BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF SOUTH DAKOTA

IN THE MATTER OF THE FILING BY SUPERIOR RENEWABLE ENERGY LLC ET AL AGAINST MONTANA-DAKOTA UTILITIES CO REGARDING THE JAVA WIND PROJECT	)	EL04-016

Direct Testimony of Timothy Woolf

On Behalf of The South Dakota Public Utilities Commission Staff

Regarding Avoided Costs for the Java Wind Project

February 18, 2005

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1. INTRODUCTION, QUALIFICATIONS AND PURPOSE

Q. What is your name, position and business address?

A. My name is Timothy Woolf. I am the Vice-President of Synapse Energy Economics, Inc, 22 Pearl Street, Cambridge, MA 02139.

Q. Please describe Synapse Energy Economics.

A. Synapse Energy Economics is a research and consulting firm specializing in electricity industry regulation, planning and analysis. Synapse works for a variety of clients, with an emphasis on government agencies, consumer advocates, regulatory commissions, and environmental advocates.

Q. Please describe your general experience regarding the electric utility industry.

A. My experience is summarized in my resume, which is attached as Exhibit TW-1. Electric power system planning, regulation and restructuring have been a major focus of my professional activities for the past twenty-three years. In my current position at Synapse, I investigate a variety of issues related to the electric industry; with a focus on energy efficiency, renewable resources, avoided costs, environmental policies, air quality, and many aspects of consumer protection.

Q. Please describe your professional experience before beginning your current position at Synapse Energy Economics.

A. Before joining Synapse Energy Economics, I was the Manager of the Electricity Program at Tellus Institute, a consulting firm in Boston, Massachusetts. In that capacity I managed a staff that provided research, testimony, reports and regulatory support to state energy offices, regulatory commissions, consumer advocates and environmental organizations in the US. Prior to working for Tellus Institute, I was employed as the Research Director of the Association for the Conservation of Energy in London, England. I have also worked as a Staff Economist at the Massachusetts Department of Public Utilities, and as a Policy Analyst at the Massachusetts Executive Office of Energy Resources. I hold a Masters in Business Administration from Boston University, a Diploma in

Economics from the London School of Economics, a BS in Mechanical Engineering and a BA in English from Tufts University.

Q. Please describe your experience with regard to avoided costs and wind projects.

A. Avoided costs are a critical component to much of the work that I have performed throughout my career I have many years of experience analyzing and critiquing electric utility integrated resource plans, which rely upon the same fundamental concepts and principles as avoided costs calculations, and are often used for the purpose of estimating avoided costs. I have worked on many different aspects of electricity industry restructuring, which has important implications regarding the costs of electricity today and the calculation of future avoided costs. Most of my work includes technical and economic analyses of electric utility supply-side and demand-side resources, whose costs and performance characteristics form the basis of avoided cost estimates. Furthermore, I have conducted many analyses of the economics of renewable energy resources, with an emphasis on wind generators, including a recent report titled *Repowering the Midwest*, which assessed the potential for developing renewable resources and energy efficiency in ten Midwestern states, including South Dakota. Finally, I have extensive experience with reviewing electric utility production cost models, and have used the PROSYM model on several occasions to model the costs and benefits of renewable resources, including wind generators.

Q. On whose behalf are you testifying in this case?

A. I am testifying on behalf of the Staff of the South Dakota Public Utilities Commission.

Q. Have you testified previously in this docket?

A. No, I have not.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to address issue 6 identified by the Public Utilities Commission of the State of South Dakota (Commission) in the Order for and Notice of Procedural Schedule and Hearing EL04-016 establishing this proceeding. Specifically, I will review and critique the avoided cost estimates proposed by Montana-Dakota Utilities (MDU) and commented on by Superior Renewable Energy LLC (Superior). Much of my testimony will respond to the testimony of Mr. Kee on behalf of MDU, because Mr. Kee's testimony provides the most substantive proposals with regard to avoided energy and capacity costs.

Q. How is your testimony organized?

A. My testimony is organized as follows:

1. Introduction, Qualifications and Purpose.
2. Summary of Findings and Recommendations.
3. PURPA and its Implications Today.
4. The Commission's Previous Order Regarding PURPA.
5. Planning-Based Versus Market-Based Avoided Costs.
6. Avoided Costs for MDU.
7. Costs to MDU Associated with Wind Generation.
8. Duration of the Contract for the Java Wind Project.

2. SUMMARY OF FINDINGS AND RECOMMENDATIONS

Q. Please summarize your findings with regard to MDU's avoided cost proposal as described by Mr. Kee.

A. My general finding is that Mr. Kee has not proposed an appropriate set of avoided costs for the Java Wind Project. There are several reasons for this, including the following:

- Mr. Kee understates the value of the Java Wind Project's capacity by using the minimum accredited capacity value for the summer peak period months.

- Mr. Kee recommends the use of market-based estimates of avoided costs, when the competitive electricity markets relevant to MDU are not yet fully developed and cannot yet be relied upon to provide accurate forecasts of market prices or avoided costs.

- Mr. Kee recommends the use of both planning-based and market-based estimates of avoided energy costs for Period 3. This methodology creates a risk of incorrectly estimating avoided costs if the two approaches are not based on the same assumption regarding the timing and type of the new, marginal generating unit.
- Mr. Kee overstates the cost of integrating the Java Wind Project into the MDU system by relying upon a study that is based on a much larger system contribution from wind generators.
- Mr. Kee recommends a purchased power agreement (PPA) duration of ten years, which may not be long enough to support the Java Wind Project and is not sufficient to put the generation from Java on a level playing field with the generation from MDU's power plants.

Q. Please summarize your primary recommendations for how the Commission should treat avoided costs for the Java Wind Project.

A. Neither party to this case has yet to present a complete set of avoided costs that are consistent with Order F-3365, consistent with the intent of PURPA, and consistent with some basic principles for how to accurately estimate avoided costs. Consequently, the Commission is not yet in a position to recommend or require any one set of numbers to be used for avoided costs. Instead, either MDU or Superior, or both parties, will need to prepare additional calculations to determine an acceptable set of avoided costs.

In Order F-3365 the Commission directed utilities to negotiate avoided costs with QF developers. The evidence in this proceeding suggests that the Commission needs to define more clearly some principles that should be used in estimating avoided costs, and thereby narrow down the potential areas of disagreement. I recommend that the Commission adopt at least the following guidelines for the purposes of estimating avoided costs:

- Avoided costs should be calculated using planning-based approaches, as opposed to market-based approaches, unless and until it can be demonstrated that the competitive electricity market relevant to MDU is capable of providing reliable and credible estimates of both avoided energy and avoided capacity costs.

- The capacity credit for the Java Wind Project should reflect the full value to MDU of the capacity produced by the project. At a minimum, the estimates of avoided capacity costs should include separate estimates for on-peak and off-peak periods.
- The avoided capacity costs should be calculated based on the capital costs associated with a peaking unit, for all years of the PPA.
- The short-term avoided energy costs should be estimated by running an electric system dispatch model to compare the energy costs of a scenario with the QF to a scenario without the QF.
- The long-term avoided energy costs should include estimates of the actual energy costs associated with the new baseload generation unit, as well as the "capitalized energy" costs of the new baseload generation unit.
- Avoided energy costs should include an estimate of the costs due to future climate change regulations. If there is insufficient evidence in this proceeding to adopt estimates of such costs, the parties should be put on notice that such costs should be included in any avoided costs updated in the future.
- Additional costs charged to the QF – such as the costs of integrating wind into the system – should not be included in the PPA unless and until MDU can demonstrate that such costs will actually be incurred, and MDU provides an estimate of such costs based on the specific conditions relevant to the Java Wind Project.
- MDU should offer Superior the option to enter into a PPA of longer duration than ten years. Furthermore, if Superior chooses a longer

contract, the PPA should include a provision requiring the two parties to estimate new avoided costs in the tenth year.

3. PURPA AND ITS IMPLICATIONS TODAY

Q. Why is the Public Utilities Regulatory and Policy Act of 1978 (PURPA) relevant in this proceeding?

A. Section 210 of PURPA requires electric utilities to purchase electricity from cogenerators and small power producers, which are referred to as Qualifying Facilities (QFs). Small power producers include renewable generation facilities such as the Java Wind Project. Superior has asked that MDU be required to purchase the output of the Java Wind Project according to the terms of Section 210 of PURPA.

Q. What does PURPA require electric utilities to pay QFs for their electric output?

A. PURPA requires that the rates that utilities pay for QF generation:

> "(1) shall be just and reasonable to the electric consumers of the electric utility and in the public interest, and
> (2) shall not discriminate against qualifying cogenerators or qualifying small power producers."[1]

PURPA also requires that the rates paid for QF power should not exceed "the incremental cost to the electric utility of alternative electric energy."[2] In other words, the rates paid for QF power should not be greater than, nor less than, the costs that can be avoided by the utility as a consequence of purchasing the QF power. It is clear that PURPA requires that the rates paid for QF power should strike the appropriate balance between paying for the full value of the QF power without placing an undue burden on electricity ratepayers.

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[1] Public Utilities Regulatory Policy Act of 1978, Section 210(b).

[2] Public Utilities Regulatory Policy Act of 1978, Section 210(b).

Q. What was the intent of section 210 of PURPA?

A. One of the goals of PURPA, especially section 210, was to encourage more efficient use of electricity generation facilities and electricity generation resources. PURPA sought to achieve this goal by allowing cogenerators and small power producers, including renewable generators, to participate in the electricity market.

At the time PURPA was enacted, the electric utility industry was composed of vertically-integrated utilities that had a monopoly on the generation, transmission and distribution of wholesale and retail electric power. One of the goals of PURPA was to encourage cogenerators and small power producers to contribute to the electricity industry by removing the barriers to entry faced by these non-utility projects. The intent of PURPA was to allow the power from qualifying facilities to compete directly with power from electric utility generation facilities. In other words, the intent of PURPA was to create a "level playing field" between utility power and QF power.

Q. Now that there is greater competition among generators in the electricity industry, especially at the wholesale level, is PURPA still relevant?

A. Yes, PURPA is still relevant in South Dakota today. While the wholesale electricity industry has become more competitive in recent years, it is still undergoing a considerable amount of change and can only be described as being in transition. The rules dictating the operation of the Midwest Independent System Operator (MISO) are still developing, and some key aspects of the wholesale market such as day-ahead trading and locational marginal pricing have not been implemented yet. In addition, MISO has not to my knowledge developed a proposal for a competitive capacity market. This is one component of wholesale electricity markets that is still not resolved even for the regional power markets with more experience, such as those in New England, New York and PJM. It may be many years before the wholesale market in the region can be considered fully operational and fully competitive.

Furthermore, the electric utilities in South Dakota and the region are still vertically-integrated, are still subject to regulation, and still charge regulated rates for their generation. As a result, absent specific regulatory provisions such as PURPA, the Java Wind Project is not able to compete directly with utility-owned generation – i.e., the playing field is still not level.

4. THE COMMISSION'S PREVIOUS ORDER REGARDING PURPA

Q. Has the Commission previously addressed the issue of avoided cost payments under PURPA?

A. Yes. In Decision and Order F-3365, dated December 14, 1982, the Commission described the approach that should be used to estimate avoided costs for the purpose of purchasing power from QFs under PURPA. The key findings of that order that are relevant to this proceeding include the following:

- For those QFs with a rated capacity of more than 100 kW, the avoided costs should be determined through contract negotiations between the QF and the electric utility.
- Avoided costs calculations should distinguish between short-term and long-term contracts, where long-term is defined as being as long as 10 years or greater.
- Avoided capacity costs for short-term contracts should be based on the costs of installed turbine peaking generation.
- Avoided capacity costs for long-term contracts should be based on the costs of base load generation, and should be based on the "average kW supplied by the QF for each month during the utility's on-peak period." (Order F-3365, page 12)
- The avoided capacity costs for long-term contracts should be made constant over the duration of the contract.
- The avoided capacity costs should be based on capacity that is actually avoided by the electric utility.

- The avoided energy costs, for both short-term and long-term contracts, should be based on the "expected hourly incremental avoided costs calculated over the hours in the appropriate on-peak and off-peak hours as defined by the utility." (Order F-3365, page 12)

Q. Do you agree that these approaches will lead to appropriate estimates of avoided costs?

A. I agree with most of the key findings in Order F-3365. However, I have one concern with the methodology that has relevance for this proceeding.

In estimating avoided costs, it is important that avoided energy costs and avoided capacity costs are based on the same type of generation unit, for each year of the analysis. Baseload generation units typically have high capacity costs but low energy costs, while peaking units typically have the inverse. If a baseload unit is the marginal or avoided resource in any one year, then the avoided capacity costs will be high but the avoided energy costs will be low. If a peaking unit is the marginal or avoided resource in any one year, then the inverse will be true.

Thus, if the avoided energy and capacity costs in any one year are based on different avoided units, then the avoided costs could be significantly in error. For example, if the actual avoided unit were a baseload unit, and the avoided energy were based on a baseload unit, but the avoided capacity were based on a peaking unit, then the avoided capacity costs would be significantly understated. Ideally, the avoided energy and capacity costs should be based on the same type of generation unit, not only for each year, but also for each month, and indeed each hour.[3]

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[3] This does not have to be the case if the differences are accounted for in the calculation of avoided energy and capacity costs. For example, peaking units can be used to represent avoided capacity costs in a year when baseload units are on the margin, as long as the capitalized energy costs of the baseload plant are included in the energy costs. This point is addressed in more detail in Section 6.4 of my testimony.

Q. Does the methodology required by the Commission in Order F-3365 ensure that avoided energy and capacity costs are based upon the same type of generation unit in each period?

A. No. In fact, the methodology could lead to a mis-match of avoided peaking and baseload units in any one year, leading to an erroneous estimate of avoided costs. The Order requires that the avoided capacity costs for short-term contracts (i.e., less than ten years) be based on peaking units, while the avoided capacity costs for long-term facilities be based on baseload units – apparently without regard for which type of facility is expected to be avoided in each year. If the utility expects to avoid a baseload unit prior to year-10, and uses this assumption in estimating avoided energy costs, then the avoided capacity costs in that prior year will be understated. Conversely, if the utility expects to avoid a peaking unit after year-10, and uses this assumption in estimating avoided energy costs, then the avoided capacity costs in that later year will be overstated.

Q. How do you recommend that the Commission address this issue?

A. I recommend that the Commission amend this requirement of the Order and Decision F-3365. This requirement stands out from all the others in that it could easily result in an erroneous estimate of avoided costs, and thus should not be used in this or any other proceeding. My recommendations for how avoided costs should be calculated are presented in Section 6.4 of my testimony below.

5. PLANNING-BASED VERSUS MARKET-BASED AVOIDED COSTS

Q. Please describe what you mean by "planning-based" and "market-based" avoided costs.

A. Planning-based avoided costs rely upon utility long-term generation expansion planning techniques, methodologies and assumptions to create a forecast of the most likely avoided costs faced by a utility. There are many ways to prepare planning-based avoided costs, but the general approach is to develop a base case electricity resource scenario (QF-Out) and compare it to an alternative scenario that includes the capacity and energy of the qualifying facility (QF-In). The difference between the two cases represents the costs that would be avoided by introducing the QF to the electricity system in question. The avoided cost methodology required by the Commission in Order F-3365 can be described as a planning-based methodology, as it requires utilities to use long-term planning scenarios and assumptions to estimate avoided costs.

In contrast, market-based avoided costs are based on market prices for power bought and sold through a competitive wholesale electricity market. If a utility has access to a competitive wholesale spot market, the price for that spot market power can be a good indication of short-run avoided costs. If the utility is short on power in any one hour, then it can purchase power at the spot market price. Similarly, if the utility is long on power in any one hour, then it can sell power at the spot market price. Thus, the competitive spot market price represents the short-run avoided costs to a utility, regardless of how much power they have at any one point in time, and does not necessarily require an estimate of which generating unit is likely to be the marginal units for the utility at any one point in time.

The spot market price itself, in theory, is based upon the marginal unit for the system, and thus represents the avoided costs for the system. Unlike planning-based avoided costs, estimates of market-based avoided costs do not require the same assumptions regarding electric utility loads, resources and operating characteristics over the long-term future. They do however, require forecasts of electricity spot market prices, which create their own challenges.

Q. Should planning-based avoided cost estimates lead to the same results as market-based avoided cost estimates?

A. In theory, the two approaches should lead to the same result. However, there are many conditions that must be met before one can expect them to lead to the same result. For example, the planning-based avoided costs must be derived from long-term resource plans that are optimized in the two scenarios (QF-In versus QF-Out), and that are consistent with the way that the electricity system would be optimized by the competitive market forces. In other words, if the competitive market indicates that a new baseload coal plant should be built in 2008 to minimize total costs, then the planning-based scenarios will need to assume the same thing in order for the two approaches to lead to the same result. There can also be differences in the cost of financing new capacity. Merchant plants, or power plants developed by non-utilities in a competitive market, can have higher cost of capital due to the risks faced by their projects.

As another example, the market-based avoided costs should be based on a fully developed and fully competitive wholesale market for both capacity and energy that is not constrained by barriers to entry, market power problems, uneconomic treatment of transmission constraints or other institutional problems. If such constraints exist, then the avoided costs from the market-based approach are likely to be inconsistent with, and probably higher than, avoided costs from the planning-based approach.

Thus, while the two approaches should ideally lead to a similar result, there are many factors that might cause them to lead to significantly different results.

Q. Is one method of estimating avoided costs generally preferable to another?

A. In general, and under the proper conditions, market-based avoided cost estimates are preferable to planning-based estimates. Market-based costs rely upon the prices that are actually used by buyers and sellers of energy and capacity, and thus are likely to be a better indication of costs that could truly be avoided by qualifying facilities.

However, as noted above, several important conditions must exist before market-based avoided costs can be considered reliable or preferable to planning-based. If these conditions do not exist, then it is necessary to rely upon planning-based avoided costs instead.

Q. Do you think it is appropriate for MDU to use market-based avoided costs at this time?

A. No. The MISO wholesale spot market, the regional market that MDU is a member of, is not yet sufficiently developed to use for estimating avoided costs. The MISO energy spot market has not been fully developed and is not yet fully functional. Experience in other electricity markets suggests that the first few years of operation can result in volatile and unexpected prices. My understanding is that the trading hub that would apply to MDU has not even been developed and would not be operational when the MISO Day 2 market starts. Thus, there are currently no wholesale energy prices administered by MDU that are relevant to MDU at this time.

In addition, the MISO market does not yet include a separate market for capacity. While it is likely to develop such a market at some point in the future, it is not clear at all how such a market will be structured and what its prices will be like. Thus, there are currently no wholesale capacity prices administered by MDU that are relevant to MDU at this time.

In other, more developed, electricity markets there are "forward" markets where buyers and sellers arrange to exchange electricity for pre-determined prices. These forward markets provide a market-based indication of electricity prices for several years into the future, and thus provide a reliable and credible source for estimating electricity market prices for at least the early years of a long-term contract. To my understanding, the MISO market does not currently have any forward markets for either energy or capacity relevant to MDU, and thus does not provide this useful indication of market prices or avoided costs.

Q. What approach do you recommend MDU be required to use in estimating avoided costs for the Java Wind Project?

A. I recommend that MDU be required to use planning-based estimates of avoided costs, because market-based estimates are not yet available. I provide more detail on how these planning-based estimates should be calculated in the following section.

6. AVOIDED COSTS FOR MDU

6.1 CAPACITY VALUE OF THE JAVA WIND PROJECT

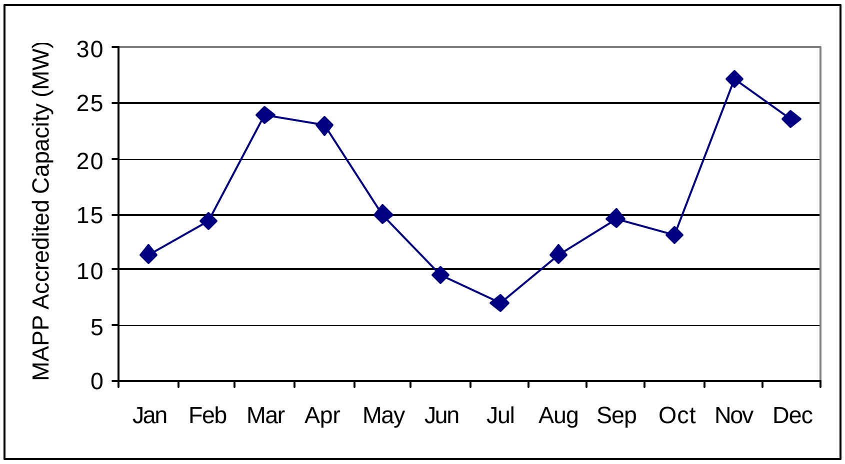
Q. How much capacity is the Java Wind Project expected to provide to the MDU system?

A. Both MDU and Superior agree that the MAPP capacity accreditation procedure should be used to determine the amount of capacity from the Java Wind Project that should be given credit on the MDU system. Table 1 and Figure 1 below provide monthly capacity values that Superior expects the Java Wind Project to have once it becomes operational. These values are from Table 1 of Mr. Ferguson's testimony on behalf of Superior. I have put the values in graphic form in Figure 1 to illustrate the extent to which these values can vary from month-to-month.

Table 1. Monthly Capacity Values for the Java Wind Project

Month	MAPP Accredited Capacity (MW)
Jan	11.3
Feb	14.4
Mar	23.9
Apr	23.0
May	15.0
Jun	9.5
Jul	7.0
Aug	11.3
Sep	14.7
Oct	13.2
Nov	27.2
Dec	23.6

Figure 1. Monthly Capacity Values for the Java Wind Project



Q. How can these monthly values be used to identify the capacity value of the Java Wind Project?

A. In their Order F-3365, the Commission found that:

> "Capacity credits included in long-term contracts should reflect the average kW supplied by the QF for each month during the utility's on-peak period." (page 12)

The Commission also noted in that order that avoided capacity costs should be based on "capacity actually avoided" by the QF. (page 17)

The first quote above suggests that utilities should use several months during the peak period to estimate capacity value. Thus, if the peak period were defined as June through September, the capacity value for the Java Wind Project would be 10.6 MW (the average of the accredited capacity values for those months).

However, Mr. Kee argues that the second quote above from Order F-3365 dictates that MDU use the minimum accredited capacity value that is available during the peak periods, not the average value. He argues that MDU must have sufficient capacity to meet peak demand during each summer month, and that for planning purposes the Company can only assume the minimum amount of capacity will be available for meeting reliability needs. Otherwise, MDU is at risk of falling short of capacity if it assumes a higher capacity value than what the Java Wind Project actually delivers. (Testimony of Edward D. Kee, pages 21-22 and pages 32-34) Mr. Kee concludes that the Java Wind Project should be credited with only 7 MW of capacity, as this is the minimum accredited capacity value during the summer months.

Q. Do you agree with Mr. Kee's conclusion and recommendation?

A. I am concerned that Mr. Kee's approach would not compensate the Java Wind Project for the full value of the capacity it would provide. MDU's peak demand occurs sometimes in July and sometimes in August. For the five years 1999 through 2003, the peaks occurred three times in August and twice in July. (MDU's response to Superior's first data request, Response No. 6, Attachment A). It is also conceivable that MDU's peak could occur in June or in September in some years. In all of these instances when the peak does not occur in July, Superior would not be fully compensated for the Java capacity output.

Furthermore, the Java Wind Project is expected to provide considerably more capacity value in other months of the year – in some cases more than three times the 7 MW value that Mr. Kee proposes. This off-peak period capacity would presumably have some value to MDU, even if the per-unit value (i.e., in $/kW-month) is less than the per-unit value in the peak period.

In an ideal world, there would be a real-time, competitive, wholesale capacity market into which MDU could buy and sell capacity. In such a world, MDU would benefit from the actual capacity value provided by the Java Wind Project in every month of the year, and would be able to compensate Superior for the exact amount of capacity provided in each month at a price that reflects the actual value in each month. Unfortunately, such a capacity market does not exist in South Dakota today, and may not exist for several years. It is the absence of such a market that makes it difficult to determine exactly how much capacity the Java Wind Project will allow MDU to actually avoid.

Q. Mr. Kee also recommends that the amount of avoided capacity from the Java Wind Project should be updated after every year of operation to reflect the new actual MAPP accredited capacity. Do you agree with this recommendation?

A. This could be a reasonable approach. It would mean that the avoided capacity credit in each year would be based on the most recent information available. A better way to address this issue would be to use the average results of the previous years, in order to smooth out any fluctuations from year to year. A rolling average of at least three years of experience would probably be sufficient to achieve this.

Q. Mr. Kee also recommends that MDU should be refunded some of the initial avoided capacity payments if the actual minimum monthly MAPP accredited capacity in the summer peak is less than 7 MW. Do you agree with this recommendation?

A. This approach could be reasonable, but only if it were symmetrical. In other words, avoided capacity payments could be reconciled every year to match the actual MAPP accredited capacity in that year, whether it be higher than anticipated or lower. In this way, Superior would be compensated for exactly the amount of capacity provided in each year. If the capacity payments were only reconciled in the instance when output is lower than expected, as proposed by Mr. Kee, then Superior would not be fairly compensated for the Java Wind Project in those years with relatively high output.

A symmetrical reconciliation would essentially be a performance-based payment mechanism – where Superior receives higher payments in years when the Java Wind Facility performs above average, and lower payments in those years where it performs below average. The disadvantage of this reconciliation is that Superior would not necessarily be receiving constant payments over time. While on average the total payments over time should be the same, Superior might prefer to have a constant payment stream for financial reasons.

Q. What methodology do you recommend be used to determine the capacity value of the Java Wind Project?

A. I recommend that the Commission make a finding that using the minimum accredited capacity value during the summer peak period, as proposed by Mr. Kee is likely to undervalue the capacity provided by the Java Wind Project. Furthermore, I recommend that the Commission adopt a capacity valuation methodology that addresses this concern. One option would be to require MDU to use the average of Java Wind Facility accredited capacity for the four summer months. Based on Superior's current estimates of monthly accredited capacity, the Java Wind Project would receive payments for 10.6 MW of capacity.

Another option would be to require MDU to establish two avoided capacity costs, one based on peak period capacity amounts and costs, and another based on off-peak period capacity amounts and costs. The option would compensate Superior for capacity provided during the winter season, but at rates that reflect the lower avoided capacity costs at that time of year.

Either one, or both, of these options would help strike a better balance between (a) MDU paying for capacity actually avoided, and (b) Superior being adequately compensated for the capacity value of the Java Wind Project.

6.2 AVOIDED CAPACITY COSTS

Q. Please summarize Mr. Kee's methodology and assumptions for estimating avoided capacity costs.

A. Mr. Kee makes different avoided cost estimates for three different periods, as follows:

- Period 1, which lasts through the end of 2006. Mr. Kee assumes that MDU "has sufficient capacity to meet the MAPP contingency reserve requirements and does not need any additional capacity." (Testimony of Edward D. Kee, page 24) He therefore assumes the avoided cost in this period is zero. (Testimony of Edward D. Kee, Exhibit EDK-3, page 1)

- Period 2, which includes 2007 through June 14, 2010. Mr. Kee assumes that MDU will need to "make the most economic purchase of short-term peak period capacity in order to meet MAPP contingency reserve requirements." He further assumes that the most economic short-term capacity would be in the form of leased portable combustion turbine (CT) units. (Testimony of Edward D. Kee, page 24) He estimates that these would result in avoided capacity costs of roughly $69/kW-yr in 2007, increasing to roughly $73/kW-yr in 2010. (Testimony of Edward D. Kee, Exhibit EDK-3, page 2)

- Period 3, which begins June 15, 2010, and continues for the rest of the study period. Mr. Kee assumes that MDU would acquire new baseload coal capacity for this period. MDU has three coal plant options currently under consideration, and Mr. Kee expects that the most economic option would be for MDU to purchase a share in a large new baseload coal plant built by a group of utilities in the region. (Testimony of Edward D. Kee, pages 24-25) He estimates these costs to be roughly $264/kW-yr. (Testimony of Edward D. Kee, Exhibit EDK-3, page 3)

Q. Do you agree with Mr. Kee's assumptions regarding the avoided capacity costs in Period 1?

A. No. Assuming that avoided capacity costs are zero – in any year – is likely to understate the value of avoided capacity. If MDU does not require additional capacity during Period 1, then perhaps it can sell any excess capacity it has. In theory, avoided costs should represent either (a) the costs avoided by not having to purchase capacity in years when the utility would be in deficit, or (b) the revenues that could be obtained by selling capacity in years when the utility would have excess capacity. In many cases, the cost of purchasing capacity would be the same as the prices that could be charged for selling capacity, and thus it becomes less relevant whether the utility has a capacity surplus or a capacity deficit – the avoided costs would be the same either way.

Q. Do you agree with Mr. Kee's assumptions regarding the avoided capacity costs in Period 2?

A. I agree with his overall methodology of using a peaking resource to represent the avoided capacity costs during these years. However, I am concerned that Mr. Kee's methodology understates the capacity value of the Java Wind Project during the nine off-peak months of the year. He essentially assumes that the capacity value during these months is zero. Presumably, the Java Wind Project will provide some amount of accredited capacity during these months, and there will be some value to this capacity. A more accurate methodology for estimating avoided capacity costs would include a value for avoided capacity during peak periods and another value during off-peak periods. The value during off-peak periods would be relatively low, but is likely to be greater than zero.

Q. Do you agree with Mr. Kee's assumptions regarding the avoided capacity costs in Period 3?

A. No. I believe that a peaking unit should be used to estimate avoided capacity costs – even in those years when a baseload unit is expected to be the marginal unit on the system. Baseload power plants are not built for the purpose of providing capacity – they are generally built for the purpose of providing low-cost energy. When a utility *only* needs additional generating capacity, it would typically build new peaking units such as combustion turbines. As a result, combustion turbines are a better representation of "pure peaking" capacity costs than baseload power plants – at any point in time.

However, if a new peaking unit is used to estimate avoided capacity costs in a period when a baseload power plant is expected to be the marginal unit, then it is necessary to increase the energy costs of the baseload power plant in order to reflect the full capital costs associated with that marginal unit. I describe the rationale and methodology for this approach in more detail below in Section 6.4 of my testimony.

6.3 AVOIDED ENERGY COSTS

Q. Please describe how Mr. Kee characterizes stipulated avoided energy costs versus market-based avoided energy costs.

A. As far as I can tell, what Mr. Kee refers to as stipulated avoided energy costs are the same as what I have been referring to as planning-based avoided energy costs. We may, however, be defining market-based avoided costs somewhat differently. While we are both referring to using the same market as the source of avoided costs, I recommend that market prices would be used to forecast avoided costs, but that these forecasts would be used throughout the contract term regardless of what the actual market prices turn out to be. Mr. Kee, on the other hand, implies that actual market-based costs should be used in each year of the contract, perhaps through some form of annual reconciliation process. (Testimony of Edward D. Kee, pages 37-38) If this is what Mr. Kee intends, it would be a significant deviation from standard approaches to making avoided cost payments for QFs, and thus is an important point that should be clarified.

Q. Do you agree with Mr. Kee's approach to estimating stipulated avoided energy costs?

A. In general, I agree with the methodology that Mr. Kee uses to estimate stipulated avoided energy costs, where a production costing model is used to estimate the differences between energy costs of a QF-In scenario and a QF-Out scenario.

However, Mr. Kee recommends that the stipulated avoided energy costs only be used until the MISO Day 2 electricity market is operational. (Testimony of Edward D. Kee, page 42) He also points out that this market is expected to be operational in 2005. (Testimony of Edward D. Kee, pages 12-13) Thus it appears as though Mr. Kee's stipulated avoided energy costs will not be used to set the avoided energy costs for the Java Wind Project, and therefore are irrelevant. Consequently, I have not reviewed his methodology or assumptions regarding these costs in detail and have not reached any conclusions with regard to them at this time.

Q. Do you agree with Mr. Kee's approach to estimating market-based avoided energy costs?

A. No. I have two concerns with the methodology that Mr. Kee proposes to estimate market-based avoided energy costs. First, as described above in Section 5 of my testimony, the MISO market is not yet developed enough to provide reliable estimates of market prices for either energy or capacity. Thus, I do not agree with the concept of using market-based avoided costs for MDU at this time.

It is instructive to note that Mr. Kee has not proposed a forecast of MISO energy market prices that can be used for avoided costs in this proceeding. This makes it difficult to assess the implications of his methodology, and also points out the fundamental flaw in his approach: the lack of useful data. Unless and until one of the parties in this proceeding provides market-based estimates of avoided costs that are reliable, credible and based upon fully functional electricity markets, the Commission has no choice but to rely upon planning-based estimates.

Q. What is your second concern with Mr. Kee's approach to estimating market-based avoided energy costs?

A. Mr. Kee recommends that in Period 3, when MDU is expected to require new coal baseload generation, the market-based energy payments have two components. The first component would be equal to the avoided energy costs associated with avoidable coal unit, for the energy that would be expected from the amount of capacity that the Java Wind Project is given credit for (according to Mr. Kee this would initially be 7 MW). The second component would be equal to the market-based energy price for any energy that the Java Wind Project produces above that accounted for in the first component. (Testimony of Edward D. Kee, page 41) In other words, the first component would be a planning-based avoided energy cost for the avoided capacity portion of the wind output, and the second component would be a market based avoided energy cost for the remaining portion.

My concern with this approach is that combining a planning-based estimate with a market-based estimate could lead to erroneous results. As I point out in Section 3 of my testimony, it is very important that the estimates of avoided energy and the estimates of avoided capacity be based on the same assumptions regarding the avoided unit in each year. If one estimate is based on a baseload unit being avoided in any one year while the other is based on a peaking unit being avoided, then the results will be incorrect, and probably by a significant amount. If market-based estimates are used for both avoided energy and capacity costs, then it is safe to assume that the two avoided costs are based on the same avoided units in the marketplace in any one year.[4] When combining a market-based approach with a planning-based approach it is very difficult to ensure that they are both based on the same avoided unit in each year. In the case of Mr. Kee's methodology, he has not demonstrated that the market-based energy costs in Period 3 will be driven by a baseload coal unit – i.e., he has not demonstrated that a baseload coal unit will be the marginal unit for the electricity market in those years. If it is not, then his approach to estimating market-based avoided energy costs will lead to erroneous results.

Q. Do you have any additional concerns with the avoided energy costs discussed by Mr. Kee?

A. Yes. I believe that Mr. Kee's methodology does not account for all the future costs associated with environmental regulations. Both Mr. Slater and Mr. Kee agree that the costs of allowances associated with currently regulated pollutants should be included in the estimates of avoided energy costs. (Testimony of Kenneth J. Slater, page 13; Testimony of Edward D. Kee, page 55.) Mr. Kee also notes that appropriate capital costs associated with environmental regulations (e.g. for emissions control equipment) should be included in the avoided capacity cost estimates. (Testimony of Edward D. Kee, page 55.)

However, neither of these witnesses address the costs that are likely to be borne by electric utilities and their ratepayers as a consequence of *future* environmental regulations.

[4] This assumption is based on the premise that wholesale capacity markets will accurately indicate the cost of new capacity. This remains a contentious issue, even for wholesale electricity markets that are more developed than MISO.

Q. Why should a utility estimate the cost of future environmental regulations that do not yet exist?

A. There are many uncertainties involved in electric utility planning and forecasting. Fuel prices are one example of uncertain future costs that are routinely estimated for planning purposes, despite considerable uncertainty. Any prudent business should make a reasonable estimate of all expected future costs, regardless of the uncertainty involved. It is clear that MDU will be subject to some form of climate change regulation within the study period for this proceeding, and thus the costs for complying with such regulation should be included in the avoided cost estimates.

Q. Why do you believe that some form of climate change regulation is so likely in the near- to medium-term future?

A. It is becoming increasingly accepted that some form of climate change regulations will be applied to all electric utilities in the US. Several states and regions have already adopted such regulations, and these efforts are expected to lead to federal regulations. As one indication of how this issue is becoming viewed in the industry, the most recent edition of Public Utilities Fortnightly included two articles discussing the developments of CO_2 and climate change regulations at the state, regional and federal levels. These two articles are attached to my testimony as Exhibit TW-2.

Q. Are some utilities already making efforts to reduce their CO_2 emissions?

A. Yes. Some of the country's largest utilities are already responding to state regulation and other pressures to reduce CO_2 emissions. Table 2 below shows some of the greenhouse gas emission targets that some utilities have already adopted[5].

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[5] Jocobsen, Sanne B., Numark, Niel J., and Sarria, Paloma. "A Changing U.S. Climate." Public Utilities Fortnightly. Vol 143, No.2. February 2005. p.30.

Table 2. A Comparison of Utility GHG Emission Targets

AEP	4% below 1998-2001 by 2006
Cinergy	5% below 2000 by 2010-2012
Entergy	2000 levels by 2005
FPL Group	Reduce GHG emissions per MWh by 18% below 2001 levels between 2003-2008
PSEG	Reduce GHG emissions per MWh by 18% between 2000-2008
Xcel	Reduce CO_2 emissions per MWh by 7% between 2003-2012

Note: Other utilities developing targets under EPA's Climate Leaders program include Calpine, Exelon, Green Mountain Energy, and We Energies.

Q. Are there regional initiatives already in place to address greenhouse gas emissions?

A. Yes. There are several regional initiatives that seek to reduce the amount of CO_2 emitted by the energy industry. These are described in Exhibit TW-2.

Q. Is it likely that these local and regional initiatives will eventually become federal regulations?

A. Yes. State and regional initiatives create inter-regional leaks, market distortions, complexity for utilities operating in multiple states, and investor uncertainty. In order to simplify forecasts of future costs and reduce the uncertainty associated with this issue, the business community is expected to eventually push the federal government to enact nationwide legislation.

Q. What is the current status of carbon dioxide legislation in the U.S. Congress?

A. A number of U.S. Representatives are introducing – or re-introducing – legislation aimed at reducing the output of CO_2. These include the McCain-Liebermann Climate Stewardship Act and Carper-Chafee Clean Air Planning Acts.

As a counter example, the Bush Administration's "Clear Skies Initiative" has no mandatory CO_2 reductions. However, this initiative failed to pass last session, and appears unlikely to pass this session as well. As reported in the February 2, 2005 edition of Megawatt Daily, "getting 'Clear Skies' through the Senate is expected to be difficult, especially before [the Senate Environment and Public

Works Committee] where half the 18 members also want mandated reductions on carbon dioxide, a key ingredient to climate change”.[6]

Q. Are there markets for CO_2 allowances already in operation today?

A. Yes. One prominent example is the European Union’s (EU) carbon emission trading system, which took effect in January 2005 but has been trading since February 2003. Thus, there is now two years worth of trading data to indicate the value of CO_2 allowances. Near term trades (2005-2007 delivery) in January of 2005 centered around US$11.50/ton of CO_2.[7] This would equate to roughly $11.35/MWh for a typical coal plant.

Since CO_2 emissions lead to global climate change, the market for CO_2 emissions is expected to be global as well. Therefore, market prices of CO_2 allowances in the European Union are an indication of the types of prices that might eventually apply in the US.

Q. Are any other utilities or power companies currently accounting for the costs of future CO_2 regulations in their planning efforts?

A. Yes. Several utilities have already decided that future CO_2 regulation is likely and that expected costs from such regulation should be accounted for in their planning efforts. Table 3 shows the estimates that are currently being used by several electric companies for planning carbon regulation costs. Table 3 also indicates the years that each utility assumes that these CO_2 costs will be relevant. Note that all of the utilities listed assume that these costs will be relevant by 2010, well within the contract periods being discussed for the Java Wind Project.

6 “Senate panel to vote on ‘Clear Skies’ February 16”. Megawatt Daily. Volume 10, Issue 22. February 2, 2005. p.8.

7 Andrew, “Point Carbon to launch volume-weighted EU ETS index,” Carbon Market Europe, Point Carbon, January 28, 2005. Conversion as of 9 February 2005, wherein 1EURO=1.27 US dollars.

Table 3. CO_2 Emissions Trading Assumptions For Various Electric Companies.[8]

PG&E	$8/ton (2008)
Avista	$1-11/ton (2004-2023)
Portland's General Electric	$10/ton (2010)
Xcel	$6-12/ton (2009)
Idaho Power	$12.3/ton (2008)
PacifiCorp	$4.19-$12.85/ton (2010 – 2024)[9]

Q. Have other state commissions ruled on the inclusion of carbon emission costs?

A. Yes. The California PUC recently decided to "adopt a range of values to explicitly account for the financial risk associated with GHG emissions of $8 to $25 per ton of CO_2, to be used in the evaluation of fossil generation bids. This range is taken from information in the present record, and is consistent with actions undertaken by other electric utilities across the country."[10]

Q. Why is this issue important for MDU?

A. MDU currently produces roughly a large portion of its electricity from coal, and coal plants have especially high rates of CO_2 emissions. As such, MDU is at risk of incurring especially high costs to comply with future climate change regulations. Ignoring these future costs will clearly understate the avoided costs of the MDU system and thus undervalue the output from the Java Wind Project.

Q. How do you recommend the Commission treat this issue in this proceeding?

A. I recommend that the Commission make a finding that estimates of avoided costs should include the costs of future environmental regulations, in those instances when such regulations (a) are more likely than not to be implemented within the relevant study period, and (b) are expected to have a significant impact on

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8 Wiser, Ryan and Bolinger, Mark. "An Overview of Alternative Fossil Fuel Price and Carbon Regulation Scenarios." Lawrence Berkeley National Laboratory. October 2004.

9 "Technical Appendix for the 2004 Integrated Resource Plan." PacifiCorp. January 20, 2005. Table C.7. www.pacificorp.com/File/File47424.pdf.

10 Opinion Adopting PG&E, SCE, and SDG&E's Long Term Procurement Plans. Rulemaking 04-04-003. Decision 04-12-048, 16 December 2004, p.152.

avoided costs. Both of these conditions hold true for future regulations regarding climate change.

The costs of future environmental regulations would be included only in those years of the forecast when the regulations are expected to be in effect. Uncertainty regarding the year in which future regulations might take effect could be addressed by assigning probabilities to the questionable years and multiplying the forecasted cost by the probability of implementation in each year.

Q. Should the Commission adopt values for the costs associated with climate change regulations in this proceeding?

A. There has been very little information presented in this proceeding on this issue. Thus, the Commission does not have much evidence that can be used to adopt specific costs associated with climate change regulations at this time.

Consequently, I recommend that the Commission put the parties on notice that the costs of climate change regulations should be accounted for in avoided cost estimates that are re-negotiated or re-estimated in the future. In particular, I recommend in Section 8 of my testimony that MDU offer Superior the option of entering into PPA contracts of duration longer than ten years, and that the avoided costs would be updated after ten years to account for more recent events and information. I recommend that the Commission put both MDU and Superior on notice that such future estimates of avoided costs should include the best available estimates of the costs of climate change regulations.

6.4 RECOMMENDED APPROACH FOR ESTIMATING AVOIDED COSTS

Q. What methodology do you recommend for the purpose of estimating avoided capacity and energy costs?

A. I recommend that planning-based estimates be used to calculate both avoided energy and capacity costs, for each year of the PPA. As noted above, the wholesale markets for energy and capacity are not developed enough to provide reliable and credible estimates of avoided costs.

Q. What methodology do you recommend for the purpose of estimating avoided capacity costs?

Q. I recommend that avoided capacity costs be based on the real levelized cost of a combustion turbine unit. The CT costs should be used to represent avoided capacity costs for all years of the PPA – regardless of whether a CT unit is expected to be the marginal unit in that year. As described above in Section 6.2 of my testimony, baseload power plants are not built for the purpose of providing capacity – they are generally built for the purpose of providing low-cost energy. When a utility only needs additional generating capacity, it would typically build new peaking units such as combustion turbines. As a result, combustion turbines are a better representation of pure peaking capacity costs than baseload power plants – at any point in time. It is this pure peaking capacity that should form the basis for avoided capacity costs, as these are the capacity costs – and the only capacity costs – that would truly be avoided by QF capacity on the system.

Q. What methodology do you recommend for the purpose of estimating avoided energy costs?

A. I recommend that avoided energy costs be calculated differently for two separate periods: short-run energy costs and long-run energy costs. The expression "short-run" refers to that period during which the electric utility does not need to build or buy new generation capacity. In these years, the utility has surplus generation capacity, with reserve margins equal to or above those required to meet reliability requirements. The term "long-run" refers to that period when the utility is planning to build or buy new generation capacity in order to meet growing demand. The long-run avoided costs begin in the first year that generation capacity is needed and continue out through the remainder of the study period.

The methodology for estimating short-run avoided costs focuses on the costs of the existing electricity system, while the methodology for estimating long-run avoided costs focuses on the costs of the next new power plant to be installed on the system. For those utilities with little surplus capacity on their system, the short-run avoided cost period may be for only a year or two. For those with lots of surplus capacity, the short-run avoided cost period may last for ten years or more. With regard to Mr. Kee's testimony, the short-run period for MDU would run from now through June 14, 2011, and the long-run period would include all years after that.

Q. How would you recommend the short-run avoided energy costs be estimated?

A. With regard to this period in time, I agree with the general methodology proposed by Mr. Kee for estimating stipulated avoided energy costs. An electric system dispatch model should be used to estimate the difference in energy costs between a scenario with the QF installed versus a scenario without the QF. Furthermore, I recommend that each scenario should include the estimated costs of likely future environmental regulations. In particular, estimates of costs associated with future climate change regulations should be included in avoided cost estimates at this time.

Q. How would you recommend the long-run avoided energy costs be estimated?

A. The long-run avoided energy costs should be based on the costs of the next baseload generation unit to be added to the system. According to Mr. Kee's testimony, this is most likely to be a coal plant installed mid-year in 2011.

However, recall that I have recommended that the avoided capacity costs during this period be based on a peaking unit. Thus, the sum of the avoided capacity cost of the peaking unit plus the avoided energy cost of the baseload unit will not capture the full avoided costs of the marginal baseload unit in this period. A portion of the capacity costs of the baseload unit (i.e., the difference between the capacity costs of a baseload unit and the capacity costs of a peaking unit) have not yet been accounted for. These capacity costs should be added in to the avoided energy costs. In this way, the avoided energy costs will include all of the energy costs of the marginal generating unit, plus the capital costs that are incurred for the purpose of generating relatively low-cost energy. These incremental capacity costs of the baseload unit are often referred to as "capitalized energy" costs because they represent the additional capital cost that is necessary to generate electricity at the lower energy costs.

Q. Is this approach to estimating long-run avoided energy costs used in other jurisdictions?

A. Yes. I am aware of three states – Massachusetts, New York and Vermont – that have used capitalized energy costs to represent long-run avoided energy costs. There may be other states that have used this same approach, but I am only certain about these three states.

Q. Please summarize your recommended methodology for estimating avoided energy and capacity costs.

A. My recommended methodology would include the following five components:

- Avoided capacity costs should be calculated based on the capital costs associated with a peaking unit, for all years of the study period.
- A short-term period should be identified by estimating the point in time when a new baseload generating unit is needed on the system to meet reliability needs and provide low-cost power to the system.
- The short-term avoided energy costs should be estimated by running an electric system dispatch model to compare the energy costs of a scenario with the QF to a scenario without the QF.
- The long-term avoided energy costs should include the energy costs associated with the new baseload generation unit.
- The long-term avoided energy costs should also include the capitalized energy costs of the new baseload generation unit.

7. COSTS TO MDU ASSOCIATED WITH WIND GENERATION

Q. Mr. Kee recommends that Superior be charged $4.60/MWh to reflect the fact that output from the Java Wind Project will increase costs associated with generation balancing and regulation. Do you agree with this recommendation?

A. No. Mr. Kee has not provided sufficient evidence to support his proposed additional cost. He cites a study prepared by Enernex for Xcel Energy that estimated that the additional costs of adding wind generation to a utility system is about $4.60/MWh. He recommends this same amount be applied to the Java Wind Project.

Mr. Kee neglects to mention that the cost cited above was a result of adding much more wind capacity than the Java Wind Project would represent. The Enernex study assessed the impacts of adding 1,500 MW of wind capacity in the same year that the Xcel system was estimated to have a system peak of 9,933 MW. (Testimony of Edward D. Kee, Exhibit EDK-7, page 24) Thus, the Enernex study assessed the impacts of adding wind capacity equal to roughly 15% of the local utility system peak demand.

The Java Wind Project is expected to contribute a much smaller portion to the MDU system. At 31 MW, it will be roughly 6.5% of the MDU peak demand of 473 MW in 2007 and roughly 6% of the MDU peak demand of 500 MW after 2012. (MDU's response to Superior's first data request, Response No. 2, Attachment A) As such, the Java Wind Project would result in much smaller integration costs than those proposed by Mr. Kee.

Q. Is it possible that the Java Wind Project would increase costs to MDU for generation balancing and regulation?

A. Yes, it is possible. However, the magnitude of the costs will be very much dependent upon conditions specific to the host utility and the wind project. Some of the conditions that would affect the wind integration costs include: size of the wind project relative to the utility system, variability of wind patterns, other generation resources on the system available to assist with balancing, the size and operating capabilities of these other generation resources, transmission constraints that might limit contributions from other generation resources, transmission links to neighboring utilities that might assist with generation balancing, and the variability of electricity demand from day-to-day and hour-to-hour. The combination of these many factors will have a significant impact on the costs of integrating wind into a utility system.

Q. Are you aware of other studies that investigate the cost of integrating wind into a utility system.

A. I am aware of several recent studies that analyze the potential for additional costs on an electric system due to the intermittent nature of wind generation. Most of these studies find that wind generation will impose some additional costs as a result of the need to balance generation from day to day, hour to hour, and even minute to minute. A summary of these studies is attached to my testimony as Exhibit TW-3.

It is difficult to transfer the results of these studies directly to MDU, because of the different utilities and different conditions relevant to each one. Nonetheless, the studies suggest some general conclusions that might be applicable to other utilities. In particular, the costs associated with generation balancing and reserves tend to increase as the amount of wind generation on the total electric system increases. This is one of the reasons why it is not appropriate to take the wind integration costs estimated for one utility and apply them to a specific wind project such as the Java Project.

Q. How do you recommend this issue be addressed in this proceeding?

A. Given that this issue has not been thoroughly analyzed, particularly with regard to the implications of the Java Wind Project, I recommend that the burden of proof be on MDU to demonstrate that these costs are significant enough to require recovery from Superior. In order to meet this burden, MDU should be required to provide sufficient demonstration that such costs will actually be incurred, and estimates of such costs must be based on an assessment of the specific conditions relevant to MDU and the Java Wind Project.

8. DURATION OF THE CONTRACT FOR THE JAVA WIND PROJECT

Q. What term does MDU recommend for the Java Wind Project PPA?

A. Mr. Kee recommends that MDU enter into a ten-year PPA with the Java Wind Project. He claims that this term "reflects an appropriate balance between the desire of Superior for a long-term stipulated price sales agreement and the risks presented to Montana-Dakota and its customers from such an agreement." (Testimony of Edward D. Kee, page 47) Mr. Kee adds that long-term contracts create a risk that MDU would be required to make payments above avoided cost.

Q. Do you agree that long-term contracts create a risk to MDU of making payments above avoided costs?

A. Yes, there is such a risk. The longer the term of a contract, the greater is the risk that the avoided cost estimates made at the beginning of the contract are in error. However, this risk of incorrectly estimating the avoided costs goes in both directions. Mr. Kee neglects to mention that the long-term estimates of avoided costs could turn out to be too low, resulting in a windfall for MDU.

Q. Do you agree that a ten-year contract strikes the appropriate balance between a developer's need for financial stability and a utility's need to address concerns about risk?

A. No. I believe that MDU should offer Superior the choice of entering into a longer contract. Superior should have the option to sign a contract for as long as 15 years, 20 years, or even 25 years.

Q. Why is it so important for Superior to have the choice of a longer-term contract?

A. One of the greatest challenges facing wind developers today is in obtaining financing for their projects. Even in states where there are public policies to support renewable resources, such as renewable portfolio standards, wind developers are finding it difficult to obtain financing for their projects. This is because there is too much uncertainty in today's evolving electricity industry to ensure a stable revenue stream from the competitive marketplace over the long-term. As a result, it is very difficult, if not impossible to finance a wind project today without a long-term contract.

Q. Do you have any evidence indicating the importance of long-term contracts in developing wind projects in today's electricity industry?

A. Yes. My company recently conducted a survey to investigate the contract terms of the wind projects recently developed in the US. We researched all of the wind projects developed since 2001 that are at least 40 MW in size. We found that of the 31 such projects, 29 of them had long-term contracts, while the remaining two were constructed by regulated electric utilities who were able to recover the costs of the wind projects from ratepayers. Some of the contracts were as short as ten years, while many were 15, 20 and 25-year contracts. The implication of this finding is obvious: if a wind project does not have a sufficiently long contract for power – typically even longer than ten years – then it will not be built. This is why I believe that MDU should be required to offer Superior the opportunity for a contract with a term of longer than ten years.

Q. Would a contract of longer than ten years be inconsistent with PURPA? That is, would it be going too far to support the wind project at the risk of MDU's ratepayers?

A. No, I believe that Superior should be offered contract terms of longer than ten years in order to be consistent with PURPA. As noted above in Section 3 of my testimony, PURPA clearly was designed to put QF generation on a level playing field with electric utility generation. It is critical to keep this point in mind when addressing this issue. Electric utility power plants can be funded through ratepayers for the full construction costs and lifecycle operating costs (as long as the utility builds and operates the plant prudently). In other words, electric utility power plants are essentially guaranteed financing, and typically can be financed at relatively low cost due to the utility's regulated rates of return and low risk. Thus, electric utility power plants are not even close to being on a level playing field with QFs – they have a significant advantage. Providing the option for a long-term contract for the output of a QF will help to address this imbalance.

Q. Are there measures that MDU and Superior can take to reduce the chance of incorrectly estimating avoided costs?

A. Yes. With longer term contracts the risks to both parties of incorrectly estimating avoided costs increase. I recommend that both parties consider a provision in the PPA that after the first ten years of the contract the avoided costs will be re-estimated and the new estimates will be used for the remaining years of the contract. Historic avoided cost payments would not be reconciled, as this would undermine the concept of a fixed-price contract. The re-estimate of avoided costs would adhere to the same principles adopted in this proceeding, in order to eliminate some of the uncertainty and potential for disagreement, but would account for all the most recent cost and market information available at the time. Such a re-estimate of avoided costs could take place at years 10, 15 and 20, depending upon how risk-averse the two parties choose to be.

I believe that this approach of re-estimating avoided costs draws the appropriate balance between providing Superior with a longer-term contract and protecting both parties from the risks of incorrectly estimating avoided costs.

Q. Does this conclude your testimony at this time?

A. Yes, it does.

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Tellus Institute, Boston, MA. Senior Scientist, Manager of Electricity Program, 1992-1997. Responsible for managing six-person staff that provided research, testimony, reports and regulatory support to consumer advocates, environmental organizations, regulatory commissions, and state energy offices throughout the US.

Association for the Conservation of Energy, London, England. Research Director, 1991-1992. Researched and advocated legislative and regulatory policies for promoting integrated resource planning and energy efficiency in the competitive electric industries in the UK and Europe.

Massachusetts Department of Public Utilities, Boston, MA. Staff Economist, 1989-1990. Responsible for regulating and setting rates of Massachusetts electric utilities. Drafted integrated resource planning regulations. Evaluated utility energy efficiency programs.

Massachusetts Office of Energy Resources, Boston, MA. Policy Analyst, 1987-1989. Researched and advocated integrated resource planning regulations. Participated in demand-side management collaborative with electric utilities and other parties.

Energy Systems Research Group, Boston, MA. Research Associate, 1983-1987. Performed critical evaluations of electric utility planning and economics, including production cost modeling and assessment of power plant costs and performance.

Union of Concerned Scientists and Massachusetts Public Interest Research Group, Cambridge and Boston, MA. Energy Analyst, 1982-1983. Analyzed environmental and economic issues related to nuclear plants, renewable resources and energy efficiency.

EDUCATION

Masters, Business Administration. Boston University, Boston, MA, 1993.
Diploma, Economics. London School of Economics, London, England, 1991.
B.S., Mechanical Engineering. Tufts University, Medford, MA, 1982.
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TESTIMONY

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Québec Régie de l'énergie (Docket R-3473-01). Direct testimony of Timothy Woolf and Philp Raphals regarding Hydro-Québec's Energy Efficiency Plan: 2003-2006. On behalf of Regroupment national des Conseils régionaux de l'environnement du Québec. February 5, 2003.

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Nevada Public Utilities Commission (Docket No. 01-7016). Direct testimony regarding the Nevada Power Company's Demand-Side Management Plan. On behalf of the Bureau of Consumer Protection, Office of the Attorney General. September 26, 2001.

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GREENHOUSE-GAS EMISSIONS

A New World Order

Pressure for national legislation builds as the Northeastern U.S. goes it alone and carbon trading takes off in the European Union.

By Peter Fontaine

Domestic and international pressures are building rapidly on the United States to enact some form of legislation to curb greenhouse-gas emissions, as a spate of recent developments turns up the heat on the Bush administration. Internal pressure is building on several fronts. First, coalitions of nine Northeast states and three West Coast states are moving forward with their own regional greenhouse-gas cap-and-trade programs, raising the prospect of uneven CO_2 regulation across the nation and electricity market distortions. Second, the bi-partisan National Commission on Energy Policy published a report in December urging the Congress and the White House to implement national legislation establishing a mandatory, economy-wide, tradable-permits program to limit greenhouse gas emissions. The regional greenhouse-gas programs and the recommendations of the National Commission on Energy Policy are likely preludes to the reintroduction in early 2005 of the McCain-Lieberman Climate Stewardship Act. The bill would establish a national greenhouse gas cap-and-trade program to reduce CO_2 to year 2000 emission levels over the period 2010 to 2015.

International pressure on the United States is building as well. In November 2004, Russia defied conventional wisdom by ratifying the Kyoto Protocol, thereby clearing the way for the treaty's long-awaited enforcement. The Protocol will go into effect on Feb. 16, 2005. Also, in November, the Arctic Council published alarming new data showing that global warming is already having a profound impact on the arctic environment, decades earlier than predicted. Then, in December, at the 10th annual meeting of Conference of Parties (COP) of the United Nations Framework on Climate Change, the United States was roundly criticized for blocking efforts to schedule a new round of talks aimed at achieving additional greenhouse gas reductions beyond 2012, and for supporting a Saudi Arabian proposal to compensate oil export nations for the reduction in oil revenue induced by the global effort to reduce CO_2 emissions. Finally, just last month, the EU commenced its Emissions Trading Scheme (ETS), resulting in mandatory CO_2 emissions caps and the trading of CO_2 allowances among 12,000 EU industrial installations.

With Russia's ratification of the Kyoto Protocol and the onset of the EU Emissions Trading Scheme (ETS), overseas trading of emissions allowances has taken off. Analysts predict the market will soon exceed $100 billion, with CO_2 allowances currently trading at around €8.45 ($11.52). However, because the United States has not ratified the Kyoto Protocol, U.S. companies will be left out on emissions trading with the EU unless linkage of emissions programs can occur outside the Kyoto Protocol (or the Bush administration decides to ratify Kyoto). Accordingly, the world's greatest capitalist country could be left out of the world's newest capital market.

Northeastern Regional Greenhouse-Gas Initiative

Perhaps the most far-reaching climate-change development in the United States to date is the Regional Greenhouse-Gas Initiative (RGGI), a mandatory CO_2 cap-and-trade program being developed by the Northeastern states of Connecticut, Delaware, Maine, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, and Vermont. Two additional states, Pennsylvania and Maryland, as well as the District of Columbia, the Eastern Canadian Provinces and New Brunswick, are official "observers" of RGGI, meaning they may elect to join at a later date. Collective CO_2 emissions from the RGGI states are substantial in the global context, according to 2001 data from the Oak Ridge National Laboratory. The states have combined emissions of 527 million metric tons of CO_2 ($MMTCO_2$)—9.3 percent of total U.S. CO_2 emissions and nearly the emissions level of the United Kingdom. Collectively, the states are the fifth highest CO_2 emitter in the world.

The RGGI program currently covers CO_2 emissions from some 758 fossil fuel-fired electricity generating units (EGUs) having a nameplate capacity of 25 MW or more within the nine member states. Under the model rule being developed, CO_2 emissions from EGUs will be capped at specified levels that have not yet been determined. The model rule—due in April 2005—will outline the conceptual framework for the cap-and-trade program. After the program is up and running in 2006, participants may choose to expand the program to other carbon-intensive sectors to achieve further reductions.

Not surprisingly, recent modeling of the impact of RGGI on electricity prices conducted by Connecticut predicts that average wholesale electricity prices will increase significantly over the forecast period. Similar electricity price increases in the EU are forecast as a result of the EU ETS.[1]

EU Emissions Trading Takes Off

On Jan. 1, 2005, the EU commenced CO_2 emissions trading under the ETS. The program applies to some 12,000 installations, namely producers of energy, steel, cement, glass, ceramic, brick, pulp, and paper. The first phase of the EU ETS runs from Jan. 1, 2005, to Dec. 31, 2007. The second phase runs from 2008 to 2012. Under the ETS, each covered facility is required to hold a sufficient number of "allowances" (one allowance equals one metric ton of CO_2) representing its authorized level of CO_2 emissions, or its "cap." Each EU member is allocated allowances to its covered facilities pursuant to each country's National Action Plan. Before April 30 of each year, subject facilities are required to surrender a sufficient number of allowances covering their actual emissions for the year. To meet their emission caps, facilities can either reduce their CO_2 emissions down to their specified level, or purchase allowances from the emissions allowance market.

The EU allowance market will be supplied by excess allowances generated by facilities that have reduced their emissions below their caps. While allowances will be generated primarily by facilities within the EU, allowances may also be supplied by other non-EU CO_2 trading systems, pursuant to the EU's so-called Linking Directive. The Linking Directive allows EU ETS installations to purchase allowances from outside the EU to satisfy their emissions caps.[2] The Directive states that CO_2 emissions reduction undertaken outside the EU pursuant to the Kyoto Protocol's Joint Implementation (JI) and Clean Development Mechanism (CDM) programs may qualify for allowances that can be bought and sold within the ETS. Thus, an installation within the EU that needs to reduce its CO_2 emissions can obtain the needed allowances through the lowest-cost option available. In lieu of undertaking expensive pollution reductions, this might involve funding an emissions project outside the EU in a nation that has adopted Kyoto, either in a non-EU industrialized country like Russia (through the JI mechanism) or in a non-EU developing country like a Caribbean nation (through the CDM mechanism). In this way, the most economically efficient option for emission reductions can be pursued. However, because the United States has elected not to ratify Kyoto, American companies with installations in the EU are subject to CO_2 emissions caps but cannot take advantage of low-cost emission reductions at their facilities in the United States or elsewhere. This disavantages American companies in the EU.

Trans-Atlantic Emissions Trading: The Future of RGGI

Because the impact of CO_2 emissions and similar pollutants, like ozone-depleting substances, are global in scope, the location of emission reductions is immaterial. The nature of CO_2 is such that cap-and-trade programs can be linked together to expand the number of opportunities for efficient emissions reductions and thereby reduce cost. In recognition of this, the EU's recently adopted Linking Directive expressly directs that the EU Environmental Commission to explore opportunities for mutual recognition of CO_2 allowances generated by other mandatory greenhouse-gas emissions trading schemes. Talks on linkage began in May 2004, when the Northeast states met with a British delegation. More recently, at the December 2004 COP 10 meeting in Buenos Aires, RGGI and EU representatives discussed their desire to link CO_2 allowance trading programs. The EU also is exploring the possibility of linkage with the CO_2 allowance program of the Australian state of New South Wales.

It is possible that states located outside the Northeast region will join the RGGI effort. The most likely candidate states are the West Coast states of California, Oregon, and Washington. In November 2004, they announced their own regional global warming initiative that will likely include a regional CO_2 cap-and-trade program similar to RGGI. In fact, representatives from the West Coast initiative are participating in the RGGI meetings. Collectively, the West Coast states' CO_2 emissions of 491 $MMTCO_2$ are roughly comparable to the RGGI states. Combining both the Northeast and the West Coast into a single cap-and-trade program would represent 1,018 $MMTCO_2$ emissions, according to the same 2001 Oak Ridge National Laboratory data, or nearly the emissions level of Japan. Linking emissions trading systems on the West and East Coasts is therefore logical. Most of the RGGI states, and California and Oregon have adopted mandatory CO_2 reduction legislation. Nearly all of the RGGI states also have adopted California's tough new tailpipe standards for cars and light-duty trucks. RGGI offers the prospect for other states and nations to join in a larger cap-and-trade program that would force the United States to adopt federal legislation to avoid severe electricity market distortions and the disruption of interstate commerce.

All told, the past three months have witnessed a succession of political, scientific, and economic developments in the climate-change arena that have substantially increased pressure on the United States to enact federal legislation to deal with global warming. Recent events signal the emergence of a carbon-constrained global economy. If the United States is to be a player and not a spectator in this new economic paradigm, it will have to adopt some form of national legislation to cap emissions.

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Endnotes:

1. Some observers predict that these competitive impacts will prompt the EU to seriously consider imposing a carbon tax on imported goods manufactured in the United States without carbon controls. See "Global Warming: The Gathering Storm," *Public Utilities Fortnightly*, August 2004.
2. See EC Directive 2004/101/EC of the European Parliament and of the Council, Oct. 27, 2004, *http://europa.eu.int/smartapi/cgi/sga_doc?smartapi!celexapi!prod!CELEXnumdoc&lg=EN&numdoc=32004L0101&model=guichett#top.*

GREENHOUSE-GAS EMISSIONS

A Changing U.S. Climate

The states are getting into the act on greenhouse emissions, and the power industry is getting more proactive. What policy measures are appropriate?

By Sanne B. Jacobsen, Neil J. Numark and Paloma Sarria

A growing number of U.S. utility companies have come out in favor of federal mandatory limits on emissions of carbon dioxide (CO_2) from their facilities. Edison International's Chairman John Bryson recently called for a comprehensive national program to address global warming; eight companies constituting the "Clean Energy Group" support national "four-pollutant" legislation that would among other things seek to stabilize carbon emissions at 2001 levels by 2013; and Cinergy has voiced its support for mandatory limits on carbon emissions. Cinergy, which relies heavily on coal, is among the companies named in the landmark public nuisance lawsuit filed last July by a coalition of eight state attorneys general, led by New York's Eliot Spitzer. Furthermore, shareholder pressure has forced Cinergy and other companies to examine their risks related to climate-change regulation. Finally, companies doing business in states with mandatory carbon caps under development, such as those in Regional Greenhouse-Gas Initiative (RGGI) states, would rather have federal regulation extend those limits to the entire industry, thereby leveling the playing field on a national scale.

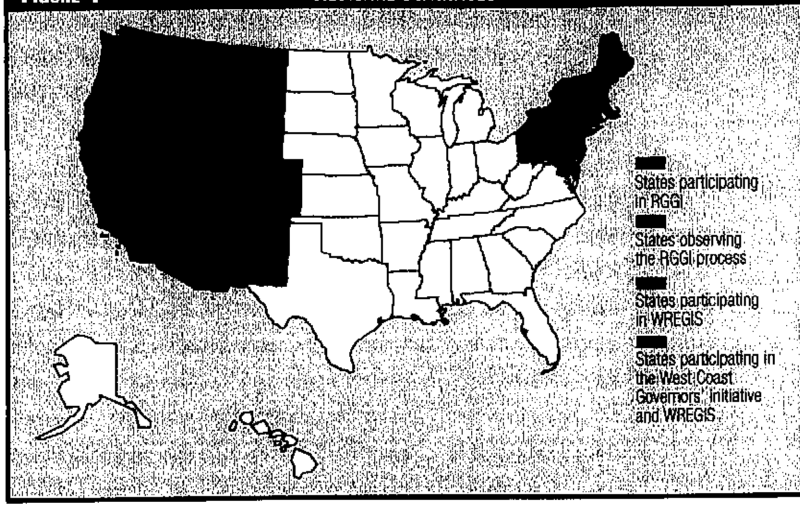
Proponents of mandatory carbon limits—though increasing in number—still constitute a minority within the utility industry. Most utilities prefer voluntary greenhouse-gas (GHG) emissions reductions ,or take the view that CO_2 should not be considered a pollutant at all. Yet if the current momentum continues, the utilities calling for mandatory GHG regulation will continue to grow. Shareholder resolutions, litigation, public scrutiny and state actions to regulate GHGs all contribute to this drive. This article provides an overview of the state regulation trend; actions taken by the utility sector to address GHG emissions; and industry views on proposed mandatory GHG caps to be implemented at the federal level.

Overview of State Climate Change Actions

Twenty-eight states have set forth plans to combat climate change by reducing their net emissions of GHGs, implementing policies that vary in scope and stringency. One example: seven states (New York, New Jersey, Rhode Island, Connecticut, Massachusetts, Maine, and Vermont) have adopted or have stated intentions to adopt California's requirement that automakers cut global-warming emissions from new vehicles by more than 29 percent in the next decade. Together these eight states comprise 26 percent of the American auto market, a portion large enough to cause automakers to re-evaluate the efficiency of their fleets on a national scale.[1]

Electric power generation accounts for approximately one-third of GHG emissions nationally, according to the Department of Energy's Energy Information Administration. Accordingly, in addition to targeting vehicle emissions, much

FIGURE 1 **REGIONAL INITIATIVES**



Source: Josh Bushinsky, Pew Center on Global Climate Change

of the recent effort by states has focused on the utility sector. More than a dozen state legislatures have passed renewable energy mandates, which require a specific percentage of electricity produced to come from renewable sources.

In November 2004, Colorado citizens became the first in the country to pass such a mandate by state initiative, requiring major utilities to produce 10 percent of electricity output from renewables by 2015. Twenty-three states collect revenue from utilities to create "public benefit funds" that are used to promote energy efficiency, research and development of new technologies, and renewable energy. In 40 states, citizens can sell electricity generated privately (via solar panels, for instance) back to their utility thanks to "net metering" programs.[2]

Perhaps more significantly, regional efforts that transcend state and even international borders also are taking place. At a recent Capitol Hill roundtable organized by the Sustainable Energy Institute (SEI), Josh Bushinsky of the Pew Center on Global Climate Change identified regional initiatives now under development (*see Figure 1*).[3] In an effort initiated by New York Gov. George Pataki in 2003, nine Northeastern and Mid-Atlantic states (with two more observing), as well as five Eastern Canadian provinces, are working to develop a regional CO_2 cap-and-trade program by April 2005 as a part of their broader cooperation on climate change. This Regional Greenhouse Gas Initiative (RGGI) aims to reduce GHG emissions to 1990 levels by 2010, and 10 percent below those levels by 2020. As Franz Litz of the New York State Department of Environmental Conservation stated at the SEI roundtable, these nine states are equivalent to the world's third-largest economy and account for more than 3 percent of world GHG emissions.

Regional efforts are ongoing in the West as well. In 2003, the governors of California, Oregon, and Washington announced plans to coordinate actions such as development of renewable energy technologies and accounting methods for GHG emissions. In June 2004, the Western Governors' Association unanimously accepted a proposal by Gov. Arnold Schwarzenegger of California and Gov. Bill Richardson of New Mexico, calling for the 18 states represented by the group to generate 30,000 MW of electricity from renewable sources by 2015 and to improve energy efficiency by 20 percent by 2020. Although specific policies have yet to be implemented, a working group has been formed to evaluate these proposals and provide recommendations in the next two years. In addition, the Western governors are developing a renewable energy tracking system that will facilitate the trading of renewable energy credits. The Canadian provinces of British Columbia and Alberta are collaborating in the development of this system.

International outreach by states is not limited to collaboration with Canada. Dialogue is ongoing between designers of emissions trading systems for RGGI and the European Union. Anticipating future emissions trading between the two regions, policy-makers are motivated to consider compatibility issues as they design their cap-and-trade programs.[4]

States also have joined forces in litigation against the utility industry. California, Connecticut, Iowa, New Jersey, New York, Rhode Island, Vermont, and Wisconsin filed suit in July 2004 against the country's largest emitters of CO_2, a group of

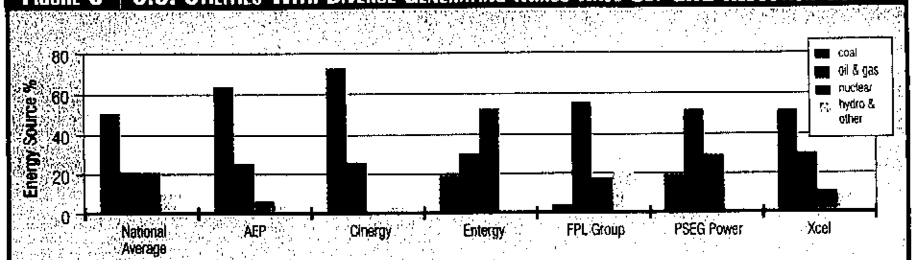
FIGURE 2 **A COMPARISON OF GHG EMISSIONS TARGETS**

Kyoto Protocol – Intended US target	7% below 1990 levels by 2008-2012
McCain-Lieberman Climate Stewardship Act S.139	2000 levels by 2010
Carper-Chafee Clean Air Planning Act S. 843	2005 levels by 2009 2001 levels by 2013 (CO_2 emissions only)
Bush Administration Target (*voluntary*)	Reduce GHG intensity (emissions/GDP) by 18% between 2002 and 2012
Regional Greenhouse Gas Initiative (RGGI)	1990 levels by 2010 10% below 1990 by 2020
AEP	4% below 1998-2001 by 2006
Cinergy	5% below 2000 by 2010-2012
Entergy	2000 levels by 2005
FPL Group	Reduce GHG emissions per MWh by 18% below 2001 levels between 2003-2008
PSEG	Reduce GHG emissions per MWh by 18% between 2000-2008
Xcel	Reduce CO_2 emissions per MWh by 7% between 2003-2012

Note: Other utilities developing targets under EPA's Climate Leaders program include Calpine, Exelon, Green Mountain Energy, and We Energies.

five utility companies responsible for 10 percent of the nation's annual CO_2 emissions.[5] The suit, based on the common law principle of public nuisance, is the first filed directly against utility companies for CO_2 emissions and will seek emission reductions rather than financial penalties.

FIGURE 3 | U.S. UTILITIES WITH DIVERSE GENERATING MIXES HAVE SET GHG REDUCTION GOALS*



* Data sources: National Average, Energy Information Administration, 2002 Electricity Quick Stats; AEP, http://www.aep.com/about/powerplants/default.htm; Cinergy, 2003 Annual Report; Entergy 2003 Annual Report; FPL Group, 2003 Annual Report; PSEG Power, spokesman Neil Brown, January 5, 2005; Xcel, http://www.xcelenergy.com/XLWEB/CDA/0,3080,1-1-1_4795-127-5_406_664-0,00.html

Note: Figures for AEP, PSEG, and Xcel represent generation capacity (MW); all other data represent actual electricity production (MWh).

Bushinsky described the impact of these state actions at the SEI event, noting that the policies have spurred research and investment in new energy technologies and served as testing grounds for future policy. However, Bushinsky noted that the emergence of diverse state regulations may prove burdensome to utility companies operating in numerous states. He also added that the absence of federal regulation combined with the long capital-planning cycles faced by utilities create uncertainty for those making investment decisions. Bushinsky concluded that federal GHG regulations would benefit not only the environment but the utility industry as well.

The current patchwork of state regulation could create "leakage," the tendency of companies to move power generation to states with more lenient emissions requirements. State policy-makers also are challenged by the regional nature of energy markets as they set out to design effective policy. California, for example, imports over 22 percent of its power. Reducing California's contribution to climate change will require policies that reach beyond state lines. Regional efforts, such as RGGI, demonstrate attempts to address these issues.

Industry Responses

Though state GHG regulations are still emerging, some of America's largest utilities already are making voluntary efforts to cut emissions (*see Figure 2*). What's more, these companies come from a variety of quarters in terms of their fuel generating mix (*see Figure 3*). Speaking at the SEI roundtable, industry representatives identified state regulation and pending litigation as just two of the many motivations utilities have to reduce GHG emissions. Brent Dorsey, director of Corporate Environmental Programs at Entergy, said Entergy hopes state efforts like RGGI will serve as templates for a more universal approach. He added that Entergy believes an effective GHG federal policy would establish a reasonable cap on GHG emissions, equitably distribute emission allowances, create tradable credits that allow market forces to determine the most efficient fuel mix, and provide offset mechanisms that will allow for industry growth in a sustainable manner. Michael Bradley of the Clean Energy Group (CEG), a coalition of eight electric generating and distribution companies, said momentum is building for federal regulation of GHG emissions. Bradley stressed that state and regional efforts should be stepping stones towards federal action. He noted CEG's support for the Clean Air Planning Act (CAPA), a comprehensive four-pollutant plan sponsored by Sens. Tom Carper, D-Del., Lincoln Chafee, R-R.I., and Judd Gregg, R-N.H., which among other things would seek to stabilize carbon emissions at 2001 levels by 2013.

Desire to decrease the cost of future regulation has been an important incentive for companies to act voluntarily. By reducing emissions early and more gradually, these companies will be able to adjust to future regulations at lower cost. Insurers and investors, who are increasingly focusing attention on the risk that future regulation poses to utility companies, view early action favorably.

In addition, setting emissions targets encourages companies to "get in on the ground level," gaining knowledge of energy markets and technologies that are likely to become more prominent in the future. Even if a utility itself is not regulated, it may soon be able to sell its emissions reductions to companies regulated elsewhere through emissions trading markets. For instance, AEP, a large Midwestern coal user, is a founding member of the Chicago Climate Exchange, a pilot project that coordinates multi-sector trading of GHG emissions. In addition, utilities that actively engage in state efforts to address climate change, such as RGGI, play an influential role in policies that may someday serve as blueprints for federal regulation.

Many of these benefits, however, depend heavily on the likelihood of mandatory carbon limits and the timing of that legislation. In response to shareholder pressure, TXU, the country's fifth largest emitter of CO_2, recently released a report detailing its decision not to undertake voluntary GHG emissions reduction measures. While it acknowledged many of the benefits described above, the company found that costs of voluntary measures were not warranted due to the high degree of uncertainty surrounding GHG legislation.

A company statement on the decision reads: "Whether an investment now would be justified depends importantly on timing—the time it would take to implement control options as well as the likely timing of any mandatory program."

Factors affecting power-sector attitudes towards climate change measures include:

- State policies designed to cut GHG emissions
- Litigation by states seeking GHG emissions reductions
- Shareholder resolutions to disclose risk posed by climate change and by potential non-compliance with future requirements
- Pressure from insurance companies to reduce risk
- Prospects for lower bond ratings as financial analysts evaluate environmental risk exposure
- Desire to "level the playing field" by companies operating in GHG-regulated states

TXU found that until carbon constraints were on the more immediate horizon and the specifics of those constraints could be more accurately predicted, investment in emissions reductions is too risky. TXU also fears that early reductions will result in lower emissions allocations under a future cap-and-trade program—*i.e.*, no credit for early action. In addition, the company warned that the cost of voluntary reductions would not be recoverable in the market, and would instead be borne by shareholders in the form of reduced company profits.[6] Regulatory uncertainty also has been cited by Duke Energy to explain its choice not to undertake voluntary emissions reductions.[7]

The limitations of the current regulatory environment were highlighted by Ethan Podell, former senior vice president at the Chicago Climate Exchange, in recent testimony before the Senate Committee on Commerce, Science, and Transportation.[8] At present, only Massachusetts has instituted a mandatory CO_2 cap-and-trade program, while outside that state steps to reduce emissions are being taken on a voluntary basis. Only those companies with prospects to sell allowances are acting, Podell stated, while potential buyers "are not yet prepared to join a voluntary cap-and-trade program." Thus, while voluntary measures by the utility industry demonstrate the ability to reduce emissions, and state regulations address climate change in a piecemeal manner, it appears that significant reductions in U.S. GHG emissions will require federal legislation that mandates participation.

The Debate Reaches Capitol Hill

As noted above, though still in the minority, a growing number of U.S. utilities now favor mandatory federal carbon caps. Shareholder resolutions, litigation, public scrutiny, and a patchwork of state actions to regulate GHGs all contribute to this drive. State policies in particular have the potential to affect utility views on federal action by:

- Creating a clearer picture of the form of future federal regulation, thus reducing investment uncertainty;
- Increasing demand for emissions reduction credits, thereby making emissions markets more efficient and less risky. The potential for financial gains in these markets increases incentive for utilities to voluntarily reduce emissions, regardless of their regulatory status;
- Shortening the time period in which utilities expect federal action, thereby making investments in cleaner technologies more valuable in the short term; and
- Encouraging companies operating in carbon-constrained—and mostly deregulated—states to push for federal regulation, while rate regulators in states without carbon constraints (which are largely regulated states) may be increasingly willing to accept the costs of carbon constraints, which can be passed on to ratepayers.

State measures to address climate have not, of course, gone unnoticed by policy-makers on Capitol Hill. As Alexandra Teitz, minority counsel at the House Committee on Government Reform, noted at SEI's roundtable, there is a history of state policies acting as catalysts for federal legislation, serving as policy testing grounds for legislators. But perhaps more important, Teitz added, state action creates a more favorable political climate for action at the federal level.

In the case of climate-change policy, it is too soon to tell if the state actions will prompt federal measures. The Bush administration recently announced its intention to push its "Clear Skies" proposal—addressing the power sector's emissions of SOx, NOx and mercury—through Congress early this year. The proposal does not include limits on GHG emissions.[9] The chairman of the Senate Environment and Public Works Committee, Sen. James Inhofe, R-Okla., has committed to working with the president to pass Clear Skies and has been one of the harshest critics of climate-change legislation.[10] Speaking at the SEI roundtable, John Shanahan, majority council on the Environment and Public Works Committee and representative for Sen. Inhofe, warned that "those who say the science is behind this are misleading us."

At the same time, two bipartisan bills—the Carper-Chafee-Gregg bill and another bill sponsored by Sens. Jim Jeffords, I-Vt., and Susan Collins, R-Me.—would impose limits on the power sector's emissions of carbon in addition to the other three pollutants. Meanwhile, Sens. John McCain, R-Ariz., and Joseph Lieberman, D-Conn., have vowed to reintroduce their bill, the Climate Stewardship Act (S.139), in the new term (following its 43-55 defeat last year).[11] That bill targets all industries—not just the power sector—and would establish a cap-and-trade system for the nation's largest emitters. Finally, Sen. Chuck Hagel, R-Neb., intends to introduce an additional proposal in early 2005, and he conferred on the subject with British Prime Minister Tony Blair last December.[12]

At this time there is only speculation as to the second-term agenda of the Bush administration with respect to climate change issues. Most bets are that the administration intends to continue emphasizing the development of technologies and voluntary actions to cut emissions, and to reject the regulation of carbon and any international commitments to cut emissions.

But it is worth noting that Jeffrey Holmstead, EPA assistant administrator for air and radiation, told a coal industry conference last year that "there in some point in the future will be a carbon-constrained world," and that uncertainty regarding government policy on GHGs has "got to be frustrating for business people who are trying to anticipate" the future regulatory landscape. Depending on the degree of interest from industry, which appears to be increasing for the reasons cited earlier, pressure on the administration to take action on carbon could build. As the *Wall Street Journal* editorialized critically on Dec. 13, 2004, just as the COP-10 meeting in Buenos Aires got under way, there is a "budding corporate enthusiasm for mandatory reductions in greenhouse gases" and that "big business becomes a lobby for CO_2 regulation."[13]

But for the moment the action is in the states, and the prospects for federal movement may depend on the actions of influential state governors like Arnold Schwarzenegger of California and George Pataki of New York.

[Editor's Note: Recently, the Sustainable Energy Institute convened a panel of federal and state officials, as well as utility sector and non-profit representatives, to share their views on the emergence of state-level regulations limiting GHG emissions and the implications for the utility sector. This article was based in part on the views expressed at the event. See *http://www.s-e-i.org/september2004.html.*]

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Endnotes:

1. Danny Hakim, "Several States May Follow California's Lead on Cars," *International Herald Tribune*, Saturday-Sunday June 12-13, 2004, p. 15.
2. The description of state policies is based largely upon a recent report by the Pew Center on *Global Climate Change: Climate Change Activities in the U.S.: 2004 Update*, pp. 9-17.
3. From Josh Bushinsky, Pew Center on Global Climate Change, "Implications of State Climate Change Policies for the Utility Sector," presentation to Sept. 24, 2004 SEI Roundtable.
4. Under the Kyoto Protocol, EU countries will not be able to earn credit for emissions reductions in the U.S. However, regulated American companies may be allowed to buy emissions credits from the EU.
5. Utilities named in the suit are AEP, Southern Co., Tennessee Valley Authority, Xcel, and Cinergy.
6. For TXU's complete white paper, see *http://www.txucorp.com/envcom/reports/Env_Study100104.pdf.*
7. See Global Climate Change: Position on State, National, and International Policy. *http://www.duke-energy.com/company/ehs/policies/gcc/.*
8. Testimony delivered Oct. 1, 2003. Subject of hearing: McCain-Lieberman Climate Stewardship Act.
9. Juliet Eilperin, "White House to Push 'Clear Skies' Legislation; EPA Rule Put on Hold as Bush Seeks Bill," *The Washington Post*, Dec. 14, 2004, p A3.
10. Andrew Freedman, "Climate Change: Sen. Inhofe Denounces Climate 'Alarmism' as Clear Skies Debate Looms," *Energy and Environment Daily*, Vol. 10, No. 9, Jan. 6.
11. Andrew Freedman, "Climate Change: Stevens, McCain Sound Alarm Over Arctic Warming," *Energy & Environment Daily*, Vol.10, No.9., Nov. 15, 2004.
12. Robert G. Kaiser, "The Political Veteran; He Survived Vietnam and Won the Senate. Could Chuck Hagel Take the White House?," *The Washington Post*, Nov. 15, 2004, p. C1.
13. "Kyoto 'Capitalists'," *The Wall Street Journal*, Dec. 13, 2004, p. A16.

Review of Several Recent Studies of the Costs of Integrating Wind Into an Electric System

Synapse Energy Economics

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The addition of any new generating resource requires transmission system modifications to carry the new energy. In that regards, wind is like any other new power plant. However wind resources introduce new operating challenges because of its inherent variability. Other resources may be needed to balance that additional variability.

The problem of managing an electrical power system is to keep the generation and loads in balance in real-time. Loads, although they have a regular daily pattern, are not fully predictable and have minute-to-minute and hour-to-hour variations. In addition, loads during peak periods such as hot summer days can be very unpredictable. Uncertainties also exist in conventional generation where individual units can have sudden full or partial outages. Other uncertainties exist in transmission where a line could fail for a variety of reasons. Thus the variability of wind generation just adds another uncertainty to already existing ones. That uncertainty has a cost, but it fits within the standard framework of electric system operation.

A several recent studies have looked at the additional system costs incurred because of the natural variability in wind generation. There are basically three time scales of interest with different types of solutions and costs:

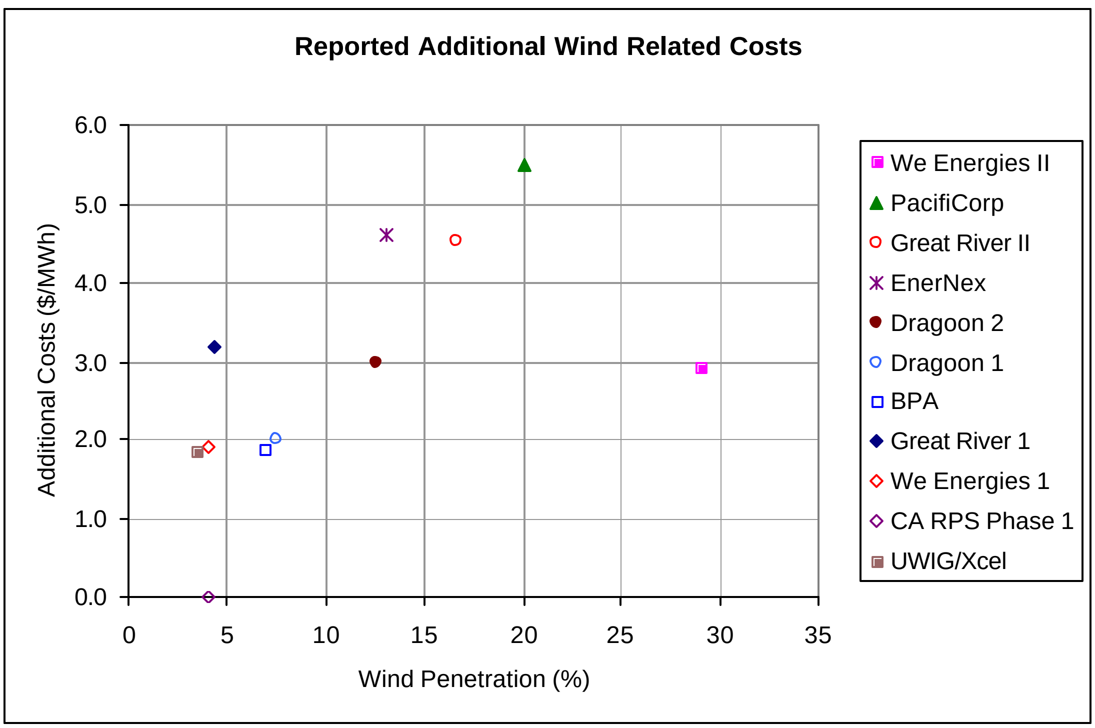
- Unit-Commitment: horizon of 1 day to 1 week. Units made ready to provide generation as needed. Usually this is done with a reserve margin of about 15% above the predicted load.
- Load-Following: horizons of 5-10 minutes to 1 hour. On-line ready response units to adjust generation to match changes in load or wind generation.
- Regulation: horizon is minute to minute in increments of 1-5 seconds. This is provided by units with Automatic Generation Control (AGC) that can respond rapidly to follow very short term imbalances between load and generation.

Table 1 and Figure 1 below summarize the results from several recent studies. The additional system costs associated with levels of wind contribution from 3.5% to 29% range from 1.47 to 5.50 $/MWh. The largest cost component appears to be associated with unit commitment of additional reserve resources. More accurate wind forecasts will reduce these costs. Note also that these additional costs can vary considerably by system and circumstances.

Table 1: Summary of Wind Power Impact Studies[1]

		Additional Wind Associated Costs ($/MWh)			
Study	Relative Wind Penetration[2] (%)	Regulation	Load Following	Unit Commitment	Total
BPA	7	0.19	0.28	1.00-1.80	1.47-2.27
CA RPS Phase 1	4	0.17	na	na	na
Dragoon 1	7.5				2.0
Dragoon 2	12.5				3.0
EnerNex	13	0.23	0	4.37	4.60
Great River 1	4.3				3.19
Great River II	16.6				4.53
Hirst	0.06-0.12	0.05 - 0.30	0.70 - 2.80	na	na
PacifiCorp	20	0	2.50	3.00	5.50
UWIG/Xcel	3.5	0	0.41	1.44	1.85
We Energies 1	4	1.12	0.09	0.69	1.90
We Energies II	29	1.02	0.15	1.75	2.92

Figure 1: Comparison of Additional Wind Related Costs from Various Studies



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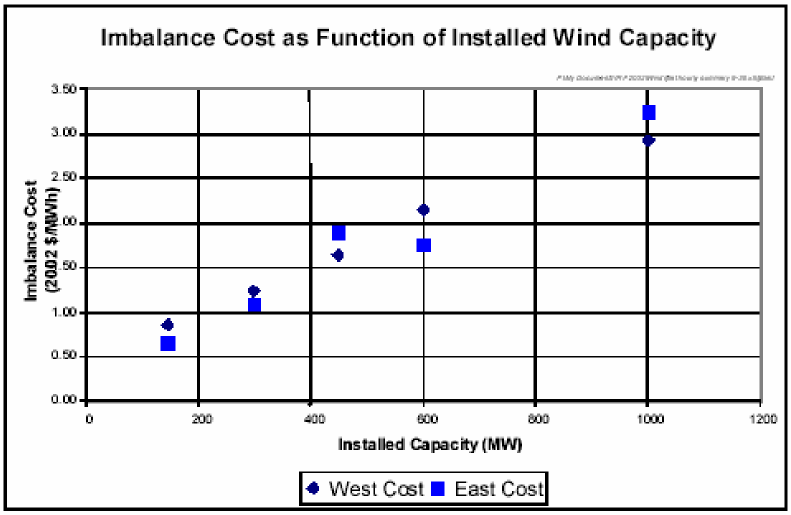
1 Original from Smith 2004. Additions made by Synapse.

2 Wind penetration is typically represented as maximum wind capacity as a percentage of the peak system load. It is not uncommon for wind generation to exceed that fraction during times when loads are less than peak.

Figure 2 below shows the cost increases calculated in one study of the U.S. West (Dragoon 2003) as additional wind capacity is added to an 8,000 MW system consisting of 77% coal, 14% hydro and 8% natural gas. As expected the additional system costs increased with greater wind capacity. The highest installed wind capacity of 1000 MW represents a 11% penetration. Actual costs depend on the specific system configuration and are also likely to decline as experience is gained.

Figure 2: Imbalance Cost as a Function of Installed Wind Capacity



This table is copied directly from Dragoon 2003.

The most recent wind integration study was performed by GE Energy for NYSERDA and just released as a draft report in February 2005. This study looked at the effects of integrating 3,300 MW of wind into a system with a peak load of 34,704 MW (~10% wind fraction). One zone had a wind fraction of 36%. They concluded that this amount of wind capacity could be managed without any significant changes in the current system. One thing they do mention is that wind generation may need to be curtailed during some periods of low system loads and high wind capacity to prevent the uneconomic shutdown of critical base load generation.

Electric systems with substantial amounts of energy-limited hydro resources are a very good match for wind generation since hydro plants incur low costs by being on-line and can respond very rapidly to changes in loads. The wind generation also serves to conserve limited hydro energy. One can almost view hydro as a very efficient energy storage system when paired with wind.

In addition, stability issues can be addressed by utilizing the wind generators less than their full potential in those times when grid stability is a concern. For example, if loads are low and balancing resources are not available or are too expensive, then the amount of wind power can be limited by turning off (or down) the wind generators until conditions improve. This may reduce to some small extent the total annual energy delivered from the wind resources, but system stability is maintained.

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