



## **A Review and Update Regarding The 2000 AWEA Transmission Access Priority Issues Report**

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This report provides a review and update on transmission access policy issues previously identified in the American Wind Energy Association's ("AWEA") 2000 report titled, *Fair Transmission Access for Wind: A Brief Discussion of Priority Issues* ("2000 Report").<sup>1</sup> The report begins with a short overview of the policy concerns identified in the 2000 Report. This is followed by a brief update of major policy developments in the regulatory arena, primarily developments at the Federal Energy Regulatory Commission ("FERC" or "Commission"). The third section of the paper reviews how those new policy developments address the specific concerns identified in the 2000 Report and what "next steps" or solutions to those concerns may be advocated by AWEA.

It is critical to keep in mind that there are two interrelated but distinct steps with any proposed solution. The first step is to have regulators adopt transmission access and related market policies that recognize the concerns of wind generation. The second step is to ensure that the transmission providers implement the adopted policies correctly both through the formal tariff filings and operational protocols.

### Overview of the 2000 Report

The 2000 Report identified the priority transmission problems faced by wind power in the United States and proposed solutions for each of them. The interplay between wind generation characteristics and transmission policies is important to understand. Because of the intermittent nature of the wind resource, its production timing and duration is not easily predictable the previous day, unlike the more traditional forms of power production such as coal, natural gas and nuclear generation resources. Hence, transmission policies that impose stringent scheduling requirements, including non-cost based imbalance penalties, or otherwise fail to accommodate the characteristics of the generation resources result in implicit discrimination against non-traditional resources like wind. Additionally, wind generation is only feasible where the "fuel" resource exists. Because the wind resources are typically remote from load centers, the development of wind generation requires development of associated long-distance transmission lines that reach those locations. Therefore, to avoid penalizing wind generation,

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<sup>1</sup> The 2000 Report is available at <http://www.awea.org/policy/documents/transmission.PDF>.

pricing policies should avoid structures that discriminate against more remote generation resources. Finally, because wind generation has been a relatively new (and growing) entrant into the competitive marketplace, policies that favor existing resources or grandfathered rights can create undue discrimination or barriers to entry for wind.

As noted in the 2000 Report, the particular characteristics of wind power must be considered by policy makers to determine the fairness of proposed and existing transmission policies. Otherwise, policies that appear to be nondiscriminatory on their face can have a discriminatory impact against wind in the marketplace, and can frustrate the objective of fuller utilization of the nation's wind energy resource.

The 2000 Report identified the five highest transmission policy priorities of the American Wind Energy Association:

- (1) the allocation of embedded costs of transmission facilities,
- (2) schedule deviation penalties in the creation of real-time balancing markets,
- (3) the elimination of rate pancaking,
- (4) the equitable allocation of congested capacity among competing users, and
- (5) the nondiscriminatory interconnection of new generation facilities.

### Overview of Recent Major Policy Developments

Before reviewing and updating the five highest transmission policy priorities, a brief review of major market developments since the 2000 Report will be helpful. There were two major “proactive” market design initiatives developed at the FERC: Order 2000 (regarding RTO development) and the Standard Market Design (“SMD”) Notice of Proposed Rulemaking (“NOPR”) (regarding standards for a national wholesale electric market structure). We label these proceedings as “major proactive initiatives” because: (1) they were initiated as efforts to advance the competitive market structure that began with Order 888; (2) they address a very broad set of transmission issues; and (3) their potential application governs all transmitting utilities nationwide. Additional proactive actions by FERC include two generation interconnection NOPRs—one for generators less than 20 MW capacity and the other for larger generators. The SMD and the two interconnection NOPRs are pending before FERC at the time of this writing. Order 2000 is in place, but, as a practical matter, has not been implemented.<sup>2</sup> As described in greater detail below, these major FERC policy developments reflect successful efforts by AWEA to shape policies that are conducive to wind development. However, because the proceedings continue to evolve, diligence will be required—particularly with respect to subsequent implementation of those policies

FERC has also undertaken a number of “reactive” steps that may impact the evolution of competitive markets, and therefore have the potential to impose requirements that are inconsistent with the characteristics of remote and intermittent generation such as wind power. The reactive proceedings follow from the fall-out of the Enron scandals and California's market-

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<sup>2</sup> Only one RTO (Midwest Independent System Operator (“MISO”)) has been certified under the Order 2000 standards and MISO has yet to implement the tariff that conforms to Order 2000 principles.

structure meltdown. When viewed from a distance, these evolutionary pressures on market design have some wind-specific implications. First, accusations about “gaming” in the marketplace have driven certain market-rule changes intended to address the exercise of market power via physical or economic withholding, or significant intentional deviations from final schedules. Examples include: (1) outage reporting requirements, potentially coupled with either a “must-offer” or other “availability” standard; (2) penalties associated with significant schedule deviations; and (3) bidding limitations intended to identify and curb market power abuses on an *ex ante* basis, such as the “automated mitigation procedure” or AMP.

Outage reporting and availability standards or requirements are typically focused on non-intermittent fossil and nuclear facilities where strategic withholding of supply is a behavioral possibility, although such regulations may not exempt intermittent technologies. Generally speaking, intermittent resources, by their nature, cannot pursue withholding strategies where subsequent operations cannot be certain. To the extent that the scheduling rules do not incorporate a mechanism specifically tailored to intermittents, such as the intermittent scheduling mechanism adopted in California<sup>3</sup>, rules that penalize schedule deviations (positive or negative) will have greater—and unreasonable—impacts on intermittent resources. *Ex ante* market power mitigation measures like AMP that force resources to bid close to operating costs do not work for resources like wind that essentially have no variable operating costs.

#### *Order 2000 and SMD NOPR*

FERC’s Order 2000, released in December 1999 and further refined in February 2000, directed the creation of Regional Transmission Organizations (“RTOs”) in an effort to foster more efficient, regional markets throughout the Nation.<sup>4</sup> The Order directed that transmission-owning entities place their assets under the operational control of an Independent Transmission Provider (“ITP”) entity (whether an the RTO or Independent System Operator (“ISO”)), thereby improving operational efficiency, improving competitive market functions and eliminating the potential of discrimination in access to the transmission network. Order 2000 established certain minimum characteristics and functions for RTOs. Order 2000 built upon the initial “open access” framework established under Order 888’s *pro forma* transmission tariff requirements. Although Order 2000 anticipated a December 2001 initiation date for RTOs throughout the Nation, the pace of development and the scope of controversies associated with individual RTOs caused that deadline to be abandoned. Although Order 2000 remains in force, implementation has been essentially superceded by SMD.

Following-on from the efforts of Orders 888 and 2000, in July 2002, FERC initiated an effort to standardize the design of markets operated by RTOs, ISOs or ITPs and replace the

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<sup>3</sup> CAISO’s Amendment No. 42 was adopted by FERC and referenced in the SMD NOPR. *See*, SMD NOPR, paragraph 275, page 157-158. *See also*, *California Independent Operator Corp.*, 98 FERC ¶ 61,327, order accepting compliance filing, 99 FERC ¶ 61,309 (2002).

<sup>4</sup> *Regional Transmission Organization, Order 2000*, 65 Fed. Reg. 208 (January 6, 2000), as modified on rehr’g, *Regional Transmission Organizations, Order 2000-A*, 65 Fed. Reg. 12,088 (March 2000).

Order 888 pro-forma Open Access Transmission Tariff.<sup>5</sup> This new Standard Market Design Notice of Proposed Rulemaking (“SMD NOPR”) effort was prompted by concerns that existing rules allowed continuing inefficiencies in interstate transmission. These inefficiencies include failure to efficiently operate and expand transmission facilities as well as undue discrimination in favor of native utility loads or affiliated power marketing efforts. The SMD NOPR also sought to remove so-called “seams issues” from the marketplace by eliminating, or at least minimizing, potential discrimination and market inefficiencies that can occur at the borders of adjoining control areas where differing pricing or other rules exist. Some central requirements of the standardized market envisioned by the Commission are: (1) centralized “spot” markets for energy, ancillary services and congestion mitigation; (2) elimination of rate “pancaking” across a region; (3) market-power mitigation measures; (4) creation of “congestion revenue rights” (“CRRs”) to help hedge costs associated with limited transmission capacity; (5) use of “locational marginal pricing” (“LMP”) for transmission costs that provide pricing signals for congestion and transmission investments; (6) a “resource adequacy” requirement to assure a sufficiency of supplies in support of reliability and reasonable market results; and (7) elimination of “point-to-point” service in favor of a pure network-oriented approach.

Most, if not all, of the regulatory policy refinements contemplated under the SMD NOPR are consistent with policies advocated by AWEA, including, for example, refined scheduling mechanisms that accommodate intermittent resources. However, some aspects of the SMD NOPR are controversial, leading to delays with the finalization of the rule and the subsequent development and implementation of the market design improvements within the various regions. Currently it appears that the effort will not progress uniformly. For example, the Commission has essentially severed Western market developments from other regions. At the time of this writing the Commission is reviewing the first phase of comments filed by a wide range of parties. In addition, FERC is hosting a series of technical conferences to address aspects of the SMD NOPR and reviewing additional comments in early 2003.

### *Interconnection NOPRs*

The interconnection of new generation resources and its interaction with the existing transmission grid, is the subject of two sets of NOPRs. In October of 2001 the Commission released an Advance Notice of Proposed Rulemaking (“ANOPR”) concerning standardized generator interconnection procedures and agreements.<sup>6</sup> FERC’s efforts here were intended to remove uncertainties and differences in both the processes and contractual terms related to interconnections, with the goal of removing some barriers to the entry of new generation. Additionally, the ANOPR sought to address the extent to which a new generation resource will be responsible—or not—for certain transmission network upgrade costs. The proposed policies highlight issues surrounding the “queuing” of new generation interconnections. By standardizing the processes and agreements associated with new generation interconnections, the Commission’s goal is to streamline the addition of new infrastructure by removing procedural uncertainty and significantly reducing transaction costs associated with contract negotiation.

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<sup>5</sup> *Remedying Undue Discrimination through Open Access Transmission Service and Standard Electricity Market Design, Notice of Proposed Rulemaking*, (“SMD NOPR”) (July 2002), as modified by three errata in August 2002. See, 67 Fed. Reg. 55,452 (Aug. 29, 2002), FERC Stats. & Regs. 32,563 (2002) in FERC Docket RM01-12.

<sup>6</sup> *Standardizing Generator Interconnection Agreements and Procedures, Advance Notice of Proposed Rulemaking*, (October 25, 2001), FERC docket RM02-1.

After a series of collaborative efforts, parties in the ANOPR (primarily utilities and representatives of larger thermal units) developed a “consensus” interconnection procedure (“IP”) and interconnection agreement (“IA”) in January of 2002. The Commission subsequently issued its Interconnection NOPR in April, 2002, generally based upon those consensus materials.<sup>7</sup> Significantly, the consensus proposal did not adopt or address streamlining proposals advanced by advocates for renewable energy. Comments on the Interconnection NOPR were filed in June 2002.

In response to these comments, including notably comments from AWEA, the Commission released a new ANOPR aimed at interconnection procedures and agreements for smaller generation resources, i.e., those under 20 MW, with additional differentiation for resources under 2 MW.<sup>8</sup> The ANOPR recognizes that many of the smaller interconnections will be associated with renewable wind or solar facilities. The intention of the ANOPR is to provide interconnection rules and agreements that are even more streamlined for smaller resources that are more likely to have *de minimus* impacts on the larger transmission system. Also, in response to further comments from AWEA and others, the FERC has agreed to hold technical conferences in January 2003, on details of the large generator Interconnection NOPR and its conformance to the proposed SMD tariff.

#### Review and Update of the Five Highest Transmission Policy Priorities

Given these major regulatory developments since the 2000 Report, we now undertake a detailed review and update of the five topic areas developed in that report. Those five policy priorities are:

- (1) the allocation of embedded costs of transmission facilities,
- (2) schedule deviation penalties in the creation of real-time balancing markets,
- (3) the elimination of rate pancaking,
- (4) the equitable allocation of congested capacity among competing users, and
- (5) the nondiscriminatory interconnection of new generation facilities.

It bears repeating that while the FERC may have announced policies that address certain of these concerns, most of the proceedings are not completed and diligence will be required to assure that erosion does not occur prior to finalization of the regulatory policies. Moreover, simply because regulators may adopt policy directives consistent with AWEA’s transmission policy priorities, additional work will be required to assure that those policy directives are fully implemented. Nonetheless, the discussion below reveals that FERC has expressed support for the policy positions advanced by AWEA in the 2000 Report on nearly all of the priority issues.

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<sup>7</sup> *Standardization of Generator Interconnection Agreements and Procedures, Notice of Proposed Rulemaking*, FERC Stats. & Regs. ¶ 32,560 (April 2002).

<sup>8</sup> *Standardization of Small Generator Interconnection Agreements and Procedures, Advance Notice of Proposed Rulemaking*, (August 2002). FERC docket RM02-12.

## *Priority No. 1: The Allocation Of Embedded Costs Of Transmission Facilities*

### A. The Problem

“Embedded costs” are the capital invested in the construction and operation of existing facilities. This fixed cost component of transmission costs can be recovered through charges (generally referred to as “access charges”) assessed to users or generators of electricity, or to both.<sup>9</sup> Historically, some utilities have charged generators for embedded costs, calculating the rate according to the distance between the generating facility and load center. Some utilities have also charged generators based upon their maximum (or “peak”) use of the transmission system within a given time period rather than the average use or the number of kilowatt-hours of use over that time period. Both of these policies result in disproportionately increasing embedded costs charged to wind generators. Distance-based allocation of embedded costs increases the share paid by wind because wind facilities are usually sited at locations that are remote from load, and allocation based on peak use results in a higher rate because of the intermittent nature of wind generation. Such policies have in the past served as a barrier to entry for new wind facilities.

### B. The Solution

In its 2000 assessment of this issue, AWEA’s preferred solution was a policy that: (1) allocates embedded costs to end-use customers rather than generators; (2) allocates costs on a “postage stamp” or “license plate” basis, i.e. without respect to location of the source of generation; and (3) reflects charges based on average or kilowatt-hour use of the transmission system rather than peak demand.

As discussed in the 2000 Report, the allocation of embedded costs to end-use customers makes sense for several reasons. First, end users end up paying for embedded costs anyway – either directly as an access fee or indirectly as a component of generator’s energy charges. Second, charging end users for system embedded costs more accurately identifies the charge as a means of paying for past investments in infrastructure rather than as a generation-related cost. Finally, this policy recognizes the important distinction between sunk costs in the existing integrated grid (which should logically be assessed on an averaged basis) and incremental costs associated with adding generation (which generators pay separately in the form of congestion costs and transmission loss adjustments).

### C. 2002 Assessment

Three years ago, when AWEA originally undertook to examine this issue, there was no single accepted approach to embedded cost recovery. The California Independent System Operator (CAISO), one of the first functional ISOs, had adopted a policy of collecting embedded costs through an access charge paid by end users. The CAISO access charge was a “license

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<sup>9</sup> Access charges are generally assessed on all transactions making use of a transmission provider’s system, including transactions where the generator and load are located within the same system, and where either the generator or the load (or both) are located outside of the transmission provider’s system.

plate” rate, i.e. a charge for use of the entire ISO-controlled grid that was based on the revenue requirement of the transmission owner in the zone in which the end user was located. AWEA supported that approach conceptually and advocated for its adoption in FERC proceedings for implementation of Order 2000, and in comments in response to the SMD Options Paper.

In the SMD NOPR, FERC has conceptually adopted the approach favored by AWEA, citing reasons that reflect some of AWEA’s concerns:

First, we propose that transmission owners recover embedded costs through an access charge assessed mainly to load-serving entities, based on their respective shares of the system’s peak load, i.e. their load ratio shares. Our goal is to minimize the distorting effects that an access charge can have on economic choices. We propose to assess access charges primarily on loads, but not on generators, because the economic choices of loads (such as where to locate) are less likely to be affected by access charges than are the choices of generators. Moreover, even if access charges were imposed on generators or other market participants, it is likely that they would pass along most or all of their access charges to their customers, so that loads would ultimately bear most or all of the transmission fixed costs.<sup>10</sup>

Under FERC’s proposal, customers paying access charges would receive Congestion Revenue Rights (“CRRs”), or alternatively, revenues from the auction of CRRs. Thus, in exchange for paying the fixed costs of the transmission system, load-serving entities would receive the financial benefits – the stream of congestion revenues – resulting from usage of the transmission system.<sup>11</sup> The SMD access charge would at least temporarily permit the use of license plate rates such as those that are currently in effect within ISOs, but FERC is contemplating requiring postage stamp rates in all regions after a transitional period.<sup>12</sup> As for inter-regional transfers, the SMD NOPR proposes that the current practice of charging multiple access fees be replaced by a policy under which export transactions would only pay the access charge for the transmission system where power is ultimately delivered to load.<sup>13</sup>

AWEA has submitted SMD comments supporting FERC’s policy of allocating access charges to load, and it appears likely that FERC will continue to support this approach to collection of embedded costs. However, there are several potential obstacles to its implementation in a manner that benefits wind development. Therefore we recommend that AWEA continue to pursue this issue, with particular attention to the following areas:

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<sup>10</sup> SMD NOPR ¶ 169.

<sup>11</sup> FERC also proposes to maintain the explicit and implicit transmission rights currently held by customers. CRR allocation issues are discussed separately below.

<sup>12</sup> SMD NOPR ¶ 174.

<sup>13</sup> SMD NOPR ¶ 180. However, the transaction would still be responsible for applicable congestion charges and transmission losses in the originating and any intermediate transmission systems.

- (1) There is some resistance to mandated standardization of cost recovery methodology. While FERC has attempted to head off such criticisms by allowing for the possibility of regional variations and empowering Regional State Advisory Committees, it is likely that there will be continued opposition to standardization, and delay in the implementation process as a result. AWEA needs to continue to actively defend SMD in general, and a standardized methodology for embedded cost recovery in particular. AWEA should also continue encouraging the Commission to adopt SMD policies such as this one on an incremental basis.
- (2) While FERC's SMD NOPR espouses embedded cost recovery policies that are conceptually in line with the interests of wind development, there is a danger of losing ground in implementation. AWEA should remain actively involved in the SMD proceeding, and should also monitor the RTO proceedings that are taking place simultaneously.
- (3) The issue of embedded cost recovery is closely related to the issues of cost recovery in inter-regional transfers and also the allocation of CRRs. While FERC has subdivided the issues for purposes of discussion in the SMD proceedings, they all relate to the central question of wind's access to transmission at a fair and reasonable price. AWEA needs to coordinate its participation in proceedings addressing each cost component.
- (4) The determination of what is included in "embedded costs" has important implications for wind developers. One key question, which crosses over to the Interconnection NOPR proceedings, is whether and to what extent upgrades to the integrated transmission grid will be included as part of embedded costs. This has historically been an issue of intense dispute between wind developers and transmission providers, and will continue to be until FERC develops clear and fair cost allocation guidelines *and* adopts procedural reforms that remove cost allocation decisions from the discretion of the utilities. Again, this is an area that is currently under discussion in SMD workshops and in the Interconnection NOPR proceedings.<sup>14</sup> These issues have significant financial implications for development and siting of new wind facilities, and should be followed closely. The vertically integrated utilities have significant financial incentives to impede reform in this area, and to promote policies that allocate a large proportion of expansion costs to new generation. AWEA should actively participate in discussion of upgrade cost allocation in FERC proceedings (both SMD and Interconnection) and in the development of RTO/ISO policy in the region-specific proceedings.

### *Priority No. 2: Schedule Deviation Policies*

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<sup>14</sup> See SMD NOPR ¶¶ 191-202. FERC has proposed that under SMD costs for system expansion will be allocated to whoever benefits, through a "participant funding" mechanism administered by the Independent Transmission Provider. In the absence of independence, the Commission would employ a presumption of regional benefits and a "bright line" policy allocating upgrades of 138 kV and above region-wide, and those below 138kV to a sub-region (e.g. a single transmission owner or a license plate zone). FERC has also invited other pricing proposals from participants in the SMD process.

## A. The Problem

In its initial order (Order 888) implementing open access to the transmission grid, FERC mandated *pro forma* tariff provisions imposing financial penalties for deviations by generators from filed schedules. The rationale for such penalties is to ensure accurate scheduling, and the underlying assumption is that all generators are capable of accurately forecasting their hourly transmission requirements well in advance. Of course, in reality this is not the case for intermittent generation sources such as wind<sup>15</sup>, whose output varies according to changes in the weather and cannot be accurately forecast except in the hour or two immediately preceding generation and delivery of power into the grid.

The bandwidth for deviation under most of the Order 888 tariffs in effect around the countries is extremely narrow, and the penalties for scheduling deviations are significant compared to commodity prices. As a result, existing scheduling deviation policies have functioned as a major deterrent to wind development. In many cases, the tariffed schedule deviation penalties exceed the commodity value of the wind energy being delivered.

## B. The Solution

FERC has acknowledged that schedule deviation policies are ineffective, economically inefficient, and unfair as applied to intermittent resources. Both FERC and system operators are taking incremental steps toward addressing the problem. First, in Order 2000, FERC instructed RTOs to develop real time balancing markets in part to accommodate intermittent generation sources.<sup>16</sup> At the same time, some system operators, notably the NY ISO and ERCOT, implemented exceptions to scheduling rules in order to allow intermittent resources to deliver power in real time without incurring penalties. The PJM ISO adopted a market structure and a tariff that operates without penalties for schedule deviations and thus “naturally” accommodates intermittent resources.

Next, in response to an initiative by wind industry representatives, the California ISO formed a collaborative from which emerged new tariff provisions for scheduling intermittent resources. Under the CAISO program, participating intermittent generators are required to submit schedules that are formulaically consistent with hourly forecasts. The forecasts are determined according to a methodology jointly developed by CAISO and an industry working group. The forecasting protocol is subject to ongoing independent oversight, and is continuously monitored and updated to ensure accuracy and avoid bias. Deviations are allowed to average out on a monthly basis, and participants are responsible for paying settlement amounts equal to their net monthly deviations at a monthly average price, which are expected to be *de minimus* if the

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<sup>15</sup> Many resources other than wind, notably “demand response” or customer actions to reduce consumption during shortages or periods of high prices, share this characteristic.

<sup>16</sup> Order 2000 at p. 423.

forecasting protocol is working properly. The CAISO proposal was submitted as a tariff amendment and approved by FERC.<sup>17</sup>

In the SMD NOPR, FERC has taken a step further toward institutionalizing scheduling reforms to accommodate intermittent resources. FERC again has mandated creation of real time markets, and FERC expressly proposed that the CAISO scheduling option be adopted as part of SMD. Meanwhile, other system operators confronting the need for creating scheduling policies appropriate for wind have adopted (or in some cases are in the process of adopting) interim procedures requested by wind developers and AWEA in order to exempt wind from existing deviations penalties. For example, the Bonneville Power Administration has exempted wind generators from high minimum penalties in its current tariff and has proposed exemptions for wind from most, but not all, energy imbalance penalties in its new proposed tariff.

### C. 2002 Assessment

In mid-2000 AWEA decided to make the elimination of discriminatory scheduling rules its most immediate priority in the campaign for transmission policy reform. That effort has paid off, and AWEA can be justifiably proud of the progress it has made in just two years on this important issue. However, there is much work to be done before the industry can be assured that scheduling policies appropriate for intermittent resources are in place nationwide. Future efforts should be directed as follows:

- (1) Follow through on FERC's initiative in the SMD NOPR. While FERC has recommended universal implementation of the CAISO program, the SMD NOPR correctly notes that the California proposal was not designed for a day-ahead market. FERC also queries whether the CAISO program can be adapted to regions where there is less wind development. AWEA has provided initial comments on how to implement the CAISO program in the context of SMD, and asked FERC to adopt it immediately as a transitional policy imperative. AWEA's efforts at FERC on this issue should continue, and AWEA should make every effort to continue playing a leadership role through the implementation phase.
- (2) At the same time that AWEA is working on implementation of scheduling policy reform in the context of SMD, AWEA should monitor and participate if necessary in FERC proceedings dealing with individual RTO/ISO/ITP proposals, since this is where crucial policy implementation details will be worked out.
- (3) Although the CAISO program has been approved and is in place, it is not currently operational. Regulatory uncertainty and other factors have delayed new project development in California, and existing wind QFs are still allowed to be scheduled as "negative load" in utilities' portfolios. AWEA should ensure that the CAISO program is implemented as soon as possible. We understand that new

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<sup>17</sup> *Order Accepting In Part And Rejecting In Part Tariff Amendment 42*, 98 FERC ¶ 61, 327 (2002); *Order Accepting Compliance Filing*, 99 FERC ¶ 61,309 (2002).

wind projects should be coming on line in spring 2003, and it is important that both these projects and QFs begin operating under the new scheduling protocol.

- (4) As other new intermittent technology projects (e.g. solar and especially demand response) emerge, AWEA should coordinate with project developers and trade associations to ensure that intermittent resource scheduling protocols are adapted and implemented effectively. It will serve the interest of wind development to ensure that scheduling protocols designed for intermittent resources are available to all eligible customers.

### *Priority No. 3: The Elimination of Rate Pancaking*

#### A. The Problem

The concept of “rate pancaking” comes from the potential transmission pricing impact on remote resources that are forced to cross multiple system boundaries to deliver power to loads. In such situations, each control area (or zone within a control area) may have distinct transmission access charges. The resulting rate pancaking can yield an inequitable result for more remote resources, such as wind. Pancaked rates create regional market inefficiencies, and are typically one of the readily identifiable “seams issues.”

#### B. The Solution

The 2000 Report recognized that the best solution to this problem is to eliminate it through the development of regional markets, such as the RTOs envisioned by Order 2000.<sup>18</sup> AWEA supported those aspects of RTO requirements in Order 2000 that eliminate rate pancaking. However, the 2000 Report noted significant concerns about the pace and scope of implementation of Order 2000.

#### C. 2002 Assessment

AWEA’s concerns regarding the scope and pace of Order 2000 implementation have been justified, and although the Commission’s initial policy pronouncements on pancaking are laudable, not much progress has been made in RTO formation.

The SMD NOPR is explicit with respect to the elimination of rate pancaking:

170. Second, we propose to eliminate all “rate pancaking,” which involves charging separate embedded cost charges for moving power over separate Independent Transmission Provider service areas. We propose to eliminate rate pancaking both within an Independent Transmission Provider’s service area and between service areas. Rate pancaking impedes the ability of distant generators to compete with nearby generators by imposing charges to transmit energy from distant generators that are unrelated to actual variable transmission costs.

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<sup>18</sup> See, 2000 Report, pages 8 – 9.

Assessing the access charge primarily to load-serving entities based on their load ratio share rather than on the number of service areas over which energy is transmitted increases generation competition by allowing distant generators to compete more easily with nearby generators. (SMD NOPR, paragraph 170, page 97-98.)

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183. Rate pancaking across the numerous transmission owning utilities that comprise the RTO has been eliminated by the implementation of license plate rates, while continuing to provide an opportunity for the transmission owners to recover their full revenue requirements. We propose that the same or a similar rate structure should be applied to inter-regional transfers. In a competitive market environment, reliability and the supplier's cost of generation, rather than sunk transmission costs, should be the primary drivers for a customer's choice of power suppliers. To the extent rate design facilitates that result, transmission owners would have a greater incentive to join an RTO based on where their transmission facilities most benefit customers and markets, not on where their generators have better opportunities to make off-system sales (i.e., an access charge for exporting power from one region to a neighboring region should not be the deciding factor). (SMD NOPR, paragraph 183, page 104.)

In light of the Commission's policy announcements in Order 2000 and the SMD Order, it is clear that from a policy perspective the inequities and inefficiencies associated with rate pancaking, as well as the potential barrier to market entry for remote wind resources, has been squarely—and properly—addressed. However, given the delays facing the development of new RTOs, ISOs and ITPs, diligence is required to assure that timely and effective implementation will take place.

#### *Priority No. 4: Transmission Capacity Allocation and Congestion Mitigation Policies*

##### A. The Problems

As noted earlier, the fourth priority issue identified in AWEA's earlier paper concerned policies to deal with transmission congestion. In that paper, AWEA identified that wind facilities are especially vulnerable to congestion because of their generally remote location with respect to major loads and their greater dependence on inter-regional transmission. They are also more vulnerable because they are new market entrants without "grandfathered" transmission rights. AWEA identified two fundamental problems affecting wind development related to congestion: (1) the allocation of congested capacity on a "grandfathered" or other discriminatory basis; and (2) the problems of intermittency in bidding for congested capacity. As discussed below, FERC policy has moved in the direction suggested by AWEA with regard to both aspects of the congestion problem.

#### Elimination Of "Grandfathering" And Other Forms Of Discrimination

## B. The Solution

In the 2000 Report, AWEA suggested that FERC move toward policies that eliminate “grandfathering” and discrimination with regard to allocation of congested capacity:

“Congested transmission capacity should be allocated without regard to time of entry in the market. “Grandfathering” or “first come, first served” allocation schemes are an inherent barrier to entry for any new market participant, not just wind facilities. However, they have a particularly egregious impact on wind facilities due to these facilities’ greater vulnerability to congestion. Instead, congested transmission capacity should be allocated based upon the societal value of the transactions involved. [Footnote omitted]. At a minimum, this means that transmission users should be able to bid for congested capacity on an equal-footing. This will ensure that such capacity is allocated to those who value it most.”

## C. 2002 Assessment

With regard to this issue, FERC’s response has been almost perfectly consistent with the direction sought by AWEA. This is reflected, for example, in the Commission’s “SMD-101” summary of its recent proposal for a standard market design:

“A primary difference between the existing form of network service and the new tariff the Commission proposes is a feature creating a market for firm transmission rights to lock in a fixed price for transmission across power-grid bottlenecks. This approach assures that customers who value the transmission pathway the most will get to use it.” [“SMD-101” at p. 5]

As the foregoing summary indicates, the proposed SMD policy reflects FERC’s agreement with AWEA that congested capacity should not be allocated based on time of market entry or other discriminatory criteria. FERC’s proposal for congestion pricing and related tradable CRRs, together with its proposal that transmission-owning utilities bid for capacity on an equal footing with other users, comprises essentially the policy advocated by AWEA to eliminate preferential access to congested transmission capacity. While obviously final adoption and implementation of this policy remain major challenges, the policy debate at the FERC is heading in the direction supported by AWEA in the earlier paper.

### The Problems of Intermittency in Bidding for Congested Capacity

#### A. The Problem and Solution

However, fair allocation of congested capacity does not remove congestion as a serious barrier to wind development. Due to its intermittent nature, wind energy faces disadvantages even where congestion is allocated based purely on value. AWEA’s 2000 Report noted this problem and suggested solutions:

Thus, while an improvement, these bidding systems do not address all the needs of the wind industry. To truly address the congestion problem facing wind developers, the FERC needs to take additional action. AWEA has identified three possible additional types of solutions which separately or in combination can help address this problem: 1) eliminating congestion through upgrades; 2) allowing wind to bid for congested capacity closer to the operating hour; and 3) to allocate capacity reserved for “N-1” reliability to intermittent resources on a “non-firm” basis subject to curtailment when needed to maintain system reliability.

AWEA’s preferred solution for congestion is that it be eliminated through transmission upgrades. Policies which ensure rational planning and timely installation of upgrades to relieve congestion will have the ancillary benefit of supporting the introduction of additional wind generation. Furthermore, such policies will increase electric competition by reducing the segmentation of markets caused by congestion. Accordingly, AWEA urges FERC to adopt policies which strongly encourage transmission congestion relief.” (AWEA paper at 11).

#### B. 2002 Assessment

The FERC has done little with regard to expressly allowing wind to bid for congested capacity nearer to real-time (although it has addressed the related problem of deviation penalties as discussed earlier). However, FERC’s proposed SMD policy eliminates the firm/non-firm distinction and therefore should aid in making available formerly “non-firm” capacity, assuming the policy is properly implemented and reflected in available capacity determinations. However, it is unclear at this juncture how the FERC’s proposed market design will impact determinations of available capacity (such as the “N-1” issue discussed in the earlier paper).

But as to AWEA’s preferred congestion solution—building new capacity to eliminate congestion—the FERC concurs:

“By providing predictable rules and clear rewards for investment, the Commission expects the proposal to spur needed expansion of the nation’s highly interconnected electricity grid.” (SMD-101 at p. 5).

In the NOPR itself, the Commission again makes clear its agreement that new transmission investments should be encouraged:

“191. The existing transmission grid has fallen far behind the demands that have been placed on it. Over the last ten years, we have seen a strong increase in the amount of new generation, which has been built largely in locations that make the most economic sense for the builder of the generation (i.e., where land is affordable and economic sources of fuel, water and labor are near). However, we have yet to see a parallel jump in construction of transmission infrastructure. The absence of needed new transmission facilities has led to more and more congestion, which hinders customers from seeking and depending on more distant and competitive supply choices.” (SMD NOPR at p. 108).

To encourage new upgrades, the Commission has or proposes to put in place several reforms. One is the concept of RTOs, which will help bring a more regional focus to transmission planning and thereby encourage broader markets and regional cooperation. RTOs (or ITPs) also provide a critical measure of independence in the determinations regarding the need for transmission expansion, removing barriers created by placing these decisions in the hands of market participants that may benefit from congestion. AWEA strongly supports this concept for many reasons, including that it will encourage regional transmission upgrades.

Another policy is the congestion pricing mechanism described above. This pricing policy will send an appropriate signal regarding the value of congestion relief to all market participants—including utilities formerly immune from it. This price signal will provide an incentive for expansion. AWEA supports the policy for that and other reasons.

A third mechanism is reform of FERC policy regarding the pricing of transmission expansion. There the SMD NOPR proposes the right policy goal but a pricing reform that may pose potential problems:

196. Our goal is to remove any cost recovery impediments to transmission expansion so that needed upgrades get built now. Traditional means of expansion pricing may not be the most effective way of encouraging new transmission infrastructure, in part perhaps because they do not take into account the wide regional benefits of higher voltage upgrades that can accrue beyond a single transmission owner's system.

197. We believe that a more precise matching of beneficiaries and cost recovery responsibility would encourage greater regional cooperation to get needed facilities sited and built. Our preference is to allow recovery of the costs of expansion through participant funding, i.e., those who benefit from a particular project (such as a generator building to export power or load building to reduce congestion) pay for it.

198. The Generator Interconnection proposed rule introduced the idea that participant funding may be an acceptable pricing policy where an independent entity determines: (1) the cost of and responsibility for needed upgrades; (2) congestion price signals to which the customer responds (along with Congestion Revenue Rights); and (3) the assumptions underlying the power flow analysis. [fn. omitted].

199. The Commission envisions that, under Standard Market Design, the Independent Transmission Provider will perform all of these functions, which will allow the Commission to consider the use of participant funding. However, full compliance with Standard Market Design will take some time. We are eager to see new infrastructure in place as soon as possible and believe that participant funding will be a useful tool to make that happen. Accordingly, we propose that, for proposed transmission facilities that are included in a regional planning process which is conducted by an entity, whether an RTO, ISO, or other

independent entity, that is independent, we will consider participant funding for that project.

200. In the absence of independence, we would apply a default pricing policy that would recognize the regional benefits of transmission expansions. Under this default policy, we propose to roll-in on a region-wide basis all high voltage network upgrades of 138 kV and above. Since lower voltage, sub-regional transmission needs are less likely to benefit the whole region, the cost of network facilities below 138 kV could be more appropriately allocated to a sub-region (e.g., a single transmission owner or a “license plate” zone) where the expansion facilities will be located. Consistent with our proposal for interregional transmission service pricing, costs would be allocated to the region that benefits from the expansion, which may not be the same as the region in which the expansion facilities are located. This proposal recognizes that high voltage expansions can have benefits beyond the borders of the local transmitting utility and, therefore, assigns a portion of these costs to more distant beneficiaries.” (SMD NOPR at p. 110-112).

AWEA supports the FERC “rolled-in” approach in the absence of independence, and also supports allowing participant funding with appropriate incentives (including perhaps provision of CRRs) on a voluntary basis. However, AWEA believes there is also a place for continued “rolled-in” regional pricing of upgrades even where there is independent administration. Indeed, in principle the Commission agrees, as shown by its decision to continue allowing “rolled-in” pricing for upgrades that enhance regional reliability. (*See* SMD NOPR ¶194 at p. 109). AWEA believes this principle is also applicable to some other upgrades as well and would not support *mandatory* participant funding for *all* “economic” upgrades. AWEA believes the Commission should allow RTOs / ITPs to price regional upgrades on a “rolled-in” basis when reliability *or other* regional benefits exist.

In particular, where a state or region determines that regional ratepayers will benefit from new transmission due to greater generation diversity (including the greater generation reliability that flows from such diversity), the Commission should defer to a state or region’s determination that all regional ratepayers are beneficiaries of such policies. In such a case, the Commission should allow “rolled-in” pricing for such transmission expansion facilities even where the regional benefit is not confined to just transmission reliability.

Overall, AWEA gives the Commission high marks with respect to its congestion management policies. If the SMD proposals are adopted as proposed and implemented consistently with the stated goals, wind projects will benefit from a more fair allocation of congested capacity as well as a reduction in congestion. Looking ahead with regard to this issue, AWEA needs to focus on the successful final adoption and implementation of the proposed policies. Apart from that, the remaining policy issues are ensuring curtailable access to “N-1” capacity, continuing to work on proposals allowing congestion bidding nearer to real-time and adoption of rolled-in pricing for upgrades that provide regional generation diversity. These issues need to be highlighted in the FERC workshops and next round of SMD Comments in early 2003.

## *Priority No. 5: Nondiscriminatory Interconnection Policies*

### A. The Problem

As detailed in the 2000 Report, wind development has been substantially inhibited and delayed by discriminatory interconnection policies and discriminatory administration of the interconnection process by self-interested utilities. Interconnection is an essential prerequisite to market access. However, the interconnection process has been (and remains) largely within the control of vertically integrated utilities with an incentive to bar entry to the market.

Interconnection problems affecting wind generation fall into two rough categories. First, there is the problem of policies and regulations that are not appropriate for wind. For example, existing rules regarding interconnection system impact and facilities studies were mostly designed for larger thermal projects. They are disproportionately costly and are not easily adaptable for the sort of phased project development that is characteristic of wind projects. Similarly, existing rules generally assess interconnection costs based on peak generator output on peak transmission loading days. Peak transmission line loadings generally occur on hot windless days. Therefore, wind projects are assessed upgrade costs for bottlenecks they will never cause and which, almost by definition, are uneconomical to relieve because they occur so rarely.

The second area in which wind development experiences problems is in the lack of an independent entity to administer the interconnection process. Historically, the same vertically integrated utilities that were competing with wind for market share in generation have also been in charge of interconnecting new generation facilities. Utilities have had broad discretion in designing and performing system impact and facilities studies, which are used to determine the cost of interconnection. Utilities also have been in charge of managing the interconnection “queue,” which directly affects the timetable for project development. While Order 888 and 889 slightly improved the access to information by mandating the posting of some information on OASIS bulletin boards, much of the utilities’ administration of the interconnection process has essentially taken place inside of a “black box,” making it very difficult to understand, let alone challenge the exercise of discretion by utility transmission providers.

The primary legal recourse for utility abuse of discretion is through an action at FERC under sections 202 and 210 of the Federal Power Act. However, that remedy is inadequate because it takes a disproportionate investment in time and resources. For new wind projects, financing, permitting, tax and other development deadlines do not accommodate lengthy litigation delays.

### B. The Solution

In the 2000 Report we concluded that the two principal solutions to the problems described above are standardization of requirements and independent administration of the interconnection process. Efforts in both areas are well underway, but the reform process is far from complete.

The first efforts toward standardization on a regional and national scale are underway, largely as a result of aggressive advocacy on the part of renewable energy producers. After a

lengthy (and relatively unproductive) collaborative process, FERC issued its generic Interconnection NOPR in April 2002. However, the Interconnection NOPR itself did not significantly advance the effort toward standardization. While it did propose rules and deadlines for processing interconnection requests, it did not establish a process for development of specific standards for conducting interconnection studies or administering the queue, and it also did not address the needs for separate standards applicable to small generators. AWEA and other industry participants have urged FERC to include these key reforms in the NOPR process, and have had some initial successes.

Notably, earlier this year FERC issued a companion ANOPR addressing interconnection standards for small (less than 20 MW) generators. That ANOPR proceeding has provided a critical forum for discussion of the issues and development of consensus standards that will be truly workable for smaller intermittent generators. AWEA has participated in the consensus process and is planning to file comments largely supporting the proposed tariff recommendations. In the meantime, FERC has not yet issued a final rule in the Interconnection NOPR process, partly due to continued lobbying by AWEA to address the weaknesses in the NOPR itself. This issue will be resolved within the next few months.

With respect to the other key interconnection issue, independent administration, FERC has taken a strong stance in both the Interconnection NOPRs and the SMD proceeding. Recognizing the potential for discrimination and arbitrary exercise of discretion, FERC has taken the position that the interconnection process should be administered by an Independent Transmission Provider rather than the transmission-owning utilities. This is an important first step toward the elimination of interconnection as an obstacle to wind development.

### C. 2002 Assessment

In the area of interconnection reform, some initial progress has been made in the past few years. However, sustained effort will be needed to ensure that the first steps result in genuine change. Interconnection policy is at a crucial crossroads, with the current NOPR proceedings creating rules that will be in effect for years to come. It is extremely important that the standards and protocols being developed in these proceedings work for wind. For this reason, AWEA should devote careful attention to interconnection issues, particularly in the context of these regulatory proceedings.

- (1) AWEA should continue its efforts in the FERC Interconnection NOPR proceeding. This is the proceeding in which interconnection procedures will be established for generators of 20 MW or more.<sup>19</sup> The proposed rule is flawed to the extent that it leaves certain study functions in the hands of the utilities and does not establish specific standards to govern the exercise of utility discretion. AWEA has urged FERC to remedy this shortcoming by convening workshops to address standards, and AWEA is urging FERC to issue the final rule so that at

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<sup>19</sup> Whether the distinction between large and small generators will be drawn at 20 MW is still a subject of debate at FERC. Some utilities are arguing in the small interconnection ANOPR that this threshold should be lower.

least partial reform can be accomplished without further delay. These efforts should continue.

- (2) The ANOPR effort for small generators is still underway, and needs continued monitoring and participation by wind industry advocates. The initial consensus policies for small generation will be an enormous improvement over the status quo, but there is continued resistance by the utilities, and it will take sustained effort to ensure implementation after the formal NOPR process is complete.
- (3) Closely related to the goal of ensuring that good, workable interconnection standards emerge from the current FERC proceedings is the need to work on transitional procedures. For example, AWEA and other advocates may be successful in obtaining FERC rules that mandate independent administration of the process by RTOs and ISOs, but in many jurisdictions RTO/ISO development is taking time. So in the meantime, there must be a proxy for RTO/ISO administration, or else any value associated with the current reforms may be lost for years. AWEA should work on developing innovative and workable transitional mechanisms to safeguard interconnection reform during the (probably lengthy) implementation period.
- (4) An emerging issue not explicitly addressed in the 2000 Report is queue management. Given wholesale discretion, the utilities have employed queue management practices that result in discrimination, confusion, and delay. Partly as a result of AWEA's advocacy, FERC has scheduled a workshop in January 2003 to discuss interconnection queuing issues. It will take a significant effort and sustained participation on behalf of wind advocates to ensure that the initial impetus toward reform of queue management ultimately bears fruit.
- (5) Closely related to the previous issue is the need for examination of current administration of OASIS sites. It is our understanding that utilities are not uniformly complying with even the minimal requirements for non-discriminatory information sharing mandated under Order 889. In addition, the Order 889 requirement needs to be carefully reviewed and critiqued with the objective of making the interconnection process and queue management more transparent and fair to all market participants.

### The New Priorities

As a matter of policy, the foregoing discussion demonstrates the remarkable progress that has occurred since the 2000 Report on AWEA's five priority transmission issues. It is fair to say that with the policies of the Interconnection and SMD NOPRs, FERC is now in general policy agreement with AWEA on most of these priority issues. Despite this success, however, AWEA must remain focused on these policies through their final adoption and implementation. That should be AWEA's first priority.

At the same time, however, events of the past two years also suggest that some refinement of AWEA's priorities is in order. For example, as discussed above, the issues of

scheduling deviations and congestion have taken on a different dimension in light of recent developments such as the California ISO forecasting procedure and the move away from point-to-point transmission service. Similarly, as also discussed above, AWEA must be cognizant of the impacts that various market power mitigation proposals not extant when the earlier paper was written (such as AMP) will have on intermittent resources.

Of all the newly-emerging issues, however, a highest priority must be given to interconnection of new wind generation and, specifically, the question of the interconnection “queue.” While interconnection issues were among the five priority issues identified in the earlier paper, it is now clear that this issue is gaining further prominence. Across the nation, the uncertainties of the queuing protocol and the related inflation of transaction and upgrade costs have posed a significant barrier for all new resources, not just wind facilities. However, because wind projects are smaller and quicker, their tolerance for many of the problems is not as great as for larger, longer lead-time projects. (Indeed, interconnection time problems negate one of the principal advantages of wind generation: its ability to come on line more quickly and thereby better match load growth).

Problems with the interconnection/queuing procedure include: (1) very high study costs associated with getting into, and then maintaining a place in, the queue; (2) inflated upgrade costs resulting from utility incentives to discourage competition and to fund improvements to their systems; (3) inflated upgrade costs resulting from “phantom” projects in the queue; (4) disconnects between the requirements for queuing and the requirements of project licensing and financing; (5) ambiguities regarding the degree to which interconnection requires mitigation of the economic impacts of congestion (as distinct from reliability impacts); (6) fundamental policy questions regarding the relationship between interconnection, deliverability and congestion management; and (7) inequitable allocation of upgrade costs for similarly situated projects based on queue position and the “lumpiness” of transmission upgrades.

FERC’s proposal for streamlined procedures for small generators in that ANOPR is an important forum for many of these issues. In addition, AWEA is encouraged that the FERC has scheduled a technical conference regarding the queuing issues as part of its SMD process. AWEA should place a high priority on addressing these issues as part of both the Interconnection and SMD NOPRs. The next six months are critical to cement these reforms into FERC standard practice. Implementation and enforcement at the regional level will be an enduring task for AWEA.

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