

# Electricity Markets and Forecasts, how they interact

## ESIG Tutorial – Forecasting and Markets Workshop

Aidan Tuohy and Erik Ela  
EPRI Grid Operations and Planning

Denver, June 4 2019



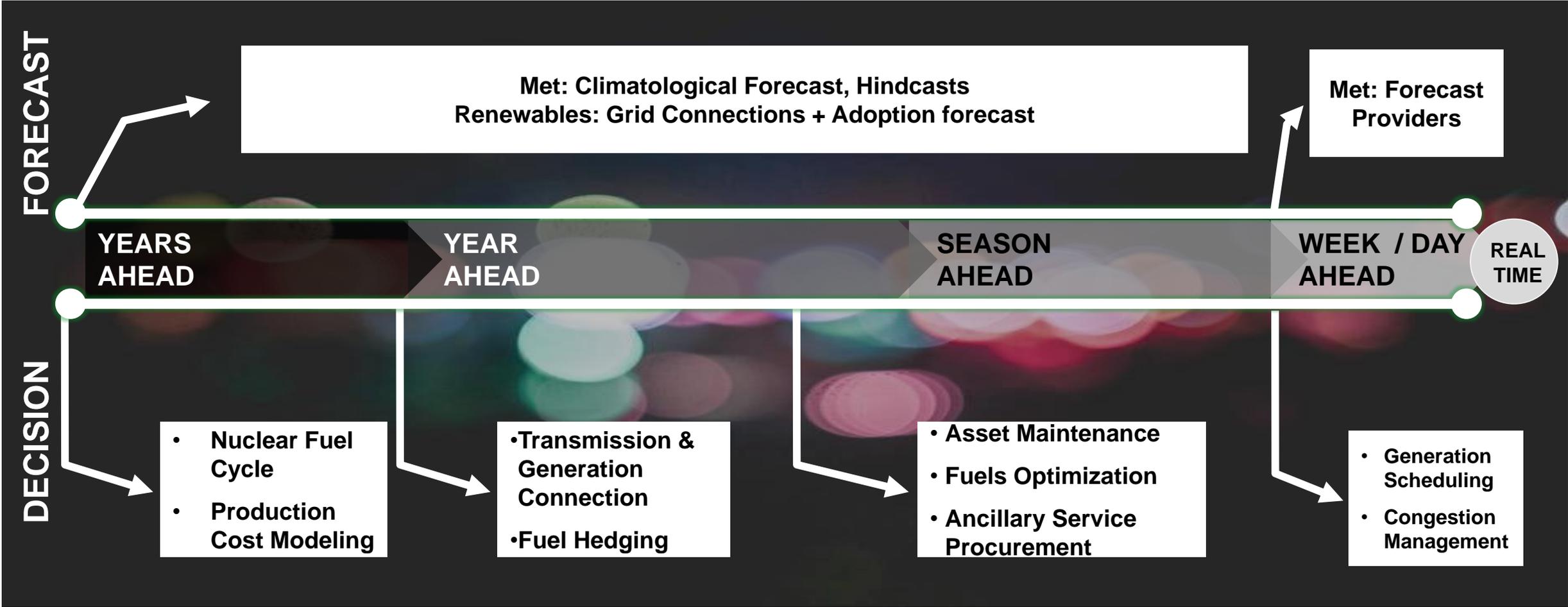
# Objectives of Tutorial

- Provide general background for those less familiar on two important and increasingly interrelated topics
  - Forecasting of renewables
  - Electricity market operations
- Provide more detailed discussion on several advanced R&D topics and latest learnings from EPRI and others
- Discussion on the topics so that we can all learn from each other!

# Agenda

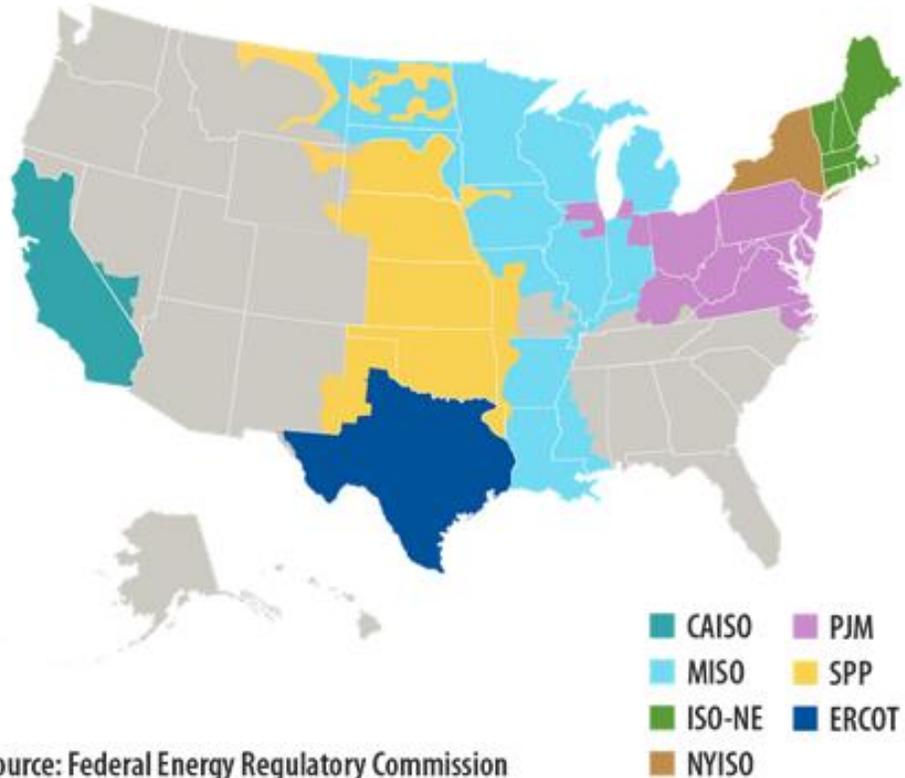
| TIME        | TITLE   | SPEAKER                        |
|-------------|---|--------------------------------|
| 8:00-8:30   | Session Overview  | Aidan Tuohy and Erik Ela, EPRI |
| 8:30-9:15   | Wind and Solar Forecasting Utilization 101                                | Aidan                          |
| 9:15-10:00  | Energy and Ancillary Services Markets 101                                 | Erik                           |
| 10:00-10:30 | Break   |                                |
| 10:30-11:00 | Advanced Forecasts 201: How advanced forecasts could be used in operation | Aidan                          |
| 11:00-11:30 | Electricity Markets 201: Capacity Markets, FTRs, emerging trends          | Erik                           |
| 11:30-12:00 | Forecasting and Market Design Integration: Advanced Research              | Erik/Aidan and Audience        |

# Bulk System Forecast Uses



# North American Electricity Market Design

Wholesale Electric Power Markets



Source: Federal Energy Regulatory Commission

Capacity

Energy

Ancillary Services

Financial Transmission Rights

# Together...Shaping the Future of Electricity

# Using Wind and Solar Forecasts in Power System Operations and Planning

Aidan Tuohy  
Principal Project Manager

ESIG Tutorial  
June 4, 2019



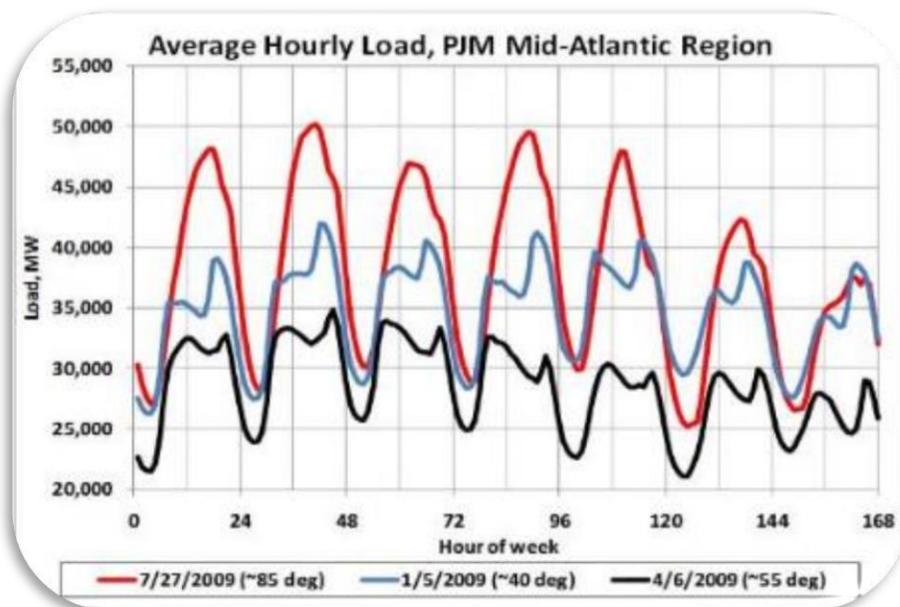
# Agenda

- Evolution of forecast use in operations and planning
- Evaluation of forecasting
- Forecasting in integration studies

# Where are forecasts used in operations today?

# We Already Have a Weather Dependent System

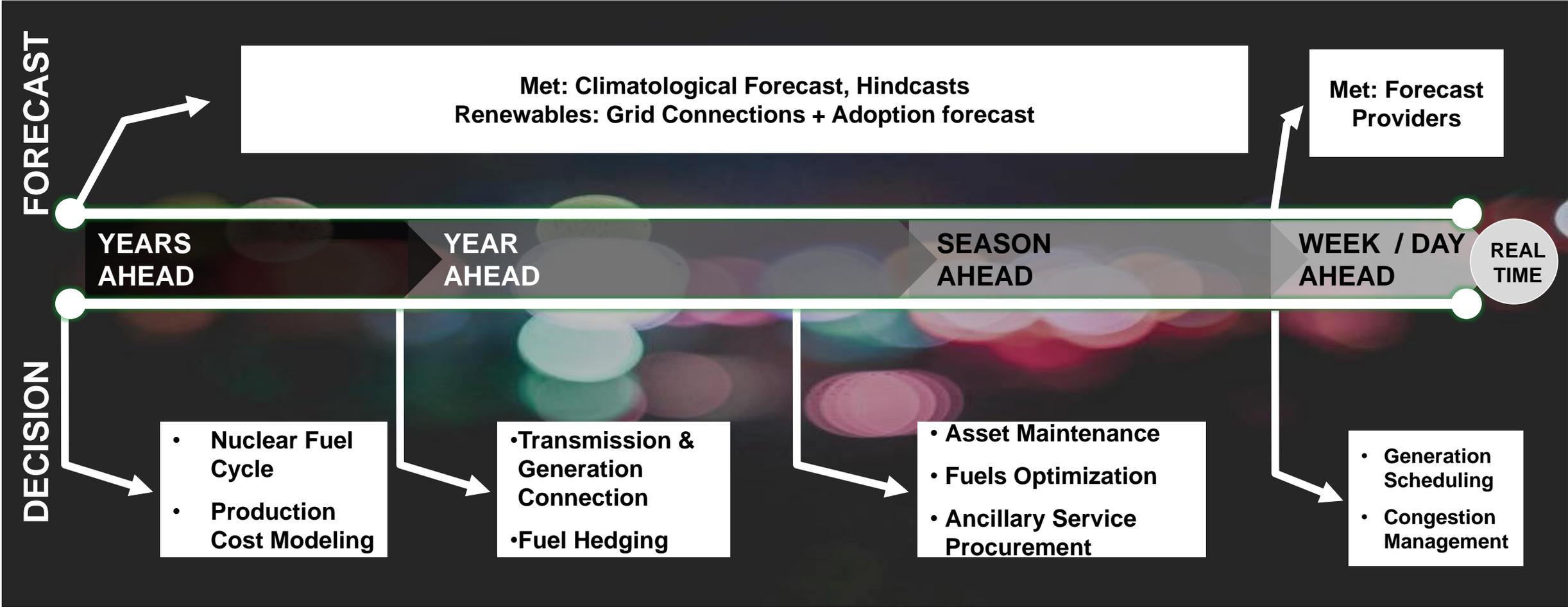
- Load: temperature, humidity, wind
- Distribution: wind, snow and ice
- Transmission: temperature, fire, ice, wind
- Generation: temperature and extreme temperature events



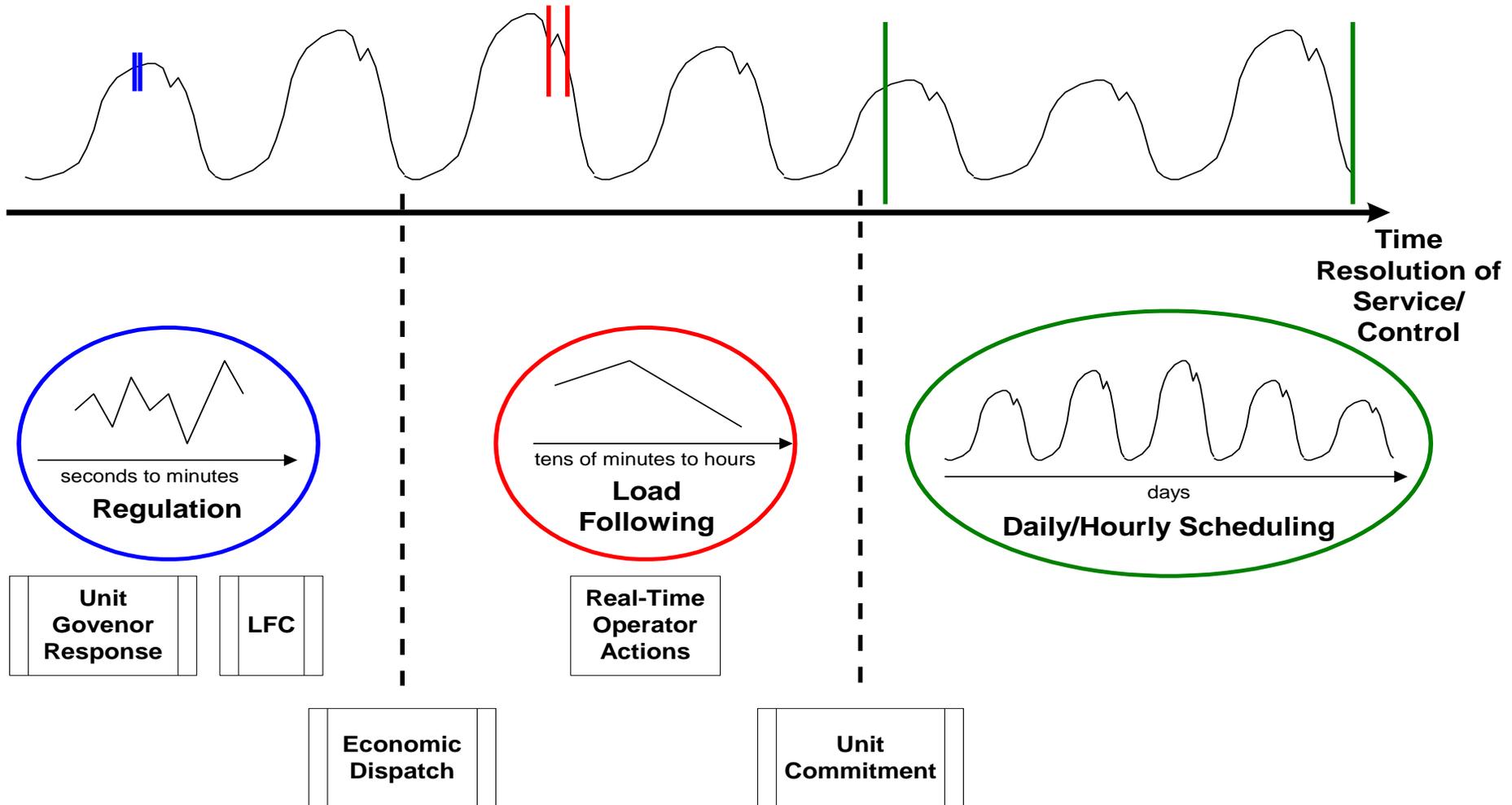
# Status of Renewable Forecasting in US Markets

- **All ISOs/RTOs now use centralized wind power forecasting**
  - Many other non-ISO areas also use wind power forecasting
  - Most areas have solar forecasting in use or coming online
- **Used for multiple applications**
  - Day(s) ahead and short term (5-60 mins) forecasts used
  - Used in clearing markets and operational planning
  - Different time horizons, frequency of provision and granularity provided to different users based on their needs
- **Ramp forecasts are also used by some operators**
  - Some may prefer to just use one forecast
  - Some are using ensembles provided by vendor, or multiple vendors
- **DER forecasting is becoming more challenging and important**
- **Cost allocation of forecast provision varies by region**

# Bulk System Forecast Uses



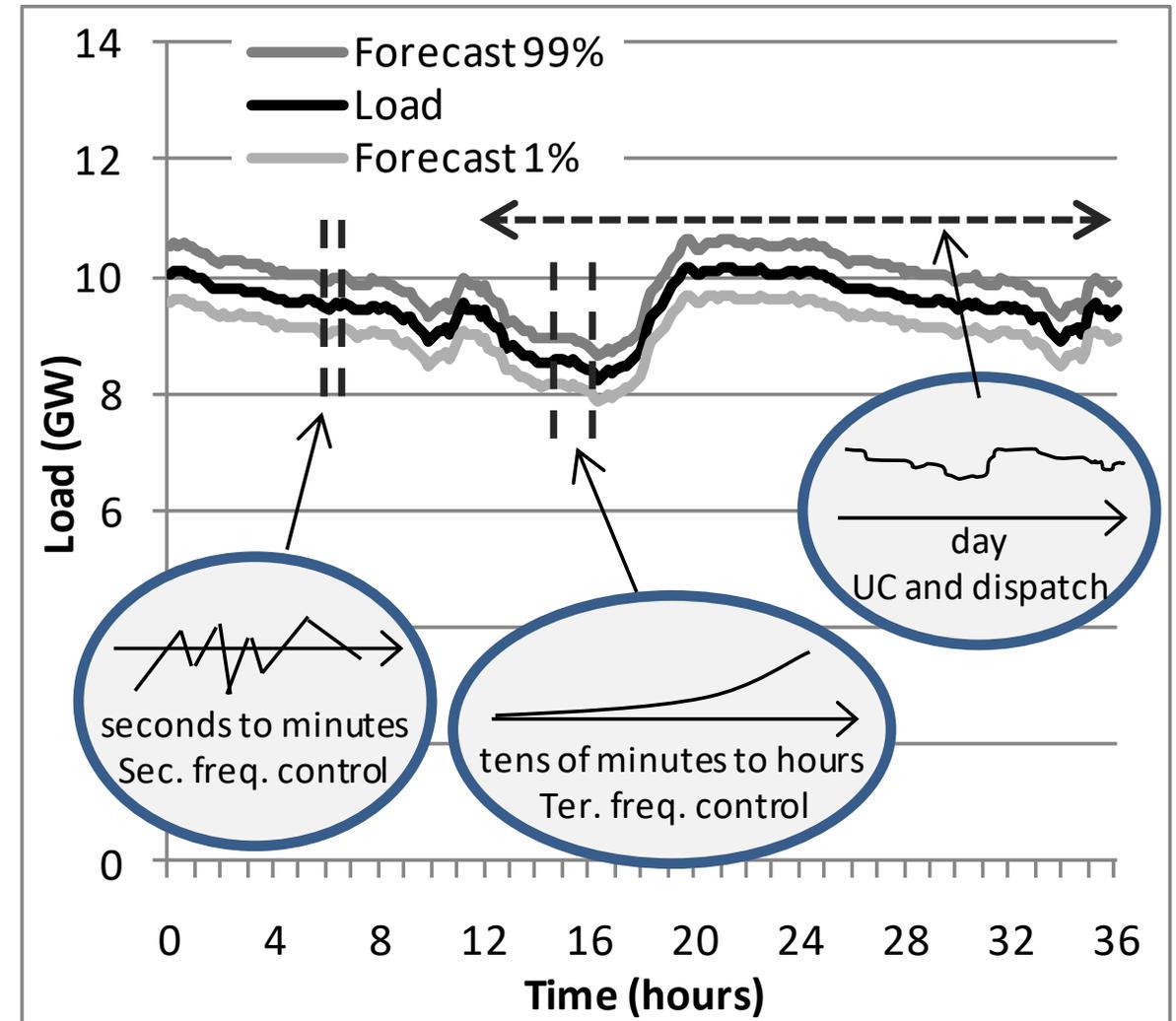
# Timeframes of Interest for Forecasting



**We use these timeframes for operations, but also in planning studies to examine impacts of variability and uncertainty on resource needs**

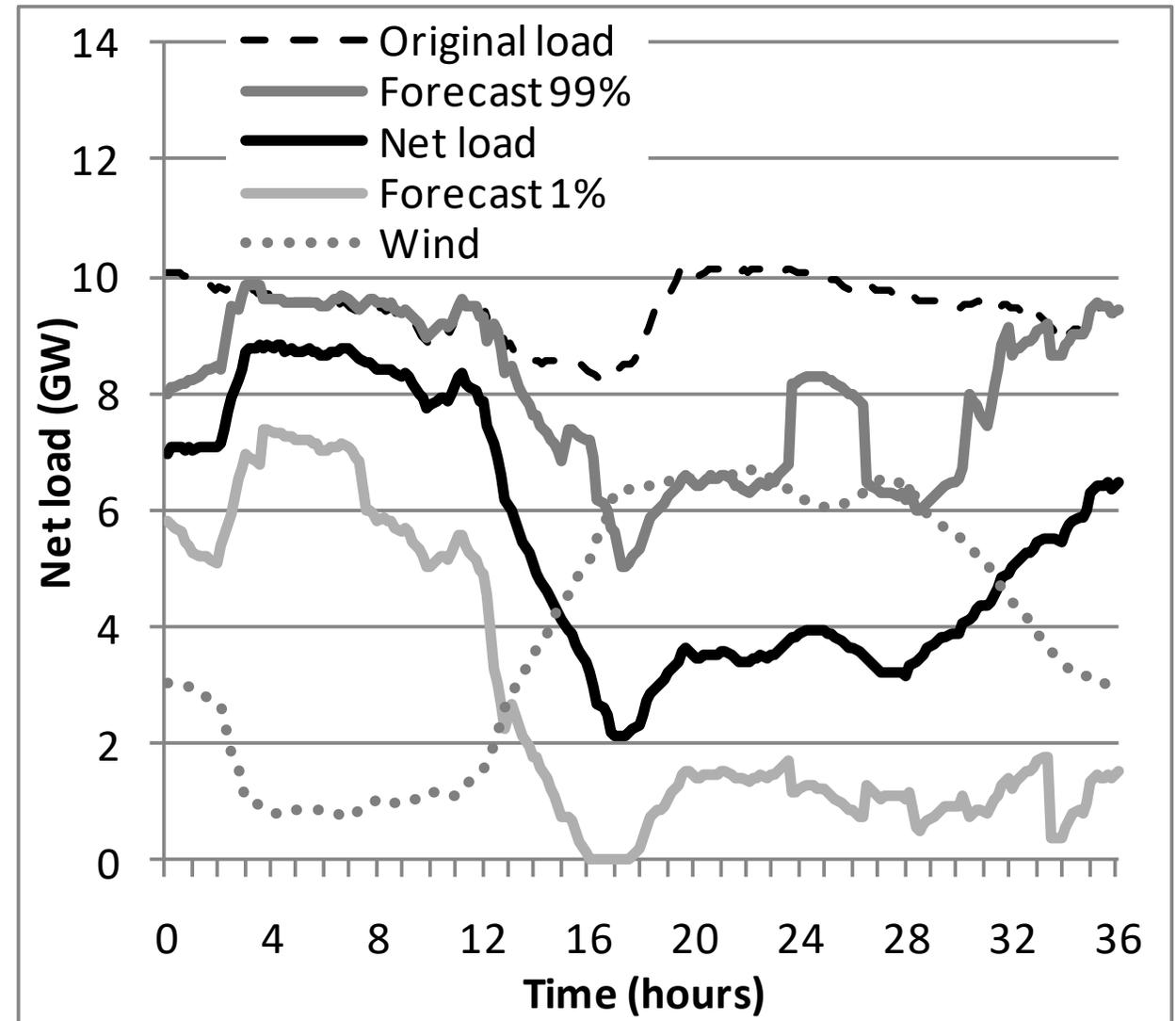
# Unit Commitment and Dispatch without Wind/Solar

- During operation demand drifts from the prediction and power plants or power lines may fail
- Reserves keep the system in balance
- UC plans the operation for the next day
- ED dispatches the resources available
- Reserves cover the periods in between

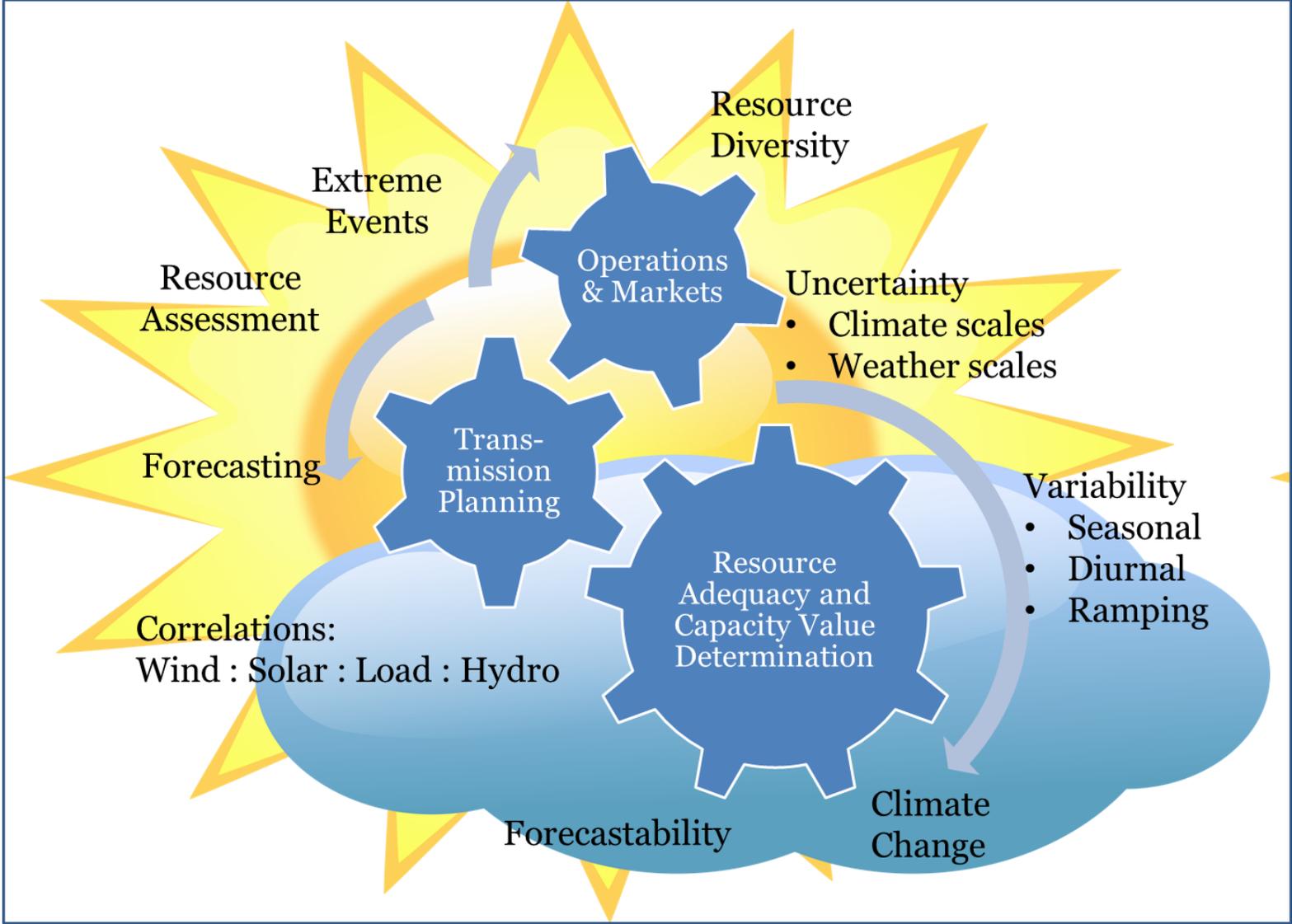


# UC with Wind/Solar

- Expected residual load (load minus wind power production)
- Variability and uncertainty increases
- More flexibility required
  - Generation
  - Responsive load
  - Possible curtailment of wind power
- Required amount depends on the variability and forecast accuracy of wind and load during the relevant time period

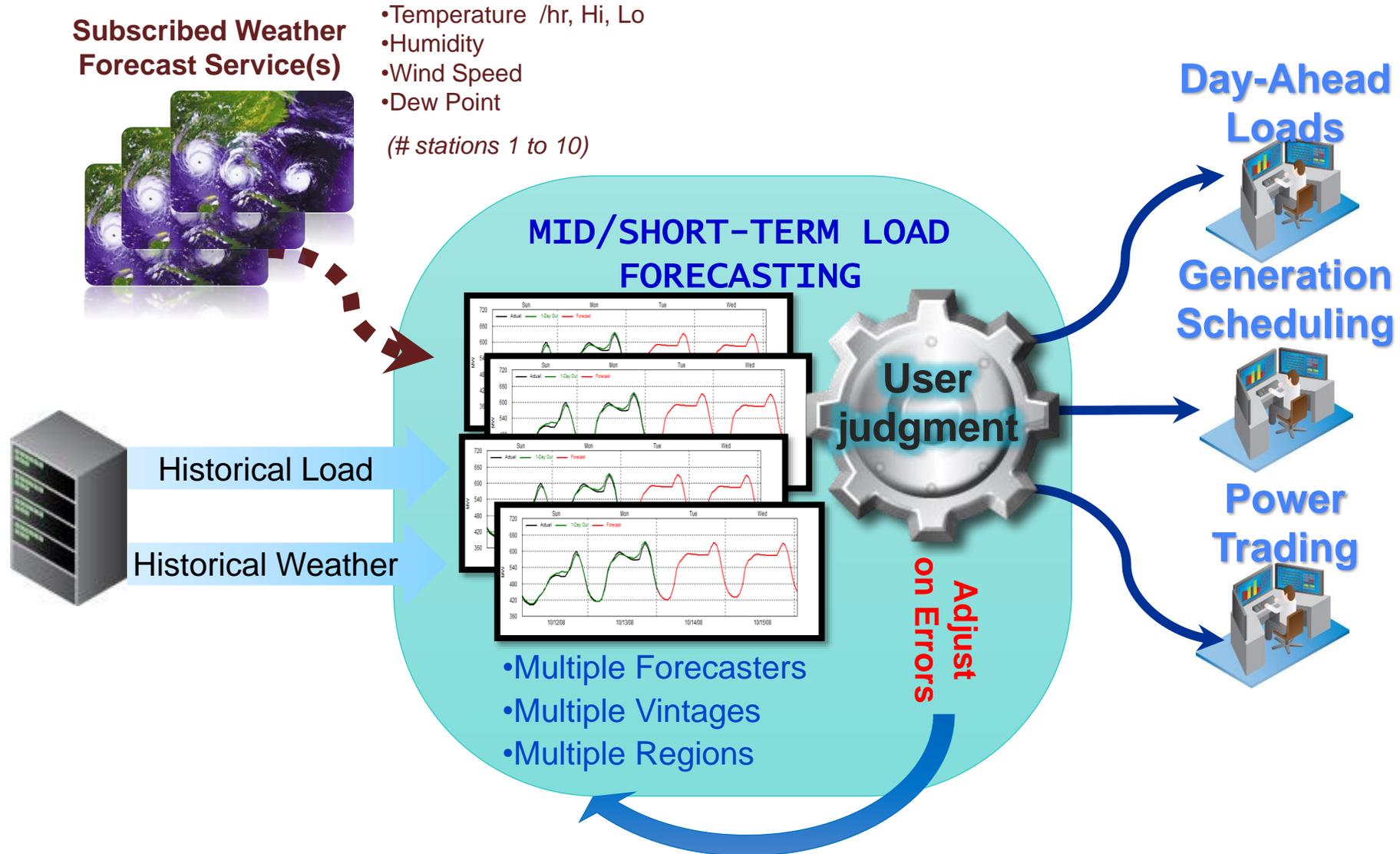


# Broader Use of Meteorology in Ops/Planning

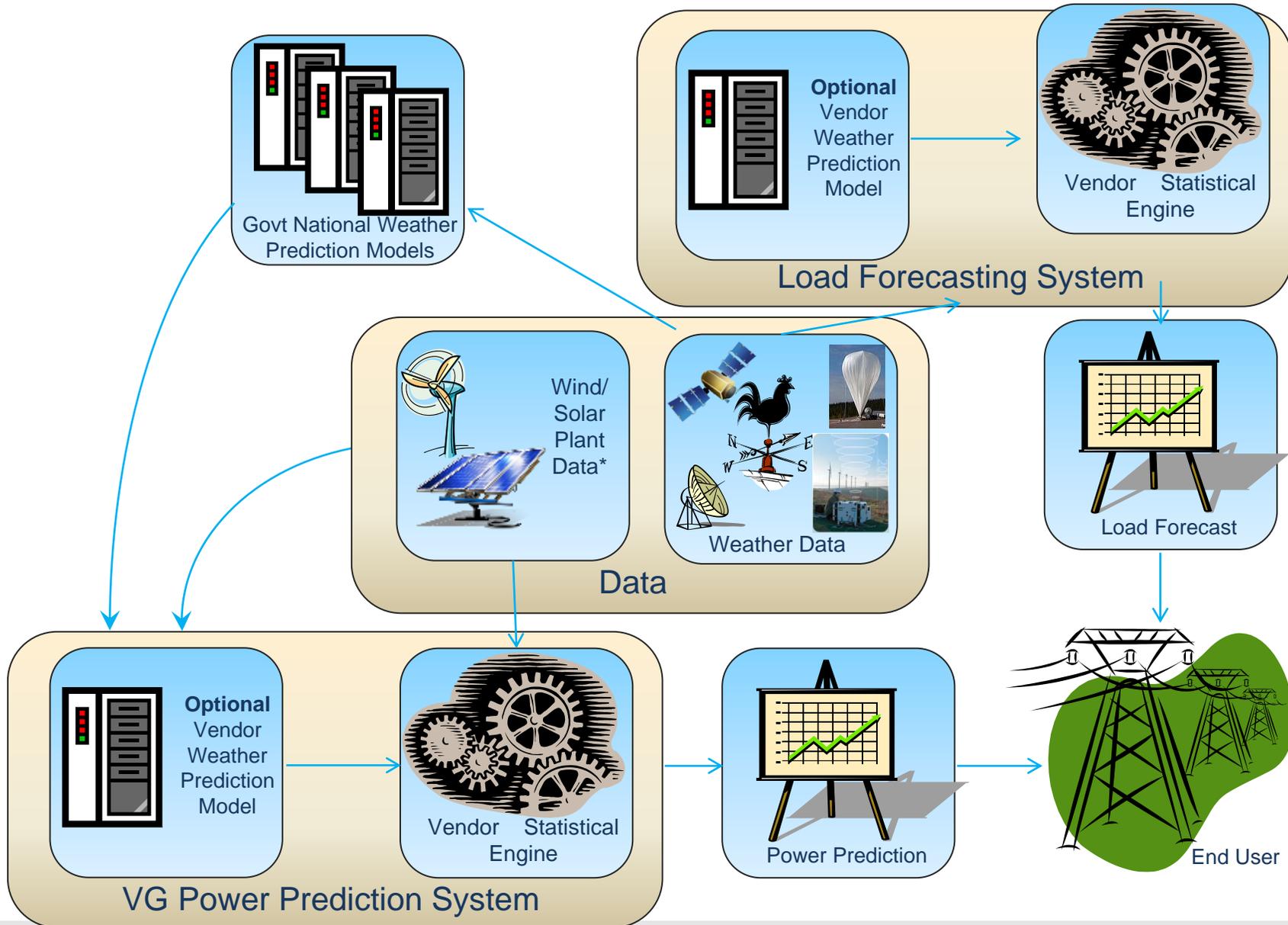


# How are forecasts developed and used – data and models

# Short-term Load Forecasting Typical Setup



# Adding VER - Forecasting Electricity Supply and Demand

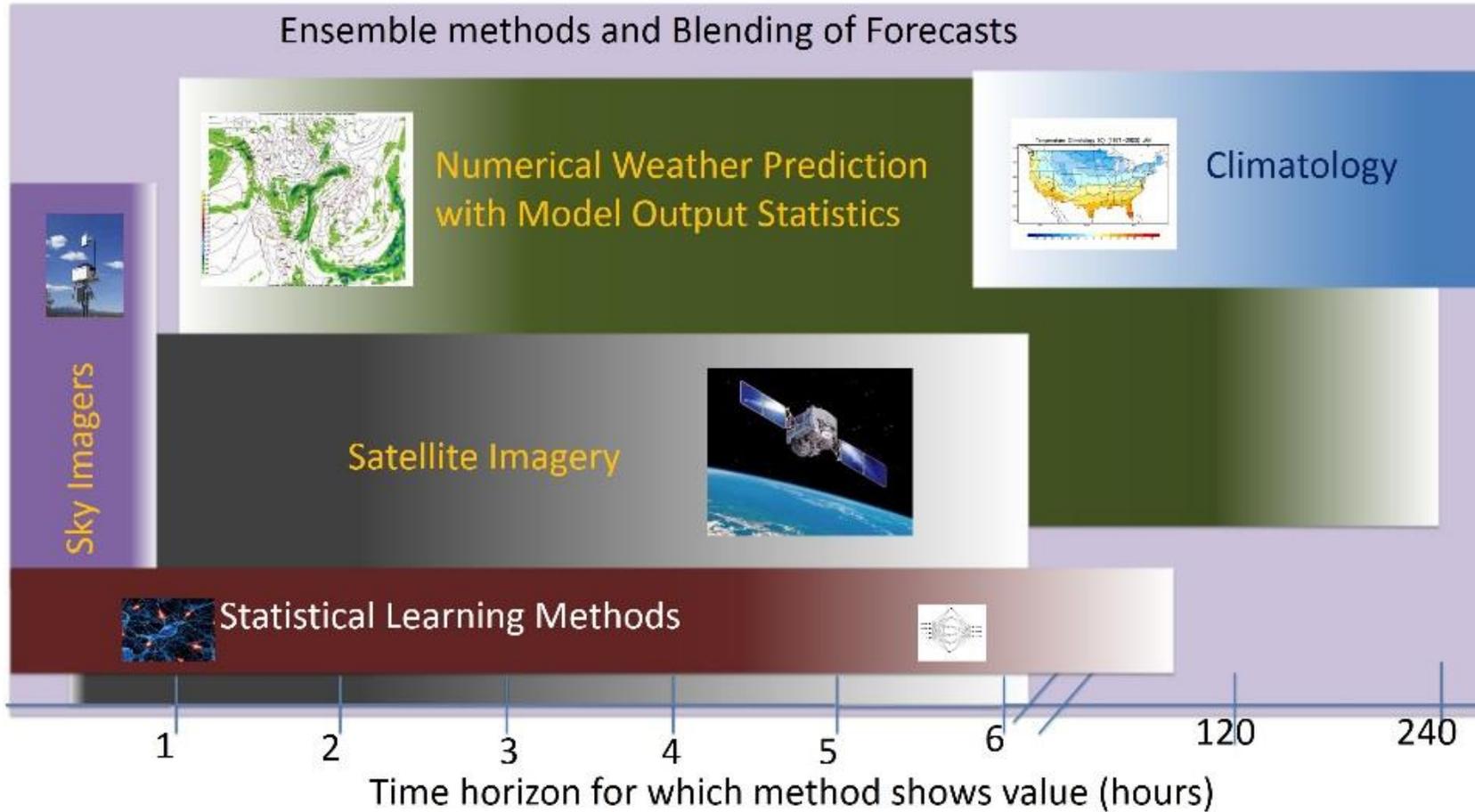


# Summary: Types of forecasts, their applications, and methods for producing them

|                  | Type of Forecast | Time Horizon                            | Key Applications  | Methods   |
|------------------|------------------|---|---|---|
| Generation       | Intra-hour       | 5-60 min                                | Regulation, real-time dispatch market clearing                                      | Statistical, persistence.                         |
|                  | Short term       | 1-6 hours ahead                         | Scheduling, load-following, congestion management                                   | Blend of statistical and NWP models               |
|                  | Medium term      | Day(s) ahead                            | Scheduling, reserve requirement, market trading, congestion management              | Mainly NWP with corrections for systematic biases |
|                  | Long term        | Week(s), Seasonal, 1 year or more ahead | Resource planning, contingency analysis, maintenance planning, operation management | Climatological forecasts, NWP                     |
| Decision support | Ramp forecasting | Continuous                              | Situational awareness, Curtailment  | NWP and statistical                               |
|                  | Load forecasting | Day ahead, hour-ahead, intra-hour       | Congestion management, demand side management                                       | Statistical                                       |

Source: [http://greeningthegrid.org/resources/factsheets/copy\\_of\\_ForecastingWindandSolarGeneration.pdf](http://greeningthegrid.org/resources/factsheets/copy_of_ForecastingWindandSolarGeneration.pdf)

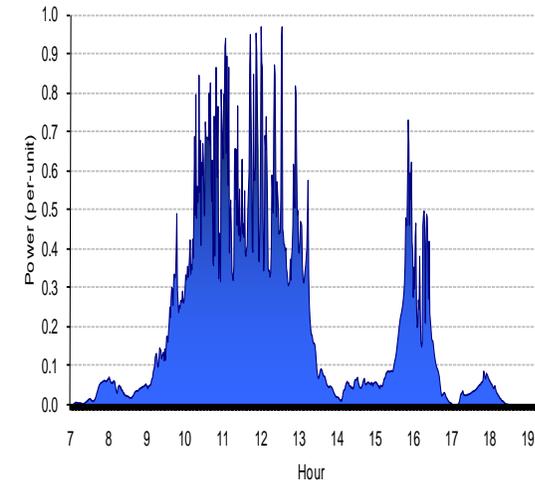
# Solar Forecasting Methods



A. Tuohy, J. Zack, S.E. Haupt, J. Sharp, M. Ahlstrom, S. Dise, E. Gritit, C. Möhrlen, M. Lange, M.G. Casado, J. Black, M. Marquis, and C. Collier, "Solar Forecasting", IEEE Power & Energy Magazine, Nov/Dec 2015

# Solar vs Wind Forecasting

- Observability
  - Solar is better observed in short time scales → cloud detection
  - Potentially more difficult day ahead to catch cloud formation
- Variability
  - Solar plants more variable in small sizes
  - But, over larger system, may be less variable
- Location
  - Windy sites tend to be more windy than average
  - Sunny sites tend to be less cloudy
- System Operations
  - Quasi-linear relationship versus cubed for wind
  - Well known clear sky day relationship

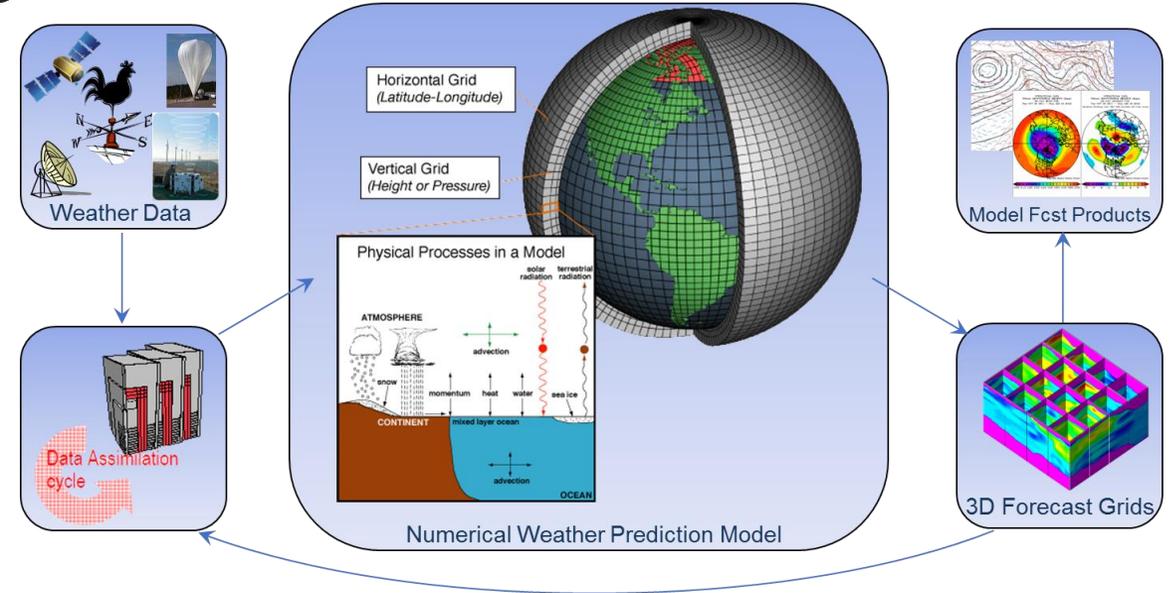


# Wind/Solar Forecasts versus Load Forecasts

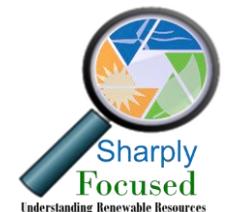
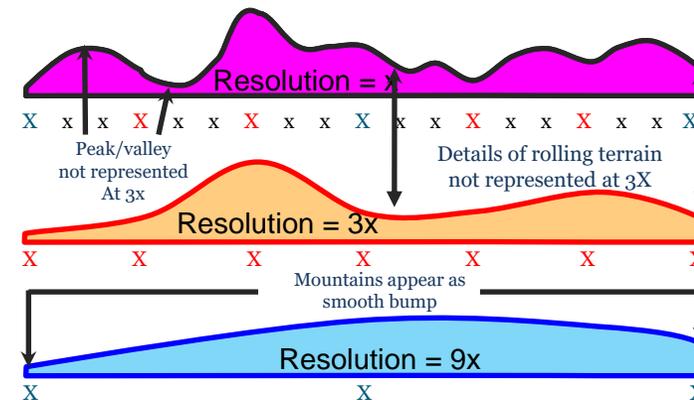
- Electricity demand follows a regular pattern that is modulated by weather...mainly temperature
- Variable generation forecasts are defined by weather
- Wind and irradiance harder to forecast than temperature and exhibit more spatial and temporal variability
- Thus, we should expect load forecasts to exhibit considerably lower errors.

# Numerical Weather Modeling

- Solves equations for evolution of the atmosphere to predict weather
  - Typical resolutions of 40km to 1km, 30 to 140 horizontal levels
  - Mapped onto 3D grid, with intervals of 15 minutes to one hour



- Several important factors:
  - Initial conditions – data assimilation and boundary conditions
  - Parameterizations
  - Resolution
  - Model numerics
  - Uncertainty quantification



# Observational Data

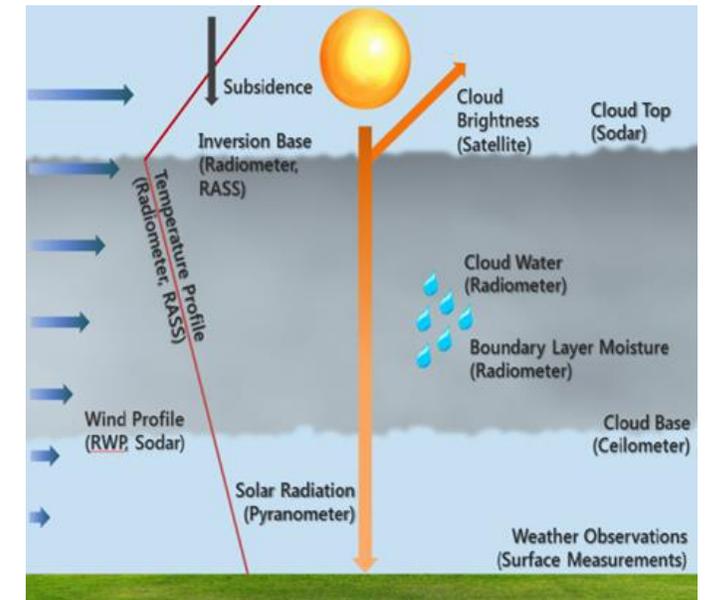
- On-site facility data
  - Metadata (configuration, static data)
  - Archived and real time power and status data
  - Meteorological data
- Satellite data
  - Latest GOES satellites and equivalent around the world provide high resolution information
- Sky imagers
  - Potentially useful for short term, though still in R&D for most applications
- Offsite observations
  - Meteorology stations placed upstream
  - Includes lidar, sodar, ceilometer, radiometer, etc.



**GOES-R** THE FUTURE OF FORECASTING

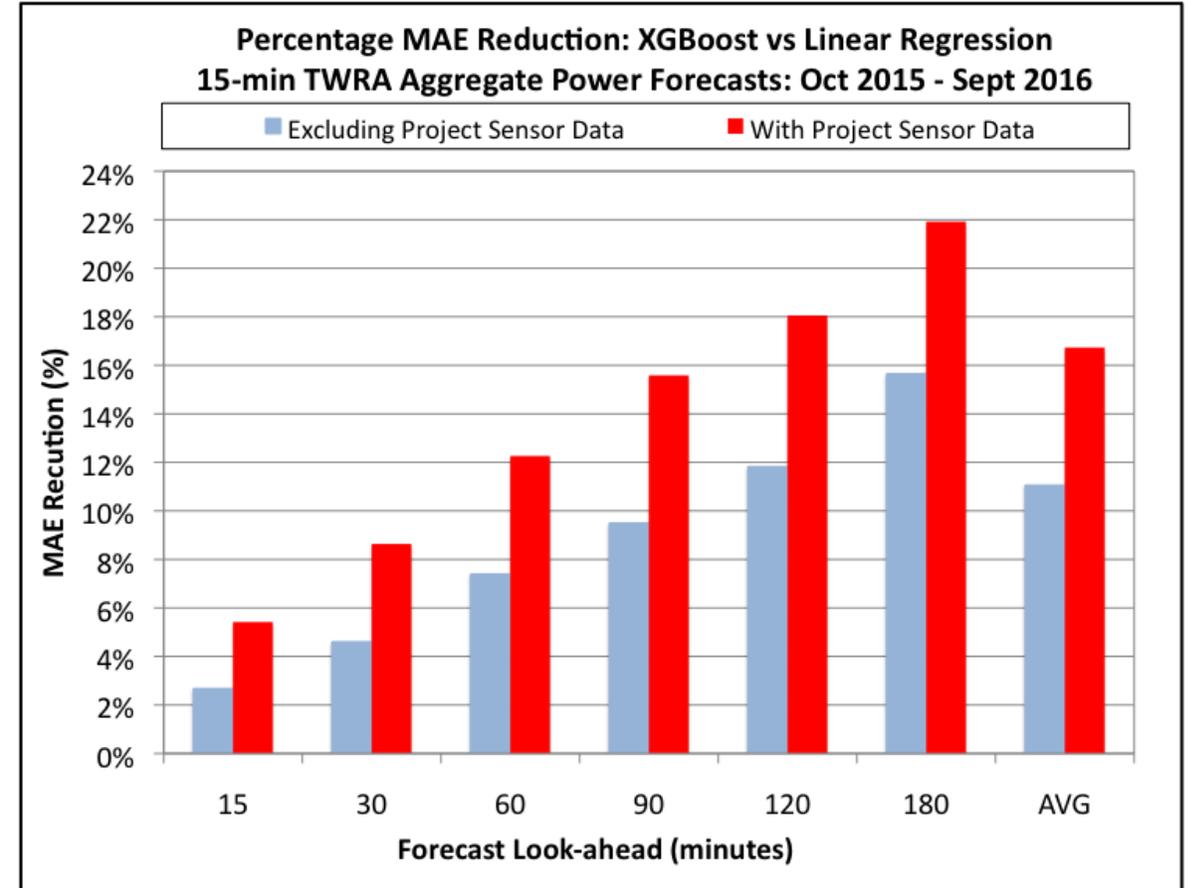
- 3X MORE CHANNELS**  
Improves every product from current GOES Imager and will offer new products for severe weather forecasting, fire and smoke monitoring, volcanic ash advisories, and more.
- 4X BETTER RESOLUTION**  
The GOES-R series of satellites will offer images with greater clarity and 4x better resolution than earlier GOES satellites.
- 5X FASTER SCANS**  
Faster scans every 30 seconds of severe weather events and can scan the entire full disk of the Earth 5x faster than before.

GOES 2005 | GOES-R 2016



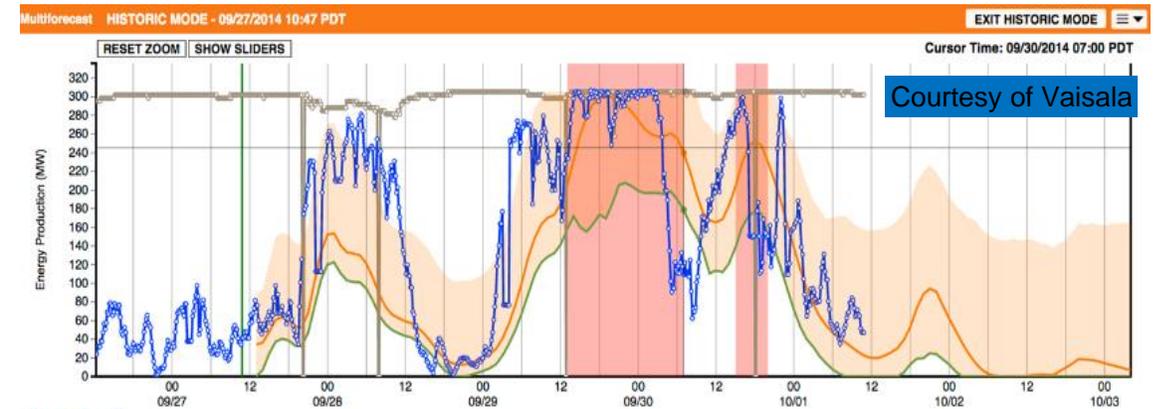
# Statistical Modeling

- Statistical methods used extensively throughout process
- Machine learning used for correcting model bias and other post processing of models
- Very short term forecasting (less than one hours) often uses statistical approaches
- Load forecasting has traditionally used neural networks and similar with temperature forecast for load forecast up to days ahead
- With increased prevalence and improvements in AI methods, new techniques can show significant improvement versus older methods



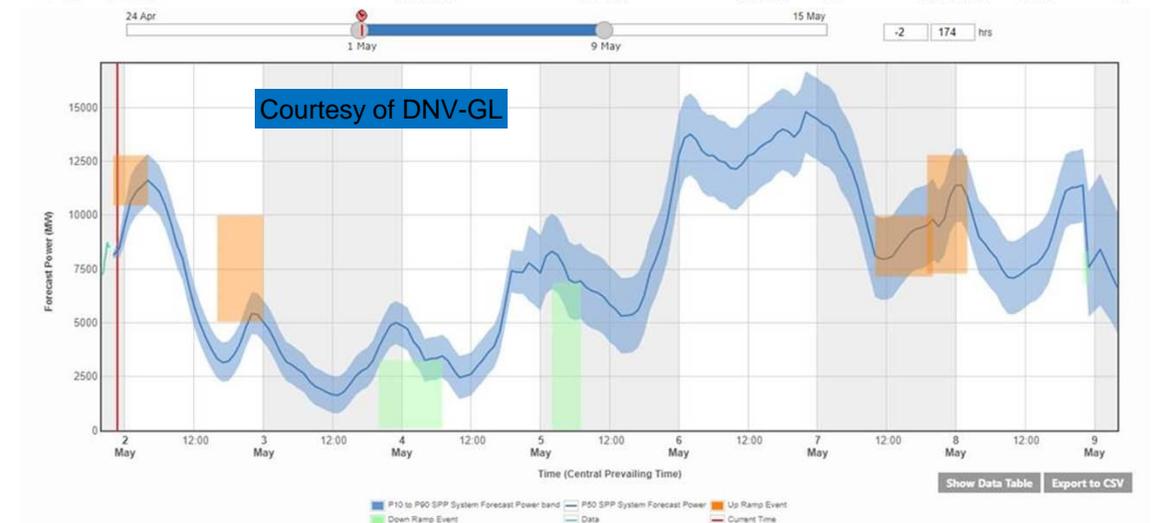
# Examples of Forecast Products

- Deterministic ‘best guess’ forecast
  - Most typical forecast
  - Easiest to use and understand
  
- Probabilistic forecast
  - Confidence intervals around deterministic forecast
  - Scenario based forecasts
  - Used for awareness or to support decisions
  
- Event based forecast
  - Shows high risk periods for awareness
  
- Situational awareness
  - Figures of the services territory with weather patterns
  - Regional generation spread, etc.



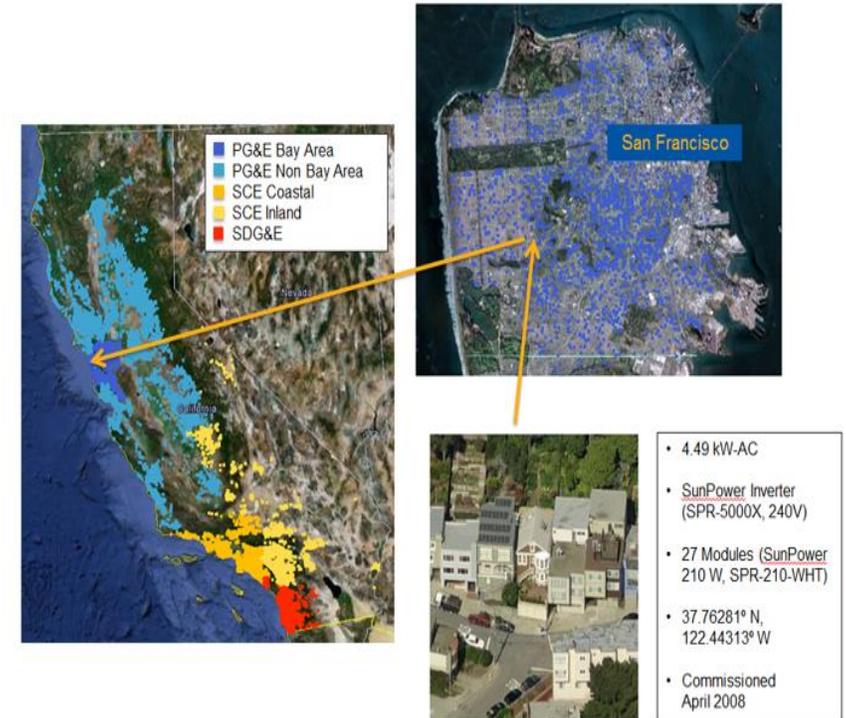
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| Value | Trace | 80% Interval | Components | Project/Group | Nameplate Capacity | Type        | Field          | Source      | Available From                  |
|-------|-------|--------------|------------|---------------|--------------------|-------------|----------------|-------------|---------------------------------|
| 240   |       | hide         |            | Rolling Hills | 305 MW             | Forecast    | Power          | 3TIER Blend | Latest <input type="checkbox"/> |
| 112   |       |              |            | Rolling Hills | 305 MW             | Observation | Power          | Observation | Latest <input type="checkbox"/> |
| 305   |       |              |            | Rolling Hills | 305 MW             | Observation | Power Capacity | Observation | Latest <input type="checkbox"/> |
| 179   |       |              |            | Rolling Hills | 305 MW             | Forecast    | P90            | 3TIER Blend | Latest <input type="checkbox"/> |



# Challenges for Load Forecasting with Distributed PV

- Requires accurate solar forecasting as an input to load forecasting
  - Could be direct modifier or included in the load forecast
- May not have all data needed
  - PV production in real time
  - Info about weather conditions
  - Design specs of PV
- Relative importance of data will vary based on
  - Geographical conditions,
  - PV penetration and type,
  - Size of system operator's territory
  - Type of utility/ISO and their load forecast methodology



From Clean Power Research for CA

# Evaluating Forecasting For Operations

# Forecast Skill/Value Assessment

- Need to understand forecast performance for multiple reasons:
  - What is expected uncertainty of my forecast tomorrow, based on past forecasts?
    - Average or extreme errors under different conditions need to be understood
  - Which of two or more forecast providers performs better?
    - How do I compare forecasts in a meaningful, fair way?
  - If I am planning to integrate wind/solar in the future, what type of uncertainty may be seen?
    - What type of operating reserves should I be planning on carrying?
    - How should I simulate uncertainty when planning for the future?
- EPRI-CPS Energy and EPRI-Southern Company solar forecasting trial examined multiple solar forecasts in Texas to better understand above questions

# Trial Description – **Key Facts**

**6 Months**  
Trial Duration

**4 Sites**  
Across the USA



**Advanced  
Forecast  
Benchmark**

**10+** 

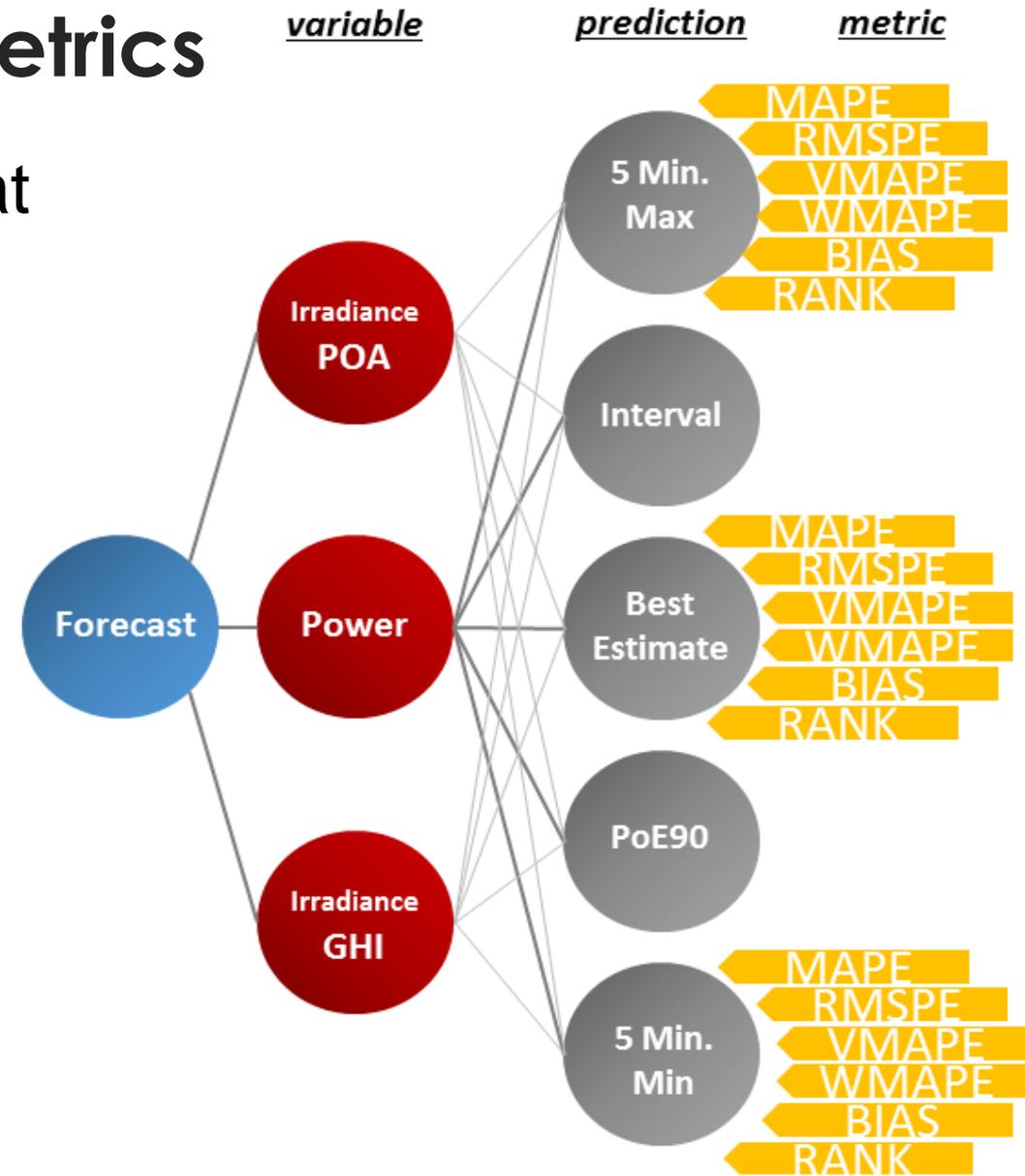
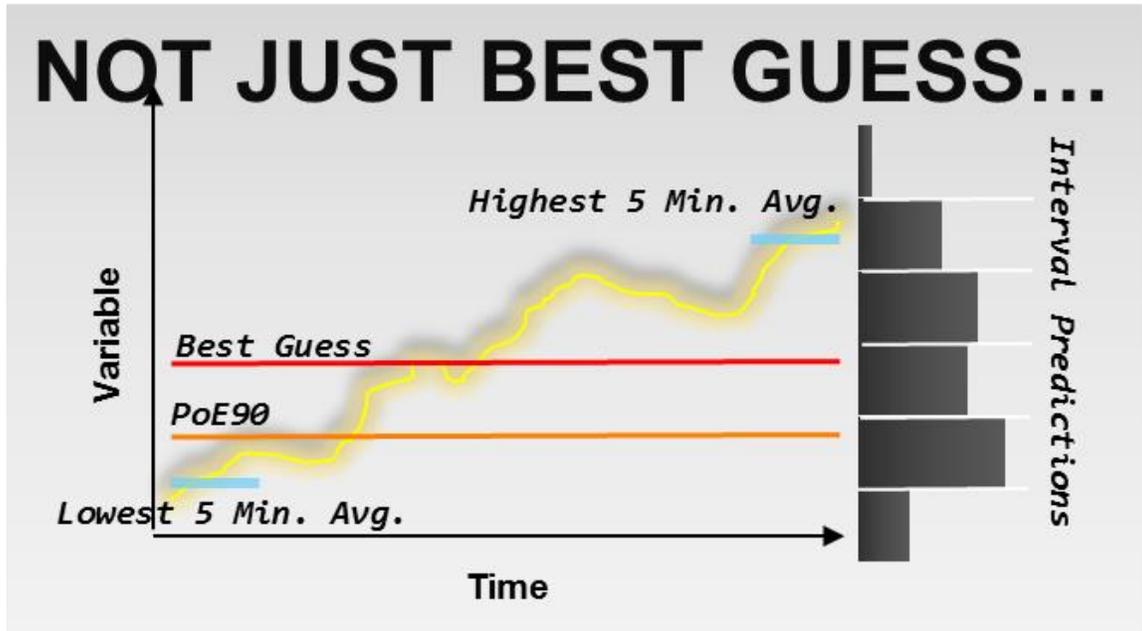
**Forecast Vendors**

**ANONYMOUS**  
Forecast Upload & Evaluation

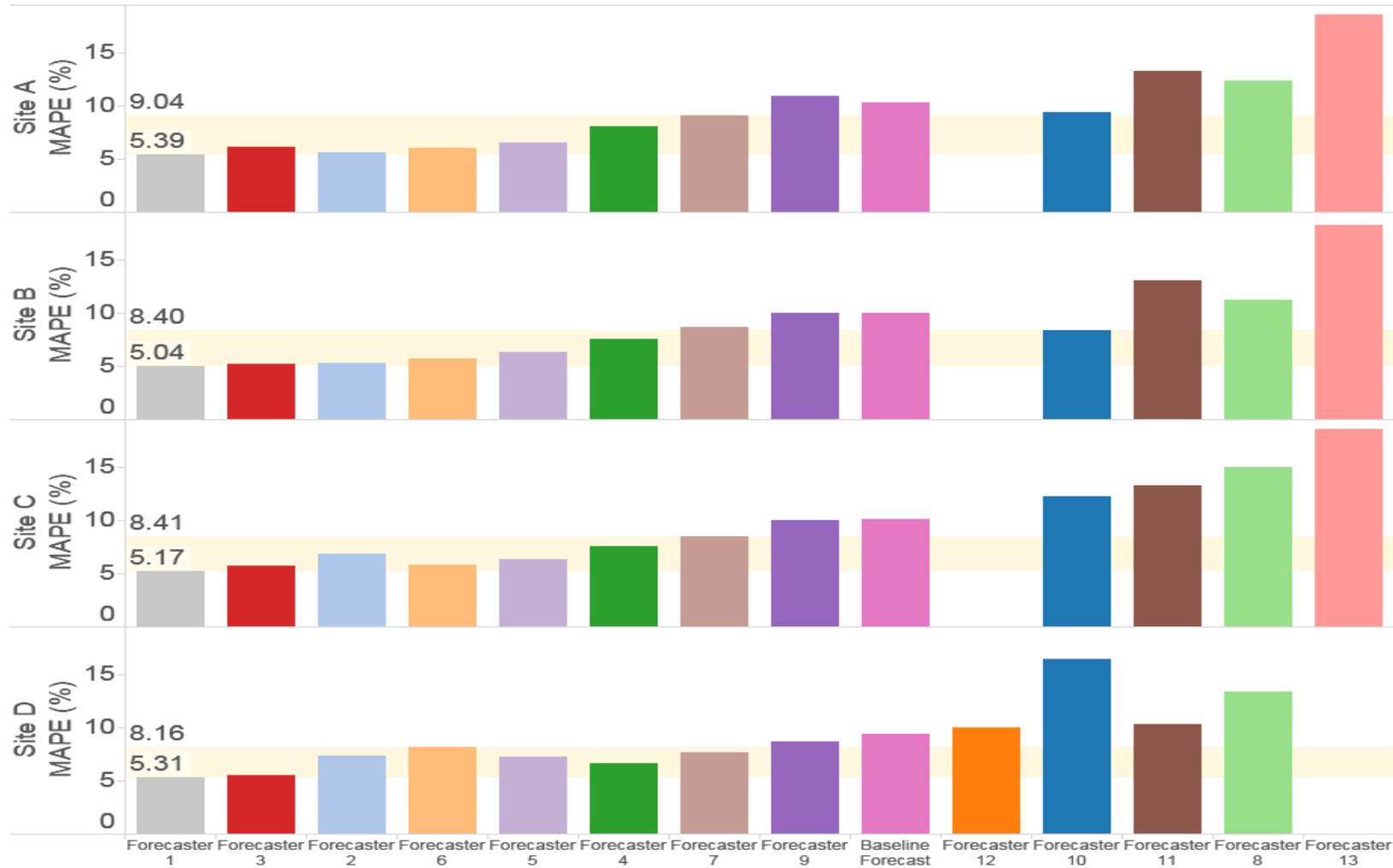
**Horizon: Now - D+10**  
**Resolution: 1 Hour**  
**Updated: Hourly**

# Standard Forecast Format & Metrics

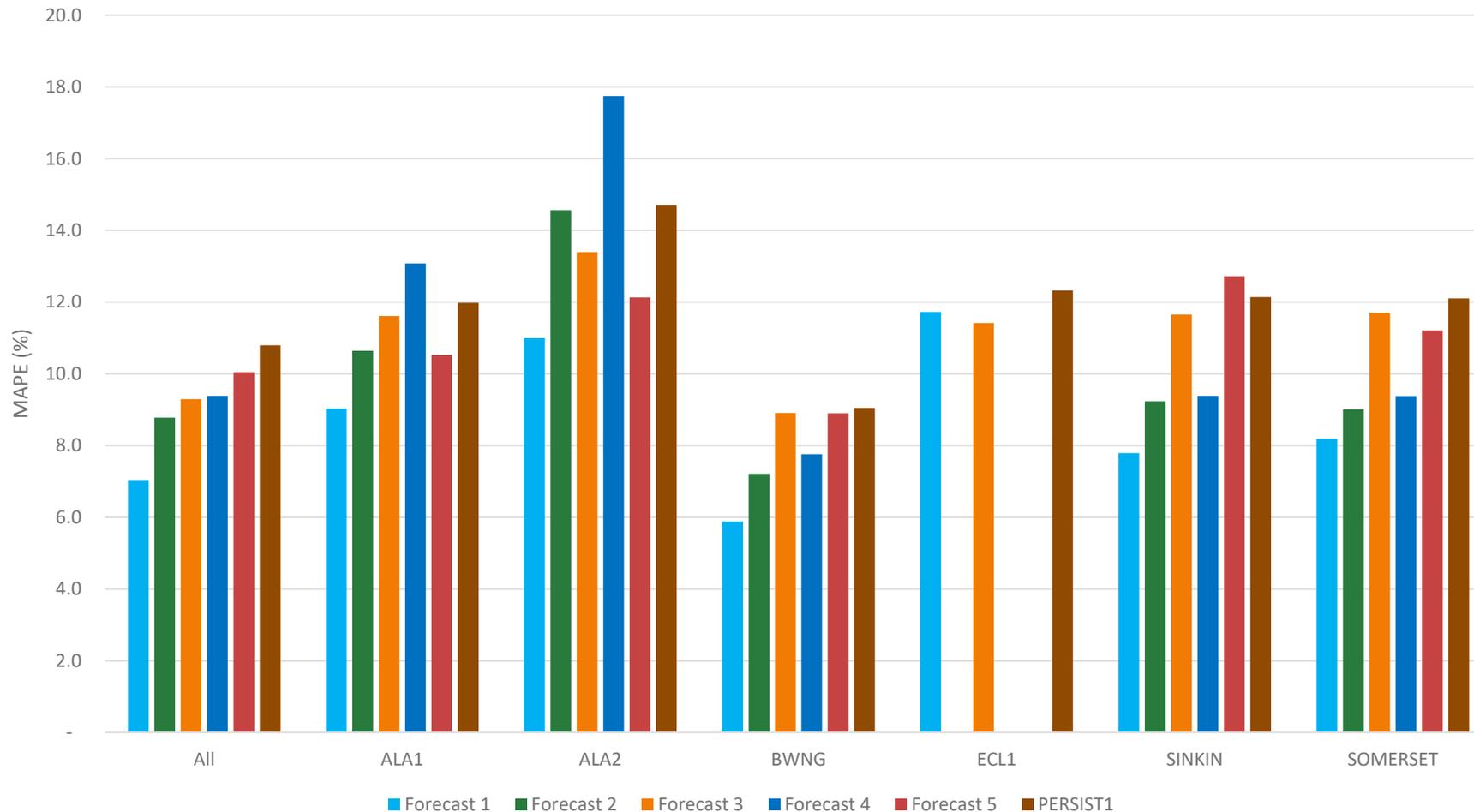
- Standard XML based forecast format
- Multiple Variables
- Multiple Predictions
- Multiple Metrics



# Average MAPE – Southern Company Sites

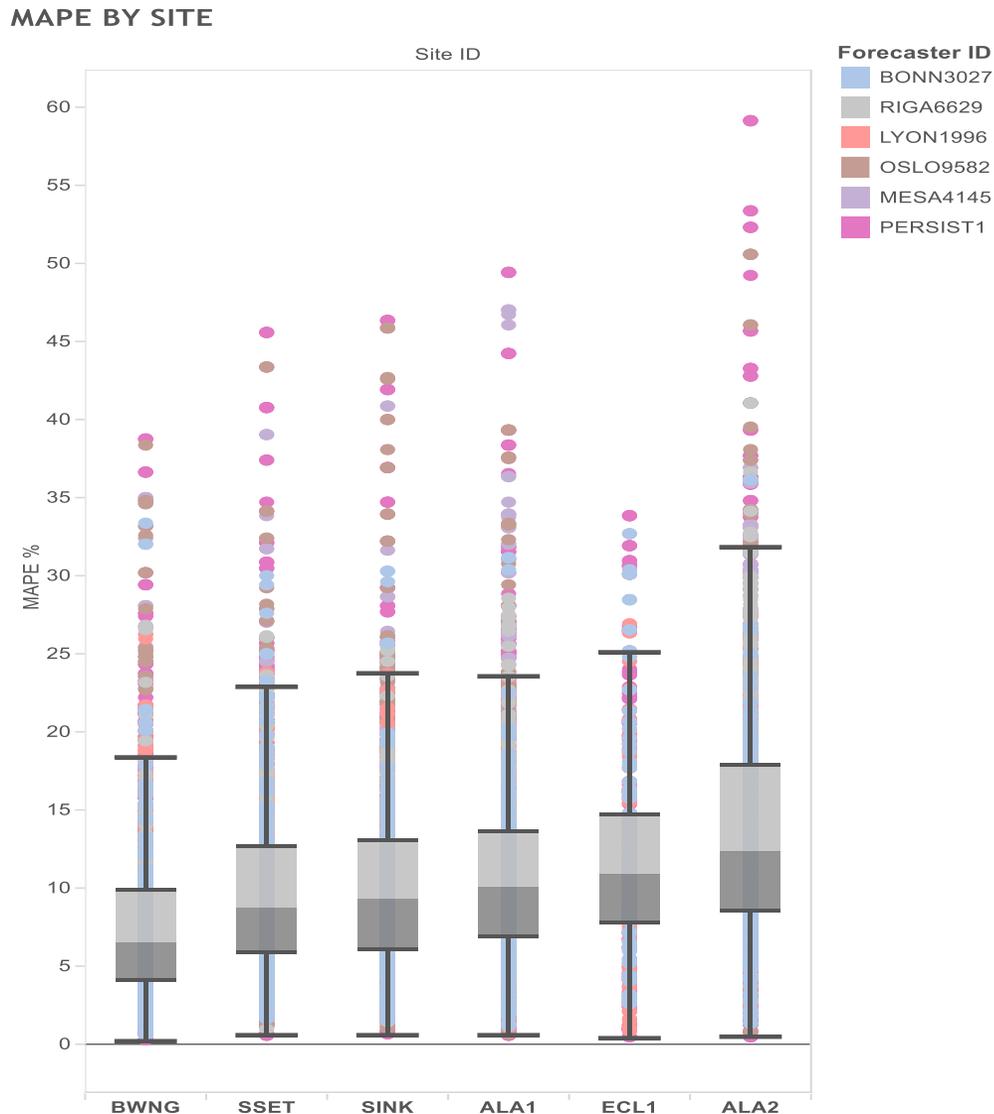


# Summary Metrics – Mean Absolute Error – CPS Energy



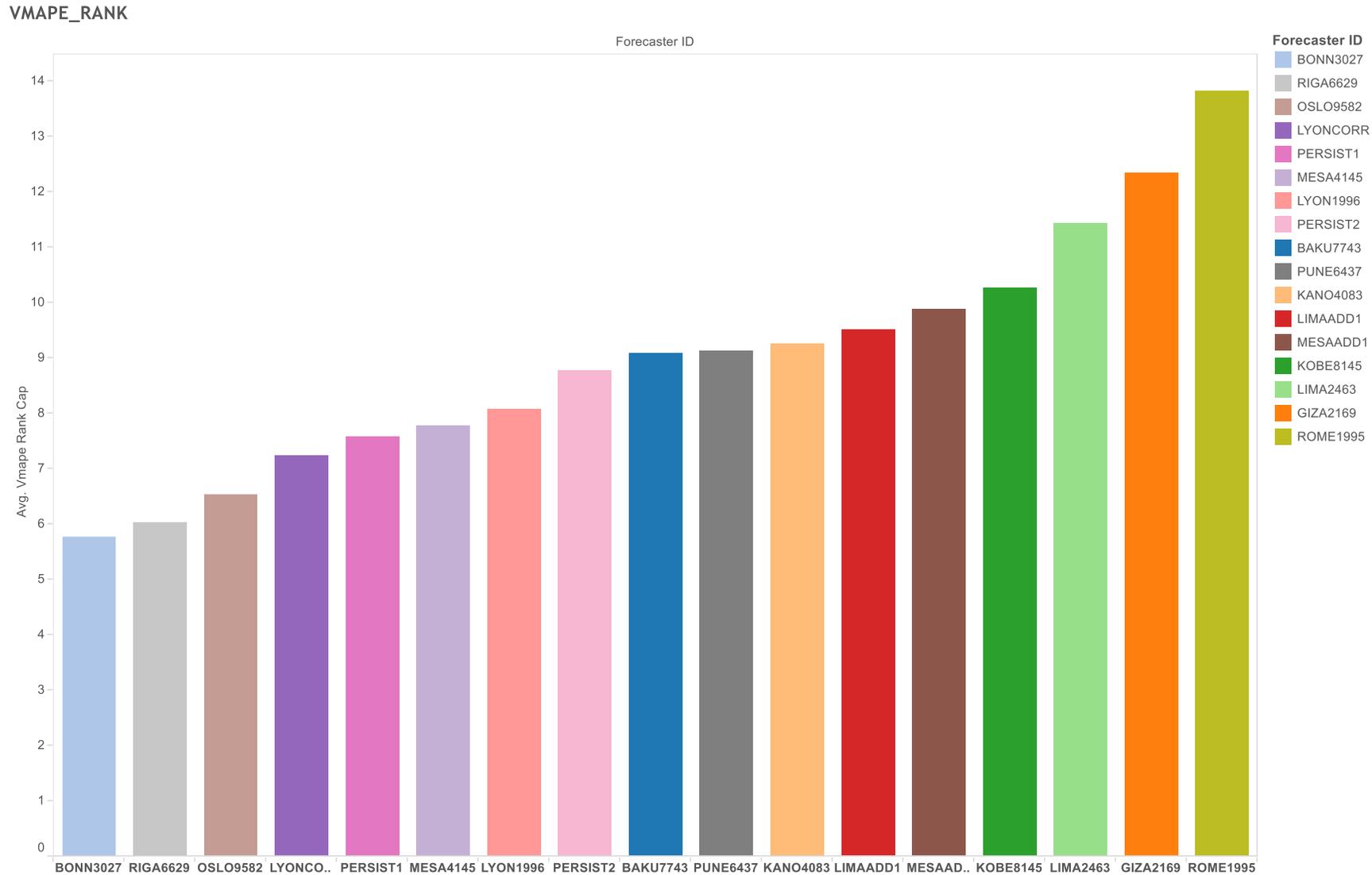
**Performance varies widely for different forecasters and across solar farms, due to data availability and technology**

# Daily performance by site



- Each dot represents performance in one day
- Shows even the best can be pretty far off in any day
- Sites with dual axis tracking seem to be more difficult to forecast
- While persistence does OK some days, on others it can have largest error

# Average Ranking for Variable Periods

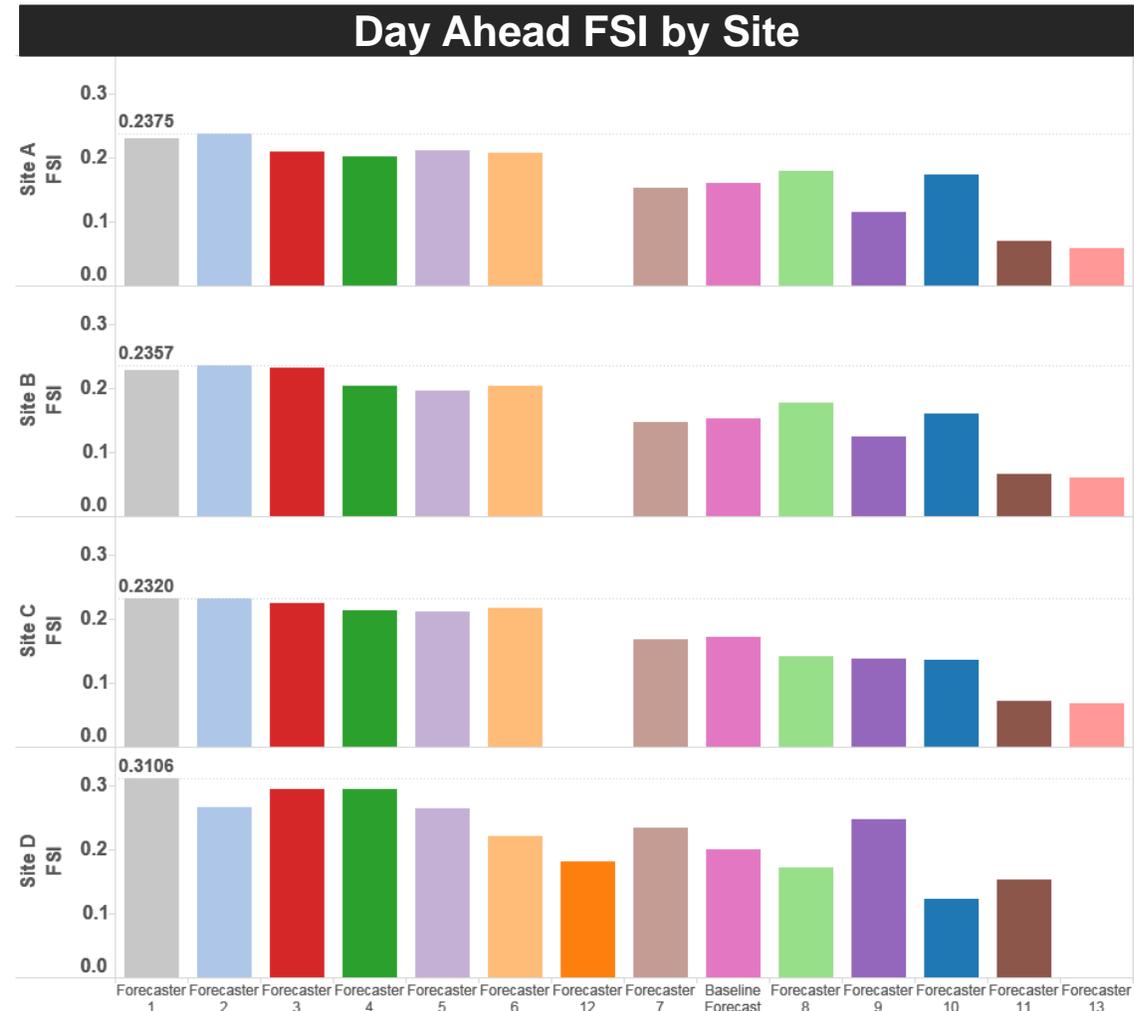


# Forecast Skill Index - FSI

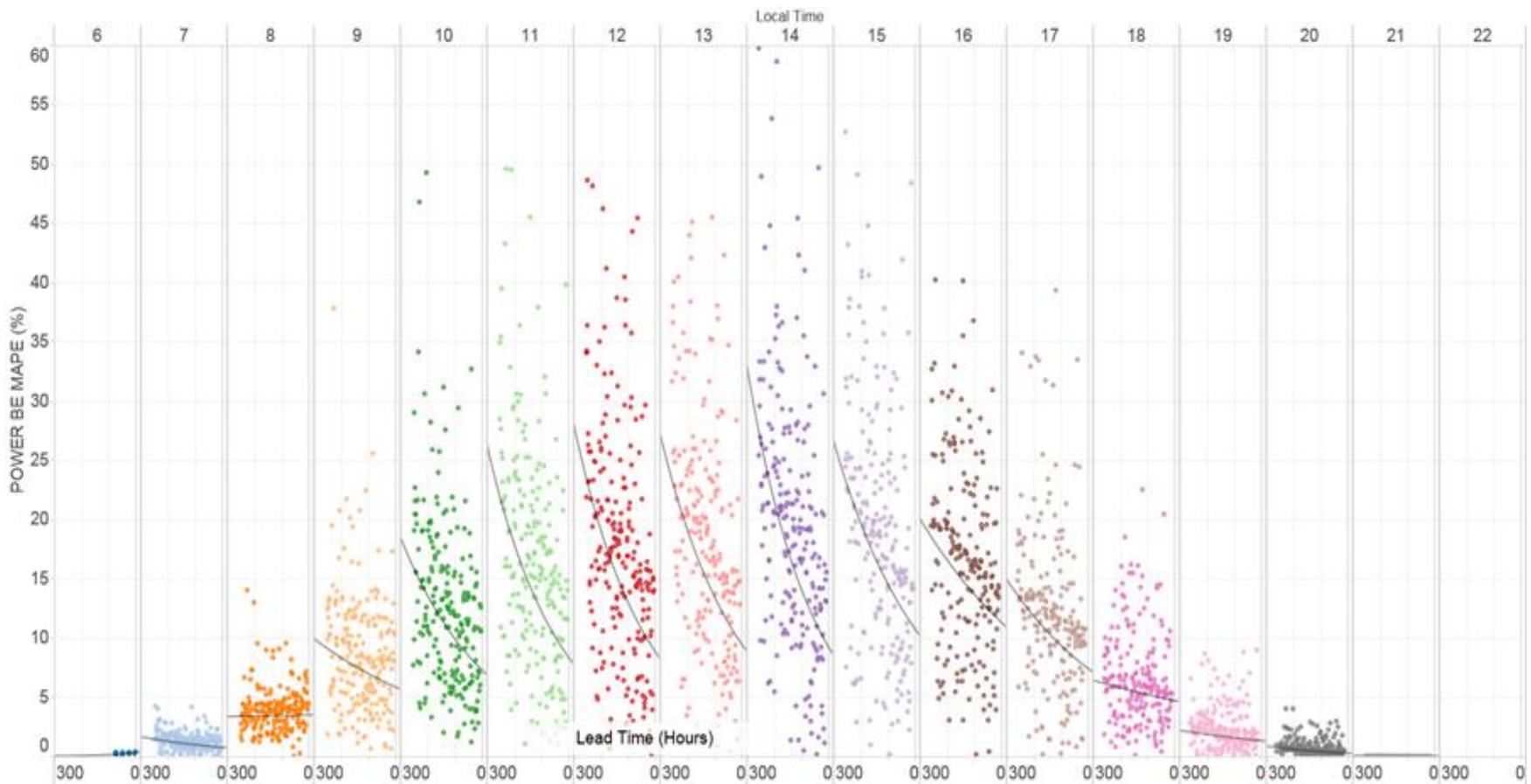
Used in previous trial to combine multiple accuracy assessments.

## FSI includes:

- MAPE (value, rank)
- RMSPE
- MAPE during variable periods
- MAPE weighted by time of day



# Performance of forecast by time of day and look ahead



More info: *Solar Power Forecasting for Grid Operations: Evaluation of Commercial Providers*, Electric Power Research Institute, December 2017. Palo Alto, CA. 3002012135

# General Approaches for analyzing value

## Simulation

- Production simulation to examine impact of improved forecasts or reduction in risk/reserves
- Can look at future higher penetration systems
- Captures the interaction of wind/solar and system costs

## Historical

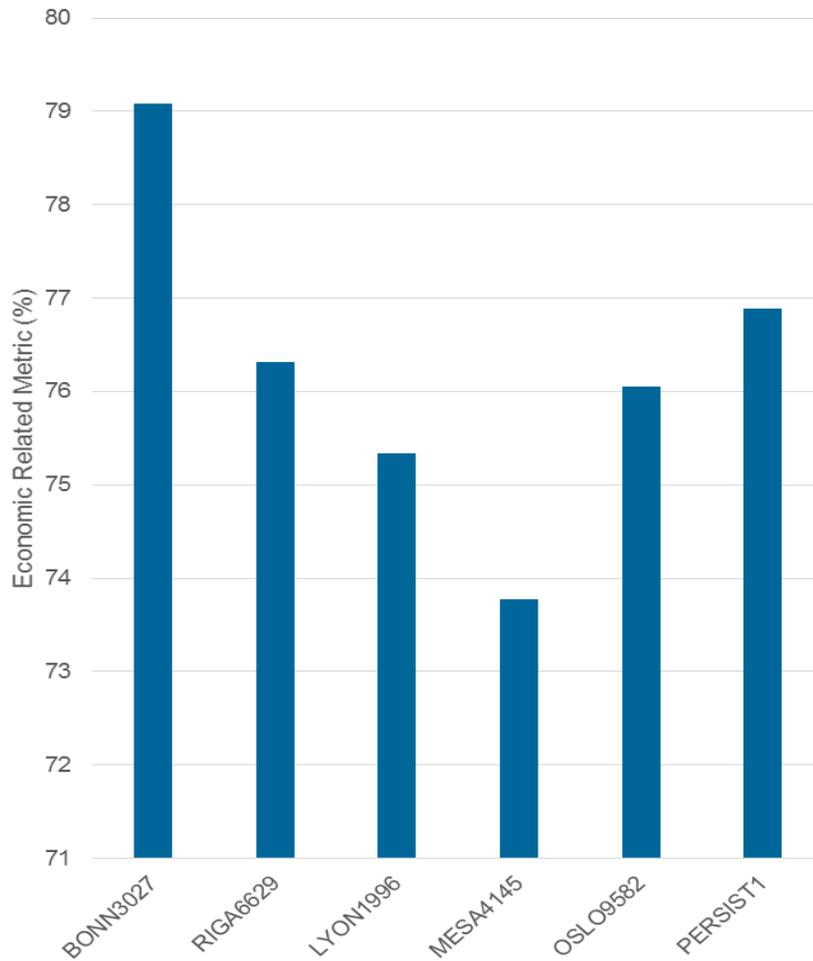
- Examine forecast value based on prices or system lambda
- Example “What is the value of an improved forecast in my trading decisions?”
- Straightforward for lower penetrations, but may not allow interaction between wind/solar and costs to be considered

# Methodology for system value assessment and baseline forecast performance (California solar project)

- Determine a methodology to capture the value of improved forecasts in economic and reliability terms
  - Based on discussion with stakeholders
  - Potential metrics could include reduced production cost, reduced reserve requirements, improved utility procurement, improved distribution switching operations, line rating increase for transmission, etc.
- Calculate the values of a forecast improvement based on prevailing system conditions in 2017 and 2018
  - Where appropriate, capture future value through simulations using the Power System Optimizer (PSO) production cost tool and datasets that represent future grid conditions in California

**How do you currently value forecasts? Looking for input**

# CPS Energy Economic Based Metric

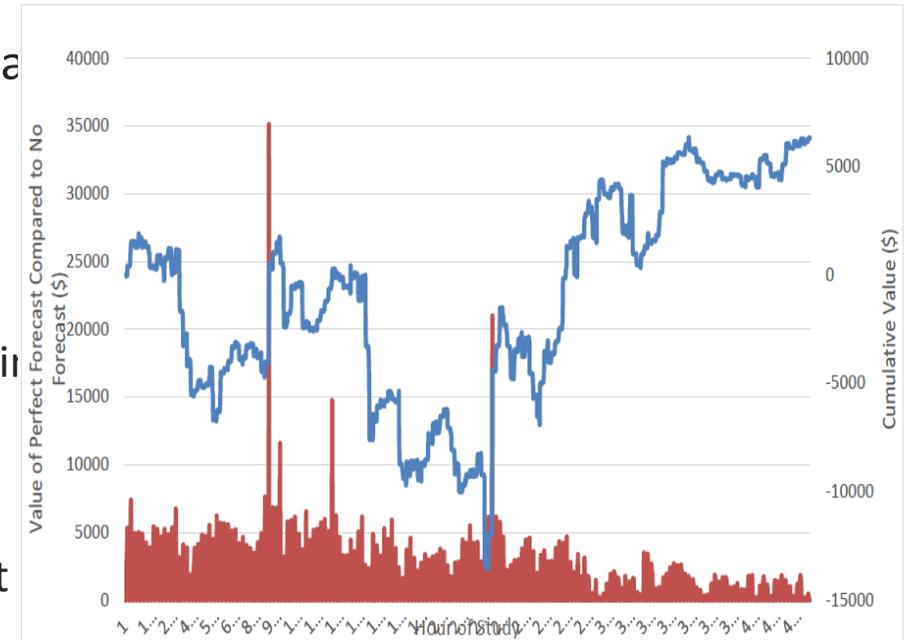


- Developed by CPS Energy to support trial
- Based on price spread between day ahead and real time
- Should reflect periods of high risk rather than specific spreads
  - We don't know what spread is in advance - just want to reduce risk
- Weighted by time of day and normalized to DA-RT
- 100% is best
- Same forecast always wins...
- OSLO does better in many metrics that look at value or variability compared to others, so may be reason for high value
- Persistence also does well

Shows some link for value as market participant/purchasing, not for ops

# Historical Analysis of Value

- Normally takes the form of using prices or marginal costs to understand additional revenue or reduction in generation costs
- Difference between prices or energy costs in day ahead and real time to produce value of knowing more in day ahead
- Finding: More related to the actual prices analyzed and their profiles than the value of forecasts
  - E.g. if DA always higher price or cost, then it may be better to bid in at 100% and then make up difference in real time
  - Doesn't capture penalties and increased risk as penetration increases
  - May be able to instead put a value on error and quantify how that changes with improved forecast

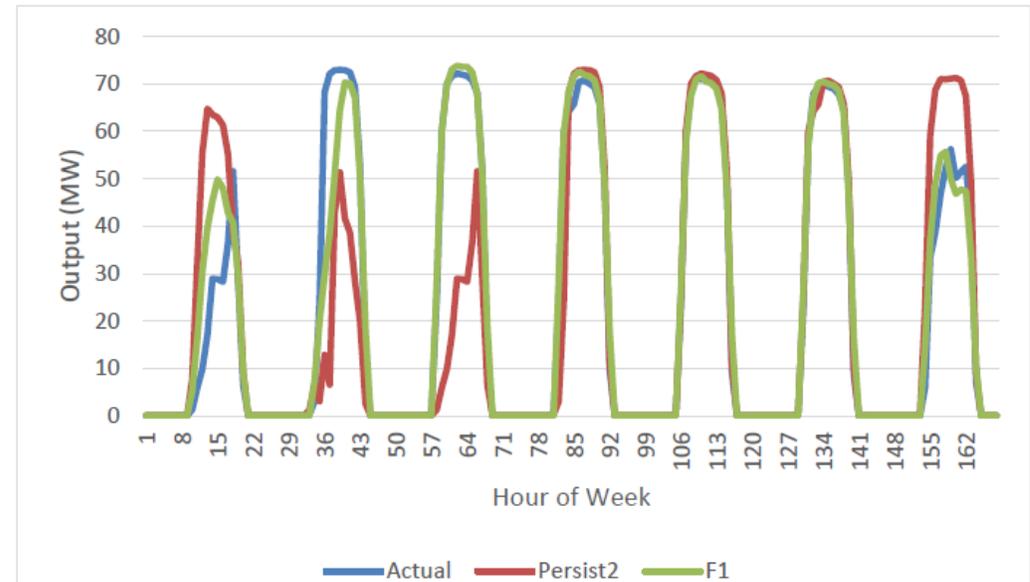


Additional value from perfect forecast in DA vs RT

**Not likely to be particularly useful manner to assess forecast performance**

# Simulation based metrics – simple case study

- Used FESTIV tool
  - 1 week data for IEEE 118 bus
  - 3 forecast types examined
- Value in using any forecast compared to none at all
- Not much difference among skilled forecasts and simple persistence method
  - Maybe some reliability implication but not very clear
- System used and operational policies are likely to impact
  - Time resolution used, look ahead, resources startup times, etc.
- More detailed study of particular system should be performed



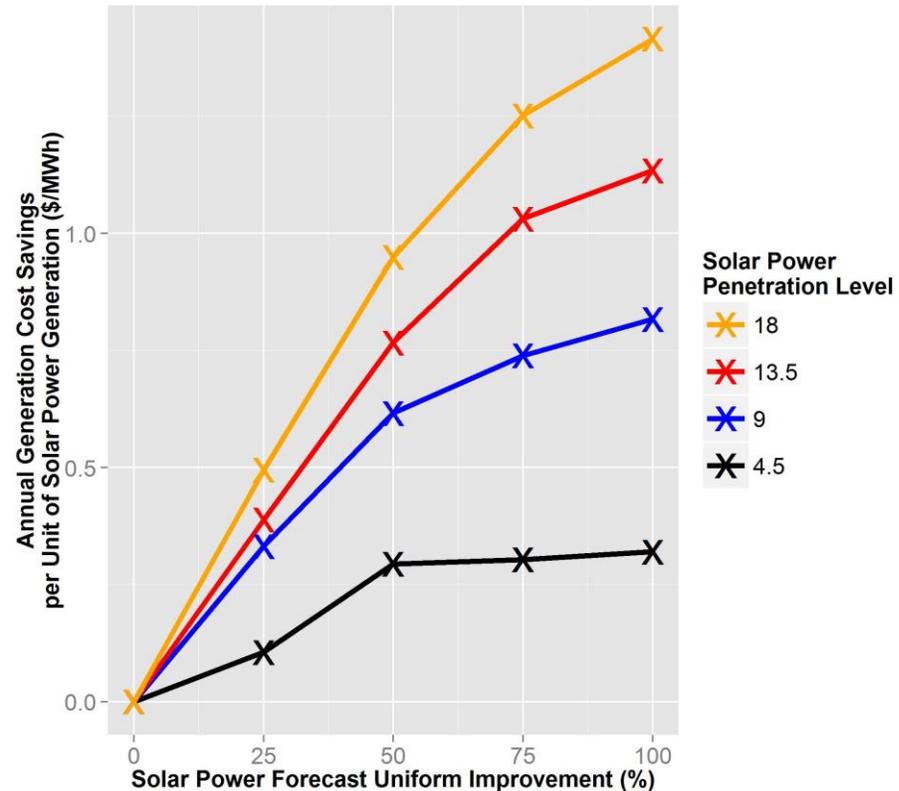
|  | Perfect     | Persistence | F1          | Zero        |
|--|-------------|-------------|-------------|-------------|
| <b>Production Costs</b>                    | \$3,210,503 | \$3,210,101 | \$3,211,399 | \$3,311,727 |
| <b>Additional cost compared to perfect</b> | \$0         | (\$402)     | \$896       | \$101,223   |
| <b>% additional cost</b>                   | 0.00%       | -0.01%      | 0.03%       | 3.15%       |
| <b>AACE</b>                                | 247.7       | 254.6       | 252.3       | 323.2       |
| <b>Sigma ACE</b>                           | 2.0         | 2.2         | 2.2         | 9.0         |

**Value of improved day ahead forecasts not always easy to measure**

# Example: the value of day-ahead solar power forecasting improvements in ISO-New England

- NREL study for different regions of the country
- Based on simulations, improving solar forecasting for ISO-NE:
  - Lowers generation from fast-start and lower efficiency plants
  - Reduces ramping of all generators
  - Decreases solar power curtailment
  - Lowers start and shutdown costs
  - ...resulting in a reduction in overall operational electricity generation costs

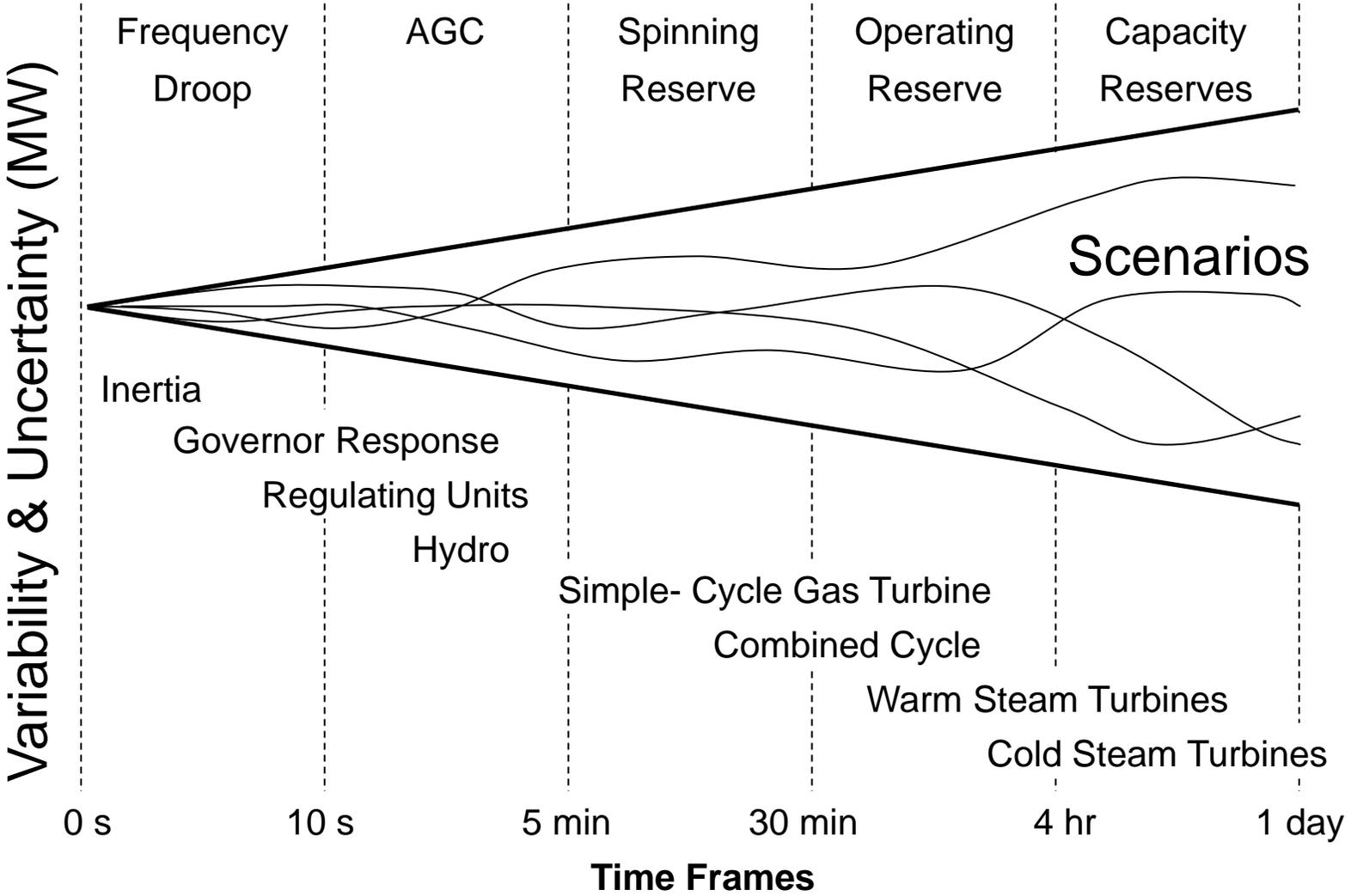
Source: Brancucci et al. (2015). *The Value of Day-Ahead Solar Power Forecasting Improvement (Draft)*.



*Improving day-ahead state-of-the-art solar power forecasts in the ISO-NE system with 13.5% solar penetration decreases annual variable electricity generation costs by US \$13.2M*

# Use of Operational Forecasting in Planning

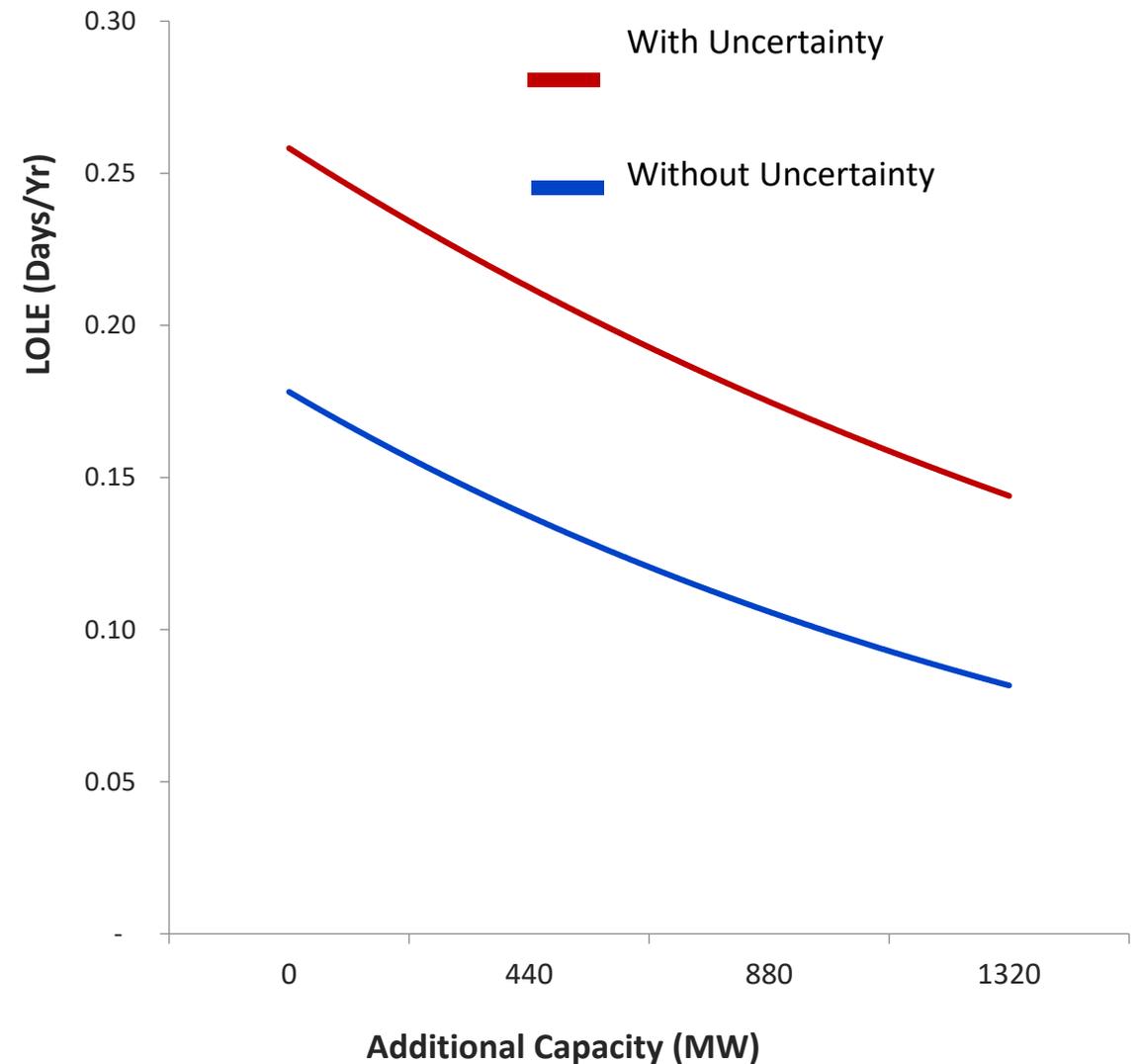
# Background: Time Frames and Uncertainty



Source: Russ Philbrick, PES General Meeting, Detroit, July 2011

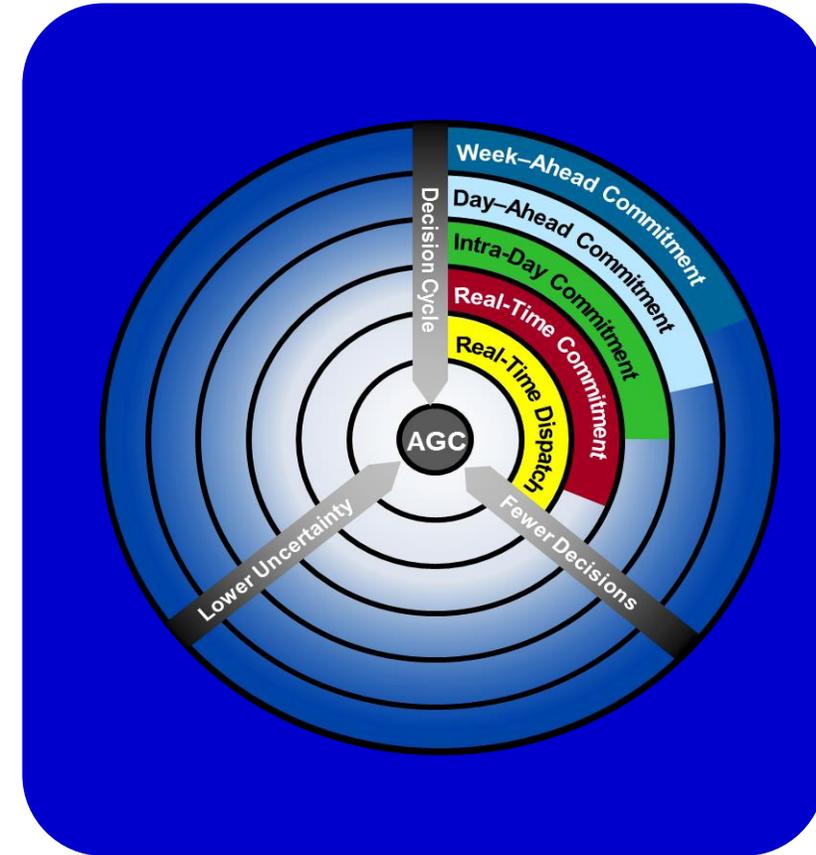
# Why is modeling of uncertainty in planning studies important?

- Example from 2013 study – using SERVUM production cost tool with operational uncertainty modeled
- Shows that reliability metrics calculated using perfect foresight may be underestimating the impact of uncertainty
- Other impacts will also be important
  - Cycling of generation and costs of flexibility
  - Use of energy storage and demand response
  - Other reliability metrics



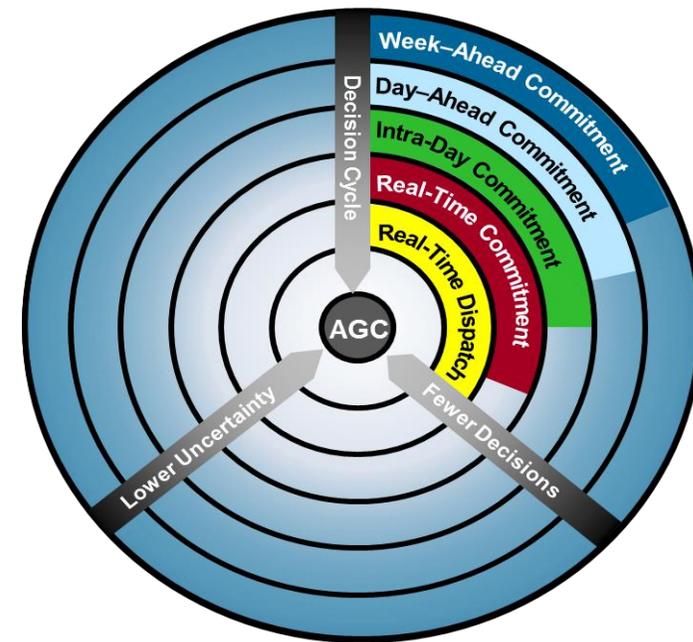
# Simulating Operations: Production Cost / Operations Simulation Models State of the Art

- Simulate at least two-stages of scheduling process
  - Day-ahead and real-time
- Include network security constraints
  - DC-OPF SCUC, SCED, model
- Detailed generating unit constraints
  - Ramp rate, min on/off time, start-up time
  - Advanced: Hydro reservoir and cascade constraints, combined cycle modes, energy storage optimization
- Annual simulations, hourly or down to five-minutes
- Outputs: Production costs, marginal costs, power flows, generation production, load shed or reserve shortage violations

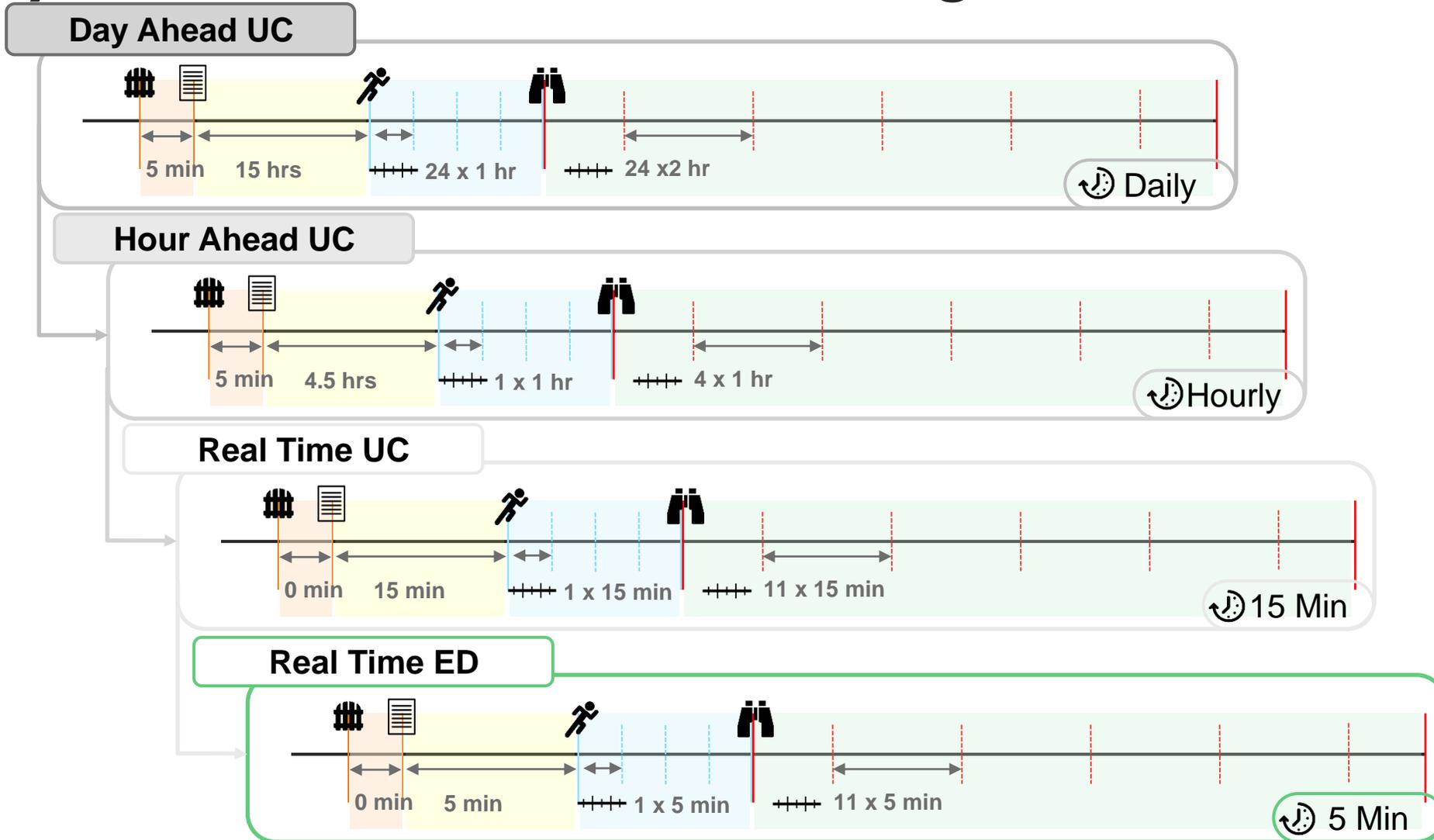


# Multiple cycles in modeling

- Historical simulation tools did not capture the multi-cycle multi-decision, multi-timescale approach of current steady-state electricity operations
  - As horizon approaches real-time, uncertainty impact decreases
  - As timescale resolution approaches zero, variability impact decreases
  - As horizon approaches real-time, fewer decisions are available to the operator
- Simulation tools that model multiple cycles can more realistically represent the impacts of variability and uncertainty and the mitigation strategies for those impacts



# Multi-cycle, Multi-scenario modeling



 Gate Closure

 Results Posted

 Binding Periods

 Look Ahead Periods

 Scheduling Frequency

# Conclusions

- Wind and solar forecasts are widely used and understood for system operations
- Various models and methods, with large amounts of data, are used to produce forecasts
- Important to understand the performance of forecasts when considering how they should be used
- Simulation tools for studying renewable integration should use forecasts to capture short term uncertainty

# Together...Shaping the Future of Electricity

# Electricity Market Design 101

Erik Ela  
Principal Technical Leader

ESIG Meeting  
June 4, 2019  
Denver, CO



# Agenda

- Electricity Markets Quick Primer
- EPRI Electricity Market Operations Research Area
- Key Market Design Research Questions
- Program 39: Electricity Market Design Reference Guide
- Key Topic Deep Dive
  - Reliability Services Valuation in Electricity Markets
  - Electric Power Supply Resilience
  - Price Formation



# A Market Like No Other

- Electrical energy cannot be stored (no inventory)
  - It can be converted to other forms of energy and stored but with additional capital and efficiency losses (e.g., pumped hydro plants)
- Energy is generated and consumed at almost the exact same time
- Electricity must be transported to consumers at the speed of light often from far distances

# A Market Like No Other

- Laws of physics will dictate where power will go, who will get it, and how much of it will be lost along the way
  - If the road is full of trucks, you can't deliver anymore supply, and you can't use a different road
- Rules and economics will influence how resources are deployed, subject to technical constraints
- There are many different ways to supply it, but the consumer is indifferent as to the end product
  - Some suppliers have large capital costs and low variable costs, others are the opposite (price highly volatile even throughout day)
- Consumers rarely, if ever, are exposed to true costs. Therefore, and for other reasons, market failure is rampant

# Independent System Operators/ Regional Transmission Operators (ISO/RTO)

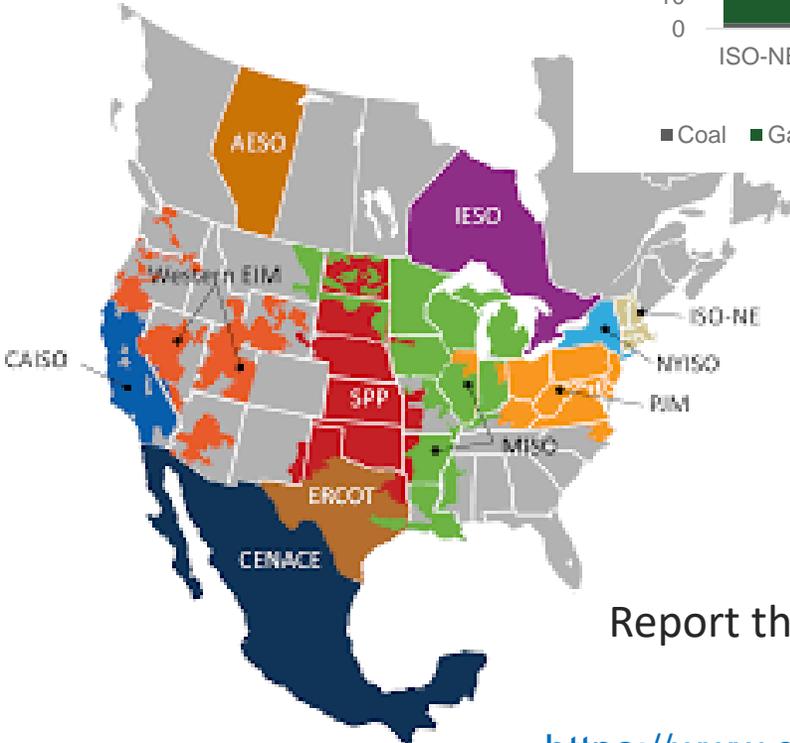
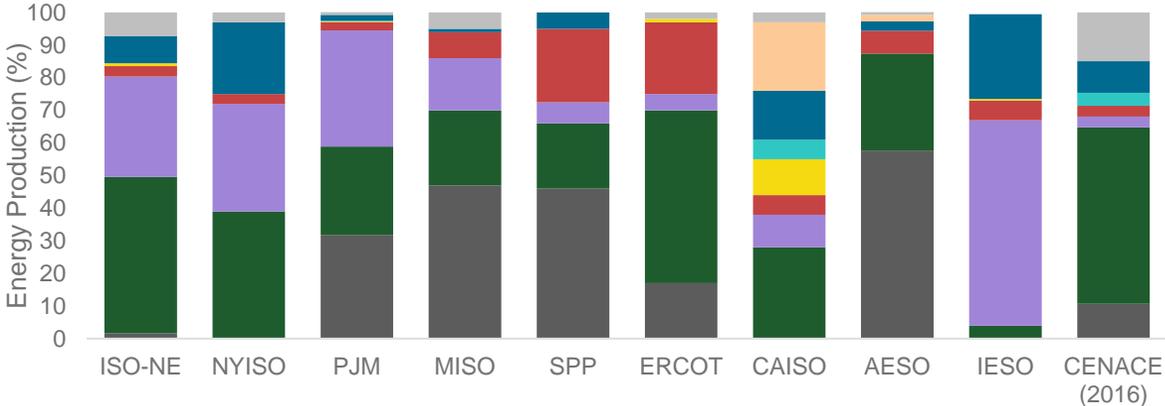
- Job #1 - System operating reliability
  - Real time balancing
  - Generator and transmission scheduling
  - Ensure long-term reliability
- Coordinate/facilitate long-term planning for generation and transmission
- Operate and administer markets
  - Day-ahead energy
  - Real-time energy
  - Ancillary services
  - Transmission rights
  - Capacity markets
- Not involved on retail transactions

## The Actors

- ISO/RTOs
- Vertically integrated utilities
- Transmission owners
- Merchant generators (IPP)
- Load serving entities
- Municipalities
- Cooperatives
- Public Power agencies (TVA, WAPA, NYPA)
- Privately run power trading companies

# Organized Electricity Markets in North America

Nine Independent System Operators (ISOs) and Regional Transmission Organizations (RTOs) serve 66% of consumers in the U.S. and more than 50% of Canada's population. See the ISO/RTO Council website: [www.isorto.org](http://www.isorto.org).

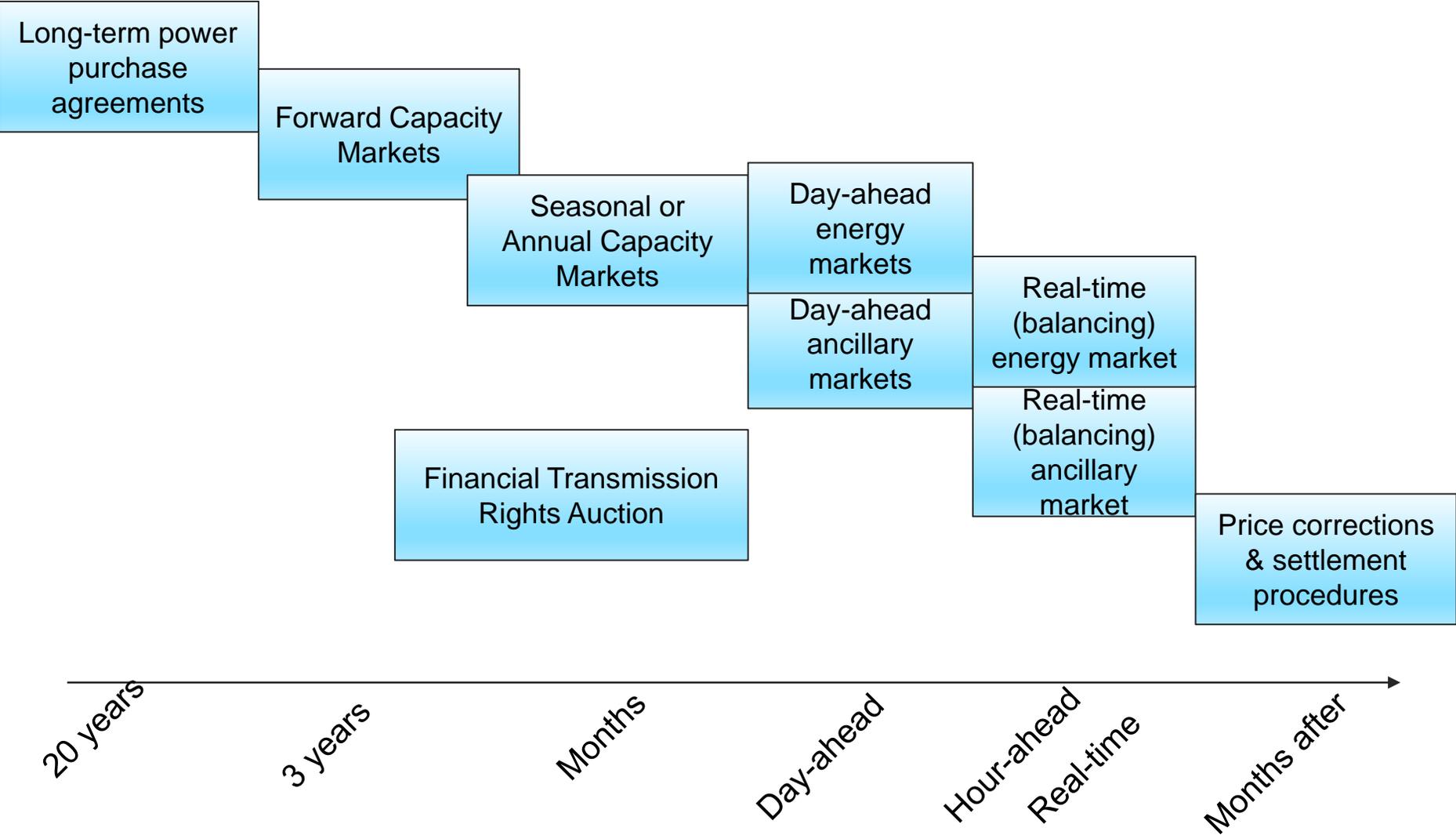


Report that covers all of this!

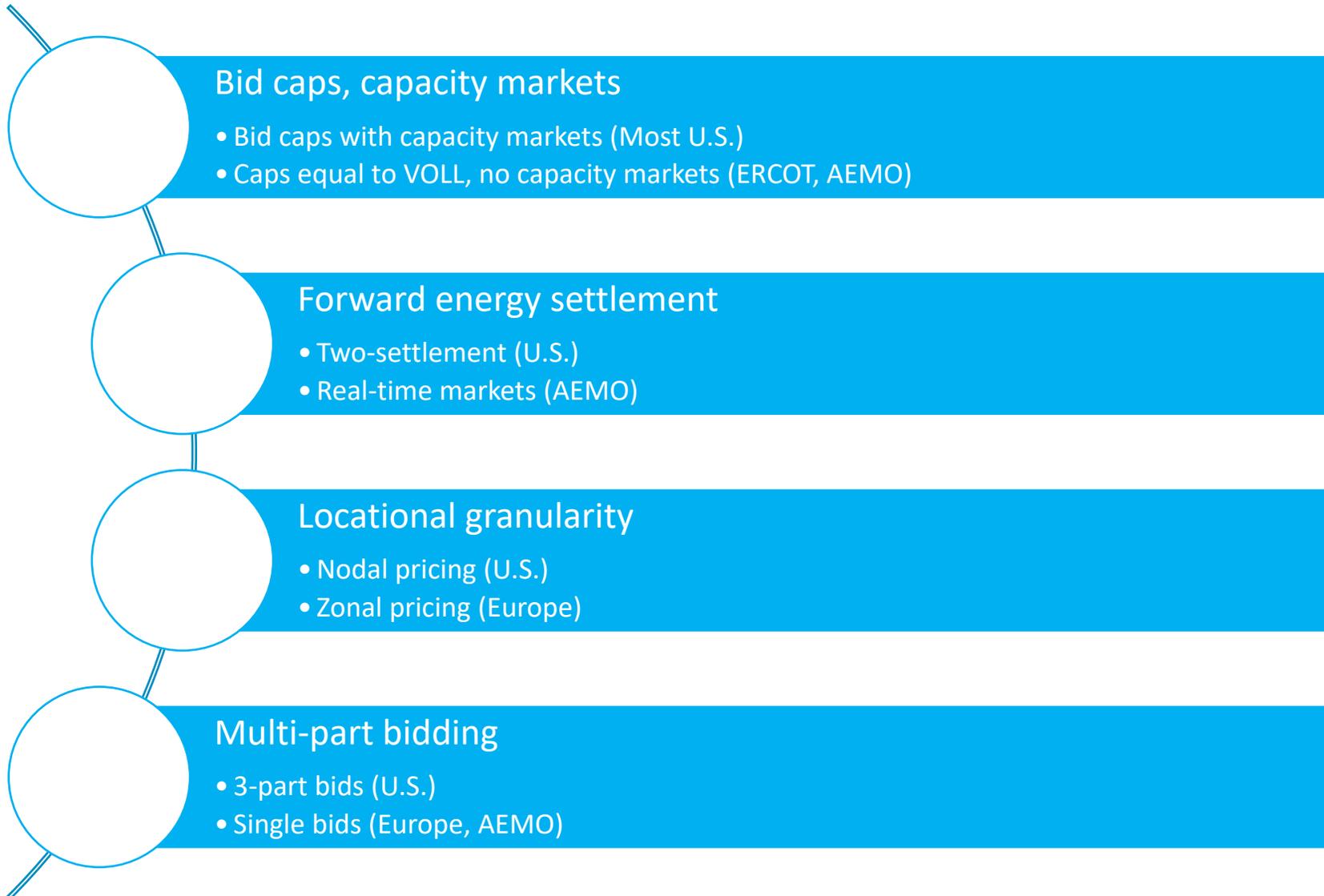
<https://www.epri.com/#/pages/product/000000003002009273/?lang=en>

|              | Total Market Volume (\$B) | All-in-Price (\$/MWh) | Energy (\$B) | Ancillary Services Markets (\$M) | Uplift (\$M) | Financial Transmission Rights (\$M) | Capacity Market (\$M) |
|--------------|---------------------------|-----------------------|--------------|----------------------------------|--------------|-------------------------------------|-----------------------|
| AESO (CAD\$) | 3                         | 25.5                  | 1.8          | 81                               | 0.23         | N/A                                 | N/A                   |
| CAISO        | 9.3                       | 42                    | 8.7          | 172                              | 108          | 80                                  | N/A                   |
| ERCOT        | 14                        | 30.15                 | 10           | 323                              | 0.5          | 379                                 | N/A                   |
| IESO (CAD\$) | 17                        | 15.8                  | 2.2          | 57                               | 146          | N/A                                 | N/A                   |
| ISO-NE       | 9.1                       | 76                    | 4.5          | 128                              | 52           | 30                                  | 2,240                 |
| MISO         | 26.9                      | 31.35                 | 24.7         | 69                               | 104          | 252                                 | 47                    |
| NYISO        | 8.7                       | 40                    | 5.3          | 110                              | 38           | 222                                 | 3,000                 |
| PJM          | 40.0                      | 54                    | 23.5         | 508.1                            | 129          | 542                                 | 8,800                 |
| SPP          | 16.7                      | 24.08                 | 6.3          | 80                               | 68           | 308.8                               | N/A                   |

# Electricity Market Timelines



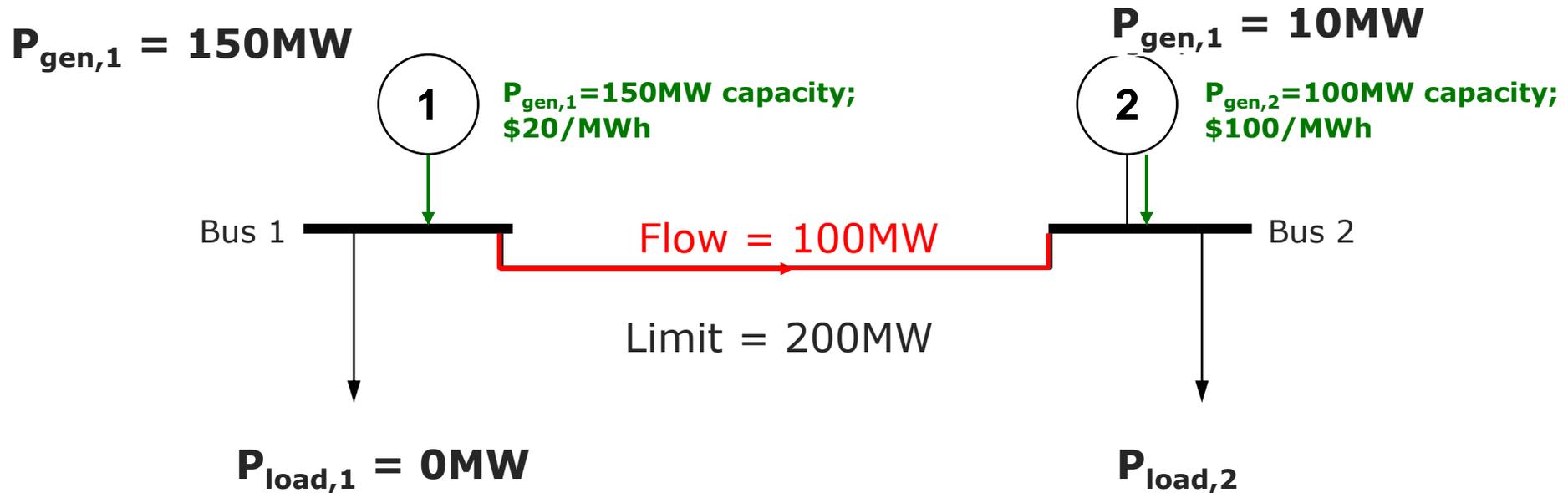
# Energy Markets



# Locational Marginal Prices Overview

- LMP definition: incremental operating cost to serve the next increment of demand at a particular location and time
  - LMP =
    - [Marginal Cost of Energy] +
    - [Marginal Cost of Transmission Congestion] +
    - [Marginal Cost of Transmission Losses]
  - Mathematically: Partial derivative of objective value (production cost) divided by partial derivative of demand (solved through dual solution of economic dispatch problem)
- Locational granularity: Suppliers – nodal; demand – zonal
- Temporal granularity: Day-ahead – hourly; Real-time – 5-min
  - Real-time: Settled hourly in PJM, ISO-NE, MISO until FERC Order 825, otherwise 5-minute settlements

# LMP in action



$P_{load,2} = 90\text{MW}$      $LMP_1 = \$20/\text{MWh}$      $LMP_2 = \$20/\text{MWh}$

$P_{load,2} = 120\text{MW}$      $LMP_1 = \$20/\text{MWh}$      $LMP_2 = \$100/\text{MWh}$

$P_{load,2} = 160\text{MW}$      $LMP_1 = \$100/\text{MWh}$      $LMP_2 = \$100/\text{MWh}$

# Two Settlement System

Market engine: Security-constrained unit commitment (SCUC)

Market engine: Security-constrained economic dispatch (SCED)



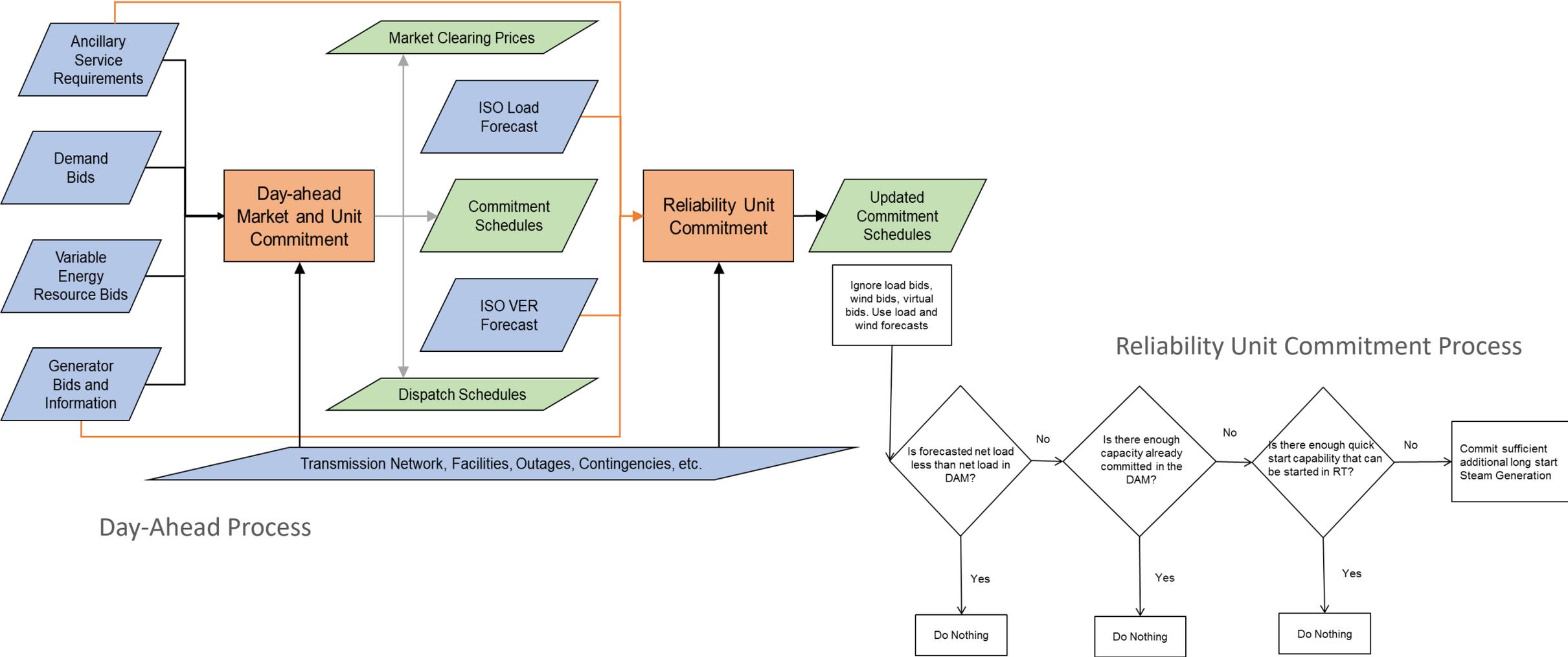
## Day-Ahead Market (DAM)

- Financial
- Hourly pricing, day solved simultaneously
- Generally predictable pricing
- Generators offer amounts they are willing to generate for, loads bid in amount of load needed
- Commit enough generation to meet tomorrow's demand plus a certain amount of reserves
- LMPs created and generators are paid for energy schedule regardless of actual conditions
- About 95% of all energy in two-settlement markets is sold in the DAM

## Real-Time Market (RTM)

- Physical
- Five-minute pricing, market solved usually every five-minutes at a time
- RTM will make up differences by dispatching units to meet actual load
- Supply resources will get paid RTM LMP if they produce above their DA schedule or will pay RTM LMP if they produce below their DA schedule
- Payments are based on actual generation not schedules
- Generally, same constraints are used in the RTM as DAM, with the exception that generator starts are not common

# Day-Ahead Commitment Process



# Virtual Trading

- **Virtual trading:** Market participants with or without physical supply or load buying/selling/transacting in the day-ahead market and buying/selling/transacting energy back in the real-time market who earn revenue off arbitrage
- Virtual trading now allowed in all markets – all markets now have two (or more) settlement systems (SPP 2014)
- Hedge or speculate
- Any entity regardless of physical asset (just credit requirements)
- Paired virtual “spread” trading transactions allowed in PJM and ERCOT, being evaluated in other ISOs
- Objectives of virtual trading
  - Convergence of day-ahead and real-time prices and day-ahead commitment
  - Increased competition and liquidity in market
  - Hedging of physical assets
  - Limit supply- and demand-side market power by other physical asset holders
  - Show market designers market modeling flaws??
- Markets have different locational requirements (PJM all nodes, others only gen nodes and load zones, NYISO only load zones)



# Uplift and make-whole payments

- ISO guarantees a generator following ISO directions to recover all bid-in operating costs
  - Mitigation and verification may be required for bid-in costs excessively high
- When the price for energy does not cover all costs, additional side payments (make-whole payments or revenue sufficiency guarantee) are paid to individual generators
- Typically happens because no-load costs and start-up costs do not influence the energy price paid
- Also for reliability must run resources
- Uplift usually allocated to loads, but also to generators that deviate from schedule
- Additional uplifts also occur
  - Day-ahead profit assurance
  - Price volatility make-whole payment
  - Alternative fuel make-whole

# Ancillary Services Markets

# Ancillary Services (FERC)

## 1. Scheduling, system control and dispatch:

Provided by the ISO or RTO, not applicable to this discussion.

## 2. Reactive supply and voltage control from generation service:

Generally supplied as a cost-based service. Lost Opportunity Costs provided if applicable.

## 3. Regulation and frequency response service:

Today, regulation is typically supplied and priced by dynamic markets in ISO/RTO regions. It is used to correct ACE. However, frequency response, as defined by the droop response of governors autonomously responding to frequency is generally not included in any dynamic markets nor is it given cost-based rates.

## 4. Energy imbalance service:

Energy imbalance is typically the service of the real-time markets balancing out the imbalance from the forward markets, and therefore is priced by the real-time energy markets. However, some areas have implemented or proposed new market mechanisms to support ramp products for energy imbalance.

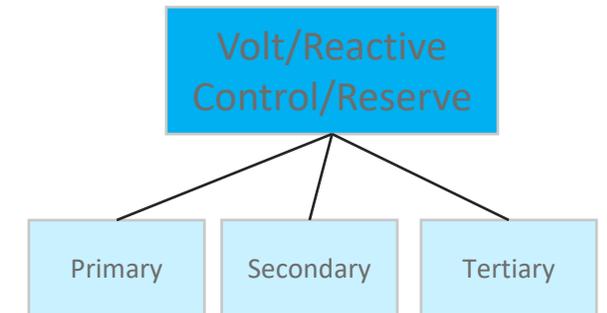
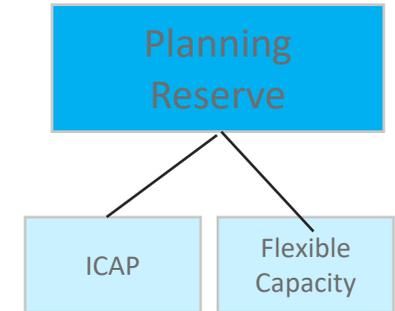
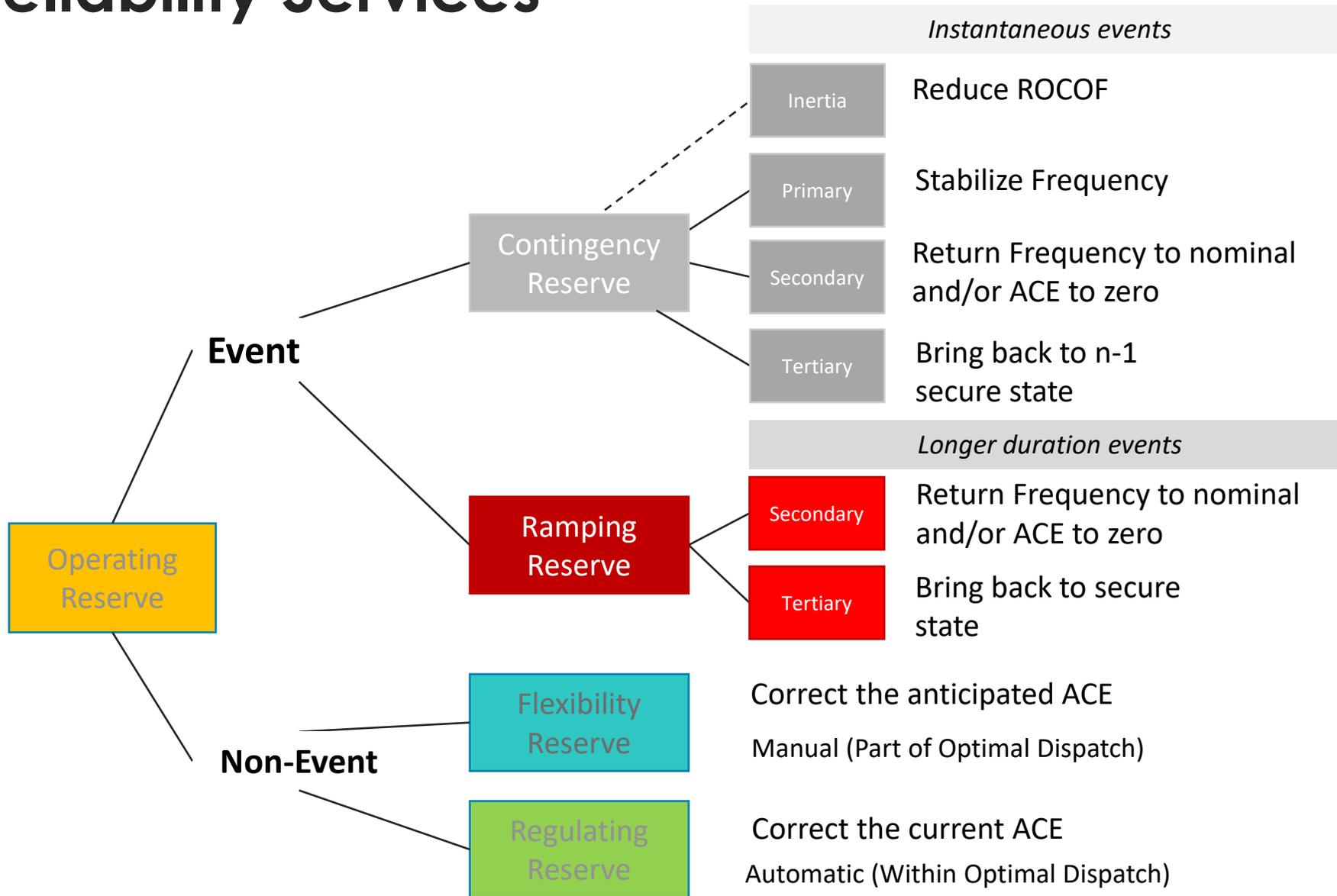
## 5. Operating reserve – synchronized reserve service:

This service is typically supplied and priced by dynamic markets in ISO/RTO regions.

## 6. Operating reserve – supplemental reserve service:

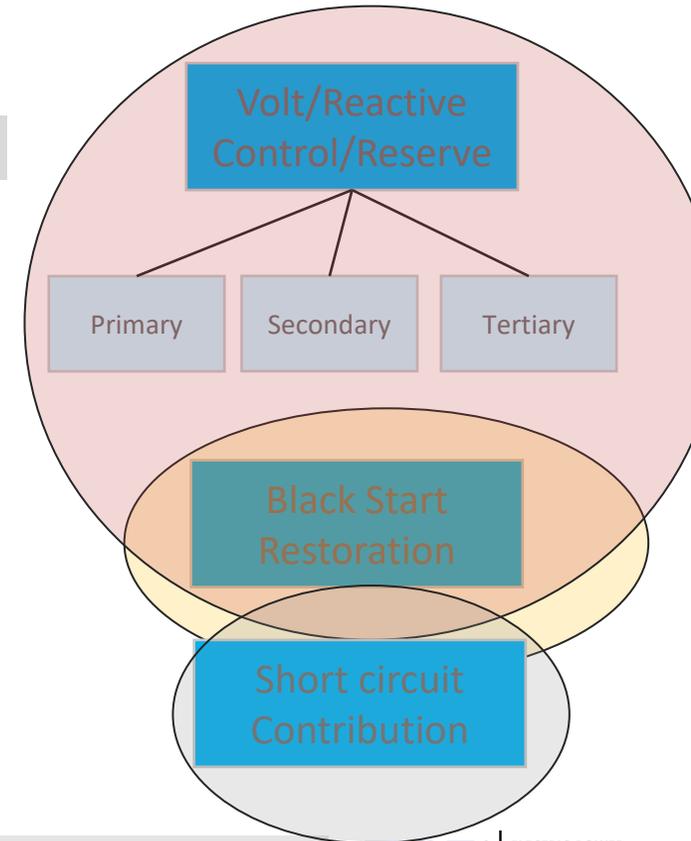
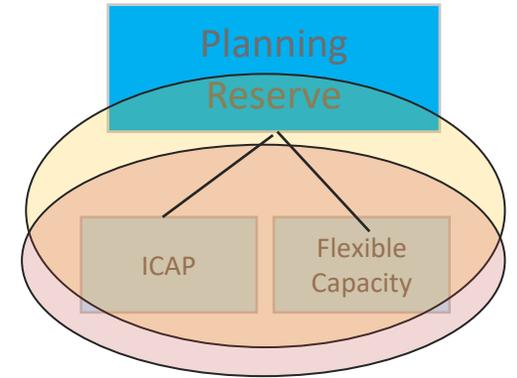
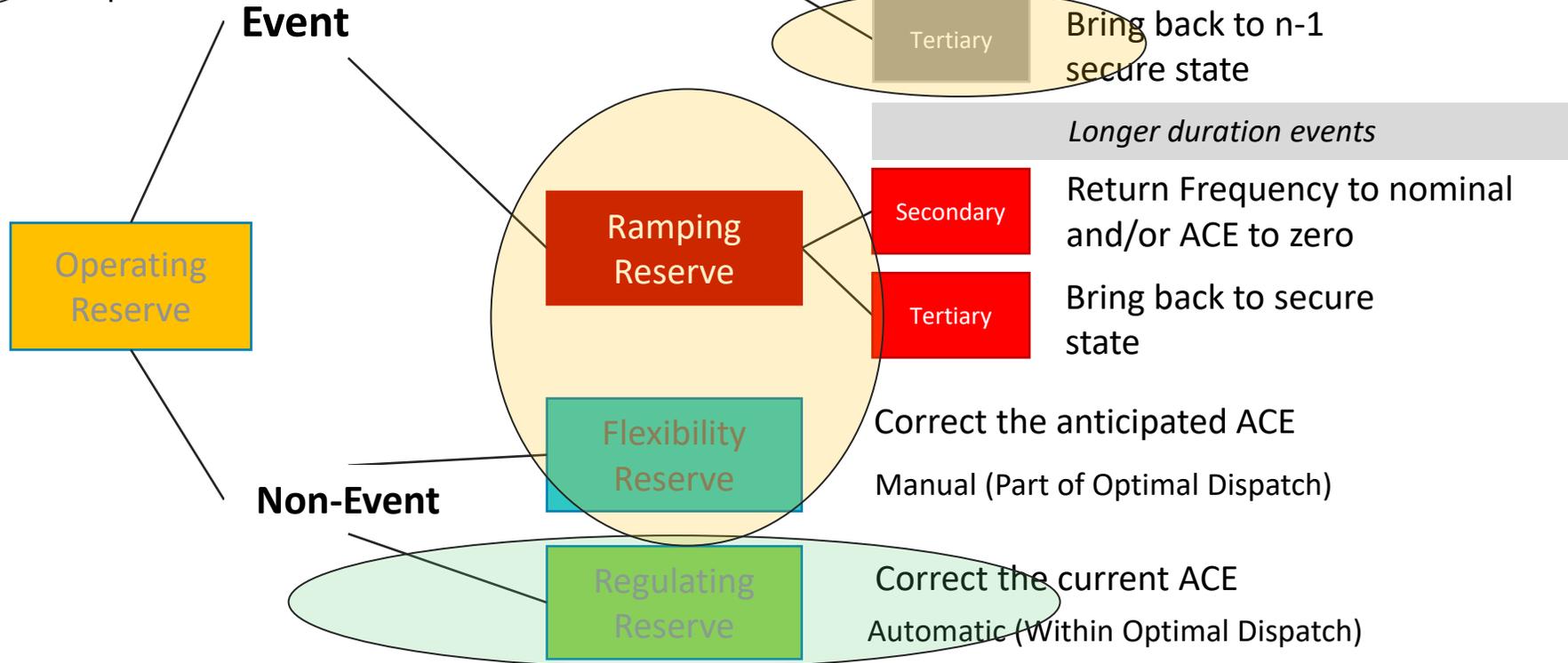
This service is typically supplied and priced by dynamic markets in ISO/RTO regions.

# Reliability Services



# Reliability Services

- Competitive auctions
- Sometimes Competitive auctions
- Cost recovery
- No known compensation



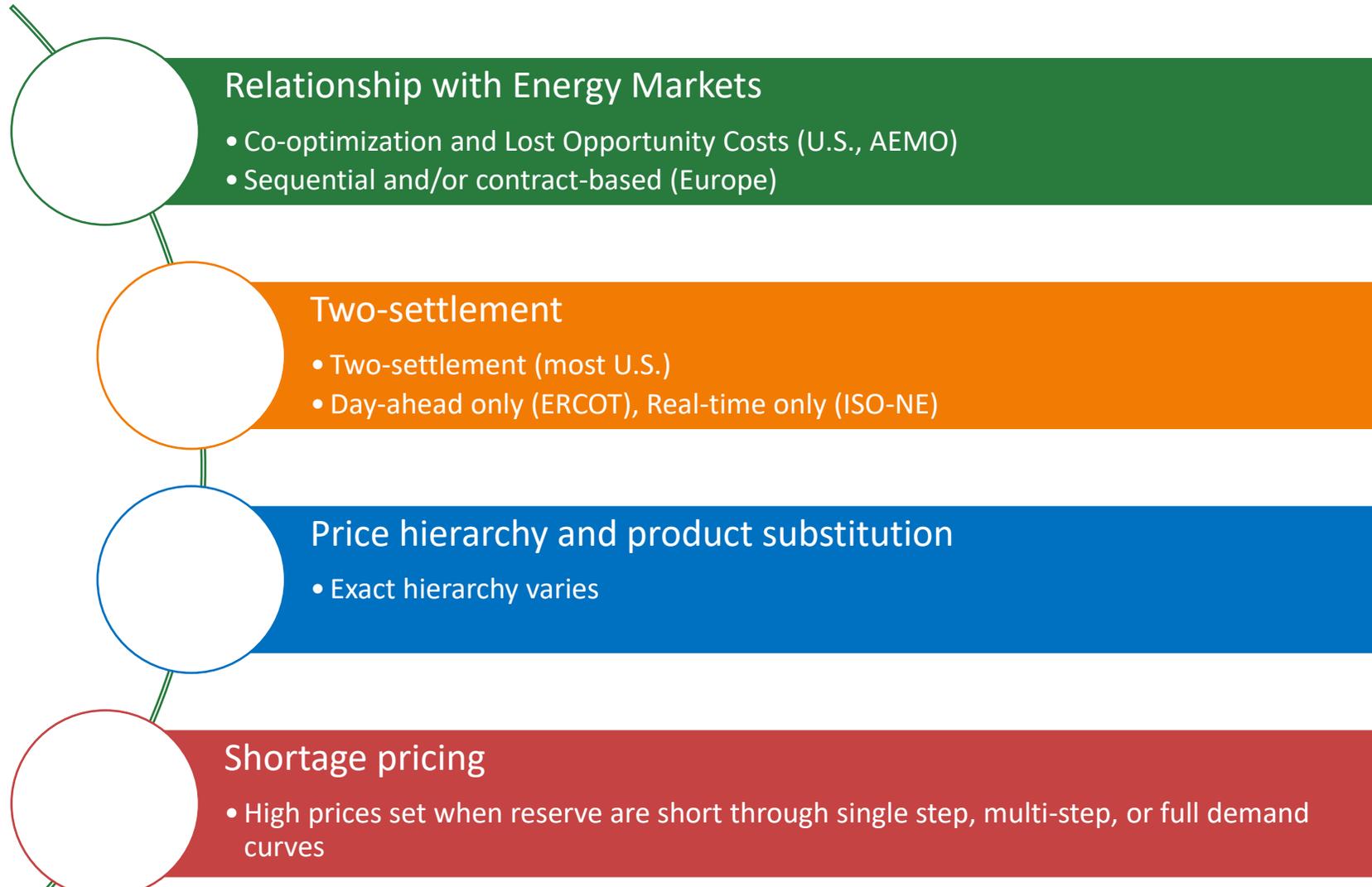
# Reliability Service Compensation

- Some reliability attributes are not currently incentivized:
- Sometimes auctions and market-based pricing for certain services may be impractical
- Prioritization of market design and software changes also key
  - It cost money to develop, discuss, test, implement, and administer new designs

| Reasons why a market product may not be implemented  | Example                           |
|--|-----------------------------------|
| Too complex to design (e.g., software complexity)  | Volt/VAR support                  |
| Too specific to certain local areas (little to no competition)                                     | Volt/VAR support                  |
| System inherently has more than sufficient amounts of the service                                  | Synchronous Inertia               |
| Costs for the service may be small, so cost of administrating market product may outweigh benefits | Black start (restoration) service |
| A specific resource requirement rather than a system-wide need                                     | Low Voltage Ride Through          |

The examples are used for illustrative purposes only and the reason may not be necessarily true for each example in each region.

# Ancillary Service Markets



**Ancillary Services typically paid clearing price for capacity, then paid energy price when deployed. Regulation also paid a mileage price for amount of movement.**

# Co-optimization

|      | Energy Cost | Capacity | Reserve Cost |
|------|-------------|----------|--------------|
| Gen1 | 10 \$/MWh   | 100 MW   | 1 \$/MWh     |
| Gen2 | 20 \$/MWh   | 100 MW   | 5 \$/MWh     |
| Gen3 | 25 \$/MWh   | 150 MW   | 15 \$/MWh    |

Load = 250 MW

Reserve Requirement = 50 MW

## Sequential

|       | Energy Schedule |
|-------|-----------------|
| Gen1  | 100 MW          |
| Gen2  | 100 MW          |
| Gen3  | 50 MW           |
| Total | 250 MW          |

## Co-optimized

|       | Energy Schedule | Reserve |
|-------|-----------------|---------|
| Gen1  | 100 MW          | 0 MW    |
| Gen2  | 50 MW           | 50 MW   |
| Gen3  | 100 MW          | 0 MW    |
| Total | 250 MW          | 50 MW   |

# Lost opportunity Cost

|      | Energy Cost | Capacity | Ramp Rate |
|------|-------------|----------|-----------|
| Gen1 | 10 \$/MWh   | 100 MW   | 1 MW/min  |
| Gen2 | 20 \$/MWh   | 100 MW   | 5 MW/min  |
| Gen3 | 25 \$/MWh   | 150 MW   | 8 MW/min  |

|                      |  |
|----------------------|--|
| <b>Load = 250 MW</b> | <b>Reserve Requirement = 50 MW, 5-minute response required</b> |
|----------------------|--|

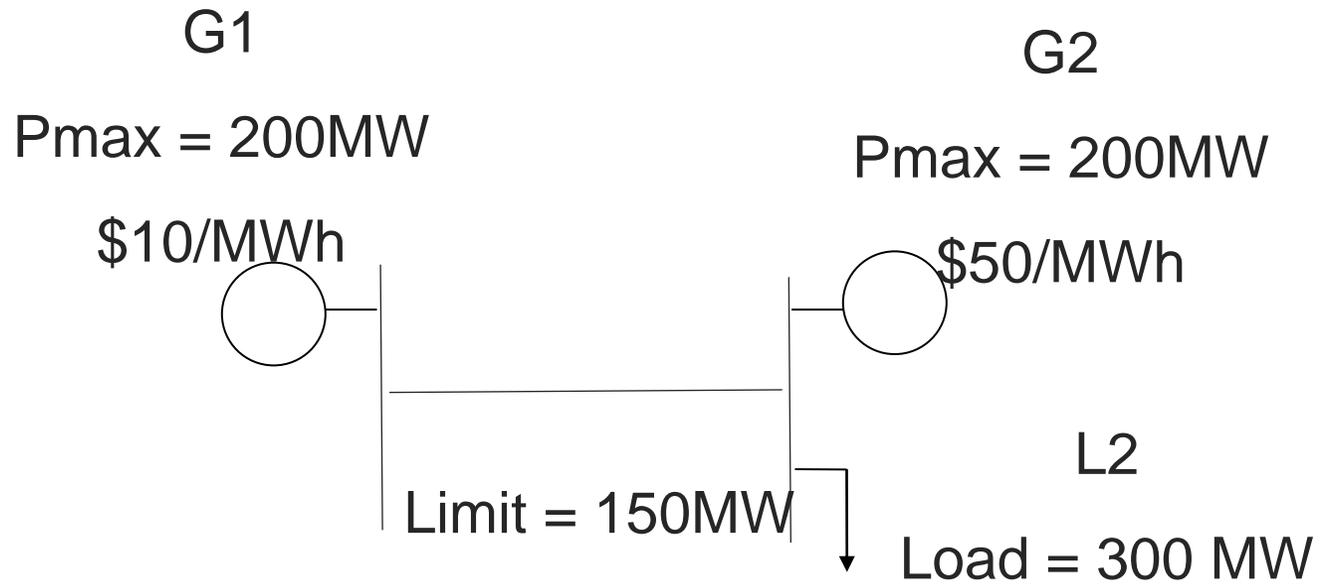
|       | Energy Schedule | Reserve |
|-------|-----------------|---------|
| Gen1  | 100 MW          | 0 MW    |
| Gen2  | 90 MW           | 10 MW   |
| Gen3  | 60 MW           | 40 MW   |
| Total | 250 MW          | 50 MW   |

Energy Price = \$25/MWh

Reserve Price = \$5/MWh

# Financial Transmission Rights

# Financial Transmission Rights



# Financial Transmission Rights

|       | Gen Payments Received | Load Payments Provided |
|-------|-----------------------|------------------------|
| G1    | \$1500                |                        |
| G2    | \$7500                |                        |
| L2    |                       | \$15000                |
| Total | \$9000                | \$15000                |

???

P1 = 150MW

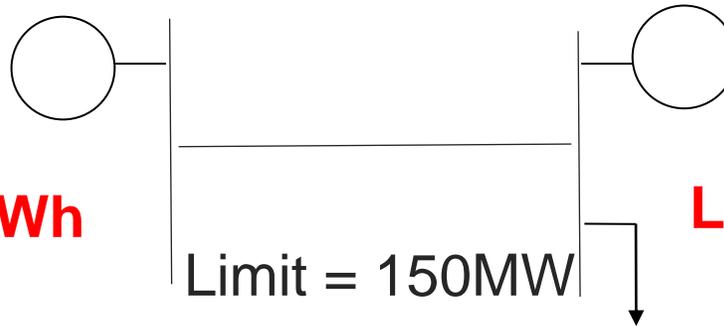
P2 = 150MW

LMP = \$10/MWh

LMP = \$50/MWh

Limit = 150MW

Load = 300 MW



# Financial Transmission Rights

- Physical transmission rights (PTR) cannot allow an efficient optimal scheduling of the supply resources on the transmission system
- PTR transitioned to Financial Transmission Rights (FTR) in organized electricity markets
- When transmission congestion is present in the energy market, there is more money collected from loads than is paid to generators
- Market Participants bid on rights to these moneys through FTR auctions, then “financially” owning the transmission line where congestion occurs
- Do not have to physically own line
- Does not impact scheduling in energy market
- Congestion amounts based on day-ahead congestion, funds from day-ahead congestion
  - Some ISOs guarantee full funding to FTR holders, others do not

# FTR market designs

|  | ISO-NE                                       | NYISO  | PJM                                     | MISO                        | SPP                                   | ERCOT  | CAISO  | IESO  |
|--|--|--|---|-----------------------------|---------------------------------------|--|--|---|
| <b>Name</b>                                      | FTRs   | Transmission Congestion Contracts (TCCs)     | FTRs                                    | FTRs                        | Transmission Congestion Rights (TCRs) | Congestion Revenue Rights (CRRs)             | CRRs   | Transmission Rights (TR)                                |
| <b>Mechanism for allocating auction revenues</b> | Point-to-point Auction Revenue Rights (ARRs) | Auction revenues allocated after the auction | Point-to-point ARRs                     | ARRs                        | ARRs                                  | Auction revenues allocated after the auction | CRRs directly allocated prior to the auction | Revenues go to the transmission rights clearing account |
| <b>Auction period for short-term FTRs</b>        | Annual and monthly                           | 6-month and monthly                          | Long-term (3-year), annual, and monthly | Annual and monthly          | Annual and monthly                    | Semi-annual and monthly                      | Seasonal and monthly                         | Annual and monthly                                      |
| <b>Options</b>                                   | No   | No   | Yes                                     | No                          | No                                    | Yes  | No   | No  |
| <b>Classes</b>                                   | Peak and off-peak                            | Single                                       | Peak, off-peak, and full day            | Peak and off-peak           | Peak and off-peak                     | Peak weekday, Peak week-end, off-peak        | Peak and off-peak                            | Single  |
| <b>FTR funding shortfall procedure</b>           |  | Full funding through uplift                  | FTR shortfalls under-funded             | FTR shortfalls under-funded |                                       |  | FTR shortfalls under-funded                  | Full funding through clearing account                   |

# Capacity Markets

# Missing Money Example

- Peaking unit is used 20 hours per year
- In those 20 hours, it sets the price based on its offer – typically based on its variable cost (fuel and O&M)
- There is no additional rent to use to recover the capital cost that is not reflected in the energy market bid
- When the ISO is short on capacity or reserve in the energy market, it may set the price at scarcity prices
- These prices are higher than the peaker's variable cost and can help recover fixed capital cost
- Regulators often do not allow these scarcity prices to go too high
- Nor do they allow shortage conditions to occur too frequently
- If the peaker is to remain, how does it earn its revenue?

# Other means of RA and capital cost recovery

|                                  | Regulated Planning<br>(Customers Bear Most Risk) |   |  | Market Mechanisms<br>(Suppliers Bear Most Risk)    |   |  |
|----------------------------------|--|---|--|--|---|--|
|                                  | Regulated Utilities                              | Administrative Contracting                  | Capacity Payments                            | LSE RA Requirement                                 | Capacity Markets                          | Energy-Only Markets                          |
| Examples                         | SPP, BC Hydro, most of WECC and SERC             | Ontario                                     | Spain, South America                         | California, MISO<br>(both also have regulated IRP) | PJM, NYISO, ISO-NE, Brazil, Italy, Russia | ERCOT, Alberta, Australia's NEM, Scandinavia |
| Resource Adequacy Requirement?   | Yes (Utility IRP)                                | Yes (Administrative IRP)                    | Yes (Rules for Payment Size and Eligibility) | Yes (Creates Bilateral Capacity Market)            | Yes (Mandatory Capacity Auction)          | No (RA not Assured)                          |
| How are Capital Costs Recovered? | Rate Recovery                                    | Energy Market plus Administrative Contracts | Energy Market plus Capacity Payments         | Bilateral Capacity Payments plus Energy Market     | Capacity plus Energy Markets              | Energy Market                                |

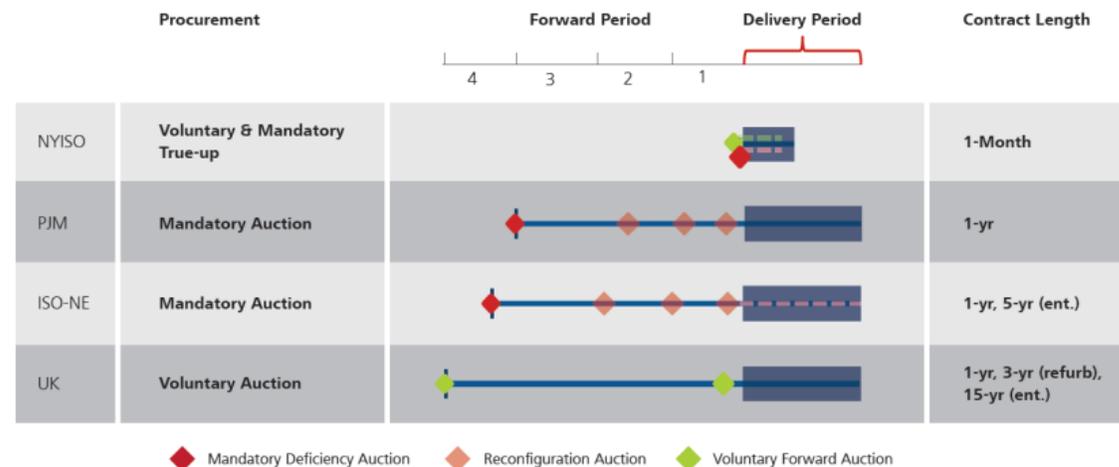
ORDC  
High Scarcity

Pfeifenberger and Spees (2009), *Review of alternative market designs for resource adequacy*.

# Capacity Markets

- Capacity Markets – Loads will pay resources strictly based on capacity to meet future resource adequacy needs and reliability “guarantees”
  - Day-ahead must offer requirement
- A reserve margin is used for uncertainties with forced outages or unexpected high demand
  - Typical numbers: 12-18%
- If a peak demand is 10,000 MW then the operator must make sure it has at least 11,500 MW of capacity installed with a 15% reserve margin
  - If capacity is scarce and more capacity needs to be built, the price for capacity will be higher

• These markets can give peaking generators enough money to recover fixed costs that they cannot get in the energy market



G. Anstey and M. Schönborn, “The British Capacity Market: Reflections on a Visible Hand,” *Energy Market Insights*, no. 11, Dec. 2014.

# Capacity market designs

|                                 | PJM                             | ISO-NE                        | NYISO                            | MISO                            |
|---------------------------------|---------------------------------|-------------------------------|----------------------------------|---------------------------------|
| <b>Name</b>                     | Reliability Pricing Model (RPM) | Forward Capacity Market (FCM) | Installed Capacity (ICAP) Market | Planning Resource Auction (PRA) |
| <b>Sloped demand curve</b>      | Yes                             | Yes (only for system wide)    | Yes                              | No                              |
| <b>Maximum price</b>            | Net CONE                        | Net CONE                      | Net CONE                         | Net CONE                        |
| <b>Minimum offer price rule</b> | Yes                             | Yes                           | Yes                              | No                              |
| <b>Number of locations</b>      | 9 zones                         | 3 zones                       | 4 zones                          | 10 zones                        |
| <b>Must-offer requirement</b>   | DAM energy                      | DAM energy and RTM energy     | DAM energy                       | DAM energy                      |
| <b>Forward period</b>           | 3 years ahead                   | 3 years ahead                 | 1 month prior                    | 2 months prior                  |
| <b>Commitment period</b>        | 1 year                          | 1 year                        | 6 months                         | 1 year                          |
| <b>Product definition</b>       | Generic MW                      | Generic MW                    | Unforced capacity                | Unforced capacity               |

# Emerging Challenges

# Key R&D Challenges

- More resources may be needed for fewer periods, but still needed
  - Do they have the long-term incentives to avoid retirement?
  - Will responsive demand and a smarter grid reduce the need for resources?
- Are there proper incentives to get the increased amount of flexibility on the system that is needed to maintain system reliability
  - **Short-term:** Attract available flexible resources to provide this flexibility
  - **Long-term:** Attract new or existing facilities to build or modify with flexibility attributes
- How are “essential reliability services” being incentivized and valued?
  - Services that used to be inherent that may be declining
  - Should these be incentivized through market products or otherwise?

# Key R&D Challenges (2)

- What is the right price?
  - Non-Convexities, minimize uplift vs. marginal prices, out-of-market vs. in-the-market, alignment of pricing and reliability, market transparency vs. private information
- Should the market internalize policy-related externalities (such as technology favoring policies)?
  - Environmental, job preservation, fuel diversity, local tax
- Interfacing transmission/wholesale with distribution/retail
- Changing resource mixes have new characteristics: Technology agnostic vs. realism?
  - Energy storage technologies, demand response, renewables, distributed energy, natural gas
- Simplicity vs. complexity
  - Do stochastics, reactive power, multi-state configurations need to be part of the market clearing?
- Are there incentives for resources to withstand and recover from extreme events?

# Market Evolution

| FERC Order | Year Issued | Description  |
|------------|-------------|--|
| Order 831  | 2016        | Offer Caps in Markets Operated by Regional Transmission Organizations and Independent System Operators; raises the price cap of energy from \$1,000/MWh to \$2,000/MWh |
| Order 825  | 2016        | Aligns settlement periods with pricing periods, and updates triggers for scarcity pricing  |
| Order 841  | 2018        | Definition of Electric Storage Resource (ESR) and common requirements for the ESR market participation model   |
| Order 842  | 2018        | Order requiring all newly interconnecting resources to have capability to provide primary frequency response   |
| Order 844  | 2018        | Order directing rules for allocation of uplift costs and additional transparency measures for out of market procedures   |

- Western EIM continues expanding utilities
- DER Aggregation Market Participation Workshops
- Canadian Market Evolution (IESO Market Renewal, AESO Capacity Market)
- Fuel Security Market Designs (PJM, ISO-NE)
- Carbon Pricing (NYISO, PJM)

# Common and Unique Initiatives

|                                      | Common or Similar Initiatives   | Unique Initiatives   |
|--------------------------------------|---|--|
| <b>Energy Markets</b>                | <p>Improved coordinated transaction scheduling (NYISO, ISO-NE, PJM, MISO, SPP, and CAISO)</p> <p>Combined Cycle Modeling Improvements (PJM, MISO, SPP)</p> <p>Virtual spread product (e.g., up-to-congestion, or point-to-point) (NYISO, MISO, CAISO)</p> <p>Pricing of fast start resources (ISO-NE, NYISO, MISO, CAISO)</p> | <p>Do-not-exceed limits for wind generation (ISO-NE)</p> <p>Flow control resources as market participants (MISO)</p> <p>Fifteen minute market (CAISO)</p> <p>Integrated day-ahead market (CAISO)</p> |
| <b>Ancillary Service Markets</b>     | <p>Regulation pay-for performance improvements (PJM, SPP, CAISO)</p> <p>Ramp products (MISO, SPP, CAISO)</p> <p>Primary frequency response (MISO, ERCOT, CAISO)</p>   | <p>Synchronous Inertia service (ERCOT)</p> <p>Gas system limitations on reserve provision (NYISO)</p> <p>Reserve product for voltage (MISO)</p>  |
| <b>Financial Transmission Rights</b> | <p>FTR funding issue resolution and shortfall allocation methods (PJM, MISO, CAISO)</p> <p>Long-term FTR (ISO-NE, MISO, CAISO)</p> <p>Incorporating transmission outages into FTR auctions (SPP, CAISO)</p>   | <p>Third-party FTR clearing (ISO-NE)</p> <p>Rights for PAR-controlled lines (NYISO)</p>  |
| <b>Capacity Markets</b>              | <p>Sloped demand curves (ISO-NE, MISO)</p> <p>Locational capacity market improvements (ISO-NE, NYISO, MISO)</p> <p>Performance incentives (ISO-NE, NYISO, PJM)</p> <p>Locational price hedging (NYISO, PJM, MISO)</p>   | <p>Flexible capacity procurement (CAISO)</p> <p>Changing from annual to seasonal markets (MISO)</p>  |

# Thank You!!

**Together...Shaping the Future of Electricity**

[eela@epri.com](mailto:eela@epri.com)

# Advanced Use of Forecasting

## Probabilistic Methods and Other Advanced Techniques

Aidan Tuohy

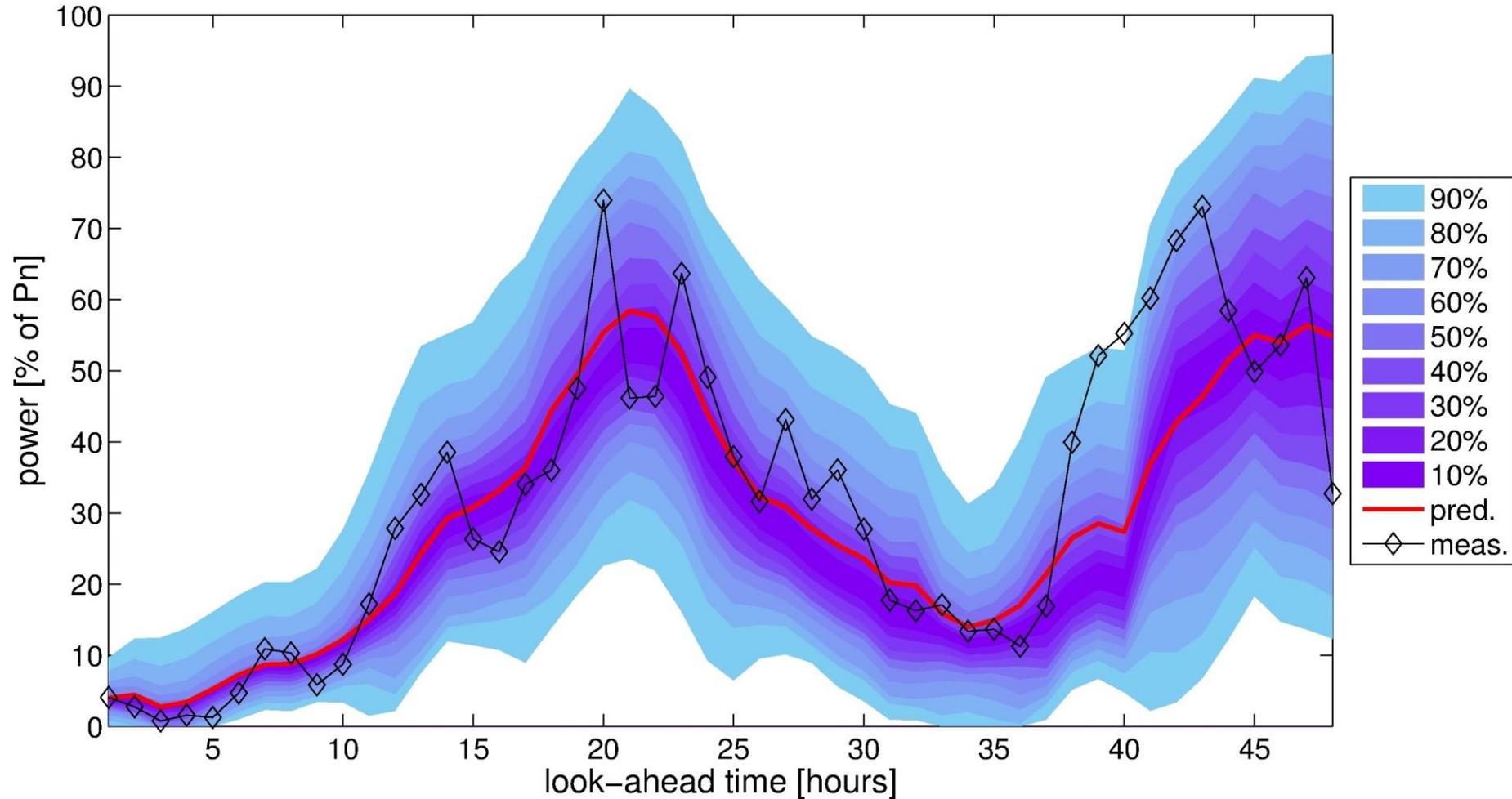
ESIG Forecasting and Markets Workshop  
June 4, 2019



# Agenda

- Overview of probabilistic forecasts
- Use of probabilistic information in operations
- Other uses of forecasting – reserves, frequency response, DER

# We can't forecast perfectly – so, use probabilistic forecasts

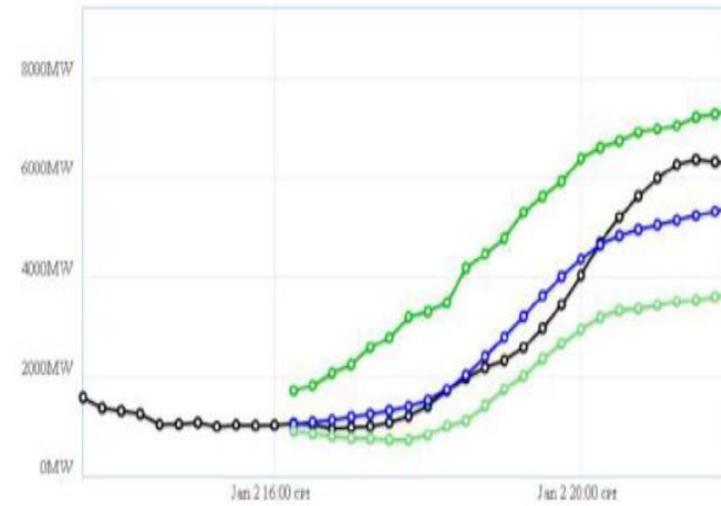


Probabilistic data, in useful form, can be used for more than awareness

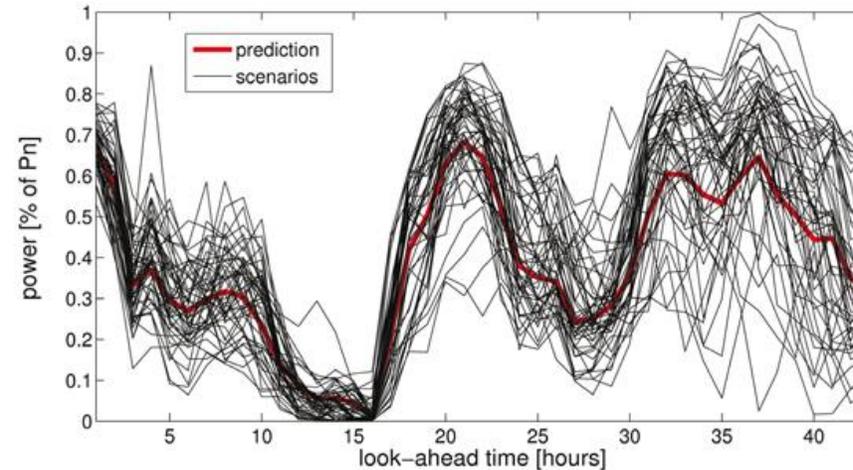
Source: Pierre Pinson, DTU, Denmark

# Why use probabilistic forecasts?

- Takes advantage of risk-based methods such as stochastic programming
- Captures outliers (assuming data is representative)
- Should be more economically efficient while can also be more reliable than traditional methods
- May give us better rationale for responding to some extreme events, e.g. extreme cold

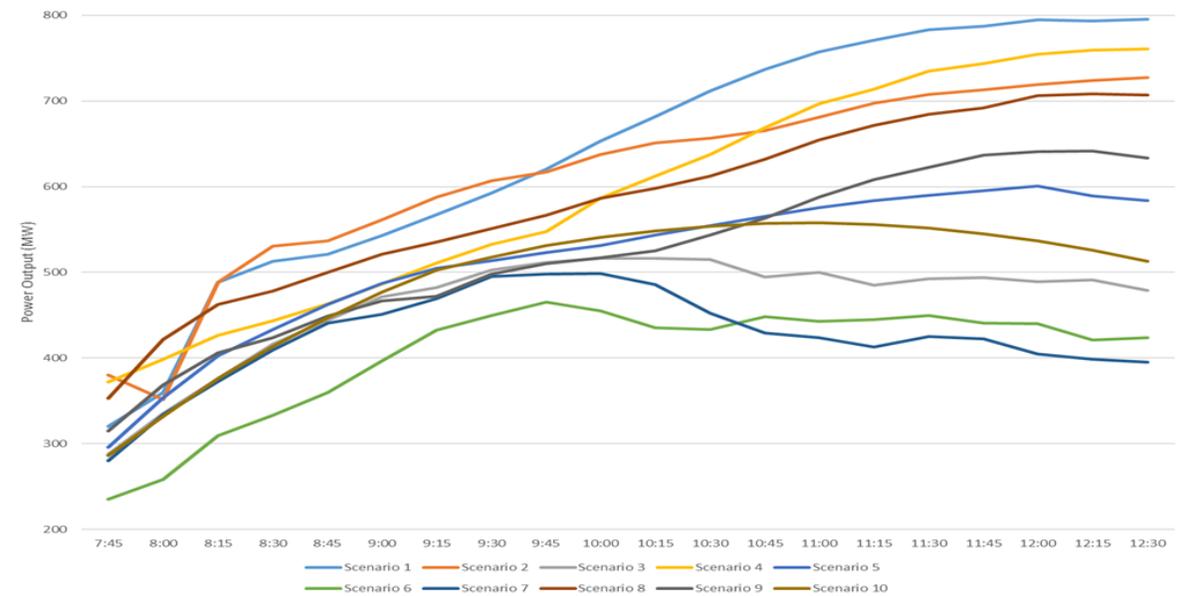


Source: David Maggio, Using probabilistic information in real life, 2011 UWIG Forecasting Workshop



# Probabilistic Forecasting Methods

- EPRI studies and others have shown potential benefits of using probabilistic info.
  - WECC system study to examine potential use of this info
  - Showed that use of probabilistic forecasts can improve reliability and/or economics over current deterministic methods
  - Typically in order of few % (<5%)
- Research needs identified in area of probabilistic forecasting
  - Improved probabilistic forecasts that capture the uncertainty in a suitable narrow band
  - Operational tools that can use such forecasts to assist decisions, e.g. operating reserve requirements
  - Education on how these tools could be used and further developed
  - Identifying different use cases – ISO and utility use cases



PV output scenarios

**Probabilistic forecasts can improve operations and provide situational awareness  
- but we need to know how best to use them**

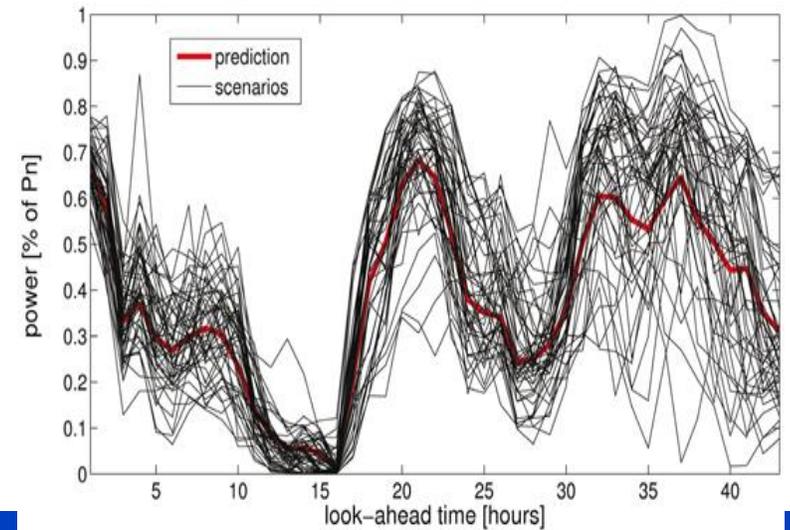
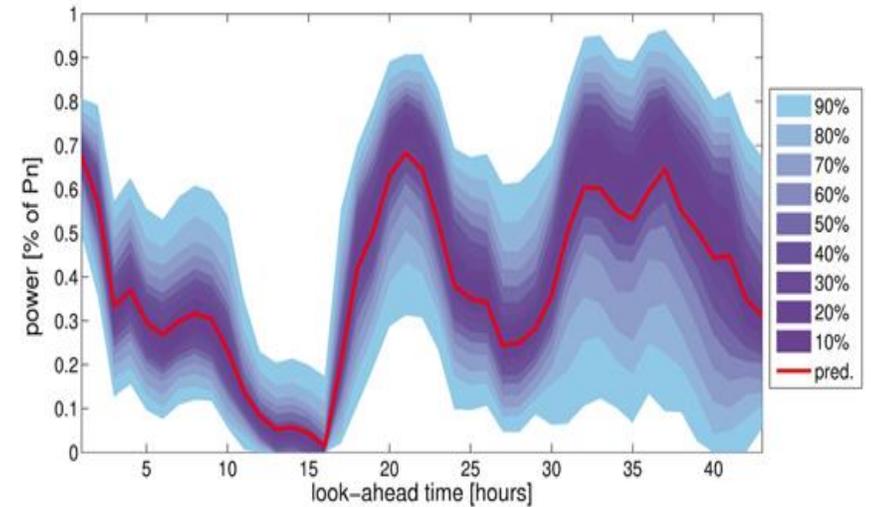
# Probabilistic Forecasting Applications

| Application  | Description   | In use? |
|--|---|---------|
| Stochastic Scheduling (STUC)                           | Committing or dispatching resources to meet multiple potential scenarios based on minimizing the expected cost  | N/A     |
| Robust optimization-based Unit commitment and dispatch | Similar to STUC, but only using the “worst case” scenario to ensure the decisions are robust towards those situations   | N/A     |
| Do Not Exceed Dispatch VER Limits                      | Using probabilistic forecasts to determine the likelihood of VER providing greater energy than expected that can exceed balancing capabilities or network limit violations  | ISO-NE  |
| Outage Planning  | Using long-term probabilistic forecasts to determine whether it is optimal to take certain units (including non-renewable ones) or transmission facilities out for maintenance when it is likely they are not needed and economic losses are minimal                                  | N/A     |
| Energy Market Trading (E.g., virtual trading)          | Using potential scenarios and probability of those scenarios to assist in taking financial positions within the market (either as a VER, load, or virtual trader).<br>Longer term probabilistic forecasts can also be used for long-term markets, like financial transmission rights. | Yes     |
| Level of frequency response                            | Using probabilistic forecasts to understand the level of frequency response (or synthetic inertia) a wind plant or collection of wind plants can provide  | N/A     |

Others: Real-time contingency analysis, topology switching, reserve scheduling

# Generation of Probabilistic VG Scenarios - Motivation

- With increasing levels of VG, operations will be more concerned with uncertainty than before → need tools that can manage this uncertainty
- Uncertainty can be characterized in a number of ways and is already provided by some vendors
  - Probabilistic information as a distribution
  - Confidence intervals or exceedance levels
  - Ensembles/multiple forecasts
  - Scenarios for how the future may unfold
- Operations or Integration study applications



**Probabilistic data, in useful form, can be used for more than awareness**

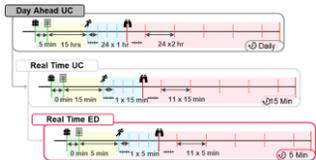
# Other advanced forecasting uses

# EPRI Dynamic Reserve Requirement Method

## Reserve Characteristics

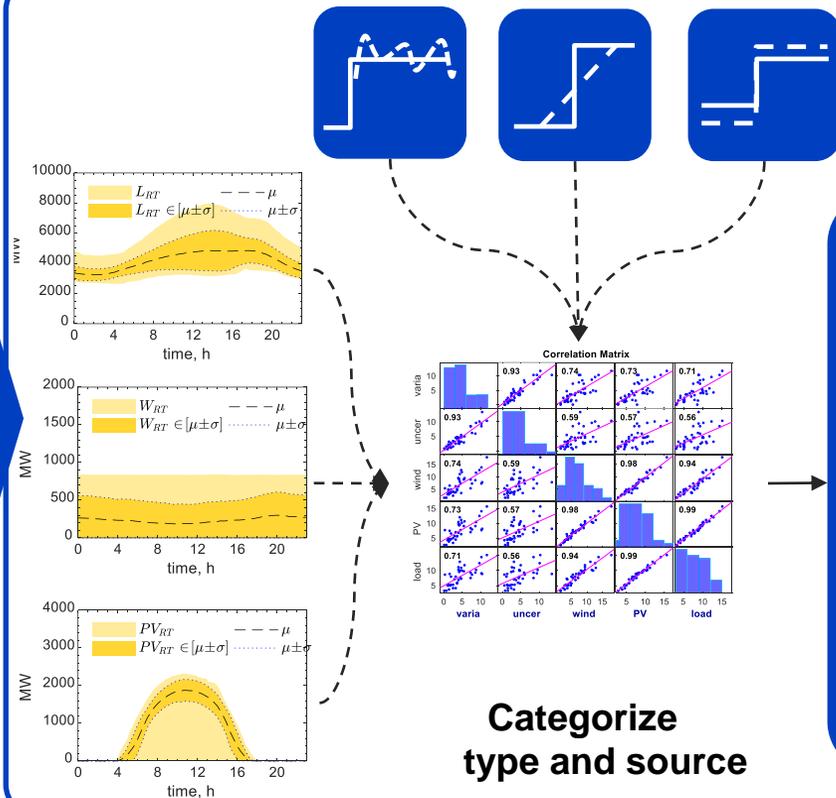
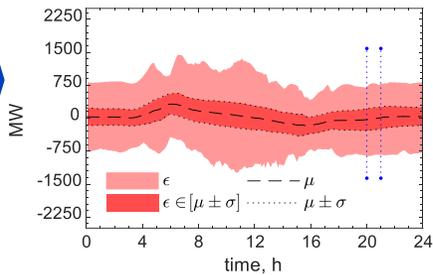
BA process:

- Held
- Released
- Direction



## Historical Assessment

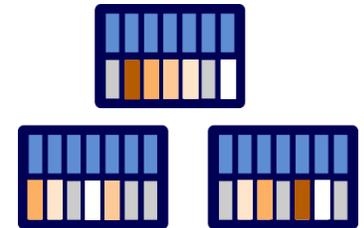
Historical assessment to determine the exact reserve requirements



## Explanatory variable:

- Temporal:
  - Hour
  - Season
  - Week/wknd
- Production:
  - P-level
  - $\Delta \rightarrow$
  - $\Delta \leftarrow$
  - $|\Delta|$

## Assemble using best explanatory variables



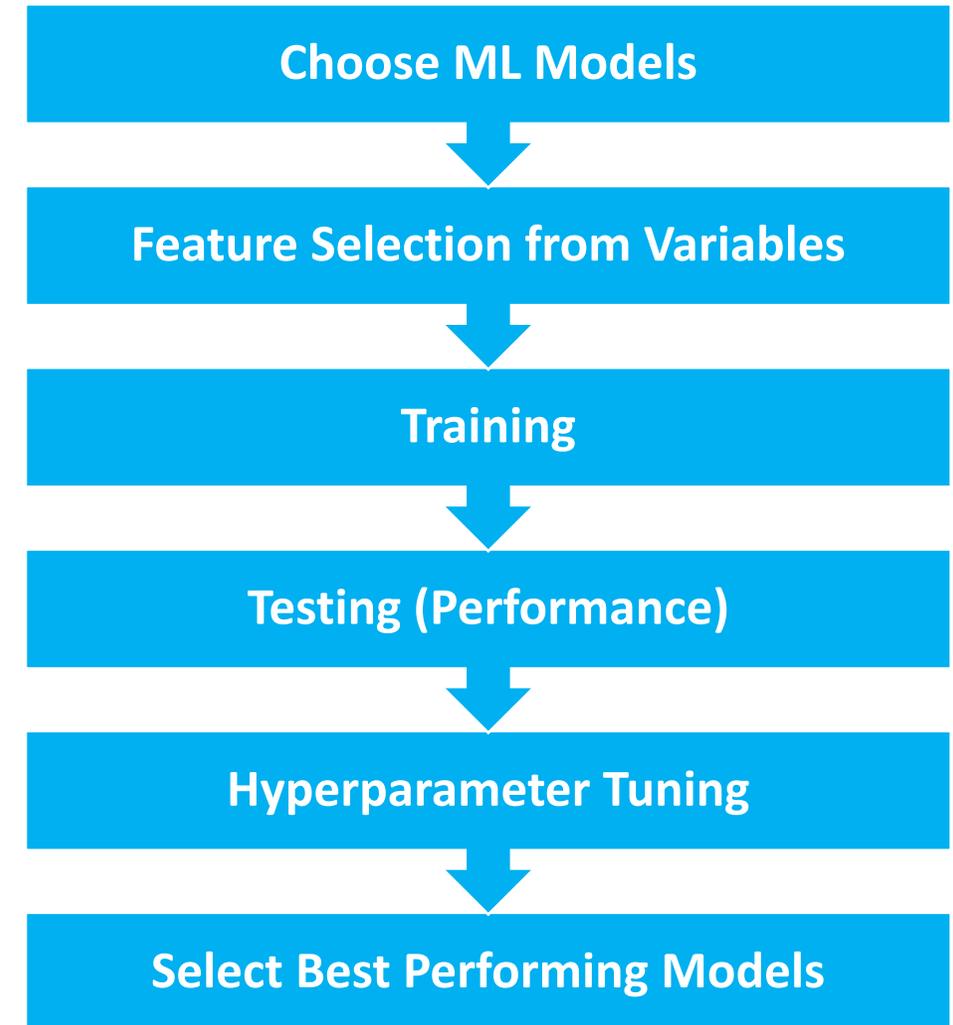
$$R_t = f(\cdot)$$

Reserve requirement is “forecasted,” just like load or RES production

# 2018 Reserve Forecasting Improvements

- **Current** EPRI “Clustering Method” uses correlations across explanatory variables to create a lookup table of all reserve needs and impact sources (load, wind, solar); that aggregated produce the forecast for reserve requirements
- **Motivation for 2018:**
  - Apply available machine-learning (ML) tools for reserve forecasting to improve performance over existing methods
  - ML methods have been successfully applied to power system forecasting applications and exist in commercial tools
  - Test, study performance, and implement ML methods in DynADOR

## Forecasting Steps

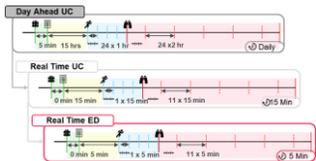


# Dynamic Reserve Requirement Methods

## Reserve Characteristics

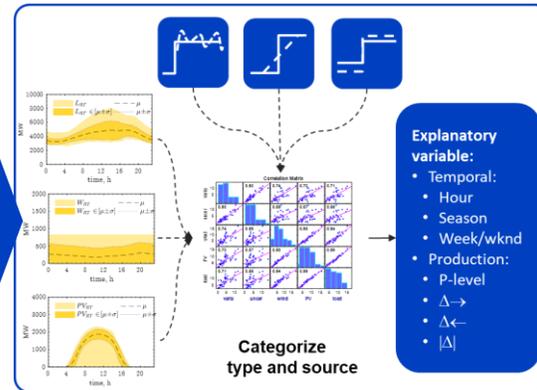
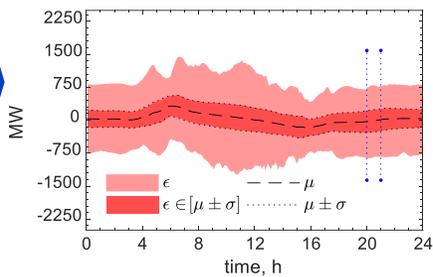
BA process:

- Held
- Released
- Direction

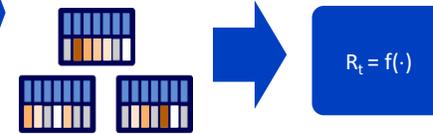


## Historical Assessment

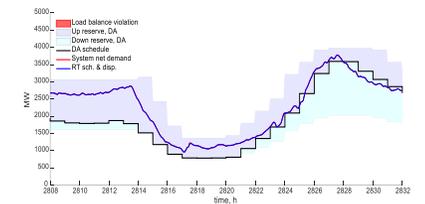
Historical assessment to determine the exact reserve requirements



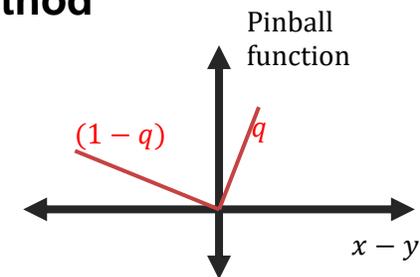
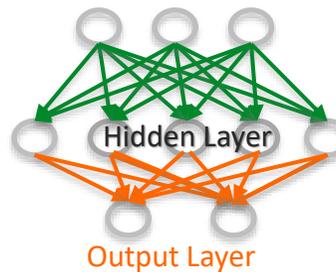
## Assemble using best explanatory variables



## Determine Dynamic Reserve Requirements



## ANN Method



Alternative Methods to Determine Dynamic Reserve Requirements

# Related: HECO Study Overview and Conclusions

- Evaluate current, proposed (now existing), and recommended operating reserve requirement methods on Oahu as well as other operational recommendations
- Study impacts of higher VER
  - Utility scale: 108 MW to 287 MW; DPV: 291 to 564MW
- Simulation using FESTIV tool (commitment, dispatch, AGC)
- Metrics: Costs, ACE, frequency error, HECO compliance, head room risk
- Conclusions:
  - Cycling of mid-merit resources for balancing can provide economic benefits
    - However, other reasons for must-run status must be considered
  - Combined use of cycling and advanced dynamic reserve requirements can provide economic and reliability benefits
    - **Estimated \$21-\$24M annual savings (4%) in addition to improved reliability**
  - VER Curtailment during high ACE required on future system
  - Evaluate frequency responsiveness as part of reserve providers

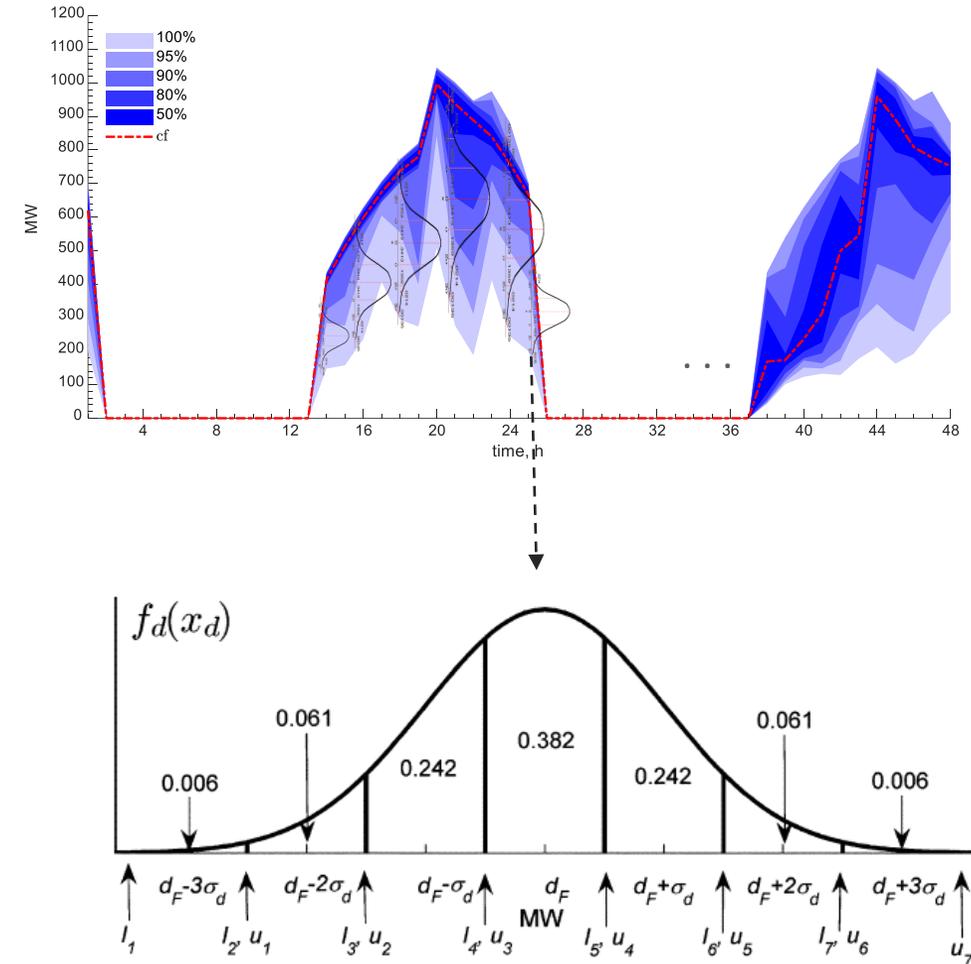
# EPRI DOE Solar Forecasting Project– Three Workstreams

- 3 Year Project, anticipated \$1,8M DOE funding, \$760k EPRI/utility cost share (\$110k from 173.05 over 3 years)
- A Forecasting Work Stream to develop and deliver probabilistic forecasts with targeted improvements for utility scale and behind-the-meter (BTM) solar
- A Design Work Stream to identify advanced methods for managing uncertainty based on results from advanced scheduling tools
- A Demonstration Work Stream to develop and demonstrate a scheduling management platform (SMP) to integrate probabilistic forecasts and scheduling decisions in a modular and customizable manner



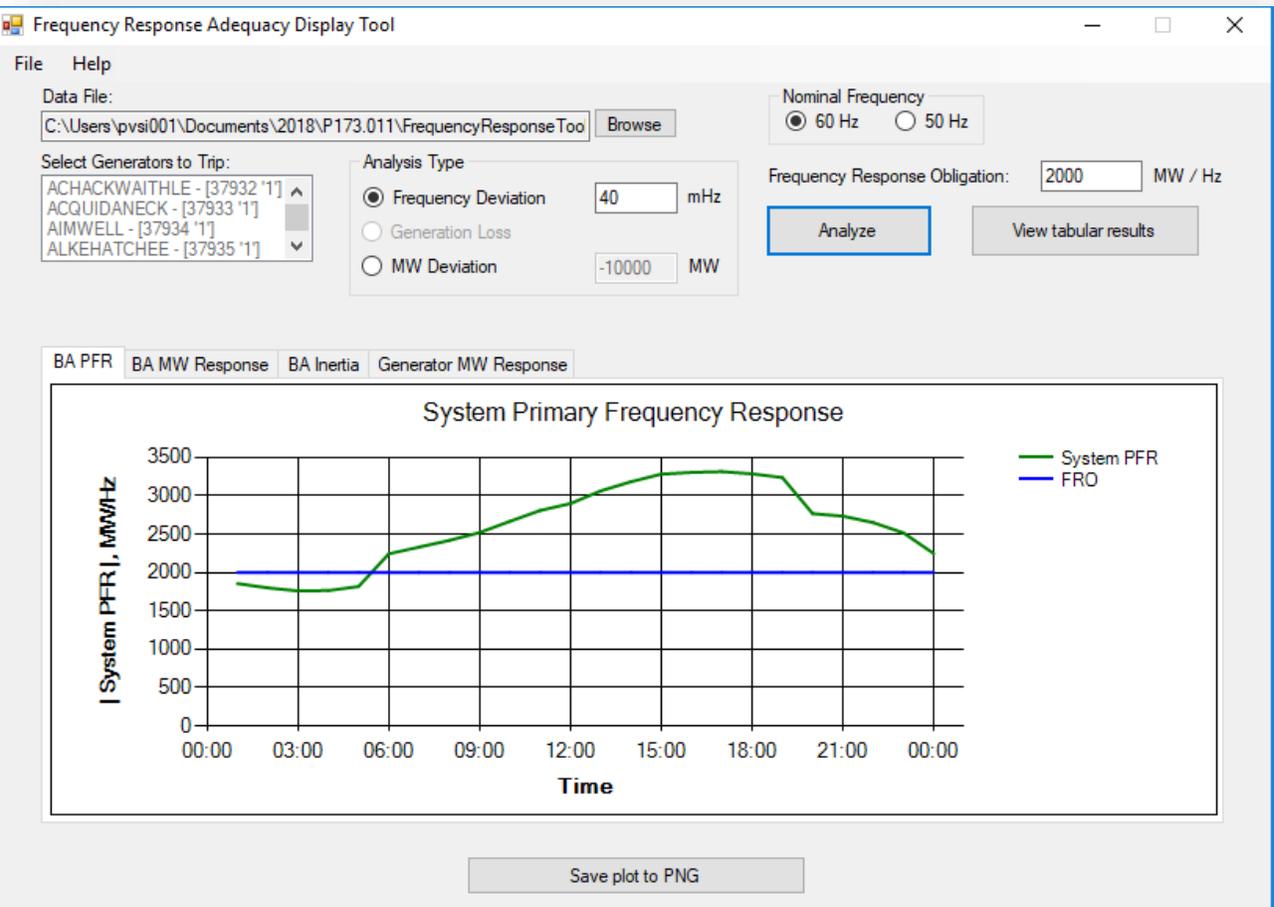
# Probabilistic Forecasts in DynADOR

- Reserve determination using probabilistic forecasts
- Part of the DOE-funded OPTSUN project
- Determination:
  - For a given probabilistic forecast, determine the likelihood of net demand materialization
  - For each possible net demand combinations, determine dynamic reserves
  - The dynamic reserve requirements are given by the aggregation of the weighted individual reserve requirements



M. A. Ortega-Vazquez and D. S. Kirschen, "Estimating the Spinning Reserve Requirements in Systems with Significant Wind Power Generation Penetration," *IEEE Transactions on Power Systems*, Vol. 24, Issue 1, pp. 114-124, Feb. 2009.

# Forecast Frequency Response



Calculate anticipated PFR and compare to FRO

- PFR actually depends on event

Response for a predefined frequency deviation (+/-)

Response for a predefined MW deviation (+/-)

Individual generator MW responses, as well as total load response.

# FRADT: "What-if" Mode

Tabular Results

File

Generator Dispatch Load Response System Response Generator Response

| Timestamp        | Generator | Original Dispatch [MW] | PFR, MW/Hz | MW Response | Final Dispatch [MW] | Pmin [MW] | Pmax [MW] | Inertia [MW.s] | Δ PFR, MW/Hz |
|------------------|-----------|------------------------|------------|-------------|---------------------|-----------|-----------|----------------|--------------|
| 2017-08-01 21:00 | G1        | 28.10                  | 0.0000     | 0.0000      | 0.00                | 28.10     | 82.10     | 0.0            | 0.0000       |
| 2017-08-01 21:00 | G2        | 27.79                  | 0.0000     | 0.0000      | 0.00                | 27.79     | 82.10     | 0.0            | 0.0000       |
| 2017-08-01 21:00 | G3        | 61.33                  | -17.8896   | 24.7670     | 86.10               | 27.90     | 86.10     | 258.3          | 0.0000       |
| 2017-08-01 21:00 | G4        | 71.46                  | -9.9990    | 13.8430     | 85.30               | 27.78     | 85.30     | 85.3           | 0.0000       |
| 2017-08-01 21:00 | G5        | 108.89                 | -18.3541   | 25.4100     | 134.30              | 58.33     | 134.30    | 268.6          | 0.0000       |
| 2017-08-01 21:00 | G6        | 134.30                 | -0.0722    | 0.1000      | 134.40              | 57.58     | 134.40    | 134.4          | 0.0000       |
| 2017-08-01 21:00 | G7        | 22.68                  | -15.129    | 0.0000      | 0.00                | 0.00      | 0.00      | 0.0            | 0.0000       |
| 2017-08-01 21:00 | G8        | 22.57                  | -15.097    | 0.0000      | 0.00                | 0.00      | 0.00      | 0.0            | 0.0000       |
| 2017-08-01 21:00 | G9        | 22.41                  | -17.694    | 0.0000      | 0.00                | 0.00      | 0.00      | 0.0            | 0.0000       |
| 2017-08-01 21:00 | G10       | 22.52                  | -17.389    | 0.0000      | 0.00                | 0.00      | 0.00      | 0.0            | 0.0000       |
| 2017-08-01 21:00 | G11       | 0.00                   | 0.0000     | 0.0000      | 0.00                | 0.00      | 0.00      | 0.0            | 0.0000       |
| 2017-08-01 21:00 | G12       | 63.75                  | -16.143    | 0.0000      | 0.00                | 0.00      | 0.00      | 0.0            | 0.0000       |
| 2017-08-01 21:00 | G13       | 0.00                   | 0.0000     | 0.0000      | 0.00                | 6.90      | 52.90     | 0.0            | 0.0000       |
| 2017-08-01 21:00 | G14       | 0.00                   | 0.0000     | 0.0000      | 0.00                | 6.90      | 49.90     | 0.0            | 0.0000       |
| 2017-08-01 21:00 | G15       | 103.95                 | -0.0361    | 0.0500      | 104.00              | 60.00     | 104.00    | 104.0          | 0.0000       |
| 2017-08-01 21:00 | G16       | 103.95                 | -0.0361    | 0.0500      | 104.00              | 60.00     | 104.00    | 104.0          | 0.0000       |
| 2017-08-01 21:00 | G17       | 0.00                   | 0.0000     | 0.0000      | 0.00                | 30.00     | 50.00     | 0.0            | 0.0000       |
| 2017-08-01 21:00 | G18       | 0.00                   | 0.0000     | 0.0000      | 0.00                | 15.00     | 25.00     | 0.0            | 0.0000       |
| 2017-08-01 21:00 | G19       | 0.00                   | 0.0000     | 0.0000      | 0.00                | 50.00     | 208.00    | 0.0            | 0.0000       |
| 2017-08-01 21:00 | G20       | 179.90                 | -0.0722    | 0.1000      | 180.00              | 63.00     | 180.00    | 360.0          | 0.0000       |

Allow user to adjust input (dispatch, commitment, etc)



Run "What-if"

Frequency Response Adequacy Display Tool

File Help

Data File: C:\Users\pvsi\Documents\2018\VP173.011\Utility\_input data - one day.xlsx

Analysis Period: From: 2017-08-01 To: 2017-08-02

Nominal Frequency:  60 Hz  50 Hz

Frequency Response Obligation: -200 MW / Hz

Select Generators to Trip: G1 - [1 '1'] G10 - [10 '1'] G11 - [11 '1'] G12 - [12 '1'] G13 - [13 '1'] G14 - [14 '1'] G15 - [15 '1']

Analysis Type:  Frequency Deviation 40 mHz  Generation Loss  MW Deviation -200 MW

Analyze View tabular results

BA PFR BA MW Response BA Inertia Generator MW Response

System Primary Frequency Response

Save plot to PNG

Tabular Results

File

Generator Dispatch Load Response System Response Generator Response

| Timestamp        | Generator | Original Dispatch [MW] | PFR, MW/Hz | MW Response | Final Dispatch [MW] | Pmin [MW] | Pmax [MW] | Inertia [MW.s] | Δ PFR, MW/Hz | Δ MW Response | Δ Final Dispatch [MW] |
|------------------|-----------|------------------------|------------|-------------|---------------------|-----------|-----------|----------------|--------------|---------------|-----------------------|
| 2017-08-01 21:00 | G1        | 28.10                  | -26.2196   | 22.5273     | 50.63               | 28.10     | 82.10     | 246.3          | -26.2196     | 22.5273       | 50.63                 |
| 2017-08-01 21:00 | G2        | 27.79                  | -26.2196   | 22.5273     | 50.32               | 27.79     | 82.10     | 164.2          | -26.2196     | 22.5273       | 50.32                 |
| 2017-08-01 21:00 | G3        | 61.33                  | -27.4970   | 23.6249     | 84.96               | 27.90     | 86.10     | 258.3          | -9.6074      | -1.1421       | -1.14                 |
| 2017-08-01 21:00 | G4        | 71.46                  | -16.1177   | 13.8480     | 85.30               | 27.78     | 85.30     | 85.3           | -6.1186      | 0.0049        | 0.00                  |
| 2017-08-01 21:00 | G5        | 108.89                 | -29.5853   | 25.4191     | 134.31              | 58.33     | 134.30    | 268.6          | -11.2313     | 0.0091        | 0.01                  |
| 2017-08-01 21:00 | G6        | 134.30                 | -0.1164    | 0.1000      | 134.40              | 57.58     | 134.40    | 134.4          | -0.0442      | 0.0000        | 0.00                  |
| 2017-08-01 21:00 | G7        | 22.68                  | -14.8823   | 12.7865     | 35.47               | 22.68     | 46.60     | 46.6           | 0.2472       | -8.1592       | -8.16                 |
| 2017-08-01 21:00 | G8        | 22.57                  | -14.8503   | 12.7591     | 35.32               | 22.57     | 46.50     | 46.5           | 0.2466       | -8.1417       | -8.14                 |
| 2017-08-01 21:00 | G9        | 22.41                  | -17.4052   | 14.9542     | 37.37               | 22.41     | 54.50     | 54.5           | 0.2891       | -9.5424       | -9.54                 |
| 2017-08-01 21:00 | G10       | 22.52                  | -17.0858   | 14.6798     | 37.20               | 22.52     | 53.50     | 107.0          | 0.2838       | -9.3673       | -9.37                 |
| 2017-08-01 21:00 | G11       | 0.00                   | 0.0000     | 0.0000      | 0.00                | 27.96     | 82.90     | 0.0            | 0.0000       | 0.0000        | 0.00                  |
| 2017-08-01 21:00 | G12       | 63.75                  | -26.0214   | 22.3570     | 86.11               | 27.86     | 86.10     | 86.1           | -9.8783      | 0.0080        | 0.01                  |

Display impact of change (graphical & tabular)



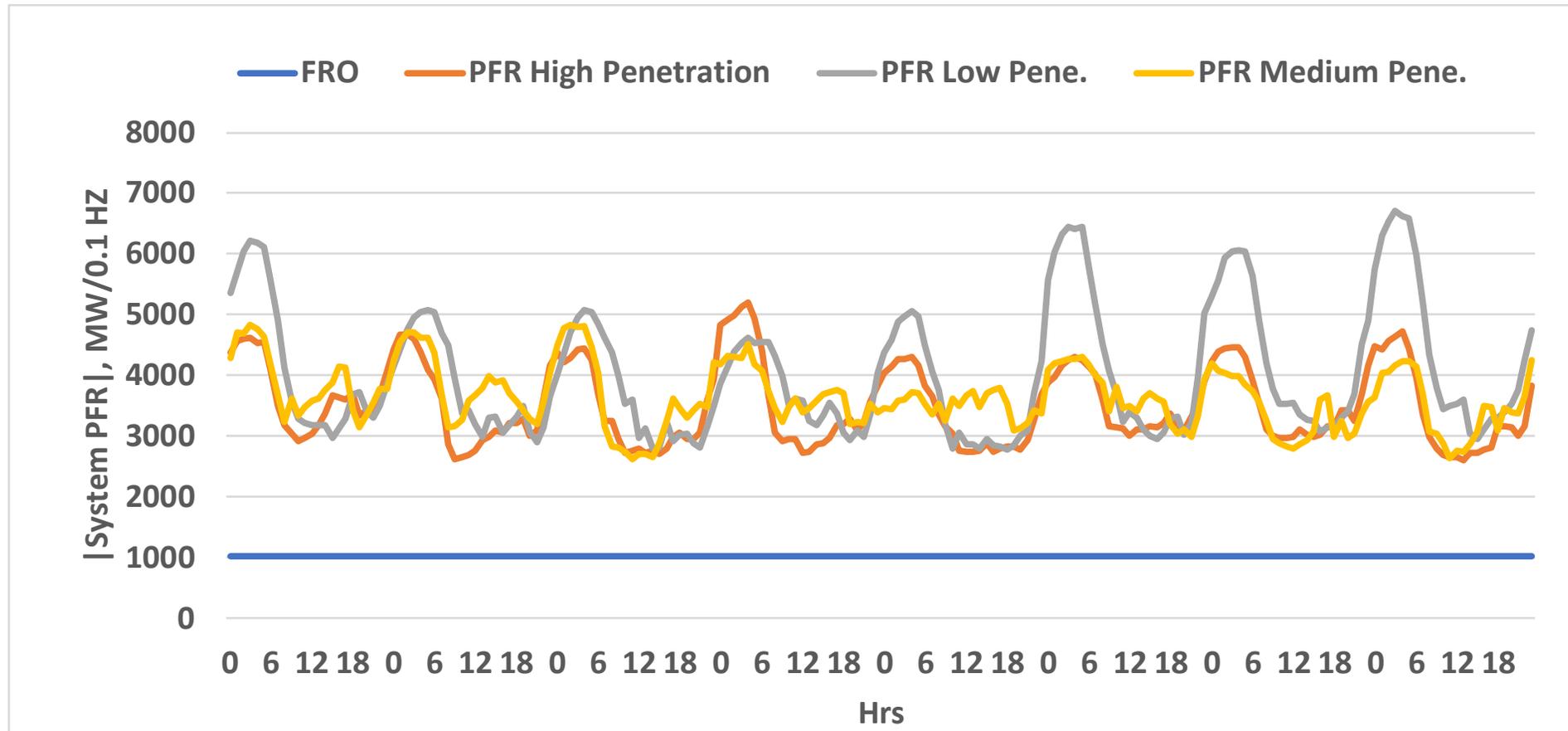
# FRADT: Case Study

*Forward Looking Analysis of Eastern Interconnection (EI) Primary Frequency Response*

- A case study to show how the tool can be used at an interconnection level for forward looking analysis.
  - **Aim of this study is to demonstrate the application. Results have not been vetted and should only be viewed as a way to analyze results of the tool, not as future predictions**
  - Detailed insights on interconnection level results will be provided in 2019.
- Scenarios developed in NREL's Eastern Renewable Generation Interconnection Study (ERGIS) are used in this FRADT case study
  - More details on ERGIS study can be obtained from the NREL website <https://www.nrel.gov/grid/ergis.htm> ; Report: <https://www.nrel.gov/docs/fy16osti/64472.pdf>

# FRADT: Case Study

Application using ERGIS Data - El Primary Frequency Response for -0.1 HZ Frequency Deviation



- The plot shows that EI has adequate PFR for -0.1 Hz frequency deviation, based on the assumptions made

# Conclusions

- Advanced uses of forecasting are being developed in a few areas
  - Use of uncertainty information
  - Development of new operating practices (reserves, frequency response)
- Probabilistic information is beginning to be used for more than situational awareness
- Other operational processes can use VER forecasts and also concepts developed in forecasting area

# Together...Shaping the Future of Electricity