. I consider my system to be resource adequate **if LOLE is less than 2.4 hours/year**)

What is capacity credit?

How can we assess solar capacity credit?

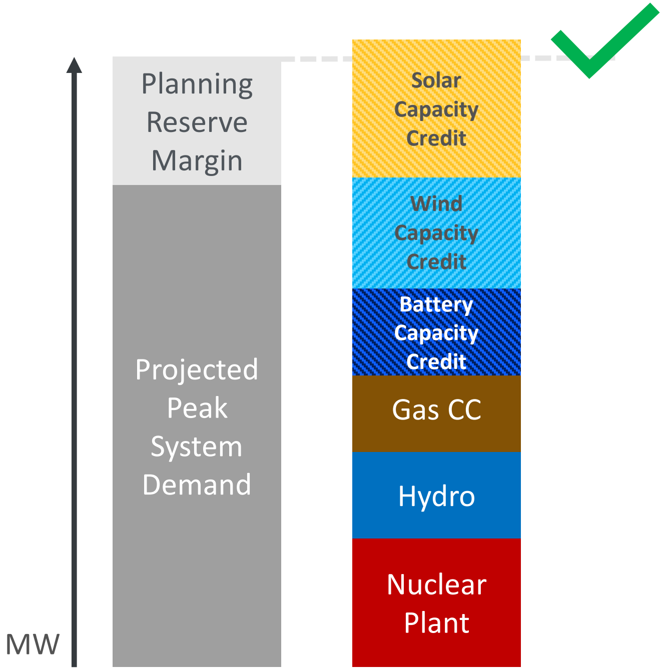
1. A heuristic method
2. Equivalent firm capacity

What is Capacity Credit?

A means to an end:
Capacity credit provides a way to approximate the contribution of non-conventional resources (such as variable generation and storage) in a conventional capacity-based resource adequacy paradigm

Not a panacea:
- No information on expected frequency, duration, and magnitude of capacity shortfalls
- Doesn't consider impact of transmission congestion and outages

Yet, a useful heuristic and often the best option available in established capacity-centric contexts (planning reserve margin-based capacity expansion models, capacity markets, etc.)

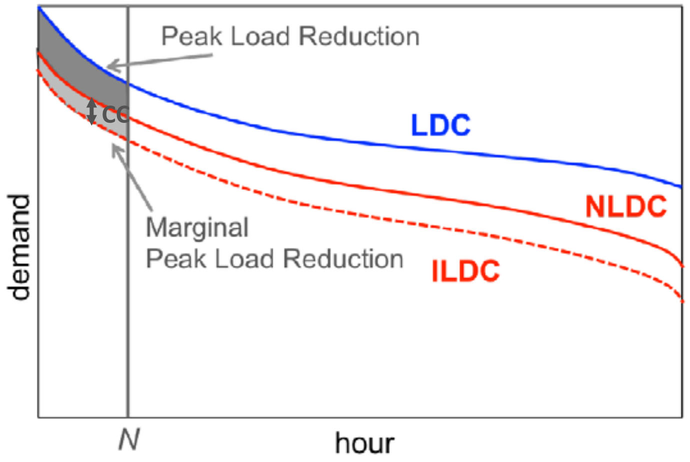


Capacity Valuation Methods: INLDC

Incremental Net Load Duration Curve Method

- Compare net load duration curves before and after adding resource of interest
- Capacity value approximated by average net load reduction over highest N net load hours, as a fraction of the resource's nameplate capacity
- Used endogenously by RPM (top 100 hours)
- Results for top 10, 50 and 200 hours also considered in this analysis

LDC = load duration curve
NLDC = net load duration curve
ILDC = incremental load duration curve (with added resource)

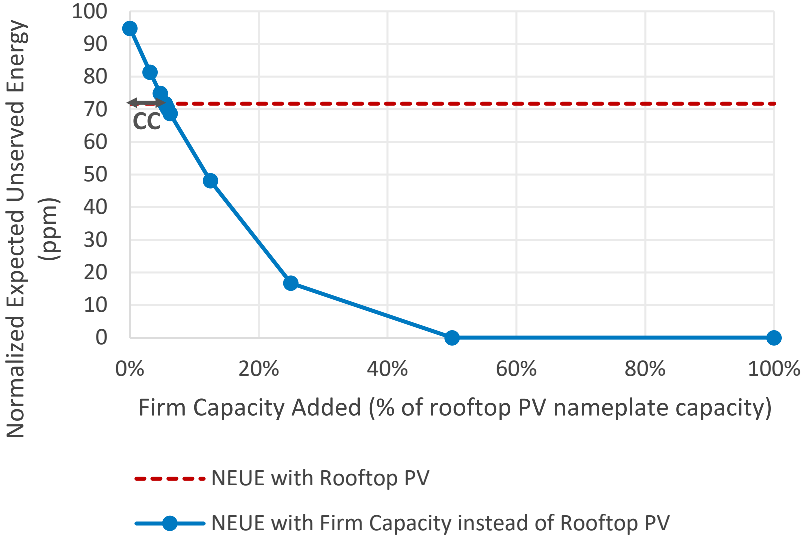


Hale, Stoll, and Mai, 2016

Capacity Valuation Methods: EFC

Equivalent Firm Capacity Method

- Calculate probabilistic resource adequacy metric for system with resource of interest added
- Remove resource of interest and determine level of firm (dispatchable with 100% availability) capacity that would be required to restore the system to previous probabilistic resource adequacy level
- Capacity value of a variable resource defined as equivalent firm capacity as a fraction of resource's nameplate capacity
- Results in this analysis calculated with expected unserved energy (EUE) probabilistic resource adequacy metric



How do heuristic methods used in a capacity expansion model compare to probabilistic results in the context of high-PV power systems?

Study Description

Key questions:

- How do planning reserve margin approaches compare to probabilistic resource adequacy assessment at higher solar PV penetrations?
- How do peak net load approaches to capacity credit estimation compare to probabilistically-derived approaches?

Planning Model (RPM) → **Resource Adequacy / Capacity Credit Model (PRAS)**

System buildouts corresponding to five scenarios over five future years

Probabilistic resource adequacy assessment and capacity credit calculation for VG

Study Scenarios

Reference

DPV, Gas Price, PV Cost, Storage Cost, and RPS

- Midline DPV projections
- Midline assumptions from the NREL 2018 ATB and the EIA AEO 2018
- Existing RPS policy as of 2018

These assumptions are used in all scenarios and locations unless stated

Focus Goal

DPV and RPS, within Focus Region only

- RPS with no REC trading to replicate the 2017 NREL Standard Scenarios' National 80% RPS case within the focus region
- More-aggressive DPV in the focus region in line with low NREL 2018 ATB PV cost projections

National Goal

PV Cost, DPV, and RPS

- RPS replicating the 2017 NREL Standard Scenarios' National 80% RPS case, applied across the whole WI
- More-aggressive DPV in line with low NREL 2018 ATB PV cost projections
- Low NREL 2018 ATB PV cost projections for all PV technologies

These assumptions are also used in the two National Goal sensitivity scenarios, Low Natural Gas Price and Low Storage Cost

Low Natural Gas Price

Gas Price

- Lower gas prices from EIA AEO 2018 "high oil and gas resource and technology" scenario

Low Storage Cost

Storage Cost

- Low NREL 2018 ATB cost projections for battery storage

DPV = distributed photovoltaics
RPS = renewable portfolio standard
REC = renewable energy credit
WI = Western Interconnection

Western Interconnection Representation in PRAS

Imported from RPM:

- 36 transmission regions / BAs
- Interregional power transfer limits
- Load and variable generation profiles
- Generator capacities, forced outage rates, and mean times-to-repair

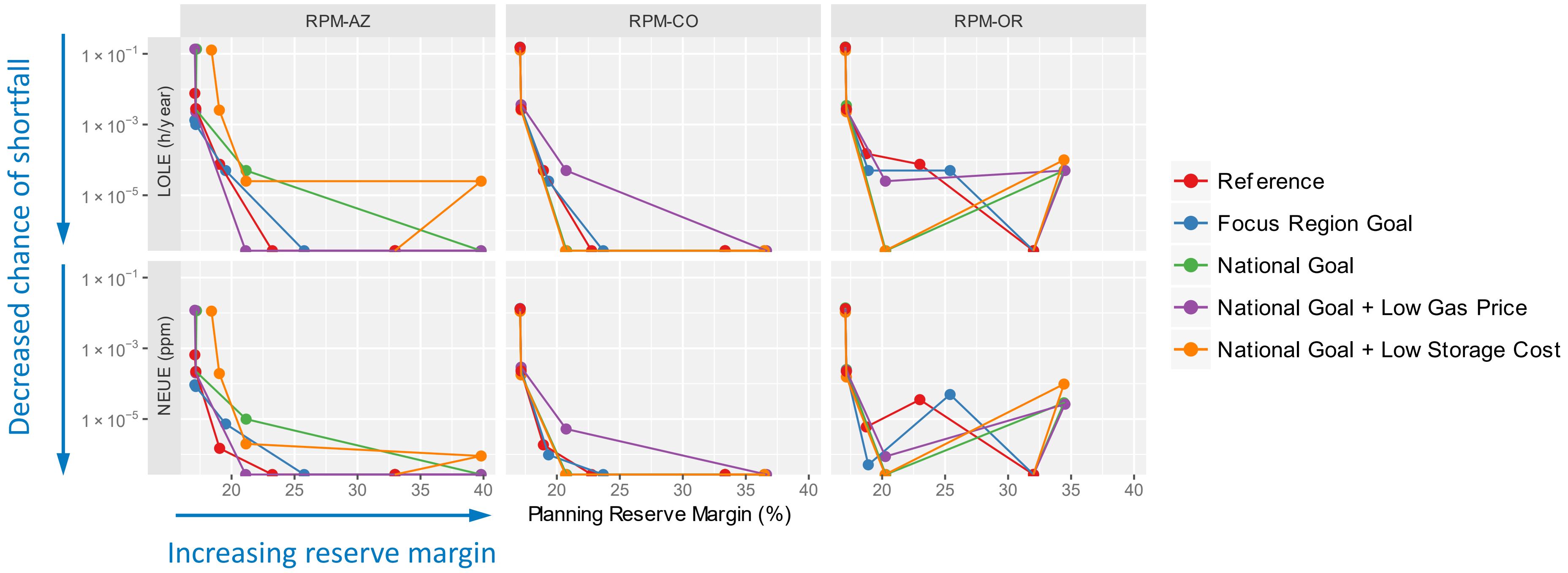
Transmission links assumed 100% reliable (no outages)

40,000 Monte Carlo samples of simplified system operations (annual extent, hourly resolution) under randomly-drawn unit outages

Key Caveats

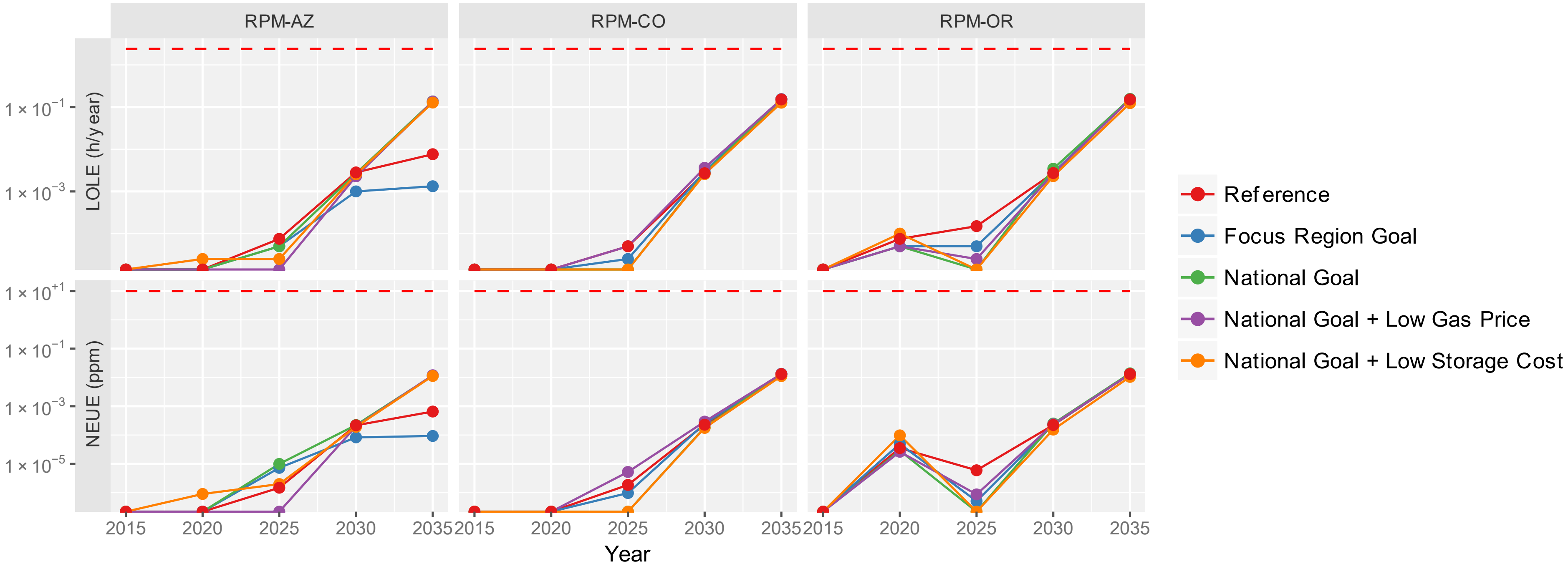
- Energy-limited resources (e.g. pumped hydro and battery storage) were modeled as 100% firm capacity by PRAS (although not RPM)
- PRAS only considered a single year of wind, solar, and load conditions: the same single year used by RPM when considering expansion decisions
- Economic retirement decisions are not fully modeled by RPM
- Transmission was not modeled in detail, nor were transmission outages considered
- Overall, resource adequacy results here may be overstated: ongoing and future work is addressing these shortcomings

Probabilistic Metrics vs Reserve Margin



Capacity reserve margins not always correlated with probabilistic resource adequacy metrics (e.g. LOLE, EUE)

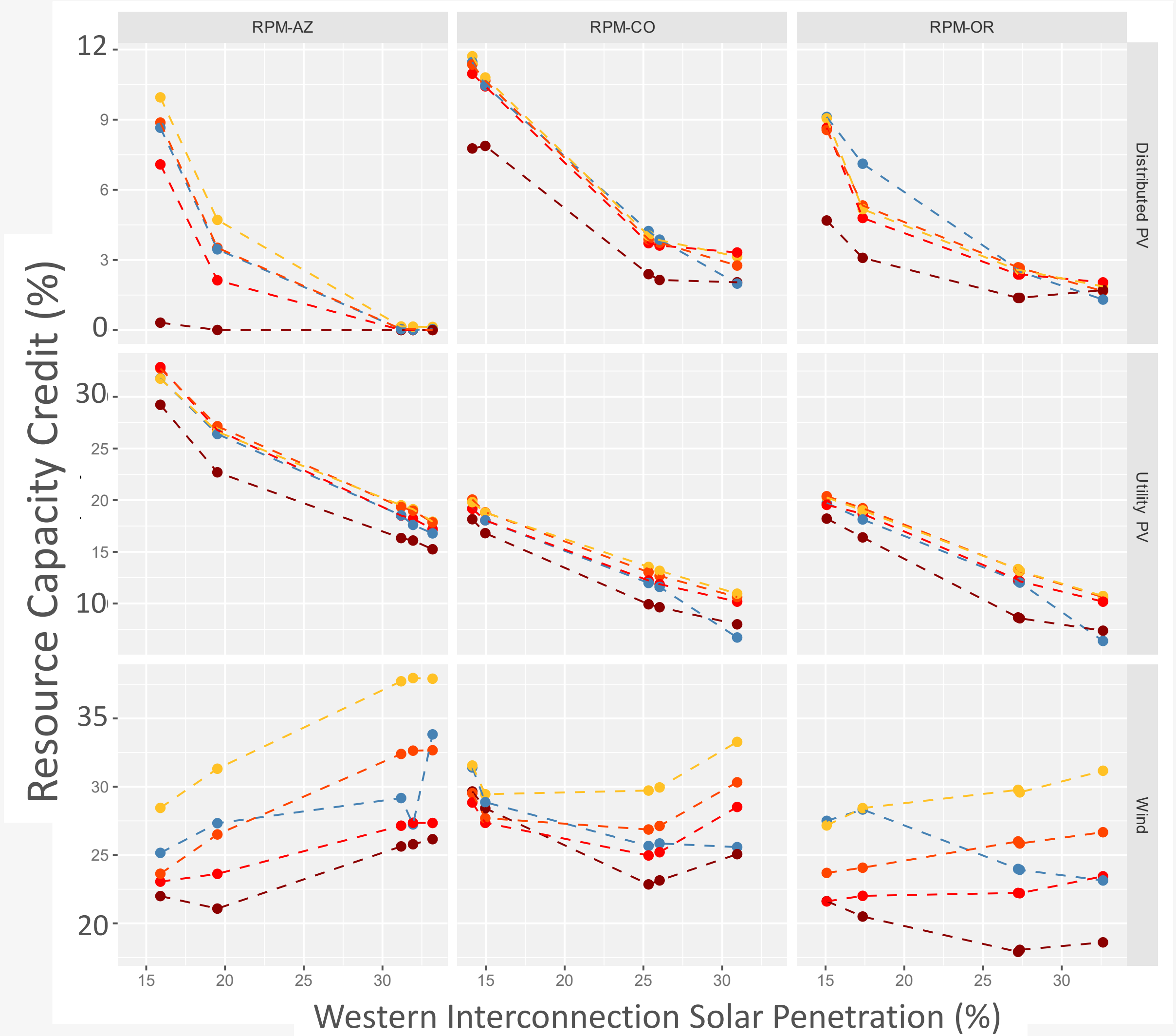
Resource Adequacy Assessment



RPM's planning reserve margin approach maintains system resource adequacy under probabilistic evaluation (subject to the aforementioned caveats)

Capacity Credit Method Comparison

Choice of capacity credit calculation method can influence assigned resource contributions, although general trends persist



Resource Adequacy and the Capacity Credit of Solar: Two Key Takeaways

1 **Larger planning reserve margins do not always correspond to improved probabilistic resource adequacy metrics (e.g. LOLE, EUE)**

- Resource adequacy is more than the sum of reliability-derated generator capacities – interactions between resources through time matter
- The systems studied were well within resource adequacy thresholds.[1] Heuristic methods should be double-checked more frequently against their probabilistic counterparts as one approaches such thresholds.

2 **The choice of capacity credit calculation method influences assigned resource contributions**

- EFC and INLDC methods provide comparable results at moderate solar penetrations, but may begin to diverge at higher levels
- No one choice of INLDC peak hour parameter consistently tracks the more rigorous EFC method

[1]As best as the team could determine with the methods available at the time. Known shortcomings include a single year of wind and solar data, assumed full capacity credit for storage resources, and an incomplete assessment of retirements that could occur during the study period.

Simulating Distributed Energy Resource Responses to Transmission System-Level Faults Considering IEEE 1547 Performance Categories on Three Major WECC Transmission Paths

Richard ‘Wallace’ Kenyon, Barry Mather

https://www.nrel.gov/docs/fy20osti/73071.pdf

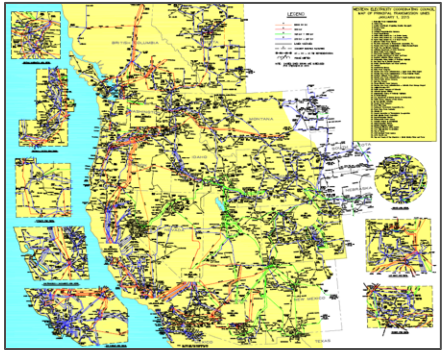
Study Impetus

With ever growing quantities of distributed energy resources (DERs) on the Western Interconnect (nearly 10 GW of capacity today), and varying connection standards regarding abnormal condition ride-through (IEEE 1547: 2003 (legacy), 2018; Category I, Category II, Category III), how can we best understand the impact that these DERs have on the bulk electric system using our current simulation capabilities?

Ride-through: indicates if, and for how long, the DER maintains its pre-disturbance power supply through a disturbance (frequency/voltage deviations). Not necessarily indicative of any grid-support functionality.
distributed generation (DG): a subset of DERs, assumed to be Solar PV (I.e. DPV) for this study.

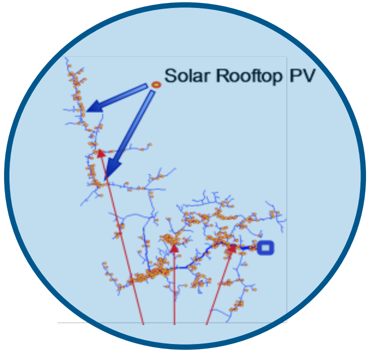
Two Types of Simulators; One Power System

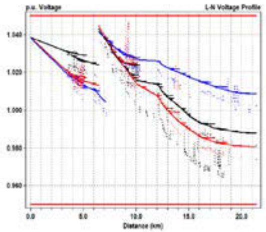
Transmission Simulations:



- Positive sequence/balanced
  - Reduces three phases to one
- Bundled Load/DERs
  - *Obscured individual operation*
- Reduces complexity/enables large system simulations

Distribution Simulations:





- Three phases/unbalanced
- Models radial networks
  - Feeder head to secondaries
- Individual inverter operation
  - *Can apply IEEE 1547 compliant ride through to individual devices*
- Single/few feeder simulations

How do we incorporate the response of DERs, as determined in distribution simulations, in transmission simulations?

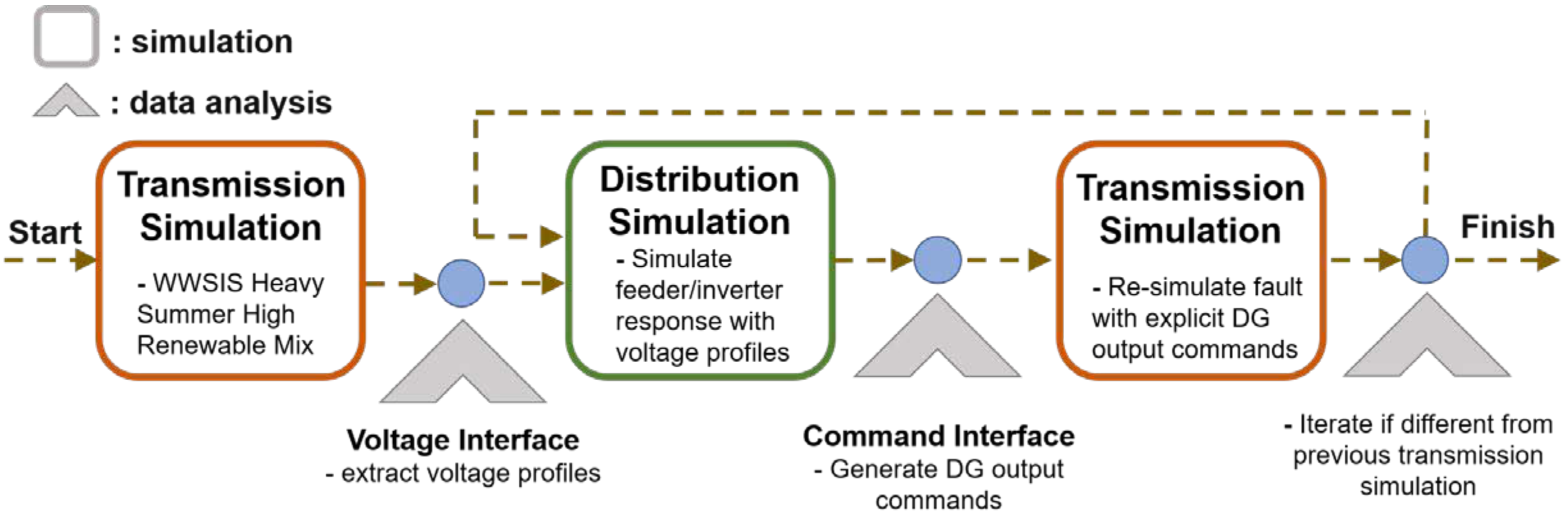
Study Impetus

With ever growing quantities of distributed energy resources (DERs) on the Western Interconnect (nearly 10 GW of capacity today), and varying connection standards regarding abnormal condition ride through (IEEE 1547: 2003 (legacy), 2018; Category I, Category II, Category III), how can we best understand the impact that these DERs have on the bulk electric system with our current simulation capabilities?

Our solution:

Couple transmission and distribution level modeling with interfacing data sets at the feeder point of connection to assess the impacts of these various standards.

Simulation Pathway



WWSIS: Western Wind and Solar Integration Study [1]

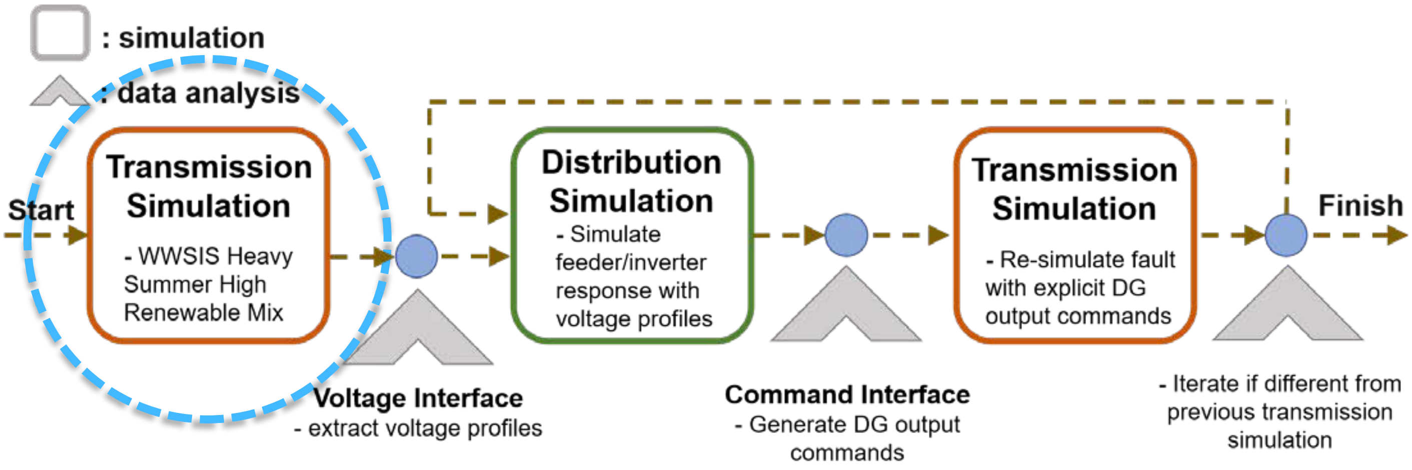
DG Output Command: feeder-level aggregate distributed generation response

[1]: Miller et al. *Western Wind and Solar Integration Study Phase 3. GE Energy 2014*

Example

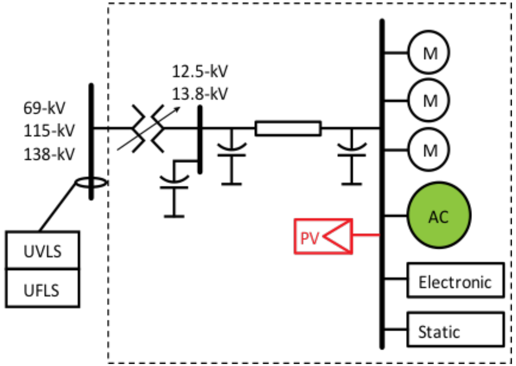
Determining the response of DG to a three-phase fault on Path 61 under varying IEEE 1547 performance categories – CA case. I'll talk about AZ case at the end.

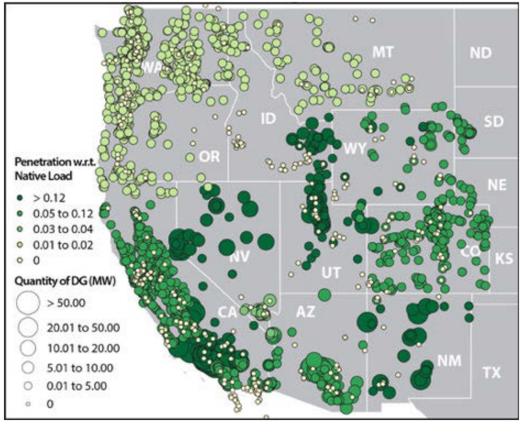
Initial Transmission Simulation



Simulations of the Western Interconnection (WI)

- GE Positive Sequence Load Flow
- Heavy Summer 2023 planning case with high levels of utility scale (~17%), and distributed (~5%), renewable sources
- Composite load model with generation is used
- Three phase fault scenario on all WI Paths to identify the most severe reactions
    - Fault cleared after six cycles; 0.1 s
    - Severity with respect to DG assessed with the introduced Volt-Sec, Volt-Sec-DG metric [2]

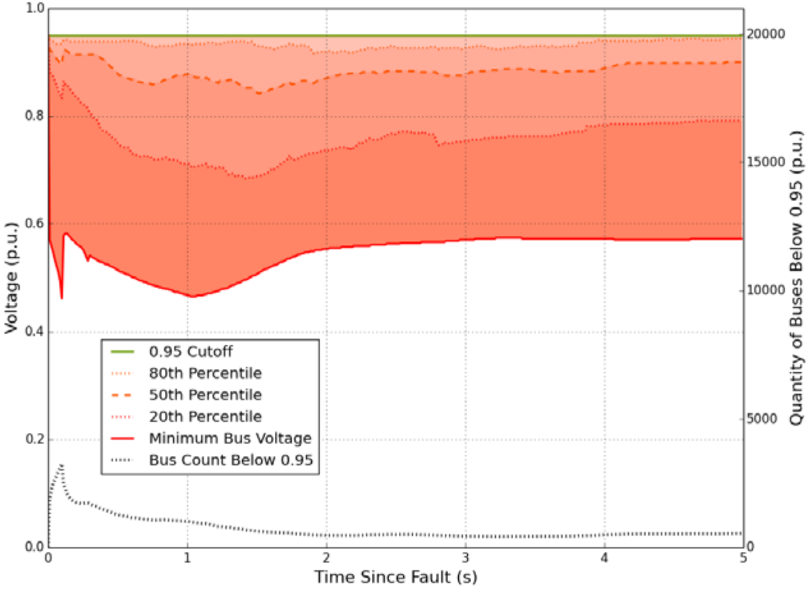


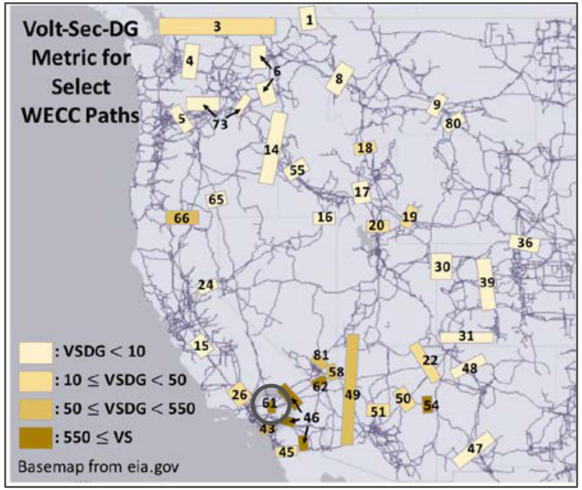


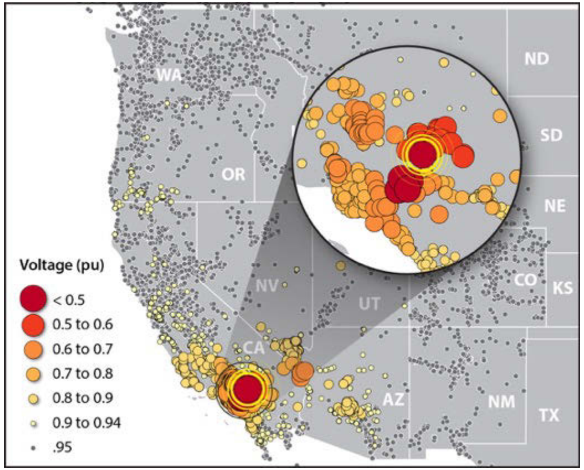
[2]: R. W. Kenyon and B. Mather, ''Quantifying transmission fault voltage influence and its potential impact on distributed energy resources,'' in Proc. IEEE Electron. Power Grid (eGrid), Nov. 2018, pp. 1–6.

Path 61 Lugo 500 kV

Voltage Distribution

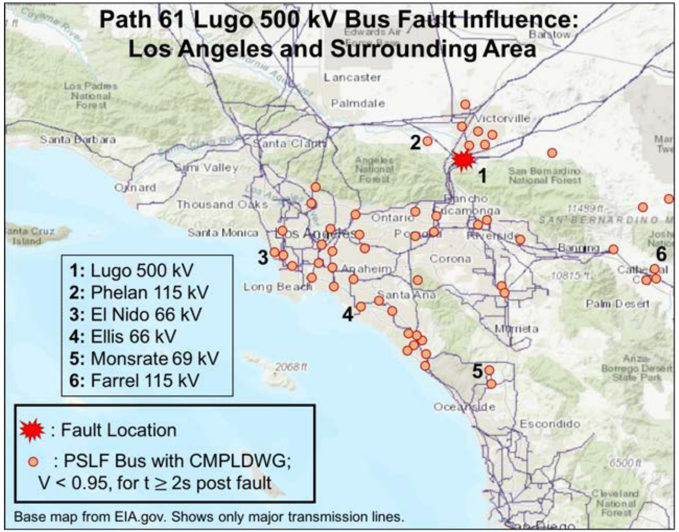


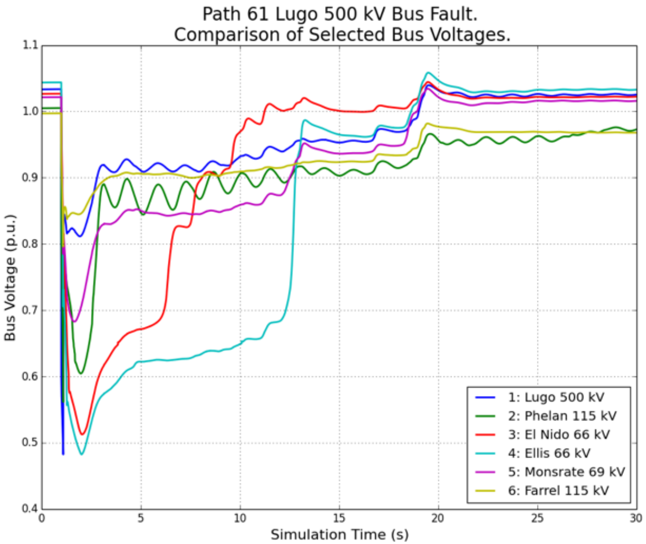




- All buses across the system; any transmission voltage level
- Fault Induced Delayed Voltage Recovery (FIDVR)

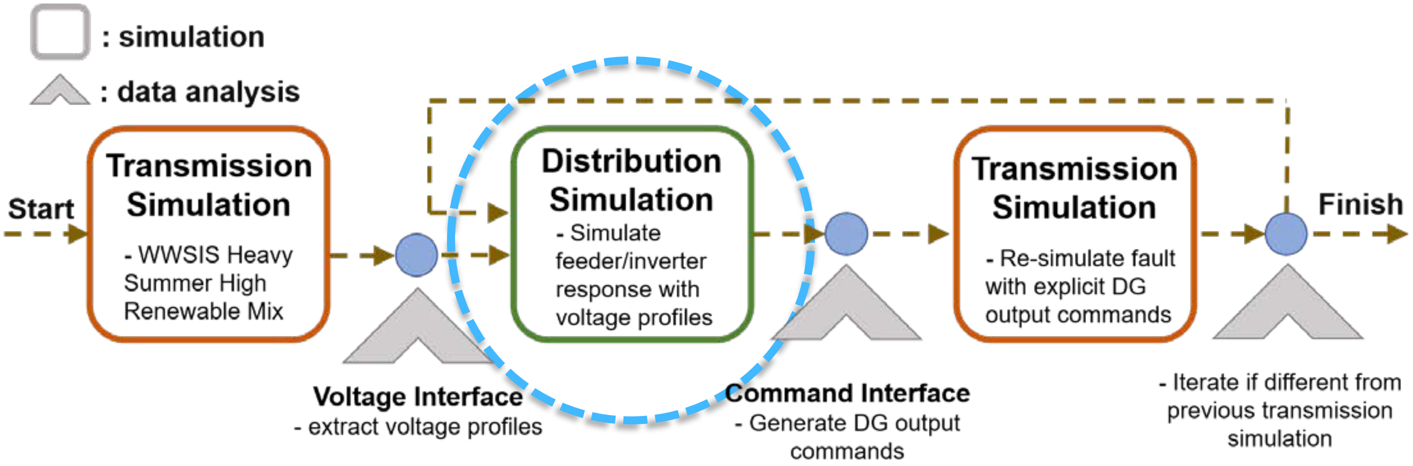
Path 61 Lugo 500 kV: Extracted Information





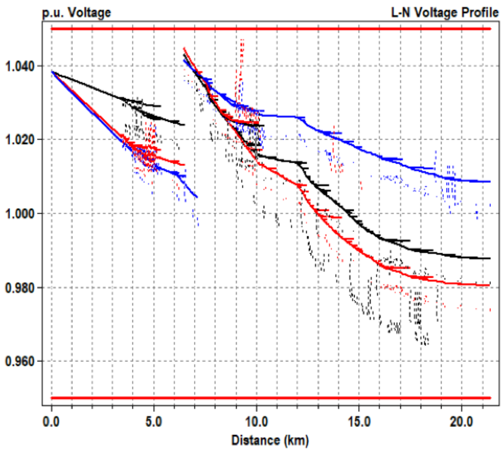
- 123 composite load models with voltage deviations triggering IEEE 1547 action
- Accounts for approximately 4 GW of DG across this system
- Majority of influence is in Southern California

Transmission -> Distribution Interface

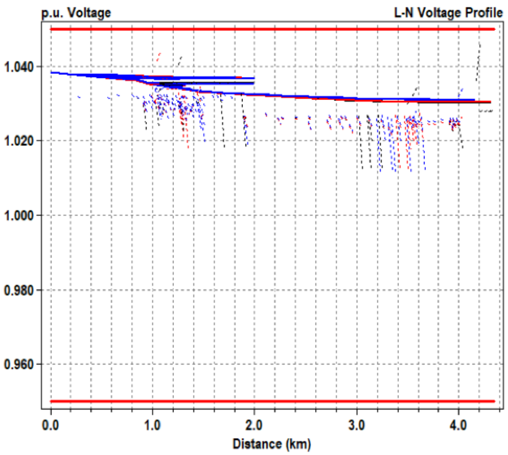


- Interface Open Distribution System simulations with voltage profiles from Positive Sequence Load Flow simulations

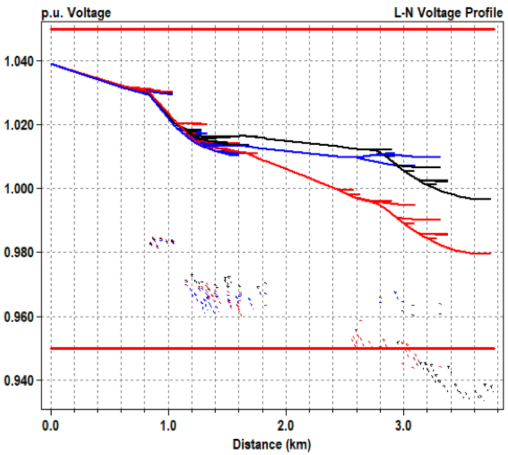
Open Distribution System Simulations



Commercial/residential: 12 kV



Industrial: 16 kV



Residential: 4 kV

- 123 ‘feeder head’ voltage profiles for distribution systems
- 50 inverters (DG units) compliant to selected IEEE 1547 ride-through criteria on each feeder; located on secondaries.
- Proportional representation of residential/commercial/industrial feeders based on impacted region.

IEEE 1547 Ride Through Implementation

<table>
<tr><th>Voltage</th><th>IEEE 1547: 2003 Pessimistic</th><th>IEEE 1547: 2018 Category I</th><th>IEEE 1547: 2018 Category II</th><th>IEEE 1547: 2018 Category III</th></tr>
<tr><td>$V < 0.3$</td><td rowspan="5">Immediate trip</td><td rowspan="2">Immediate trip</td><td>Immediate trip</td><td rowspan="2">Momentary cessation; trip after 1.0 s</td></tr>
<tr><td>$0.3 \leq V < 0.5$</td><td rowspan="2">Momentary cessation; trip after 0.32 s</td></tr>
<tr><td>$0.5 \leq V < 0.65$</td><td rowspan="2">Momentary cessation; trip after 0.16 s</td><td rowspan="2">Continuous operation; trip after 10.0 s</td></tr>
<tr><td>$0.65 \leq V < 0.7$</td><td rowspan="2">Trip after 3 s + (8.7 s/p.u.) × (V – 0.65 p.u.)</td></tr>
<tr><td>$0.7 \leq V < 0.88$</td><td>Trip after 0.7 s + (4 s/p.u.) × (V – 0.7 p.u.)</td><td>Continuous operation; trip after 20.0 s</td></tr>
<tr><td>$0.88 < V$</td><td>Continuous operation</td><td>Continuous operation</td><td>Continuous operation</td><td>Continuous operation</td></tr>
</table>

- All ride-through control based on pessimistic interpretation of standard—i.e., if current injection is not explicitly required, then current injection is assumed to be zero

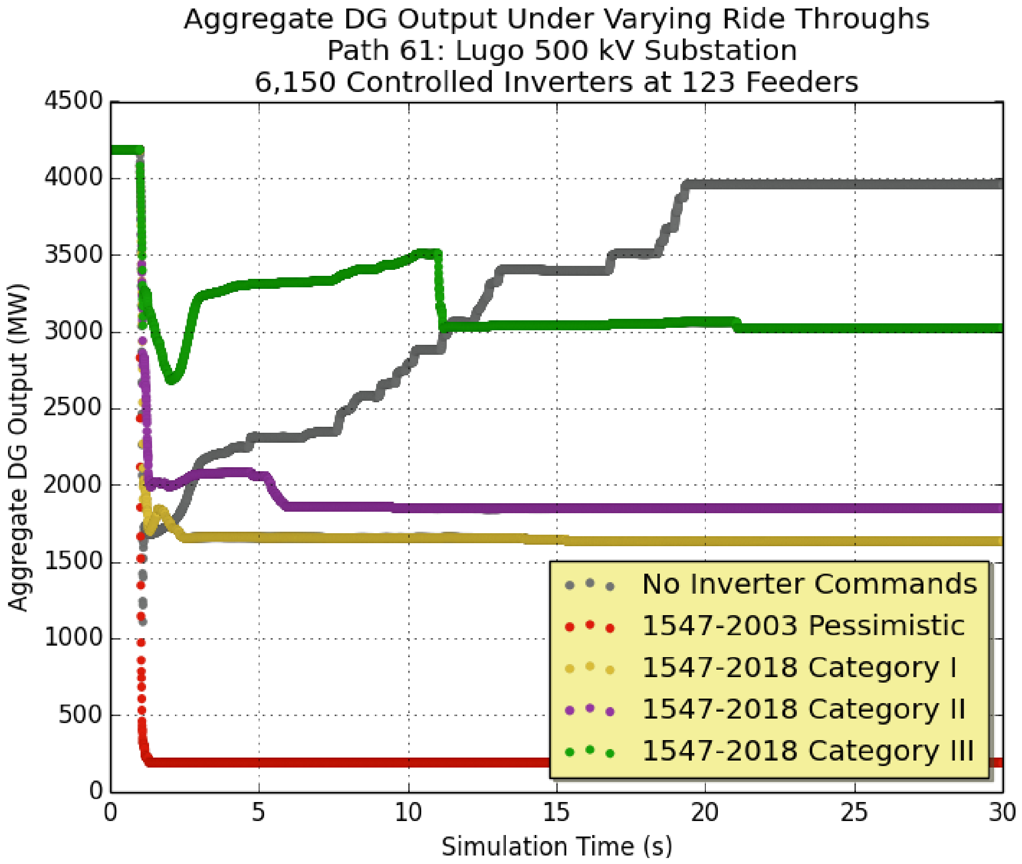
In general, greater ride through participation at lower voltages, for longer periods of time.

Overall Distributed Generation Loss

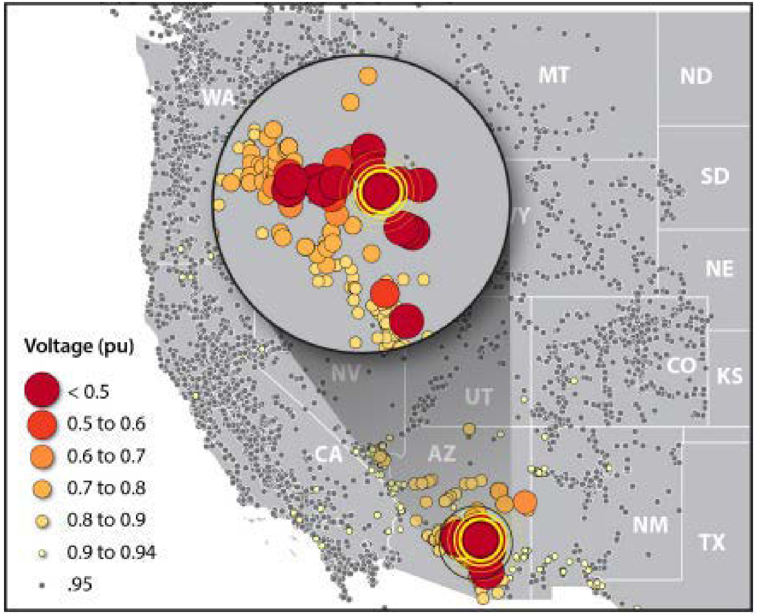
- Results of these distribution simulations scaled to match the DG levels in the transmission system
- Four simulations of each unique voltage profile dependent on type of ride-through criteria implemented

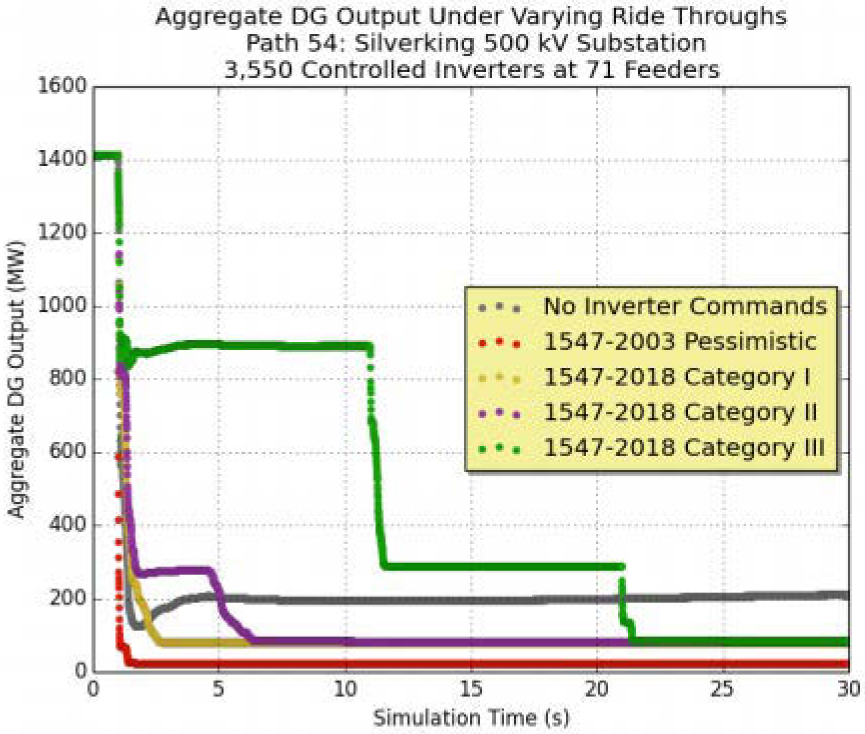
	IEEE 1547 2003 Pessimistic	**IEEE 1547 2018 Category I**	**IEEE 1547 2018 Category II**	**IEEE 1547 2018 Category III**
Lost Distributed Generation	4,000 MW	2,550 MW	2,340 MW	1,500 MW

Aggregate Results



What about for AZ?





- Initial loss of DER is limited to about 550 MW with IEEE 1547-2018 Cat III

Key Findings

- The specific performance of distributed generation during fault conditions can have a large impact on the recovery of the power system.
- The temporal elements of the IEEE 1547 performance categories require more involved modeling efforts than those implemented today (DER_A models are now available, were not at the time of project).
- Fault induced delayed voltage recovery events can generate persistent low-voltages at distribution-voltage levels, which can in some cases persist beyond the trip criteria of distributed generation.
- IEEE 1547-2003 allows a near immediate real power reduction. IEEE 1547-2018 categories I and II yield similar yet improved real power results. Category III yields a respectively smaller total real power generation decrease.

Thank you

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