UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Assessing the State of Wind Energy in Wholesale Electricity Markets	Docket No. AD04-13-000

PRE-TECHNICAL CONFERENCE COMMENTS OF THE TRANSMISSION ACCESS POLICY STUDY GROUP

Pursuant to the Commission's October 4, 2004 Notice of a December 1 Technical Conference, the Transmission Access Policy Study Group ("TAPS") submits these comments to highlight a tariff issue that is impeding the development of wind generation and resulting in continued discrimination against transmission dependent utilities ("TDUs"). Specifically, the Commission should act to ensure that non-control area and control area utilities have an equal and non-discriminatory opportunity to develop and utilize wind resources. Under many tariffs today, non-control area utilities are subject to energy imbalance penalty charges for deviations that control area utilities can treat as inadvertent energy subject to return-in-kind requirements, making it prohibitive for transmission dependent utilities that are not control areas to participate in wind generation. TAPS asks the Commission to promptly address the disparate and punitive treatment of energy imbalance under Schedule 4 of the Open Access Transmission Tariff as compared with inadvertent energy among control areas, especially with respect to wind generation.

I. INTERESTS OF TAPS

TAPS is an informal association of transmission-dependent utilities in more than 30 states, promoting open and non-discriminatory transmission access.[1] As entities entirely or

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[1] TAPS is chaired by Roy Thilly, CEO of Wisconsin Public Power, Inc. Current members of the TAPS Executive

predominantly dependent on transmission facilities owned and controlled by others, TAPS members have supported the Commission's initiative to form truly independent, regional transmission organizations and to foster efficient investment in transmission and generation facilities. TAPS recognizes the critical importance of truly non-discriminatory open access to the development of wind power and other alternative sources of power, and to TAPS members' ability to continue to provide reliable service to their customers at a reasonable, predictable cost.

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II. THE DISCRIMINATORY TREATMENT OF ENERGY IMBALANCE MUST BE ADDRESSED TO ENABLE TDUS TO EFFECTIVELY UTILIZE WIND POWER

Under the Order 888-A OATT, non-control area utilities are subject to ancillary service Schedule 4, which covers the "difference that occurs over a single hour between the scheduled and the actual delivery of energy to a load located within a control area."[2] Under this service,

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Committee include, in addition to WPPI, representatives of: American Municipal Power-Ohio; Blue Ridge Power Agency; Clarksdale, Mississippi; ElectriCities of North Carolina, Inc.; Florida Municipal Power Agency; Geneva, Illinois; Illinois Municipal Electric Agency; Indiana Municipal Power Agency; Madison Gas & Electric Co.; Missouri River Energy Services; Municipal Energy Agency of Nebraska; Northern California Power Agency; Oklahoma Municipal Power Authority; Southern Minnesota Municipal Power Agency; and Vermont Public Power Supply Authority.

[2] *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888-A, 62 Fed. Reg. 12,274 (Mar. 14, 1997), *reprinted in* [1996–2000 Regs. Preambles] FERC Stat. & Regs. ¶ 31,048, at 30,229, *order on reh'g*, Order No. 888-B, 62 Fed. Reg. 64,688 (Dec. 9, 1997), 81 F.E.R.C. ¶ 61,248, *aff'd in part and remanded in*

outside a return-in-kind deviation band (of +/- 1.5%, with a 2 MW minimum), the customer is subject to a payment obligation designed as a penalty.[3] Specifically, the typical charge for out-of-band energy imbalance service is the greater of $100/MWh or 110% of the control area's incremental cost of supplying energy that replaces the under-deliveries. Because 110% of incremental cost rarely reaches $100/MWh, for most hours the charge is $100/MWh. When the customer over-delivers, it typically receives 90% or less of the control area's savings (its decremental cost) from having its energy output replaced by the over-deliveries.

The Commission has long recognized the treatment of non-control area utility energy imbalances to be discriminatory, especially as compared with control area operators. The NOPR leading up to Order 2000 found (FERC Stat. & Reg. ¶ 32,514, at 33,746-47) that it is discriminatory to penalize customers for imbalances while allowing control area operators to draw on inadvertent accounts and pay back those imbalances in kind. In Order 2000,[4] the Commission concluded:

> In the NOPR, we noted that unequal access to balancing options can lead to unequal access in the quality of transmission service, and that this could be a significant problem for RTOs that serve some customers who operate control areas and other customers who do not. We conclude that control area operators should face the same costs and price signals as other transmission customers

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part sub nom. Transmission Access Policy Study Group v. FERC, 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom. New York v. FERC*, 535 U.S. 1 (2002), *order on reh'g*, Order No. 888-C, 82 F.E.R.C. ¶ 61,046 (1998)

[3] The Commission characterized its "primary goal" as "promoting good scheduling practices." Order 888-B, 81 F.E.R.C. at 62,086.. In the NOPR leading up to Order 888, the Commission proposed a charge of 100 mills/kWh for imbalances outside the +/- 1.5% bandwith, stating: "We propose the emergency service charge for this purpose because, as with emergency service, the rate should provide an incentive to minimize energy imbalances." *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, FERC Stat. & Regs. ¶ 32, 514, at 33,150 (1995). While Order 888 left the imbalance charge to case by case determination (*see* Order 888-A, FERC Stats. & Regs. Preambles ¶ 31,048, at 30,234), the Commission has accepted 100 mills/kWh as "a standard industry practice" for both energy imbalance and emergency service. *See, e.g.*, *Detroit Edison Co.*, 88 FERC ¶ 61,224, at 61,734 (1999).

[4] *Regional Transmission Organizations*, Order 2000, 89 F.E.R.C ¶ 61,285, at 61,896 (1999).

> and, therefore, also should be required to clear system imbalances through a real-time balancing market. We believe that providing options for clearing imbalances that differ among customers would be unduly discriminatory.

Nevertheless, except in RTOs where real time energy markets are now in place, TDUs continue to labor under burdensome energy imbalance penalty charges. The inherently unpredictable and intermittent nature of wind power heightens the sheer magnitude and discriminatory nature of this continued treatment, and discourages non-control area utilities from developing and participating in wind resources. Even assuming (contrary to Order 2000's finding) that this practice were not otherwise unduly discriminatory, its relationship to the development of wind power demonstrates that it is bad policy.

For example, Oklahoma Gas and Electric Company ("OGE") and TAPS member Oklahoma Municipal Power Authority ("OMPA") jointly take power from a 102 MW wind farm, developed and operated by FPL Energy, which went on line on September 29, 2003. The farm's output is divided equally (51 MW each) between OGE and OMPA, in each case on a "take and pay" basis.[5] OMPA is projected to obtain some 8% of its total energy requirements from the wind farm.

OMPA makes every effort to accurately schedule this wind resource (in accordance with the model provided by FPL Energy) and to adjust the schedule to the extent permitted — *i.e.*, 20 minutes before the hour, or effectively 30 minutes given tagging complexities, using information only one hour old. Despite these continuing efforts, if OMPA were taking service for this

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[5] OMPA is the nominal owner of a 51 MW share of the facility itself, whereas OGE purchases output from the 51 MW owned by FPL Energy. But OMPA takes its power under a Power Sales contract that is operationally equivalent to OGE's output purchase arrangement.

resource under an OATT, [6] Schedule 4 charges would more than double its energy cost from the wind farm.

As shown in the Attachment tables, during the wind farm's first full year of operation, the wind farm produced 154,019 MWh for $2,515,478, or $16.33/MWh. If Schedule 4 had applied to OMPA's deliveries from the wind farm and OMPA had perfectly predicted its loads,[7] OMPA would have had to pay OGE an additional $2 to $3.4 million in energy imbalance service, considering only under-deliveries associated with this resource beyond the 2 MW deadband, due to application of the $100/MWh charge.[8] Consequently, energy imbalance for just the out-of-band under-deliveries would have increased OMPA's costs by something like $13.20 to $22.10 for each MWh generated by the wind farm, above and beyond OMPA's $16.33/MWh actual out-of-pocket payments for the wind energy. Energy imbalance charges would have significantly increased (by 81% to 135%) OMPA's wind energy cost without even considering other ancillary services or the fact that over-deliveries are reimbursed at less than (typically 90% of) the Transmission Provider's decremental cost.

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[6] OMPA currently takes transmission service from OGE under an grandfathered transmission service agreement. However, OMPA will soon be transitioning to service under the SPP OATT.

[7] Of course, other real time imbalances in OMPA loads and generation may or may not operate to counter-balance or increase (*e.g.*, by eating into the 2 MW deadband) the imbalance charges identified here.

[8] The wind farm under-delivered its schedule by more than the 2 MW deadband for a total of 40,668 MWh, and had over-deliveries in excess of 2 MW of 14,320 MWh. This difference in quantities resulted from neutral application of FPL's model and the inherent characteristics of wind technology, not from any intention to lean on the grid for imbalance. As shown in Attachment A, application of the $100/MWh Schedule 4 charge for under-deliveries in excess of 2 MW, netted against the cost of the wind power (which is slightly below OMPA's $18.23/MWh average cost of energy) would yield $3,403,762 in additional energy imbalance payments. Divided by OMPA's share of the total output of the farm, this amounts to some $22.10/MWh of additional charges. Even taking an overly conservative approach of assuming replacement of under-deliveries would have cost $50/MWh every hour of the year (assuming that gas costs $5/mmBTU and that the marginal generator is a gas unit with a heat rate of 10,000 BTU/kWh), the $100/MWh energy imbalance minimum charge for out-of-band undersupply would have imposed an additional $2,033,400. Divided by OMPA's share of the total output of the farm, this amounts to some $13/MWh of additional charges.

Because it operates a control area (even though it takes delivery at the same location from the same wind farm), OGE would not be subject to this charge. The unpredictable changes in the wind farm's output (along with deviations in all other loads and resources within the control area) would be followed by OGE's generation subject to AGC or at worst, treated as inadvertent energy between control areas, subject to return-in-kind treatment.

Indeed, not only is OGE exempt from paying energy imbalance penalties, but it would receive the imbalance charges OMPA would pay. With its subsidy from OMPA's imbalance payments taken into account, OGE would have received its share of the wind farm energy for little or nothing.

This example demonstrates how energy imbalance service (and generator imbalance service that some transmission providers charge) makes environmentally friendly sources of energy prohibitive for non-control-area operators. The punitive energy imbalance charges imposed on non-control area utilities far exceeds the true costs of integrating wind generation.[9]

The Commission should promptly end this disparate treatment of imbalances, which effectively makes wind generation a resource that only control-area operators can afford to develop and use. TDUs should not have to wait for introduction of real time RTO energy markets (something which in many parts of the country may be akin to waiting for Godot), and should not have to accept the risks and detriments of such markets, in order to escape what the Commission has recognized to be discriminatory treatment of imbalances. Nor should wind

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[9] The $13 to $22/MWh penalty that OMPA would have had to incur just for energy imbalance on underschedules is well beyond the $1.47 to $5.50/MWh range of the total costs for integrating wind generation (regulation, load following, unit commitment) as reported in "Wind Power Impacts on Electric Power System Operating Costs: Summary and Perspective on Work to Date," presented at the American Wind Energy Association WindPower Conference, March 28-31, 2004, *available at* http://www.uwig.org/windpower2004.pdf (last visited Oct. 27, 2004).

resource developers have to wait for such markets to get a real opportunity to sell their facilities or output to TDUs.

Respectfully submitted,

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Attachment

TABLE 1

Oversupply and Undersupply Bandwith Equals +/- 2, EIB Unit Cost is Avoided Ga

Month	Actual Wind Production	Wind Caused Undersupply	Wind Caused Oversupply	Average Wind Unit Cost	EIB Cost Less Unit Cost (1)	Total Cost of Actual Wind	Total EIB Cost Due to Undersupply
October 2003	9,214	2,917	1,595	$ 18.31	$ 50.00	$ 168,708.34	$ 145,850.00
November 2003	13,242	3,091	456	$ 15.21	$ 50.00	$ 201,410.82	$ 154,550.00
December 2003	15,030	4,790	618	$ 14.86	$ 50.00	$ 223,345.80	$ 239,500.00
January 2004	10,238	3,949	1,178	$ 15.76	$ 50.00	$ 161,350.88	$ 197,450.00
February 2004	11,808	3,073	691	$ 16.31	$ 50.00	$ 192,588.48	$ 153,650.00
March 2004	14,786	3,494	1,298	$ 16.83	$ 50.00	$ 248,848.38	$ 174,700.00
April 2004	12,551	4,222	828	$ 16.90	$ 50.00	$ 212,111.90	$ 211,100.00
May 2004	21,077	4,242	1,741	$ 17.05	$ 50.00	$ 359,362.85	$ 212,100.00
June 2004	9,760	3,167	1,248	$ 16.13	$ 50.00	$ 157,428.80	$ 158,350.00
July 2004	10,447	3,155	1,424	$ 16.31	$ 50.00	$ 170,390.57	$ 157,750.00
August 2004	10,794	2,503	2,106	$ 16.13	$ 50.00	$ 174,107.22	$ 125,150.00
September 2004	15,072	2,065	1,137	$ 16.31	$ 50.00	$ 245,824.32	$ 103,250.00
Total	***154,019***	***40,668***	***14,320***			***$ 2,515,478.36***	***$ 2,033,400.00***
					$/MWh	***$ 16.33***	***$ 13.20***
					Total Costs	***$ 29.53***	

(1): Unit cost for EIB calculation is $50 = $5/mmBtu gas at a 10,000 heat rate (LM6000 CT)

Schedule Imbalance cost 81% more than the actual energy supplied, considering<u>only</u> the $100/MWh minimum charge for undersupply.

TABLE 2

Oversupply and Undersupply Bandwith Equals +/- 2, EIB Unit Cost is Monthly Average Wind Cos

Month	Actual Wind Production	Wind Caused Undersupply	Wind Caused Oversupply	Average Wind Unit Cost	EIB Cost Less Unit Cost (2)	Total Cost of Actual Wind	Total EIB Cost Due to Undersupply
October 2003	9,214	2,917	1,595	$ 18.31	$ 81.69	$ 168,708.34	$ 238,289.73
November 2003	13,242	3,091	456	$ 15.21	$ 84.79	$ 201,410.82	$ 262,085.89
December 2003	15,030	4,790	618	$ 14.86	$ 85.14	$ 223,345.80	$ 407,820.60
January 2004	10,238	3,949	1,178	$ 15.76	$ 84.24	$ 161,350.88	$ 332,663.76
February 2004	11,808	3,073	691	$ 16.31	$ 83.69	$ 192,588.48	$ 257,179.37
March 2004	14,786	3,494	1,298	$ 16.83	$ 83.17	$ 248,848.38	$ 290,595.98
April 2004	12,551	4,222	828	$ 16.90	$ 83.10	$ 212,111.90	$ 350,848.20
May 2004	21,077	4,242	1,741	$ 17.05	$ 82.95	$ 359,362.85	$ 351,873.90
June 2004	9,760	3,167	1,248	$ 16.13	$ 83.87	$ 157,428.80	$ 265,616.29
July 2004	10,447	3,155	1,424	$ 16.31	$ 83.69	$ 170,390.57	$ 264,041.95
August 2004	10,794	2,503	2,106	$ 16.13	$ 83.87	$ 174,107.22	$ 209,926.61
September 2004	15,072	2,065	1,137	$ 16.31	$ 83.69	$ 245,824.32	$ 172,819.85
Total	***154,019***	***40,668***	***14,320***			***$ 2,515,478.36***	***$ 3,403,762.13***
					$/MWh	***$ 16.33***	***$ 22.10***
					Total Costs	***$ 38.43***	

(2): Unit cost for EIB calculation is the monthly average Wind Unit Cost.

Schedule Imbalance cost 135% more than the actual energy supplied, considering<u>only</u> the $100/MWh minimum charge for undersupply.