Evaluating the Impacts of Real-Time Pricing on the Usage of Wind Generation

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***Abstract*—One of the impediments to large-scale use of wind generation within power systems is its non-dispatchability and variable and uncertain real-time availability. Operating constraints on conventional generators such as minimum generation points, forbidden zones, and ramping limits as well as system constraints such as power flow limits and ancillary service requirements may force a system operator to curtail wind generation in order to ensure feasibility. Furthermore, the pattern of wind availability and electricity demand may not allow wind generation to be fully utilized in all hours. One solution to these issues, which could reduce these inflexibilities, is the use of real-time pricing (RTP) tariffs which can both smooth-out the diurnal load pattern in order to reduce the impact of binding unit operating and system constraints on wind utilization, and allow demand to increase in response to the availability of costless wind generation. We use and analyze a detailed unit commitment model of the Texas power system with different estimates of demand elasticities to demonstrate the potential increases in wind generation from implementing RTP.**

of renewable generation and reduce it elsewhere can increase wind utilization in a transmission-constrained system.

Over the last few years a number of authors have advocated real-time pricing (RTP) of electricity, in which retail electric prices change frequently to reflect changes in the supply of electricity and the cost of serving load (they typically suggest rates change hourly or sub-hourly since the cost of service can vary significantly on this timescale). These authors have typically advocated RTP for standard economic reasons, such as increasing social welfare by having consumers face the actual marginal cost of electricity service, or decreasing generators' market power by making demand more elastic. Reference [5] suggests that the demand response resulting from RTP could have lessened the severity of the 2000-2001 California electricity crisis, while [6] and [7] simulate the efficiency gains from RTP. These and other simulations generally show that RTP has the effect of changing the diurnal load pattern by flattening peaks and shifting those loads to off-peak hours, since peak prices tend to be higher than the fixed retail rates customers would otherwise face whereas off-peak prices are lower—which is the exact change in the load pattern which may increase system flexibility and allow greater use of renewable energy resources. The use of locational prices can help alleviate transmission bottlenecks and further 're-shape' the load pattern in different parts of the transmission network to more-closely follow the availability of renewable energy.

In this paper we use a detailed unit commitment model with historical system, market, and wind availability data from 2005 in the Electricity Reliability Council of Texas (ERCOT) system, to simulate the potential for RTP to increase the utilization of large-scale wind farms. We demonstrate that introducing demand response increases both the percentage of total load which is served by wind generation, and the assumed to only make binding commitments as opposed to dispatches. Both the day-ahead unit commitment and real-time dispatch models were formulated as mixed-integer linear programs (MILPs) using GAMS and solved using cplex 9.0.

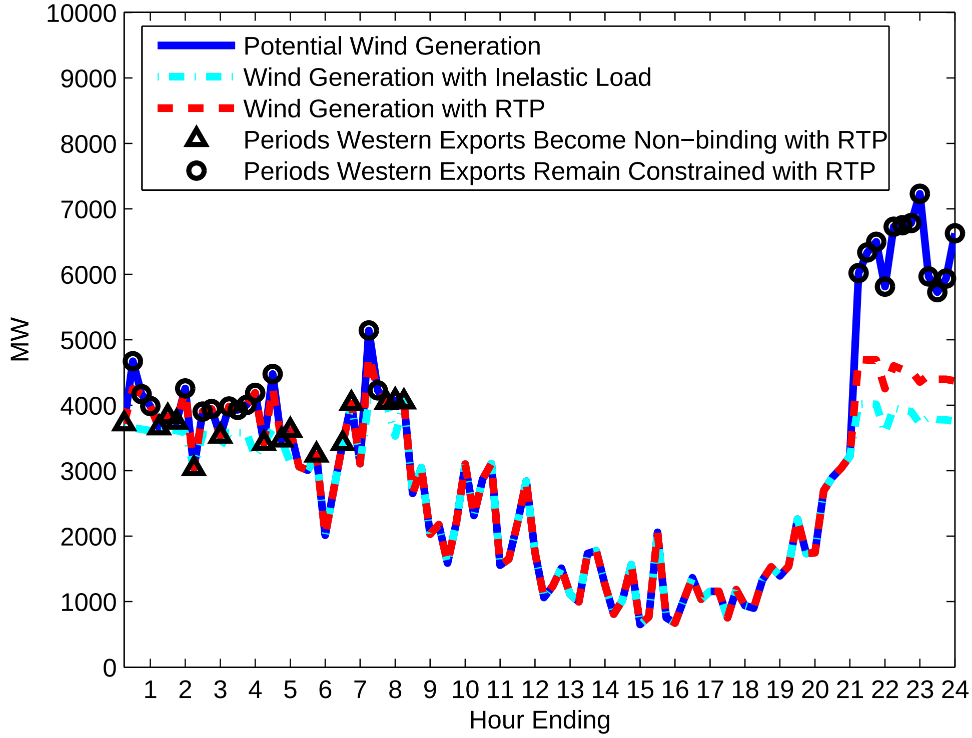
Generator costs were modeled as consisting of three parts—a startup cost, which is incurred whenever a generator is started up; a spinning no-load cost, which is incurred whenever a generator is online; and a non-decreasing stepped variable generating cost function. Generator capacities, minimum generating points, ramp rates, AS capabilities, minimum up and down times, and must-run requirements were included in the model formulation as well. Generator costs were computed using heat rate values, fuel and emission permit prices, and variable operation and maintenance costs obtained from Global Energy Decisions and Platts Energy. Generator constraint parameters were also obtained from the same sources.

Power flows within the network were represented using the linearized zonal DC power-flow model used in ERCOT's congestion management system—consisting of five zones and six commercially significant constraints (CSCs). Power transfer distribution factors (PTDFs) between zonal injections and CSCs, and total transfer capacities (TTCs) on each CSC were obtained from ERCOT. The PTDF data consisted of monthly averages, whereas TTCs were the monitored limit on each CSC, reported at 15-minute intervals.

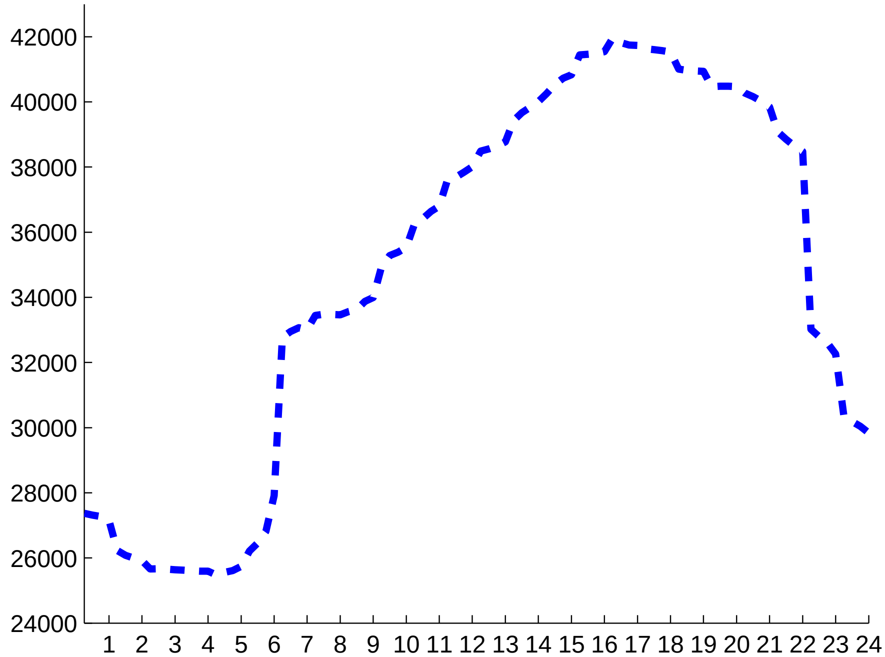
Simulations without RTP were conducted using actual historical load data, which were obtained from the Public Utility Commission of Texas (PUCT). The PUCT data included both day-ahead load forecasts as well as actual real-time loads reported at 15-minute intervals. Simulations with RTP were conducted by constructing a price-elastic demand function, and formulating the unit commitment objective to maximize social surplus as opposed to minimizing cost. Following [7] we assume that cross-price elasticities between demands in different periods are zero.[5] As done in [10], we construct the demand function by assuming a fixed elasticity and calibrating the demand function so it goes through the locus defined by the actual historical load and the retail price of electricity—since the actual historical loads reveal demand for electricity at the historical retail price. Because different customer types face different retail prices, loads were broken down into industrial, commercial, and residential segments, based on**s**

III. Simulation Results

Tables I and II summarize the results of our simulations, showing wind utilization averages for the days simulated. Table I shows the average percentage of potential wind generation that is actually dispatched in real-time for different demand elasticities and day-ahead wind schedule ratings, whereas table II reports the average percentage of total load that is served by wind generation. Our results show substantive increases of up to 7% in the usage of potential wind generation, which translates into an increase of up to 1%



10000
9000
8000
7000
6000
5000
4000
3000
2000
1000
0
MW
Potential Wind Generation
Wind Generation with Inelastic Load
Wind Generation with RTP
Periods Western Exports Become Non−binding with RTP
Periods Western Exports Remain Constrained with RTP
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour Ending


42000
40000
38000
36000
34000
32000
30000
28000
26000
24000
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24

- $sp_{i,t}, ns_{i,t}$: spinning and non-spinning reserves provided by generator $i \in I$ in period $t \in T$, respectively
- $u_{i,t}, s_{i,t}, h_{i,t}$: binary variables indicating if unit $i \in I$ is up, started-up, and shutdown in period $t \in T$, respectively
- $g_{w,t}$: wind generation provided by wind generator $w \in$ in period $t \in T$
- ${}_{z,t}$: load served in transmission zone $z \in Z$ in period $t \in T$
- ${}_{z,t}$: net exports from transmission zone $z \in Z$ in period $t \in T$

The problem is formulated as maximizing social surplus:

$$\max \sum_{z,t} \int_{0}^{l_{z,t}} p_{z,t}(x)dx -$$
$$\left(\sum_{i,t} C_i(q_{i,t}) + N_i u_{i,t} + SU_i s_{i,t} \right);$$

subject to the following constraints:

- zonal load-balance ($\forall\ z \in Z, t \in T$):

$$ {}_{z,t} = \sum_{i \in I(z)} q_{i,t} + \sum_{w \in W(z)} g_{w,t} - {}_{z,t}, $$

  where $I(z)$ and (z) are conventional and wind generators located in zone $z \in Z$;
- no net exports ($\forall\ t \in T$):

$$\sum_{z \in Z} e_{z,t} = 0;$$

- total and spinning reserve requirements ($\forall\ t \in T$):

$$\sum_{w \in W} g_{w,t} + \sum_{i \in I}(q_{i,t} + sp_{i,t} + ns_{i,t}) \geq (1 + {}^{n}) \sum_{z \in Z} {}_{z,t}$$
$$\sum_{w \in W} g_{w,t} + \sum_{i \in I}(q_{i,t} + sp_{i,t}) \geq (1 + {}^{s}) \sum_{z \in Z} {}_{z,t};$$

- conventional generator minimum and maximum generation bounds ($\forall\ i \in I, t \in T$):

$$K_i^- u_{i,t} \leq q_{i,t}$$
$$q_{i,t} + sp_{i,t} \leq K_i^+ u_{i,t}$$
$$q_{i,t} + sp_{i,t} + ns_{i,t} \leq K_i^+;$$

- conventional generator AS bounds ($\forall\ i \in I, t \in T$):

$$0 \leq sp_{i,t} \leq$$

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