

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Imbalance Provisions for Intermittent
Resources

Docket No. RM05-10-000

Assessing the State of Wind Energy in
Wholesale Electric Markets

Docket No. AD04-13-000

**COMMENTS OF THE
TRANSMISSION ACCESS POLICY STUDY GROUP**

Pursuant to the Commission’s Notice of Proposed Rulemaking (“NOPR”) in the captioned proceedings, issued April 14, 2005¹ and published in the Federal Register on April 26, 2005,² the Transmission Access Policy Study Group (“TAPS”) hereby comments on the proposed rule. TAPS believes that with some technical corrections,³ the proposed rule is an improvement over current rules, but that its scope of applicability is much too narrow to adequately promote efficient, renewable energy and to fulfill the Commission’s responsibility to end undue discrimination. Its elimination of the \$100/MWh penalty charge for out-of-band imbalances, and its more flexible approach to bandwidths, should be broadened to include all situations — including energy imbalance — where diligent customers cannot avoid the penalty.

¹ 111 FERC ¶ 61,026 (2005).

² 70 Fed. Reg. 21349 (April 26, 2005).

³ In addition to the issue discussed below regarding the definition of intermittent resources, TAPS notes that proposed Schedule XYZ refers to the “Transmission Provider’s” System Incremental Cost and System Decremental Cost. Where the Transmission Provider does not operate generation, these terms’ meaning is unclear. The Commission should clarify that these incremental and decremental costs refer to the hour’s marginal generator that responds to control area signals.

INTEREST OF TAPS AND COMMUNICATIONS

TAPS is an informal association of transmission-dependent utilities in more than 30 states, promoting open and non-discriminatory transmission access.⁴ As entities entirely or 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, to foster efficient investment in transmission and generation facilities, and to provide for non-discriminatory transmission access.

Many TAPS members have or are in the process of acquiring interests in wind resources. Because of this strong interest in wind power and wind-related transmission issues, TAPS has submitted several sets of comments in Docket No. AD04-13,⁵ and participated as panelists at both the December 1 Technical Conference in Denver⁶ and the March 16-17 Technical Workshop in Portland.⁷

TAPS' November 12, 2004 Comments (corrected December 22, 2004) examined how the standard OATT Schedule 4 would differentially treat the identical imbalances of Oklahoma Gas

⁴ TAPS is chaired by Roy Thilly, CEO of Wisconsin Public Power, Inc. Current members of the TAPS Executive 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.

⁵ See TAPS Pre-Technical Conference Comments, filed November 12, 2004, and corrected December 22, 2004 (providing a concrete example of the significant and discriminatory impacts of the Commission's current energy imbalance policy, which permits control areas to collect the higher of \$100/MWh or incremental cost plus 10% for underdeliveries in excess of a narrow 1.5%/2 MW deviation band); TAPS January 28, 2005 Post-Technical Conference Comments (expressing views on key issues included in the December 21 notice (imbalance, planning, alternatives to the queue, pricing, pancaking, seams and new wind-tailored transmission service); and TAPS April 13, 2005 Post-Workshop Comments (pertaining to new transmission services for wind power).

⁶ See Statement of John A. Krajewski, P.E, Municipal Energy Agency of Nebraska, for the December 1 Technical Conference (filed Dec. 2, 2004).

⁷ TAPS counsel, Cynthia Bogorad, appeared for TAPS at the March 16-17 Workshop.

and Electric Company (“OGE”) and TAPS member Oklahoma Municipal Power Authority (“OMPA”). We demonstrated that a narrow bandwidth on generator imbalances gives control areas an undue competitive advantage as operators of intermittent generation, and thereby narrows both the market for hosting intermittent generators and non-control-areas’ generation options. We also commented on the related issue of long-term rights, but will leave further comment on that issue for Docket No. AD05-7.⁸

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COMMENTS

Imbalances that cannot be predicted and controlled through the exercise of diligent Good Utility Practice should not suffer \$100/MWh penalty charges.

⁸ In order to allow intermittent generation resources to flourish, it is necessary to provide for long-term rights to the financial delivery of those resources’ output to the loads which finance them. Intermittent generation must be built where nature provides its energy source, not where the load is. Without assurance that the economic value of intermittent generators’ output will actually reach the load that finances its creation, it will be underfinanced. In his technical conference testimony, TAPS witness Krajewski emphasized that “[t]he needs of wind energy resources are not unlike the needs of other high installed cost, low energy cost, generating resources that can’t be sited in everyone’s backyard. These needs include a reliable and robust transmission system, an effective approach to planning, building and funding needed transmission improvements, assurances of long-term deliverability at a predictable price.” However, TAPS will leave further comment on this aspect of the problem to its comments in the long-term rights proceeding, Docket No. AD05-7.

The NOPR's explicit, and correct, premise is that "intermittent resources, unlike dispatchable generation, have a limited ability to predict and control their output." NOPR at P 10. The NOPR then reasons, also correctly, that because "penalties must be avoidable by customer actions, and should not limit market participation," it is unduly discriminatory and inappropriate to apply imbalance penalties to resources whose output varies with the wind. *Id.* at P 57. A \$100/MWh or similar penalty applied to any imbalance that market participants cannot control will not be consistently avoidable, and even more important, will impel market participants to intentionally distort their schedules so that the penalty does not apply as often as it would if they scheduled neutrally. For example, suppose a wind farm has to pay at least \$100/MWh whenever it generates less than predicted in its schedule, but is paid only 90% of system decremental costs when it generates more than scheduled. Its rational strategy will be to schedule less than its anticipated actual output, trading the opportunity to collect the remaining 10% of marginal prices⁹ for reduced incurrence of \$100/MWh penalties.

The NOPR recognizes (at P 59) that even without the \$100/MWh penalty, *i.e.*, even if the downside of producing less actual output than scheduled is limited to incurring a 10% premium above system incremental cost for the energy that replaces that imbalance, "the proposed pricing structure may create an incentive to underschedule in an effort to reduce exposure to being charged 110 percent of the transmission provider's system incremental cost." The distorting incentive of the \$100/MWh penalty is far greater. For example, when system incremental cost is \$40/MWh, the \$100/MWh rate is 250% of system incremental cost. The resulting bias toward

⁹ For simplicity, we assume a rational, competitive market such that system marginal costs and market prices are equal. Note also that in a large market, decremental costs almost always equal incremental costs, so that is simpler to conflate both costs as "marginal" costs.

overly conservative scheduling by non-control-area operators is not merely to be expected. As discussed below, it has been empirically demonstrated in the Pacific Northwest.

But wind output is far from the only uncontrollable variable that is biasing schedules and producing imbalance penalties that even diligent market participants cannot control.

First, other generation resources likewise have actual energy output that, even when operating normally, varies substantially from schedulable predictions based on uncontrollable external variables. The NOPR (at P 12) correctly identifies “run-of-river hydroelectric and solar power” as two examples. But for any generation resource whose energy source is other than impounded water or stored¹⁰ fuel, it may well be technically infeasible to keep generation output closely matched to the quantity predicted twenty minutes before the operating hour. For example, ocean wave power, which is now becoming a reality,¹¹ likewise depends on natural inputs that can neither be controlled nor precisely predicted.

It would be unwise to attempt to identify each existing technology type that shares this characteristic, and impossible to anticipate all future ones. The proposed regulatory text already points in a better direction; rather than apply specifically to “wind,” its Section 35.28(g)(1) defines an intermittent resource as “an electric generator that is not dispatchable and cannot store its fuel source and therefore cannot respond to changes in system demand or respond to transmission security constraints.” However, this well-intentioned attempt at a more general definition goes awry. “Dispatchable” as used in this definition is vague and open to improper

¹⁰ In this context, storage includes fuel (*e.g.*, natural gas) that is delivered by pipelines, whose line pack acts as storage and removes fuel interruption as a source of post-scheduling output variability in normal operation.

¹¹ *See, e.g.*, Electric Power Research Institute, Final Summary Report, Offshore Wave Power Feasibility Demonstration Project (Jan. 14, 2005), *available at* http://www.epri.com/attachments/297213_009_Final_Report_RB_01-14-05.pdf . Wave-produced electricity is now the second most famous product of Scotland’s Isle of Islay.

application; the issue is less responsiveness to system conditions than predictability of output;¹² the reference to “fuel source” ill fits generators whose energy source is direct harnessing of natural forces rather than fuel; and it is conceivable that a future technology will combine a storable fuel source with another, un-storable energy input to produce uncontrollable output. TAPS suggests that intermittent generators instead be defined as those which “produce electricity using energy that is not stored, and therefore cannot, even when applying Good Utility Practice to predict and schedule their output and not encountering an equipment failure, consistently match actual output to scheduled output.”

Second, and more important, intermittent generators are not the only market participants who are encountering steep imbalance penalties that are not “avoidable by [transmission] customer actions” and which “limit market participation.” Firm retail load isn’t controlled by wholesale-level transmission customers either, and it is both punitive and distorting to impose a \$100/MWh penalty for guessing wrong about uncontrolled external variables — such as the net load of retail customers with their own, distributed behind-the-retail-meter, intermittent generation, and weather’s effect on the next hour’s thermal load. The Commission has “recognized that the amount of energy taken by load in an hour is variable and not subject to the control of either a wholesale seller or a wholesale requirements buyer.”¹³ Just as is true for intermittent generators, the ability to change schedules shortly before the hour (which in practice,

¹² Setting aside use of emergency ratings, generators producing at maximum output, whether intermittent or not, cannot increase their output at dispatchers’ direction. The definition as proposed therefore seems to be directed principally at the question whether the generator can reduce its output to schedule when so directed. But wind farms may well be “dispatchable” in the sense that when the wind blows harder than predicted, they can be reset, through turbine angling or the like, to reduce their output to meet or more closely approach their schedule. Likewise, solar panels can be taken off line or pointed away from the sun. The distinction that should shape the definition is twofold. First, with intermittent resources, conforming output to schedule will waste energy available in nature. Second, with intermittent resources, output may fall significantly below a schedule that was set as accurately as due diligence could set it, just because in a particular hour, an uncontrollable energy input came in surprisingly low.

¹³ NOPR at P 13 (citing Order No. 888-A at 30,230).

with the time required for tagging, requires a decision on the schedule quantity at least 30 minutes before the hour, not 20 as the NOPR assumes) does not resolve the fact that schedulers are not clairvoyant and cannot precisely predict the next hour's weather, loads, or net retail loads. To apply the \$100/MWh penalty to transmission customers who extract power drawn by uncontrolled firm retail load, and exercise good utility practice in scheduling to meet it, is no less discriminatory than it is to apply that penalty to transmission customers who inject power generated by uncontrolled intermittent generation.

Consider a second hypothetical example, mirroring the example discussed above with regard to intermittent generation. Suppose a rational load-serving entity has to pay at least \$100/MWh whenever its load exceeds that predicted in its schedule, but is paid only 90% of system decremental costs when its load absorbs less than scheduled. Its rational strategy will be to schedule its load as being larger than actually anticipated (which on most transmission systems will oblige it to arrange generation to match the larger, as-scheduled load). That will reduce its exposure to \$100/MWh penalties, but only by giving the competing LSE that runs its control area an energy discount valued at 10% of marginal prices.

The Bonneville Power Administration's experience proves that it is feasible to eliminate the \$100/MWh charge on unintended imbalances across the board, limiting that penalty rate to Intentional Deviations by either generators or load. It also provides empirical proof that on systems that retain the \$100/MWh charge, its distorting effect is real.

Through an open stakeholder/settlement process that was conducted in the second half of 2002, and which started out focusing on wind, BPA agreed to eliminate the \$100/MWh charge on all unintended imbalances. BPA's Transmission Business Line agreed to the revision on November 27, 2002. It was subsequently approved by BPA's formal rate-setting process, and by

this Commission in Docket No. EF03-2021.¹⁴ The penalty now applies only to “Intentional Deviation,” an anti-gaming provision that can be triggered by a pattern of abuse.¹⁵ Absent such bad intent, both generation imbalance and load imbalance are handled through a three-band regimen that amounts to system marginal price plus 0%, 10%, or 25%, not the multiple that the \$100/MWh price often represents.¹⁶ With this regimen, not only have Northwestern lights stayed on, but scheduling accuracy has improved, as market participants have ceased having to bias their schedules in an attempt to steer clear of the \$100/MWh penalty rate.¹⁷

Especially given this successful experiment, the \$100/MWh penalty and 2 MW/1.5% bandwidth must not be left in place as to load elsewhere, even while eliminating the penalty and widening the bandwidth as to intermittent generation. Such disparate treatment of uncontrollable imbalances is unduly discriminatory.

Sharpening this discrimination is the fact that in many instances, the very same uncontrolled weather variable that makes wind output fall short of its schedule by more than today’s narrow bandwidth will also make load exceed its schedule and bandwidth. When the

¹⁴ *United States Department of Energy - Bonneville Power Administration*, 104 FERC ¶ 62,207 (2003) (finding, *inter alia*, that BPA’s new ancillary service rates and terms satisfy reciprocity and FPA § 212 standards).

¹⁵ An Intentional Deviation may be found where “a deviation is persistent during multiple consecutive hours or at specific times of the day,” or “a pattern of under-delivery or over-use of energy occurs,” or there is “persistent over-generation or under-use during Light Load Hours, particularly when the customer does not respond by adjusting schedules for future days to correct these patterns.” See FERC eLibrary No. 20030605-0252, Appendix B, p.71.

¹⁶ In the innermost band (within 2 MW/1.5% of schedule), imbalances are netted monthly (separately for on-peak and off-peak periods) and then priced at 100% of the system incremental/decremental cost, with no percentage scale-up for net withdrawals and no percentage scale-down for net injections. In the mid-band (up to 10 MW/7.5% of the schedule), imbalances receive 90% or pay 110% of the system marginal price. Beyond that, outer-band imbalances receive 75% or pay 125% of the system marginal price.

¹⁷ See, e.g., *Advantage of Tight Hour Ahead Forecasts*, WINDPOWER MONTHLY (Dec. 2003), at 44 (graph showing improved forecast accuracy at the Condon Wind Farm in Oregon; not only has the range of forecast error narrowed as the article’s text discusses, but the graph shows that a bias toward under-scheduling wind output has been removed).

breeze dies in the surprisingly still heat of a summer afternoon, not only do wind turbines power down, but fans and air conditioners start up.

Similarly, the retail sales load that is reflected in transmission schedules and subject to imbalance charges may actually be the net metered load, after ultimate consumers meet a portion of their energy needs from their own distributed generation located behind the retail meter. On many systems, such generation includes significant quantities of intermittent retail-owned netting generation, such as rooftop solar panels or wind turbines used for water pumping. The Commission may be directly familiar with the variability of their output: Atop its Washington D.C. headquarters at 888 First St. NE, solar panels generate electricity that reduces the building owner's net retail consumption, and the fluctuations in those panels' output is visible on a read-out in the entrance lobby. Of course, that is far from the only example of distributed intermittent generation owned by ultimate consumers that reduces schedulable load. According to the U.S. Department of Energy's Distributed Wind Technology program,¹⁸

In 2001, annual sales of the U.S. small wind turbine industry were estimated to be 13,400 turbines, valued at about \$20 million. ... Machines range in size from those that generate 400 watts (W) of electricity for specific small loads such as battery charging for sailboats and small cabins, to 3 to 15 kilowatt (kW) systems for a home, to those that generate up to 100 kW of electricity for large loads such as a small commercial operation. ... [S]mall wind turbines could meet 3% of U.S. electricity consumption by 2020.

Suppose a diligent LSE predicts and schedules next-hour load of 200 MW, representing 210 MW of gross electricity consumption minus 10 MW owned by its retail customers and used to reduce their metered load, but the wind dies and actual load is 210 MW minus 5 MW. The

¹⁸ See http://www.eere.energy.gov/windandhydro/wind_dist_tech.html.

LSE will have 2 MW of out-of-band imbalance (beyond the 3 MW deadband).¹⁹ Why should it be charged \$100/MWh for that imbalance, when it has been correctly been found unreasonable to charge a wholesale-level wind generator who delivers less wind output than scheduled a \$100/MWh for its out-of-band imbalances?

Conversely, it is equally unreasonable to charge a \$100/MWh generator imbalance charge when the net of ultimate consumer gross energy usage and distributed generation is net output (rather than net usage, as assumed in the prior paragraph), but that output varies from its schedule because uncontrolled firm retail load reduces the distributed generation's net output. For example, consider a co-generator that injects onto the grid the net of its electricity generation and energy consumption by its host consumer. Schedules for such injections must reflect the net of predicted energy output and host consumer energy consumption. Thus, unpredicted consumption can create an imbalance between scheduled and actual net output, just as occurs when wind input is less than forecast. Furthermore, like intermittent generation that converts unstored energy to electricity, co-generation has environmental benefits and reduces use of non-renewable fuel.

The general point that encompasses the netting examples discussed above is that in practice, generator-side and load-side imbalances are not as distinct as the NOPR (at 8-9) assumes. Both forms of imbalance are sides of the same coin. In fact, contrary to the NOPR's belief as to how load-side imbalance is being applied, TAPS members operating outside of (or prior to) RTO-administered imbalance markets have been charged for load imbalance when their load matched its schedule, but their generation injections that reached their control area did not. Consequently, load can even be subject to imbalance charges when a TLR isolates the load from

¹⁹ With a 2 MW/1.5% deadband, the band will extend to 203 MW. But its actual load will be 205 MW.

its resources. Such imbalances are yet another example of how load-serving-entities cannot — despite their diligent application of good utility practice, including timely updating of well-forecast schedules — control the events that make them subject to \$100/MWh imbalance charges.

The NOPR is therefore right when (at n.97) it finds comparable (a) intermittent generators' need for a bandwidth to cover necessarily imprecise predictions of their actual energy output and (b) load serving entities' need for a bandwidth to cover necessarily imprecise predictions of their load's actual energy usage. But it fails to justify applying a narrower bandwidth to load than will apply to intermittent generation. Most important, it fails to justify applying a load bandwidth limited to 2 MW/1.5% before the \$100/MWh penalty for over-withdrawing kicks in, when the bandwidth that protects intermittent generation from a \$100/MWh penalty for under-injecting is infinite (*i.e.*, the penalty is eliminated).

Even if it was appropriate to leave this structural discrimination in place, there are two readily available partial measures that would mitigate it somewhat. First, the revenues from the \$100/MWh penalty (*i.e.*, the amount by which \$100/MWh exceeds 110% of system incremental cost) should flow exclusively to transmission customers who are subject to paying the penalty if they incur out-of-band imbalances. Control-area operators must not be allowed to turn penalties into a profit center. The Commission has already ruled on a case-by-case basis that imbalance penalties should be credited exclusively to non-offending customers within the classifications subject to that are subject to them. *See Entergy Services, Inc.*, 109 FERC ¶ 61,095 at PP 65-67 (2004); *Carolina Power & Light Co.*, 103 FERC ¶ 61,209 at P 25 (2003). The rulemaking here should, at minimum, codify and nationalize that ruling. However, that is far from a complete solution, because it does not reach the far greater profits that control area operators enjoy by

receiving the discounted energy that is dumped onto their system by entities subject to and seeking to steer wide of the \$100/MWh charge. Second, the Commission should make effective the NOPR's clarifying tariff interpretation (at 39) that "that transmission providers must allow transmission customers to modify schedules up to 20 minutes before the hour and that any net hourly imbalance calculation will be determined from the last accepted schedule," by adopting regulatory text under which imbalance charges must be calculated based on the last schedule presented by the transmission customer 20 or more minutes before the hour, even if the transmission provider failed to timely process that schedule.

But these are band-aids where surgery is statutorily required. As the NOPR correctly notes (at P 9), "The Commission has a duty to prevent unduly discriminatory practices in transmission access." Indeed, once the Commission finds that undue discrimination exists, it has a statutory obligation to remedy that discrimination forthwith. *See New York v. FERC*, 535 U.S. 1, 27 (2002) ("Were FERC to investigate this alleged discrimination and make findings concerning undue discrimination in the retail electricity market, §206 of the FPA would require FERC to provide a remedy for that discrimination. See 16 U. S. C. §824e(a) (upon a finding of undue discrimination, the Commission shall determine the just and reasonable ... regulation, practice, or contract ... and shall fix the same by order.").

That duty includes an obligation to end, at last, the unduly discriminatory practice of charging non-control-areas \$100/MWh when their load shows up more than 1.5% above the scheduled, reasonable prediction — while allowing control areas to just return their imbalances in kind as inadvertent energy,²⁰ even while absorbing (to the detriment of markets for load-

²⁰ Dr. Eric Hirst (an independent consultant who was formerly a fellow at Oak Ridge National Laboratory) and Jeffrey Hild (of Xcel Energy) have observed that control area operators do not have to acquire regulating or load-following resources to counter-balance each fluctuation in wind output:

following energy²¹) the excess energy that non-control-areas give away in an effort to give the \$100/MWh penalty a wide berth. The Order 888 compliance filings through which that penalty became widespread were made in 1996. In Order 2000, the Commission acknowledged the need for comparable access to imbalance.²² Since then, the Commission may have felt that it was moving the industry toward a cure for this discrimination by promoting RTO-operated imbalance markets. But it must be acknowledged that much of the nation will not have such markets any time soon.

As the tenth anniversary of the \$100/MWh penalty approaches, the Commission's statutory duty demands more than the brush-off (NOPR at P 68) that "We believe that this issue [discrimination as between control area and non-control-area utilities] is beyond the scope of this proceeding, and therefore, it will be addressed at a later time." This is "a later time," and the

The North American Electric Reliability Council (NERC 2001) requires that each control area maintain its generation:load balance within limits set by its Control Performance Standard (CPS) 1 and 2. Neither CPS1 nor CPS2 requires a control area to maintain a zero ACE. Small imbalances are permissible, as are occasional large imbalances. Both CPS1 and 2 are statistical measures, the first a yearly measure and the second a monthly measure. Also, both CPS standards measure the aggregate performance of a control area, not the behavior of individual loads and generators.

The implications of these NERC requirements for a volatile resource, such as wind, are profound. To meet the CPS requirements, the system operator need not acquire regulation and load-following resources to exactly counter every change in wind output. All the system operator need do, when unscheduled wind output appears on its system, is maintain its average CPS performance at the same level it would have without the wind resource.

Integrating Large Amounts Of Wind Energy with a Small Electric-Power System (April 2004), at 4, *available at* http://www.regie-energie.qc.ca/audiences/3526-04/MemoiresParticip3526/Memoire_CCVK_25_WindIntegrationReport.pdf. But outside of narrow bandwidths, non-control-area utilities do have to counter every change in wind output, and every change in their own load, lest they face a \$100/MWh penalty,

²¹ TAPS member OMPA has sought, without success to date, to arrange to purchase cost-based load-following energy from AEP. Why would a control area voluntarily sell that product, when it can make \$100/MWh from customers' energy imbalances and retain the excess energy that they inject to steer away from that charge?

²² See TAPS Pre-Technical Conference Comments at 3-4.

time to achieve comparable treatment of these two market participant classes is long past due.

The Federal Power Act, as definitively construed in *New York v. FERC*, brooks no further delay.

Respectfully submitted,

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