Outline

1. Introduction
2. Statistical Analysis
3. Production Simulation Analysis
4. Quasi-Steady-State Analysis, QSS
5. Operational Implications and Mitigation Methods
   - Terminology and validation of results
   - Relationships between analyses
   - Operational implications by time frame
     - Key findings
     - Evaluation of possible mitigation methods
6. Conclusions and Recommendations

Operation Implications: Terminology and Validation

1-hr Delta: Change from the previous hour

- Schedule Flexibility

5-min Delta: Change from previous 5-minute period

- Load Following, Economic Dispatch

1-min Delta: Change from the previous minute

- Regulation

Validation:

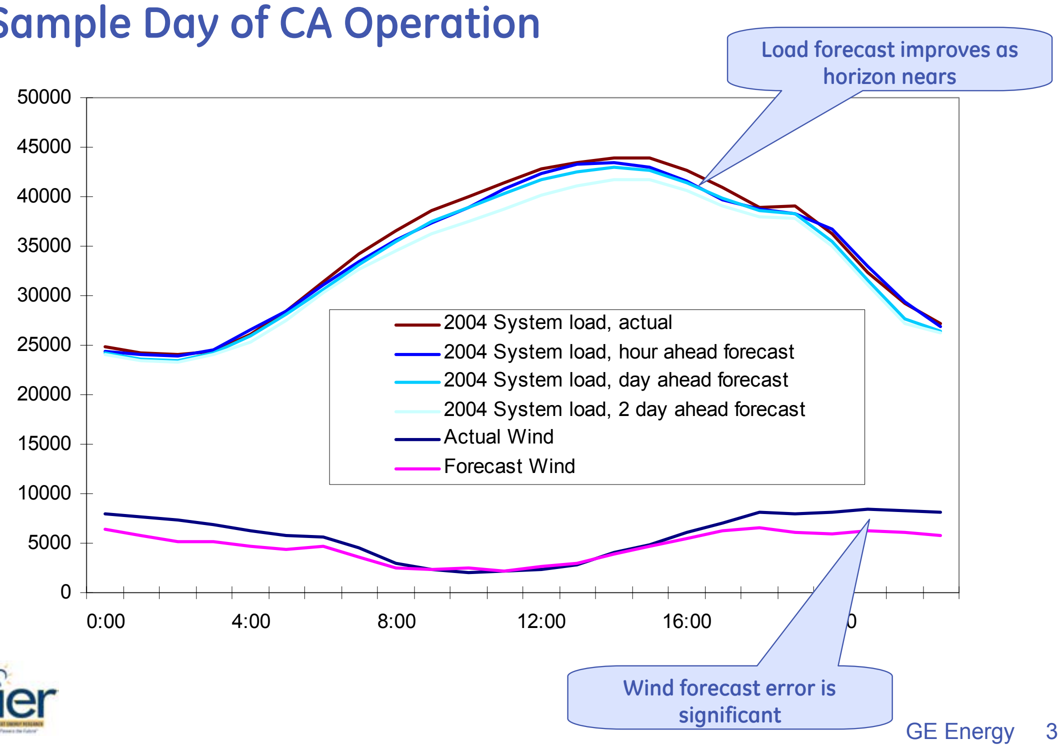
Results

Selected examples from historical operations

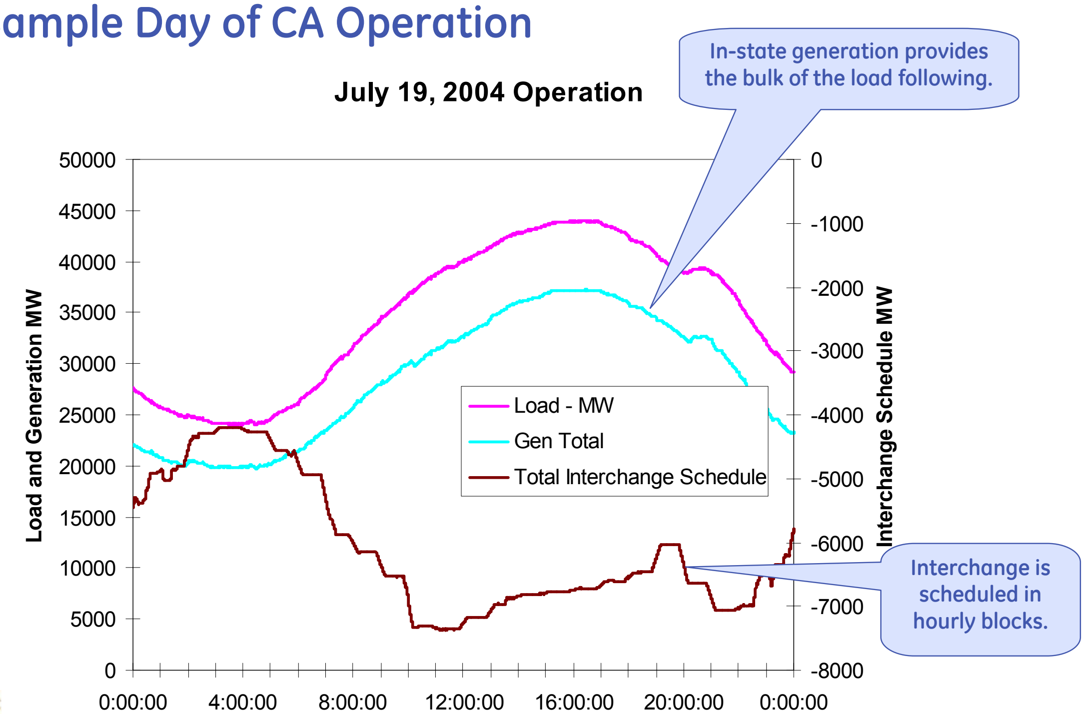
Approach

Connections between historical performance and analyses

Validation – Forecast
Sample Day of CA Operation

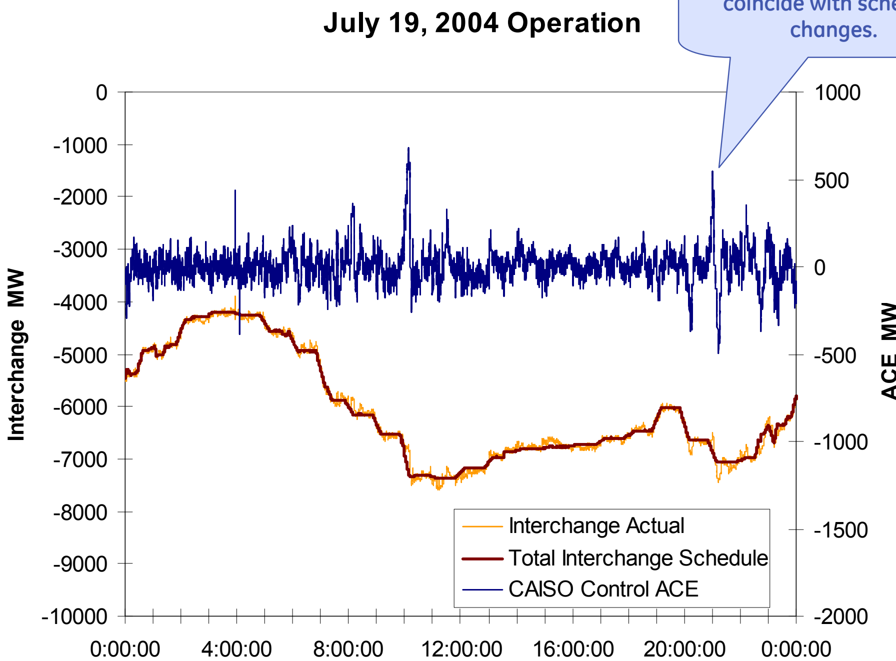


Validation – Schedule & Load Following
Sample Day of CA Operation

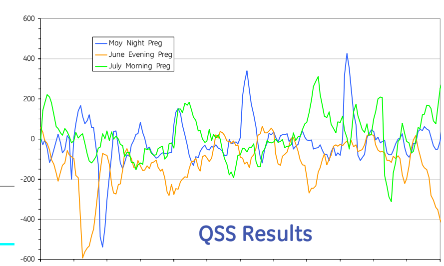


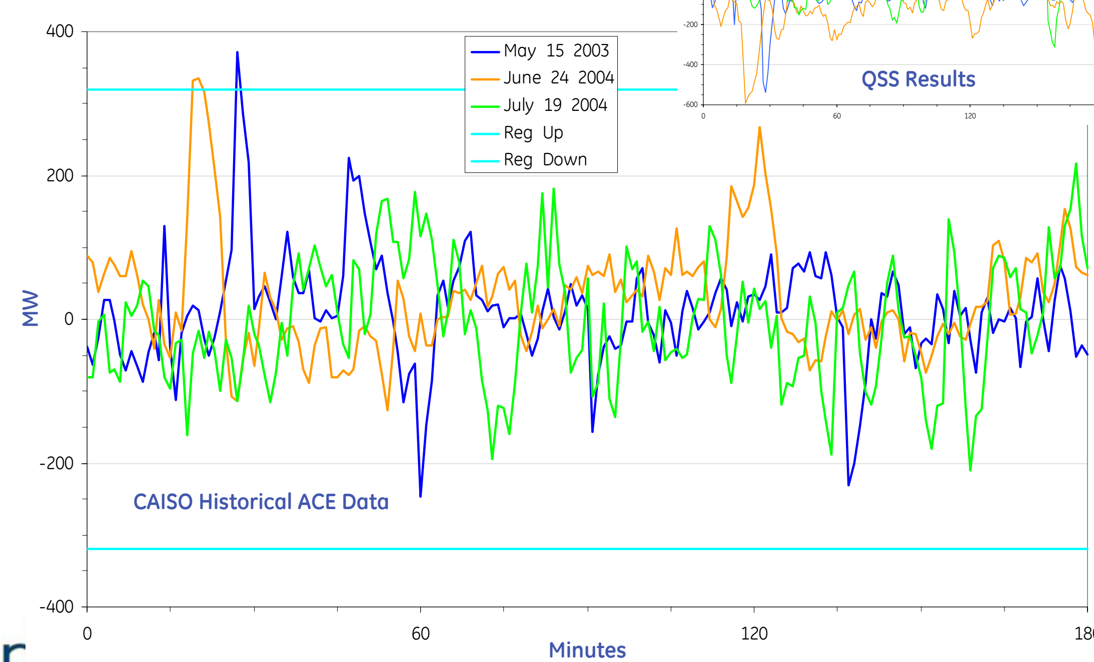
Validation – Interchange & Regulation Sample Day of CA Operation

Large ACE events tend to coincide with schedule changes.

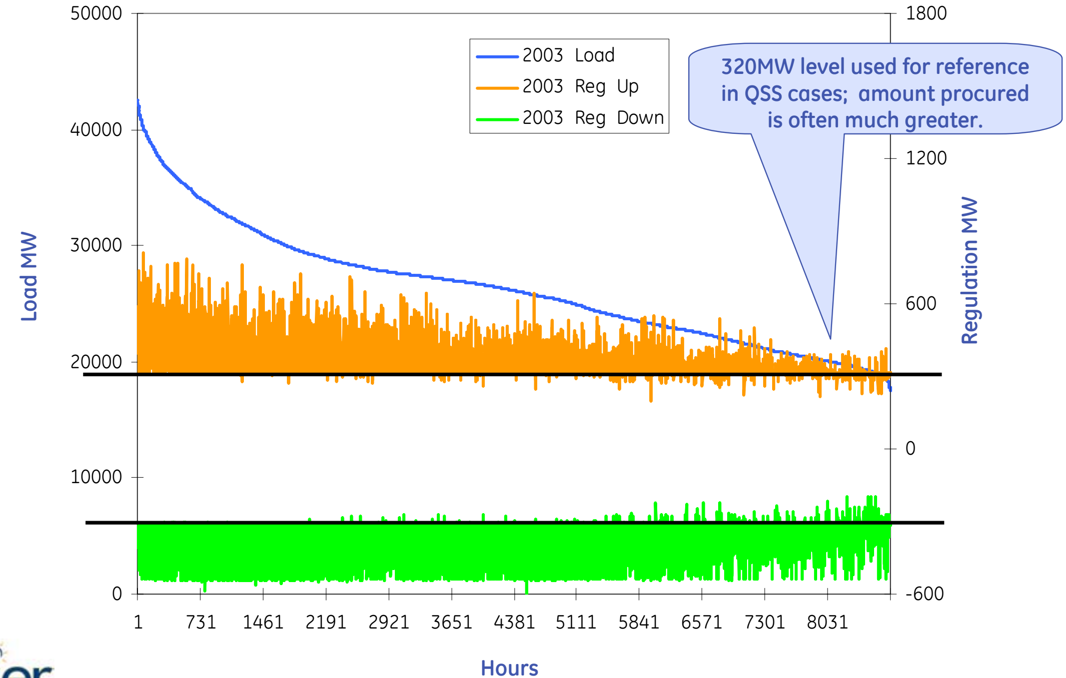


Validation – Regulation & ACE





Validation – Regulation Procurement



Operation Implications: Relationship between Statistics, MAPS Results and QSS Simulations

- Statistics provide insight into variability and what changes are due to intermittent renewables. Statistics don't tell whether the system will perform satisfactorily
  - 3 times standard deviation (σ) is a proxy for maneuverability/flexibility requirements: the vast majority (99.7%) of events fall within +/-3 σ (in a normal population)
  - Increase in 3σ is one measure of requirement for additional maneuverability/flexibility due to increased variability
- Economic simulations with MAPS identify the mix of resources available at any given time to meet the maneuverability/flexibility requirements
- Time simulations with QSS illustrate the relationship between the statistics and the minute-to-minute behavior of the system

Operation Implications

- Highlight operational implications of variability (i.e., what did we learn?)
  - Day ahead commitment
  - Hourly flexibility
  - Load-following
  - Regulation
  - Show the relationship between the 3 classes of analysis
  - Examine one or two mitigation options that are (primarily) focused on the adverse implications of variability in a given time frame

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Change in Flexibility Requirements: Total Variability

	Total		
	σ 1-Hour Δs (MW)	σ 5-Min Δs (MW on 15-Min RA)	σ 1-Min Δs (MW from 15-Min RA)
2006 Load	1436	189.3	44.8
2006 L-W-S Change	15 (+1%)	0.3 (+0.2%)	0.1 (+0.2%)
Increased Requirement (3 σ)	45	0.9	0.3
2010 Load	1575	207.6	49.1
2010T L-W-S Change	48 (+3%)	6.9 (+3%)	1.6 (+3%)
Increased Requirement (3 σ)	144	21	5
2010X L-W-S Change	129(+8%)	14.2(+7%)	3.3(+7%)
Increased Requirement (3 σ)	387	42.6	9.9

Variability for all hours of the year increases ~3% across all time frames.

Variability for all hours of the year increases ~7-8% across all time frames.

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Change in Flexibility Requirements: Total and Light Load (10th Decile) Variability

	Total				Light Load (10th Decile)		
	σ 1-Hour Δs (MW)	σ 5-Min Δs (MW on 15-Min RA)	σ 1-Min Δs (MW from 15-Min RA)		σ 1-Hour Δs (MW)	σ 5-Min Δs (MW on 15-Min RA)	σ 1-Min Δs (MW from 15-Min RA)
2006 Load	1436	189.3	44.8		669	86.5	40.8
2006 L-W-S Change	15 (+1%)	0.3 (+0.2%)	0.1 (+0.2%)		30 (+4%)	2.7 (+3%)	0.1 (+0.2%)
Increased Requirement (3 σ)	45	0.9	0.3		90	8	0.3
2010 Load	1575	207.6	49.1		734	94.9	44.8
2010T L-W-S Change	48 (+3%)	6.9 (+3%)	1.6 (+3%)		199 (+27%)	14.2 (+15%)	1.1 (+3%)
Increased Requirement (3 σ)	144	21	5		597	42.6	3.3
2010X L-W-S Change	129(+8%)	14.2(+7%)	3.3(+7%)		347(+47%)	19.8(+21%)	2.9(+7%)
Increased Requirement (3 σ)	387	42.6	9.9		1041	59.4	8.7

Increases in 1-hour and 5-minute variability for lowest 10% hours of the year are higher.

2010X vs 2020 Statistical Analysis: Total Variability

	σ 1-Hour Δs (MW)	Max, Min 1-Hour Δs (MW)
2010 Load	1575	6714, -5617
2010T L-W-S	1623	6312, -5713
Change	48	-402, -96
2010X L-W-S	1704	7219, -5986
Change	129	505, -37
2020 Load	1977	8427,-7049
2020 L-W-S	2019	8747,-7351
Change	42	321,-302

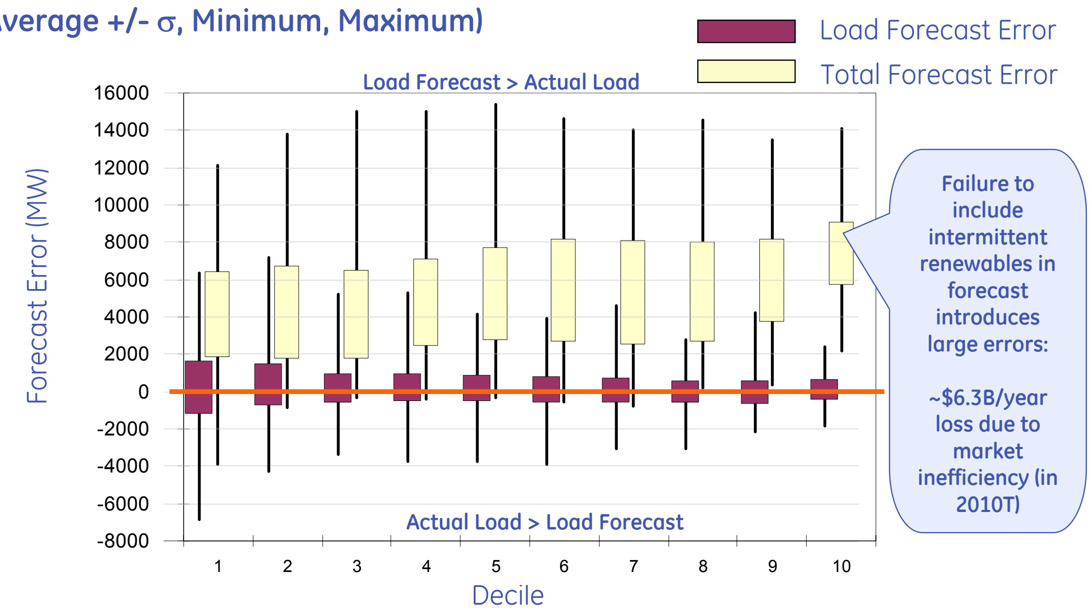
Relative impact of intermittent renewable generation is less in 2020 than in 2010x case.

Operation Implications: Day Ahead Forecasting

- Implications of not using forecasts
- Energy associated with forecasting error

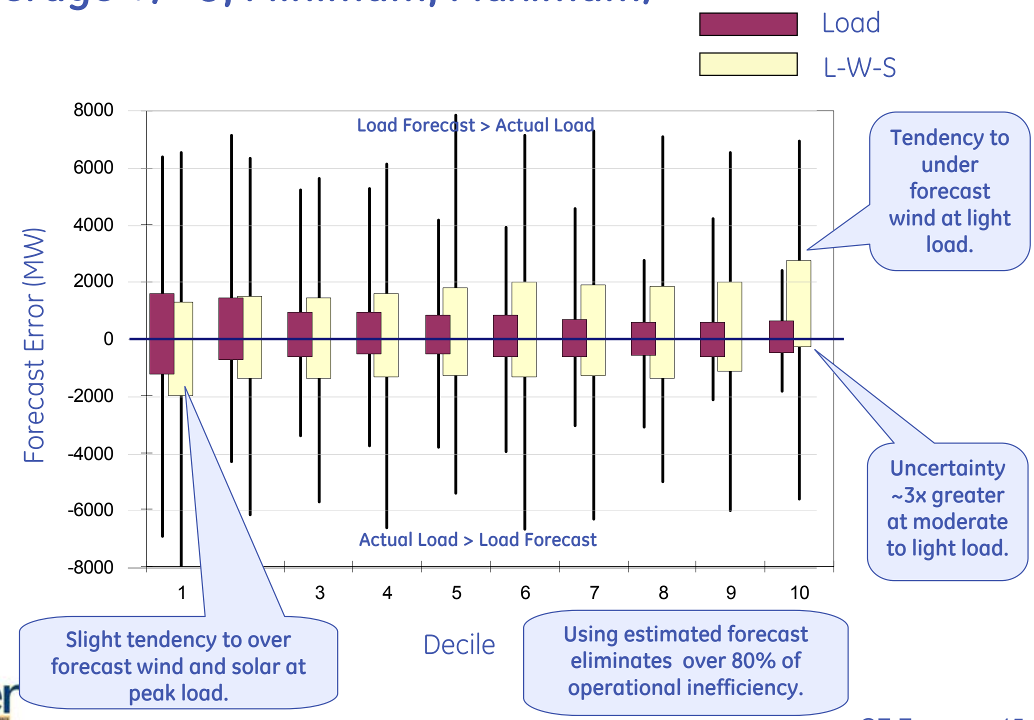
2010X Load Forecast Error and Total Forecast Error *IGNORING* Wind and Solar Forecast

(Average +/- σ, Minimum, Maximum)



Forecasting increases value (I.e., reduces variable operating cost) of intermittent resources by ~$170M/year.

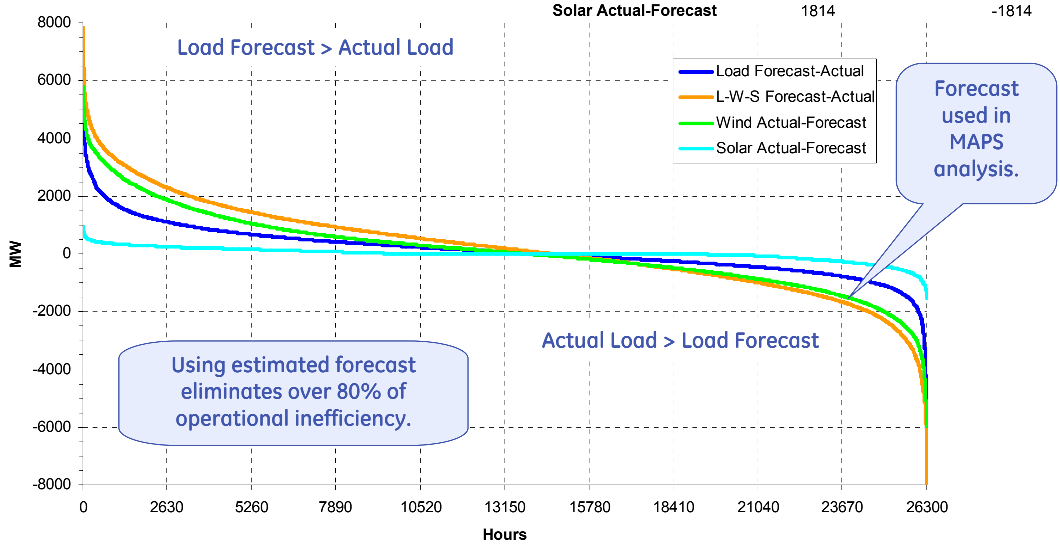
2010X Load & Load-Wind-Solar Forecast Error (Average +/- σ, Minimum, Maximum)



2010X Day-Ahead Forecast Error Duration Curves

All Years	MW
Load F-A (Sigma)	857
Wind+Solar A-F (Sigma)	1566
L-W-S F-A (Sigma)	1620

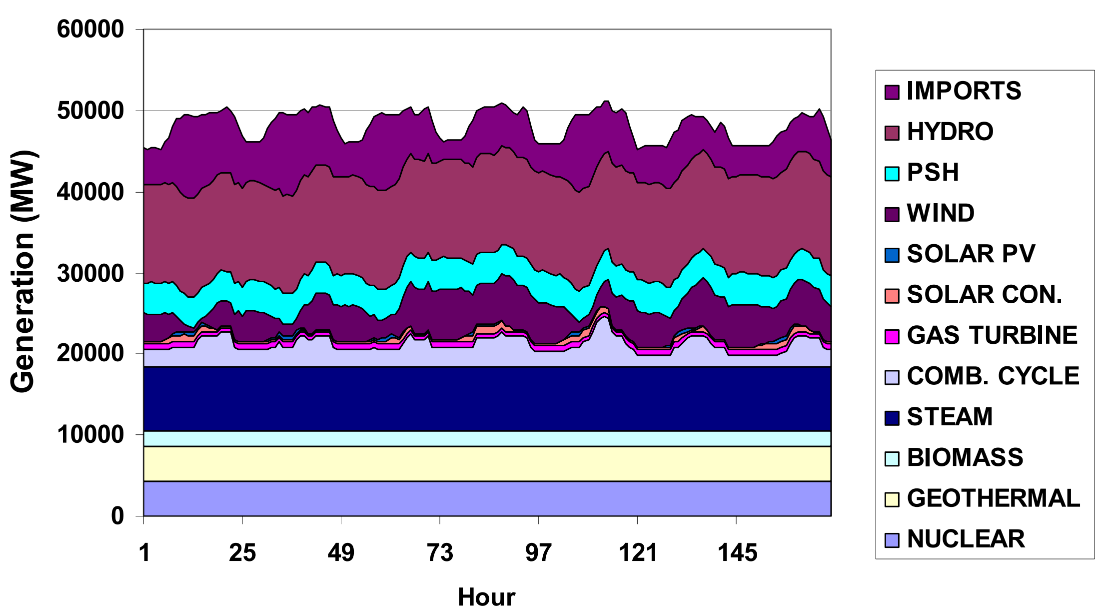
	Positive Energy (GWh)	Negative Energy (GWh
Load Forecast-Actual	9612	-6442
L-W-S Forecast-Actual	19453	-13142
Wind Actual-Forecast	14723	-11583
Solar Actual-Forecast	1814	-1814



Operation Implications: Unit Commitment and Schedule Flexibility

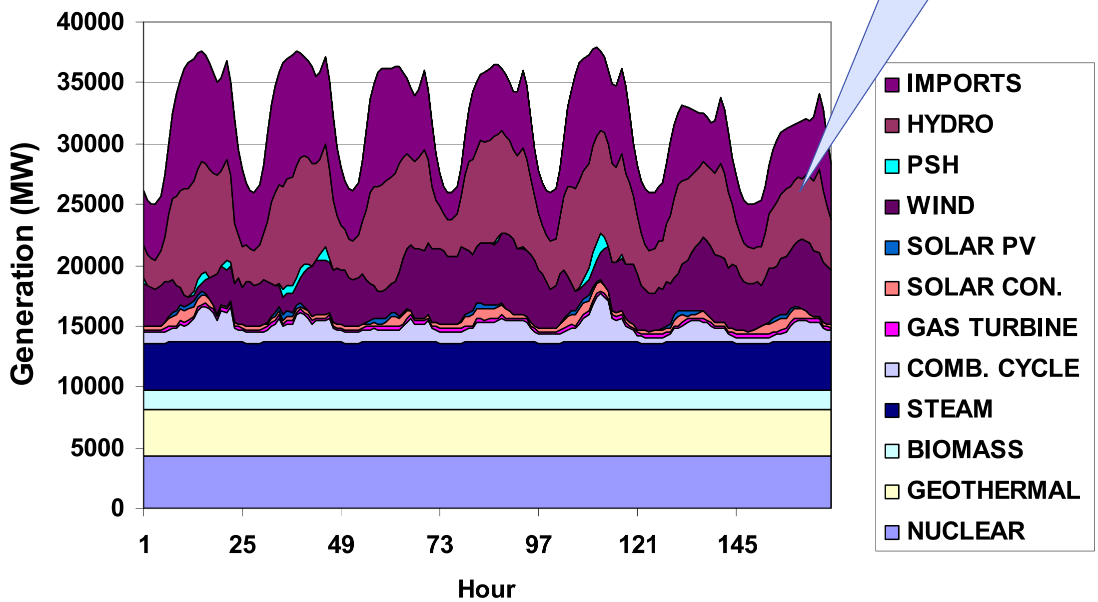
- Changes in commitment and dispatch
- Implications for schedule flexibility requirement and capability

Commitment – Week of May 10th

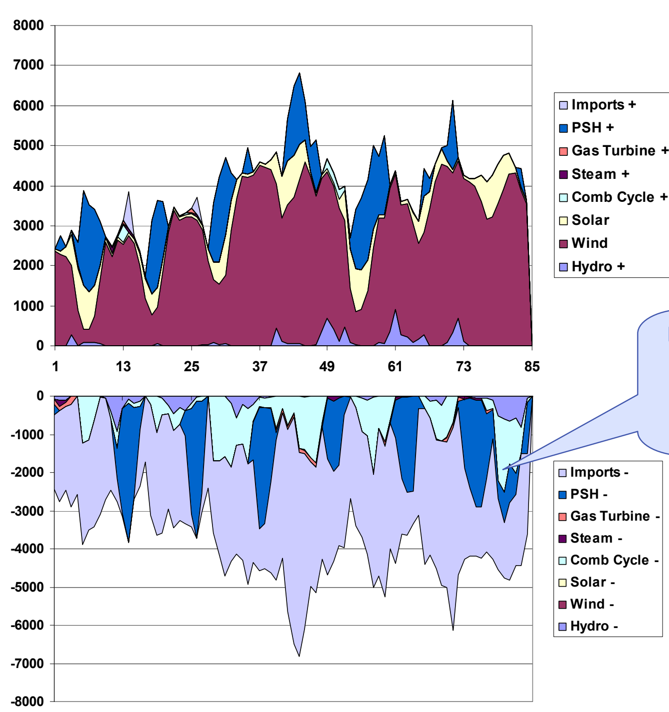


Dispatch – Week of May 10th

Hydro energy for May simulation same as May 2006

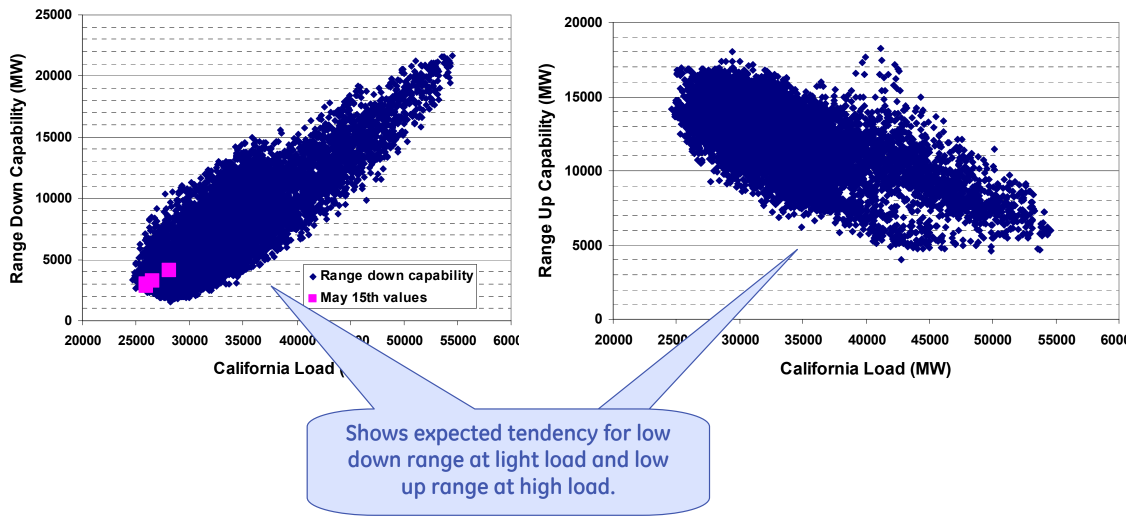


CA Displacement – Week of May 10th

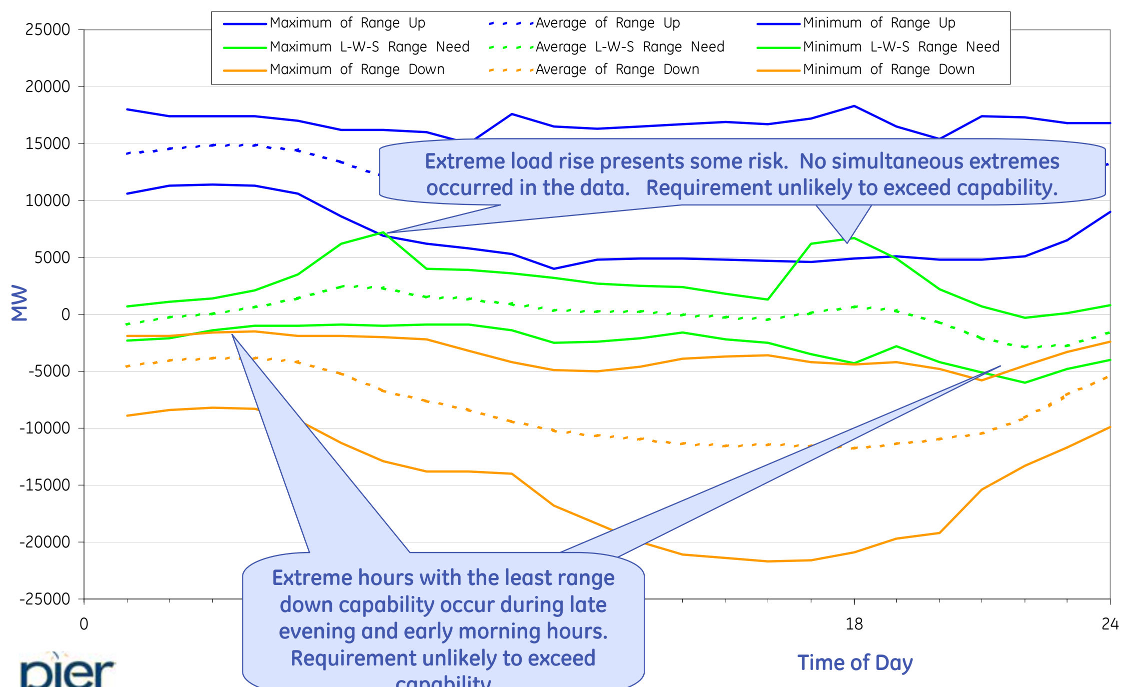


Hour-to-hour shifting of dispatch. Overall displacement is essentially all CC and Imports.

2010X Range Capability



Schedule Flexibility: Committed Generation Range vs Maximum Hourly L-W-S Change



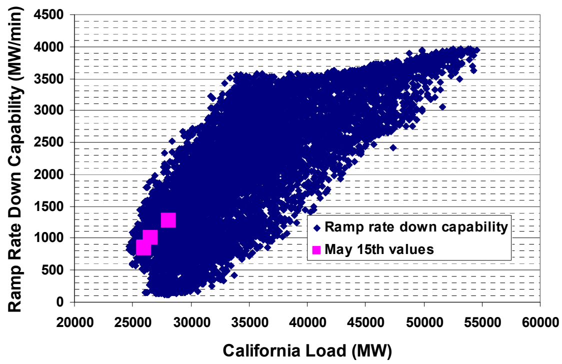
Mitigation Methods: Unit Commitment & Schedule Flexibility

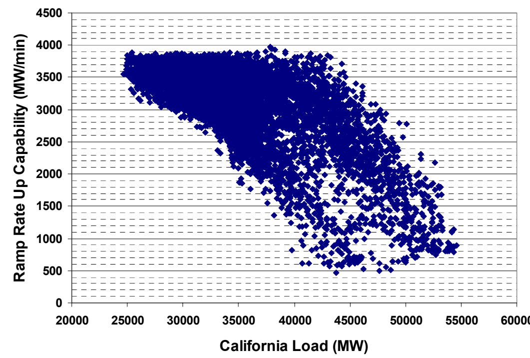
- QSS May example showed that changing commitment by substituting maneuverable units for fixed dispatch units would increase available range.
- Cost implications of displacement of lower cost generation vs. wind curtailment:
  - If de-committing base-load unit means that it will be off-line for an extended period (including higher price/higher load periods) then curtailing wind will probably be the lower total cost option.
  - However, if you expected to curtail wind for extended periods/large amounts of production, then de-committing base-load units will more cost effective.
- Providing deeper runback capability helps mitigate this problem, and eliminate the curtailment/de-commitment decision. Generators realize further benefits by avoiding start/stop costs.
- Storage reduces the need for these other mitigation methods; some storage technologies may provide benefits in other time frames.
- Short term modification of interchange schedule would provide similar benefits.
- Need for these mitigation methods drops as load increases.

Operation Implications: Load Following Discussion

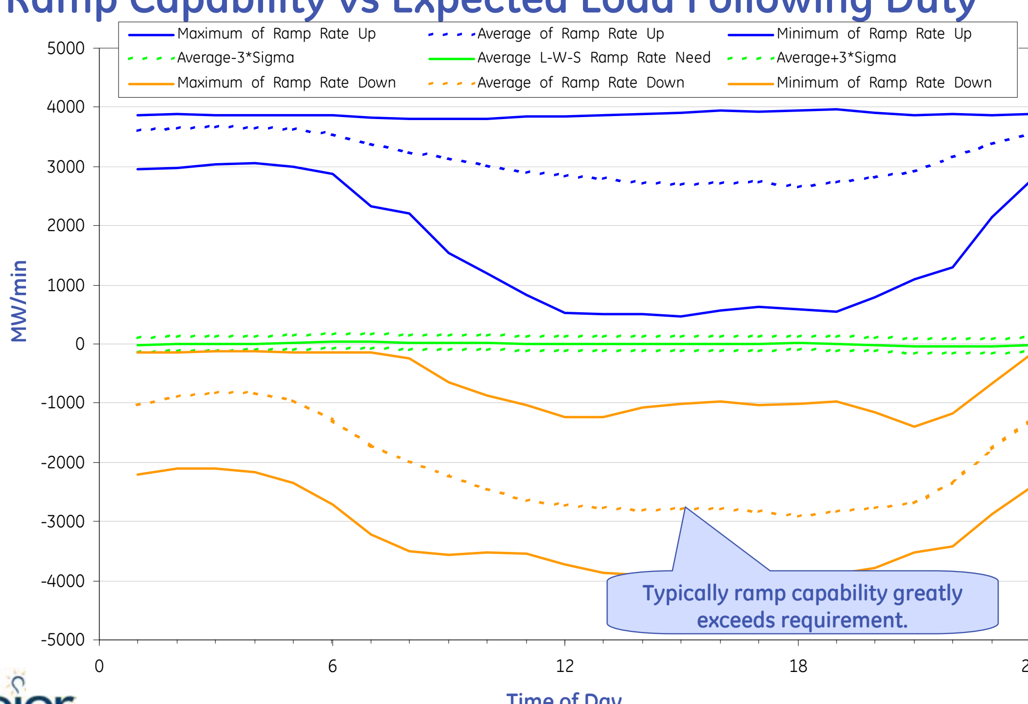
- MAPS & statistics correlation
- Implications for ramp rate capability

2010X Ramp Rate Capability

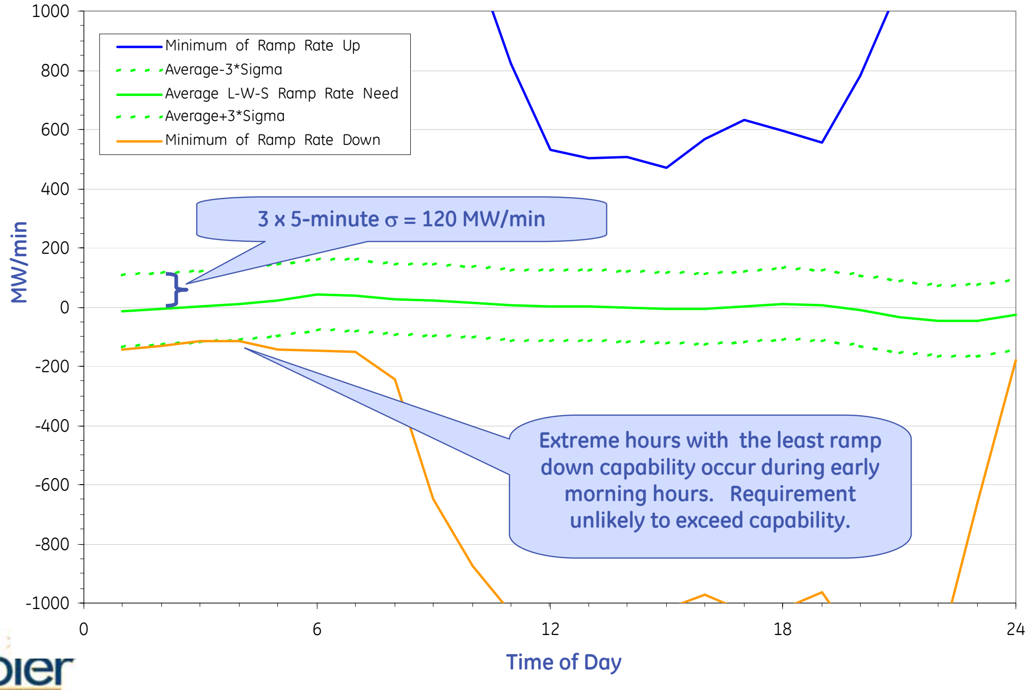




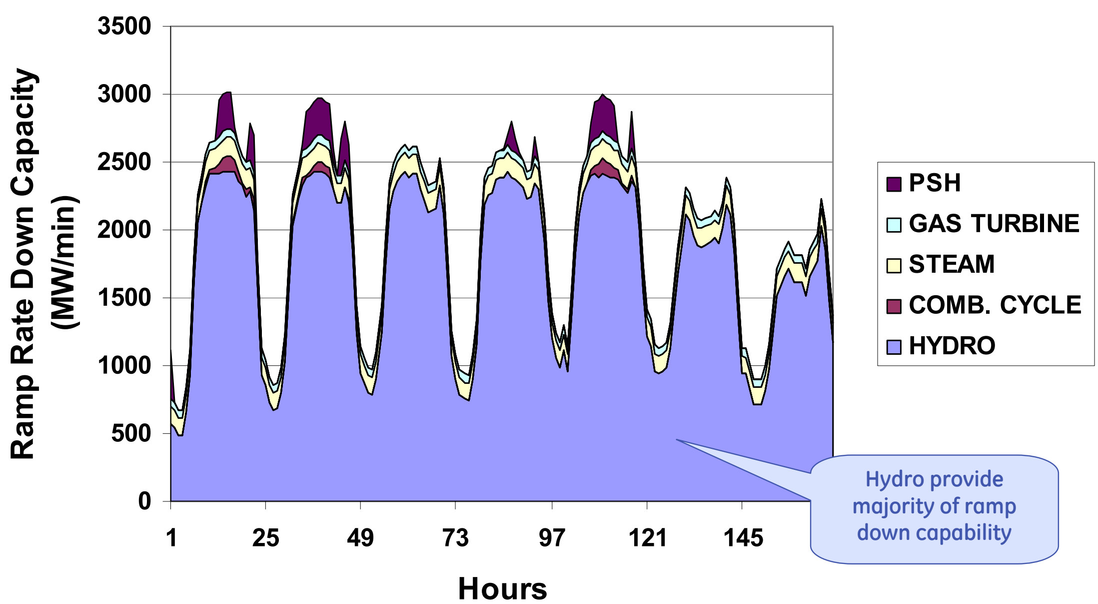
Load Following Capability: Committed Generation Ramp Capability vs Expected Load Following Duty



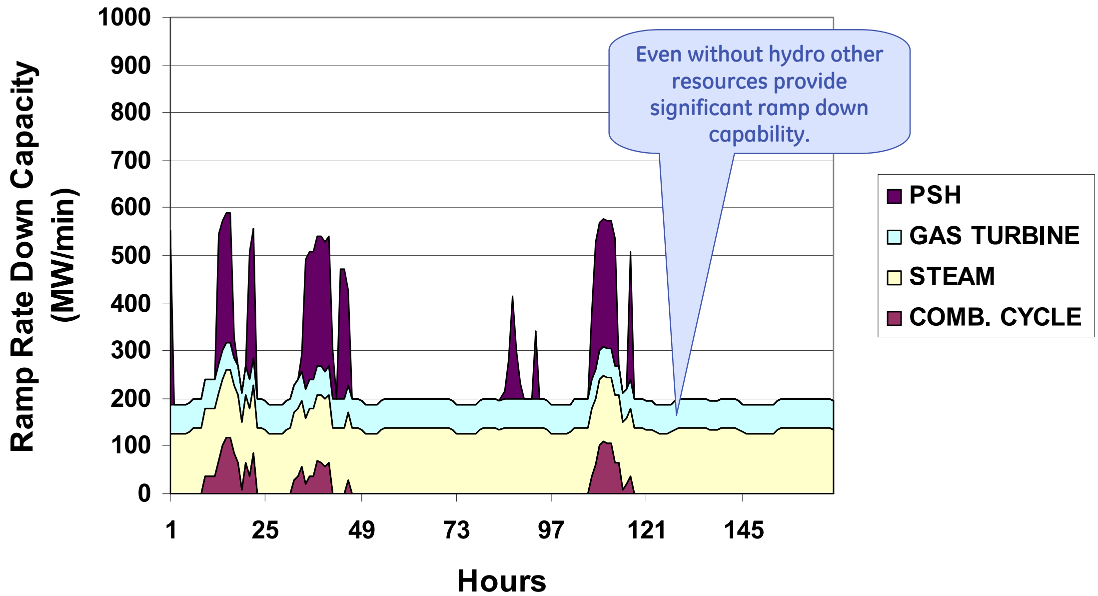
Load Following Capability: Committed Generation Ramp Capability vs Expected Load Following Duty (detail)



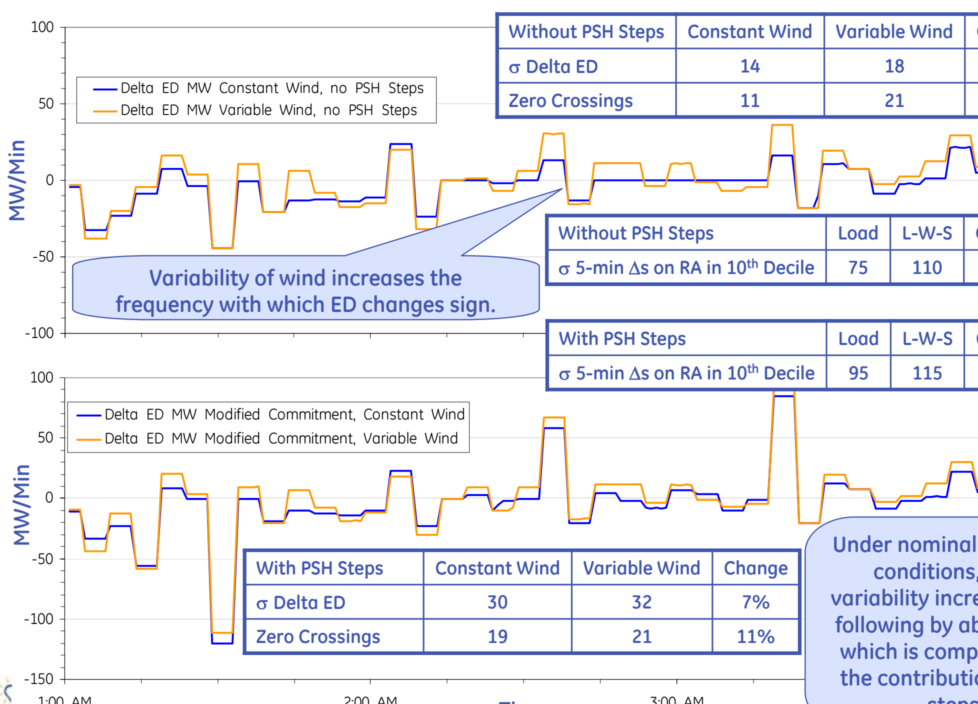
Ramp Rate Down Capacity – Week of May 10th



Ramp Rate Down Capacity w/o Conventional Hydro – Week of May 10th



May Night: Impact of Wind Variability w/o PSH Steps



Without PSH Steps	Constant Wind	Variable Wind	Change
σ Delta ED	14	18	29%
Zero Crossings	11	21	91%

Without PSH Steps	Load	L-W-S	Change
σ 5-min Δs on RA in 10th Decile	75	110	47%

With PSH Steps	Load	L-W-S	Change
σ 5-min Δs on RA in 10th Decile	95	115	21%

With PSH Steps	Constant Wind	Variable Wind	Change
σ Delta ED	30	32	7%
Zero Crossings	19	21	11%

Under nominal light load conditions, wind variability increases load following by about 20%, which is comparable to the contribution of PSH steps

Operation Implications: Implied Costs of Load Following Discussion

- Relationship to statistics on load following and economic dispatch
  - Year round incremental load following requirement is 3 x 14.2 MW per 5 minutes
  - If this incremental duty is assigned to regulation, then incremental regulation capability must cover 5 minutes of incremental LF
  - 3 x 14.2 MW of up regulation and down regulation
  - 43 MW x ($28/MW per hour up + $21/MW per hour down) x 8760 hr/year = $18.5M or 48¢/MWhr
  - For 10^{th} decile only
    - (3 x 19.8) x ($28 +$21) x 8760 X 0.1 = $2.5M = 7 ¢/MWhr
- Implications of curtailment strategies
  - Statistics and MAPS results suggest that curtailment is unlikely to ever be necessary for economically operated system.
  - Curtailment results in wind energy loss during periods of low spot price
    - Example: A 5% curtailment during all minimum load periods would result in ~300,000 MWhr of lost wind production. Average spot price is ~ $23/MWhr, or about $7M, or 18 ¢/MWhr.

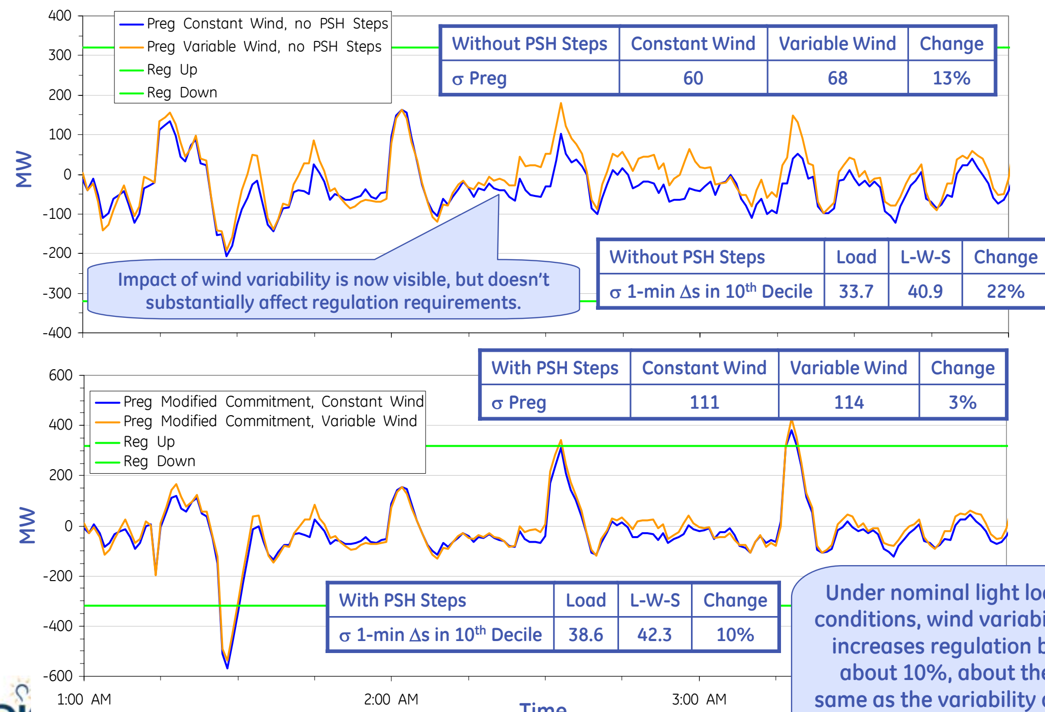
Mitigation Methods: Load Following

- QSS June example showed that imposing short term wind curtailment with rate limits on recovery relieves temporary depletion of ramp down capability
- QSS May night example showed that curtailment can increase available ramp capability
- Storage can increase available ramp capability; variable speed pumped storage can provide ramp capability during pumping
- Adding loads (e.g. controlled pump loads) has similar benefits

Operation Implications: Regulation and CPS Discussion

- Statistics show an increase of 20 MW in regulation requirement
- Average cost of regulation (per CAISO data) is $28/MW up, $21/MW down
  - One MW-yr up is ~= $245,000
  - One MW-yr down is ~= $184,000
- 20 MW in each direction is a total of $8.6M/year, or 22¢ /MWhr

May Night: Impact of Wind Variability w/o PSH Steps



Without PSH Steps	Constant Wind	Variable Wind	Change
σ Preg	60	68	13%

Without PSH Steps	Load	L-W-S	Change
σ 1-min Δs in 10th Decile	33.7	40.9	22%

Impact of wind variability is now visible, but doesn't substantially affect regulation requirements.

With PSH Steps	Constant Wind	Variable Wind	Change
σ Preg	111	114	3%

With PSH Steps	Load	L-W-S	Change
σ 1-min Δs in 10th Decile	38.6	42.3	10%

Under nominal light load conditions, wind variability increases regulation by about 10%, about the same as the variability due to switching PSH

CPS2 Discussion

- Minimum CPS2 is 90%, but is usually higher (i.e., better)
- For 2010T, the increase in 1-min delta σ due to intermittent renewables is 1.6 MW/min (from 49.1 MW/min to 50.7 MW/min).
  - 90% CPS2 would be expected to decline to 88.9%
  - 95% CPS2 would be expected to decline to 94.2%
- For 2010X, the increase in is 2.5 MW/min (from 49.1 MW/min to 52.4 MW/min).
  - 90% CPS2 would be expected to decline to 87.7%
  - 95% CPS2 would be expected to decline to 93.3%
- Without additional regulation, CPS2 performance would be expected to decline ~1-2% due to the increase in fast variability.

No additional regulation is expected to be required to meet 90% criteria if CPS2 is at least 91.1% (2010T scenario) or 92.1% (2010X scenario).

Mitigation Methods: Regulation

- Production simulation showed a 1 MWhr increase of GT generation per 20MWhr of wind and solar energy
  - 1-min 3 sigma increase is 10 MW per minute
  - 5-min 3 sigma increase is 43 MW per 5 minutes
- Modern GTs have at least 10% MW/minute (from cold start) and 20-100% range per MW of nameplate (vs ~50-100% typical for existing fleet)
- Therefore, 100 MW of new GT would cover the system-wide increase of regulation due to all intermittent renewables in 2010X (10MW/min / 0.10 = 100 MW)
- And, 54 MW of new GT would cover the system-wide increase of load following due to all intermittent renewables in 2010X (43MW/0.80 = 54MW

About 200 MW of new GT will meet all additional regulation and load following requirements for 15,000 MW of intermittent renewables