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Wind Power and Electricity Markets

A living summary of markets and market rules for wind energy and capacity in North America

Prepared by the Utility Wind Integration Group

Market Operation and Transmission Policy Best Practices Users Group
Information compiled through September 21, 2007

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UWIG plans to update this information as regional electricity markets evolve

Wind Power and Electricity Markets

The following table addresses market rules for wind power purchase in key regions of North America. Table entries are responses to the following questions:

- **Scheduling in Energy Markets:** How is wind energy scheduled and procured?
- **Imbalance Settlement:** How are wind energy imbalances settled – either through a balancing market or another settlement procedure?
- **Ancillary Services:** How are wind plants' ancillary service needs and costs recognized?
- **Wind Forecasting:** What role does wind forecasting play?
- **Capacity Calculation:** How is capacity value or capacity credit for wind plants calculated? Is there a distinction between capacity values for planning reserves (months and years time frame) and operating reserves (same-day to next-day)? If so, what is it?
- **Capacity Recognition:** How is capacity value recognized in capacity obligations and capacity markets?

As a baseline for the table, FERC Order 888's discussion of these questions, as updated in Order 890, is summarized here:

Imbalance Settlement: Energy imbalance charges may apply if energy deliveries differ by more than +/- 1.5% from advance schedules. Under Order 888, actual penalties or payments for underdeliveries/overdeliveries left to discretion of transmission provider, but may be substantial. Under Order 890, FERC requires that imbalances of less than or equal to 1.5% of scheduled energy, or up to 2 MW be netted monthly and settled at the transmission provider's incremental or decremental cost. Imbalances of between 1.5% and 7.5% of scheduled energy, or between 2 and 10 MW (whichever is larger), are settled at 90% of decremental costs and 110% of incremental costs. Imbalances greater than 7.5% (or 10 megawatts, whichever is larger) would be settled at 75 percent of the system decremental cost for overscheduling imbalances or 125 percent of the incremental cost for underscheduling imbalances. Intermittent resources, however, would be settled at 90% of decremental costs and 110% of incremental costs for imbalances greater than 7.5% or 10 megawatts.

Ancillary Services: Transmission provider required to offer scheduling and billing services and to act as purchasing agent for transmission customers that need ancillary services.

Wind Forecasting, and Capacity Calculation and Recognition

	PJM	NYISO	ISO-NE	Ontario IESO
Scheduling in Energy Markets	Day-ahead scheduling; wind usually submits zero. Takes real-time LMP for energy provided. If a capacity resource, wind must bid at least its capacity value (i.e., 20%) in the day-ahead market	Day-ahead scheduling available but not required. Up to 1000 MW: compensated for all energy produced and exempt from under-generation penalties. Developing rules to extend beyond current 1000 MW limit.	Day-ahead bid option; or self schedule day before. Settle at real-time nodal price.	Generators required to submit energy forecasts. Energy from renewable intermittent generation accepted as generated—wind resources are treated as price-takers in the hourly spot market. Day-ahead market under development.
Imbalance Settlement	Operating reserve deviation charges apply on differential between day-ahead and RT levels; (5 MW dead band; differentials less than this incur no deviation charges).	If scheduling day-ahead, buy out shortfalls at real-time LBMPs.	If deviations, notify ISO. No imbalance charges.	No penalties for settlement imbalances but penalties can be assessed for not meeting forecasting obligations.
Ancillary Services	Wind doesn't participate in ancillary service markets. No impact yet on the level of ancillary-services requirements in the market.	Wind doesn't participate in ancillary service markets, but is not precluded from seeking qualification to do so.	Operating reserves market. Considering products to mitigate variability.	Ancillary service costs, such as automatic generator control and operating reserves, are borne by loads in the market. Wind connections are required to satisfy interconnection standards, such as low-voltage ride-through and reactive requirements, for reliability.

	PJM	NYISO	ISO-NE	Ontario IESO
Wind Forecasting	No role so far.	Uses persistence forecasting. Pursuing implementation of a centralized wind forecasting system for day-ahead and real-time.	No role so far. Likely to change with higher penetrations.	Wind operators provide forecasts. Forecasts must be provided by 11 a.m., covering every hour of the remainder of that day and the next day. Wind operators can provide updates. Real-time scheduling uses persistence. Under review by the Wind Integration Working Group.
Capacity Calculation	3-yr rolling average, hours ending 3-to-6 pm output, 6/1 through 8/31; default value: 20% of net plant rating until actual operating data become available. Wind must bid into day-ahead market to be a capacity resource and receive capacity market revenues.	Wind generator's capacity factor between 2 p.m. and 6 pm from June through August and 4 pm through 8 pm from December through February. Intermittent resources not required to participate in day-ahead market to receive capacity revenues.	Historic capacity factor, adjusted for maintenance. Under forward capacity auction, wind generators can request capacity credit up to nameplate capacity, supported by site-specific data. Actual capacity factor data will replace requests from wind generators.	For capacity assessments, presently using 10% for long-term forecasting (e.g., seasonal); zero percent for 1 to 34 days ahead. Wind operators provide forecasts for current day and next day on a hourly market schedule. These are also under review based on experience and assessment at the Wind Integration working group.
Capacity Recognition	LSEs may procure capacity bilaterally, self-supply, or purchase capacity credits from PJM capacity auctions. PJM implemented forward capacity auctions in 2007.	LSEs may self-supply, purchase bilaterally, or purchase capacity in monthly auctions or biennial six-month capacity auctions.	First auction to take place in February 2008 for the procurement period beginning with the 2010-2011 Power Year.	No capacity markets in Ontario at this time.

	MISO	SPP	ERCOT	CAISO
Scheduling in Energy Markets	If intermittent resource is designated as a 'capacity resource', then it has a must offer obligation in the day-ahead market and the reliability assessment commitment (RAC) process. Otherwise, the resource can – but has no obligation to – offer into the markets.	No centralized energy market; transactions done on bilateral basis. SPP implemented a central energy imbalance market on February 1, 2007; wind is forecasted and scheduled as any other resource.	Wind scheduled as all other resources, as part of a Qualified Scheduling Entity's (QSE) portfolio. No centralized energy market; transactions done on bilateral basis. Plans to adopt LBMP in 2009.	Wind Energy is sold to Load Serving Entities via QF or Bi-Lateral contracts. The Scheduling Coordinator (SC) for the wind energy can either make its best forecast of energy production and schedule it in the Day-Ahead or Hour-Ahead Market, or it can participate in the CAISO PIRP (Participating Intermittent Resource Program) Program. In PIRP, the wind generation forecast is used as the energy schedule in the Hour-Ahead Market. LMP-based market scheduled to launch on March 31, 2008. Under that market, the wind generator will also be able to sell the energy into the real time market if they are willing to accept the real time market price. The energy will still be scheduled hour ahead (defined as 75 minutes ahead) but it could be a price taker.

	MISO	SPP	ERCOT	CAISO
Imbalance Settlement	If resource designated by market participant as 'intermittent', then is price taker in the real-time market with no uninstructed deviation penalties. Wind generators subject to imbalance charges if participating in the day-ahead market.	Real-time balancing market launched in February 2007. The real-time balancing market is an offer-based market, and locational prices will be based on the resource offers submitted to SPP. Order 888 tariffs currently in effect, to be replaced by Order 890 tariffs when finalized.	Any imbalances are settled at zonal Market Clearing Price of Energy (MCPE). No take back of payment for over generation if within + or – 50% of scheduled capacity. Wind-only QSEs are exempt from charges due to deviation from submitted energy schedules.	If the SC has opted to use the PIRP program, then hourly deviations are settled at a monthly weighted average market-clearing price and accumulated for monthly average of energy imbalances. If the hourly forecast of wind energy production is accurate, then the cumulative amount of imbalance energy charges at the end of the month is a relatively small amount of dollars. If the SC has not opted to use the PIRP program, then they are subject to the same 10-minute imbalance energy charges as any other SC.
Ancillary Services	MISO does not offer ancillary services directly, since MISO is not a control area operator. MISO is developing an ancillary services market that is scheduled to begin in June 2008.	SPP does not offer ancillary services directly, since SPP is not a control area operator. As under Order 888, SPP can act as the transmission customer's agent to procure ancillary services.	All ancillary service costs are borne by loads, not generation. The impact of increasing installed wind generation on the need for ancillary services is being studied.	Wind doesn't participate in ancillary services market. Participation in the PIRP program specifically excludes the wind generator from participating in the ancillary services market.

	MISO	SPP	ERCOT	CAISO
Wind Forecasting	Under consideration.	No role so far.	A centralized wind forecasting methodology is being developed and is planned to be included as part of the nodal market transition in 2009.	Participants in the PIRP program pay small amount toward forecasts developed for CAISO on ongoing basis. Exports out of CAISO control area subject to export fee. CAISO working with stakeholders to make design improvements, and perhaps to derive new fee structure for PIRP.
Capacity Calculation	Wind given a 15% capacity value for transmission planning purposes.	Output level that wind plant equals or exceeds during 85% of period defined by top 10% of load hours.	Wind generation is included in capacity reserve margin calculations at 8.7% of nameplate capacity, based on stochastic analysis of effective load-carrying capability.	Under CPUC rules, three-year rolling average of the monthly average of wind energy generation between 12 and 6 p.m. for the months of May through September.
Capacity Recognition	Payments received in bilateral market for capacity if designated as a Network Resource in MISO meeting Network Load. As a designated Network Resource, must offer capacity into the Day-Ahead Market.	SPP does not operate a capacity market. Capacity demonstration is the responsibility of the entity owning, operating, and/or contracted for wind farm capacity.	There are no payments received by any generation for capacity in ERCOT.	No payments received for capacity—just credit toward overall system reliability through reserve margins.

	Alberta Electric System Operator
Scheduling in Energy Markets	Wind generators do not submit offers into the energy market and are price-takers. The AESO is proposing through the Market and Operational framework that wind generators must provide a forecast to the AESO and will not offer into the energy markets.
Imbalance Settlement	No penalties.
Ancillary Services	The AESO procures ancillary services such as regulating reserve through a day-ahead ancillary service market. The AESO has proposed in the Market and Operational framework that additional regulating reserves or equivalent type service would be procured to supplement the energy market ramp rate for forecast wind power ramps. The costs of these additional ancillary services will be paid for by load

	Alberta Electric System Operator
Wind Forecasting	<p>AESO launched a Wind Forecasting Pilot Project in order to develop forecasting methods and requirements for the Alberta system. The pilot project will specifically:</p> <ul style="list-style-type: none"> • Test multiple wind power forecasting methods and providers • Identify the most effective method(s) to forecast wind power in Alberta • Identify the most effective providers of wind power forecasts • Educate industry on the capabilities of wind power forecasting in Alberta <p>Once requirements are established wind generators will be required comply with the requirements and participate in wind power forecasting.</p>
Capacity Calculation	<p>The capacity value for wind power has been given a 20% value until further studies and investigation determine a better value or method.</p>
Capacity Recognition	<p>No capacity markets at this time.</p>