

ENERGY AMBITIONS : Can Wind Work in a LMP Market?

INTRODUCTION

This edition of ENERGY discusses the confluence of two current trends in electricity markets - the move to locational marginal pricing (LMP) and the increasing role of renewables as a resource. Although the pace of electricity market restructuring has slowed, it continues nonetheless with, for example, California slated to move to LMP in 2007. In addition, renewable portfolio standards (RPS) have been implemented by many states, with more in the midst of considering their adoption. Hence, the interaction between renewables and LMP markets will become an increasingly important area for policy makers. We discuss some of the key issues here.

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With a relatively low population density and high average wind speeds, the Republic of Ireland (RoI) is an ideal location for generating electricity using wind turbines. Accordingly, developers plan to install 985 MW of wind farm capacity by 2010, which will represent over 15% of installed capacity in the RoI.¹ At the same time, the RoI's energy regulator (the Commission for Energy Regulation or CER) has been considering a redesign of the electricity market. The CER was considering a move from the current bilateral market to a Locational Marginal Pricing (LMP) market, similar in concept to that adopted by most independent system operators (ISOs) in the U.S. However, the possible move to an LMP market raised concerns among some wind farm developers - might the new design jeopardize the RoI's renewable energy ambitions? In this edition of ENERGY, we discuss some of the main issues faced by wind farms in LMP markets and outline market design approaches that can accommodate wind while ensuring efficient market outcomes.² We limit ourselves to three economic questions:

Do intermittent generators such as wind farms need special forms of Financial Transmission Rights (FTRs)?

Can wind farms participate in the market for operating reserves?

Should all wind farms be exposed to LMPs?

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TRANSMISSION RIGHTS FOR
INTERMITTENT GENERATORS

In every trading period an LMP market generates a price for each 'node' on the network. Consequently, there is a risk that the price at a generator's node could reach a low level relative to competing generators. To manage this risk, in many LMP markets participants can buy Financial Transmission Rights or FTRs. FTRs entitle the holder to a share of the price difference between two nodes and are usually issued for a fixed capacity. For example, a generator who usually produces 50 MW of power could buy a 50 MW FTR between node A (where he is) and node B (where the electricity price is usually 'reasonable'); Table 1 illustrates these numbers. If the price at node A is \$30/MWh, and the price at node B is \$50/MWh, the value of the FTR is \$1,000/h (=50 MWh * \$20/MW). The generator receives \$1,500/h for electricity, but when the income from the FTR is accounted for, the total income is \$2,500/h, equivalent to a price of \$50/MWh – the 'reasonable' node B price.

Many FTRs are issued as an *obligation* – while the FTR owner receives income when the price at node A is below the price at node B, if the price at node A rises above the price at node B then the FTR owner must pay out on the FTR. This feature of FTRs leads to one of the first potential problems wind farms face in an LMP market. Both a thermal generator and a wind farm have an obligation to pay out on the FTR when the price at their node is high. However, the thermal generator will usually be producing electricity and selling it at the 'high' price. This income will offset the payout the generator has to make on the FTR. In contrast, if there is insufficient wind, the wind farm will not be generating, and so will receive no income to offset the FTR payout.

Consequently, there is a risk that the wind farm will actually have a negative cash flow as a result of the FTR. Table 1 illustrates the idea for two consecutive trading periods; in the first period the price at the generators' node is below the benchmark 'reasonable' price, and in the second period the price is above the benchmark price.

Table 1 Example of cash flows for a thermal plant and a wind farm with an FTR

MARKET PRICES AND FTR PAYOUT			
<i>Trading period</i>	[1]	1	2
<i>Price at benchmark node, \$/MWh</i>	[2]	50	50
<i>Price at generators' node, \$/MWh</i>	[3]	30	70
<i>FTR capacity, MW</i>	[4]	50	50
<i>Payout under FTR, \$/h</i>	[5] $\{[2]-[3]\} \times [4]$	1000	-1000

ELECTRICITY GENERATION			
<i>Thermal plant generation MWh/h</i>	[6]	50	50
<i>Wind generation MWh/h</i>	[7]	50	0

WIND FARM REVENUES			
<i>Wind revenues with the FTR, \$</i>	[8] $[7] \times [2] + [5]$	2500	-1000
<i>Wind revenues without the FTR, \$</i>	[9] $[7] \times [2]$	1500	0
<i>Value of FTR to wind farm, \$</i>	[10] $[9] - [8]$	1000	-1000

THERMAL PLANT REVENUES			
<i>Thermal plant revenues with FTR, \$</i>	[11] $[6] \times [2] + [5]$	2500	2500
<i>Thermal plant revenues without FTR, \$</i>	[12] $[6] \times [2]$	1500	3500
<i>Value of FTR to Thermal plant, \$</i>	[13] $[12] - [11]$	1000	-1000

Some wind farms in the RoI argued that they should pay less for FTRs, because of the risk of negative cash flows. In fact, as Table 1 shows, the FTR is worth exactly the same to both the thermal generator and the wind farm, and so both groups should pay the same price for an FTR (zero in the example in Table 1). The problem of negative revenues is a more real concern; on the one hand, banks or other lenders may insist that wind farms hold an FTR to reduce the risk of a drop in the LMP at their node. However, holding an FTR exposes the wind farm to negative revenues if the LMP rises during periods when the wind farm is not producing. Wind farms may find it difficult to finance projects as a result, particularly in LMP markets with very volatile prices.

One way to overcome this problem is to design a special 'wind FTR', based not on capacity, but on produced energy. Rather than holding an FTR for say, 100 MW, the wind farm would pay out or be paid for the FTR based on the amount of energy they generate in each trading period. Returning to the previous



example, suppose the price at the wind farm node is \$80/MWh, the benchmark price is \$50/MWh, and the wind farm generates 40 MWh/h. While the wind farm would have to pay out \$1,200/h on the FTR, it would also receive \$3,200/h from selling power. If the wind farm was not generating, it would not have to pay anything on the FTR.

While the 'wind FTR' solves the problem of negative cash flows for wind farms, it is not without implementation problems for the Market Operator (MO). For example, the MO must decide how much capacity to allow the wind FTR, to avoid selling too high a capacity of FTRs on a particular route. Nevertheless, a modified form of FTRs may play an important role as one of the support mechanisms for wind farms.

CAN WIND FARMS PARTICIPATE IN THE MARKET FOR OPERATING RESERVES?

Many MOs run markets for operating reserves, which are required to meet unexpected plant failures or changes in demand. Typically, generators will part-load their plant, offering the unused capacity as operating reserves for which they receive a payment. In principle, wind farms could also offer operating reserves, given the right market design. For example, if a wind farm is currently generating 100 MW, it could turn down to 60 MW and offer 40 MW in the reserve market. Of course, the problem is that between the time the wind farm makes the reserve offer, and the time the reserve is called, the wind speed might drop so that the wind farm cannot make good on its reserve offer. However, while wind speeds are unpredictable many days in advance, the wind speed between one hour and the next tends to change relatively little. Therefore, if the period between the wind farm making the reserve offer and the time that reserve offer could be called is short, the wind farm can be confident that it will be able to provide the promised reserve.

Nevertheless, there is always some risk that the wind speed will drop after a wind farm has made a reserve offer. It seems reasonable to 'discount' a wind farm's reserve offer to a level that the wind farm is reasonably certain of being able to provide in say, one hour from now. By studying historical wind speeds for an area, one can develop a probability distribution for how wind speed might change from one hour ahead, from which one can judge the certainty of a wind farm's reserve offer. But how 'certain' does the wind farm need to be of providing the promised reserve? One approach is to recognize that thermal generating plants may also fail to deliver operating reserves due to breakdowns and use the failure rate of these plants as a benchmark for wind farms.

For example, suppose we calculate that a 50 MW wind farm in the RoI has only a 0.1% chance of experiencing a drop in output of more than 25 MW from one hour to the next. In other words, if the wind farm is producing at 50 MW, there is a 99.9% chance that one hour later it will be able to produce

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at least 25 MW of power. For comparison, a running combined cycle gas turbine (CCGT) (which might typically provide operating reserve) has about a 0.2% chance of failing in the next hour. Therefore, a wind farm operating at 50 MW output could turn down to 0 MW, offer 25 MW as operating reserve in the next hour, and be a more reliable source of operating reserve than a CCGT. Of course, the reserve price would need to be high to justify this action by the wind farm – but that is a matter for the market. With careful market design there is no reason to stop participation by wind farms in the reserves market based on the intermittency of their energy source.

SHOULD ALL WIND FARMS BE EXPOSED TO LMPs?

The CER proposed that relatively small wind farms (for example, one or two wind turbines) should receive the price that consumers pay, which is an average of all LMPs, rather than the relevant LMP for their electricity. Most market parties agreed with this; however, there was much debate over who should qualify to receive the average price rather than their LMPs. One of the regulator's initial proposals was that generators connected to the transmission network should get the LMP while those connected to the distribution network would not. The logic was that most of the small generators would be connected on the distribution network and the rule would ensure that these generators were not exposed to LMPs.

We calculated that, in the RoI, the average consumer price would be about 5% higher than the average LMP received by a generator. Therefore, generators – including wind farms – would have an incentive to connect to the distribution network, even if it was actually cheaper for them to connect to the transmission network. This could be inefficient.

In our view, the motivation for 'small' wind generators to be paid the price that consumers pay (rather than LMP) is two-fold. First, small wind farms typically consume a significant proportion of their own generation. A small producer might have to buy back most of its produced electricity at a price 5% higher than they sold it for, despite the fact the electricity has



not 'left' the wind farm site. Second, the administrative costs associated with exposure to LMPs, particularly if this is linked to market participation (with the associated exposure to reserve costs, obligations to provide output forecasts, submit offer prices, and respond to control instructions), might be excessive for smaller generators.

It seems logical that the criteria for paying LMP or not should be based on the original motivations, *i.e.*, that small consumers should not be forced to buy back their own power at a loss and that administration costs should be reduced to a reasonable level. We developed several alternative rules for determining what price a wind farm received, which follow these original motivations:

- Allow wind farms that consume a 'high' percentage of their own production to receive the average consumer price for their electricity.
- Where wind farms produce more electricity than they consume, allow them a rebate on their own consumption of electricity to make up the difference between the average consumer price and the LMP.
- Allow wind farms below a certain production capacity to receive the average consumer price.
- A hybrid of the 'self-consumption' and capacity criteria. For example, wind farms who consume more than a certain percentage of their own production could receive the average consumer price, as long as their total production capacity was below a given amount.



The first two criteria are attractive in that they ensure renewable energy generators are not forced to buy back their own electricity at a loss, and could be implemented via the development of the trading site concept. This is already used to allow Combined Heat and Power plants to net-off the on-site demand they supply from their gross generation for transmission charging purposes. For example, a wind farm and a nearby housing estate could be defined as a ring-fenced trading site. The MO could deem that the wind farm would supply consumers within the trading site, without passing through the national transmission lines. Any excess generation would be sold at the relevant LMP, and any shortfall bought at the average consumer price. The trading site concept is not without problems. For example, it may not be straightforward to develop the rules for specifying what technical configurations should qualify as trading sites. However, the concept has been successfully applied in the U.S. and British electricity markets.

CONCLUSION

Many people hope that wind farms will contribute an increasing share of the world's electricity consumption, enabling society to benefit from 'greener' electricity. However, for this vision to become a reality, regulators and market operators must think carefully about how intermittent generators such as wind farms can fit into existing market designs that have been developed largely with thermal generating plants in mind. With modest adjustments, there should be no reason why wind farms cannot operate side-by-side with thermal generating plants while contributing toward a more sustainable future.

ENDNOTES

- ¹ Source: Generation Adequacy Report 2004 – 2010, Transmission System Operator Ireland, November 2003.
- ² In this newsletter we leave aside the potential electrical system issues that may arise from incorporating intermittent energy sources into the grid.

NEXT ISSUE: Natural Gas and Electricity Markets: Exploring the Interdependence

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MARC CHUPKA PROMOTED TO PRINCIPAL

Marc Chupka has two decades of public and private sector experience analyzing the market impacts of both domestic and international energy and environmental policy. He assists energy market clients and counsel in a broad span of management analysis, regulatory proceedings and litigation support. Mr. Chupka has focused on the litigation in Clean Air Act matters, electricity and fuel procurement policies, renewable energy policy design, and climate change policies.

Mr. Chupka's recent work has included testimony on implementing real-time pricing tariffs, evaluating the capacity and energy allocations of a large hydroelectric facility undergoing relicensing and modeling the contribution of wind power in wholesale markets. He formerly served as the Acting Assistant Secretary for Policy and International Affairs at the U.S. Department of Energy, and was the Associate Director for Air, Energy and Transportation at the White House Office for Environmental Policy.

RECENT BRATTLE WORK

UPDATE ON TRIENNIAL MARKED-BASED RATE FILINGS AT THE FERC

In the year since FERC ordered sellers with MBR authority to update their eligibility using the Commission's new interim generation market power test (107 FERC P 61,018; 107 FERC P 61,168), over 80 suppliers have submitted their filings, with many passing the new tests and receiving MBR approval. However, 13 investor-owned utilities have failed the market share screens in their home control areas, leaving the status of their MBR sales in these markets in doubt. While these few utilities have filed additional historical data in support of their application to continue MBR authority, the FERC has nevertheless ordered these entities for further proceedings under Section 206 of Federal Power Act.

In addition, the FERC staff has issued a series of "deficiency letters" instructing MBR applicants to improve their filings - these letters provide further clarification regarding how the FERC's two indicative screens (pivotal supplier and market share) should be calculated, and what data and workpapers should be submitted in support of those computations. A summary of these issues, along with a list of the companies we have assisted thus far can be found on our website, www.brattle.com.

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RECOVERY OF ENVIRONMENTAL COMPLIANCE COSTS

Utilities are facing substantial capital projects to comply with environmental regulations. These investment requirements have created significant pressure on utilities' cash flow and credit ratings. Johannes Pfeifberger and Sam Newell found in a recent survey that, in response to these pressures, twelve out of thirty non-restructured states - close to half of traditionally-regulated states which heavily rely on coal-fired generation - have implemented mechanisms to facilitate the financing and cost recovery of environmental capital projects. These mechanisms include environmental rate riders, pollution control bonds, and environmental trust financing.

For more information please contact Johannes Pfeifberger in our Cambridge office at 617.864.7900.

RECENT BRATTLE PUBLICATIONS

- "Wind Power Grid Integration - How to Evaluate Potential Grid Impact of Proposed Wind Projects," Judy W. Chang, presented at Electric Power 2005 Conference, Chicago, IL, April 6, 2005.
- "Betting Against the Odds? Why Broadband over Power Line (BPL) Can't Stand Alone as a High-Speed Internet Offering," William P. Zarakas and Kenneth J. Martinian, *Public Utilities Fortnightly*, April 2005.
- "Dynamic Pricing and Learning in Electricity Markets," James D. Reitzes, Alfredo Garcia, and Enrique Campos, *Operations Research*, March-April 2005.
- "Obstacles to Investment: How Regulators Create Incentives for Electric Infrastructure Investment Depends on How They Deal With a Long List of Incentives," Frank C. Graves and August J. Baker, *Electric Perspectives*, March-April 2005.
- "Rethinking the Grid: Avoiding More Blackouts and Modernizing the Power Grid Will Be Harder Than You Think," Peter S. Fox-Penner, *The Electricity Journal*, March 2005.
- "Arabian Gulf LNG in North West Europe: Managing Risks," Carlos Lapuerta and Morten Frisch, presented at the Fifth Doha Conference on Natural Gas: Stretching Frontiers, Doha, Qatar, February 28, 2005.
- "Current Issues in the Application of the CAPM to Rate Regulation," Stewart C. Myers, prepared for Wisconsin Investor-Owned Electric Utilities, January 2005.
- "Keeping Up with Retail Access? Developments in U.S. Restructuring and Resource Procurement for Regulated Retail Service," Johannes P. Pfeifberger, Joseph B. Wharton, and Adam C. Schumacher, *The Electricity Journal*, December 2004.

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