NREL National Renewable Energy Laboratory
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Office of Energy Efficiency & Renewable Energy
Innovation for Our Energy Future

Wind Integration Impacts: What Have We Learned?

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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
- Recent high-penetration studies
- Insights and remaining issues
- Ongoing work

Wind System Integration at NREL

- National Wind Technology Center
- Systems Integration Team
- Advising PUCs and the power industry as technical reviewers to integration studies
- Method development

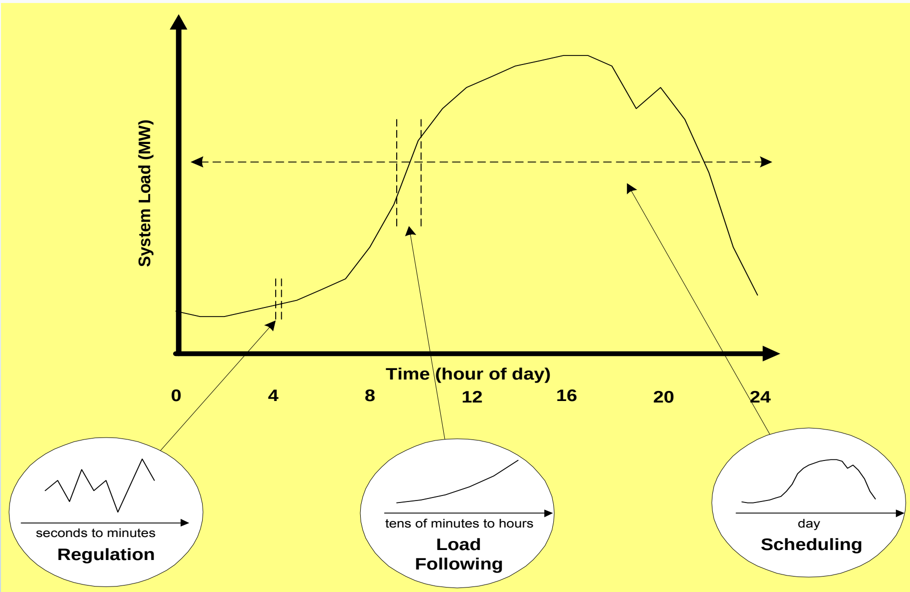
Problem Introduction

- Reliable power system operation requires balance between load and generation *within acceptable statistical limits*
- Output of wind plants cannot be controlled and scheduled with high degree of accuracy
- Wind plants becoming large enough to have measurable impact on system operating cost
- System operators concerned that ***additional*** variability introduced by wind plants will increase system operating cost

Emerging Study Best-Practices

- Start by quantifying physical impacts
- Divide the impacts by time scale
  - Regulation
  - Load following and imbalance
  - Scheduling and unit commitment
  - Capacity value
- Analyze cost impact of wind in context of entire system in each time scale
  - Load variability
  - Wind variability
  - What is wind's impact on total variability and cost?
  - Allocation: recognize wind's positive and negative impacts

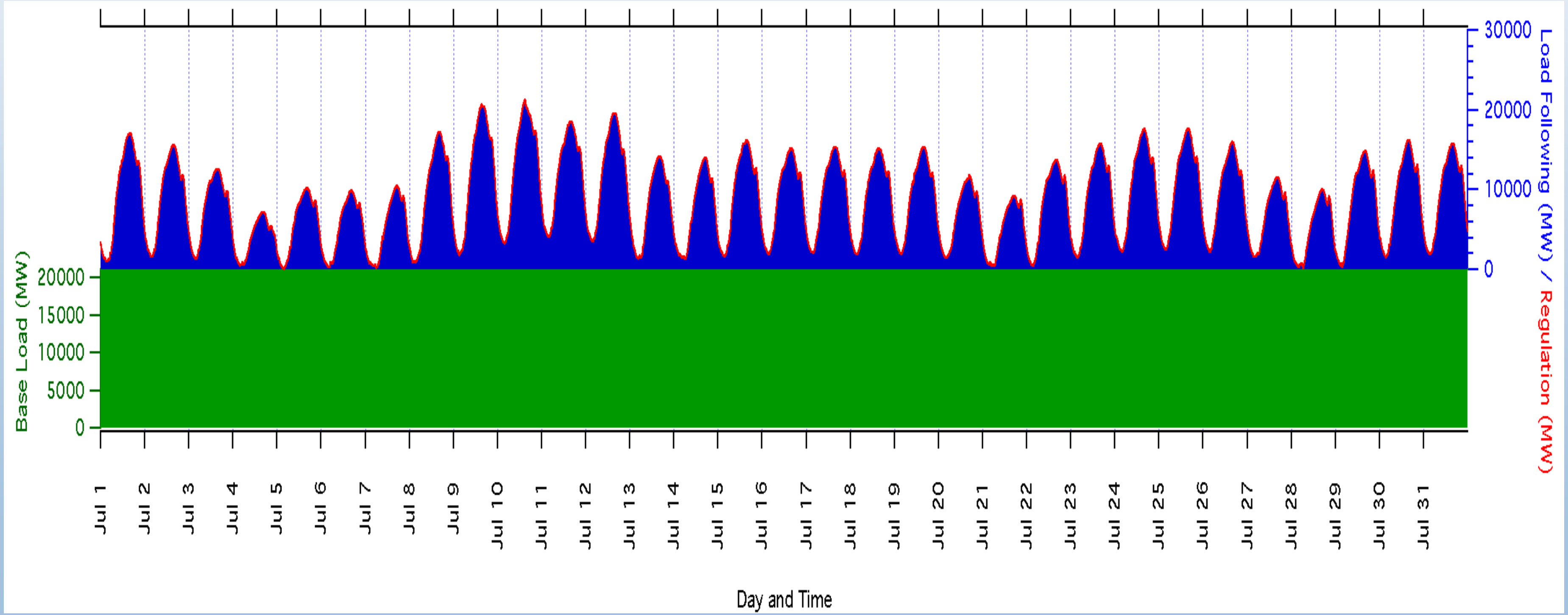
Time Frames of Wind Impact



- 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)

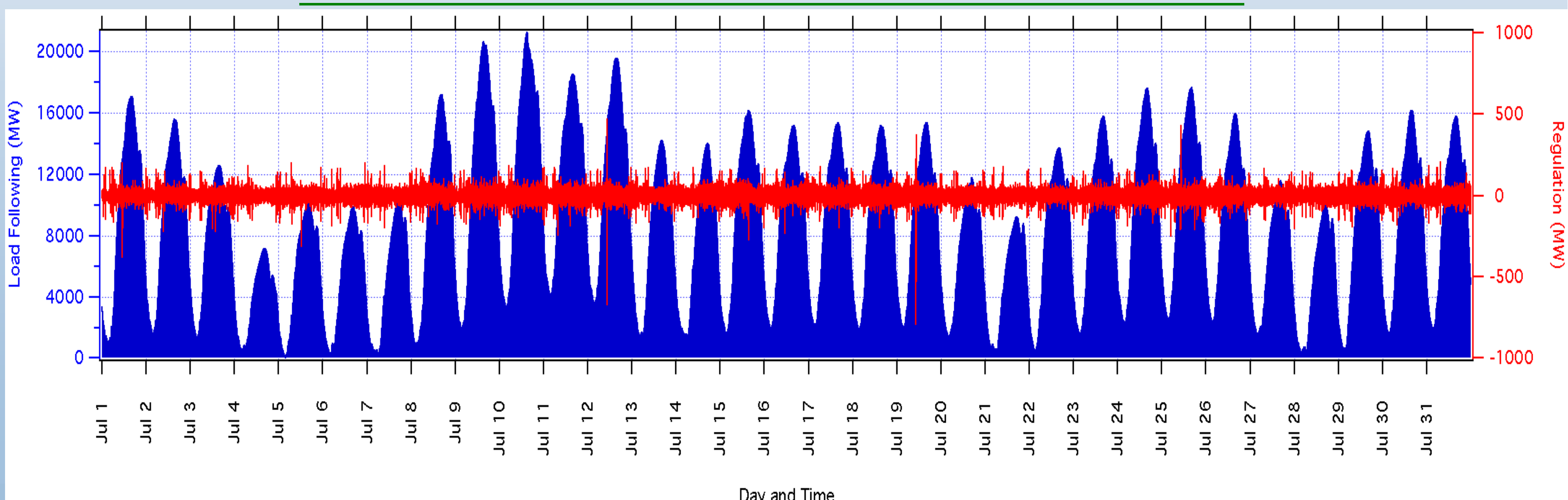
Decomposition of Control Area Loads

- Control area load & generation can be decomposed into three parts:
  - Base Load
  - Load Following
  - Regulation



Regulation & Load Following

	REGULATION	LOAD FOLLOWING
Patterns	Random, uncorrelated	Largely correlated
Generator control	Requires AGC	Manual
Maximum swing (MW)	Small	10 – 20 times more
Ramp rate (MW/minute)	5 – 10 times more	Slow
Sign changes	20 – 50 times more	Few



Impact of Variable Power Sources

- Power system is designed to handle tremendous variability in loads
- Wind adds to that variability
- System operator must balance loads=resources (within statistical tolerance)
- Key implication: ***It is not necessary or desirable to match wind's movements on a 1-1 basis***

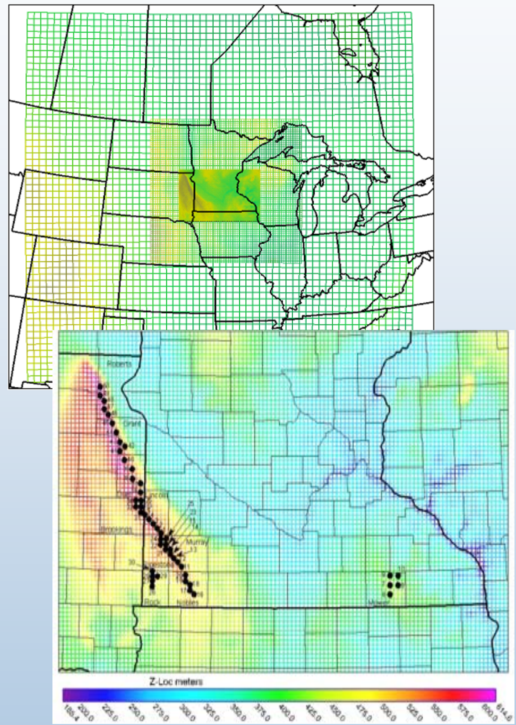
Typical Objective of Integration Studies

- 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

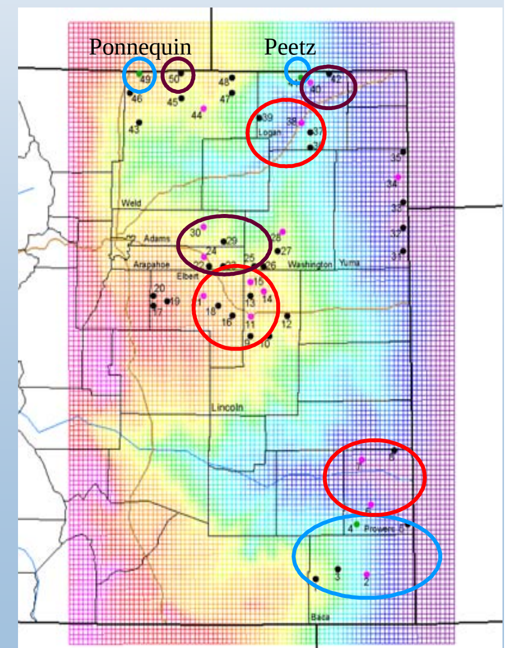
Where Does Wind Data Come From?

- Meso-scale meteorological modeling that can "re-create" the weather at any space and time
- Model is run for the period of study and must match load time period
- Wind plant output simulation and fit to actual production of existing plants

Minnesota: Xcel



Colorado: Xcel



Challenges of Actual Data

- Power Information (PI) system
- Data storage error
  - Results from PI system data compression
- Old wind technology behavior does not reflect current-future performance

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

Date	Study	Wind Capacity Penetration (%)	Regulation Cost ($/MWh)	Load Following Cost ($/MWh)	Unit Commitment Cost ($/MWh)	Gas Supply Cost ($/MWh)	Total Operating Cost Impact ($/MWh)
May '03	Xcel-UWIG	3.5	0	0.41	1.44	na	1.85
Sep '04	Xcel-MNDOC	15	0.23	na	4.37	na	4.60
June '06	CA RPS Multi-year	4	0.45*	trace	na	na	0.45
Feb '07	GE/Pier/CAIAP	20	0-0.69	trace	na***	na	0-0.69***
June '03	We Energies	4	1.12	0.09	0.69	na	1.90
June '03	We Energies	29	1.02	0.15	1.75	na	2.92
2005	PacifiCorp	20	0	1.6	3.0	na	4.60
April '06	Xcel-PSCo	10	0.20	na	2.26	1.26	3.72
April '06	Xcel-PSCo	15	0.20	na	3.32	1.45	4.97
Dec '06	MN 20%	31**					4.41**

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

** highest integration cost of 3 years; 30.7% capacity penetration corresponding to 25% energy penetration; 24.7% capacity penetration at 20% energy penetration

*** found $4.37/MWh reduction in UC cost when wind forecasting is used in UC decision

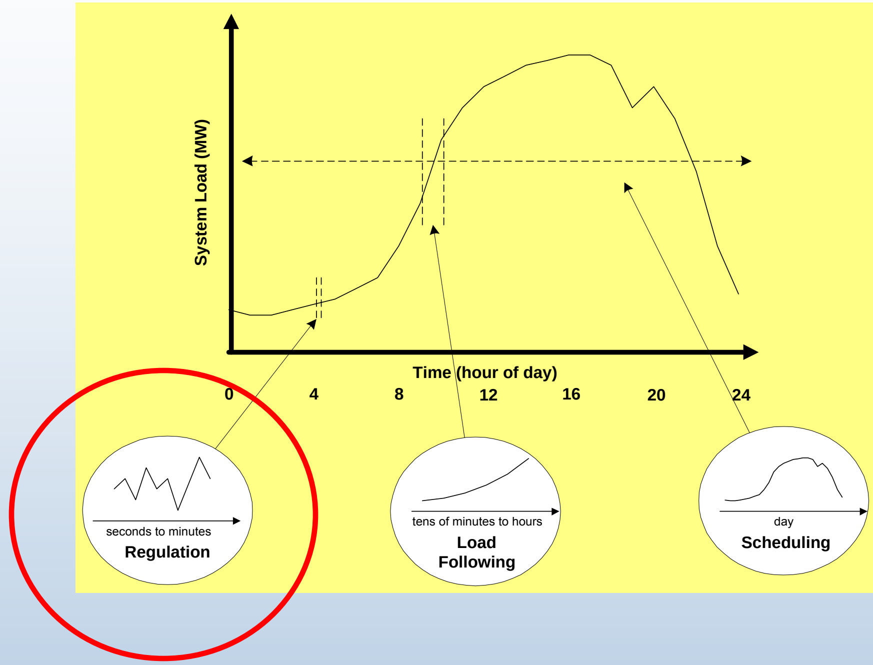
Wind Capacity Value in the US

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)
Minnesota 20% Study	ELCC	Found significant variation in ELCC: 4%, 15%, 25% and variation based on year
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	Full ELCC study using 10-year data set; inaccuracies introduced by load forecasting algorithm. Average approximately 12.5%
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

How Are Wind's Impacts Calculated?

How is Regulation Impact Calculated?

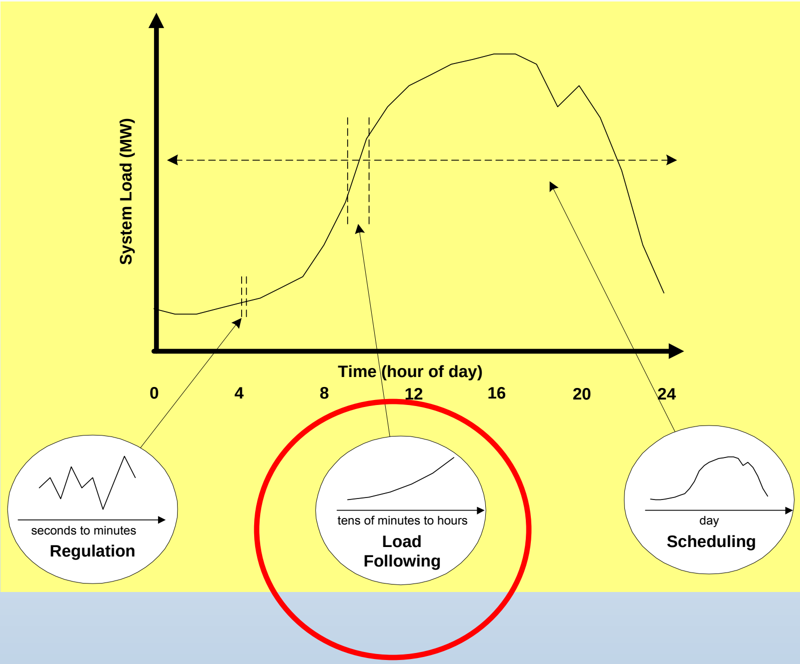
- Based on actual high-frequency (fast) system load data and wind data
- If wind data not available, use NREL high-resolution wind production data characteristics
- Impact of the wind variability is then compared to the load variability
- Preferred metric: ORNL regulation allocation approach
- Regulation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

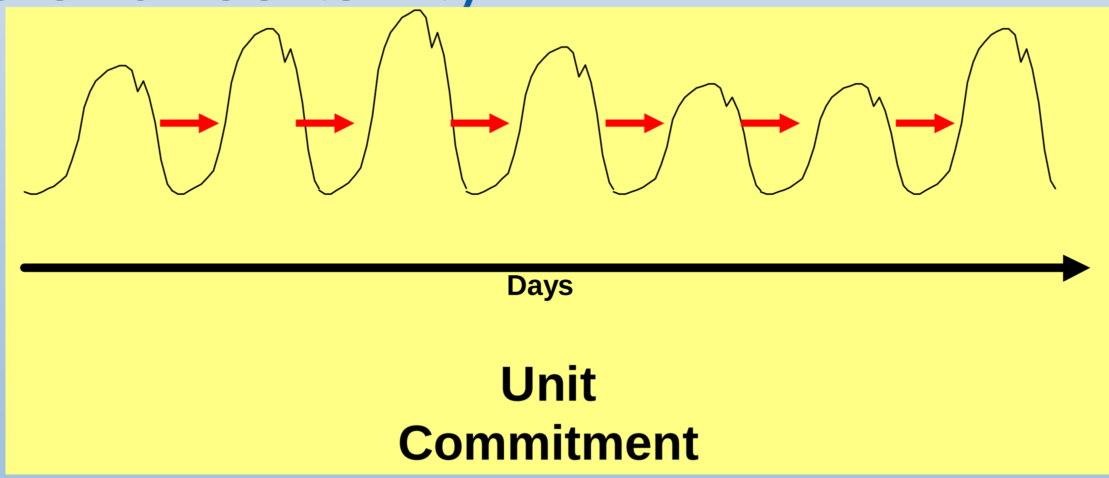
- Based on actual system load data
- …and wind data from *same* time period
  - Meteorological simulation to capture ***realistic*** wind profile, typically 10-minute periods and multiple simulated/actual measurement towers
  - Realistic calculation of wind ***plant*** output (linear scaling from single anemometer is incorrect)
- Wind variability added to *existing system variability*



→ Implies no one-one backup for wind

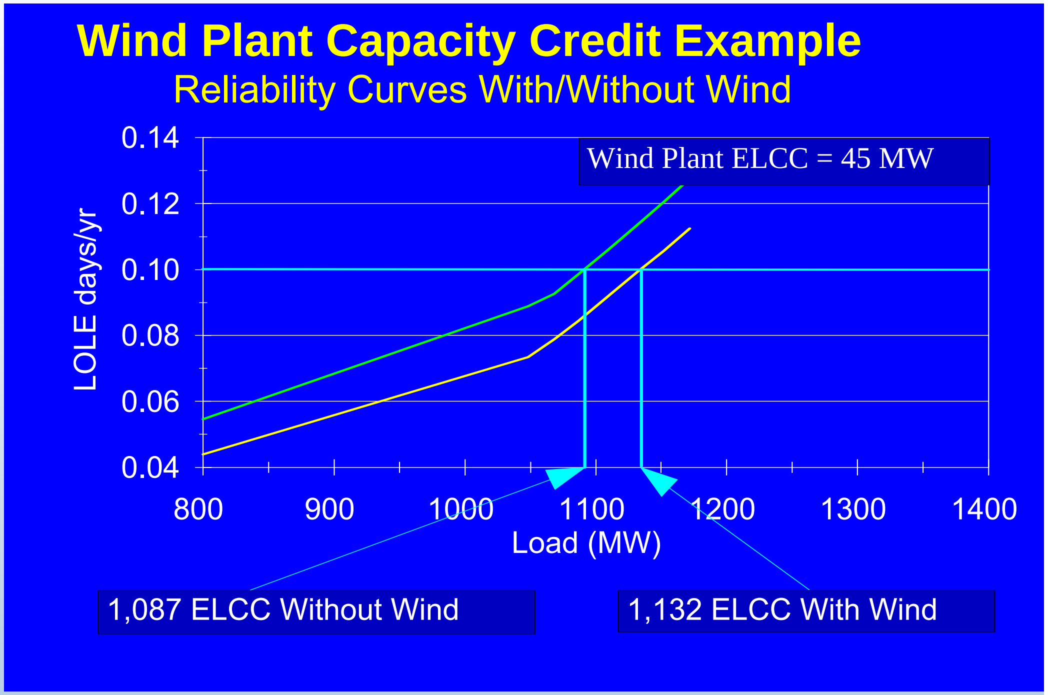
How is Unit Commitment Impact Calculated?

- 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



High-Penetration Cases

- Minnesota PUC: 15-25% wind penetration (based on energy)
- Idaho Power: about 30% (peak)
- Avista: 30% peak

Minnesota 20% Wind Study

- Objective: Calculate ancillary service cost and capacity value of 20% wind penetration (by energy)
- Study analyzed 15, 20, 25% case
- Wind Capacity 5,689 MW on system peak of 18,527 MW (25% energy case; 30.7% capacity penetration)
- Connection with the MISO market

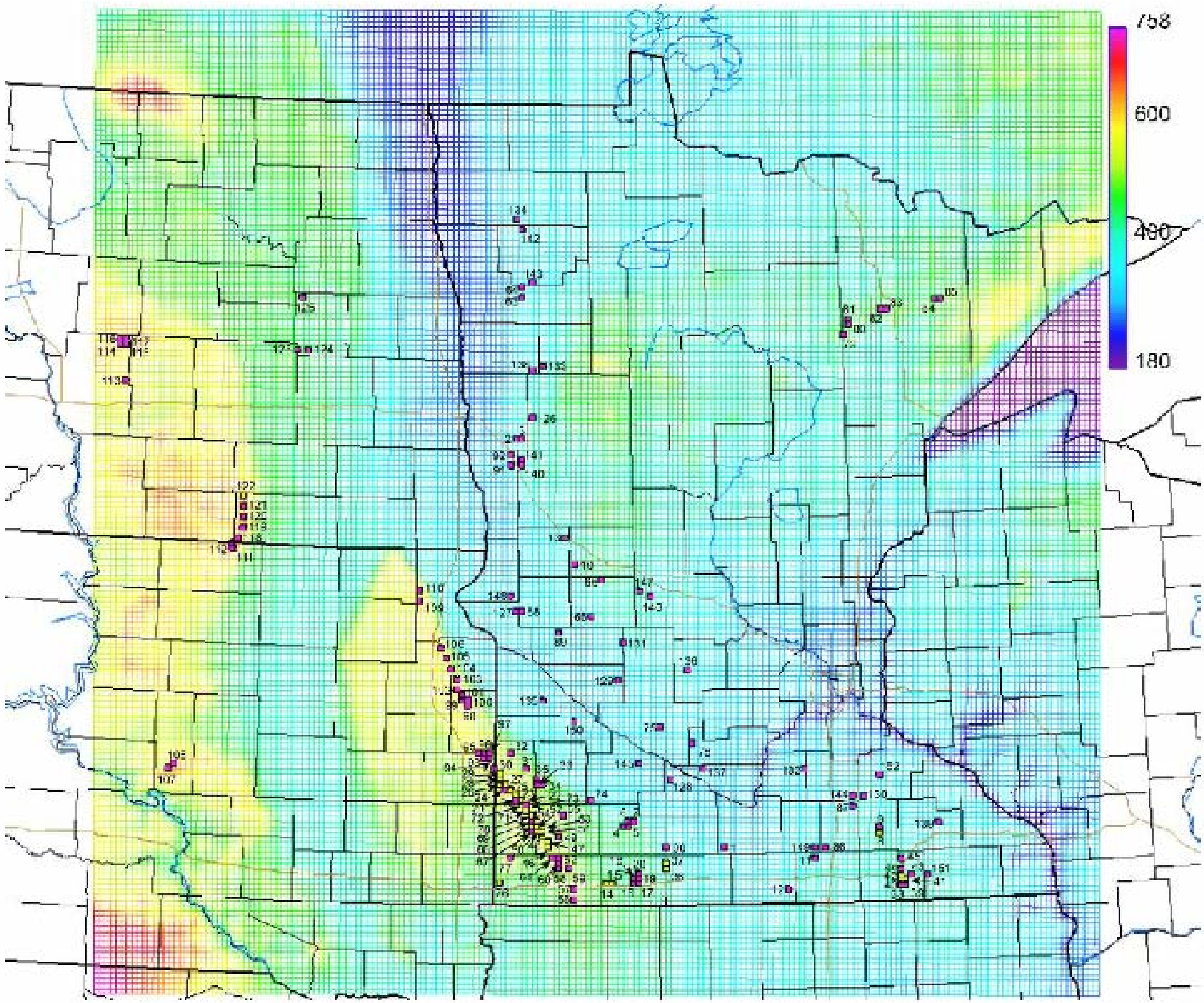
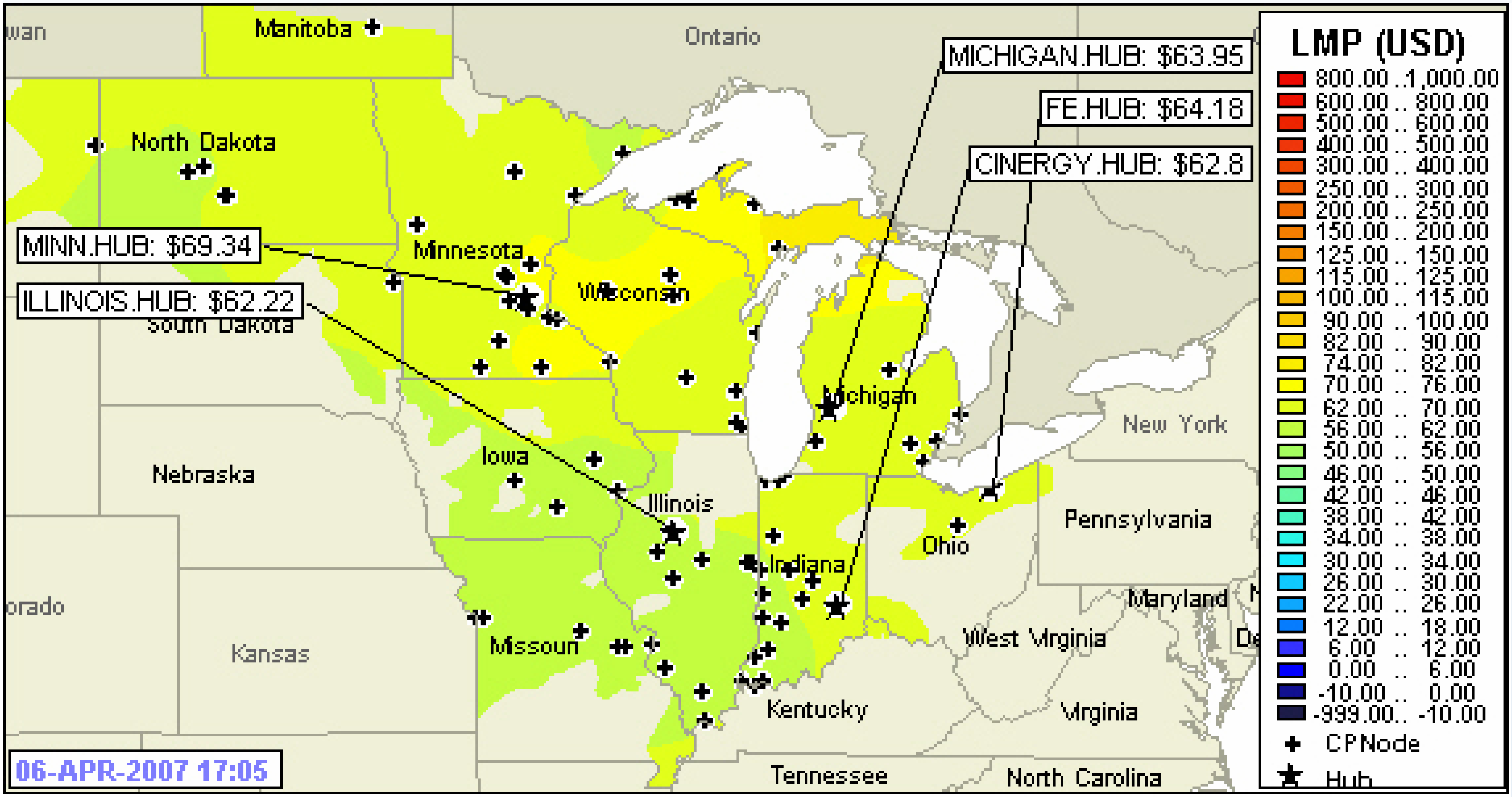
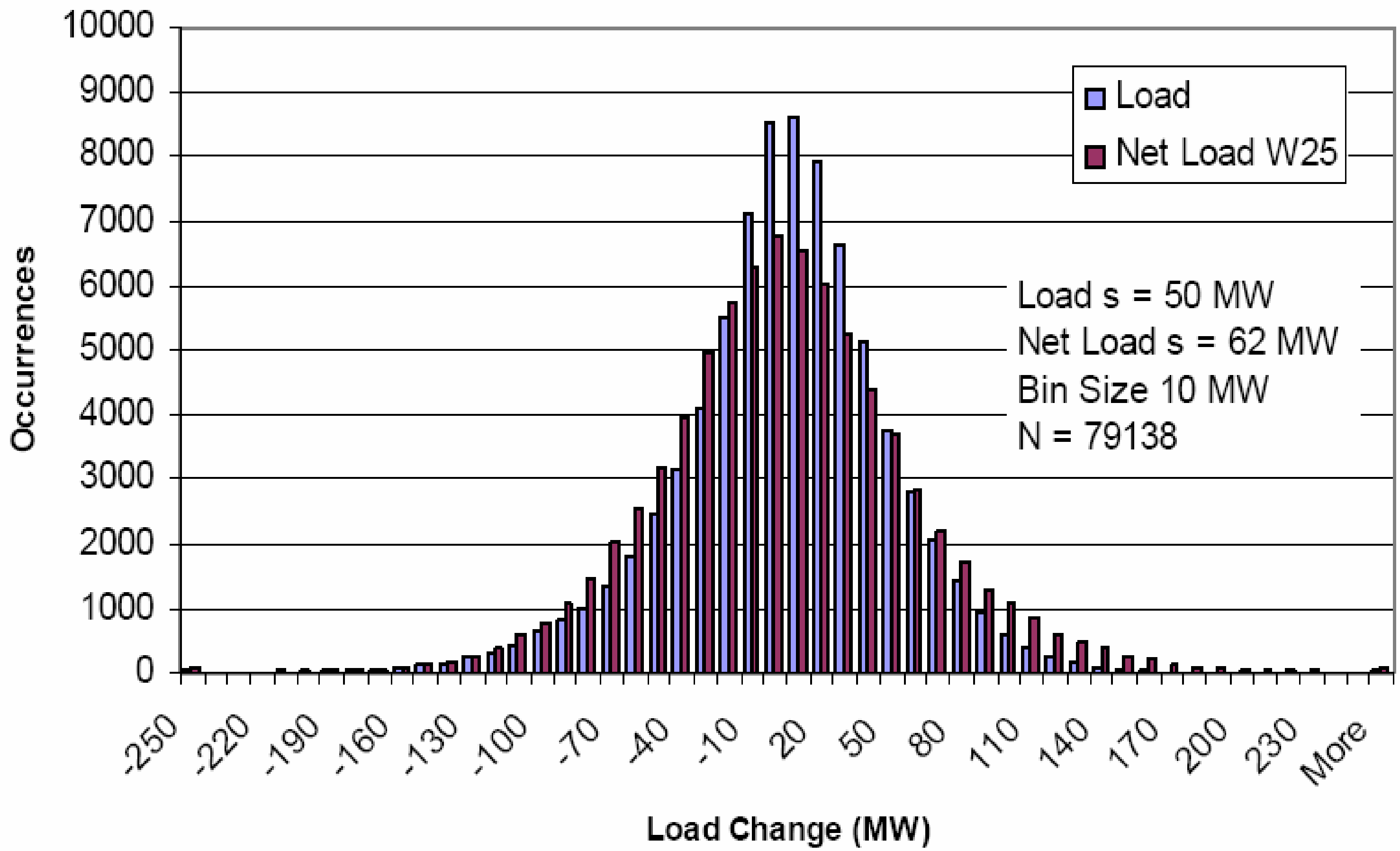


Figure 1: Location of "proxy towers" (model data extraction points) on inner grid.

Imbalance Across MISO Footprint



5-Minute Load/Net Load Changes: 25% Wind Case: Within-hour movement handled within MN



Key Innovation: Use of Variable Operating Reserve Dependent on Wind Generation

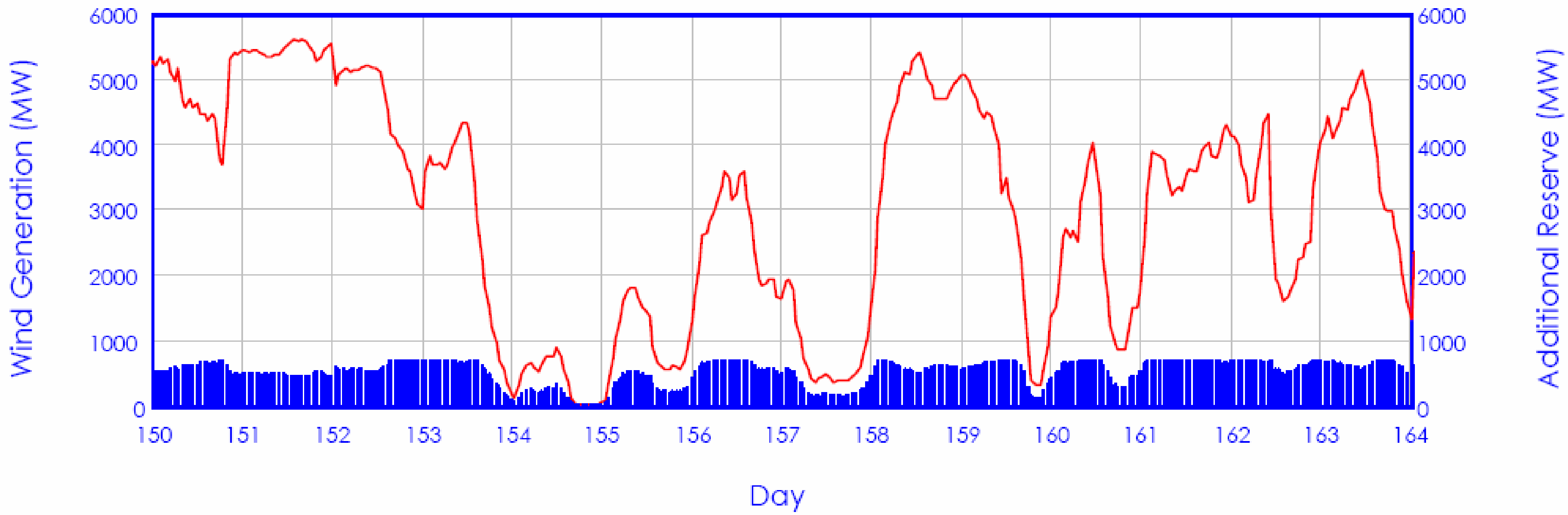


Figure 30: Illustration of time varying "operating reserve margin" developed from statistical analysis of hourly wind generation variations.

Wind Impact on Operating Reserves

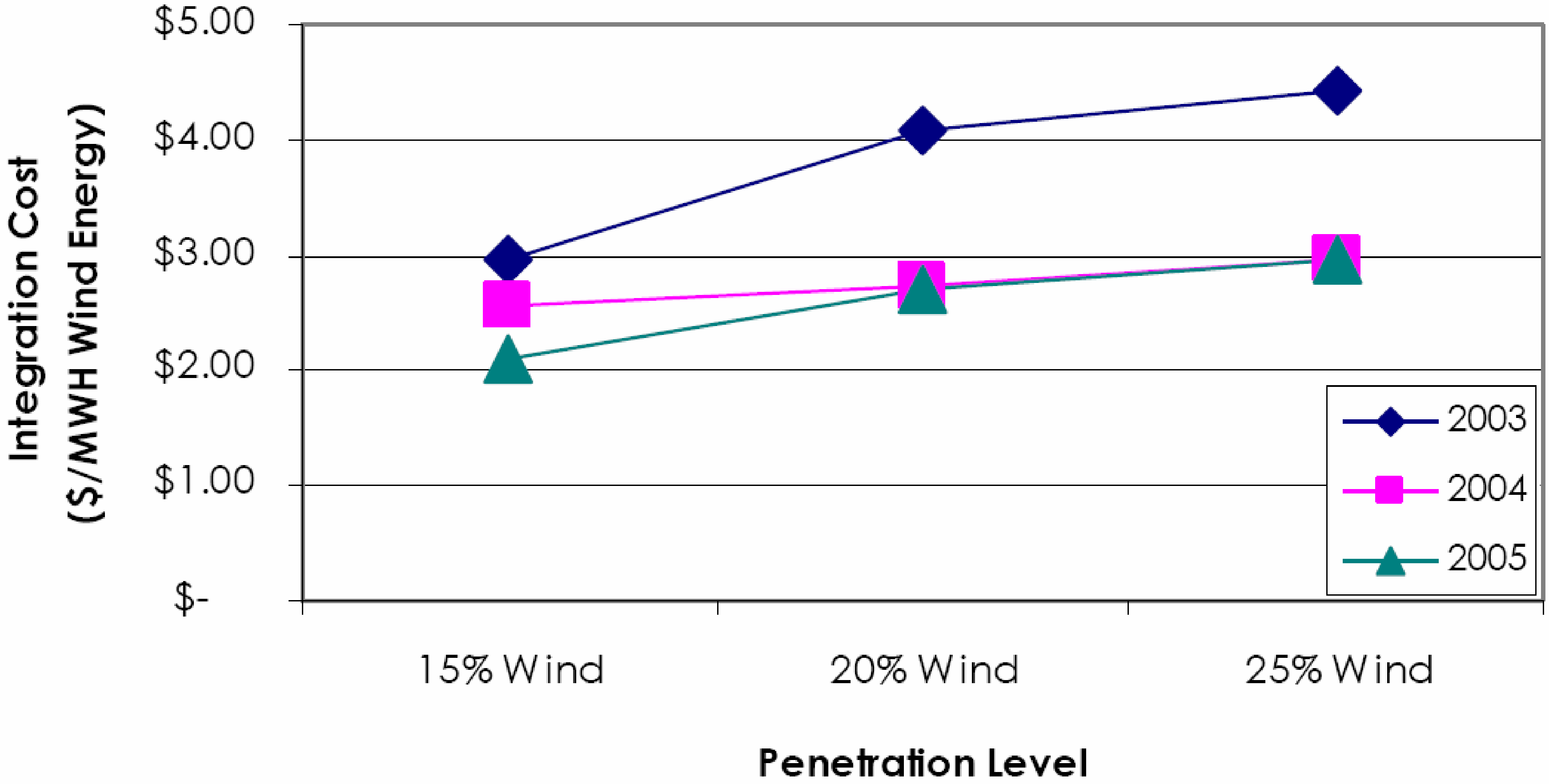
Table 18: Estimated Operating Reserve Requirement for MN Balancing Authority – 2020 Load

Reserve Category	Base		15% Wind		20% Wind		25% Wind	
	MW	%	MW	%	MW	%	MW	%
Regulating	137	0.65%	149	0.71%	153	0.73%	157	0.75%
Spinning	330	1.57%	330	1.57%	330	1.57%	330	1.57%
Non-Spin	330	1.57%	330	1.57%	330	1.57%	330	1.57%
Load Following	100	0.48%	110	0.52%	114	0.54%	124	0.59%
Operating Reserve Margin	152	0.73%	310	1.48%	408	1.94%	538	2.56%
Total Operating Reserves	**1049**	**5.00%**	**1229**	**5.86%**	**1335**	**6.36%**	**1479**	**7.05%**

Notes on Table:

- Assumes 2020 MN Balancing Authority peak load of 20984 MW
- Requirements for load following and reserve margin based on two standard deviations of the five-minute variability and next hour forecast error, respectively.

Wind Integration Costs



Recent Studies in the Northwest

- Avista Utilities: Up to 30% wind penetration (peak)
- Idaho Power: Up to about 30% wind penetration (peak)
- BPA: analytical work in progress; integration cost is consistent with others
- Potential follow-on work to the NW Wind Integration Action Plan (NWIAP) on regional basis
- Northwest Wind Integration Action Plan: http://www.nwcouncil.org/energy/Wind/Default.asp

Idaho Power

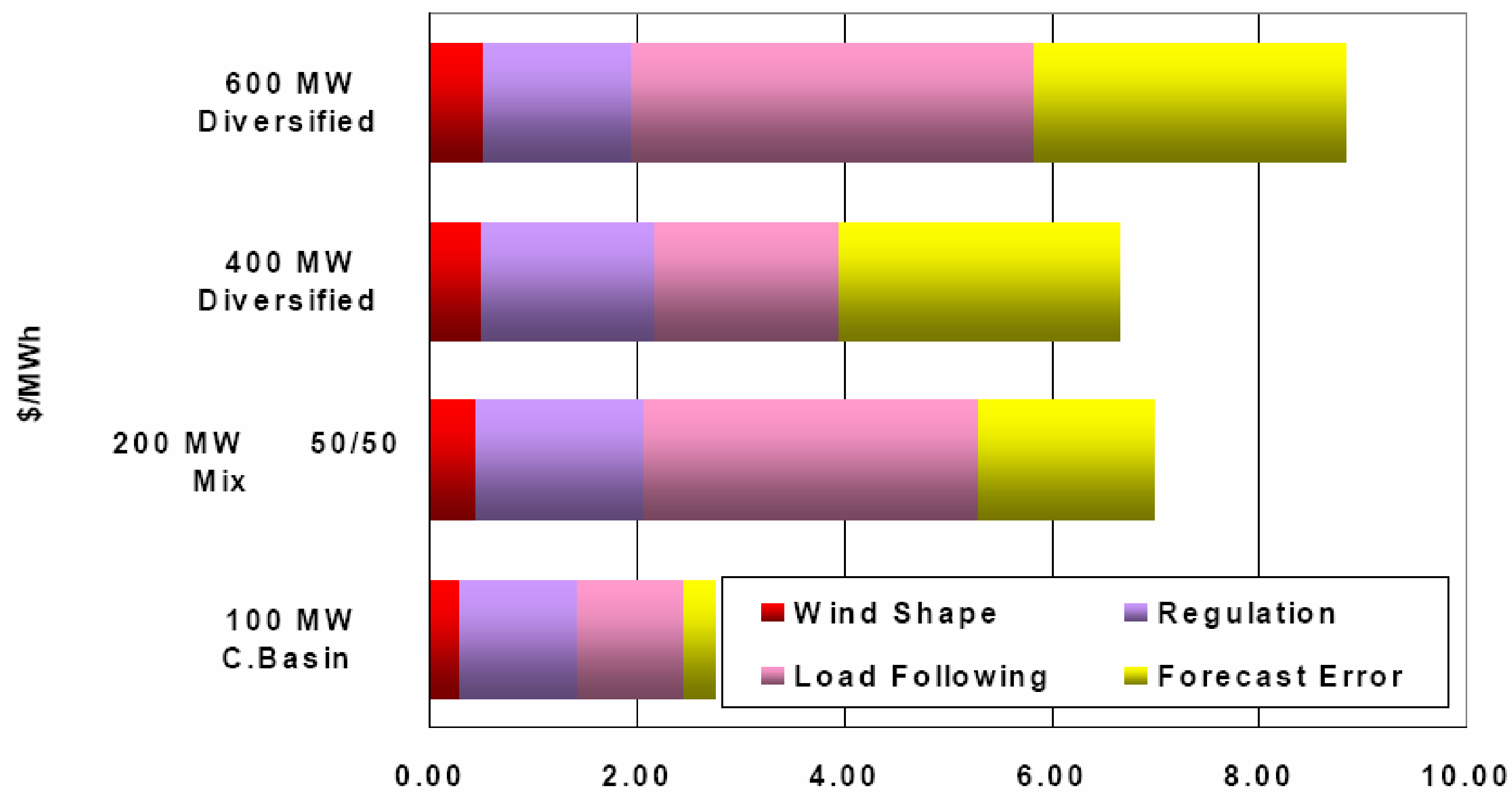
Table 15. Vista results using historical mid-C prices

Vista Results Using Historical Mid-C Prices				
study year	penetration level (MW)	cost per MWh wind	annual avg energy price	cost as % energy price
1998	300	$3.19	$27.61	11.6%
1998	600	$4.73	$27.61	17.1%
1998	900	$6.06	$27.61	21.9%
1998	1,200	$6.92	$27.61	25.1%
2000	300	$21.89	$132.17	16.6%
2000	600	$30.30	$132.17	22.9%
2000	900	$39.06	$132.17	29.6%
2000	1,200	$39.40	$132.17	29.8%
2005	300	$10.69	$58.19	18.4%
2005	600	$9.32	$58.19	16.0%
2005	900	$10.58	$58.19	18.2%
2005	1,200	$8.12	$58.19	14.0%

From Idaho Power Corp Wind Integration Study

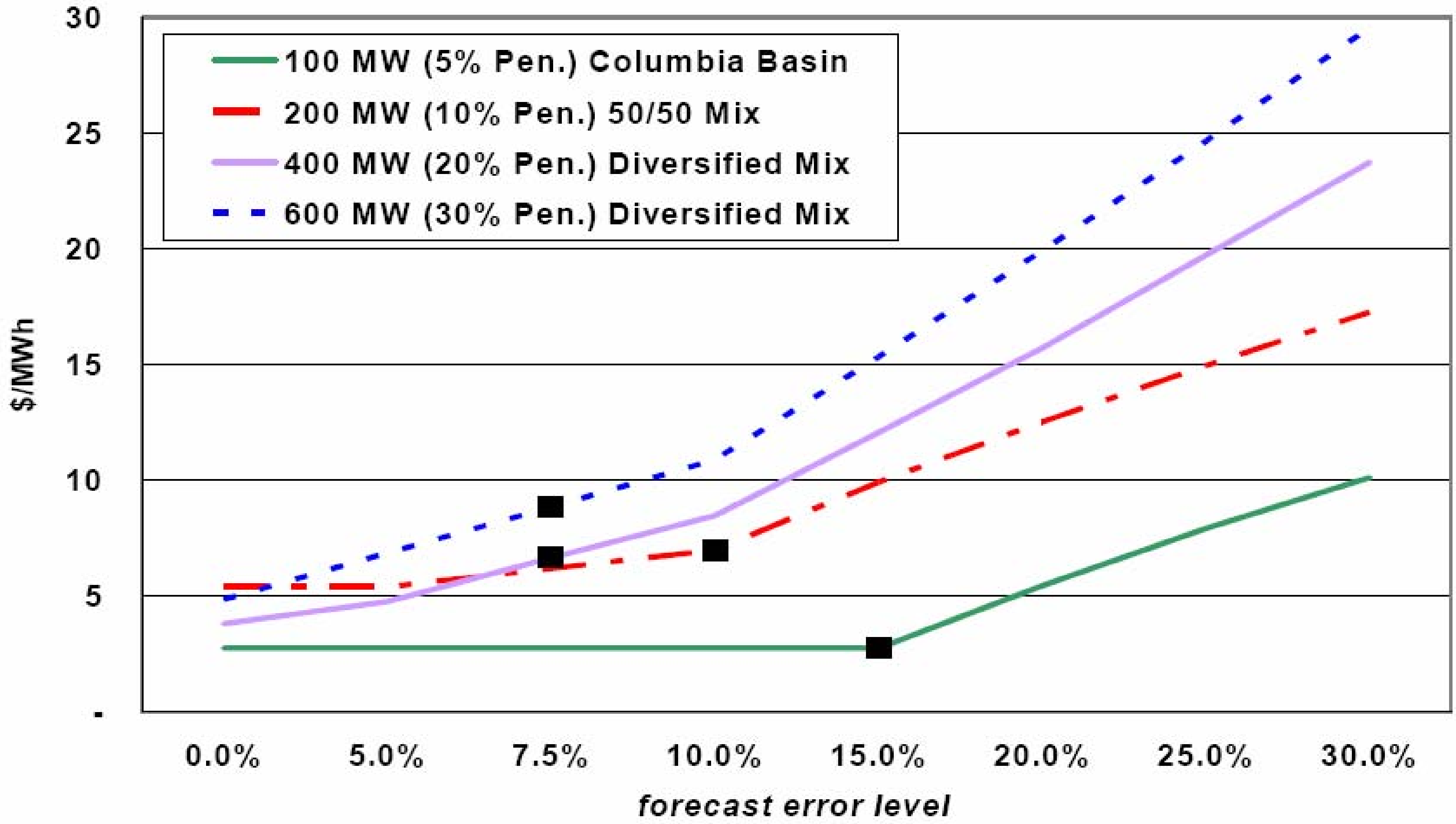
Avista

Wind Integration Cost Components



From Avista Wind Integration Study: Kalich, UWIG

Impact of Forecast Error



AVISTA

From Avista Wind Integration Study: Kalich, UWIG

California Intermittency Analysis Project (from GE Energy, CEC Workshop)

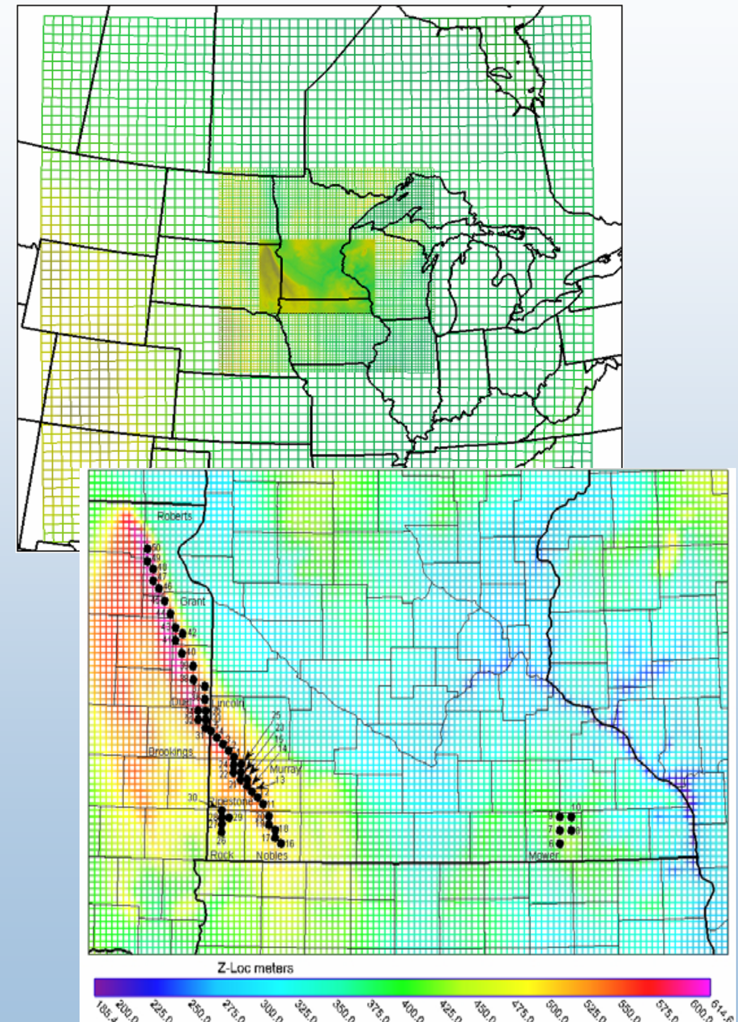
Conclusions

- System operation with 12,500 MW of wind generation and 2,600 MW of solar is feasible with 2010X scenario infrastructure. 2020 scenario will be easier.
- An economically rational unit commitment must include intermittent resource forecasts.
- Such a commitment results in sufficient flexibility for successful operation.
- Some operating conditions will be more challenging:
  - Periods of high load rise, such as winter evening peak, may see an increased rate of rise.
  - Periods of light load will increase in frequency, and when combined with extremely high wind, may require mitigation (e.g., curtailment).
- Requirements for load following and regulation increase, resulting in increased duty for the balance of the generation portfolio. Possible additional cost for increased regulation ranges from 0 to 69 ¢ / MWhr of intermittent renewable.
- Changes in revenue are likely to affect economic viability of incumbent generators. It is possible that some will exit.
- Variable cost of production, wholesale load payments, total emissions and natural gas consumption drop substantially.
- Mitigation schemes examined in the study will be beneficial for challenging operating conditions, and can be pursued on an incremental and systemic basis.

Other Recent Studies

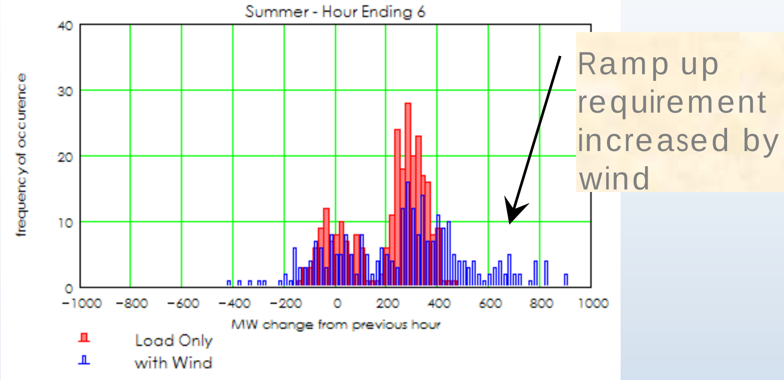
Minnesota Dept. of Commerce/ Enernex Study Framework

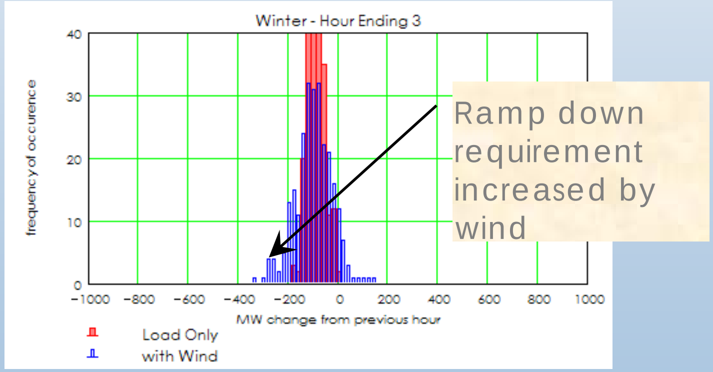
- 2010 scenario of 1500 MW of wind in 10 GW peak load system (< 700 MW wind currently)
- WindLogics:10-minute power profiles from atmospheric modeling to capture geographic diversity
- Wind forecasting incorporated
- Extensive historic utility load and generator data available
- Monopoly market structure, 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%



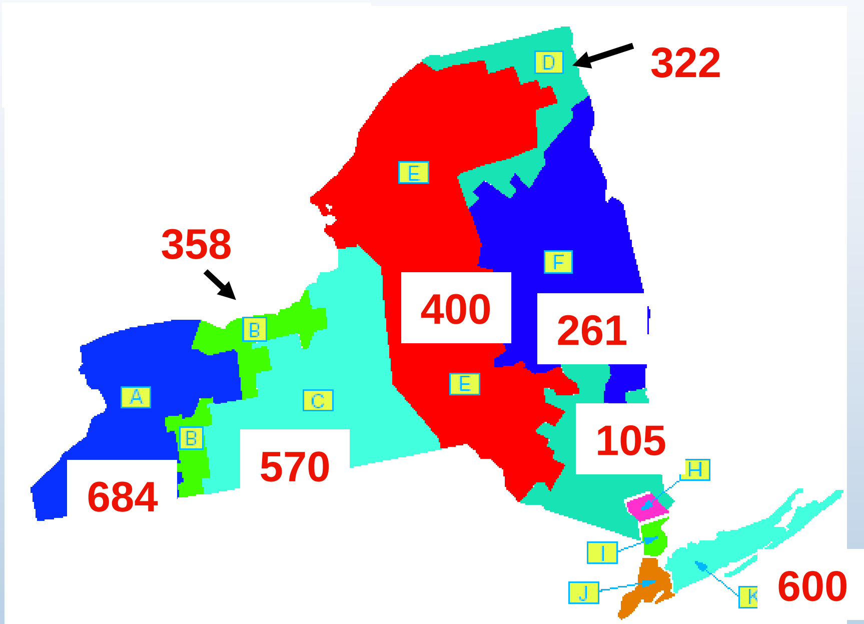


Completed September 2004 *www.commerce.state.mn.us*

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

New York ISO and NYSERDA/ GE Energy Study

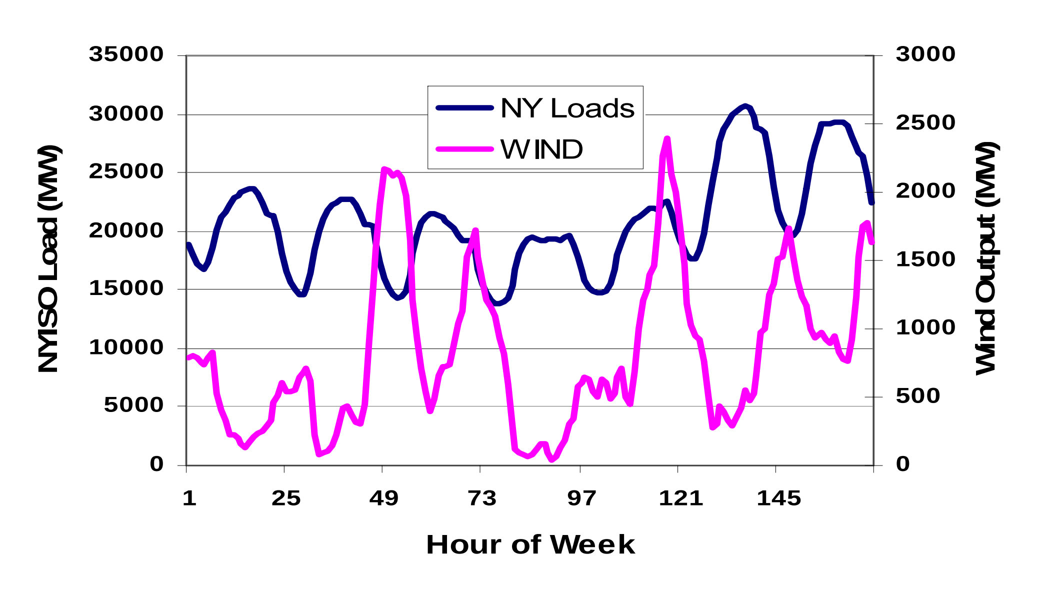
- 2008 scenario of 3300 MW of wind in 33-GW peak load system (< 200 MW wind currently)
- AWS Truewind: wind power profiles from atmospheric modeling to capture statewide diversity



- 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



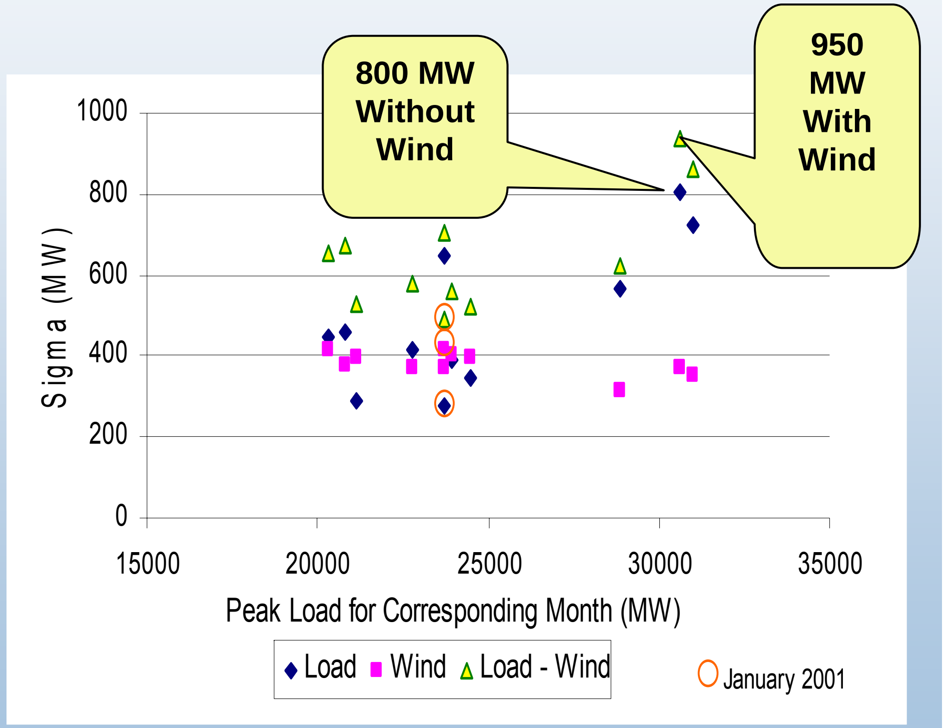
- All increased needs can be met by existing NY resources and market processes
- Capacity credit (UCAP) of 10% average onshore and 36% offshore
- Significant system cost savings of $335- $455 million on assumed 2008 natural gas prices of $6.50-$6.80 /MMBTU.

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

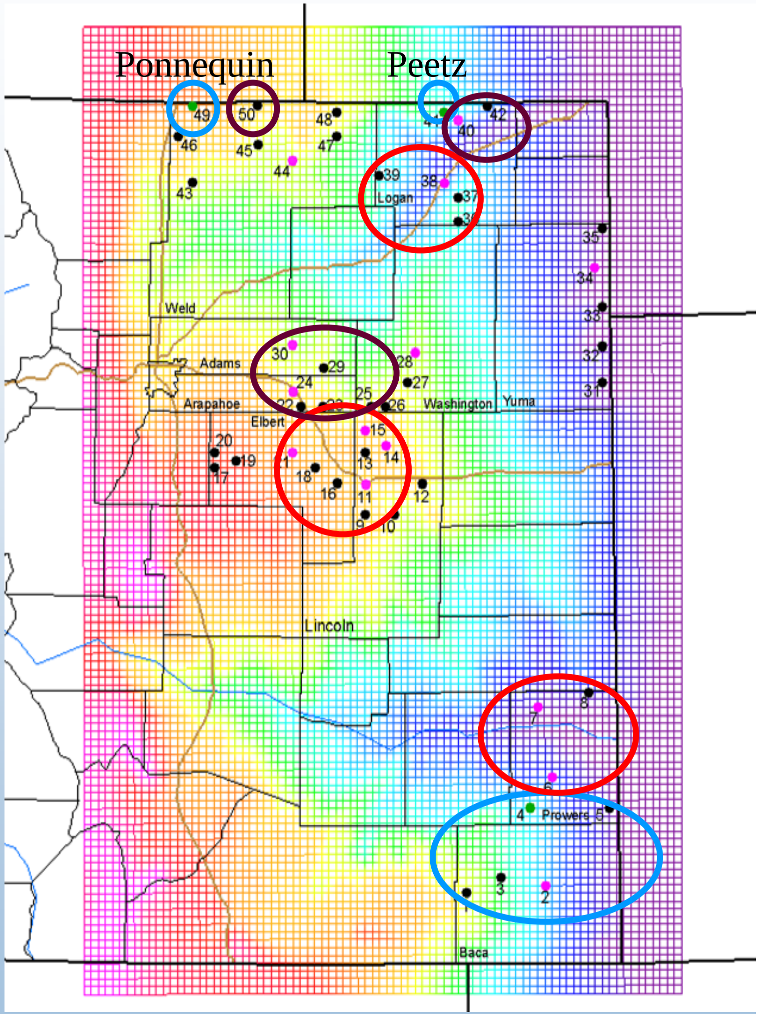
Standard Deviations of Day-Ahead Forecast Errors



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

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

Factors that Influence Integration Cost Results

- Wind penetration
- Balancing area size
  - Conventional generation mix
  - Load aggregation benefits
- Wind resource geographic diversity
- Market-based or self-provided ancillary services
- Size of interconnected electricity markets

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 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 and integration cost
  - Scheduled maintenance of conventional generation
  - Hydro dispatch (needs more systematic work)
  - Interchange schedules, markets

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)

- 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

In Process

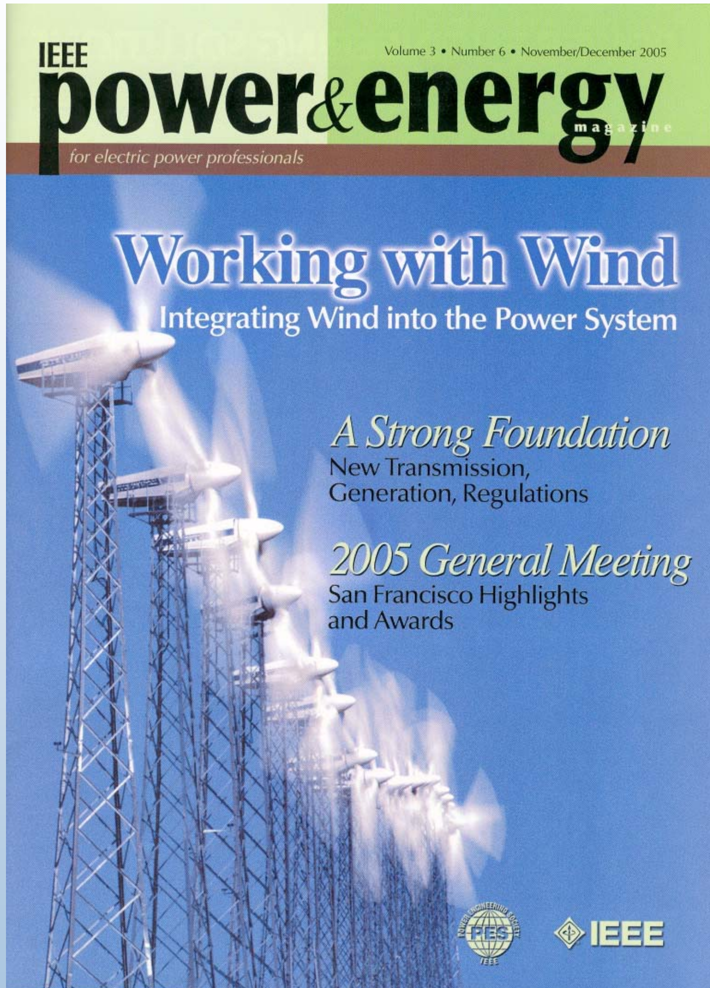
- Smaller balancing authority projects
  - Sacramento Municipal Utility District: high penetration, investigate value of pumped hydro
  - Public Service of New Mexico: limited conventional resources, high ramping wind, export and minimum load issues
  - Grant County projects: integrate with constrained existing hydro

Indicates NREL Systems Integration Participation

In Process

- Xcel Colorado 20% wind scenario (based on wind capacity to peak)
- BPA/Northwest Wind Integration Forum
- 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
- Southwest Public Service (not yet started)
- Northern Tier Transmission Group (discussion)
- Western Wind Integration Study

Increasing Attention in North America



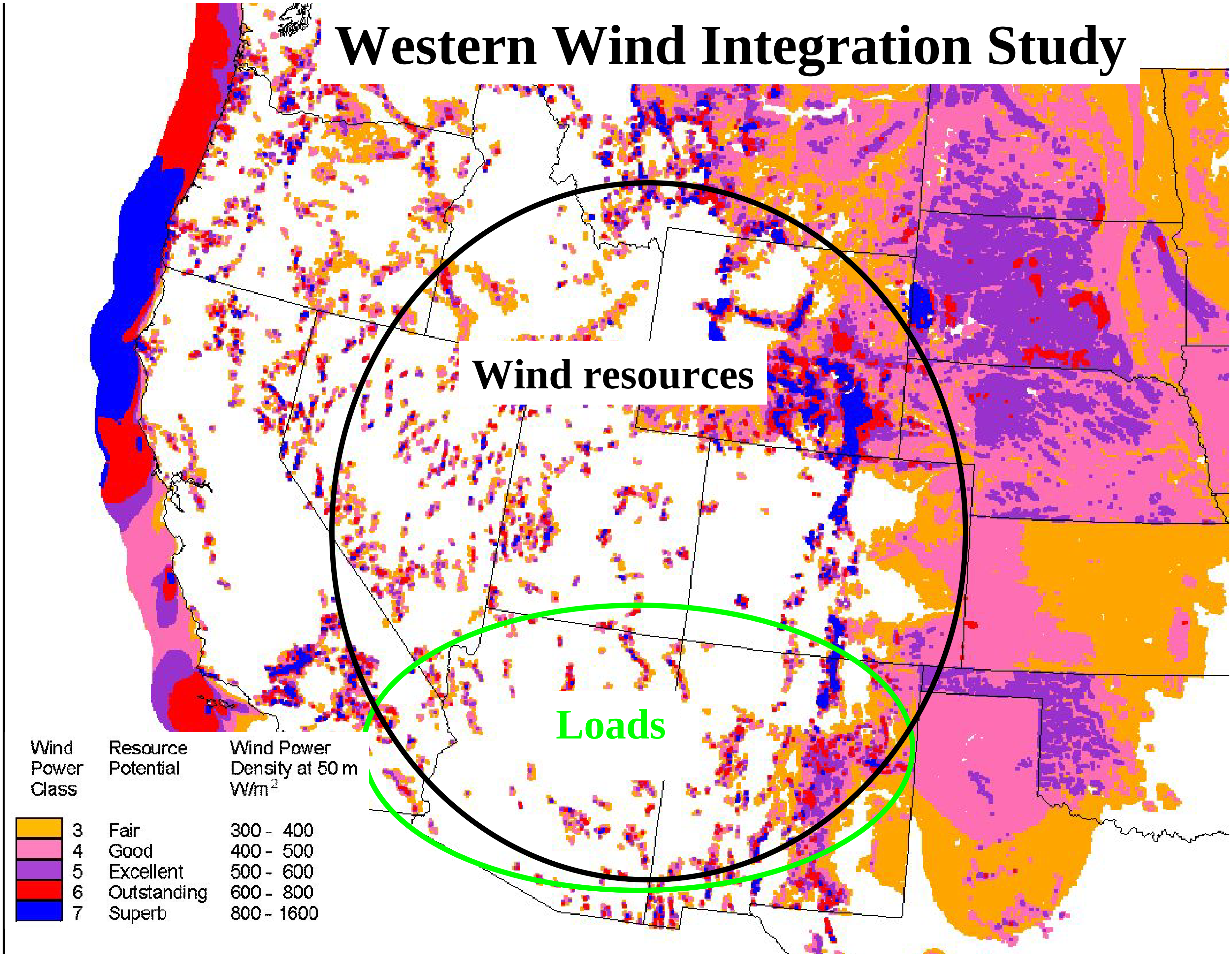
- IEEE Power Engineering Society Magazine, November/December 2005
- Planning update in Nov/Dec 2007
- Wind Power Coordinating Committee kickoff June 2006, Montreal PES meeting
- Utility Wind Integration Group (UWIG): Operating Impacts and Integration Studies User Group
- www.uwig.org

UWIG Utility Wind Integration Group

Accelerating the Integration of Wind Generation into Utility Power Systems

New Study
Western Wind Integration Study

Western Wind Integration Study



Questions to address

- Is it cheaper to use local wind resources or import better class resources from out-of-state?
- How do out-of-state resources compare to local wind resources for matching load profiles? Does geographical diversity help reduce system variability?
- What are the benefits from long distance transmission that accesses multiple wind resources that are geographically diverse?
- Can the required transmission costs be covered by wind or other future generation sources?
- What additional aggregate system operational impacts or costs are imposed by wind variability? What kinds of mitigation measures help to manage that incremental variability?
- How does hydro help with wind integration?
- What is the role and value of wind forecasting?
- What benefit does Balancing Area cooperation or consolidation bring to wind variability management?
- Is there a benefit to aggregating regional wind demand instead of individual utility action?
- How does each wind area contribute to reliability and capacity value?

Key Tasks

- Stakeholder group
- Technical review committee
- Meso-scale modeling of wind
- Preliminary analysis
  - Examine load and wind profiles
  - Preliminary control area consolidation analysis
  - Build wind/transmission supply curves
- Design scenarios
- Evaluate scenarios for cost and operational impacts
  - Production Simulation Analysis
  - Evaluate physical performance and limitations of power grid
  - Evaluate economic/financial performance
- Evaluate mitigation measures
  - Operational strategies
  - Technology options