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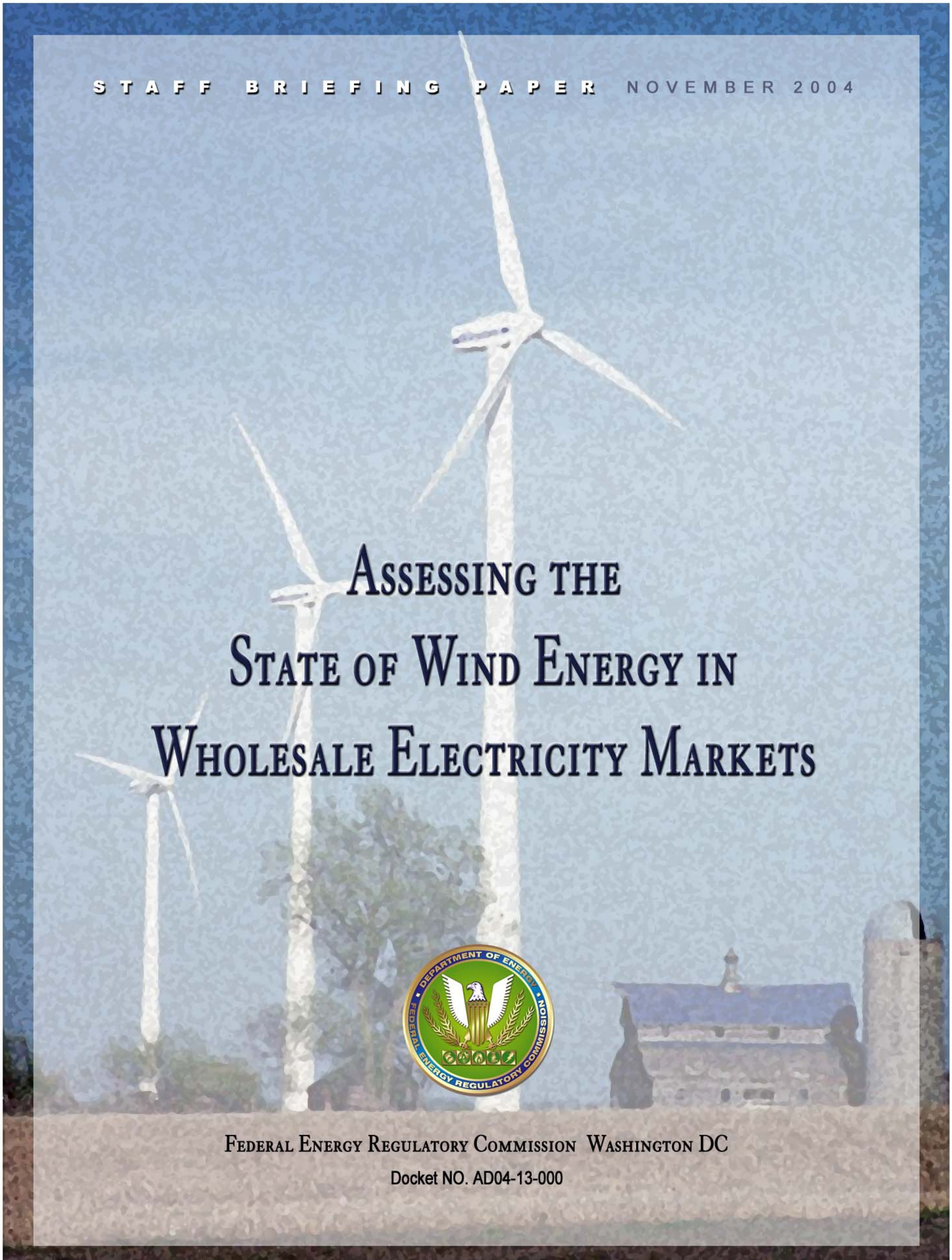
Assessing the State of Wind Energy in Wholesale Electricity Markets



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Executive Summary

Wind energy, while a relatively new market entrant, is the fastest growing electricity generation technology in the world today. Favorable public attitude, increasingly attractive economics and technological advances are combining to drive industry development. To date, wind has gained limited market acceptance primarily due to unique operational characteristics that do not allow wind generators to fully optimize their output in the current environment.

The evolution toward regionalized electricity markets, combined with technological innovation lowering the unit cost of wind generated electricity, has allowed wind generators to operate in a "merchant" role. In many regions of the country, wind generation now has the ability to compete with thermal resources. However, due to remoteness from load, transmission remains a concern that affects its competitiveness.

While there has been significant progress towards integrating wind resources into suppliers' and loads' portfolios, some challenges result from the terms and conditions of transmission service required by utilities subject to the jurisdiction of the Federal Energy Regulatory Commission (FERC).

Staff makes the following key findings from this study:

There are a number of public policy factors, both at the state and federal level, currently driving the development of wind energy.

Wind energy development is currently aided by the environmental benefits associated with energy production from clean, renewable resources. State Renewable Portfolio Standards and State Renewable Energy Credits place requirements upon load serving entities to procure certain amounts of their energy from renewable resources. The federal government has also reauthorized the Production Tax Credit for parties that engage in the development of renewable energy resources.

Wind project developers confront several hurdles in obtaining financing for wind projects under current market conditions.

Projecting revenues for wind generation is more difficult than for typical generation sources due to higher variability of production. Given difficulties associated with projecting merchant revenue streams for wind projects, financings have typically required power purchase agreements for the full output of the facilities. Overlooked in most early power project finance deals, transmission issues (*e.g.*, the intermittent nature and distance from load) have become a focus as investors recognize the importance of transmission service to project completion and economics.

The operational challenges facing competitive electricity suppliers (*e.g.*, available transmission, pancaked rates, and capacity value recognition) increase for wind generation.

Wind generation is unable to maximize its use of reserved transmission capacity due to its intermittent nature. When purchasing firm transmission, a wind generator pays more for that transmission (on a per unit basis) when accounting for its low capacity factor. Also, because wind resources are only optimum in specific locations, wind generation does not have similar site selection flexibility as thermal resources and may incur multiple transmission charges when delivering to load. Finally, because wind generation is not recognized as having a capacity value in certain markets, wind generators lose value in those markets.

Current open access pro forma tariff provisions place challenges on wind generation's ability to compete in electricity markets.

These challenges take the form of industry standard approaches to the calculation of transmission losses, the scheduling rules that result in imbalance penalties, and the reservation of transmission service. In addition, the interconnection issues, currently addressed in Order No. 2003-A, are being addressed through separate technical discussions and are not addressed in detail here.

Development of regional transmission organizations (RTOs) and independent system operators (ISOs) are one approach to treating wind generation on an equal basis.

Commission-approved RTOs and ISOs may remove many of the challenges that wind generation faces. RTOs and ISOs effectively remove pancaked rates, allow for scheduling flexibility and create real-time imbalance markets. These centralized markets reduce imbalance penalties, optimize transmission capability through region-wide dispatch, and provide for independent regional planning to expedite grid expansion.

Outside of RTOs and ISOs, there are novel approaches that can be considered to overcome the challenges that traditional regulatory rules place upon wind generators.

Transmission services that allow for the unique operational characteristics of wind energy such as conditional firm, curtailable firm, priority non-firm, and hourly firm may offer wind generators increased certainty for gaining access to the transmission grid. Measures can also be taken to reduce the impact of imbalance penalties and innovative methods can be developed to allow wind resources to contribute to regional reserve requirements and capacity markets.

Experience from the natural gas industry can also be applied in developing alternatives to the traditional transmission services under the open access rules.

Individual pipeline companies offer various non-traditional services that may serve as conceptual models in the development of non-standard transmission services. Under small customer rate schedules, for example, customers schedule and pay for transmission service on a volumetric basis, limited only by maximum daily volumes established for the service. These services usually allow for no-notice variations in scheduled quantities.

The Commission can facilitate change through proposed modifications to its pro forma open access transmission tariff.

Change often requires balance. Proper consideration must be given to minimize the negative effects that the current pro forma transmission tariff may have on certain market segments. In order to provide the proper forum to adequately address the issues that may result in regulatory reform, Staff recommends using a part of the December 1, 2004 technical conference to determine the appropriate vehicle to facilitate change, if such change is deemed necessary.

Comments concerning this report may be filed in Docket No. AD04-13-000.

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Staff Briefing Paper: Assessing the State of Wind Energy in Wholesale Electricity Markets

Disclaimer: This Report contains analyses, presentations and conclusions that may be based on or derived from the data sources cited, but do not necessarily reflect the positions or recommendations of the data providers.

Wind Energy: Introduction

Policymakers across the U.S. are increasingly interested in developing renewable sources of energy in order to reap the potential environmental benefits, diversify the country's generation portfolio, and decrease the Nation's dependence on foreign sources for energy. Wind energy, as evidenced by its recent growth, has been the greatest beneficiary of Federal and State-mandated programs for the development of renewable energy. As a complement to the Commission's efforts in Order 2003-A,[1] Staff undertook a study of wind energy development. This paper represents Staff's initial thoughts with regard to issues facing wind development and offers several reforms to further the development of wind energy in wholesale markets.

Since 1980, modern advanced technology wind turbines have grown in size from 55 KW to as large as 4.5 MW. Wind farms recently receiving large financings tend to include 100 or more 1.0-1.65 MW turbines; smaller turbines are generally used on rural wind farms across the country while the larger turbines are being evaluated for off-shore projects. Because wind farms consist of multiple, small-megawatt turbines, the project size may be more readily customized to meet incremental demand than fossil fuel-fired counterparts.

Wind power has been the fastest growing power source in the world, achieving a 28 percent annual growth rate in the U.S. for the time period 1991 to 2003. The U.S. has tremendous wind resources.[2] As shown in Table 1 on the next page, of the top twenty states with the most potential for wind generation development, California and Texas lead in the construction of new wind power, followed by Minnesota and Iowa. Despite having an abundance of desirable sites for wind generation, the Dakotas have installed little wind due primarily to the remoteness of their windy areas from load centers, necessitating major transmission additions, and the siting and associated cost allocation issues.

[1] In Order 2003-A, the Commission generally recognized that certain standard interconnection provisions could disadvantage generators relying on non-synchronous technology, namely wind generation. In order to avoid further exacerbating the obstacles that wind generation currently faces, the Commission allowed several deviations to the interconnection standards to accommodate newer technologies, such as wind generators. *See*, *Standardization of Generator Interconnection Agreements and Procedures, Order No. 2003*, 68 Fed. Reg. 49,845 (2003), FERC Stats. & Regs., Regulations Preambles ¶ 31,146 (2003) (Order No. 2003), *order on reh'g*, 69 Fed. Reg. 15,932 (2004), FERC Stats & Regs., Regulations Preambles ¶ 31,160 (2004) (Order No. 2003-A), *reh'g pending*.

[2] http://www.nrel.gov/wind/wind_map.html. Wind resources require a minimum annual average wind speed of at least 11 to 13 miles per hour for any prospective site to be considered viable. For a specific location, annual average wind speed is used to calculate the amount of energy in the wind blowing through a wind turbine's rotor per square meter of area. The energy available in the wind is then assigned a wind power class from 1 to 7. State officials and developers use this information to find the best areas for wind development. Sites in wind power class 3 or higher are candidates for wind farm development. Class 2 sites or higher offer possibilities for adding small wind generators.

Table 1: Wind and the Lower 48 States

Source: FERC analysis, derived from data in: Platts *PowerDat*, American Wind Energy Association (AWEA) website. As of September 2004.

Top 20 States for Wind Potential

Rank	State	KWh (Billion)
1	North Dakota	1,210
2	Texas	1,190
3	Kansas	1,070
4	South Dakota	1,030
5	Montana	1,020
6	Nebraska	868
7	Wyoming	747
8	Oklahoma	725
9	Minnesota	657
10	Iowa	551
11	Colorado	481
12	New Mexico	435
13	Idaho	73
14	Michigan	65
15	New York	62
16	Illinois	61
17	California	59
18	Wisconsin	58
19	Maine	56
20	Missouri	52

Top 20 States by Installed Wind Capacity [12/03]

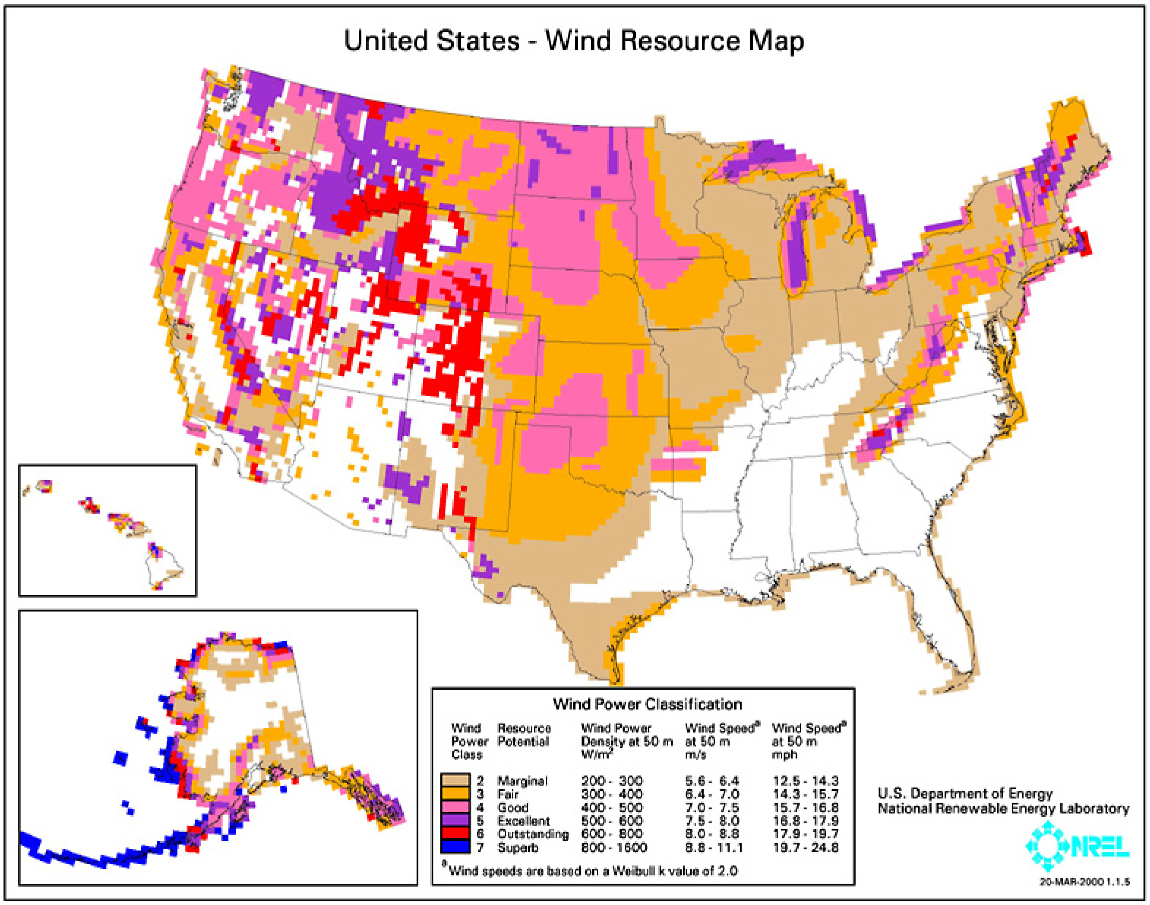
Rank	State	MW	% of total	Total MW Installed
1	California	2043	4.4%	46,157
2	Texas	1293	1.7%	77,842
3	Minnesota	563	6.4%	8,749
4	Iowa	471	5.4%	8,723
5	Wyoming	285	4.5%	6,277
6	Oregon	259	2.1%	12,096
7	Washington	244	0.9%	25,892
8	Colorado	223	2.5%	8,833
9	New Mexico	207	3.8%	5,489
10	Oklahoma	176	1.2%	14,855
11	Pennsylvania	129	0.5%	27,055
12	Kansas	114	1.2%	9,204
13	North Dakota	66	1.4%	4,753
14	West Virginia	66	0.4%	16,017
15	Wisconsin	53	0.4%	12,373
16	Illinois	50	0.2%	28,438
17	New York	49	0.2%	28,671
18	South Dakota	44	1.6%	2,825
19	Nebraska	14	0.3%	5,138
20	Vermont	6	1.2%	515
	U.S. Total	6,375	0.9%	708,318

As shown in Figure 1 on the next page, many of the best resource areas are located far from load centers and in areas of the country outside of centralized markets. In addition, it is estimated that the area between 5 and 50 nautical miles off the coast of the U.S. contains roughly 907 GW of wind potential.[3] While fossil fuel-fired counterparts locate near load centers to avoid transmission constraints, wind resources must be sited where the wind blows. Nationally, strong wind sites are located an average distance of 500 miles from major metropolitan centers; to even connect with the grid, wind generators must invest in transmission interconnections of over 10 miles.[4]

[3] W. Musial & S. Butterfield, "Future for Offshore Wind Energy in the United States." June 2004.
[4] National Renewable Energy Laboratory.

Figure 1: United States Wind Resource Map

Source: U.S. Department of Energy, National Renewable Energy Laboratory



Although wind turbines generally have high availability factors (most manufacturers now guarantee 97 percent), their capacity factors, or usage rates, tend to be low (ranging from 25 to 40 percent) due to natural variability of the wind.[5] Wind generation is an intermittent electricity resource; much like other intermittent generators such as solar energy, or run-of-river hydro, wind output is controlled by natural variability rather than dispatched based on load or markets. Also like other intermittent resources, wind generation's availability rarely conforms to the peaks and valleys of customer demand, *i.e.*, it cannot freely be ramped up or down but is constrained by the availability of the wind.

[5] The capacity factor of an individual generator or of an entire wind farm is the actual energy generated during a given period divided by its maximum output, if the turbine were running at its rated power during all 8760 hours of the year. Capacity factors for wind resources theoretically vary from 0 to 100 percent, but on average are 25 to 40 percent.

Drivers of Wind Energy Development

Over the past decade, a heightened awareness of the environmental impacts of fossil generation and increases in fossil fuel prices has led to the increased demand for clean renewable resources. Today, wind project developers benefit from strong environmental demand, decreasing costs from technological advances, and government initiatives including states with renewable portfolio standards and recently extended federal production tax credits.

Environmental Benefits

Unlike conventional power plants running on coal, oil, or natural gas, wind generation relies upon a renewable, abundant and free fuel to produce clean energy. It has no harmful air emissions, does not consume or pollute water, and does not produce greenhouse gases that contribute to global climate change.[6] Shifting a significant fraction of global energy demand from carbon-intensive fossil fuels to modern renewable energy technologies such as wind power could have important environmental and economic benefits. The most important environmental advantages may be reduced impacts on human health locally, declining risk of acid deposition and land degradation regionally, and decreased risk of climate change globally. Reduced dependencies on fossil fuels could help mitigate future price increases and free-up the fuel sources for alternative uses.

As illustrated in Table 2, it is estimated that every MWh of electricity generated by a wind turbine offsets the equivalent of 1,100 to 2,200 pounds of carbon dioxide, depending upon the type of fuel used to generate the electricity. Based on the national average fuel mix, wind energy also offsets up to 15 pounds of sulfur and nitrogen oxides and particulates, 3.5 ounces of trace metals, and more than 440 pounds of solid waste from fossil-fueled generation.[7]

Table 2: Comparative Air Emissions of Wind and Other Fuels

Source: American Wind Energy Association

Fuel	CO_2 Emitted per KWh generated (lbs.)	SO_2 Emitted per KWh generated (lbs.)	NO_x Emitted per KWh generated (lbs.)
Coal	2.13	0.0134	0.0076
Natural Gas	1.03	0.000007	0.0018
Oil	1.56	0.0112	0.0021
Wind	0	0	0

[6] Comparative Air Emissions of Wind and other Fuels. Wind Energy Fact Sheet. American Wind Energy Association.
[7] Wind Energy. EPA Website. January 2000.
http://yosemite.epa.gov/oar/globalwarming.nsf/uniqueKeyLookup/SHSU5BWK54/$file/windenergy.pdf?OpenElement Accessed July 2004.

Advances in Generator Technology

Advances in technology which have resulted in increased turbine sizes have enhanced wind project economics. Coupled with various government initiatives, advances have allowed the unit cost of wind generation to fall dramatically.[8] The cost per KWh has fallen by between 60 percent and 80 percent, with capital costs decreasing from $2,000 per installed KW to between $800 and $1,100 today (and anticipated to fall 25 percent further by 2010).[9]

Large wind projects are now competitive with new coal-fired generation on an installed capacity cost basis, but are still substantially more expensive than new gas-fired generation capacity. American Electric Power's Desert Sky required total debt and equity investment of just over $1,100/KW compared to an estimated $700/KW for financing of gas-fired combined cycled capacity. [10,11] All-in variable and fixed costs for wind generation have declined from 30¢/KWh in 1980 to between about 2.5 – 4.0¢/KWh today, once available tax and other incentives are factored in.[12] At current rates, wind is competitive with today's gas generation, which assuming even a potential $6.00/mmBtu gas price, would cost 5.5¢/KWh, including both fuel and capital costs.[13] As demand for wind turbines increases, additional economies of scale in the manufacturing process may decrease turbine costs further.[14]

Government Initiatives

Regulatory Policy Regarding Avoided Cost Pricing

Wind development has relied upon and benefited from the Public Utility Regulatory Policies Act of 1978 (PURPA)[15] and the avoided cost pricing principles contained therein. State regulatory authorities have been implementing PURPA programs since 1980 in order to encourage the development of cogeneration and small power production facilities. Many wind installations around the country benefit from the provisions contained in PURPA.

Congress is considering rescission of PURPA as a part of pending energy legislation. The provisions contained in PURPA are beneficial to the continued expansion of wind energy. If energy legislation is passed and the rescission of PURPA remains a piece of that legislation, the wind industry will need to find more innovative methods in which to continue being a viable provider of energy. The ways in which PURPA affects the wind industry are characterized below.

Section 210(b) requires electric utilities to purchase electric energy from Qualifying Facilities (QFs) at rates that are (1) just and reasonable to the electric consumers of the electric utility and in the public interest, (2) nondiscriminatory with respect to QFs, and (3)

[8] AWEA, Fair Transmission Access for Wind: A Brief Discussion of Priority Issues, http://www.awea.org/policy/documents/transmission.PDF, Accessed November 2003.

[9] "Spot Picking," Project Power Finance Report, September 2004.

[10] "Americas Renewables Deal of the Year," Project Finance Magazine, March 2003.

[11] FERC Staff analysis based on gas-fired financing information collected from public sources.

[12] New Mexico Energy, Minerals, and Natural Resources Department, Energy Conservation and Management Division, Wind Energy, http://www.emnrd.state.nm.us/ecmd/html/wind.htm, Accessed November 2003.

[13] "Not Just Tilting Anymore" *Wall Street Journal,* October 14, 2004, based on interview with Ryan Wiser, Lawrence Berkeley National Laboratory.

[14] Technology standardization can reduce investor perception of uncertainty of future performance as track records are established. Parallels to gas turbine manufacture can be drawn in regards to technology risk but also to level of and faith in manufacturer performance guarantees.

[15] 16 U.S.C. §824a-3, 796(17-22) (1982).

not in excess of "the incremental cost to the electric utility of alternative electric energy." Section 210(d) of PURPA defines the incremental cost of alternate energy as "the cost to the electric utility of the electric energy which, but for the purchase from such cogenerator or small power producer, such utility would generate or purchase from another source."[16]

This statutory definition is supplemented by the Commission's regulations, which requires a utility to pay nothing more than its "avoided costs" for purchases from new QF capacity in the absence of a negotiated rate.[17] "Avoided costs" are defined by the regulations as the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the QF or QFs, such utility would generate itself or purchase from another source.[18]

The avoided costs of electric utilities can include both energy and capacity costs. Energy costs are the variable costs associated with the incremental production of electric energy. They represent the cost of fuel, and some operating and maintenance expenses. Capacity costs are the costs associated with providing the capability to meet the demand for electric energy. Capacity costs may be incurred by a utility in order to build generating facilities, institute conservation and load management programs, or purchase power on the wholesale market. Under the Commission's current regulations, capacity payments need to be made when, and only when, the purchase or construction of capacity will be avoided by the purchasing electric utility as a result of its purchase of QF power.

However, if a utility needs capacity, and would be building capacity itself or purchasing capacity from another wholesale source, it must first offer to buy such capacity from QFs. Utilities are not permitted to withhold purchasing from QFs any portion of their capacity needs, provided that QFs are offering power that is comparable to the capacity that the utility would otherwise obtain from alternative sources. Furthermore, in

[16] 16 U.S.C. §824a-3(d) (1982).

[17] 18 CFR §292.304 (a) (2003). State regulatory authorities and nonregulated electric utilities can set lower rates for QF capacity built before the enactment of PURPA. 18 CFR §292.304 (b) (1987). The Commission's regulations also allow the QF and the purchasing utility to negotiate a rate which differs from the rate otherwise required by the Commission's regulations. 18 CFR §292.301 (b) (1987).

[18] 18 CFR §292.101 (b)(6) (2003).

American Ref-Fuel Co., et al., the Commission granted a petition for declaratory order finding that PURPA contracts for the sale of QF capacity do not convey renewable energy credits or similar tradeable certificates to the purchasing utility absent agreement among the parties.[19]

Under section 210 of PURPA, an electric utility's ratepayers are intended to be at least indifferent, in terms of the rates they pay, as to the source of power. In other words, the ratepayer is not to pay any more for power because the utility has purchased power from a QF rather than generating the power itself or purchasing power from another wholesale source. This is the purpose underlying the incremental cost ceiling on the rates utilities have to offer to purchase QF power.[20] The Commission's regulations, in order to maximize the incentives for QFs, provide that the rates for purchases from QFs, absent negotiations, are to be at the statutory ceiling. Thus, the avoided cost rate is neither more than nor less than the price the utility would have paid for comparable power from other sources, including other wholesale sources.

It is the above stated principles contained in PURPA that assist the wind industry, as well as other alternative energy sources, in maintaining a foothold within the energy industry. If the provisions contained in PURPA are removed from the Commission's rules and regulations, many of the QFs that supply cost effective energy will be left without an assured method in which to generate revenues and thus may be forced to exit the market once existing contracts expire. Thus, the possible rescission of PURPA has the potential to affect the future of the wind industry.

State Renewable Portfolio Standards (RPS)

Together, advances in wind turbine technology and fossil fuel-related supply and environmental concerns have led to the growing existence of green marketing programs and State-mandated RPS, driving utilities across the country and around the world to increase the amount of wind in the mix of energy resources.[21]

As shown in Figure 2 on the next page, nineteen states have enacted RPS. An RPS reflects a state's commitment to add renewables to the mix of generation, generally at levels which increase yearly and which apply to all retail electricity suppliers. The duration of an RPS and the goal or percentage of renewables required to be in each supplier's generation portfolio vary widely. A few RPS programs specify not only an overall renewables portfolio percentage, but also percentages of the total which must be met by particular fuel types, such as wind or solar. Some states which have already achieved their initial goals are considering raising them by amending their RPS. Developing and implementing these RPS initiatives have aided in the development of renewable energy.

Appendices 2 & 3 provide further information regarding the current RPS programs in the U.S.

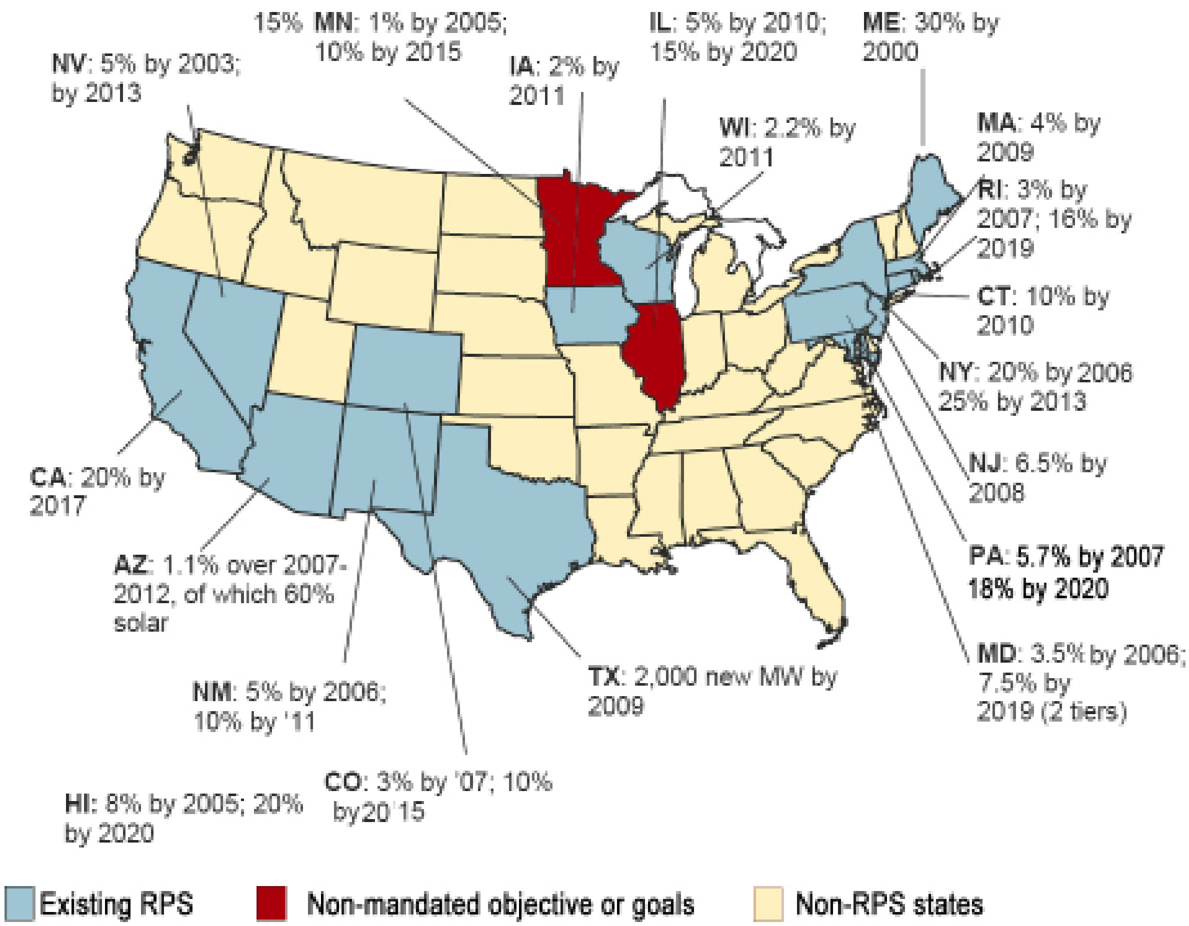
[19] *See*, *American Ref-Fuel Co.*, et al., 105 FERC ¶ 61,004 (2003), *reh'g denied,* 107 FERC ¶ 61,016 (2004), *sub nom. Xcel Energy Services Inc.* v. FERC D.C. Cir. No. 04-1182 (D.C. Cir. filed Jun. 14, 2004).

[20] See Conference Report on PURPA, H.R. Rep. No. 1750, 95th Cong., 2nd Sess. 98, reprinted in 1978 U.S. Code Cong. & Ad. News 7797, 7832, and in FERC Statutes and Regulations ¶5151 , at p. 5106. The full avoided cost rate applies to purchases from new capacity, i.e., capacity built after November 9, 1978. Rates for purchases from old capacity, i.e., capacity built before November 9, 1978, may be set below avoided cost if the state commission or nonregulated utility determines that a lower rate is consistentwith section 292.304(a) of the regulations. See 18 CFR §292.304 (b)(3) (1987).

[21] Green marketing takes advantage of electric consumers' willingness to pay for products that provide environmental, health or other public benefits. Market research indicates that a significant number of electric customers claim a willingness to pay a premium in order to buy "green" electric service. By providing customers with a choice in the type of generation, it is possible to create a voluntary market for renewables.

Figure 2: Renewable Portfolio Standards in 19 States

Source: FERC analysis, derived from data in: Edison Electric Institute's *State Restructuring Service*; DSIRE Database of State Incentives for Renewable Energy, http://www.dsireusa.org/; State PUC websites; Trade press.



- **Nine States enacted or amended Renewable Portfolio Standards (RPS) in 2004.***
- **Colorado voters passed first RPS by ballot in November 2004.**
- **Pennsylvania's "RPS" consists of separate agreements between the PUC and each utility.**
- **Definition of renewable resource varies by State, although all include wind and solar.**
- **Many States are considering raising goals.**

Notes: *Arizona, Colorado, Hawaii, Maryland, Nevada, New Jersey, New York, Pennsylvania, and Rhode Island enacted or amended a RPS in 2004.

** Minnesota's RPS is a non-mandated objective, requiring that utilities make a "good faith effort" to meet the goals (except for a mandate for XCel Energy to develop 1,125 MW of wind power by 12/31/2010.

*** Illinois has a "renewables portfolio goal" without verification or credit trading. While

**** Maine has the highest RPS standard in the U.S., but the 30% is less than is already in use there.

***** Pennsylvania's alternative portfolio standard was passed on 11/20 and is pending before the governor.

State Renewable Energy Credits (REC)

Many, but not all, of the states with an RPS have established Renewable Energy Credit (REC) programs, which give retail suppliers flexibility regarding compliance with an RPS. REC programs involve the trading of energy credits rather than the physical commodity and typically resemble tradable emissions credits.

Production Tax Credits (PTC)

Federal production tax credits (PTC) have also been important in promoting wind generation projects. Currently the PTC, as renewed in October 2004, provides a credit of 1.8¢/KWh produced for ten years from the date a facility is put into operation. To qualify, a wind facility must be operational before the PTC expires in December 2005.

The Federal PTC has contributed to periods of intense wind development. In periods when there is no PTC, potential developers are reluctant to commit resources to the planning and construction of new capacity. AWEA estimates that $3 billion of wind energy projects were on hold, awaiting the most recent PTC extension. Appendix 4 lists the wind developments announced since the renewal of the PTC.

Challenges to Future Wind Energy Development

Even with the advances in wind development, wind generation is a relatively new entrant to markets that were not designed specifically for intermittent energy sources or for generation sited remotely from load centers. As such, wind generation faces several challenges to achieve widespread acceptance, including siting and permitting issues, financing issues, and transmission policies that are currently designed for generating units that are more centrally located and able to be dispatched. Solving issues facing wind generation may not only encourage investment in this clean generation source, but may also result in lower prices to customers, particularly if natural gas prices remain at or above current levels.

Impacts of Wind Development

While there are environmental benefits to wind generation, there are also adverse environmental impacts that must be addressed when siting a wind farm. For example, the potential impact of wind turbines on birds including resident, breeding, and migrating species has frequently been a concern at both proposed and existing wind power sites. Birds have been reported killed at wind power plants in various locales around the world.

Avian fatalities are typically confined mainly to areas where large numbers of birds congregate or migrate, or where protected species are affected. This could encompass quite a few locations, however, because some of the traits that characterize a good wind site also happen to be attractive to birds. For example, mountain passes are frequently windy because they provide a channel for winds passing over a mountain range; for precisely the same reason, they are often the preferred routes for migratory birds.

If preliminary research indicates that a wind project is unlikely to seriously affect bird populations, further studies may be needed to verify this conclusion. These could include monitoring baseline bird populations and behavior before the wind project begins, then simultaneously observing both a control area and the wind site during construction and initial operation. In certain cases, operational monitoring might have to continue for years.

For existing wind plants where bird conflicts are already a concern, the immediate task is to develop and implement practical ways to reduce the number of bird deaths and injuries. Research is being carried out to determine which strategies are most effective in different situations. Proposals include changing the color of wind turbine blades, eliminating places on towers where birds are likely to perch, and using radar to alert wind project operators to the imminent passage of large flocks of birds so that parts of the wind plant can be shut down. Deaths from high-voltage transmission lines and equipment can be avoided by methods such as discouraging perching near uninsulated wires.

Additionally, wind turbines, out of necessity, are highly visible structures. Modern wind turbine towers stand 100 to 160 feet above the ground, excluding the blade rotor, which may be up to 130 feet in diameter. Turbines are often deployed in arrays of a dozen or more machines on prominent ridges or hilltops in order to maximize the performance of each turbine.

However, steps can be taken to reduce the number of complaints by making wind turbines less obtrusive and more pleasing to the eye. For example, tubular towers are less offensive than lattice towers, and partly for this reason they now are preferred by most wind developers. Also, taking steps to avoid scarring the land is important, as is eliminating unnecessary clutter by burying transmission lines and hiding buildings and other structures behind ridges or vegetation.

There have also been complaints regarding noise generated from turbine blades. Those affected by the noise generated by wind turbines typically live within a few miles of a large wind power plant or within several hundred feet of a small plant or individual turbine. Although the noise at these distances is not great – a 300-kilowatt turbine typically produces less noise at 400 feet than does light traffic 100 feet away — it nevertheless is sufficient to be heard indoors and may be especially disturbing in the middle of the night when traffic and household sounds are diminished.[22]

Significant progress has been made in reducing turbine noise since the first machines were installed in the early 1980s. The larger machines now on the market generate less noise (per unit of energy output) than the smaller machines they replaced. Overall, wind turbine noise is now, in general, a minor concern to communities near wind projects under development today. With proper attention to setback distances and sound-reduction engineering, fewer residents will likely be affected.

Siting and Permitting

Not unlike the siting of other generation, wind development can arouse community and environmental concerns. Additionally, with the remote location of the wind resource, accessibility to and cost of transmission are issues in any siting decision. The siting of wind resources includes several steps including extensive locational assessment to measure wind availability, environmental impacts, and economic feasibility; contract negotiations for easements, construction, maintenance, and off-take; and lengthy regulatory filings to gain necessary approvals from federal, state, and local agencies as well as from the public.[23]

In typical wind projects, small development firms do much of the initial development, performing initial site selection and preliminary analysis from self-generated funds and some "sweat" equity with the hope of high returns. For small projects (<12 MW[24]), small developers may complete development themselves for self-generation or in partnership with local utilities in a position to sign off-take agreements to fulfill renewables standards or corporate strategic goals. At times, they bring on additional equity investors who value tax credits.[25]

[22] Wind Energy Environmental Issues. National Wind Coordinating Committee Wind Energy Series No. 2. January 1997.

[23] Derived from American Wind Energy Association Fact Sheet; *10 Steps in Building a Wind Farm*. Downloaded from www.awea.org, October 1, 2004; www.awea.org/pubs/factsheets/10stwf_fs.PDF.

[24] Based on Wind Industry classifications - http://www.windustry.org/opportunities/project_types.htm

[25] Over 1400 MW of wind power projects have been announced or put back on track since the most recent PTC extension, with 1000-2000 MW announced as advanced stage, likely, or in development, which demonstrates the importance of the PTC. Although the renewal was approved in October 2004, only 480 MW of wind generation are expected to be completed by the end of the year compared with almost 1,700 MW of additions in 2003. GE Wind Energy has already received contracts for 750 MW of turbines for 2004-05, and another 750 MW of commitments; valued together, these represent $1.3 billion in new wind development.

However, more often, once the project is more defined, small developers will sell a majority of the project to a strongly-capitalized co-development partner such as Florida Power and Light (FPL), American Electric Power (AEP), or Zilkha Renewable Energy, among others. These larger strategic developers have greater financial resources and legal and technical expertise to address detailed costs, finance complexity, tax advantages, and risks of wind power development and can leverage their own balance sheets to lower project costs.

Project Financing

Wind project developers confront several hurdles of process and perception in financing wind projects under current electric and financial market conditions. New wind projects must obtain debt and equity funds. In the past few years, many lenders to the traditional fossil generation sector have suffered from underperforming loans, and some have reluctantly exchanged their debt for equity in plants. In many regions, weak margins on the sale of power, and surplus generation capacity have depressed the value of recently built and financed generation.

While liquidity has increased and financing terms are returning to more favorable levels for sponsors, debt and equity investors continue to require extensive due diligence before providing funding. Only a limited number of lenders – primarily European banks that funded many European wind developments – have extensive experience with wind generation finance. For new sources of capital, developers must illustrate that risks, whether real or perceived, are understandable and manageable.

Projecting revenues for wind generation is harder than for typical generation sources because of higher variability of production. The variability of production is highly dependent on wind speed – a 2 mph difference can change the economics of a facility significantly. For example, according to the American Wind Energy Association, a change in wind speed from 16 to 18.07 mph would result in a 144 percent increase in output and a 25 percent reduction in cost per MWh.[26] While wind speed measurement technology is improving, wind speeds will continue to vary by season, month, day, and even hour. Extensive new evaluations have revealed seasonal and annual patterns such that annual generation falls within +/-10 percent of predicted annual production.

Given difficulties associated with projecting merchant revenue streams for wind projects, financings have typically required "must take as available" power purchase agreements for the full output of the facilities with creditworthy counter parties to mitigate production and price risk and make lenders comfortable with energy revenue forecasts to support debt. On the demand side, load serving entities have been encouraged by RPS to enter such long-term contracts for wind generation to meet their regulated requirements and hedge long-term price risk.

Even with an energy contract, PTCs are important to project revenues and investment. There is an active financial equity market for projects with tax credits in the U.S. for investors that have familiarity with investing in tax credits from Section 29 (synfuel) and Section 8 (low income housing) credits. Commercial and

[26] Windletter – The Monthly Newsletter of the American Wind Energy Association, Volume 22, Issue No. 5 – May 2003, page 2.

investment banks, insurance companies and private equity funds ascribe value to the credits because they are willing to undertake the associated risk. As long as the project produces energy the ensuing tax credits shield taxable income that need not be associated with the project itself.[27] In recent deals, lenders have also been willing to lend money against credits as PTC revenues have been leveraged along with the Power Purchase Agreement (PPA) revenues. From a lender perspective PTCs bear less credit risk than PPA revenues because their counterpart is essentially the federal government.

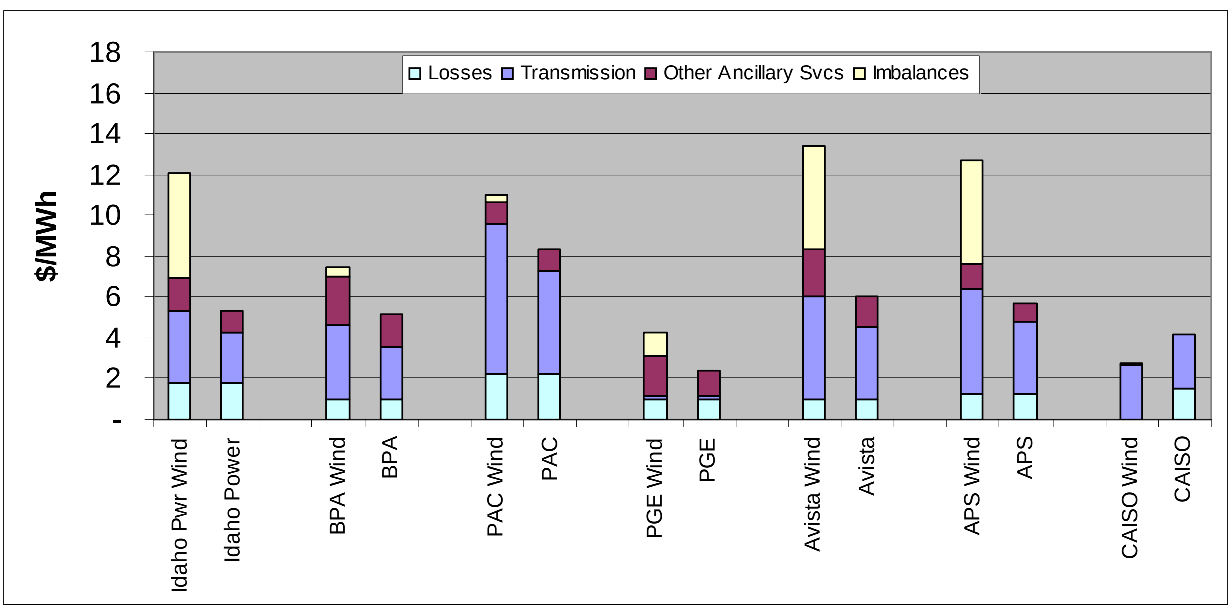
Transmission Issues

Operationally, wind plants have much lower capacity factors than conventional thermal facilities and their output is quite variable - typically deviating quite significantly from their pre-arranged schedule. As a result of this, the effective transmission charges for wind generators are typically much higher than those faced by conventional thermal plants, yet these differences vary significantly on a region-by-region basis. These factors are important components in the calculation of traditional transmission rates.

As shown below in Figure 3, these differences are not consistent between various power systems and differing transmission rate designs can have considerable impact on wind generators. Some utilities have agreements with alternative fuel generators that can significantly mitigate the pricing impact faced by the wind facilities. Additionally, the rate differentials for wind plants vary significantly between RTO and non-RTO regions.

Figure 3: Cost Comparison of Transmission for Wind vs. CCGT Plants

Source: FERC analysis, derived from data in OATT Tariffs, NREL, CAISO, PacifiCorp, FERC OMTR, FERC OMOI



Note: Calculations based on OATT tariff schedules; 55 percent capacity factor for CCGT and 38 percent capacity factor for wind; scheduling imbalance error of 1 percent for CCGT and 20 percent for wind; $50/MWh average system price for power; CAISO rate based on SCE TAC rate.

[27] "Spot Picking", *Project Finance* September 2004, pp. 13-16.

Available Transmission Capacity (ATC)

A fundamental problem facing wind generators is the lack of long-term firm available transmission capacity (ATC) over many key interfaces, even though operational data show that many of these interfaces are congested for no more than twenty to fifty hours per year. This means that there would be adequate capacity available to move wind output in many hours, but no way of securing long-term firm transmission service needed to attract financing.[28]

Under current capacity-based reservation rules, wind generators typically must acquire long-term firm transmission for the maximum output of the facility even though actual use of the reserved capacity is much less. Due to this, wind developers face higher costs relative to other transmission users who may more efficiently use the transmission capacity.[29] Thus, wind generators are required to reserve more transmission capacity than necessary (and pay for the unused capacity). Although the Order No. 888 *pro forma* tariff permits a customer to sell or transfer surplus capacity under an agreement, wind generators argue that, without an active secondary market, the wind generator receives little to no value for its surplus firm transmission.[30]

The choice between the standard long-term firm point-to-point transmission service in excess of what they need, and non-firm point-to-point transmission service that is less than what they require and with no guarantee of availability, puts wind resources in a difficult competitive position. The reservation charges for firm point-to-point transmission are akin to take-or-pay charges, meaning generators must reserve transmission capacity in advance and pay for that capacity regardless of how much energy is actually scheduled and transmitted. In addition, non-firm service is only available under *pro forma* tariffs for periods of up to one year. Wind generators that require 10 or 15-year contracts for transmission will not be able to make use of non-firm service in order to obtain financing.

RTO and ISO tariffs are generally able to overcome this problem through the provision of transmission service in concert with centrally-dispatched energy markets. Under these tariffs, most customers take regional, or network, transmission service rather than point-to-point service. Because this transmission service is billed based on the amount of service taken, rather than on a reserved amount of service, a wind generator (or customer of wind resource) avoids transmission payments based on reservation amounts.

Nevertheless, even under the *pro forma* tariff, there are alternatives that can be considered in order to remedy the problem of uneconomic long-term firm point-to-point transmission service. These alternatives may include hourly firm point-to-point and curtailable, or "conditional," firm point-to-point transmission service. These

[28] This is because a "firm" request by a wind generator is considered by the transmission provider the same as a firm request from a thermal generator, for example, that may be expected to generate at consistently high capacity factors. Therefore, instead of determining whether surplus ATC may be available for a wind project given its intermittent nature and low average capacity factor, the transmission provider is required to evaluate a customer's request for firm service on the basis that ATC must be available all the time at 100 percent of the customer's request for firm service.

[29] Under the Order No. 888 *pro forma* OATT, only long-term agreements in excess of one year are subject to rollover rights under Section 2.2 (Reservation Priority for Existing Firm Service Customers). Accordingly, in order to ensure the availability of capacity to transmit energy as it is generated for the life of the project, the generator must reserve the maximum required capacity on a long-term basis. Otherwise there is no guarantee of availability. *See*, 18 CFR Part 35.

[30] While Section 23 of the *pro forma* OATT allows a transmission customer to sell or assign all or part of its reserved transmission services, it is unlikely that wind generators can accurately forecast over continuous terms (*e.g.*, one week) in order to capture value of foregone transmission.

products may offer the wind generator more certainty for gaining access to the grid and would assist in securing financing for the construction of new generation. These new services are not part of the Order No. 888 *pro forma* tariff, and,

thus, they are not widely available throughout the industry. These newly proposed transmission products offer the possibility of increased grid access for wind generation.

One alternative to the industry standard, capacity-based transmission access fees could be a commodity charge for service to small and/or low load-factor customers. Such a charge could be billed as service is scheduled and used up to a specified reservation level (essentially, simulating an energy-based access fee by substituting the effective capacity of an intermittent generator into the generally applicable capacity-based fee).[31] This approach may be best suited for facilities that have an operational history. 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. Although not a true energy-based tariff, such an arrangement could partially address issues facing wind energy.[32]

A variation to this approach may be for the intermittent generator to reserve firm transmission capacity equivalent to the unit's effective capacity, 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

[31] The effective capacity would account for the operational differences inherent in wind generation in order to determine an appropriate capacity factor as an input to the access fee calculation. For example, access fees could be calculated based upon an effective capacity rating of 30 percent, a reasonable estimate of a wind farm's production capabilities.

[33] A policy question would be whether this should be offered as an incentive only to wind generators or should it be made available to all low-load factor customers.

generator that is using non-firm transmission service would have the right to match longer-term non-firm service before being displaced.

An example of the process in which market participants are developing alternatives to the current Order No. 888 tariff services is the Rocky Mountain Area Transmission Study (RMATS).[33] In the RMATS region there is no firm ATC on transmission paths, even while actual physical congestion occurs for less than 20 to 50 hours per year.[34] RMATS is seeking to test if there is any physical capacity on certain paths in the current system that could be utilized to move significant amounts of wind energy. The goal of the RMATS is to demonstrate the value of removing institutional impediments to support additional wholesale competition.

The work done in RMATS has led to the development of conditional-firm and priority non-firm transmission services. The conditional-firm transmission product would be for firm service during a defined period of the year and conditional-firm service for the balance of the year. Conditional-firm service would be curtailed prior to firm service, but after all non-firm service. This priority of curtailment combined with a clear understanding of the curtailment risk during the conditional months will give generators and utilities more confidence in their ability to move power to loads. In addition, the development of a priority non-firm transmission tariff product in which the customer would agree to be curtailed when operations were constrained could also benefit wind generators. A more detailed explanation of these services appears in Appendix 1.

The Commission has accepted various novel transmission products, in electric as well as gas markets, which may provide the wind industry with a working model for the development of further transmission services. For example, El Paso Electric Company filed revisions to its open access transmission tariff to provide hourly firm point-to-point transmission service.[35] Hourly firm transmission service has the potential to free up transmission capacity that otherwise would not be available. By purchasing an hourly firm transmission service, wind generators have the opportunity to acquire transmission for only the periods in which they are able to generate electricity, thereby lowering the embedded costs of providing energy.[36]

The Commission has also accepted a recallable firm transmission service that provides customers with additional transmission service options and enhanced flexibility.[37] Under the recallable firm transmission service, a transmission provider may offer, on a first-come, first-served basis, firm transmission service under an OATT on a comparable basis. The transmission provider will retain the right to recall all or a portion of the

[33] The purpose of the study is to identify in an open and public process, potential generation projects in the Rocky Mountain sub-region and the electric transmission needed to support these projects.

[34] *See*, Rocky Mountain Area Transmission Study Final Report. September 2004.

[35] Docket No. ER04-567-000.

[36] Although short-term firm service does not guarantee access to the grid for all hours, it may be possible for the generator to combine short-term and long-term service to reduce its costs as compared to acquiring only long-term firm service.

[37] *See*, *Southern Company Services, Inc.*, 100 FERC ¶ 61,314 (2002); *Duke Energy Corporation*, 88 FERC ¶ 61,184 (1999), *order on reh'g*, 89 FERC 61, 190 (1999).

reserved transmission capacity, subject to a reasonable notification period. The terms of service are negotiated to include the delivery and receipt points, the price structure, the amount of capacity subject to recall, the length of the recall period, and the length of time that a customer must respond to a recall notice. This form of firm service would have the characteristics of long-term firm point-to-point with regard to reservation for periods greater than one year and the opportunity for a level of rollover rights.

In the gas industry, Northern Natural Gas Company (Northern Natural) offers a volumetric firm transmission service for which it charges a volumetric rate based on a shipper's projected load factor with a minimum term of one year.[38] A shipper must maintain its projected market share from Northern Natural, *i.e.*, it cannot use Northern Natural as a swing supplier. The volumetric service allows a shipper to "pay as it goes" and to shift some weather-related risks to the pipeline. For example, if a winter is warmer than expected and a shipper's demand is reduced, its overall payment would be lower than if it had purchased firm service and paid monthly reservation charges. On the other hand, if the winter were colder than normal and the shipper's demand were higher, it would pay more overall.

This type of service could be applied to electric transmission service through the development of firm point-to-point service based upon an estimate of the capacity factor of a generation plant. Rather than an intermittent resource reserving transmission capacity based upon its peak or contract output, it can reserve annual transmission service based on its projected capacity factor, adjusted annually. Any over-use from each year's designated capacity would be paid by the generator through non-firm service.

Many pipelines, including Northern Natural and ANR Pipeline Company (ANR), also offer a limited firm transportation service.[39] Limited firm service is firm service up to 20 days per month. Typically, there is no minimum term, and shippers pay two-part rates for the service derived from the monthly firm service rates, converted into a daily charge. The pipeline can choose not to schedule the service, in whole or in part, on any day, for any reason, up to 10 days per month. Service for more than the maximum number of days per month must be done under a separate contract and rate schedule.

An identical form of service can be applied to open access transmission. A transmission owner that experiences predictable monthly patterns can offer service for a specified number of days per month. Alternatively, longer periods, such as specific months per year can be offered on those transmission systems that experience significant peaks in either summer or winter, but have excess capacity during the shoulder months. Thus, the service offering could be calculated as seasonal rates and only available for specific periods per year.

It is important to note that any type of new transmission service created to accommodate wind will impact other market participants. For example, conditional firm service or priority non-firm service will affect traditional firm and non-firm service by changing the process in which customers are curtailed. This may cut into the flexibility enjoyed by existing customers, who may have a sense of entitlement to such flexibility, seeing it as part of the service they have contracted and paid for. The effects of these services must be closely examined to ensure that one class of customer does not subsidize another class.

[38] *See*, *Northern Natural Gas Company*, FERC Gas Tariff, Fifth Revised Volume No. 1, Eighteenth Revised Sheet No. 54; *ANR Gas Pipeline Company,* FERC Gas Tariff, Second Revised Volume No. 1, Substitute Second Revised Sheet No. 37.

[39] *Id*.

Rate Pancaking

Except for transactions within the ISO/RTOs now in place, transmission customers are faced with additional charges for every utility border they cross. This pancaking of access fees may be even more acute for wind. Such duplicative charges can restrict the area in which wind can be economically secured, particularly since wind is so often located in remote areas away from major load centers.

The emergence of RTOs and ISOs in certain areas of the country has assisted in alleviating the problem of rate panacking; however, the problem remains in the areas where RTO/ISO development has slowed or stalled due to the inability to collapse multiple systems into one independently managed regional transmission system.

To overcome this, utilities may choose to work together to eliminate the payment of multiple charges for transmission. This has occurred within ISOs/RTOs and is being explored outside as well.[40] The Commission has encouraged the elimination of pancaked rates for transmission services within a regional transmission system and supports transition periods for moving to a system of non-pancaked rates. While initially expressing a preference for "postage stamp" rates (a single, uniform, average rate across all utilities in the regional transmission system), the Commission permitted "license plate" rates (a rate for service that would vary based on the zone where the power was delivered), because it avoids rate averaging and allows a utility to maintain its existing rate for deliveries on its system, license plate rates minimize cost shifts. Under such a rate design, upgrades built on one utility's system would be paid for by that utility's load through the load ratio share.

Losses

Transmission losses are generally a function of distance and, therefore, are of greater importance to remote resources. The Commission has stated a preference for energy prices and the associated transmission usage charges based on marginal costs, in order to promote economic efficiency. Any protocol that results in greater loss charges based on distance, such as marginal losses, may discourage wind resource development more than other technologies.

The Commission, in regions, is moving toward a marginal cost transmission pricing policy. The Commission believes that moving toward a marginal cost pricing approach will lead to an efficient, least-cost dispatch for energy. When prices at each location reflect the full marginal cost of delivery (*i.e.*, energy, congestion and losses), customers can make efficient choices among suppliers at different locations. To the extent that a marginal cost approach for transmission disadvantages remote resources, the Commission has allowed State entities along with interested market participants to offer proposals to counter any negative impact of marginal losses on wind and other remote resources.[41]

[40] Rocky Mountain Area Transmission Study Final Report. September 2004.

[41] *California Independent System Operator Corp*. 107 FERC ¶ 61,274 (2004). *order on reh'g* 108 FERC ¶ 61,254 (2004).

Imbalance Charges

An additional delivery issue for wind energy is how imbalance charges are imposed under the *pro forma* tariff. Imbalance charges were developed in order to ensure that generators' actual hourly output matched their scheduled amounts. These imbalance charges work to enhance reliability, encourage accurate scheduling and discourage gaming. However, this type of energy imbalance penalty is particularly punitive to intermittent resources, as they have greater difficulty predicting scheduled amounts and even less control over their dispatchability.[42]

Since wind is not completely unpredictable on a day-ahead basis, it is possible for some wind capacity to be scheduled on such a basis. Statistical methods can be used to commit wind energy in advance. For example, the prior day's wind or the prior hour's wind can be used to estimate the wind speed, and hence the capacity available for the next period.

Centralized markets are often able to address this issue, both with respect to substituting real-time energy markets for imbalance penalties and with respect to novel tariff provisions. A potential solution outside of centralized markets is for individual transmission operators to allow generators the flexibility to schedule closer to real-time. The ability of wind generators to predict their output increases dramatically in the hour preceding the delivery hour. It is conceivable that intermittent resource schedule adjustments would represent negligible changes in overall system conditions and therefore not greatly affect system reliability.

The Commission-approved California Independent System Operator (CAISO) Participating Intermittent Resources Program (PIRP) exempting wind from hourly imbalance penalties and substituting monthly netting of imbalances in return for centralized wind delivery forecasting is an example of the type of tariff reforms that could facilitate wind development.[43] The CAISO's voluntary PIRP, was created to accommodate projected growth of wind generation attributable to California's renewable supply requirements. Under the PIRP, the CAISO forecasts and schedules wind output, and nets any imbalances over the course of a month.

Transmission Planning

Given that wind is a remote resource, transmission planning is especially important for wind. Also, while transmission expansion is a time intensive process, wind farms can move from paper to production in a relatively short period of time. This mismatch often leaves wind farm development waiting for transmission expansion to catch up.

The emergence of RTOs and ISOs has assisted in broadening transmission planning and expansion into regional efforts. Rather than performing expansion on a utility-by-utility basis, an independent entity can be charged with the responsibility of expanding the grid in an efficient manner. Regional entities are better equipped to represent interests of the region's various market participants and expand the transmission grid in an economically efficient manner. However, RTOs and ISOs are not the only way to accomplish regional planning and cost allocation.

[42] Under Schedule 4 of the OATT, the Transmission Provider establishes penalties for energy imbalances exceeding +/- 1.5 percent of the scheduled transaction. The Commission however, has allowed more flexible deviation bands of +/- 10 percent for open access retail service under the OATT due to a customer's inability to accurately forecast load and submit accurate schedules. Similar flexibility could be incorporated into the OATT for transmission service involving wind generation.

[43] *California Independent System Operator Corp*., 98 FERC ¶61,327, *order on compliance filing*, 99 FERC ¶ 61,309 (2002).

For example, the RMATS process is addressing these issues by attempting to determine efficient ways in which to expand the grid on a regional basis.

Interconnection

Order No. 2003,[44] issued by the Commission on July 24, 2003, requires all public utilities that own, control, or operate facilities for transmitting electric energy in interstate commerce to (1) file revised open access transmission tariffs containing Commission-adopted standard generator interconnection procedures and a standard interconnection agreement, and (2) provide interconnection service to electric generating facilities having a capacity of more than twenty megawatts. While Order No. 2003 recognized that it would not resolve all issues that may arise, the single, uniformly applicable set of procedures and agreements it sets forth to govern the process of interconnecting large generators to a Transmission Provider's Transmission System will play a crucial role in bringing much-needed generation into national energy markets to meet the growing needs of electricity customers.

In Order Nos. 2003 and 2003-A, the Commission generally recognized that certain standard provisions contained in the standard interconnection procedures and agreement could disadvantage generators relying on non-synchronous technology, namely wind generation.[45] In order to avoid further exacerbating the obstacles that wind generation currently faces, the Commission, in Order No. 2003-A, clarified several of the interconnection standards to accommodate newer technologies, such as wind generators.[46] Additionally, in Order No. 2003-A the Commission added a new blank Appendix G to its standard generator interconnection agreement to serve "as a placeholder for inclusion of requirements specific to newer technologies."[47]

Recently, wind industry representatives have proposed that the Commission consider including in Appendix G a national "grid code" applicable to the interconnection of large wind generators. The proposed "grid code" contains point of interconnection technical standards and more flexible interconnection queuing and study procedures. The Commission held a technical conference on this proposal on September 24, 2004, and accepted post-technical conference comments from interested parties. The Commission will likely issue a Notice of Proposed Rulemaking (NOPR) regarding Appendix G in the near future.

Capacity Credits

Wind advocates contend that wind generators can provide capacity value (and not just energy) to the system. Others suggest that, due to the inability to instantly dispatch a wind generator, wind generators have no capacity value and should not count toward reserve margins.

[44] *Standardization of Generator Interconnection Agreements and Procedures, Order No. 2003*, 68 Fed. Reg. 49,845 (2003), FERC Stats. & Regs., Regulations Preambles ¶ 31,146 (2003) (Order No. 2003), *order on reh'g*, 69 Fed. Reg. 15,932 (2004), FERC Stats & Regs., Regulations Preambles ¶ 31,160 (2004) (Order No. 2003-A), *reh'g pending.*

[45] *See* Order No. 2003-A at P 407, n. 85.

[46] *Id.*

[47] *Id.*

In order to ensure electric reliability, Load Serving Entities (LSEs), ISOs and RTOs collect outage data to determine the probability that a generator will be available to deliver electricity when needed.[48] Operators use this outage data to calculate the probability that generating capacity will be insufficient to meet load and reserve requirements. This calculation results in the loss of load probability (LOLP).[49] By utilizing the LOLP a model can be developed to calculate the Effective Load Carrying Capability (ELCC) of a generator. The ELCC is the increase in system peak that can be supported by the generator, maintaining a target reliability level.[50] It is reasonable to apply these models to wind generation in order to determine the ELCC and therefore assign a particular capacity value to each respective generating unit (or farm). Results vary by location, but capacity credits using ELCC models are often in the range of 20 percent of nameplate capacity. In lieu of studies, some regions use historical output during summer months.

One significant drawback is that methods such as ELCC require significant data. Typically, one year of load and wind output data is required, and multiple years are preferred, to capture the variability in wind output and load. In light of this deficiency operators may choose to apply other techniques that approximate ELCC with less effort and reduced data requirements. Such methods include measuring a generator's capacity contribution at system peak or during peak and off-peak periods. These estimates may be further adjusted by a generator's forced outage rate and by a generating plant's internal plant energy consumption.

Certain regions, such as PJM Interconnection, LLC (PJM), ISO-New England (ISO-NE), and New York Independent System Operator (NYISO), have adopted policies that allow wind generation to participate in the market as a capacity resource.[51] This has enabled wind resources to contribute to grid reliability while earning an additional revenue stream increasing the economic viability of the wind farm.

[48] To capture year-by-year variation in outages, multiple years of outage data may be required for a particular generator. For newer technologies or generators without that level of data, some utilities and RTOs will aggregate the outage data by generator technology to determine a generator technology "class average."

[49] An industry standard is to keep Loss of Load Expectation (LOLE, based on the LOLP calculations) to one day in 10 years.

[50] For example, if a system has a LOLE of 1 day in 10 years, the ELCC is the increase in system peak that could be supported at the same reliability level after adding a wind power plant. ELCC calculations are based on hourly LOLP calculations for at least one year, meaning that the LOLP and the load-carrying capability of a generator are measured during peak and off-peak hours.

[51] The California Public Utilities Commission, as part of its resource adequacy proceeding, is developing a methodology to allow LSE's to utilize wind resources to meet reserve requirements.

In PJM wind generators are eligible to receive a capacity credit.[52] For wind projects in operation for three years or more, after adjusting the wind generator's nameplate capacity by the equivalent forced outage rate of a wind generator, PJM determines the capacity credit by measuring the capacity factor of a wind generator delivering energy during the hours of 3 to 6 p.m., from June 1 through August 31. The capacity credit is a rolling three-year average, with the most recent year's data replacing the oldest year's data. This methodology applies to wind projects that have been operating for three years or more.

For new projects that lack sufficient data, PJM uses a class average, defined as the annual average capacity factor of all wind projects in PJM during the 3-6 p.m. hours from June through August. Operating data for an individual wind plant replaces the wind class average when such data are available.

Both ISO-NE and the NYISO allow wind projects over 1 MW in capacity to qualify for a capacity credit in each respective territory. Wind generators can submit the results of a four-hour sustained maximum output test, for both summer and winter. The results of the tests are the wind generator's initial capacity credit in ISO-NE and the NYISO. Both ISOs adjust the capacity credit monthly based on data submitted by the generator on actual generation and maintenance hours the previous month.

[52] PJM approved a proposal from a working group in April 2003, with the effective date of June 1, 2003 (PJM 2003c).

Conclusion

The installation of 100,000 MW of wind power by 2020 – comprising approximately six percent of the U.S. electricity supply – is attainable.[53] The United States faces many challenges as it prepares to meet its future energy needs. Electricity supply crises, volatile natural gas and gasoline prices, and heightened concerns about the security of the domestic energy infrastructure and of foreign sources of supply are all elements of the energy policy challenge. As the United States seeks to become less dependent on fossil fuels as an energy source, more priority has been given to renewable energy. Wind energy has the potential to be an important part of the diverse energy portfolio that is needed for a stable, reliable energy sector in the United States.

The movement to address issues related to the wind industry is currently gaining momentum. The accommodations in Order No. 2003 to address the interconnection needs of wind generation highlight this fact. Nevertheless, certain transmission tariff provisions may create barriers for innovative technologies that do not operate with the same characteristics as current thermal resources.

Staff recommends that the Commission undertake technical discussions in order for the energy industry to inform the Commission and each other on the changes necessary for competitive integration of new resources. Through these discussions participants would be able to discuss whether changing the market structure would essentially remove the need for technological innovation in order to overcome regulatory hurdles and compete effectively in the market. Through these conferences, the Commission could use its experience to further electric competition and to identify consensus on policy initiatives necessary to institute change if those changes are unable to come about through the natural evolution of the electric industry.

[53] Presentation of Deputy Secretary of Energy, Kyle McSlarrow, at Global Windpower 2004, Chicago, March 24, 2004.

Appendix 1: Conditional-Firm Service Tariff Product[54]

The conditional-firm transmission product would be for firm service during a defined period of the year and conditional-firm service for the balance of the year. Conditional-firm would be curtailed prior to firm service, but after all non-firm service. This priority of curtailment combined with a clear understanding of the curtailment risk during the conditional months will give generators and utilities more confidence in their ability to move power to loads.

The Conditional-Firm Service would have the following characteristics:

- Conditional-firm service would be offered to customers when ATC to meet a long-term firm request is not available for the full amount of the request for twelve months of the year.
- Conditional-firm service would be offered for the same duration as long-term firm.
- Conditional-firm service would be a combination of firm service for a set number of months of the year with service curtailment for the remainder of the year.
- This transmission service would be curtailed after all non-firm service but prior to firm service and would be subject to curtailment only as necessary to maintain system reliability and not for economic or other non-reliability reasons.
- Customers purchasing conditional-firm service would be given detailed information about curtailment risk, i.e. the hours of likely curtailment, during conditional service months of the year in advance of their commitment.
- Customers purchasing conditional-firm service have a right to retain their original queue status.
- This service would be appropriately priced relative to long-term firm service, reflecting its higher potential for curtailment.

Priority Non-Firm Service Tariff Product

Point to point transmission service is defined in OATT-compliant tariffs as either firm or non-firm. NERC and tagging processes have defined seven levels of firmness for point-to-point service: 1-redirect from secondary points on the system, 2-hourly non-firm, 3-daily non-firm, 4-weekly non-firm, 5-monthly non-firm, 6-network service from secondary non-Network resources, and 7-firm. These categories allow transmission operators to curtail by level of firmness. The priority non-firm transmission tariff product would essentially be a new "category 5.5" service, available long term, in which the customer would agree to be curtailed when the operations were constrained.

The requirements associated with network service (priority 6) and the fact that non-firm service is not available for periods longer than one year is an impediment for new intermittent generators to procure financing. Yet there is transmission capacity available on most paths in many hours of the year. A Priority Non-Firm transmission product could enable generators to

[54] Rocky Mountain Area Transmission Study Final Report. September 2004 pp5-14.

use this capacity. This product would have a lower priority than firm service, and would therefore be subject to curtailment before any firm curtailment. A level 5.5 priority would also be curtailed prior to curtailment of a secondary network resource, but would receive priority over all other non-firm service. Because Non-Firm Point-To-Point Transmission Service applies to non-network loads and resources, a long-term product would be useful for either merchant wind plants or for entities that don't have a network agreement in place.

The Long-Term Priority Non-Firm Point-To-Point Transmission Service Product would have the following characteristics:

- Long-Term Priority Non-Firm service would be offered to customers when there is sufficient capacity available in most hours of the year.
- Long-Term Non-Firm would be offered for a period of up to ten years.
- The curtailment priority would mean that the transmission service would be curtailed after non-firm priorities 1-5 but prior to secondary service, priority 6 and firm service, priority 7.
- Customers purchasing long-term non-firm service would be given detailed information about curtailment risk in advance of their commitment.
- Customers purchasing long-term non-firm service would have a right to retain their original queue status.
- Pricing for this service would be based on proportionate use of the system.

Appendix 2: Renewable Portfolio Standards by State

State	Status	Date	First Goal	End Goal	Required Location?
Arizona	Enacted Amended	1996 • Mar-01	0.2% in '01	1.1% over 2007-20012	Arizonaexcept solar
California	Enacted	Sep-02	*	20% by ,17	No
Colorado	Ballot initiative	Nov-04	3% by '07	10% by 2015; of which 4% solar	Colorado 1.25% credit
Connecticut	Enacted Amended	Apr-98'99, '03	6.5% by '03	10% by 2010	NEPOOL, NY, PJM (if RPS)
Hawaii	Enacted Amended	2001Jun-04	7% by '03; 8% by '04	20% by '20	Hawaii
Illinois	Enacted	Jun-01	5% by '10	15% by '20	Illinois
Iowa	Enacted Re-Enacted	19831991	105 MW	2% by 2011	IA or contractual obligation
Maine	EnactedAmended	19992003	*	30% by '00	Maritimes control area
Maryland	Enacted	Apr-04	3.5% by '06	9.5% by '18	PJM
Massachusetts	Enacted Regulations	19992002	1% by 2003	4% by 2009	No
Minnesota	Enacted Amended	20012003	1% by '05	10% by 2015 + 1% biomass	No
Nevada	Enacted(2nd law)	Jun-01Apr-04	5% by'03 & '04	15% by '13 of which 5% solar	NV or dedicated transmission line
New Jersey	Enacted Amended	1999Apr-04	6.5% by '08 of which 90 MW solar by '08	6.5% by '08	PJM: generated or delivered into
New Mexico	Enacted	Dec-02	5% in '06	10% by 2011	No
New York	Enacted	Sep-04	2006: add 0.94%	25% by 2013 = ~ 3700 MW	NS
Pennsylvania	Enacted Re-enacted	1999 Nov '04	5.7% by '07	18% by 2020	PJM
Rhode Island	Enacted	Jun-04	3% '07	16% by '19	NEPOOL
Texas	Enacted	1999	400 MW by '02	2000 MW by '09- '19	Texas
Wisconsin	Enacted Amended	Apr-98 Oct-99	0.5% by '01	2.2% by 2011	WI or contract path to WI

Sources: FERC analysis, derived from data in: DSIRE Database of State Incentives for Renewable Energy; State PUCs, Energy Information Administration, DOE; Edison Electric Institute; Lawrence Berkeley National Laboratory; *The Wall Street Journal*; interviews, trade press* unable to obtain complete information by publication time (11/16/04)NS= No Standard Set

Appendix 3: RPS Mechanisms by State

State	State Renewable Energy Funds	Wind-supportive State Funds or Programs	Tracking & Verification System?	Renewable Energy Credits (REC)	RPS-applicable Sectors	Government Green Power Purchase Programs ****
Arizona	no	no	quasi	no	regulated utilities	1 Local
California	yes	yes	yes	no	retail sellers	3 local
Colorado	no	no**	planned	planned	retail sellers customers =⇢ 40K	2 Local
Connecticut	yes	yes	*	yes	regulated utilities	1 State
Hawaii	no	*	*	no	regulated utilities	no
Illinois	yes	yes	no	no	regulated utilities	1 State1 Local
Iowa	no	yes	no	no	2 IOUs, based on peak load	no
Maine	no	no	*	yes	regulated utilities	1 State
Maryland	yes	yes	planned	yes	retail sellers	1 State
Massachusetts	yes	yes	yes	yes	regulated utility	1 State 1 Local
Minnesota	yes	yes	*	yes	good faith effort; Xcel mandate	no
Nevada	*	*	*	yes	retail sellers	no
New Jersey	yes	yes	yes	yes	IOUs	1 State
New Mexico	*	*	yes	yes	regulated utilities	being studied
New York	yes	yes	planned	*	regulated utilities	1 State
Pennsylvania	yes	yes	planned	*	competitive default suppliers	1 State
Rhode Island	yes	yes	*	*	retail sellers	1 State
Texas	yes	yes	yes	yes	retail sellers	no
Wisconsin	yes	yes	yes	yes	regulated utilities	1 Local

Sources: FERC analysis, derived from data in: DSIRE Database of State Incentives for Renewable Energy; State PUCs, Energy Information Administration, DOE; Edison Electric Institute; Lawrence Berkeley National Laboratory; *The Wall Street Journa*l; interviews, trade press Note: Some States have created Clean Energy Funds to support early-stage R&D of clean energy technologies. Wind and Solar have received the majority of these funds. Non-RPS States with Clean Energy Funds include: Delaware, Ohio, Oregon, and Montana***** unable to obtain complete information by publication time (11/16/04)** Colorado's RPS gives utilities extra incentive on their rate of return for renewables; other states have similar programs.***Mandate requires retail sellers to offer green-pricing programs; Choice indicates programs exist for retail customers. These also exist in many non-RPS States****State or local governments that have passed laws requiring a certain amount of power be purchased from renewable sources.

Appendix 4: New Projects Announced Since PTC Renewal

Date Announced	State	Project Name	Developer	Date(est) Installed	Size (MW)	Power Usage/ Other	RPS-eligible
Jul-04	OK	Weatherford Wind EC	FPL Enegy	2005	106.5	waited for PTC extension; 20-year PPA	no
Sep-04	CO	TBA	Xcel Energy	TBD	up to 500	asked Colorado PSC to accelerate RFP process to take advantage of credit	yes
Sep-04	IA	Blairsburg	enXco; Clipper Wind Power	2004	310	MidAmerican buying output from two farms; will bring it to 12% renewables	yes
Sep-04	IA	Storm Lake	enXco; Clipper Wind Power	2005	*	⇢ 80% sold under long-term PPAs to MidAmerican	yes
Oct-04	W.V.	Liberty Gap: Franklin Ridge	U.S. Wind Force	2005	79	talks with 4 potential off-takers	no
Oct-04	VA	Liberty Gap-Phase II	U.S. Wind Force	2006	100	in talks with 4 potential off-takers; more MW may be added later	no
Oct-04	IA	TBA	Alliant Energy	2005	130	will be added under PPAs with PTC extention	yes
Oct-04	WI	TBA	Alliant Energy	2005	100	will be added under PPAs with PTC extention	yes
Oct-04	NB	Ainsworth	Nebraska Public Power District	2005	60	Omaha PPD will purchase 10 MW; Renewable Energy Systems will build	no
Oct-04	MN	Trimont	PPM Energy	2005	100	15 year PPA with Great River Energy, a co-op	yes
Oct-04	OR	Klondike II	PPM Energy	2005	75	announced shortly; fully permitted	no
Oct-04	MD	Roth Rock	Synergics Wind Energy	2005	40	n/a	yes
Oct-04	AZ	Sunshine Wind Park	Foresight Energy Sunshine	2005	60	Seeking a PPA with APS	yes
Oct-04	TX	Callahan Divide	FPL Energy	1Q 2005	114	FPL will B-O-O; output sold under long-term contract	yes
Oct-04	TX	Wildorado	Cielo Wind Power	2005	160	Xcel Energy: long-term PPAs	yes
Oct-04	NM	San Juan Mesa	Padoma Wind Power	2005	120	Xcel Energy: long-term PPAs	yes
Oct-04	NM	Tucumcari	Cielo Wind Power	2004-05	80	Xcel Energy: contracted for all output to meet NM RPS	yes
Oct-04	SD	Rolling Thunder	Clipper Windpower	200-300 MW/2-3 yrs	3,000	still in negotiations; plans to stage over several years	no
Nov-04	WI	multi	six developers	*	~400	4 Wisconsin utilities contracted to purchase output from farms constructed in /05	yes
Nov-04	CA	Kumeyaay	Superior Renewable Energy	*	50	San Diego G&E: 10-year PPA for entire output	yes

Note: projects FERC was aware as of 11/15/04Definitions: B-O-O, Build-Own-Operate; PPA, Power Purchase Agreement
Sources: FERC analysis, derived from data in: DSIRE Database of State Incentives for Renewable Energy; State PUCs, Energy Information Administration, DOE; Edison Electric Institute; Lawrence Berkeley National Laboratory; *The Wall Street Journal*; interviews, trade press

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