

# **Demand Response via Real-Time Pricing to Increase Use of Operational Wind Energy Generators**

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1



# Introduction

- An impediment to integrating large-scale wind generation into a power system is its limited-dispatchability, variable availability, and errors in forecasting availability
- These characteristics of wind generation combined with operational requirements of power systems may require curtailing wind generation
- Question: To what extent can real-time pricing (RTP) alleviate some of these issues relating to wind integration?

# Wind Integration Issues

- Depending on the specifics of a power system, wind generation may have to be curtailed due to:
  - Limited flexibility of thermal generators due to ramping, minimum load, must-run, or commitment constraints
  - Increased ancillary service requirements due to wind availability uncertainty may increase need for conventional generators, further adding to issue of conventional generator constraints
  - Correlation between wind availability and electric load
  - Availability of transmission capacity, especially if wind resource is far from load centers
- Some systems with high wind penetration currently curtail wind for these and other reasons

# Wind Curtailment

## European Power Systems

- European power systems have relatively high wind penetration ( $\sim 2/3$  of world capacity) and many curtailment issues
- Denholm and Margolis (2007) and Porter *et al* (2007) cite several examples:
  - Frequent curtailments on cold windy nights in Denmark due to low loads and reliance on combined heat and power thermal generators with minimum generation constraints
  - Spain curtailed wind generation in 2004 when it was above 12% of demand due to local grid constraints
  - In Germany, E.On Netz implemented “generation management” program in 2003 to curtail wind in Schleswig-Holstein and Lower Saxony regions, and will not allow new wind farms to interconnect unless they participate in program

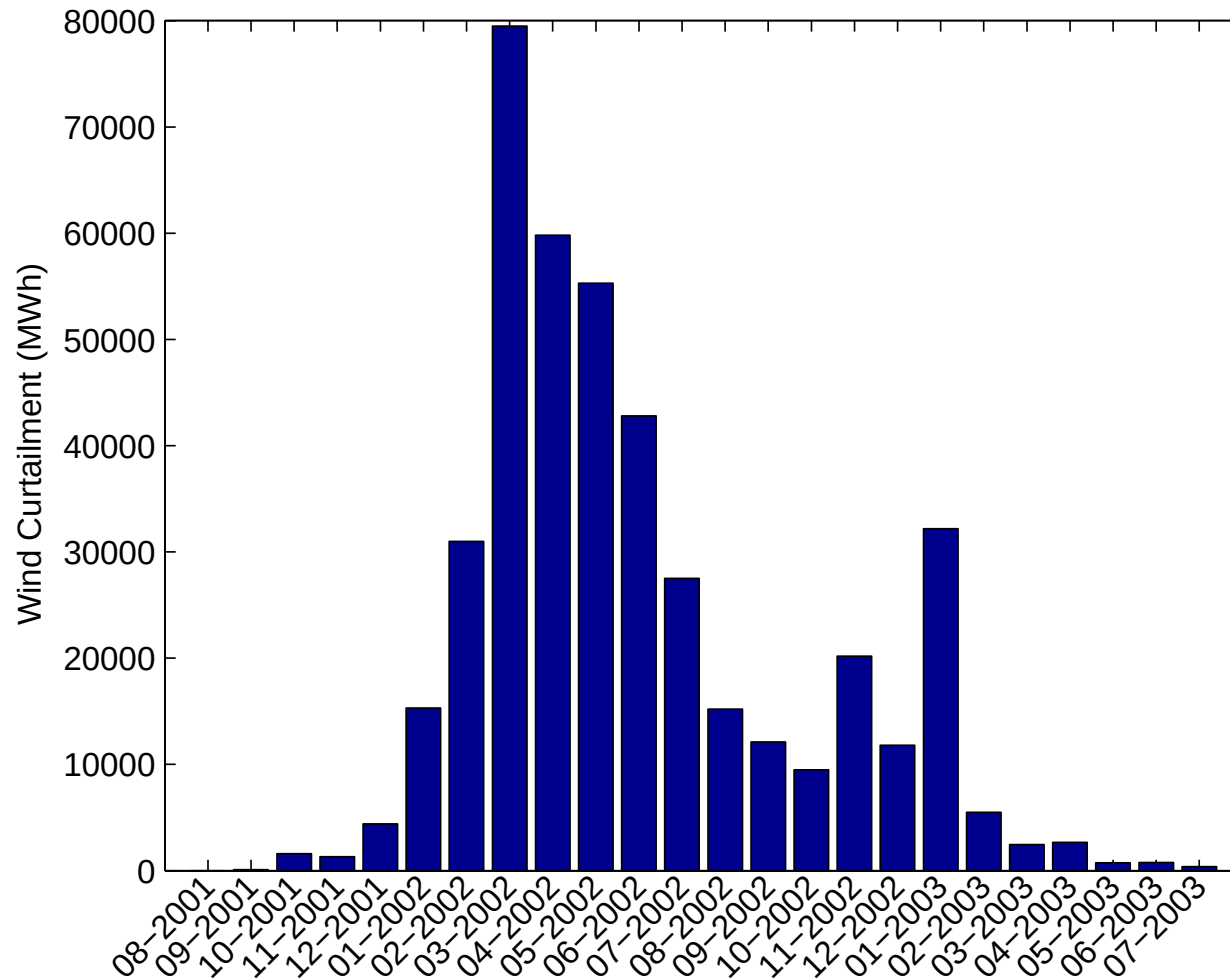
# Wind Curtailment

## Texas Power System

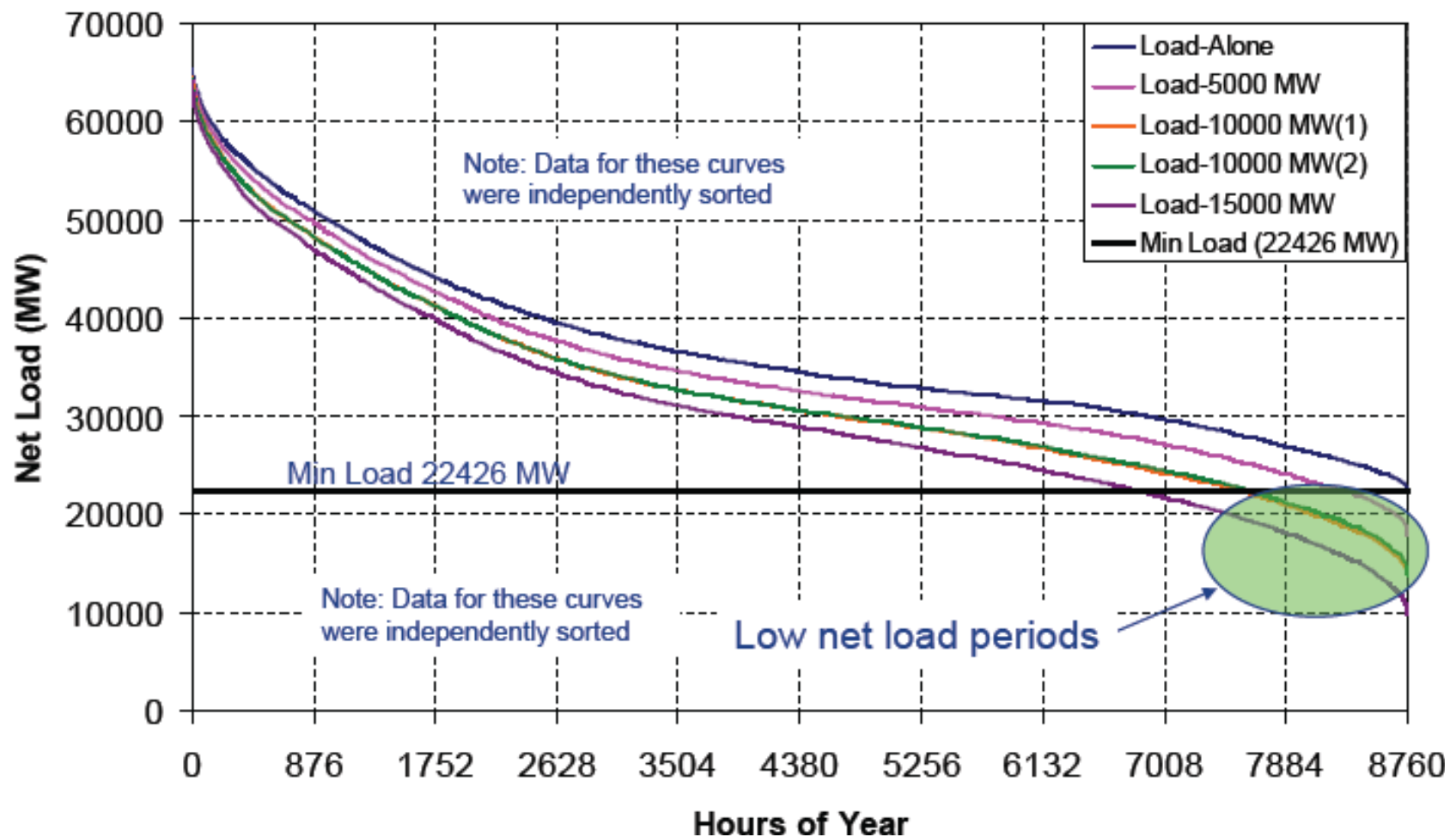
- In the US, Texas has relatively high wind penetration, especially in the west, and has similarly run into curtailment issues:
  - In 2002, 758 MW of wind in the McCamey area with only 400 MW of transmission capacity resulted in 380,000 MWh of curtailment valued at ~\$21.4 million
  - Recent GE wind integration study shows that even without transmission limits, thermal generator minimum load constraints could require curtailment with as little as 5 GW of wind
    - Further confounded by wind generation being somewhat negatively correlated with load, with average wind output being double during low load hours
    - Also predicts higher ancillary service requirements due to added supply uncertainty

# Wind Curtailment Texas Power System

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# Wind Curtailment Texas Power System



# Introducing Demand Response

- Real-time pricing (RTP) may help alleviate wind curtailment issues by:
  - Plateauing load peaks and reducing the number of ramp-constrained units during shoulder periods
  - Increasing off-peak and overnight loads to reduce the impact of thermal generator minimum load constraints
  - Using locational prices to increase demand in a region with wind resource available but exports constrained
- We model the extent to which RTP would increase wind utilization
- Show that RTP:
  - Results in increases in wind utilization
  - Can be effective if applied to only commercial and industrial (C&I) customers

# Modeling Approach

## Overview

- Use unit commitment (UC) models to represent day-ahead (DA) and real-time (RT) commitment and dispatch of Texas (ERCOT) system for a sample of 165 days in 2005
  - DA model has hour-long time steps, RT 15-minute intervals
  - DA uses forecasts of wind, load, and transmission availability; RT uses actual values and assumes unit commitments are fixed based upon DA model
  - DA assumes a 9% reserve requirement, half of which must be met by spinning reserves (the rest can use non-spinning)
  - Assume forecasted DA wind schedules may be derated in AS requirement to account for increased AS requirements due to supply uncertainty

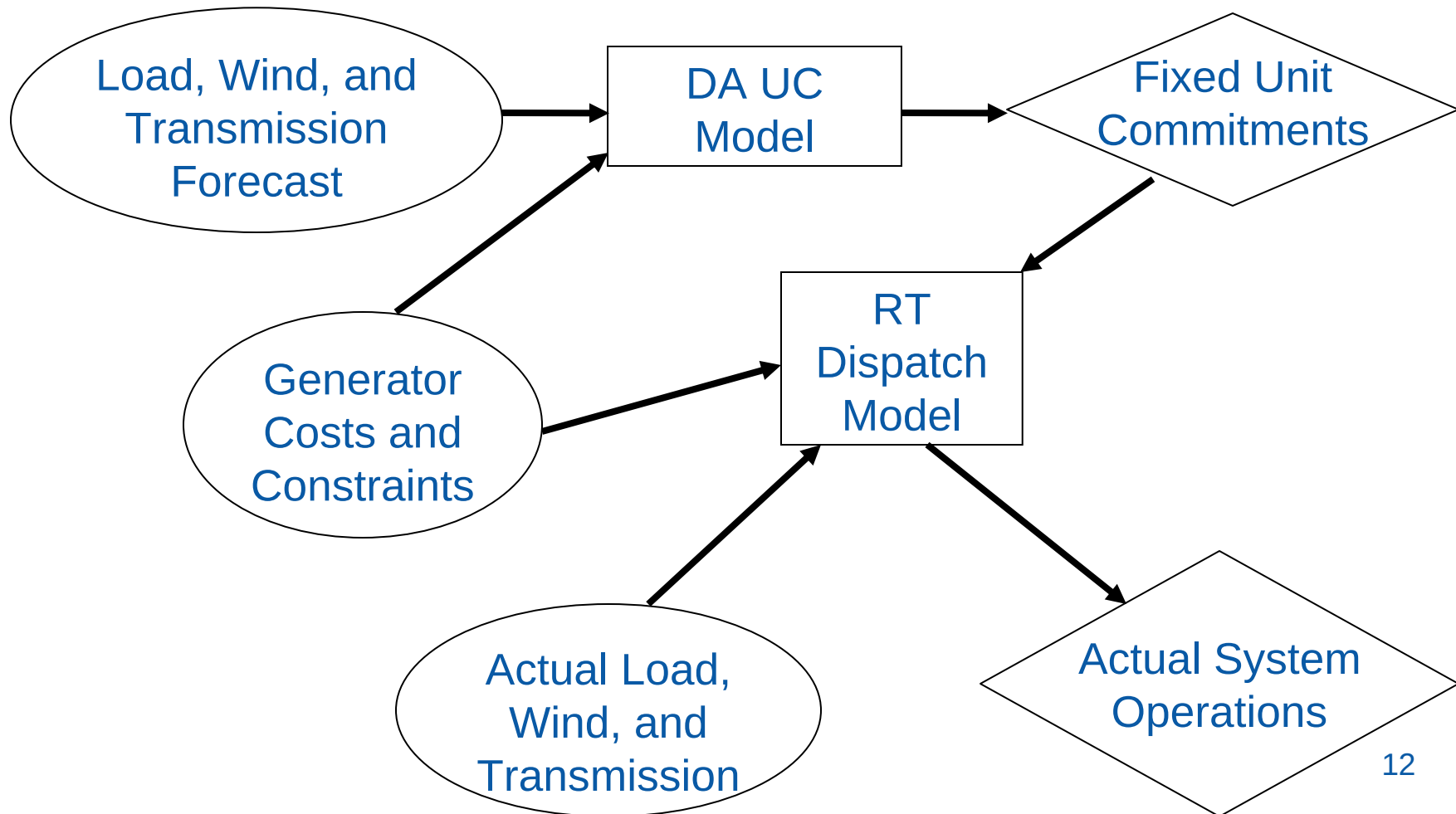
# Modeling Approach

## Model Formulation

- DA model formulated choose the operation of conventional and wind generators to maximize social welfare (consumer surplus minus generation cost) subject to constraints on unit and system operations:
  - Load balance
  - AS requirements
  - Transmission limits (ERCOT's zonal DC power-flow)
  - Minimum and maximum generation of each unit
  - Ramp limits of each unit
  - Minimum up and down times units are started and stopped
- RT model is same, except commitments are fixed, actual (not forecasted) data used, and 15-minute as opposed to hourly timestep

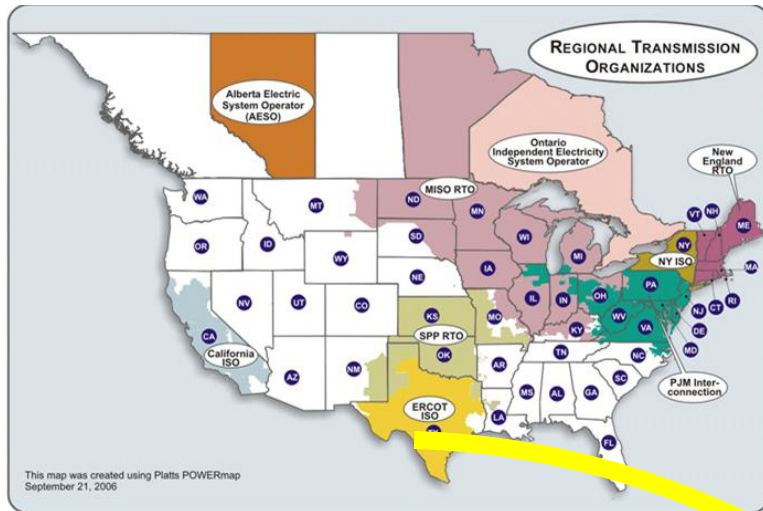
|                              |                                                                                                                  |                     |                               |
|------------------------------|------------------------------------------------------------------------------------------------------------------|---------------------|-------------------------------|
| $\max_{q,w,sp,ns,u,s,h,e,l}$ | $\sum_t \left( \sum_z \int_0^{l_{z,t}} p_{z,t}(x) dx - \sum_i c_i(q_{i,t}) + N_i u_{i,t} + SU_i s_{i,t} \right)$ | $\left. \right\}$   | Maximize surplus              |
| $s.t.$                       | $l_{z,t} = \sum_{i \in Z} q_{i,t} + \sum_{\sigma \in Z} w_{\sigma,t} - e_{z,t}$                                  | $\forall z,t$       | $\left. \right\}$             |
|                              | $\sum_z e_{z,t} = 0$                                                                                             | $\forall t$         | $\left. \right\}$             |
|                              | $\sum_i (q_{i,t} + sp_{i,t}) + \sum_{\sigma} \rho w_{\sigma,t} \geq 1.045 \sum_z l_{z,t}$                        | $\forall t$         | $\left. \right\}$             |
|                              | $\sum_i (q_{i,t} + sp_{i,t} + ns_{i,t}) + \sum_{\sigma} \rho w_{\sigma,t} \geq 1.09 \sum_z l_{z,t}$              | $\forall t$         | $\left. \right\}$             |
|                              | $-TTC_{\lambda,t} \leq \sum P TDF_{\lambda,z,t} e_{z,t} \leq TTC_{\lambda,t}$                                    | $\forall \lambda,t$ | $\left. \right\}$             |
|                              | $K_i^- u_{i,t} \leq q_{i,t}, \quad q_{i,t} + sp_{i,t} \leq K_i^+ u_{i,t}$                                        | $\forall i,t$       | $\left. \right\}$             |
|                              | $-R_i \leq q_{i,t} - q_{i,t-1}, \quad q_{i,t} + sp_{i,t} + ns_{i,t} - q_{i,t-1} \leq R_i$                        | $\forall i,t$       | $\left. \right\}$             |
|                              | $0 \leq sp_{i,t} \leq SP_i u_{i,t}, \quad 0 \leq ns_{i,t} \leq NS_i$                                             | $\forall i,t$       | $\left. \right\}$             |
|                              | $s_{i,t} \geq u_{i,t} - u_{i,t-1}, \quad h_{i,t} \geq u_{i,t-1} - u_{i,t}$                                       | $\forall i,t$       | $\left. \right\}$             |
|                              | $\sum_{\tau=t-n_i+1}^t s_{i,\tau} \leq u_{i,t}, \quad \sum_{\tau=t-f_i+1}^t h_{i,\tau} \leq 1 - u_{i,t}$         | $\forall i,t$       | $\left. \right\}$             |
|                              | $u_{i,t}, s_{i,t}, h_{i,t} \in \{0,1\}$                                                                          | $\forall i,t$       | $\left. \right\}$             |
|                              |                                                                                                                  |                     | Conventional unit constraints |

# Modeling Approach Schematic



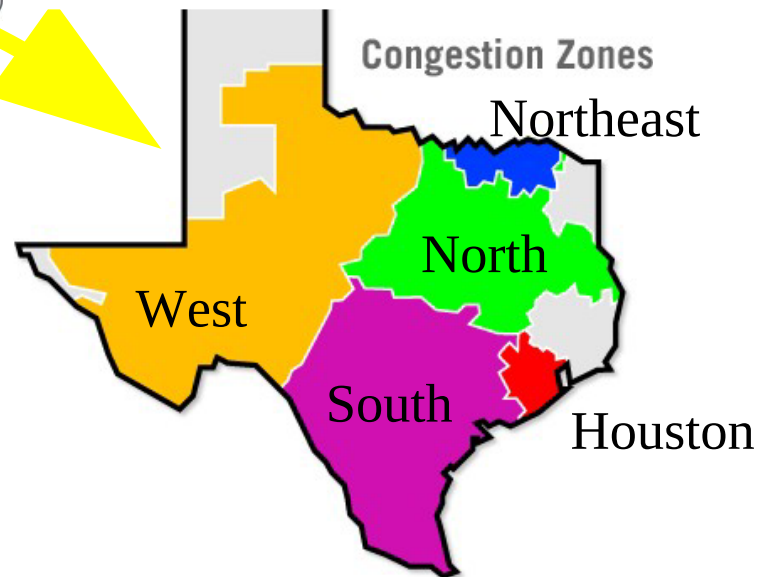
12

# ERCOT System



Population: 18 Million (85% of TX)  
Peak Load: 63,000MW  
Annual Total Energy: 300,000GWh  
Generation Capacity: 80,000MW  
Average Net Imports: None  
Annual Wholesale Market: \$20bn  
Zonal pricing in 5 congestion zones

ERCOT is an autonomous system that is not connected to the rest of the US grid (except for few DC lines) and is not under FERC jurisdiction



# Data Sources

- Generation costs (consisting of startup, spinning no-load, and stepped marginal generation) computed based upon heat rate and fuel cost, VO&M, and emission price data from Platts Energy and GED
- Generator constraint data obtained from GED
- Transmission data based on actual monitored limits and shift factors used by ERCOT
- Actual and forecasted wind generation availability based on mesoscale model data from AWS Truewind
- Included all wind projects expected to be completed by 2011 to get high wind penetration

# Data Sources

## Load

- Actual DA and RT load data obtained from ERCOT
- Models without RTP were formulated to serve fixed load at minimum cost
- Models with RTP were formulated with a stepped non-increasing demand function
  - Demand functions used an assumed own-price elasticity (used a set of values between -0.10 and -0.30)
  - Functions calibrated to go through the point defined by the actual load and the retail rate of electricity
    - Retail rate computed for three customer segments: residential, commercial, and industrial, based on EIA data for Texas
    - Load apportioned to three segments based on EIA load data
    - This calibration point differs between DA and RT models due to different forecast and actual load

15

# Impacts on Wind Generation

## Summary

- Average percentage of total load served by wind, showing slight increase with RTP

|            |       | Wind Schedule Rating |      |      |
|------------|-------|----------------------|------|------|
|            |       | 0.1                  | 0.5  | 1.0  |
| Elasticity | -0.00 | 8.89                 | 8.91 | 8.91 |
|            | -0.10 | 9.20                 | 9.25 | 9.28 |
|            | -0.20 | 9.47                 | 9.53 | 9.57 |
|            | -0.30 | 9.71                 | 9.77 | 9.83 |

# Impacts on Wind Generation

## Summary

- Average percentage of available wind utilized, showing large increase with RTP

|            |       | Wind Schedule Rating |       |       |
|------------|-------|----------------------|-------|-------|
|            |       | 0.1                  | 0.5   | 1.0   |
| Elasticity | -0.00 | 75.00                | 75.23 | 75.24 |
|            | -0.10 | 77.53                | 77.79 | 77.80 |
|            | -0.20 | 79.86                | 80.10 | 80.11 |
|            | -0.30 | 82.01                | 82.22 | 82.24 |

# Impacts on Wind Generation

## Transmission Constraints

- Low average wind utilization is due, in part, to transmission constraints limiting exports from West zone, where most wind farms are located, to eastern Texas, where load centers are
- Locational prices under RTP relieve binding transmission constraints or increase wind utilization when constraints would otherwise bind with fixed loads

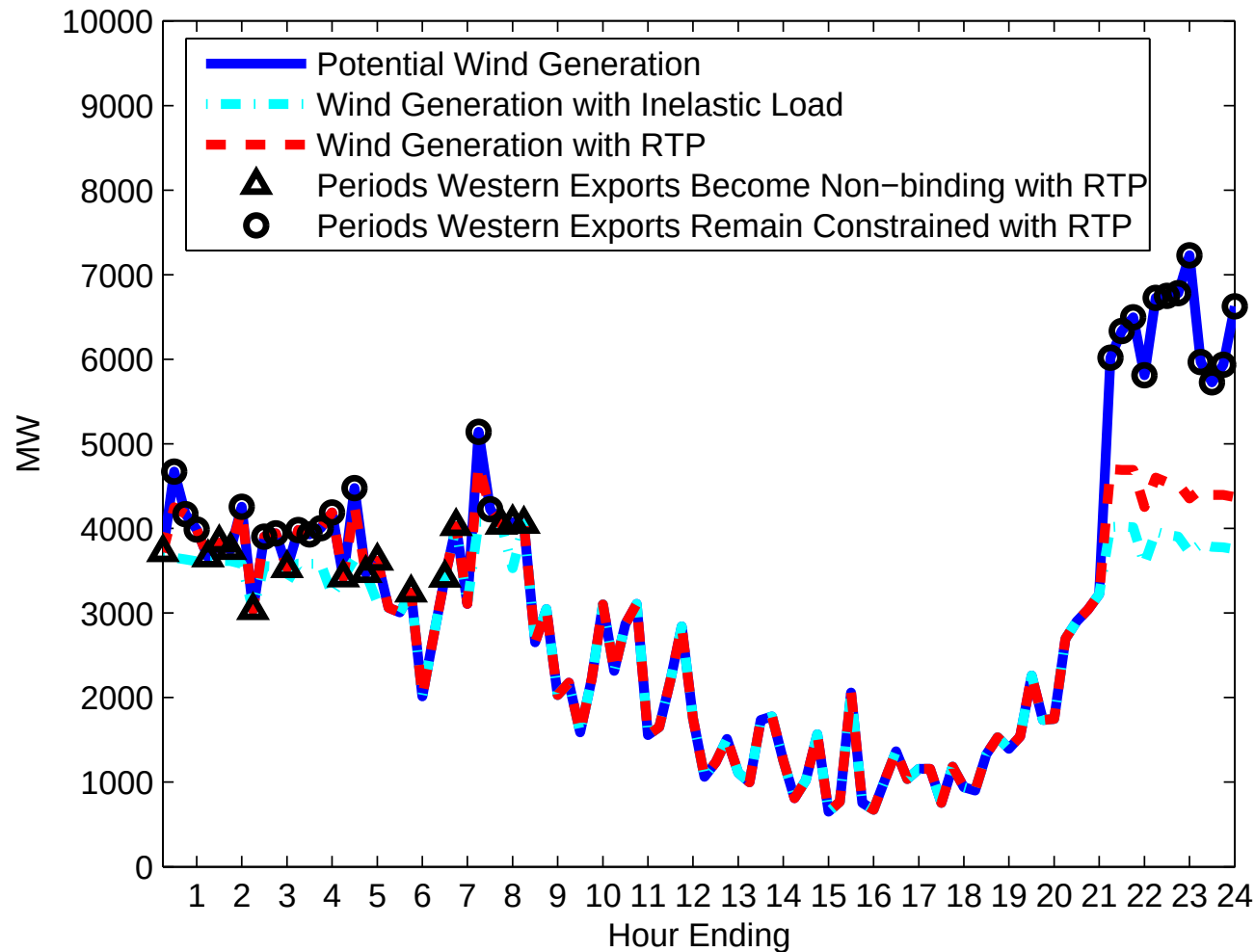
- Number of 15-minute intervals in which exports from West zone are constrained:

|            |       | Wind Schedule Rating |        |        |
|------------|-------|----------------------|--------|--------|
|            |       | 0.1                  | 0.5    | 1.0    |
| Elasticity | -0.00 | 10,432               | 10,320 | 10,323 |
|            | -0.10 | 10,364               | 9,865  | 9,698  |
|            | -0.20 | 10,361               | 9,848  | 9,775  |
|            | -0.30 | 10,208               | 9,869  | 9,878  |

- Increase in wind generation in periods in which West zone exports become unconstrained:

|            |       | Wind Schedule Rating |        |        |
|------------|-------|----------------------|--------|--------|
|            |       | 0.1                  | 0.5    | 1.0    |
| Elasticity | -0.10 | 1,003                | 7,154  | 8,697  |
|            | -0.20 | 1,408                | 9,256  | 11,686 |
|            | -0.30 | 804                  | 11,528 | 13,356 |

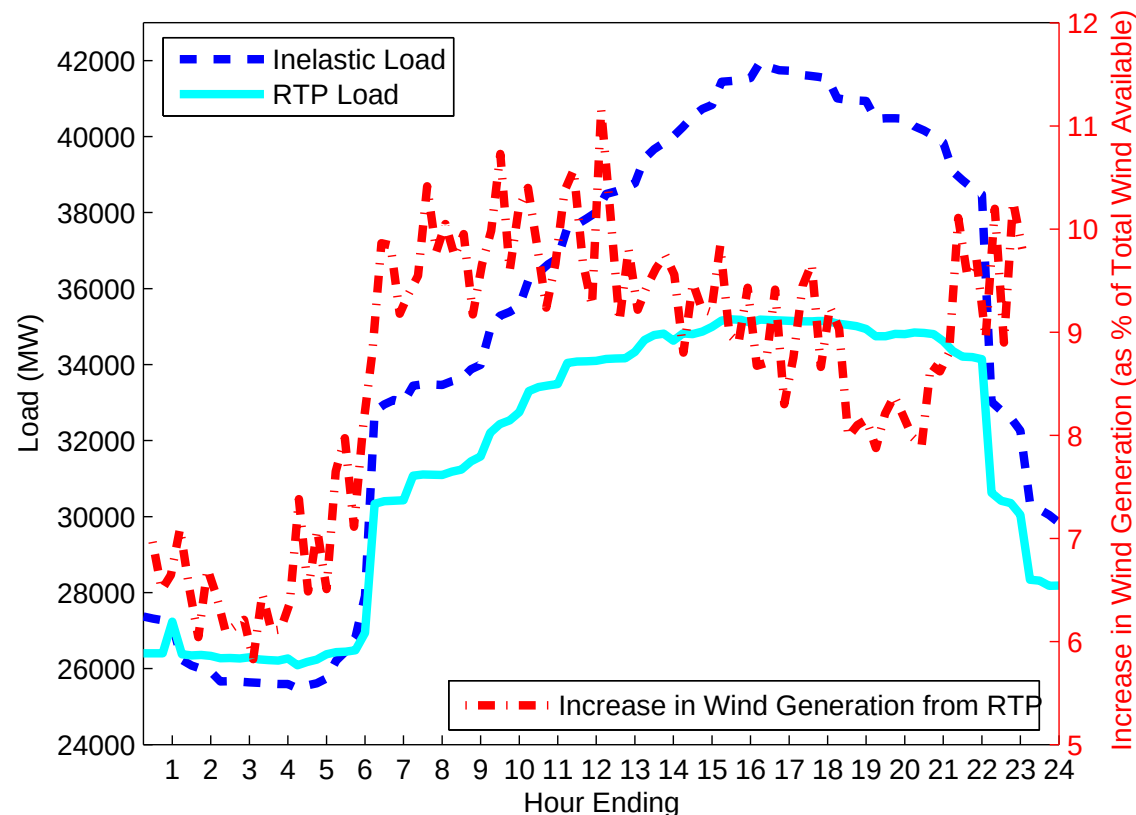
- Even when transmission constraints remain binding, RTP can still increase wind generation by increasing demand on the “export side” of the constraint



# Impacts on Wind Generation

## Ramping Constraints

- RTP plateaus the load peak, reducing conventional generator ramp constraints during shoulder periods
  - $E_{\lambda}$



- Number of ramp-down-constrained conventional generators per hour

| Hour  | Elasticity |       |
|-------|------------|-------|
|       | -0.00      | -0.30 |
| 2     | 23         | 15    |
| 3     | 12         | 0     |
| 4     | 2          | 1     |
| 19    | 1          | 0     |
| 20    | 1          | 6     |
| 21    | 2          | 0     |
| 22    | 12         | 11    |
| 23    | 50         | 22    |
| 24    | 9          | 8     |
| Total | 112        | 63    |

- Number of ramp-up-constrained conventional generators per hour

| Elasticity |       |       |      |       |       |
|------------|-------|-------|------|-------|-------|
| Hour       | -0.00 | -0.30 | Hour | -0.00 | -0.30 |
| 4          | 3     | 0     | 13   | 2     | 13    |
| 5          | 2     | 0     | 14   | 0     | 11    |
| 6          | 8     | 1     | 15   | 4     | 11    |
| 7          | 21    | 4     | 16   | 3     | 14    |
| 8          | 32    | 12    | 17   | 4     | 8     |
| 9          | 31    | 7     | 18   | 1     | 6     |
| 10         | 8     | 9     | 22   | 2     | 0     |
| 11         | 18    | 13    | 23   | 6     | 0     |
| 12         | 2     | 17    |      |       |       |
| Total      | 147   | 126   |      |       |       |

# Impact of RTP For C&I Customers

- An impediment to implementing RTP is high price of deploying interval meters and developing a means of communicating RT price information to customers
  - There are also potentially issues of bill volatility and loss of cross-subsidies, especially for residential customers
- An alternative is to restrict RTP to commercial and industrial (C&I) customers, keeping residential customers on a fixed tariff
  - Would cover a large portion of load with lower meter installation costs, *e.g.* 62% of load in Texas in 2005
  - Some states, *e.g.* California, already require interval meters for large loads
- Repeated analysis with C&I customers on RTP only<sup>24</sup> and fixed residential loads

- Average percentage of total load served by wind with C&I customers on RTP only:

| Elasticity | Wind Schedule Rating |      |      |
|------------|----------------------|------|------|
|            | 0.1                  | 0.5  | 1.0  |
| -0.10      | 9.14                 | 9.19 | 9.22 |
| -0.20      | 9.37                 | 9.43 | 9.46 |
| -0.30      | 9.59                 | 9.64 | 9.69 |

- Average percentage of total load served by wind with all customers on RTP:

| Elasticity | Wind Schedule Rating |      |      |
|------------|----------------------|------|------|
|            | 0.1                  | 0.5  | 1.0  |
| -0.00      | 8.89                 | 8.91 | 8.91 |
| -0.10      | 9.20                 | 9.25 | 9.28 |
| -0.20      | 9.47                 | 9.53 | 9.57 |
| -0.30      | 9.71                 | 9.77 | 9.83 |

- Average percentage of available wind generation utilized with C&I customers on RTP only:

|            |       | Wind Schedule Rating |       |       |
|------------|-------|----------------------|-------|-------|
| Elasticity |       | 0.1                  | 0.5   | 1.0   |
|            | -0.10 | 76.62                | 76.88 | 76.90 |
|            | -0.20 | 78.14                | 78.38 | 78.39 |
|            | -0.30 | 79.59                | 79.82 | 79.83 |

- Average percentage of available wind generation utilized with all customers on RTP:

|            |       | Wind Schedule Rating |       |       |
|------------|-------|----------------------|-------|-------|
| Elasticity |       | 0.1                  | 0.5   | 1.0   |
|            | -0.00 | 75.00                | 75.23 | 75.24 |
|            | -0.10 | 77.53                | 77.79 | 77.80 |
|            | -0.20 | 79.86                | 80.10 | 80.11 |
|            | -0.30 | 82.01                | 82.22 | 82.24 |

- Placing only C&I customers, who represent 62% of the load, yields much of the potential gains from placing all customers on RTP:
  - More than 64% of the gains in wind generation as a fraction of total load
  - More than 80% of the gains in utilization of available wind generation
- C&I customers have lower retail rates than residential
  - Placing residential customers on RTP tends to increase residential loads in all hours since there is a smaller fraction of on-peak periods in which real-time price is higher than the high residential retail rate
  - Placing C&I customers tends to cause “load-shifting” with decreases in on-peak and increases in off-peak loads due to real-time price being higher and lower than their retail rate, respectively

# Summary and Conclusions

- Operating constraints on conventional generators and electric power systems can impact use of wind generation (as well as other variable renewable energy sources)
- RTP can alter the load pattern, reduce binding generator and transmission constraints, and increase wind generation
- Placing C&I customers on RTP only can reap much of the gains, at lower implementation costs
  - This result is dependent, to some extent, on the rate structure in Texas, and may not apply to other jurisdictions