APPLICANTS' EXHIBIT 42

SOUTH DAKOTA PUBLIC UTILITIES COMMISSION

CASE NO. EL05-022

IN THE MATTER OF THE APPLICATION BY OTTER TAIL POWER COMPANY

ON BEHALF OF THE BIG STONE II CO-OWNERS

FOR AN ENERGY CONVERSION FACILITY SITING PERMIT FOR THE

CONSTRUCTION OF THE BIG STONE II PROJECT

PREFILED REBUTTAL TESTIMONY

OF

BRYAN MORLOCK

MANAGER OF RESOURCE PLANNING

OTTER TAIL POWER COMPANY

JUNE 16, 2006

BIG STONE II

PARTNERS IN GENERATION

TESTIMONY OF

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BEFORE THE SOUTH DAKOTAPUBLIC UTILITIES COMMISSION

DIRECT REBUTTALTESTIMONY OF

BRYAN MORLOCK

I. INTRODUCTION

Q: Please state your name and business address.

A: Bryan Morlock, 215 South Cascade Street, Fergus Falls, Minnesota 56548-0496

Q: Did you previously submit testimony in this proceeding?

A: Yes. I submitted direct testimony, Applicants' Exhibit 10. My qualifications were provided previously as Applicants' Exhibit 10-A. I submitted rebuttal testimony on June 9 as Applicants' Exhibit 32. I also submitted direct testimony in the related transmission certificate of need proceeding in Minnesota.

II. PURPOSE AND SUMMARY OF TESTIMONY

Q: What is the purpose of your testimony?

A: I will respond on behalf of all the Applicants to the May 26, 2006 testimony of Minnesota Center for Environmental Advocacy (MCEA) witnesses Schlissel and Sommer with regard to the need for baseload capacity, capacity surpluses in MAPP, and various resource planning issues. I will respond to the same witnesses with regard to resource planning issues specifically affecting Otter Tail Power. Other Applicants' resource planning witnesses will do the same for issues specifically affecting their respective systems.

Q: Please summarize your testimony.

A: The Applicants have a clear need for the additional baseload capacity and energy that Big Stone Unit II is designed to provide. Each Applicant has performed detailed resource planning studies that show this. The impending need for additional baseload in this region has been building and well known as common knowledge for years. Examination of projected capacity surpluses alone, without consideration of costs or transmission issues, is insufficient to determine the appropriate timing of low energy cost, baseload facilities. The capacity surpluses in MAPP are either oil and natural gas-fired, with either high fuel costs or tied to similarly-high market prices, or are otherwise unavailable to the Applicants due to transmission and other constraints.

The Applicants have extensive plans for demand-side management (DSM) and renewables, in concert with Big Stone Unit II and other developments. They have performed detailed, system-level studies of these resources, and as a result have proposed a combination of DSM *and* renewables *and* Big Stone Unit II that is least-cost for their customers. Such system-level studies more appropriately capture the true costs and benefits of wind and other resources, compared to the simplified busbar analysis Schlissel and Sommer have offered.

Finally, the Applicants have used the environmental externality cost values as required by the Minnesota legislature and the Minnesota Public Utilities Commission, which are the "best" estimates of externalities for these Applicants. The use of other large and unsupported environmental externality factors in the selection of energy resource alternatives would bias the selection of those alternatives beyond the requirements of Minnesota law and, for some of the Applicants, is in violation of North Dakota Law. And, as I will discuss later in this rebuttal testimony, the use of such high externalities (indirect costs) would result in significant additional *direct* costs to consumers on their electric bills, because such assumptions would favor the use of alternatives to Big Stone Unit II that have higher direct costs.

III. NEED FOR AND TIMING OF BASELOAD CAPACITY

Q: At pages 3 to 4 of their May 26 testimony, MCEA witnesses Schlissel and Sommer state that the Applicants do not need additional baseload capacity in 2011. Do you agree?

A: No. As the Applicants described in the Application, and in our direct testimony, the regional need for reliable, low cost baseload energy is a primary driver of the need for Big Stone Unit II.

Q: How do the Applicants know they need baseload capacity, rather than other sources?

A: Each of the Applicants has performed detailed system studies to examine their future energy resource needs. These studies, which I will describe later in my rebuttal testimony with specific regard to Otter Tail, and other Applicants' witnesses will describe in their respective rebuttal testimonies, clearly show the need for Big Stone Unit II's baseload capacity starting in 2011, along with other resources including demand-side management (DSM) and renewables.

Q: Is the Applicants' need for additional baseload capacity a relatively new development?

A: No. Four of the seven Applicants (Otter Tail, GRE, SMMPA and MRES) are required by Minnesota law to file detailed Integrated Resource Plans (IRP) biannually to the MPUC. These plans, which are rigorously reviewed during their typically two-year cycles for approval by the MPUC, have in most cases and for some time shown the impending need for additional baseload capacity in the region in the time frame proposed for Big Stone Unit II.

The South Dakota Commission, too, has been aware of these growing regional needs. The last significant baseload facility installed in this region will have been in-service for nearly a quarter-century by the time Big Stone Unit II will go in-service. As Peter Koegel points out in his rebuttal testimony, essentially all of the new generating capacity installed since then is fired by increasingly-costly natural gas. So, the baseload need the Applicants are working to meet with Big Stone Unit II should be no surprise to anyone in this region.

Q: Throughout their testimony, MCEA witnesses Schlissel and Sommer state that alternatives should be examined in the context of their performance as part of the integrated system. Do you agree?

A: Yes.

Q: Did Schlissel and Sommer attempt to undertake such a system-level analysis of any of the Applicants in this proceeding?

A: No.

Q: Did the Applicants perform a system-level analysis?

A: Yes. All seven of the Applicants performed system-level analyses of their own systems, as I describe later in my testimony.

IV. CAPACITY SURPLUSES AND PURCHASES

Q: At pages 5 to 6 of their testimony, MCEA witnesses Schlissel and Sommer point to capacity surpluses in MAPP, saying these show the Applicants do not need their proposed shares in Big Stone Unit II. Are capacity surpluses alone a reasonable measure of the need for a baseload facility?

A: No. Schlissel and Sommer are incorrectly using the MAPP 15% Reserve Capacity Obligation as a measure for the appropriate timing of generation additions. As Peter Koegel of MAPP discusses in his rebuttal testimony, there are many reasons why utilities would install capacity such that their installed generation reserves exceed the MAPP Reserve Capacity Obligation in any particular year.

Q: What are those reasons as they apply to the Applicants?

A: First, the MAPP 15% Reserve Capacity Obligation is a *minimum* installed capacity requirement, established for purposes of reliability. This is a "floor" level of generation capacity the MAPP Members are required to maintain. Instead of a floor, Schlissel and Sommer are inappropriately trying to use it as a ceiling.

Second, compliance with the Reserve Capacity Obligation is measured after-the-fact in terms of *actual* peak demands; not forecasted ones. To the extent extreme weather causes customer demand peaks that are above forecasted levels, a utility that plans to exactly meet the 15% requirement based on their forecasted demand alone, as Schlissel and Sommer' testimony is apparently suggesting, can easily fall short of meeting the requirement. The MAPP reserve levels Schlissel and Sommer are using are based on forecasted demand; not actual demand. So, they do not include weather uncertainty.

Consequently, each MAPP Member must plan in advance to meet the reserve requirement, no matter what the weather subsequently does to the Member's load. To ensure compliance, MAPP will allocate additional capacity and associated costs after-the-fact, under a FERC-approved tariff, to those members who fail to meet their Reserve Capacity Obligation. Accordingly, the prudent utility planner allows for weather variability and its potential effects on actual peak demands when adding resources, commensurate with the cost and risk of being deficient.

The MAPP capacity surplus/deficit data reflects the floor level of the reserve capacity obligation. The fact that some surpluses may exist does not indicate that other MAPP members are willing to sell their surpluses to the Applicants or, if they are willing to sell, that the surpluses are an economic alternative.

Third, and particularly important for a baseload facility like the one being considered in this proceeding, relative energy costs need to be considered in the timing of capacity additions. Utilities that are currently selling surplus capacity are generally only willing to do so with the energy price subject to market conditions, or tied to an index such as natural gas futures. This does not represent the low-cost energy supply that Big Stone Unit II is intended to fulfill. Some of the Applicants are already purchasing significant amounts of capacity and energy from the market. They need Big Stone Unit II to replace those costly sources.

With the currently high and volatile cost of natural gas, the ongoing decline in generation reserve margins and the associated decline in the availability of reasonably-priced energy available for sale on the market, the installation of additional capacity that can produce low-cost energy must be done in a timely manner. Many of the Applicants are finding that the benefit of having Big Stone Unit II's low-cost energy available in 2011 pays for itself by offsetting high-cost production from oil and gas units and similarly high-priced market purchases they would otherwise have to employ. Schlissel and Sommer ignore this critically-important consideration.

Finally, as a practical matter, a utility typically does not have generation additions scheduled for every year. The Commission is already aware that there are very few baseload plants currently being pursued in this area. Consequently, the Big Stone Unit II project is a relatively rare opportunity for the Applicants. Most of the Applicants are too small in size to be able to construct a baseload generating unit large enough to take advantage of economies of scale. The Applicants have decided to work together to develop such an opportunity as a group. Since such opportunities are extremely limited, such a unit addition typically needs to meet several years of growth following its installation.

If we would accept the Schlissel and Sommer suggestion regarding capacity reserves and surpluses, they would have the Applicants wait to install Big Stone II until they were absolutely sure that *actual* weather conditions would result in exactly 600 MW of capacity deficit in a particular year, and try to find a way to coordinate all seven Applicants' needs such that together they totaled 600 MW in that exact year, and ignore the energy cost value of installing low energy cost baseload capacity to offset energy production from more-expensive existing units, and then immediately experience capacity deficits again in the following year. This process would then have to be repeated, year-after-year. At some point, this becomes imprudent planning. If we use the Schlissel and Sommer view, we are at that point.

Q: Are Schlissel and Sommer correctly reporting the capacity surpluses in MAPP in their testimony?

A: As Mr. Koegel of MAPPCOR describes in his rebuttal testimony, the MCEA witnesses are referring to the correct numbers. However, the numbers alone are not instructive about whether the surpluses are useful as alternatives for Big Stone Unit II as the MCEA witnesses suggest.

Q: Why don't the MAPP surplus numbers to which the MCEA witnesses are referring represent a possible alternative to Big Stone Unit II?

A: Beyond quoting mere numbers as the MCEA witnesses are doing, it is important to consider what those surpluses consist of, and whether they are actually available for use by the Applicants.

For example, at page 4, lines 1 to 11 of their May 26 testimony, Schlissel and Sommer point to MAPP-US winter season capacity surpluses ranging from 4,000 MW in the 2011-2012 winter season, dropping to 3,300 MW in the 2012-2013 winter season. They suggest these winter season surpluses are a readily-available pool of capacity the Applicants should use, rather than installing Big Stone Unit II. These surplus numbers are correct, but the numbers alone are very misleading.

Q: Why are MCEA witnesses' numbers misleading?

A: As Mr. Koegel describes in his rebuttal testimony, MAPP-US has about 7,900 MW of installed capacity fired by oil and natural gas, in both summer and winter seasons. So, by far the entire winter season surpluses the MCEA witnesses are referring to, and then some, are fired by costly oil and natural gas.

To depend on these surpluses to offset Big Stone Unit II as the MCEA witnesses are proposing would not only involve more oil and gas consumption in the winter seasons (an undesirable outcome that Big Stone Unit II will avoid), it would place summer season reliability at risk. MAPP in total is summer-peaking and many generators have lower summer capacity ratings than winter ratings; so available surpluses are lower then. In fact, as Mr. Koegel illustrates in his rebuttal testimony, there are no summer season surpluses available at all in MAPP-US by 2011. Instead, capacity deficits are forecasted if Big Stone Unit II is not installed.

Q: What is the capacity surplus situation in MAPP-Canada?

A: As Mr. Koegel discusses in his rebuttal testimony, a portion of the installed capacity in MAPP-Canada, similar to MAPP-US, is also oil and gas-fired. Accordingly, a portion of the MAPP-Canada surpluses MCEA witnesses are purporting to be an alternative for Big Stone Unit II is oil- and natural gas-fired.

In addition to the fuel source makeup of the surpluses in MAPP-Canada, and again looking beyond the mere numbers to which the MCEA witnesses are pointing, it is important to consider whether those surpluses are actually available for sale by Canadian utilities, and if they are deliverable via the transmission system.

As Mr. Koegel discusses in his rebuttal testimony, Manitoba Hydro Electric Board (MHEB) represents 1,350 MW of the 1,383 MW of apparent MAPP-Canada surplus in 2011. So, they represent the lion's share of the apparent surplus. However, like MAPP-US, the capacity numbers alone as Schlissel and Sommer are using are inadequate to provide a complete picture.

MHEB is predominantly a hydro system, with much of their energy production coming from run-of-river facilities or facilities with limited storage capability. As such, their planning function is geared toward energy analysis. This results in a system characteristic of appearing to have surplus capacity, but without the associated energy to go with that capacity. This is similar to the situation of a wind machine, whose energy output is subject to the availability of its fuel source (i.e., the wind). The installed capacity exists, but cannot produce useful energy unless the fuel source (water or wind) flows or blows. Once again, the capacity number alone does not guarantee a resource really represents a partial or total alternative for a baseload energy source.

Recent history provides a clear example of that situation. In the past few years, Manitoba Hydro has had surplus capacity, but has had to purchase spot-market energy because they did not have the water available to generate all of the energy they require. Manitoba Hydro is currently not in an energy-purchasing mode. But focusing only on their capacity as a component of apparent MAPP-Canada capacity surpluses, as Schlissel and Sommer are doing, provides a very misleading and incorrect conclusion.

Q: Have the Applicants talked with MHEB regarding their interest in selling these apparent surpluses in the time frame of Big Stone Unit II?

A: Yes, of course. MHEB provided Otter Tail with three proposals that were included as alternatives in the resource-planning model. The proposals were only sufficient to meet Otter Tail's needs and not the entire 600 MW to be provided by the BSPII project. The planning model did not select any of these MHEB proposals due to cost.

The specific details of the MHEB proposals are covered by a confidentiality agreement and cannot be publicly revealed. However, historic MHEB contracts have included provisions that energy purchased from MHEB may have to be returned to them on demand in the event that they have water shortages. That clause demonstrates that while MHEB may be capacity surplus, they can simultaneously be energy deficient. The Applicants need reliable baseload generation that can produce energy year-around.

Q: Have Schlissel and Sommer talked to MHEB on this topic?

A: There is no evidence in their testimony that they have done that.

Q: Does transmission capacity also affect the availability of MAPP-Canada surpluses for sale to the U.S.?

Yes. The existing transmission between Canada and the U.S. is essentially "full" with the current transactions in the summer seasons, so any additional transactions would require major transmission construction of perhaps 500 miles in length or more. Such developments would require a Certificate of Need and a Route Permit for any portions in Minnesota, similar to the proceeding for this project now underway there. Attached as Applicants' Exhibit 42-A is a document from the Midwest Independent Transmission System Operator (MISO) that demonstrates available transfer capability on existing transmission "flowgates" in the MISO footprint. A flowgate is used by MISO to monitor transmission flows on key lines or sets of lines to ensure that transmission limits are not exceeded.

As can be seen on Exhibit 42-A – which is actually two documents, the first of which is taken from the Manitoba Hydro Electric Board OASIS, and the second from MISO that shows available transfer capacity on various MISO flowgates (see lines 433, 435, and 437), the "Manitoba" interface is fully subscribed in the summer of 2011 (1,839 MW subscribed, of a possible 1,849.7 MW).

The Applicants need a reliable, year-around, baseload resource that provides low-cost energy. This would require year-around firm transmission service. The Manitoba transmission interface is booked-up in the summer season, and has no additional capacity to offer. That by itself eliminates the possibility of a year-round energy source.

However, even if we assume transmission capacity would be available in the winter season, it is our experience that MHEB currently is not interested in selling a fully-dispatchable, baseload product. They'd rather sell a non-dispatchable, take-or-pay intermediate product, with the price mechanism designed to track wholesale market prices. For the Applicants, this would be the worst of all worlds as an alternative to Big Stone Unit II. The product isn't dispatchable, it has relatively high energy costs, and the Applicants could end up having to take it when they least need or want it.

Q: Schlissel and Sommer state at page 5, lines 4 and 5 of their testimony that the total MAPP system does not need any new capacity until the summer of 2013. Do you agree?

A: No. As I discussed earlier, capacity surpluses alone do not determine the appropriate timing for installation of a baseload addition. To do so is overly simplistic and, frankly, wrong.

Q: At page 7, lines 21 to 25, Schlissel and Sommer state that the addition of a new baseload generation facility can be the lowest-cost option even if the capacity is not needed immediately to ensure that an owner has adequate capacity. Do you agree?

A: Yes. That is my point.

V. DEMAND-SIDE MANAGEMENT (DSM)

Q: MCEA witnesses Schlissel and Sommer advocate the use of demand-side management (DSM) in their testimony. Do the Applicants use DSM in their resource plans?

A: Yes. The Applicants have enacted significant DSM measures. And, their plans include accomplishment of a lot more DSM in future years, in addition to Big Stone Unit II.

Q: What have the Applicants accomplished in DSM to-date?

A: They have done a lot. Taken together, as of 2005 they have reduced peak demand by approximately 560 MW, or the equivalent of a large-size generating plant not even considering reserve requirements, and reduced energy consumption by about 370 GWh per year.

Q: Do the Applicants' plan to do more DSM, in addition to Big Stone Unit II?

A: Yes. Together, over the next few years, the Applicants plan to reduce peak demand by an additional 240 MW, and reduce energy consumption by an additional 780 GWh per year, compared to 2005 levels.

Q: Are any of the Applicants subject to the Minnesota Conservation Improvement Program (CIP) legislation?

A: Yes. Otter Tail is subject to CIP for our operations in Minnesota. The members of GRE, SMMPA, MRES and CMMPA are also subject to CIP.

Q: What does CIP require these Applicants to accomplish?

A: They must invest at least 1.5% of their gross annual revenues in customer energy conservation programs.

Q: Are these programs and their progress reviewed by the state of Minnesota?

A: Yes, they are reviewed in detail by the Minnesota Department of Commerce.

Q: Are these Applicants meeting their CIP requirements?

A: Yes, they are all meeting or exceeding their respective CIP requirements.

Q: How does Otter Tail consider the effects of DSM as part of its resource planning?

A: As I described in my direct testimony, Otter Tail uses the IRP-Manager optimization model to develop its IRPs. A variety of resource alternative inputs to the model are used, including DSM. The model performs a side-by-side consideration of demand-side and supply-side resources to identify the most economic plan. This determines the most cost-effective levels of each of the alternatives, including DSM, and is the basis for the amount of DSM we are proposing to accomplish.

Q: Please explain Otter Tail's ongoing DSM efforts.

A: I detailed those efforts on pages 10 to 11 of my direct testimony.

Q: What do you conclude from the collective DSM efforts of the Applicants?

A: The Applicants are already including a substantial amount of DSM in their plans. These are efforts that MCEA witnesses Schlissel and Sommer have neglected to mention or acknowledge in their testimony. In summary, Otter Tail and the other Applicants need both DSM programs *and* the Big Stone Unit II facility.

VI. RENEWABLES

Q: At pages 8 to 14 of their testimony, MCEA witnesses Schlissel and Sommer devote a lot of testimony to the Burns & McDonnell study (Exhibit 23-A), stating that study should have allocated capacity value to wind energy. Do you agree?

A: No. As described in Jeffrey Greig's rebuttal testimony, assuming no capacity value for wind in the Burns & McDonnell study (Applicants' Exhibit 23-A) was an appropriate thing to do, within the context in which that study was performed.

Q: From a system resource planning perspective, why was this assumption appropriate in Exhibit 23-A?

Exhibit 23-A is an analysis of busbar costs of various Big Stone Unit II alternatives based on comparison of *plant-to-plant* characteristics. In this analysis, the reliability benefits of being connected to the transmission network are not considered, in order to examine the reliability and cost impacts of the various individual baseload plant options by themselves, and to compare them to each other. So, to achieve a comparable reliability level for the wind energy option compared to others, and considering there would be periods of time each year when the output of the wind energy system would be zero, it was completely appropriate in this analysis to use 600

MW of CCGT capacity in combination with the wind resource. Again, this was done to achieve a comparable *plant* reliability and level of baseload dependable dispatchability compared to the other individual plant options in the Exhibit 23-A study.

As I discussed in my June 9 rebuttal testimony, the Applicants agree that wind would be eligible for some form of capacity value. To do this, and in contrast to the purpose of the Exhibit 23-A, Burns & McDonnell study, a utility system-level analysis is required instead. Such an analysis would take into account the interaction of the utility's generating resources. This analysis is far more comprehensive and complicated than the Exhibit 23-A study, and is the approach that each of the Applicants use as part of their resource planning process to actually determine the appropriate mix of all resources to be planned for and proposed.

The ability to allocate any form of equivalent capacity value to wind energy resources is dependent upon the existence of a robust, non-constrained, diverse transmission and generation network that allows regional firm generating capacity resources like the proposed Big Stone Unit II plant to back up the non-dispatchable, intermittent wind energy resource when the wind is not blowing. So, it is adequate and timely amounts of reliable generating capacity like Big Stone Unit II, together with the transmission system and transmission improvements like those included in the proposed Big Stone Unit II project, that enable any recognition of equivalent capacity value for wind at all.

It is these same transmission capabilities, in concert with appropriate regional reliability studies, that allow the regional capacity installed reserve margins, established in the interest of regional reliability, to be as low as they are. As Mr. Koegel describes in his direct and rebuttal testimonies, this keeps costs low while providing acceptable generation system reliability. In a constrained or non-existent transmission environment, where it is not universally possible to move large amounts of energy from wherever it is generated to wherever it is needed at any time, the local reserve margins would need to be much greater. That is essentially the context used in the Exhibit 23-A study. However, it does not represent a regional reliability or system-level study.

Q: At page 10, lines 15 to 17 of their testimony, Schlissel and Sommer state that the existing system should be used to back up wind generation instead of installing Big Stone Unit II. Do you agree?

A: No. I agree that whatever generation exists in the then-existing system would have to back up wind generation, but only to the extent it is available and possible. However, as other Applicant witnesses point out, there will be insufficient capacity available in the system in 2011 without Big Stone Unit II. So, it is very unclear exactly what existing system capacity the MCEA witnesses are expecting the Applicants and the South Dakota Commission to depend upon without the addition of Big Stone Unit II.

Plus, there are operating considerations. In addition to the MAPP Reserve Capacity Obligation, MAPP members must also maintain a spinning generation operating reserve, available to respond to system emergencies immediately. Further resources must be available to be on-line and generating within 10 minutes. Thus, for operating reasons there are resources that a utility must maintain within these reserve requirements that cannot be used for any other purpose.

Q: Does MAPP recognize that wind energy has a capacity value?

A: Yes. As Peter Koegel discusses in his rebuttal testimony, MAPP assigns a monthly equivalent capacity value to the nameplate capacity of installed wind energy systems, based on the actual performance of the wind machine in its wind regime and correlated to the utility's monthly peak demand.

Q: Do the Applicants themselves assume that wind has capacity value in their system-level studies?

A: Yes.

Q: How do the wind capacity values used by the Applicants compare to those used by Schlissel and Sommer?

A: As Mr. Koegel describes in his rebuttal testimony, actual results of MAPP accreditation show ranges of wind capacity values between 5% and 20% (accredited capacity divided by nameplate capacity, expressed as a percentage) for the MAPP summer season (including the months of May though October). These values should be no surprise, after viewing the monthly and hourly wind distribution patterns I discuss later in my rebuttal.

Within this range, the Applicants are seeing summer season capacity values generally ranging from 10% to 15%, with only two as high as 18% to 22%. And, this latter 22% value is based specifically on the claims of a wind developer for a particular wind development that have not yet been subjected to actual performance measurements in the field and associated accreditation.

So, it appears Schlissel and Sommer's lower-range assumption of 15% is more reasonable, rather than their higher value of 25%.

Q: At page 15, line 13 of their testimony, Schlissel and Sommer characterize their 15% to 25% range of wind capacity values as "extremely conservative." Do you agree?

A: No. A summer season range of 10% to 15% is more reasonable, and reflects the actual experience with accreditation in MAPP, which is summer peaking.

Q: At page 13, lines 4 to 7 of their testimony, Schlissel and Sommer refer to a wind modeling study that concluded wind resources may have capacity values between 27 percent and 34 percent. Should the Applicants be using that for determining capacity values?

A: No. The modeling study quoted by Schlissel and Sommer discussed, among other things, various theoretical ways of calculating capacity values for wind. One of those methods resulted in the range of capacity values Schlissel and Sommer quoted. The same study, on the next page after the one Schlissel and Sommer are quoting, recognizes that the MAPP method that Mr. Koegel describes in his rebuttal testimony also exists, and yields different (and lower) capacity value results.

Schlissel and Sommer have chosen to quote from this study a theoretical method whose calculation may yield a high capacity value that they would prefer to see. However, because MAPP in its responsibility for system reliability continues to be the official arbiter of capacity values for the Applicants, we as MAPP Members continue to comply with the MAPP method.

Q: What do you conclude from Schlissel and Sommer's discussion of the Burns & McDonnell study in their testimony?

A: The MCEA witnesses are taking the Burns & McDonnell study out of context to try to show the Applicants did not assign wind a capacity value, and therefore their economics of a supercritical coal plant are biased. In fact, the Applicants do assign capacity values to wind in their system studies, and those values fall within the range of values the MCEA witnesses are promoting. Simply, Schlissel and Sommer have created a tempest in a teapot on this issue by devoting six pages of their testimony to argumentatively agreeing with the Applicants that wind has some capacity value, though, as Mr. Koegel testifies, the value is likely less than what Schlissel and Sommer ascribe to wind.

The bottom line is that the Applicants' detailed, system level studies, the kind the MCEA witnesses say need to be done but have not done themselves, already include capacity values for wind in the range the MCEA witnesses are proposing. Even including such capacity values in the analysis, the Applicants find that wind energy is not an alternative to their respective proposed shares of Big Stone Unit II. We propose to do wind *and* Big Stone Unit II; not wind *instead of* Big Stone Unit II, as the MCEA witnesses are trying to propose.

Q: Were the MCEA witnesses aware they were taking the Burns & McDonnell study out of context?

A: Yes. We told them in our response to MCEA Data Request Set No. 6, Question 69, which I have attached as Applicants' Exhibit 42-B. We do not know why they chose not to recognize it.

Q: Do the Applicants' plans include the use of renewables, in addition to Big Stone Unit II?

A: Yes. Taken together, the Applicants have already installed or are making purchases from renewable resources, and plan to do a lot more, in addition to Big Stone Unit II.

Q: What have the Applicants done so far in renewables?

A: Taken together, as of 2005 the Applicants are already producing or purchasing more than 740 GWh per year from a variety of renewable resources.

Q: What do the Applicants plan to do in renewables in future years?

A: Taken together, the Applicants plan to install or purchase an additional 2,170 GWh per year of renewable energy over the next few years. Putting the total 2,910 GWh per year of existing and planned renewables efforts of the Applicants in perspective, although it will come from a variety of renewable sources, it is equivalent to more than 950 MW of wind machines operating at a 35% annual capacity factor.

Q: Are any of the Applicants subject to the Minnesota Renewable Energy Objective (REO)?

A: Yes. Otter Tail, GRE, SMMPA, MRES and CMMPA are subject to the REO for their operations in Minnesota.

Q: What does the REO require these Applicants to accomplish?

A: They must demonstrate good faith efforts to supply at least 10% of their 2015 retail sales in Minnesota using qualifying renewable energy resources. In the case of Otter Tail, we also work to examine the feasibility of achieving the REO across our entire service area in Minnesota, South Dakota and North Dakota as well.

Q: Is the Applicants' progress toward the REO reviewed by the state of Minnesota?

A: Yes, it is reviewed in detail by the Minnesota Department of Commerce through annual data filings in concert with resource plan filings before the MPUC.

Q: Are these Applicants meeting the REO goals?

A: Yes, with the exception of some recent limitations with respect to the availability of wind turbine equipment and land easements, they are all meeting their respective REO goals.

Q: Describe Otter Tail's efforts in complying with the REO.

A: Over the past few years, Otter Tail's resource mix has varied from 9% to 11% renewable resources on an energy basis. Not all of these resources qualify to count toward the REO. Otter Tail believes that it currently has sufficient qualifying resources to comply with the Minnesota REO across its entire system (including North and South Dakota) through Mid-2008.

On March 31, 2006, the Company issued a Request-for-Proposals (RFP) for 75 MW of additional qualifying renewable resources. Depending upon the resource selections that are made in that process, Otter Tail expects that it will then not only achieve the REO goal for Minnesota, but across its entire multi-state system through the end of 2011. Otter Tail's resource plan calls for adding the equivalent of 110.5 MW of new wind generation by 2015 toward REO compliance, and we intend to meet that.

Q: What are the other, non-Minnesota Applicants doing in renewables?

A: Hoa Nguyen of Montana-Dakota and John Knofczynski of Heartland discuss these actions in their rebuttal testimonies.

Q: What do you conclude from the Applicant's renewables efforts?

A: The Applicants are already including a substantial amount of renewables in their plans. Similar to DSM, these are efforts that MCEA witnesses Schlissel and Sommer have neglected to mention or acknowledge in their testimony. In summary, Otter Tail and the other Applicants need renewables *and* Big Stone Unit II.

VII. RESOURCE PLANNING

Q: Schlissel and Sommer state the Applicants have no evidence to suggest you need baseload capacity. Do you agree?

A: No. As I described in my direct testimony, Otter Tail Power uses resource planning techniques including sophisticated, fully-integrated resource planning computer models to determine the correct, cost-effective combinations of DSM, renewables and other resources to be used to meet our customers' needs. The results of these analyses have determined that a baseload resource like Big Stone Unit II is needed by 2011, in addition to cost-effective levels of DSM, renewables, and other resources.

Q: At page 20, lines 18 to 24 of their testimony, Schlissel and Sommer state that the Applicants have not examined additional wind or DSM resources as an alternative to Big Stone Unit II. Do you agree?

A: No. As I described in my previous response, in our capacity planning efforts Otter Tail and the other Applicants have considered various levels of wind and DSM as resource options. Our modeling determined that additional wind and DSM efforts beyond those least-cost levels we currently plan would not be a cost-effective replacement for the Applicants' respective shares of Big Stone Unit II. The various Applicants' rebuttal witnesses describe these results for their systems in more detail.

Q: Do the system studies the Applicants performed identify Big Stone Unit II as the only resource they should be pursuing for the future?

A: No. They show that the Applicants should pursue DSM *and* renewables *and* Big Stone Unit II, together with other resources, as a balanced and diverse resource plan. The results of these analyses by the Applicants show that optimal levels of conservation and renewables are not a replacement for the Applicants' respective proposed shares in Big Stone Unit II. The South Dakota Commission can take comfort in the fact that we are pursuing all of these resources, not in an either/or approach like the intervenors are proposing; but in a symphony of resources designed to go together with and compliment each other.

Q: What did your analysis find with specific regard to the need for baseload?

A: While peak demand determines the amount of generating capacity that is required to meet load and reserve requirements, the consideration of energy needs by the resource planning model determines the appropriate mix, type and timing of generating technologies. For Otter Tail, the IRP-Manager model I described in my direct testimony selected 120 MW of Big Stone Unit II as part of a least-cost plan to meet both the capacity and energy requirements of Otter Tail's customers. This is the conclusion of our IRP presently before the MPUC [Otter Tail Power Company Application for Resource Plan Approval 2006-2020, submitted June 1, 2005, MPUC Docket No. E017/RP-05-968].

Q: Schlissel and Sommer challenge whether the individual Applicants have shown the need for their respective shares in Big Stone Unit II. Is the 600 MW that Big Stone Unit II is intended to provide enough generation capacity to meet the Applicants' future anticipated needs in the coming years?

A: No. The Applicants have determined that there is actually more need among the participants than a 600 MW Big Stone Unit II plant with a 2011 in-service date could provide. In essence, the participants could use more baseload capacity and output that their respective shares of Big Stone Unit II allow. The forecasting efforts undertaken by the Applicants show that more than 600 MW of baseload energy will be required in the years past 2011.

Q: Is Otter Tail Power Company going to need more new generation than its share of Big Stone Unit II will provide?

A: With regard to Otter Tail, our company recently secured 23 MW of new, industrial customer load to our system, which will have a high load factor requiring a reliable baseload source of generation. This new load was not included in our planning for Big Stone Unit II and underscores the growing need for electricity in our service area.

In addition, our capacity expansion planning modeling that determined optimized levels of DSM, renewables and other resources including Big Stone Unit II, indicated in various scenarios that more than our proposed 116 MW share of Big Stone Unit II would be beneficial to our customers.

Q: Are there other examples?

A: Yes. As described in their Integrated Resource Plan (MPUC Docket No. ET2/RP-05-1100) and as summarized in the testimony of Great River Energy (GRE) witnesses, GRE has a significant need for additional intermediate and baseload resources in the 2010 to 2012 time frame that exceeds their proposed 116 MW share the proposed Big Stone Unit II. Great River Energy's Stan Selander addresses this in more detail in his Rebuttal Testimony, Applicants' Exhibit 43.

Also, similar to Otter Tail, Missouri River Services (MRES) in their capacity expansion modeling performed as part of its resource planning process (MPUC Docket No. ET-10/RP-05-1102) found in many modeling scenarios that a larger portion of Big Stone Unit II than their currently-proposed 110 MW share (150 MW when factoring in the 40 MW participation agreement it has with Hutchinson Municipal Utilities) would also be beneficial to their members. Gerald Tielke of MRES further discusses this need in his Rebuttal Testimony, Applicants' Exhibit 44.

Q: Would you please summarize the Applicants' respective needs for baseload generating capacity, in total, compared to their proposed MW shares in the unit?

A: Yes. Applicants' Exhibit 42-C attached to this rebuttal testimony provides such a summary.

Q: Why didn't the Applicants design Big Stone Unit II for more than 600 MW?

A: A 600 MW plant was determined to be the best technical and economical size for the facility. Supercritical pulverized coal plants are generally in the size of 500-600 MW.

Q: In the event an Applicant is unable to demonstrate a need for its share of the proposed Big Stone Unit II project, would one or more of the other Applicants be interested in increasing their shares?

A: Yes. If it should be concluded contrary to what the Applicants assert that one of the Applicants does somehow not satisfactorily demonstrate its respective "need" for its share of the proposed unit, the remaining Applicants would be interested in reallocating their ownership shares to pick up additional capacity. In fact, our contractual arrangements contemplate and provide for this contingency.

Q: Exhibit 42-C shows that Otter Tail is one of the Applicants that could use more baseload capacity than their proposed share of Big Stone Unit II. Would you please provide more details?

A: Yes. As I noted earlier, our modeling shows a 120 MW share of Big Stone Unit II would be optimum for Otter Tail. This is only slightly larger than our proposed 116 MW share of the unit. So, our modeling confirms our proposed share is a good fit for our capacity and energy needs in 2011.

The rest of Otter Tail's forecasted capacity and energy needs is satisfied through conservation measures, assumed capacity ratings and output of additional wind generating facilities, and other developments contained in the resource plan. Again, none of the resource plan filing analyses or our Application in this proceeding included the new, 23 MW of firm load we were recently notified as coming on-line consisting of two ethanol plants, a pipeline project, and an agricultural process load. It is quite possible that, if we included this new load in our modeling, the model would select more than 120 MW of Big Stone Unit II.

VIII. USE OF ENVIRONNMENTAL EXTERNALITIES

Q: MCEA witnesses Schlissel and Sommer use environmental externalities to say that Big Stone Unit II is not the least-cost option. Do you agree?

A: No. Otter Tail is required to use the environmental externality values established by the Minnesota Public Utility Commission. Further, Otter Tail is prohibited by North Dakota law from using environmental externalities, or any other values to represent potential legislation that has not yet been enacted, in the selection of resources.

Otter Tail examined several scenarios without environmental externalities and with environmental externalities as required by Minnesota law. In all of those scenarios, the model selected the Big Stone Unit II project for implementation. As discussed in Thomas Hewson's rebuttal testimony, the ranges of externality values that MCEA witnesses are proposing are higher than the values established by the MPUC, and otherwise appear unreasonable. This unreasonably and inappropriately biases their results against Big Stone Unit II.

Q: What are the implications of using these externality values?

A: If you assume externality values that are outside the bounds of accepted values, you will tip the scales of any analysis comparing resource alternatives. The challenge in this proceeding is to select the appropriate values, in compliance with the requirements of state law.

IX. COMBINATION WIND/NATURAL GAS ALTERNATIVE

Q: At page 19, lines 1 to 19 of their testimony, Schlissel and Sommer claim that the Applicants have not considered combinations of wind and other resources as an alternative to Big Stone Unit II. Do you agree?

A: No. The Applicants have considered such combinations in their respective system-level analyses that I described earlier. These analyses resulted in the Applicants' proposed plans for a mixture of wind, DSM, Big Stone Unit II and other resources.

Q: At pages 14 to 18 of their testimony, MCEA witnesses Schlissel and Sommer propose a combination of wind and natural gas as an alternative to Big Stone Unit II. Is this a good idea?

A: No. The combination scenario, whose apparent cost-effectiveness is entirely driven by Schlissel's and Sommer's choice of externalities penalty factors, is not good idea for a number of reasons.

First, similar to the conditions I described in my June 9 rebuttal in response to the testimony of MCEA witness Goldberg, the amount of wind capacity that Schlissel and Sommer are proposing as an alternative to Big Stone Unit II is very large (800 to 1200 MW). This would be *in addition to* the more than 800 MW of wind (nameplate) installed capacity the Applicants already plan to enact by the 2015 to 2020 time frame. So, adding the Schlissel and Sommer proposed amount of additional wind capacity to existing plans would mean the Applicants would be doing more than 1,600 MW to 2,000 MW of wind over the next few years.

For comparison, it has taken Xcel Energy 15 years to achieve 600 MW of installed wind capacity on the Buffalo ridge in Southwestern Minnesota. This highlights how difficult it would be to add an *additional* 800 MW to 1,200 MW *beyond* the Applicants current plans in time to offset Big Stone Unit II, as Schlissel and Sommer suggest, in the five years remaining until 2011.

Q: How do these large amounts of wind capacity compare with operating limits of the system?

A: The additional 800 to 1,200 MW of wind capacity that Schlissel and Sommer seem to be suggesting, in addition to the Applicants' own plans, violate system-operating standards.

The Applicants will have a total peak demand of about 6,640 MW in 2015, the year in which the Minnesota Applicants must meet their REO goal. Using their own plans, the Applicants' will have wind capacity representing 13% of their total peak demand in that year. That fits within the current operating standard of between 15% to 20%.

However, Schlissel and Sommer have apparently overlooked the Applicants' own wind capacity plans. Adding their 800 MW of additional wind capacity to the Applicants' plans results in 1650 MW of wind, for a 25% ratio of wind capacity to peak demand in 2015; thereby violating the standard. Further, their 1,200 MW scenario would result in a 30% ratio of wind capacity to peak demand. This would violate the standard even further.

Q: Where Schlissel and Sommer aware that such a wind capacity to peak demand standard exists?

A: Yes. At page 10, lines 12 to 14 of their May 26 testimony, they state that this limit is 20%.

Q: Would their calculations for the value of their wind/gas combination be valid if you ignore the operating standard?

A: No. Even if we ignore the fact the Schlissel and Sommer proposal would be "pan-caked" on top of the Applicants already major wind development plans, the reliability implications of such a huge amount of a non-dispatchable, variable resource are a serious matter. When the wind is blowing, the wind machines proposed by Schlissel and Sommer alone could produce up to twice as much as the 600 MW Big Stone Unit II. However, on the average that is only 30% to 35% of the time. When the wind isn't blowing, the resulting capacity shortfall would be the scale of hundreds of Megawatts.

To remedy this situation, Schlissel and Sommer propose, theoretically, to back up the wind machines with natural gas-fired, combined-cycle generating units. So, in this combination, we have the disadvantages of variability of wind installed in large quantities, backed up by a smaller quantity of a resource fueled by one of our highest-cost fuels: natural gas. If you strip away the high externality costs the MCEA witnesses are using, that reveals a big direct cost penalty for South Dakota and regional customers.

Q: You stated the Applicants have performed system-level analyses of wind while Schlissel and Sommer have not. What is the difference between their analysis and your system-level studies?

A: In short, their levelized cost analysis is overly-simplified, and does not include consideration of the impacts of the alternatives they are trying to assess on the integrated generation system. The system is comprised of many components working together to provide service to customers. The Schlissel and Sommer analysis simply is not capable of analyzing such important items.

Q: How is the Schlissel and Sommer analysis overly-simplified?

A: One important shortcoming is that, in its simplicity, it treats all MWh of energy as if they were the same. In their attempt to create a comparable alternative to Big Stone Unit II, Schlissel and Sommer developed various combinations of wind energy and natural gas combined-cycle plants to yield, *on average*, a similar amount of annual energy as Big Stone Unit II will produce.

As I described in my June 9 rebuttal of MCEA witness Goldberg's testimony, wind energy is not comparable to the baseload characteristics, because of the variability of the wind resource. There is an old adage that averages can be deceiving, and that adage really applies here. Adding natural gas combined-cycle plants to the combination does not materially help this situation, either. Schlissel and Sommer have theorized a resource combination that has little correlation with the characteristics of a baseload facility like Big Stone Unit II.

The most important difference, and resulting shortcoming of the Schlissel and Sommer analysis, is that it implicitly assumes that the *timing* of when energy is delivered does not matter in the analysis. Keep in mind that the timing of energy delivery from Big Stone Unit II will be essentially constant for every hour during the year. In a scenario involving a large quantity of wind like Schlissel and Sommer are posing, this is obviously not the case.

As I described in my June 9 rebuttal of MCE witness Goldberg, if you have a large quantity of wind energy as Schlissel and Sommer are using in their analysis (in their case, up to twice as much installed capacity as the 600 MW Big Stone Unit II), compared to Big Stone Unit II, in any particular hour you either have too much energy being delivered, or too little, depending on the variability of the wind at the time. Adding natural gas capacity to back up the wind machines for purposes of peak period reliability does not change this wide variability in energy output, as far as impacts on the system are concerned.

Q: How does this affect system-level costs?

A: Comparing the timing of energy delivery from the 800 MW to 1200 MW wind energy alternative to Big Stone Unit II, the wind energy system will deliver its energy in a highly variable manner over time. So, there will be hours where the wind resource is producing far more energy than would be produced by Big Stone Unit II, and other hours when it will be producing far less.

Exhibit 42-D illustrates the importance of this variability. The Exhibit depicts the distribution of annual energy output of a wind farm, depending on the month of the year and the time of day. The red portions of the graph depict the time when the wind is most likely to blow, resulting in peak output of the wind resource.

On the other hand, the blue areas depict those times during the year when the wind is far less likely to blow, or does not blow at all. This Exhibit vividly shows the wide swings in annual energy distribution to be expected from a wind resource. If the Schlissel and Sommer analysis were correct, this entire chart would be all one color—because they are implicitly assuming the wind is equally likely to blow during any hour of the year. This is clearly not the case.

Q: How does this over-simplification of the Schlissel and Sommer analysis affect their results?

A: It overstates the value of wind energy compared to Big Stone Unit II. First, their approach understates the amount of wind energy that would occur in off-peak hours (i.e., the red areas on Exhibit 42-D).

At a system level, when too much wind energy is produced compared to Big Stone Unit II, during off-peak hours it will tend to offset lower-cost energy that is available at that time. The wind energy cannot be stored, so it would back down lower-cost production sources to make room for it. This would result in cost penalties to the system, because in those hours the $50/MWh for wind energy that Schlissel and Sommer are assuming would be more costly than the energy that would otherwise have been produced.

Q: How would a system-level analysis correct this over-simplification?

A: It would consider and calculate the cost penalties associated with $50/MWh wind energy being used to offset lower-cost sources of energy during off-peak hours with lower system energy production costs.

Q: How important are the penalties during off-peak periods?

A: Very important. As you can see on Exhibit 42-D, it is far more likely for the wind to blow during off-peak months and off-peak hours, as evidenced by the red areas on the Exhibit. The wind is far more likely to blow during off-peak months and at night than during on-peak periods of June and July and during the middle of the day, when peak demands occur on the system. We know Big Stone Unit II will be running during peak times. Exhibit 42-D shows we cannot count on the wind.

Q: Are there other effects of Schlissel and Sommer's over-simplification?

A: Yes. Their analysis assumes that the amount of natural gas-fired energy that would be required in their wind/gas combination would be based on the average output of the wind component of the combination. This is also incorrect. The wind machines will run when the wind blows, not in a manner that defines an orderly amount of annual natural gas energy to be provided as Schlissel and Sommer's analysis is assuming. Actually, Exhibit 42-D shows that there is an *inverse* correlation of wind energy with peak demand periods.

So, the Schlissel and Sommer analysis is likely to be understating the amount of natural gas that will be necessary to back up the wind during peak times when the wind is not blowing. Again, the distribution of wind energy delivery over time matters. The Schlissel and Sommer analysis completely ignores this fundamental consideration.

Q: How would a system-level analysis correct this over-simplification?

A: It would consider and calculate what the actual expected generation levels would be from the natural gas-fired, combined-cycle units. Because energy from these units costs more than Big Stone Unit II, additional production from them results in additional cost penalties for the system.

Q: Does the Schlissel and Sommer analysis capture these cost penalties associated with the variability of wind?

A: No.

Q: Do the system-level analyses performed by the Applicants capture these penalties?

A: Yes.

Q: Schlissel and Sommer are using the results of the Burns and McDonnell study, which used the same levelized cost approach on behalf of the Applicants. Isn't this an inconsistency?

A: No. If the Applicants had only done the Bums and McDonnell screening analysis, the interveners would have a point. But, the Applicants did not stop after the screening study. We did systems analysis, too. Schlissel and Sommer stopped after their simplified screening analysis, and their analysis is not useful as a result.

Q: What did the Applicants' system-level analyses show for wind/gas combinations in general?

A: While the Applicants' individual analyses did choose significant quantities of wind, and they therefore plan to accomplish those developments, the system-level optimization models either did not select a wind/gas combination at all, or did not select those resources in quantities sufficient to offset Big Stone Unit II. The other Applicants' resource planning witnesses will address this topic in more detail for their respective systems in their rebuttal testimony.

Q: Have the Applicants performed a system-level analysis of the specific wind/gas combination alternative that Schlissel and Sommer describe in their testimony?

A: Yes. For purposes of illustration one of the Applicants, MRES, modeled their pro rata share of the Schlissel and Sommer wind/gas combination scenarios as an alternative to their proposed 110 MW share of Big Stone Unit II. For the reasons I described earlier, this system-level modeling shows that the 800 MW and 1200 MW wind/gas scenarios offered by Schlissel and Sommer and using the high 15% wind capacity value based on experience in MAPP would result in an 8% to 9% cost penalty compared to Preferred Plan including Big Stone Unit II. This represents a total cost penalty of $27 million to $ 110 million to the Applicants customers, based on MRES' 18.3% share of Big Stone Unit II *alone*.

Simply, if we force the optimization models to use a non-optimized alternative instead of Big Stone Unit II like Schlissel and Sommer suggest, the models will report cost penalties resulting from that non-optimization, compared to their optimized plans that include Big Stone Unit II. Jerry Tielke of MRES describes these results in more detail in his rebuttal testimony. And, in addition to these penalties, the wind/gas scenario would also subject the Applicants to additional natural gas price and other risks, because it depends more on natural gas than does the Applicants' Big Stone Unit II proposal.

Further, Montana-Dakota has determined that their pro-rata share of the amount of wind energy that the Schlissel and Sommer scenarios suggest, combined with Montana-Dakota's already-planned amounts of wind energy, would result in an unreasonably high level of wind for their system. So, the Schlissel and Sommer proposal is not even feasible for Montana-Dakota. Hoa Nguyen discusses this in more detail in his rebuttal testimony.

Q: What are the implications of these cost penalties on consumers and businesses in South Dakota and the region?

A: They represent cost penalties that consumers and businesses will see directly on their electric bills if the Commission would choose the wind/gas combo scenario instead of Big Stone Unit II. These penalties underlie the decision regarding the wind/gas combo scenario that Schlissel and Sommer propose to the Commission, masked by their assumed high environmental externality values.

Q: Are there other system-level impacts of the uneven distribution of energy over time from the wind resource in Schlissel and Sommer analysis?

A: Yes. Keep in mind that the wind/gas scenarios would include 1,200 MW to 1,620 MW of installed capacity, compared to 600 MW for Big Stone Unit II. So, the Schlissel and Sommer wind/gas combination alternative involves two to 2.7 times as much installed generation capacity as the Big Stone Unit II proposal. This will demand additional transmission capacity investment to accommodate the additional capacity in the Schlissel and Sommer plan, compared to Big Stone Unit II.

Even if we assume like Schlissel and Sommer do that the wind/gas combination may represent the same amount of annual energy as Big Stone Unit II, the variability of the wind necessitates two to 2.7 times the transmission capacity to accommodate the variability of the wind. Simply, there would be a lot of transmission installed capacity devoted to serving wind that is blowing 40% of the time or less. A baseload plant like Big Stone Unit II, with its constant output over time, uses less transmission capacity to deliver the same amount of annual energy.

Q: Have Schlissel and Sommer included costs for this additional transmission that would be needed for their wind/gas combination alternative?

A: No. From a system perspective, their simplified analysis provides only an "apples-to-oranges" comparison to Big Stone Unit II. The cost penalties from additional transmission would be *in addition to* the cost penalties I described earlier, based on the generation system analysis alone.

Q: At pages 15 to 16 of their May 19 testimony, Schlissel and Sommer say that choosing to build a natural gas-fired power plant without consideration of the future volatility of

natural gas costs would be imprudent. Why do they then include natural gas in their wind/gas combination?

A: That is not clear. After criticizing the use of natural gas as a resource, they then use it as an apparently important part of their alternative plan on page 17 of their May 26 testimony. Clearly, Tables 1 and 2 on page 17 included natural gas-fired combined-cycle gas turbines (CCGT) as part of the wind/gas combo. Are Schlissel and Sommer talking out of both sides of their respective mouths by recommending the very natural gas alternative they see has overly volatile prices? It appears so.

Q: Did Schlissel and Sommer include consideration of volatile natural gas costs in their wind/gas combination scenario?

A: No. Using their analogy from pages 15 to 16 of their May 19 testimony, they themselves appear to have decided that a combination wind/gas plan would be "worth it", regardless of what gas might cost in the future. By their own definition in their May 19 testimony, this alone would appear to make their wind/gas combination imprudent.

Q: In their recommendation to the Commission at page 44 of their testimony, Schlissel and Sommer appear to say a combination of wind, other renewable resources and DSM should be considered as an alternative to Big Stone Unit II. To what other renewable resources are they referring?

A: That is unclear as well. The only clear alternative that Schlissel and Sommer are proposing is a wind/gas combination. They do not offer any other specific proposals for alternatives.

Q: What do you conclude from this analysis?

A: The wind/gas combination alternative suggested by Schlissel and Sommer would be pan-caked on top of more than 800MW of wind capacity that the Applicants already plan to do, and is not a cost-effective substitute for Big Stone Unit II.

X. CUSTOMER RATE IMPACTS

Q: At pages 40 and 41 of their testimony, Schlissel and Sommer say the Applicants have not performed any analyses of the customer rate impacts of Big Stone Unit II. Is this a problem?

A: No. As a general rule, utilities do not calculate customer bill rate impacts for every project or initiative they are planning. They do, however, regularly forecast their electric rates for their system as a whole, including all projects and general cost trends. This is just good business practice.

Like other regional utilities, the Applicants are aware of ongoing trends in energy costs in general and their implications on electric prices for customers. Continuing growth in customer energy needs, increasing natural gas prices, diminishing supplies of low-cost baseload generating capacity, increasing environmental regulation and inflationary effects on the capital costs of all kinds of new generating resources mean electricity prices will increase in the coming years, compared to the past.

As resource planners, our job within these global trends is to work to minimize the revenue requirements of the projects we are considering. As we work toward least-cost or best-cost options, we are working to manage the anticipated increase in rates. So, we know and care about the difference in revenue requirements associated for our resource options, as they would affect our customers. The fact we do not translate all of these differences into specific, individual $/month rate impacts of each project on customers bills is not a shortcoming of our efforts, as Schlissel and Sommer are suggesting.

Q: Does this conclude your testimony?

A: Yes.

Queried from the MHEB OASIS at 3:15 CDT on 6/14/06
Query includes Confirmed, Accepted, and Study requests for Yearly Firm Service

OASIS Reference	Customer	Seller	Service	Path Name	POR	POD	Status	Start	Stop	Bid Price	Offer Price	Capacity Requested	Capacity Granted	Request Type	Confirmed
76418115	MHEM	MHEB	YEARLY FIRM POINT_TO_POINT FULL_PERIOD FIXED	_/MHEB/362-704//	MHEB	MHEB-MISO	STUDY	05/01/2009 00:00:00 ES	05/01/2015 00:00:00 ES	/ ($/MW-Year)	/ ($/MW-Year)	50/50	/	ORIGINAL	
76409708	MHEM	MHEB	YEARLY FIRM POINT_TO_POINT FULL_PERIOD FIXED	_/MHEB/362-704//	MHEB	MHEB-MISO	CONFIRMED	05/01/2006 00:00:00 ES	05/01/2007 00:00:00 ES	/ ($/MW-Year)	/ ($/MW-Year)	50/50	50/50	RENEWAL	
76388073	MHEM	MHEB	YEARLY FIRM POINT_TO_POINT FULL_PERIOD FIXED	_/MHEB/362-704//	MHEB	MHEB-MISO	CONFIRMED	05/01/2006 00:00:00 ES	05/01/2007 00:00:00 ES	/ ($/MW-Year)	/ ($/MW-Year)	100/100	100/100	RENEWAL	
76388070	MHEM	MHEB	YEARLY FIRM POINT_TO_POINT FULL_PERIOD FIXED	_/MHEB/362-704//	MHEB	MHEB-MISO	CONFIRMED	05/01/2006 00:00:00 ES	05/01/2007 00:00:00 ES	/ ($/MW-Year)	/ ($/MW-Year)	100/100	100/100	RENEWAL	
76357811	MHEM	MHEB	YEARLY FIRM POINT_TO_POINT FULL_PERIOD FIXED	_/MHEB/362-704//	MHEB	MHEB-MISO	CONFIRMED	05/01/2006 00:00:00 ES	05/01/2009 00:00:00 ES	/ ($/MW-Year)	/ ($/MW-Year)	50/50	50/50	REDIRECT	
76357746	MHEM	MHEB	YEARLY FIRM POINT_TO_POINT FULL_PERIOD FIXED	_/MHEB/MHEB-NSP//	MHEB	NSP	CONFIRMED	11/01/2005 00:00:00 ES	11/01/2006 00:00:00 ES	/ ($/MW-Year)	/ ($/MW-Year)	213/213	213/213	RENEWAL	
76345399	MHEM	MHEB	YEARLY FIRM POINT_TO_POINT FULL_PERIOD FIXED	_/MHEB/362-704//	MHEB	MHEB-MISO	CONFIRMED	11/01/2005 00:00:00 ES	05/01/2009 00:00:00 ES	/ ($/MW-Year)	/ ($/MW-Year)	64/64	64/64	RENEWAL	
75245551	MHEM	MHEB	YEARLY FIRM POINT_TO_POINT FULL_PERIOD FIXED	_/MHEB/362-704//	MHEB	MHEB-MISO	CONFIRMED	06/01/2002 00:00:00 ES	06/01/2007 00:00:00 ES	/ ($/MW-Year)	/ ($/MW-Year)	100/103	100/103	ORIGINAL	
75005328	MHEM	MHEB	YEARLY FIRM POINT_TO_POINT FULL_PERIOD FIXED	_/MHEB/MHEB-NSP//	MHEB	NSP	CONFIRMED	05/01/1997 00:00:00 ES	11/01/2016 00:00:00 ES	/ ($/MW-Year)	/ ($/MW-Year)	0/200	0/200	ORIGINAL	20
75004147	MHEM	MHEB	YEARLY FIRM POINT_TO_POINT FULL_PERIOD FIXED	_/MHEB/MHEB-NSP//	MHEB	NSP	CONFIRMED	05/01/2000 00:00:00 ES	05/01/2012 00:00:00 ES	/ ($/MW-Year)	/ ($/MW-Year)	30/64	30/64	ORIGINAL	3
75003500	MHEM	MHEB	YEARLY FIRM POINT_TO_POINT FULL_PERIOD FIXED	_/MHEB/MHEB-NSP//	MHEB	NSP	CONFIRMED	05/01/2002 00:00:00 ES	05/01/2007 00:00:00 ES	/ ($/MW-Year)	/ ($/MW-Year)	50/53	50/53	ORIGINAL	
75003362	MHEM	MHEB	YEARLY FIRM POINT_TO_POINT FULL_PERIOD FIXED	_/MHEB/MHEB-NSP//	MHEB	NSP	CONFIRMED	05/01/2005 00:00:00 ES	05/01/2015 00:00:00 ES	0.0000/0.0000 ($/MW-Year)	0.0000/0.0000 ($/MW-Year)	529/529	529/529	ORIGINAL	52
75003358	MHEM	MHEB	YEARLY FIRM POINT_TO_POINT FULL_PERIOD FIXED	_/MHEB/MHEB-NSP//	MHEB	NSP	CONFIRMED	05/01/1997 00:00:00 ES	11/01/2014 00:00:00 ES	/ ($/MW-Year)	/ ($/MW-Year)	0/150	0/150	ORIGINAL	15
75003355	MHEM	MHEB	YEARLY FIRM POINT_TO_POINT FULL_PERIOD FIXED	_/MHEB/MHEB-NSP//	MHEB	NSP	CONFIRMED	05/01/1991 00:00:00 ES	11/01/2014 00:00:00 ES	/ ($/MW-Year)	/ ($/MW-Year)	0/150	0/150	ORIGINAL	15
															105

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TRM and CBM Values updated May 25th 2006

Sr. No.	OASIS Pathcode	Winter Rating	Winter TRM	Winter CBM	Summer Rating	Summer TRM	Summer CBM	TRM FACTOR A	TRM FACTOR B
1	11M20MBNNALC	167	9	0	135	7	0	0	0
2	11M20MXFPTDF	167	8.35	0	135	6.75	0	0	0
3	471NELCORNEL	1800	36	0	1721	34.42	0	1	1
4	526TILBALWMV	287	46.34	0	287	46.34	0	1	0.8761329
5	526TILWMVEWF	287	46.34	0	287	46.34	0	1	0.8761329
6	8STKERARNHAZ	223	4.46	0	200	4	0	0	0
7	8STKERWEMPAD	223	4.46	0	200	4	0	0	0
8	ABBHEN__PTDF	239	4.8	37	218	4.4	37	1	0.5
9	ABBHENCULGVW	239	4.8	45	218	4.4	45	0	0
10	ABBNW_ABBHEN	287	31.04	14.96	287	31.04	16.2	1	0.8150773
11	ABNCROWMVEWF	287	26.44	0	264	25.98	0	1	0.7967667
12	ABNXFM__PTDF	478	29.86	0	478	29.86	0	1	0.6798392
13	ABNXFMBRECAS	478	9.56	0	478	9.56	0	1	0
14	ABNXFMDUMWIL	478	9.56	0	478	9.56	0	1	0
15	ABNXFMGIBPET	478	9.56	0	478	9.56	0	1	0
16	ADKBTY__PTDF	1386	52	0	1042	52	0	1	1
17	ADKBTYKILMRQ	1434	64	0	1279	64	0	1	1
18	ADMXFMHAZADM	300	27.8	0	357	28.94	0	1	0.7532827
19	ADNZIO__PTDF	1255	25.1	0	1096	21.92	0	1	0
20	ADNZIOPLPZIO	1434	28.68	0	1096	21.92	0	1	0
21	ALBCRONEWXEN	287	26.44	0	264	25.98	0	1	0.7967667
22	ALBGARQUAH47	215	6	17	215	6	17	1	0.8
23	ALBPRS__PTDF	272	14.04	0	211	12.82	0	1	0.6708268
24	ALBPRSPLPRAC	322	6.44	0	279	5.58	0	0	0
25	ALBPRSWEMPAD	322	6.44	0	279	5.58	0	1	0
26	ALBPRSWEMROE	322	6.44	0	279	5.58	0	1	0
27	ALNLULBAYMON	1609	32.18	0	1609	32.18	0	1	0
28	ALNXFMMONBAY	1024	38.48	41.4	890	35.8	41.4	1	0.5027933
29	AMEBJCMTZBON	100	2	0	75	1.5	0	0	0
30	ANTJFR__PTDF	2165	135	25	2165	135	25	0	0
31	ARCGVL__PTDF	1255	25.1	0	1096	21.92	0	1	0
32	ARCSTEMARXFM	191	53.72	0	191	53.72	0	1	0.9288905
33	ARCSTEPCKCHK	191	53.72	0	191	53.72	0	1	0.9288905
34	ARCSTEPCKWFR	191	53.72	0	191	53.72	0	1	0.9288905
35	ARCSTEWMVEWF	191	53.72	0	191	53.72	0	1	0.9288905
36	ARGBAT__PTDF	1525	98.2	0	1242	92.54	0	1	0.7315755
37	ARGBATARGTOM	1525	30.5	0	1242	24.84	0	1	0
38	ARGMRWARGBTL	335	10.3	7	330	10.2	7	1	0.3529412
39	ARNHAZ__PTDF	717	100.54	0	717	100.54	0	1	0.8573702
40	ARNHAZDORFOR	717	14.34	0	717	14.34	0	0	0
41	ARNHAZMTZBON	717	14.34	0	717	14.34	0	0	0

Sr. No.	OASIS Pathcode	Winter Rating	Winter TRM	Winter CBM	Summer Rating	Summer TRM	Summer CBM	TRM FACTOR A	TRM FACTOR B
42	ARNHAZWEMPAD	717	14.34	0	717	14.34	0	1	0
43	ARNVINARNHAZ	335	21.2	0	276	20.02	0	1	0.7242757
44	ASBERWSAMWYL	1792	0	0	1792	0	0	0	0
45	ATJATATHTJWL	235	36.4	0	235	36.4	0	1	0.8708791
46	AVNLDN__PTDF	287	26.14	0	277	25.94	0.12	1	0.7864302
47	AVNLDNGHEWLX	287	14.35	0	276	13.8	0	1	0
48	AVNXFM__PTDF	574	28.7	0	434	21.7	0	1	0
49	AVNXFMBAKBRO	621	31.05	0	536	26.8	0	1	0
50	AVOBE1AVOBE2	1153	85.86	0	1030	83.4	0	1	0.7529976
51	AXTDANJFRANT	459	37	0	408	37	0	0	0
52	AXTXFMJFRANT	981	82	0	906	82	0	0	0
53	AXTXFMJFRCLV	981	82	0	906	82	0	0	0
54	BALCAH__PTDF	1673	87.86	0	1297	80.34	0	1	0.6771222
55	BALCAHBALSTA	1793	35.86	0	1684	33.68	0	1	0
56	BALCAHCOFROX	1793	35.86	0	1684	33.68	0	1	0
57	BALCAHSTAROX	1793	35.86	0	1684	33.68	0	1	0
58	BAYFOSLEMFOS	1076	51.12	0	1076	51.12	0	1	0.5790297
59	BAYMON__PTDF	1793	316.66	0	1536	311.52	0	1	0.9013867
60	BAYMONDBELEM	1793	35.86	0	1536	30.72	0	1	0
61	BAYMONLEMMAJ	1793	35.86	0	1536	30.72	0	1	0
62	BAYMONLUL3TM	1793	35.86	0	1536	30.72	0	1	0
63	BAYTOUDBEBEA	326	34.12	0	286	33.32	0	1	0.8283313
64	BAYXFM__PTDF	903	25.46	42.9	740	22.2	42.9	1	0.3333333
65	BAYXFMLUL3TM	903	18.06	42.9	740	14.8	42.9	1	0
66	BEABROBEADBE	188	9.06	0	132	7.94	0	1	0.6675063
67	BEADBE__PTDF	1153	262.06	0	1030	259.6	0	1	0.9206471
68	BEADBEGALFOS	1153	23.06	0	1030	20.6	0	1	0
69	BEDCLRGOOLOC	459	9.18	42.9	445	8.9	42.9	1	1
70	BEDDOUPRNMTS	2598	130	43	2598	130	85	0	0
71	BELPLVCHESIL	430	2	0	445	2	0	0	0.0000
72	BLAFRA__PTDF	13[illegible]7	57.14	0	1072	51.04	0	1	0.5799373
73	BLAFRALUTESX	1523	30.46	0	1273	25.46	0	1	0
74	BLAFRAMCROVE	1523	30.46	0	1273	25.46	0	1	0
75	BLAFRASTFLUT	1523	30.46	0	1273	25.46	0	1	0
76	BLKCORPADTLR	393	19.86	0	403	20.06	0	1	0.5982054
77	BLKCRDWEMROE	393	7.86	0	403	8.06	0	1	0
78	BLLVOL__PTDF	2598	129.9	0	2598	129.9	0	0	0
79	BLLVOLWBNVOL	2598	129.9	0	2598	129.9	0	0	0
80	BLMDENBEDCOL	478	19.86	0	478	19.86	0	1	0.5186304
81	BLOBEDPRNMTS	2953	148	69	2783	139	138	0	0
82	BLUBUL__PTDF	265	13.25	0	233	11.65	0	1	1.2446352
83	BLUBULBAKBRO	265	13.25	0	233	11.65	0	1	0
84	BLUBULGHEWLX	265	13.25	0	233	11.65	0	1	0
85	BLUBULTRMCLF	281	5.62	0	233	4.66	0	1	0
86	BLUXFMBAKBRO	296	5.92	0	276	5.52	0	1	0
87	BMTXFM__PTDF	2196	110	0	1887	94	0	0	0

Sr. No.	OASIS Pathcode	Winter Rating	Winter TRM	Winter CBM	Summer Rating	Summer TRM	Summer CBM	TRM FACTOR A	TRM FACTOR B
410	MARPLVRHESIL	295	5.9	0	260	5.2	0	1	1
411	MASMTPDCKTAZ	137	27.44	0	137	27.44	0	1	0.9001458
412	MASMTPHAVESF	137	27.44	0	137	27.44	0	1	0.9001458
413	MASXF3MASXF2	478	33.26	0	478	33.26	0	1	0.7125676
414	MCBOVEMTGOVE	335	17	0	297	16.24	0	1	0.6342365
415	MCROVEBLAF_G	921	77.22	0	921	77.22	0	1	0.7614608
416	MCTLPTSTWDUM	191	10.52	0	156	9.82	0	1	0.6822811
417	MCTTRADUMSTW	143	9.86	0	143	9.86	0	1	0.7099391
418	MCTTRAOLVGRA	143	9.86	0	143	9.86	0	1	0.7099391
419	MERINPDCKTAZ	187	23.54	0	159	22.98	0	1	0.8616188
420	MERLEMCAHMER	287	21.94	0	285	21.9	0	1	0.739726
421	MFTWLMFOSSCK	1315	66	76	1315	66	76	1	1
422	MFTXFMEBDTER	556.4	45.228	0	474.8	43.596	0	1	0.7821819
423	MFTXFMJEFHRC	556.4	11.128	0	474.8	9.496	0	0	0
424	MFTXFMROCJEF	556.4	11.128	0	474.8	9.496	0	0	0
425	MFTXFMZIMXFM	556.4	11.128	0	474.8	9.496	0	0	0
426	MGLRGVMGPODN	198	8.36	0	180	8	9	1	0.55
427	MGPSTRMGPST3	124	7.88	0	124	7.88	0	1	0.6852792
428	MH_ONT_E	300	6.1	0	300	6.1	0	1	0.0163934
429	MH_ONT_W	300	6.5	0	300	6.5	0	1	0.0769231
430	MH_SPC_E	475	80.7	0	475	80.7	0	1	0.88228
431	MH_SPC_W	450	38.2	0	450	38.2	0	1	0.7643979
432	MHEX_MAPP_N	1050	521	0	675	513.5	0	1	0.9737098
433	MHEX_MAPP_S	2050	200.3	0	2050	200.3	0	1	0.795307
434	MHEX_MISO_N	1050	521	0	675	513.5	0	1	0.9737098
435	MHEX_MISO_S	2050	200.3	0	2050	200.3	0	1	0.795307
436	MHEX_N	1050	521	0	675	513.5	0	1	0.9737098
437	MHEX_S	2050	200.3	0	2050	200.3	0	1	0.795307
438	MID870__PTDF	247	4.94	0	219	4.38	0	1	0
439	MID870MILPDW	311	6.22	0	271	5.42	0	1	0
440	MITELR__PTDF	547	27	0	526	26	0	0	0
441	MITELRSAMWYL	681	34	0	598	30	0	0	0
442	MITELRWYLCAB	681	34	0	598	30	0	0	0
443	MKROHCELIFOS	1526	137	0	1281	137	0	0	0
444	MLDXFM__PTDF	70	1.4	0	70	1.4	0	0	0
445	MLREPOMLRLOW	1732	86.6	0	1732	86.6	0	0	0
446	MLRLOWDNLMCK	1732	86.6	0	1732	86.6	0	0	0
447	MNSCHABVAHAN	1837	36.74	0	1641	32.82	0	0	0
448	MNSHGHMNSHOY	1673	77.46	0	1640	76.8	0	1	0.5729167
449	MNTZUMA_W	765	116	0	765	116	0	1	0.6560345
450	MOBOVETHIMCC	290	9.6	0	242	8.64	0	1	0.4398148
451	MONBAY__PTDF	1793	217.16	0	1536	212.02	0	1	0.855108
452	MONBAYFOSBAY	1793	35.86	0	1536	30.72	0	1	0
453	MONBAYLUL3TM	1793	35.86	115	1536	30.72	115	1	0
454	MONBNS__PTDF	2210	300.8	0	1548	287.56	8.26	1	0.8923355
455	MONBNSMONWNE	2210	44.2	0	2007	40.14	305	1	0

Sr. No.	OASIS Pathcode	Winter Rating	Winter TRM	Winter CBM	Summer Rating	Summer TRM	Summer CBM	TRM FACTOR A	TRM FACTOR B
364	KRESEN__PTDF	320	23.6	34.4	283	22.86	33.29	1	0.7524059
365	KRESENCABWYL	401	8.02	0	339	6.78	0	1	0
366	KRESENMANHOY	401	8.02	0	339	6.78	0	1	0
367	KRESENWYLSAM	227	4.54	42	227	4.54	42	1	0
368	KSHLKVPLPZIO	329	6.58	0	288	5.76	0	0	0
369	KYDLIV__PTDF	335	6.7	0	290	5.8	0	1	0
370	KYGSPOAMOSXF	1610	145	5	1438	145	5	0	0
371	KYGSPOBAKBRO	1610	145	5	1438	145	5	0	0
372	LABMASLABWWD	1195	68.4	0	1195	68.4	0	1	0.6505848
373	LACCOTWRVRXF	236	14.42	0	202	13.74	0	1	0.705968
374	LACNEOLACSTI	1124	0	0	1124	0	0	0	0
375	LACNEOLANWIC	1159	35	0	1159	35	0	0	0
376	LACWGRLACSTI	2109	113	0	1802	113	0	0	0
377	LAKFOXLAKLKF	216	55.32	0	160	54.2	0	1	0.9409594
378	LANWICSTILAC	956	0	0	956	0	0	0	0
379	LATGENTHTJWL	280	22.5	0	280	22.5	0	1	0.8156371
380	LATLANSPREAS	236	48.92	0	202	48.24	0	1	0.9162521
381	LBRITADPRLBR	1625	32.5	8.2	1739	34.78	8.2	1	1
382	LCOBYNNELELC	1405	28.1	365.8	1739	34.78	365.8	1	1
383	LCONEL__PTDF	1572	92.9	0	1234	92.9	0	1	1
384	LCONELWEMPAD	1799	36	0	1530	31	0	1	1
385	LEMFOS__PTDF	1677	67.84	161.4	1423	62.76	146.7	1	0.5465264
386	LEMFOSBAYFOS	1793	54	0	1598	54	0	1	1
387	LEMMAJBAYMON	956	75.32	0	956	75.32	0	1	0.7461498
388	LEMWENLEMFOS	284	10.78	0	239	9.88	0	1	0.5161943
389	LESNE_LESHIP	247	4.94	0	222	4.44	0	0	0
390	LIMEMEADAHAZ	223	95.46	0	202	95.04	0	1	0.9574916
391	LIMEMELEHWEB	223	95.46	0	202	95.04	0	1	0.9574916
392	LKFFOXLKFWLM	216	55.32	0	160	54.2	0	0	0
393	LKHJFFEAUARP	344	14.98	0	321	14.52	0	1	0.5578512
394	LKJFOXARNHAZ	216	4.32	0	160	3.2	0	0	0
395	LKJFOXLKJTRI	216	4.32	0	160	3.2	0	0	0
396	LKVZIOZIOPLP	295	6	0	261	5	0	0	0
397	LNSXFMKINLTH	308	6.16	0	308	6.16	0	0	0
398	LOBITBDPBLOB	1625	32.5	0	1739	34.78	0	1	1
399	LOMDESLOMITA	1625	32.5	17.5	1530	30.6	17.5	1	1
400	LORTRKWEMPAD	271	47.62	0	200	46.2	0	1	0.9044149
401	LORTRKWPAD_G	223	46.66	0	200	46.2	0	1	0.9044149
402	LUTESXNWMSTF	1225	0	0	1195	0	0	0	0
403	MANBV2MANBV1	1162	72	0	1162	64	0	1	1
404	MANBVA__PTDF	1162	58	0	1162	58	0	1	3.3655172
405	MANBVAMANCRS	1162	29	0	1162	26	0	1	1
406	MANCRSBVACRS	1162	101	0	1162	65	0	1	1
407	MANHOYMANHGH	1434	60.28	14.4	1288	57.36	14.4	1	0.5509066
408	MANIPMDOLSWS	260	38	0	260	38	0	0	0
409	MARPLV__PTDF	253	10.3	0	210	10.3	0	1	1

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF SOUTH DAKOTA

In the Matter of Otter Tail Power Company on behalf of Big Stone II Co-owners for an Energy-Conversion Facility Permit for the Construction of the Big Stone II Project	Docket No. EL05-022 **BIG STONE II CO-OWNERS' RESPONSES AND OBJECTIONS TO PROPOUNDING INTERVENORS SIXTH SET OF INTERROGATORIES AND COMBINED REQUEST FOR PRODUCTION OF DOCUMENTS**

The Big Stone II Co-owners (hereinafter referred to as "Applicants"), by and through their attorneys of record, make the following responses and objections to the Sixth Set of Interrogatories and Combined Request for Production of Documents propounded by Minnesotans For An Energy-Efficient Economy, Izaak Walton League of America – Midwest Office, Union of Concerned Scientists, and Minnesota Center for Environmental Advocacy ("Propounding Intervenors") dated April 5, 2006.

In order to avoid unduly lengthy objections and responses and in order to avoid repetition of objections, objections that appear frequently in the responses or that have general applicability to all the responses are set forth below. The "objections of General Application" apply to each and every one of the Interrogatories and Request for Documents. Any answers provided or documents produced are subject to and provided notwithstanding any objections. The "objections Raised by Reference" describe the objections that are specifically set forth as to each Interrogatory.

Objections of General Application

A. Applicants object to each and every one of the Interrogatories and Requests for Documents to the extent that the same purport to seek responses from Applicants' counsel of record, who are not parties to this matter; seek attorney-work product; or seek information which is privileged and therefore not subject to discovery.

B. Applicants object to any and all instructions or definitions beyond the requirements imposed by the South Dakota Rules of Civil Procedure.

C. Applicants object to each request to the extent it is unreasonably cumulative or duplicative, or the information sought by the request is obtainable from some other source that is more convenient, less burdensome, or less expensive.

D. Applicants do not waive any of their general or particular objections in the event answers or documents coming within the scope of any such objections are furnished.

EXHIBIT
Applicants' Exhibit 42-B

c) SMMPA would generally expect the avoided cost numbers to change with each of its IRP filings. This would be a reflection of both the changing costs in the market for energy and capacity as well as the different resource mixes of SMMPA plans in the future. SMMPA has updated its avoided costs as a part of its 2006 resource planning process scheduled for completion later this year. Updated avoided energy cost estimates are higher for years 2006-2012 and lower for years 2013-2021. The reason for the higher costs in the early years is due primarily to the increase cost of natural gas and its effects on the generation market. The estimated cost of 2006 avoided energy is \$31.50/MWh. The new avoided energy estimate is based upon an energy mix of 78% baseload (at \$15.55/MWh), 13% intermediate (at \$68.70/MWh), and 9% peaking energy (at \$116/MWh). Avoided energy costs decrease in the 2012 – 2021 period given the inclusion of new baseload generation in 2011. Avoided energy costs in 2012 are \$16.60/MWh and increase to \$20.80/MWh in 2021. Conversely, avoided capacity costs go from \$20/kW-yr to \$210/kW-yr reflecting the larger capital costs associated with the installation of the base load generating plant.

(Response by Larry Johnston, Southern Minnesota Municipal Power Agency)

69. Refer to Applicants' Exhibit 23-A, page 4-18. Regarding the pairing of 600 MW of wind capacity with a 600 MW CCGT, answer the following:

a) Was the combination analyzed because Mr. Greig, Mr. Gosoroski and/or the Co-owners believe that "non-firm" capacity such as wind requires firm backup power rated at 100% of the non-firm resource's capacity?

Response: No.

b) If the answer to a) is "yes," list which of the individual Co-owners, Mr. Greig and/or Mr. Gosoroski believe this to be the case.

Response: Not applicable.

c) If the answer to a) is "yes," provide copies of the analyses or assessments that provide the basis for this conclusion.

Response: Not applicable.

d) If the answer to a) is "no," why was this assumption made? Could a CCGT of a size smaller than 600 MW serve as backup to a 600 MW wind farm?

<u>OBJECTION</u>. The Applicants object to subpart (d) of the request because it is grounded on a false premise. The referenced Exhibit 23-A Burns & McDonnell study is not applicable to answer the premise of the question.

Exhibit 23-A is an analysis of busbar costs of various BSPII alternatives based on comparison of *plant-to-plant* characteristics. In this analysis, the reliability benefits of being connected to the transmission network are not considered, in order to examine the reliability and cost impacts of the various individual plant options by themselves and to compare them to each other. So, to achieve a comparable reliability level for the wind energy option compared to others, and considering there would be amounts of time each year when the output of the wind energy system would be zero, it was completely appropriate in this analysis to use 600 MW of CCGT capacity in combination with the wind resource. Again, this was done to achieve a comparable *plant* reliability and level of baseload dependable dispatchability compared to the other individual plant options in the Exhibit 23-A study.

The premise of the question appears to be expecting that wind would be eligible for some form of capacity value. To do this, and in contrast to the purpose of the Exhibit 23-A Burns & MacDonald study, a system-level analysis is required instead. Such an analysis would take into account the interaction of various regional generating resources, interconnected by an unconstrained transmission system. This analysis is far more complicated than the Exhibit 23-A study, and is the approach that each of the Co-Owners use as part of their resource planning process to actually determine the appropriate mix of all resources to be planned for and proposed.

Ironically with regard to this question, the ability to allocate any form of equivalent capacity value to wind energy resources is dependent upon the existence of a robust, non-constrained diverse transmission and generation network that allows regional firm generating capacity resources like the proposed BSPII plant to back up the non-dispatchable, variable wind energy resource when the wind is not blowing. So, it is the transmission system and transmission improvements like those included in the proposed BSPII Project that enable any recognition of equivalent capacity value for wind at all.

It is these same transmission capabilities, in concert with appropriate regional reliability studies, that allow regional capacity installed reserve margins, established in the interest of regional reliability, to be as low as they are. This keeps costs low while providing acceptable generation system reliability. In a constrained or non-existent transmission environment, where it is not universally possible to move unlimited amounts of energy from wherever it is generated to wherever it is needed at any time, the local reserve margins would need to be much greater. The Exhibit 23-A study was not a regional reliability study.

e) Are any of the Co-owners, Mr. Greig and/or Mr. Gosoroski, aware of any utility-scale wind capacity which has a firm resource backup of equal capacity rating dedicated solely to the purpose of backing up the wind capacity so that it can be dispatched as a firm, baseload resource? If your answer is yes, provide the details of any such examples.

OBJECTION. Relevance Objection. The question is grounded on a false assumption. See response to I.R. 69(d), above. Notwithstanding any objections, the Applicants do not utilize wind-generated energy as a firm, dispatchable capacity resource. Therefore, it is a *non sequitur* to talk about "backing up wind capacity."

f) For those Co-owners with existing wind capacity, list the backup firm resource for that capacity, if any, and indicate whether any or a portion of the firm resource's capacity is dedicated solely to backing up the wind capacity and provide that backup capacity's MW rating.

OBJECTION. See response to I.R. 69(e). There is no individual discrete backup resource dedicated solely for wind energy. The backup for wind energy is the integrated system network, interconnected with transmission lines to move firm generating capacity to where it is needed. As discussed in the response to #69, part d), an integrated system-level analysis is necessary to assess these impacts; not Exhibit 23-A.

(Response by Bryan Morlock, Otter Tail Power)

70. Refer to Exhibit 25-B the "Applicants' Supplemental Information Required by Commission's Order of December 19, 2005." Provide the annual revenue requirements of the alternatives to Big Stone Unit II by utility.

RESPONSE: Documents responsive to this request are contained on the attached CD ROM disk in the folder labeled bates stamp JCO0002479-4000.

(Response by Kiah Harris, Burns & McDonnell)

71. Regarding the Direct Testimony of Peter Koegel and the 2005 MAPP Load & Capability Report, please answer the following:

a) In electronic spreadsheet format for each MAPP resource, provide the following: Plant Name, Plant Owner (indicate % ownership if jointly owned), Primary Energy Source, Summer Capacity, Winter Capacity and years through 2014 for which the resource was forecasted to be available. If any of the resources were assumed to have capacity derates or uprates at any point through 2014, state what assumption was made.

b) Does the 2005 L&C Report include in its capability forecast all MAPP utility owned capacity currently under construction? If not, why not? If your answer is yes, indicate which resources in the Report are under construction.

c) Does the 2005 L&C Report include in its capability forecast, all MAPP utility owned capacity that have been permitted but have not yet started construction? If your answer is yes, indicate which resources in the Report are permitted. If your answer is no, explain.

d) Does the 2005 L&C Report include in its capability forecast, all MAPP utility owned capacity currently that is currently in the permitting process? If your answer is yes, indicate which resources in the Report are currently in the permitting process. If you answer is no, explain.

COMPARISON OF APPLICANTS' BASELOAD NEEDS IN 2011
AND PROPOSED SHARES IN BIG STONE UNIT II

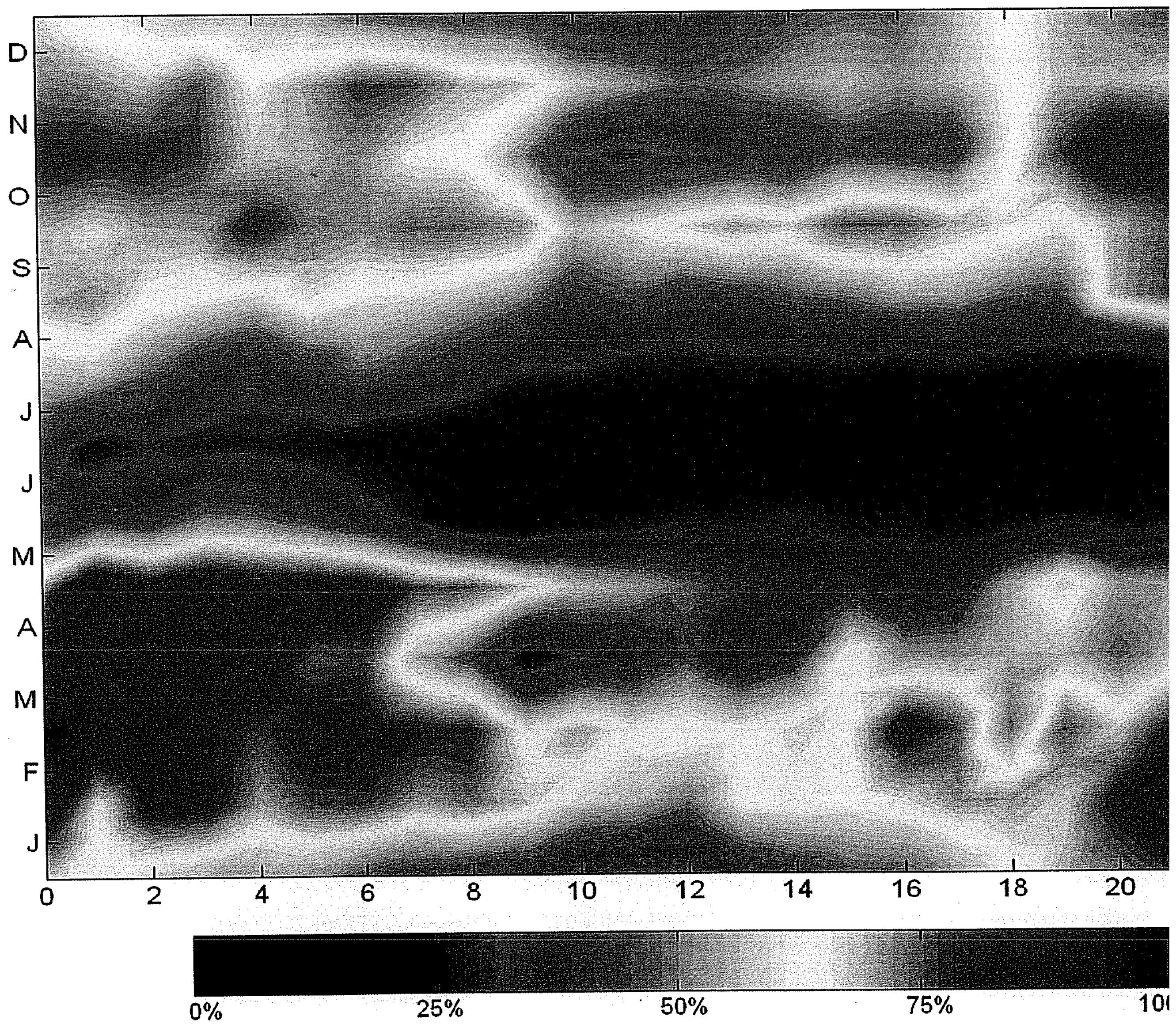
Applicant	Baseload Need in 2011 (MW)	Proposed Share in Big Stone II (MW)
CMMPA	60	30
GRE	150	116
HCPD	30	25
MDU	126	116
MRES[1]	200	150
OTP	120	116
SMMPA	100	47
Totals	**786**	**600**

Notes:
1. Includes Hutchinson.

EXHIBIT
tabbies
Applicants' Exhibit 42-C

Wind Farm Output Pattern (2004)

Color scale: 80MW = 100%



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