Wind Integration Cost and Ancillary Service Impacts

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WEATS

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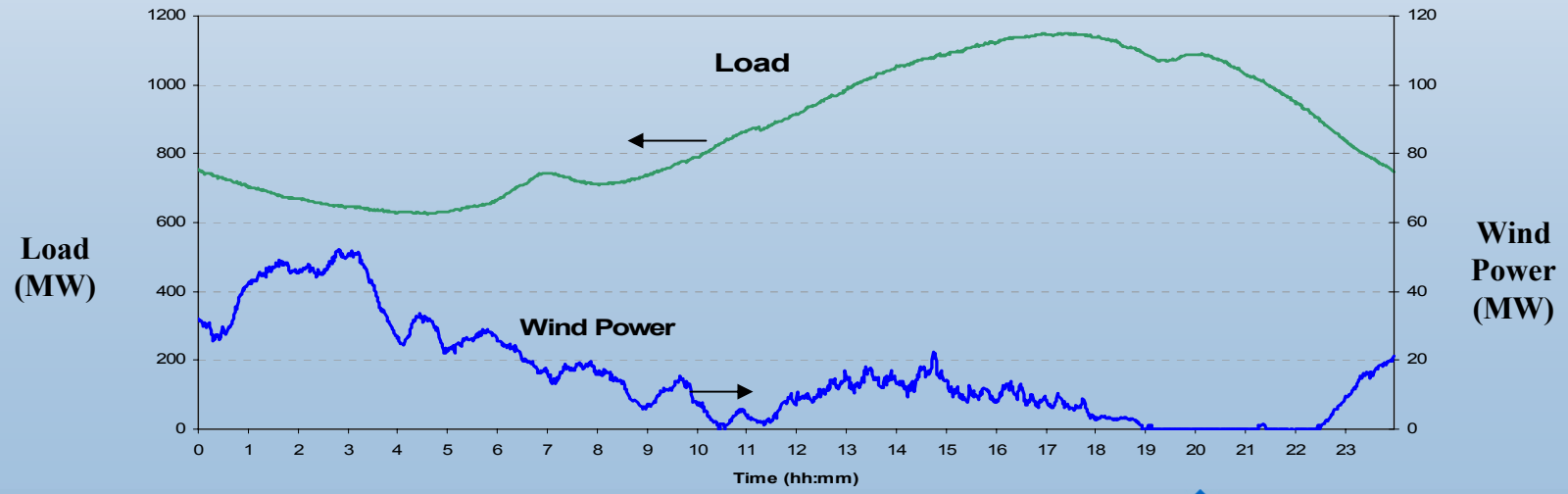
Presentation Outline

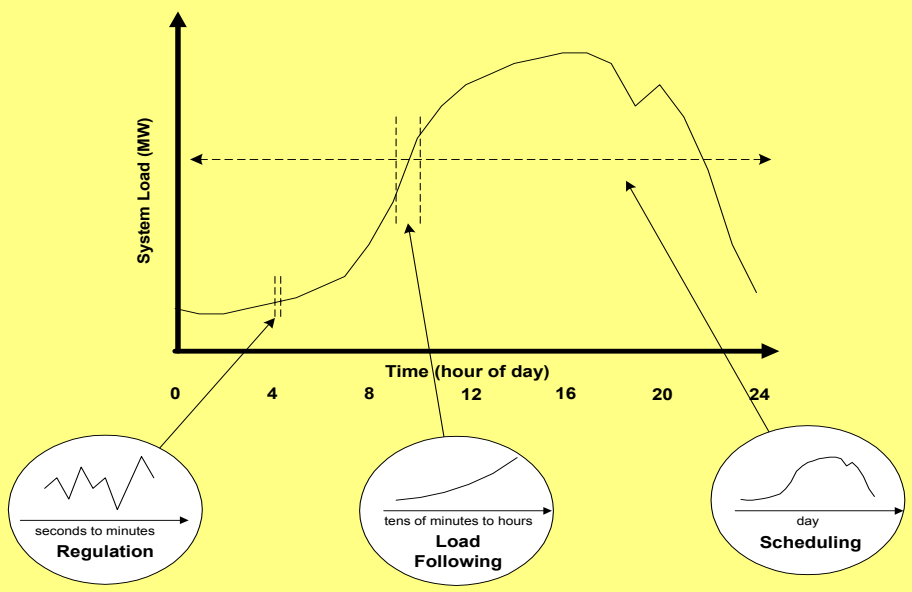
- Issues and time frames of importance
- What are wind's impacts, how are they measured?
- Principles of integration analysis
- Emerging best practices
- Stakeholder best practices
- Comparison of recent studies
- Conclusions and remaining issues
- Ongoing work

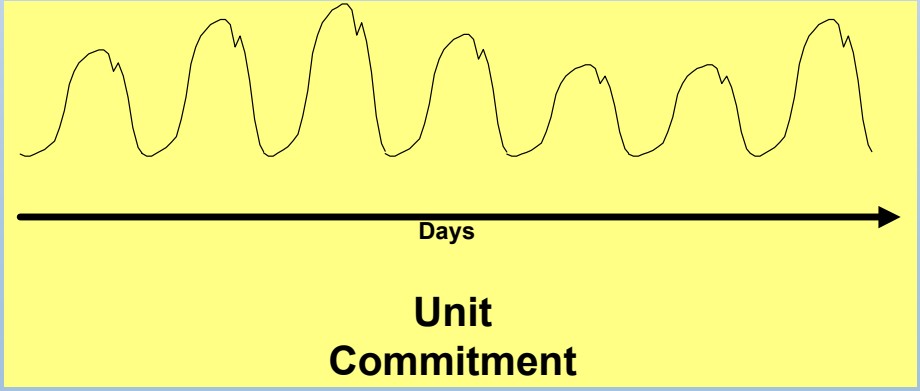
Issues

- Committing unneeded generation
- Allocating extra load-following capability
- Allocating additional regulating capacity
- Increased cycling operation
- **These are reflected in *ancillary services* costs**



Time Frames of Wind Impact





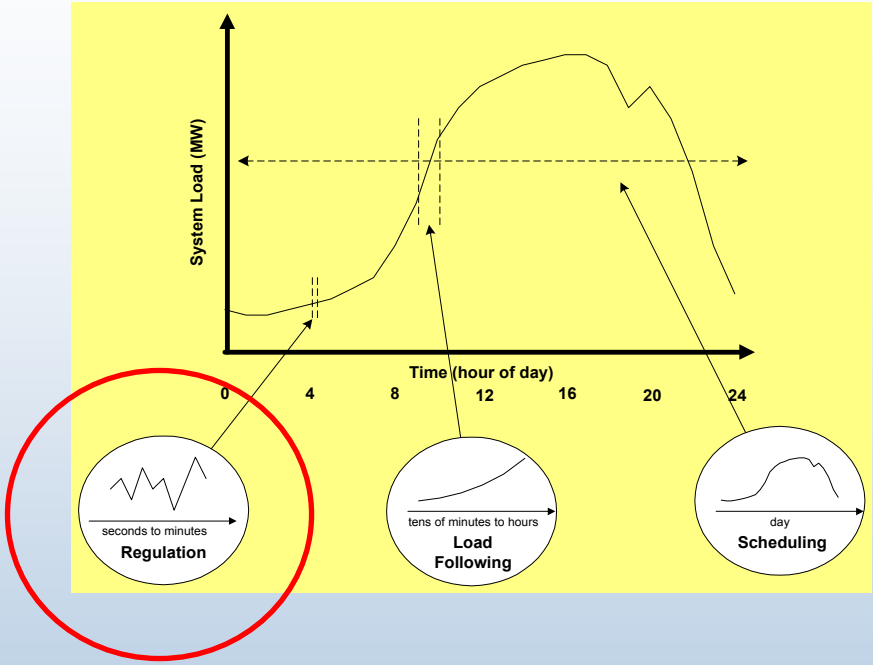
- Typical U.S. terminology
  - Regulation -- seconds to a few minutes -- similar to variations in customer demand
  - Load-following -- tens of minutes to a few hours -- demand follows predictable patterns, wind less so
  - Scheduling and commitment of generating units -- hours to several days -- wind forecasting capability?
  - Capacity value (planning): based on reliability metric (ELCC=effective load carrying capability)

Typical Objective of Integration Studies

- Determine the physical impact of wind on system operation across important time frames
  - Regulation (a capacity service; AGC)
  - Load following (ramp and energy components)
  - Unit commitment (scheduling)
  - Planning/capacity credit (same as capacity value)
- Use appropriate prices/costs to assess ancillary service cost impact of wind based on the measured physical impacts
- Not all studies focus on all time frames

How is Regulation Impact Calculated?

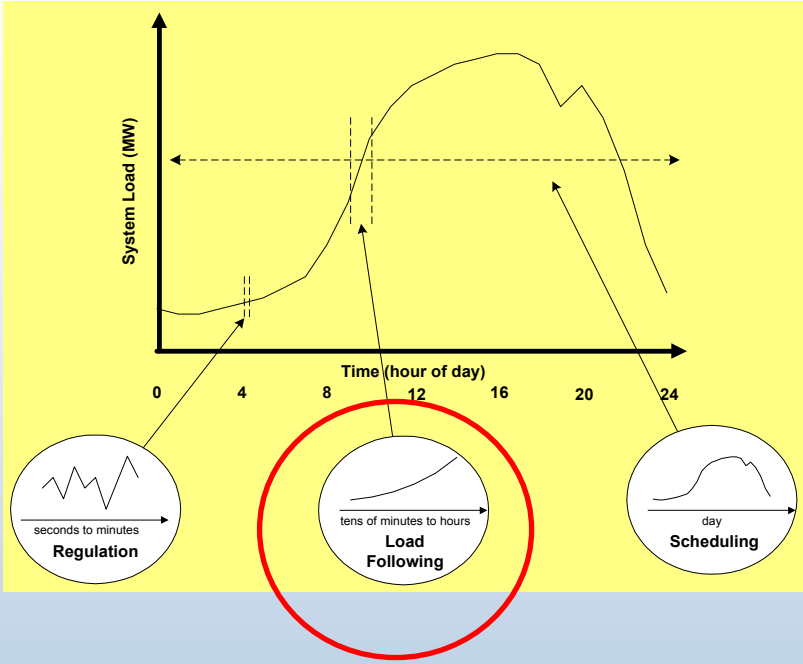
- Based on actual high-frequency (fast) system load data and wind data
- If wind data not available, use NREL high-resolution wind production data characteristics
- Impact of the wind variability is then compared to the load variability
- Preferred metric: ORNL regulation allocation approach
- Regulation cost impact of wind is based on physical impact and appropriate cost of regulation (market or internal)



–Realistic calculation of wind ***plant*** output (linear scaling from single anemometer is incorrect)

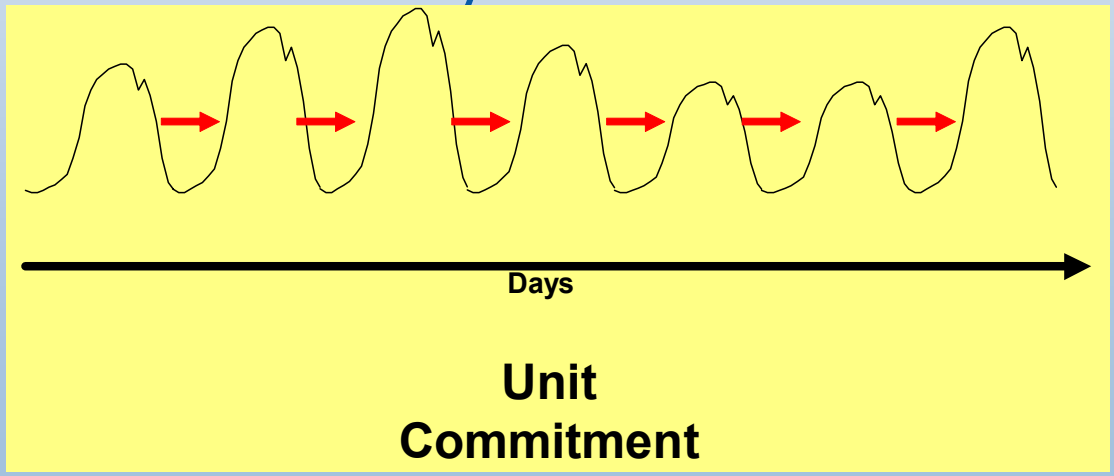
How is Load Following Impact Calculated?

- Based on actual system load data
- …and wind data from *same* time period
  - Meteorological simulation to capture ***realistic*** wind profile, typically 10-minute periods and multiple simulated/actual measurement towers
  - Realistic calculation of wind ***plant*** output (linear scaling from single anemometer is incorrect)
- Wind variability added to *existing system variability* → Implies no one-one backup for wind



How is Unit Commitment Impact Calculated?

- Requires a realistic system simulation for at least one year (more is better)
- Compare system costs with and without wind
- Use load and wind forecasts in the simulation
- Separate the impacts of variability from the impacts of uncertainty

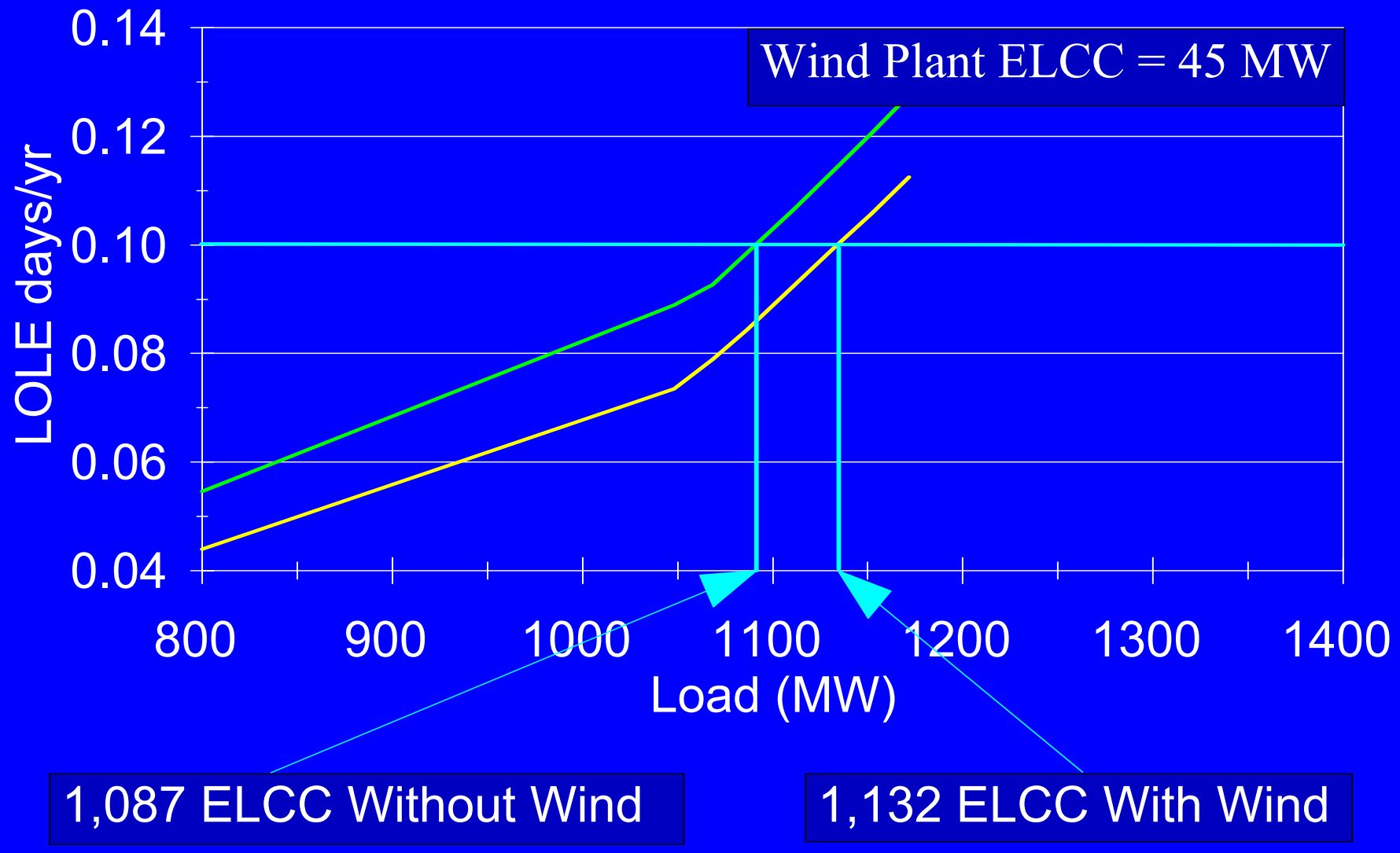


How is Capacity Value Calculated?

- Uses similar data set as unit commitment modeling
  - Generation capacities, forced outage data
  - Hourly time-synchronized wind profile(s)
  - Several years' of data preferred
- Reliability model used to assess ELCC
- Wind capacity value is the increased load that wind can support at the same annual reliability as the no-wind case

Wind Plant Capacity Credit Example

Reliability Curves With/Without Wind



Comparison of Cost-Based U.S. Operational Impact Studies

Date	Study	Wind Capacity Penetra-tion (%)	Regula-tion Cost ($/MWh)	Load Following Cost ($/MWh)	Unit Commit-ment Cost ($/MWh)	Gas Supply Cost ($/MWh)	Total Operating Cost Impact ($/MWh)
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April '06	Xcel-PSCo	10	0.20	na	2.26	1.26	3.72
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* 3-year average; total is non-market cost

Wind Capacity Value in the US

Region/Utility	Method	Note
CA/CEC	ELCC	Rank bid evaluations for RPS (mid 20s); 3-year near-match capacity factor for peak period
PJM	Peak Period	Jun-Aug HE 3 p.m. -7 p.m., capacity factor using 3-year rolling average (20%, fold in actual data when available)
ERCOT	10%	May change to capacity factor, 4 p.m. -6 p.m., Jul (2.8%)
MN/DOC/Xcel	ELCC	Sequential Monte Carlo (26-34%)
GE/NYSERDA	ELCC	Offshore/onshore (40%/10%)
CO PUC/Xcel	ELCC	PUC decision (30%), Full ELCC study using 10-year data has begun; Xcel using MAPP approach (10%) in internal work
RMATS	Rule of thumb	20% all sites in RMATS
PacifiCorp	ELCC	Sequential Monte Carlo (20%). New Z-method 2006
MAPP	Peak Period	Monthly 4-hour window, median
PGE		33% (method not stated)
Idaho Power	Peak Period	4 p.m. -8 p.m. capacity factor during July (5%)
PSE and Avista	Peak Period	PSE will revisit the issue (lesser of 20% or 2/3 Jan C.F.)
SPP	Peak Period	Top 10% loads/month; 85th percentile

Methods
Emerging Best Practices

- Capture system characteristics and response through operational simulations and modeling
- Capture wind deployment scenario geographic diversity through synchronized weather simulation
- Couple with actual historic utility load and load forecasts
- Use actual large wind farm power statistical data for short-term regulation and ramping
- Examine wind variation in combination with load variations
- Utilize wind forecasting best practice and combine wind forecast errors with load forecast errors
- Examine actual costs independent of tariff design structure

Stakeholder Review
Emerging Best Practices

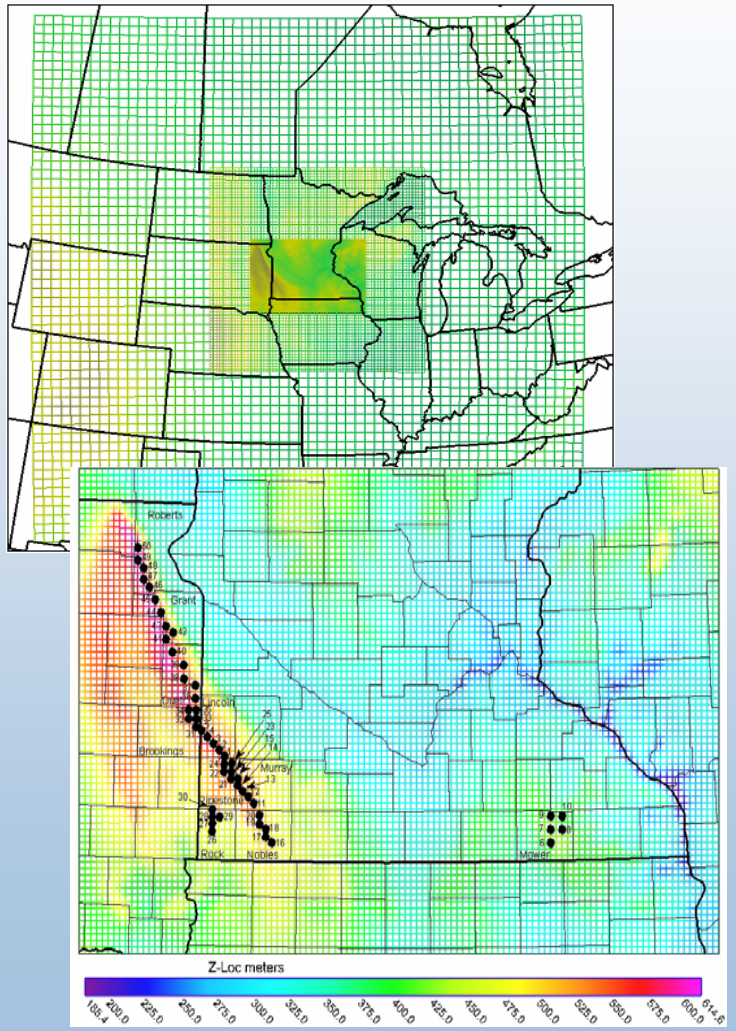
- Technical review committee (TRC)
  - Bring in at beginning of study
  - Discuss assumptions, processes, methods, data
- Periodic TRC meetings with advance material for review
- Examples in Minnesota, Colorado, California, New Mexico, and interest by other states

Typical Study Results

- Start with physical impact of wind on the system
- Assess costs, either via market or internal
- Capacity value sometimes also assessed

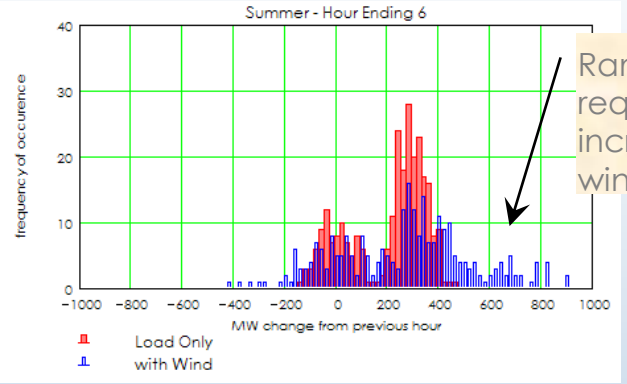
Minnesota Dept. of Commerce/ Enernex Study Framework

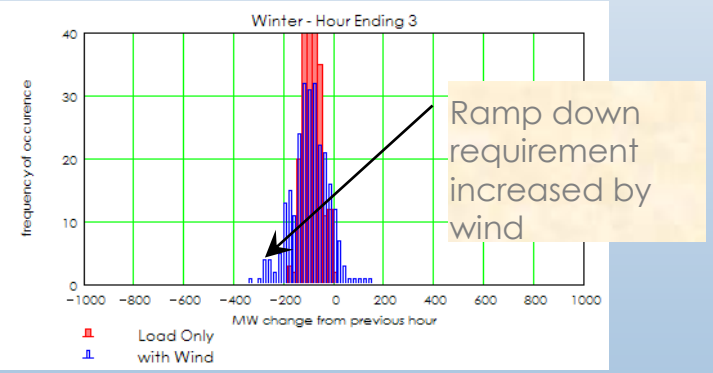
- 2010 scenario of 1500 MW of wind in 10 GW peak load system (< 700 MW wind currently)
- WindLogics:10-minute power profiles from atmospheric modeling to capture geographic diversity
- Wind forecasting incorporated
- Extensive historic utility load and generator data available
- Monopoly market structure, no operating practice modification or change in conventional generation expansion plan



Minnesota Dept. of Commerce/ Enernex Study Results

- Incremental regulation due to wind 3σ = 8 MW
- Incremental intra-hour load following burden increased 1-2 MW/min. (negligible cost)
- Hourly to daily wind variation and forecasting error impacts are largest costs
- Monthly total integration cost: $2-$11/MWh, with an average of $4.50/MWh
- Capacity Credit (ELCC) of 26%



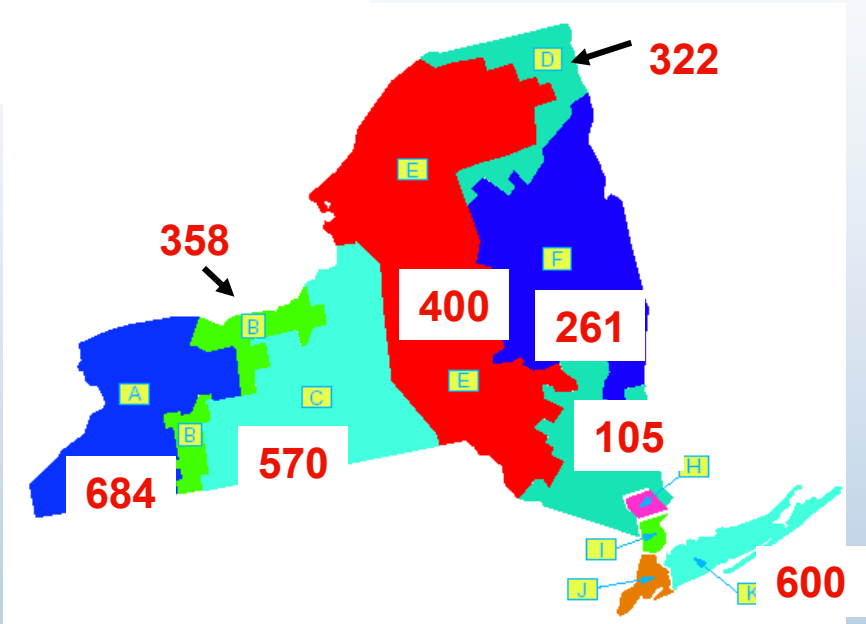


Completed September 2004 *www.commerce.state.mn.us*

(Industry Info and Services / Energy Utilities / Energy Policy / Wind Integration Study)

New York ISO and NYSERDA/ GE Energy Study

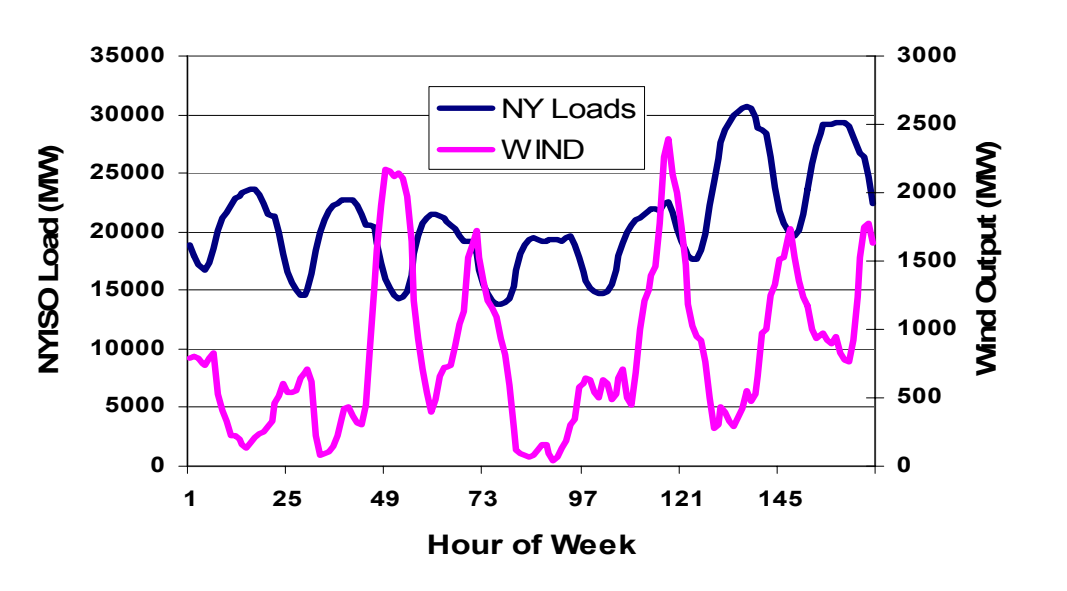
- 2008 scenario of 3300 MW of wind in 33-GW peak load system (< 200 MW wind currently)
- AWS Truewind: wind power profiles from atmospheric modeling to capture statewide diversity



- Competitive market structure:
  - for ancillary services
  - allows determination of generator and consumer payment impacts
- Transmission examined: no delivery issues
- Post-fault grid stability improved with modern turbines

New York ISO and NYSERDA/ GE Energy Study Impacts

- Incremental regulation of 36 MW due to wind
- No additional spinning reserve needed
- Incremental intra-hour load following burden increased 1-2 MW/ 5 min.
- Hourly ramp increased from 858 MW to 910 MW



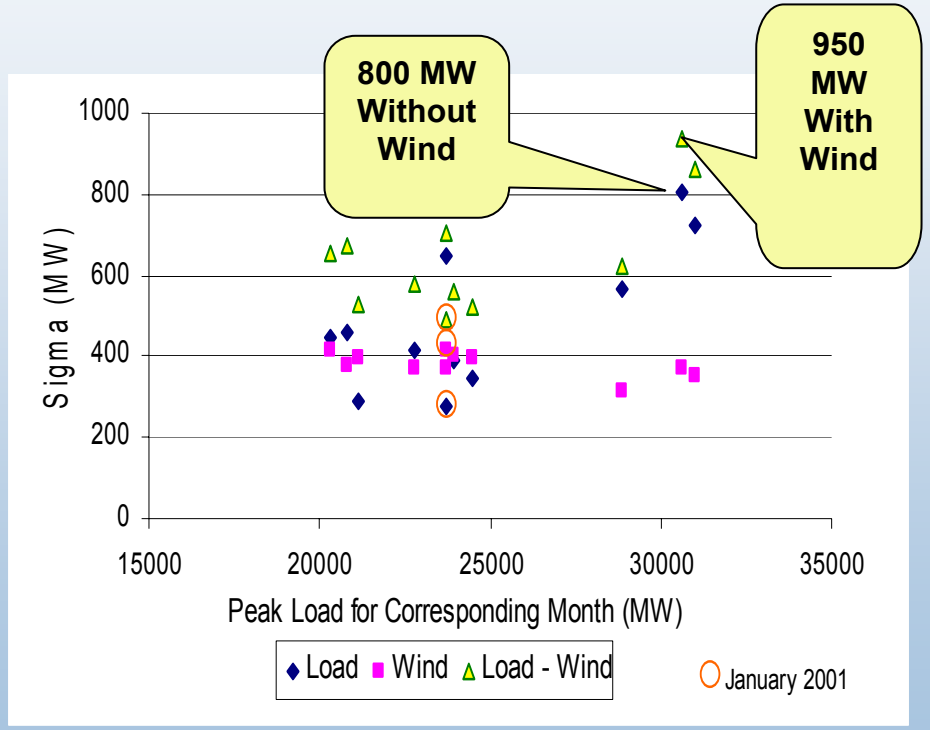
- All increased needs can be met by existing NY resources and market processes
- Capacity credit (UCAP) of 10% average onshore and 36% offshore
- Significant system cost savings of $335- $455 million on assumed 2008 natural gas prices of $6.50-$6.80 /MMBTU.

New York ISO and NYSERDA/ GE Energy Study

Forecasting and Price Impacts

- Day-ahead unit-commitment forecast error σ increased from 700-800 MW to 859-950 MW
- Total system variable cost savings increases from $335 million to $430 million when state of the art forecasting is considered in unit commitment ($10.70/MWh of wind)
- Perfect forecasting increases savings an additional $25 million

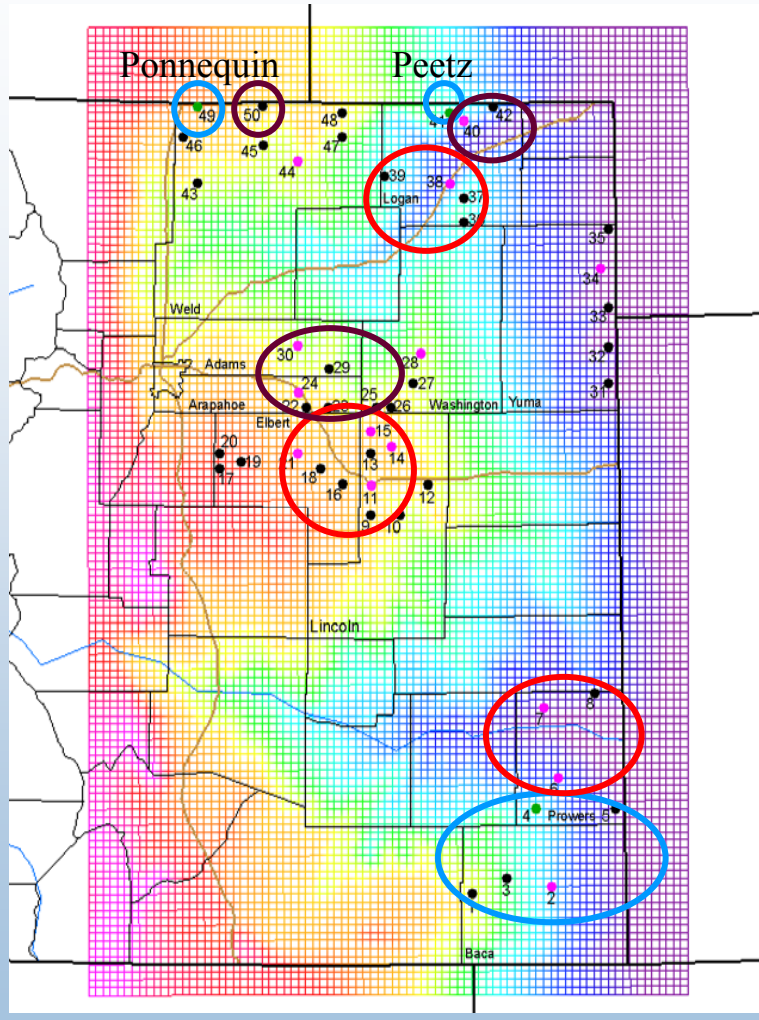
Standard Deviations of Day-Ahead Forecast Errors



http://www.nyserda.org/publications/wind_integration_report.pdf

Xcel Colorado/Enernex Study

- 10%, 15%, and 20%* penetration (wind nameplate to peak load) examined for ~7 GW peak load
- Gas storage & nominations
  - Gas imbalance
  - Extra gas burn for reserves
- Gas price sensitivity
- Transmission constraints
- O&M increase for increased start/stops
- Real-time market access



* 20% case is currently underway

Xcel Colorado/Enernex Study

Penetration Level	10%	15%
Hourly Analysis	$2.26/MWh	$3.32/MWh
Regulation	$0.20/MWh	$0.20/MWh
Gas Supply (1)	$1.26/MWh	$1.45/MWh
Total	**$3.72/MWh**	**$4.97/MWh**

(1) Costs includes the benefits of additional gas storage

Additional work is underway to analyze a 20% penetration case.

- **Without use of 300 MW pumped hydro unit, costs at 10% would be $1.30/MWh higher**

Gas Storage Benefits/Results

- Summer/winter arbitrage
  - Cost savings in filling in summer and withdrawing in winter
- Reduction in need for financial hedge (call option)
  - Because the price of the gas in the storage field is known, there is no need to financially hedge the market price of the gas

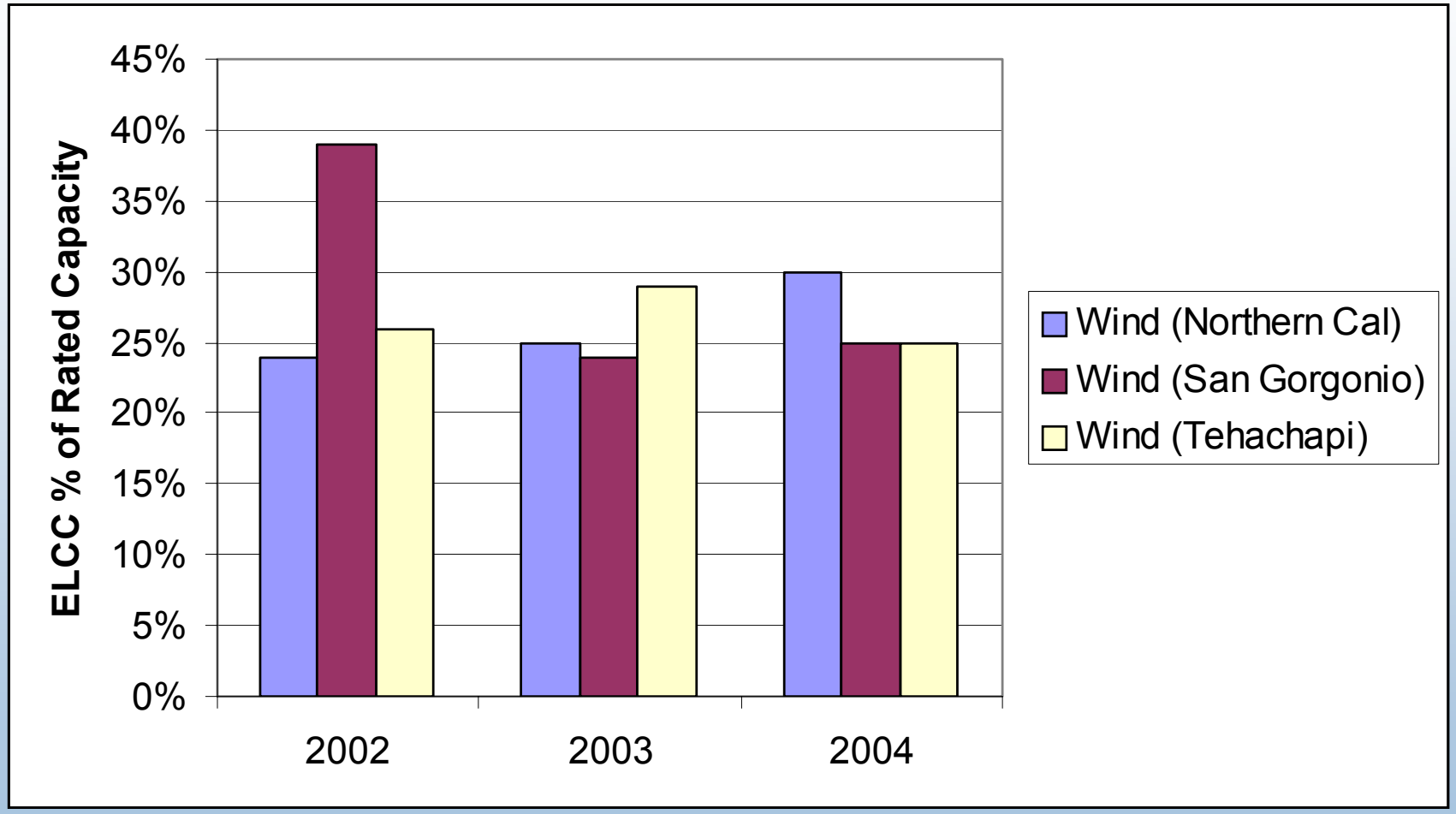
Wind Penetration	10%	15%
$/ MWH Gas Impact No Storage Benefits	$2.17	$2.52
$ / MWH Gas Impact With Storage Benefits	$1.26	$1.45

CA RPS Integration Cost Multi-Year Analysis

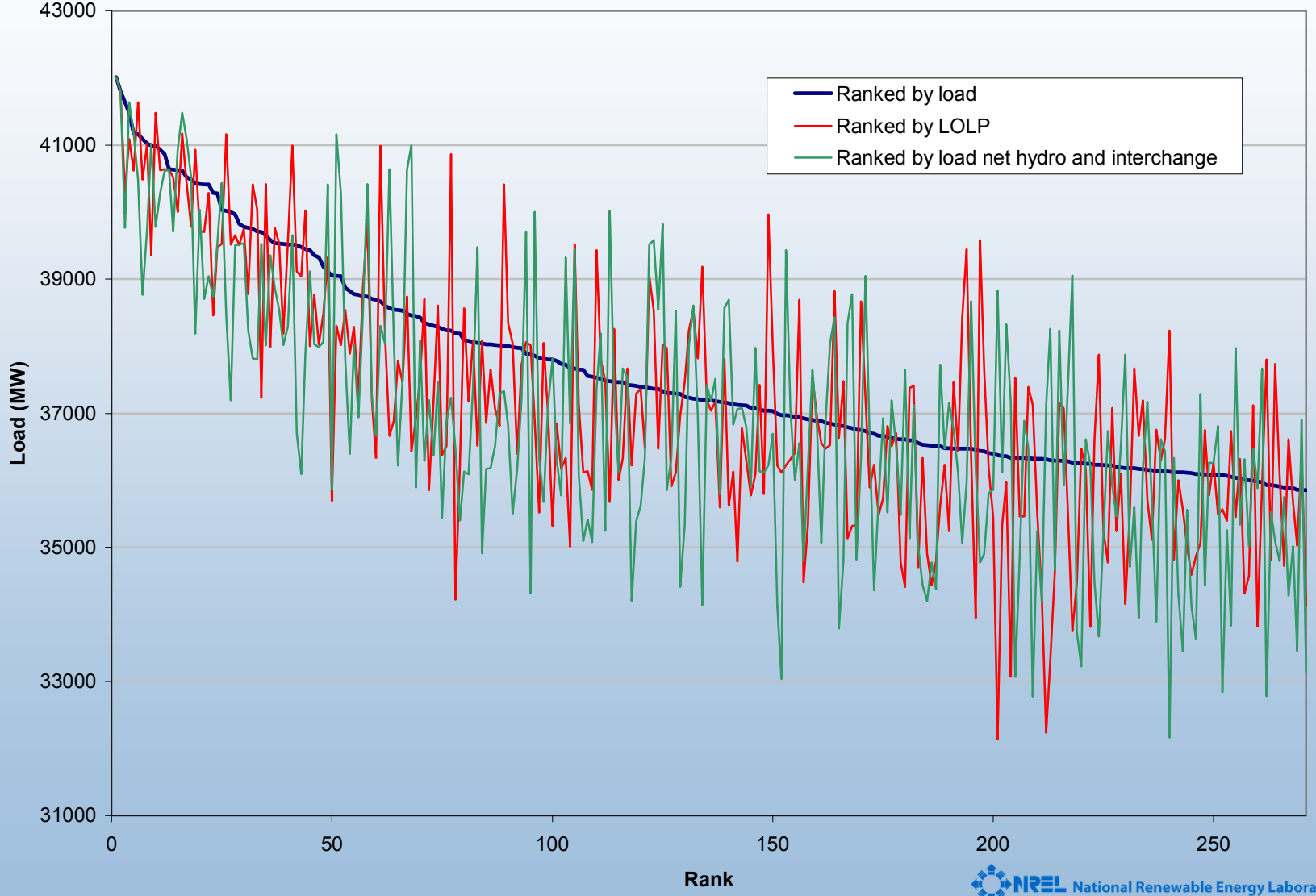
- Perform integration cost and capacity value calculation for 2002 – 2004 for all renewable technologies
- Motivations:
  - Verify applicability of methodologies over additional years
  - Verify consistency of data over several years
  - Examine changes in integration costs over a multi-year period

Final report available at
http://www.energy.ca.gov/2006publications/CEC-500-2006-064/CEC-500-2006-064.PDF

Capacity Value for Wind

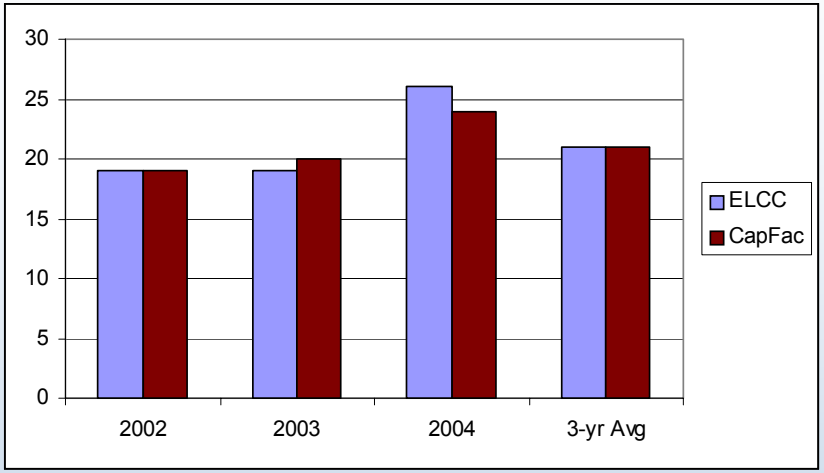


Hydro and Interchange Affect The Risk Profile and ELCC

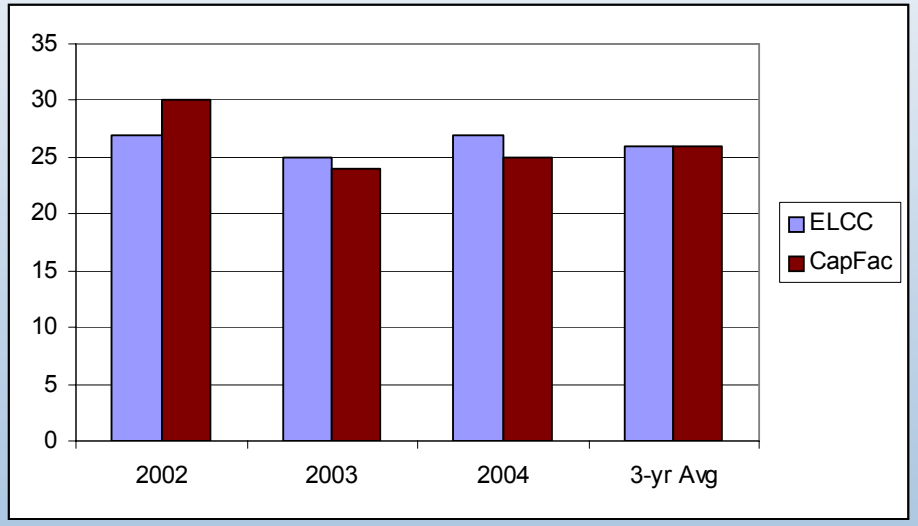


ELCC Without Hydro, Exchange Compared to Capacity Factor Jun-Sep 12p-6p

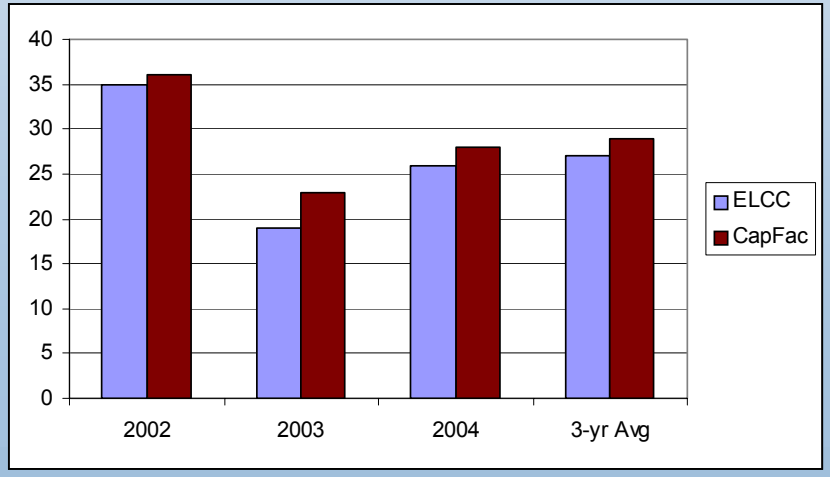
Northern California



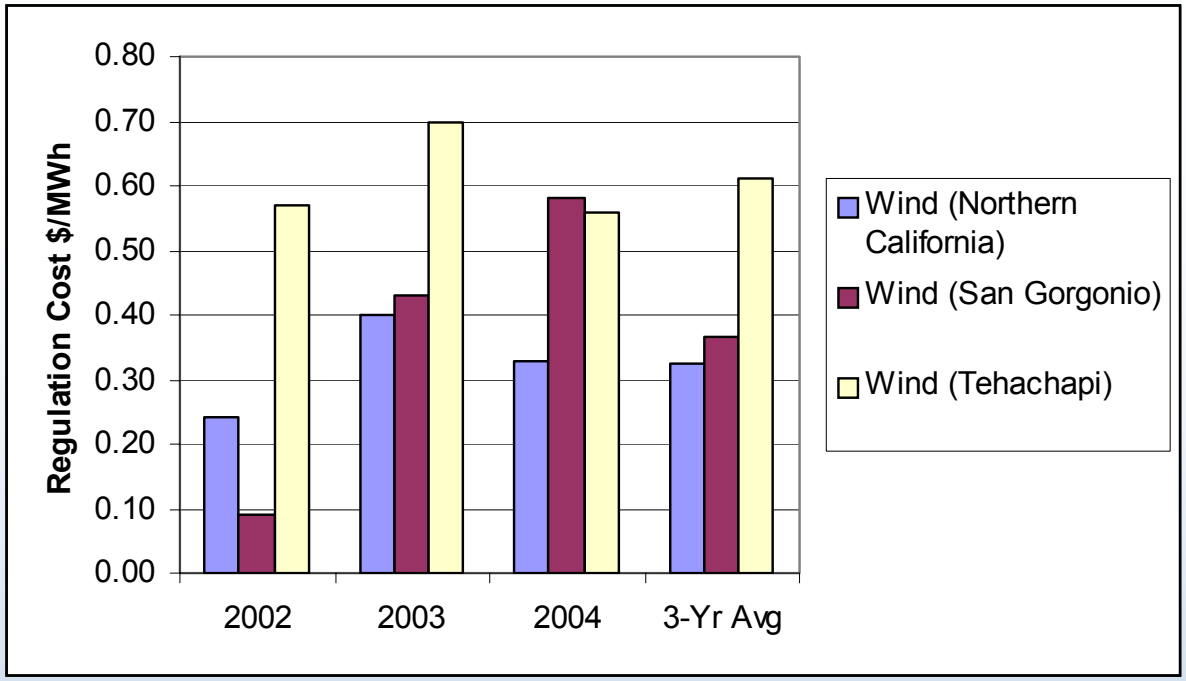
Tehachapi

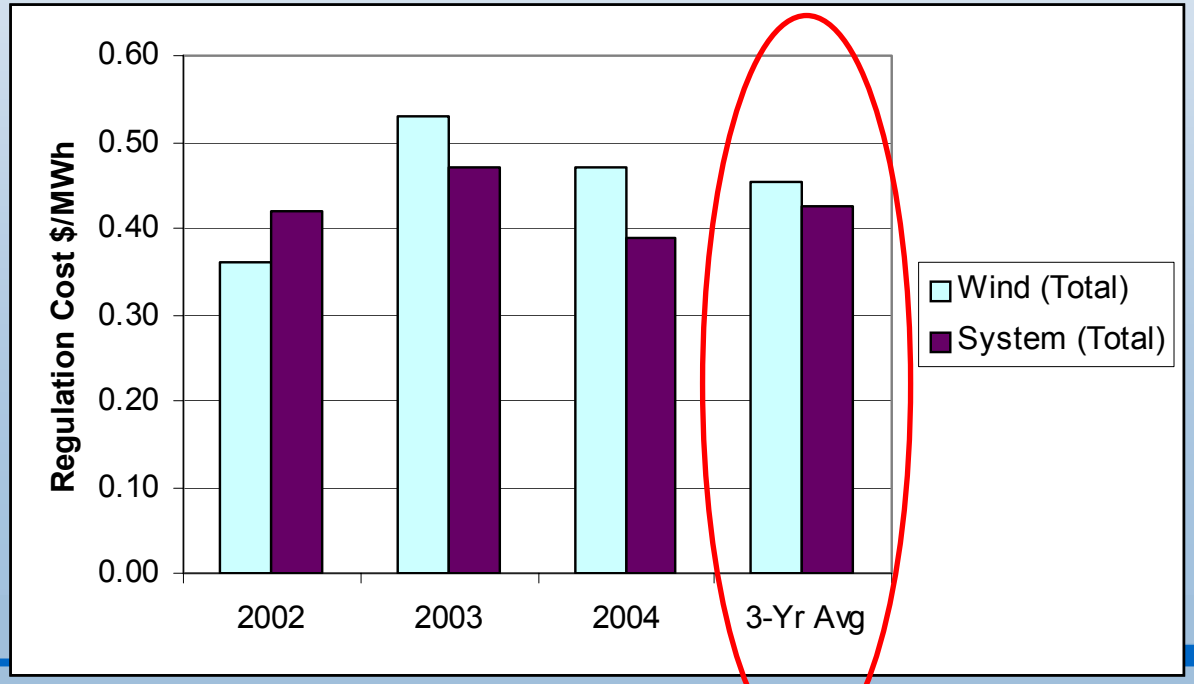


San Gorgonio



Regulation


Regulation Cost $/MWh
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
2002
2003
2004
3-Yr Avg
Wind (Northern California)
Wind (San Gorgonio)
Wind (Tehachapi)


Regulation Cost $/MWh
0.60
0.50
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0.00
2002
2003
2004
3-Yr Avg
Wind (Total)
System (Total)

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* 3-year average; total is non-market cost

Factors that Influence Integration Cost Results

- Balancing area size
  - Conventional generation mix
  - Load aggregation benefits
- Wind resource geographic diversity
- Market-based or self-provided ancillary services

Conclusions and Insights

- Additional operational costs are moderate for penetrations at or above portfolio standard levels
- For large, diverse electric balancing areas, existing regulation and load following resources and/or markets are adequate, accompanying costs are low
- Unit commitment and scheduling costs tend to dominate
- State of the art forecasting can reduce costs
  - majority of the value can be obtained with current state-of-the-art forecasting
  - additional incremental returns from increasingly accurate forecasts
- Realistic studies are data intensive and require sophisticated modeling of wind resource and power system operations

Conclusions and Insights

Data and Modeling Assumptions Matter

- Data from CAISO PI (Power Information) system
  - compression may artificially smooth high-resolution (fast) data
  - Missing data correction algorithm introduced artificial ramps in wind data
- Complex system influences wind capacity value
  - Scheduled maintenance of conventional generation
  - Hydro dispatch
  - Interchange schedule

Some Remaining Issues

- Higher wind penetration impacts
- Effect of mitigation strategies
  - Balancing area consolidation and dynamic scheduling
  - Complementary generation acquisition (power system design; quick-response generation) and interruptible/price responsive load
  - Power system operations practices and wind farm control/curtailment
  - Hydro dispatch, pumped hydro, other storage and markets (plug-hybrid electric vehicles, hydrogen)
- Integration of wind forecasting and real time measurements into control room operations

In Process
(Enernex, WindLogics, Ariva, UWIG team)

- 2006 Minnesota Wind Integration Study
  - Statewide, 20% by *energy* (5 GW wind)
  - New MISO market structure
  - Examine transmission & mitigation strategies
  - Comparison of market operational and reliability rules
  - Completion date 11/06
- Xcel (MN) Renewable Development Fund: Control Room Integration of Wind
  - Define, design, build and demonstrate a complete wind power forecasting system for use by Xcel system operators
  - Optimize the way that wind forecast information is integrated into the control room environment
  - R&D on defensive operating strategies: Value of off-site met towers, high wind warning system, rapid update cycle (RUC) model

Indicates NREL Systems Integration Participation

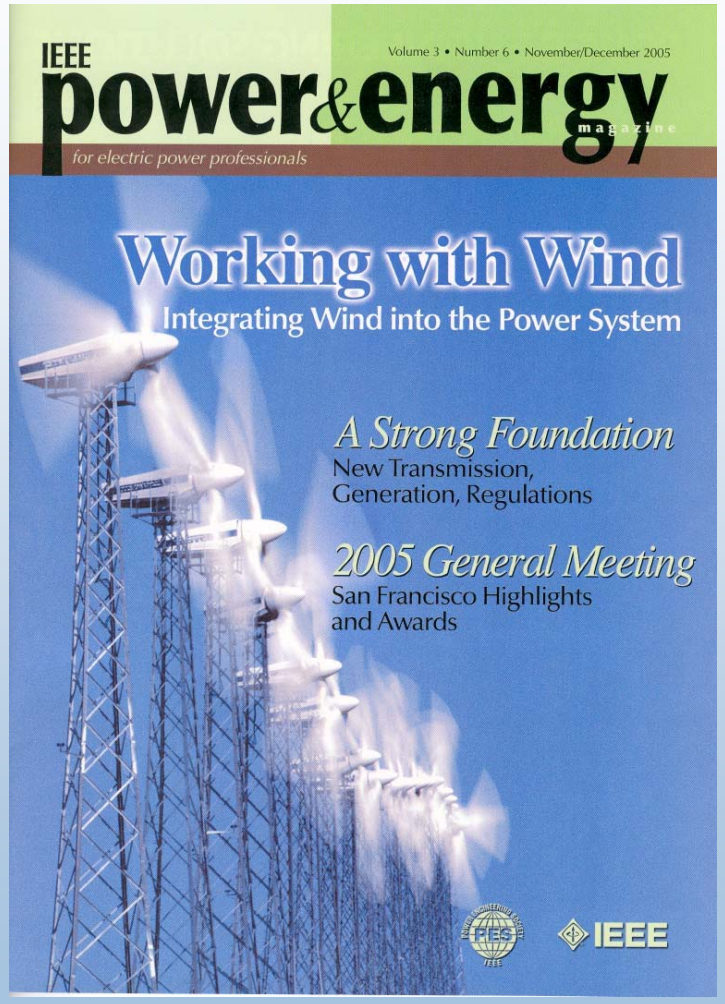
In Process

- California Energy Commission Intermittency Analysis Project
  - 5 GW of wind by 2010, up to >10 GW by 2020 (~15% by capacity)
  - Will consider whether mitigation measures are necessary at certain times (such as low load, high wind production)
  - Lead contractors: Davis Power Consultants and GE Energy with wind resource simulation by AWS Truewind
  - Completed by end of 2006
- Smaller balancing authority projects
  - Sacramento Municipal Utility District: high penetration, investigate value of pumped hydro
  - Public Service of New Mexico: limited conventional resources, high ramping wind, export and minimum load issues
  - Idaho Power and Grant County projects: integrate with constrained existing hydro

In Process

- Xcel Colorado 20% wind scenario (based on wind capacity to peak)
- Xcel 10-year ELCC study in Colorado
- BPA/Northwest Wind Integration Action Plan
- Western Governors' Clean and Diverse Energy Plan (CDEAC) recommendations and follow thru
  - Increased participation in transmission studies (SWAT, NTAC/BPA, MISO, etc.)
- Interest by Northwestern Energy (MT) in integration study

Increasing Attention in North America



- IEEE Power Engineering Society Magazine, November/December 2005
- Wind Power Coordinating Committee kickoff June 2006, Montreal PES meeting
- Utility Wind Integration Group (UWIG): Operating Impacts and Integration Studies User Group
- www.uwig.org

UWIG Utility Wind Integration Group

Accelerating the Integration of Wind Generation into Utility Power Systems