

**BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D.C.**

Regional Transmission Organizations

Docket No. RM99-2-000

**COMMENTS OF
THE NATIONAL WIND
COORDINATING COMMITTEE**

Contact:

Gabe Petlin
Senior Outreach Coordinator
National Wind Coordinating Committee

1255 23rd Street, NW, Suite 275
Washington, DC 20027

(202) 965-6209

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In response to Federal Energy Regulatory Commission (FERC) Notice of Proposed Rulemaking (NOPR) on Regional Transmission Organizations (RTO) issued on May 13, 1999, the National Wind Coordinating Committee (NWCC)¹ files this motion to submit late-filed comments. As a multi-party collaborative organization, the NWCC must reach consensus among

¹ The NWCC is a collaborative endeavor formed in 1994 that includes representatives from electric utilities and their support organizations, state legislatures, state utility commissions, consumer advocacy offices, wind equipment suppliers and developers, green power marketers, environmental organizations, and state and federal agencies. The NWCC identifies issues that affect the use of wind power, establishes dialogue among key stakeholders, and catalyzes activities to support the development of an environmentally, economically, and politically sustainable commercial market for wind power. More than 1,300 individuals from diverse sectors and wind resource areas across the country have contributed to the NWCC's collaborative efforts.

its diverse membership before releasing any public information. The reason for the late filing of these comments is the time required for the NWCC Steering Committee to approve this filing.

EXECUTIVE SUMMARY TO COMMENTS

Wind generation is an environmentally attractive electric power source approaching competitive economics and experiencing growing market acceptance in several regions of the United States. Over the past 15 months, some 1000 MW of new wind generation have been installed in this country. Unlike firm generation, wind is an intermittent resource. Wind power is generated only when the wind is available. In addition, wind resources are often most plentiful in remote areas. These characteristics make transmission a very important issue for wind. Transmission rules and tariffs will have a large impact on the continued success of wind power.

Fairly or unfairly, present-day transmission terms and conditions often do not work well for intermittent technologies such as wind. Firm transmission could result in an intermittent wind generator paying for transmission when the wind resource is unavailable, and secondary resale markets for transmission have generally not emerged. On the other hand, non-firm transmission may not always be available at times when the wind resource is available.

Wind characteristics and their relationship to transmission issues are addressed in an NWCC report that was published earlier this year². NWCC submits this report to the FERC for its consideration and review. It represents a body of carefully developed comments that are germane to the current rulemaking process on RTOs, and that reflect a broad consensus of the

² *Transmitting Wind Energy: Issues and Options in Competitive Electric Markets*. Additional bound copies of the report are available from NWCC upon request.

NWCC's diverse membership³. We enclose both a bound copy and a version in the prescribed FERC format. The report is also available on our web site at <http://www.nationalwind.org>.

In addition, the NWCC is currently conducting a series of new case studies on electric transmission issues as they affect wind energy generation and development. As these studies are completed, the NWCC will share relevant findings and information with the FERC. We also would like to participate in any additional regional or technical conferences on RTOs such as the FERC-led spring 2000 collaborative process proposed in the NOPR docket.

We hope FERC will consider these comments and the resources of the National Wind Coordinating Committee as it proceeds with this important rulemaking.

³ To encourage participation and ownership in the many projects sponsored by NWCC, the NWCC operates on a consensus basis; i.e., every member of the NWCC must accept (i.e., be able to "live with") the themes and conclusions of a report before it is published.

Transmitting Wind Energy

Issues and Options in Competitive Electric Markets

by

Andrew Brown
Christopher Ellison
Ellison & Schneider

Kevin Porter
National Renewable Energy Laboratory

National Wind Coordinating Committee
www.nationalwind.org

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PREFACE

Transmitting Wind Energy: Issues and Options in Competitive Electric Markets is a follow-up to an earlier National Wind Coordinating Committee (NWCC) report, *Wind Energy System Operation and Transmission Issues Related to Restructuring*, that was published in June 1998. That report was designed to provide an introduction to various utility system and transmission issues that may be of interest to the wind energy community. The NWCC commissioned this Phase 2 report in 1997 to expand upon the transmission issues identified in the earlier report, and a draft of this report was distributed to NWCC members for review in October 1997. This preface explains who the NWCC is, how this report originated, and how this report was prepared.

The NWCC is a multi-party organization with representatives from utility, environmental, state regulatory, consumer advocate, state legislative, and federal government organizations, in addition to green power marketers and wind energy companies. To encourage participation and ownership in the many projects sponsored by NWCC, the NWCC operates on a consensus basis; i.e., every member of the NWCC must agree or be comfortable with the themes and conclusions of a report before it is published. Primarily for this reason, the release of this report has been delayed to address the comments received, to develop a glossary of terms used throughout the report, and to add an executive summary.

Developments in electric restructuring are fluid, with legislative and regulatory initiatives moving at varying speeds. Because electric restructuring remains a work in progress, the

discussion in this report is kept broad to address the essential principles. Nevertheless, developments in 1997 and 1998 have dated some of the material in this paper. Although the paper provides a good overview of transmission issues and wind power development, readers are cautioned that there have been subsequent developments in many of these areas.

For instance, one of the topics discussed in this paper is whether secondary markets for transmission capacity will develop, and what niche wind projects will occupy. Order 888, issued by the Federal Energy Regulatory Commission (FERC) in 1996, allows transmission customers to assign their transmission rights to other parties, subject to a rate cap. The rate cap limits the resale price to the higher of the transmission rate paid to the transmission provider by the assignor, the rate in effect for the service at the time of the transaction (the current tariff rate), or the assignor's opportunity cost. To date, however, a robust market for secondary transmission capacity has not developed. Reasons may include the adjustment by all market participants to an open access transmission market; the unpredictability of when transmission capacity may be available and for how long; and the continued refinement of the Open Access Same Time Information System (OASIS), where transmission providers must post transmission availability and information on a computer network that is accessible to all transmission customers.

The report also broadly discusses independent system operators (ISOs), with particular focus on the two ISOs under development and industry-wide discussion at the time: the California and Pennsylvania-New Jersey-Maryland (PJM) ISOs. Since that time, another eight ISOs have developed that are in various stages of discussion or operation. FERC has approved five of these, including the California and PJM ISOs. In addition, this paper envisioned ISOs

having a power exchange either as part of the ISO (as with the PJM), or closely coordinated with the ISO (as in California). Newer ISOs generally are not bundled with power exchanges, in the belief that market participants may form their own power exchanges. FERC approved such an ISO in September 1998—the Midwest ISO. More recently, three transmission-owning electric utilities—Entergy Corp, First Energy and Northern States Power—have announced plans to form independent transmission companies as an alternative to ISOs.

The report also discusses development in congestion pricing, and the emergence of some form of fixed transmission rights (FTRs) or transmission congestion contracts (TCCs), and whether a secondary market may emerge for these forms of transmission rights. The PJM ISO filed an FTR proposal with FERC in 1998, and the California ISO filed a FTR proposal with FERC, also in 1998.

Finally, because electric restructuring remains a work in progress, the discussion in this report focuses broadly on essential principles. The report raises several issues with transmission and ancillary services and wind energy technologies and in some cases, discusses some possible implementation issues, such as the “who pays and who benefits” questions of allocation. These implementation issues are complex in nature, and a thorough analysis is beyond the scope of this report. Given their importance, the NWCC or other parties may wish to consider additional analysis in these areas.

Notwithstanding these developments, we believe this report will be of service to those who are interested in issues surrounding wind generation, electric restructuring and transmission.

We hope you enjoy the report.

Prepared by Kevin Porter, NREL

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We also thank the members of the NWCC transmission working group, who worked on designing the project, and helped the authors through numerous drafts and iterations. The NWCC transmission working group includes Chuck Linderman of the Edison Electric Institute; Randy Swisher of the American Wind Energy Association; Peter Goldman and Jack Cadogan of the U.S. Department of Energy; Ed DeMeo, formerly of the Electric Power Research Institute and now an independent consultant; Ron Lehr, an attorney in Denver, Colorado; Brent Alderfer of the Colorado Public Utilities Commission; Carl Weinberg, a renewable energy consultant; Eric Blank of the Land and Water Fund of the Rockies; Ward Marshall of Central and South West Services; Michael Tennis of Allenergy Inc.; Matthew Brown of the National Conference of State Legislatures; Len Rogers and Karen Lane of the Utility Wind Interest Group; Roger Hamilton of the Oregon Public Utilities Commission; Mark McGree of Northern States Power; Gail Miller of Pacificorp; and Robert "Hap" Boyd of Enron Wind.

We also wish to acknowledge the contributions of the staff of Resolve—who administer the NWCC—for setting up conference calls of the NWCC transmission working group, sending

out drafts for peer review, and for helping the authors with numerous other details associated with this project. We especially thank Heather Rhodes, formerly of Resolve and now with Global Energy Concepts, without whose efforts this report may never have been completed. Finally, we thank Susan Savitt Schwartz, an editor for Resolve, and Leann Stelzer of the National Conference of State Legislatures, for skillfully editing the final draft report and shepherding it through production and publication.

Many parties provided helpful comments and insights on early drafts of this report. Their contributions immeasurably strengthened the final document. Those who filed comments are listed below:

Steven Stoft, The Brattle Group

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Report Summary

Introduction

This paper follows the June 1998 *Wind Energy System Operation and Transmission Issues Related to Restructuring* (Phase I) report. Specifically, this paper expands upon the five transmission issues identified and prioritized for additional study in the Phase I report:

- ? **Whether bidding protocols present market participation opportunities that are consistent with the intermittent and locational characteristics of the wind resource;**
- ? **Whether, and to what extent, the pancaking of access fees presents a significant market barrier for wind generation;**
- ? **The possible impact of ancillary services requirements on wind generation;**
- ? **The advantages and disadvantages of energy-based access charges, in place of the FERC “pay-for-what-you-use” tariff approach discussed in the Phase I report; and,**
- ? **How, and to what degree, the creation of a secondary market in transmission will develop, and the possible niche for wind projects.**

Summary of Discussion and Conclusions by Topic

? *Do bidding protocols present opportunities to participate in the market that are consistent with the intermittent and remote location characteristics of the wind resource?*

Although any energy bidding system is conceptually independent from the requirements to secure transmission rights, the two systems necessarily intersect: first, in determining transmission costs and how they are imposed; and, second, in terms of transmission system reliability concerns due to interface constraints (congestion) or voltage support. Two bidding models are considered: a hypothetical request for proposals (RFP), and a model that allows load bids to pair with energy bids under some competitive auction. Bidding systems with certain attributes may pose problems for intermittent renewable resources. When bidding systems are designed, wind proponents should address the issues of 1) timing and flexibility for bid submissions and 2) how costs are imposed on “winning bidders” who are not able to deliver because of the intermittent nature of the wind resource.

? *Whether, and to what extent, the pancaking of access fees presents a significant market barrier.*

The “pancaking” of access fees occurs when multiple charges are incurred by crossing zones within a region, or by crossing multiple transmission providers’ systems. Pancaking may present a significant market barrier for remote generation such as wind, particularly when the

rate design results in a significant increase in the wheeling party's cost responsibility relative to other customers.

Because wind is intermittent, the assessment of capacity-based access fees on generation will require wind generators to recover this fixed cost over fewer production hours and, potentially, through a spot market energy price that varies over time. Because this will place an upward pressure on energy prices, and because loads effectively drive the market for generation, access fees should be placed on loads, not on generation. An alternative approach, the energy-based access fee (discussed below), may be another way of mitigating differences in generation characteristics while still providing a means of collecting the revenue requirement.

? *The possible impact of ancillary services requirements on wind generation.*

“Ancillary services” are defined under Federal Energy Regulatory Commission Order 888, which separated into six distinct services certain functions that the utilities routinely provided as part of transmission and distribution service:

- ? Scheduling, system control and dispatch service;
- ? Reactive supply and voltage control from generation sources service;
- ? Regulation and frequency response service;
- ? Energy imbalance service;
- ? Operating reserve—spinning reserve service; and,
- ? Operating reserve—supplemental reserve service.

These services are to be secured by the transmission customer before taking service under the open access tariffs. Alternative transmission schemes (like the ISO model) also require that the customer secure (or pay for securing) ancillary services. This raises two related issues: 1) the possible impact of ancillary service requirements and costs upon wind generators and 2) whether wind energy providers will have the ability to participate in any ancillary services market. Proponents may want to further explore the proper measure of capacity for wind generation as it is used to price individual ancillary services, and whether wind can participate in ancillary service markets.

? *Energy-based access charges.*

Transmission pricing design is driven by two key issues: 1) the ability of the transmission provider to recover the fixed costs of the transmission network, and 2) pricing for congestion. Assuming the price increases as a transmission interface or system becomes congested, transmission capacity will be allocated to those willing to pay the most for service.

As independent system operators have emerged, there has been increasing interest in breaking transmission rates into two parts. The first, the access fee, is levied on all users and recovers the fixed and administrative costs of running the transmission grid that the ISO administers. The second part of the fee recovers the congestion costs that may be imposed. If the access fee is energy-based, then those that send the most energy across the ISO grid would pay a proportionally greater amount of the fixed costs of the ISO. Such a system may work

better for intermittent technologies such as wind, since the fee would be more closely in line with the energy produced by wind generators. On the other hand, it is unclear whether congestion charges can act as a means of driving transmission expansion, since adding transmission is, by nature, capacity-based. It is also unclear whether congestion costs will be an adequate incentive for market participants to finance transmission expansion on their own, given the extensive permitting and regulatory requirements that are involved. Finally, it is not clear whether energy-based access charges will be beneficial for wind energy in all circumstances. If adequate non-firm transmission capacity exists, it may be more cost effective for wind generators to use it than to participate in a regime that relies exclusively on energy-based access charges. Likewise, in situations where the capacity factor of the wind generator is greater than the load factor on the transmission interface, energy-based access charges may be more expensive for project developers than capacity-based charges. Additional research is needed on the design and implementation of energy-based access charges, the possible impacts and implications for wind energy technologies, and “who pays and who gains” under a regime of energy-based access charges.

Another potential means of simulating an energy-based access fee would be to substitute the “effective capacity” of an intermittent generator into the generally applicable capacity-based fee. This approach may be best suited for facilities that have an operational history, although a proxy effective capacity rate could be applicable, especially where the facility’s production can be reasonably estimated. Although this is not a true energy-based tariff, it should correct for part of the inequity of charging based on the facility’s nameplate rating alone. Daily and annual variations will not be perfectly captured by this method; however, it is more administratively

attractive, allows for advanced billing, and may avoid the need for additional metering and information systems.

Although capacity-based tariffs have been the historic norm, proponents of wind energy may wish to pursue an energy-based access charge, as long as this approach would allow collection of the funds necessary for transmission providers to cover their revenue requirements. In the alternative to a pure energy-based tariff design, the unintended effects associated with capacity-based tariffs could be mitigated in part by the use of effective capacity measures. In pursuing the proper tariff design, there may be more questions about the proper effective capacity rating for new projects and resource areas than for proven facilities and resources.

? How and to what degree will the creation of a secondary market in transmission develop and what possible niche might there be for wind projects?

FERC Order 888 specifically required that transmission customers be allowed to assign their rights under the service agreement. A rate cap applicable to the resale of capacity is designed to remove any incentive to purchase excessive amounts of capacity and then charge monopoly rents. With this condition, the price for capacity on the secondary market should be equal to or less than the price charged by the transmission provider. Whether a robust secondary market develops for transmission capacity may depend on three related issues: 1) demand for capacity on a line, 2) willingness of reservation holders to discount, and 3) the timing requirements to transact within the market. Proponents of wind energy should work to ensure that there are few obstacles to the development of robust secondary markets. Some work may be

required to anticipate the demand for capacity over specific lines and pathways that are likely to be in demand for promising wind resource areas. Research also may be useful to determine how line congestion dynamics change assuming certain energy market profiles.

1. Introduction

The Phase I Report

This paper is the companion to the National Wind Coordinating Committee's (NWCC) June 1998 report, *Wind Energy System Operation and Transmission Issues Related to Restructuring* (Phase I). The purpose of this Phase II report is to expand upon the five transmission issues identified and prioritized for additional study in the conclusions and recommendations section (part X) of the Phase I report. This report briefly reviews the Phase I conclusions, then explores in more detail the authors' responses to the five issues identified in the first report.

This report was written for those who are interested in the current role and future development of wind resources in the developing competitive environment. Some familiarity with restructuring efforts and industry issues has been assumed. Differences in project ownership—whether utility or private—generally are not significant for this discussion. However, some areas are addressed where impacts on current operation may vary by ownership.

The Current State of Market Transition

Developments in the restructuring arena remain fluid. Regulatory proceedings and legislative proposals are advancing at varying speeds and directions at the state, regional and national levels. Because of the inherent uncertainty in discussing works in progress, the focus of

this paper is purposefully kept broad in order to address essential principles, rather than the specifics of any one particular proposal. Nevertheless, certain proposals are discussed as examples of approaches that are germane to any discussion to the deregulated energy marketplace. Finally, although the focus of this paper is on transmission, energy bidding protocols are discussed to some degree because they are inextricably connected with the transmission issues.

The Phase I Conclusions and Recommendations

In Phase I of this report, we concluded that, because of its natural variability, wind as a generation resource differs from “conventional” resources in a number of significant respects

- ? **Wind is an intermittent energy resource.**

- ? **Wind development must occur where the wind resource is, which may or may not be near customer load or transmission systems. Promising sites also may be more remote from load centers than sites that are available to competing fossil-fired resources.**

- ? **Wind systems have lower capacity factors (20 percent to 40 percent) than conventional resources, meaning wind has fewer kilowatt-hours (kWh) over which to spread fixed transmission costs.**

Transmission pricing and scheduling protocols may be of particular concern to wind generation because of the potential unintended negative effects on intermittent resources and/or remote resources. The potential issues here include the following:

- ? ***Take-or-pay contract provisions.*** Under the open access tariff design, the transmission customer is liable for costs associated with the transmission reservation, whether or not that service is actually used by the customer. Because wind is an intermittent resource, purchasing firm transmission service may result in a wind developer not having wind output when transmission capacity is available. This may mean that a wind developer might need to choose a mix of firm and non-firm transmission service—which may or may not be optimal—or work with transmission providers to arrange for “flexible firm” transmission service that recognizes the intermittent nature of wind but provides some firm transmission service when wind is reasonably expected to be available. “Flexible firm” cannot be defined generically—it will depend on what arrangements (if any) a wind company can make with a transmission owner.
- ? ***Scheduling flexibility.*** Transmission protocols may vary in the amount of advance scheduling required, or may impose penalties on deliveries that deviate from the amount scheduled. Because forecasts of wind resource availability are imperfect, protocols that allow schedule modifications shortly before the proposed time of delivery are preferable. Additionally, protocols that allow multi-facility scheduling (i.e., deliveries from multiple points without modification to the agreement) could give wind energy suppliers the opportunity to “firm” deliveries with generation from another source.

- ? ***Consequences of schedule deviations or delivery imbalances.*** Different transmission protocols treat delivery deviations differently. Some allow deviations within a deadband (some percentage of the scheduled delivery amount) without penalty; deviations beyond the deadband are penalized to deter potential threats to reliability. If the scheduled delivery is small, the deadband will be narrow, requiring small sources to monitor actual deliveries more closely. Other protocols, such as the Independent System Operator (ISO) / Power Exchange (PX) model, look at deviations as purchases or sales at the spot market price. Some protocols handle energy imbalances through true-up periods, but may restrict the ability to utilize a “market” of other customers’ imbalances.
- ? ***Secondary market for transmission capacity.*** The ability to secure or resell transmission capacity in a secondary market is an important feature for wind generation because it should allow some hedging against long-term take-or-pay commitments. The robustness of the secondary market will likely vary by the demand for capacity on a given line and the timing and extent of line congestion. Failure to develop secondary markets on those transmission systems used by intermittent resources will increase their transmission costs relative to competition because of wind generation’s naturally low capacity factor and the difficulties in resource forecasting. Wind generators must balance the need for firm service, the costs incurred in carrying unused and unresellable transmission capacity, and the risk that capacity will not be available on a non-firm basis at the right time.

To date, secondary markets for transmission capacity have been slow to develop and may not even exist in some regions of the country. Reasons for this are unclear, but it could be that transmission customers are holding onto and using firm transmission service and do not have excess capacity to spare. It could also be that transmission customers, particularly non-utility entities such as power marketers, are using non-firm instead of firm transmission service. Market participants also may be adjusting to an open access transmission and independent system operator market environment. There also may be a “chicken and egg” problem in that sellers of transmission will not participate in a resale market if they do not believe buyers will be present, and buyers will not participate if they do not see a deep enough market. Finally, the nature of this market—that transmission capacity may be available for short times and perhaps upon short notice—may be too unpredictable and too difficult for utility Open Access Same-time Information Systems (OASIS) to process expeditiously.

? *Ancillary services requirements.* The ability to enter into transmission agreements generally is conditioned on the purchase or self-provision of certain ancillary services. If resource forecasting is difficult or inaccurate, the intermittent resources may be forced to over-contract for ancillary services or to forego participation in the market.

Transmission pricing and scheduling protocols may have unintended negative impacts on wind resources due to their distance from load and/or the need to use constrained facilities.

Issues here include the following:

? ***Distance-based rates and access fees.*** Charges based on the distance to the load will make market entry problematic for remote wind resources. The purpose of this rate element is typically for recovery of the fixed portion of system revenue requirements. The fee will be more problematic for remote resources if it is distance-dependent, or more favorable to remote resources if a “postage-stamp” methodology is used (the same unit charge is assessed, regardless of the distance between the generation resource and the load). Although distance-based rates are designed to provide an incentive for owners of new generation to locate near load, relocating a remote intermittent wind resource is not an option for wind developers. In other words, wind developers must develop where the wind resource is, whether remote from load or not. In regard to access fees, this issue will not affect wind disproportionately where the cost is imposed on customer’s loads rather than on generation.

? ***Real power losses.*** The imposition of charges or additional deliveries required to make up for power losses during transmission are traditionally determined by distance from load center. Although actual losses are dynamic in any system (that is, they can vary by time, system load, weather and other factors), the protocols may impose a static formula that presupposes a loss rate that may not accurately reflect the actual losses attributable to remote customers. In addition, if wind production is at off-peak times, then the value of making up the losses may be less than the cost of charging average losses. Of course, if wind production is at on-peak times, then the opposite is true: the value of making up the losses may exceed the cost of charging average losses.

- ? ***Pancaking of fees.*** Transmission tariffs can vary significantly according to how many distinct charges a remote customer may face when making regional transactions. Pancaking may occur according to the number of zones crossed within a specific control area, or when transacting with multiple transmission owners or areas (e.g., “wheeling through”). Remote facilities that move power over distances will face the pancaking issue. The emergence of ISOs in some regions of the country may help to partially alleviate this problem.
- ? ***Constraint management.*** Protocols vary in how transmission capacity is priced and allocated. Generally, remote sellers are more likely to face transmission bottlenecks that will increase transmission costs and potentially block access to regional markets. The open access tariffs generally address the congestion issue through the determination of available transmission capacity (ATC) for a specific line segment. Other proposals may apply congestion pricing during periods of constraint and may use separate auctions for financial or physical rights across the interface, or may assign congestion costs to all transmission customers on a pro rata basis.
- ? ***Consistency issues.*** To the degree individual wind generators must transact with multiple transmission providers (as is the case in wheeling-through transactions), there may be issues concerning the consistency of data required, and the presentation and use of data in the various transmission providers’ OASIS systems. Where there are inconsistencies between the OASIS nodes (such as what a specific hourly period is called), transaction costs increase and there is increased potential that service requests will not be finalized quickly.

- ? ***Regional transmission planning:*** Future project development in promising locations may not occur due to lack of existing (or planned) transmission near those areas or because existing transmission constraints downstream could effectively preclude any new generation development. Regional transmission development also may be frustrated where coordination between transmission owners and states does not occur. Recent coordination efforts and the development of umbrella planning organizations may address this issue. Notwithstanding this positive development, several issues are not likely to be addressed.
- ? ***Coordination with IRP and consideration of diversity and environmental benefits.*** Transmission planning generally is driven by public plans to develop specific generation sites. Consideration of environmental impacts, mitigation of potential fuel supply shocks through resource diversity, and other least-cost tools such as Integrated Resource Planning historically have been used to screen proposals for new generation resources. These same tools may not be as extensively applied in the development of regional transmission plans. This leads to a problem because promising wind generation projects are not proposed where transmission is not readily available for that site. This scenario generally works against the exploitation of undeveloped wind resource sites.
- ? ***Effects of new competitive pressures.*** To the degree that existing transmission owners consider new or additional transmission investments as beneficial to their competitors, it is likely that the investment will be avoided. Therefore, the increase of competitive pressures may actually hinder regional transmission planning efforts.

- ? *Effects of restructuring uncertainty.* The uncertainties associated with industry restructuring naturally make investments in new or additional transmission facilities speculative. Until issues regarding planning responsibilities and the control and ownership rights for new and additional transmission facilities are addressed in various restructuring proposals, it is unlikely that new transmission projects will be proposed. This is a disadvantage to wind generation because it makes development of new resource locations unlikely where additional supporting transmission is required.

Readers are encouraged to refer to the Phase I report for additional details on these topics.

The Phase II Topics

The Phase I report concluded by suggesting five topics for further review:

- ? **Whether bidding protocols present opportunities to participate in the market that are consistent with the intermittent and locational characteristics of the wind resource;**
- ? **Whether, and to what extent, the pancaking of access fees presents a significant market barrier for wind generation;**
- ? **The possible impact of ancillary services requirements on wind generation;**

- ? **A tariff proposal for presentation at the FERC regarding pay-for-what-you-use; and**

- ? **How, and to what degree, the creation of a secondary market in transmission will develop, and what niche there may be for wind projects in this market.**

Discussion of these topics (with one exception) forms the body of this report. In place of the “pay-for-what-you-use” tariff proposal, a discussion is included of a two-part transmission charge that is being used in some ISOs. The rate consists of an access charge designed to recover the fixed costs of the transmission grid, and a congestion charge intended to ensure that users who value their transaction the most will have their transaction go forward, and to serve as a signal for possible expansion of the transmission system. If it is possible to reduce the topics to a core question, it would be this: What must the proponents of wind generation be concerned about to positively position this resource in the new era of competitive energy and transmission markets given the resource’s unique characteristics?

2. BIDDING PROTOCOLS

The concern addressed here is whether energy bidding protocols could negatively affect wind projects, either because they constitute an intermittent energy source, or because they are remotely located. Issues concerning certain prerequisites to transmission services—such as ancillary services requirements or creditworthiness—are not discussed here.

The focus for this topic is the interplay between transmission services and energy bidding protocols. Although any energy bidding system is conceptually independent from the requirements to secure transmission rights, the two systems necessarily intersect in two important ways. First, the costs of using transmission to move power to market, and how those costs are imposed, can preclude participation in the bidding (i.e., transmission may become an economic barrier). Second, the reliability of the transmission system may become an issue in terms of making delivery impossible because of interface constraints (congestion) or other reliability concerns such as voltage support.

The Bidding Models

Two bidding models are discussed in this section. The first could apply to those regions that operate under the Order 888 Network Integration Transmission Service (NITS) or Point-to-Point Transmission Service (PPTS) tariffs. Although Order 888 did not create an energy bidding

protocol or energy market per se, the underlying premise is that open access transmission tariffs would foster greater competition for energy and ultimately lower prices for consumers.

Therefore, for our purposes, a hypothetical RFP is the bidding protocol to be analyzed as the first scheme.

The second scheme will assume the development of some marketplace via restructuring proposals beyond Order 888. This model allows load bids to pair with energy bids under some competitive auction. This second scheme is conceptually similar to that adopted for the Pennsylvania-New Jersey-Maryland (PJM) system or the California Independent System Operator / Power Exchange model (“ISO / PX”). In this case, both the load and energy bids could include characteristics that are reflected in price. Other ISO proposals, such as the Midwestern ISO, do not include a power exchange in the belief that market participants may form power exchanges on their own. More recent proposals involve the formation of independent transmission companies or either for-profit or not-for-profit transmission companies, or transcos. These concepts are not considered in any more detail in this paper.

Model 1: The RFP

The soliciting party controls the rules for bidding and ultimately is concerned with securing energy resources that meet its criteria for cost, reliability, environmental impact, etc. It is assumed here that an intermittent resource can bid on a stand-alone basis.¹ The request for proposals (RFP) may require both all costs bids (cost for delivery at a specific point with the cost of transmission borne by the energy provider—probably under PPTS), or energy only bids (cost assuming that transmission is secured by the soliciting party—possibly using NITS).

Unless excess transmission costs are internalized (i.e., transmission costs incurred beyond those attributable to an actual delivery are paid out of pocket and not reflected in the bid), the wind facility's all costs bid is likely to appear higher than a fossil competitor's bid. This is because the PPTS is a capacity-based reservation system with take-or-pay contracts and the wind resource's lower capacity factor will require that transmission costs be recovered over fewer production hours. Even if the wind facility is able to secure non-firm PPTS, it will reserve transmission capacity sufficient to deliver full output during those hours it is likely to generate.² Because forecasting is inherently inaccurate, however, and because actual facility output may vary over the scheduled delivery hour, it is likely that full transmission costs would not be covered by the price paid for energy delivered under the contract.³

Bidding would be further complicated if transmission constraints limit the available transmission capacity (ATC) along the preferred path during those hours the facility is likely to produce. Assuming another path is unavailable, the availability of non-firm PPTS on the preferred path may be questionable, especially if another use requests a non-firm transaction of a longer term or requests firm transmission, both of which could bump non-firm customers if they do not exercise their right to extend the transaction. In this case the wind facility must determine whether the costs involved with securing long-term firm service for itself can be adequately offset over the term of the agreement by the price paid to the winning bid or via any resale of excess transmission capacity or some other contractual arrangement, or whether the wind facility can match power deliveries with non-firm transmission service, at the possible cost of foregoing some capacity payments.

However, under the second hypothetical for this model—the energy-only bid—the wind facility would not be similarly disadvantaged. This assumes that the soliciting party would secure required transmission. This bidding protocol design may be especially preferable if NITS is applied because, under the network approach, all lower-capacity factor resources could be integrated with the high capacity-factor resources dedicated to the soliciting party. In this way the soliciting party could alter the output from specific facilities over the various hours to approach the least-cost dispatch. Under this scenario, the wind project does not face the same risk presented by a take-or-pay contract for reserved, but unused, transmission capacity. Additionally, there is less concern under NITS about project deliveries being excluded due to congestion, because NITS capacity is “carved out” of the available capacity calculation for PPTS under the FERC rules.

Model 2: The PJM or ISO / PX Approach

The second model mimics the basic hourly competitive marketplace envisioned by the PJM or California ISO/PX approaches. This model uses a centralized market to pair load bids and energy bids to develop the energy clearing price for the period in question (day-ahead, hour-ahead and real time). Bids may include additional information from loads (regarding the reliability of service desired) or from generators (regarding generator operating costs, ramping times, etc.).

Where the set of energy bids submitted for a specific hour indicate to the control area operator that transmission constraints will arise, some form of mitigation will be necessary. This

could be handled in a number of ways, including predetermined priority schemes, firm tradable rights, a distinct auction or market for the limited transmission capacity, or through additional bid iterations designed to alleviate the constraint; by directly assigning the congestion costs to transmission customers causing the congestion; or by assigning congestion charges on a pro rata basis to all transmission customers.

For example, under the California ISO/PX proposal, the two goals (i.e., least-cost energy and efficient management of transmission congestion) are met through exchanges of information between the ISO and the scheduling coordinators (SCs), which includes the PX. When an SC's proposed schedule for a given hour indicates transmission or reliability problems for a given set of bids, the ISO sends back a proposed solution set with changes to the bid array. The SC may then confer with its resources and alter its dispatch merit order in the hope of alleviating the problem.⁴ If a solution is not reached within the time allowed for finalizing schedules, the ISO may then act to protect the system. The congestion cost associated with such transactions is the price difference for energy between the two zones separated by the congested interface.⁵

Similar models based on the PJM concept also may separate the energy market functions from the grid management function. Generally, the energy market takes a standard design. Various methods of clearing congestion have been proposed. For instance, transactions across congested interfaces may require bidders to have secured transmission access on the particular line in advance of bidding. Allocation of the limited capacity may be made via a separate auction for physical and/or financial rights. Transmission congestion contracts (TCCs),⁶ transmission capacity rights (TCRs),⁷ and some clearance pricing mechanism combine to

efficiently allocate the limited transmission resource.⁸ In this way, a distinct transmission bidding system functions to manage transmission congestion by pricing it according to demand. Entities then have the option of pursuing the transaction with the elevated transmission costs, or foregoing the transaction during periods of congestion.

Discussion

These bidding system proposals may present problems for wind generation if intermittence or distance work against the bidder. One of the most readily identifiable obstacles is the advance requirement. If the bidding protocol requires submission of bids a day before the time for delivery, wind projects will be at risk if they do not deliver. If the protocol allows for adjustments in schedule at some period near the delivery window, the wind bidders can adjust their bids to reflect more contemporaneous information regarding availability.

Protocols for energy bids (and transmission services) generally require advance notice of an intended bid schedule and price for each hour. Protocols can vary as to when and how long that bidding window stays open before the hour at issue. Once the final schedule is set, all bidders are committed to their bids. To the extent that there is flexibility in the protocols to allow for changes in schedules close to the hour at issue, the intermittent nature of the wind resource and the difficulties in forecasting are partially accommodated. If there is little flexibility, the intermittent wind resource faces greater risk for failing to deliver or for any deliveries over the scheduled amount.

The issue is how protocols treat delivery deviations during settlement when what is bid or scheduled is compared with what actually is delivered. Some may use deviation deadbands to impose “penalties” when the deviation exceeds some percentage amount.⁹ Because the quantity of penalty free deviation is a function of the total scheduled delivery quantity, smaller projects have less leeway in terms of delivery fluctuations. The amount of penalty could vary depending on whether the system is in an over- or under-generation condition. Other protocols—such as the California ISO/PX, the PJM ISO, the NE-ISO and the NY ISO—treat deviations as real-time elections to buy or sell at the spot price. If the wind project delivers past the scheduled quantity, it is deemed to have sold at the clearing price. If it fails to deliver as obligated, it is deemed as having purchased at that price. Therefore, any deviation penalty is seen in terms of the value of energy at that time.

To some extent, the interests of wind generators in a more short-term market, such as an hourly spot market, is shared by other market participants such as power marketers who want to take advantage of buying and selling opportunities at short time intervals. The California ISO and the PJM ISO, for example, each have formulated hourly spot markets. Such a market likely will pose challenges for computer and communication systems, simply for the administration of transmission reservations and scheduling. Control areas must coordinate all transactions with neighboring control areas to ensure reliability, and computer and communication systems may not be efficient enough to allow for quick changes in transmission reservations or schedules. In addition, these hourly markets may be restricted to those who already have bid in the day-ahead market, and need to quickly adjust their generation or demand schedules.

An alternative arrangement is to consider wind resources as a must-run or negative load resource through an agreement with the ISO/PX, where wind systems will automatically receive the spot market price for each hourly or half-hourly bid increment, based upon the amount of energy produced and delivered to the ISO/PX. The ISO/PX would conduct the bidding system to meet the projected requirements of the power system, net of the forecasted production of the wind power systems. Wind power systems would need to provide some forecast of their anticipated energy production to enable the ISO/PX to predict the net energy requirements for the power system. In addition, some prearranged limit may need to be placed on how much wind can be accepted under such an arrangement. It should be noted, however, that such an arrangement could be at odds with the competitive electric market that is beginning to emerge. In addition, the spot market price may not be high enough to cover the wind power system's capital or financing costs.

A variant may be the formation of private power exchanges that may contain a component for green power supplies, or may include flexible bidding, scheduling and power delivery policies. The Automated Power Exchange (APX) in California, for example, has a green power market segment that can automatically match buyers and sellers of renewable energy through a spot market. The APX accepts orders starting a week in advance of deliveries and stays open continuously until the California ISO's deadline for submitting schedules. This allows sellers and buyers to schedule deliveries and purchases in advance of renewable energy production, which helps to reduce price uncertainty. The flexibility in APX's green market

segment, if replicated elsewhere, may be promising for wind power generators.¹⁰ In addition to the APX, the California Power Exchange announced plans to launch a Green PX.

The emergence of individual—and even multiple—private market power exchanges is an interesting contrast to the initial ISOs that featured a power exchange integral to the ISO, i.e., the California, NE-ISO and PJM ISOs. Indeed, the newer proposed ISOs have specifically cited the cost and complexity in developing a power exchange and the interest of market participants in forming their own power exchanges as reasons for not including a power exchange with an ISO.

Finally, another alternative is to take advantage of dynamic scheduling, which is the electronic transfer from one control area to another of the time-varying electricity consumption associated with a load, or the time-varying electricity production associated with a generator. Wind generators may wish to aggregate the output of several generating units in several control areas and sell the energy and capacity to a single customer or to another control area. Alternatively, other generation could be electronically transferred as a means of “firming” the intermittent characteristics of wind generation. Although there are costs in using dynamic scheduling, the costs in using this service may be less than any possible penalties from scheduling or delivery deviations.¹¹

If the bidding system places too much financial risk on individual wind projects because of forecasting uncertainties for a specific hour, there may be a reluctance to bid. Individual projects that do participate in the market should seek a high degree of coordination with the marketplace because of pressures imposed by uncertain forecasting and resource availability. If

the bid requirements are too volatile for the individual project, alternative contractual arrangements with lower overall transactional costs may be preferred to deliver to market. Wind project development activity may be significantly dampened if it is based solely on spot market participation. Therefore, wind developers may wish to pursue alternative approaches, such as dedicated contracts to a marketer or other purchaser. These approaches are discussed in more detail below.

Alternative Arrangements

Wind projects can avoid some bid system transaction costs by entering alternative arrangements. One example would be a bilateral contract with a consumer for the project's output. This would remove the energy price bidding concerns and permit longer-term transmission obligations. Another option would be to commit output to a power marketer who then applies the energy to a load or loads outside the spot market. Delivery could be to a specific location under the open access tariff (PPTS), or the broker/ marketer could assume the obligation of securing the transmission (possibly under NITS). In either case, the broker or marketer could be subject to transmission congestion charges that in turn may be passed in part or totally to the wind developer.

Assuming that entities other than the actual wind projects—such as brokers and marketers— can bid into the system, the individual project may be able to reach the market without facing the potential risks associated with forecast uncertainty, intermittence, and energy

bid and transmission take-or-pay related costs. The project then would be able to concentrate on the production of energy, while the marketer would handle locating the buyer and arranging for transmission and ancillary services.

An advantage to the diversified portfolio approach is that the marketer may be able to self-provide “firming” power for when the dedicated intermittent generation begins to taper off. It also may be able to self-provide required ancillary services from within its portfolio. Prices paid to the generator could take any number of forms, including a fixed price for a term, or a price indexed to the market, less some service fee. Additionally, wind fits well into the potential niche market for green power that is desired by customers who value renewable resources for reasons beyond simple low-cost energy.

Another alternative approach, conceptually similar to a marketer’s diverse portfolio, is a specific contractual arrangement with another merchant generator. This approach would have the higher capacity-factor resource “cover” for the wind generator during those periods when the output is below that forecasted for delivery. This arrangement may be beneficial for the combustion technology if it can avoid higher operating costs during those hours the wind facility is available. Under this approach, the risks associated with forecast uncertainties are mitigated by the ability to apply the output from the merchant facility to firm any shortfalls during the hour. This process could apply for the wind facility’s ramping period (i.e., when the wind resource begins to become available, or when production tapers down during the hour). In power pools or ISOs where creditable capacity is an important criterion, this approach may be a problem for owners of the combustion turbine, since the capacity from the combustion turbine

that is being used for firming the wind system cannot be counted as accredited capacity for the pool or the ISO.

Issues relevant to this approach include whether the bidding and transmission protocols allow for injection of power from multiple points, when the final schedule must be submitted, and potential ramifications on required ancillary services. Additional complications could include system congestion and loop flows¹² if firming of tapering intermittent resource production during the hour requires that deliveries be made from the two facilities at the same time. This raises issues concerning the application of reserves (ancillary services) for purposes other than a true loss of generation.¹³

Another potential obstacle to wind participation in the spot market could be the requirements to make up for losses due to its distance from the market. While the PPTS tariffs require that losses be made up, the use of preestablished line loss estimates either may over collect or under collect. Because line losses are dynamic for any given time (as a function of line load, quantity delivered and other varying conditions), the amount of energy that must be delivered under the bidding protocol for the purpose of covering losses could exceed the amount actually lost during transmission. Losses may be a more significant issue if wind power is not well correlated with load or transmission system loading. In these situations, incremental losses attributable to wind may occur during periods where the cost of power is lower than average. Charging wind systems the average cost for losses thus may overstate the real value of system losses.

The merits of charging real as opposed to average losses must be weighed carefully, however. Estimating incremental line losses for individual transactions may be complex and difficult, particularly for a power resource like wind, which has varying output. In addition, the incremental losses for the last transaction loaded onto a power system may be quite high relative to average losses. Therefore, wind developers may wish to consider whether the possible gain from a system of charging real rather than average losses is worth the additional complexity.

Conclusions and Recommendations

Proponents of wind energy should recognize that bidding systems that have certain attributes may pose problems for intermittent renewable resources. Specifically, a number of issues play a significant role in a wind project's decision to participate in competitive energy bidding and, for this reason, should be addressed by wind proponents when bidding systems are designed.

The first issue concerns the timing and flexibility of bid submissions. If bid submission is allowed closer in time to the period of delivery (or in real time), problems inherent in intermittent resource availability and forecasting are partially mitigated. If, however, bids must be posted significantly in advance (e.g., a day ahead) and there is little flexibility in changing or withdrawing the bid before it becomes final, the potential wind bidder is forced to balance its probability of generating against the costs it will incur (e.g., make-up power, ancillary services and take-or-pay transmission costs). Risk-averse bidders will avoid bidding for those hours

when their confidence in resource availability is marginal. In some cases this risk-avoiding behavior will prove accurate, but at other times, when the resource does prove to be available during the hour in question, this low variable cost resource will be lost to the market.

The second issue concerns costs a bidding system (and related transmission arrangements) imposes on winning bidders who are not able to deliver during a specific hour. This, of course, is the primary risk that must be balanced. Clearly, the load that was matched to the non-delivering generator needs to be met.¹⁴ How the bidding system requires the non-delivering projects to make up (cover) their generation shortfall may deter market entry. For example, if the shortfall is covered from ancillary services sources, two tariffed rates may apply—supplemental reserves, plus any additional costs associated with regaining the required reserve margin. (Some of the issues related to ancillary services are addressed in more detail in chapter 4). If the cost of covering a shortfall is not relatively predictable or is subject to significant swings, bidding and/or development of intermittent technologies will be deterred. The development of hour-ahead bidding systems by the California and PJM ISOs, however, may help mitigate some of these concerns for intermittent technologies.

3. PANCAKING OF ACCESS FEES

The pancaking of access fees may present a significant market barrier for remote generation technologies such as wind. Pancaking occurs because access fees are additive when crossing zones within a region, or because regional transactions cross multiple transmission providers' systems and thereby incur multiple charges. Any transmission customer who moves power at a distance is likely to encounter the pancaking of fees. Pancaking becomes a problem when the rate design results in a significant increase in the wheeling party's cost responsibility relative to other customers, especially when compared to the rates that would be collected if all the zones were collapsed into a single area.

How Pancaking May Occur

Fees and obligations can pancake in any number of areas. There could be multiple access fees involved with distant wheeling. There could be multiple penalties associated with delivery deviations. There could be a pancaking of congestion charges if the transaction is made through a number of constrained interfaces. There could be a pancaking of ancillary services obligations. There could also be a pancaking of administrative costs associated with distant transactions where the burden of transacting with multiple parties is complicated by varying standards (e.g., the middle control area has more stringent scheduling windows and more bottlenecks, effectively hampering proposed transactions because arrangements cannot be concluded in the required

time). Although these types of pancaking may present elevated transaction costs (in terms of administrative burdens for the transmission customer as well as the actual fees involved), this type of pancaking cannot be considered inequitable if the rate design for the fees properly reflects system costs associated with the overall transaction. Elevated transaction costs may be alleviated to the extent that the electronic bidding systems and OASIS nodes are well standardized. Nonetheless, it is when the rate design overcollects through pancaking that inequities develop. The balance of this discussion focuses on this type of pancaking.

To illustrate the problem, consider the following. Zone A has a revenue requirement of \$100, a native zone load of 40 megawatts (MW), and 10 MW wheeling through. The access fee for Zone A is determined to be \$2 per megawatt-hour (MWh) ($\$100 / 50 \text{ MW}$). The adjacent zone, Zone B, also has 40 MW of native zone load and 10 MW wheeling through, but has a revenue requirement of \$200. The access fee for Zone B is determined to be \$4/MWh ($\$200 / 50 \text{ MW}$). The 10 MW that wheels through both Zone A and Zone B would pay both access fees, or a total of \$6/MWh in pancaked access fees. However, if Zone A and Zone B merge to form Zone AB and the pancaking potential is removed, the access fee that the wheeler faces significantly changes. The new revenue requirement for Zone AB would be \$300, the total native zone load would be 80 MW, and 10 MW still would wheel through. However, the access fee, which is paid by all parties that utilize Zone AB, changes to approximately \$3.33/MWh ($\$300 / 90 \text{ MW}$).

Zones and Access Fees

As electric systems are restructured and ISOs are created, access fees may be differentiated between zones to avoid inequitable fee hikes that otherwise would occur under a single zone system. For example, two adjacent zones currently may have similar transmission capacity, but one zone may have recently upgraded its facilities. The two zones may have very differing revenue requirements. Collapsing the two into a single zone would appear inequitable to ratepayers in the lower cost zone. However, this issue may be addressed by the imposition of declining legacy rates, where the more expensive zone's cost increment in excess of the neighboring zone is collected over time at an elevated rate.¹⁵ After the excess costs are paid out—and to the degree any capital additions in neighboring zones are made—the boundaries can be removed when the revenue requirements approach something closer to parity. At that time the zones can be collapsed and an averaged access fee can be imposed.

Zones also may be drawn based on loop flow problems. Loop flow issues are more common outside the western United States. Pancaking also will be seen to the degree a remote resource must cross a number of these zones. Currently, loop flow-based tariffs are the subject of limited experimentation.¹⁶ Where loop flow issues present a significant problem, it should be anticipated that similar zone designs will be implemented. For the Western states, however, this issue is of less significance because of extensive coordination between WSCC members.

The market barrier that pancaking presents is a financial one. Because the access fee must be collected from some party (load or generation), the delivered price of energy will be

elevated. Therefore, assuming that the load pays the access fee, the customer faces a choice between the local producer that does not carry additional transmission costs and the more remote producer whose price may carry multiple fees.

If the access fee is placed on generation, then the locational price signal embedded in the access fee encourages project siting in the same zone as the load. In the case of wind, the assessment of access fees on generation has two ramifications: 1) because wind is intermittent, it will be required to recover this fixed cost over fewer production hours and potentially through a spot market energy price that varies over time; and 2) the locational signal embedded in the fee may preclude the development of distant resources, effectively penalizing the generation technology.

Conclusion

The imposition of capacity-based access fees on low capacity-factor intermittent technologies will place an upward pressure on energy prices because they are required to recover those costs over fewer production hours. Otherwise, the intermittent generator must internalize that portion of the cost that drives the energy price above its competitor's in order to participate in the market. Because of this effect, access fees should be placed on loads, and not on generation.¹⁷ An alternative approach, the energy-based access fee discussed in chapter 5, may be another way to mitigate differences in generation characteristics, while still providing a means of collecting the revenue requirement.

4. ANCILLARY SERVICES REQUIREMENTS

Issues Regarding Ancillary Services and Intermittent Generation

Ancillary services are defined under FERC Order 888. That decision separated into six distinct services certain functions that utilities routinely provided as part of transmission and distribution service. Because of their technical nature, these services were taken for granted and rarely discussed in rate hearings. As defined by Order 888, ancillary services now are separately scheduled services to be secured by the transmission customer before taking service under the open access tariffs. Alternative transmission schemes, like the ISO model, also require that the customer secure ancillary services, or pay the ISO to secure those ancillary services on its behalf. This topic poses two related questions: 1) the possible impact of ancillary service requirements and costs upon wind generators and, 2) whether wind will have the ability to participate as a provider in any ancillary services market.

Some ancillary services must be secured from the control area operator (i.e., the transmission provider in the area of interconnection). Other ancillary services can be self-provided or contracted for from third parties. To the degree that wind facilities can self-provide certain ancillary services (which is a technical issue beyond the scope of this paper), they may be able to provide the services required to transmit across the grid. Presumably, the transmission providers will define the tests required to certify self provision of ancillary services. Despite the

foundation for an ancillary services market, FERC's pro forma open access tariffs are unclear as to when and how often a transmission customer can change its ancillary services provider.

Some practical issues do arise for all ancillary services. Generally speaking, the open access regime views the ancillary services requirement both as grid reliability insurance (necessary reserves to meet load where there is a generation outage) and as part of the cost for a functional grid (purchasing reactive power, frequency, etc., required to move energy). Although this paradigm is valid for conventional high capacity-factor facilities, a basic inequity can result for lower capacity-factor facilities. For example, ancillary services typically are purchased on the basis of the amount of transmission capacity reserved (e.g., \$/kW/hour or \$/kW/month.) However, in the case of wind generation, the proper measure of capacity can be problematic. Wind capacity can be viewed either: 1) as an instantaneous output measure (i.e., looking at a single point in time when the facility may be at peak or nameplate output), or 2) as an effective capacity measure (reflecting a lower time aggregated capacity factor for the facility determined by the naturally limited availability of the resource). Charges for ancillary services based on straight nameplate or reserved transmission capacity may work poorly for a wind facility because of its naturally lower capacity factor. Purchasing ancillary services only for those hours of probable wind resource availability may be uneconomic because the short-run unit price typically may be larger than a longer-term ancillary services purchase commitment (i.e., the cost for a service on an hourly basis is larger than subscribing for a month's worth of service). This problem is obviously compounded by forecasting uncertainties when the facility may not know the actual output quantity adequately in advance. Unless some adjustment is made to the quantity of ancillary services purchase requirement, the wind system will be required to purchase

services in excess of its actual deliveries over the day, and must balance the cost of hourly-based services over longer-term purchase commitments and the number of hours it will not require the services. Therefore, the wind system's demand for ancillary services may be more appropriately evaluated on the basis of equivalent or creditable capacity, instead of nameplate rating. Further study may be required, and it is likely this may be specific to the particular wind system.

Within the new competitive framework, the load-following service historically provided by an integrated utility could take place within the new market structure. It is possible to duplicate, in effect, the integrated portfolio structure through bilateral arrangements between intermittent and conventional resources. Entities that have control over both intermittent resources and more conventional high capacity-factor resources could mitigate the reduced wind production in real time.¹⁸ As mentioned before, a kW of capacity from a conventional resource that is used to back up or firm a wind resource cannot be credited in a pool or ISO where capacity credits are an important criterion.

Wind generators may wish to purchase their required ancillary services based on their effective capacity, rather than on the basis of nameplate capacity of the wind system. For instance, back-up reserves may not be applicable at the full capacity rating of a facility during a specific hour because the wind plant's varying output will not reach full capacity during that hour. In the alternative, some effective capacity measure may be more appropriate for determining the quantity of certain ancillary services required to back up that generation source. If the tapering off of the wind generation occurs over a period longer than an hour, it may be more equitable to have the generator cover that increment that it is likely to lose over the hour.¹⁹

Additionally, for facilities or locations where there is adequate information about historical resource availability, it may be reasonable to base ancillary services on projected generation estimates, given that information.

For the ISO model, it is possible that wind generators could purchase ancillary services from the ISO. Depending on the ISO, participants can self-provide ancillary services (other than scheduling or reactive supply and voltage control, which must be obtained from the transmission owner); participate in a daily auction for ancillary services sponsored by the ISO; or have the ISO procure ancillary services for them. The latter typically is done by the ISO on a last recourse basis, although this depends on the specific ISO. It is possible wind generators may be able to secure the necessary ancillary services from an ISO to cover the expected wind generation, rather than on the basis of the wind system's nameplate capacity.

In addition, as discussed earlier, a wind generator also may be able to use dynamic scheduling to aggregate all its generation for one control area, which may help minimize ancillary service costs.

Specific FERC-Required Ancillary Services

FERC designated six types of ancillary services that transmission providers are required to unbundle and make available for purchase on an individual basis. FERC also has encouraged utilities and other potential ancillary service providers to repackage and provide for sale on a nondiscriminatory basis other bundles of services.²⁰ It is not unreasonable to believe that the

market for ancillary services could respond with a specific package tailored to intermittent generation. The following discussion is intended to help discern what special ancillary services considerations are applicable to wind generation.

The following paragraphs review the specific ancillary services required by FERC as outlined in the Phase I report. Each type of service is included, with special emphasis on those services that may present a more significant burden to intermittent resources.

? *Scheduling, System Control and Dispatch Service*

This service includes those efforts by the control area operator or transmission provider on the customer's behalf to coordinate the movement of power across the area and to other areas. This service must be purchased from the transmission provider. Fees are based on the transmission capacity reserved, with a deterrent adder (penalty) if the services are used above the contract reservation quantity. This service does not appear to impose undue costs on wind generation, although it may be argued that the intermittence of the wind resource may require more interaction with the control area operator. Note also that there should be some differentiation between this service under the open access functional unbundling regime, in which the control area operator or the transmission provider could be coordinating with a number of other areas, and an ISO / PX model in which there is a single coordinator for a larger region.

? *Reactive Supply and Voltage Control from Generation Sources Service*

This service includes provision of reactive power necessary to keep lines energized and grid services reliable. This service must be purchased from the transmission provider, although

users of the transmission system could self-provide some or all of their reactive power requirements. The open access transmission tariffs could be read to impose case-by-case analysis of each transaction's requirements.²¹ How this is done may vary by transmission provider or it could be standardized by the applicable reliability organization. Rate design probably will be the traditional embedded-cost method. To the degree wind facilities supply reactive power and voltage support, their contribution could be reflected by a reduction in the initial obligation to secure this service or by some offset to the cost of the service. There should be no differentiation between the need for this service under a functional unbundling model or under the ISO/PX model. Wind facilities can supply reactive power if designed to do so. Northern States Power has required reactive capabilities in the wind request for proposals it has issued. Wind developers could install capacitors and reactors, or other equipment external to the wind system itself.

? *Regulation and Frequency Response Service*

This service includes provision of instantaneous load-following capacity, make-up of energy shortfalls, and the supply of marginal reserve to maintain the 60 hertz (Hz) grid frequency. Transmission customers must secure or self-provide and the transmission provider must offer the service when the PPTS is used to serve load within its control area. Because wind resources do not operate as dispatchable units under automatic generation control (AGC), wind projects may need to secure greater degrees of this service than conventional technologies. To the degree that a delivery is scheduled and the facility cannot deliver because of inaccuracies in resource forecasting, some make-up energy may be provided from this service. Power conditioning equipment (such as solid-state inverters) may serve to alleviate a portion of this requirement in

terms of maintaining the required frequency. There should not be a differentiation between the functional unbundling model and the ISO/PX model in regard to a load-following requirement. However, under the ISO/PX design, deviations from scheduled deliveries are considered either sales or purchases of power at the spot price. Ultimately, this service is related to energy imbalancing.

? *Energy Imbalance Service*

This service includes the cumulative provision of any energy required to meet the transmission customer's load changes or when the regulation and frequency response service accumulates an imbalance over the hour. It is, in effect, a balancing account service. This service is offered to correct mismatches between scheduled deliveries and loads on an hourly basis. Transmission customers must secure or self-provide and the transmission provider must offer the service when the PPTS is used to serve load within its control area. The tariffed service operates with a ± 1.5 percent deadband (2 MW minimum) to allow for load variations.²² There is a 30-day rolling window for true-up of imbalances. Failure to true-up will trigger additional charges for the cost of energy provided (e.g., average incremental price of energy during that period).

FERC believes that generators should be able to generate with precision. It will not allow the deadband to protect fluctuations in generation. Rather, the deadband applies only to changes in load over a given hour. FERC believes that giving generators flexibility under the energy imbalance deadband would encourage poor generation practices and gaming of generation to increase energy revenues. Instead, FERC envisions negotiations between the transmission

provider or control area operator and the customer that would create interconnection and service agreements “tailored to the parties’ specific standards and circumstances.”²³ Shortfalls on the generation side are made through provision of reserve services, as discussed below.

Although the FERC decisions are vague on this point, it also may be possible to provide make-up power for imbalance deficits during those periods when the wind resource is ramping up. A possible tariff design could allow the wind facility to contract with the transmission provider (or other party) to deliver power as an ancillary service provider when the resource first becomes available (but before the facility otherwise would be confident enough to bid energy).

? *Operating Reserve - Spinning Reserve Service*

Operating reserves are generation resources, generally located near load, that can provide power in the case of a transient event or unplanned outage.²⁴ The spinning reserve service includes provision of instantaneous power to cover any loss of generation. This is typically provided by online but unloaded generation facilities. Transmission customers must secure or self-provide and the transmission provider must offer the service when the PPTS is used to serve load within its control area.

Additional conventional resources may be required to be online to cover any loss of wind generation, especially if it coincides with an upward swing in customer demand. If wind generation has enough market penetration during a given hour, the swing potential may trigger a need for additional conventional resources to go on line and operate at minimum or no-load status. Arguably, the ISO/PX approach may be able to handle this issue differently than the

functional unbundling model through the spot buy/sell mechanism described earlier. The functional unbundling approach also could address this issue through ancillary services bundles that are tailored to meet the unique needs of intermittent generation types.

? *Operating Reserve - Supplemental Reserve Service*

This service is related to spinning reserves insofar as it is another form of operating reserve. Supplement reserves do not provide instantaneous cover, but typically have a short start-up period. Potential sources of this service include online and unloaded resources, quick starting resource (gas turbines), or (potentially) loads under contract to curtail. Transmission customers must secure or self-provide and the transmission provider must offer the service when the PPTS is used to serve load within its control area.

Some interesting technical questions arise if complications due to interface congestion and the location of reserves coincide. The issue involves remote resources such as wind generation that purchase the requisite reserve services from sources that are close to the load (per Order 888), but that are located on the other side of a congested interface. If the wind facility fails to deliver but the reserves are provided from the other side of a congested interface (i.e., through a bottleneck), will the interface become more congested even though the remote generation did not use the interface but the covering reserve source must travel through a congested path? Conversely, if the wind generation source is on the “bad” side (i.e., must move through a bottleneck), will the congestion be partially relieved by the release of the reserved capacity across the interface and the increased generation by the reserve on the good side? Although this issue may appear academic, if wind resources must fall back on reserve services to

cover lost generation during a given hour, these issues indicate that the location of certain ancillary services such as supplemental reserves actually may increase grid reliability concerns and therefore impose additional costs.

Conclusion

Ancillary service requirements present another area where tariff design may have unintended consequences for the ability of wind and other intermittent generation to participate in the competitive market. Although this issue raises a number of technical engineering questions, the proponents of wind generation should seek to ensure that the underlying rationale behind any requirement is as conceptually sound when applied to wind and other intermittent generation technologies. Proponents may want to further explore the proper measure of capacity for wind generation as it is used to price individual ancillary services.

5. ENERGY-BASED ACCESS CHARGES

Design Issues

Transmission pricing design is driven by two key issues: the ability of the transmission provider to recover the fixed costs of the transmission network, and pricing for congestion. If there is enough transmission capacity on an interface to meet the demands for all users of the system, then it is said to be uncongested. If demand for transmission service exceeds available capacity, some transmission customers may not be able to secure transmission service.

Assuming the price of transmission increases as a transmission interface or system becomes congested, transmission capacity will be allocated to those willing to pay the most for service.

Firm transmission service typically has been sold based on capacity reservation, where transmission customers pay for guaranteed access to a specified amount of transmission capacity. The transmission customer must pay for this reserved capacity, regardless of how much energy is delivered across that reserved transmission capacity. Capacity reservation handles congestion by limiting the amount of available firm transmission capacity that is sold. If congestion occurs, then non-firm customers would be curtailed first. Therefore, firm capacity transmission is kind of an insurance against curtailment.

Intermittent Renewable Energy

A problem for intermittent renewable energy resources is that they may end up paying for firm transmission capacity that they may not be able to use. Intermittent generators may be able to circumvent this by purchasing non-firm transmission capacity, or a combination of firm and non-firm transmission capacity, as discussed below. However, if there is significant congestion on a transmission provider's system, or if these generators face possible displacement by transmission customers that desire firm or longer-term non-firm transmission, then intermittent generators may face a difficult choice of reserving more firm transmission, or choosing non-firm transmission and risk being interrupted or displaced. In addition, intermittent generators could try to sell unused firm transmission capacity on a secondary market, although such a market has been slow to emerge in some regions.

In recent years, as restructuring proceeds, a number of transmission providers and transmission-dependent entities have participated in the formation of independent system operators, or ISOs. A challenge to these ISOs is ensuring the recovery of transmission system costs from a variety of parties that may or may not own generation, or that may or may not serve customer load. In addition, there has been some experimentation with transmission pricing methodologies, and with different measures of measuring and pricing transmission congestion.

Access Fees and Congestion Charges

So far, the general approach appears to be to split transmission rates into two parts: an access fee that is imposed on either load or generation and is set to recover the fixed costs of the transmission system, and a variable rate based on congestion. The congestion rate could be based on the difference in generation prices between two nodes on the transmission system (locational-based marginal pricing, or LBMP), or through the costs of re-dispatch or out-of-merit dispatch. ISOs differ on how congestion is handled and priced, and also on how congestion drives transmission expansion. In some, if congestion is serious and sustained, then it is believed market participants will act to expand existing transmission capacity or build new transmission capacity to ensure their transactions go through. In other words, congestion costs may act as the driver for new transmission capacity or expansion. In other ISOs, a transmission customer may ask the ISO or transmission owners to build new transmission capacity, at that transmission customer's expense. (This is similar to how it is treated under Order 888.)

The fixed transmission costs account for the majority of operating costs. Although congestion pricing is important, the fixed transmission costs dwarf congestion costs. If the access charge is assessed on generators, an important consideration for intermittent generators is that the access charge be based on energy, not capacity, since the intermittent resource has fewer hours in which to recover a capacity-based access charge through energy sales.²⁵

Potential Problems

There is some question about whether congestion charges can act as a means of driving transmission expansion, since transmission capacity is, by nature, a capacity-based mechanism. It is unclear whether congestion costs by themselves will be an adequate incentive for market participants to finance transmission expansion on their own, given the extensive permitting and regulatory requirements that are involved. In addition, there is some activity regarding the development of mechanisms for allocating transmission capacity during transmission congestion, or transmission rights when new transmission capacity is added, such as TCCs, TCRs and so forth.

Finally, it is not clear whether energy-based access charges will be beneficial for wind in all circumstances. If adequate non-firm transmission capacity exists, it may be more cost-effective for wind generators to use non-firm transmission than to participate in a regime that relies exclusively on energy-based access charges. Likewise, in situations where the capacity factor of the wind generator is greater than the load factor on the transmission interface, energy-based access charges may be more expensive for project developers than capacity-based charges.

Alternative Approach

Another potential means of simulating an energy-based access fee would be to substitute the effective capacity of an intermittent generator into the generally applicable capacity-based

fee.²⁶ This approach may be best suited for facilities that have an operational history so that disputes regarding the appropriate effective capacity rate can be avoided. However, a proxy effective capacity rate could be applicable, especially where the facility is within a geographic area that has known resource characteristics and the facility's production can be reasonably estimated.²⁷ Although not a true energy-based tariff, it should partially correct the inequity of charging based on the facility's nameplate rating alone. Obviously, daily and annual variations will not be perfectly captured by this method. However, it is more administratively attractive, allows for advanced billing, and may avoid the need for additional metering or information systems.

A variation of this approach would be for the intermittent generator to reserve firm transmission capacity equivalent to the effective capacity discussed above, and use available non-firm transmission if output is more than the effective capacity. Problems may arise if the financing used for the intermittent facility requires a certain level of energy production that involves transmission to the purchasing party, and if the certainty of this transmission service affects the likelihood of a loan default. A lender may require an intermittent generator to reserve firm transmission capacity to ensure power delivery. In addition, users of non-firm transmission may be curtailed if congestion exists on the transmission system, or may be displaced by transmission customers that desire firm transmission or non-firm transmission of greater length. In these situations, the intermittent generator that is using non-firm transmission service has the right to match the firm or longer-term non-firm service before being displaced.

Conclusion and Recommendations

Proponents of wind energy should pursue energy-based tariff designs. Although capacity-based tariffs have been the historic norm, there is evidence that the energy-based approach could collect the funds necessary to cover revenue requirements, while providing technology- and resource-neutral price signals. As long as transmission owners recover costs, they should be indifferent to the rate design. Although energy-based tariffs may impose additional metering and data collection burdens, it is reasonable to assume that this burden would not necessarily be greater than the metering needed in a fully competitive spot market.

As an alternative to a pure energy-based tariff design, the unintended effects associated with capacity-based tariffs could be mitigated in part by the use of effective capacity measures. In pursuing the proper tariff design, additional research may be necessary regarding the best measure of effective capacity, especially if there is a preference against the use of ex-post fees. Specifically, there may be more questions about the proper effective capacity rating for new projects and resource areas than for proven facilities and resources.

6. SECONDARY TRANSMISSION MARKET

Order 888 specifically required that transmission customers be allowed to assign their rights under the service agreement. There is a rate cap applicable to the resale of capacity that generally limits the resale²⁸ price to the higher of the rate paid to the transmission provider by the assignor, the rate in effect for the service at the time of the transaction (current tariff rate), or the assignor's opportunity cost. The purpose of the price cap is to remove any incentive to purchase excessive amounts of capacity and then charge monopoly rents. With this condition, the price for capacity on the secondary market should be equal to or less than the price charged by the transmission provider.

Three Issues for a Secondary Market

Development of a robust secondary market for transmission capacity may depend on three related issues: demand for capacity on a line, the willingness of reservation holders to discount, and the timing requirements to transact within the market.

The first issue concerns demand for capacity on the line. If the line is not constrained, there may be little demand for capacity and those parties that have transmission rights they wish to resell may not be able to find a willing buyer unless they offer significant discounts. The time when a specific line becomes constrained may or may not coincide with system peak demand for

energy. Congestion can depend on a number of factors, including how the physical dynamics of loop flows affect the grid. Additionally, depending on the future market response to deregulation, historical congestion patterns may not adequately indicate future grid use, especially if some generation units on the grid do not operate below a certain market clearing price for energy.²⁹ It is possible that the periods of line constraint could significantly vary with the demand for energy and the market clearing price for that energy. If this is the case, the holder of rights that cannot use the rights should not assume that the presence of constraints necessarily means sufficient demand for their capacity will exist.

The second consideration is how far holders of transmission rights are willing to discount their excess capacity to ensure a resale. Even when a line is not congested, holders of excess capacity reservations should have an incentive to discount capacity below the going market rate (the price cap) to avoid carrying the entire reservation cost under the take-or-pay tariff scheme. This gives the holder partial financial recovery, but exposure continues for the remainder of the take-or-pay burden. Additionally, as noted above, the fact that a line has become constrained does not necessarily indicate that the market clearing price for energy is sufficiently high to prompt others to purchase their rights at cost.

If the generator's availability is not well correlated to periods of congestion on a specific line, issues regarding securing transmission capacity via the secondary market may not be significant—the line should have capacity available. If the intermittent generator is trying to resell capacity during periods of constraint, however, resale at cost (without discount) will be a function of demand for the capacity at the sale or resale clearing price. The presence of capacity

at discount may entice other generators that otherwise would not enter the market for that hour to participate because their relatively higher variable cost (either the fuel or the congestion cost) could be offset by the transmission discount.

The third issue concerns the timing requirement to transact in the secondary market.³⁰ In some sense, this can be seen to reflect the relative efficiency of the secondary market's operation. If the operation of that market dictates that transactions occur well in advance of the target delivery period, parties who cannot know whether they will want to purchase or resell capacity may be effectively precluded from the market. Operational efficiency could be determined by how well the OASIS system functions as a marketplace, the presence of alternative forums distinct from OASIS (e.g., informal relationships between non-transmission owner-affiliated entities such as marketers), and the formal advanced scheduling requirements of the system operator. If the formal scheduling constraint is minimal (i.e., the system operator does not require day-ahead scheduling), and fast transactions are possible (i.e., a willing seller can find a willing buyer quickly and the assignment can be finalized quickly), intermittent generation facilities may be able to purchase or resell capacity relatively easily. Such a robust market would be optimal and should be the policymaker's goal. If, however, formal or informal scheduling burdens push transactions outside the time frame of reasonable resource forecasting ability for the technology, intermittent generation may be functionally excluded from the market. Additional complications are likely to arise where the remote intermittent generator holds capacity across a number of zones where the scheduling requirements are not consistent and multiple resale transactions will be required (e.g., each zone has a different transmission owner

that must allow the assignment, or a resale purchaser is interested in only part of the original multi-zone right).

Mechanisms for Congestion Management

In non-pro forma tariff systems, the mechanisms designed for congestion management also may develop distinct secondary markets. For example, where rights across a congestion interface are prioritized in favor of holders of physical transmission rights (PTRs) or transmission congestion contracts (TCCs), there may be a secondary market for these preferences. The TCC serves as a financial hedge against elevated congestion charges between nodes or zones.³¹ Some access fee already has been paid to use the network within the zone. The holder of a TCC can use a congested interface without paying the elevated congestion charges because the holder has purchased separate insurance to hedge against those elevated charges. If the holder of a TCC will not be delivering power during the congestion period, it has an incentive to resell the preference for the period the holder cannot use it. Resale would allow the holder of the TCC to recapture part of the expense for the insurance, and it would benefit the purchaser in terms of avoided congestion charges. The transmission owner should be indifferent because it already has received a premium price for the preference associated with some set quantity of capacity. Efficient allocation of the capacity should dictate that the holder of a TCC could extract a premium price for the right, potentially capped at the node/zone price differential.

Similarly, a proposal made in the California ISO/PX docket calls for the creation of longer term firm transmission rights. Pursuant to a FERC order, the ISO/PX filed a program in June 1998 for implementation in 1999.³² Although the details remain to be seen, a competitive allocation of transferable firm transmission rights eventually will be put into place. The system should include release provisions if the capacity is not used or hoarded to prevent potential market abuses. Presumably, these firm rights will have a limited duration to allow market reevaluations of their value.³³ The firm rights system will work in parallel with the currently authorized spot allocation of transmission capacity made via the iterative scheduling protocols and application of congestion charges. The greatest benefit of the firm system will be advanced pricing of transmission capacity, allowing some transactional certainty required for project (generation or transmission) planning and financing.

Obviously, the niche that a wind facility finds itself will be determined by what strategy it adopts in selling power and the balance the facility strikes between minimizing transmission costs and ensuring that power can be moved to market when available. This balancing effort may be required for each system the facility must wheel through. Some wind facilities may wish to avoid the issue by contracting with a third party, such as a marketer, that would accept responsibility for securing the required transmission. Other facilities that choose to sell directly (e.g., under a bilateral arrangement or into a power exchange where they must secure transmission to a specific point) will need to gather information about all transmission systems along the pathway. Information regarding the transmission system(s) will be necessary to anticipate potential limitations between the point where the facilities deliver and where the energy will be withdrawn. Where the transmission is exposed to dynamic changes in availability

due to loop flows, for example, it may be useful to anticipate those problems. Anticipated periods of transmission limitation then should be compared to the facility's estimated operational profile to anticipate the risk of being curtailed or excluded from the market because of constrained paths.

In some instances, where there are few or no anticipated bottlenecks, the project should be able to use non-firm hourly transmission services or procure short-run services from a secondary market, if available.³⁴ In other instances, where the project anticipates the need for firm service because of capacity constraints, it could adopt a strategy of taking firm service for those hours it is confident the wind resource will be present, with the balance of required capacity during any hour coming from non-firm service or the secondary market.³⁵

Conclusion and Recommendations

Proponents of wind energy should work to ensure that there are few obstacles to the development of robust secondary markets. For example, they should seek to minimize the time required to transact in the marketplace. This could include efforts to ensure that there is consistency in timing requirements across systems where wheeling through is likely to occur. Some work may be required to anticipate the demand for capacity over specific lines and pathways that are likely to be in demand for promising wind resource areas. Research also may be useful to determine how line congestion dynamics change, assuming certain energy market profiles.

NOTES

1. By this we mean that the intermittent resource is not required to firm as a condition of bidding.

2. We assume that a bidder would reflect actual transmission costs for a reservation consistent with its projected ability to deliver. Otherwise the bidder carries the risk of unexpected transmission costs not reflected in the bid price. For a detailed discussion of transmission pricing issues and the advantages of hourly reservations under PPTS and an alternative in energy-based access charges, see S. Stoft, C. Webber, and R. Wiser, *Transmission Pricing and Renewables: Issues, Options and Recommendations*, LBNL-39845 / UC-1321 (Berkeley, Calif., Lawrence Berkeley National Laboratory, May 1997).

3. We have assumed the RFP would pay a fixed price for actual deliveries made. Obviously other arrangements are possible. Note that secondary market considerations (purchase or resale of reserved but unused transmission capacity) are addressed in Chapter 6.

4. Freeze out rules have been suggested to deter bid gaming. Under this concept, bidders would be precluded from participating in subsequent iterations if certain bid characteristics are not improved. This is primarily aimed at strategic bidding that would affect the energy clearing price. Such rules may or may not change grid congestion. See R. Wilson, "Activity Rules for the Power Exchange," Market Design, Inc., March 1997.

5. For congestion within a zone, the price is the redispatch cost and it is paid by all users in the zone.

6. TCCs generally are seen as financial instruments akin to insurance. Securing a TCC will protect the holder from elevated congestion charges for some amount of capacity. These contracts generally are seen as assignable.

7. TCRs generally are considered as physical rights to some block of transmission capacity. The concept of TCRs is consistent with that of firm transmission rights.

8. A similar auctioning of physical transmission rights has been proposed for the California ISO/PX. FERC ordered a filing due June 30, 1998, which will allow for firm transmission rights and a secondary market. See Federal Energy Regulatory Commission, "Order Providing Guidance and Establishing Procedures," 80 FERC ¶ 61, 128 (July 30, 1997), mimeo at page 25. Although the specifics remain to be seen, ultimately there will be a firm long-run physical rights primary and secondary market along with the spot ISO controlled market for energy transmission.

9. This is similar in concept to the deadbands used in the Open Access tariffs. See Schedule 4, Energy Imbalance Service, in "Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities and Recovery of

Stranded Costs by Public Utilities and Transmitting Utilities,” Order No. 888-A, 78 FERC ¶ 61,220 (March 4, 1997), mimeo at page 166 (Hereafter “Order 888-A”).

10. For more on the APX, see Janis Pepper, “Opportunities for Wind in the APX Green Power Markets” (presentation at *Windpower '98*, Bakersfield, Calif., April 30, 1998).

11. For more on dynamic scheduling, and examples of how it is used, see Eric Hirst and Brendan Kirby, *Ancillary Service Details: Dynamic Scheduling*, ORNL/CON-438 (Oak Ridge, Tennessee: Oak Ridge National Laboratory, January 1997).

12. Loop flow generally concerns unintended impacts on the transmission system caused by electricity flowing according to the laws of physics rather than contracts. Because the transmission system is dynamic, injection of power may cause actual electric flows to impose constraints and costs on facilities outside the contemplated contract path.

13. The issue here is the ultimate cost for loss of intermittent generation during a particular hour. If spinning or supplemental reserves identified as ancillary services are applied to make up for the gradual loss of the intermittent resource, the cost may exceed the true cost of generation in the spot market, and may trigger the need to provide back-up to the reserves currently used to firm. This topic may require additional research and is beyond the scope of this report.

14. This assumes that the load is not interruptible or has not otherwise elected to be directly tied to wind production. Those options are available to loads because they may dictate the quality of power that they wish to purchase. Presumably, different loads could have differing preferences in the types and sources of power.

15. This is the rate design used by IndeGO. See Internet, [www.idahopower.com] for the pricing document.

16. See the “General Agreement on Parallel Paths” (GAPP) experiment authorized by FERC on March 25, 1997 (78 FERC ¶ 61,134 in docket ER 97-697). This system charges customers based on filed open access tariffs for the primary path and then allocates revenues to the transmission providers proportional to their system’s use according to actual power flows. The primary path for any customer’s transaction is initially determined by loop flow modeling. If the initial modeling of the transaction shows a flow path other than the contract path, the customer may then be referred to the primary path transmission providers for service. GAPP is an information-intensive effort because it will attempt to capture the dynamics of loop flow. The ultimate benefit will come in terms of a better match between fees charged and actual costs incurred for the regional transactions.

17. Imposition of access fees on loads also is preferable because loads effectively drive the market for generation. Imposing the fee on the ultimate source of demand presents a more correct set of price signals and related choices in how the customer’s energy services will be provided.

18. This may require use of network integration service or a similar tariff design that would allow simultaneous input from multiple sources. Obviously, if output is altered significantly over a specific hour, questions related to dynamic changes in congestion or other reliability issues such as loop flow arise.

19. Note that a wind facility's generation production curve is driven by factors particular to the location and the season. If a number of facilities in a general geographic area are viewed as a single aggregated resource, the production curve for the wind resource is likely to appear more smooth than that for any single facility. Therefore, whatever the measure of capacity for the aggregate facility, the reduction in resource availability will not be similar to a conventional facility of that size tripping off the grid. Assuming that the production curve can be estimated, some aggregated rate of production loss could be presumed to occur over the hour. From the market's perspective, it is that quantity of production lost during the hour that is similar to capacity lost by a transient outage, and that the ancillary services reserves must make up.

20. See Order 888-A.

21. See Order 888, pp. 209-211, for a discussion of this service. Order 888 indicates that, to the degree customers are able to reduce requirements, their obligation should be reduced. This may be reflected in the degree to which a generator can provide localized

voltage stability. If wind facilities are able to assist in voltage support in remote locations, their obligation should be reduced accordingly.

22. See Order 888-A, mimeo at p. 164.

23. See Order 888-A, mimeo at p. 159.

24. See Order 888-A, mimeo at p. 156.

25. Intermittent generators may be indifferent to an energy-based or capacity-based access charge if the charge is placed on load as opposed to generation, since load presumably would pay the same access charge regardless of which generators the load contracts with. Also, the issues raised here regarding the difficulty in recovering a capacity-based access charge may apply to peaking resources as well as to intermittent resources. Finally, another question is whether a kWh delivered in November should be valued the same or differently as a kWh in July, i.e., whether there should be some time-differentiated value in kWhs delivered under an energy-based access charge.

26. Effective capacity can be an estimated number that reflects the likely amount of production for a given resource availability rate by a specific generator type. In some cases it could also be the facility's capacity-factor (rather than a nameplate rating). Note, however, that annual variations in production are common, so some questions about updating or truing-up the value could be appropriate.

27. See, for example, M.R. Milligan and M. Graham, *An Enumerated Probabilistic Simulation Technique and Case Study: Integration Wind Power into Utility Production Cost Models*, NREL/TP-440-21530 (presentation at IEEE Power Engineering Society Summer Meeting, Denver, Colo., July 29-August 1, 1996).

28. Resale and assignment are synonymous in this context.

29. This dynamic may not always be true. For example, the California ISO / PX proposal designates some facilities as must-run for transmission reliability purposes. This would potentially negate part of the potential congestion dynamic when prices fall below the marginal operating cost of some selected facilities because those facilities are under a distinct obligation to operate for reliability purposes.

30. This is distinct from any time constraints associated with participation in the relevant energy market.

31. Generally, the TCCs are seen as financial instruments and not as the traditional physical rights that typically are associated with transmission services contracts. However, to simplify the discussion here, I have collapsed the two concepts for the purposes of assuming that a secondary market could develop to allocate the limited ability to use an interface to those that are most willing to pay.

32. See FERC “Order Providing Guidance and Establishing Procedures.”

33. One proposal suggests FCC type auctions for capacity units across transmission interfaces. Bidders could structure a set of bids to secure rights across a number of zones. This would allow remote users access through congested interfaces without being locked out of a crucial interface. The quantity of capacity rights that are subject to auction would be a conservative estimate of capacity consistently available on an interface—that is, some quantity not subject to reduction due to season, flow direction, or other system dynamics. Holders of existing transmission contracts would be given grandfathered capacity rights for the remaining term (without evergreening) of the contract. These firm transmission rights would have relatively short lives, especially while experience is being gained. The short lives help ensure that efficient primary and secondary markets can develop, and that value price signals for capacity are routinely refreshed.

34. See S. Stoft et al. regarding the relative advantage of hourly service (which approximates an energy-based charge) over longer-term capacity-based take-or-pay contracts. Of course, project financing may demand the certainty of firm service, and reliance on non-firm service puts the project at potential risk of displacement if some other facility makes a firm service request and reserves all remaining ATC.

35. For example, if a facility is confident that it would operate regularly during a certain set of hours of the day for a certain percentage of its output, it may elect to reserve service for those hours at that fractional output. The facility then would attempt to secure

non-firm service to schedule deliveries in the hours before and after its firm service period when its resource forecasts indicate that is prudent. It also would seek non-firm service during the firm service periods for increments of capacity greater than the fraction under reserved service.

GLOSSARY

Most of the following definitions were drawn from “Maintaining Reliability in a Competitive U.S. Electricity Industry,” the DOE Reliability Task Force Committee report that is available at the DOE web site (<http://www.doe.gov>). That glossary is drawn mostly from the 1996 North American Electric Reliability (NERC) Glossary. We also incorporated the NWCC Transmission Phase I glossary; some terms from the National Council on Competition in the Electric Industry; and some definitions prepared by Bob Putnam and Kevin Porter.

Access fees—A fee paid by a transmission customer or a power supplier to the transmission owner, or to the independent system operator, for the ability to send or receive electricity through the utility’s or ISO’s transmission or distribution systems.

Ancillary services—Those services necessary to support the transmission of energy from resources to loads while maintaining reliable operation of the transmission provider’s transmission system.

Available transmission capacity (ATC)—The amount of transmission capacity available for third party transactions after subtracting transmission needed for a utility to serve its native load and a reserved amount of transmission capacity to comply with the utility’s or regional reliability council’s standards for maintaining reliability.

Backup power—Power provided by contract to a customer when that customer’s normal source of power is not available.

Bid gaming—Refers to generators or parties that own transmission and that take certain actions in an attempt to favor their competitive market position. Commonly, it refers to generators that withhold generating capacity—or transmission owners that withhold transmission capacity—at strategic times in an attempt to drive up the market price for electricity.

Bundled utility transmission service—Includes both transmission service and those services necessary to support the transmission of energy from resources to loads while maintaining reliable operation of the transmission provider’s transmission system.

Bundles of service—Refers to service providers packaging of commodities or offerings to customers, such as electric, gas, cable and Internet services to residential customers; the bundling of electric energy and ancillary services; or the bundling of green and non-green power.

Capacity-based tariffs—Refers to electric transmission service being purchased or committed on a capacity basis.

Capacity—The rated continuous load-carrying ability, expressed in megawatts (MW), megavolt-amperes (MVA), or megavolt-amperes-reactive (MVAR) of generation, transmission or other electrical equipment.

Capped—Upper limit.

Commodity price—The generation-only cost for a unit of electricity, not including any transmission or ancillary service costs.

Comparability—The requirement that public utilities that own and/or control facilities used for the transmission of energy in interstate commerce provide third-party access to such facilities under the same terms and conditions that the public utility takes service for its own wholesale sales and purchases.

Congestion charges—Refers to the imposition of fees to reflect constraints in transmission capability to meet demand for transmission.

Constraint fees—Fees charged for the purpose of recovering congestion costs or to provide a market mechanism to clear transmission.

Contract path—The specific transmission facilities identified in the contract to be used to deliver energy from the seller to a buyer.

Control area—An electric system or systems, bounded by interconnection metering and telemetry, capable of controlling generation to maintain its interchange schedule with other control areas and contributing to frequency regulation of the Interconnection.

Deadband—A narrow range within which no action is taken.

Distributed resources—Typically smaller sized generation resources located on the distribution and/or transmission system close to selected loads and often used as an economic alternative to transmission or distribution system expansions or significant generation capacity additions. Often considered an alternative to large central generating plants.

Distribution system—The portion of an electric system that transports electricity from the bulk-power system to retail customers; it consists primarily of low-voltage lines and transformers.

Dynamic scheduling service—The interconnected operations service that provides the metering, telemetering, computer software, hardware, communications, engineering and administration required to electronically move a transmission customer's generation or demand out of the control area to which it is physically connected and into a different control area.

Economy power—Generally, non-firm energy purchases made from off-system, where the purchase price would be below the purchaser's marginal cost of generation. A typical

example would be purchases of hydroelectric power generated by fish flows or releases made to increase storage availability. Absent the purchase, the energy would often be lost.

Electric system losses (losses)—Total electric energy losses in the electric system. The losses consist of transmission, transformation and distribution losses between supply sources and delivery points. Electric energy is lost primarily due to heating of transmission and distribution elements.

Energy imbalance service—The ancillary service that provides energy correction for any hourly mismatch between a transmission customer's energy supply and the demand served.

Energy-based access charges—Where an access charge to a transmission system is based on the electric energy, in MWh, transmitted over the transmission system.

Environmental externalities—Environmental costs associated with electricity production, distribution and consumption that are not reflected in the commodity price. Examples include the cost impact of various air emissions on human health, crops and natural ecosystems. The costs could be that of the damages themselves, the economic losses that ensue from the damages, the remediation of or response to the damages, and/or the intrinsic loss of value in destroyed or radically altered environments.

Firm transmission—The commitment of transmission service to a customer under a filed schedule with a regulatory body to which the parties anticipate no planned interruption. The allocation of the generating resources for transmission may be system wide, or only for a named unit. The time of availability usually is prescribed as well.

Firming, firm-up—The use of other system resources to compensate for the variability of intermittent resources such as wind.

Flow-based contracts—Contracts that specify only the amount of energy to be delivered without identifying specific line segments.

Frequency—The rate, in cycles per second (or Hertz, Hz), at which voltage and current oscillate in electric-power systems. The reference frequency in the North American Interconnections is 60 Hz.

Functionally unbundle—To separate the ownership of electrical generation resources from ownership of transmission and distribution facilities, primarily through regulatory requirements other than mandatory divestiture.

Green power—Refers to the source of electric power that is considered more environmentally friendly than the prevailing sources of electric power. Typically, green power is renewable sources of electricity, although it also may encompass energy efficiency,

donations to environmental groups, retirement of older automobiles, or retirement of sulfur dioxide emission credits under the Clean Air Act.

Grid—A system of interconnected power lines and generators that is managed so that the generators are dispatched as needed to meet the requirements of the customers that are connected to the grid at various points. Gridco is sometimes used to identify an independent company responsible for the operation of the grid.

Hertz (Hz)— A unit of frequency equal to one cycle per second.

Independent system operators (ISOs)—A neutral operator responsible for managing a transmission system. ISOs are created when a transmission-owning utility—or group of transmission-owning utilities—transfers some or all operating control (but not ownership) over designated transmission facilities to an independent, nonprofit, or not-for-profit organization. ISOs may or may not operate a control area; dispatch transmission; run a power exchange or spot market; administer an ancillary services market and deliver ancillary services; conduct transmission planning; and, with transmission owners, expand transmission capacity.

Integrated resource planning (IRP)—A public planning process and framework within which the costs and benefits of both demand- and supply-side resources are evaluated to develop the least-total-cost mix of utility resource options. In many states, IRP includes a means for considering environmental damages caused by electricity supply or

transmission and identifying cost-effective energy efficiency and renewable energy alternatives. IRP has become a formal process prescribed by law in some states and under some provisions of the Clean Air Act Amendments of 1990 and the Energy Policy Act of 1992.

Interchange—Electric power or energy that flows from one entity to another.

Interconnected operations services (IOS)—Services that transmission providers may offer voluntarily to a transmission customer under Federal Energy Regulatory Commission Order No. 888 in addition to ancillary services. See also ancillary services.

Interconnected System—A system consisting of two or more individual electric systems that normally operate in synchronism and has connecting tie lines.

Interconnection—When capitalized, any one of the four major electric system networks in North America: Eastern, Western, ERCOT, and Alaska. When not capitalized, the facilities that connect two systems or control areas. Additionally, an interconnection refers to the facilities that connect a nonutility generator to a control area or system.

Interface—The specific set of transmission elements between two areas or between two areas that comprise one or more electrical systems.

Island—A condition where, due to the partial loss of generation or portions of the transmission network, some generation resources and nearby loads are isolated from the rest of the network and resources.

ISO PX model—Refers to an independent system operator (ISO) that includes a centrally dispatched power exchange (as with the PJ, NY or NE ISOs), or a power exchange that is closely coordinated with an ISO (as in California).

Legacy Rates—In the context of independent system operators or other regional transmission entities, it is the charging of present transmission rates correspondent to the current transmission owner's service territory until a predetermined transition period expires, or the transmission owner recovers its costs of the transmission system, or both. At that time, the zone boundaries, which typically corresponds to the transmission owner's service territory, can be collapsed, and an average transmission rate can be charged.

Level playing field—No party to a transaction is the recipient of incentives, subsidies or other advantages that are not received by all other parties.

Load centers—A geographical area where large amounts of power are drawn by end-users.

Load Following—Regulation of the power output of electric generators within a prescribed area in response to changes in system frequency, tieline loading, or the relation of these to

each other, so as to maintain the scheduled system frequency or the established interchange with other areas within predetermined limits.

Load—A consumer of electric energy; also the amount of power (sometimes called demand) consumed by a utility system, individual customer or electrical device.

Locational-based marginal pricing (LBMP)—A system of measuring the difference in electric energy costs between two points, adjusted for transmission losses. The difference in electric costs, as adjusted for losses, is attributed to transmission congestion or constraints.

Losses—See Electric system losses.

Make-up power—Refers to electric power that is delivered to account for electricity losses over transmission lines, or for electric power that is delivered to meet electric schedule commitments that could not have been met previously because of resource constraints (i.e., lack of wind).

Margin—The difference between net capacity resources and net internal demand. Margin is usually expressed in megawatts (MW) for operating reserves and as a percentage of either system load or installed generating capacity for planning reserves.

Marketer—An agent for generation projects who markets power on behalf of the generator. The marketer also may arrange transmission, firming or other ancillary services as needed.

Although a marketer may perform many of the same functions as a broker, the difference is that a marketer represents the generator, while a broker acts as a middleman.

Nameplate output—The amount of electric power that the manufacturer of a wind turbine guarantees to deliver, continuously, at rated terminal voltage and rotor speed. Also called nameplate capacity.

Native load customers—The wholesale and retail customers on whose behalf the transmission provider, by statute, franchise, regulatory requirement, or contract, has undertaken an obligation to construct and operate the transmission provider's system to meet the reliable electric demand of such customers.

Native zone load—Refers to the group of customers being served by electric utilities in a designated zone. See also native load customers.

NE ISO—The New England ISO, formerly the New England Power Pool.

Netted out—Subtracted from.

Network integration transmission service (NITS)—Whereby the control area of the transmitting utility functions like a pool and NITS transactions are primarily an issue of load balancing.

Nodal pricing—The difference in price between two nodes, adjusted for transmission losses.

Nodes—The origination and destination point of a transmission transaction on a transmission system

Non pro forma tariff—A tariff that has conditions different than those in the pro forma tariff as part of Order 888. FERC allows utilities under its jurisdiction to have tariffs different from the pro forma tariff, on a case-by-case basis, but only if the utility can show that the terms and conditions under its tariff are the same or superior to those in the pro forma tariff.

Non-firm transmission—Transmission service that is provided under a commitment of limited or no assured availability.

North American Electric Reliability Council (NERC)—A council formed in 1968 by the electric utility industry to promote the reliability and adequacy of bulk power supply in the electric utility systems of North America. The NERC consists of 10 regional reliability councils and encompasses essentially all the power systems of the contiguous United States and Canada. The NERC regions are as follows: 1) Alaskan System

Coordination Council (ASCC); 2) East Central Area Reliability Coordination Agreement (ECAR); 3) Electric Reliability Council of Texas (ERCOT); 4) Mid-American Interpol Network (MAIN); 5) Mid-Atlantic Area Council (MAAC); 6) Mid-Continent Area Power Pool (MAPP); 7) Northeast Power Coordinating Council (NPCC); 8) Southeastern Electric Reliability Council (SERC); 9) Southwest Power Pool (SPP); and 10) Western Systems Coordinating Council.

North American Electric Reliability Organization (NAERO)—The planned successor to NERC.

NY ISO—The New York ISO, formerly the New York Power Pool.

Open Access Same-Time Information System (OASIS)—A computer network or software program that is administered and maintained by transmission owning utilities, which are required by FERC to post information on transmission availability and available discounts on transmission service to all parties.

Open access—The requirement that public utilities that own and/or control facilities that are used for the transmission of energy in interstate commerce provide nondiscriminatory, third-party access to such facilities.

Operating reserve:

Spinning reserve service—The ancillary service that provides additional capacity from electricity generators that are online, loaded to less than their maximum output, and available to serve customer demand immediately should a contingency occur.

Supplemental reserve service—The ancillary service that provides additional capacity from electricity generators that can be used to respond to a contingency within a short period, usually 10 minutes.

Pancaking—The multiple charges that result from a utility being subject to multiple tariffs or zones when transmitting energy from resources to loads.

Parallel path flows—The difference between the scheduled and actual power flow, assuming zero inadvertent interchange, on a given transmission path. Synonyms: loop flows, unscheduled power flows, and circulating power flows.

Peak load or peak demand—The electric load that corresponds to a maximum level of electric demand in a specified time period.

PJM system—Refers to the Pennsylvania-New Jersey-Maryland ISO.

Point-to-point transmission services (PPTS)—The services that support bilateral arrangements between generator and purchaser.

Point-to-point—The reservation and/or transmission of energy between contractual points of receipt and delivery on the transmission provider’s system.

Postage-stamp pricing—The use of a single unitized charge, regardless of the distance between the generation resource and the load.

Power exchange (PX)—A specialized market institution for electricity that can function as a day-ahead, hour-ahead, and/or real-time market for electric. Power exchanges can be a centralized market where participants can bid to buy or sell electric energy, or can consist of private exchanges for parties to bid to buy or sell electric energy.

Price cap (rate cap)—Where a market participant is limited to a predetermined price or rate, or by a price paid to another entity, in selling a product or service.

Pro forma tariff—The tariff FERC attached to its Order 888 open access transmission order in 1996, stating that utilities that filed tariffs with the same conditions as the pro forma tariff will be in compliance with Order 888.

Ramping, ramp-up—The process of gradually increasing or decreasing the output of system resources. The rate at which the output of system resources increases or decreases is called the ramp rate.

Reactive power—The portion of electricity that establishes and sustains the electric and magnetic fields of alternating-current equipment. Reactive power must be supplied to most types of magnetic equipment, such as motors and transformers. It also must supply the reactive losses on transmission facilities. Reactive power is provided by generators, synchronous condensers, or electrostatic equipment such as capacitors, and directly influences electric system voltage. It is usually expressed in kilovars (kVAR) or megavars (MVAR).

Reactive supply and voltage control from generating sources service—The ancillary service that provides reactive supply through changes to generator reactive output to maintain transmission line voltage and facilitate electricity transfers.

Real power loss service—The interconnected operations service that compensates for losses incurred by the host control area(s) as a result of the interchange transaction for a transmission customer. The Federal Energy Regulatory Commission's Order No. 888 requires that the transmission customer's service agreement with the transmission provider identify the entity responsible for supplying real power loss.

Real Power—The rate of producing, transferring or using electrical energy, usually expressed in kilowatts (kW) or megawatts (MW).

Real-time marginal spot price—As used in this context, the instantaneous cost of producing or not producing an incremental unit of energy for a short period of time.

Regulation and frequency response service—The ancillary service that provides for following the moment-to-moment variations in the demand or supply in a control area and maintaining scheduled Interconnection frequency.

Reliability organization—Either the North American Electric Reliability Council (NERC), or one of the 10 regional councils that comprise NERC. See the definition for the North American Electric Reliability Council.

Reliability—The degree of performance of the elements of the bulk-power system that results in electricity being delivered to customers within accepted standards and in the amount desired. Reliability may be measured by the frequency, duration and magnitude of adverse effects on the electric supply. Electric system reliability has two components—adequacy and security. Adequacy is the ability of the electric system to supply the aggregate electrical demand and energy requirements of the customers at all times, taking into account scheduled and unscheduled outages of system facilities. Security is the ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system facilities.

Rolling window—The most dated unit of time within the measurement period for ancillary services is dropped and the most recent unit of time is added, making the resulting measurement period current.

Schedule—An agreed-upon transaction size (megawatts), start and end time, beginning and ending ramp times and rate, and type required for delivery and receipt of power and energy between the contracting parties and the control area(s) involved in the transaction.

Scheduling, system control, and dispatch service—The ancillary service that provides for a) scheduling, b) confirming and implementing an interchange schedule with other control areas, including intermediary control areas that provide transmission service, and c) ensuring operational security during the interchange transaction.

Spinning reserves—Reserve generation capacity that is spinning, synchronized to the grid, and ready to take up load. Public utilities maintain spinning reserves in order to account for load forecast uncertainties and possible outages of other generating plant.

Spot market—Commodity transactions whereby participants make buy and sell commitments of relatively short duration, in contrast to the contract market in which transactions are long-term.

Spot price—The prevailing price for a certain period of time (real-time, hour-ahead or day-ahead) from a spot market.

Stranded transmission capacity—Transmission capacity that is contracted for but unused.

Subfunctionalized pricing—The imposition of access fees based on the value of individual assets that are used along a specific transmission path.

System—An interconnected combination of generation, transmission and distribution components that comprise an electric utility, an electric utility and independent power producer(s) (IPP), or a group of utilities and IPP(s).

Take or pay—Contracts that maintain the tradition of requiring a take-or-pay reservation of firm transmission capacity require advance commitments to transmission that are difficult for intermittent technologies.

Tariff—A published volume of rate schedule and general terms and conditions under which a product or service, e.g. electric energy or transmission, will be supplied.

Tieline—A transmission line that interconnects two control areas or regions.

Transco—An independent organization that owns and operates a regional transmission grid. A transco differs from an independent system operator (ISO) in that an ISO does not own the transmission resources.

Transmission—An interconnected group of lines and associated equipment for the movement or transfer of electric energy between points of supply and points at which it is transformed for delivery to customers or is delivered to other electric systems.

True-up—A process of returning to forecasted or administratively set cost, revenues or service measures, and adjusting these measures to reflect actual costs, revenues or performance.

Turnkey—Turnkey preparation of a facility or system means that a single contractor acquires and sets up all necessary premises, equipment, supplies and operating personnel to bring a project to a state of operational readiness. In some cases, the contractor may continue to operate the facility for the customer, or the customer may assume operational control.

Unbundling—Disaggregating electric utility service into its basic components and offering each component separately for sale with separate rates for each component. For example, generation, transmission and distribution could be unbundled and offered as discrete services.

Universal truths—Undisputable facts or conditions known to all.

Voltage control—The control of transmission voltage through adjustments in generator reactive output and transformer taps, and by switching capacitors and inductors on the transmission and distribution systems.

Voltage—The unit of measure of electric potential.

Volt-amperes reactive (VAR)—The unit of measure of the power that maintains the constantly varying electric and magnetic fields associated with alternating-current circuits. See Reactive Power.

Wheeled, wheeling—Moving or transmitting electricity.

Wholesale power market (power marketers)—The purchase and sale of electricity from generators to resellers (who sell to retail customers) along with the ancillary services needed to maintain reliability and power quality at the transmission level.

Wholesale transmission services—The transmission of electric energy sold, or to be sold, at wholesale in interstate commerce (from The Energy Policy Act of 1992).

WSCC—The Western System Coordinating Council, a voluntary industry association that was created to enhance reliability among western utilities.

Zonal pricing—A grouping of nodes with similar spot prices. Congestion pricing is determined as the difference in prices between zones.

Zones—A predefined area of transmission—and/or distribution—facilities