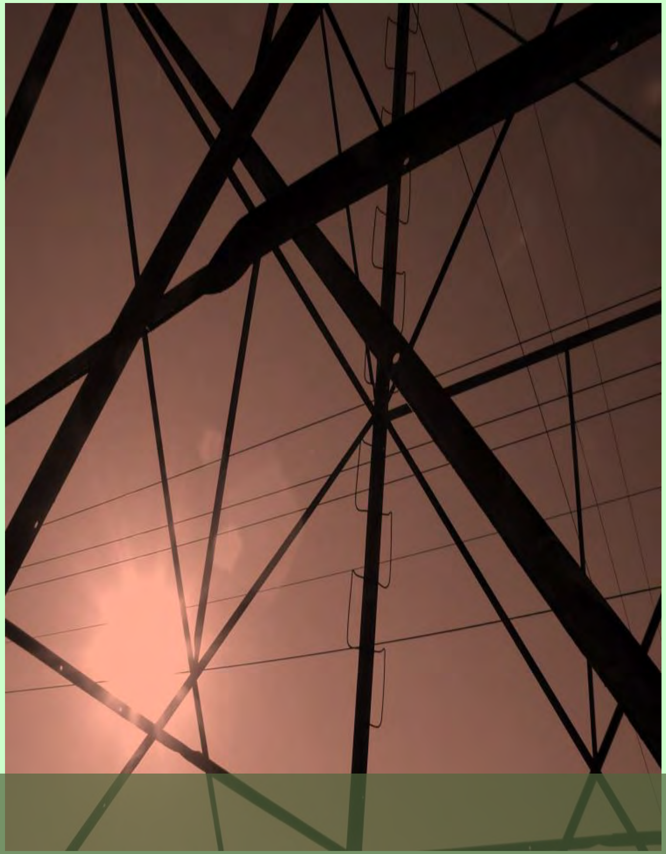
Grid Integration & Modeling Distributed & Variable Renewable Energy Resources



IPU Grid School 2024

June 12, 2024

Institute of Public Utilities

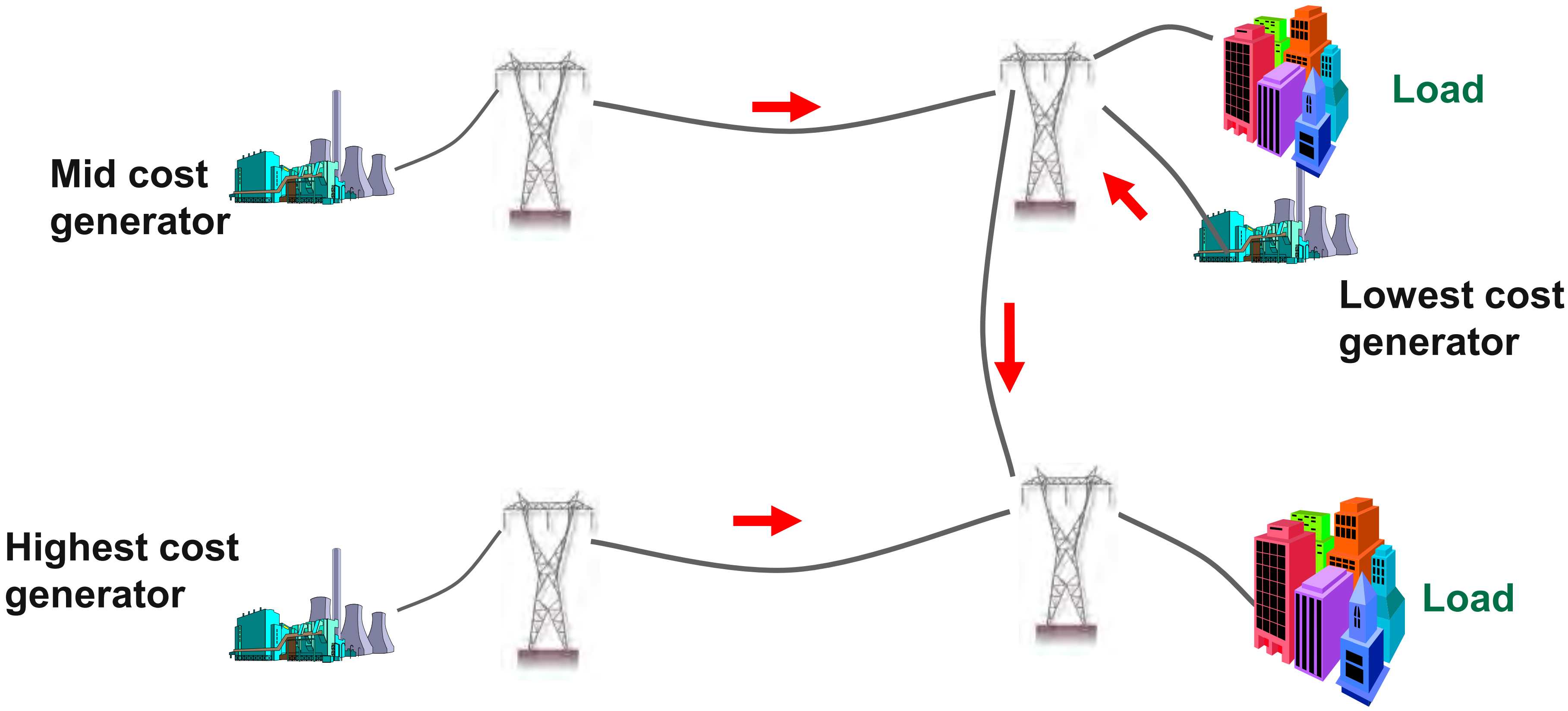
Thomas Veselka

Argonne National Laboratory

MICHIGAN STATE UNIVERSITY

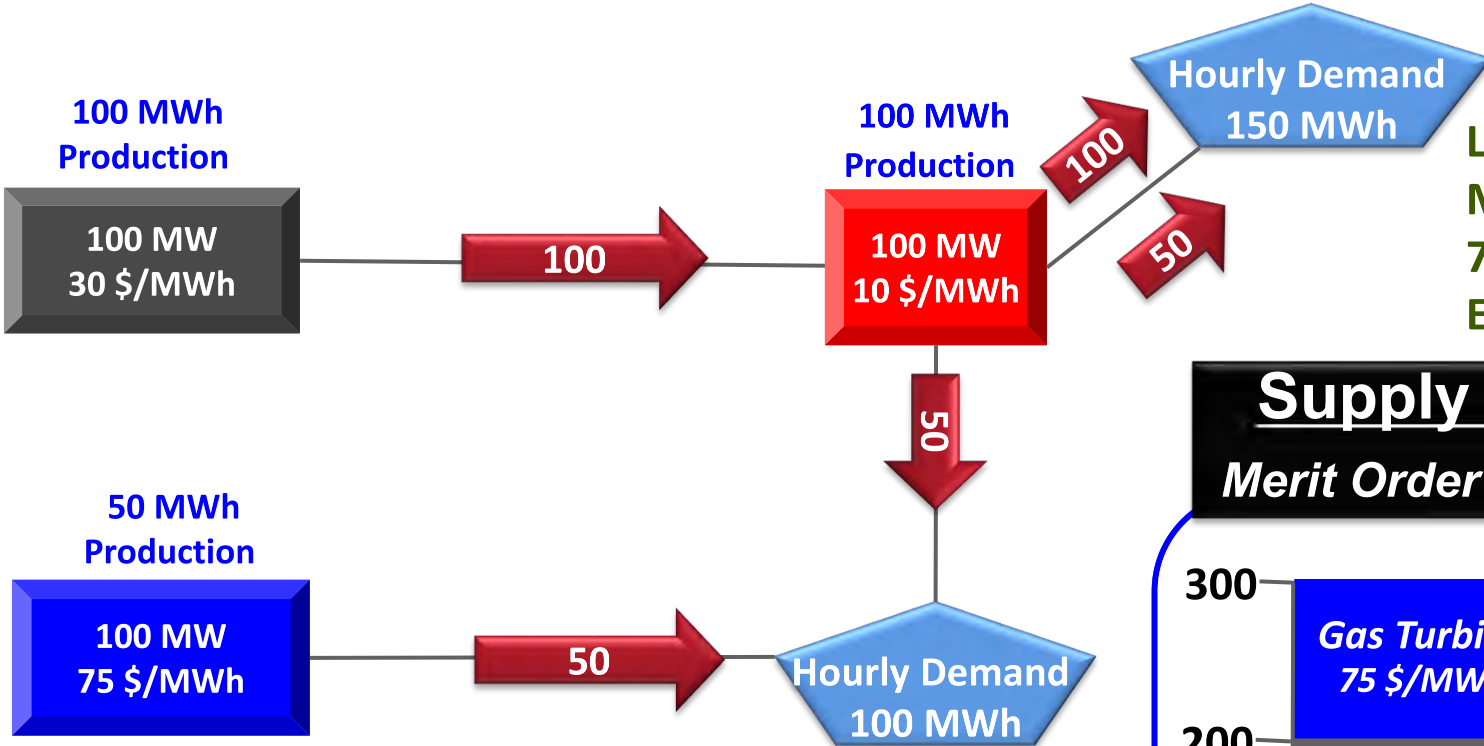
Power Grid Dispatch and Production Costs

In the absence of transmission congestion and transmission losses, low-cost generators are typically deployed first, and expensive generators are used last

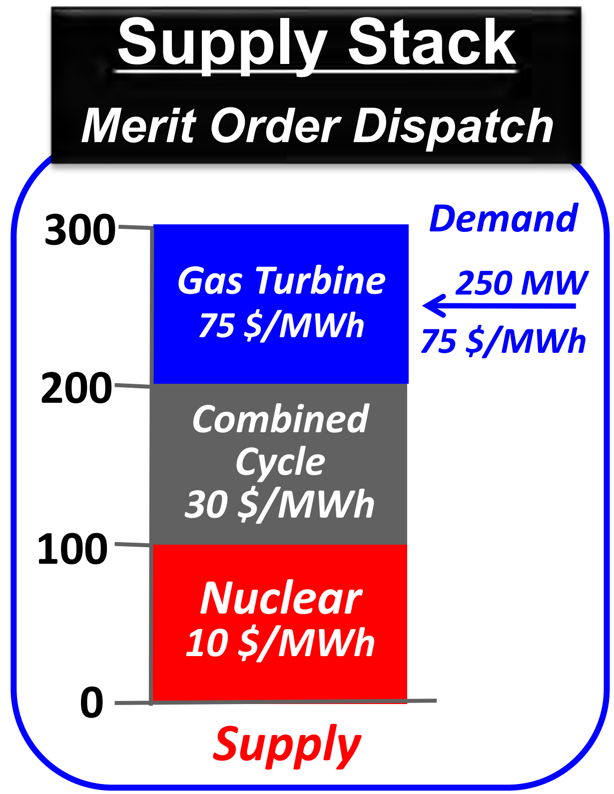


The marginal cost to serve load is the same throughout the system

Example: Dispatch with Demands of 250 MW *without Congestion (Radial Network)*



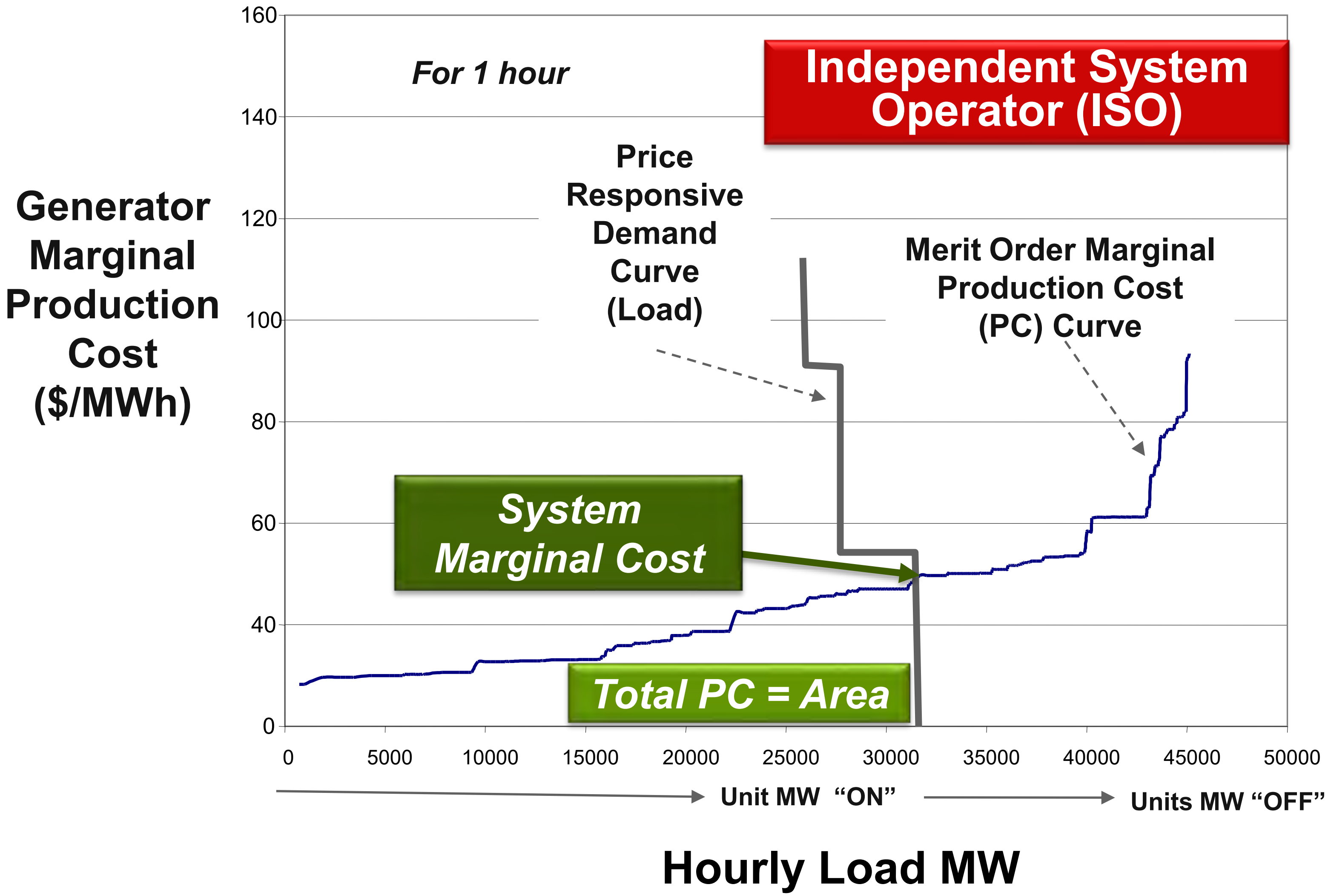
Locational Marginal Price: 75 $/MWh Everywhere



Total Production Cost

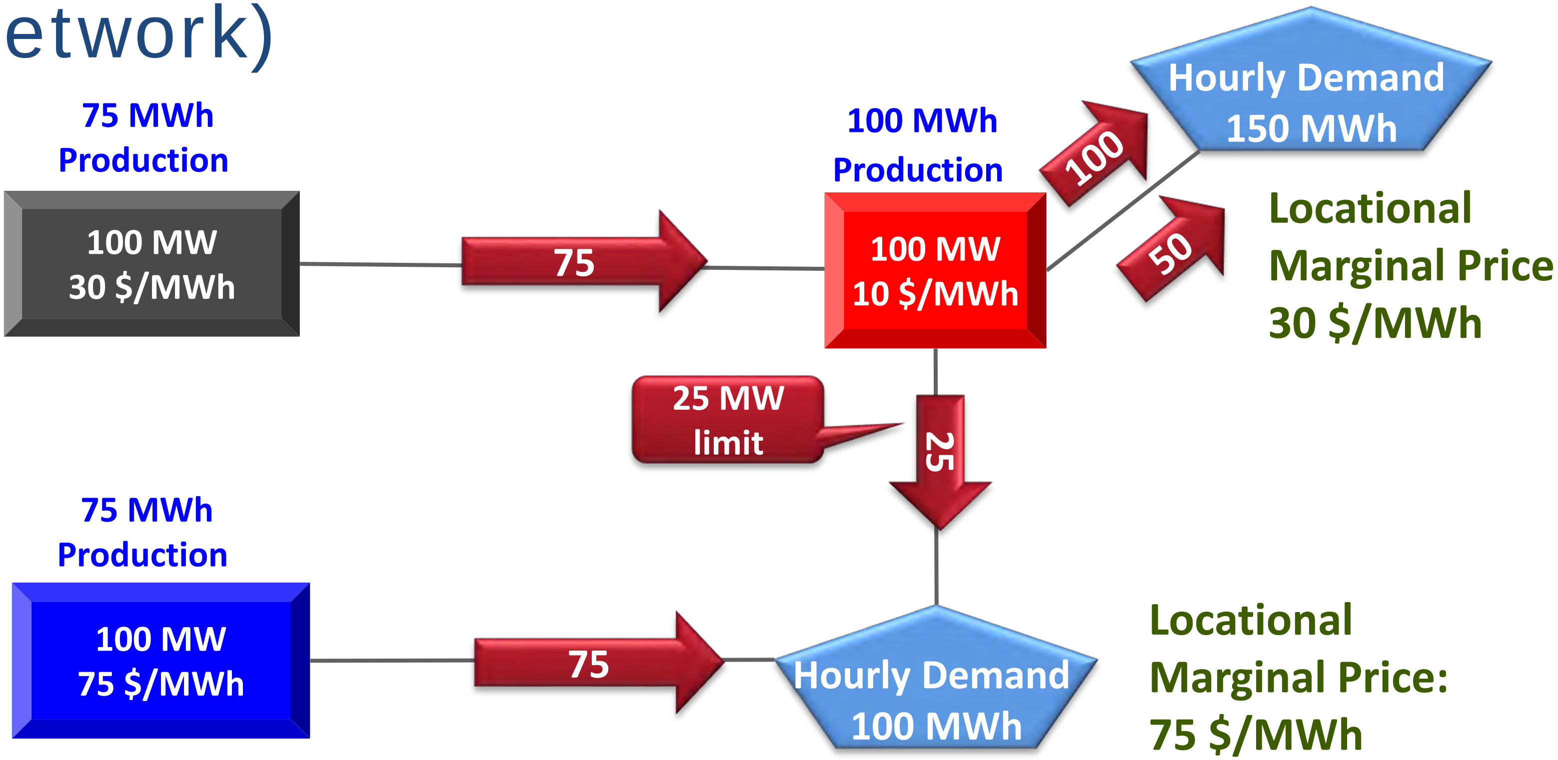
100 MW X 10 $/MWh = 1,000
100 MW X 30 $/MWh = 3,000
50 MW X 75 $/MWh = 3,750
Total = 7,750

In a System without Transmission Congestion and Losses, Marginal System Costs Can Be Computed with Supply and Demand Curves



Example: Loads on all Lines Are less than the Total Transfer Capability of each Line – Unconstrained Dispatch

Dispatch with Demands of 250 MW *with* Congestion (Radial Network)



Dispatch with congestion

Total Production Cost

100 MW X 10 $/MWh = $1,000
75 MW X 30 $/MWh = $2,250
75 MW X 75 $/MWh = $5,625
Total = $8,875

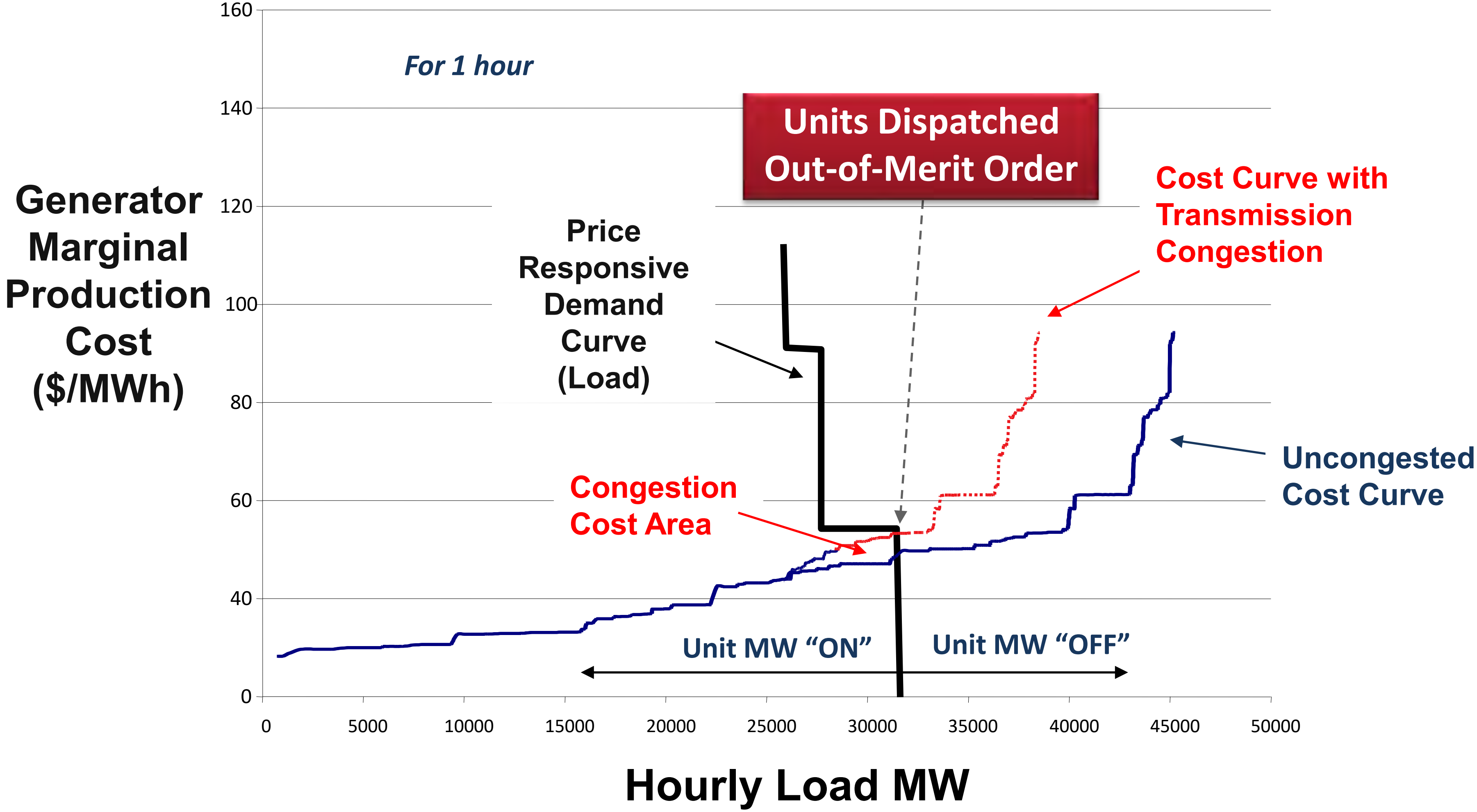
Cost Increase =$1,125

Dispatch without congestion

Total Production Cost

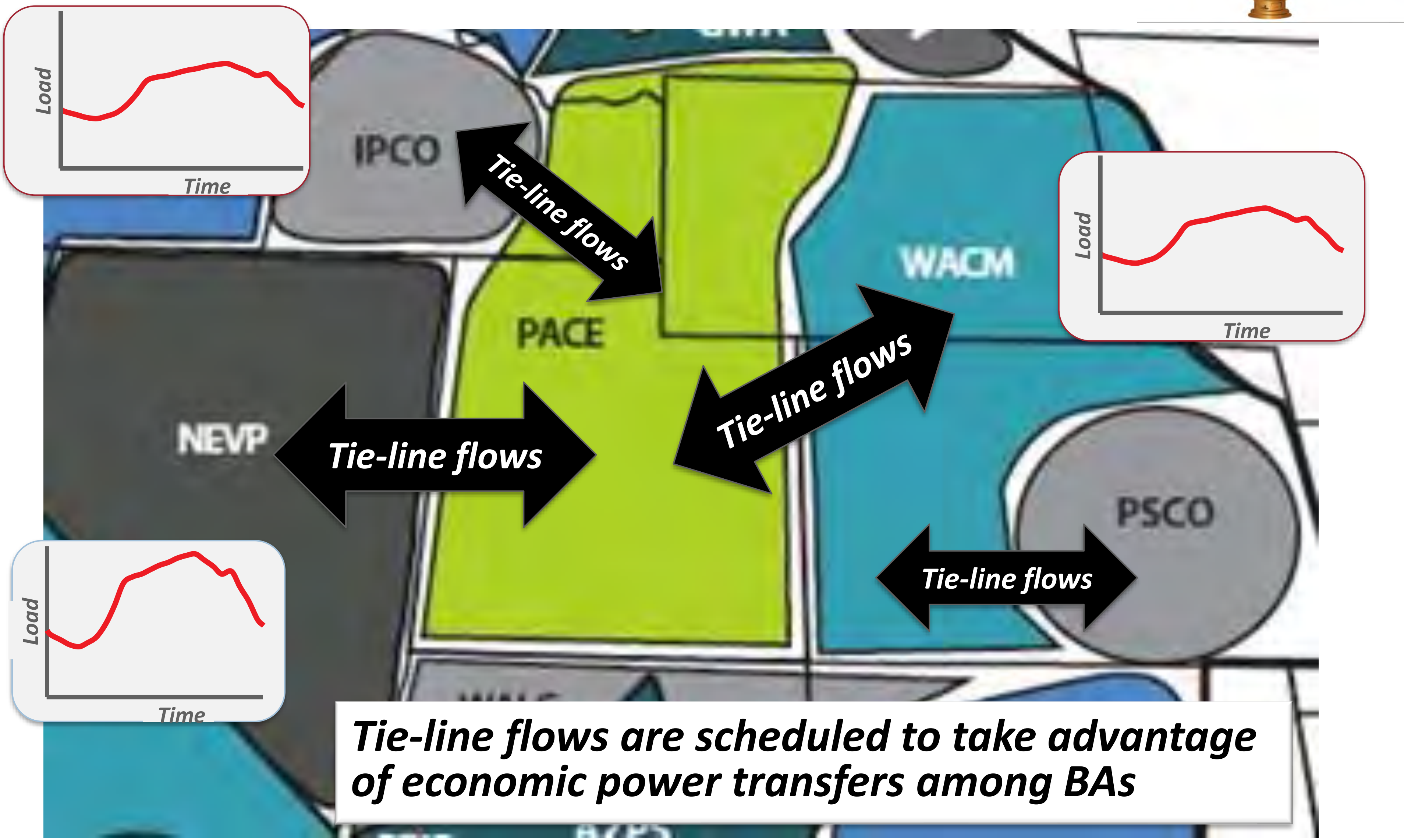
100 MW X 10 $/MWh = $1,000
100 MW X 30 $/MWh = $3,000
50 MW X 75 $/MWh = $3,750
Total = $7,750

Units Are Dispatched Out of Merit Order Because of Transmission Congestion



Transmission congestion alters the unit dispatch and increase grid production cost

A Balancing Authority (BA) Operator Maintains Load and Generation Balance within an Area and Supports Interconnection Frequency in Real-time

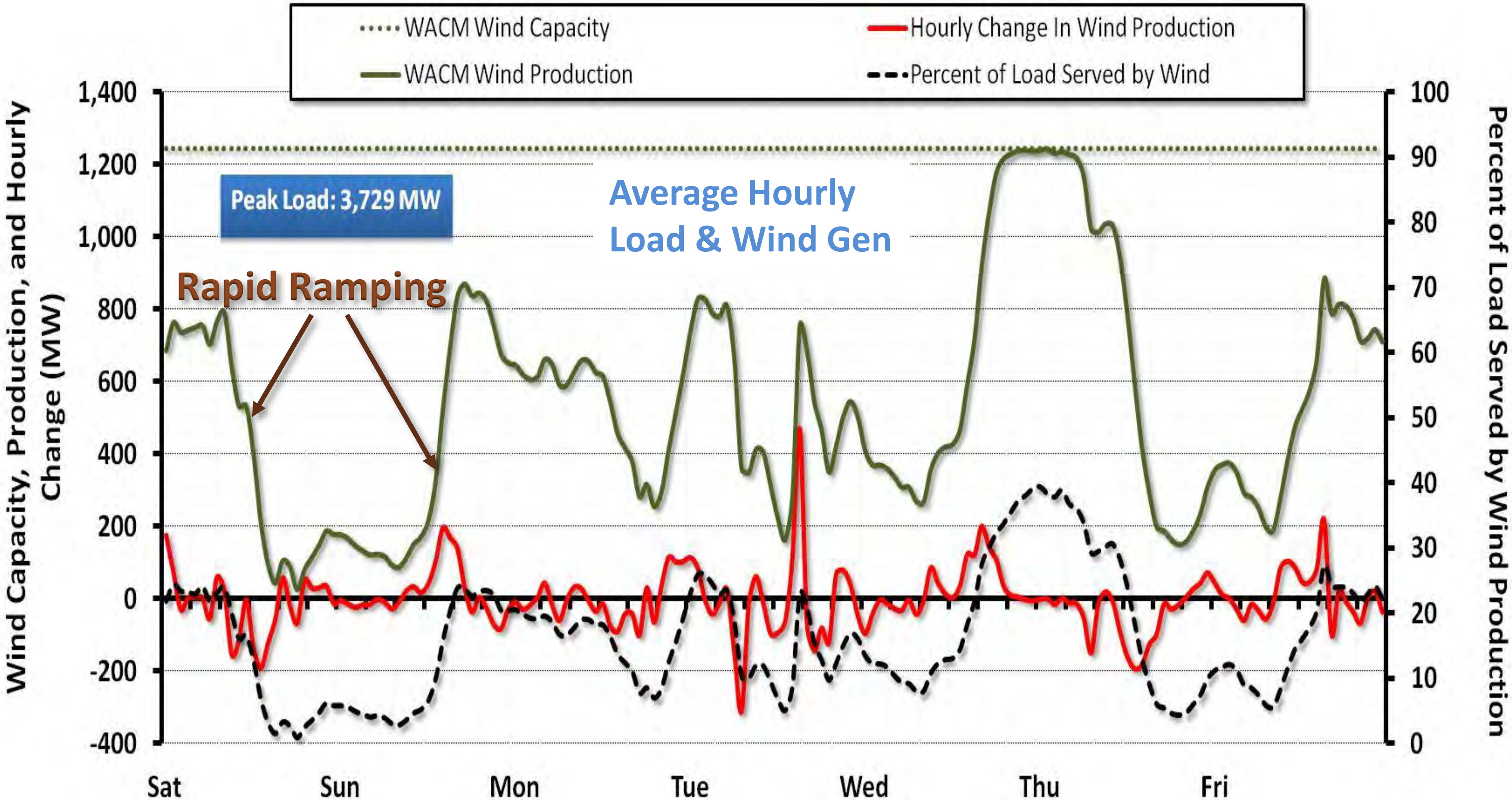


Tie-line flows are scheduled to take advantage of economic power transfers among BAs

Production Fluctuation from Variable Renewable Energy (VRE) Resources

Primarily Wind and Solar Photovoltaic (PV) but also Run-of-river Hydropower

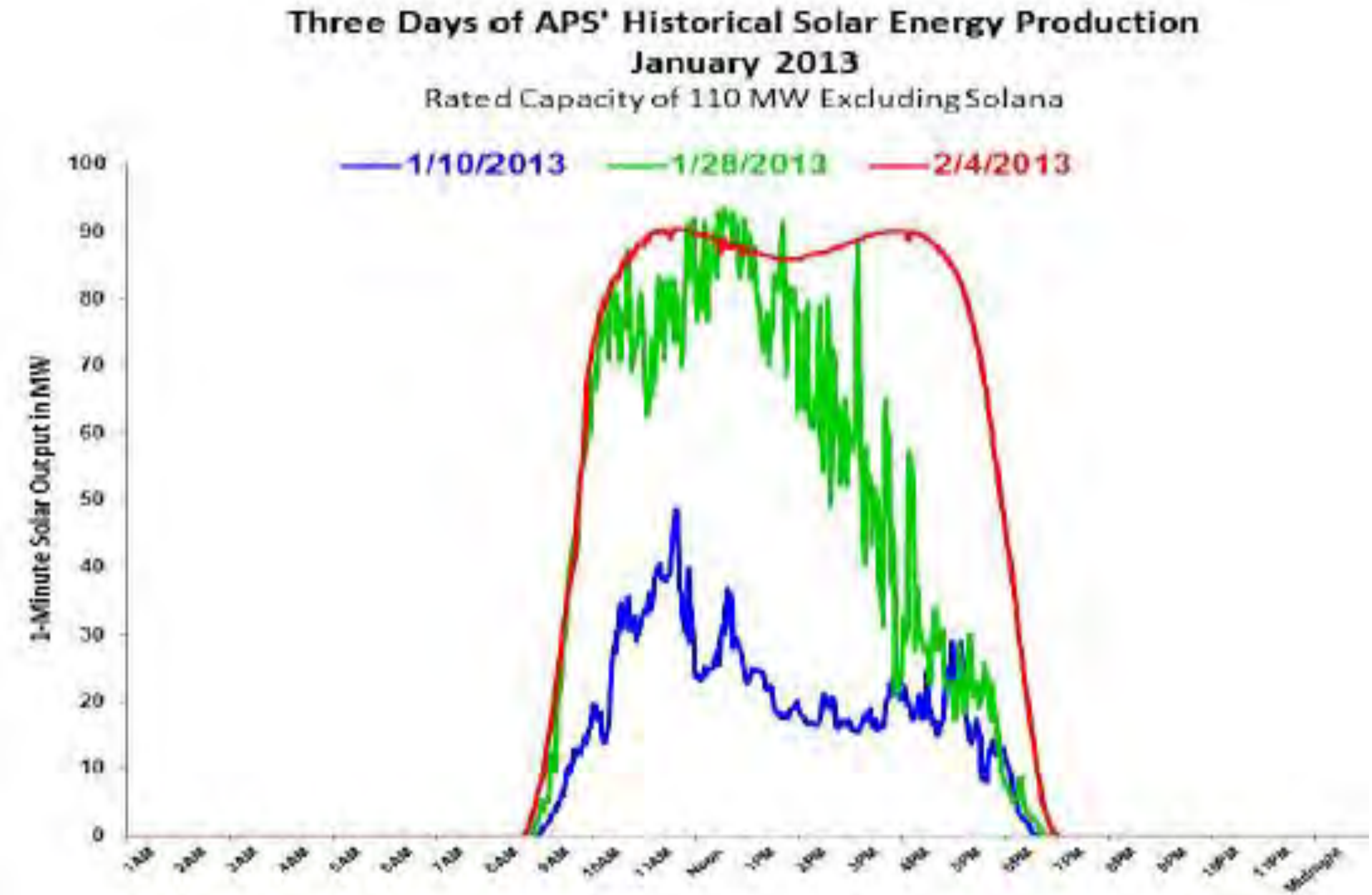
A Major Challenge for Integrating VRE into the Grid Is to Respond to Rapid Fluctuations Production Levels under Uncertain *(Forecasting Error)*



Other generating resources or loads need to adjust quickly

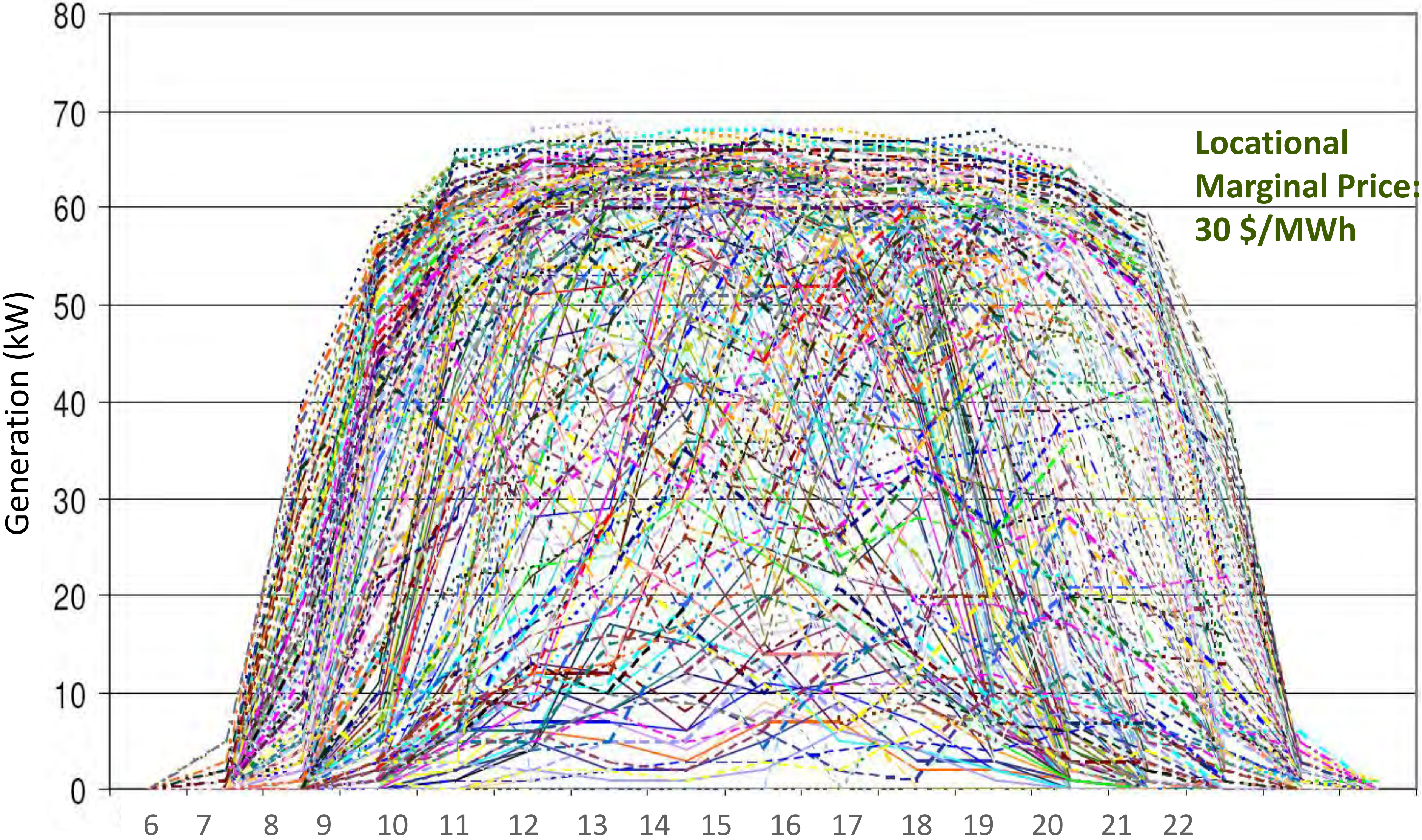
Western Area Power Administration – Colorado-Missouri (WACM)

Arizona Public Service Solar Production



The graph is from an APS presentation given to the Arizona Corporation Commission on 9/11/2014

Historical Photovoltaic Output Ensemble Data for 1 Year

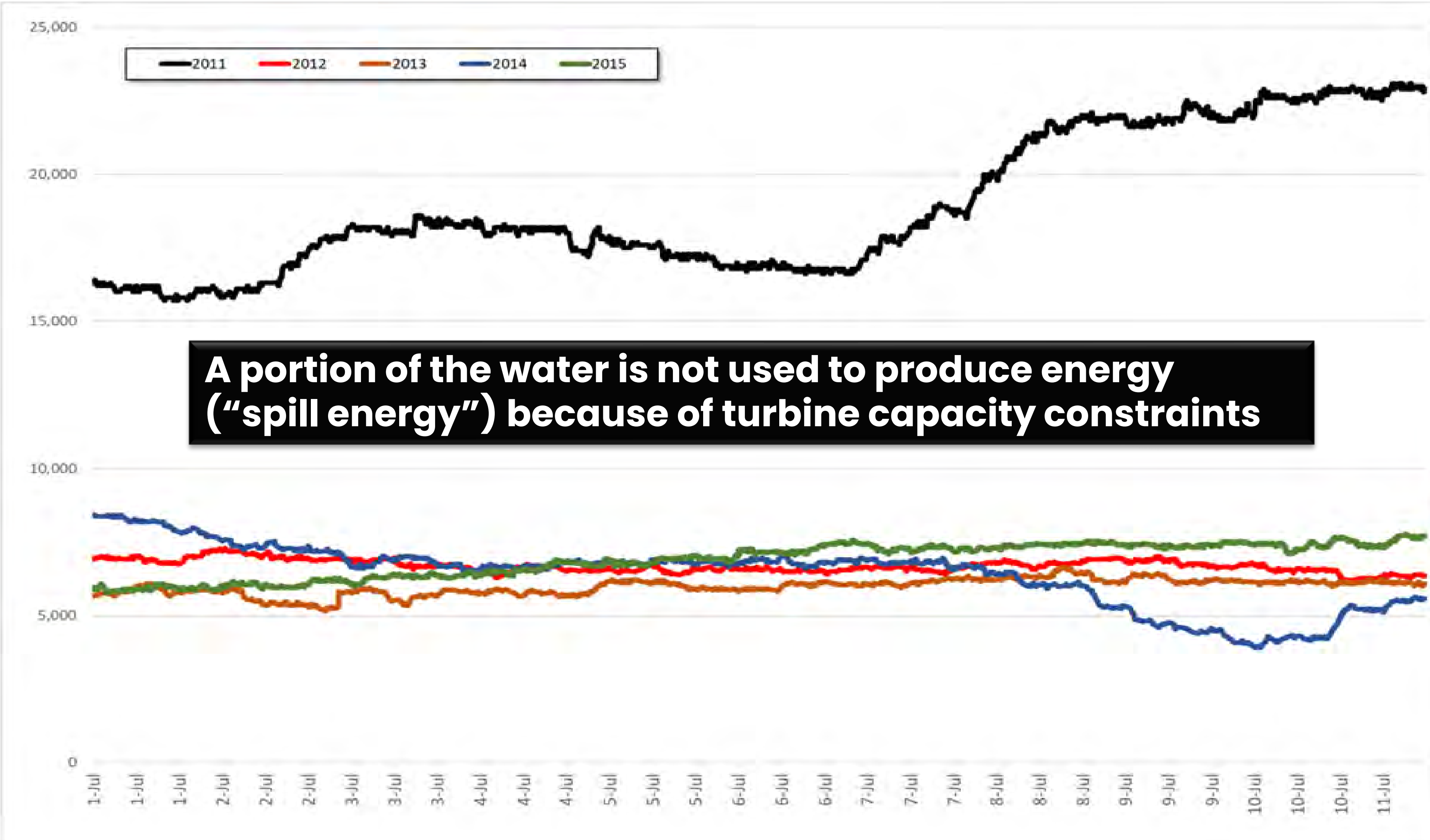


Locational Marginal Price: 30 $/MWh

Source: http://www.icrepq.com/ICREPQ'09/abstracts/520-ramon-abstract.pdf

Run-of-**River Hydropower “the Other VRE”**

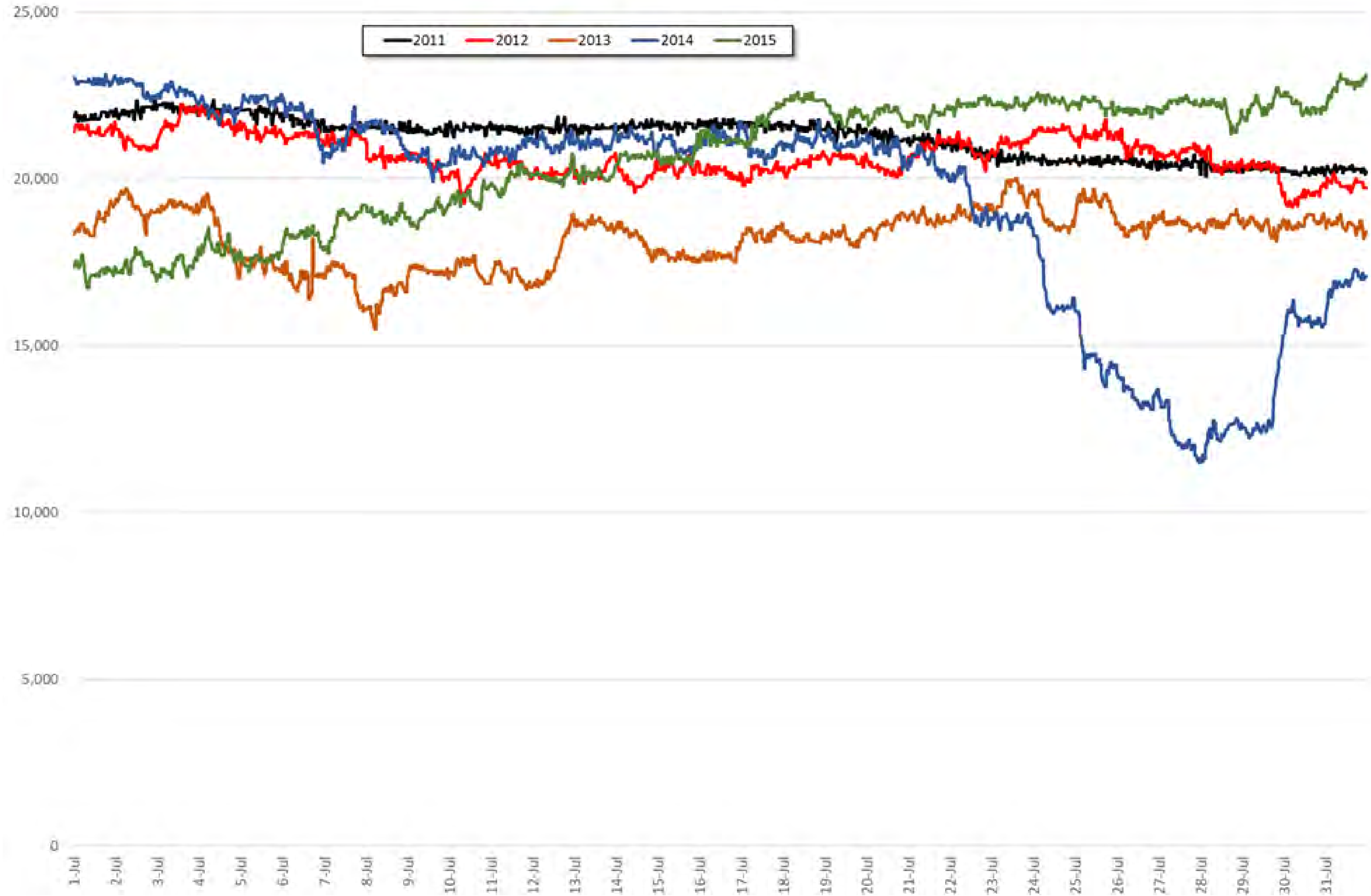
July Flow Rate (cfs) Profiles at Snake River Gauge, 2011-2015



Wind and solar resources may also need to occasionally “spill” energy

Run-of-**River (ROR) Hydropower "the other VRE"**

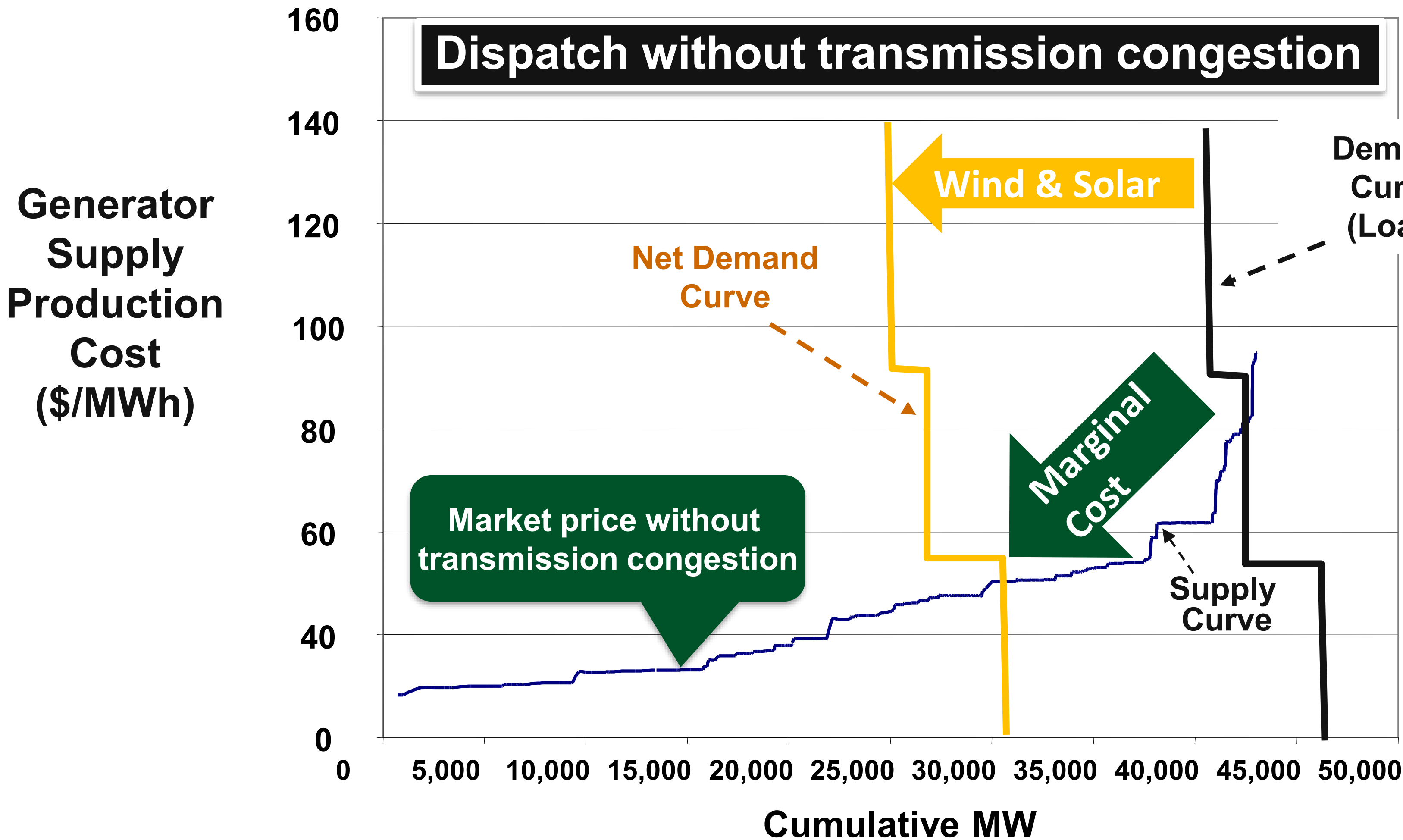
July Power Production (W) Profiles (Snake River ROR Plant), 2011-2015



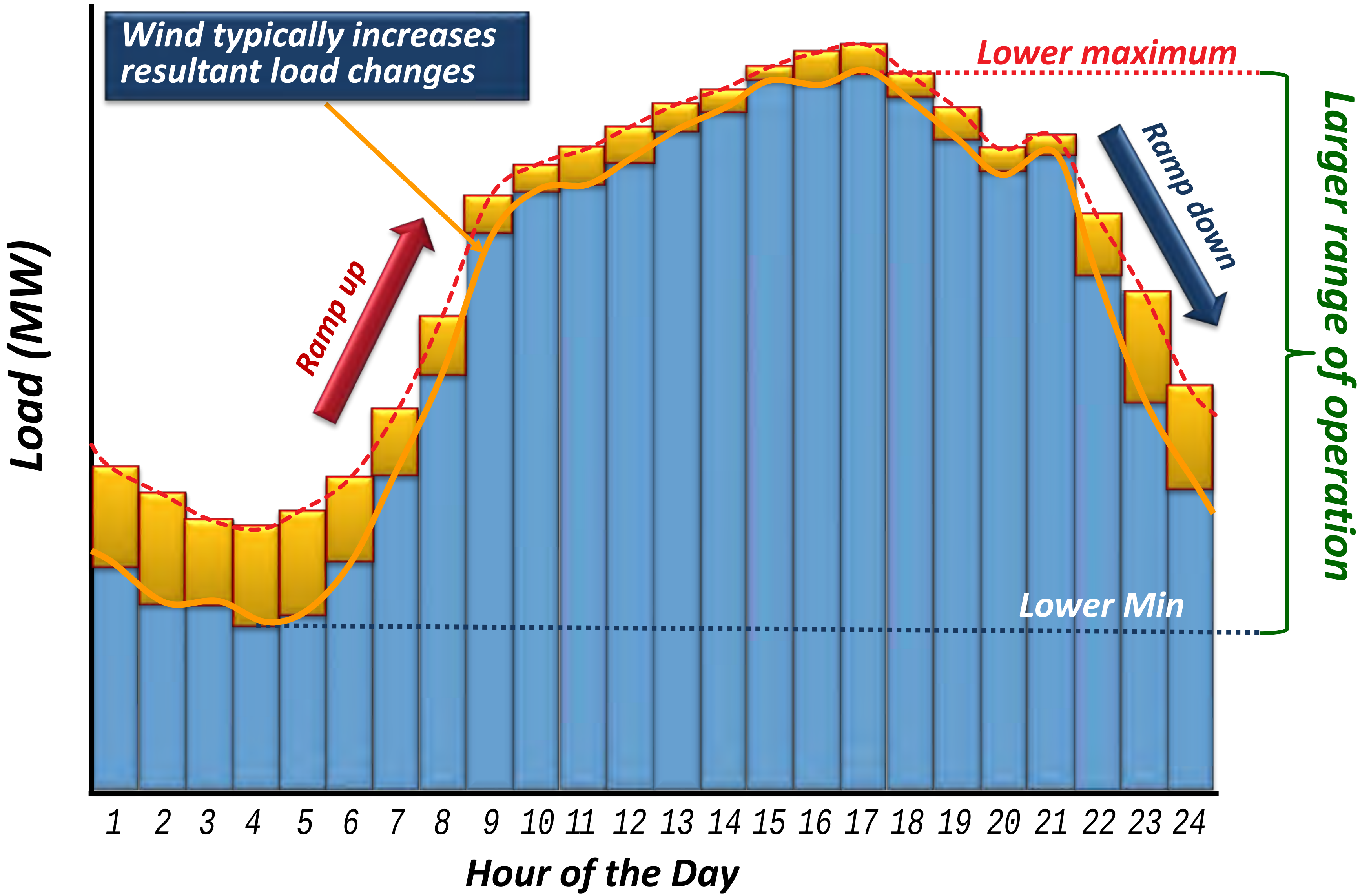
Net Loads

Load - VRE Resource Generation

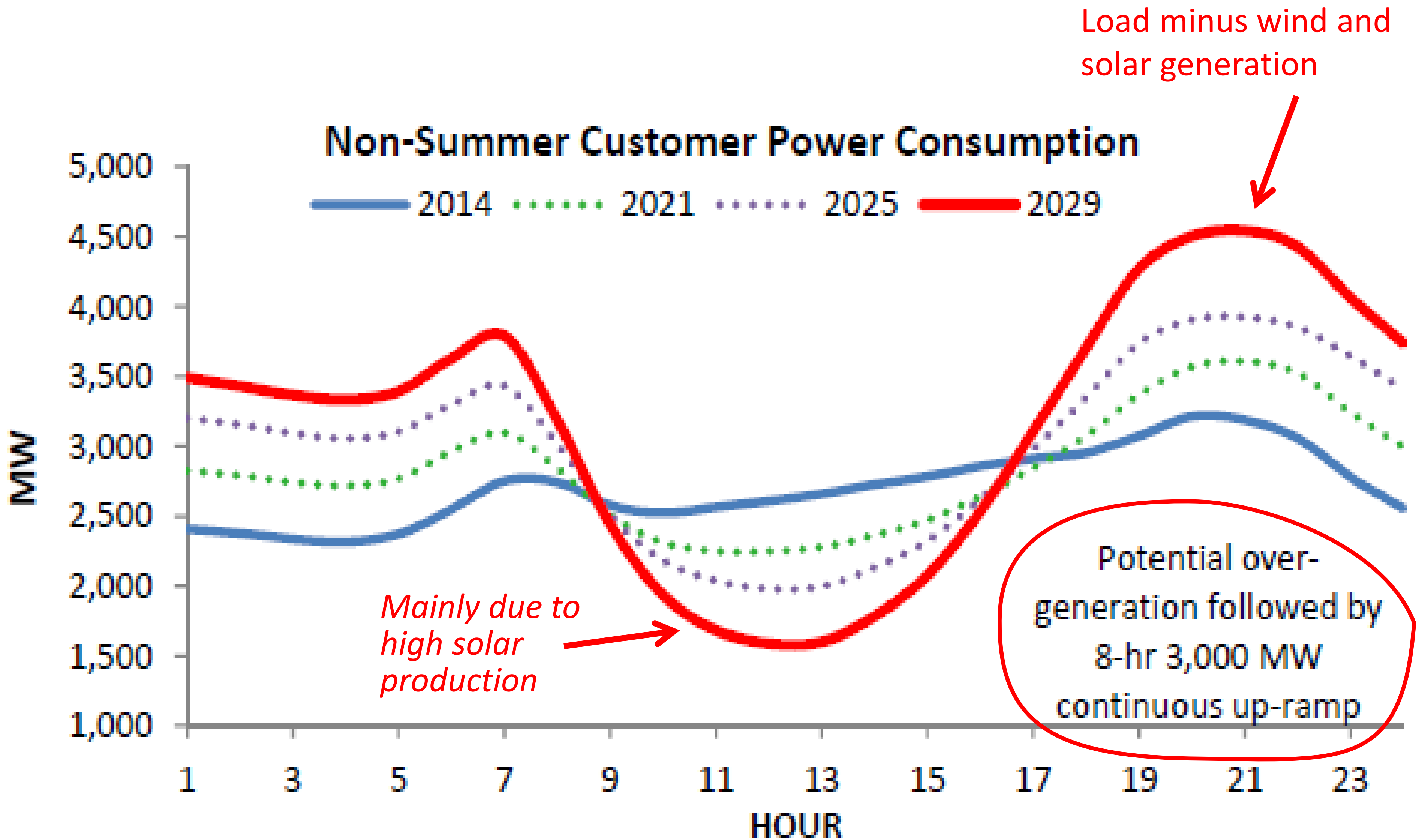
Wind and Solar Production Tend to, but not Always, Reduce both Marginal and Total Production Costs



Dispatchable Units Serve a Load Profile that Typically, but not always, Has Greater Fluctuations Relative to the Case where there Is no Wind

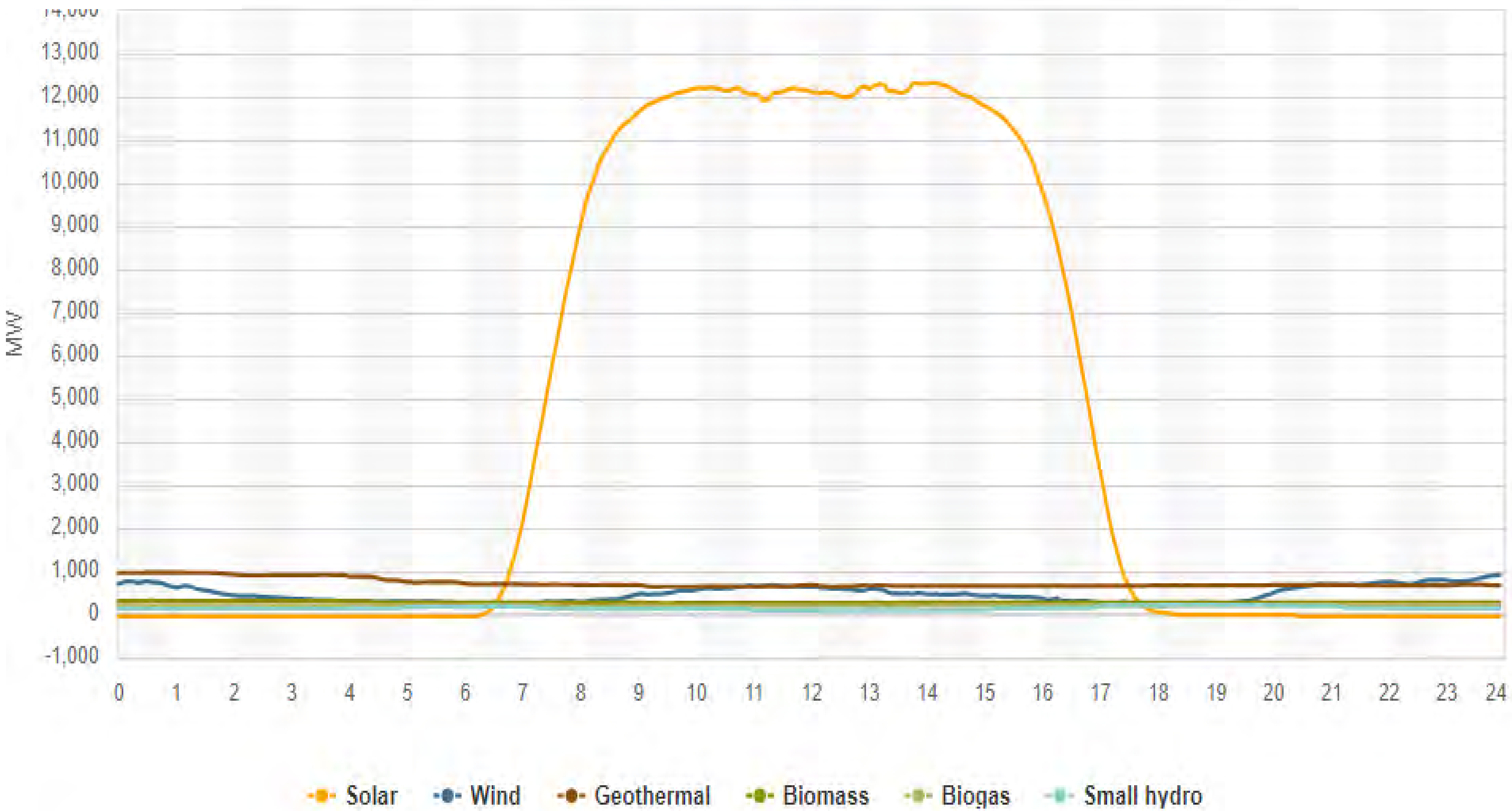


Arizona Public Service Solar Production



The graph is from an APS presentation given to the Arizona Corporation Commission on 9/11/2014

CAISO Renewable Energy Generation Profile
March 1, 2021

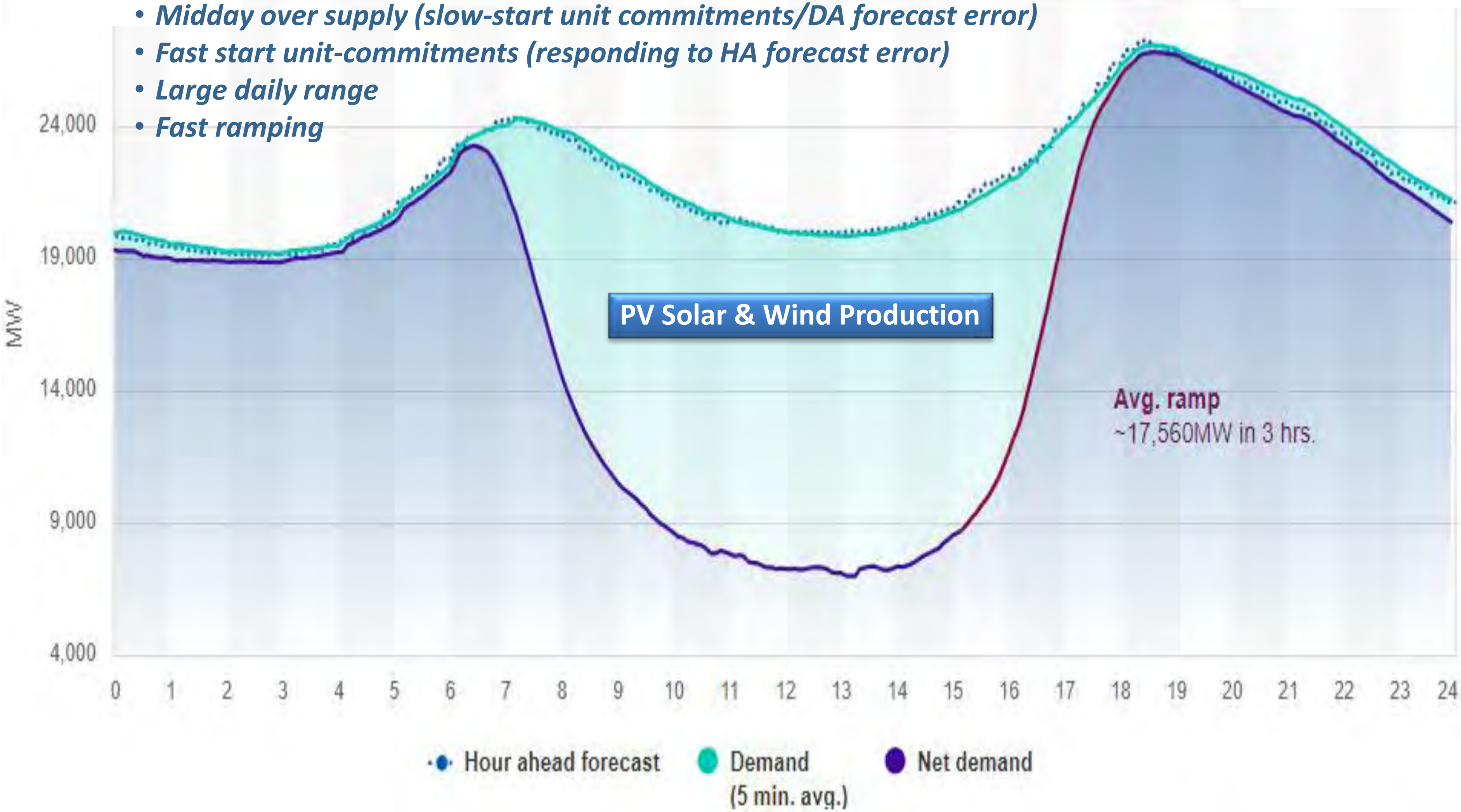


http://www.caiso.com/TodaysOutlook/Pages/supply.aspx

CAISO Net Demand Profile, *March 1, 2021*

Operating Challenges

- *Unit commitments (min/max gen)*
- *Midday over supply (slow-start unit commitments/DA forecast error)*
- *Fast start unit-commitments (responding to HA forecast error)*
- *Large daily range*
- *Fast ramping*



http://www.caiso.com/TodaysOutlook/Pages/supply.aspx

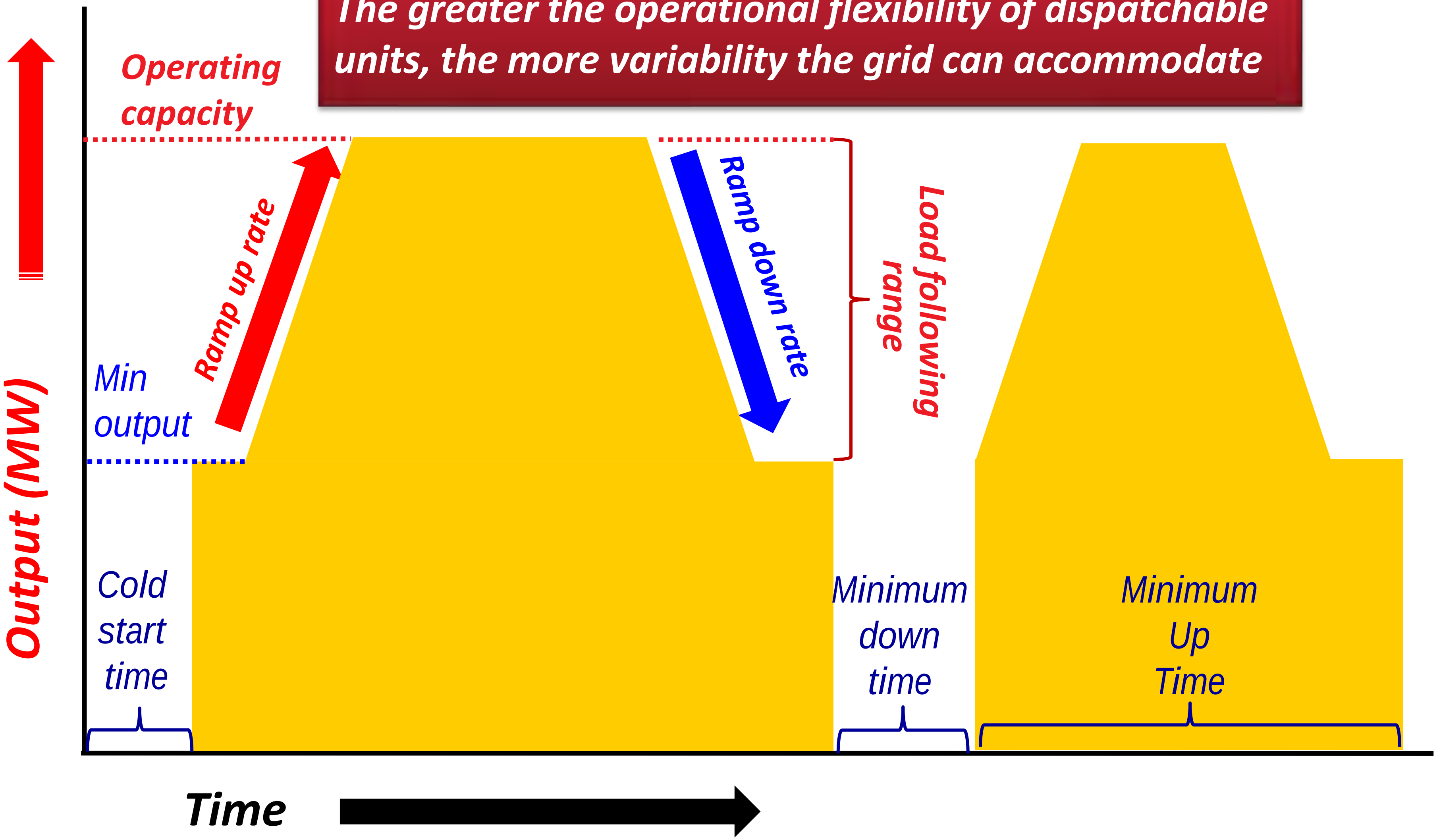
Thermal Generation Resources

Ability to Respond to Temporal Changes in Net Load

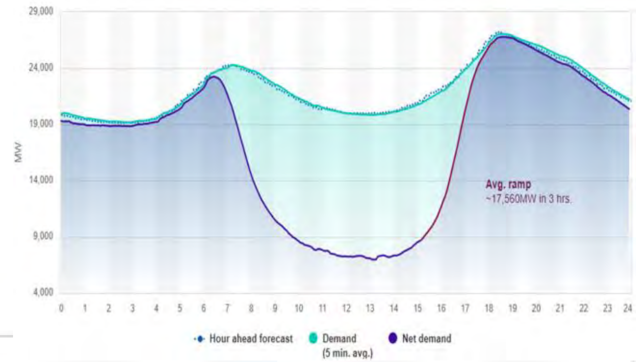
Operational Flexibility

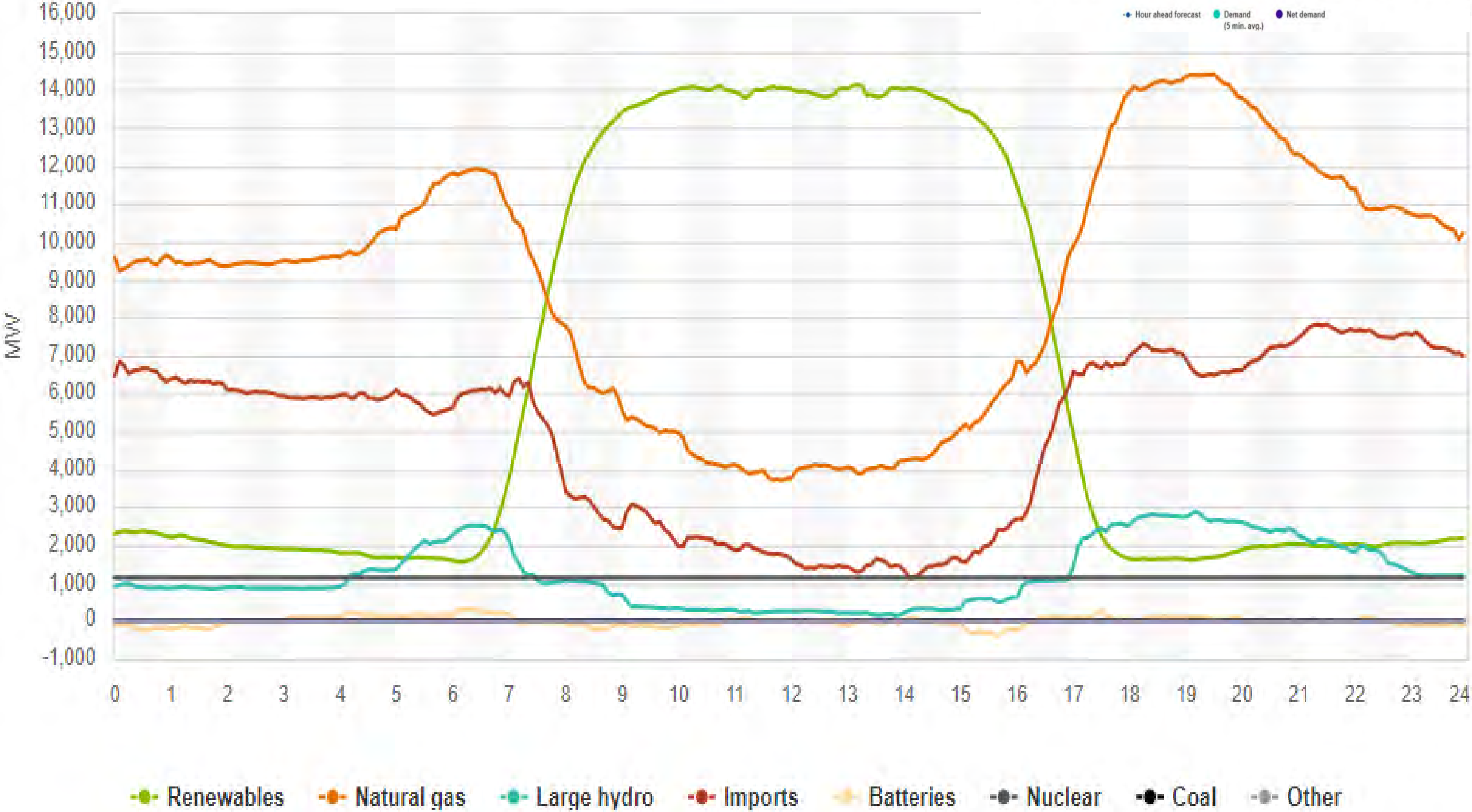
Changes in Net Load Are Mainly Resolved by Adjusting Thermal Unit and Hydroelectric Power Plant Outputs

The greater the operational flexibility of dispatchable units, the more variability the grid can accommodate



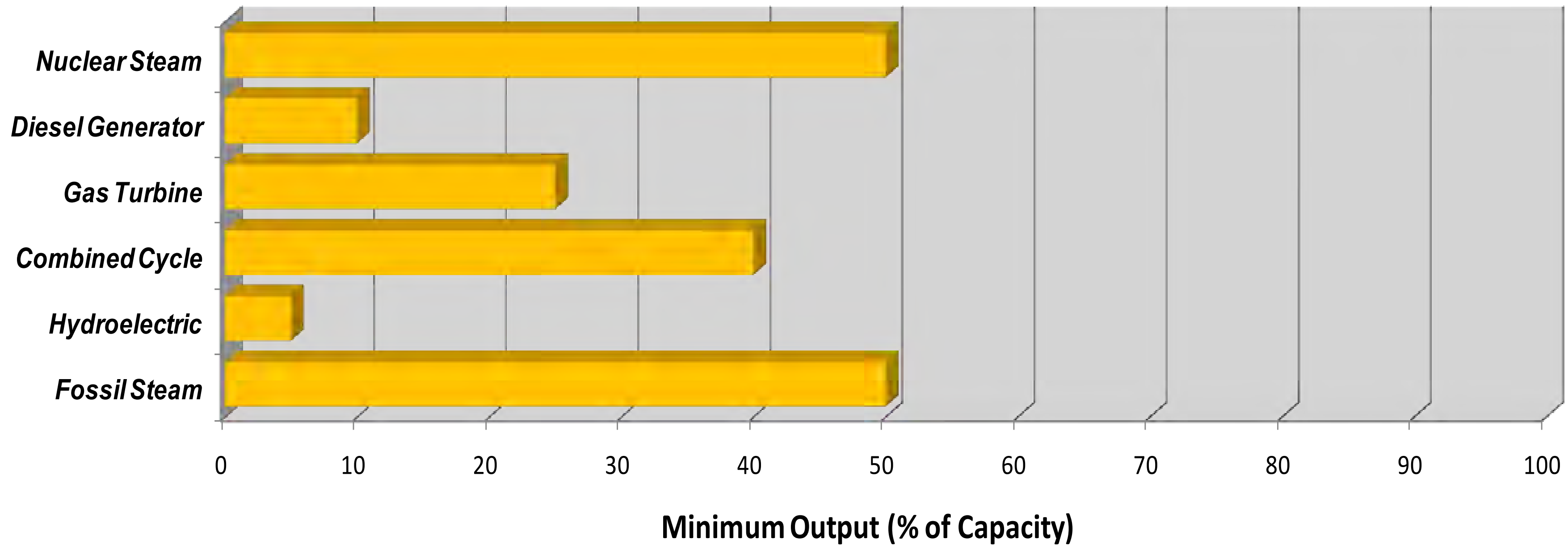
CAISO Generation Profile
March 1, 2021

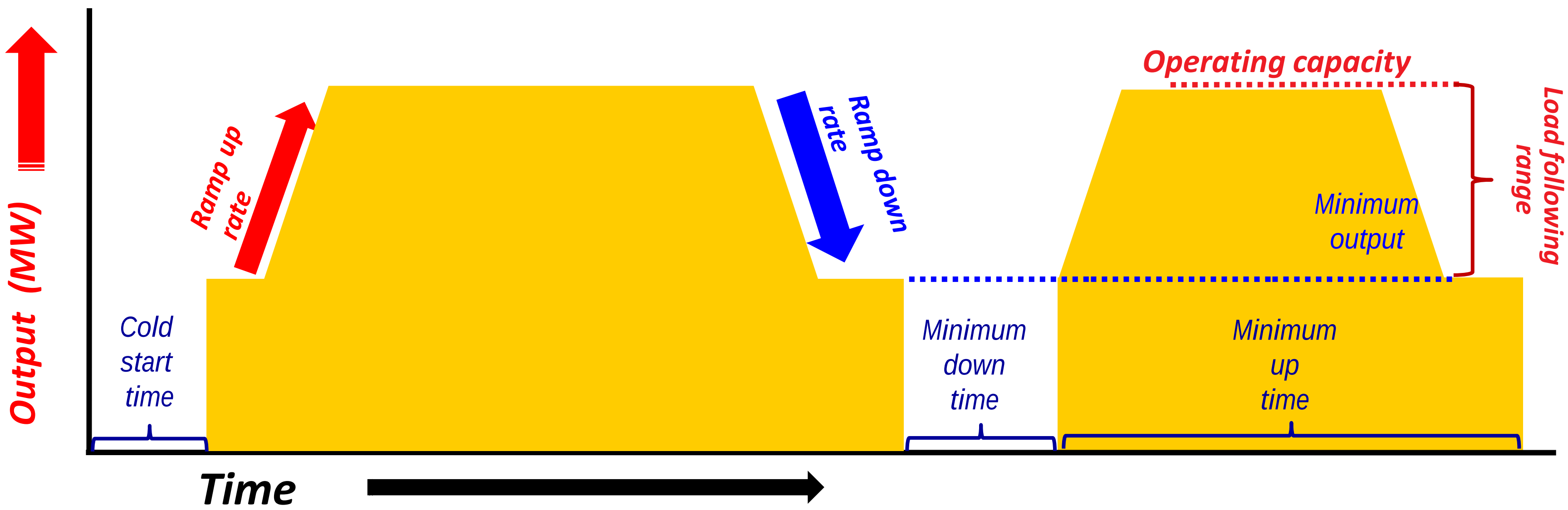




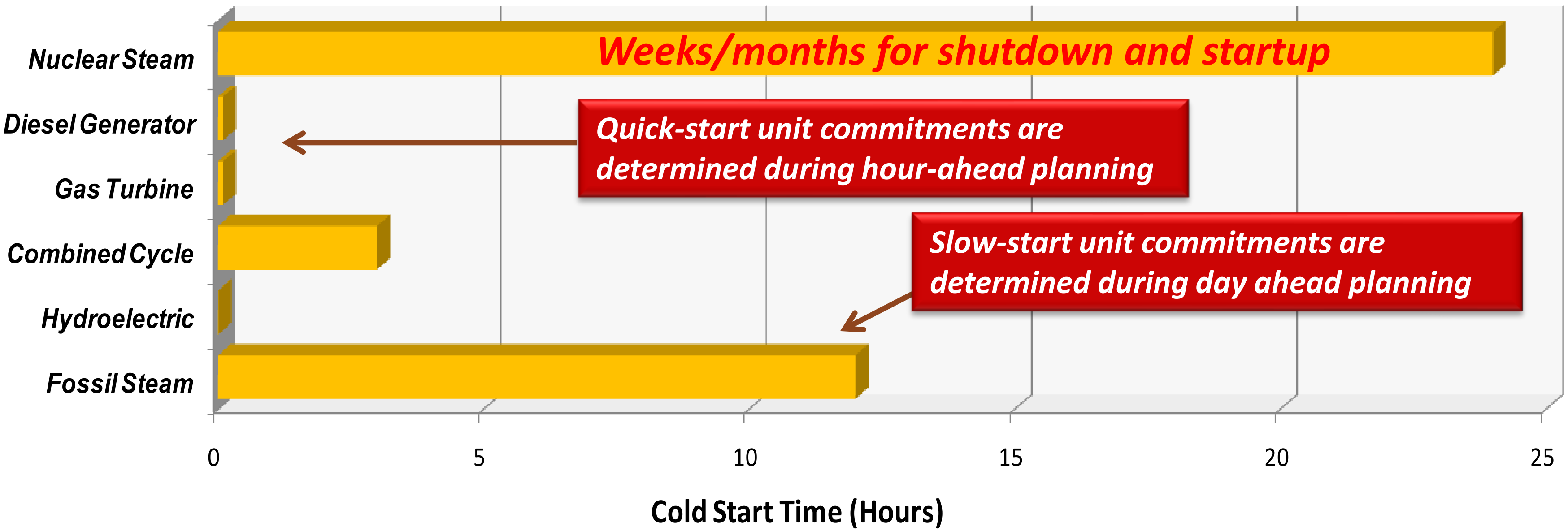
http://www.caiso.com/TodaysOutlook/Pages/supply.aspx

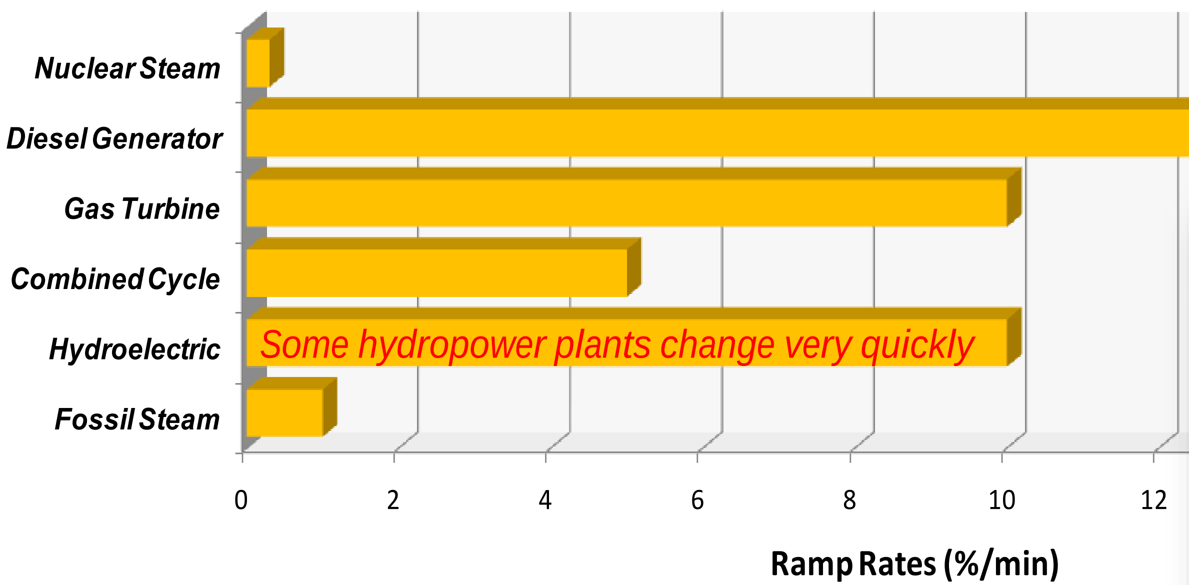
Net Load Following Is Restricted by the Unit's Output
Range and Ramp Rate Limts

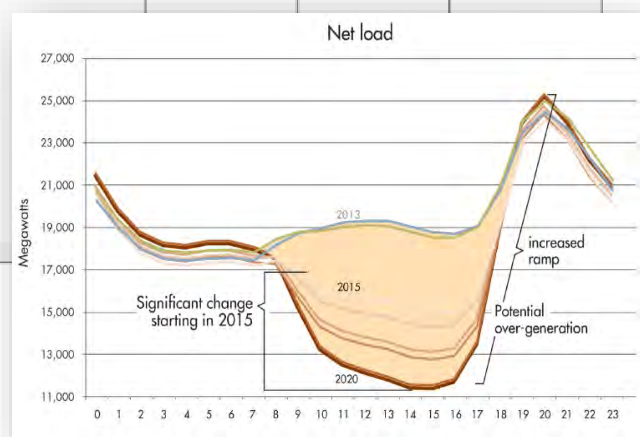




Some Technologies Are Able to Come On-line Quickly to Respond to Rapid Load Changes while Others Are Less Flexible

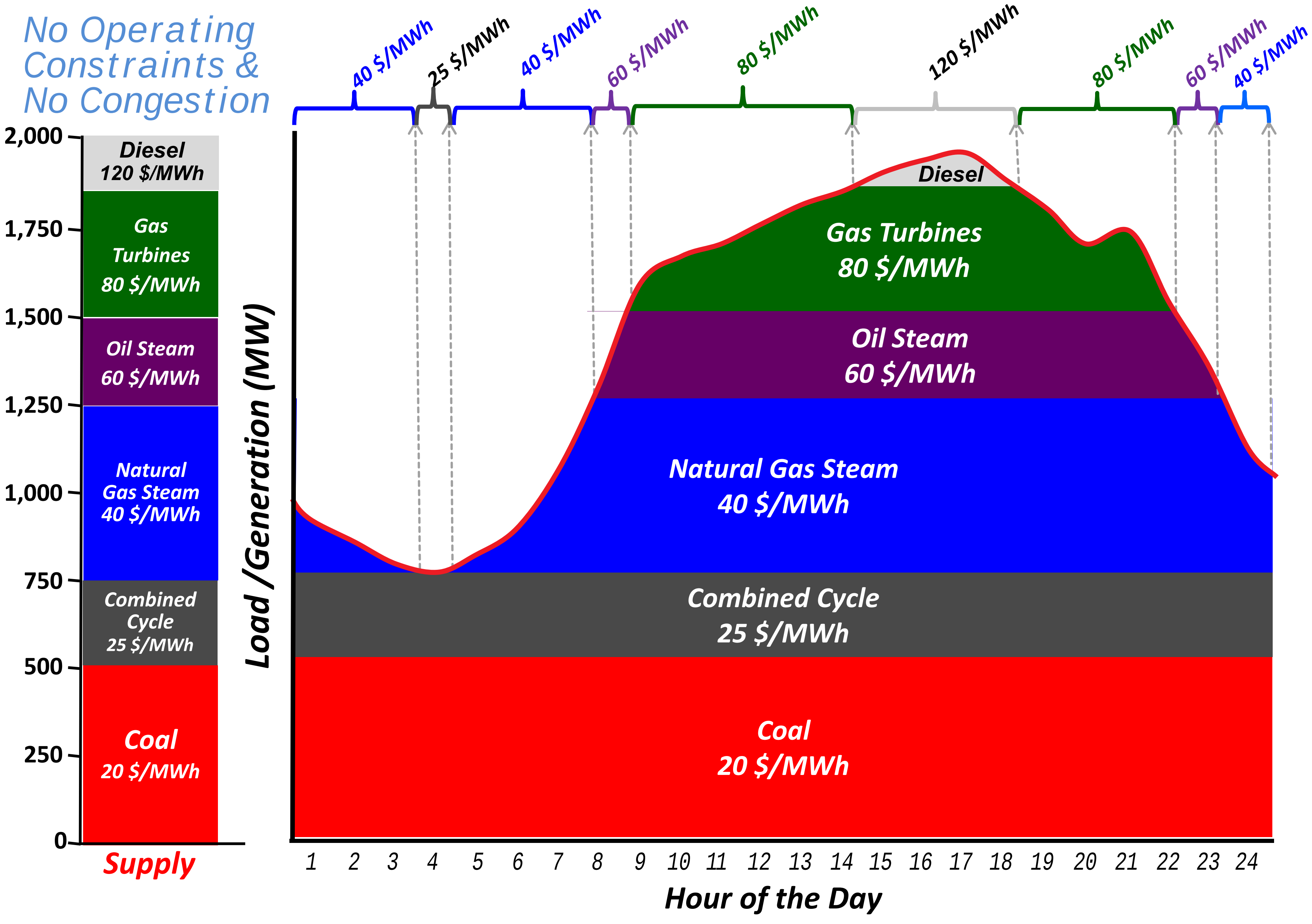




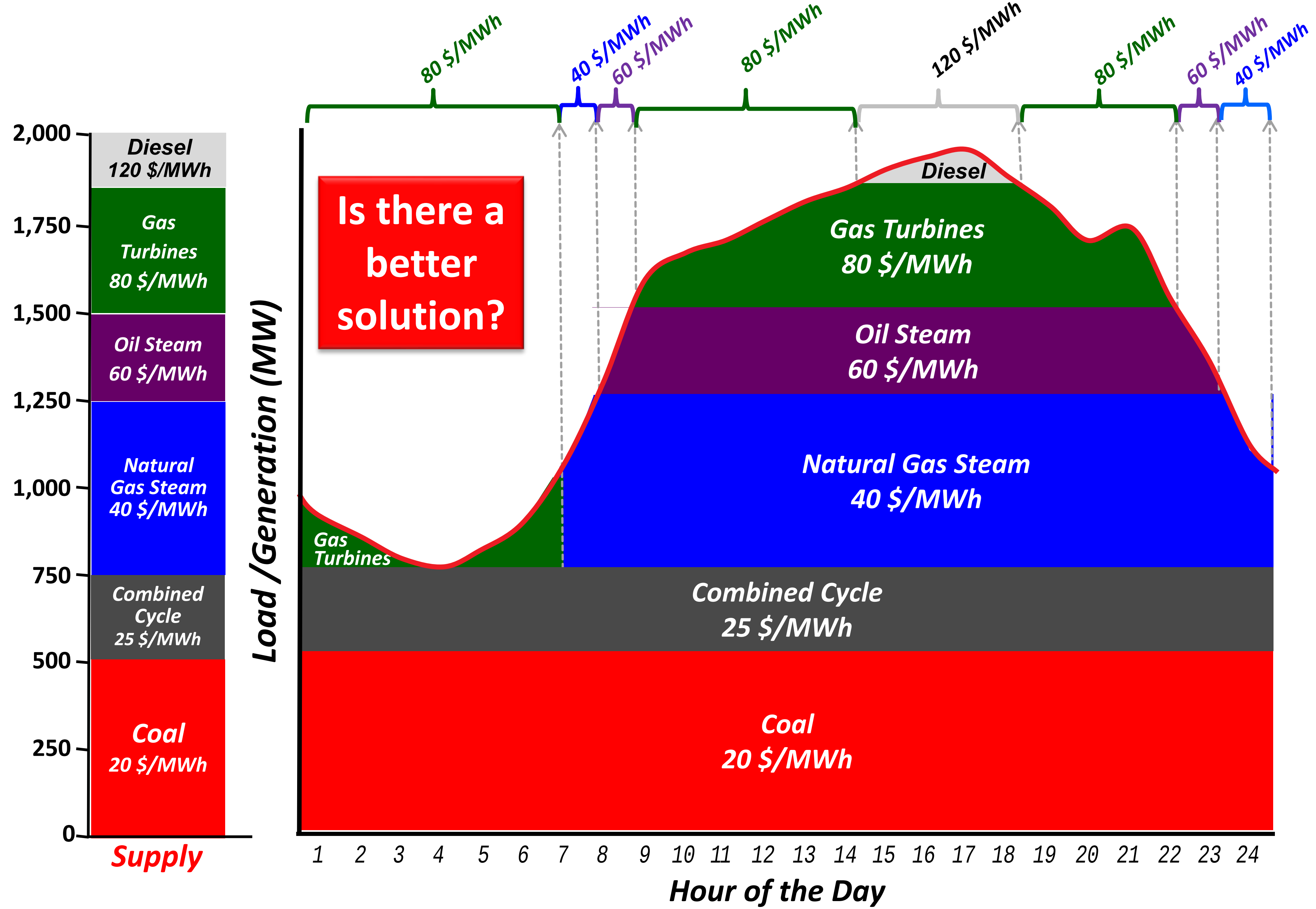


Ideally, Units Are Dispatched Based on Production Cost

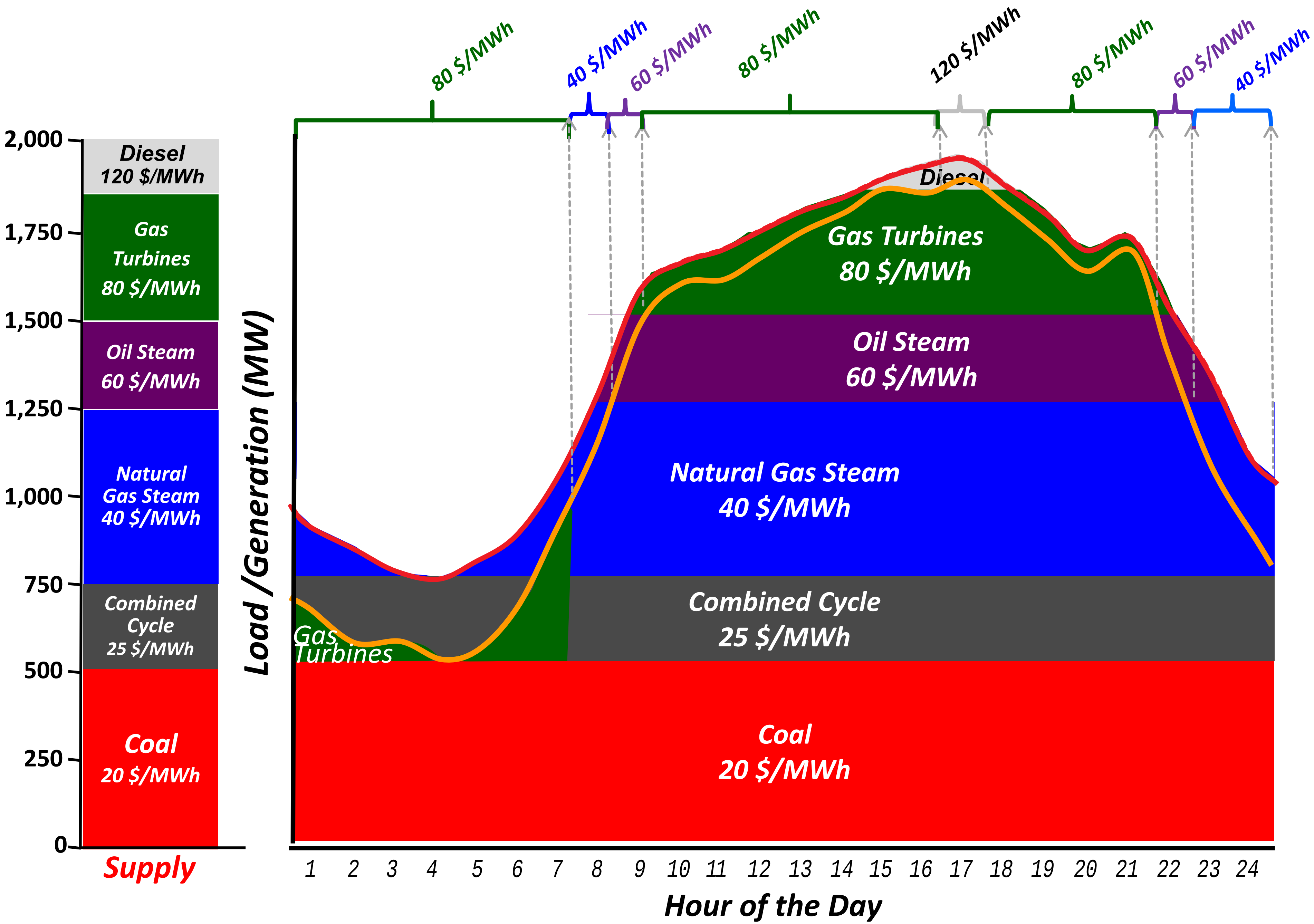
No Operating Constraints & No Congestion



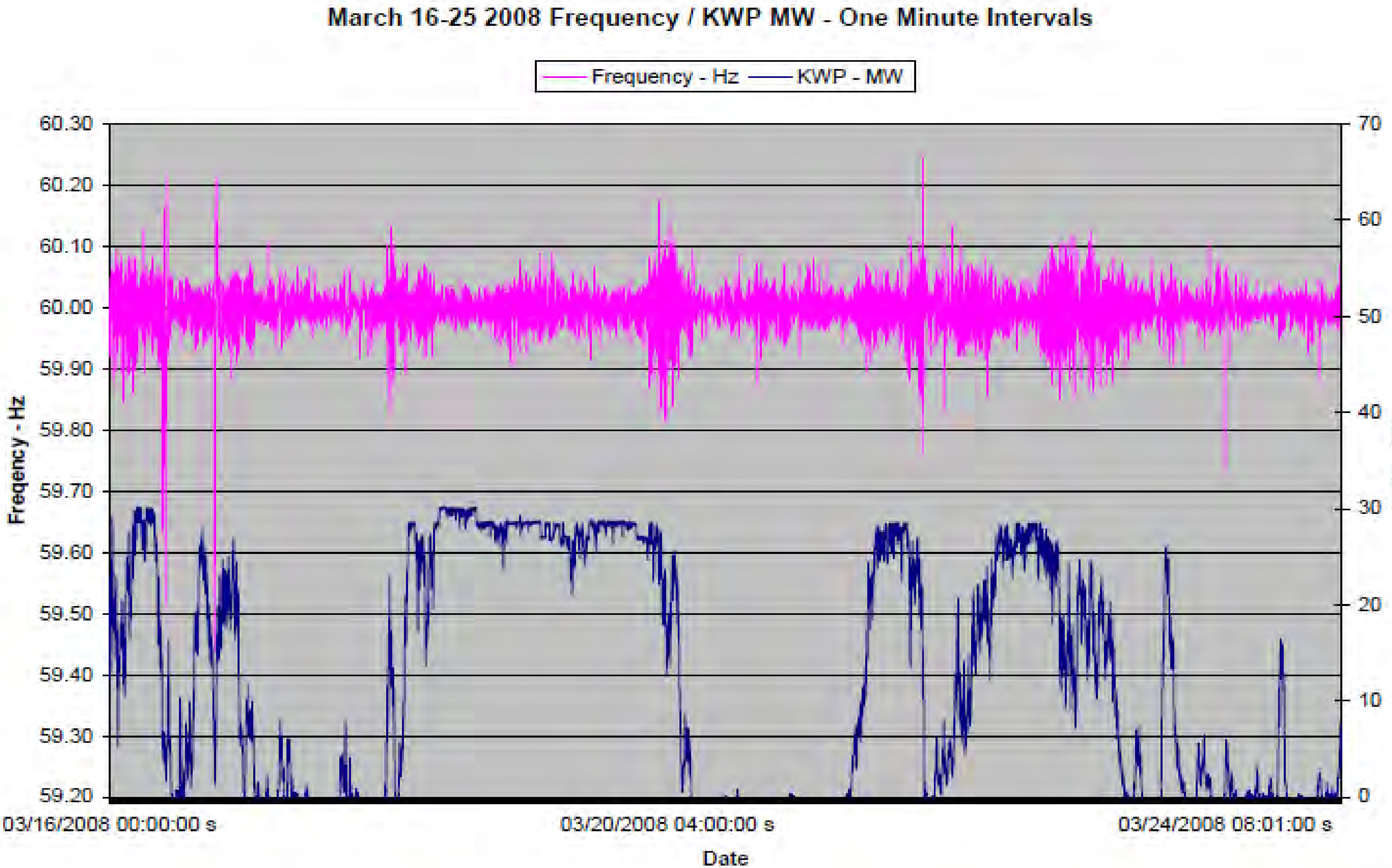
A Steam Plant Does not Have the Flexibility to Operate at a Low Level



Cost Typically Decrease at Different Levels During a Day

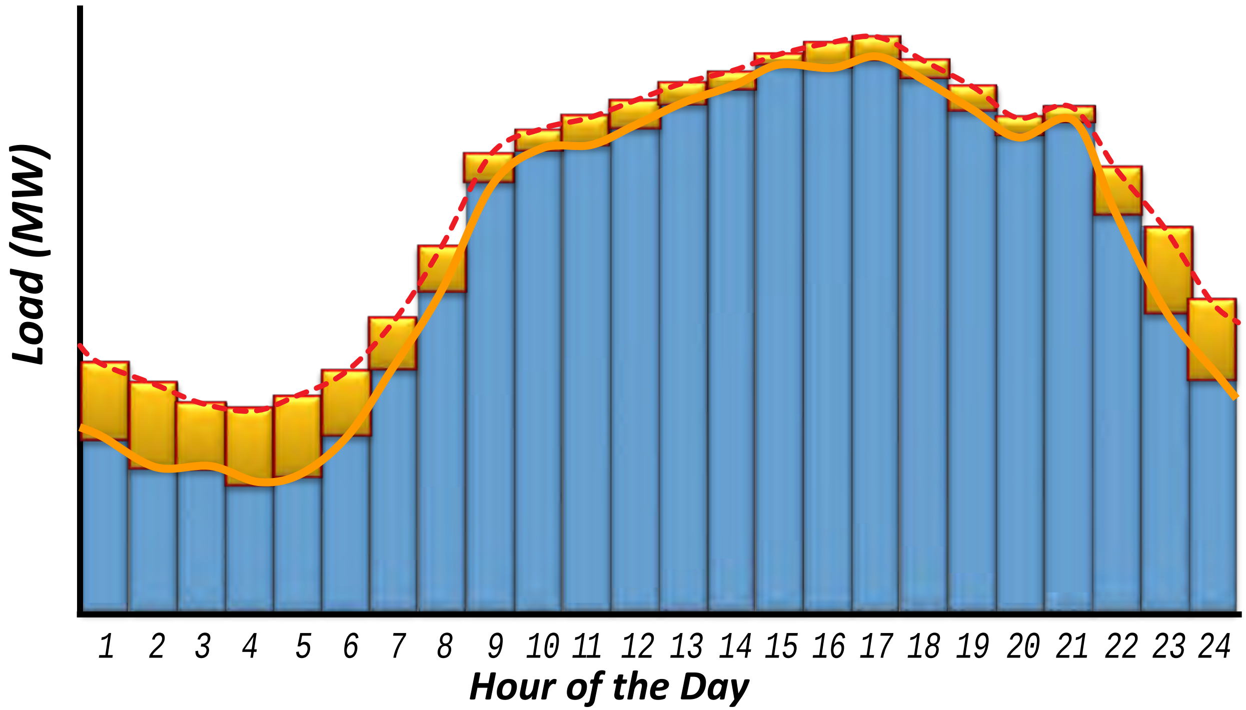


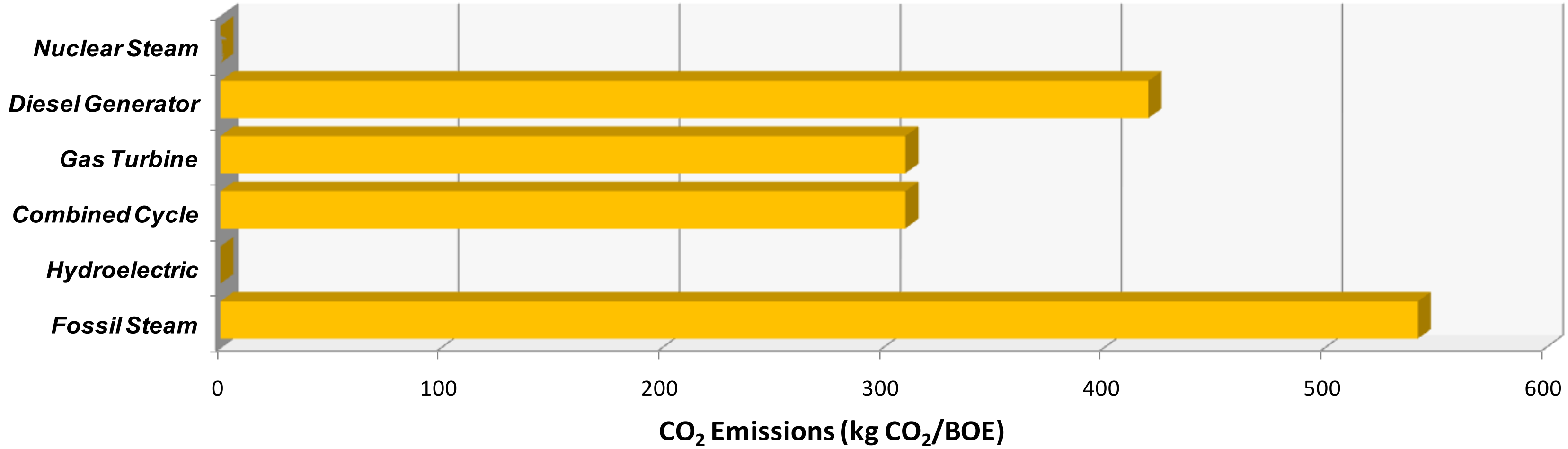
Lanai 1.5 MW Hawaii's largest solar farm in service as of Dec 2008



Sandia National Laboratory (SNL)

Variable Resources Displace Fossil Fuels and Reduces Pollution





Plans for future operations

Scheduling Unit Commitments/Generation and System Real Time Dispatch

Actual operation of the system

Typical Scheduling and Dispatch Sequence

Schedulers and Operators React to Changing Projections and RT Grid Conditions

Week Ahead (WA) Scheduling

- Project loads (weather is a main driver)
- Engage in bilateral purchases/sales
- Production Cost (PC) modeling (schedule supply to meet load)
- Allocated daily water releases from hydropower plants
- Determine very slow start unit commitments

Day Ahead (DA) Scheduling

- Revise load projections (latest/updated weather forecast)
- Production/cost modeling (schedule supply to meet load)
- Day-ahead market transactions
- Determine slow start unit commitments

Hour Ahead (HA) Scheduling

- Revise load projections (latest/updated weather forecast)
- Production/cost modeling (schedule supply to meet load)
- Hour-ahead market transactions
- Fast start-unit commitments & ramping sufficiency

Real-time (RT) Operations

- Dispatch generating units in real-time
- React to changing grid conditions
- Real-time 5-minute market transactions (where applicable)
- Deploy ancillary services (deviate from unit schedules)

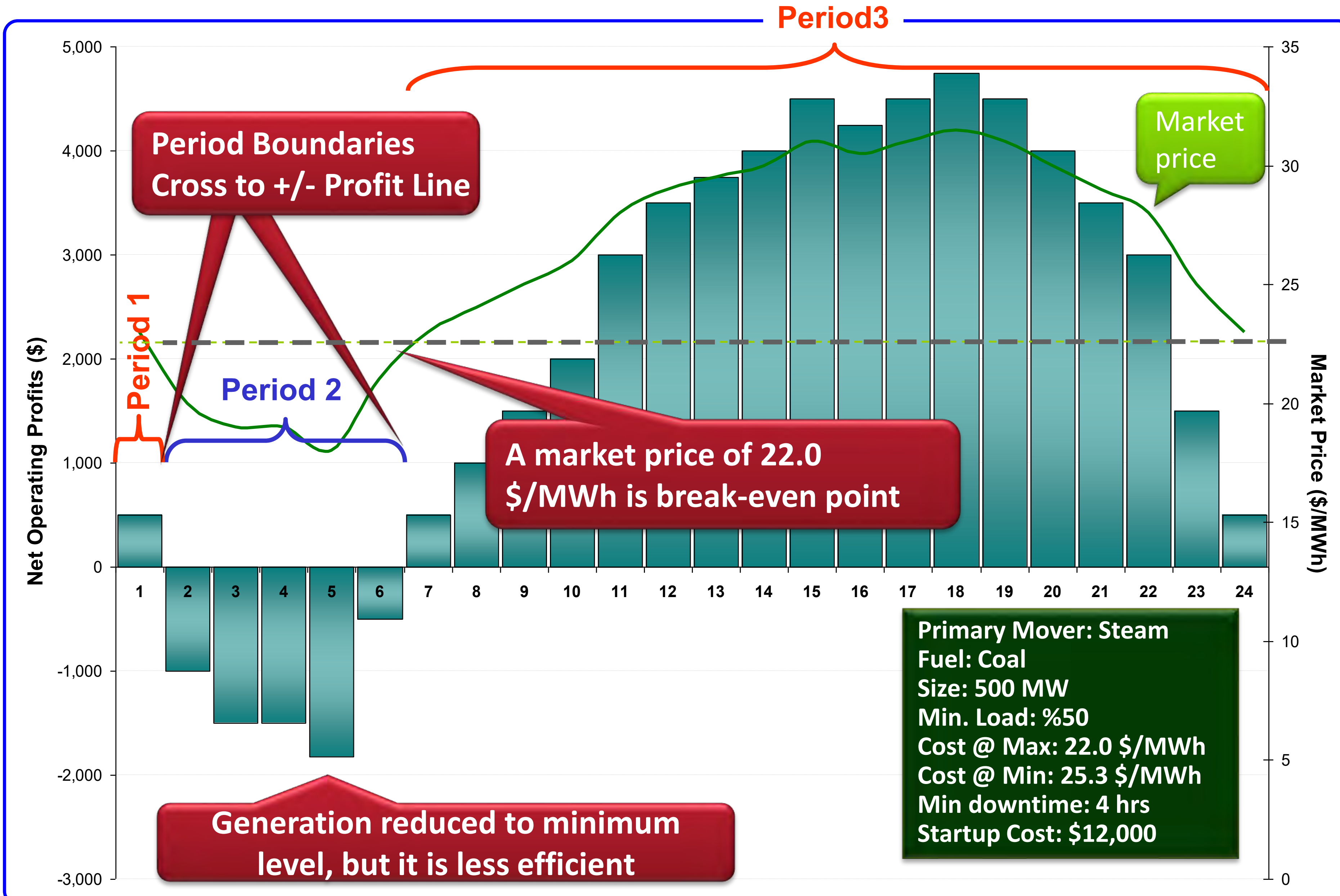
Financial Settlements

- Charges
- Payments

Unit Commitments

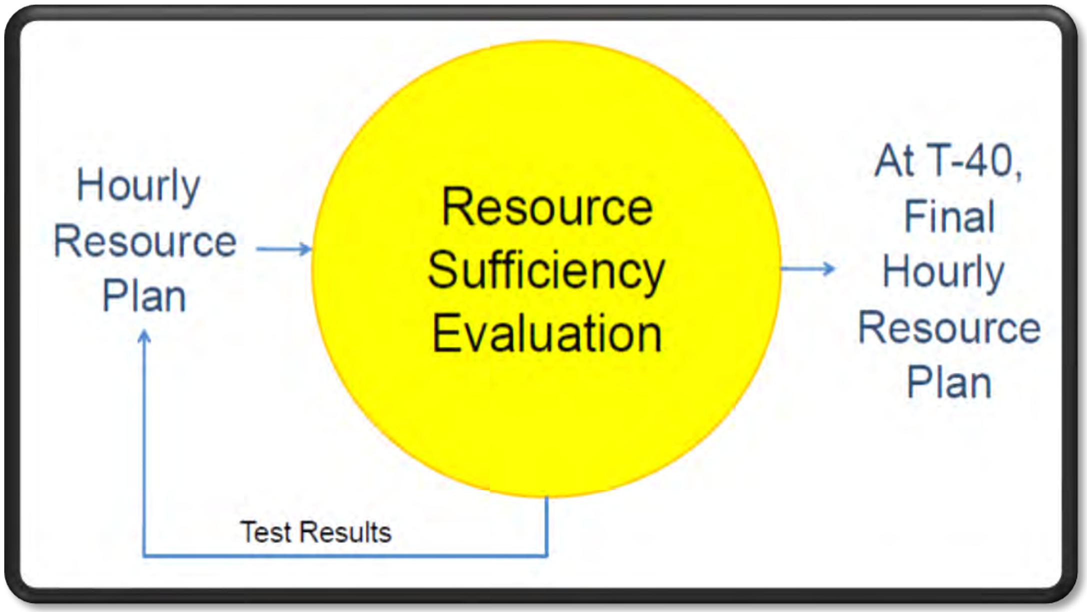
- Based on load profiles, unit constraints, and forecast error, decisions are made regarding when each individual unit should be turn on (commit) and when to turn it off
- It is important to not only have enough capacity on-line to always meet load, but have sufficient ramping capabilities and operational flexibility to meet fluctuating grid demand
- For example, all units may not be needed during low load periods, and therefore some are turned off, but as load grows, resources must have the operational flexibility to match net load growth
- To minimize cost, cheap units are typically utilized first, but these low production cost units typically are the ones that cannot be quickly turned on quickly and may be expensive to start
- Frequent unit cycling typically results in higher O&M expenses, refurbishment costs and longer down-times

Unit Operational Status (on/off) Is Primarily Based on Variable Production Costs and on Start-up/Shut-Down Costs



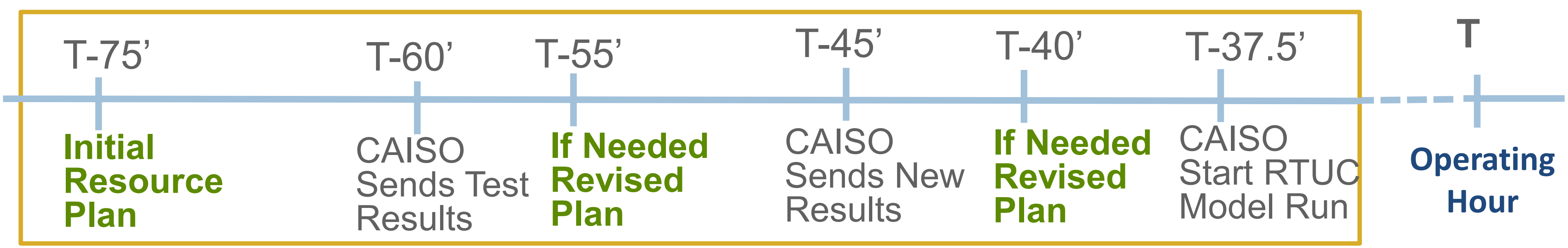
CAISO Hourly Resource Sufficiency Evaluation

- **CAISO resource checks**
  - o Balanced *Base Schedules*
  - o Sufficient flexibility ramping capacity
  - o Unresolved transmission congestion



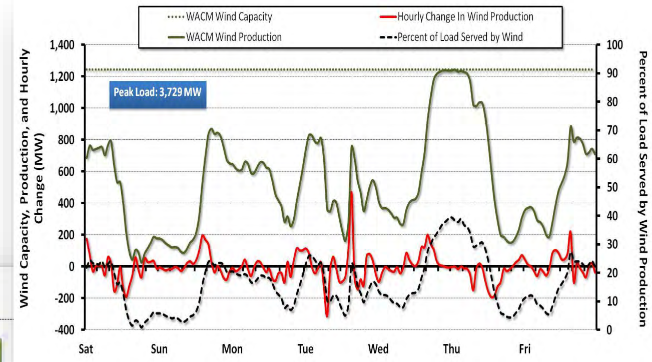
***Resource Sufficiency* Reduces a BA from "Leaning" on other EIM Entities**

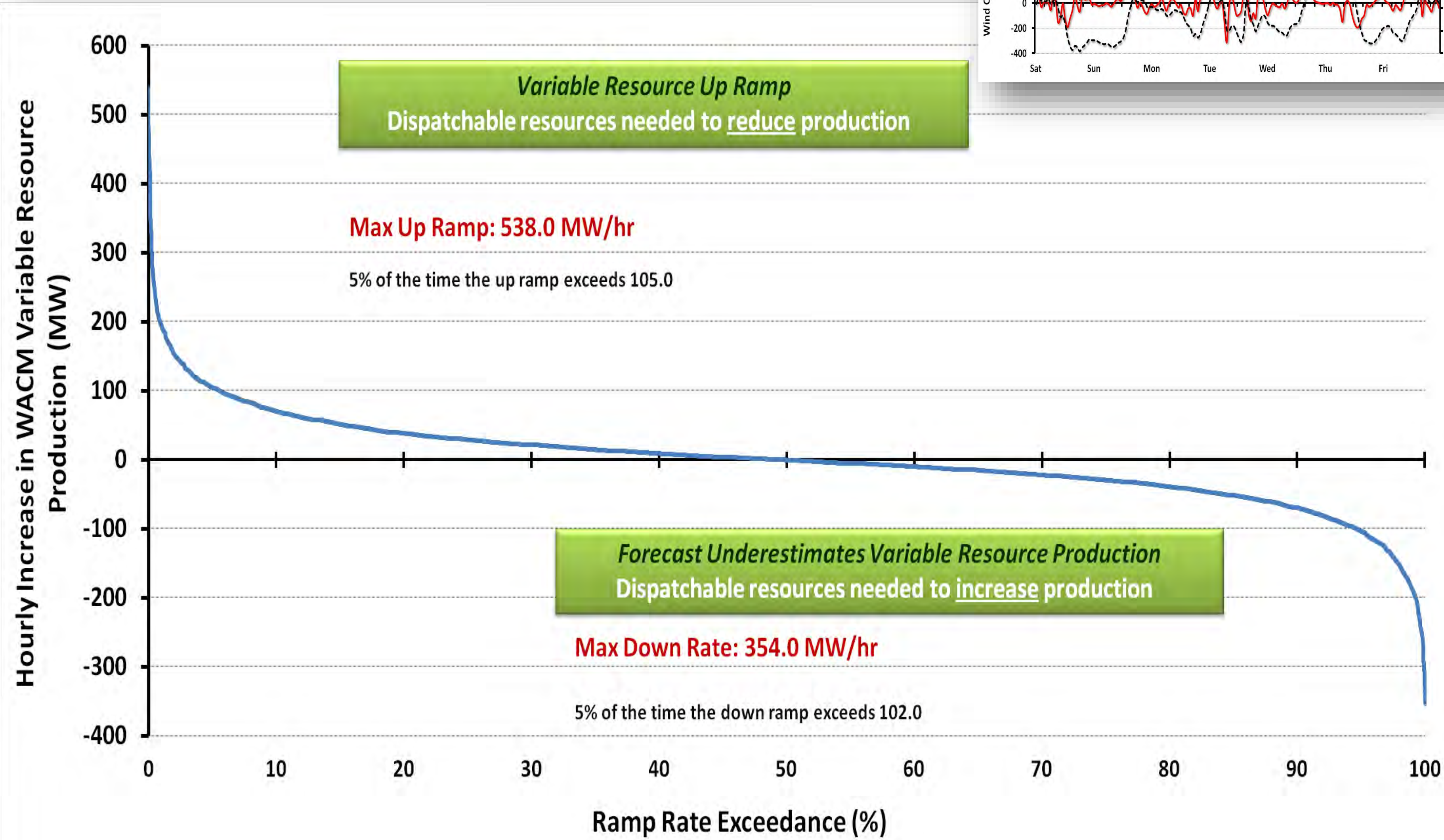
The *Resource Plan is* "Set in Stone" by the CAISO 40-minutes prior to the start of the operating hour and is the benchmark for energy deviation calculations



Longer-Term (Hourly) Movements

Hourly Wind Ramping Events in the WALM BA





Locational Marginal Prices (LMPs) In Non-Radial Networks

Locational Marginal Price Components

Supply components:
1. Marginal cost to purchase electricity
2. Cost of transmission congestion
3. Losses

Marginal loss is often significantly higher than the average

LMP = **Marginal Energy Bid Price** + **Transmission Congestion Cost** + **Cost of Marginal Losses** + **Other (air emissions)**

Most expensive bid accepted

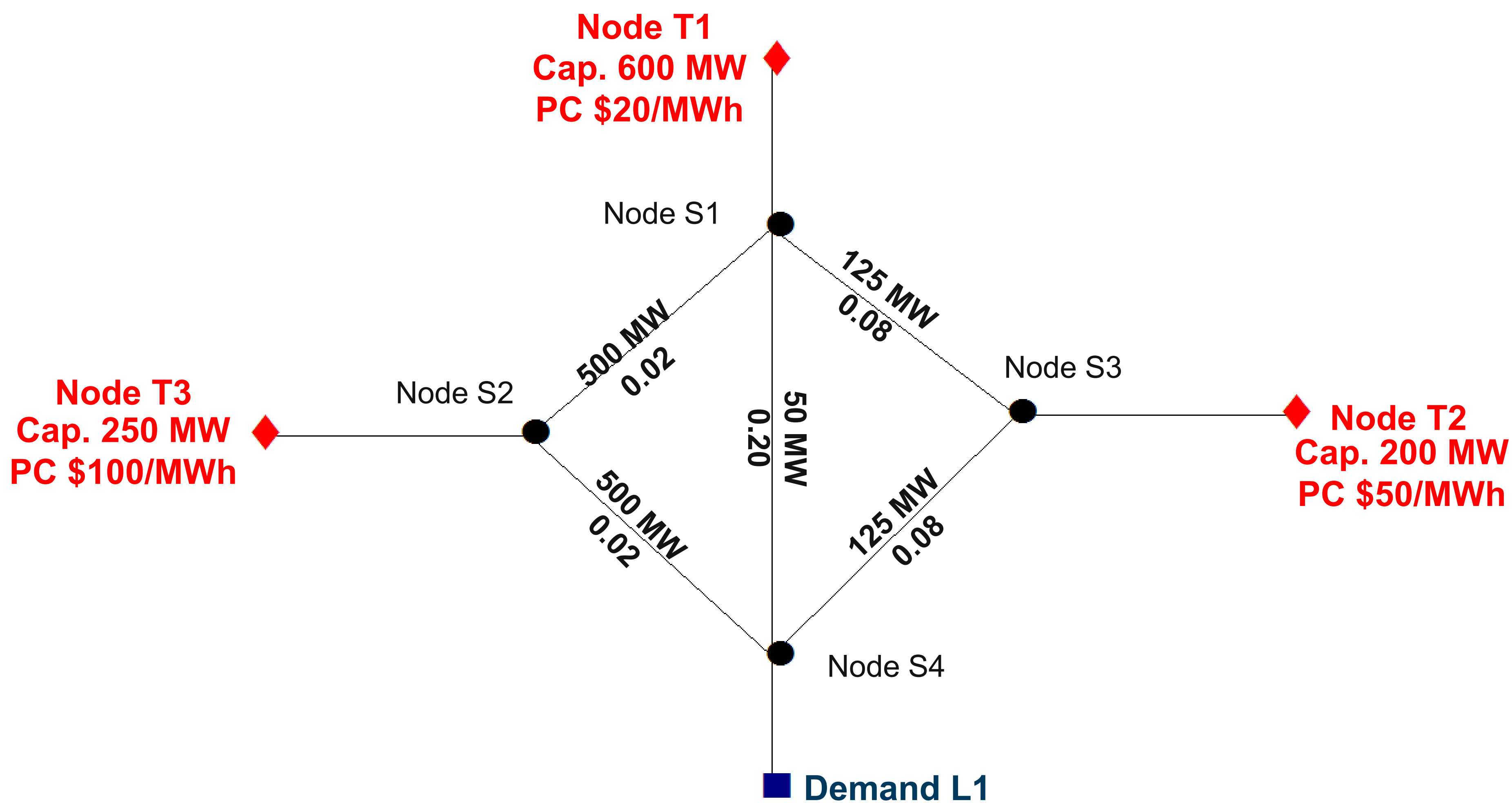
Cost of unit re-dispatch to avoid overloading of one or more lines

Load:
1. Payment or incentive to a consumer to reduce demand

- **LMP is a methodology that determines the optimal unit dispatch**
- **It simultaneously computes marginal energy costs at all locations (buses)**
- **It also computes the cost of transmission congestion in the power grid**

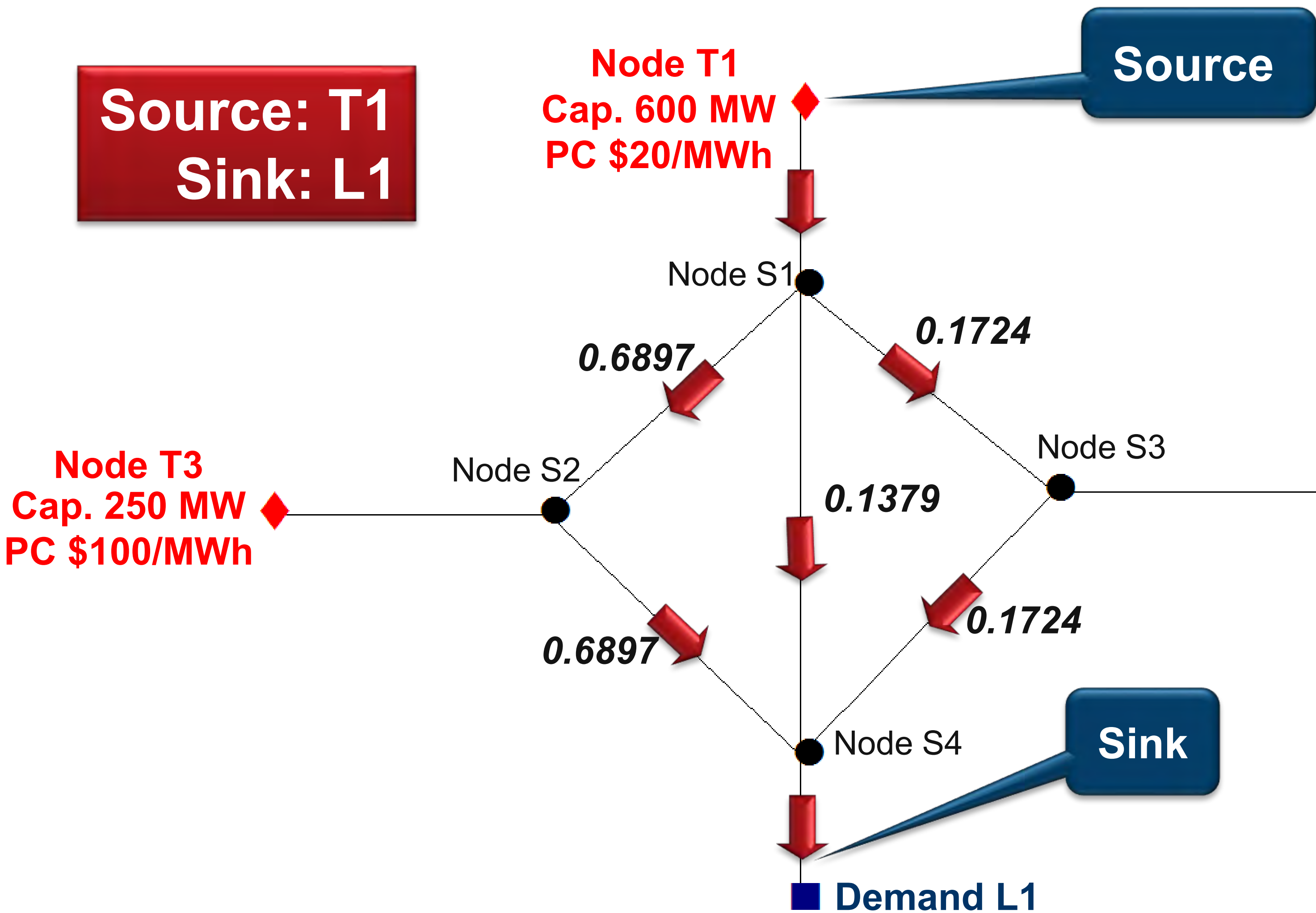
Bids are <u>not</u> required to reflect production costs, but LMPs may be adjusted in the market mitigation process

LMPs in a Simple Non-Radial Grid (Capacity & Costs)



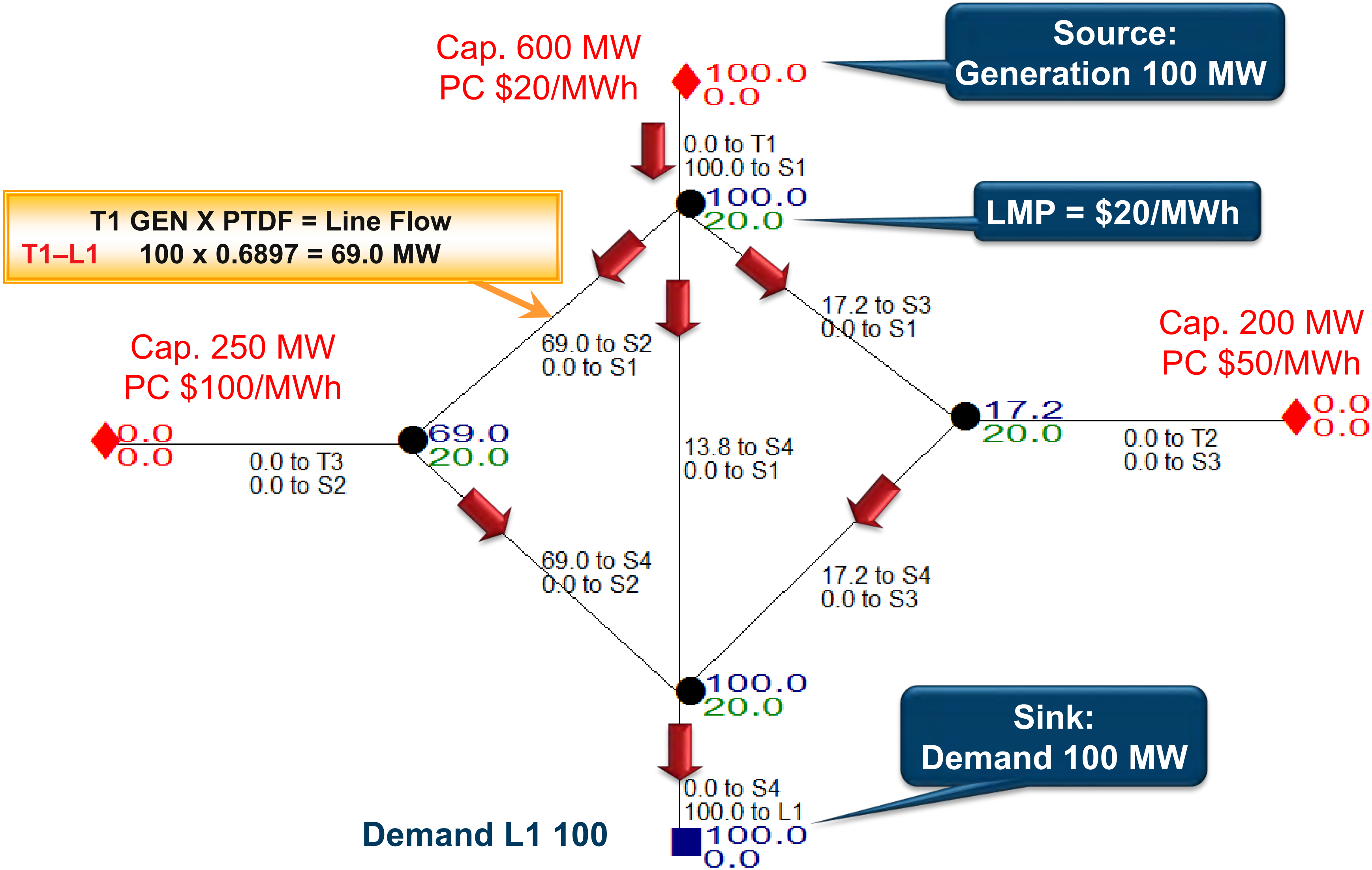
PC = Production Cost ($/MWh)
Cap. = Capacity (MW)

LMPs in a Simple Non-Radial Grid (PTDF T1 to L1)



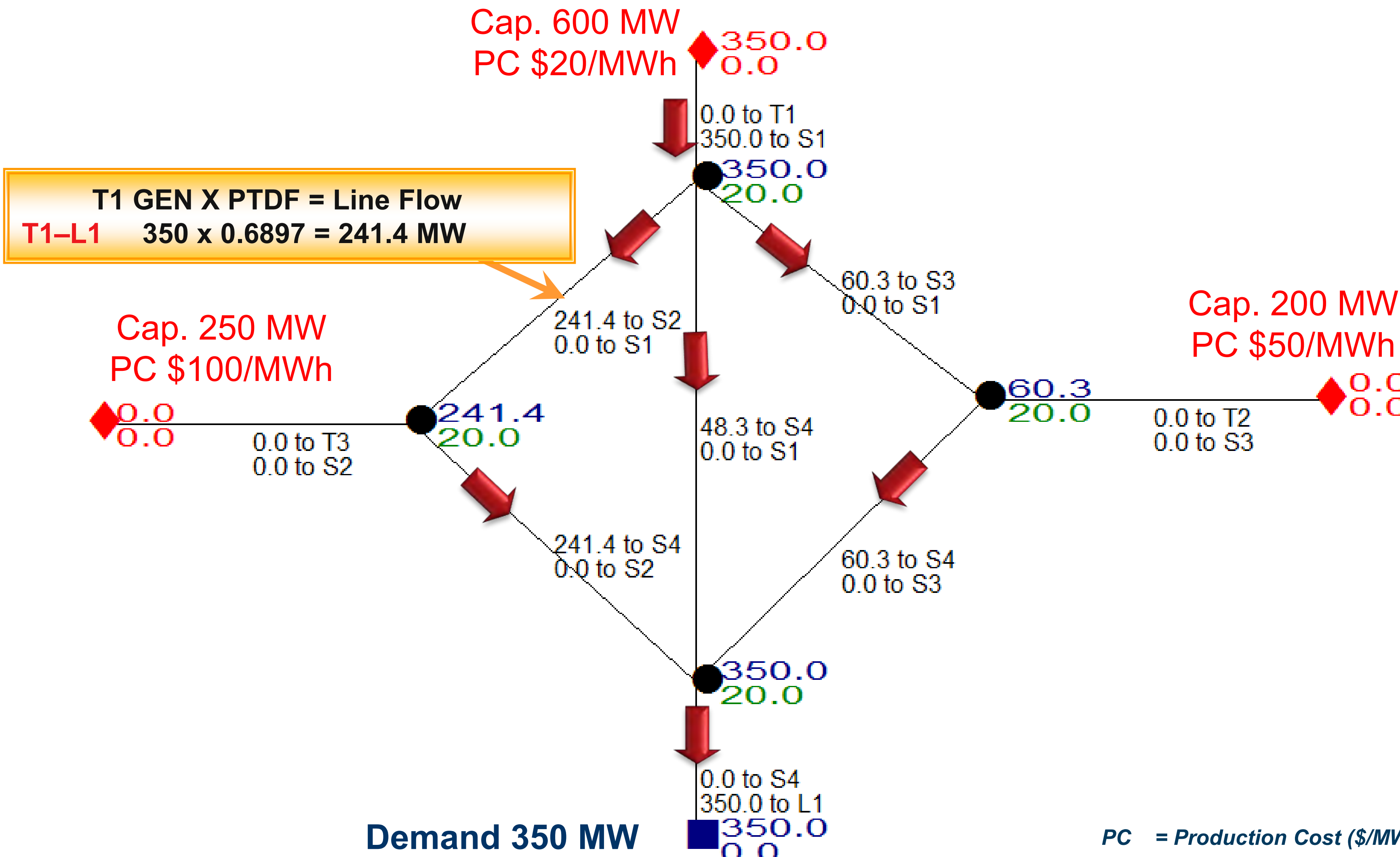
PC = Production Cost ($/MWh)
Cap. = Capacity (MW)

Single Source & Single Sink - Simple Non-Radial Grid



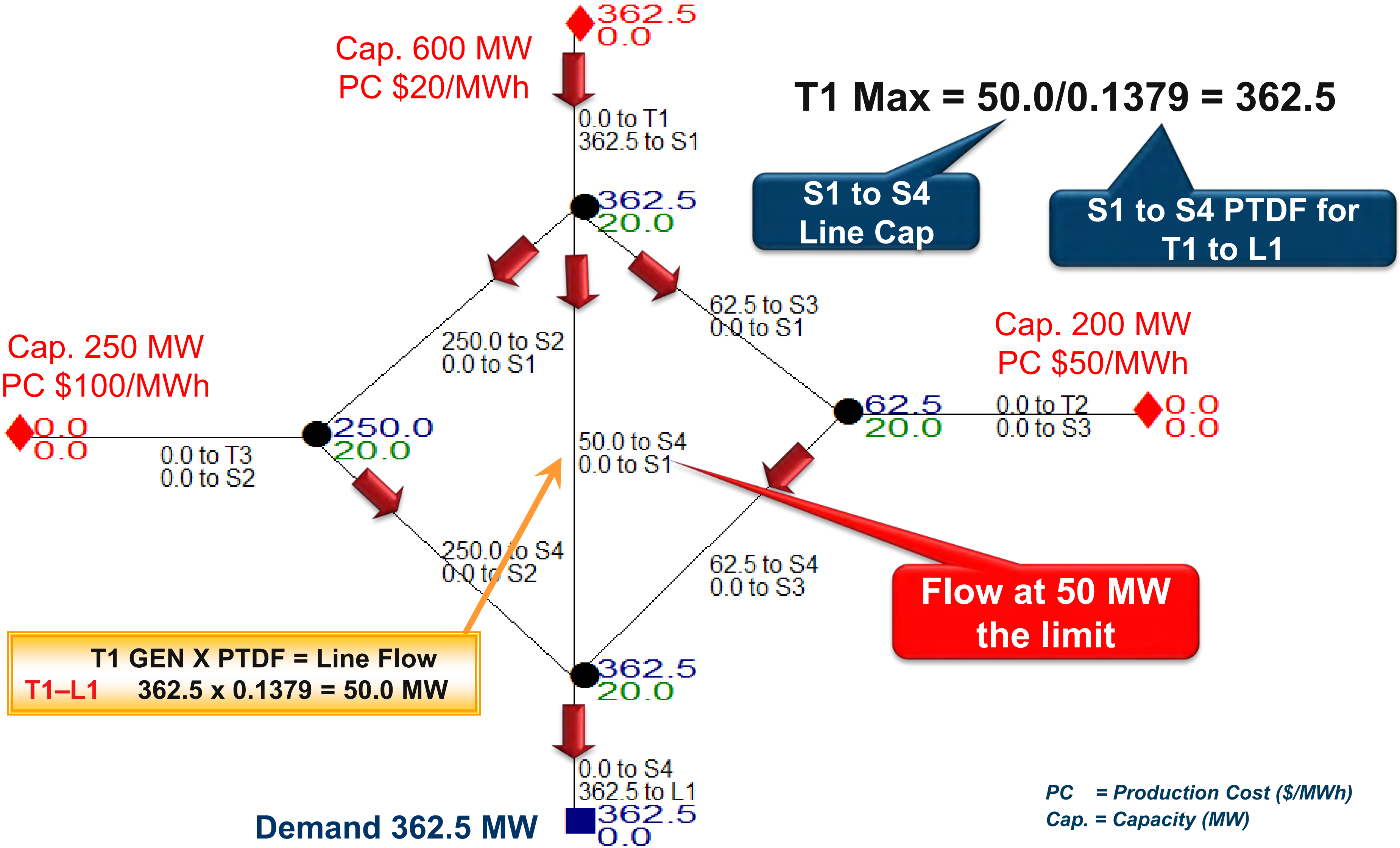
PC = Production Cost ($/MWh)
Cap. = Capacity (MW)

Single Source & Single Sink - Proportionality (350 MW Load)

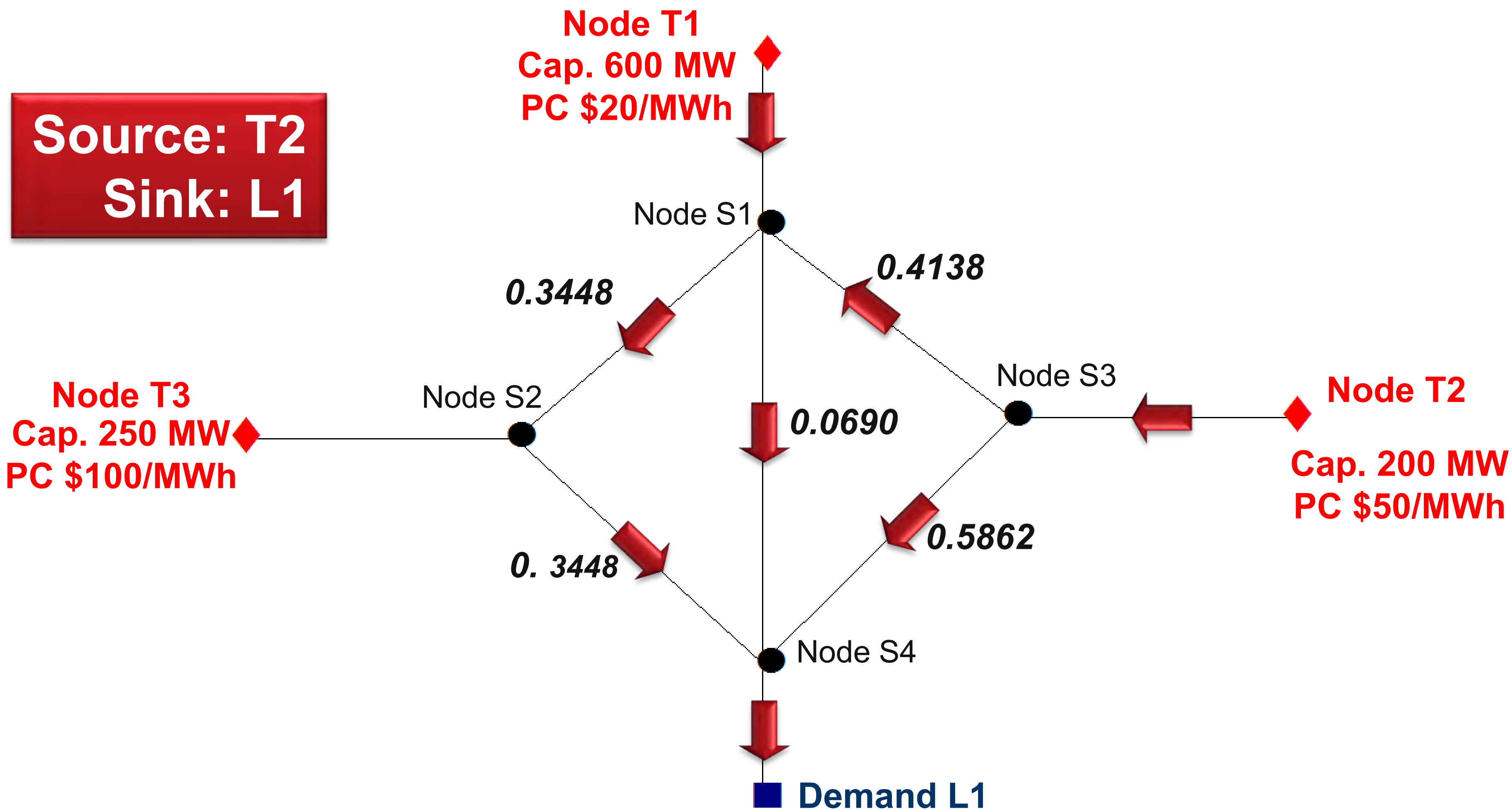


PC = Production Cost ($/MWh)
Cap. = Capacity (MW)

The Power Flow Limit on the T1-L1 Transmission Line Is Reached When T1 Output and Demand Is 362.5 MW



Loads > 362.5 MW Will Require T2 To Be Dispatch (PTDF T2 to L1)

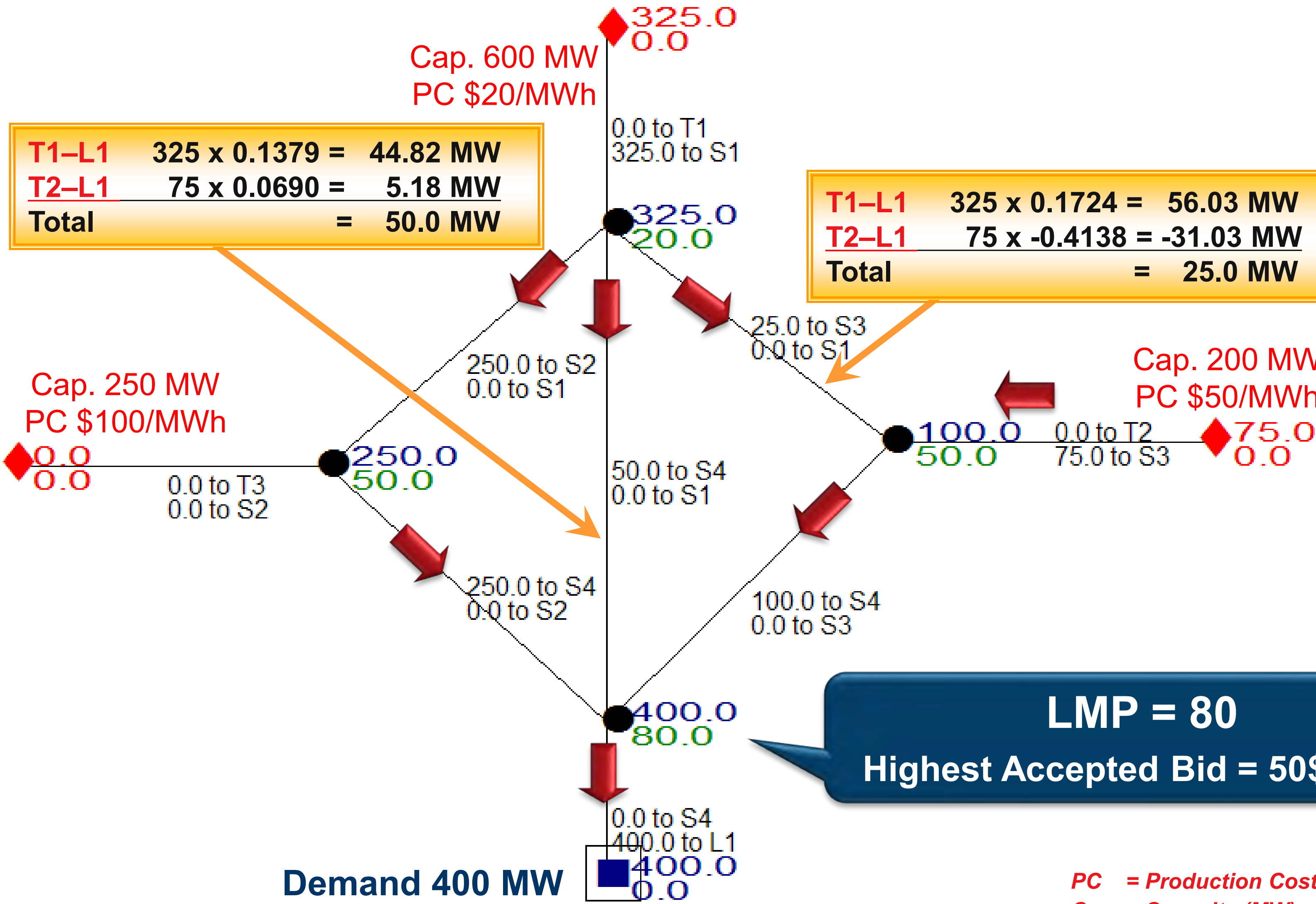


PC = Production Cost ($/MWh)
Cap. = Capacity (MW)

When T2 Generates, T1 Reduces Generation below 362.5 MW to Avoid Line Overload -- Superposition (400 MW Load)

T1–L1	325 x 0.1379 =	44.82 MW
T2–L1	75 x 0.0690 =	5.18 MW
Total	=	50.0 MW

T1–L1	325 x 0.1724 =	56.03 MW
T2–L1	75 x -0.4138 =	-31.03 MW
Total	=	25.0 MW

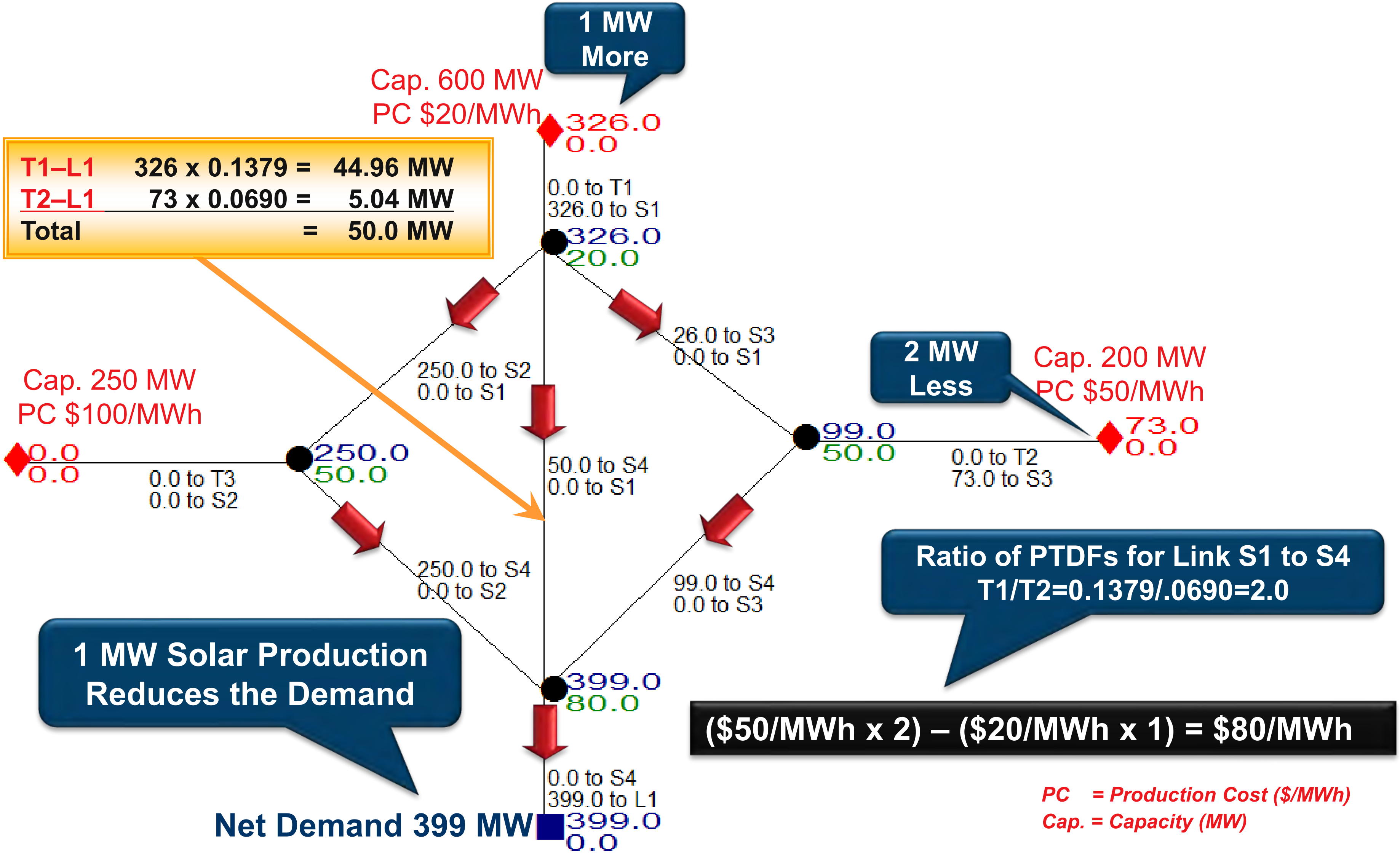


LMP = 80

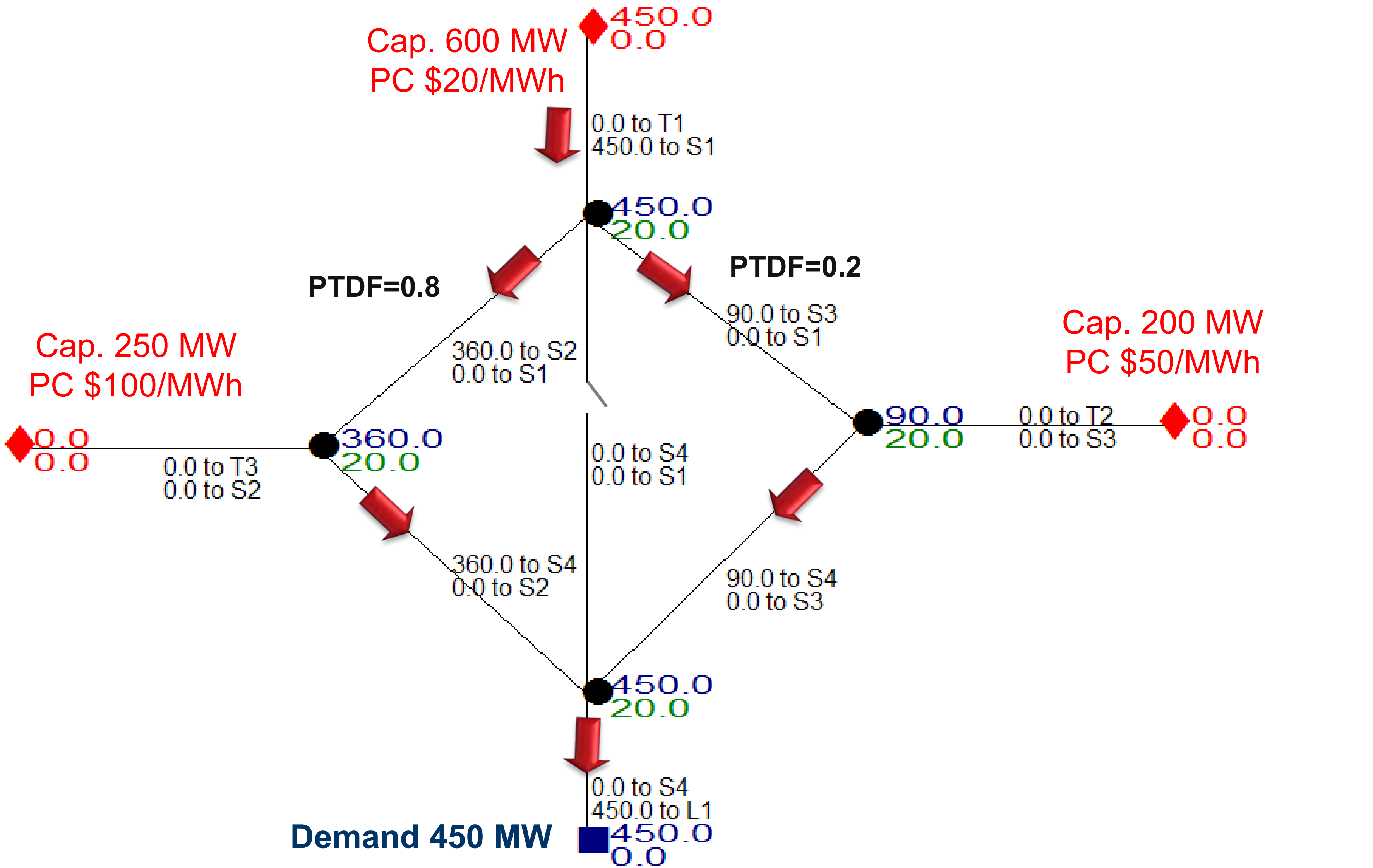
Highest Accepted Bid = 50$/MWh

PC = Production Cost ($/MWh)
Cap. = Capacity (MW)

The Value of VRE Production In a Congested Grid Can be Calculated by Serving the Load with A VRE and then Recalculating Production Costs



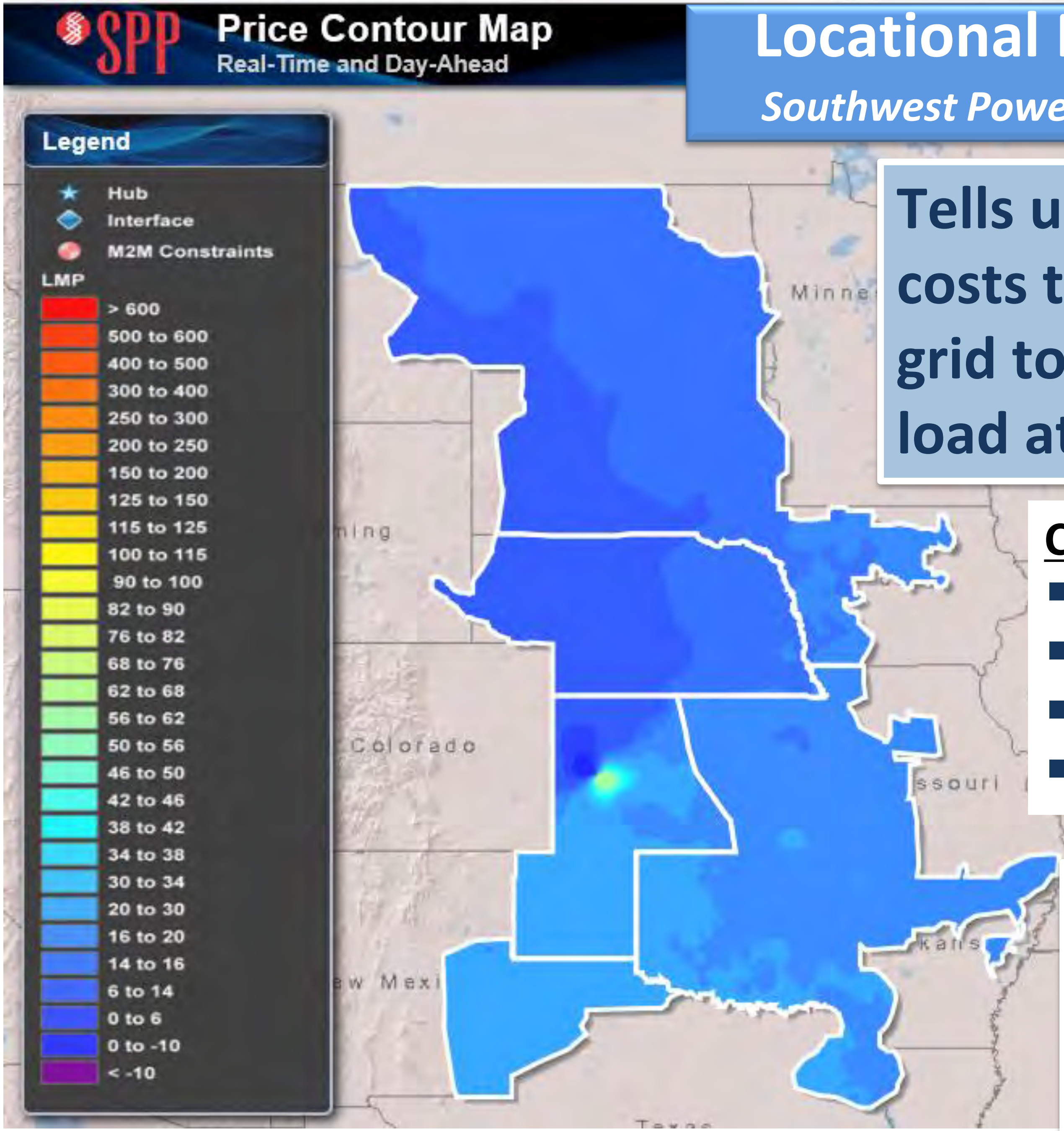
The ISO Relieves Congestion by Opening the Congested Line



PC = Production Cost ($/MWh)
Cap. = Capacity (MW)

Locational Marginal Prices

Southwest Power Pool Real-time LMPs



http://pricecontourmap.spp.org/pricecontourmap/

Tells us how much it costs the entire power grid to serve 1 MWh of load at a specific point

Computed for the

- Day-ahead market
- Hour-ahead market
- 15-minute scheduling
- Real-time market

LMPs change over time, differ by time horizon and by location

Hourly Energy Imbalances

Balancing Authority (BA)
and Energy Imbalances (EI)

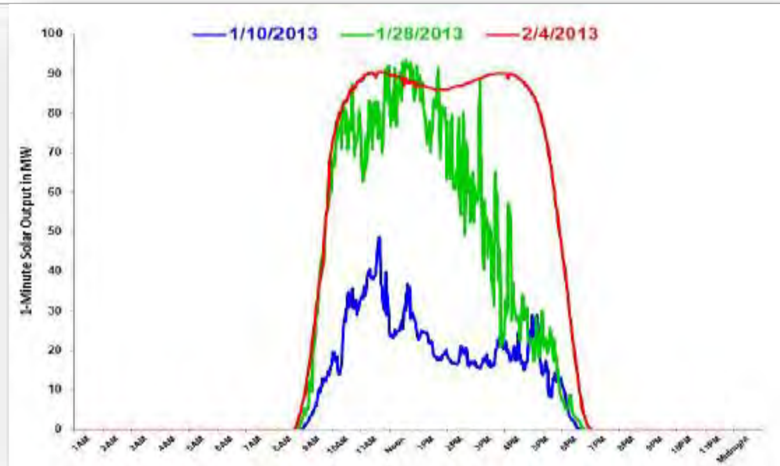
EI Is Caused by the Difference between Scheduled and Actual levels

Resources Are Needed to Respond to Error

Flexibility Reserves

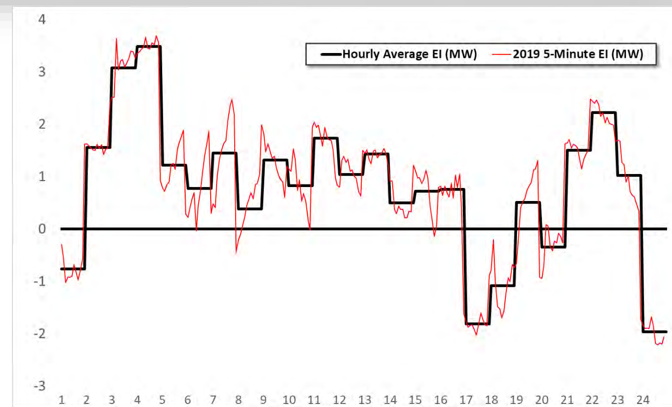
Flex/Regulation

- Short-term forecast errors
- Respond to changes faster than re-dispatch period
- Automatic generation control (AGC)



Spin/Spinning

- Longer term forecast errors
- Larger, slower, less frequent variations
- AGC not required
- 10-minute response
- Synchronized to the grid



Non-spinning/Supplemental

- Large, infrequent, slow moving events such as ramp forecast error
- 30-minute response

Forecasts Are *not* Perfect in the Short-Term and less Accurate in the Long-Term

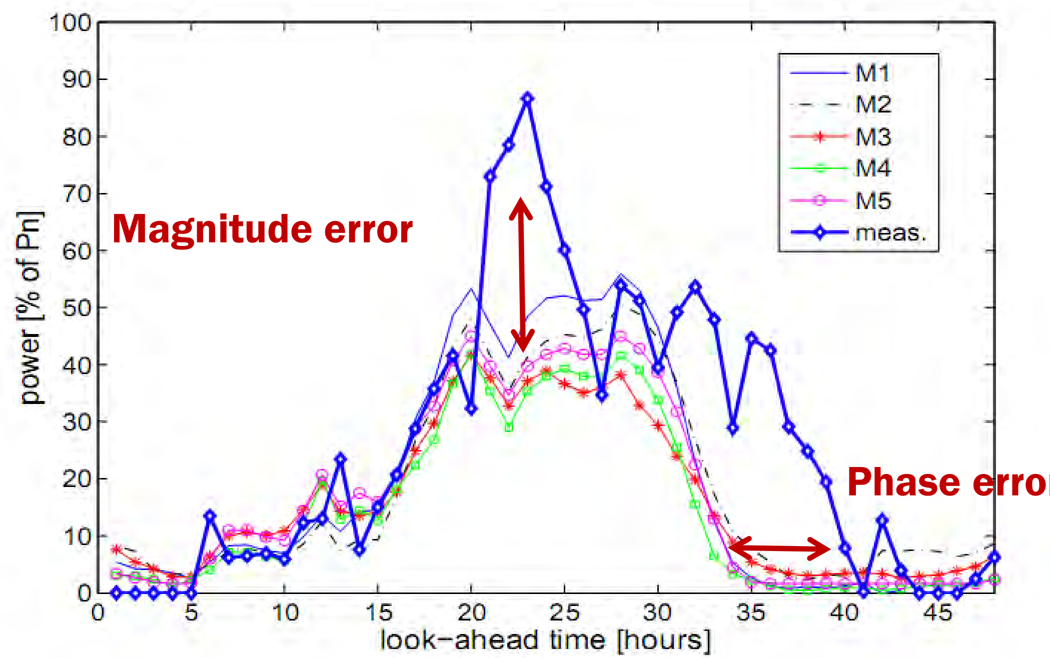
- Error depends on several factors
  - Prediction horizon
  - Time of the year
  - Capacity of resources
  - Model inputs
  - Model type
  - Terrain complexity
  - Spatial smoothing effect

Error in meteorological forecasts

Conversion process error

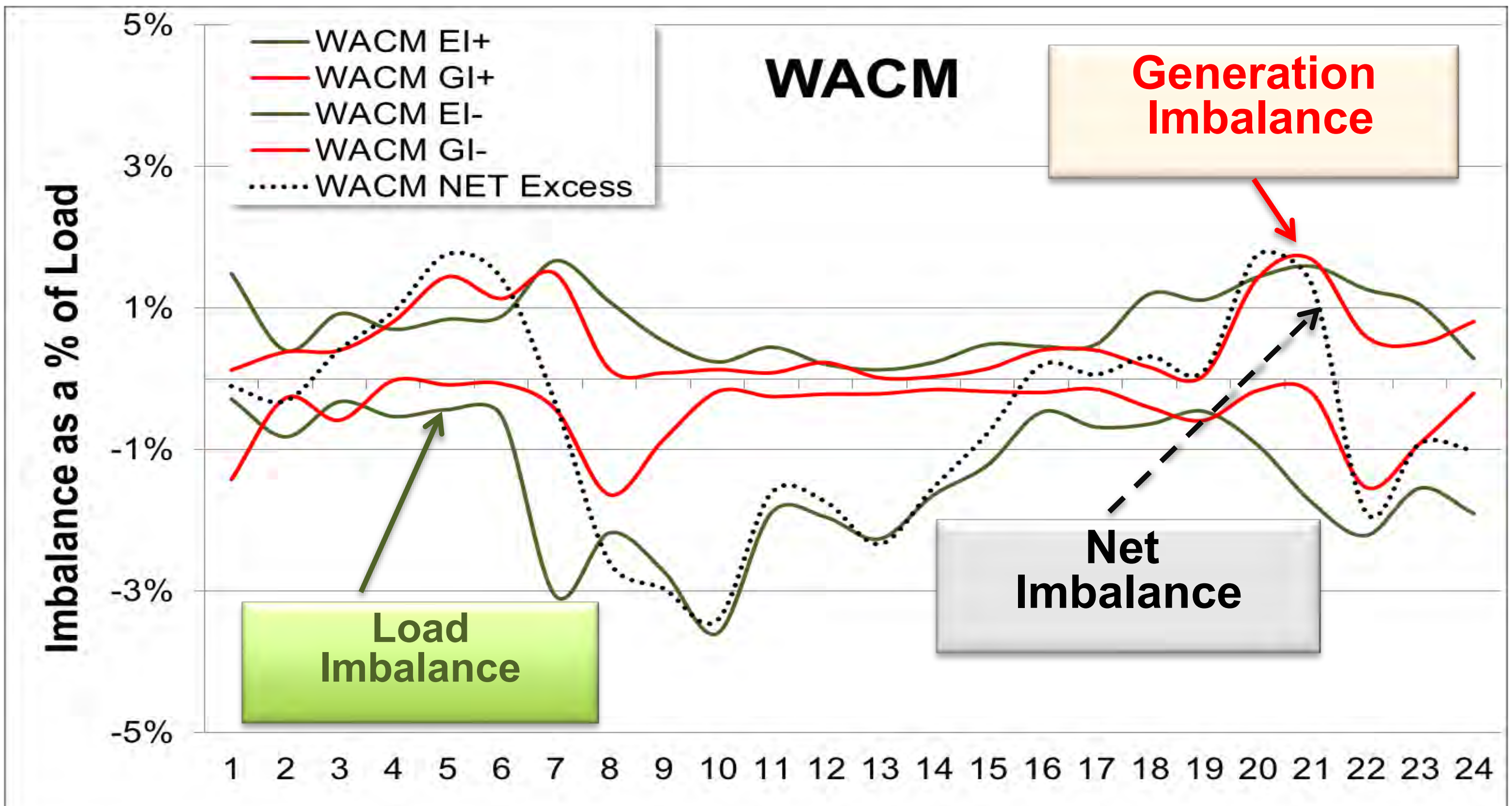
Errors in SCADA information and reseource operation

For example, wind power output is proportional to the wind speed cubed



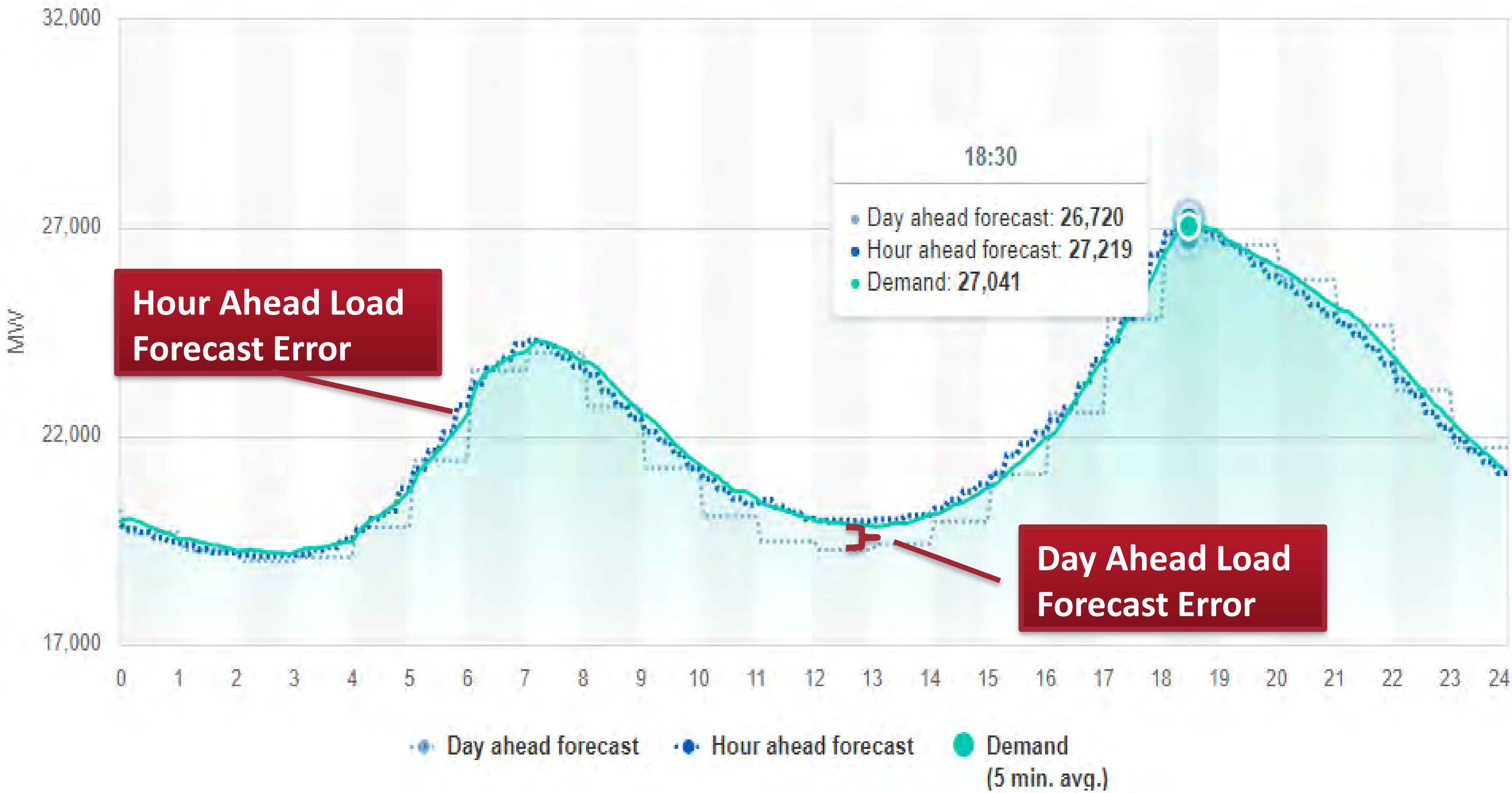
An *energy imbalance* (EI) is the difference between scheduled and actual levels

- Applies to generation & loads
- Is a function of temporal scheduling granularity & dispatch interval
- Usually computed at the entity level

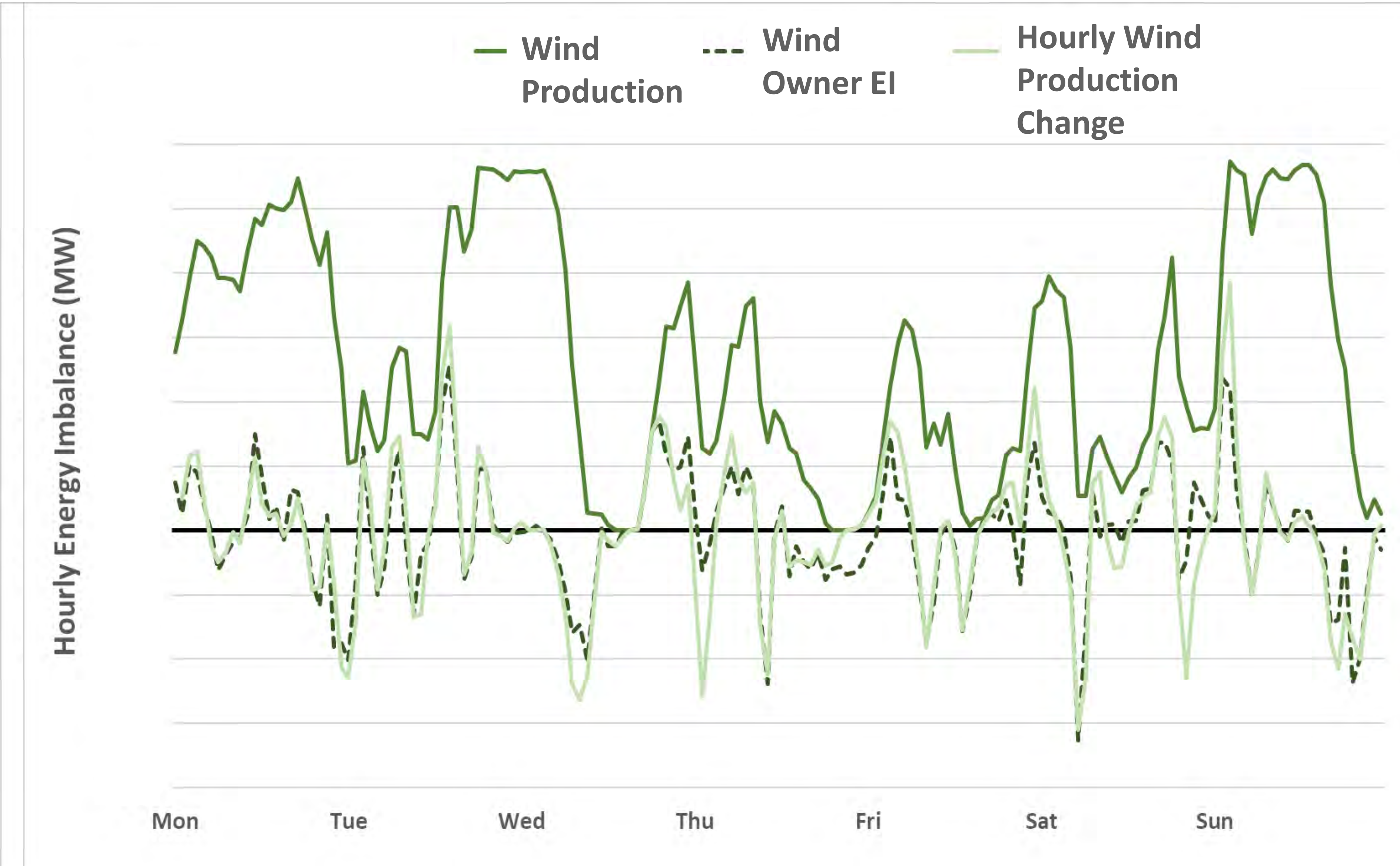


CAISO Projected Load for Scheduling and Actual Load - *March 1, 20201*

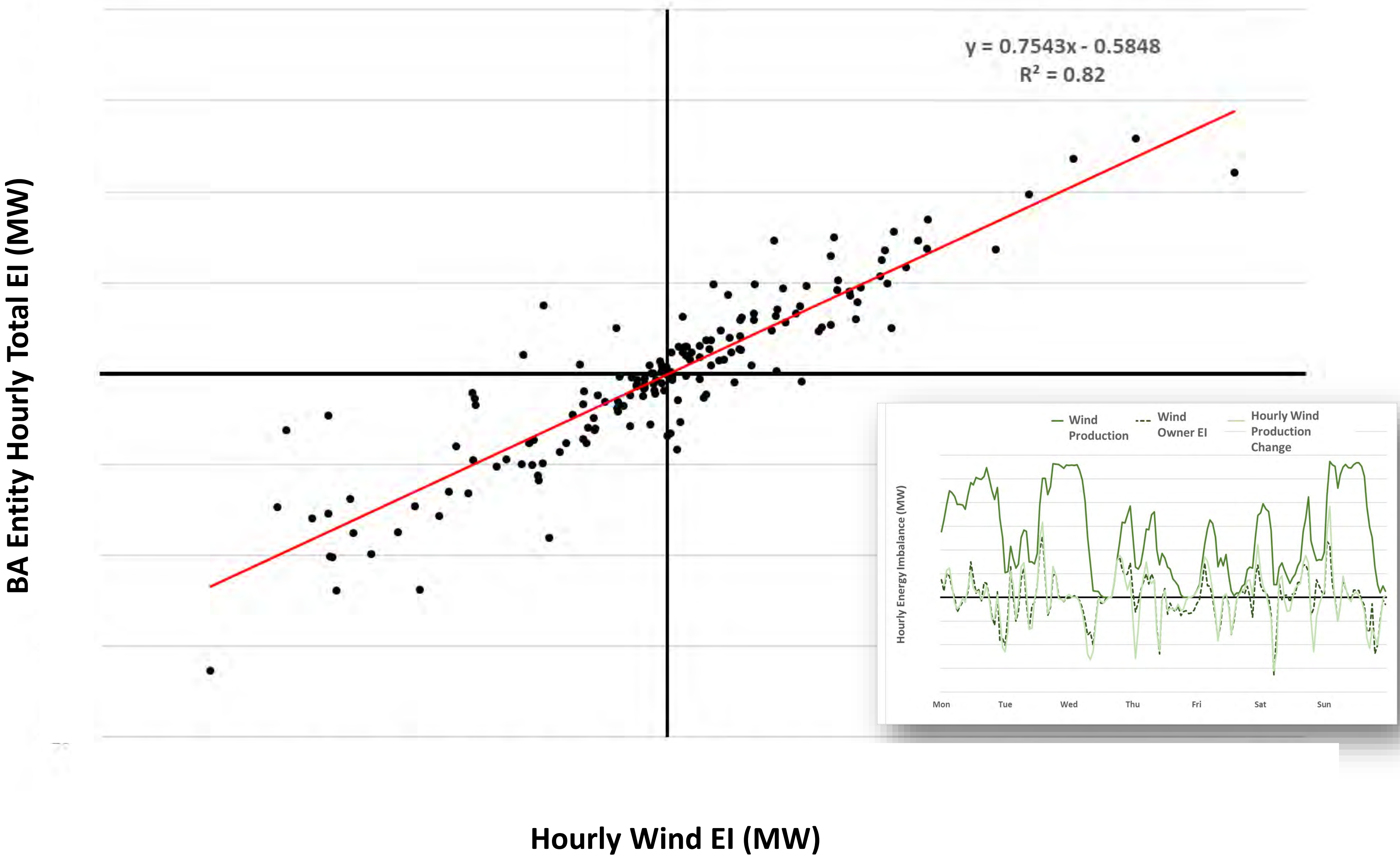
Unit commitment schedules are typically based on these projections



Generator EI Example:
Wind Turbine EI Caused by Forecast Error

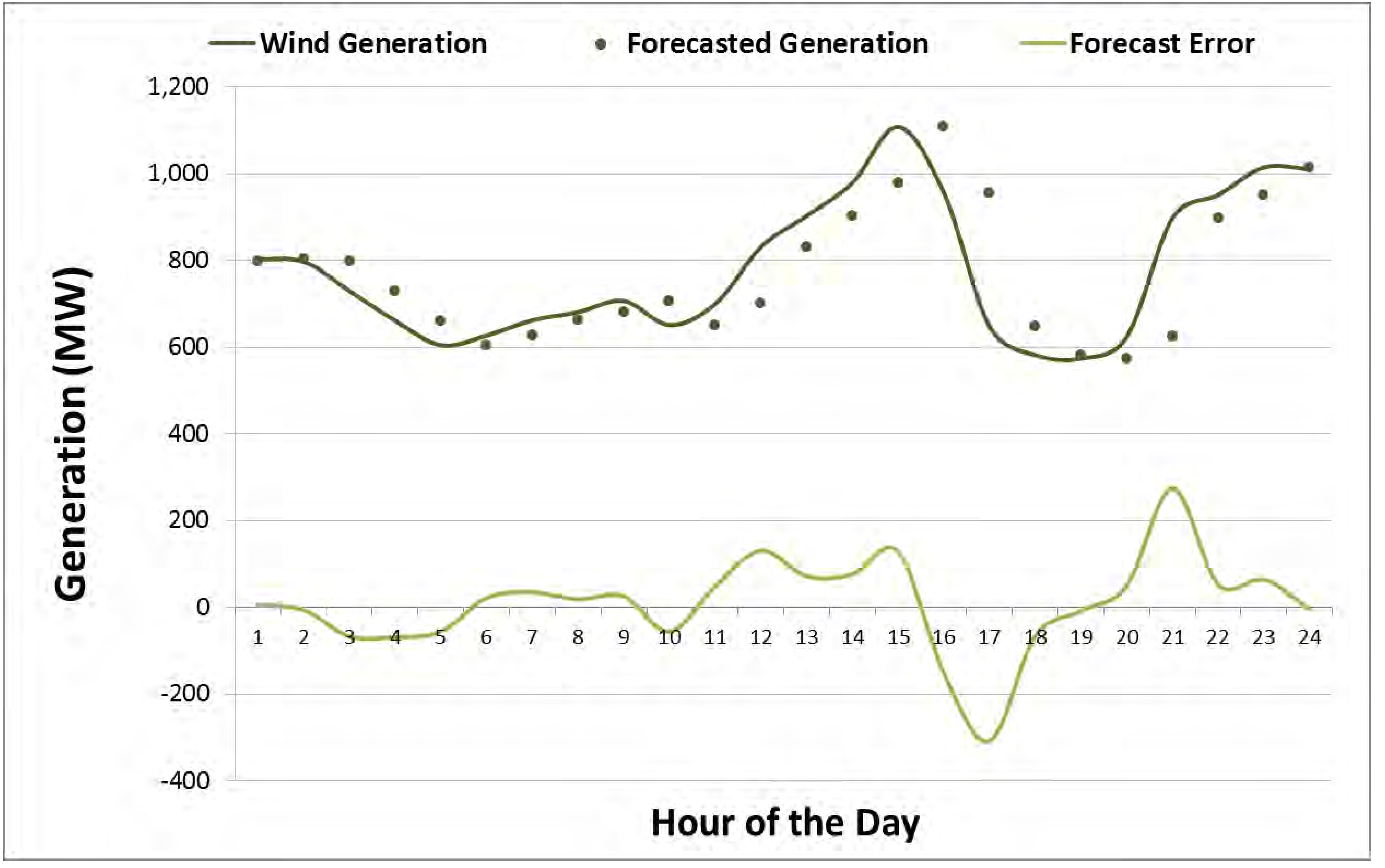


Wind EI May Be a Significant Contribution to Net EI for a <u>Specific Entity (wind owner) within a BA</u>

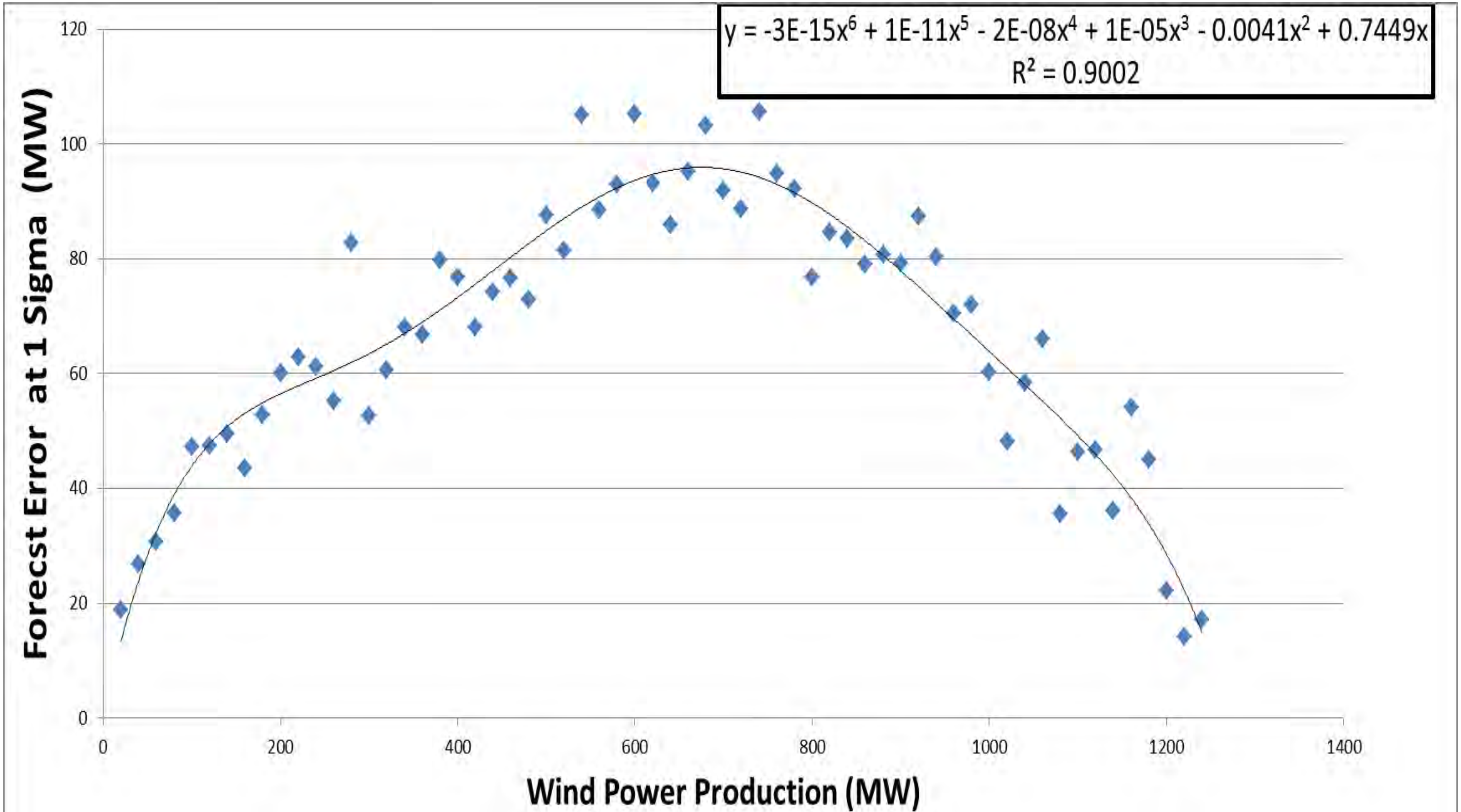


HA Forecast Error

Forecast Error Example Is Based on Persistence Forecasting



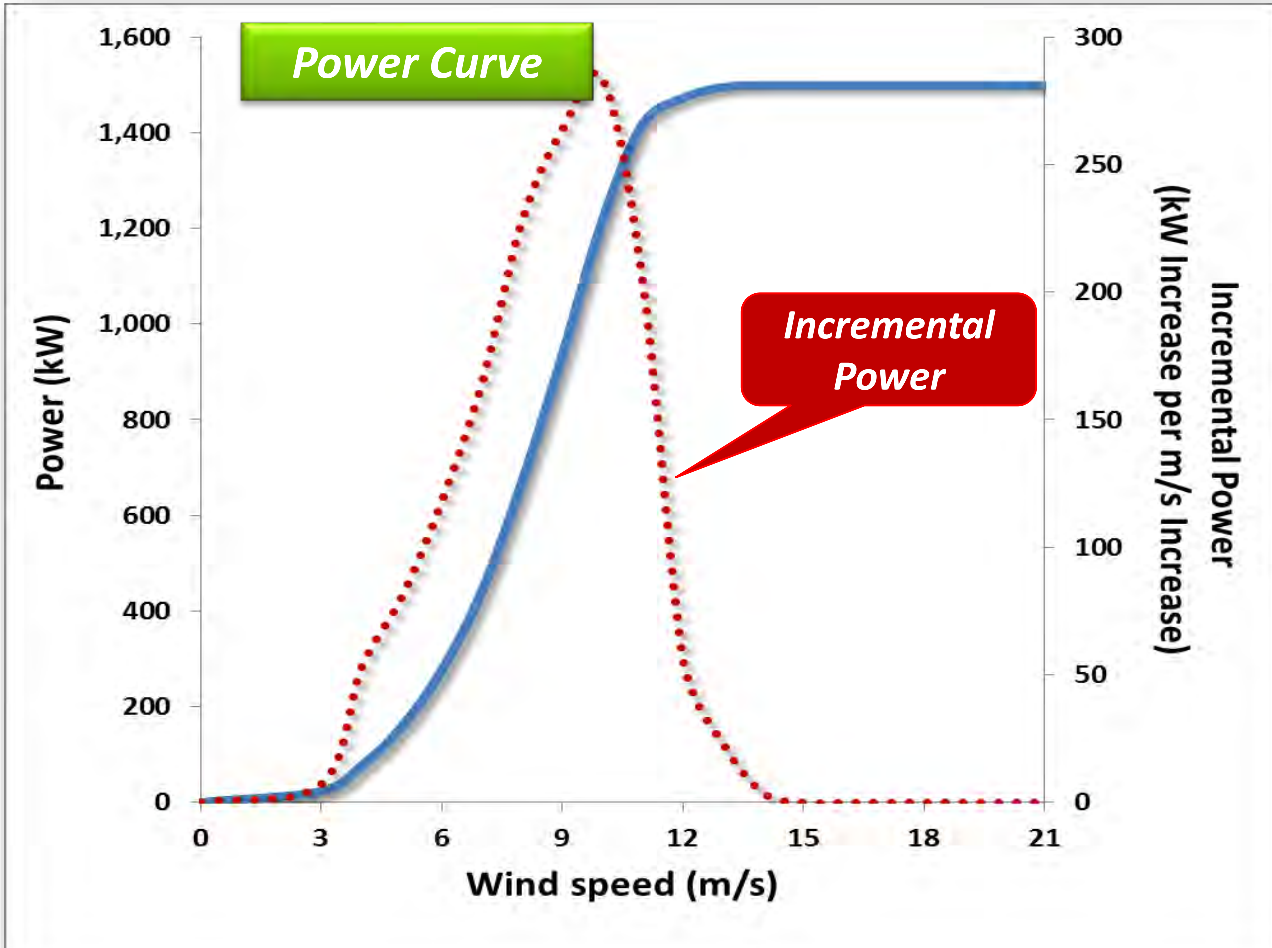
Flexible Reserve Requirements Are Sometimes Based on the Current Variable Resource Generation Level



Western Area Power Administration – Colorado-Missouri

Persistence Forecast Error Is Related to the Characteristics of the Wind Power Curve

Wind Plant Characterization



WIND SPEED (M/S)	POWER (KW)
0	0
3	21.9
4	75.1
5	155.8
6	274.3
7	439.3
8	668
9	932.1
10	1215.4
11	1418.2
12	1473.7
13	1496.5
14	1500.0
15	1500.0
16	1500.0
17	1500.0
18	1500.0
19	1500.0
20	1500.0
21	1500.0
22	1500.0

CUT-IN WIND SPEED: 3.0 M/S

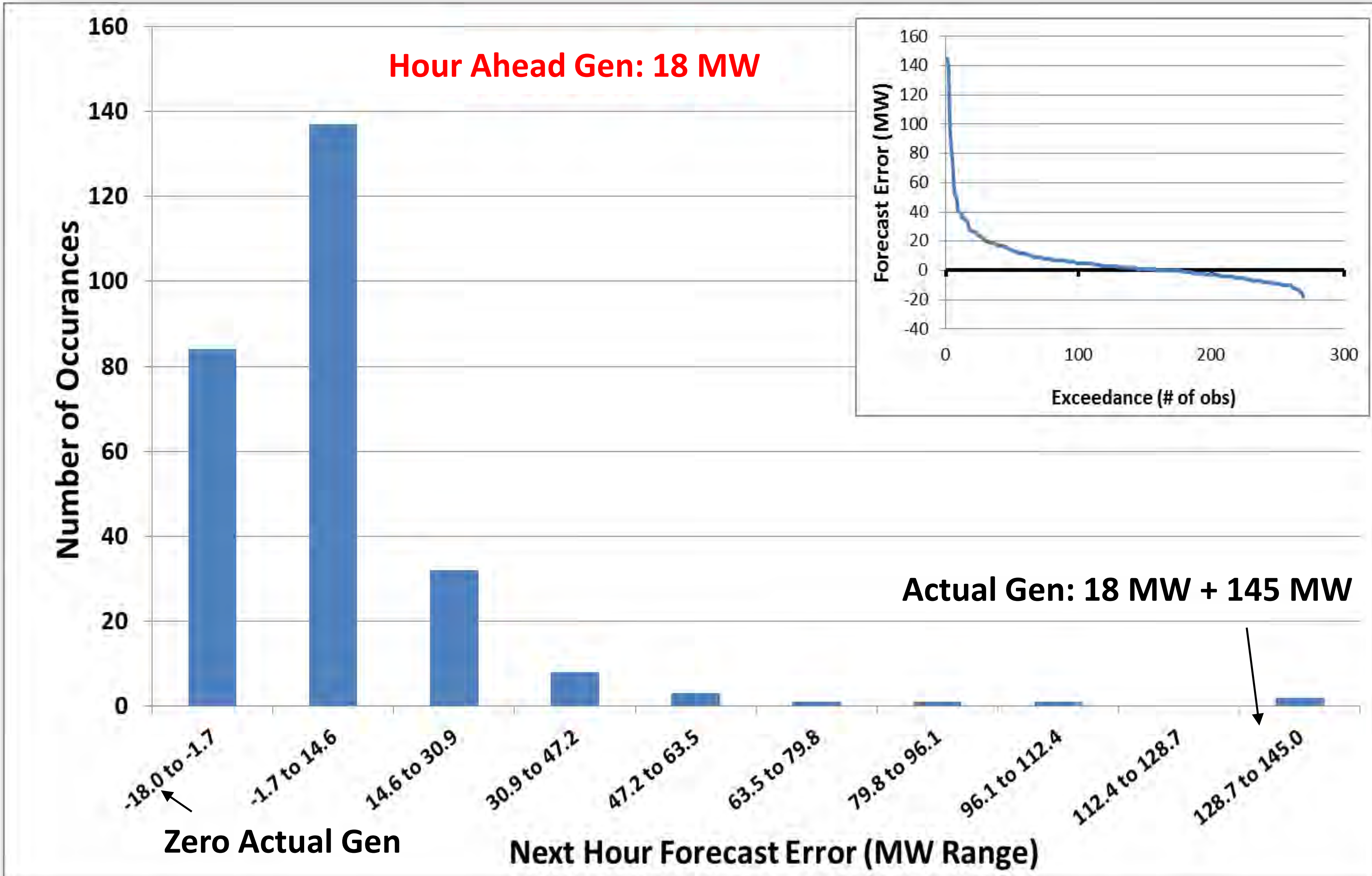
CUT-OUT WIND SPEED: 22 M/S

Air Density → ρ; Rotor Area → A; Performance Coefficient → C_P; Wind Speed → V_∞^3

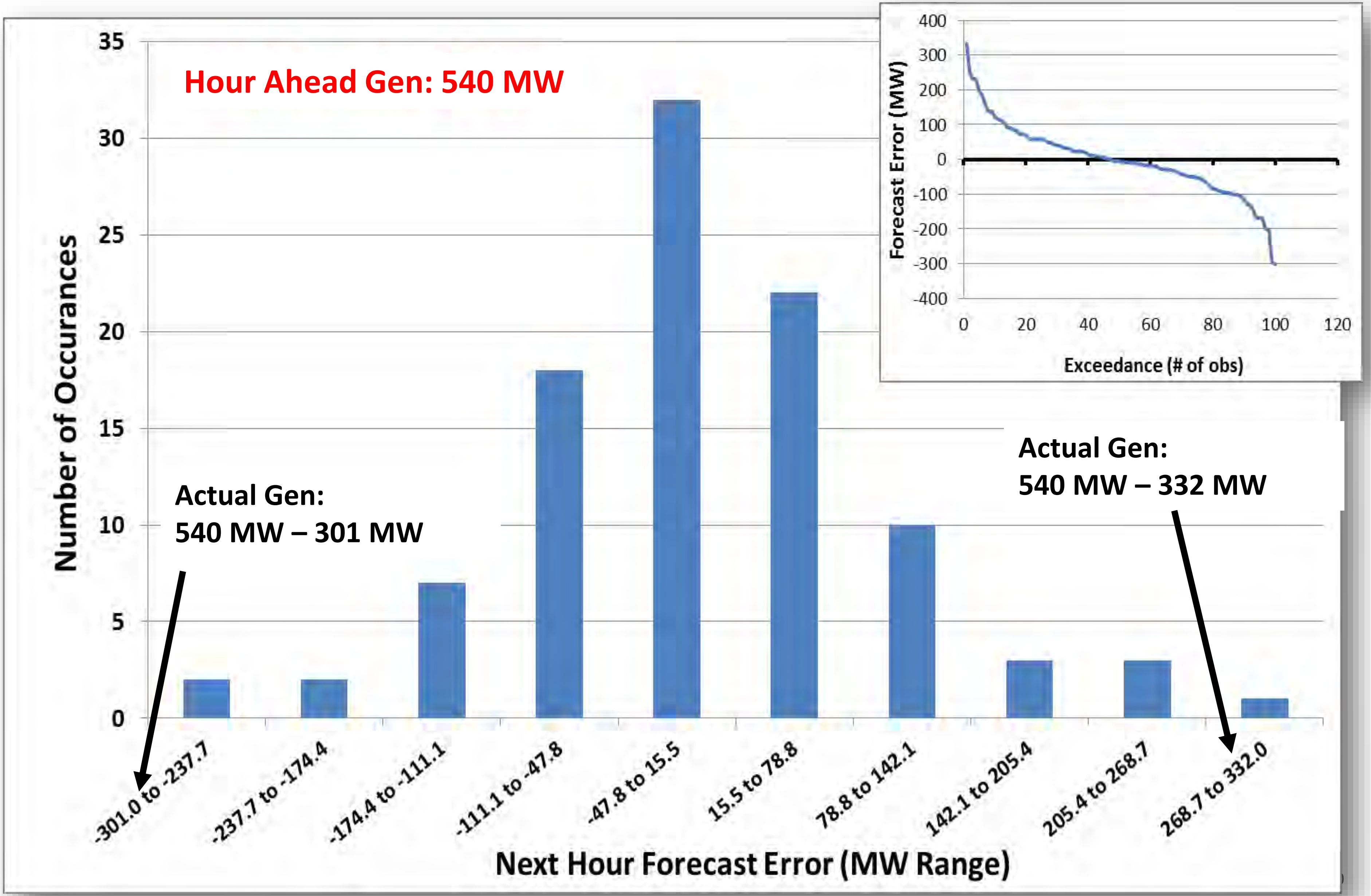
$$WindPower = \frac{1}{2}\rho A C_P V_\infty^3$$

POWER OUTPUT IS REDUCED DUE TO GENERATOR LOSSES (20% - 50%) AND GEAR BOX LOSSES (~5%)

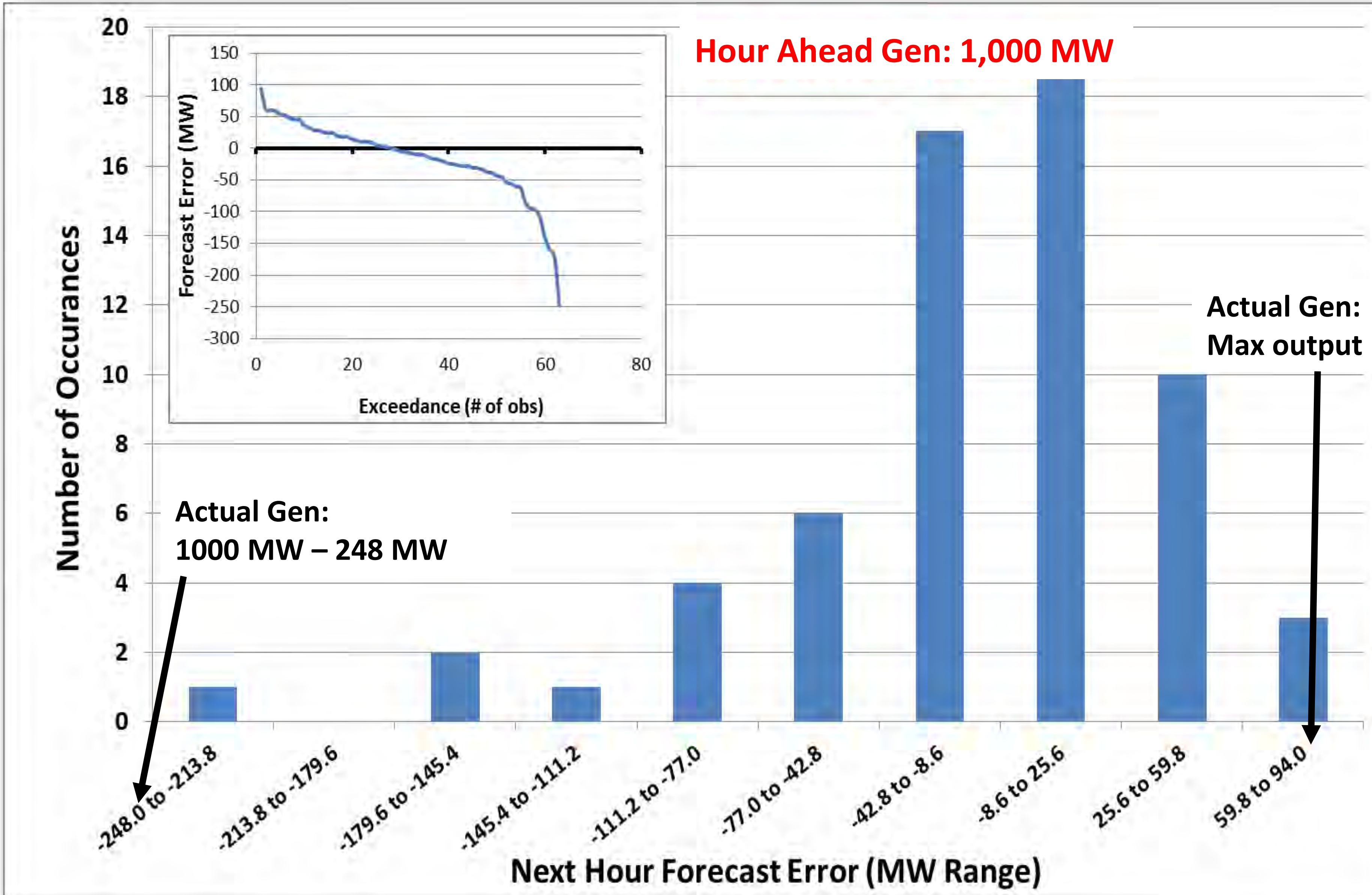
Flexible Reserve Requirements Is Based the Current Variable Resource Generation Level - *Low Generation*



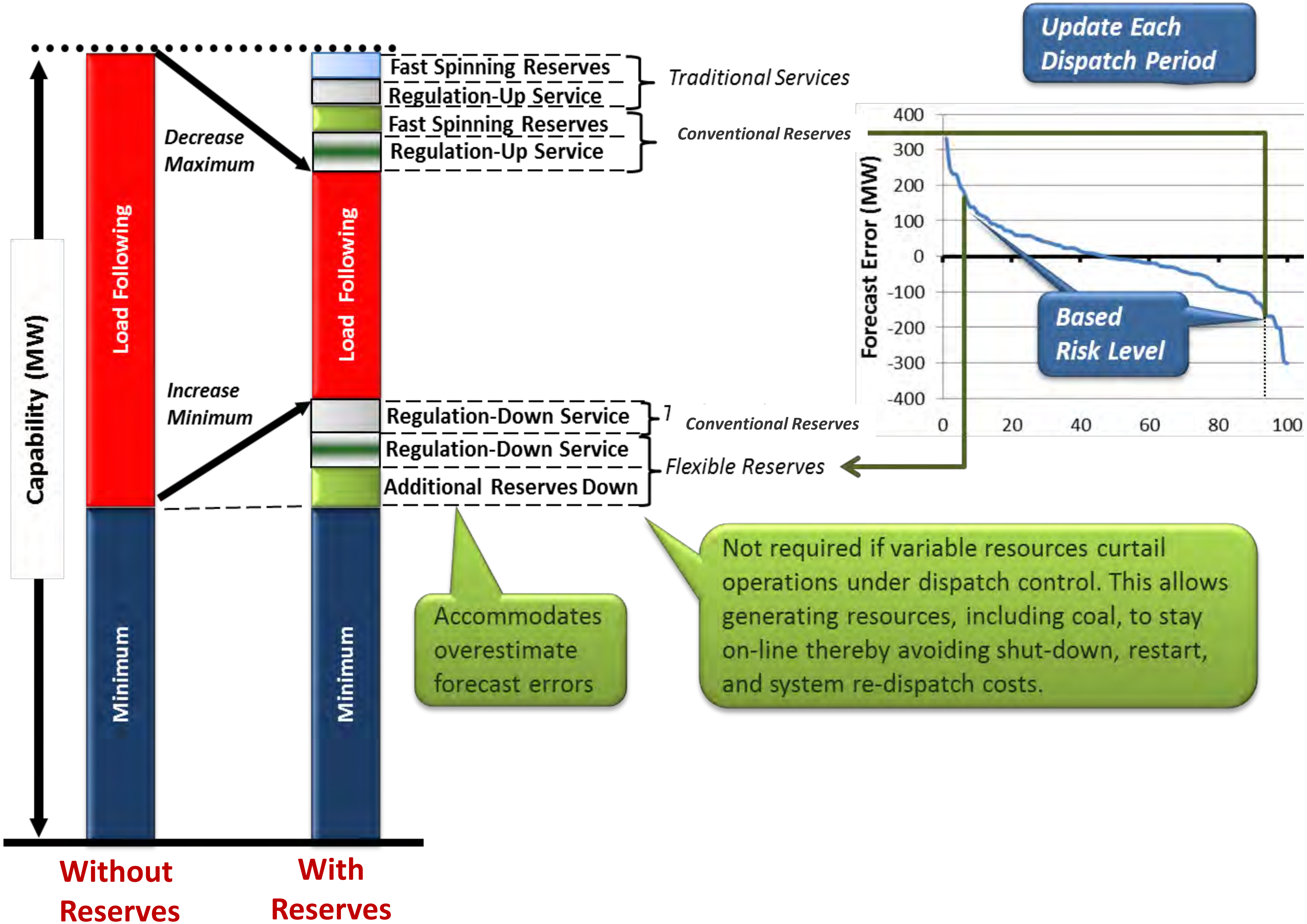
Flexible Reserve Requirements Is Based the Current Variable Resource Generation Level - *Medium Generation*



Flexible Reserve Requirements Is Based the Current Variable Resource Generation Level - *High Generation*

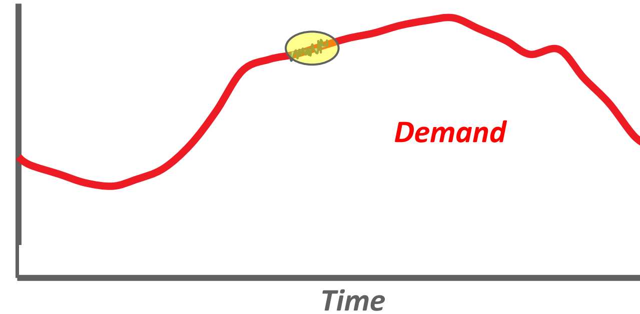


Flexible Reserve Requirements Affect the Operational Range of a Power Plant



Instantaneous Energy Imbalances

Area Control Error (ACE) Is a Measure of System Error in Balancing Area Interchange and Time Error



Actual Versus Scheduled Net Interchanges (MW) Over BA Tie-Lines

Actual Versus Target Frequency (Hz)

Time Error (seconds)

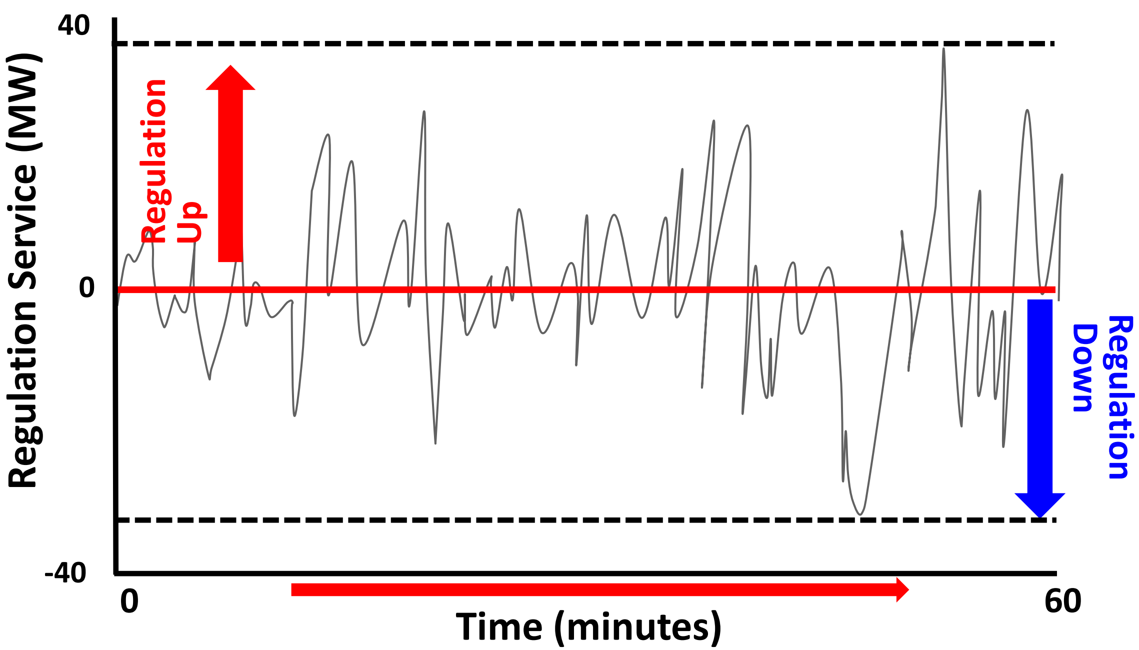
$$\mathbf{ACE} = (T_a - T_s) - 10B_f\,(F_a - F_s) +/- B_t\ T_e$$

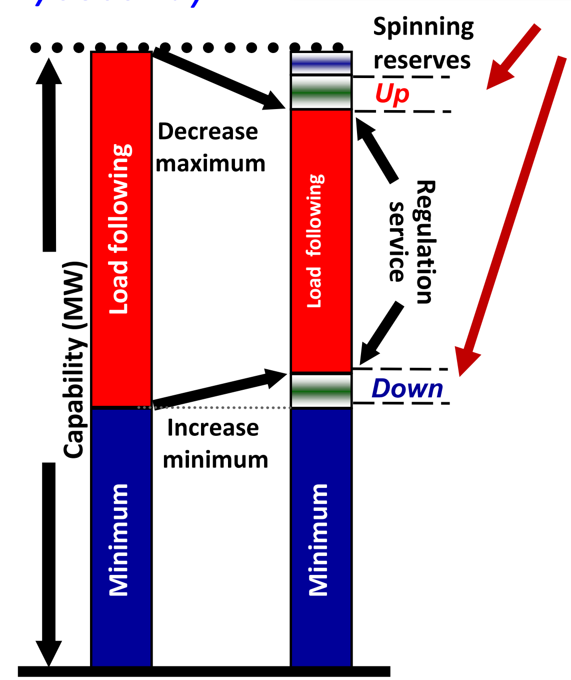
Area Bias per 0.1 Hz (MW/Hz)

Fast (+) Slow(-) clock

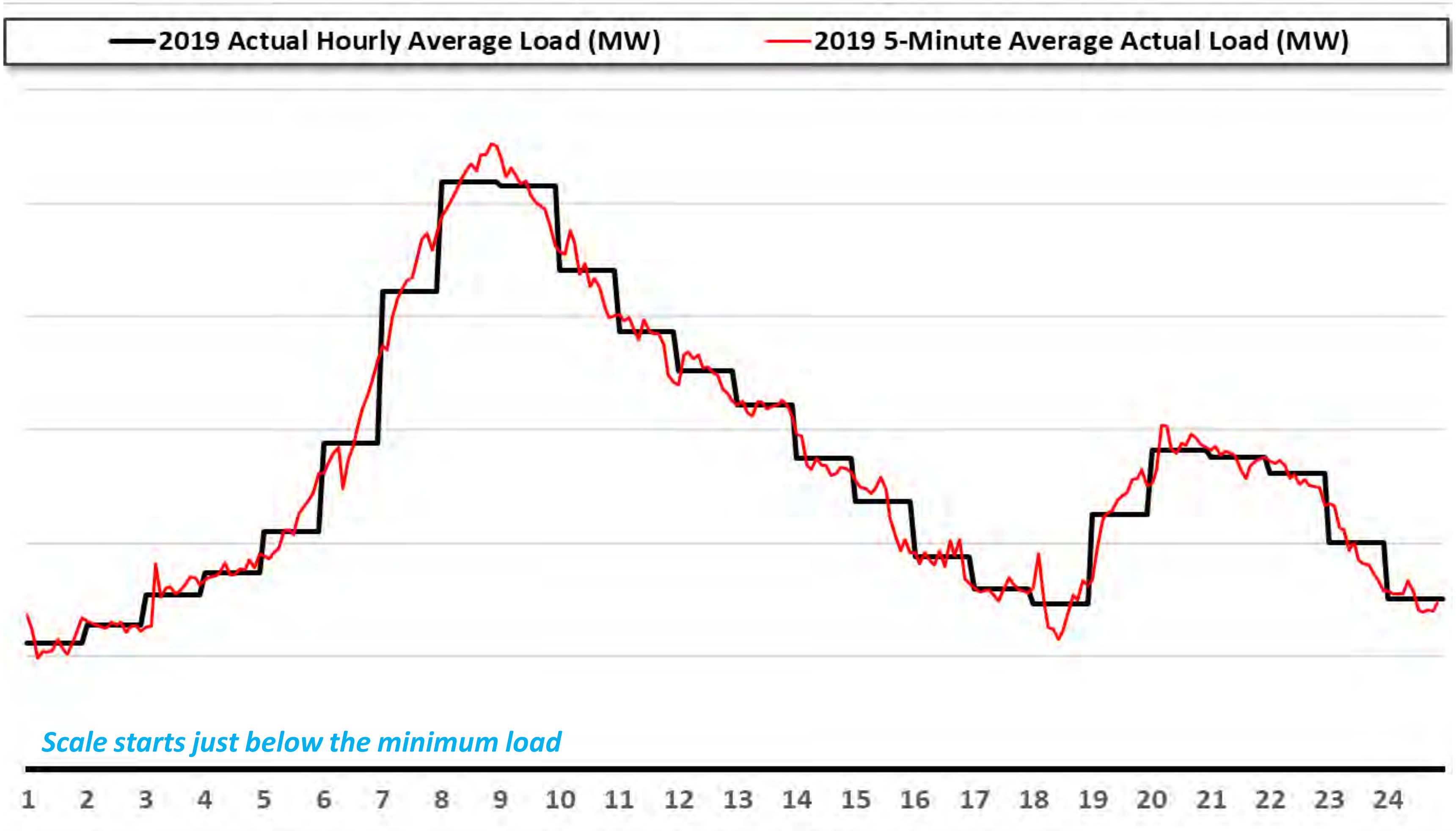
Time Error Bias (MW/second)

Units on Automatic Generation Control (AGC)



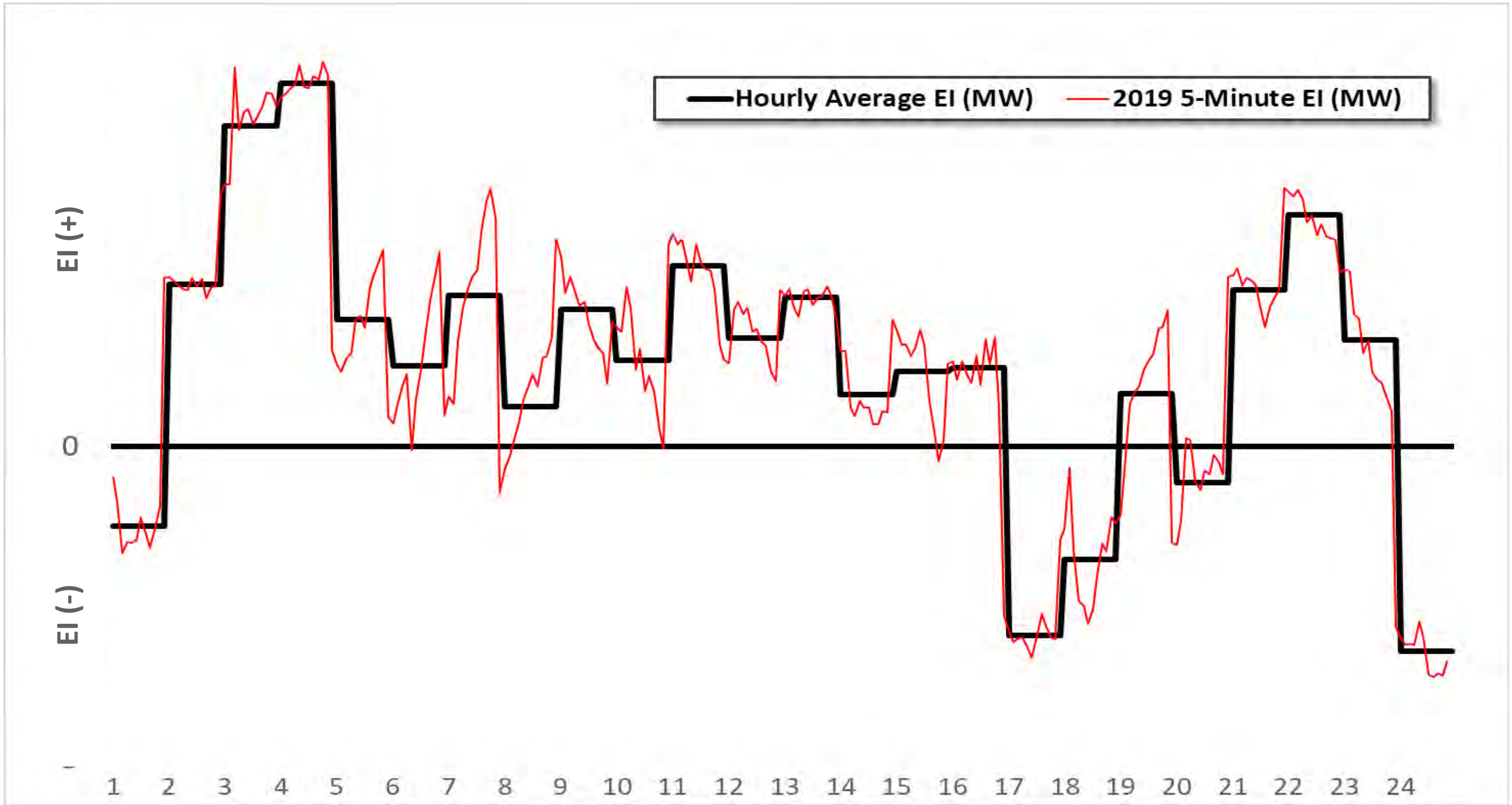


Load EI Occurs on an Instaneous Basis



Load EI+: Actual load less than scheduled load
Load EI-: Actual load than scheduled load

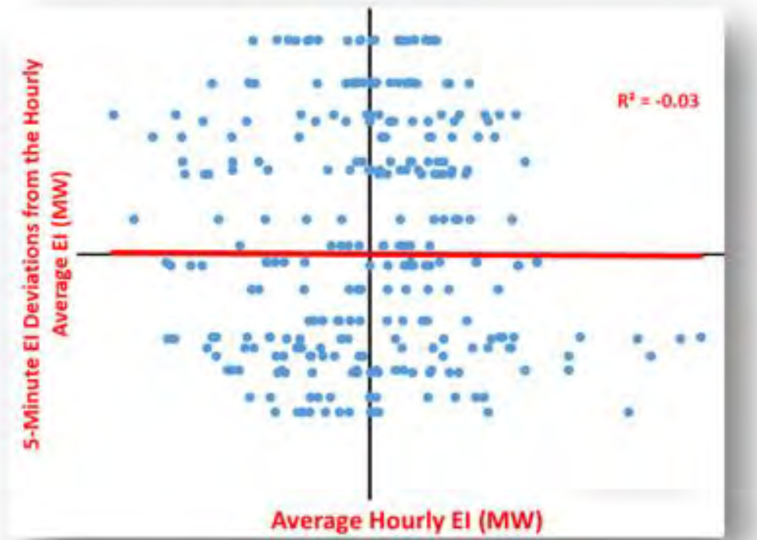
EI Is either Positive (EI+: Energy Long) or Negative (EI-: Energy Short)

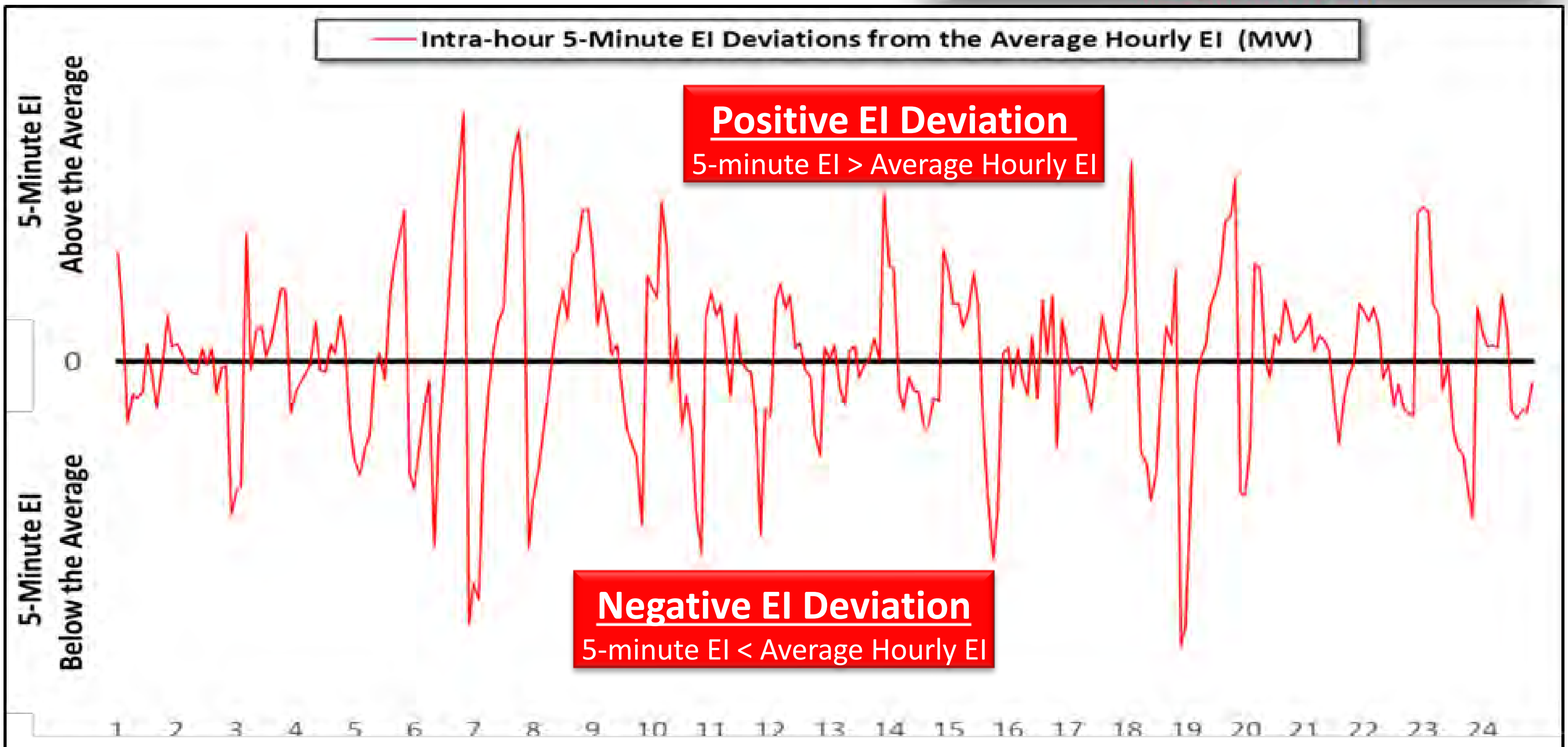


<u>In addition to Load EI and Gen EI , EI is also caused by</u>

Inadvertent flows: EI+: higher than scheduled net inflow
EI-: Less than scheduled load

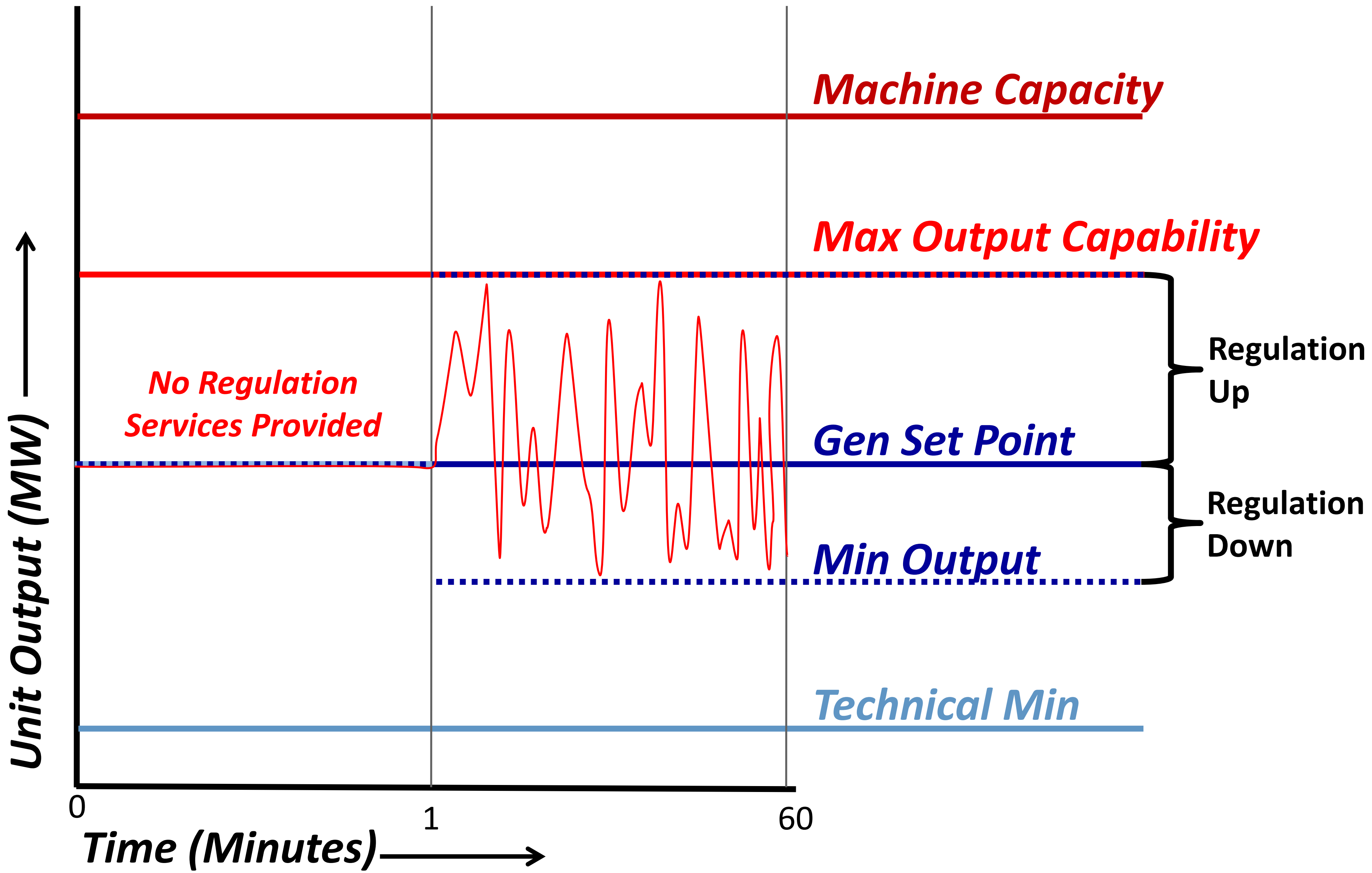
EI Has Random Properties both at the Hourly and 5-minute Time Steps



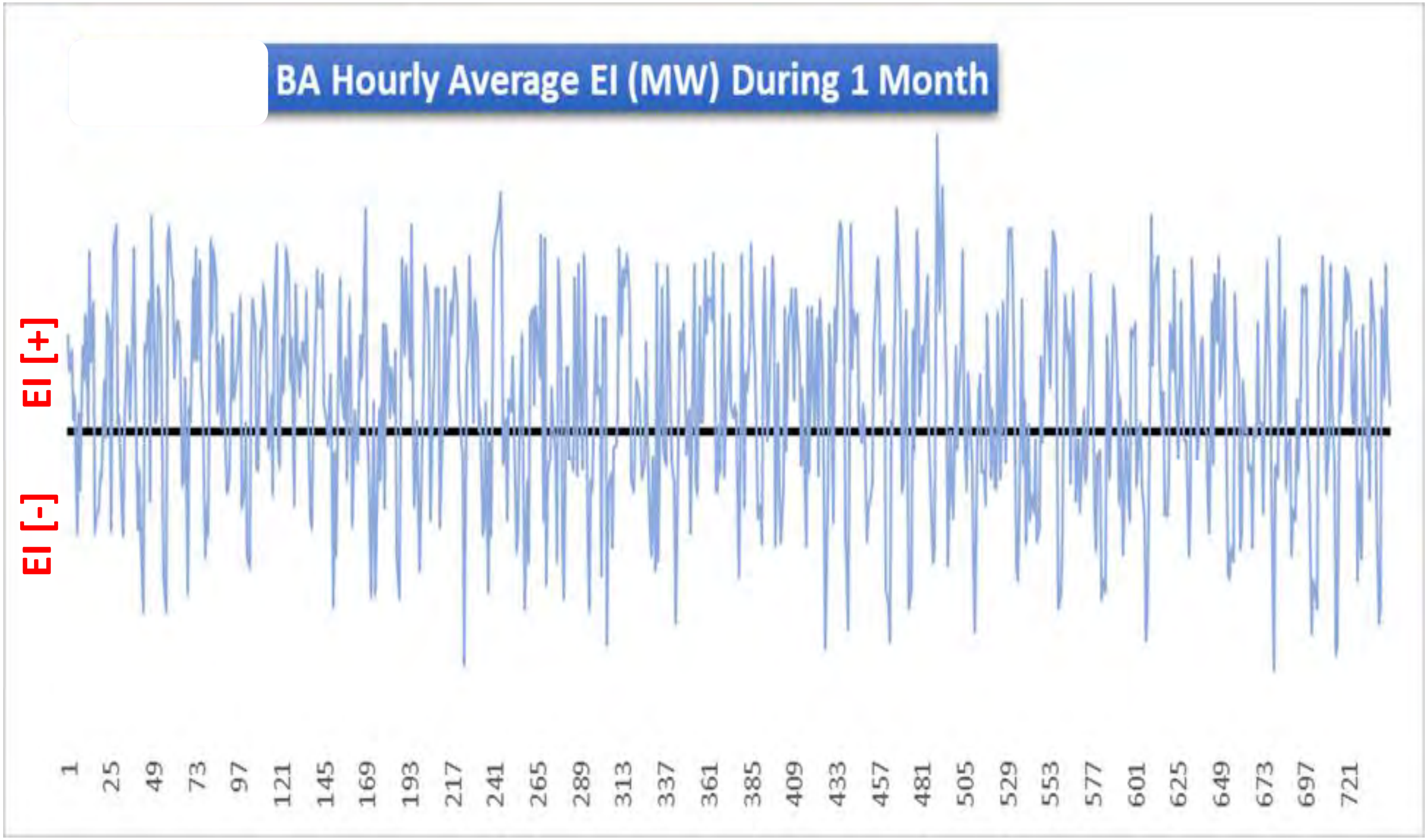


Regulation Up and Down Services
Intra-Base Unit Time Assumptions

Unit on Automatic Generation Control (AGC)

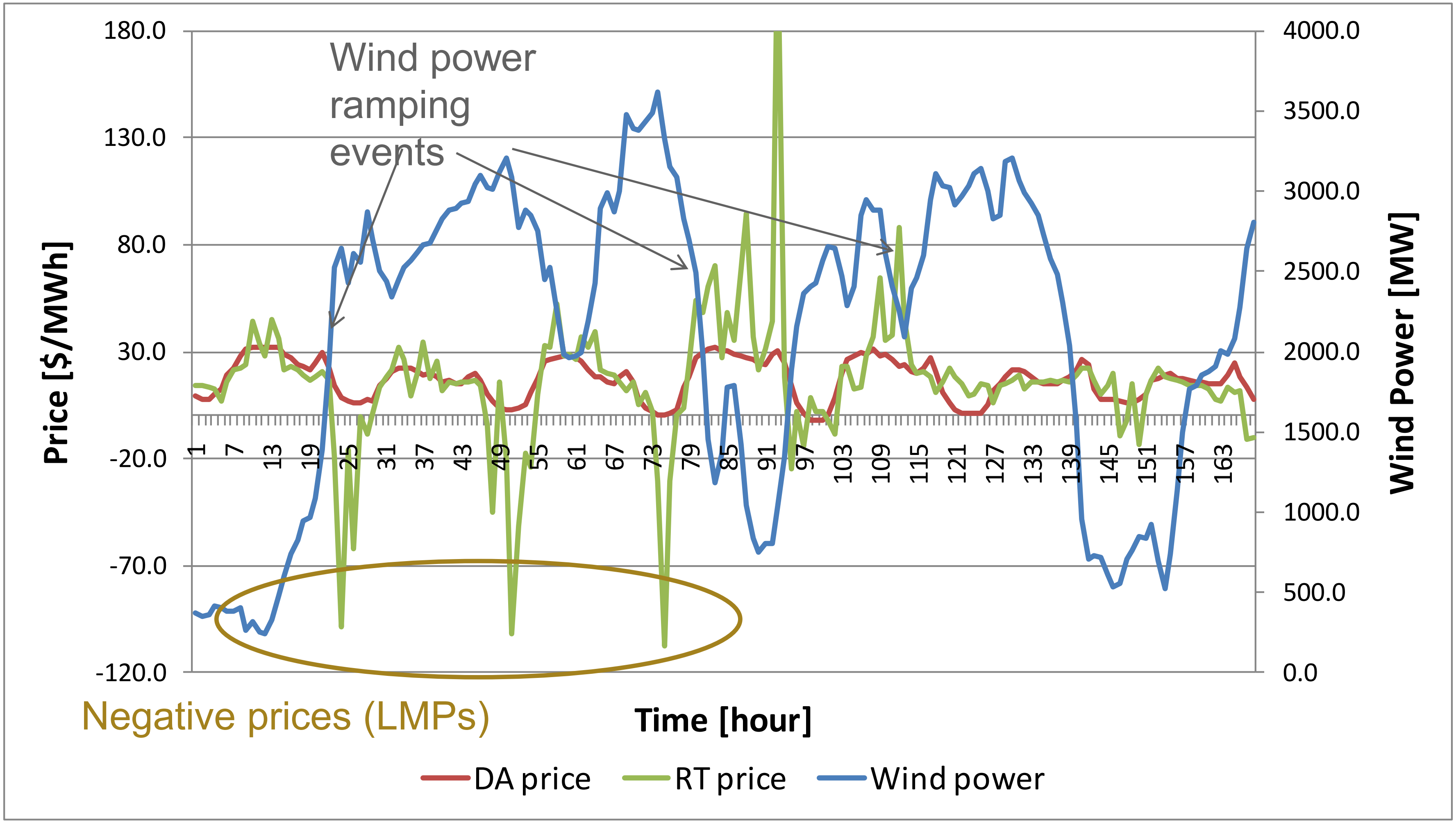


Traditionally, Operators Resolve EI Using Only Those Resources that Reside within its BA



Wind Power Influences Electricity Prices

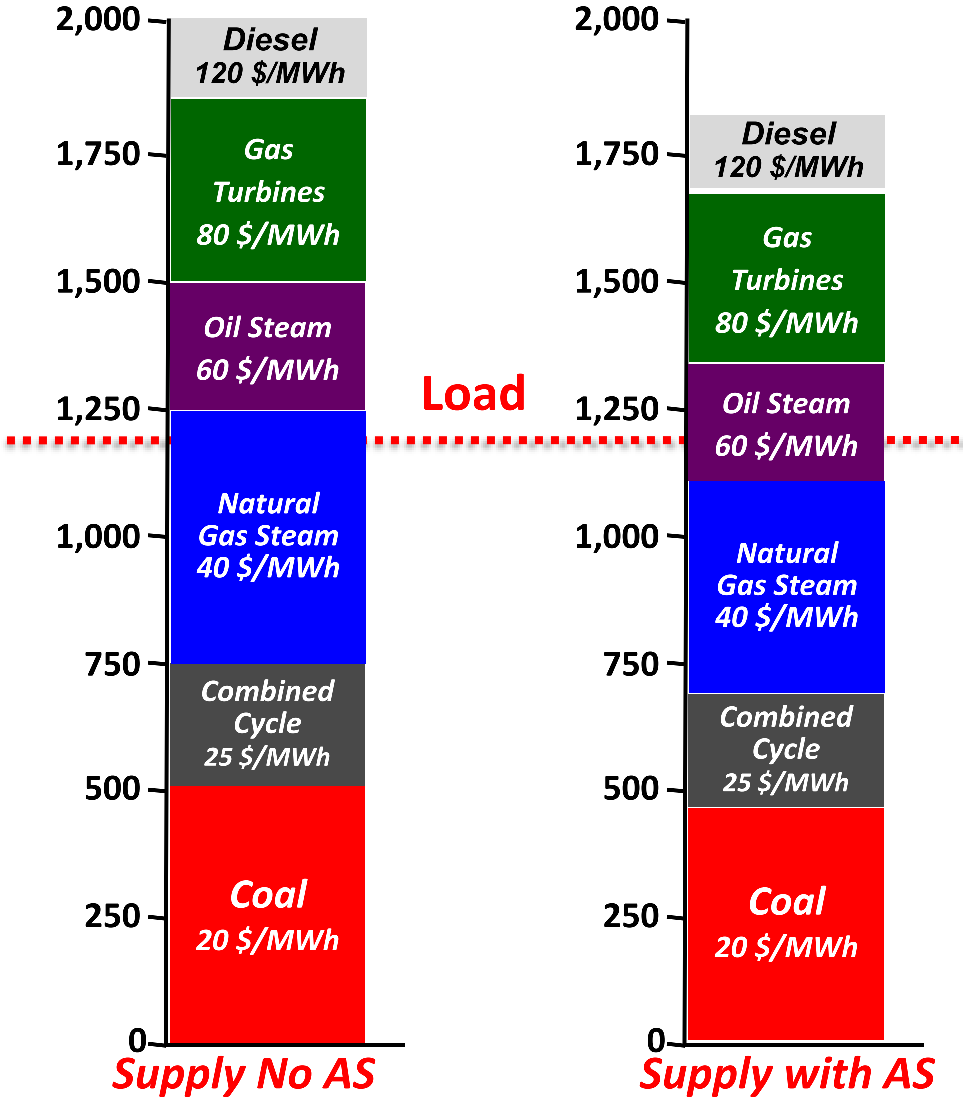
Midwest ISO Wind Power and Iowa LMPs, May 11-17, 2009:*



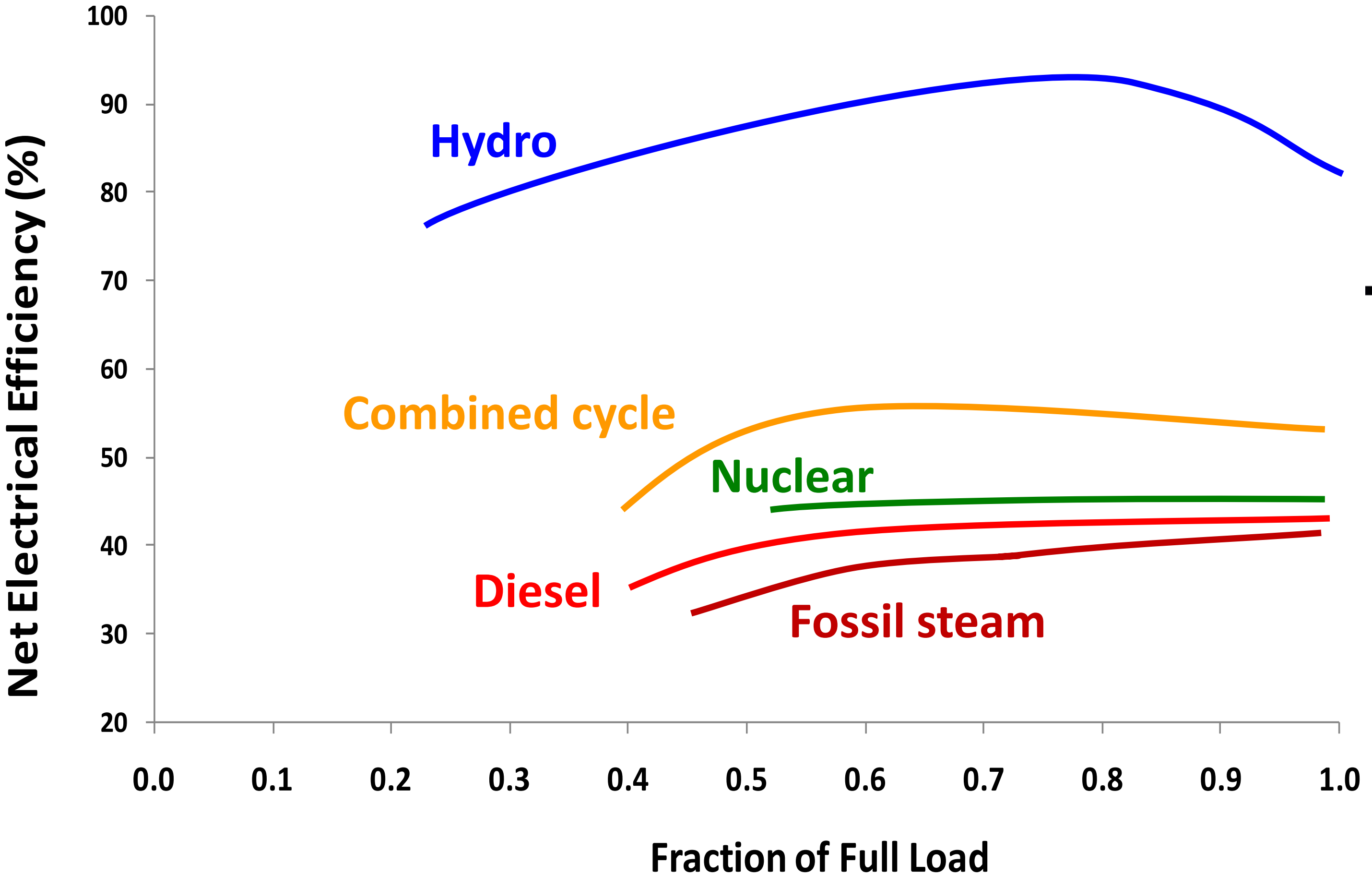
Economic and Finaincial Cost of Providing Ancillary Services

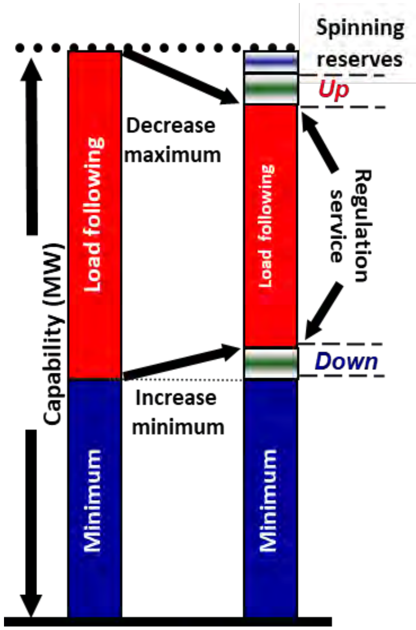
Ancillary Services (AS) Incurs Grid Economic Costs

Commit More and Higher Cost Units



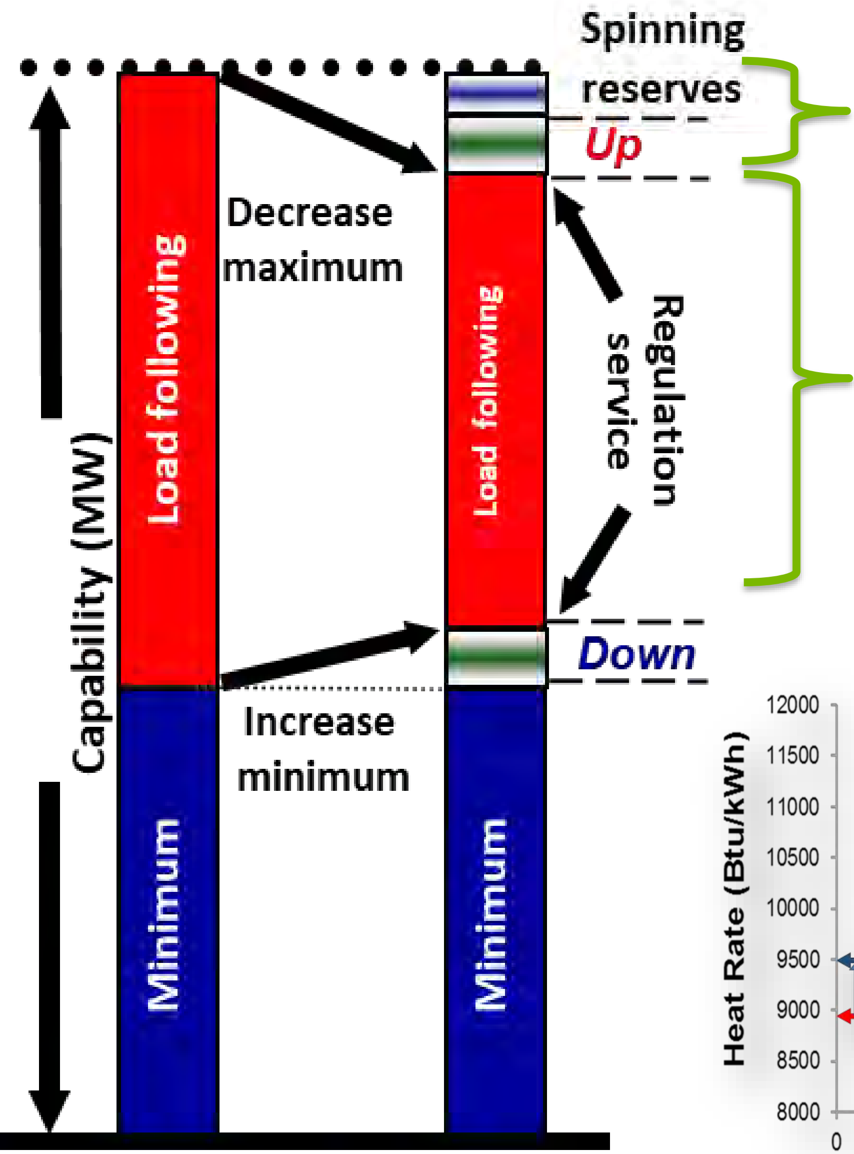
As a Result of Grid VRE Some Units Will Operate at a Different Efficiency Point





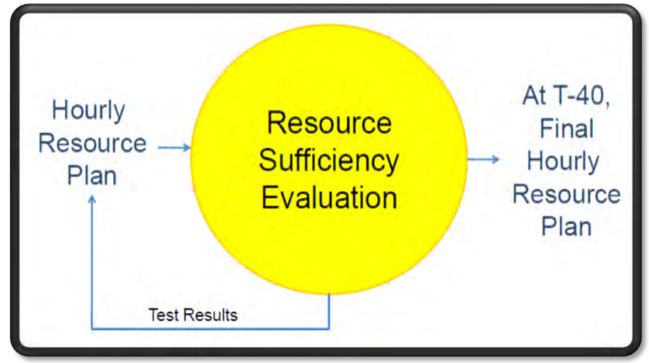
Financial Implications for Generation Owner/Operators

Ancillary Service Markets Provide Incentives to Provide These Services

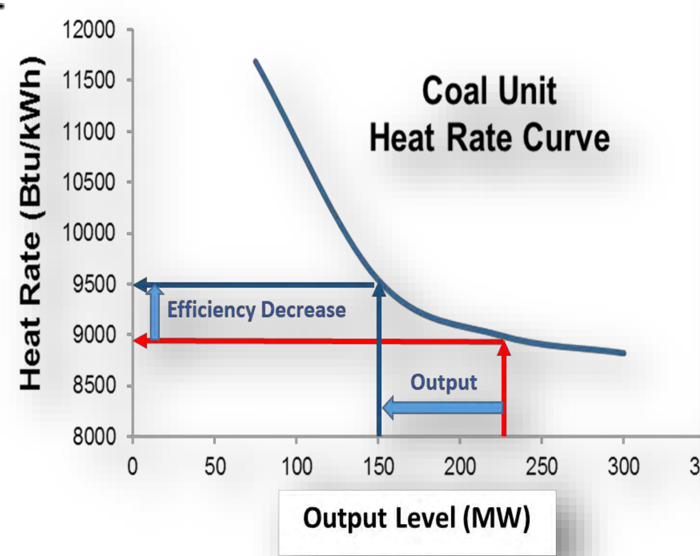


Lost Opportunity (Cost) to Sell Higher Levels in the Energy Market

Reduced Operating Flexibility

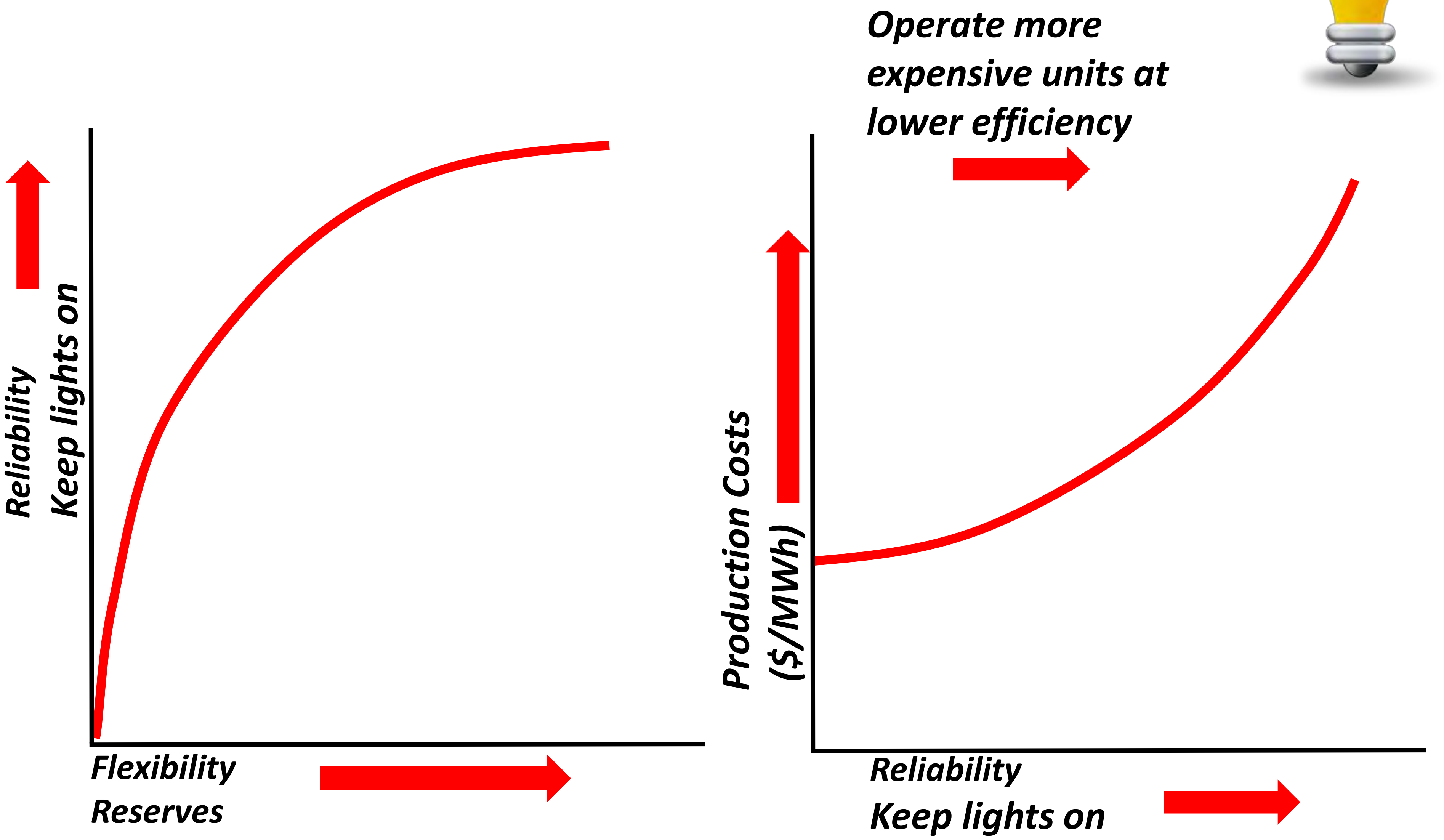


Lower Efficiency (e.g., need to burn more fuel)



Load	Partial Load Penalty (%)			
	Coal (ST)	Gas (CC)	Gas (CT)	Oil (CT)
25 %	34.19	44.84	64.97	113.46
50 %	9.06	13.20	17.97	26.82
75 %	2.24	3.82	4.76	5.27
100 %	0.00	0.00	0.00	0.00

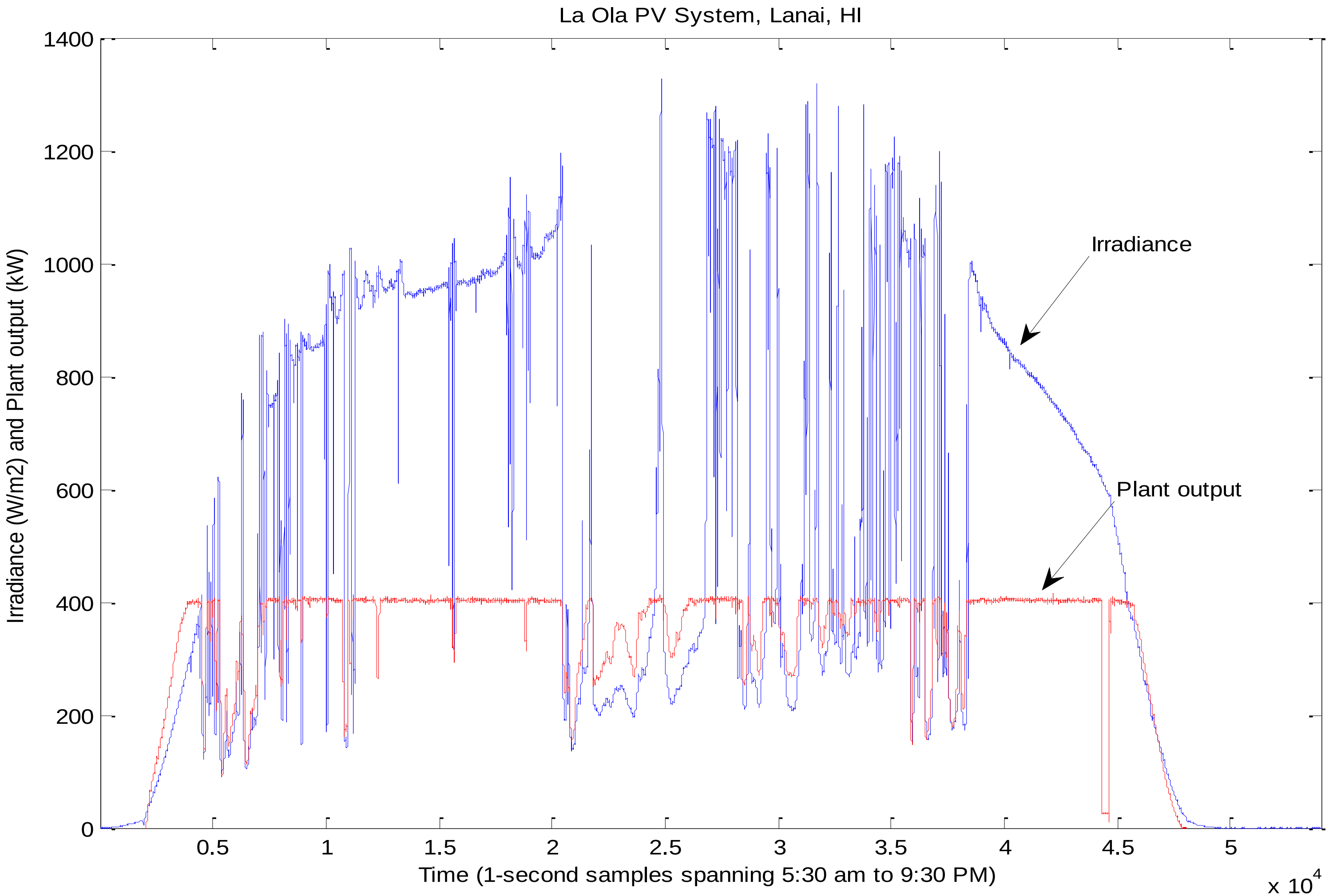
Reliability Increases as More Reserves Are Added but Higher Reliability Is Increasingly More Expensive



VRE Technology Solutions

Clouds Can Produce Rapid Changes in Incoming Solar Energy

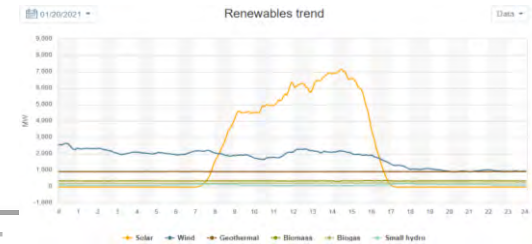
PV Variability in the La Ola PV System

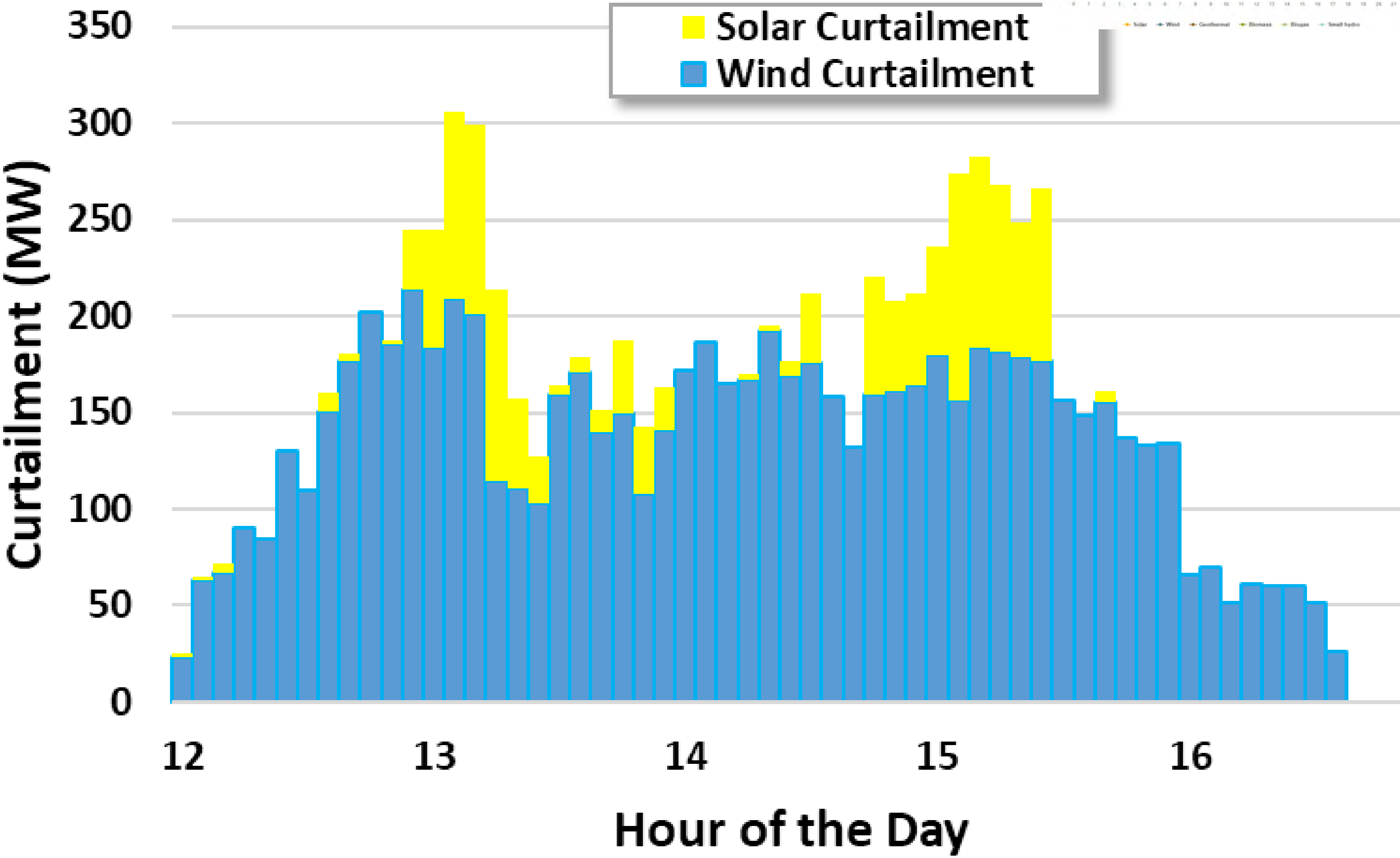


Irradiance and PV system ac output (typical partly cloudy day in July)

Sandia National Laboratory (SNL)

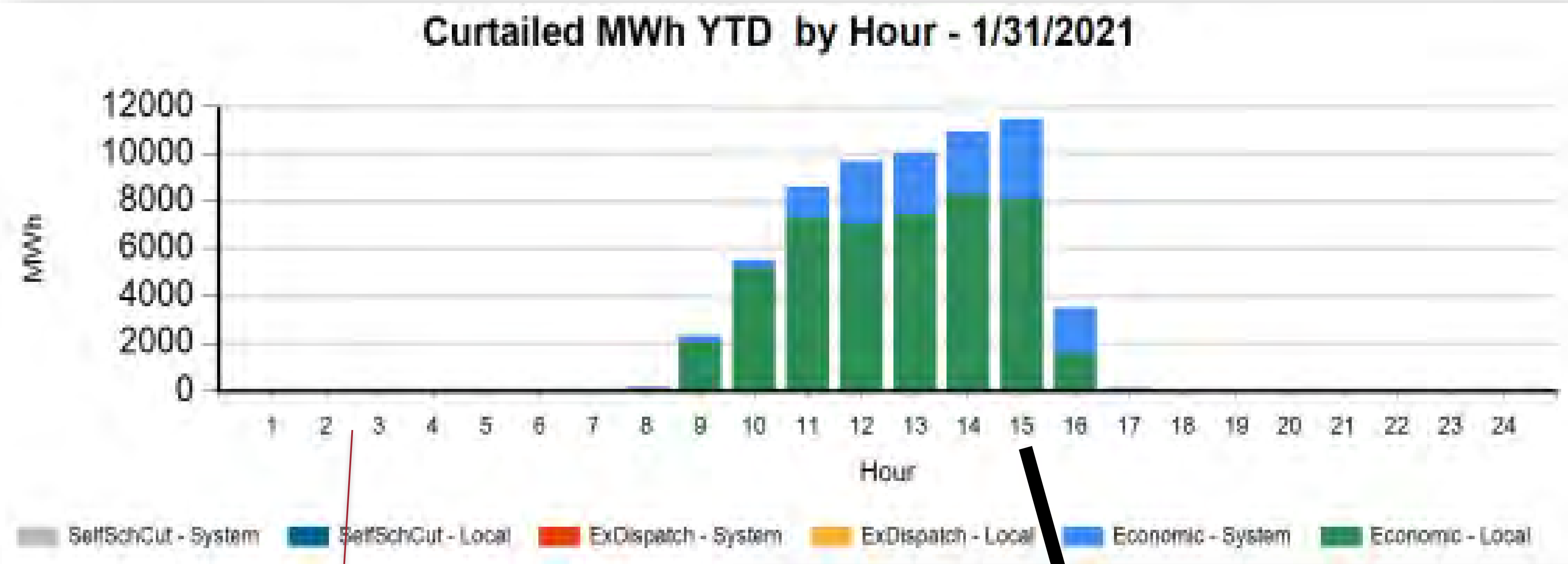
Jan 20th 2021 CAISO Curtailments



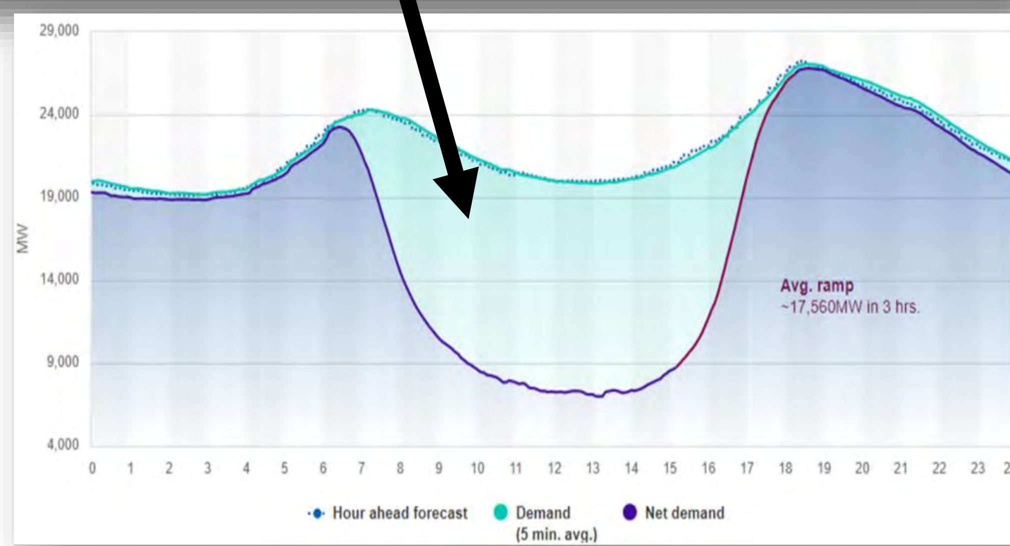


http://www.caiso.com/informed/Pages/ManagingOversupply.aspx#dailyCurtailment

Cumulative Hourly CAISO Wind and Solar Curtailment for the Month of January 2021



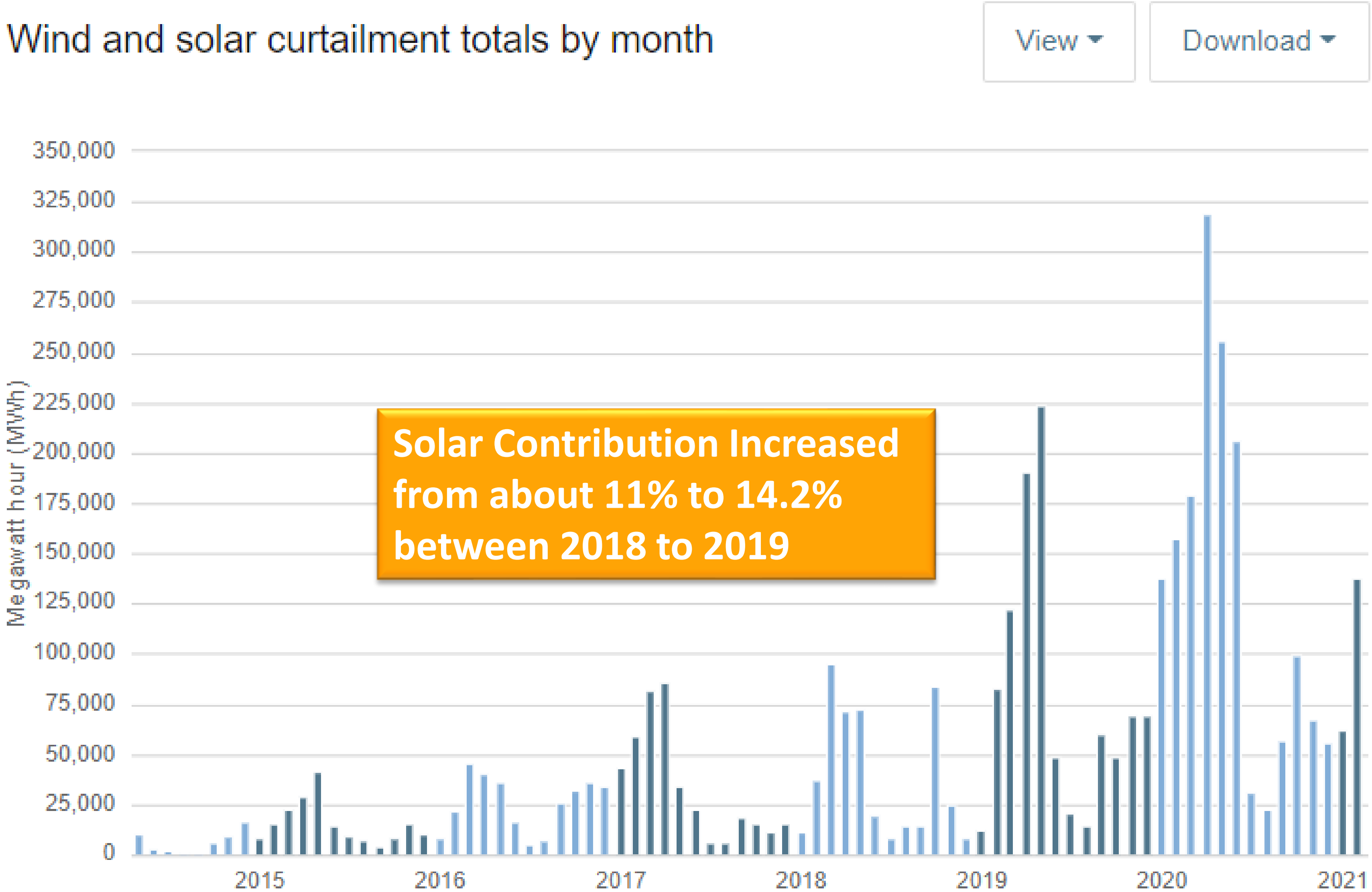
During Hours of Relatively Low VRE Production, Curtailments Are not Needed



Without curtailments the bottom of the trough would be deeper and the ramping would be steeper

http://www.caiso.com/Documents/Wind_SolarReal-TimeDispatchCurtailmentReportJan31_2021.pdf

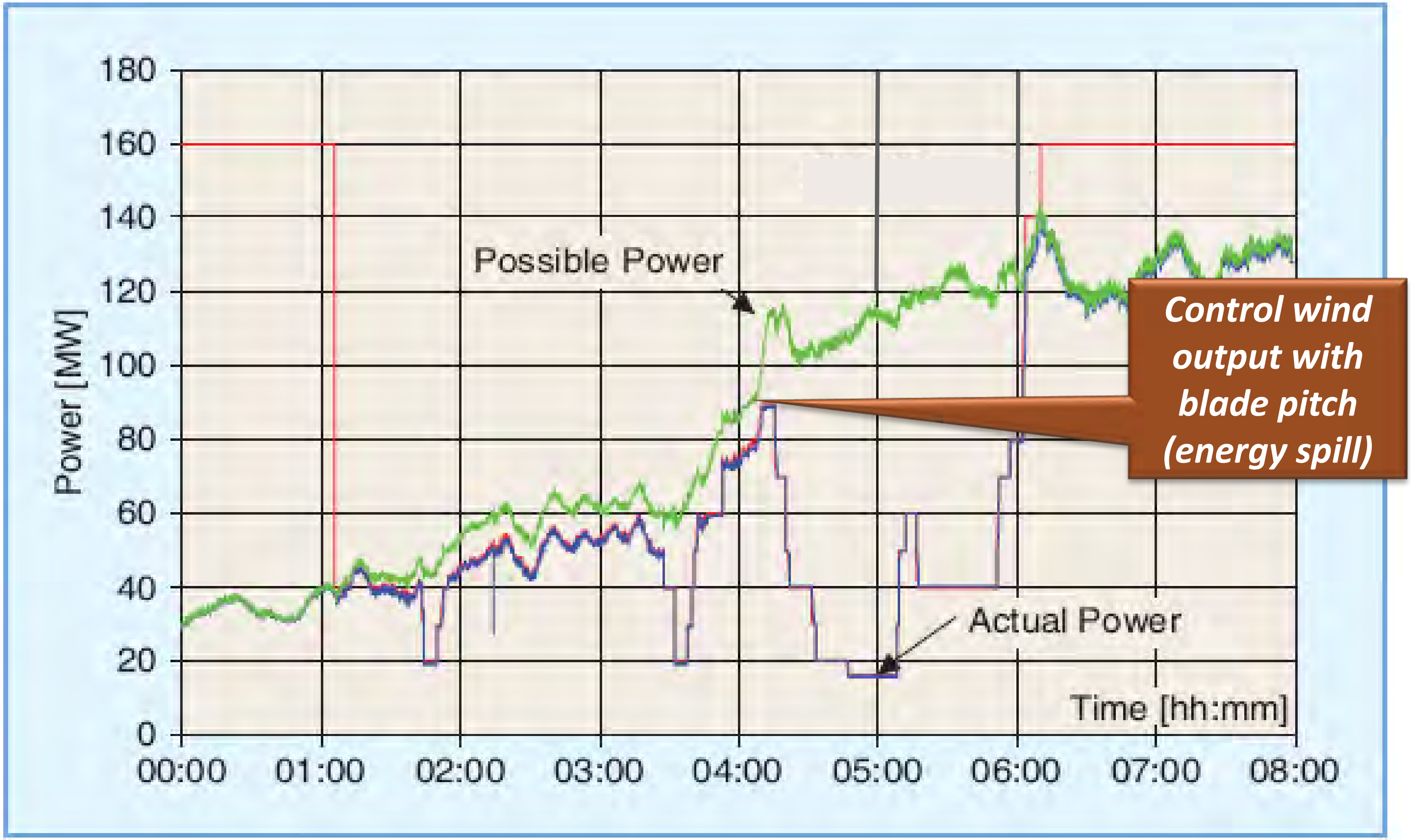
Curtailments Increase as Solar Contributions to the Supply Mix Grows



http://www.caiso.com/informed/Pages/ManagingOversupply.aspx#dailyCurtailment

Wind Technology Improvements Are Also Alleviating Some Problems Associated with Integrating Wind Energy into the Grid

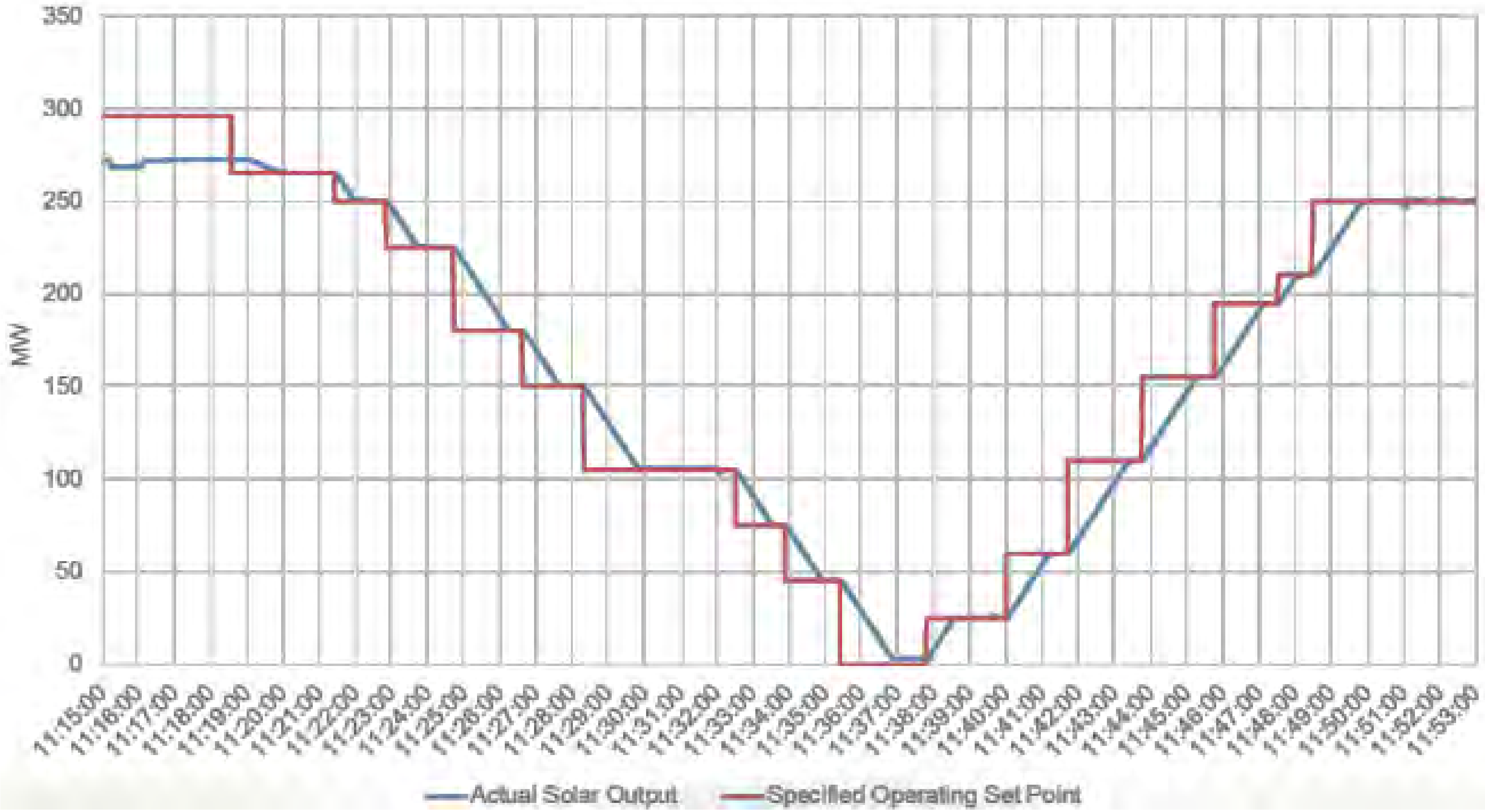
Example: The Danish Horns Rev Wind Farm Is Providing Regulation (Frequency Response) and Balancing Response



Source: Smith et al., IEEE Power and Energy Magazine, Vol. 7. No.2, 2009.

Actual Results from Solar Plant Ramping Test

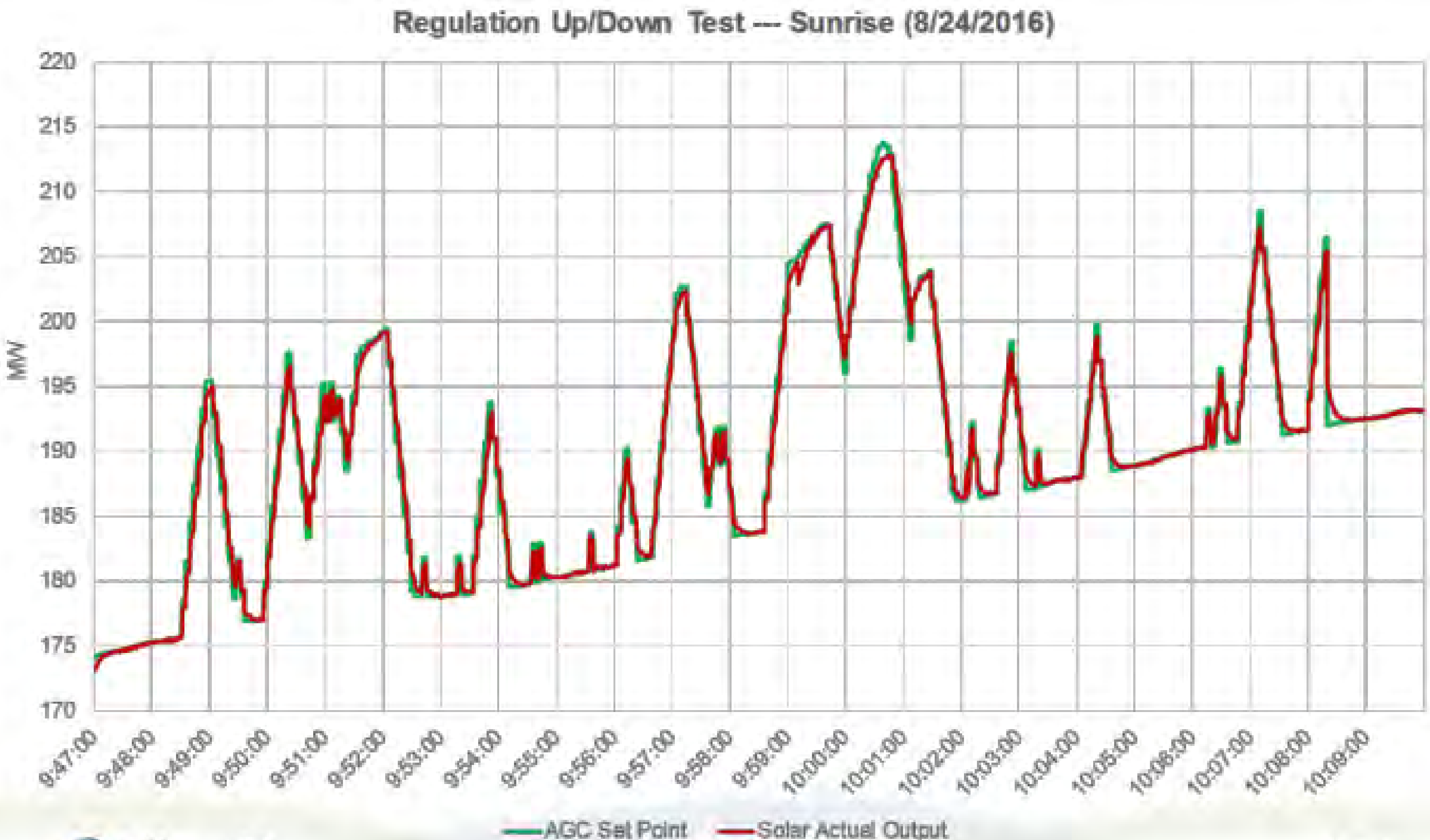
Output Closely Follows a Time Series Set Points



https://www.caiso.com/Documents/Briefing_UsingRenewables_IncorporateRenewables-Presentation-Dec2016.pdf

Actual Results from Solar Plant Regulation Test

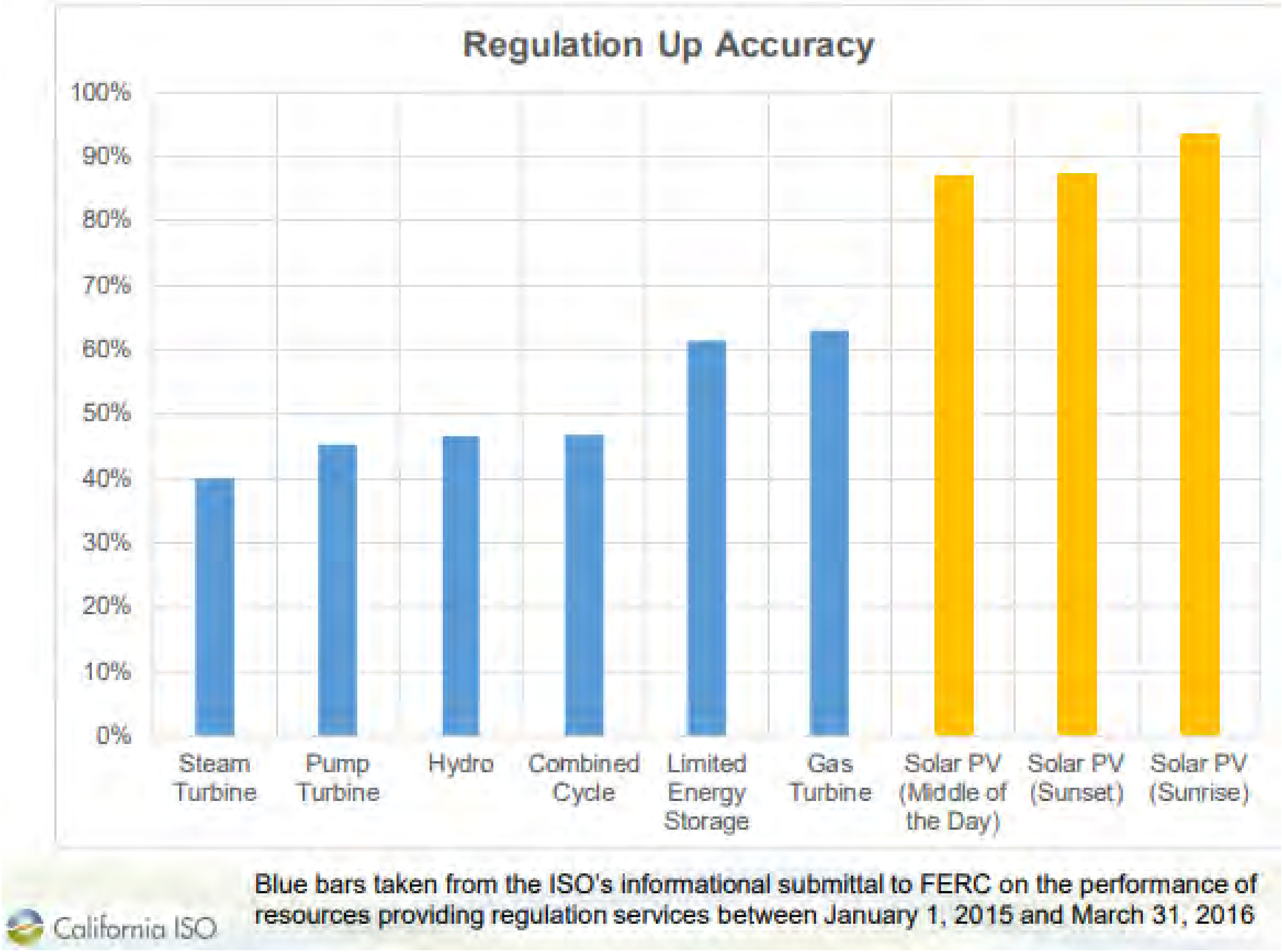
Output Closely Follows 4-second Regulation Signals



California ISO

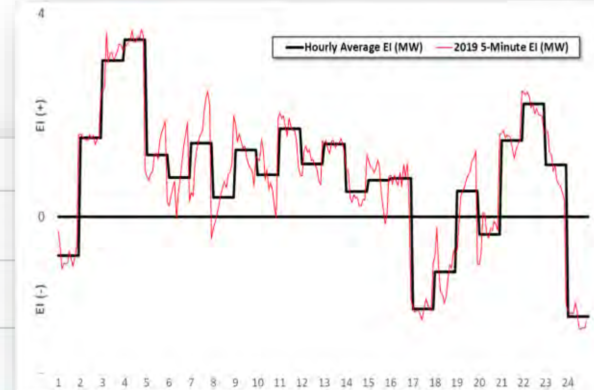
Actual Results from Solar Plant Regulation Test

Solar Regulation Accuracy Outperformed other Technologies



https://www.caiso.com/Documents/Briefing_UsingRenewables_IncorporateRenewables-Presentation-Dec2016.pdf

CAISO Battery Operation- *Jan 20, 2021*



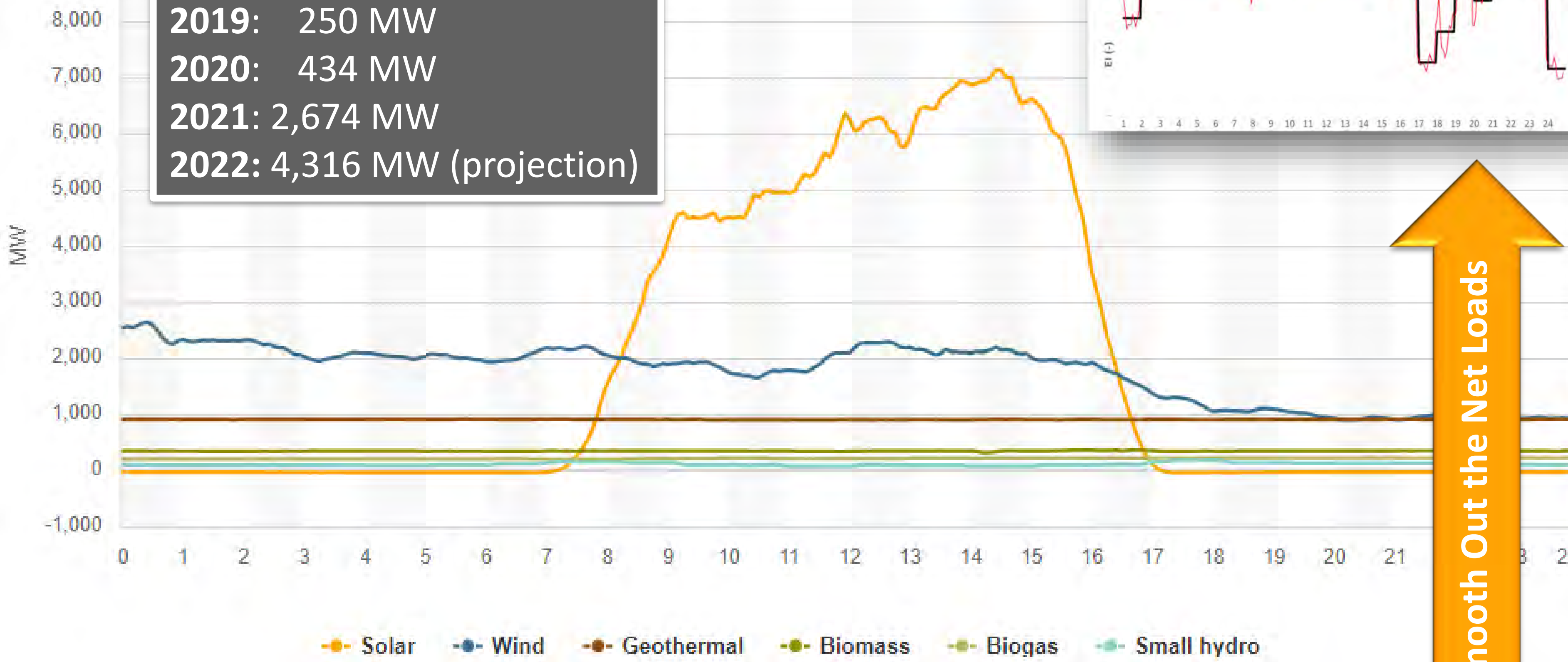
Battery Storage Capacity

2019: 250 MW

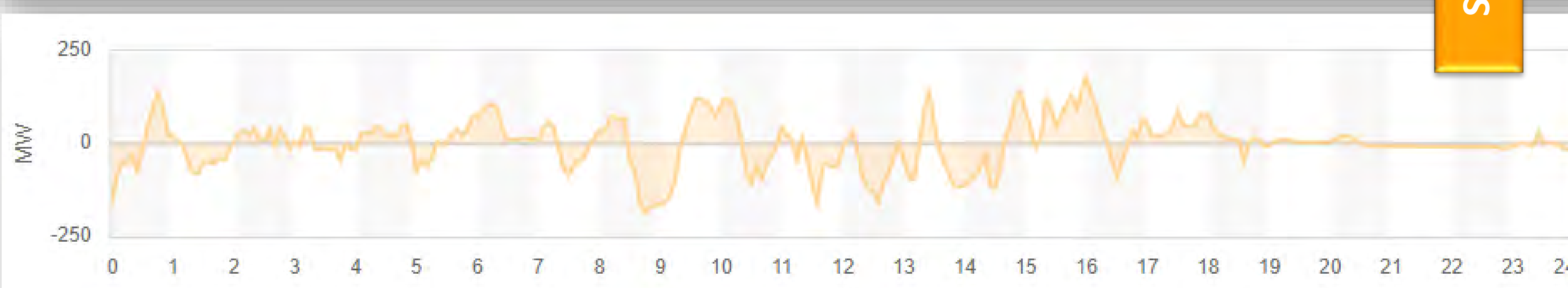
2020: 434 MW

2021: 2,674 MW

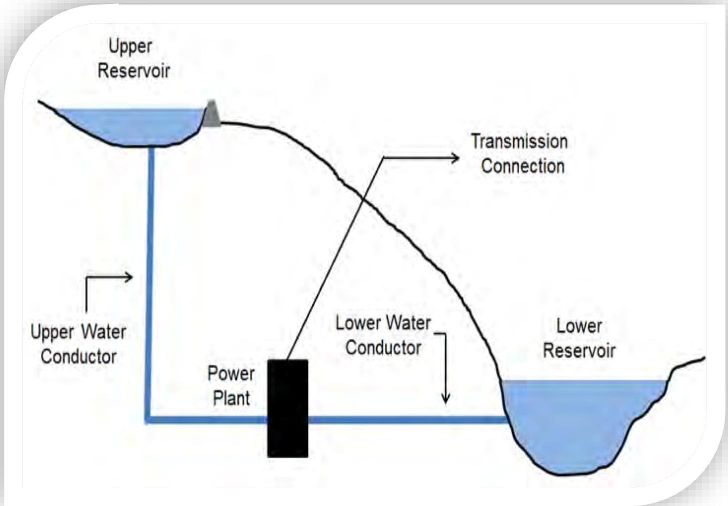
2022: 4,316 MW (projection)



Smooth Out the Net Loads



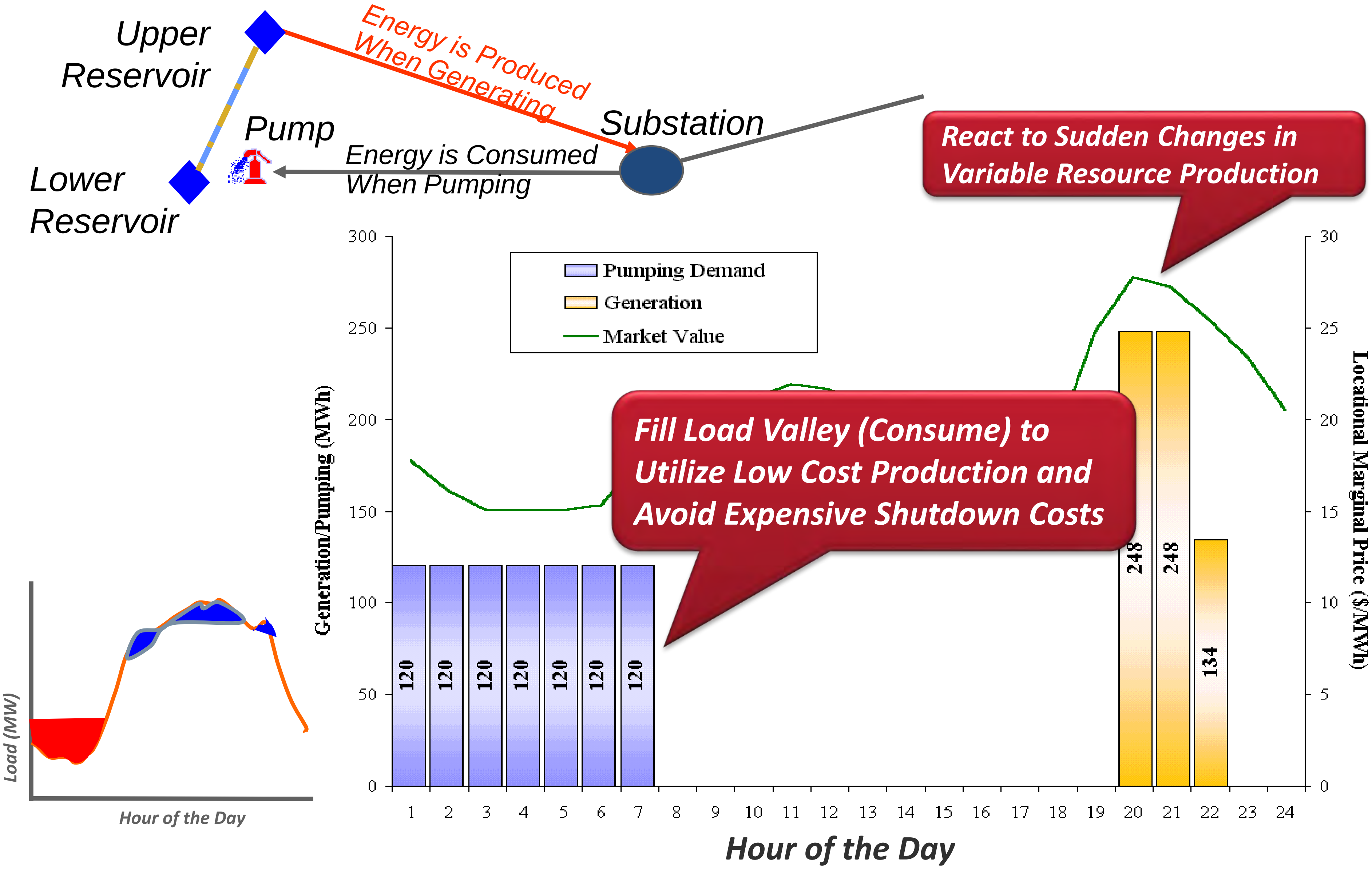
Pumped Storage Plants (PSH) Provide a Variety of Benefits



- Load shifting (energy arbitrage)
  - Increases efficiency of system operation:
    - Increasing the generation of base load units
    - Reduces the operation of expensive units
- Contingency reserve (spinning and non-spinning)
  - Provides large amount of quick contingency reserve (e.g., for the outages of large nuclear and coal units)
- Regulation reserve
  - Helps maintain system frequency at a narrow band around nominal system frequency by balancing supply and demand
- Load following
  - Provides a quick-ramping capacity
- Energy imbalance reduction
  - Compensates the variability of wind and solar power

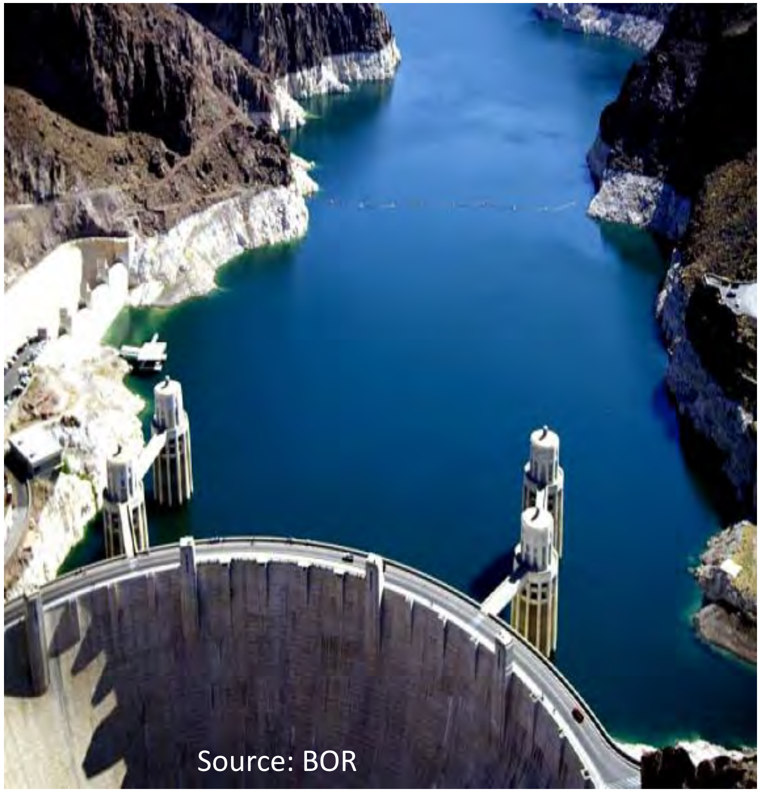
❑ Variable speed pumps provide flexibility in pump mode
❑ Traditional pumps are either on or off

Pumped Storage Plants Can Be Used Fill Net Load Valleys and Shaves Peak Net Loads

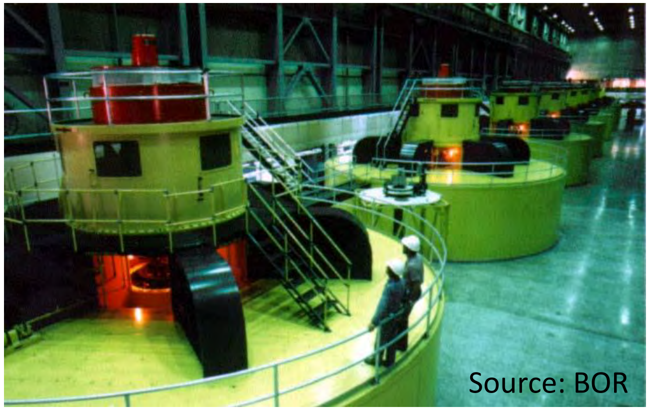


In Some Situations, Hydropower Plants Can Help Alleviate Variable Resource Integration Challenges

- Very flexible operation
  - Change operations quickly
  - Large range of operations
  - Good resource for ancillary services
- No fuel required
  - Very low production costs
  - Zero air emissions except for GHG
- High fixed costs
  - Expensive to build
  - Maintain dam, reservoir, & plant
- Environmental concerns
  - Effect operations and economics
- Institutional and contractual barriers

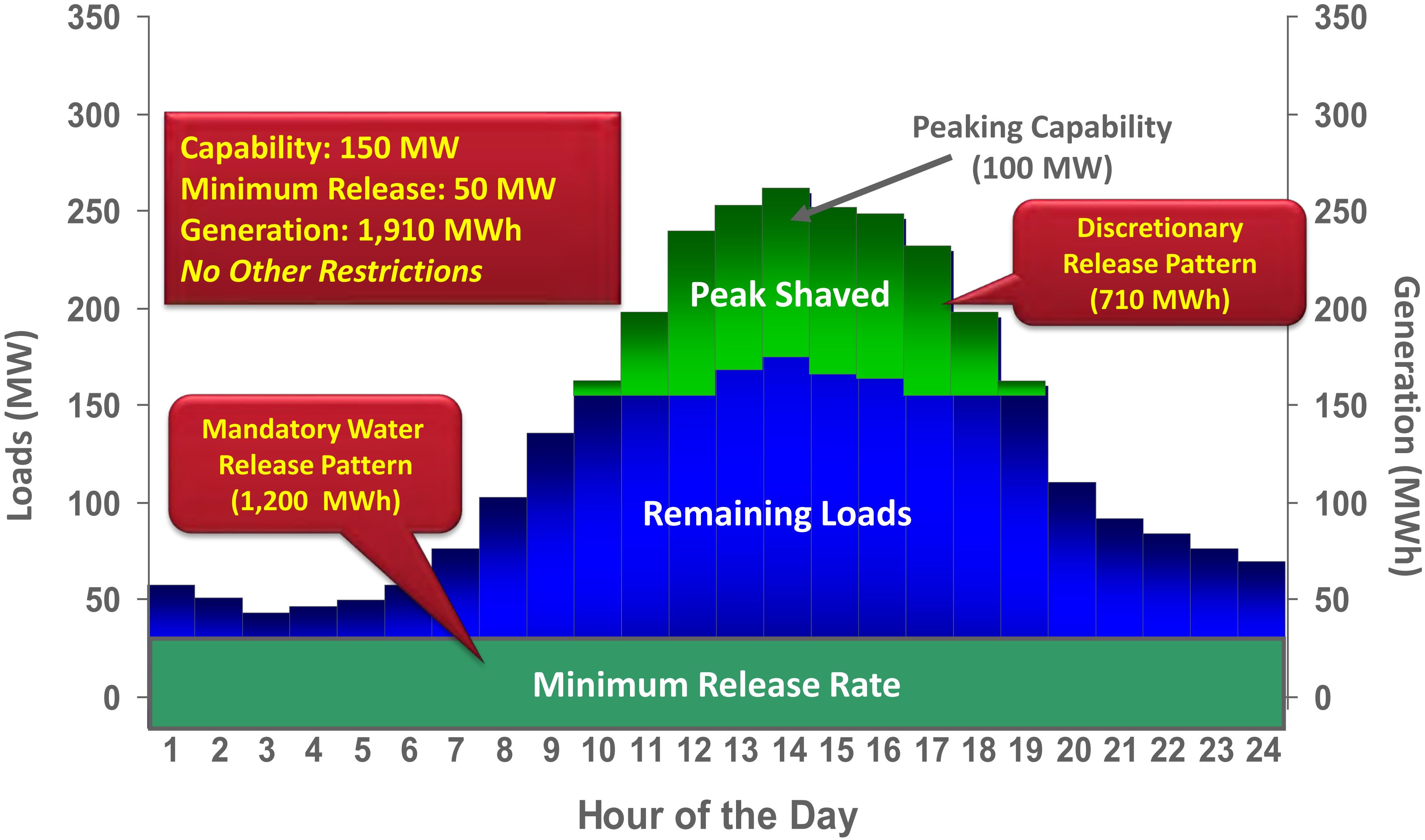


Source: BOR

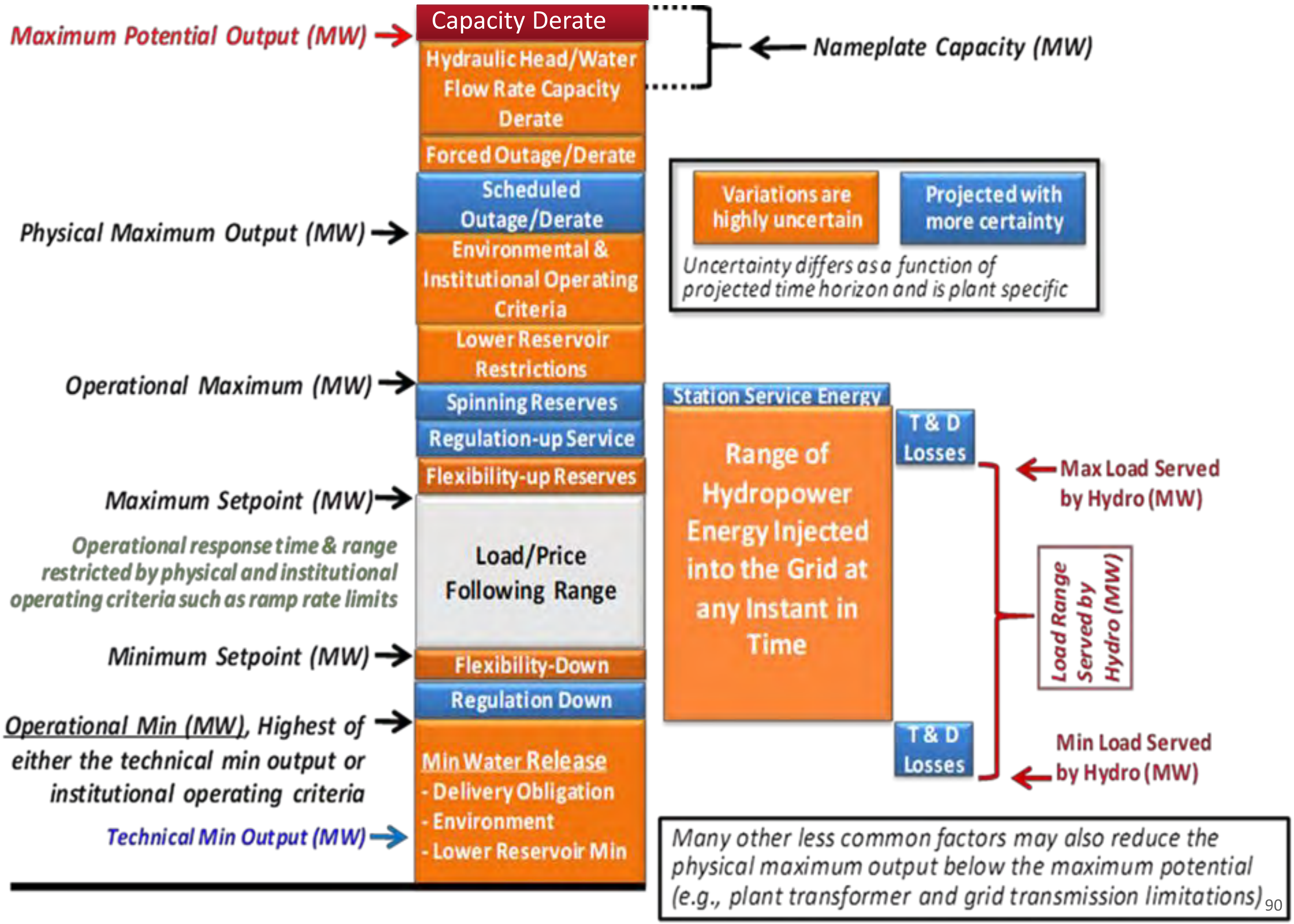


Source: BOR

Hydropower Plant Dispatch Displaces High Cost Thermal Generation and Minimize Ramping Levels



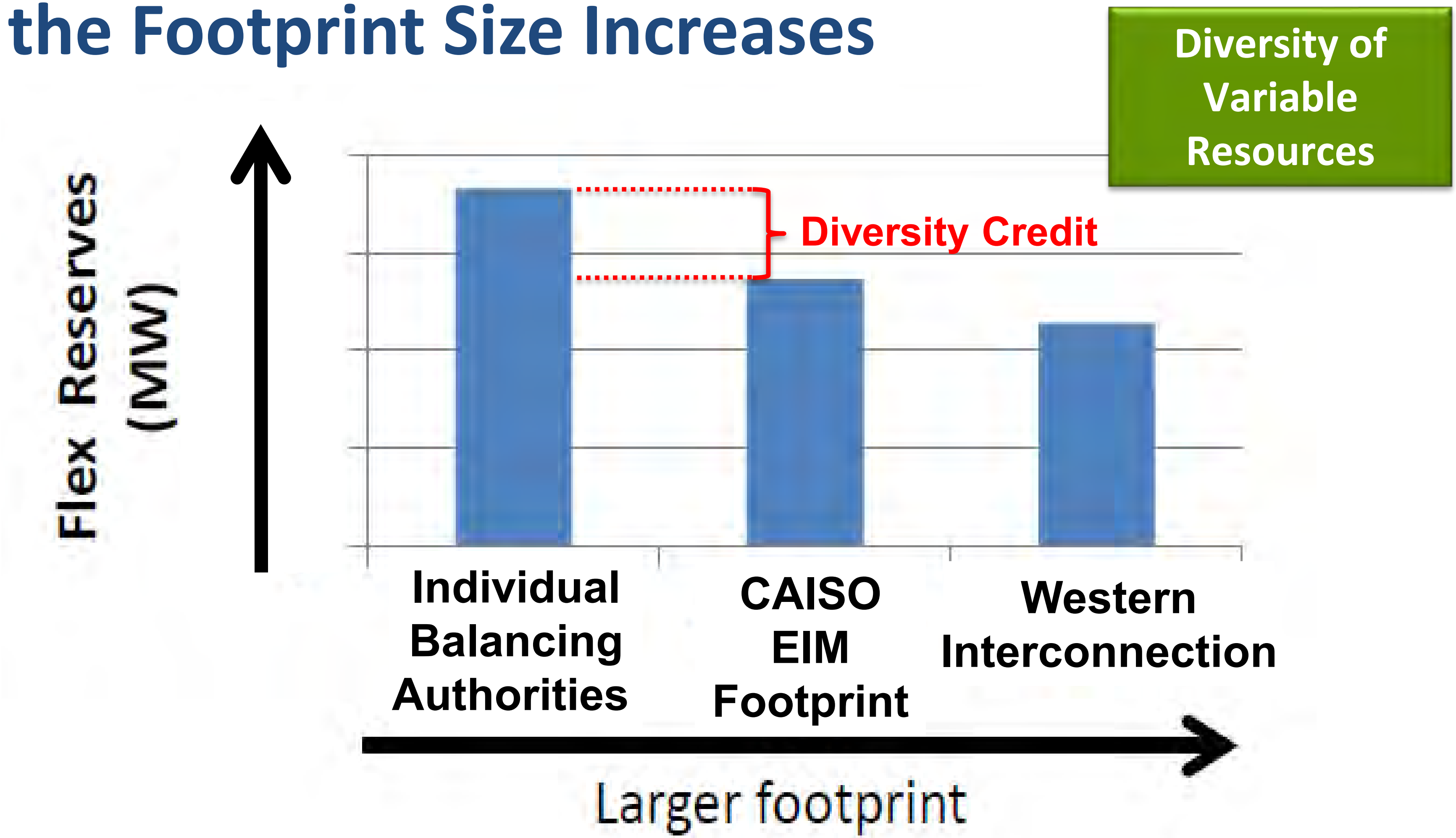
Hydropower: *Available Capacity/Capability & Uses*



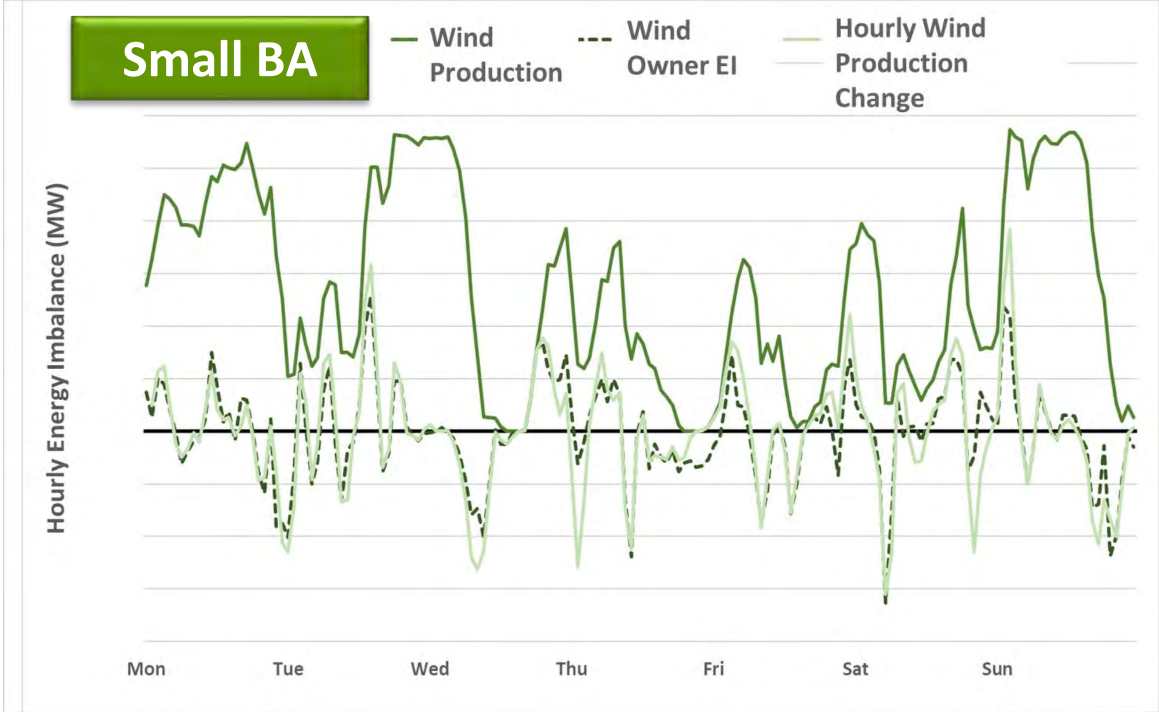
Institution/Market Solutions

Energy Imbalance Market (EIM)

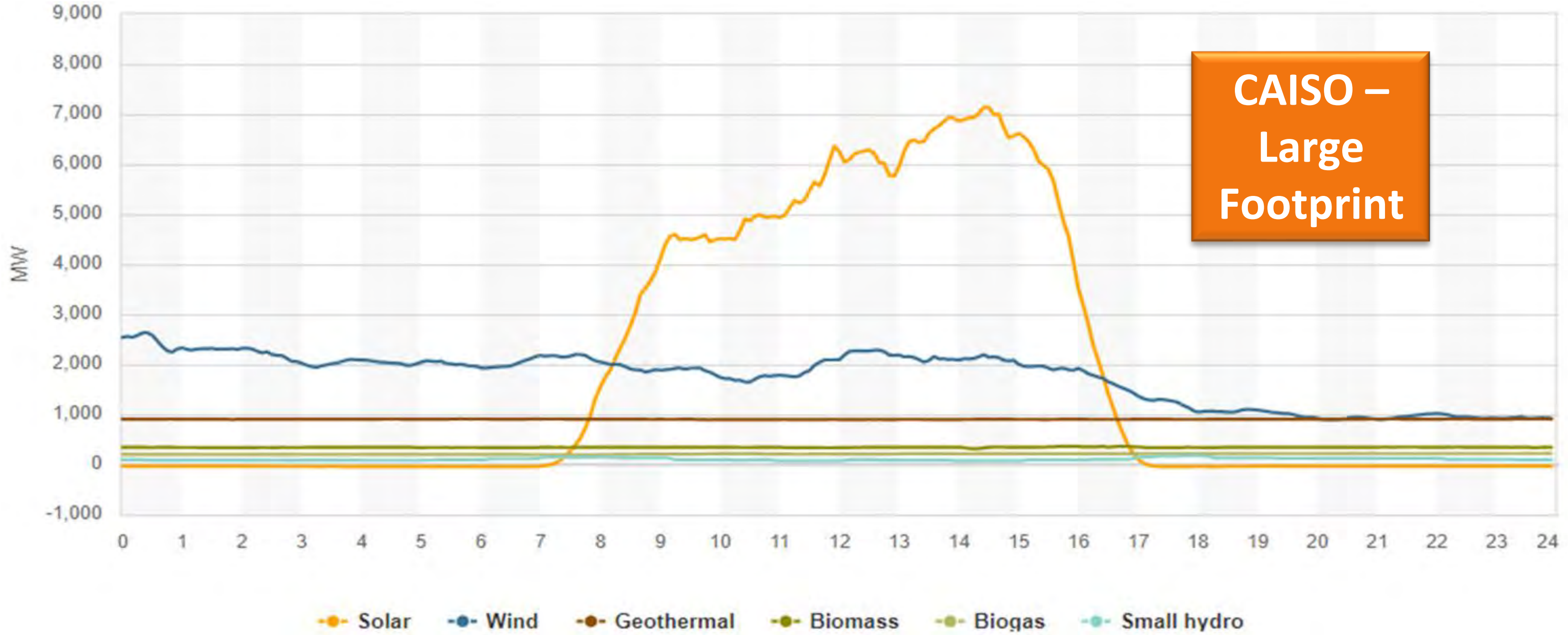
Flexible Reserve Requirements Decrease as the Footprint Size Increases



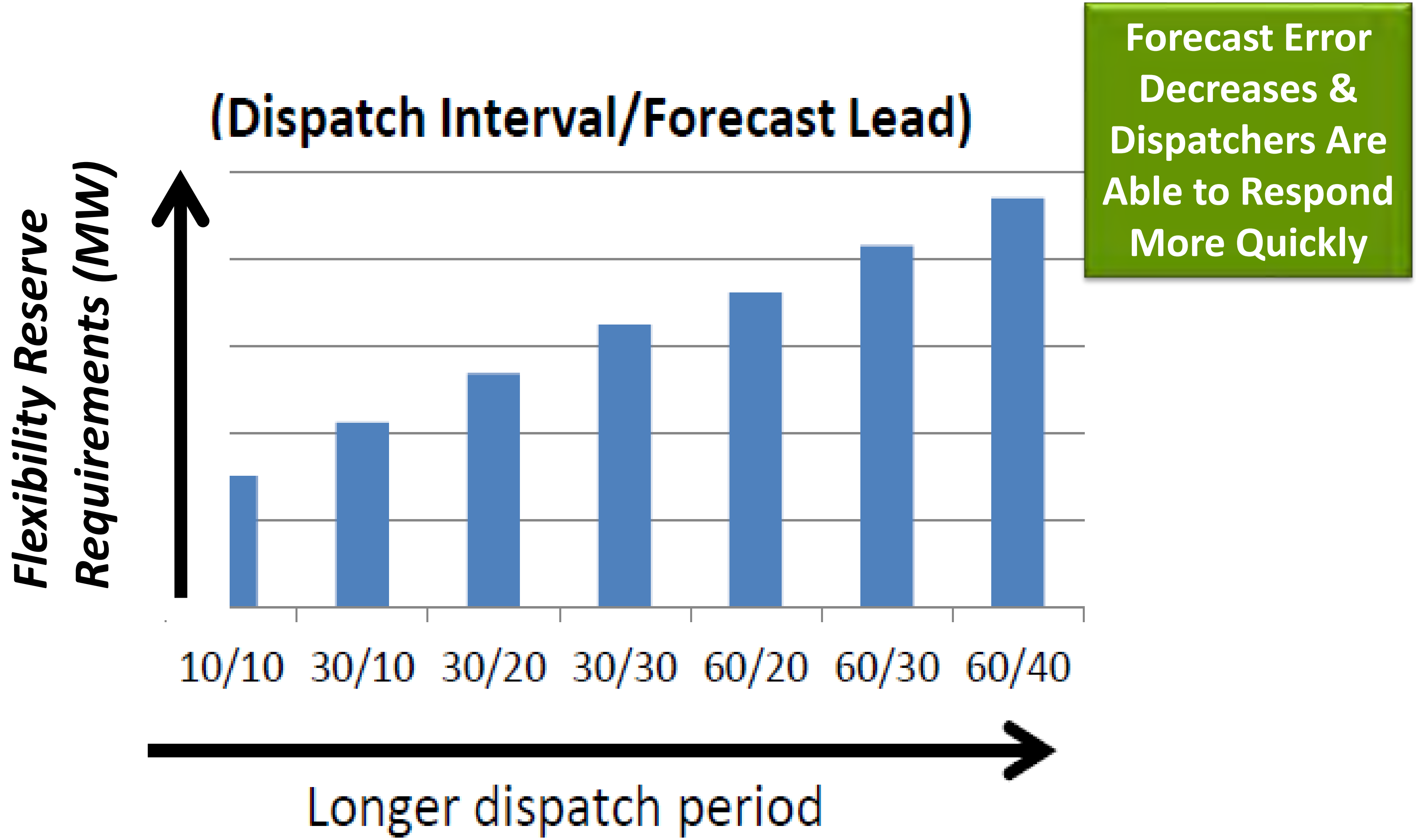
- Greater diversity
- Wider and more refined grid visibility
- Expanded resource pool and larger dispatch footprint



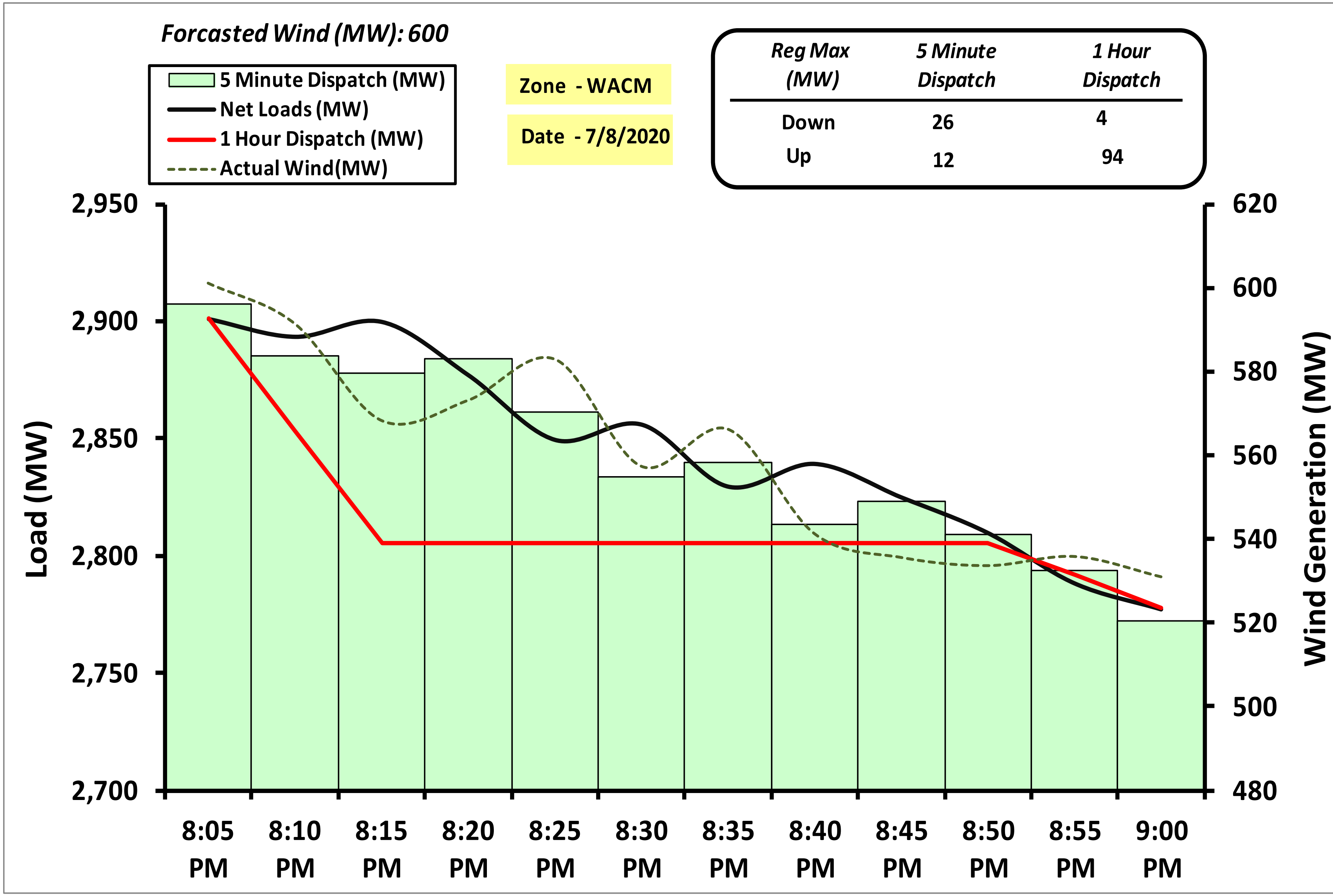
The Relative Level of Flexible Reserve Requirements Decrease as the Footprint Size Increases



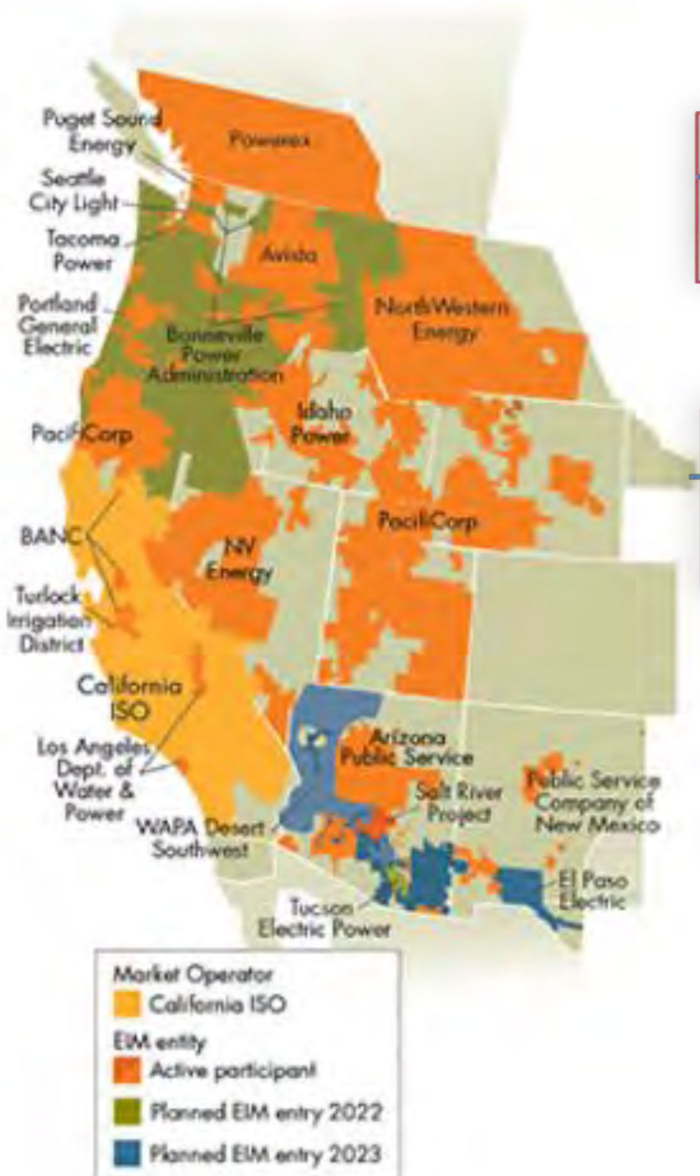
Flexible Reserve Requirements Increase as the Dispatch Time Interval Increases



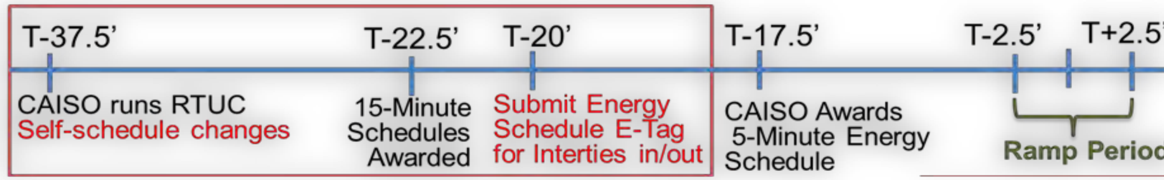
Lower Flexible Regulation Is Needed when the Grid Is Dispatched Every 5 Minutes - *Down Ramp Trend*



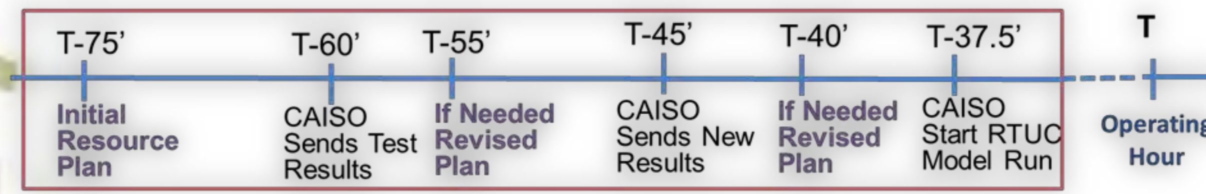
CAISO EIM Growing List of Participating BAA

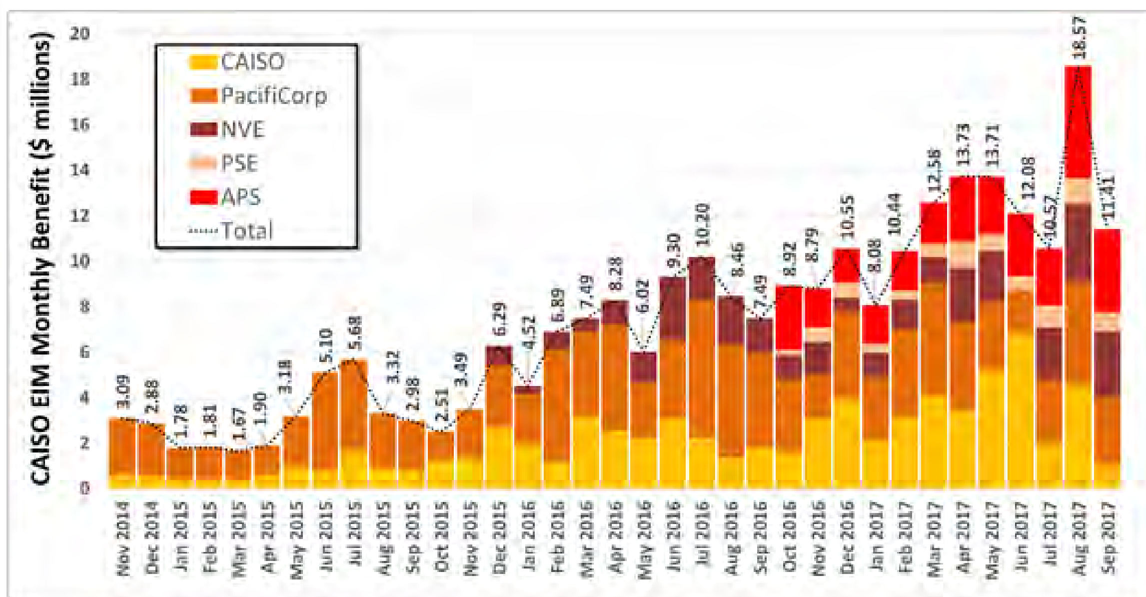


CAISO EIM Timeline of 15-minute Scheduling and 5-minute Dispatch



Ramping Sufficiency Test Schedule



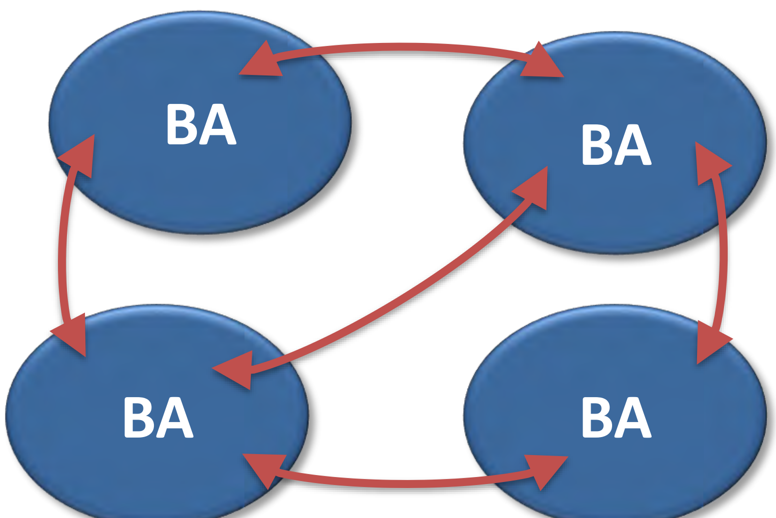


http://www.caiso.com/participate/Pages/default.aspx

Comparison of Current Energy Imbalance Practices with the CAISO EIM

	Without EIM	CAISO EIM
Footprint	Single BA	Multiple BAs
Balancing	Individual BA and Sub-BAs	Optimize Participating Resources Dispatch
Time Step	Hourly	Hourly, 15 min, 5 min
Settlement	Financial or Energy Payback	Locational Marginal Price (LMP) & Neutrality Accounts

Balancing occurs among EIM Entities

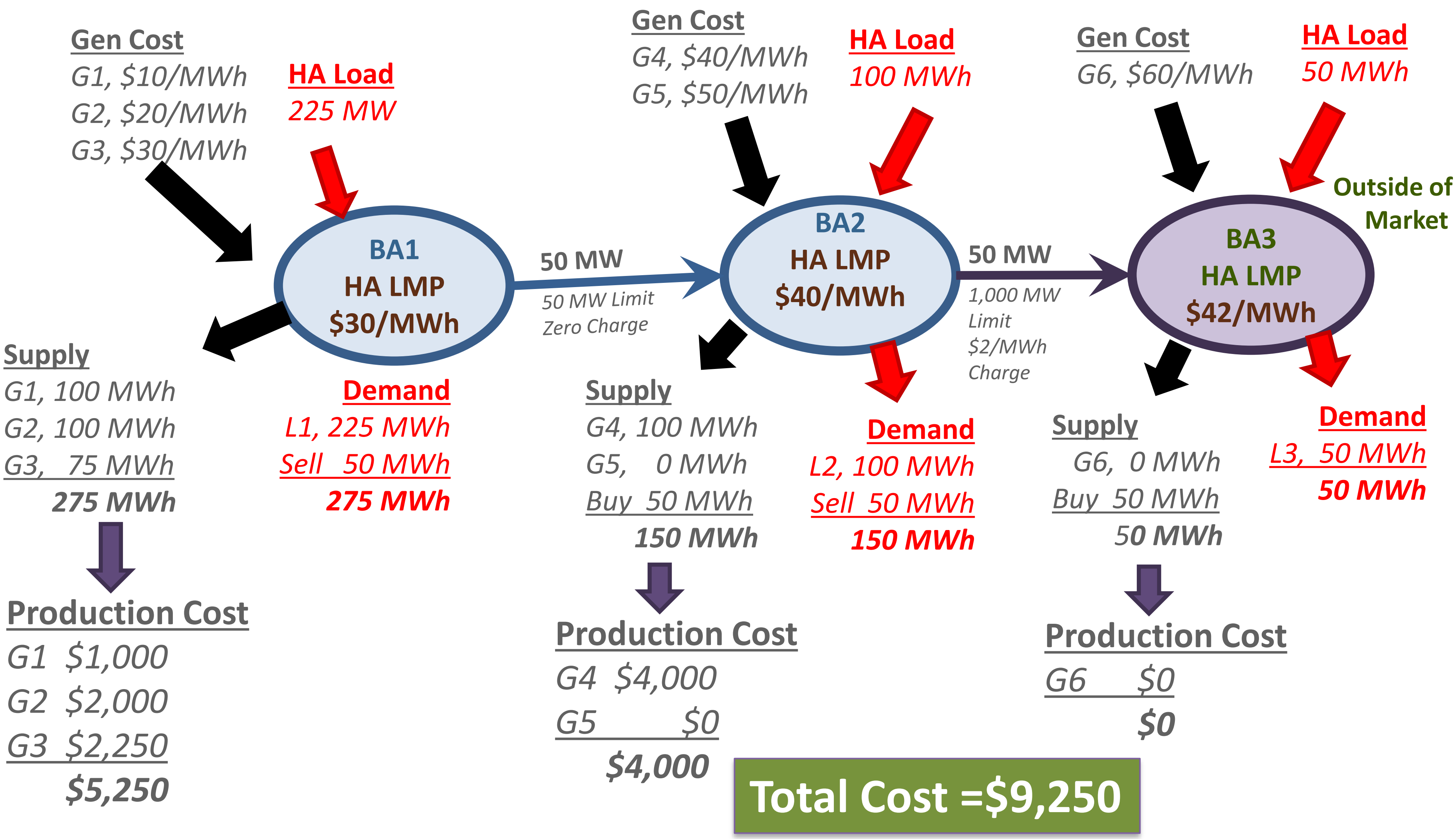


An expanded set of pooled resources over a larger footprint lowers the cost of resolving energy imbalances

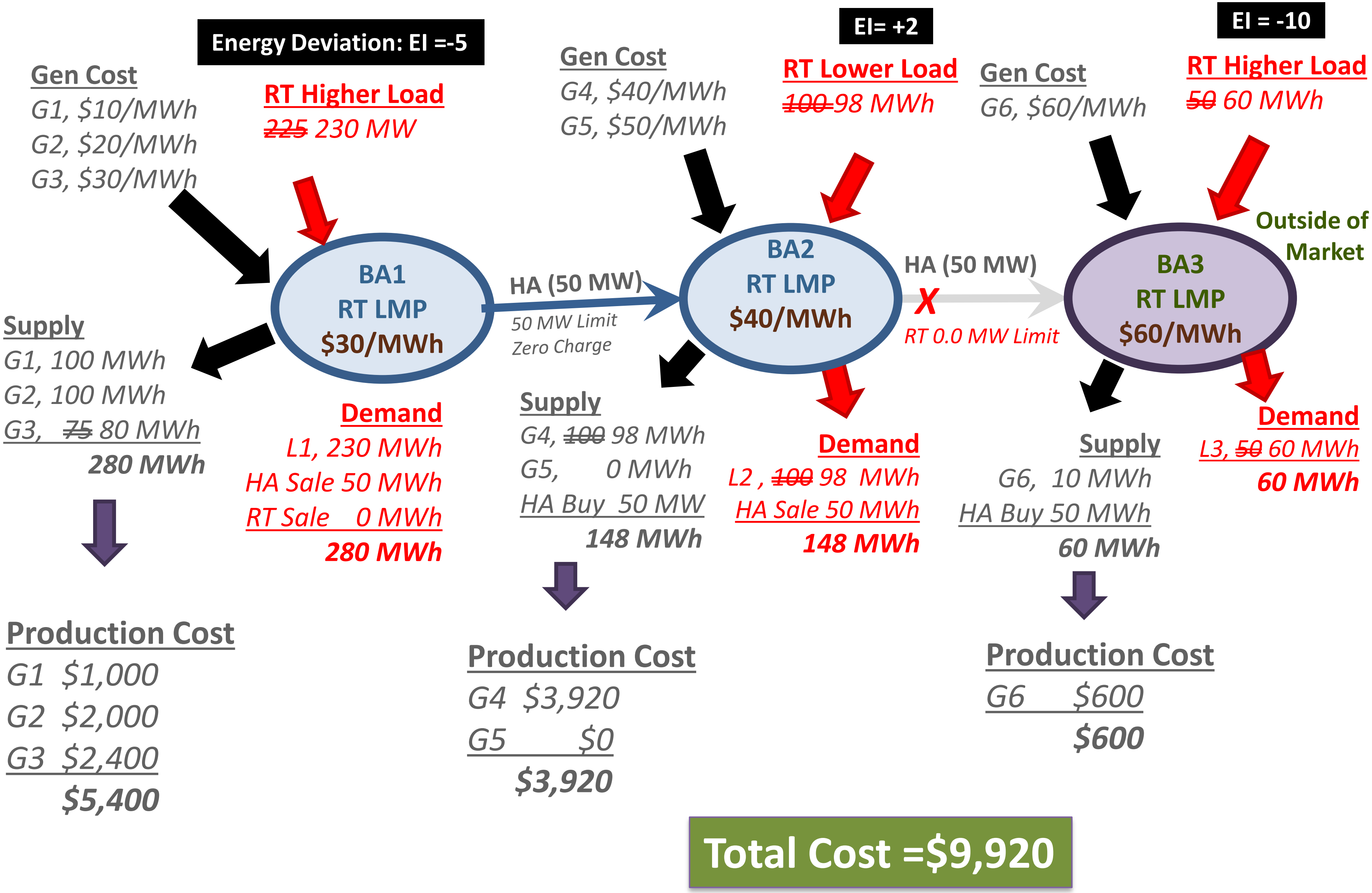
Hour Ahead Schedule

A Larger Pool of Generation Resources Enable Markets to Reduce Production Costs

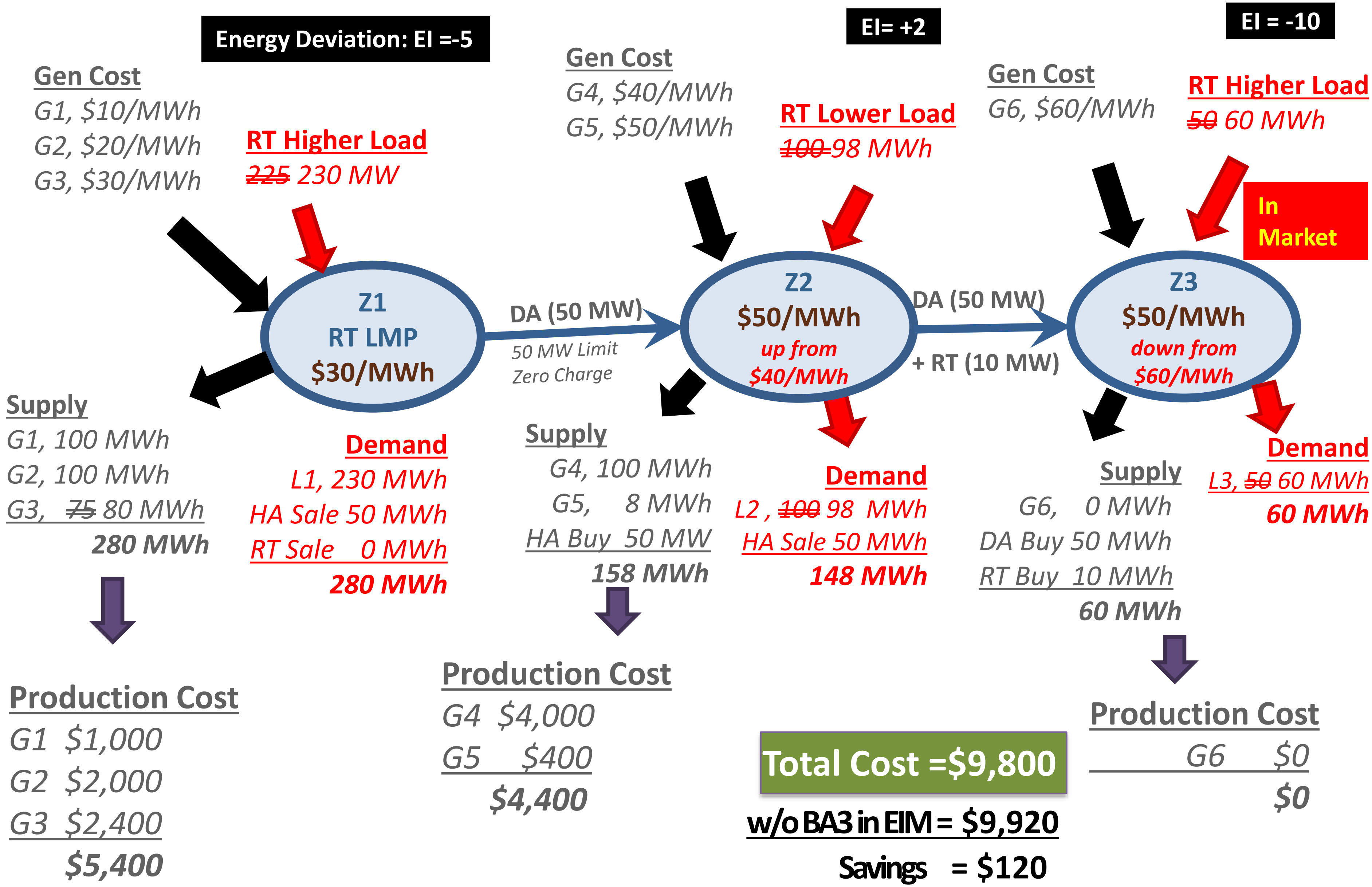
Each Gen has a 100 MW Capacity



Real-time Example: BA3 Outside of the EIM Market

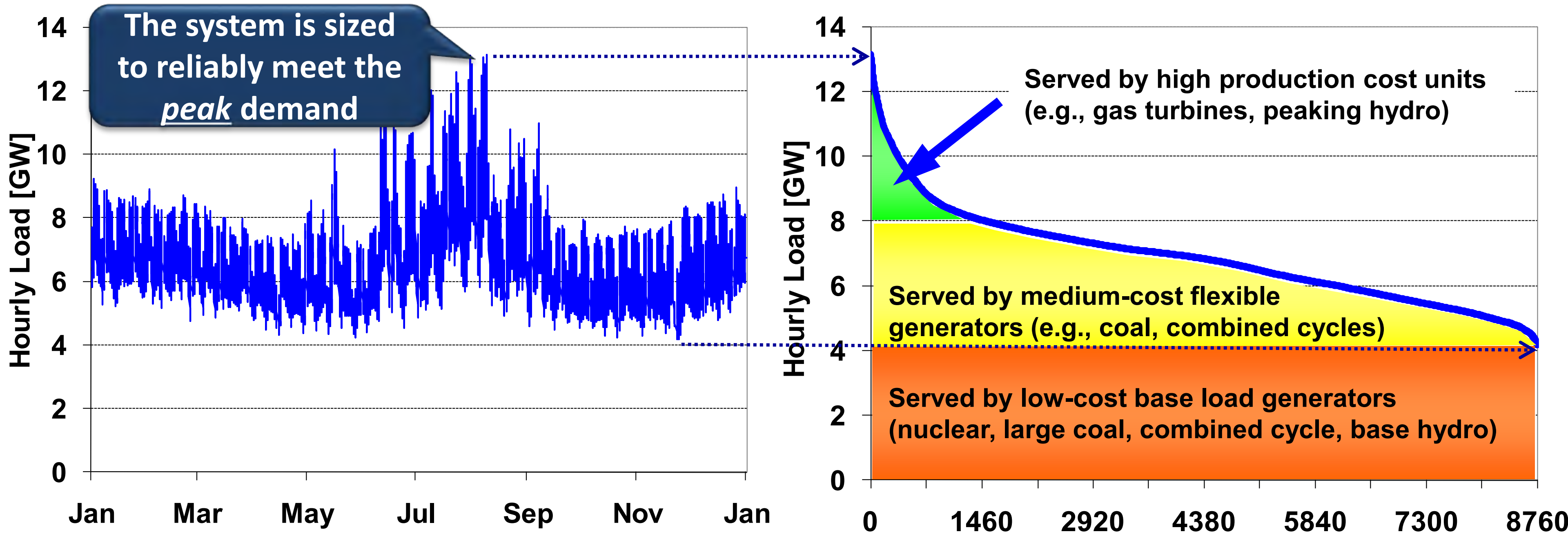


Real-time Example: BA3 Joins the EIM Market



The Long-term View

How Do We “Best” Supply Future Demand Reliably



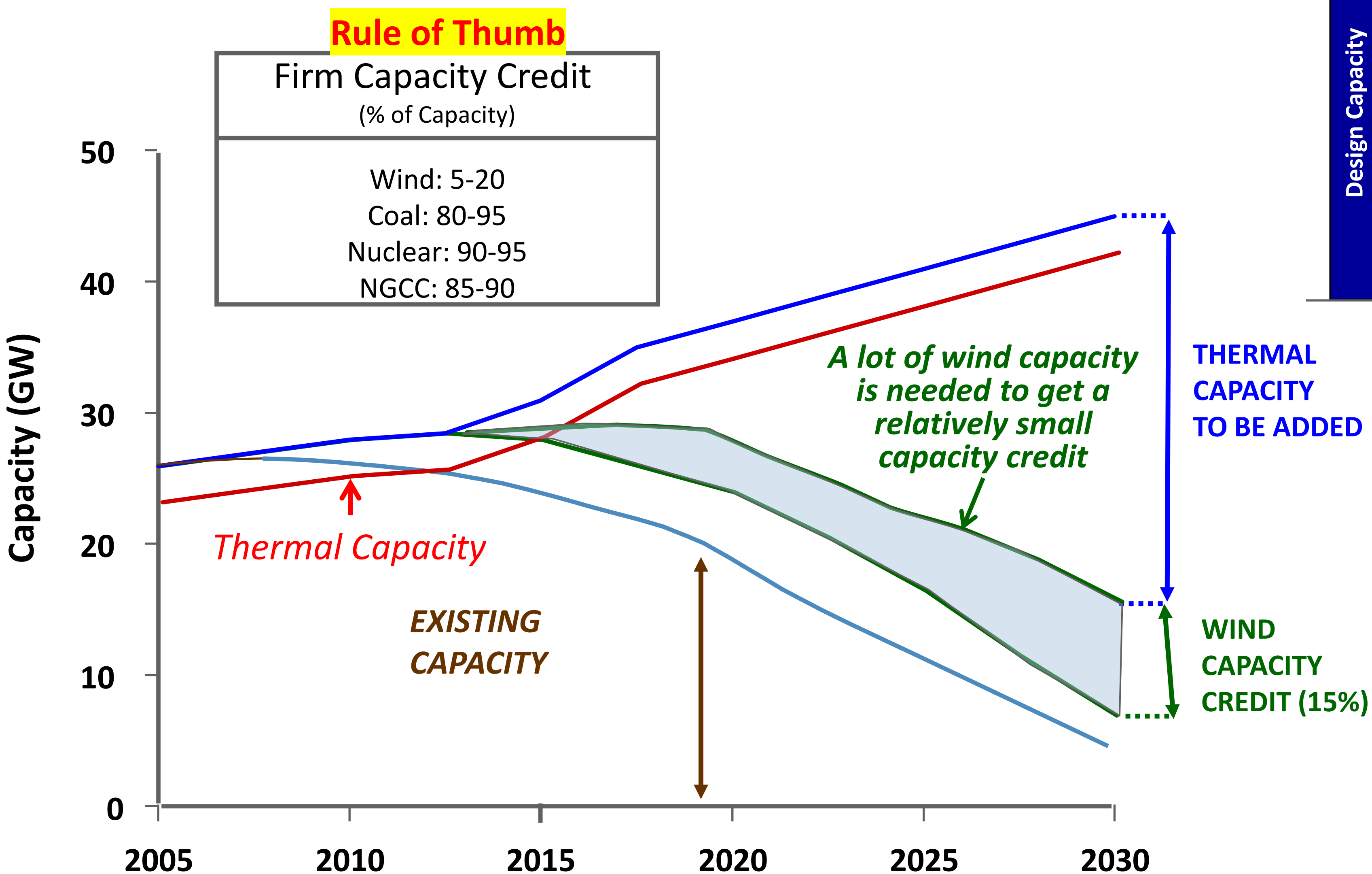
- Each technology has different technical and economic characteristics
  - Maximum output
  - Response & ramp time
  - Start up time
  - Minimum operating level
  - Dispatchable (Y/N)
  - Energy source(s) and efficiency profile
  - Capital cost
  - Fixed and variable operating and maintenance costs
  - Rules, Priorities, Goals, and Objectives

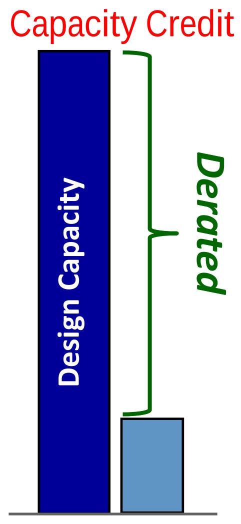
Operating Flexibility (Response & ramp time; Start up time; Minimum operating level; Dispatchable (Y/N))

Integration of VRE influences dispatchable technology mix

Economics Financial Viability (Energy source(s) and efficiency profile; Capital cost; Fixed and variable operating and maintenance costs; Rules, Priorities, Goals, and Objectives)

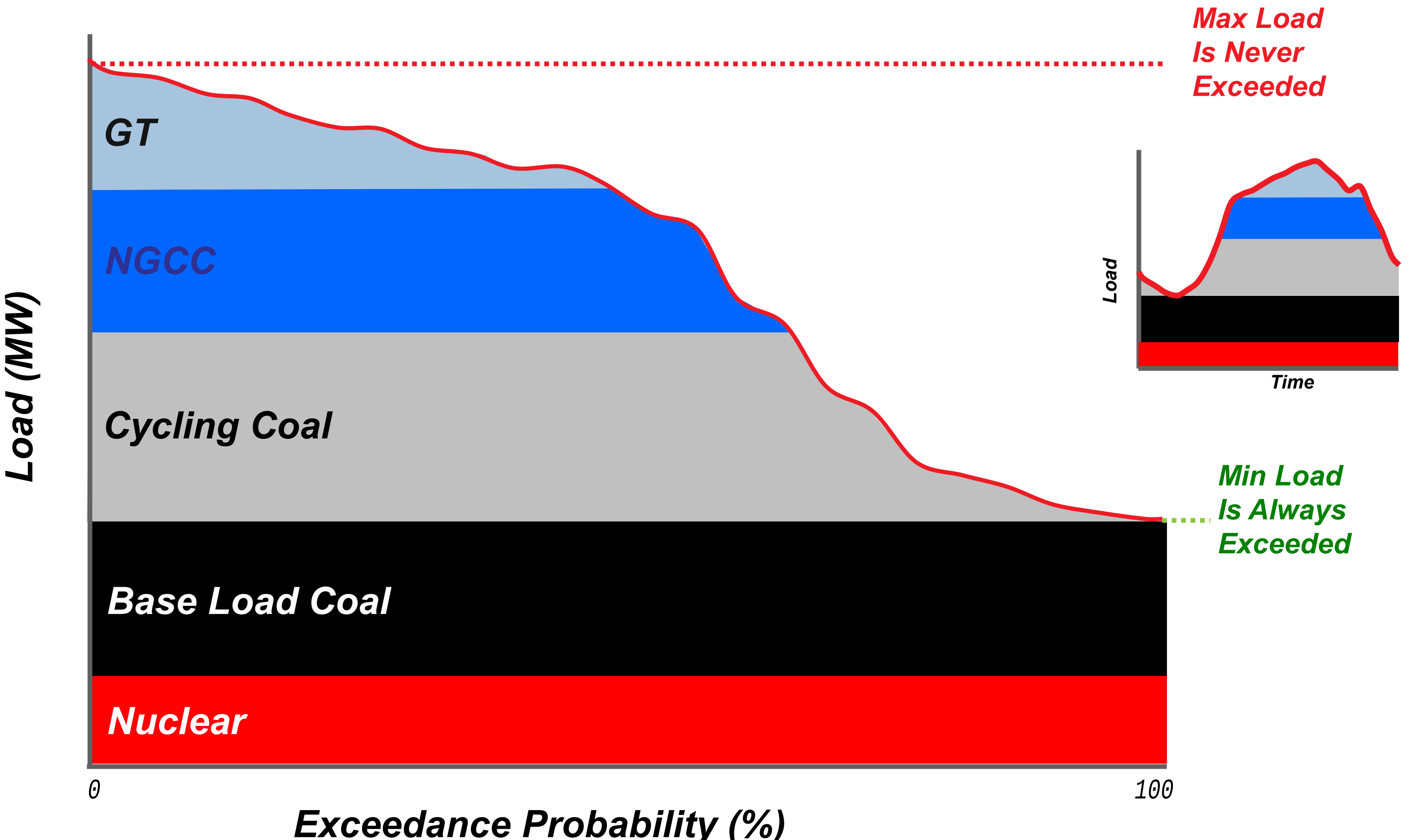
A Lot of Wind Capacity Is Needed to Meet Renewable Portfolio Standards (20% Energy)





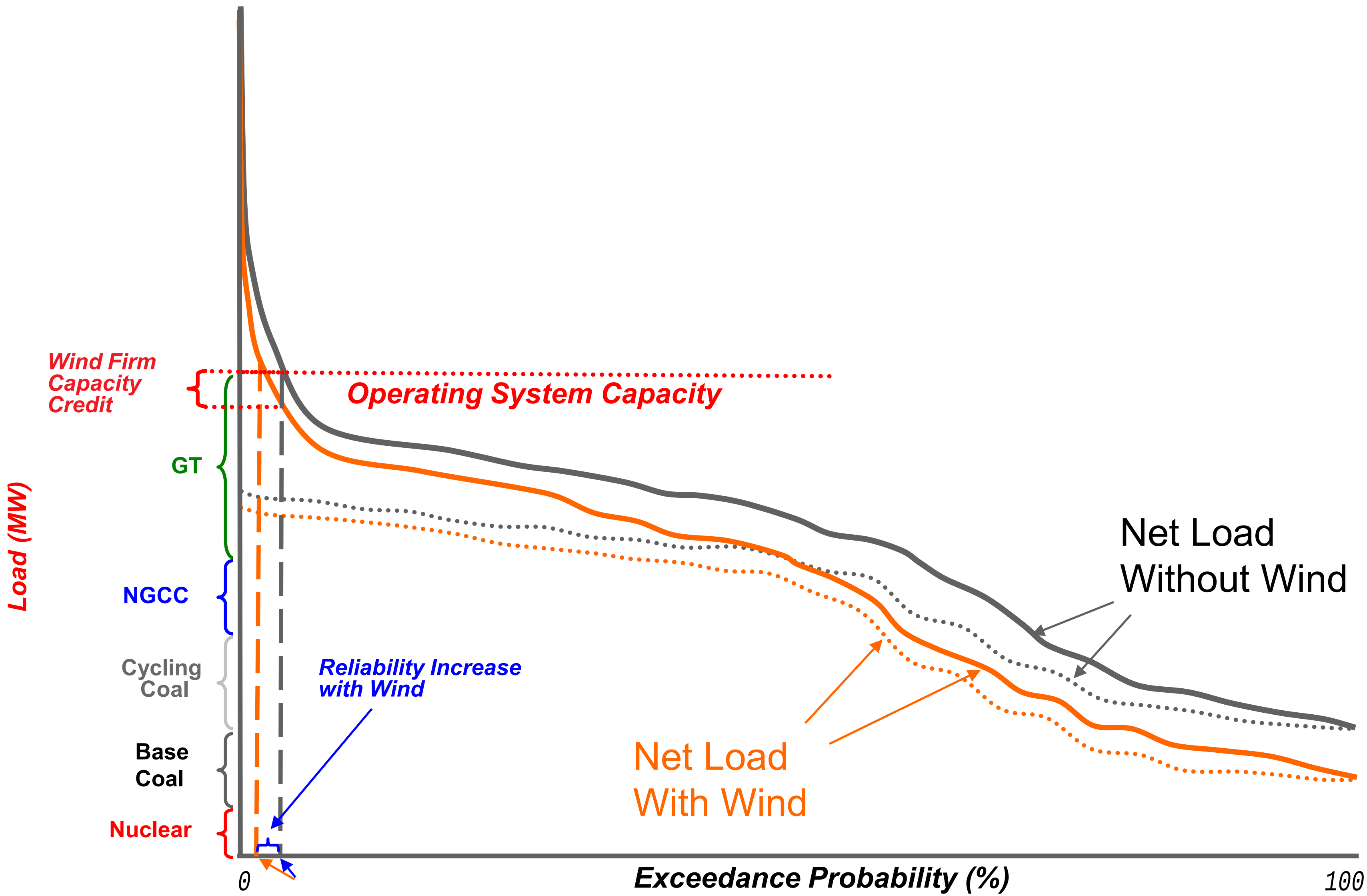
For wind and solar the capacity credit depends on the <u>probability and amount</u> of power that it provides during the time of peak load

Unit Production Levels Can Be Estimated Using a Load Duration Curve

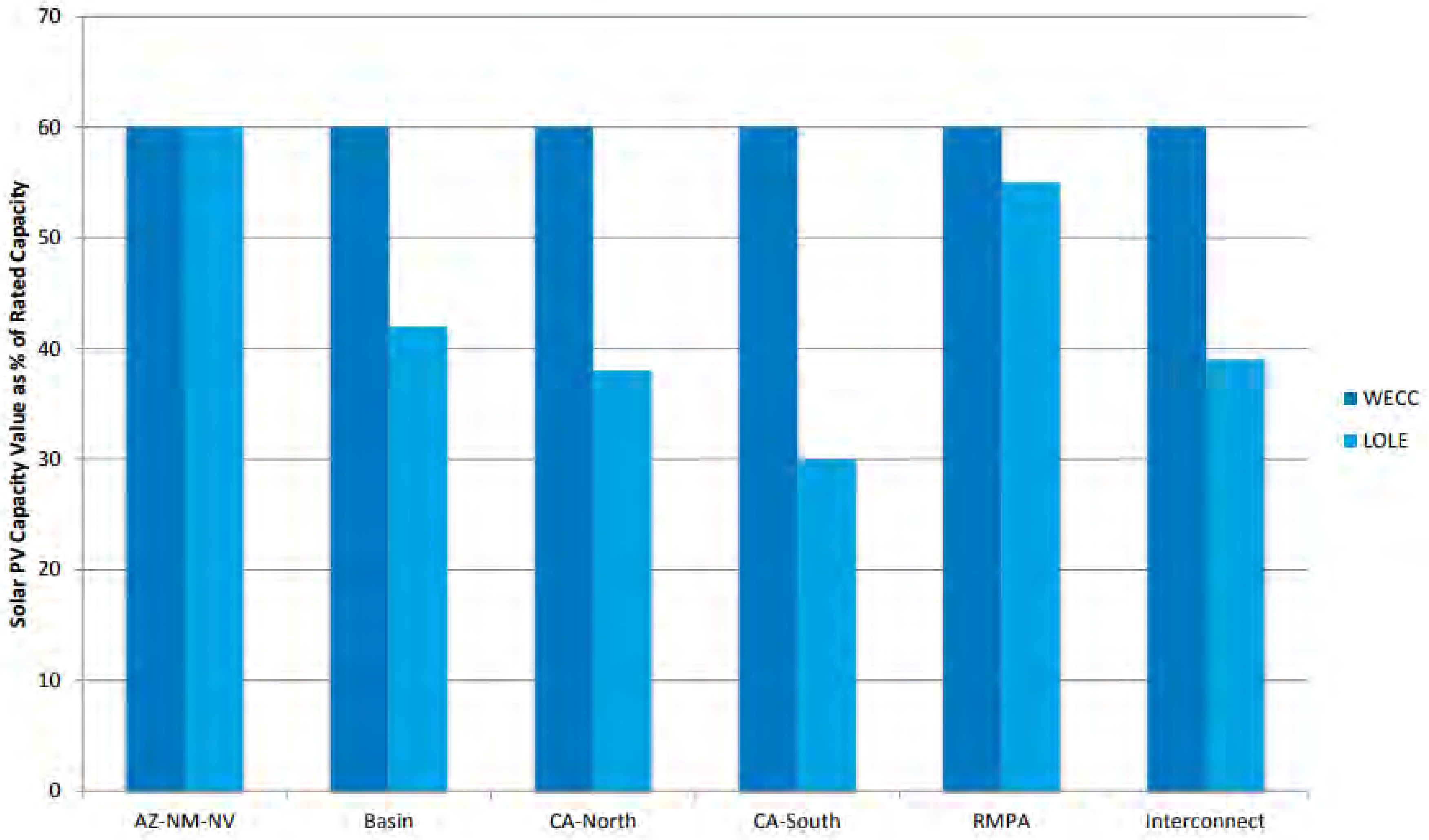


Information such as unit ramping and unit starts/stops is lost

The Firm Capacity Credit for Wind Can Be Based on a System Reliability Measure

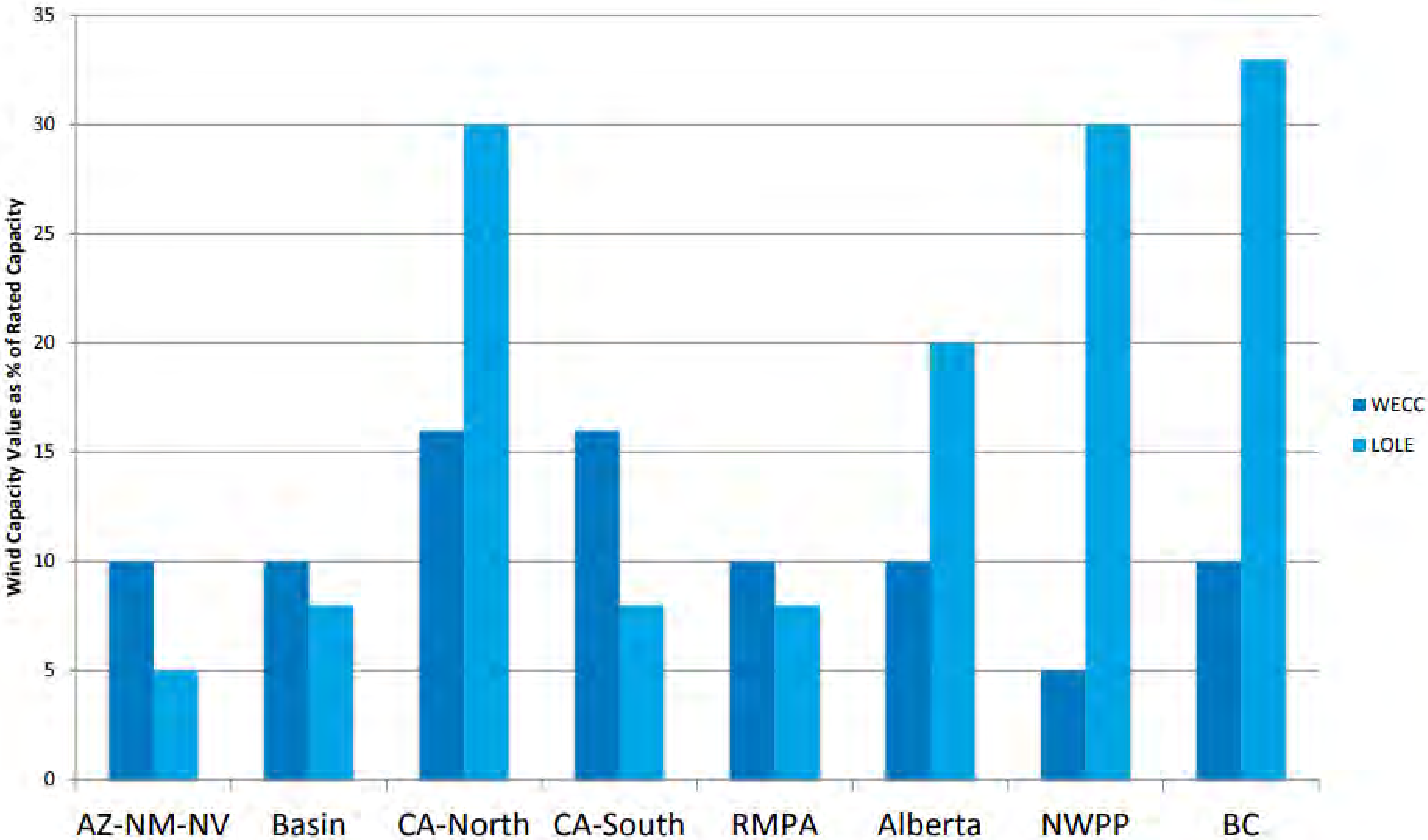


PV Solar Firm Capacity: WECC Rule of Thumb Values and Loss of Load Equivalent (LOLE) Estimate by NREL



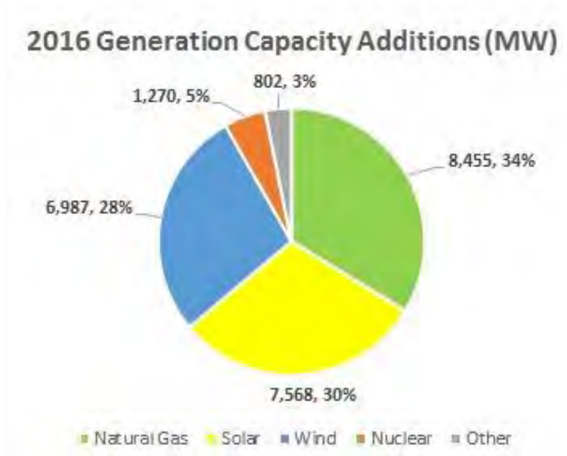
Capacity Value: Evaluation of WECC Rule of Thumb; NREL (National Renewable Energy Laboratory) (Conference) | OSTI.GOV

Wind Firm Capacity: *WECC Rule of Thumb Values and Loss of Load Equivalent (LOLE) Estimate by NREL*



[Capacity Value: Evaluation of WECC Rule of Thumb; NREL (National Renewable Energy Laboratory) (Conference) | OSTI.GOV]

VRE Capacity Additions and Levelized Cost of Electricity (LCOE)

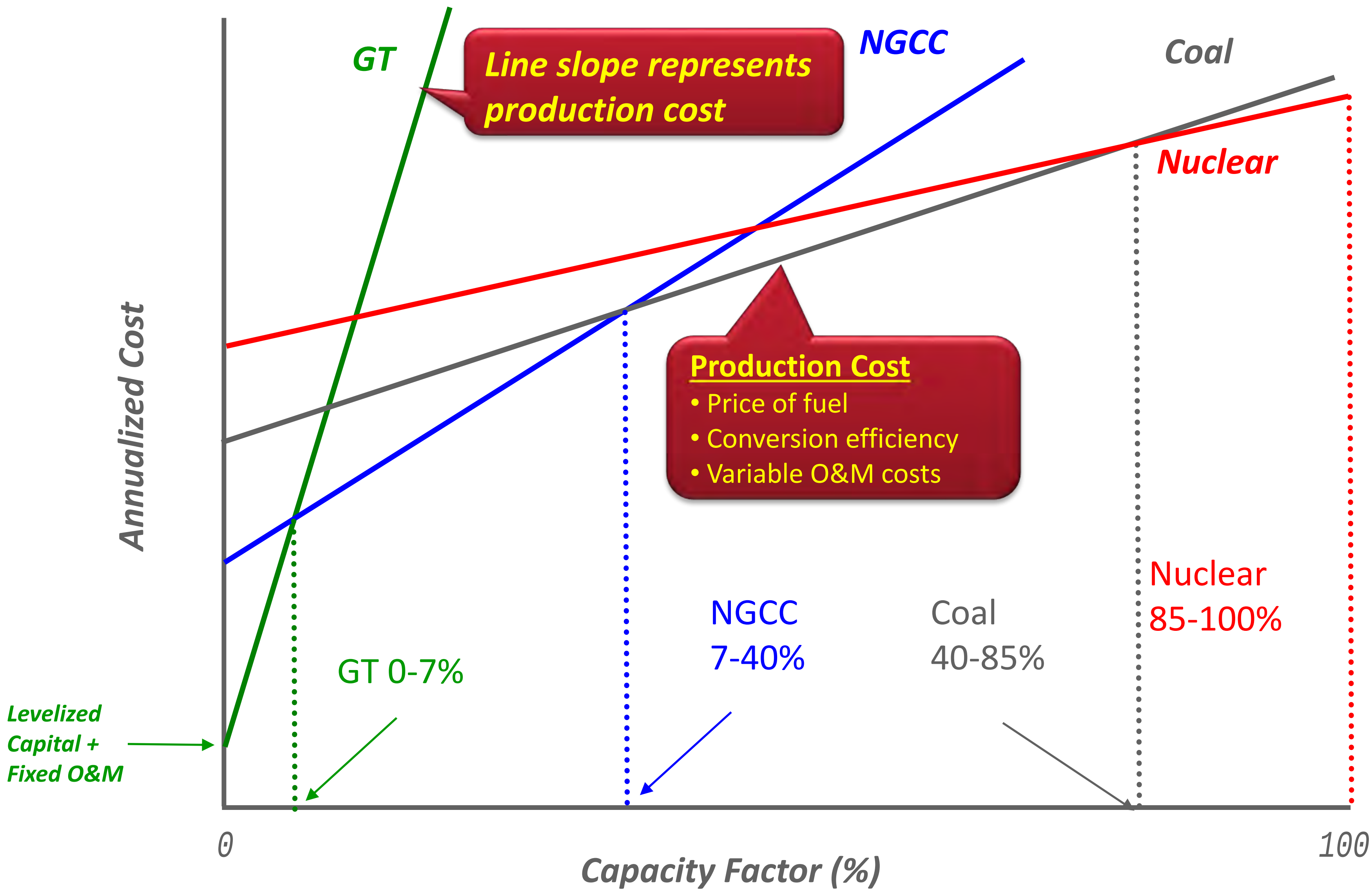


http://www.renewableenergyworld.com/ugc/articles/2017/01/14/2016-us-solar-capacity-by-state-recap.html

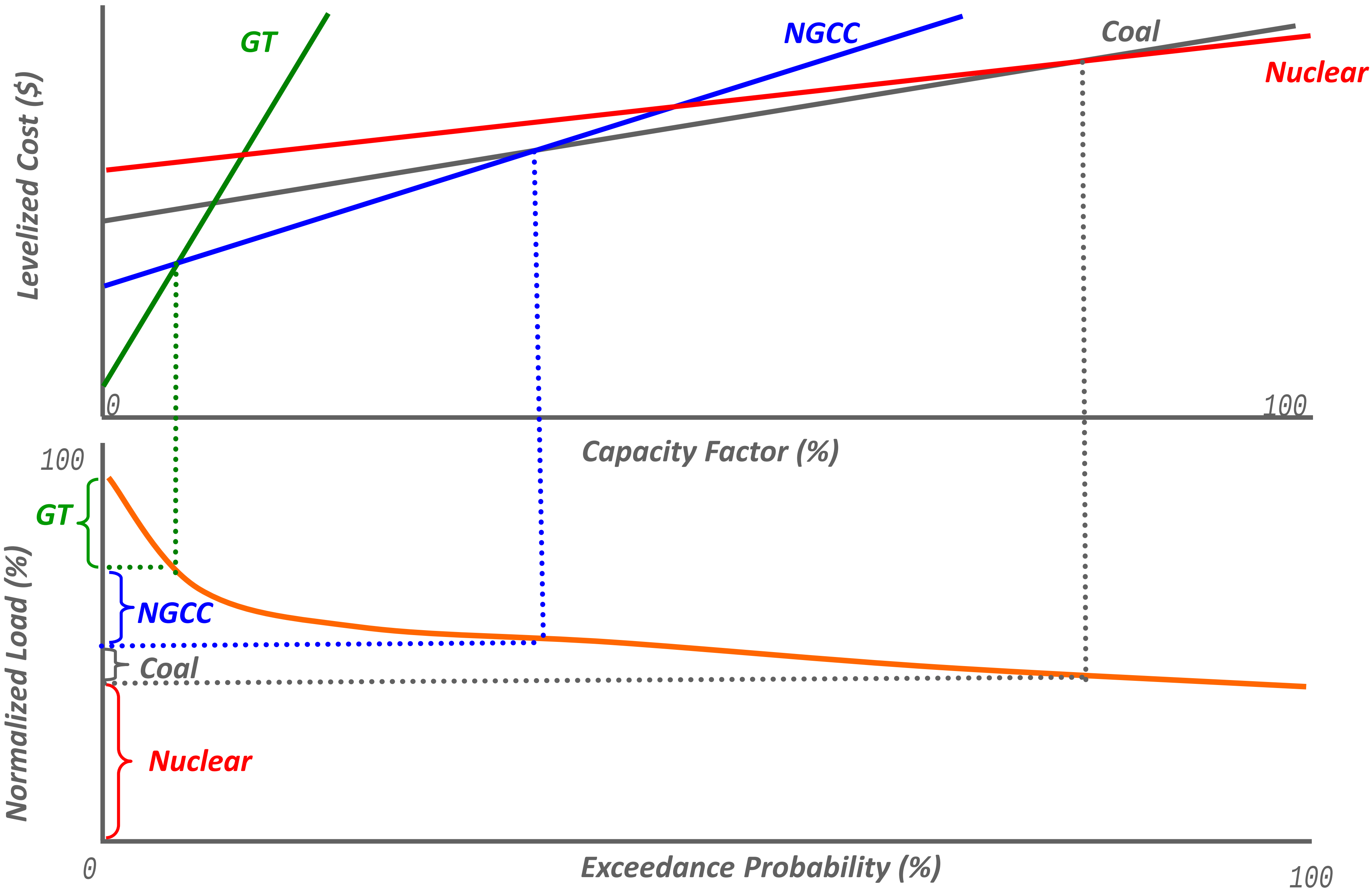
Plant type	Capacity factor (%)	Levelized capital cost	Levelized fixed O&M	Levelized variable O&M	Levelized transmission cost	Total system LCOE	Levelized tax credit[2]	Total LCOE including tax credit
Dispatchable technologies								
Coal with 30% CCS[3]	NB	NB	NB	NB	NB	NB	NA	NB
Coal with 90% CCS[3]	NB	NB	NB	NB	NB	NB	NA	NB
Conventional CC	87	13.0	1.5	32.8	1.0	48.3	NA	48.3
Advanced CC	87	15.5	1.3	30.3	1.1	48.1	NA	48.1
Advanced CC with CCS	NB	NB	NB	NB	NB	NB	NA	NB
Conventional CT	NB	NB	NB	NB	NB	NB	NA	NB
Advanced CT	30	22.7	2.6	51.3	2.9	79.5	NA	79.5
Advanced nuclear	90	67.0	12.9	9.3	0.9	90.1	NA	90.1
Geothermal	91	28.3	13.5	0.0	1.3	43.1	-2.8	40.3
Biomass	83	40.3	15.4	45.0	1.5	102.2	NA	102.2
Non-dispatchable technologies								
Wind, onshore	43	33.0	12.7	0.0	2.4	48.0	-11.1	37.0
Wind, offshore	45	102.6	20.0	0.0	2.0	124.6	-18.5	106.2
Solar PV[4]	33	48.2	7.5	0.0	3.3	59.1	-12.5	46.5
Solar thermal	NB	NB	NB	NB	NB	NB	NB	NB
Hydroelectric[5]	65	56.7	14.0	1.3	1.8	73.9	NA	73.9

https://www.eia.gov/outlooks/aeo/pdf/electricity_generation.pdf

Each Thermal Generating Technology Has a Niche

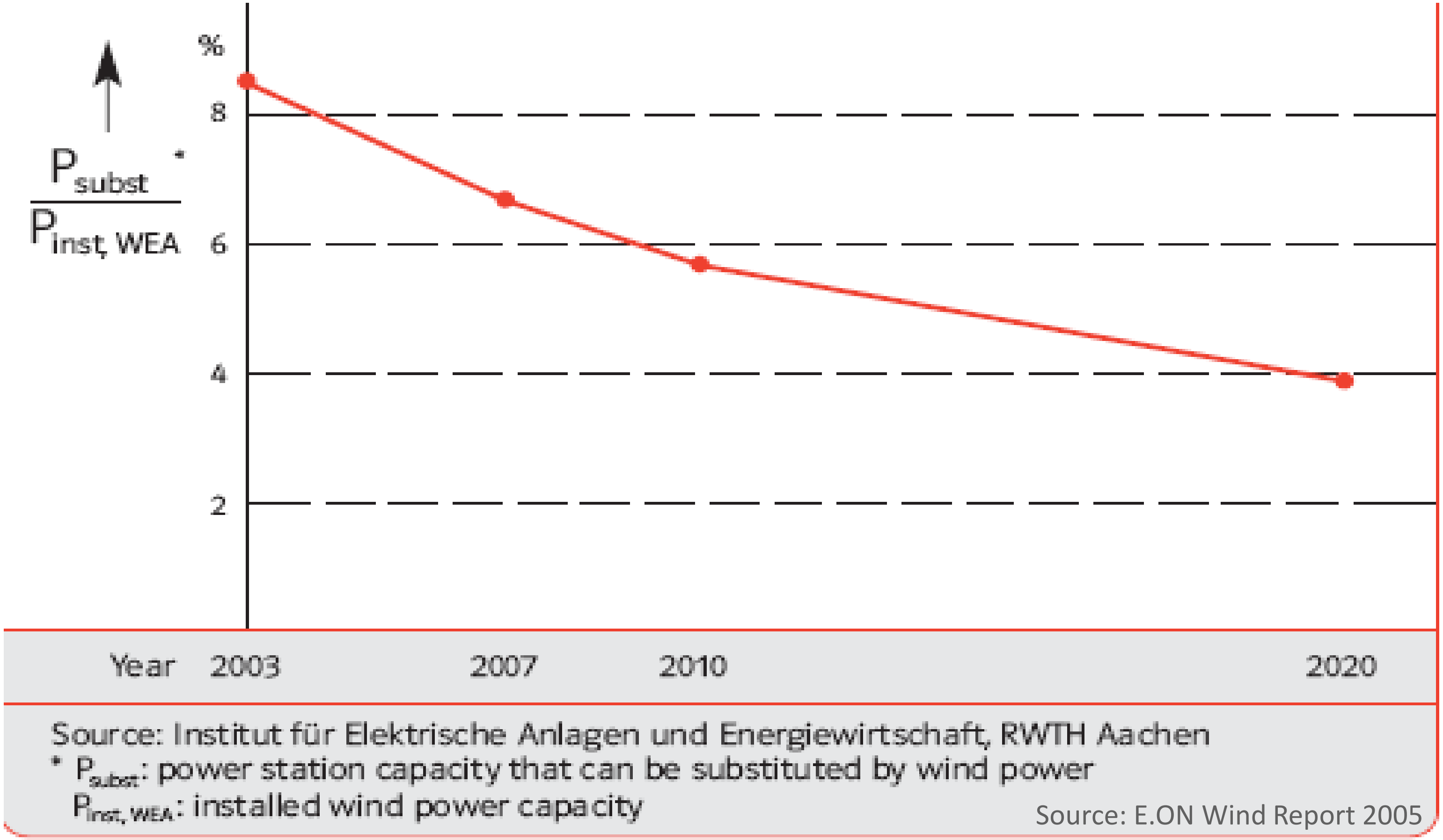


Combining Screening Curves with the Load Duration **Curve Approximates the "Ideal" Capacity Mix**



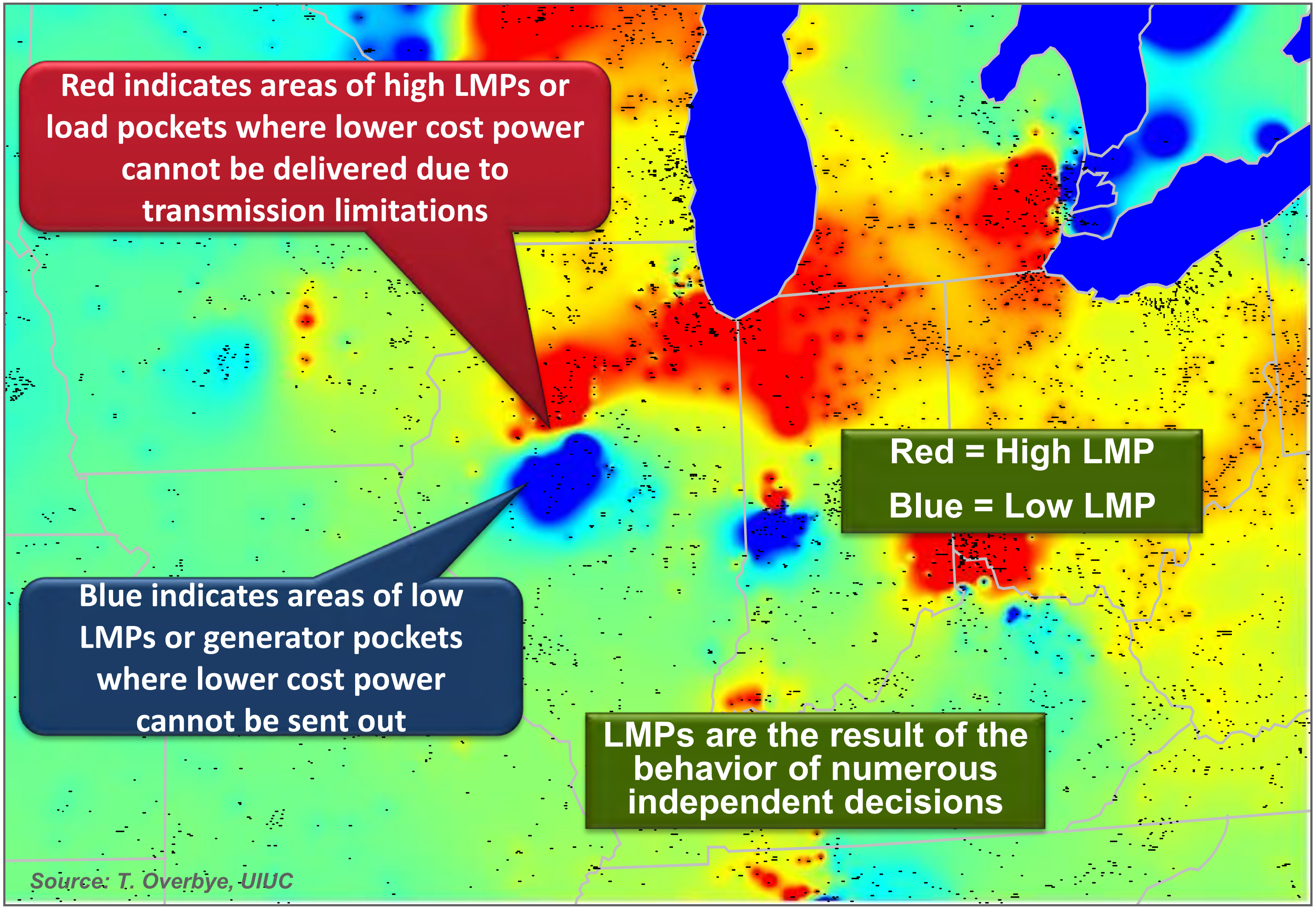
The Capacity Credit Decreases with Higher Penetration of Wind Capacity in the System

- German utility E.ON: "The more wind power capacity is on the grid, the lower the percentage of traditional generation it can replace."
  - Firm capacity from wind in 2007: about 7% of installed capacity
  - Firm capacity in 2020 is expected to drop to 4%.



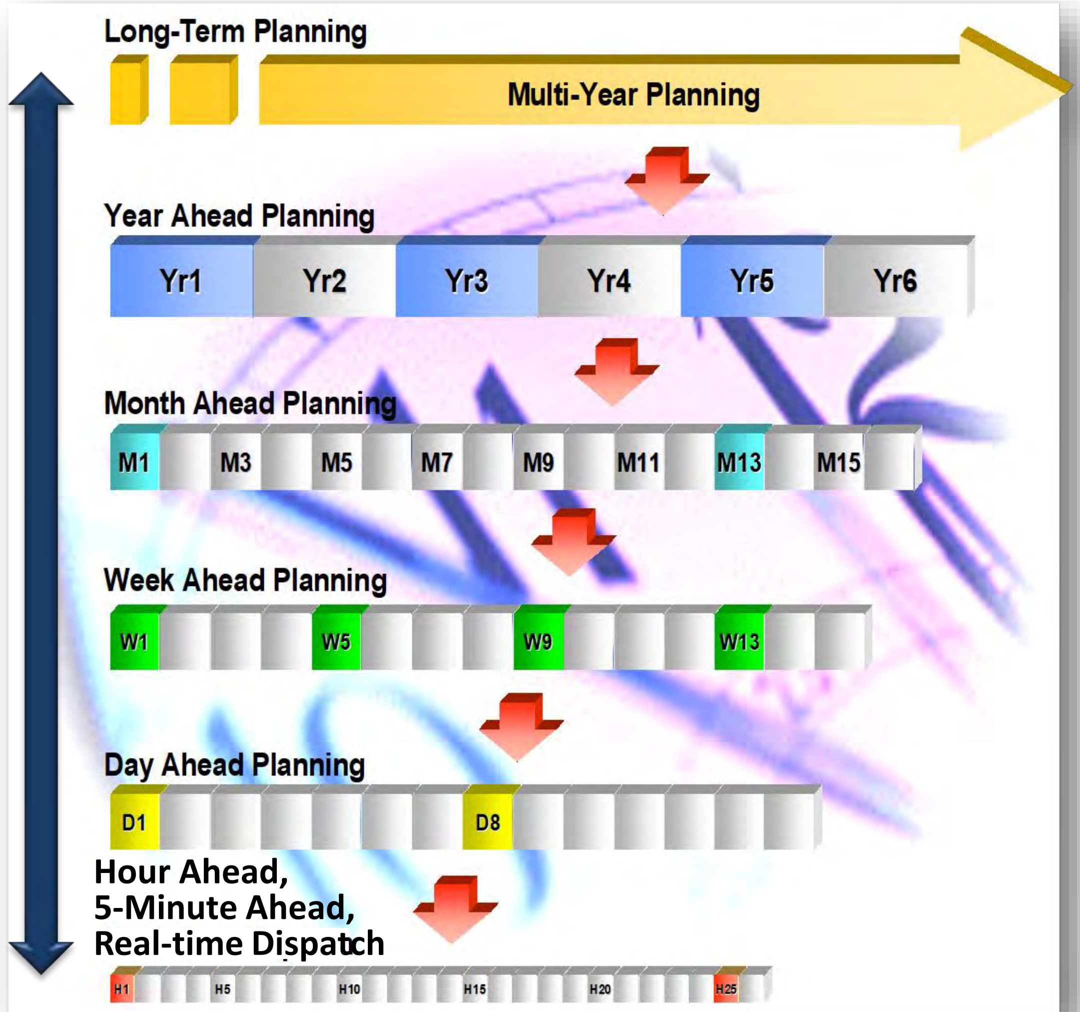
Source: E.ON Wind Report 2005

If Possible Build Were Prices Are the Highest



VREs and Integrated Resource Planning (IRP)

- Produces a long-term resource strategy
- Integrates both supply and demand-side options
- Should consider risks and external impacts
- Evaluates cost-effectiveness and trade-offs among multiple objectives



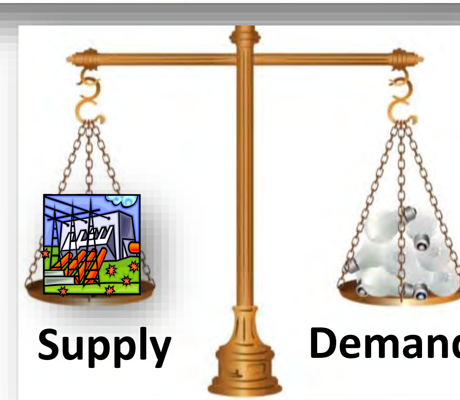
➢ ***Resource schedule***

- *Technology (type of gen)*
- *Reserve capacity*
- *Demand-side management*
- *System flexibility*

When?

What?

How Much?



History → ***Near-term Projects*** → ***Long-term Goals*** → ***End-effects***

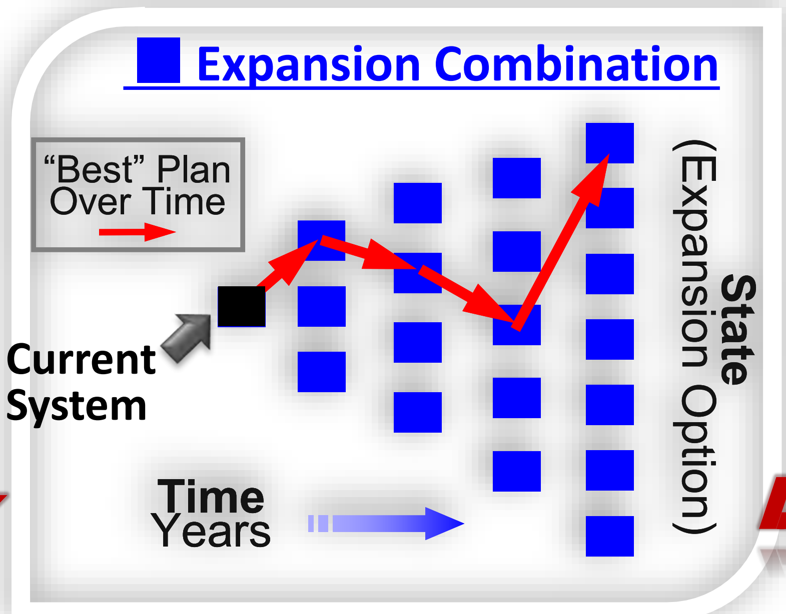
IRP Analyses Typically Use Capacity Expansion Models

- Dynamic Programming (DP) capacity expansion models combine a production cost (dispatch) model with DP optimization
- Production cost models simulate power system operation and project costs for each expansion combination in each year of the study period
- The DP model finds the expansion path with the lowest net present value (NPV) of all **investments plus operating costs** that reliability serves demand

Inputs
- Demand forecast
- Load profiles
- Existing units
- Candidate technologies
- Cost data
- Reliability parameters and constraints
- Environmental data and constraints

→ **Production Cost Model** → **Dynamic Programming Model** →

Results
- NPV of investment and operating costs
- Timing and schedule of new capacity additions
- Operating costs
- Cash flow (financial)
- Reliability results
- Environmental impacts



THE CURSE OF DIMENSIONALITY

THE CURSE OF DIMENSIONALITY

Colorado Spring Utility IRP Process

Project Plan

- **Project Plan**
  - Assumptions
  - Previous EIRP and Scope Planning

First Public Mtg.

- **Purpose: Introduction and Education**
  - Project Planning and Stakeholder Engagement - Advisory Group begins meeting
  - Data Collection and Analysis/Evaluation of Technologies

Scenario Screening

- **Evaluation:**
  - Renewable and Traditional Resources
  - Create Scenarios Based on Environmental Impacts, Risk, and Cost

Second Public Mtg.

- **Purpose: Evaluation and Reporting Back - Mid-point of EIRP Process**
  - Share Preliminary Scenarios with Public
  - Risk Analysis and Testing - Metrics and Assessment

Technical Analysis

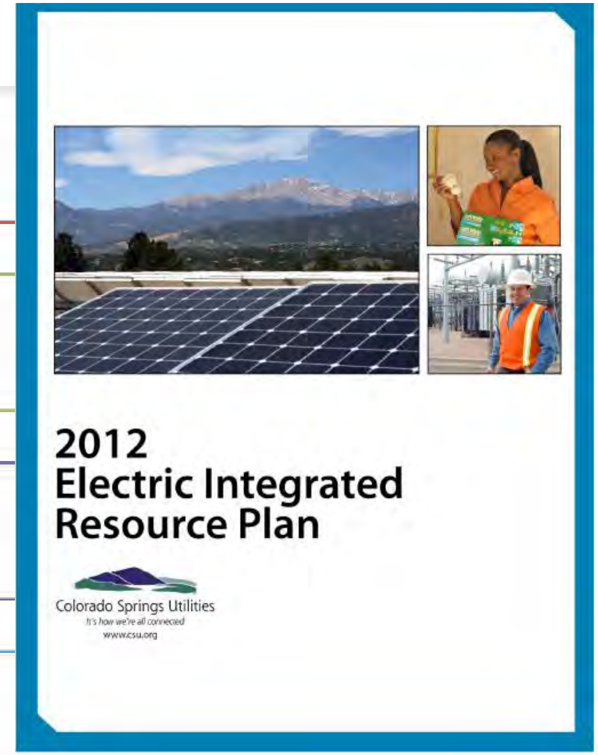
- **Portfolio Analysis and Resource Selection**

Third Public Mtg.

- **Purpose: Share Results of Scenario and Portfolio Development**
  - Obtain Input on Final Portfolio Selection - Prepare for Final Fourth Public Mtg.
  - Advisory Group participates in Kepner-Tregoe, Risk and Cost Analyses

Fourth Public Mtg.

- **Purpose: Final Review of Recommended Portfolios/Obtain Input**
  - Share Recommendations and Selection Criteria- Obtain Comments for UPAC and UB Review
  - Outliline Plan Update Process



IRP Considers

- Supply
- Demand
- Contractual Obligations
- Economics
- Demand Response
- Uncertainties (prices)
- Environment

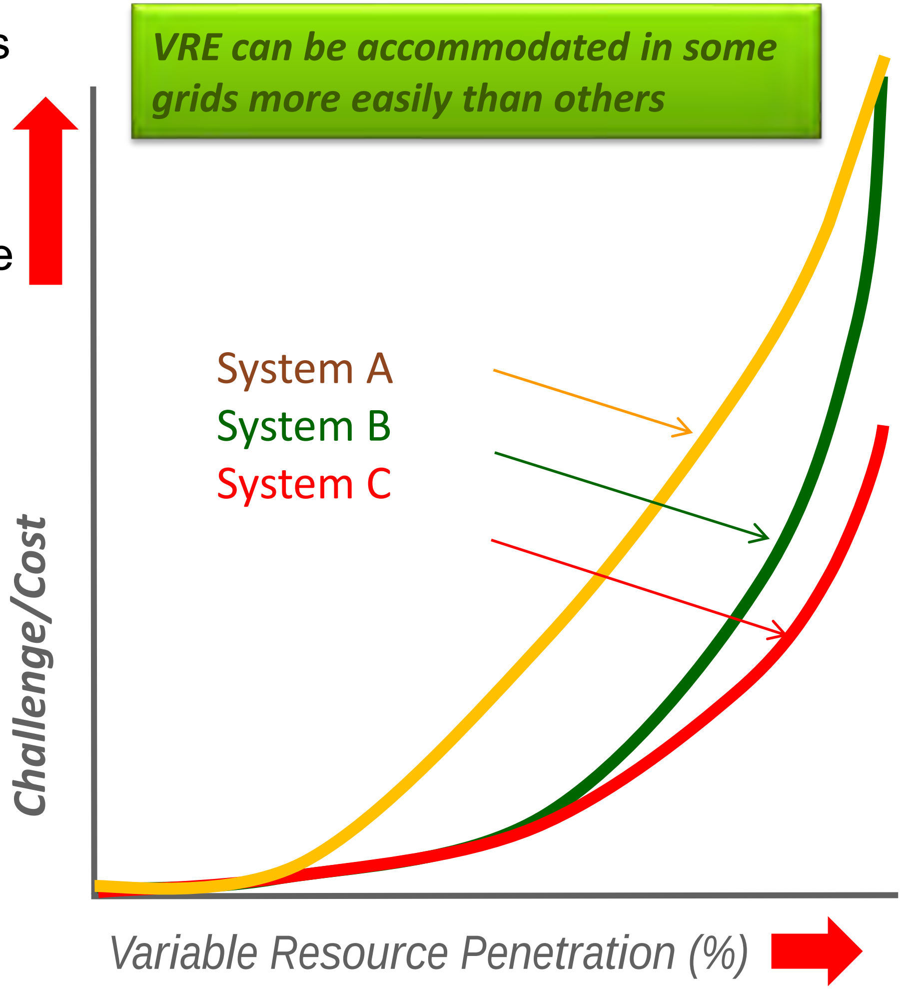
https://www.csu.org/CSUDocuments/eirp.pdf

Colorado Springs Utility Scenario Analysis (No Simple Answer)

#	Scenario	Net Present Value-$ million	Diff in NPV to Scenario 1 EV2020	Load Forecast	DSM Percent of sales by 2020	RPS Renewables Percent by 2020	Envir. Reg Adder $/MWh	CO2 Adder $/Ton	Gas and Electric Market Price	Coal Price
1	Energy Vision - Expected case	2,421.0	Base	Medium	10%	20%	1.5	3	Medium	Medium
2	Current Business Environment - Current Environmental Cost	2,255.6	-165.3	Medium	4%	10%	1.5	Zero	Medium	Medium
3	Current Business Environment - Mid Evironmental Cost	2,621.8	200.8	Medium	4%	10%	7.5	3	Medium	Medium
4	Energy Vision - -20% carbon reduction	3,286.2	865.3	Medium	10%	20%	1.5	25	Medium	Medium
5	Low Load Growth	2,204.6	-216.4	Low	10%	20%	1.5	3	Medium	Medium
6	High Load Growth	2,670.1	249.1	High	10%	20%	1.5	3	Medium	Medium
7	High Environmental Regulation - High CO2 Cost	4,236.5	1,815.6	Medium	10%	30%	10.0	50	Medium	Medium
8	High GasPrice -High Electric Market Price	2,484.2	63.2	Medium	10%	20%	1.5	3	High	Medium
9	Low Gas Price -Low Electric Market Price	2,310.5	-110.5	Medium	10%	20%	1.5	3	Low	Medium
10	Mid DSM	2,447.0	26.0	Medium	6%	20%	1.5	3	Medium	Medium
11	No New Fossil Fuel	2,749.0	328.1	Medium	10%	30%	1.5	3	Medium	Medium
12	High RPS, Mid Environmental Cost	2,955.9	535.0	Medium	10%	30%	7.5	3	Medium	Medium
13	PPACG Sustainability	2,812.3	391.4	Medium	20% by 2030	50% by 2030	1.5	3	Medium	Medium
14	High DSM	2,334.5	-86.4	Medium	20%	20%	1.5	3	Medium	Medium
15	Low Load Growth - 10%RPS	2,165.9	-255.0	Low	10%	10%	1.5	3	Medium	Medium
16	Energy Vision - 10% RPS	2,374.5	-46.5	Medium	10%	10%	1.5	3	Medium	Medium
17	Energy Vision - 30% RPS	2,749.0	328.1	Medium	10%	30%	1.5	3	Medium	Medium
18	Current Business Environment - 6% DSM	2,248.8	-172.2	Medium	6%	10%	1.5	Zero	Medium	Medium
19	Energy Vision - Low Wind Integration Cost	2,411.4	-9.6	Medium	10%	20%	1.5	3	Medium	Medium
20	Current Business, No wind until RPS requires	2,296.6	-124.4	Medium	4%	10%	1.5	Zero	Medium	Medium
21	Current Business Environment - 10% DSM	2,251.5	-169.5	Medium	10%	10%	1.5	Zero	Medium	Medium
22	Current Business Environment - Low Gas Price	2,056.0	-365.0	Medium	4%	10%	1.5	Zero	Low	Medium
23	Energy Vision - Limited to 50MW of wind in 2013	2,465.8	44.8	Medium	10%	20%	1.5	3	Medium	Medium
24	Energy Vision - High Coal Price	2,919.4	498.4	Medium	10%	20%	1.5	3	Medium	High
25	Energy Vision - Low Coal Price	2,111.2	-309.8	Medium	10%	20%	1.5	3	Medium	Low
26	Current Business Environment - High Coal Price	2,790.6	369.6	Medium	4%	10%	1.5	Zero	Medium	High
27	Current Business Environment - Low Coal Price	1,919.6	-501.3	Medium	4%	10%	1.5	Zero	Medium	Low
28	Current Business Environment - High Gas Price	2,365.9	-55.1	Medium	4%	10%	1.5	Zero	High	Medium
29	Current Business Environment - High Load	2,513.5	92.6	High	4%	10%	1.5	Zero	Medium	Medium
30	Current Business Environment - Low Load	2,039.2	-381.8	Low	4%	10%	1.5	Zero	Medium	Medium
31	Energy Vision - zero CO2 adder	2,301.8	-119.1	Medium	10%	20%	1.5	Zero	Medium	Medium
32	Energy Vision - with no capacity for DSM	n.a.	n.a.	Medium	10%	20%	1.5	3	Medium	Medium
33	Energy Vision - Low Solar Costs	2,401.4	-19.6	Medium	10%	20%	1.5	3	Medium	Medium
34	Current Business Environment - No Pueblo Hydro	2,258.3	-162.7	Medium	4%	10%	1.5	Zero	Medium	Medium
35	Current Business Environment - No Geothermal	2,259.2	-161.8	Medium	4%	10%	1.5	Zero	Medium	Medium
36	Current Business Environment - No Pueblo Hydro - No Geo.	2,262.3	-158.7	Medium	4%	10%	1.5	Zero	Medium	Medium
37	Energy Vision, No Wind Until RPS Requires	2,528.5	107.5	Medium	10%	20%	1.5	3	Medium	Medium

What is the “Best" Amount of VRE Capacity?

- Production variability
  - Level and frequency of production swings
  - Forecast error
- Correlation among variable resource
  - Volatility and predictability of ***ALL*** variable resources combined
- Production correlation with load
  - Production change during morning load up-ramp and evening load down-ramp
- Transmission system
  - Capability of the transmission systems to move power from production to load
- Flexibility of thermal/hydropower system
  - Dispatch interval
  - Rate that dispatchable units can respond to variable production and load changes
- Load flexibility or level of control
- Willingness to spend $$$



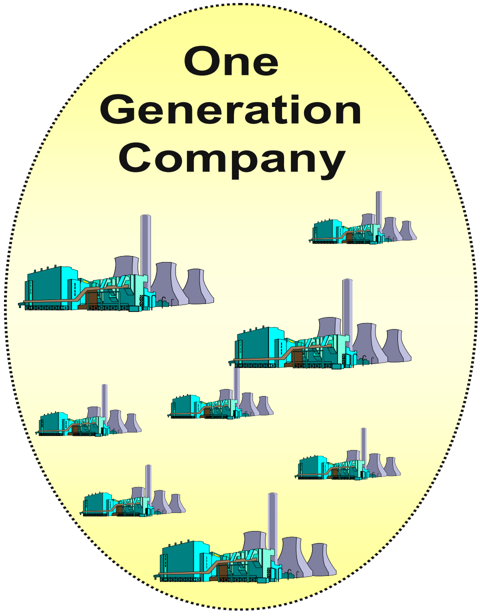
It may be easier to accommodate variable resources in the future

Thank you for your attention

Supplemental Slides

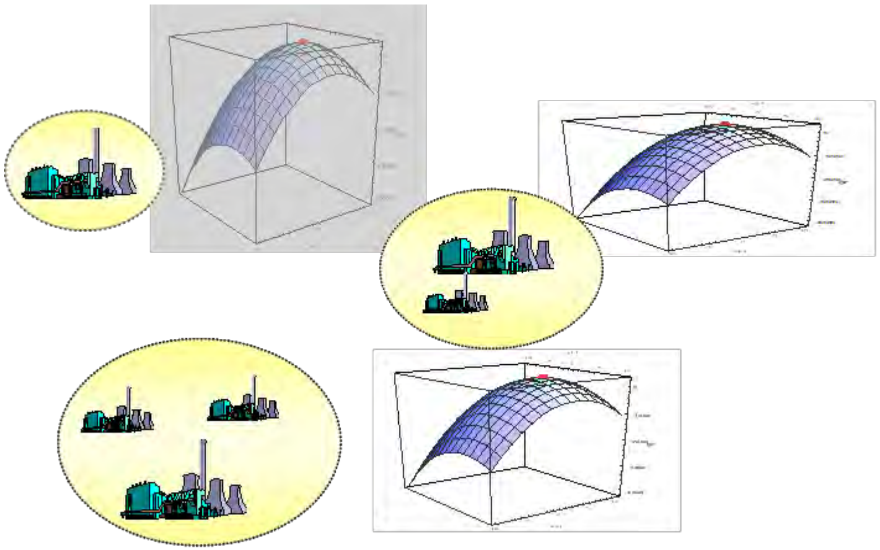
Resource Expansion Decisions

Vertically Integrated System
Single Decision Maker Model



- In a traditional power system with ***one*** vertically-integrated utility company, all options (supply, demand, transmission, etc.) are evaluated based on cost and reliability ***(total system situational awareness)***
  - Identify investment plan that reliably meets demand at the lowest net present value of all costs

Competitive Market Uncertainty
Numerous Decision Makers

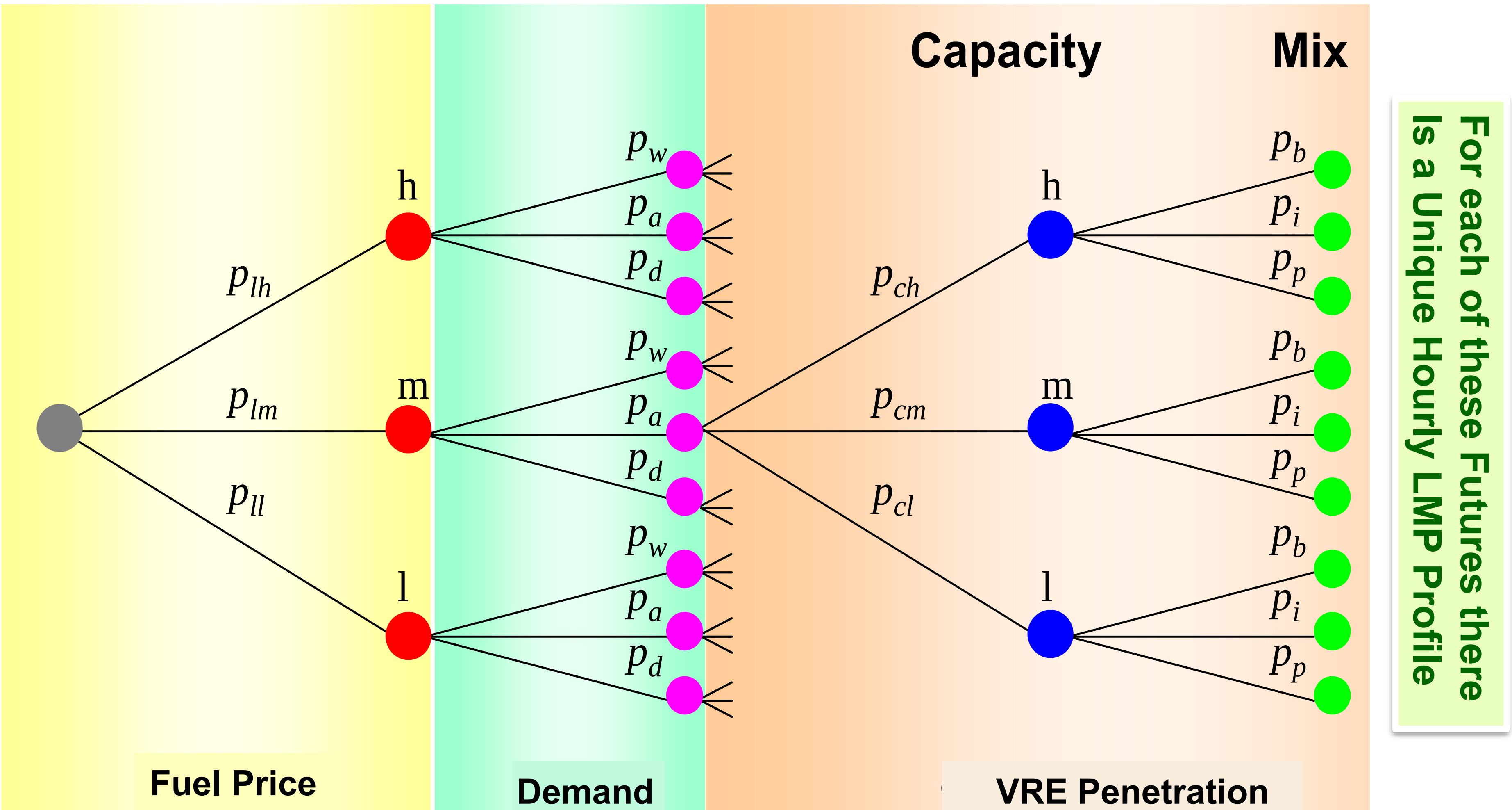


- ***Multiple*** generation companies evaluate their options based on profitability and investment risk (***company perspective***)
- Identify investment with high profit potential and limited down-side risk

Independent Financial Decisions May Result in a Path that Differs from a Least-Cost Economic System Expansion Plan

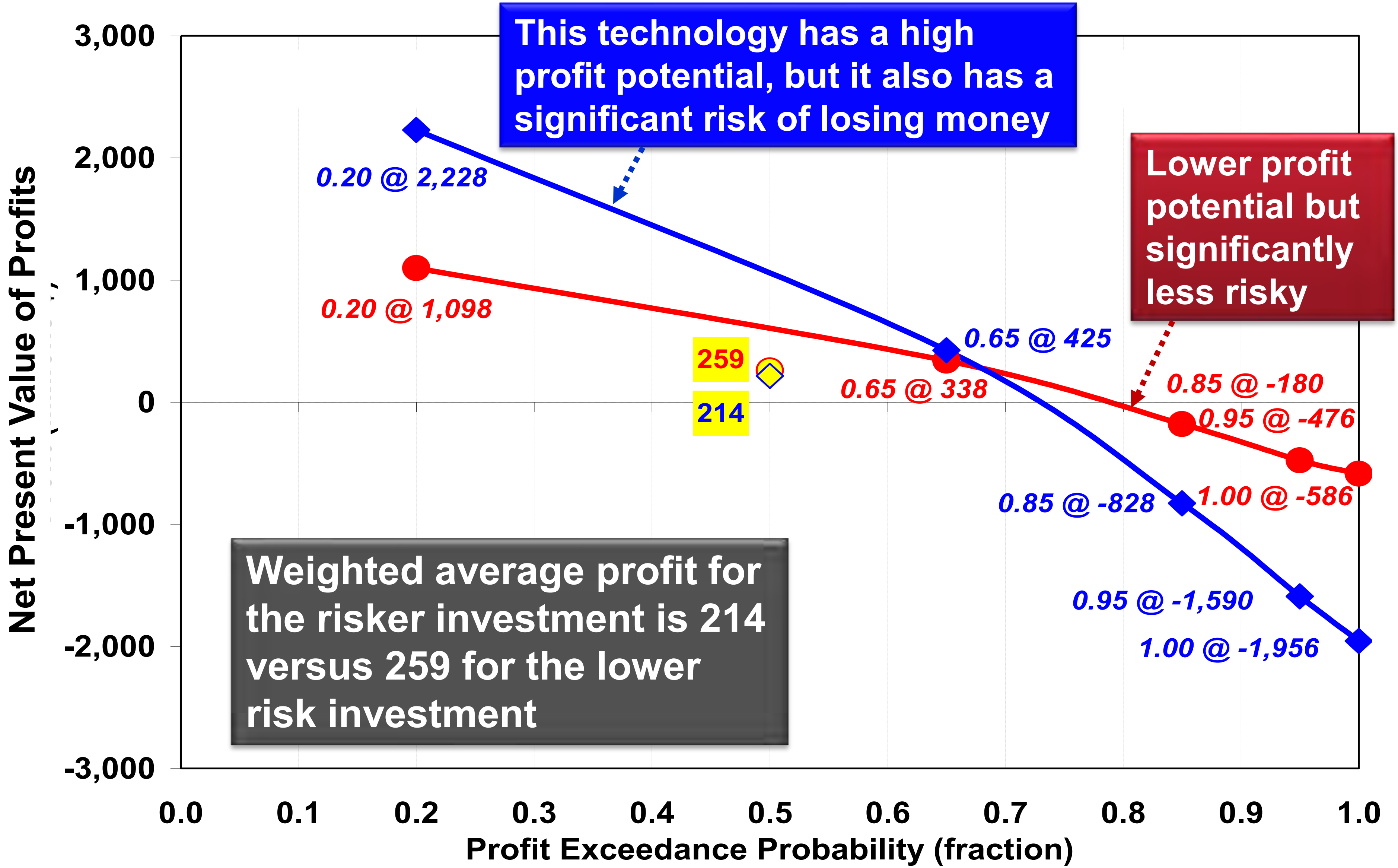
Uncertainty Analysis and Investment Decisions

- Future loads, fuel prices, etc. are uncertain
- In competitive markets multiple companies develop expectations and make ***independent investment decisions*** under uncertainty that affect LMPS



Investment Decisions Are Influenced by Risk Preferences

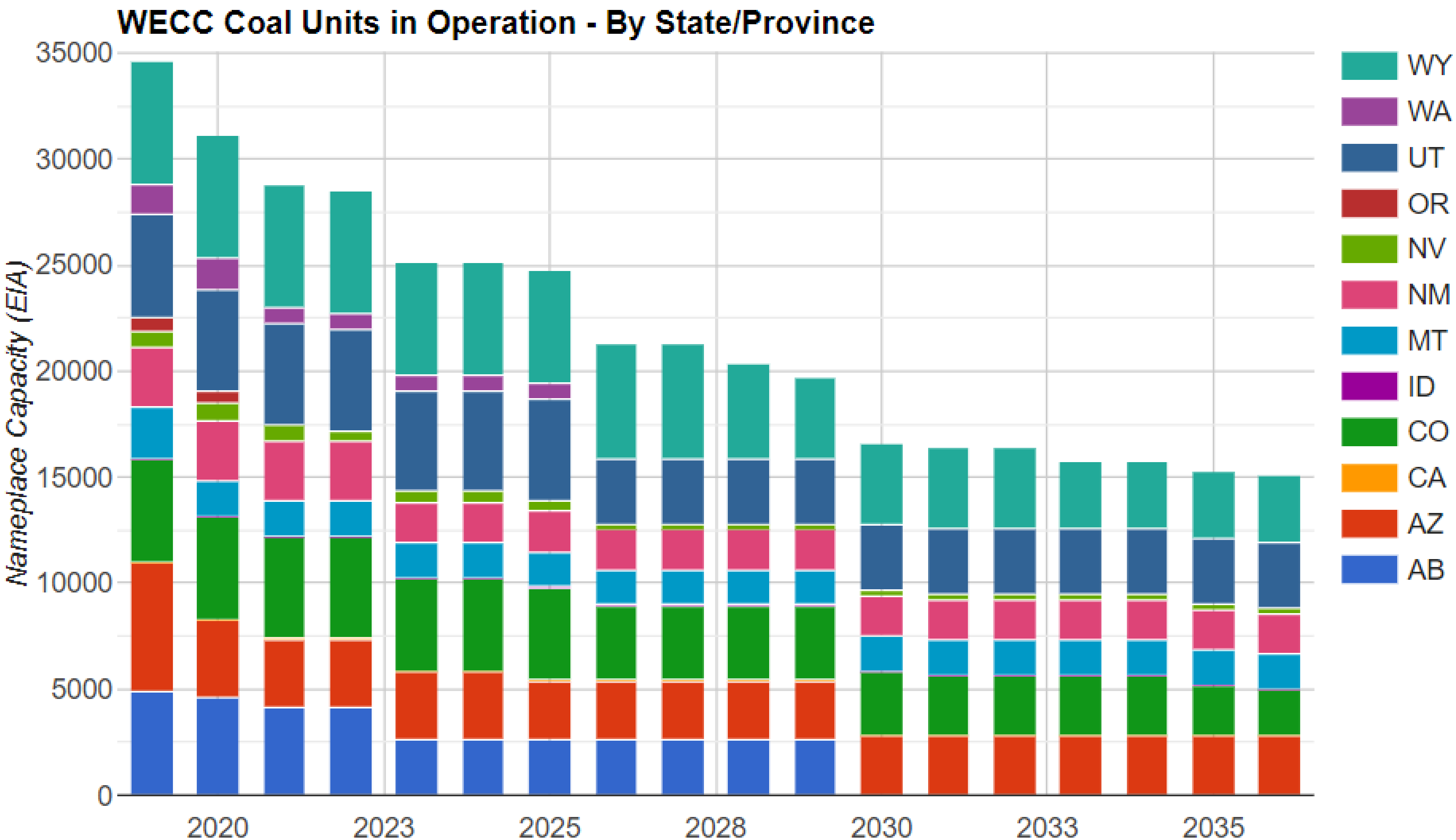
Mapping of Possible Financial Outcomes for Two Technology Choices



Survey of Integrated Resource Plans for Several Utilities in the Western US

Utility	Utility Type	Type of Generation added	When Added	Capacity Added (MW)
Public Service of CO	Investor Owned	Gas Turbines Combined Cycle	2018 to 2022 2023 to 2032	1,211 1,929
Public Service of NM	Investor Owned	Gas Turbines Solar PV	2016 to 2033 2015 to 2022	736 283
Rocky Mountain Power	Investor Owned	Combined Cycle Wind	2014, 2024 2024	645, 423 432
Arizona Public Service	Investor Owned	Natural gas (unspecified) Renewable (unspecified)	2019 to 2029 2019 to 2029	4,200 425
Tucson Elect. Power	Investor Owned	Natural gas (unspecified) Renewable (unspecified)	2015 to 2028 2014 to 2028	1,214 529
Nevada Power Company	Investor Owned	Combined Cycle Gas Turbines Solar PV	2018 to 2024 2023 to 2032 2016 to 2021	3,813 2,043 50
Sierra Pacific Power	Investor Owned	Gas Turbines Combined Cycle	2023 to 2029 2025	1,975 571
Platte River Power	Western Customer	Gas Turbines	2021	Unspecified
Colorado Springs Utilities	Western Customer	Gas Turbines Renewable (unspecified)	2029 to 2031 2018 to 2029	39 20
Tri-State G & T Assn.	Western Customer	Combined Cycle Renewable (unspecified)	2019 to 2026 2016 to 2027	1,176 350
Salt River Project	Western Customer	Natural gas (unspecified)	FY2018 +	projected 581 MW gap in 2017

Coal Capacity Is Expected to Decline
Not as Flexible as Natural Gas Technologies



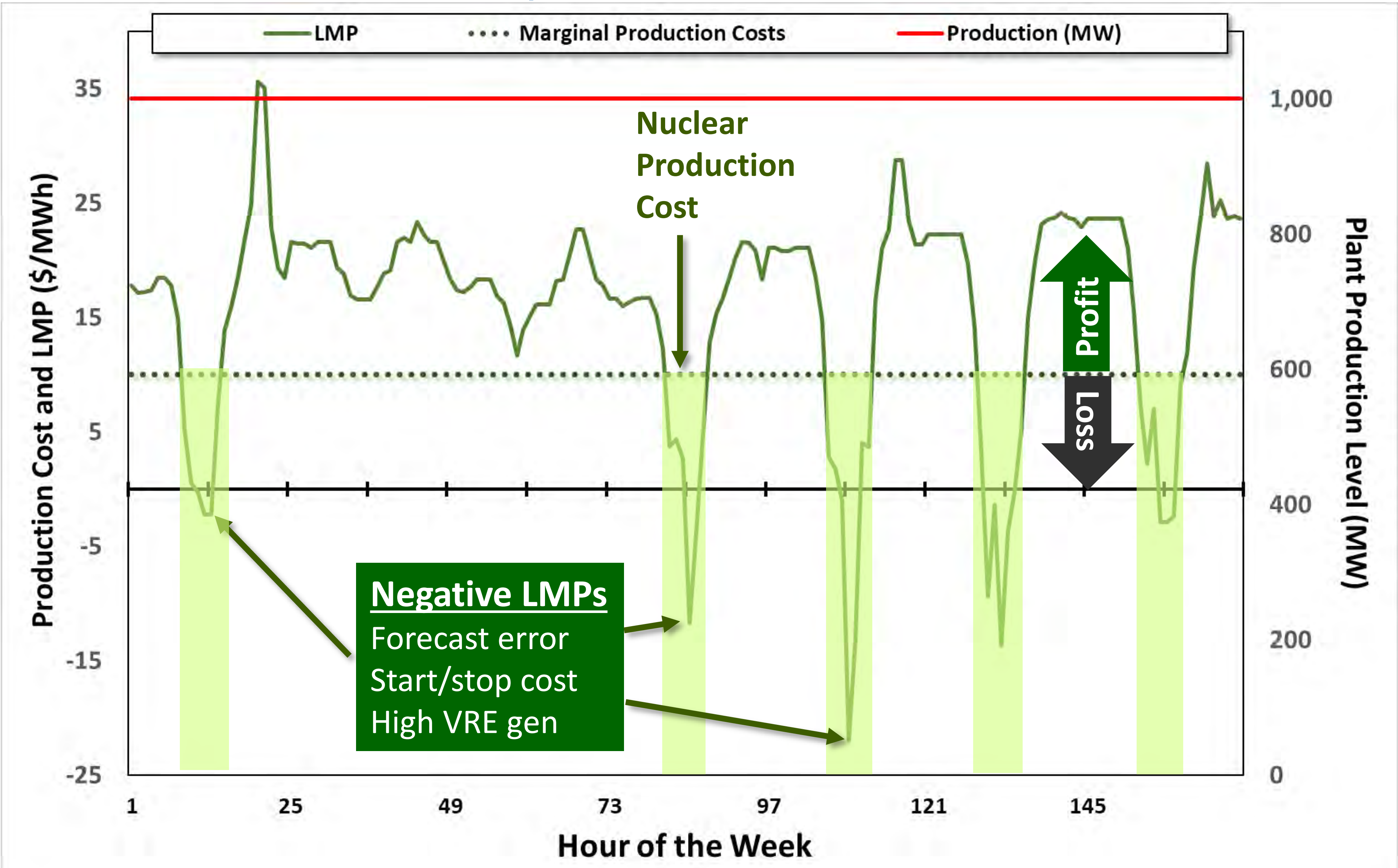
https://www.nwcouncil.org/news/coal-retirements

Supplemental Slides

LMPs and Financial Considerations

LMPs and Nuclear Plant Financial Impacts

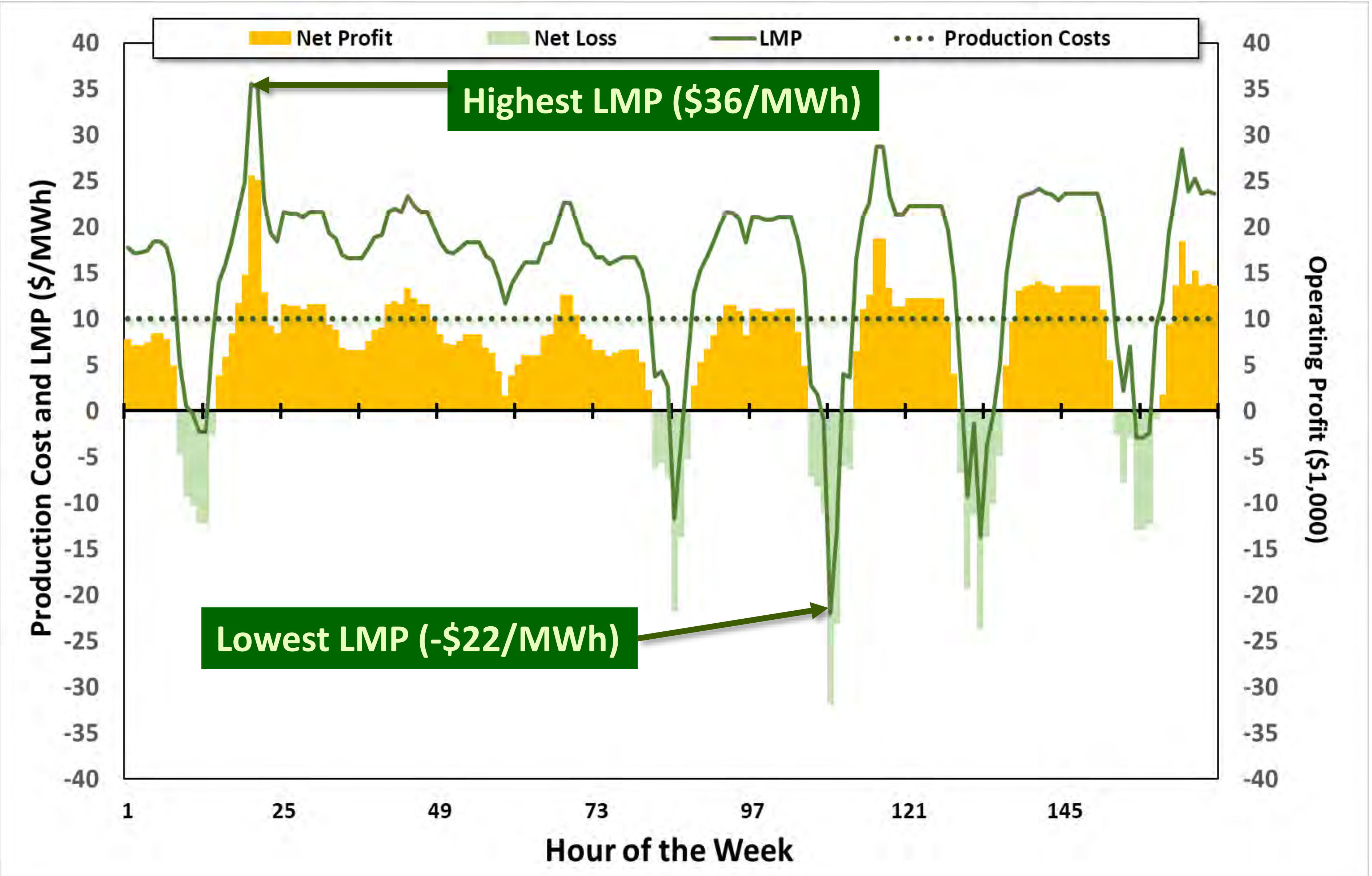
Inflexible Base Load Operations



Operating at a financial loss

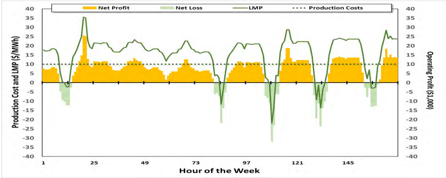
LMPs and Nuclear Plant Financial Impacts

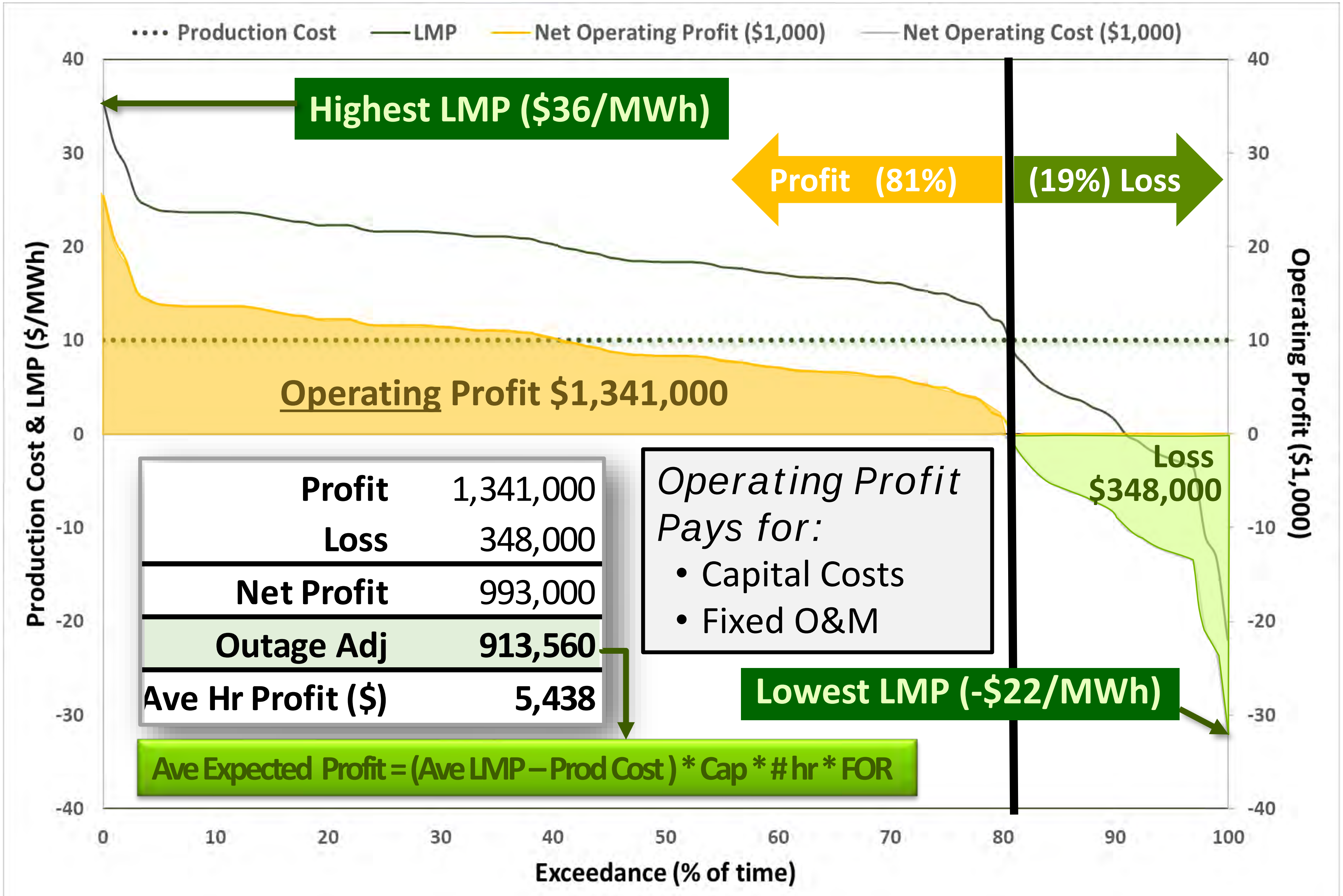
Inflexible Base Load Operations - 1 Week



LMPs and Nuclear Plant Financial Impacts

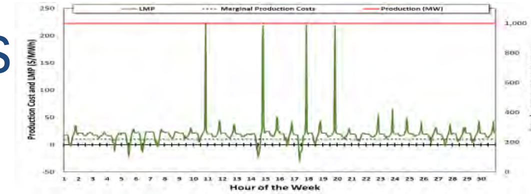
Inflexible Base Load Operations - 1 Week

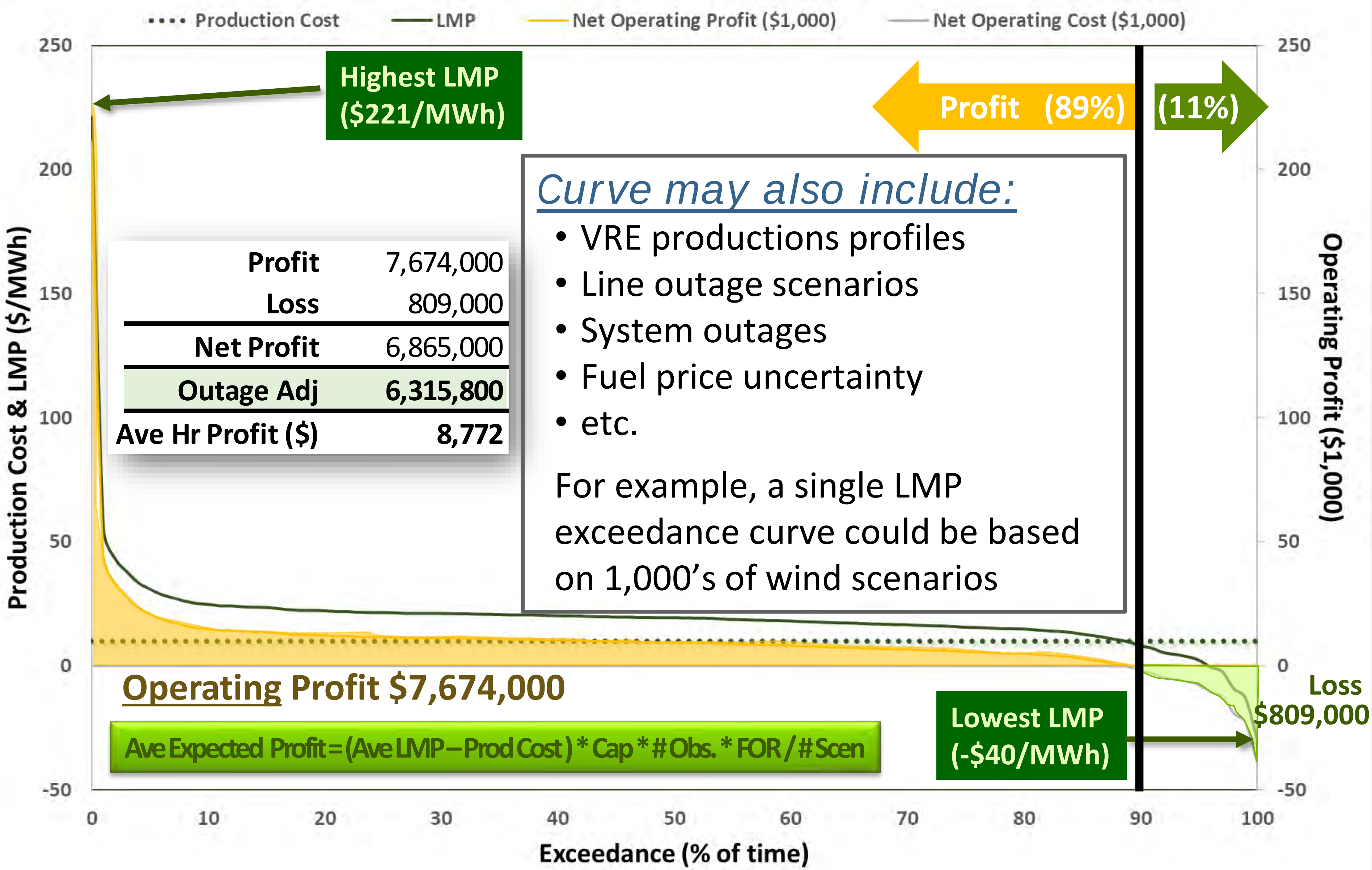




LMPs and Nuclear Plant Financial Impacts

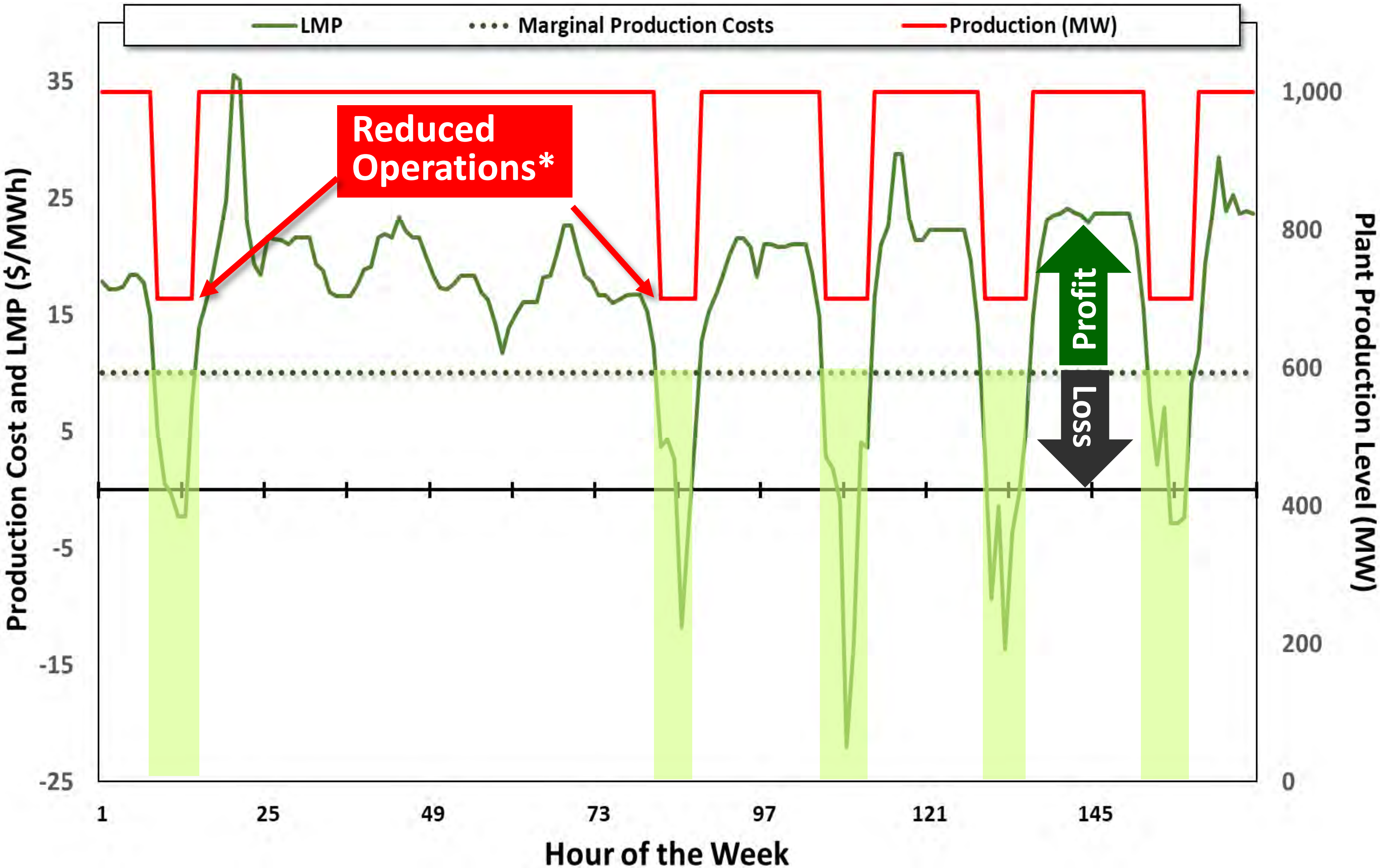
Inflexible Base Load Operations - 1 Month





LMPs and Nuclear Plant Financial Impacts

Moderate Operating Flexibility

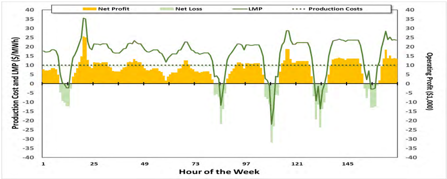


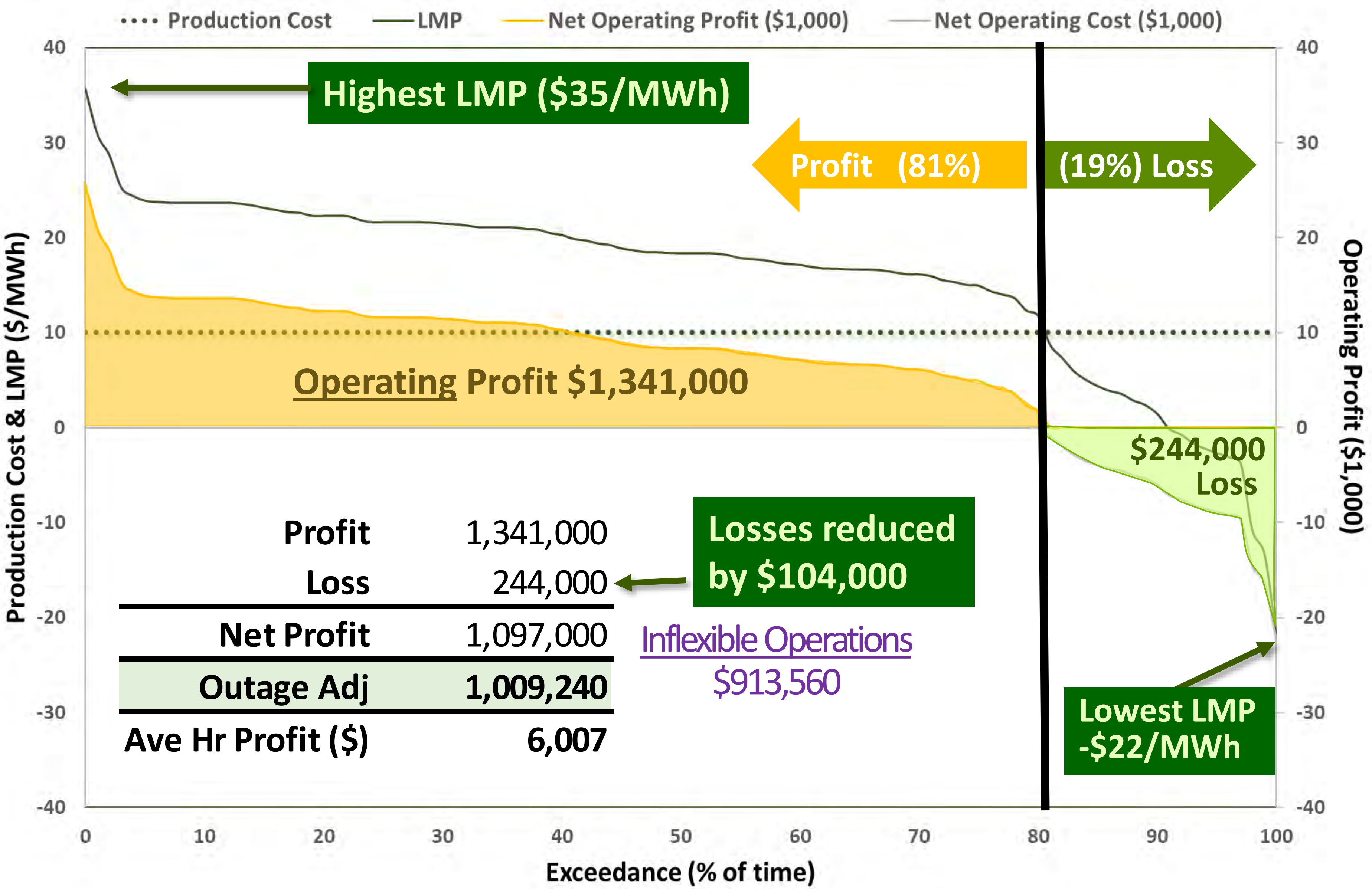
Operating at a financial loss

* Flexibility based on *"Economic Ramifications of Nuclear Load-Following in an ERCOT-like Market under High Renewables Penetration and Energy Policies"* (ANL paper funded by USDOE)

LMPs and Nuclear Plant Financial Impacts

Moderate Flexibility Case - 1 Week



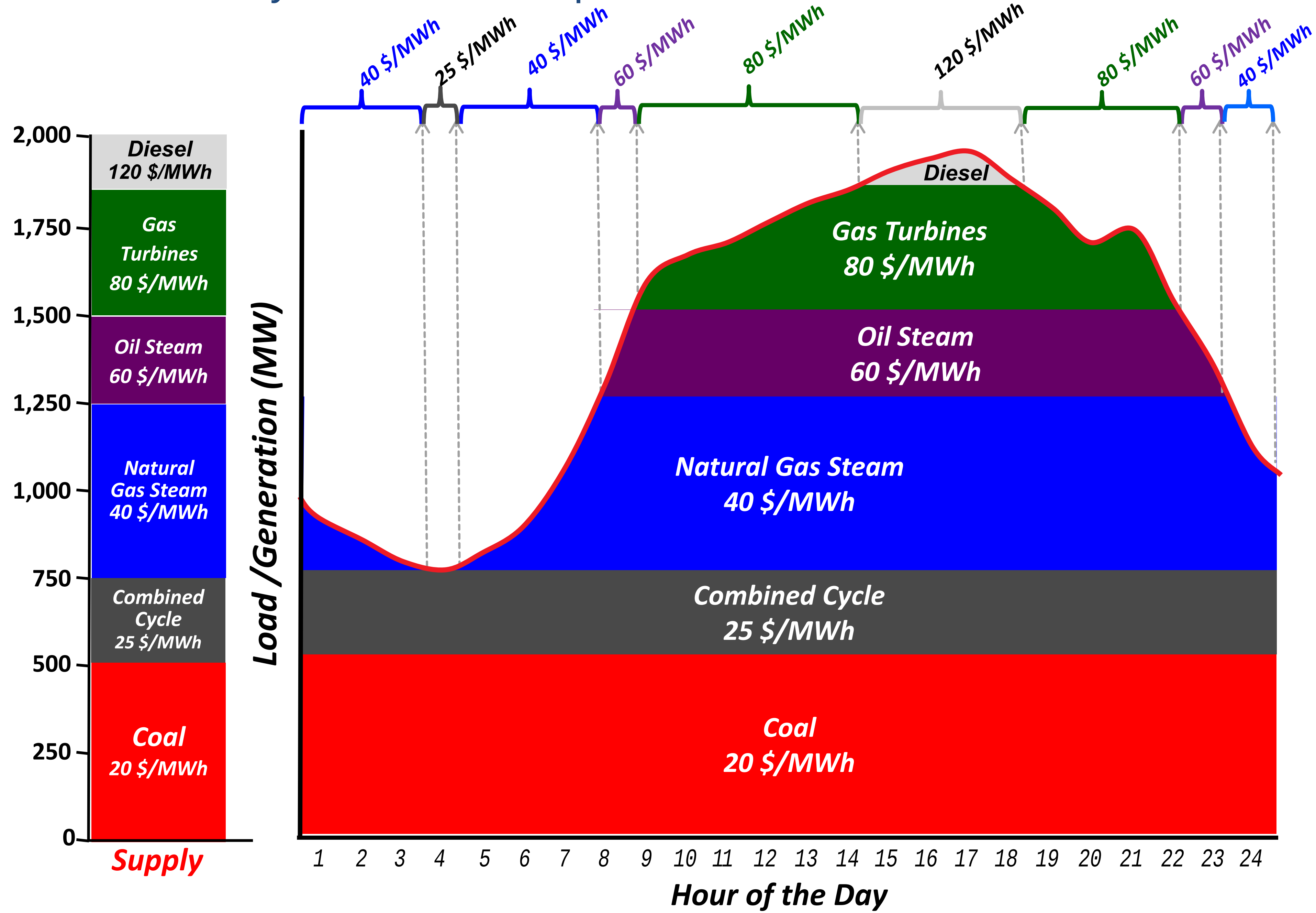


Profit	1,341,000
Loss	244,000
Net Profit	1,097,000
Outage Adj	**1,009,240**
Ave Hr Profit ($)	**6,007**

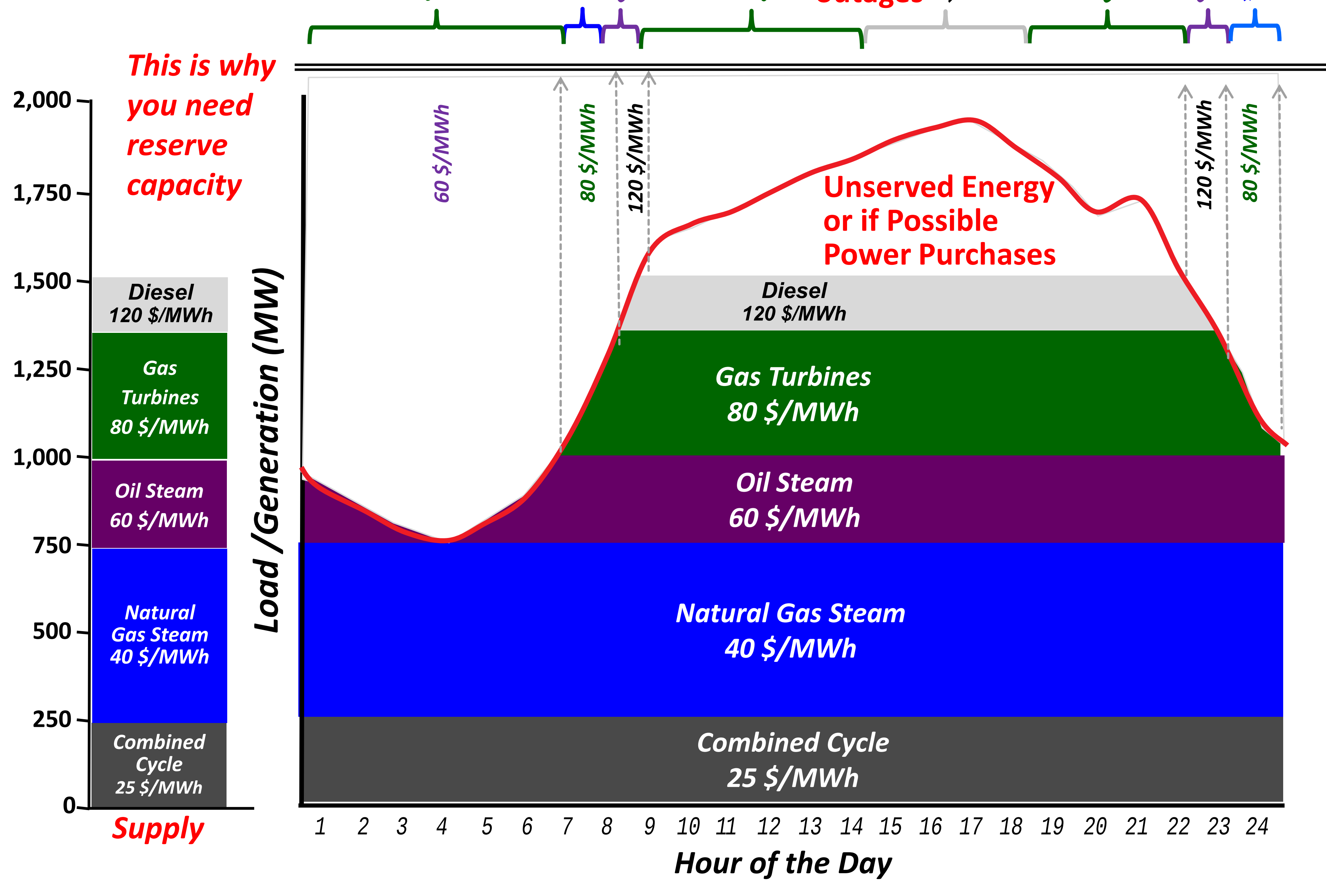
Supplemental Slides

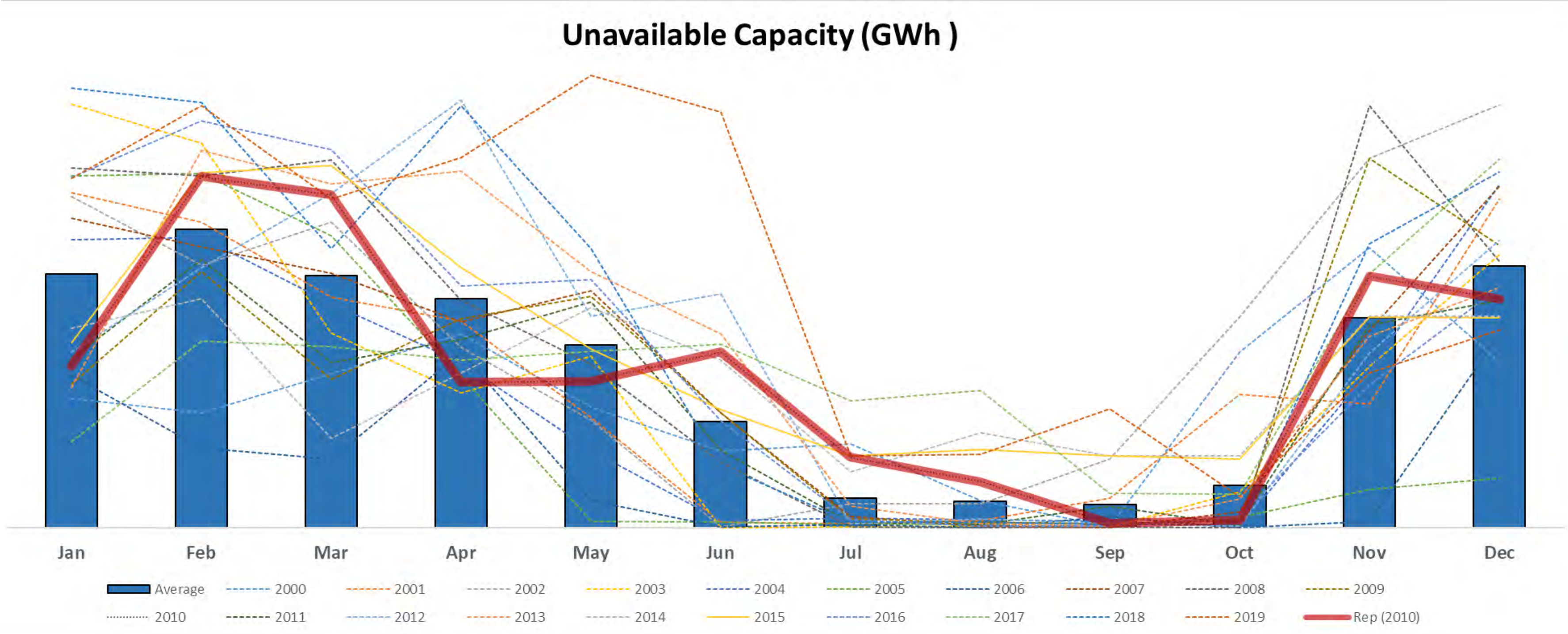
Forced and Scheduled Outages

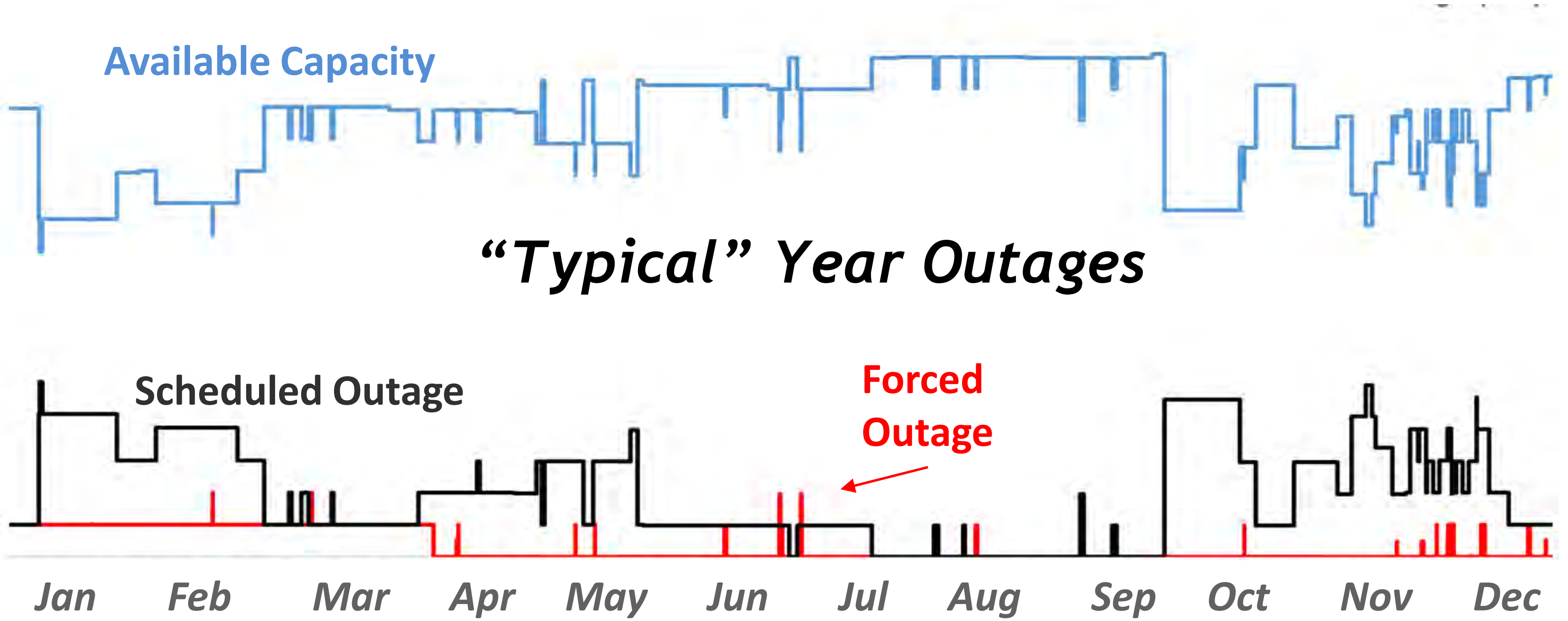
Ideally, Units Are Dispatched Based on Production Cost



Unit Outages Increase Costs

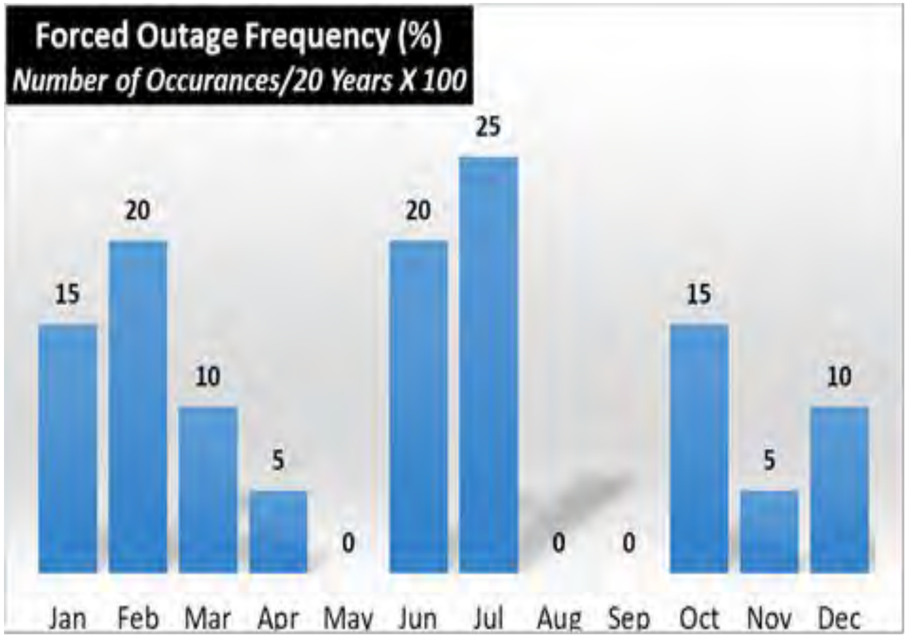


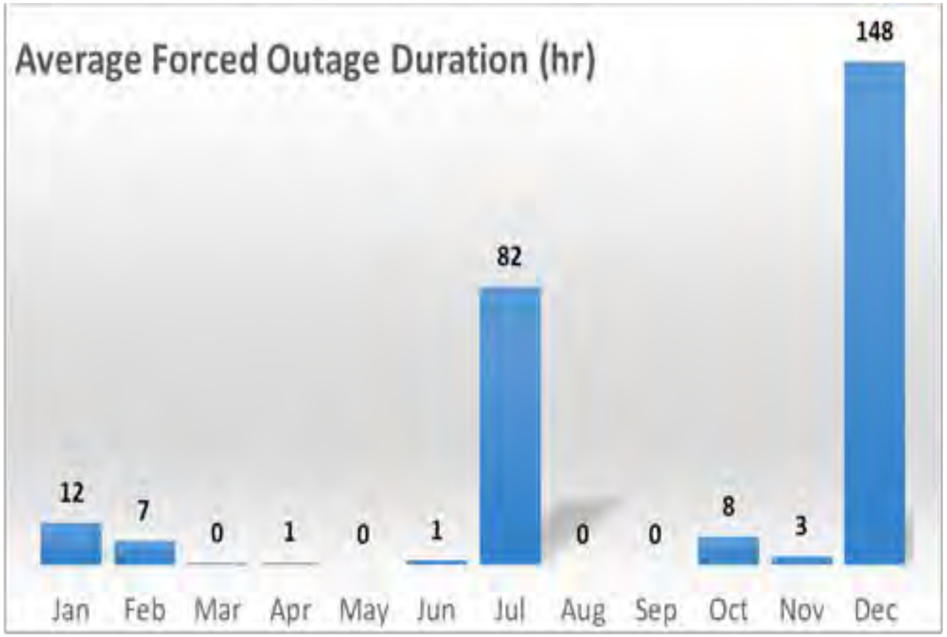

Unavailable Capacity (GWh)
Jan
Feb
Mar
Apr
May
Jun
Jul
Aug
Sep
Oct
Nov
Dec
Average
2000
2001
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
Rep (2010)

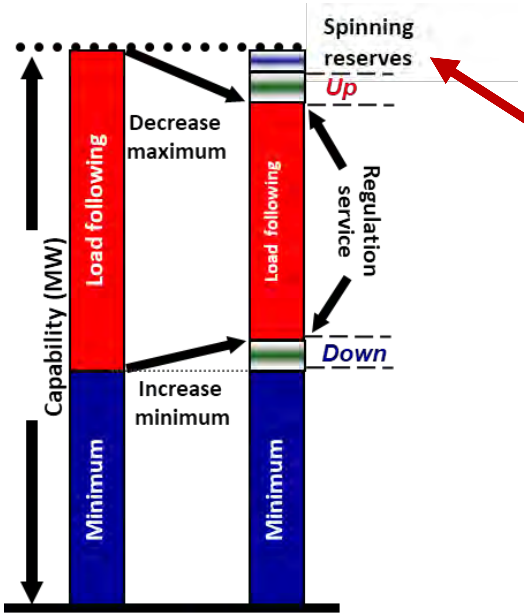

Available Capacity
"Typical" Year Outages
Scheduled Outage
Forced Outage
Jan
Feb
Mar
Apr
May
Jun
Jul
Aug
Sep
Oct
Nov
Dec

Sample Hydropower Unit Outage Statistics (2000-2019)

Outages Are Scheduled During Periods of Low Load/Energy Price







Instead of operating all units at full capacity some units are dispatched at a lower so that when a unit is suddenly forced out of service the generation shortfall is immediately replaced by deploying the reserved capacity

Assess Contingency Reserve Requirements

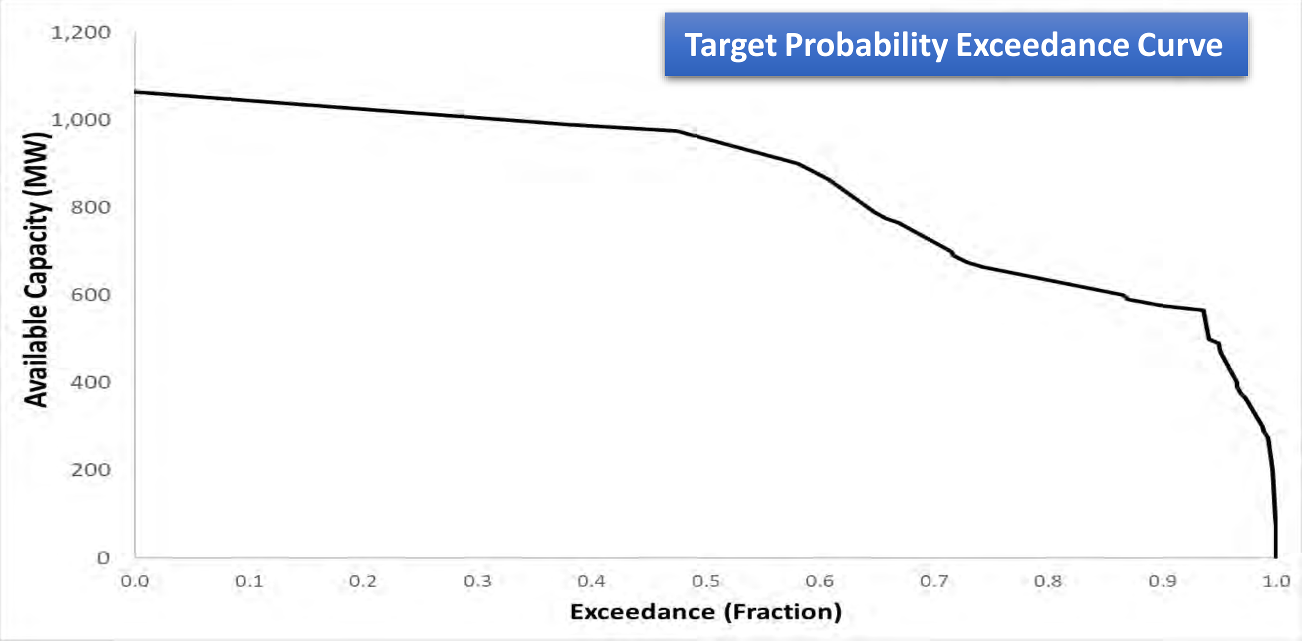
All Possible of On/Off Combinations

Probability of Occurrence Sum to 1.0

U1	U2	U3	U4	U5	
0	0	0	0	0	0.000114
0	0	0	0	1	0.000405
0	0	0	1	0	0.001072
0	0	0	1	1	0.003819
0	0	1	0	0	0.000447
0	0	1	0	1	0.001593
0	0	1	1	0	0.004216
0	0	1	1	1	0.015019
0	1	0	0	0	0.000937
0	1	0	0	1	0.003338
0	1	0	1	0	0.008834
0	1	0	1	1	0.031472
0	1	1	0	0	0.003685
0	1	1	0	1	0.013126
0	1	1	1	0	0.034740
0	1	1	1	1	0.123760
1	0	0	0	0	0.000347
1	0	0	0	1	0.001238
1	0	0	1	0	0.003276
1	0	0	1	1	0.011670
1	0	1	0	0	0.001366
1	0	1	0	1	0.004867
1	0	1	1	0	0.012881
1	0	1	1	1	0.045890
1	1	0	0	0	0.002863
1	1	0	0	1	0.010199
1	1	0	1	0	0.026993
1	1	0	1	1	0.096163
1	1	1	0	0	0.011258
1	1	1	0	1	0.040107
1	1	1	1	0	0.106149
1	1	1	1	1	0.378156

		U1	U2	U3	U4	U5
	Capacity (MW)	**400**	**300**	**75**	**200**	**90**
Outage Cause A	Occurances/year	2	1	1	4	6
	Outage Length (Days)	21	17	14	8	10
Outage Cause B	Occurances/year	4	2.5	12	1	5
	Outage Length (Days)	12	9	5	3	4

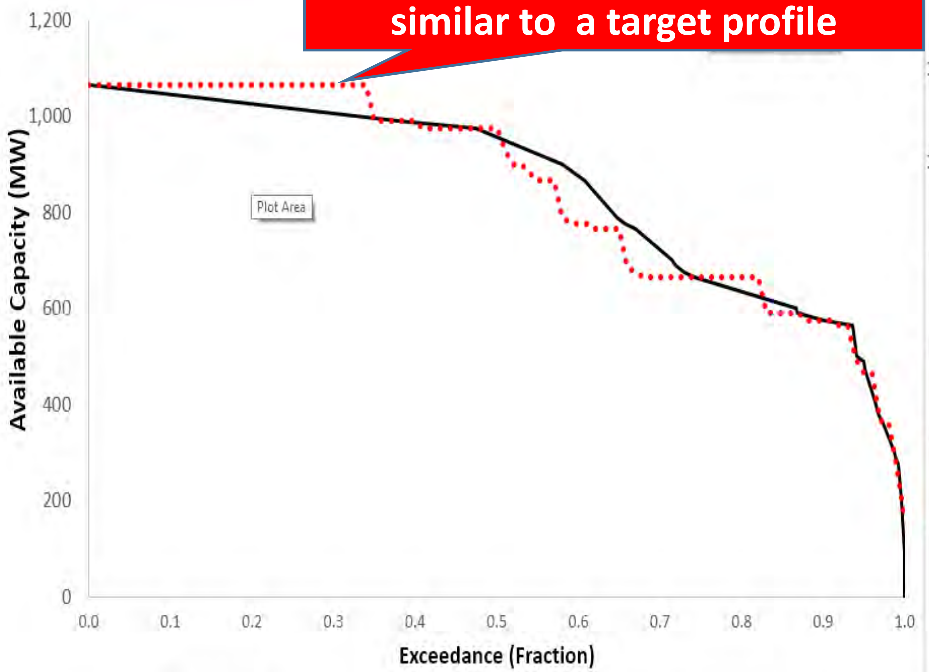
	U1	U2	U3	U4	U5
Cause A Days Out	42	17	14	32	60
Cause B Days Out	48	22.5	60	3	20
Total Days Out	90	39.5	74	35	80
Time Out of Service (frac)	0.25	0.11	0.20	0.10	0.22



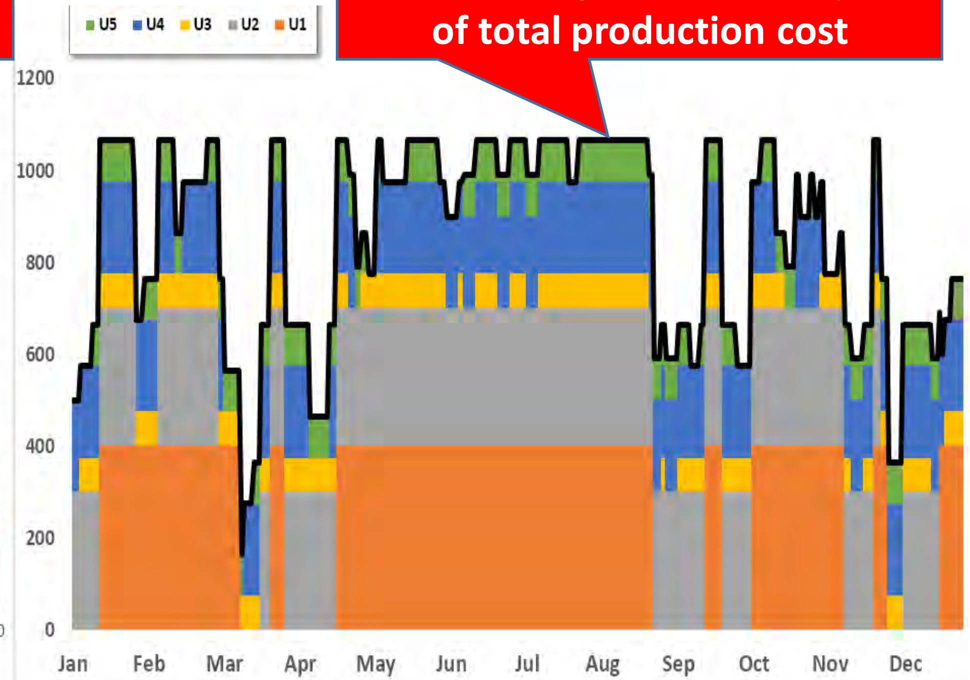
Folding a piece of paper 42 times reaches the moon – the curse of dimensionality

Representing Random Forced Outages in Real Time Models

Use a forced outage time series that has a distribution that is similar to a target profile



The time series of chronological forced outages have an impact of total production cost



Target Outages

	Cap (MW)	Cause A	Cause B	Total	% Outage	Avail Cap Hrs (GWh/yr)
U1	400	42	48	90	25	2,640
U2	300	17	48	65	18	2,160
U3	75	14	48	62	17	545
U4	200	32	48	80	22	1,368
U5	90	60	48	108	30	555
Total	1065	165	240	405		7,269

Random Draws

	Cause A	Cause B	Total	% Outage	Differnce from Target (%)	Avail Cap Hrs (GWh/yr)
U1	63	47	110	30	5	2,448
U2	27	18	45	12	-5	2,304
U3	14	48	62	17	0	545
U4	40	3	43	12	-10	1,546
U5	58	48	106	29	-1	559
Total	202	164	366			7,402
% of Target	122	68	90			

134 Differnce from Target (GWh)

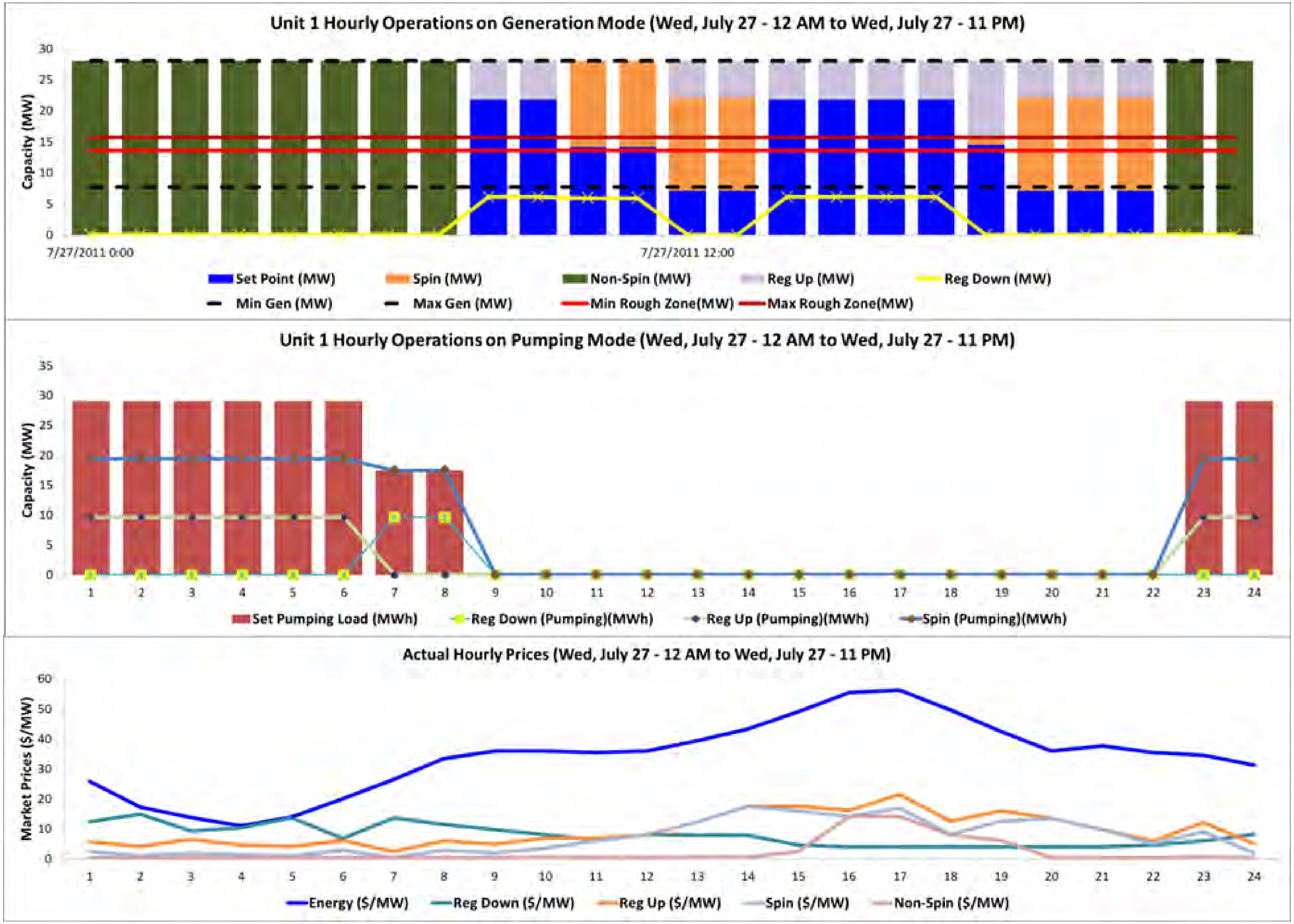
		U1	U2	U3	U4	U5
	Capacity (MW)	400	300	75	200	90
Outage Cause A	Occurances/year	2	1	1	4	6
	Outage Length (Days)	21	17	14	8	10
Outage Cause B	Occurances/year	4	2.5	12	1	5
	Outage Length (Days)	12	9	5	3	4

When an outage occurs the supply stack becomes smaller increasing LMP

Supplemental Slides

Pumped Storage Hydro

Optimal Operation of a Hypothetical Adjustable Speed PSH Unit Located in California

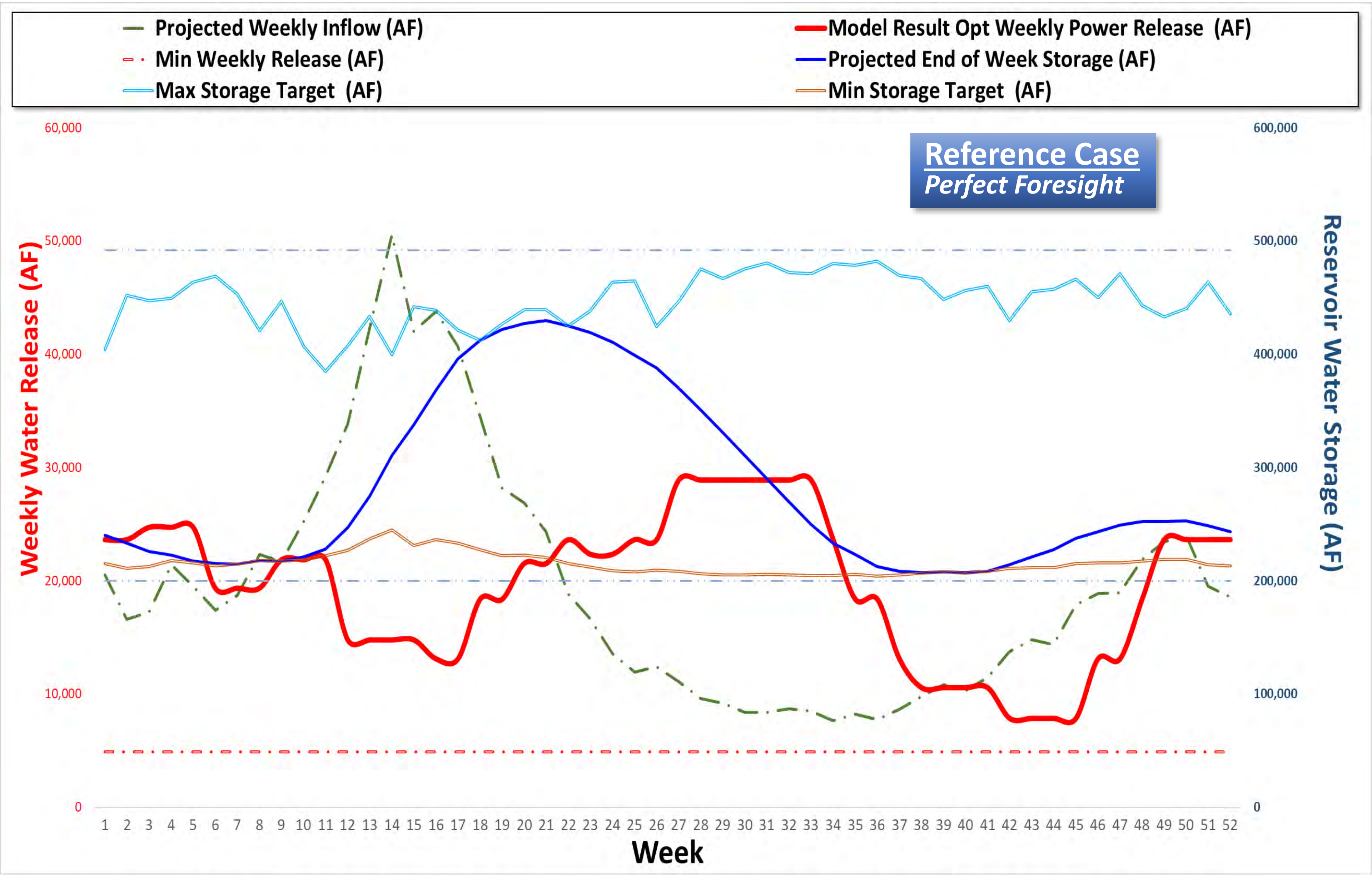


Supplemental Slides

Reservoir Inflow Forecast Error

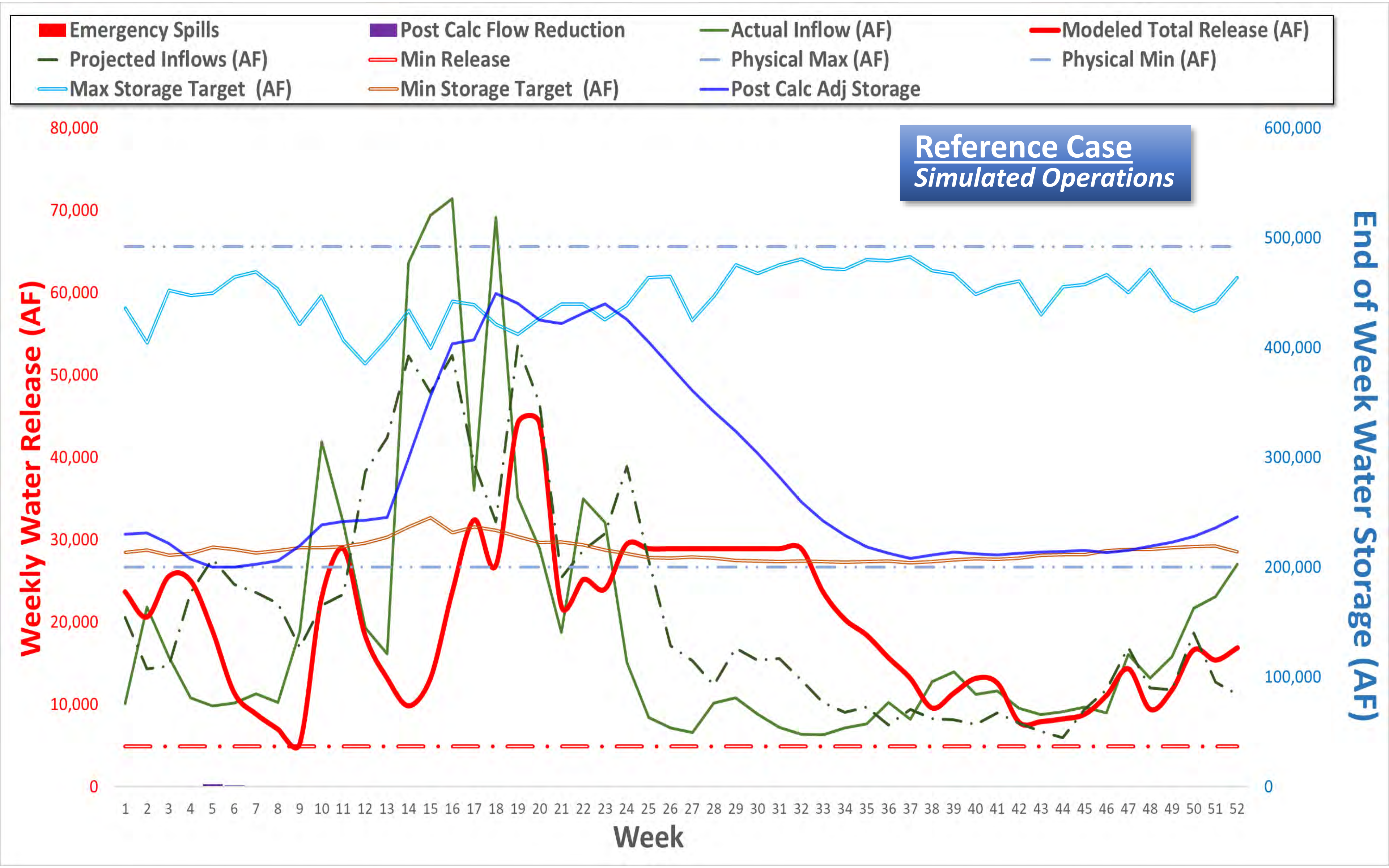
Long-term Scheduling of Limited Energy Resources

Perfect Foresight



Typical Scheduling and Dispatch Sequence

Schedulers and Operators React to Changing Projections and EvolvingConditions

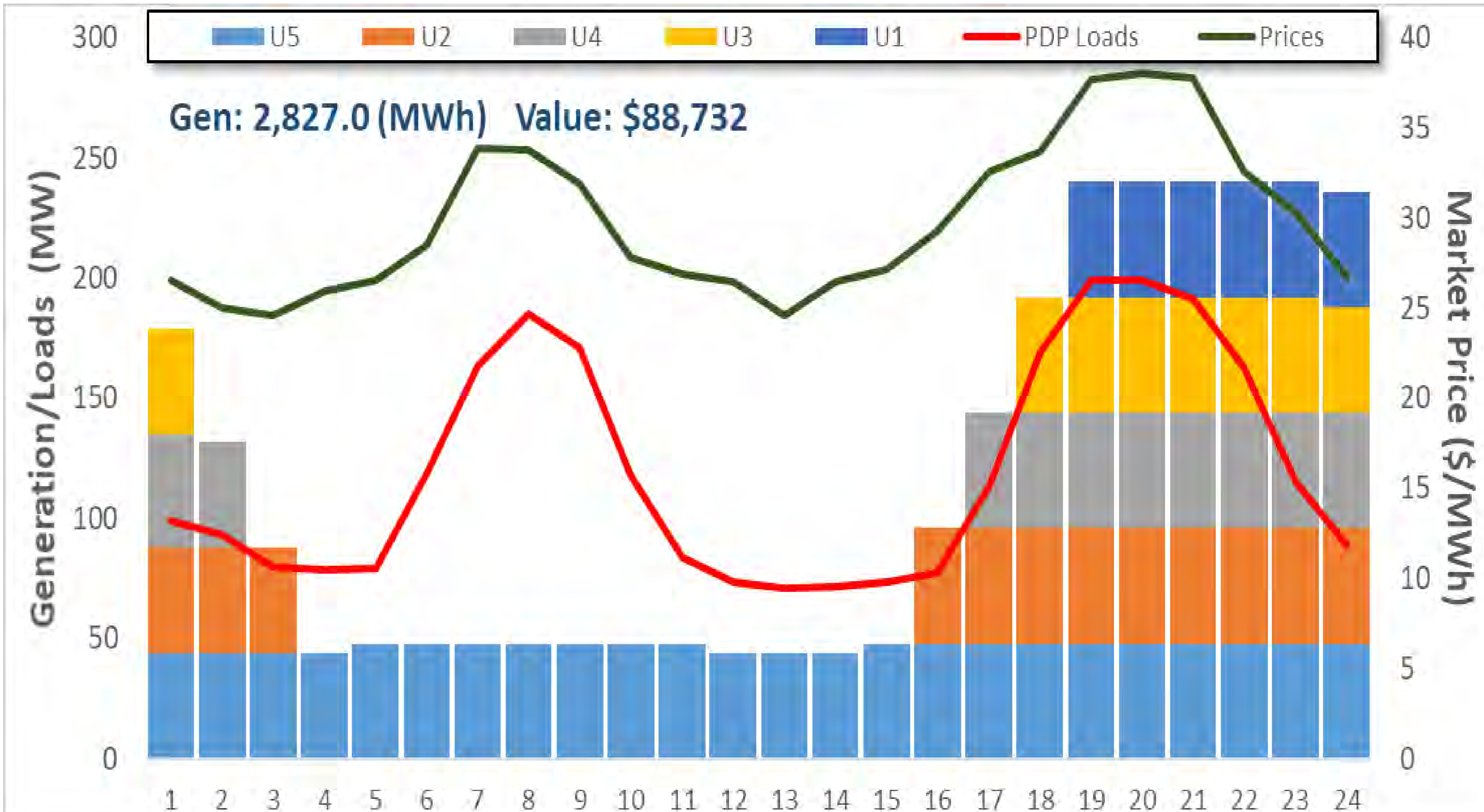


Supplemental Slides

Hydropower Dispatch Decisions Under Uncertainty

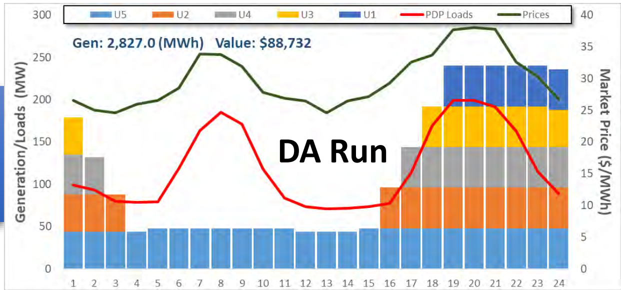
Hour Ahead Schedule Based on Projected LMPs

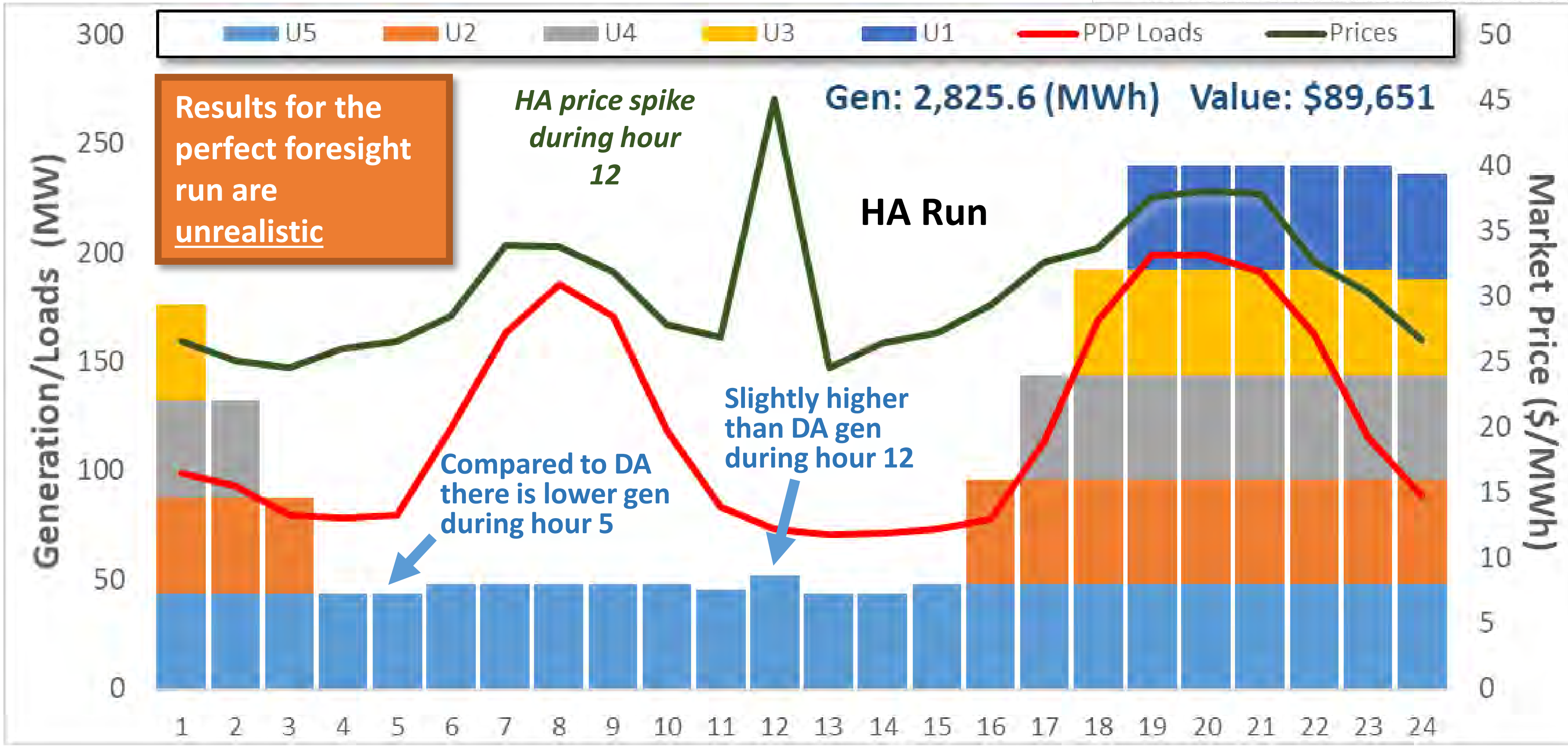
Hydropower Resource with a Limited Daily Water Release Volume



Models with "Perfect" Foresight Are Often Unrealistic

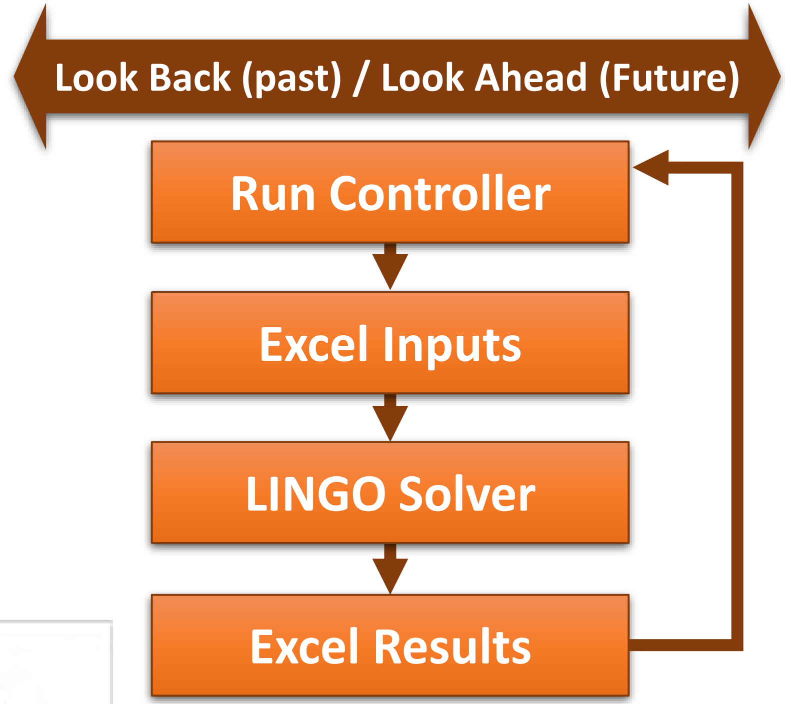
Example: DA & RT prices are the same except for the hour 12 RT spike

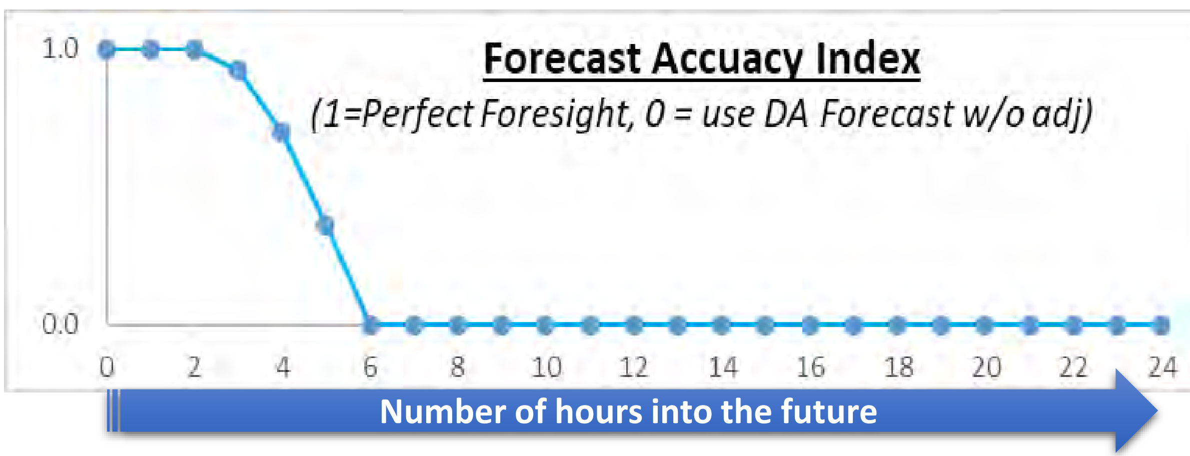




Model Runs and Sequencing that Mimic the Decision Making Process

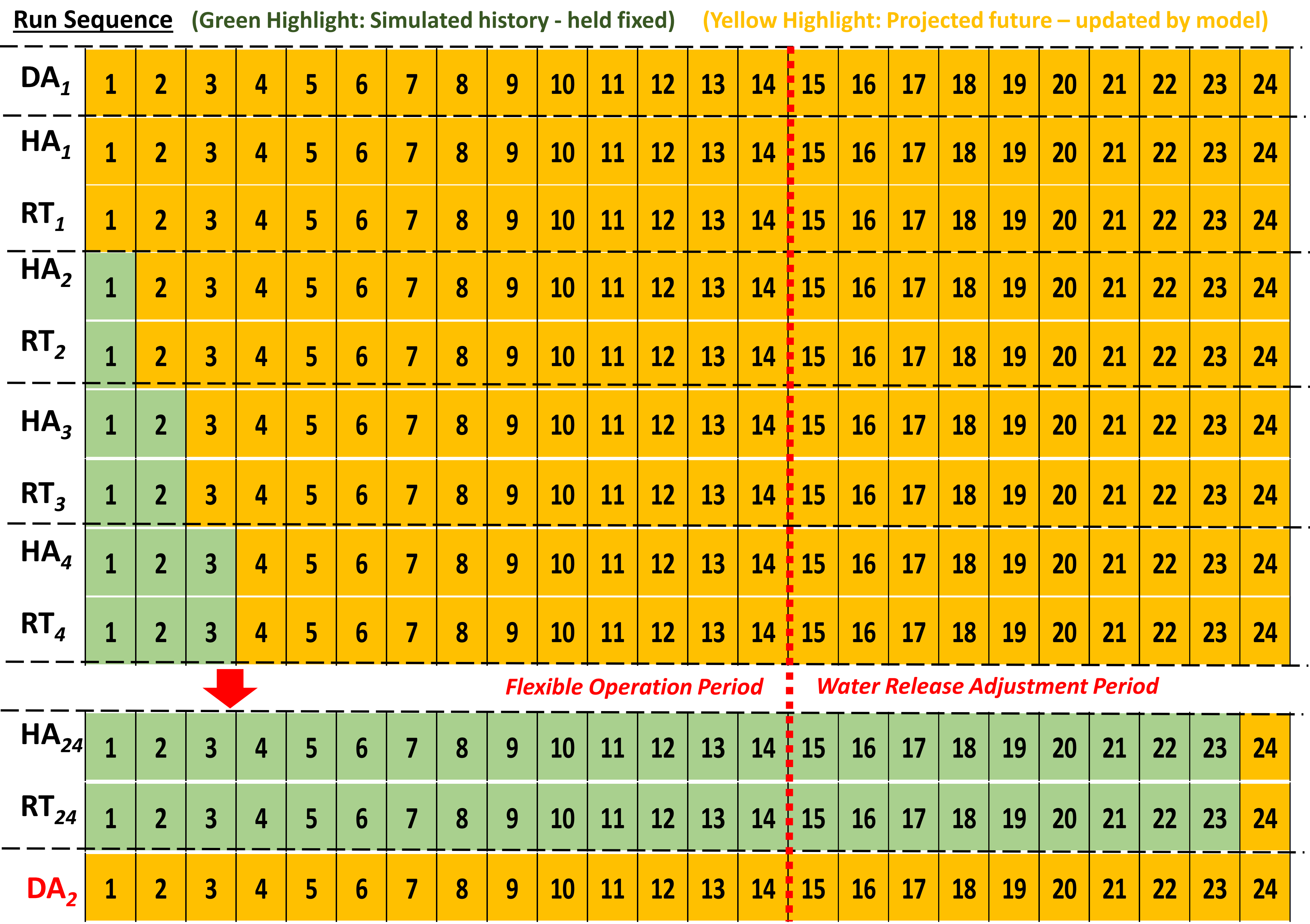
- Each model run simulates a single day
- Run HA (hourly), then DA (hourly), then RT (5-min)
- Rules represented by a combination of hard and soft constraints dictate how schedules and operations can deviate from previous schedules/operations over time
- For each day
  - DA model is run one time informing the HA & RT
  - HA is run 24 times using updated forecasts each hour
  - RT is run 24 times using updated forecast each hour





The user has knobs/levers that can be adjusted to change the shape of the forecast accuracy curve from no foresight to perfect foresight

The RT curve can differ from the RT curve


Run Sequence
(Green Highlight: Simulated history - held fixed)
(Yellow Highlight: Projected future – updated by model)
DA_1
HA_1
RT_1
HA_2
RT_2
HA_3
RT_3
HA_4
RT_4
Flexible Operation Period
Water Release Adjustment Period
HA_{24}
RT_{24}
DA_2
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24