OAH No. 12-2500-17037-2, MPUC Dkt No. CN-05-619
and OAH No. 12-2500-17038-2, MPUC Dkt No. TR-05-1275

STATE OF MINNESOTA
OFFICE OF ADMINISTRATIVE HEARINGS
FOR THE PUBLIC UTILITIES COMMISSION

In the Matter of the Application of Otter Tail Power Company and Others for Certification of Transmission Facilities in Western Minnesota

and

In the Matter of the Application to the Minnesota Public Utilities Commission for a Route Permit for the Big Stone Transmission Project in Western Minnesota

TABLE OF CONTENTS

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FINDINGS OF FACT, CONCLUSIONS OF LAW, AND RECOMMENDATION

These matters involve the applications of seven utilities for a Certificate of Need and for Route Permits for the Minnesota portions of two high voltage transmission lines that will carry electricity primarily from the Big Stone Unit II power plant in South Dakota into Minnesota. Hearings in these matters were held before Administrative Law Judges Steve M. Mihalchick and Barbara L. Neilson commencing October 9, 2006, with public sessions in Benson, Minnesota, followed by public sessions in five other cities, and ending on December 22, 2006, after nine days of evidentiary hearings in St. Paul, Minnesota.

Todd J. Guerrero, David L. Sasseville, and Alan R. Mitchell, Lindquist & Vennum PLLP, 80 South Eighth Street, Suite 4200 IDS Center, Minneapolis, MN 55402, and Peter S. Glaser, Troutman & Sanders, LLP, 401 Ninth Street, Suite 1000, Washington, DC 20004-2134, appeared on behalf of the Applicants, Otter Tail Power Company, Great River Energy, Missouri River Energy Services, Montana-Dakota Utilities, Southern Minnesota Municipal Power Agency, Central Minnesota Municipal Power Agency, and Heartland Consumers Power District (Applicants).

Julia E. Anderson, Assistant Attorney General, and Karen Hamel, Assistant Attorney General, 1400 Bremer Tower, 445 Minnesota Street, St. Paul, Minnesota 55101, appeared on behalf of the Minnesota Department of Commerce (Department).

Elizabeth I. Goodpaster and Barbara Freese, 26 East Exchange Street, Suite 206, St. Paul, Minnesota 55101, appeared on behalf of the Minnesota Center for Environmental Advocacy, Union of Concerned Citizens, the Izaak Walton League, Fresh Energy, and Wind on the Wires (Joint Intervenors or JI).

Christopher Sandberg, Lockridge, Grindal, Nauen, P.L.L.P., 100 Washington Ave. S., Suite 2200, Minneapolis, Minnesota, 55401, appeared on behalf of the Midwest Independent System Operator (MISO).

Christopher Greenman, Excelsior Energy, Inc., 11100 Wayzata Boulevard, Suite 305,

Minnetonka, Minnesota 55305, appeared on behalf of Excelsior Energy, Inc. (Excelsior Energy).

John Drawz and Mollie Smith, Fredrikson & Byron, P.A., 200 South Sixth Street, Suite 4000, Minneapolis, Minnesota 55402-1425, appeared on behalf of the South Dakota Governor's Office of Economic Development (GOED).

Kathleen M. Brennan and Andrew J. Shea, McGrann Shea Anderson Carnival Straughn & Lamb, Chartered, 800 Nicollet Mall, Suite 2600, Minneapolis, MN 55402-7035, appeared on behalf of the Minnesota Municipal Utilities Association (MMUA).

Serving as public advisors throughout the entire proceeding were David Jacobson and Robert Cupit, staff members of the Minnesota Public Utilities Commission, Suite 350, 121 Seventh Place East, St. Paul, Minnesota 55 101-2147. In addition, Deborah Pile, with the Energy Facility Permitting Division, Department of Commerce, 85 7th Place East, Suite 500, St. Paul, Minnesota 55 101-2198, served as a public advisor with regard to routing issues.

NOTICE

Under the PUC's Rules of Practice and Procedure, Minn. R. 7829.0100 to 7829.3200, exceptions to this Report, if any, by any party adversely affected must be filed within 15 days of the mailing date hereof with the Executive Secretary of the PUC, 350 Metro Square Building, 121 Seventh Place East, St. Paul, Minnesota 55101-2147. Exceptions must be specific, relevant to the matters at issue in this proceeding, and stated and numbered separately. Proposed Findings of Fact, Conclusions, and Order should be included, and copies thereof served upon all parties.

The PUC shall make its determination on the applications for the Certificate of Need and Route Permits after expiration of the period to file Exceptions as set forth above, or after oral argument, if such is requested and had in this matter. In accordance with Minn. R. 4400.1900, the PUC shall make a final decision on the Route Permits within 60 days after receipt of this Report.

Notice is hereby given that the PUC may accept, modify, condition, or reject this Report of the Administrative Law Judges and that this Report has no legal effect unless expressly adopted by the PUC.

STATEMENT OF ISSUES

Should the Minnesota Public Utilities Commission grant a Certificate of Need to the Applicants for two high voltage transmission lines?

> The Administrative Law Judges conclude that the Commission should issue a Certificate of Need to the Applicants for the construction and operation of two new transmission lines – a 230 kV line from the South Dakota border to the Morris Substation and a 345 kV line from the South Dakota border to the Granite Falls Substation. In addition, the Commission should consider imposing the conditions recommended by the Department and the Administrative Law Judges.

Which routes should be approved for construction of a high voltage transmission line between the Big Stone Plant in South Dakota and Granite Falls, Minnesota, and at what voltage?

The Administrative Law Judges conclude that the Commission should issue Route Permits for each line along the routes preferred by the Applicants, authorizing construction of the lines, substations, and associated facilities, including a new site for the Canby Substation, as described in the Applications and hearing record.

Is the Environmental Impact Statement prepared by the Minnesota Department of Commerce on the proposed transmission lines adequate?

The Administrative Law Judges conclude that the Environmental Impact Statement is adequate.

FINDINGS OF FACT

I. The Applicants

1. The Applicants for the Certificate of Need and Route Permits are the following seven utilities: Otter Tail Power Company, Great River Energy, Missouri River Energy Services, Montana-Dakota Utilities Co., Southern Minnesota Municipal Power Agency, Central Minnesota Municipal Power Agency, and Heartland Consumers Power District.

A. Otter Tail Power Company

2. Otter Tail Power Company (Otter Tail Power or OTP) is an investor-owned public utility organized under the laws of the State of Minnesota, and is the utility division of Otter Tail Corporation, a company publicly traded on the NASDAQ Stock Market. OTP is headquartered in Fergus Falls, Minnesota. OTP was originally incorporated in 1907, and first delivered electricity in 1909 from the Dayton Hollow Dam on the Otter Tail River. It provides electricity to over 128,000 residential, commercial, and industrial customers throughout Minnesota, South Dakota, and North Dakota, with approximately 58,000 customers in Minnesota. OTP's service territory is approximately 50,000 square miles and includes service to 423 communities, none of which has a population in excess of 20,000 people and all but three of which have less than 10,000 people. [1]

3. At present, 75% of OTP's electrical generation is coal-based; 10% is produced from renewable resources such as wind, hydro and biomass; and 15% is purchased from other regional power suppliers. OTP has company-owned generation resources of 699 MW, with the bulk of that coming from its ownership of three coal-fired power plants: the Big Stone Unit I, with approximately 450 MW of capacity (of which OTP's ownership share is 53.9%, or approximately 242 MW); the Coyote Station, near Beulah, North Dakota, with approximately 420 MW (of which OTP's ownership share is 35%, or approximately 147 MW); and Hoot Lake located near Fergus Falls, Minnesota, with approximately 156 MW of capacity (all of which are owned by OTP). OTP owns and operates approximately 5,300 miles of transmission lines in Minnesota, North Dakota, and South Dakota. OTP is a balancing authority of the Midwest Reliability Organization (MRO) and the Mid-Continent Area Power Pool (MAPP). [2]

4. OTP is the only Applicant that is subject to rate regulation by the Commission.

B. Great River Energy

5. Great River Energy (GRE) is a generation and transmission electric cooperative

headquartered in Elk River, Minnesota, which provides electrical energy and related services to 28 member distribution cooperatives in Minnesota and Wisconsin. These member cooperatives distribute electricity to more than 600,000 homes, businesses and farms. The service territories of GRE's 28 members stretch from the southwest corner to the northeast [3] corner of Minnesota, with one member serving a small part of northwestern Wisconsin.

6. GRE owns generation resources of 2,404 MW (summer rating) and has major purchase-resources totaling approximately 640 MW. GRE's generation system is composed of a mix of baseload and peaking power plants, including coal, refuse-derived fuel, natural gas and oil plants, as well as wind generation. In 2004, approximately 77% of GRE's electrical generation came from coal-based power plants in North Dakota, 6% from hydropower, 1.5% from natural gas-fueled plants in Minnesota, 1.5% from renewables such as biomass and wind in southwest Minnesota, and 14% purchased. As of 2005, GRE has owned-resources totaling approximately 2,400 MW. It owns and operates more than 4,500 miles of transmission lines, [4] and more than 100 transmission substations.

C. Missouri River Energy Services

7. Missouri River Energy Services (MRES) began in the early 1960s as an informal association of northwest Iowa municipalities with their own electric systems that decided to coordinate their efforts in negotiating the purchase of power and energy from the United States Bureau of Reclamation of the United States Department of the Interior. MRES was established [5] as a body corporate and politic in 1965 under Chapter 28E of the Iowa Code.

8. Municipalities in Minnesota, North Dakota, and South Dakota subsequently joined MRES pursuant to compatible enabling legislation in each state. The agreement between MRES and its members which forms the basis of the obligation of MRES to provide supplemental power supply is its S-1 Power Supply Agreement. MRES a significant part of the Western Minnesota Municipal Power Agency (WMMPA). Current membership in WMMPA consists of 24 municipalities, of which 23 are MRES' members located in Minnesota, each of [6] which owns and operates a utility for the local distribution of electricity.

9. MRES maintains a mix of generation resources, including 281 MW of the Laramie River Station. Peaking resources are provided by generation at the Watertown Power Plant, a 51 MW oil-fired combustion turbine located in Watertown, South Dakota, and the Exira Station, located near Brayton, Iowa, which is powered by two natural gas combustion turbines that provide 100 MW. In addition, generation is provided from wind resources and smaller generation units that are located, owned, operated and maintained by member utilities. MRES has a generating capacity of approximately 564 MW in the winter season and 550 MW in the [7] summer season.

10. Hutchinson Utilities Commission (HUC) was previously one of the named Applicants. However, it now has a power sale agreement to buy 40 MW of capacity and related energy from MRES and is no longer one of the Applicants in its own right. Still, its need is approximately six percent of the Applicants' total demand and part of their need for the [8] transmission lines. Thus, in its analysis, the Department considered HUC as a co-applicant.

D. Southern Minnesota Municipal Power Agency

11. Southern Minnesota Municipal Power Agency (SMMPA) is a not-for-profit municipal corporation and political subdivision of the State of Minnesota, headquartered in Rochester, Minnesota. SMMPA was created in 1977, and has eighteen municipally owned utilities as members, located predominantly in south-central and southeastern Minnesota. [9] SMMPA serves approximately 92,000 retail customers.

12. SMMPA's main source of electricity is the 884 MW Sherco 3 generating unit located near Becker, Minnesota, of which SMMPA owns a 41% interest (approximately 362 MW). SMMPA's energy resource mix also includes intermediate and peaking units owned by its members, including a small amount of wind-generated electricity. SMMPA currently owns [10] and operates approximately 238 miles of transmission lines.

E. Montana-Dakota Utilities

13. Montana-Dakota Utilities Co. (Montana-Dakota or MDU) is an investor owned public utility that operates an integrated electric system in parts of Montana, North Dakota, and South Dakota, and a separate electric system in Wyoming. Montana-Dakota is a division of MDU Resources Group, Inc., an energy company located in Bismarck, North Dakota, that engages in natural gas and oil production, construction materials and mining, domestic and international independent power production, electric and natural gas utilities, natural gas pipelines and energy services, and utility services. Montana-Dakota provides electric and [11] natural gas services to approximately 250 communities.

14. For its integrated system, Montana-Dakota owns and operates 50 miles of 345 kV transmission, 268 miles of 230 kV transmission, 568 miles of 115 kV transmission, and 2,124 miles of transmission below 100 kV. As a full member of the MISO Agreement, Montana-Dakota has turned the operational control of its 100 kV and above transmission system over to [12] MISO.

15. Montana-Dakota owns a mix of generating resources, including baseload, intermediate and peaking plants. It owns a 22.7% undivided interest in Big Stone Unit I, and a [13] 25% undivided interest in the Coyote Station in Beulah, North Dakota. Montana-Dakota has approximately 366 MW of baseload coal generation from five plants, and approximately 110 MW of gas or gas and oil fired combustion turbines used for peaking. In addition, it has power [14] purchase agreements for 66.4 MW of baseload energy and capacity.

16. Montana-Dakota has no retail electric load in the State of Minnesota. As an investor-owned electric utility, Montana-Dakota's retail electric operations are under the regulation of the Montana Public Service Commission, the North Dakota Public Service Commission, the South Dakota Public Utilities Commission, and the Wyoming Public Utilities Commission. Its transmission and wholesale sales are subject to the jurisdiction of the Federal [15] Energy Regulatory Commission (FERC).

F. Central Minnesota Municipal Power Agency

17. Central Minnesota Municipal Power Agency (CMMPA) is a not-for-profit municipal corporation and political subdivision of the State of Minnesota, headquartered in Blue Earth, Minnesota. CMMPA was formed in 1987 and has 12 members, including Blue Earth, Delano, Fairfax, Glencoe, Granite Falls, Janesville, Kasson, Kenyon, Mountain Lake, Sleepy Eye, [16] Springfield and Windom. All twelve have signed agreements with CMMPA to purchase power from the proposed Big Stone Unit II. CMMPA is responsible for supplying wholesale power to its members, who in turn provide electric energy and related services directly to [17] customers across south and central Minnesota. In addition, CMMPA has entered into a power sales agreement with the City of Willmar, Minnesota, to supply it with 9 MW in [18] participation from Big Stone Unit II. The 12 CMMPA members together with Willmar have a [19] peak load of approximately 160 MW.

18. Utilities Plus, a power marketing company wholly-owned by CMMPA, assists the members with the purchase and sale of capacity and energy on a short-term or other basis, as requested, and arranges for transmission services for such purchases and sales. The members rely on Utilities Plus to dispatch the various member resources together with [20] purchases from the market to minimize their total power costs.

19. CMMPA, its members, and Utilities Plus do not own any baseload generation at the present time. CMMPA members obtain the majority of their energy needs through contract purchases and spot market purchases, with self generation providing only 7% of their energy [21] needs. The majority of existing generation owned by CMMPA members is small, 1 to 2 MW diesel-fueled reciprocating engine-driven electric generation. Additionally, some members own larger diesel-fueled reciprocating engine units, combustion turbine units, gas-fueled team [22] electric generating units and wind turbine generating units. Some members own short, high voltage transmission lines, but CMMPA itself owns no transmission facilities.

20. Until 2009 and 2012, when CMMPA's planned baseload unit additions at Nebraska City and Big Stone Unit II, respectively, come on-line, CMMPA is projected to purchase approximately 70% of its energy from the market either directly or through contractual [23] arrangements that closely mirror market pricing.

G. Heartland Consumers Power District

21. Heartland Consumers Power District (Heartland or HCPD) is a not-for-profit public corporation and political subdivision of the State of South Dakota, headquartered in Madison, South Dakota. Created in 1969, Heartland supplies wholesale electric power and energy from a mix of resources to eighteen municipalities across eastern South Dakota, southwestern Minnesota, and northwestern Iowa, as well as to several state institutions and one electric power cooperative. The Western Area Power Administration (WAPA or Western) is the primary supplier of electricity to Heartland's members, and Heartland's role is to supply all or a portion of the supplemental power and energy to those customers who exceed their WAPA allocation.

As of 2004, Heartland's members purchased 50% of their requirements from Heartland, with the remaining load being supplied by WAPA and MRES. Heartland provides service to [24] only two Minnesota cities – Marshall and Tyler.

22. Heartland's generation resources consist of owned resources and participation power contracts. Heartland has a 50 MW undivided ownership interest in the Laramie River Station located in Wheatland, Wyoming, and currently has contracts with other utilities for 57 MW of baseload resources and 24 MW of peaking resources. Two of Heartland's members own and operate wind generators totaling approximately 1 MW. The output of the wind generators is either purchased by Heartland or applied as a credit against the customer's power [25] purchase obligations.

23. Heartland's transmission resources include a 3% undivided ownership interest in the transmission of the Missouri Basin Power Project (built as part of the construction of Laramie River Station) and a 0.3% ownership interest in the "Integrated System." The Integrated System consists of a high-voltage transmission system comprised principally of the transmission facilities operating at 115 kV and higher and owned by WAPA, Basin Electric Power Cooperative, and Heartland. The Integrated System includes over 8,500 miles of high-voltage transmission lines in seven states (Iowa, Minnesota, Missouri, Montana, North Dakota, Nebraska, and South Dakota). The Integrated System operates under its own Open Access Transmission Tariff as administrated by WAPA. Most of the facilities were originally constructed by WAPA to deliver federal hydropower to its preference customers and by Basin Electric [26] Power Cooperative to deliver power to its member systems.

II. The Other Parties

24. The Department is a party in the Certificate of Need matter. During this proceeding, analysts from its Energy Planning & Advocacy Electric Unit addressed issues such as resource planning, cost comparisons, and least-cost analysis.

25. The Department is not a party to the Route Permits matter. But, as required by law, its Energy Facility Permitting Unit prepared the Environmental Impact Statement (EIS) on the transmission project.

26. The Department opposes issuing a Certificate of Need for the transmission project because it believes the Applicants have failed to make several of the showings required by law. The Department suggests that the Applicants amend and refile the Applications, or that the Commission condition the Certificate of Need and Route Permits in such a way as to bring the Applications into legal compliance and make them consistent with the public interest.

27. The Joint Intervenors were granted intervention in the Certificate of Need [27] proceeding on February 8, 2006. The Joint Intervenors oppose the issuance of a Certificate of Need for the transmission lines primarily because they object to the construction of Big Stone II in South Dakota. The Joint Intervenors did not participate in the Route Permit proceeding as [28] full parties, but as non-party participants.

28. Excelsior Energy, Inc.'s Petition to Intervene was granted on February 8, 2006.

[29]
Excelsior Energy cross-examined witnesses and submitted argument on whether its Mesaba Project must be given preference as an alternative under Minn. Stat. § 216B.1694, [30]
subd. 2(a)(5).

29. The Midwest Independent Transmission System Operator's (Midwest ISO or MISO) Petition to Intervene was granted on April 18, 2006. The Midwest ISO is a non-profit Independent Transmission System Operator that serves the electrical transmission needs of much of the Midwestern United States. It is responsible for monitoring the electric transmission system that delivers power from generating plants to wholesale power transmitters.

30. The Midwest ISO supports issuance of a Certificate of Need and Route Permits [31]
for the transmission lines.

31. The Petition to Intervene of FPL Energy, Inc., was granted on April 18, 2006. FPL Energy supports issuance of the Certificate of Need and Route Permits for the two transmission [32]
lines.

32. The Petition to Intervene of Minnesota Municipal Utilities Association (MMUA) was granted on April 18, 2006. MMUA submitted a post-hearing brief arguing that small, municipal utilities should not be forced into using expensive resource planning methodologies in [33]
Certificate of Need proceedings.

33. The Petition to Intervene of the South Dakota Governor's Office of Economic Development was granted on April 18, 2006. The GOED offered the entire record of the proceeding before the South Dakota Public Utilities Commission on the Big Stone Unit II facility as an exhibit in this proceeding, which was received without objection. The GOED supports [34]
issuance of the Certificate of Need and Route Permits for the two transmission lines. No other agency of South Dakota participated or provided comments in this matter.

34. The Petition to Intervene of Ron Gustafson and Linda Castagneri, two citizens concerned about Excelsior Energy's Mesaba Project on the Iron Range, was granted on April 18, 2006, but only as to issues related to the Mesaba Project that might be raised by Excelsior Energy. Gustafson and Castagneri did not appear personally or by representative at the [35]
evidentiary hearing in St. Paul and did not file any post-hearing briefs.

III. Procedural Summary

35. On April 18, 2005, the Applicants submitted a proposed Notice Plan to the Commission. On June 24, 2005, the Commission issued an Order Approving Notice Plan and Requiring Proof That Plan Has Been Carried Out. The Commission delegated to its Executive Secretary the authority to approve final notice language reflecting the agreement among all parties at hearing. The Applicants were also ordered to promptly file and serve on all parties a copy of the final notice distributed under the notice plan and proof that the plan has been carried out, including proof of service of the notice on affected persons and local and tribal governments.

36. On August 25, 2005, Applicants submitted the required compliance filing to show that the amended Notice Plan had been carried out. Also on August 25, 2005, Applicants submitted for Commission approval a Supplemental Notice Plan in response to changes in the proposed project. The Supplemental Notice Plan limited the direct mailing of the Supplemental Notice to those additional landowners, mailing addresses, local and tribal governments and communities indicated on the Applicants' Revised Corridor Map. The Commission met on September 15, 2005, to consider the matter.

37. On September 23, 2005, the Commission issued an Order Requiring Supplementary Notice. It required the Applicants to prepare a Supplementary Notice pursuant to Minn. R. 7829.2550, subp. 5, clarifying that the Applicants' request for a certificate of need will request authority for a 345 kV line in the southern segment of the proposed transmission facilities to interconnect a new coal-fired unit at the Big Stone Power Plant in South Dakota (Big Stone Unit II). The Applicants were also ordered to clarify the anticipated filing date of the Applicants' Application for a Certificate of Need to construct the transmission lines in question. The Applicants were further ordered to mail the Supplementary Notice to the certain persons and organizations in the affected areas. Lastly, the Commission ordered that the Applicants' Supplementary Notice be accompanied by a brief letter explaining why the Applicants have decided that any transmission line they would propose for the southern segment would be a 345 kV line.

38. On October 3, 2005, the Applicants submitted a Certificate of Need Application to the Commission. The Certificate of Need proceeding was assigned PUC Docket No. CN-05-619.

39. On October 5, 2005, the Commission issued a Notice requesting comments on the substantial completeness of the Certificate of Need application. In its Notice, the Commission also invited comments on procedural recommendations included by the Applicants in their October 3rd filing. The Notice set comment and reply comment periods ending on October 21, 2005, and November 4, 2005, respectively.

40. The Commission received initial completeness review comments on the certificate of need filing from the Department, the Joint Intervenors, and from Carol Overland.

41. On October 25, 2005, the Commission issued an Order Extending Deadline of Minn. R. 7849.0200, subp. 5. In that Order, the Commission indicated that it would consider the substantial completeness of the Petition as soon as practicable following receipt of all written comments.

42. The Commission received reply comments from the Joint Intervenors, Excelsior Energy, and Applicants. Applicants also filed a Supplement to the Petition.

43. On November 29, 2005, the Commission issued its Order combining the Environmental Report and the Environmental Impact Statement.

44. On December 9, 2005, the Applicants submitted their Application for Route Permits for Transmission Lines in Western Minnesota. The Route Permit proceeding was assigned PUC Docket No. TR-05-1275.

45. On December 19, 2005, the Commission issued its Notice and Order for Hearing referring the matter to the Office of Administrative Hearings for the holding of a contested case proceeding and directing the Applicants to provide notice to the public of any public and

evidentiary hearings to be held.

46. The Commission also issued a companion Order on December 19, 2005, that granted Applicants a variance from the environmental review document requirements of Minn. R. 7849.0230, because the rule had been effectively superseded by the environmental report rules adopted by the Environmental Quality Board. The Commission also granted a variance from the requirements of Minn. R. 7849.0270, subp. 2, insofar as that rule calls for customer class information from HCPD, SMMPA, and MRES that was not available. The Applicants' Petition was accepted as substantially complete as of the date the Applicants submitted supplementary information, on November 4, 2005. Applicants were also ordered to file additional supplementary information including:

a. For each participating utility, construct the generation and demand-side management alternative considered most viable to match approximately the megawatt share that utility would receive from the Big Stone II plant in 2011.

b. Including the environmental cost values adopted by the Commission, compare and contrast the costs of the resulting overall generation and demand-side management alternative (i.e., the combination of all seven sub-alternatives and associated transmission improvements) with the Big Stone projects (i.e., Big Stone Unit II plus the preferred transmission alternative provided in the application).

c. To the extent possible, discuss the comparative reliability of the resulting overall generation and demand-side alternative with that of the Big Stone projects.

d. To the extent possible, further compare the resulting overall generation and demand-side alternative with the Big Stone projects, considering the data elements listed in Minn. R. 7849.0340, item B.

e. To the extent possible, discuss how changes in demand or changes in the in-service dates of the indicated resources would affect the above comparisons.

f. Provide any other information deemed relevant to comparing the Applicants' proposal and the alternative described above.

Applicants were also ordered to place the November 4, 2005, Supplement and the supplementary material required pursuant to paragraphs a through f, above, on a website at the same location as the original Petition.

47. In January 2006, notices were published in several local newspapers announcing the holding of public meetings to provide the public with information about the project and to solicit public input into the scope of the Environmental Impact Statement to be prepared by the Department. In addition, the Applicants mailed notice about the public meetings to hundreds of residents in the area. The public meetings were held in Benson, Morris, Ortonville, Canby, and Granite Falls, Minnesota, from January 24 to 26, 2006. A number of members of the public appeared at the public hearings and entered comments about the project.

48. On February 28, 2006, the Commissioner of the Department of Commerce issued the Scoping Order for the Environmental Impact Statement. The Department completed the Draft EIS on July 31, 2006, and mailed a Notice of Availability of Draft EIS to interested persons on or about that same day. The Notice advised the public that written comments on the Draft

[36]
EIS would be accepted by the Department until October 31, 2006.

49. In September and October 2006 the Applicants published notice in local newspapers about public information meetings to be held in the area to solicit public comments on the Draft EIS. Public information meetings were held in Benson on October 9, in Morris on October 10, in Ortonville on October 11, in Canby on October 12, in Granite Falls on October 13, and in St. Paul on October 16. Several people appeared at the meetings and entered
[37]
comments about the Draft EIS, the proposed transmission lines, and the Big Stone II plant.

50. The Department responded to the comments that were received on the Draft EIS and prepared a Final EIS, which became available on December 1, 2006. The Administrative Law Judges provided that written comments could be submitted on the Final EIS and on these matters until December 11, 2006. A substantial number of written public comments were
[38]
received.

51. The evidentiary hearing commenced on December 5, 2006, in St. Paul. Nine days of evidentiary hearing were held, ending on December 22, 2006.

52. The parties submitted briefs, proposed findings of fact, and reply briefs. The last reply brief was filed on February 13, 2006, at which time the record was closed.

53. The Joint Intervenors sent an email May 25, 2007, advising the ALJs of the passage of Minnesota's "Next Generation Energy Act of 2007," which had been signed by the Governor that day. It was published as Minn. Laws 2007, ch. 136. The Joint Intervenors had previously referred to parts of the Act while it was being proposed. Administrative Notice is taken of the Act, and it is noted that Article 5 of the Act, which relates to greenhouse gas emissions, has limited application to new large energy facilities whose applications to the Commission were filed before April 1, 2007.

IV. Related Proceedings

54. Four of the Applicants are required to submit Integrated Resource Plans (IRPs) to the Minnesota Public Utilities Commission pursuant to Minn. Stat. § 216B.2422. The four are Otter Tail Power – PUC Docket No. E017/RP-05-968; GRE – PUC Docket No. ET2/RP-05-1100; SMMPA – PUC Docket No. ET9/RP-06-605; and MRES – PUC Docket No. ET10/RP-05-
[39]
1102.

55. In its November 16, 2006, Order accepting the MRES Resource Plan, Dkt. No. RP-05-1102, the Commission held that its acceptance of the MRES Resource Plan was not a decision on the relative merits of the Big Stone Unit II plant and did not shift the burden of proof
[40]
in this Certificate of Need proceeding.

56. Montana-Dakota has no customers in Minnesota and is not required to submit an Integrated Resource Plan to the Minnesota Commission. However, Montana-Dakota does submit a Resource Plan to both the North Dakota Public Service Commission and the Montana
[41]
Public Service Commission.

57. Central Minnesota Municipal Power Agency and Heartland Consumers Power District are not required to submit Integrated Resource Plans to any state agency, but do [42] engage in resource planning.

58. On July 21, 2006, the South Dakota Public Utilities Commission issued an Energy Conversion Facility Siting Permit to the Applicants authorizing construction of Big Stone Unit II, subject to certain conditions such as requiring the Applicants to obtain other state, federal, and local permits. The entire South Dakota administrative record has been introduced into this [43] record.

V. "The Project"

59. Most often the parties, witnesses, and people making public comments used terms such as "the Project," "the proposed project," "Big Stone II," or "the Big Stone II Project" to refer to the proposed Big Stone Unit II generating plant project. But, sometimes they used the same terms to refer to the two high voltage transmission lines that will be built to carry the electricity from Big Stone Unit II over short distances in South Dakota and into Minnesota. And sometimes they used them to refer to both.

60. In this Report, the unqualified term "the project" will be avoided to the extent possible. "Big Stone Unit II," "Big Stone II," "Big Stone II Project," "Unit II," or "generation project" will be used to refer to the proposed Big Stone Unit II generating plant. "Transmission Project" or "transmission lines" will be used to refer to the two transmission lines at issue in this matter. Usually, such a reference will be only to the portions of the transmission lines that will be built in Minnesota and that are at issue here.

A. The Generation Project

61. The following description of Big Stone II is given primarily for background information and for a more complete understanding of the Transmission Project. Otherwise, evidence about the Generation Project is largely irrelevant, except for the fact that it is a nonrenewable energy source, which triggers certain requirements for the Transmission Project, and except for the fact that the Applicants base their need for the Transmission Project largely upon the same evidence they presented in the South Dakota proceeding on the Generation Project.

62. Big Stone Unit II is a supercritical pulverized coal-fired generating plant to be built in South Dakota. Big Stone Unit II will have a nominal operating capacity of 630 MW. The Applicants anticipate that Big Stone Unit II, when under commercial operation, will achieve a [44] capacity factor of approximately 88% on an annual basis.

63. Big Stone II will be located on the top of the bluff southwest of Big Stone Lake, which is the border between South Dakota and Minnesota at that point. It will be built adjacent to the existing Big Stone power plant (Big Stone Unit I) in Grant County, South Dakota. The Big Stone Unit I plant building is about two and one-half miles west of Minnesota; its evaporation [45] pond extends to within a mile of Minnesota's western border.

64. Big Stone Unit II is designed to be a baseload facility, which in this case means

that it is intended to be operated 24 hours per day, very nearly 365 days per year. It will be expected to be available close to 90% of the time and be "dispatchable" so that output can [46] be increased or decreased as necessary to meet system needs.

65. Big Stone Unit II will burn sub-bituminous coal from the Powder River Basin in [47] Wyoming and Montana, which is the same fuel presently being burned in Big Stone Unit I.

66. Big Stone Unit II will have state-of-the-art air pollution control equipment. It will use burners that produce low levels of nitrogen oxides. In addition, selective catalytic reduction (SCR) nitrogen oxides (NOx) control technology will be installed to keep emissions of nitrogen oxides at very low levels. This technology is not available for Unit I, but plans are underway to change the way in which Unit I's over-fire air system is operated to reduce emissions of NOx from Big Stone Unit I. Ultimately, nitrogen oxide emissions from both units will be equal to or [48] less than Unit I's historical emissions.

67. A pulse-jet fabric filter will be installed to control particulate emissions from Unit II. This equipment is considered to be the Best Available Control Technology for particulate [49] matter.

68. Coal contains sulfur and mercury, which can be emitted out the stack during operation of the plant in various chemical forms. The Applicants will install a wet flue gas desulfurization system (wet scrubber) that will capture and control emissions of sulfur dioxide and mercury from both Unit I and Unit II. When this wet scrubber is in operation, emissions of [50] sulfur dioxide from both units will be less than 1/7 of what is emitted today just from Unit I.

69. The Applicants will control mercury emissions both through use of the wet [51] scrubber and also through use of a pulse jet fabric filter. In addition, the Applicants have committed to a voluntary cap on mercury emissions limited to the amount of mercury that is presently emitted from Unit I annually – 189 pounds – beginning three years after commercial operation of Big Stone II. The South Dakota PUC imposed this commitment upon Applicants as [52] a condition of the South Dakota Energy Conversion Facility Site Permit.

70. The Applicants also are aware and have committed to comply with the requirements of the federal Clean Air Mercury Rule (CAMR). The CAMR will require the Applicants to reduce mercury emissions to less than the present 189 pounds per year or to purchase allowances from other emission facilities that have reduced mercury emissions. The Applicants intend to operate the Big Stone Plant so that mercury emissions are within the [53] CAMR allowance for the state of South Dakota.

71. In 2006, the Minnesota Legislature passed the Minnesota Mercury Emission [54] Reduction Act. This Act applies to only three existing coal-fired power plants in Minnesota – the Allen S. King Plant near Stillwater, the Sherco Plant near Becker, and the Clay Boswell Plant near Grand Rapids. The Act is intended to realize a 90% or better removal rate for

mercury from these three facilities as compared to a baseline amount that is to be determined. The Act does not apply to Big Stone II, nor to any generating facilities owned by any of the Applicants. However, the commitments the Applicants have made for controlling mercury emissions from Big Stone II are similar to the requirements of Minnesota law. Though it will be some years in the future, if the Applicants achieve the expected CAMR allowance for South Dakota, they will have achieved a better than 90% removal efficiency for mercury [55]
emissions.

72. Big Stone II will emit 4.7 million tons of carbon dioxide annually when in full [56]
operation. Because its supercritical technology requires 18-20% less coal than existing coal-fired power plants to produce the same amount of electricity, Big Stone II will produce 18- [57]
20% less CO2 than if it had the same design as existing coal-fired power plants.

73. No feasible technology exists today that will capture and sequester significant amounts of the CO2 produced by coal-fired power plants, although extensive research is [58]
underway around the world to develop methods to control CO2 emissions. The Applicants have committed to stay advised of developments with regard to control of CO2 emissions, but have no current plans for CO2 control.

74. The Applicants will have to appropriate water from Big Stone Lake to operate the Big Stone Plant. The South Dakota Water Management Board issued a permit to the Applicants to appropriate water from the lake for operation of Unit II on July 12, 2006. The Minnesota Department of Natural Resources has raised a concern about the availability of water from Big Stone Lake during drought conditions. In response, the Applicants have proposed to use groundwater for drought protection rather than a proposed 450 acre makeup water storage pond. The South Dakota Department of Environment and Natural Resources is still considering the request by the Applicants for approval to rely on groundwater for makeup [59]
water. The Minnesota DNR will have an opportunity to participate in that proceeding.

75. On December 8, 2006, Big Stone II was estimated by its Project Manager to cost $1.361 billion in 2011 dollars, assuming it went into commercial operation in 2011. This does not include any costs for transmission. He estimated the cost to be increasing at about 6% per year due to inflation – approximately $7 million per month. So a later commercial operation [60]
date would have a cost escalated by that factor.

76. The Applicants originally anticipated an in-service date of mid-2011 for Big Stone II. However, in August 2006, the Applicants decided not to enter into procurement contracts for several major pieces of equipment, which will likely result in a delay in the in-service date. The anticipated in-service date now is mid-2012, but is subject to slippage. For example, this date is [61]
contingent on Applicants receiving their South Dakota air permit by October 2007.

77. Because of the changes, some of the Applicants used different in-service dates in their studies for modeling a least-cost alternative. That difference may have some impact in evaluating the results of those studies. In addition, Applicant witnesses testified to different estimated capital costs for the generation project, and used different costs for purposes of

modeling the least-cost alternative, but were able to reconcile those costs for Joint [62]
Intervenors.

78. The Applicants will own Big Stone Unit II as tenants in common in the following [63]
percentages:

Utility	Percent Share	MW Share
MRES (w/ HUC PSA)	25.00 %	157.5 MW
GRE	19.33 %	121.8 MW
MDU	19.33 %	121.8 MW
OTP	19.33 %	121.8 MW
SMMPA	7.80 %	49.35 MW
CMMPA	5.00 %	31.5 MW
HCPD	4.20 %	26.25 MW
Totals	100.00 %	630 MW

B. The Transmission Project

79. The Transmission Project consists of the Minnesota portions of two new high voltage transmission lines that would run from the Big Stone Plant in South Dakota to substations in Minnesota. One new transmission line would run from the Big Stone 230 kilovolt (kV) Substation in South Dakota to the Morris Substation near Morris, Minnesota, a total of approximately 48 miles, about 43 miles of which are in Minnesota. The Big Stone to Morris transmission line would be constructed at 230 kV. The other transmission line would run from a new Big Stone 345 kV substation in South Dakota to Granite Falls, Minnesota, a distance of approximately 90 miles, 54 miles of which would be in the State of Minnesota. The Granite [64]
Falls transmission line would be constructed at 345 kV, but operated initially at 230 kV.

80. The Applicants investigated one system alternative to the now-proposed transmission lines – a transmission line to the Willmar, Minnesota, area rather than a line to Morris. The Granite Falls line is common to both the Morris alternative and the Willmar alternative. The Applicants also investigated several different routes for both the preferred lines [65]
and the alternative line to Willmar.

81. The Applicants require a right-of-way width of 125 feet for the Morris 230 kV transmission line and 150 feet for the Granite Falls 345 kV transmission line. However, the Applicants have requested that the designated routes be up to 2,000 feet in width to allow for flexibility in determining the actual right-of-way at the time of construction so the Applicants can [66]
work with landowners on actual structure placement.

82. Both proposed transmission lines will follow existing right-of-way for most of the length of the lines. Only about 14 miles of new right-of-way will be required for the two transmission lines; the remainder of the proposed lines will follow existing transmission line right-of-way.

83. The actual structure type will be determined once final engineering analysis is complete. Presently, H-frame structures of wood or steel are preferred by the Applicants. The structures on the Morris 230 kV transmission line will be 70 to 100 feet in height with average spans of 700 feet. The Granite Falls 345 kV transmission line will have, on average, 800 feet [67]
between spans and will be 80 to 120 feet high.

84. The anticipated conductors for the Morris line will likely be 795 26/7 ACSS (aluminum conductor steel supported) or 1272 ACSR (aluminum conductor steel reinforced), with the final selection dependent on final engineering design considerations. The line will use [68]
three single conductors and will not be bundled.

85. The Granite Falls line will likely use a 1272 ACSR conductor. There will be six conductors altogether, with two bundled conductors for each of the three phases, with the final [69]
selection dependent on final engineering design considerations.

86. Along with construction of the transmission lines, several substations will have to be upgraded. With the Morris 230 kV transmission line, the Johnson Junction Switch Station and the Morris Substation will both require additional equipment. The Johnson Junction Switch Station will become a substation as a transformer is added to the site and the station will be expanded by an area approximately 400 feet by 400 feet. No expansion is required at the [70]
Morris Substation.

87. With the Granite Falls 345 kV transmission line, the Granite Falls Substation will be upgraded with the addition of new equipment. The Granite Falls Substation has adequate [71]
space for the new equipment and will not have to be expanded in size.

88. The Applicants intend to move the location of the Canby Substation in Yellow [72]
Medicine County. The new location is approximately one mile northeast of the existing site.

89. The transmission lines will be owned by the Applicants in the same proportions as [73]
Big Stone Unit II.

90. The costs of the Transmission Project have increased from what was presented in the Route Permit Application, due to inflationary factors. In their First Supplement, Applicants estimated the total capital cost for the proposed transmission project as a range between $93.3 million and $135 million using 2010 dollars. The two transmission lines, including all substation costs except the 345 kV substation in South Dakota, are estimated to cost $109.8 million in 2006 dollars. When the costs for the delivery service are included and the figures converted to [74]
2011 dollars, the total costs are estimated to be $238 million in 2011 dollars.

91. The Granite Falls line will be constructed first to provide less risk of service interruptions when the Morris line is taken out of service. The Granite Falls line is scheduled to be in service by March 2009. Construction of the Granite Falls line will take at least two years.

[75]
The Morris line is scheduled to be in operation by June 2010.

VI. Commission Jurisdiction

92. The Applicants seek a Certificate of Need and Route Permits for two high voltage transmission lines in Minnesota to be built from points on the South Dakota-Minnesota border where they would connect to high voltage transmission lines that originate at the Big Stone power plants in South Dakota, to two termination points in Minnesota.

93. Both of the proposed transmissions lines meet the definition of "large energy facility" under Minn. Stat. § 216B.2421, subd. 2(2). All the Applicants meet the definition of "person" under Minn. Stat. § 216B.02, subd. 3. Therefore, under Minn. Stat. § 216B.243, subds. 2 and 4, the Applicants must apply for and obtain a Certificate of Need from the Commission under Minn. Stat. §§ 216B.243 and 216C.05 to 216C.30, and route permits from the Commission under Minn. Stat. Ch. 216E, prior to construction of the transmission lines in
[76]
Minnesota.

94. The Commission does not have or claim jurisdiction to require a Certificate of Need or Site or Route Permits for the Big Stone Unit II plant, or for the portions of the transmission lines in South Dakota. It does have jurisdiction to review and approve or deny a Certificate of Need and Route Permits for the portions of the transmission lines in Minnesota. To the extent Minnesota statutes or rules require the Applicants, as part of demonstrating the need for the transmission lines, to demonstrate the need for the electricity the Applicants claim must come from Big Stone Unit II and to evaluate certain alternative sources for any such electricity, the Commission has jurisdiction to consider and decide such issues. As the Commission has stated previously in this docket:

> The Commission does not accept the Applicants' further argument that the generation and demand-side information referred to by the [Joint Intervenors] is extraneous to the Commission's consideration of the merits of the Application. The need for the generating facility and the need for the transmission lines are inextricably linked. As a matter of logic, the transmission lines proposed to be constructed in Minnesota will not be needed where they are proposed if the Applicants have a more reasonable and prudent alternative generation site. And the proposed transmission lines will not be needed at all if the Applicants (due to demand-side management or any combination of other alternatives) do not need the electricity projected to be generated at the Big Stone, South Dakota facility. [77]

95. The fact that Big Stone II is so near to Minnesota is a significant issue for certain parties and many members of the public. Minnesota lies within a very few miles to the northwest, north, northeast, east, and southeast of the Big Stone II site. The prevailing westerly winds will carry airborne pollutants from the plant primarily over and onto Minnesota. The Minnesota River flows southeasterly out of Big Stone Lake and into Minnesota. Water usage and any pollution of the lake and river will primarily affect Minnesota. Thus, most of the negative impacts of Big Stone II will be felt in Minnesota, not in South Dakota. On the other hand, the proposed reductions in total emissions from Units I and II compared to the existing emissions from just Unit I will particularly benefit Minnesota. There will also be economic benefits in Minnesota if Big Stone II is built. Southwestern Minnesota will provide some of the

workers to build and operate the plant and additional money will be spent in Ortonville and the surrounding area. The Applicants, primarily Minnesota utilities, will derive benefit from owning and operating Big Stone II, and their customers will benefit from obtaining the energy it will produce. While these impacts on and relationships to Minnesota are very substantial, they do not create any legal jurisdiction for the Commission over Big Stone II.

VII. Certificate of Need Criteria and Factors

96. The primary legal requirements for a certificate of need of the type requested are set forth in Minn. Stat. § 216B.243, subds. 3 and 3a, and Minn. R. 7849.0120.

97. Minn. Stat. § 216B.243, subd. 3, provides:

> Subd. 3. **Showing required for construction.** No proposed large energy facility shall be certified for construction unless the applicant can show that demand for electricity cannot be met more cost effectively through energy conservation and load-management measures and unless the applicant has otherwise justified its need. In assessing need, the commission shall evaluate:
>
> (1) the accuracy of the long-range energy demand forecasts on which the necessity for the facility is based;
>
> (2) the effect of existing or possible energy conservation programs under sections 216C.05 to 216C.30 and this section or other federal or state legislation on long-term energy demand;
>
> (3) the relationship of the proposed facility to overall state energy needs, as described in the most recent state energy policy and conservation report prepared under section 216C.18, or, in the case of a high-voltage transmission line, the relationship of the proposed line to regional energy needs, as presented in the transmission plan submitted under section 216B.2425;
>
> (4) promotional activities that may have given rise to the demand for this facility;
>
> (5) benefits of this facility, including its uses to protect or enhance environmental quality, and to increase reliability of energy supply in Minnesota and the region;
>
> (6) possible alternatives for satisfying the energy demand or transmission needs including but not limited to potential for increased efficiency and upgrading of existing energy generation and transmission facilities, load-management programs, and distributed generation;
>
> (7) the policies, rules, and regulations of other state and federal agencies and local governments;
>
> (8) any feasible combination of energy conservation improvements, required under section 216B.241, that can (i) replace part or all of the energy to be provided by the proposed facility, and (ii) compete with it economically;
>
> (9) with respect to a high-voltage transmission line, the benefits of

enhanced regional reliability, access, or deliverability to the extent these factors improve the robustness of the transmission system or lower costs for electric consumers in Minnesota;

(10) whether the applicant or applicants are in compliance with applicable provisions of sections 216B.1691 and 216B.2425, subdivision 7, and have filed or will file by a date certain an application for certificate of need under this section or for certification as a priority electric transmission project under section 216B.2425 for any transmission facilities or upgrades identified under section 216B.2425, subdivision 7;

(11) whether the applicant has made the demonstrations required under subdivision 3a; and

(12) if the applicant is proposing a nonrenewable generating plant, the applicant's assessment of the risk of environmental costs and regulation on that proposed facility over the expected useful life of the plant, including a proposed means of allocating costs associated with that risk.

98. To summarize, Minn. Stat. § 216B.243, subd. 3, sets forth two criteria that must be met: (1) the Applicants' demand for electricity cannot be met "more cost effectively" through energy conservation and demand side management (DSM), and (2) the Applicants' need for electricity is "otherwise justified." Since "demand" and "need" are essentially equivalent terms here, consideration must be given to any of the twelve factors as may apply to either criterion. [78]

The statute expressly puts the burden of proof upon the Applicants as to both criteria.

99. Minn. Stat. § 216B.243, subd. 3a, states:

Subd. 3a. **Use of renewable resource.** The commission may not issue a certificate of need under this section for a large energy facility that generates electric power by means of a nonrenewable energy source, or that transmits electric power generated by means of a nonrenewable energy source, unless the applicant for the certificate has demonstrated to the commission's satisfaction that it has explored the possibility of generating power by means of renewable energy sources and has demonstrated that the alternative selected is less expensive (including environmental costs) than power generated by a renewable energy source. For purposes of this subdivision, "renewable energy source" includes hydro, wind, solar, and geothermal energy and the use of trees or other vegetation as fuel.

100. The proposed transmission lines will primarily transport electric power generated by Big Stone II, which uses coal, a nonrenewable energy source, as fuel. Thus, Minn. Stat. § [79] 216B.243, subd. 3a, applies to this matter. It creates two additional criteria that must be met: the Applicants, (1) must have made a reasonable study of renewable energy sources; and (2) must have demonstrated that there is no reasonable renewable energy source, or combination thereof, for generating power that is less expensive than their chosen alternative, Big Stone II. Like Subdivision 3 on energy conservation, this subdivision also expressly puts the burden of proof upon the Applicants as to both criteria.

101. Minn. R. 7849.0120 sets forth four criteria that must be met and 13 factors to be

considered regarding those criteria. It provides:

7849.0120 CRITERIA.

A certificate of need must be granted to the applicant on determining that:

A. the probable result of denial would be an adverse effect upon the future adequacy, reliability, or efficiency of energy supply to the applicant, to the applicant's customers, or to the people of Minnesota and neighboring states, considering:

(1) the accuracy of the applicant's forecast of demand for the type of energy that would be supplied by the proposed facility;

(2) the effects of the applicant's existing or expected conservation programs and state and federal conservation programs;

(3) the effects of promotional practices of the applicant that may have given rise to the increase in the energy demand, particularly promotional practices which have occurred since 1974;

(4) the ability of current facilities and planned facilities not requiring certificates of need to meet the future demand; and

(5) the effect of the proposed facility, or a suitable modification thereof, in making efficient use of resources;

B. a more reasonable and prudent alternative to the proposed facility has not been demonstrated by a preponderance of the evidence on the record, considering:

(1) the appropriateness of the size, the type, and the timing of the proposed facility compared to those of reasonable alternatives;

(2) the cost of the proposed facility and the cost of energy to be supplied by the proposed facility compared to the costs of reasonable alternatives and the cost of energy that would be supplied by reasonable alternatives;

(3) the effects of the proposed facility upon the natural and socioeconomic environments compared to the effects of reasonable alternatives; and

(4) the expected reliability of the proposed facility compared to the expected reliability of reasonable alternatives;

C. by a preponderance of the evidence on the record, the proposed facility, or a suitable modification of the facility, will provide benefits to society in a manner compatible with protecting the natural and socioeconomic environments, including human health, considering:

(1) the relationship of the proposed facility, or a suitable modification thereof, to overall state energy needs;

(2) the effects of the proposed facility, or a suitable modification thereof, upon

> the natural and socioeconomic environments compared to the effects of not building the facility;
>
> (3) the effects of the proposed facility, or a suitable modification thereof, in inducing future development; and
>
> (4) the socially beneficial uses of the output of the proposed facility, or a suitable modification thereof, including its uses to protect or enhance environmental quality; and
>
> D. the record does not demonstrate that the design, construction, or operation of the proposed facility, or a suitable modification of the facility, will fail to comply with relevant policies, rules, and regulations of other state and federal agencies [80] and local governments.

102. Other statutes, some of which are expressly incorporated by Minn. Stat. § 216B.243, subd. 3, arguably impose additional criteria to be met or factors to be considered. They are: Minn. Stat. §§ 216B.2422, subd. 4 (renewable energy preference), 216B.2426 (distributed generation), 216B.1691 (renewable energy objective), 216B.2425, subd. 7 (transmission needed to support renewable resources), 216B.1612 (community-based energy development projects), and 216B.1694, subd. 2 (innovative energy project).

103. The Applicants argue that they are only required to meet the requirements of Minn. R. 7849.0120 and not the requirements of the Minn. Stat. § 216B.243, subds. 3 and 3a. [81]

They base this argument on the language of the rule and upon statements made by the Commission in an October 23, 2006, Order granting a Certificate of Need for installation of a dry [82] cask storage facility at the Monticello nuclear plant (the Monticello Order). The section of the Monticello Order at issue begins with a heading that states, "The Company has Demonstrated Need for the Proposed Facility Under the Certificate of Need Statute and Rules." It then states:

> The certificate of need statute, Minn. Stat. § 216B.243, subds. 3 and 3a, requires the Commission to establish criteria for assessing the need for large energy [83] facilities and list factors the Commission must take into account:

The Monticello Order then sets forth the text of Minn. Stat. § 216B.243, subds. 3 and 3a. The Monticello Order then goes on to state:

> The Commission's certificate of need rules incorporate and expand on the statutory factors. Those rules require the Commission to issue a certificate of need when the following requirements have been met:

The Monticello Order then sets forth the text of Minn. R. 7849.0120 and concludes "The Legal Standard" subsection with the following statement:

> The rule's criteria are interrelated, but will be addressed individually, since the rule requires written findings on each of them. Minn. Rules, part 7855.0100. All four criteria have been met.

104. The Applicants appear to argue that this language in the Monticello Order means that what they call the "Certificate of Need Criteria" are set forth only in the rule and that the rule constitutes the "operative legal standards" that should govern the present proceeding. They then argue that they have met all the criteria in Minn. R. 7849.0120, and, because nothing more [84] is required, the Commission must issue the Certificate of Need.

105. While Minn. R. 7849.0120 states that a Certificate of Need must be granted to an applicant on determining that the rule's criteria have been met, the Applicants read the rule and the Monticello Order too broadly. First, they ignore the Commission's statement in the Monticello Order that the applicant there had demonstrated need for the proposed facility "under the Certificate of Need Statute **and** Rules," [emphasis added] and its quotation of both the statutes **and** the rule. Second, contrary to Applicants' apparent argument, the rule does not purport to repeal or replace any provision of any statute. Interpreting the rule in such a manner would be improper, because no agency has authority to adopt a rule that is contrary to a statute. Rather, as the Monticello Order states, the rule was intended to supplement and interpret the statutes and to incorporate and expand on the statutory factors. The rule's criteria and factors are stated in broad terms that attempt to encompass all the statutory criteria and factors, and sometimes do so in general terms. Thus, where a specific criterion or factor appears in an applicable statute that is not expressly stated in the rule, that criterion or factor must nonetheless be met or considered. For example, the rule does not expressly mention assessing renewable energy resources as required by Minn. Stat. § 216B.243, subd. 3a. But, that requirement fits generally within the rule's requirement for evaluation of alternatives giving consideration to comparable costs, effects upon the natural environment, and other factors. Even if it did not, it is necessary, and within the Commission's authority and statutory duties, to address the renewable energy resource requirements of the statute, either within the context of the rule's criteria and factors, or separately. In this report, Minn. R. 7849.0120 will be used as a general outline for assessing compliance with the Certificate of Need criteria. Additional statutory requirements will also be considered within the outline of the rule.

VIII. Compliance with Certificate of Need Criteria

106. Although not required by statute or rule, resource planning is the most appropriate mechanism for determining need in a case such as this and for considering the statutory preferences for conservation and renewable resources, accounting for externalities, and for [85] determining what the least-cost alternatives are for any additional generation that is needed.

107. For resource planning for more capacity, a capacity expansion computer model should be employed, such as Strategist or EGEAS. Capacity expansion models test a large number of potential expansion plans under a given set of inputs to determine the least-cost expansion path. Given the complexity of utility systems and the complexity of evaluating renewable resources and demand side management, the various resource scenarios must be run through a capacity expansion model to most easily and accurately determine what impacts are likely. With the exception of Heartland, the Applicants all used capacity expansion modeling [86] in this case.

108. Heartland explained that it did not use a capacity expansion model because it has a rigorous resource planning process that includes computer modeling that is satisfactory for its [87] purposes and a capacity expansion model is too expensive for small organizations like it.

Similarly, the Minnesota Municipal Utilities Association submitted a brief arguing that the small, municipal utilities should not be forced into using expensive resource planning methodologies in Certificate of Need proceedings.

109. The statutes and rule setting forth the Certificate of Need criteria make no distinction among applicants based upon such factors as an applicant's size, location, organizational structure, ownership, or form of regulation. They require the same showing of need by all the Applicants here. The impact of this requirement is mitigated somewhat by the fact that the Department's analysts, through discovery and conferences, worked with the Applicants' planners to assist them in developing and providing the data needed to support the Application. In turn, the planners did work with the Department and developed and provided that data where possible.

A. Would Denial of the CON Probably Result in an Adverse Effect upon the Future Adequacy, Reliability, or Efficiency of the Energy Supply?

110. This criterion relates to establishing the need, or demand, for the energy that the Applicants seek to have delivered over the transmission lines.

(1) The Accuracy of the Applicants' Forecasts

111. The demand for electricity in the Applicants' service territories is growing and is predicted to continue growing over the foreseeable future. The Mid-Continent Area Power Pool (MAPP) is a voluntary association of electric utilities and other electric industry participants serving the Upper Midwest, including the areas served by the Applicants. MAPP predicts that continuing load growth will result in inadequate generation capacity by the year 2011, unless additional generation resources are added. The most recent MAPP Load and Capability Report, released in August 2006, shows a capacity deficit of 568 MW by 2011 and 2400 MW by [88]
2014. Capacity deficit is based upon projected need, plus a fixed percentage margin.

112. The Applicants claim they need to procure additional generation resources. The following table shows the Applicants' forecasts of their baseload needs in 2012 and each [89]
Applicant's proposed share of the 630 MW from Big Stone Unit II.

Utility	Baseload Need in 2012	Share in Big Stone Unit II
CMMP	60	31.50
GRE	406	121.80
HCPD	30	26.25
MDU	126	121.80
MRES	180	157.50
OTP	115	121.80
SMMPA	100	49.35
Totals	1017	630.00

113. The Applicants provided a significant amount of information regarding their long-range forecasts, data inputs, and assumptions. However, much of that information was provided only after several requests for additional supporting information from Hwikwon Ham, an analyst for the Department who reviewed the input data, statistical modeling, output data, and historical consistency of the forecasts to evaluate their accuracy. He was of the opinion

that, eventually, all of the Applicants, except MDU, showed that their forecasts were reasonable. But he was unable to verify or reproduce MDU's forecast, so was unable to confirm its accuracy. Ham concluded that "MDU's long-term forecast process is, at best, doubtful." Because MDU owns a significant share of the generation and transmission line [90]
projects, the questions about the accuracy of its forecasted need is of some concern.

114. Hoa Nguyen, a resource planner for MDU, presented testimony explaining the manner in which MDU conducts its load forecasting. MDU has consistently used an integrated end-use model for more than 15 years, as required by North Dakota. Nguyen presented data showing that MDU's forecasts had been quite accurate in predicting annual energy usage in the [91]
past few years.

115. Nguyen explained that MDU's modeling did not determine the least-cost size that it should acquire. Rather, it confirmed that Big Stone II is the lowest cost baseload option for it. [92]

116. OTP and some of the other Applicants updated their forecasting to account for cost increases for Big Stone II. The total figures were subsequently updated to account for a revision to HUC's baseload need. According to Bryan Morlock, P.E., Director of Resource [93]
Planning at Otter Tail, the final modeling results show that the Applicants need significantly more baseload capacity starting in the 2011 to 2012 timeframe than Big Stone Unit II can provide, regardless of whether Big Stone Unit II is viewed at a nominal 600 MW rating, or a nominal 630 MW rating. The Applicants need 901 MW of baseload capacity in 2011, and more than 1,012 MW in 2012. GRE in particular shows significant capacity and energy needs during [94]
the planning period.

117. Dr. Steve Rakow testified on behalf of the Department on several issues. Dr. Rakow has Bachelors Degrees in Accounting and in Economics from Moorhead State University, a Master of Arts in Economics from Mankato State University, and a Ph.D. in Economics from the University of Nebraska. Dr. Rakow has been a Public Utilities Rates Analyst for the Department since 1996. He analyzes filings and provides testimony in contested matters before the Commission regarding conservation projects, resource plans, and [95]
miscellaneous public policy issues.

118. MDU's 19.33% share of Big Stone II was determined when Big Stone II's nominal design capacity was determined to be 600 MW. When that design capacity was increased by 5% to 630 MW to account for higher summer temperatures, MDU's percentage share was not modified. Thus, MDU's self-determined "baseload need" was increased by 5% without any re-determination of its need. Similar "over-subscribing" occurred with CMMPA, OTP, and SMMPA. However, this was not necessarily inappropriate. If the nominal design capacity has to be increased for the plant to deliver required capacity in the summer, it is necessary to do so for all the Applicants. Moreover, Dr. Rakow found the difference between these Applicants' [96]
least-cost size and share of Big Stone II so small that further review was not necessary.

119. The Applicants' load forecasts, before consideration of conservation programs,

are reasonably accurate.

(2) The Effects of Conservation Programs

120. Minn. R. 7849.0120 A(2), requires consideration of the effects of "existing or expected conservation programs and other state and federal conservation programs." However, this factor requires more than just "consideration." As Applicants state, an applicant for a Certificate of Need must show that such programs are insufficient to meet the applicant's need [97] for new power resources. That is because this rule provision encompasses the requirement of Minn. Stat. § 216B.243, subd. 3, that an applicant must show that "demand for electricity cannot be met more cost effectively through energy conservation and load-management measures." It also encompasses the very similar requirement of Minn. Stat. § 216B.243, subd. 3(8), that the Commission evaluate "any feasible combination of energy conservation improvements, required under section 216B.241, that can (i) replace part or all of the energy to be provided by the proposed facility, and (ii) compete with it economically." This provision makes it clear that there must be an assessment of whether conservation can replace part, not just all, of the energy demand. To generalize, conservation measures that would be "feasible and economical" must be considered.

121. Under Minn. Stat. § 216B.241, subds. 1a and 1b, electric utilities are generally required to spend an amount equal to 1.5% of gross operating revenue on "energy conservation improvements." Under Minn. Stat. § 216B.241, subd. 1, "energy conservation improvement" means a project that results in "energy conservation," and "energy conservation" means demand-side management of energy supplies, including load management, that reduces overall energy use. Thus, the "energy conservation improvements, required under Minn. Stat. § 216B.241," referred to by Minn. Stat. § 216B.243, subd. 3(8), are projects using demand-side [98] management of energy supplies, including load management, to reduce overall energy use. The reference to Minn. Stat. § 216B.241 was intended for definitional purposes and not to limit consideration of such projects to the 1.5% of revenue spending requirement, as Applicants [99] claim. Such an interpretation would be inconsistent with the terms of Minn. Stat. § 216B.243, subd. 3(8), in particular, and Minn. Stat. § 216B.243, subd. 3, in general.

122. The Department asserts that each Applicant in this proceeding must demonstrate that its proposal or a portion of its proposal cannot be replaced more cost-effectively by energy [100] conservation or load management. Joint Intervenors make a similar argument, calling the requirement of Minn. Stat. § 216B.243, subd. 3, that an applicant must show that "demand for electricity cannot be met more cost-effectively through energy conservation and load-[101] management measures," a "critical threshold showing." They are largely correct, but the terms "cost-effective," "feasible," and "economical" require subjective judgments, not application of fixed numeric standards. The Certificate of Need statutes and rule impose a significant, but not impossible burden upon the Applicants. They are all experienced providers of electricity familiar with resource planning requirements and methodologies and with the DSM options available in the industry; have access to experts on their staffs and consultants to assist them and provide information about the DSM efforts of other utilities; and keep well informed on what government requires. They have access to and use computer models to determine the least cost mix of resources available to provide or reduce their projected energy needs. Their burden

is not unreasonable. They are requesting authority to build a large energy facility in Minnesota and claim they need the energy that facility would deliver. So they must prove that they thoroughly investigated and analyzed known feasible combinations of DSM options for reducing demand, considered them in their analyses of demand and resources, and reasonably determined through appropriate modeling that no additional portion of their proposed demand can be replaced more cost-effectively by additional energy conservation. And like most contested matters, if other parties produce evidence that the Applicants' analyses were flawed or that additional, feasible, more cost-effective DSM options do exist, the Applicants should rebut such evidence. Ultimately, the Applicants bear the burden of proving that the Certificate [102] of Need criteria have been met.

123. The South Dakota Public Utilities Commission adopted the Applicants' proposed findings on conservation and DSM and found that the Applicants have enacted significant DSM measures and "have extensive plans" for conservation and DSM programs," achieved certain energy savings, and realized certain demand reductions. The South Dakota PUC also made findings, in essence, that each of the Applicants had included DSM in their planning and that the level of demand savings necessary to replace the energy and capacity each expected to [103] receive from Big Stone II was not practical or economically viable. For reasons discussed in the following Memorandum, those findings are not adopted here and the issues will be examined under Minnesota law.

124. Each of the Applicants has in fact implemented conservation and demand-side management programs to some degree and has reduced the amount of energy that has been used and the generating capacity that would otherwise have been required. These programs include load management incentives, rebates, discounts, and other conservation promotions. Each Applicant's load forecast takes its existing and planned conservation programs into account and each Applicant projects that it has the need for the electricity from Big Stone Unit II that it lists, after the reduction in demand that has resulted or will result from implementing such [104] programs. Applicants claim they have done all that is required regarding conservation and load management.

125. According to Department witness Christopher Davis (C. Davis), one way to make the statutorily required showing regarding conservation and DSM is to compare the price of differing amounts and types of energy conservation and load-management measures with the price of supply-side resources. If the analyses demonstrate that the proposed resource is still needed after cost-effective amounts of energy conservation and load management have been taken into account, then the required showing has been made. C. Davis testified that three steps should occur in this process: (1) assess energy conservation and load management achievable potential; (2) analyze the impact that various amounts of supply-side and cost-effective energy conservation and load management have on the total costs of providing service, using a computer model; and (3) assess whether the analysis in steps one and two indicates that the requested resource should be included in a least-cost plan for serving customers. In other words, if the modeling allowed achievable potential energy conservation and load management options to compete on an economic basis with supply-side resources, the results of the modeling would show the least-cost mix and be acceptable to make the [105] required showing.

126. According to C. Davis, four of the Applicants (Otter Tail, GRE, MRES, and SMMPA) conducted an achievable potential study and satisfactory capacity expansion modeling. In his direct testimony, he found that they met the energy conservation and load [106] management requirements.

127. C. Davis found, however, that the other Applicants (MDU, Heartland, and CMMPA) had failed to provide adequate analysis and information to show that their demand for electricity cannot be met more cost effectively through energy conservation and load management measures. Heartland did neither an achievable potential study nor satisfactory capacity expansion modeling. CMMPA did not conduct an achievable potential study, but did do capacity expansion modeling. However, it used its own costs of DSM resources, which are considerably higher than other utilities, and therefore not reasonable for modeling purposes. MDU also failed to do an achievable potential study, so, like CMMPA, its modeling did not allow energy conservation and load management to compete with supply-side resources. Thus, C. Davis concluded that Heartland, CMMPA, and MDU failed to demonstrate that they met the [107] statutory burden regarding conservation and load management.

128. MDU uses the Rate Impact Measure (RIM) test to quantify the costs and benefits of a particular DSM program, rather than the societal test preferred by the Department. The societal test measures the net cost of a DSM program looking at costs to the program participant, costs to the utility, and environmental costs, which tends to reduce the costs of the DSM program in relation to other resource alternatives. The RIM test minimizes the levelized system average rates over the modeled period, but it does not minimize costs to society. The RIM test often excludes superior energy conservation projects because it tends to eliminate projects that would be best able to defer or replace baseload resources, contrary to Minn. Stat. § 216B.243, subd. 3. The Department is of the opinion that MDU's use of the RIM test in this proceeding is unreasonable for that reason. However, use of the societal test is prohibited by North Dakota law, and the RIM test is the one mandated by North Dakota officials. So MDU [108] must use it for its integrated resource planning.

129. MDU has studied the level of cost-effective conservation and load management programs as part of its IRP process since 1989. It has conducted an analysis of residential and commercial DSM programs and then allowed all programs it considered cost-effective to compete with the supply-side resources in its analysis. Thus, Nguyen believes that he has demonstrated that future supply-side resources could not be replaced by conservation and DSM measures. MDU's 2005 IRP, using the RIM test, indicates that its achievable amount of cost-effective energy conservation and load management measures would be 2.8% of its total demand in 2012. According to Nguyen, modeling load management measures with consideration of societal costs would have a marginal impact on its need for substantial new generation and additional transmission and would not eliminate or even significantly change its [109] need for the transmission lines.

130. CMMPA owns no baseload resources and purchases almost 100% of its energy. [110]

CMMPA does not have direct control or responsibility for the conservation and DSM programs pursued by its municipal members. The current state Conservation Improvement Program (CIP) requirements apply to the individual municipalities, not to CMMPA. Each of

[111]
CMMPA's members is in compliance with applicable CIP requirements.

131. While CMMPA did not follow the process outlined by the Department for evaluating the cost effectiveness of various DSM programs, it did conduct a DSM screening study to evaluate whether generic DSM programs were lower in cost than the supply-side costs that could be avoided through their implementation. This analysis showed that DSM programs [112]
were significantly higher in cost than supply-side alternatives.

132. CMMPA has not performed a DSM potentials study beyond its DSM screening study, but has expressed a willingness to undertake a study similar to the one performed by Summit Blue Consulting, Inc., for MRES. It is willing to make other additional improvements in the way it assists its members with DSM activities. However, CMMPA believes that even if it did conduct a DSM potentials study and acted on it, the resulting DSM would not materially [113]
offset CMMPA's need for Big Stone Unit II.

133. Heartland's customers own no baseload resources. Heartland works with its customers to identify and implement conservation and demand-side programs. Heartland has not performed any kind of DSM potentials study and has also expressed a willingness to undertake a study similar to the one performed by Summit Blue Consulting, Inc., for MRES. Heartland believes that because of the growth experienced recently and anticipated by Heartland's customers, it would be unreasonable to assume that conservation would eliminate Heartland's need for its share of Big Stone Unit II. Heartland has expressed a willingness to [114]
work with the Department to develop improvements in its conservation activities.

134. MDU, CMMPA, and Heartland expect to receive 179.55 MW, or 28.53 percent of the energy expected to be produced by Big Stone II. In the Department's view, these three applicants embrace very little in the way of conservation or DSM programs and offered [115]
analyses tending to minimize reasonable conservation and DSM expectations. Their actions are driven in part by North Dakota law, which does not allow utilities to recover [116]
investments in energy conservation. The Department does not believe that accommodation should be made in this proceeding for North Dakota's lesser conservation and [117]
DSM requirements.

135. Joint Intervenors' witness Timothy Woolf testified that Minnesota law requires Applicants to comply with a "very high" conservation standard before they can obtain a Certificate of Need and presented benchmarks he developed to evaluate the reasonableness of the Applicants' assumptions. Department witness C. Davis testified that such benchmarks [118]
could be useful for that purpose.

136. The Applicants argue that no such standards are found in any of the statutes or criteria applicable to a Certificate of Need proceeding. As discussed above, the standard for evaluating whether conservation improvement options must be used to replace generation is whether the option is "feasible and economical." That is indeed a "high" standard by its own

[119]

terms and in comparison to other states. South Dakota, for example, has no such requirement. The requirement is a "narrative" or "qualitative" standard and the Applicants are correct that no "numeric" or "quantitative" standard appears in the statutes or rule. But Woolf's benchmarks are evidence in this matter of industry practice, not standards or criteria adopted by the Commission as a rule. Accurate and relevant averages developed from data from similar electricity providers could be very helpful evidence for assessing whether DSM options are cost-effective, feasible, and economical. What comparable utilities have been able to achieve is evidence relevant to the issue here. It should be considered and assessed as any other evidence and expert opinion in this matter.

137. Woolf is Vice President of Synapse Energy Economics, Inc., a research and consulting firm specializing in electricity industry regulation, planning, and analysis. He has degrees in English and Mechanical Engineering from Tufts University, a Diploma in Economics from the London School of Economics, and an MBA from Boston University. He has worked for and testified on behalf of consumer and environmental advocacy groups, regulatory commissions, and other government agencies regarding electric power system planning and regulation for 24 years. His resume does not list any testimony or employment on behalf of any

[120]

utility or industry organization.

138. Woolf established "generic benchmarks" to illustrate what many utilities around the nation are achieving with respect to DSM to help determine whether the Applicants considered a reasonable amount of DSM in their modeling. Woolf based his benchmarks on a series of studies reflecting the now substantial experience with DSM programs around the nation. He developed efficiency savings benchmarks as a percent of retail sales for both the residential

[121]

and commercial-industrial (C/I) sector, summarized in the following table.

	low	**medium**	**high**
Residential sector, average savings/yr	0.2%	0.4%	0.6%
C/I sector, average savings/yr	0.6%	0.8%	1.0%

139. Woolf testified that the high benchmarks are not the maximum amount of cost-effective, achievable DSM, but should be the minimum amount of DSM that the Applicants

[122]

should allow their capacity expansion models to consider.

140. When compared to Woolf's benchmarks, it appears that GRE, MRES, OTP, MDU, and CMMPA all constrained the ability of their models to select DSM investments. Their capacity expansion models were not allowed to consider savings routinely achieved by other utilities and compare their cost to that of the energy from Big Stone II. The one exception was SMMPA, which allowed its model to consider DSM programs that would achieve savings that

[123]

were at Woolf's high benchmark level through 2018.

141. Woolf's high benchmark energy savings are higher than the projected DSM savings of all the Applicants except SMMPA, but are substantially lower than the energy savings goal previously announced by the Governor and recently enacted by the Legislature. In the Energy Efficiency and Conservation Act (Minn. Laws 2007, Ch. 136, Art. 2), the Legislature

modified current requirements for energy conservation and demand-side management from a spending-based requirement to a statewide goal of saving 1.5 percent of retail electric sales beginning in 2010. It is likely that the legislation will cause expanded conservation efforts that will, in turn, cause reduced or delayed energy needs.

142. After seeing the Woolf analysis, C. Davis did his own study. He reviewed the customer class and total electric energy savings rates for Minnesota's four largest investor-owned utilities (IOUs): Interstate Power and Light, Minnesota Power, Otter Tail Power, and Xcel Energy. The results of his review were set forth in his Rebuttal Testimony Table 1 as follows: [124]

C. Davis Table 1: Electric Savings Rates Achieved by Minnesota's Four Large Electric IOUs 1996-2005

Utility	Residential Energy Savings As a % of Residential Sales	C&I Energy Savings as a % of C&I Sales	Total Energy Savings as a % of Total Sales
MP	0.65%	0.96%	0.93%
Xcel	0.08%	1.06%	0.80%
Interstate	0.22%	3.54%	2.43%
OTP	0.16%	0.82%	0.66%
Weighted Average	0.14%	1.07%	0.85%
Average	0.28%	1.60%	1.20%

(OTP 1996 figures were not available. Also OTP and Xcel low-income savings were excluded since historically these projects have not been cost-effective. The weighted average for the four utilities was based on sales.)

143. Based on this review of Minnesota IOU energy savings, C. Davis concluded that the range of energy savings Woolf used as benchmarks appeared to be reasonable. For example, Woolf's range of residential savings rates was from 0.2 percent to 0.6 percent, whereas, Minnesota's historical averages for residential savings rates ranged from 0.08 percent to 0.65 percent. Likewise, Woolf's C&I savings rates ranged from 0.6 percent to 1.0 percent, whereas Minnesota's IOU energy savings rates ranged from 0.86 percent to 3.54 percent. C. Davis concluded that, from a Minnesota electric IOU perspective, Woolf's C&I benchmarks may [125] be somewhat low for C&I customers, but reasonable.

144. Another factor the Department reviewed was the expenditure level for the Conservation Improvement Programs by Minnesota's four electric IOUs. C. Davis' review indicated that, assuming the measures last an average of 13 years (a conservative estimate), [126] the weighted average cost of kWh savings was $0.0099 per kWh.

145. C. Davis concluded that Woolf's benchmarks could serve as a sound tool to help evaluate the reasonableness of electric utilities' energy savings assumptions developed through achievable potential analyses, the amount of energy savings analyzed as part of resource planning, and the amount of energy savings planned for by a utility. He agreed with Woolf that

even Otter Tail, GRE, and MRES had failed to show that conservation could not replace the demand for electricity and they, too, should be able to achieve considerably higher [127] conservation and DSM savings than they demonstrated.

146. Consistent with the Department's direct testimony, and considering Woolf's analysis, C. Davis continued to conclude that SMMPA had provided a reasonable DSM analysis [128] for this proceeding.

147. The Applicants claim that it would be inconsistent and contrary to the statute if the results of their studies be disregarded in favor of generic, nationwide industry benchmarks. They state:

> The fundamental issue is that use of Woolf's and C. Davis' benchmarks would result in the Applicants being forced to select conservation that their own specific studies and models have rejected as non-cost effective. If all of the conservation hypothesized by Woolf and C. Davis (in his December 8, 2006 testimony) were, in reality, cost-effective as compared with other resources, it would have been uncovered in the Applicants' study process and chosen in the Applicants' modeling. The additional conservation wasn't chosen because it wasn't cost-effective. [129]

The claim that the Applicants would have found it if it existed must be rejected. The Applicants' argument seems to be that their evidence cannot be attacked, or that the only way to do so is for other parties to present their own evidence as to specific cost-effective conservation measures. Instead, the Department and Joint Intervenors attacked the adequacy of the Applicants' studies by showing the weaknesses in the studies and failure to plan for conservation measures at the levels being achieved by comparable utilities. As an evidentiary matter, it is a legitimate technique.

148. The Applicants presented a considerable amount of evidence attempting to rebut the evidence presented by Woolf and C. Davis. Most of the Applicants have expert staff to do their conservation methods investigation and resource modeling, and those staff testified believably. As witnesses usually are, they were biased in favor of their own work. On the other hand, Woolf has biases in favor of energy conservation, and some of his methods somewhat overstated his results in that direction. C. Davis was the most objective and his analysis was the most credible. His results were likely the most accurate. The Applicants other than SMMPA should have been more aggressive in allowing their models to consider amounts of energy conservation and DSM that have been achieved by other utilities.

149. While the studies done by all the Applicants other than SMMPA were inadequate to rely upon for solid numbers, the fact remains that the Applicants will have a large demand for baseload energy and capacity in 2011-2012 that can be alleviated only to a relatively small degree by additional energy conservation. It appears that even if the Applicants become very aggressive about energy conservation and reduce their needs even by 15 to 20 percent over the next four or five years, they will still need the energy and capacity produced by Big Stone II.

(3) The Effects of Promotional Practices

150. Dr. Rakow analyzed the Applicants' promotional activities, including economic

development activities and rate design. He requested copies of recent newsletters and bill inserts that the Applicants (or their utility customers) sent end-use customers and reviewed the individual company websites and publicly available information for specific types of rate design that, if present, could be considered promotional. Applicants provided considerable material to him. From his review, Dr. Rakow found that, other than HCPD, the Applicants do [130] not appear to promote energy demand through promotional activities.

151. There is some question about one of HCPD's promotional activities. Its economic development incentives consist of two items, an incentive payment based upon the customer's income level and a discount of a certain percentage of the customer's bill—applied either to the entire bill (for new customers) or the load increase (for existing customers). The greater the customer's energy use, the greater the incentive payment. This practice promotes energy consumption, contrary to the goal in Minnesota of reducing demand. HCPD explained that it is a political subdivision of South Dakota and, by South Dakota law, one purpose of HCPD is to encourage and extend the use of energy. The rebates are provided for the first three years of the business start-up or expansion, and only 4/10s of one percent of HCPD's demand and [131] energy forecast is enrolled in the program.

152. HCPD's economic development activities may have given rise to an increase in the energy demand, which is inconsistent with the policy behind Minn. Stat. § 216B.243, subd. 3 (4), and Minn. R. 7849.0120 A(3). However, this statute and rule set forth a consideration to be weighed by the Commission, not a criterion that must be fully met in every circumstance. In light of the fact that the activities are consistent with South Dakota statutes and are limited in duration, scope, usage, and impact on forecasted load, this inconsistency should be given only [132] slight weight in assessing HCPD's demand.

153. In general, the promotional practices of the Applicants have not given rise to an increase in the Applicants' energy demand. The one that may have was very limited in scope and should not be afforded much weight with respect to the overall determination of the Applicants' demand.

(4) Ability of Current Facilities and Planned Facilities Not Requiring a Certificate of Need to Meet the Future Demands

154. Looking at just the Transmission Project, the Applicants approached this issue assuming that Big Stone II would be built and focused on whether there were other current or planned transmission lines to meet their projected need to deliver all the electricity from Big Stone II to the electrical grid and, in large part, to themselves. They conducted an interconnection study to determine the most efficient method of integrating Big Stone II into the existing system interconnecting Big Stone I. The interconnection study showed that when Big Stone Unit II is added without any new transmission facilities, certain critical transmission lines [133] greatly exceed their maximum capacity and others come close to doing so. Similarly, a Preliminary Transmission Screening Study done by Applicants in 2004 showed that all transmission options involved transmission lines of 115 kV and higher, which would require a [134] certificate of need. As the Applicants found, it is not possible to provide an interconnection for Big Stone Unit II with transmission lines in Minnesota that do not require a Certificate of Need.

155. The Mesaba Project was the only generation facility not requiring a Certificate of Need proposed to provide the electricity that the Applicants claim they need. The Mesaba Project is an Integrated Gasification Combined Cycle facility proposed by Excelsior Energy, Inc., to be located near Taconite, Minnesota.

156. On August 2, 2007, during deliberations on Excelsior Energy's Application for Approval of a Power Purchase Agreement (PPA) with Xcel Energy, the Commission found that the Mesaba Project is an "Innovative Energy Project" (IEP) under Minn. Stat. §216B.1694. It also found the Excelsior Energy's proposed PPA with Xcel Energy was not in the public interest as currently drafted, but requested that Excelsior, Xcel, and the Department continue negotiations on a PPA that would provide for a more reasonable price in light of the Mesaba Project's environmental advantages and other factors. It also expressed interest in requiring other Minnesota utilities to purchase some of the energy produced by the Mesaba Project, [135] particularly through the application of Minn. Stat. § 216B.1694, subd. 2(a)(5).

157. The Mesaba Project, as an "innovative energy project," is exempt from the requirements for a Certificate of Need for its generation facilities and transmission [136] infrastructure. In addition, as an "innovative energy project," the Mesaba Project,

> . . . shall, prior to the approval by the commission of any arrangement to build or expand a fossil-fuel-fired generation facility, or to enter into an agreement to purchase capacity or energy from such a facility for a term exceeding five years, be considered as a supply option for the generation facility, and the commission shall ensure such consideration and take any action with respect to such supply [137] proposal that it deems to be in the best interest of ratepayers.

158. Excelsior Energy argues that the IEP Statute applies because the combination of the proposed Big Stone II and the proposed transmission lines together constitute "an arrangement to build a fossil-fuel-fired generation facility," because the two are totally [138] dependent upon one another. The relationship between the generation facility and the transmission lines is substantial. For example, there is testimony that Big Stone II may not be built if the Commission does not approve the Transmission Project. So there is merit to Excelsior Energy's argument. Moreover, Minn. Stat. § 216B.1694, subd. 2(a)(5), also includes the "purchase [of] capacity or energy from such a facility." Technically, the Applicants will not be "purchasing" capacity and energy in the traditional sense, because they will each own a share of Big Stone II. Nonetheless, they will be obtaining it for sums determined under their Participation Agreement. That arrangement would seem to be well within the legislative intent of the IEP Statute. Therefore, under Minn. Stat. § 216B.1694, subd. 2(a)(5), the Applicants should have considered the Mesaba Project as a supply option.

159. Both the Applicants and the Department offered evidence that the Mesaba Project, or a generic IGCC, would not be a least-cost resource for the Applicants' demand for capacity and energy and, therefore, the Mesaba Project did not need to be considered further. [139] The issue of timing was also raised. However, there is no least-cost requirement in Minn. Stat. § 216B.1694, subd. 2(a)(5). Rather, the statute requires that, "the commission shall ensure such consideration and take any action with respect to such supply proposal that it deems to be in the best interest of ratepayers." Best interest does not necessarily mean least-

cost if there are other benefits.

160. The Applicants gave no meaningful consideration to the Mesaba Project as required by the IEP statute. However, timing is an issue because it is unlikely that energy from the Mesaba Project will be available when Big Stone II comes online.

(5) The Effect of the Proposed Facility, or a Suitable Modification, in Making Efficient Use of Resources

161. The proposed transmission lines would use resources efficiently. They will be built on existing transmission rights-of-way for about 80 of their 94 miles. Operating the Granite Falls line at 345 kV and connecting it to another proposed 345 kV line will economically provide additional capacity for transmission from various generation sources, including wind farms.

162. Big Stone II will have a number of efficiencies in comparison to older coal-fired facilities. It will be approximately 20% more efficient than standard pulverized coal plants, [140] thereby producing relatively more electricity from less coal. It will have an 88% capacity [141] factor on an annual basis, thereby using the plant itself to the maximum extent. It will enjoy further economies by using Unit I's existing rail lines for coal delivery and by installing new and updated pollution control equipment to control emissions from both Unit I and Unit II. [142]

163. Denying the Certificate of Need for the transmission would likely result in an adverse effect upon the future adequacy, reliability, or efficiency of the energy supply to the Applicants and their customers or to the people of Minnesota and neighboring states. The Applicants will have an increase in demand for energy in the future. The energy demand is something less than the 1012 MW that the Applicants now claim they will need the transmission lines to transport, but it appears to be significantly more than the 630 MW the application is based upon.

B. Is There a More Reasonable and Prudent Alternatives to the Facility?

164. This Certificate of Need criterion requires comparisons of various alternatives to the transmission project in terms of size, type, and timing; cost; natural and socioeconomic effects; and reliability. In addition, Minn. Stat. § 216B.243, subd. 3a, requires that renewable energy sources be examined as alternatives to any proposed nonrenewable energy source. Transmission Alternatives will be discussed first.

Transmission Alternatives

(1) The Appropriateness of the Size, Type, and Timing of the Proposed Facility Compared to Reasonable Alternatives

165. The Applicants and other regional utilities conducted a Preliminary Screening Study to evaluate eleven different options for interconnecting Big Stone Unit II to the grid. It was based upon the size, type, and timing that the Applicants had determined they needed and that Big Stone II would produce, namely, approximately 600 megawatts of baseload capacity by 2011. The Applicants compared the alternatives on the basis of capital cost, reliability, system

power losses, and impacts to known constrained interfaces in the region. [143]

166. One alternative involved an upgrade of the 115 kV line to Morris to 230 kV, along with a 230 kV line to Canby and on to Granite Falls, and the second alternative involved construction of a new 230 kV line to Willmar along with the Canby/Granite Falls line. [144] The Big Stone Interconnection Study was completed in November 2004, and it showed that a new 230 kV line to Granite Falls, with either a 230 kV line to Morris or a 230 kV line to Willmar, "will work from a steady state contingency analysis standpoint given that the proper system enhancements are made within the direct area of interconnection." [145]

167. The Applicants also integrated the results of the Interconnection Study into other, ongoing regional planning efforts such as the CapX work and other exploratory studies. [146] The Applicants, other utilities, and the Department have all recognized that the transmission system, particularly in southwestern Minnesota and along Buffalo Ridge, needs to be expanded to improve reliability and to increase outlet capacity for wind generation. As a result of the desire to incorporate the Big Stone transmission into other regional needs and goals, the Applicants also decided to evaluate the option of building the Granite Falls line to 345 kilovolt specifications. [147]

168. The Applicants conducted an analysis of six different alternatives, although there were only two main questions to address: (1) whether a 230 kV line should be built to Morris or to Willmar; and (2) whether the Granite Falls line should be built at 230 kV or 345 kV. When the various iterations were compiled, the following six alternatives were examined: [148]

Alternative	Big Stone to Morris	Big Stone to Granite Falls	Big Stone to Willmar
1 (Transmission Project)	Upgrade existing 115 kV line to 230 kV	Build: 345 kV Operate: 230 kV	
2	Upgrade existing 115 kV line to 230 kV	Build/Operate new 345 kV line	
3	Upgrade existing 115 kV line to 230 kV	Build/Operate new 230 kV line	
4		Build: 345 kV Operate: 230 kV	Build/Operate new 230 kV line
5		Build/Operate new 345 kV line	Build/Operate new 230 kV line
6		Build/Operate new 230 kV line	Build/Operate new 230 kV line

The Department reviewed the Applicants' screening process and was initially concerned regarding a lack of criteria to guide the screening analysis. However, the Rebuttal Testimony of Timothy Rogelstad, P.E., provided the screening criteria, and the Department concluded that

[149]
the criteria provided were satisfactory.

169. The upgrade of the existing line to Morris to 230 kV is preferable to a new 230 kV line to Willmar. No person has advocated for the Willmar line. The Morris line can follow existing right-of-way for nearly the entire distance. Because it is shorter, it is lower cost. The Willmar line is on the order of $10 million more expensive than the Morris line. The Willmar line incurs several megawatts of additional line losses than the Morris line. The Morris line would have to be reconductored even if the Willmar line was selected. In addition, from a routing standpoint, the Morris line is preferred to the Willmar line, as the extra length and new right-of-way for the Willmar line would result in more significant impacts than upgrading the existing
[150]
Morris line.

170. Building the Granite Falls line to 345 kV is also preferable to a 230 kV installation. The 345 kV capability provides outlet capacity for additional generation not available with the 230 kV alternative. The 345 kV alternative costs about $20 million more than the 230 kV line, but the line losses are substantially less at the higher voltage because the current is lower, and losses are related to current, not voltage. A wider right-of-way is required for the 345 kV line and the poles will be higher but the line follows existing right-of-way for about 90% of the
[151]
distance.

171. Opportunities for the installation of distributed generation (DG) must be
[152]
considered in this proceeding. DG is the use of several, small, high-efficiency, low-emissions generation facilities instead of one large facility.

172. The Department asked that the Applicants provide a complete analysis of a distributed generation alternative. The Applicants' conclusion in their response was that it is not possible to describe a DG option that would serve the purpose of the proposed transmission
[153]
project.

173. The Department separately reviewed DG alternatives in the EIS. The EIS indicated that there might be a number of different DG scenarios that could be developed to meet the needs of the participating utilities. However, such a study would require that a more detailed analysis of the location, type, and size of the alternatives be conducted. Regarding the overall feasibility of a DG alternative, the EIS concluded that while it is conceivable that a DG alternative could meet the intent of providing energy to the specific load centers that the transmission lines would serve, it is unlikely at this time that a DG alternative could meet the second objective of the transmission project of increasing transmission capacity and improving reliability of the electric transmission system in the Buffalo Ridge area in Minnesota and South
[154]
Dakota.

174. The Applicants are also required to examine options such as a direct current line, double circuiting, and constructing the line underground. The Applicants did consider these options and reasonably found them not to be feasible here.

175. If Big Stone II is built as proposed by the Applicants, the Transmission Project as proposed by them is the most appropriate alternative in terms of size, type, and timing for

interconnecting Big Stone II.

(2) The Cost of the Proposed Facility and the Cost of Energy Compared to the Costs of Reasonable Alternatives

176. The Applicants' best estimate of the cost of the transmission lines, including the substation work and the South Dakota part of the lines, is approximately $110 million in 2006 dollars. When costs for delivery service, permitting, agreements, and studies are added in, and the figures converted to 2011 dollars, the total costs are estimated to be $238 million in 2011 dollars. Constructing a line to Willmar instead of to Morris would cost approximately $29 million [155] dollars more.

177. In his cost analysis of the transmission alternatives, Dr. Rakow found that the financial cost of constructing the Granite Falls transmission line to 345 kV is about $2.8 million greater than constructing it to 230 kV. Using the high externality values, the societal cost of constructing the Granite Falls transmission line to 345 kV is about $1.71 million less than constructing it to 230 kV. Using the low externality values, the result is that the societal cost of constructing the Granite Falls transmission line to 345 kV is about $0.26 million greater than constructing it to 230 kV, not a material economic difference. Using Dr. Rakow's terminology, constructing the Granite Falls line to 345 kV is "weakly preferred" (before consideration of [156] reliability benefits).

178. Among the alternatives to the proposed transmission lines screened by the Applicants, the Applicants' preferred alternative is the least-cost alternative.

(3) The Effects of the Proposed Facility Upon the Natural and Socioeconomic Environments Compared to the Effects of Reasonable Alternatives.

179. The proposed transmission lines will have little impact upon the natural and socioeconomic environments because they will follow existing transmission line right-of-way for approximately 90% of the routes. No objections to the transmission lines were made by any residents along the lines.

180. The preferred alternative – the Morris line – will have less environmental and socioeconomic impacts than the alternative line to Willmar, primarily because the Morris line will follow existing right-of-way and is approximately 30 miles shorter than the Willmar line

(4) The Expected Reliability of the Proposed Facility Compared to the Expected Reliability of Reasonable Alternatives.

181. Minn. Stat. § 216B.243, subd. 3(9), requires the Commission to consider:

> with respect to a high-voltage transmission line, the benefits of enhanced regional reliability, access, or deliverability to the extent these factors improve the robustness of the transmission system or lower costs for electric consumers in Minnesota.

182. All the Applicants are physically located within the footprints of both the Midwest Reliability Organization and the Midwest Independent System Operator. The MRO and MISO

footprints may be considered "the region" for purposes of evaluating the impact of the transmission project on regional reliability.

183. The transmission lines should have an operating life of at least 40 years and should not be out of service except for extreme weather events. The transmission project will have a positive impact on regional reliability by providing a generation outlet to the region, particularly a wind generation outlet, by increasing transmission capability from 230 kV to 345 [157] kV. It could provide more fuel diversity options in the MISO footprint.

184. Studies performed by MISO for generator interconnection requests and transmission service requests, besides those for Big Stone II, have demonstrated a need for additional capacity in a west-to-east direction across the eastern Dakotas and Western Minnesota. The transmission infrastructure in the Buffalo Ridge area itself was originally designed to serve roughly 50 MW of load, and now there are requests for roughly 2000 MW of generation, virtually all of it wind generation, to connect in the area. The resultant swing of direction in energy flow is too great for the existing infrastructure. Plans are in place and construction ongoing to achieve roughly half of the capacity required just from the Buffalo Ridge area. Other studies for generator interconnections and/or transmission service from those [158] generators, in areas around but not on the Buffalo Ridge, yield similar results.

185. MISO believes that additional capacity to move energy across western Minnesota is a positive step. The Big Stone upgrades in conjunction with the Cap X 2020 proposed lines would resolve 61 constraints [on the transmission system] in a study that analyzed 1300 MW of [159] transmission service plus the 600 MW of Big Stone.

186. MISO believes that more generation capacity is necessary in the region. It supports the Applicants' request for a Certificate of Need and urges that it be granted as being [160] in the best interest of the end-use customers in Minnesota.

187. The Transmission Project will enhance the reliability of the transmission grid in the region. However, that fact arises more out of the Midwest region's need to provide outlet capacity for energy generators, even without Big Stone II, than it does out of the Applicants' need to obtain energy.

Generation Alternatives

(5) Renewable Generation Alternatives

188. Because this proceeding involves a Certificate of Need for the transmission project and not for the generation project, the criterion and factors in Minn. R. 7849.0120 B regarding examination of alternatives in general do not apply of their own force to Big Stone II. However, because the electricity the Applicants desire to transport is from a nonrenewable energy source, Minn. Stat. § 216B.243, subd. 3a, requires that renewable energy sources be examined as alternatives to that nonrenewable energy source. In addition, the Applicants' current compliance with the REO and C-BED requirements in Minn. Stat. §§ 216B.1691 and .1612 must be considered.

189. The Applicants argue that the burden of proof on renewable energy alternatives,

as they argued on the conservation and DSM issue, is upon parties other than themselves. They state:

> Applicants do not have the burden of what the Minnesota Court of Appeals correctly characterized as "proving a negative," that is, proving the non-existence of superior alternatives. Under Minn. Rules part 7849.0120(B), the Commission "must" issue a CON unless, with respect to possible alternatives, unless [sic] "a more reasonable and prudent alternative" has "been demonstrated by a preponderance of the evidence on the record." The Commission's precedent interprets this provision as placing the burden *on other parties* to demonstrate the existence of a more reasonable and prudent alternative, and this interpretation was recently upheld by the Minnesota Court of Appeals in the *City of Hutchinson* [161] case. The Department and Joint Intervenors do not even attempt to meet [162] this burden.

190. It is a misstatement of the Certificate of Need statutes and rule, and of the *City of Hutchinson* case, to claim that the Commission "must" issue a CON unless a more reasonable and prudent alternative has been demonstrated. The non-existence of a reasonable and prudent alternative is but one of four criteria listed in the rule, all of which must be satisfied. So, it would be more correct to say that if a more reasonable and prudent alternative is demonstrated by a preponderance of the evidence, a Certificate of Need cannot be granted. It bears repeating here that, in addition to the four criteria expressly stated in the rule, there are [163] additional criteria imposed by statute that also must be met.

191. As to renewable energy alternatives, Minn. Stat. § 216B.243, subd. 3a, expressly [164] puts the burden of proof upon the Applicants. As stated in Finding No. 100, Subdivision 3a creates two additional criteria that must be demonstrated by the Applicants: They (1) must have made a reasonable study of renewable energy sources, and (2) must have demonstrated that there is no reasonable renewable energy source, or combination thereof, for generating power that is less expensive than the power from the nonrenewable source they propose.

192. *City of Hutchinson* states that Minn. Stat. § 216B.243, subd. 3, places the burden of proving the need for a proposed facility on the applicant and that that burden does not change. It also states that other parties should be required to demonstrate that a more reasonable and prudent alternative exists "without requiring an applicant to face the extraordinary difficulty of proving that there is not a more reasonable and prudent alternative." It cites *State v. Paige*, 256 N.W.2d 298, 304 (Minn. 1977), regarding the difficulty of "proving a negative." *Paige* involved a defendant convicted of carrying a concealed pistol under a statute that prohibited a person "without a license to so carry said pistol as provided by law." In *Paige*, the Supreme Court held that the trial court was justified in placing the burden upon the defendant to come forward with some evidence of a gun permit, but was not justified in further requiring the defendant to prove by a fair preponderance of the evidence that he had a permit. A prima facie showing was all that was necessary. The Supreme Court went on to state:

> Once the defendant has come forward initially with evidence of the permit, the state's difficulty in "proving a negative" is alleviated, making it reasonable for the state to disprove the defense.

[165]

193. Again, the Applicants are all experienced providers of electricity familiar with renewable resource options and requirements. It is not "extraordinarily difficult" for them to demonstrate that there are no reasonable renewable energy sources for generating power less expensively than Big Stone II. Minn. Stat. § 216B.243, subd. 3a, specifically lists the renewable energy sources they must consider. Their burden is not excessive; they do not have to prove that every conceivable alternative is unreasonable. They must prove that they have made a reasonable study of renewable energy sources and determined through economic modeling or other appropriate means that no feasible, less expensive, renewable energy sources are available. Like most contested matters, and consistent with the holdings in *Paige* and *City of Hutchinson*, if other parties have relevant evidence that the Applicants do not, those other parties must come forward with that evidence if they want it considered. And if the other parties here produce some meaningful evidence that the Applicants' analyses were flawed or that additional, feasible, more cost-effective renewable energy sources that the Applicants did not consider likely do exist, the Applicants should rebut such evidence. Ultimately, for the Applicants to prevail, the preponderance of all the evidence presented must demonstrate that all the Certificate of Need criteria in the statutes and rule have been met.

194. It must also be noted that the Applicants had the benefit of extensive prehearing discovery and the prefiled testimony of the other parties regarding their positions on all issues, including renewable energy sources. There were no previously unknown renewable energy sources. The Applicants knew what the other parties would present, had time to respond, did so, and did not have to "prove a negative."

195. The Applicants engaged in a screening study to identify those generation alternatives that had the potential to meet their identified objectives as to size, type, and timing, approximately 600 megawatts of baseload capacity by 2011, at a reasonable cost. According to the Applicants, the preliminary screening study established that no renewable energy source was capable of satisfying the three underlying objectives.

196. The Applicants hired Burns & McDonnell, an energy consulting firm, to conduct a Phase I study to compare costs, performance, and emissions characteristics of a supercritical pulverized plant with several other fossil-fuel alternatives. Burns & McDonnell completed its Phase I Report in July 2005, which concluded that a 600 MW supercritical pulverized coal plant

[166]

represented the lowest cost alternative of the technologies evaluated.

197. In order to examine in more detail the economics of the various alternatives, Burns & McDonnell was asked by the Applicants to conduct a second study to consider an expanded set of generation technologies. The alternative technologies included the following: Subcritical Pulverized Coal (Subcritical PC), Supercritical Pulverized Coal (Supercritical PC), Natural Gas Fired Combined Cycle Gas Turbine (CCGT), Wind Plus Gas-Fired Combined Cycle Gas Turbine (Wind + CCGT), Integrated Coal Gasification Combined Cycle (IGCC), and 100% Biomass Plant. Burns & McDonnell completed its Analysis of Baseload Generation Alternatives

[167]

in September 2005. This study included an analysis of carbon tax sensitivity, in which the high end of the PUC environmental cost value for CO2 ($3.64/ton) was assumed and applied to every ton of emissions of CO2 from those technologies with CO2 emissions. Once again, Burns & McDonnell found that the supercritical pulverized coal plant was the least cost option.

198. In December 2005, the PUC directed the Applicants to submit additional information regarding generation and demand-side alternatives to Big Stone Unit II. Effectively,

the information requested was a description and estimated cost of each utility's next best resource alternative to Big Stone Unit II. The Applicants requested Burns & McDonnell to respond to the PUC's request. Burns & McDonnell prepared the responses, which were [168] submitted to the PUC on February 28, 2006. Burns & McDonnell found that there was no one next best resource and that each utility would pursue a variety of more costly strategies to meet their obligations, including market purchases, gas and coal-fired generation, and [169] renewable energy resources, along with demand-side management programs.

199. In late summer 2006, after learning of higher cost estimates for Big Stone Unit II, the Applicants asked Burns & McDonnell to take another look at the cost comparison of the various generation alternatives. Burns & McDonnell looked at a 630 MW supercritical pulverized coal plant like Big Stone II, a 500 MW combined cycle gas turbine, and a combined cycle gas turbine in combination with market purchases of wind. This report was made available on October 2, 2006, and confirmed that Big Stone II was the least cost alternative. [170]

200. In doing its resource planning, OTP obtains a load forecast from a consultant, then uses IRP-Manager software to develop a series of optimized resource plans. The software is a capacity expansion program that uses an iterative process to evaluate each alternative. OTP witness Morlock testified that OTP's resource plans are a balanced and diverse mix of conservation, renewables, peaking capacity, and baseload capacity, all at their individual [171] optimal least-cost levels.

201. As the Applicants point out, the Department does not have its own computer models and does not do its own expansion modeling or resource planning. However, Dr. Rakow and the Department's other analysts have the appropriate education and relevant experience necessary to evaluate the modeling and resource planning of the utilities' experts. They know how the models work and are qualified to evaluate the model inputs and techniques used by utility resource planners. They know what Minnesota law requires and they know what Minnesota utilities do in resource planning and modeling. They typically "run" Strategist and other capacity expansion models by asking utilities to rerun their models with different inputs and operational parameters. The Joint Intevenors' witnesses from Synapse Energy do not have the same experience that some of the Applicants' planners have running the Strategist model, but they have educations and experiences that the Applicants' planners do not. They, too, have the qualifications to comment on the quality of the Applicants' modeling.

202. Wind is the renewable option that received the most interest and scrutiny in this proceeding. Wind by itself is not a feasible option to Big Stone Unit II because wind currently is [172] not a baseload resource and because it is not possible to obtain a comparable amount of power from wind developments by the 2011-2012 timeframe.

203. The Department agrees that wind as a stand-alone resource does not constitute baseload capacity. However, in the Department's view, the size, type, and timing of the need for 630 MW of baseload power by 2011-2012 remains unproven, which is the key failing on the [173] part of the Applicants in this case.

204. In the Applicants' view, the only possible alternatives to Big Stone Unit II that might satisfy the size, type, and timing needs for 630 MW of baseload power by 2011-2012 are a Combined Cycle Gas Turbine, wind generation plus a Combined Cycle Gas Turbine, or an [174] Integrated Coal Gasification Combined Cycle plant. The capital cost for a 600 MW supercritical PC unit located on the Big Stone Site is estimated at $1,800/kW. The capital cost for a CCGT plant is $605/kw (2011 commercial operation date). For an IGCC facility, the [175] estimated capital cost is $2,126/kW (2011 COD).

[176]

205. Another way compare to cost is to consider busbar costs – the cost of generating a unit of electricity. These were estimated in the September and October reports [177] from Burns & McDonnell. The figures are shown in the following table in levelized 2012 costs (except the IGCC costs are in 2011 dollars) and assume a zero carbon cost:

Alternative	Investor-Owned Utility Levelized Busbar Cost ($/MWh)	Publicly Owned Utility Levelized Busbar Cost ($/MWh))
SCPC	$69.62	$56.38
CCGT	$81.89	$81.30
Wind + CCGT	$80.79	$77.77
IGCC	$83.84	$71.05

206. The Applicants also calculated the busbar costs for each generation alternative assuming that the Big Stone Unit II facility were located in Minnesota and the Applicants had to take into account the environmental cost value established by the Commission for carbon dioxide. The highest value, which applies to generating facilities located in the Twin Cities area, [178] is $3.64 per ton of CO2 emitted. Assuming that a $3.64 cost per ton of carbon dioxide emitted is required, the cost for Big Stone Unit II is $4.87 per MWh for investor-owned utilities and $4.82 per MWh for publicly-owned utilities. For CCGT facilities, the carbon cost impact is $1.90 and $1.96 for the two types of ownership, and $1.12 and $1.15 for CCGT + Wind facilities. For IGCC, the costs are $4.83 and $4.76 per MWh. When these estimated costs are added to the busbar costs in the table above, the Big Stone Unit II facility remains the least-cost alternative. The CCGT + Wind alternative is the next lowest cost baseload energy resource, but it has a 16% higher cost for investor-owned utilities and a 38% higher cost for publicly-[179] owned utilities compared to Big Stone II.

207. The break-even point for supercritical coal, based on the figures from Burns & McDonnell, is approximately $11.10 for investor-owned utilities and $21.70 for publicly owned utilities. At those carbon costs, the SCPC plant is comparable in cost to the CCGT + Wind [180] combination.

208. Only Joint Intervenors asserted a value higher for CO2 than the Burns & McDonnell study break-even point. Their witness David Schlissel asserted that the proper

carbon risk value is $19.10, applied to all tons of CO2 emitted.[181] Dr. Rakow posited a possible figure of $7.90.[182] Xcel will be using a $9 figure in evaluating its next baseload resource alternative.[183] Duke Power is using a carbon value of $7 in its proceeding before the North Carolina Utilities Commission for approval of 1600 MW of new coal generation.[184] The Applicants' witness Thomas Hewson stated that his firm provides market advice to a large number of electric utilities, and his firm advises the use of a $6 value beginning in 2013.[185] Thus, under most assumptions made today on the cost of carbon control, Big Stone II is the least cost alternative as compared to a CCGT alternative, a CCGT + wind alternative, and an IGCC alternative.

209. The Applicants are pursuing various wind projects at this time, but believe they have included a reasonable amount of wind in their resource plans and demand calculations.[186] Their need is primarily for dispatchable baseload capacity, and wind is not a baseload resource because it does not blow all the time. Generally, the capacity factor for wind projects is between 30% and 40% of nameplate capacity on a yearly basis, and MAPP will accredit such facilities at between 5% and 20% for the summer season and between 10% and 35% for the winter season.[187]

210. In the Department's view, the following flaws in the Applicant's modeling remain unresolved.[188] Only MRES resolved all identified flaws to the Department's satisfaction:

a. CMMPA did not directly address the following fundamental flaws in their resource planning, as raised by Schlissel:

(i) The wind capacity factor assumed by CMMPA in Strategist was too low and unreasonably biased the size, type, and timing analysis against a renewable alternative.[189]

(ii) The prohibition in the modeling against adding resources in the 2008-2010 time frame combined with the lack of a reserve margin in the same years biased the model towards adding the Big Stone II unit in 2011. CMMPA's modeling made it impossible for other resources to compete with Big Stone II for meeting capacity needs in the 2008-2011 period.[190]

(iii) The potential effect of this bias on the renewable preference showing is demonstrated by Schlissel's scenario "60 MW wind + DSM + RM," which results in only 21 MW of the Big Stone II resource being added instead of 31.5 MW.[191]

(iv) In response, the Applicants' witness R. Davis asserted that a combination of short term purchases and Big Stone II were superior to all other possibilities. But, according to Dr. Rakow, such an assertion should have been tested in the resource

planning model, and since that was not done for the record in this proceeding, [192] CMMPA has failed to meet the renewable preference requirement.

b. OTP's capacity expansion modeling assumed an on-line date that was significantly earlier than is actually possible. This resulted in an unreasonable bias in favor of Big Stone II and may have prevented renewable resources, either alone or in combination with other resources, from partially or completely fulfilling OTP's energy [193] needs. Therefore, OTP failed the renewable preference requirement.

c. In Synapses' verification run of the Strategist model using all of MDU's base case assumptions, the Strategist model created a non-Big Stone II plan that has a slightly lower net present value than did MDU's Preferred Plan with 116 MW of the [194] Project. According to Dr. Rakow, if a capacity expansion model is operating properly, it should not be the case that a lower net present value could result when a non-forced element of a least-cost plan (such as the Big Stone II unit in MDU's preferred plan) is not allowed to be chosen. Yet this phenomenon occurred. One potential [195] explanation is the "tunneling phenomenon." MDU's capacity expansion modeling witness Heidell denied that Strategist was experiencing tunneling, but could not otherwise explain the fact that eliminating Big Stone II resulted in a lower cost plan. Given that the plan including Big Stone II was not least-cost, MDU has not shown that the use of renewable resources, either wholly or in part, would not result in a lower cost option than Big Stone II. Therefore, MDU failed the renewable preference requirement. [196]

d. During cross examination, GRE witness Stan Selander explained that GRE had the wholesale sales parameter "turned on" during GRE's capacity expansion modeling. According to Dr. Rakow, if a utility claims need based upon wholesale market activities, it must demonstrate all aspects of the claimed wholesale need, including such items as the accuracy of the forecasts of the market sales price and wholesale demand for energy and a demonstration regarding conservation and renewable preferences relative to the wholesale market. GRE did not do so. Therefore, GRE failed the [197] renewable preference requirement.

e. The October 2, 2006, Supplemental Direct Testimony of Larry Anderson on behalf of SMMPA re-opened the resource plan determination by re-examining the size, type, and timing of the Big Stone II resource. Specifically, the revised modeling compared peaking, intermediate, and baseload units rather than performing a certificate of need type analysis of comparing units for a given need. SMMPA's analysis did not allow its EGEAS modeling software to function as a capacity expansion model.

f. HCPD did not use a capacity expansion model. The modeling technique employed by HCPD allows only a small number of potential future options to be examined. Further, HCPD did not even attempt to examine options with greater renewable resources. Therefore, HCPD also failed the renewable preference [198] requirement.

211. The defects in the Applicants' modeling are significant and raise serious doubts about the accuracy of the final demand numbers. But some amount of renewable resources was considered by all the Applicants when they determined their need. The question is whether adequate consideration was given and that is very difficult to resolve. The impact of the flaws in the modeling is difficult to estimate. Most of the Applicants' resource planners and witnesses appeared knowledgeable and to have reasonably made the resource planning determinations that they did. Moreover, the total baseload demand now calculated by the Applicants is 1012 MW in 2012. That is 69% more than the 600 MW upon which the application is based. It is unlikely that full consideration of wind and other renewable resources would have cost-effectively displaced all or a significant part of that much energy from Big Stone II. The Applicants' evidence is sufficient to meet their burden under Minn. Stat. § 216B.243, subd. 3, regarding renewable energy sources.

(6) Minn. Stat. §§ 216B.1691 and .1612--REO and C-BED

212. Minn. Stat. § 216B.243, subd. 3(10), requires the Commission to consider whether the Applicants are in currently in compliance with the Renewable Energy Objectives statute, Minn. Stat. § 216B.1691.

213. The Renewable Energy Objectives statute is focused on increasing the use of renewable sources of electric generation or the purchase of increasing amounts of electricity generated by renewable sources. The Applicants have made satisfactory good-faith efforts [199] toward meeting their REO objectives.

214. Under Minn. Stat. § 216B.1612, electric utilities are required to establish a tariff that optimizes local, regional, and state benefits from wind energy development and to facilitate [200] widespread development of community-based wind energy projects throughout Minnesota.

215. Minn. Stat. § 216B.1612, subd. 5, states, in relevant part:

> Subd. 5. **Priority for C-BED projects.** (a) A utility subject to section 216B.1691 that needs to construct new generation, or purchase the output from new generation, as part of its plan to satisfy its good faith objective under that section should take reasonable steps to determine if one or more C-BED projects are available that meet the utility's cost and reliability requirements, applying standard reliability criteria, to fulfill some or all of the identified need at minimal impact to customer rates.
>
> . . .
>
> (c) The commission shall consider the efforts and activities of a utility to purchase energy from C-BED projects when evaluating its good faith effort towards meeting the renewable energy objective under section 216B.1691.

216. GRE, SMMPA, MRES, and CMMPA have all met the minimum requirements of the C-BED statutes. OTP has not done so yet because it has not yet completed any contracts [201] under the C-BED tariff.

217. The Applicants are substantially in compliance with applicable REO and C-BED

requirements.

C. Are the Consequences of Granting the Certificate of Need More Favorable to Society Than the Consequences of Denying It?

(1) The Relationship of the Proposed Facility to Overall State Energy Needs

218. The Integrated Resource Plan filings of four investor-owned Minnesota electric utilities (Xcel Energy, Minnesota Power, Interstate Power and Light Company, and Otter Tail), all show significant capacity and energy needs during the 2101-2015 timeframe. The IRP filed by Great River Energy also shows significant capacity and energy needs during the same timeframe. These five utilities serve the majority of customers in Minnesota and all of them need additional capacity and energy during the 2010-2015 timeframe. This general assessment of the State's energy needs during that time period is confirmed by the August 2006 Mid-Continent Area Power Pool Load and Capability Report. However, this data does not show what type of energy is needed. That determination depends on factors that would be [202] considered in an IRP analysis

219. Based upon this general assessment of the State's energy need, the proposed transmission lines will have a positive impact on meeting the State's energy needs by providing transmission to import energy generated not only from the Big Stone II generation project, but also wind-generated energy or other energy from west of Minnesota to meet the State's energy [203] need.

220. The Midwest Reliability Organization – U.S. region is projected to have significant capacity deficits during the 2010-2015 timeframe. The capacity projected to be needed during that time period can be met by newly built generation or by importing electricity from other regions. The proposed transmission lines can provide one option to meet the needs by [204] providing transmission outlets to new generation projects.

221. MISO is of the view that additional capacity is needed in a west-to-east direction across the eastern Dakotas and Western Minnesota, and believes that construction of the transmission lines proposed by the Applicants would have system-wide benefits regardless of [205] whether Big Stone II is built.

222. Robert Fagan, an energy economics analyst and mechanical engineer who works with Synapse Energy Economics, Inc., provided testimony on behalf of the Joint Intervenors about the upper Midwest bulk electric power system and the role of MISO. Fagan asserted that "[t]here is considerable room on the existing transmission systems in the region" to carry wind power to market, but acknowledged that "conservative rating mechanisms and inflexible tariff mechanisms may artificially restrain the amount of wind power that can be carried on the [206] system." Fagan's testimony is not persuasive on this point in light of contrary testimony by [207] Laverty and others who are more familiar with the transmission system in the region.

223. The transmission lines are not required to improve general regional transmission

[208]
reliability, but, if built, will likely have positive impact on regional reliability.

(2) Effects of the Proposed Facility upon the Natural and Socioeconomic Environments Compared to the Effects of Not Building the Facility

224. In the EIS, the Department discussed two "no-build" alternatives to the proposed project, in addition to the effects of the proposed transmission lines on the natural and socioeconomic environments. Under the first alternative, it was assumed that both the proposed transmission lines and the Big Stone II plant would not be built. Under the second alternative, it was assumed that the Big Stone II plant would be built but no transmission lines in
[209]
Minnesota would be built.

225. Under the first "no-build" alternative (where neither the transmission lines nor Big Stone II would be built), the Department determined in the EIS that no additional right of way would be required for the new transmission lines; no new structures would be built; and no changes would occur in existing electric and magnetic fields, noise levels, air emissions, visual resources, vegetation, or wildlife resources. Under this alternative, the Department noted that positive socioeconomic impacts would not be realized and it was possible that the Applicants' Minnesota service areas would not keep up with projected load growth and may have a less reliable transmission system, thereby reducing the potential for improvements in economic development. In addition, if the transmission lines were not constructed, the additional capacity that could be used to tie in growing industries in the area of the project (such as wind power and
[210]
ethanol) would not be available.

226. Under the second "no-build" alternative (where Big Stone II would be built but the proposed transmission lines would not), the EIS indicated that no new right-of-way would be required for direct transmission of electricity out of the Big Stone II plant, but additional right-of-way associated with new lines in other states would be necessary and other upgrades of existing lines in Minnesota may be necessary. The EIS also stated that no measurable changes would likely occur to existing electric and magnetic fields, noise levels, and visual resources. The EIS noted that the Big Stone II plant would affect air quality and water quality in Minnesota and would have minimal impact on vegetation and wildlife resources in Minnesota. If the plant were constructed, some of the short-term economic impacts resulting from plant construction could be realized in Minnesota, but the potential economic benefits in Minnesota would be difficult to realize without a transmission system with additional capacity and reliability. [211]

227. The EIS noted that, because the existing Ortonville to Morris 115 kV transmission line is nearing the end of its service life, it would need to be rebuilt under either alternative, regardless of whether or not the Big Stone II generation plant or the proposed transmission lines are constructed. It further indicated that it was possible that this rebuild could necessitate the acquisition of additional right-of-way, and cause short-term impacts to water resources and
[212]
a slight measurable increase in the electric and magnetic fields.

228. The overall effect of not building the transmission lines is negative.

(3) The Effects of the Proposed Facility on Future Development

229. Minnesota and the region have seen an increased interest in the construction of ethanol plants. Ethanol plants require significant amounts of electricity. As of April 2006, there were four ethanol plants in the region, located in Morris, Benson, Granite Falls, and Marshall. Due to growth in the ethanol sector, approximately 148 million bushels of corn were processed into ethanol in Minnesota in 2005. Projected corn use for ethanol is expected to grow to approximately 213 million bushels by 2012. Corn is one of the primary crops in each of the [213] counties crossed by the proposed transmission lines.

230. Due to the wind resources in this region of Minnesota, a number of generation and power delivery projects have been proposed or developed related to wind. Transmission constraints in western Minnesota are presently restricting wind development and the capacity to [214] be provided by the Granite Falls line will help promote wind development in the area.

231. A number of Minnesota communities expressed support for the generation and transmission projects. These communities see a need for more electricity and support the [215] projects because they will provide the electricity to them.

(4) The Socially Beneficially Uses of the Output of the Proposed Facility Including Its Uses to Protect or Enhance Environmental Quality

232. There is no evidence that the proposed transmission lines will cause any adverse environmental impacts, interfere with agricultural operations, or encroach near residential homes.

233. All of the interconnection requests received by MISO other than that of Big Stone II in the vicinity of the 345 kV portion of the proposed lines are related to wind, and there are [216] more wind requests than that line can handle. Although it is not possible to reserve the transmission line for wind only, it is likely that the proposed transmission lines will provide outlet capacity for wind generation and will encourage and allow the development of wind in the area where the lines are located.

234. The transmission lines will provide benefits to society in a manner compatible with protecting the natural and socioeconomic environments, including human health.

D. Will the Proposed Facility Comply with All Relevant Requirements of Other State and Federal and Local Governments?

235. In their Application for Route Permits in this proceeding, the Applicants have identified a number of other permits besides the Route Permits and the Certificate of Need from the Minnesota Public Utilities Commission that may be required to construct the two transmission lines. The permitting authorities include local units of government, such as counties and cities; other Minnesota agencies, such as the Minnesota Department of Natural Resources and the Minnesota Pollution Control Agency; state agencies in South Dakota for construction of the portion of the transmission lines in that state; and various federal agencies, [217] such as the U.S. Department of Energy and the Corps of Engineers.

236. Some members of the public questioned whether the Applicants are in compliance

with Section 106 of the National Historical Preservation Act. The Western Area Power [218] Administration has the lead role on that issue and is taking steps to ensure compliance.

237. The Applicants have obtained or are in the process of obtaining the necessary permits under state, federal, and local laws and policies to construct the transmission lines in Minnesota.

IX. Route Permit Criteria

238. Minn. Stat. § 216E.03, subd. 7, states, in relevant part:

Subd. 7. **Considerations in designating sites and routes.**

(a) The commission's site and route permit determinations must be guided by the state's goals to conserve resources, minimize environmental impacts, minimize human settlement and other land use conflicts, and ensure the state's electric energy security through efficient, cost-effective power supply and electric transmission infrastructure.

(b) To facilitate the study, research, evaluation, and designation of sites and routes, the commission shall be guided by, but not limited to, the following considerations:

> (1) evaluation of research and investigations relating to the effects on land, water and air resources of large electric power generating plants and high-voltage transmission lines and the effects of water and air discharges and electric and magnetic fields resulting from such facilities on public health and welfare, vegetation, animals, materials and aesthetic values, including baseline studies, predictive modeling, and evaluation of new or improved methods for minimizing adverse impacts of water and air discharges and other matters pertaining to the effects of power plants on the water and air environment;
>
> (2) environmental evaluation of sites and routes proposed for future development and expansion and their relationship to the land, water, air and human resources of the state;
>
> (3) evaluation of the effects of new electric power generation and transmission technologies and systems related to power plants designed to minimize adverse environmental effects;
>
> (4) evaluation of the potential for beneficial uses of waste energy from proposed large electric power generating plants;
>
> (5) analysis of the direct and indirect economic impact of proposed sites and routes including, but not limited to, productive agricultural land lost or impaired;
>
> (6) evaluation of adverse direct and indirect environmental effects that cannot be avoided should the proposed site and route be accepted;

(7) evaluation of alternatives to the applicant's proposed site or route proposed pursuant to subdivisions 1 and 2;

(8) evaluation of potential routes that would use or parallel existing railroad and highway rights-of-way;

(9) evaluation of governmental survey lines and other natural division lines of agricultural land so as to minimize interference with agricultural operations;

(10) evaluation of the future needs for additional high-voltage transmission lines in the same general area as any proposed route, and the advisability of ordering the construction of structures capable of expansion in transmission capacity through multiple circuiting or design modifications;

(11) evaluation of irreversible and irretrievable commitments of resources should the proposed site or route be approved; and

(12) when appropriate, consideration of problems raised by other state and federal agencies and local entities.

239. Minn. R. 4400.3150, which now applies to the Commission, states:

4400.3150 FACTORS CONSIDERED.

In determining whether to issue a permit for a large electric power generating plant or a high voltage transmission line, the board [Commission] shall consider the following:

A. effects on human settlement, including, but not limited to, displacement, noise, aesthetics, cultural values, recreation, and public services;

B. effects on public health and safety;

C. effects on land-based economies, including, but not limited to, agriculture, forestry, tourism, and mining;

D. effects on archaeological and historic resources;

E. effects on the natural environment, including effects on air and water quality resources and flora and fauna;

F. effects on rare and unique natural resources;

G. application of design options that maximize energy efficiencies, mitigate adverse environmental effects, and could accommodate expansion of transmission or generating capacity;

H. use or paralleling of existing rights-of-way, survey lines, natural division lines, and agricultural field boundaries;

I. use of existing large electric power generating plant sites;

J. use of existing transportation, pipeline, and electrical transmission systems or rights-of-way;

K. electrical system reliability;

L. costs of constructing, operating, and maintaining the facility which are dependent on design and route;

M. adverse human and natural environmental effects which cannot be avoided; and

N. irreversible and irretrievable commitments of resources.

X. Compliance with Route Permit Criteria

240. The Applicants described the potential impacts of the proposed transmission lines in the Route Permit Application and provided in table format a summary of these potential [219] [220] impacts. In addition, the Department addressed these potential impacts in the EIS. The Western Area Power Administration is also in the process of addressing potential impacts [221] of the transmission lines in its federal EIS.

241. No concerns about the transmission line routes or the potential impacts of the lines were raised during the course of these proceedings by the public or the participants.

242. The Applicants proposed one system alternative to the line to Morris, i.e., a line to Willmar. For the reasons described above, the Morris line is preferable to the Willmar line. Therefore, it is not necessary to discuss the routing criteria as they apply to the possible Willmar routes. In general, the Morris line is preferred from a routing perspective because it is shorter and does not involve new right-of-way as the Willmar route does. In addition, the Willmar [222] alternative would cost more.

A. Effects on Human Settlement

243. As discussed above, both of the proposed transmission lines will follow existing right-of-way for most of their length. It will only be necessary to acquire approximately 14 miles of new right-of-way.

244. There is no evidence that any occupied residences or businesses will be displaced because of the construction of either of the lines. The Applicants indicated in their Route Permit Application that one home along Morris Route 1 is located within 100 feet of the route alignment, and eight homes are within 300 feet. There are no homes on Granite Falls Route 1 that are located within 300 feet of the route alignment. There may be instances where property is purchased in accordance with Minn. Stat. § 116C.63, subd. 4, under which the property owner has the option to have the property that the route crosses purchased at the fair [223] market value of the land. It is not anticipated that property values for parcels of land [224] crossed by or adjacent to the proposed transmission lines would significantly change.

245. Noise concerns may be associated with both the construction and operation of the two transmission lines. Construction noise will occur only for the short period of time that construction occurs near a specific receptor. After construction is completed, operation of the transmission conductors and transformers at substations produce audible noise under certain conditions. The level of noise, or its loudness, depends on conductor conditions, voltage level, and weather conditions. Noise emission from a transmission line occurs during heavy rain and wet conductor conditions. In foggy, damp, or rainy weather conditions, transmission lines can create a subtle crackling sound due to the small amount of electricity ionizing the moist air near the wires. During heavy rain, the general background noise level is usually greater than the noise from a transmission line; however, few people generally are out near the transmission line in such conditions. During light rain, dense fog, snow, and other times when there is moisture in the air, the proposed transmission lines will produce audible noise higher than rural background levels but similar to household background levels. During dry weather, audible noise from transmission lines is an imperceptible, sporadic crackling sound. No violations of state noise standards established by the Minnesota Pollution Control Agency are expected. [225]

246. The proposed routes are located primarily in agricultural areas. The structures and transmission lines would affect the viewshed for persons living or passing nearby. Placement of the transmission lines will potentially cause visual impacts to 16 homes along Morris Route 1 and 9 homes along Granite Falls Route 1. For the most part, there are already existing transmission lines in the corridors where the proposed lines would be constructed. The visual impacts from rebuilding along existing corridors would be minimal. Building transmission lines along new alignments would be a contrast to surrounding land uses and could produce [226] perceptible visual impacts.

247. There are a variety of outdoor recreational opportunities along each of the proposed routes, including snowmobiling, biking, hiking, canoeing, boating, fishing, camping, swimming, hunting, and nature observation. The potential impacts to these activities caused by the proposed transmission lines would be primarily visual or in the nature of easements. In addition, six structures would be expected to be constructed in the Big Stone National Wildlife Refuge in connection with Morris Route 1 and one or more structures would be expected to be constructed in the Lanners Wildlife Management Area in connection with Granite Falls Route 1. There is no evidence that the proposed lines would cause a substantial interference with [227] present recreational opportunities in the area.

248. Construction of the transmission lines would have a short-term impact on socioeconomic resources as workers are located in the area during the construction period. It is expected that these short-term impacts would be relatively minor, and that the construction, operation, and maintenance of the transmission line would not have a significant effect on [228] socioeconomic resources along the route.

B. Effects on Public Health and Safety

249. No person has raised a significant concern about any public health or safety issues associated with these proposed high voltage transmission lines, but it is common to address the issues of EMF and stray voltage in route permit proceedings. The term EMF refers to electric and magnetic fields that are present around electrical conductors and devices. The

intensity of the electric field is related to the voltage of the line, and the intensity of the magnetic field is related to current flow through the conductor. Both magnetic and electric fields [229] decrease in intensity with increasing distance from the source.

250. The issue of EMF has been examined by the Minnesota Environmental Quality Board and the Public Utilities Commission in other proceedings involving routing of transmission lines. In June 2005, the EQB noted (in connection with a proceeding involving the Buffalo Ridge 345 kV transmission line) that "[t]here is at present insufficient evidence to demonstrate a cause and effect relationship between EMF exposure and any adverse health effects. . . . There is uncertainty, however, concerning long-term health impacts, and the Minnesota Department of Health, the EQB and Xcel all recommend a 'prudent avoidance' policy in which exposure is [230] minimized." While Minnesota has not established limits on magnetic field exposure, the EQB has imposed a permit condition on HVTL permits limiting electric field exposure to 8 kV [231] per meter at one meter above ground.

251. The maximum electric field intensity predicted for the 230 kV Morris line is 1.5 kV per meter. This level falls off quickly as one moves away from the line. The maximum intensity for the Granite Falls 345 kV line is 2.2 kV per meter, and this number also decreases [232] dramatically as one moves further from the line. These levels are significantly less than the 8 kV/meter that has been allowed in other permits. The maximum magnetic field is 250 milligausses for a 345 kV line and 212 milligausses for a 230 kV line. These levels are consistent with other lines of their size and the levels approach background levels about 300 [233] feet from the lines. The Applicants stated in their route permit application that the nearest home to the proposed Morris line is 172 feet away and the nearest home to the Granite Falls line is over 328 feet away. The nearest home along the preferred routes is farther than with any [234] alternative route.

252. Stray voltage is defined as a natural phenomenon that can be found at low levels between two contact points in any animal confinement area where electricity is grounded. Problems are usually related to the distribution and service lines directly serving the farm or the wiring on a farm. In those instances when transmission lines have been shown to contribute to stray voltage, the electric distribution system directly serving the farm or the wiring on the farm was directly under and parallel to the transmission lines. These circumstances are considered in installing transmission lines and can be readily mitigated. No stray voltage issues are [235] anticipated with the transmission project.

C. Effects on Land-Based Economies

253. The construction of the transmission lines and the substations will have an impact on agricultural land throughout the areas of the routes. The pole placement will impact farmland throughout the corridor, and temporary impacts such as soil compaction and crop damages within the right-of-way are also likely. Landowners will be compensated for any losses incurred during construction. It is expected that the Morris line along the preferred route will temporarily affect approximately 246 acres of agricultural land and permanently affect approximately 7 acres. The Granite Falls line along the preferred route will temporarily affect

approximately 357 acres and permanently affect 8 acres. In general, areas surrounding the transmission structures will still be available for farming. Designating a wider route than is actually necessary for the right-of-way will give the Applicants the ability to consult with landowners to determine the precise location for the transmission structures to minimize [236] potential impacts.

254. Expansion of the existing substations and construction of the new Canby substation would also have a permanent impact on prime farmland. Approximately 3.7 acres would be required for the Johnson substation construction, and approximately 6.3 acres for the [237] Canby Substation.

255. A reliable and affordable supply of electricity is a critical aspect of development in Minnesota since electricity is a significant operating cost for Minnesota businesses. Wind power, ethanol production, and other industries or commercial businesses will require access to a reliable and affordable transmission system for economic development viability in the region. [238]

256. The construction of the Granite Falls line to 345 kV specifications, along with other new transmission facilities, is likely to provide capacity for wind development in the region. Many residents and businesses in the area of these facilities have expressed an interest in seeing wind development occur in the region.

D. Effects on Archaeological and Historic Resources

257. The Applicants have identified one archaeological site that is within 500 feet of the [239] proposed Morris line and 137 historic structures that are within one mile. They have identified two archaeological sites within 500 feet of the proposed Granite Falls line along the [240] preferred route and 103 historic structures within a mile. The Applicants indicated in their application for route permits that they will make every effort to avoid impacts to identified archaeological and historic resources.

258. The Western Area Power Administration is responsible for ensuring compliance with the National Historic Preservation Act. By letter dated November 29, 2006, WAPA indicated that it had initiated consultation with thirteen tribes for the Big Stone II Project in early June 2005 to seek their input regarding the identification and preservation of historic and cultural resources. The list of tribes included the Upper Sioux Indian Community, the Lower Sioux Indian Community Council, and the Flandreau Santee, Yankton, Santee, Rosebud, Crow Creek, Cheyenne River, Lower Brule and Standing Rock Sioux Tribes. WAPA thereafter sent out copies of a draft Programmatic Agreement to the thirteen tribes as well as the Shakopee Mdewakanton Sioux (Dakota) Community, the Leech Lake Tribe of Ojibwe, and the Mille Lacs Band of Ojibwe. WAPA reported that only the Sisseton-Wahpeton Dakota Nation indicated an interest in meeting with WAPA. WAPA followed up with phone calls, received comments on the draft, and prepared a Programmatic Agreement for signature by state historic preservation officers. Because no tribal lands have been identified as being affected within the transmission corridors or plant site, WAPA stated that tribes are not required signatories for the Programmatic Agreement. As of November 29, 2006, WAPA had not made any determinations of effect on any historic properties, so the process was not yet complete. Further meetings with

[241]
the tribes were to be held in January 2007.

E. Effects of the Project on the Natural Environment

259. No measurable impacts on air quality relating to ozone are expected from operation of the proposed transmission lines regardless of the route chosen. Temporary and localized impacts to air quality during construction may occur due to traffic and the disturbance of soil, which raises fugitive dust particles.

260. The Applicants will have to cross several streams, rivers, and small wetlands during construction of the lines. There is a possibility that sediment will reach surface waters as the ground is disturbed by excavation, grading and construction traffic. Where possible, the Applicants will attempt to span wetlands along the route. The maximum span of the proposed structures is approximately 1,000 feet. It is likely that one structure will need to be placed in each of three wetlands in connection with the Morris line and that one structure will need to be placed in each of two wetlands in connection with the Granite Falls line, since those wetlands are wider than 1,000 feet. Once the transmission lines are completed, no impact on surface
[242]
water quality is expected. The Applicants will implement best management practices to minimize the impacts.

261. There are five Wildlife Management Areas (WMAs) and eight Waterfowl Production Areas (WPAs) within a mile of the preferred Morris Route, and the Big Stone National Wildlife Refuge (NWR) is also a short distance from the line. Similarly, there are eight WMAs, one WPA, and one Scientific and Natural Area (SNA) within a mile of the preferred Granite Falls route. No direct impacts to recreational opportunities in any of these areas are
[243]
anticipated.

262. The Applicants have proposed one minor change in the route for the Granite Falls line at the border crossing between South Dakota and Minnesota. This change is intended to avoid a certain parcel of land on the South Dakota side of the border on which the U.S. Fish and Wildlife Service has the potential to obtain a grassland easement. The same Minnesota
[244]
landowner is involved with the original crossing point and the new crossing point.

263. Based on the information compiled by the Applicants in the Application for Route Permits, the information reported by the Department in the Environmental Impact Statement, and the comments received from the public, there is no evidence that the preferred route of the proposed transmission lines would have a significant impact on the natural environment.

F. Effects on Rare and Unique Natural Resources

264. The Applicants and the Department both conducted an analysis of the possibility of rare and unique resources in the areas of the proposed routes. The Minnesota DNR Natural Heritage Database was consulted to determine whether any rare and unique natural resources (both species and communities) were within one mile of the proposed routes. The DNR Minnesota County Biological Survey (MCBS) database was consulted to determine whether any areas of biodiversity significance were along the proposed routes. The Applicants conducted field surveys to map remnant prairie communities along the routes. A number of rare and

[245]
unique resources were identified in the areas of the proposed routes.

265. Once the routes are selected the Applicants will survey the route alignment again to determine whether any special species or communities are present, and mitigation measures will be developed to minimize any impacts. The DNR and USFWS will continue to be consulted to minimize and avoid impacts to rare and unique resources along the route alignments. Efforts will be made to avoid placing structures within prairie remnants, natural communities, and
[246]
MCBS areas of biodiversity significance.

G. Application of Design Options that Maximize Efficiencies, Mitigate Adverse Environmental Effects, and Accommodate Expansion of Transmission or Generation

266. The Applicants examined the potential for line losses as a part of the Certificate of Need. In all cases the preferred lines to Morris and Granite Falls had less line losses than the Willmar option. In addition, it was found most effective to build and operate the Granite Falls line at 345 kV. Finally, building the Granite Falls line to 345 kV specifications but only operating
[247]
it at 230 kV resulted in lower losses than building and operating the line at 230 kV.

267. Construction of the Granite Falls line to 345 kV specifications will accommodate expansion of both transmission and generating capacity, particularly the expansion of wind
[248]
power in the area.

H. Use of Parallel or Existing Rights-of-Way and other Boundaries

268. As discussed previously, the preferred routes call for only a small addition of new right-of-way, since they will follow or parallel existing right-of-way for most of the route.

I. Use of Existing Large Electric Power Generating Plant Sites

269. This criterion is not applicable to the routing of transmission lines, although Big Stone Unit II will be located at the site of an existing generating plant (Big Stone Unit I).

J. Use of Existing Systems or Rights-of-Way

270. The preferred routes will follow or parallel existing transmission right-of-way for much of the distance. Morris Route 1 is a rebuild of an existing transmission line for approximately 99.7 percent of its length. Granite Falls Route 1 follows existing transmission line right-of-way for approximately 84 percent of the route, and 11 percent of the route parallels transportation right-of-way. Agricultural section and field lines will be followed when possible
[249]
and in consultation with landowners.

K. Electrical System Reliability

271. The Applicants conducted an interconnection study to determine the best way to connect Big Stone Unit II to the transmission grid. They determined that the line to Morris and

[250]
the line to Granite Falls provide the best method of interconnecting the new facility.

272. Although not necessary for the delivery of energy from Big Stone II to the Applicants, the Applicants have proposed that the transmission lines be designed to carry energy from wind generation in the area. While not the only solution, it is a plan strongly supported by MISO.

L. Costs that are Dependent on Design and Route

273. A line to Willmar would be more expensive than a line to Morris because it would
[251]
be longer and would require more new right-of-way.

274. Constructing the Granite Falls line to 345 kV specifications would be slightly more expensive than a 230 kV line, but the lower line losses and additional capacity with the 345 kV line make it the preferred design.

M. Adverse Unavoidable Effects

275. The significant unavoidable adverse impacts to agricultural and aesthetics caused by the proposed routes are expected to be minimal. There will be temporary impacts to prime farmland caused by construction, staging, and stringing operations, and permanent impacts from the placement of structures and access roads. Transmission lines will be aligned along section and field lines wherever possible to minimize impacts to prime farmland. In addition, the proposed transmission lines will be routed wherever possible alongside existing power lines and section lines and within road, rail, and utility right-of-ways to minimize adverse impact. Significant unavoidable adverse aesthetic impacts for the Morris Route may exist for visitors to the Big Stone National Wildlife Refuge, the Otrey and Prairie WMAs, communities within one mile, and residences within 500 feet. There will be effects on prime farmland associated with the proposed lines, but there are no unavoidable effects associated with these transmission lines that are not inherent with transmission lines of the length and voltage involved here. The Applicants will institute best management practices and other mitigative techniques to
[252]
adequately minimize the impacts of these lines.

N. Irreversible and Irretrievable Commitments of Resources

276. There are few commitments of resources associated with the proposed transmission lines that are irreversible and irretrievable. Those that do exist are primarily related to construction. Construction resources that will be used include aggregate resources,
[253]
concrete, steel and hydrocarbon fuel used by construction vehicles.

O. Other Considerations

277. Minn. R. 4400.3350 provides that "[n]o high voltage transmission line may be routed through state or national wilderness areas" and "[n]o high voltage transmission line may be routed through state or national parks or state scientific and natural areas unless the transmission line would not materially damage or impair the purpose for which the area was designated and no feasible and prudent alternative exists." The rule goes on to state that "[e]conomic considerations alone do not justify use of these areas for a high voltage transmission

line." None of the proposed routes would cross any of these prohibited areas.

278. Of the two possible routes for the Morris line, the route preferred by the Applicants (Morris Route 1) is preferable because it utilizes more existing right-of-way, it is slightly shorter, [254] it has less agricultural impact, and it is lower cost than the other Morris route.

279. Of the four possible routes examined for the Granite Falls line, the route preferred by the Applicants (Granite Falls 1) is preferable because it follows more existing right-of-way than the alternatives, it will have visual impact on fewer homes, it will have less agricultural impact, and it is lower cost than the other alternatives. In addition, this is the route that will match the route approved by the South Dakota PUC for the South Dakota portion of the line. [255]

280. Regardless of which routes are ultimately approved by the PUC, several substations will have to be upgraded. With the Morris 230 kV transmission line along either route, the Johnson Junction Switch Station and the Morris Substation will both require additional equipment. The Johnson Junction Switch Station will become a substation as a transformer is added to the site and the station will be expanded by an area approximately 400 feet by 400 [256] feet. No expansion is required at the Morris Substation.

281. With the Granite Falls 345 kV transmission line, the substation at Canby and the Granite Falls Substation will be upgraded with the addition of new equipment. The Applicants intend to move the location of the Canby Substation. The Granite Falls Substation has [257] adequate space for the new equipment and will not have to be expanded in size.

282. The new Canby Substation site is approximately one mile to the northeast of the [258] existing site. The Applicants intend to move the location of this substation because the existing site is on a very low ground elevation and within a 100-year floodplain. Water levels have been a problem in the past. In addition, the substation is old and is difficult to access, particularly in the wintertime. The owner of the land near the existing substation is not in favor of expanding the substation, and the remodeling/modification costs would be substantial. These costs offset the cost of constructing a new substation outside of the flood plain. In addition, the landowner of the property where the new substation would be located has [259] expressed approval for the relocation plan.

XI. Public Comments

283. The public was afforded numerous opportunities to submit comments about this project, and many individuals elected to do so in written comments or in oral comments at the public hearings. Nearly all the comments related to Big Stone Unit II, which was often referred to as "the project;" few comments focused on the transmission lines.

284. Many, if not most, of the comments were solicited by the Applicants or Joint Intervenors, or organizations aligned with one or the other of them. Many were form letters. They most often reflected the positions of the Applicants or Joint Intervenors. There were, however, some truly "public" comments and some different ideas and views expressed. The

public comments, and some of the responses of the parties at the public hearings, are summarized below. Other comments made by representatives of the parties have been considered as part of those parties' evidence, and are not generally repeated here.

A. Economic Impact

285. Vincent Guertin, Business Manager, and Richard Oakes, Business Representative of the International Brotherhood of Electrical Workers Local Union 949 (IBEW Local 949), representing approximately 2,500 members in Iowa, Minnesota, North Dakota, and South Dakota, expressed support for the Big Stone II project. IBEW Local 949 noted that the generation technology would produce 630 MW of electricity to serve 2.3 million customers, while producing 18% less CO2 emissions than conventional coal-fired generating plants. IBEW [260]
Local 949 urged approval of the project as being reasonable and in the public interest. IBEW members from a number of locals appeared at the public hearings to support the Big [261]
Stone II project and submitted written comments in support.

286. A very large number of members of the International Union of Operating Engineers Local 49 (IUOE Local 49) wrote in support of the project. They emphasized that it is necessary to expand regional generation and transmission of electricity to sustain the economy. [262]

287. Members of the Building and Construction Trades Union Local 49 (BCTU Local 49) noted that the use of high quality workmanship in the project will benefit participants by keeping the construction within both budget and time constraints, and asserted that the apprentice and journeymen training programs would assure safe work practices and hazard management. Similar comments were expressed by members of IBEW 426 and Carpenters [263]
Union Local 587.

288. Doug Beckman related his conversations with people in the Ortonville - Milbank area of western Minnesota. He noted that a large number of people he has spoken to support the Project due to the benefits of a steady supply of electricity and the positive economic impact [264]
associated with the Project, including additional tax revenue. Lewis Miller expressed support for the Project, so long as the cost of electricity remained low, particularly with the [265]
number of ethanol plants in the region.

289. Edward Mehl, CEO of Lake Region Healthcare Corporation, noted that his company employs 650 people in Otter Tail County and is a large user of electricity. Lake Region Healthcare Corporation supports the Project as an additional source of cost-efficient [266]
electricity for the area.

290. Donald Dargus, Manager of Plant Services for Dahlgren & Company, Inc., expressed support for the Project. Dahlgren & Company is a large edible sunflower processor and requires cost-efficient electricity that is reliable. Dargus indicated that the Project would ensure that the company would be able to expand. Michael Helgeson, CEO of Gold 'N Plump Poultry, and Gary Chestnut, Director of Purchasing for Ag Processing, Inc., expressed similar

[267]
support for the Project.

291. Members of Minnesota Utilities Investors, an interest group for public utilities shareholders, urged approval of the Project as beneficial to the economy, while improving environmental performance over current emissions. A number of OTP employee/shareholders expressed support for the Project as beneficial to both the community and the company. The Joint Economic Development Commission, a nonprofit organization for business development in North-Central Minnesota, supported the Project as improving the availability and reliability of
[268]
electricity both of which are important to business growth.

292. Scott Hain, General Manager of Worthington Public Utilities Water and Light Commission (Worthington PUC), noted that the project was a collaboration of investor-owned, municipal, and cooperative utilities designed to ensure ongoing electricity supply. The Worthington PUC expressed its support of the project by adopting a resolution urging State regulators to approve the project. Similar resolutions were passed by the Marshall Municipal Utilities Commission, Sauk Centre Public Utilities Commission, the City of Benson, the City of Granite Falls, the City of Melrose PUC, the Willmar PUC, Alexandria Power and Light, Adrian Public Utilities, the City of Elbow Lake, the City of Detroit Lakes, the City of Luverne, the
[269]
Lakefield Public Utilities, and the Moorhead Public Service Commission.

293. Marty Sunderman of the Sauk Centre Public Utilities Commission noted that 58 cities are in partnership with Missouri River Energy Services, a Joint Action Agency. This partnership has an ownership position in the Big Stone transmission project. Sunderman noted that the partnership is not involved in the project from a profit motive. The municipalities are involved in the project due to their belief that the project is the most environmentally safe means of meeting the electricity needs of the community with currently-existing technology. The municipalities have long-term contracts with Missouri River Energy running to 2046 in order to
[270]
ensure affordable electricity for the municipalities' customers.

294. Dennis Rykken, Mayor of Sauk Centre and Chairman of the City's Public Utilities Commission, described the mix of wind-, coal- and hydro-generated electricity that is purchased by Sauk Centre for its municipal utility customers. Mayor Rykken noted that Sauk Centre is among the lowest 12 cities in Minnesota for electricity rates. The fraction of energy produced by hydro-generation has fallen from 60% to an expected 35% with the addition of a new customer adding 1 MW to the City's load. Mayor Rykken noted that the only way to maintain
[271]
low rates for utility customers was to add additional coal generation to the mix of sources.

295. Rob Wolfington, City Manager of Benson, noted that Benson is also part of Missouri River Energy Services and supports the Project. Wolfington described Benson's efforts to develop other alternative energy sources within the community. Fibromin, a 55 MW baseload facility that generates electricity through biomass, is located in Benson. There are also two ethanol plants, one existing and another under development, in Benson. Wolfington indicated that the City has applications for wind generation, and the City hopes that it will
[272]
become energy-independent and a net exporter of energy.

296. Minnesota State Senator Cal Larson emphasized the impact that the Project

would have on providing affordable energy to rural areas in an environmentally [273] responsible fashion.

B. Community-Owned Wind Generation

297. An assessment of the impact of wind-generation ownership entitled "Community vs. Corporate Wind: Does it Matter Who Develops the Wind in Big Stone County, MN?" was submitted by Arne Kildegaard, Ph.D., Professor of Economics at the University of Minnesota (Morris). Relying on local wind developers and the NREL's JEDI model for cost estimates, Dr. Kildegaard concluded that community-owned wind generation plants contributed five times the economic impact on local value added productivity and 3.5 times the impact on local job creation as corporate-owned development of that capacity. [274]

298. Fresh Energy noted that a single wind turbine can generate electricity sufficient to supply 2,000 homes. With similar improvements in other generating technologies, Fresh Energy maintained that integration of these non-fossil fuel alternatives would result in a lower risk to ratepayers than that accompanying coal-generated power. OTP disputed Fresh Energy's contentions regarding both the sufficiency of wind generation and risk borne by ratepayers. OTP noted that 850 MW of wind-generated electricity was anticipated to be purchased as part of the Big Stone II project, which is the output of between 400 and 500 wind turbines. [275]

299. Gary Stoks, a participant in Community Based Energy Development described one of the overriding concerns in this proceeding as "What can we do to keep jobs and people around in greater Minnesota?" Stoks noted that "wind energy is right in our back door" and asserted that harnessing that energy helps farmers through wind tower ownership and the community through tax revenue. The overall community benefits arise through the retention of the fiscal benefits in the region. Stoks indicated that the addition of more transmission capacity provided an opportunity for wind development to increase into an "industry of wind towers." [276]

300. Minnesota State Senator Gary Kubly noted that the burdens of the power plant were being placed on the six counties in the immediate vicinity of Big Stone II. To address these burdens, Senator Kubly urged the imposition of conditions on Big Stone II, including the requirement that 300 to 600 MW of power from community-owned wind generators be purchased over a 10- to 15-year period. Senator Kubly maintains that such a condition would establish the wind generation capacity that Minnesota has been trying to foster. [277]

301. Deb Peterson, resident of Buffalo Ridge near the Lac qui Parle River, is a member of Clean Up the River Environment (CURE) and the Land Stewardship Project. Peterson maintained that the construction of the Big Stone II plant will diminish the ability of western Minnesota landowners and farmers to develop locally owned and operated wind power systems. She asserted that a renewable energy economy is in conflict with a facility that will continue to have an impact on global warming and emit pollutants including 400 pounds of mercury in the first three years of the Plant's operation. Peterson noted that the Minnesota River Watershed has already been designated as a mercury-impaired water by the Minnesota Pollution Control Agency. Peterson described the situation in Germany and Denmark. In Germany (according to the University of Minnesota's West Central CERTS Team), 88 percent

of wind development is community-based (and Germany has 35 percent of the world's installed wind capacity). In Denmark, community-based wind accounts for 84 percent of wind development (and Denmark has seven percent of the world's installed wind capacity). In contrast, the United States has 0.6 percent of wind development that is community-based. [278]

302. David Norgaard, Wind Project Developer for Southwest Wind Consulting, LLC, urged inclusion of terms to benefit the communities affected by the impacts of the HVTL. Norgaard suggested conditions similar to those imposed on Xcel Energy in its Certificate of Need matter. The inclusion of "community wind" as a condition was suggested as a possible means of reducing those impacts. The community wind power approach was supported by Swift County Commissioner Gary Hendrickx, Chair of the Upper Minnesota Valley Regional Development Commission, and Ron Antony, Yellow Medicine County Commissioner. Norgaard proposed that the Commission include a minimum of 120 MW of community wind projects as a condition to granting the Certificate of Need. This 120 MW community wind condition was supported by the County Boards of Chippewa, Lac Qui Parle, Big Stone, and Yellow Medicine Counties. He also recommended delegation of the authority to designate which generators satisfy this condition to the Upper Minnesota Valley Regional Development Commission in Appleton. [279]

C. Global Warming/CO2 Emissions

303. Retired Judge Keith Davison, an investor in both Otter Tail Company and several freight railroads, objected to the project as accelerating global warming through the emission of greenhouse gasses. With the scale of the climate change problem, Judge Davison urged the adoption of nonpolluting alternatives over the proposed coal-generated electricity. [280]

304. Hundreds of commentators noted in emailed comments that "global warming is a serious problem" and that "more investment in clean, renewable energy like wind" was needed to avoid negative impacts to our health, economy, and existing quality of life. [281]

305. Patrick Moore, Executive Director of Clean Up the River Environment (CURE) expressed concern that the additional CO2 that would be emitted by Big Stone II would have an impact on global warming. He indicated that any possible carbon tax to address that problem would mean that ratepayers in cities such as Appleton, Milan, Granite Falls and Benson would experience rate increases. Citing Barbara Freese of the Union of Concerned Scientists, CURE indicated that increases of 41 percent for electricity could result from such changes in policy. [282]

The Northstar Chapter of the Sierra Club maintained that a carbon tax was likely, and that the costs arising from such a tax should be applied over the useful life of the Project. [283]

306. Colleen Frey noted that the practice of mining the coal to power the proposed generating plant was hard on the environment, that costs are incurred to transport coal to be used in generation, and that alternatives are available. [284]

307. Hannah Hankins, a student a Lac Qui Parle Valley High School, noted that the Big Stone II plant was expected to add 4.7 million tons of CO2 to the atmosphere. Hankins

described the current state of science on the issue of climate change as 928 peer-reviewed articles over the last 10 years having been published in scientific journals, with none of these articles expressing doubt over CO2's role in global warming. She urged consideration of the information contained in Al Gore's book, *An Inconvenient Truth,* and asked that efforts be made to avoid the potential for extreme weather conditions exacerbated by global warrning. [285]

308. Dr. Peter Wycoff, a Forest Ecologist who teaches at the University of Minnesota, Morris, noted that claims regarding 96% of carbon emissions being "natural" and only 4% being caused by fossil fuel emissions did not account for the impact of those emissions on the carbon cycle. Since the "natural" emissions are balanced by capture and absorption of an equivalent amount of carbon, it is the remaining 4% which generates the rise in atmospheric CO2 and causes climate change. These changes were characterized as significantly altering the weather experienced in Minnesota. In order to address these problems, Dr. Wycoff urged the adoption [286] of plant design that would allow for retrofitting for carbon sequestration.

D. Pollutant Emissions

309. Clean Water Action objected to the project as resulting in a 348 times increase in particulate matter, a 20 times increase in sulfuric acid mist, a doubling of mercury levels and releases of selenium compounds. a 2.3 times increase of methyl chloride and methyl ethyl ketone, a 2.6 times increase in other hazardous air pollutants, and an increase in volatile organic compounds of 67%. A number of health risks from these pollutants were cited as [287] reasons for opposing coal-fired generation and using wind generation instead.

310. Frances Moore, a recent graduate of Montevideo Senior High School and participant in CURE programs, objected to the mercury emissions that would continue with the introduction of Big Stone II, due to the environmental damage that mercury can cause in lakes, rivers, and wildlife. Casey Wojtalewicz, a student at Lac Qui Parle Valley High School, described his observations of the emissions from Big Stone I as "the long brown line of pollution ... coming from the smokestack at the Big Stone plant ...." Wojtalewicz objected to allowing any mercury to be emitted from the Plant due to the harmful impact of that pollutant on water [288] quality and human health.

311. Karen Folkman raised questions concerning who would benefit from the Project. Timothy Rogelstad, PE, a manager for Otter Tail Power, responded that the immediate demand for the Project arose from the co-owners, in order to connect the new generation plant to the [289] customers of all seven participating utilities. Ms. Folkman also asked about the potential impact of deposits of pollutants that are produced from the coal plant. Terry Graumann, Manager of Environmental Services for the Applicants, described the air emissions (including SO2, nitrogen oxide, and mercury) as entering the global pool of these substances. Based on Electrical Power Research Institute studies, Graumann described the pollutants as unlikely to be deposited in greater concentrations locally. By this assessment, there is no difference in the impact of particular emissions from the Big Stone plant and any other similar plant. By EPA estimates, there are 5,300 tons per year of mercury emissions worldwide, with approximately [290] one percent of that amount arising from utilities.

312. The Sierra Club asserted that the health impact of fine particulate matter emissions alone would amount to nearly $3 billion in health care costs and other economic impacts. A number of studies were cited as demonstrating that up to 70% of uncaptured mercury is deposited within fifty miles of coal-fired emitters. A large number of commentators described the mercury impact as failing to meet the requirements of "environmental [291]
justice."

313. Emma Kvatum expressed concern over the impacts of particulate matter discharged from coal generation. She related her experiences with apples and other property covered with "a dark, greasy, oily substance" requiring scrubbing with detergent to remove. While acknowledging that she could not prove that the pollution came from a coal plant, she noted that the proximity and location of Big Stone I made it the likely source. OTP responded that Big Stone I currently uses an "advanced hybrid unit" for emissions control that is expected to be replaced with a fabric filter in the next year. Big Stone II is slated to have a scrubber and [292]
fabric filter. There are no plans for carbon sequestration as a means of reducing CO2 emissions. OTP noted that additional CO2 reduction technologies were being explored that [293]
could reduce the overall impact of the plant in the future.

314. Brian Wojtalewicz, an attorney from Appleton, Minnesota, noted that allowing significant amounts of mercury to be emitted by the Big Stone plants conflicts with Minnesota government efforts to stop mercury poisoning. The Total Maximum Daily Load requirement (TMDL) is the legal standard for determining if a body of water is impaired. TMDLs arose from the federal Clean Water Act (33 USC § 1251, *et seq.*) which was passed many years ago as a result of the demand by the public to have water cleaned up from poisons and pollution. Minnesota's state-wide mercury TMDL standard was issued in June 2006. This standard will require that mercury reductions be achieved of 93 percent of 1999 levels. With less than one percent of mercury pollutants coming from specific point sources, Wojtalewicz contends that the reduction required must come from non-point sources and the largest are air emissions from coal plants. Since 1990, mercury emissions from coal power plants has increased by 10 percent from 667 pounds to 1,825 pounds in Minnesota. Wojtalewicz urged the Commission to make approval of the Minnesota portion of the Big Stone project conditional on serious [294]
reductions in mercury emissions.

315. Duane Ninneman of Ortonville, Minnesota, submitted two studies: "Impacts of Coal-fired Power Plants on Trace Metals and Polycyclic Aromatic Hydrocarbons in Lake Sediments in Central Alberta, Canada," published in the Journal of Paleolimnology; and "Evaluation of the Emission, Transport, and Deposition of Mercury, Fine Particulate Matter, and Arsenic from Coal-Based Power Plants in the Ohio River Valley Region," from the U.S. [295]
Environmental Protection Agency. Ninneman described the studies' findings as showing that mercury at any given geographic location likely comes from the nearest source. For coal-fired power plants, mercury found in the vicinity of a coal-fired power plant most likely comes [296]
from that plant.

316. Ninneman also noted that the Clean Air Mercury Rule [297] takes effect in 2010

and at that time the mercury emissions in South Dakota will be capped for the entire state. South Dakota's mercury emissions limit starts at 144 pounds in 2010 and then declines to 58 pounds in 2018. Any additional mercury emissions will be permissible only under the terms of "Cap and Trade," an approach that essentially requires emitters to purchase the right [298] to exceed the limits.

317. Similar concerns were expressed by Darwin Dyce of the Marshall Area Peace Seekers. Dyce focused on the impact that mercury has on human health. Mercury can affect fetal brain development resulting in measurable declines in motor skills, learning capacity, IQ, behavior, and other life-changing symptoms. Dyce noted that the Centers for Disease Control and Prevention have warned that, among women of childbearing age, one in six now have [299] levels of mercury that are at or above the EPA-designated "safe" level.

318. Dyce cited the increases in the number of students who require special education due to autism spectrum disorder (from 18 in 1993 to 245 in 2003) as evidence that neurotoxins (including mercury) are having a negative impact on human health. Richard Halterman. a high school biology teacher, related his experiences with students who have experienced health problems and noted that a divalent form of mercury produced in coal combustion precipitates [300] rapidly from the atmosphere, often within 70 miles of the point of discharge.

319. Minnesota State Senator Gary Kubly noted that the Legislature had passed a bill to require a 90 percent reduction in mercury at the three dirtiest coal plants in the State of Minnesota. Senator Kubly indicated that Minnesota residents believe that emissions from coal plants need to be further reduced and that renewable energy sources were the way to go in the future. With the relative cost of wind power being lower than other options, the Minnesota Legislature has discussed requiring 20 percent of electrical generation be derived from renewables by 2020. Senator Kubly considered such a standard to be feasible and indicated [301] that the economy of the area would also stand to benefit from such an approach.

320. OTP acknowledged that the regulatory structure would apply to Big Stone II and indicated that its approach would be to improve the emissions controls to meet the limits rather than purchase allowances under Cap and Trade. OTP agreed that there is a significant economic incentive to make reductions in pollutants. Since mercury removal technology is a new and developing area, OTP has not yet selected the specific approach it will use to meet the emissions goals. In this way, OTP hopes to avoid selecting a technology that is good today but [302] five years from now finding out that there is something much better.

321. Kevin Whalen asked about the extent to which wet scrubbers at the new plant would reduce SO2, NOx, and mercury compared to the existing coal plant at that location. OTP's Graumann responded that the control technologies for the wet scrubber will remove SO2 from the flume gas screen along with certain types of mercury: Mercury that is oxidized is water soluble and much of the mercury in that state is removed by the wet scrubbing control [303] technology.

322. For nitrogen oxide emissions, different controls are used. The supercritical boiler will be equipped with low NOx burners, meaning that the combustion system will be designed

so that the amount of nitrogen oxide conversion at that stage is greatly reduced. Further NOx reductions are achieved by a catalytic reduction unit, reducing NOx emissions to nitrogen and water in the presence of ammonia. The combined technologies and adding the scrubbing technology to both the Big Stone I and Big Stone II plants will result in SO2 emissions from both plants that are no greater than the current emissions from Big Stone I. Similar results are [304] expected regarding NOx emissions from the two plants.

323. Graumann related the commitment of the Big Stone II co-owners to install control technology that will prevent mercury emissions above the historical levels experienced by Big Stone I alone. The combined mercury emissions are estimated to be 189 pounds per year. That was the amount of mercury emissions for Big Stone I in 2004. That commitment and that cap would be achieved within three years of the commercial operation date of Big Stone II. The three year period is intended to allow for evaluation of technologies to determine the best and [305] most economical way to reduce mercury emissions.

324. Mary Jo Stueve, a resident of Big Stone County and a member of Clean Water Action, noted that the Draft Environmental Impact Statement indicated that the Big Stone II project will result in a 348 times increase in particulate matter emissions, when compared to the emissions from Big Stone I after retrofitting new control technology. Increases are also shown in the Draft EIS for sulphuric acid mist (20 times increase), mercury (2 times increase), methyl chloride and methyl ethyl ketone compounds (2 times increase), selenium (2 times increase), and other hazardous air pollutants (2.6 times increase). Exposure to these pollutants are linked to decreased lung capacity, cancer, developmental toxicity, brain damage in unborn children and children, heart attacks, bronchitis, inflammation of the airways, and premature death. Stueve urged consideration of the health impacts, particularly on children, in assessing impacts [306] of the Project.

325. Rolfes explained that the 348 times increase in particulate matter emissions was the first test result of a prototype control technology. This test result, occurring when the unit was first installed, was not repeated. The prototype technology has not functioned correctly since it was installed and that technology will be replaced with a baghouse-type system on Big Stone I. Rolfes described the replacement technology as the best technology available for particulate matter control and both Big Stone I and Big Stone II will have this type of control for [307] particulates.

E. Cost/Benefit Analysis

326. Dr. Kildegaard questioned whether the obligation to serve loads applied to the parties to this proceeding, or all the utilities in the Mid-Continent Area Power Pool (MAPP). His concern was whether the Big Stone II project was directed at meeting load requirements or [308] increasing profits through sales on the wholesale market. This concern was also [309] expressed by other commentators. OTP responded that MAPP required approximately 35,000 MW of peak power and the Applicants represent about 15% of that amount, and indicated that the Project is designed to put low-cost baseline energy generation in the [310] Applicants' mix of electricity sources. OTP further noted that a capacity deficit was

expected by the time the Big Stone II coal plant goes online. This new generating capacity is expected to provide adequate supplies of electricity for four years from that time, [311] before load growth by the serving utilities exceeds capacity again.

327. Dr. Kildegaard noted that the wind portion of the source mix would amount to at most one-third of the "name-plate capacity" of the turbines. OTP suggested that one-fifth was the maximum in their experience (making the 850 MW of planned wind power into 160 MW of delivered electricity). Dr. Kildegaard maintained that the Certificate of Need analysis in Minn. Stat. § 216B.243 should apply as if the Big Stone II generating plant was to be sited in [312] Minnesota.

328. Dr. Kildegaard identified the health consequences of emissions and the environmental impact of climate change due to increased CO2 as reasons to doubt that coal-generated electricity could constitute a low-cost alternative. In addition, he indicated that bottlenecks in delivery of coal and the likely introduction of "Cap and Trade" restrictions on CO2 emissions were factors that would likely escalate the cost of coal. By comparison, the local financial impact of community-based wind development was assessed by Dr. Kildegaard as creating between 1,200 and 2,100 additional jobs in the region. OTP agreed that community wind generation has superior job-creation impacts and explained that this benefit was factored into OTP's decision to include significant local wind generation in the overall mix of electricity for Big Stone II. The transmission plan is intended to accommodate the demands placed by the [313] various forms of energy generation.

329. U.S. Representative Betty McCollum noted that the carbon emissions of the Big Stone II project were likely to come under some form of economic impact regulation over the 40-year projected lifespan of the project. Such a regulatory approach would likely result in marked cost increases that would significantly reduce any anticipated savings arising from the use of coal in generating electricity. The Project was described by Rep. McCollum as a "20th Century solution ill-suited to meet the energy and environmental challenges of the 21st [314] Century." Hundreds of commentators maintained that some form of carbon tax would be adopted to address the climate change exacerbated by CO2 emissions and that this was "sure [315] to increase the cost of coal power."

330. Rene Maes commented at the Morris public hearing that the Big Stone II Project reflected the loss of an opportunity to invest in renewable energy, and expressed the view that [316] renewable energy would, over the long run, be both more efficient and less polluting.

F. Historical/Cultural Preservation

331. Frankie Jackson of the Sisseton-Wahpeton-Sioux Tribe expressed concern that preservation of historical and cultural sites will not be adequate where these sites are affected by the Project. He inquired as to how the Project will comply with Section 106 of the National Historical Preservation Act (16 U.S.C. § 470f), which he indicated requires federal agencies to take the effect of the Project on historical and cultural properties into consideration. He also maintained that the Project co-owners needed to consult with tribes to meet the requirements of

[317]
Section 106.

332. Terry Graumann, Manager of Environmental Services for Otter Tail Power, responded during the public hearing that the Western Area Power Administration (WAPA), as the lead federal agency for developing the Environmental Impact Statement (EIS), is responsible for compliance with Section 106. He indicated that the consultation process does not occur between the Project's co-owners and the tribes, but rather takes place between the tribes and WAPA. Graumann related his understanding that WAPA has contacted the tribal leaders of the affected tribes and has been working with the tribes on the 106 consultation
[318]
process.

333. Jackson disagreed with the assessment of compliance, noting that Section 106 requires consultation with the tribal historical preservation officers or the designated cultural representative and not the tribal chairman. In Jackson's opinion, the described process does not constitute a cultural resource management plan, no MOAs have been developed, and no programmatic agreements with WAPA have been made in regards to the preservation and protection of cultural and historic sites. Jackson maintained that portions of the Project will fall within the reservation lands of the Lower Sioux, the Upper Sioux, and other Sioux nations. The potential impact renders failure to comply with Section 106 more significant, particularly where
[319]
WAPA is aware of this noncompliance.

334. Nancy Werdel, the project manager for the federal EIS, who works for the Western Area Power Administration, appeared at the October 16, 2006, public meeting and commented about the compliance of the Western Area Power Administration with the National Historic Preservation Act and its efforts to consider impacts of the Big Stone Plant on historic and cultural resources. On November 29, 2006, Werdel wrote to Terry Graumann, an Otter Tail Power employee, and identified the tribal governments that had been contacted during
[320]
development of the EIS.

G. Water Usage/Impact on Lake Levels

335. William Rois, a resident of the Big Stone Lake area, expressed concern about the potential impact of a new coal-burning plant on lake levels through increased demand for water in the plant's operations. Rois recognized the need for power generation, but suggested that wind or alternative uses would better protect the population from the impacts of global warming. Mary Jo Stueve, a member of Clean Water Action, maintained that the Project posed both a flood risk and a draw-down risk. She asserted that Big Stone Lake is a shared water public resource between Minnesota and South Dakota. Big Stone II requires an additional 10,000 acre feet of water to operate, which will be held in a storage pond. Stueve contended that, in drought conditions, the lake could be at risk of being drawn down. Stueve indicated that the structure of the holding pond constitutes a high-risk dam and the Federal Energy Regulatory Commission (FERC) has categorized the holding pond structure as such. Clean Water Action requested that the potential for and possible impact from a failure of the holding pond be assessed by a reconvened South Dakota - Minnesota Boundary Waters Commission prior to
[321]
issuing permits for the Project.

336. Patrick Moore, Executive Director of Clean Up the River Environment (CURE),

noted that South Dakota has issued a permit for the new Big Stone II plant to draw 10,000 acre feet of water from Big Stone, which is approximately 3.2 billion gallons. CURE expressed concern that this action could affect water cycles, flows of lakes and rivers, fish [322] habitat, and drought cycles.

337. Rogelstad responded that Big Stone I obtains its water resources from Big Stone Lake, but water can only be drawn from the lake when it is at or above normal levels. He also maintained that the speed of pumping will not change from current levels. For those reasons, Rogelstad maintained that Big Stone Lake should not be affected by the new generating plant. Regarding emissions, Rogelstad noted that regulated emissions (that do not currently include CO2) will be limited to current levels due to the improved controls being installed on Big Stone I. As to the dam, he indicated that the only affected area is the existing floodplain of the Minnesota River, which is already prone to natural flooding. Rogelstad stated that the purpose of the Boundary Waters Commission is to establish the appropriate lake level, and asserted that it has not met since 1971. He further indicated that the Minnesota DNR and the South Dakota DENR have both addressed the issue of water levels and amounts withdrawn from Big Stone [323] Lake.

XII. State Environmental Impact Statement

338. The Transmission Project involves a combined review of the Certificate of Need and Route applications before the Commission. Minnesota law generally requires an Environmental Report to be prepared prior to granting a certificate of need for a large energy facility and an Environmental Impact Statement for a route permit. However, in its November 29, 2005, Order Agreeing to Combining the Environmental Report and Environmental Impact Statement Document, the Commission approved the proposal by the Applicants and the Department that a single environmental document be prepared for both the Certificate of Need and routing processes (i.e., that an EIS be prepared in lieu of an Environmental Report), pursuant to Minn. R. 4410.7060, subp. 2. The Commission also ordered that joint public hearings be held to receive comments from the public on both the need and routing issues. [324]

339. The Department held public meetings in Benson, Morris, Ortonville, Canby and Granite Falls from January 24-26, 2006, to discuss the Project with the public and solicit input into the scope of the EIS to be prepared. Numerous comments were received from members of [325] the public regarding the scope of the EIS.

340. After affording interested persons an opportunity to comment on the appropriate scope of the EIS, the Commissioner of Commerce issued an Environmental Impact Statement Scoping Decision on February 28, 2006. The Department noted in its Scoping Decision that the preparation of a single EIS document would "streamline the process for the Applicants and [326] other parties and . . . assist the public participation process." The Department further indicated in the Scoping Order that "[a]ny consideration of generation alternatives or substitutions at the proposed Big Stone II plant site in South Dakota" would be deemed to be [327] outside the scope of the EIS. The Scoping Decision stated that the Department's EIS "will focus on the environmental, social, economic and cultural impacts of any alternatives that would

affect the implementation of high voltage transmissions lines in Minnesota as related to this project." The Department explained:

> The EIS will consider only alternatives that could have an impact on transmission in Minnesota. For example, an alternate generation option in the same location and of the same output as proposed would not be considered, as it would not materially affect the transmission requested for the project. The South Dakota Public Utilities Commission generation permit application process and the review thereof by the Western Area Power Administration Federal EIS are considering the generation alternatives at the proposed Big Stone II plant. These agencies are reviewing generation alternatives that would meet the applicants' proposed energy, capacity and timeline using a different fuel, plant design, pollution equipment, location or even timeline.
>
> Alternatives analyzed under this EIS will be alternatives to the applicants' proposed transmission facilities. The Department will evaluate alternatives that provide an equal amount of energy and capacity as proposed by the applicants. Such alternatives may attempt to reduce, mitigate or eliminate the need for the applicants' proposed transmission lines, while delivering the proposed "needed" energy to load centers. Any analysis of the alleged need will be conducted through the CON process generally and not specifically under the EIS. The EIS will focus on the environmental, social, economic and cultural impacts of any alternatives that would affect the implementation of high-voltage transmissions [328] lines in Minnesota as related to this project.

341. The Department's Scoping Decision identified the following alternatives that would be reviewed in the state EIS: the proposed transmission project, including the assumption of the Big Stone II plant expansion; a "no-build" option under which transmission in Minnesota would not be built; a renewables/gas option, where the proposed generation and transmission plan would be replaced by renewable electric generation coupled with a natural gas component; and a distributed generation option incorporating demand side management and other [329] conservation improvement program opportunities.

342. After the Scoping Decision was issued, David Birkholz, State Energy Planning Director, Department of Commerce Energy Facility Permitting Division proceeded to prepare the EIS. A Draft EIS was issued on July 31, 2006, and comments were received from the public [330] until October 31, 2006. The Final EIS was issued on December 1, 2006.

343. The Final EIS was prepared as a two-part document. The first part describes the human and environmental impacts of the proposed transmission lines and discusses alternatives that would have been required by Minn. R. 4410.7035 under an Environmental Report for the Certificate of Need. It evaluates issues regarding size, type and timing that would not normally be included in an EIS for a route permit. The second part of the EIS discusses the human and environmental impacts of the proposed and alternative routes in the Permit Application and other impacts identified by public comments received during the scoping [331] process as required by Minn. R. 4400.1700. Because the question of generation alternatives was being fully reviewed in a separate jurisdiction by the Federal EIS, the Department's EIS incorporated by reference the environmental impacts analysis of the federal

[332]
EIS as to any emissions of the proposed Big Stone II generation.

344. In the Final EIS, the Department included an analysis of alternatives that would [333]
have been required under the rules applicable to an Environmental Report. By taking this approach, the Department was able to assess the comparative feasibility of the Project and the alternatives laid out in the Scoping Decision. The Final EIS also includes a separate section in which the Department responded to the substantive comments it received on the Draft EIS. [334]

345. As reflected in the Direct Testimony of Birkholz and the associated Final EIS, the Department found that none of the alternatives examined in Part 1 of the Final EIS would have lesser impacts than the proposed Transmission Project. In the view of the Department, the No-Build Option does not account for customer need or grid reliability, nor would it mitigate the pollutants from the plant. The Department found that the other two options account for fulfilling customer need, but are not favorably comparable on a cost or reliability scale. As to the alternatives examined in Part 2 of the Final EIS, the Department found that the proposed route offers the least new impact on the environment and on the populace as a whole. The Department emphasized that the transmission project as proposed includes replacing lines within existing utility rights-of-way. Additionally, the Department found that longer spans in [335]
some areas may mitigate some of the current impacts on wetland areas.

346. Minn. R. 4400.1700, subp. 10, requires the PUC to make a determination of the [336]
adequacy of the Environmental Impact Statement prepared on the proposed project. The Final EIS is adequate if it:

> A. addresses the issues and alternatives raised in scoping to a reasonable extent considering the availability of information and the time limitations for considering the permit application;
>
> B. provides responses to the timely substantive comments received during the draft environmental impact statement review process; and
>
> C. was prepared in compliance with the procedures in this chapter.

347. The Joint Intervenors argued that the State EIS failed to comply with statutory requirements primarily because it failed to consider the environmental impacts of the Big Stone II unit, including its contribution to global warming. They also asserted that the comparison of alternatives was heavily skewed in favor of the Big Stone II project by focusing solely on the costs of building the transmission lines rather than the costs of building the generating unit. [337]

348. The PUC rules provide that "Once the [Commissioner] has determined the scope of the environmental impact statement, the scope must not be changed except upon decision of the [Commissioner] that substantial changes have been made in the project or substantial new information has arisen significantly affecting the potential environmental effects of the project or

[338]

the availability of reasonable alternatives." Thus, in determining the adequacy of the EIS, it is necessary to compare the document with the scoping document.

349. In the Scoping Decision, the Commissioner made it clear that the State EIS would focus on the Transmission Project in Minnesota, not Big Stone II in South Dakota. The Scoping Decision identified the environmental impacts that would be examined and alternatives to the transmission project that would be considered. The State EIS adequately addresses the issues and alternatives that were identified in the Department's Scoping Decision and the environmental, social and economic impacts of the Transmission Project in Minnesota.

350. It was appropriate for the Department to determine that the generation plant was outside the scope of the State EIS and rely on the Federal EIS to provide information about the impacts of Big Stone II generation. The State's Final EIS focuses on the specific subject of the certificate of need and routing dockets in this case: the transmission lines proposed to be located in Minnesota for interconnection to the planned Big Stone generation plant in South Dakota. The Department made its cost comparisons in its review of alternatives in the EIS based on the correct assumption that the Big Stone II plant can exist independently of the other alternatives reviewed.

351. While the State EIS does not directly address the global warming impacts of the proposed Big Stone II generation plant, the record in this matter reflects the Joint Intervenors' concerns as to the proposed Big Stone II plant as well as the Department's assessment of the impact of the costs of CO2 projected to be emitted by the non-renewable generation source slated to transmit power over the requested transmission line (as compared to renewable alternatives). Moreover, the record from the South Dakota PUC proceeding has been received as an exhibit in this case, and that record includes the Federal Draft EIS prepared by the Western Area Power Administration evaluating alternatives to the Big Stone II plant.

352. Unlike the State EIS, the Federal EIS will include an analysis of the impact of the emissions from the proposed Big Stone II generation plant itself. The Western Area Power Administration described the scope of the draft federal EIS (which was issued on or about May 23, 2006) as follows:

> The Draft EIS evaluates the environmental impacts of the proposed Big Stone II plant, the transmission alternatives and the substation modifications on air quality, water resources (ground water, floodplains, surface water), geology, minerals, paleontological resources, soils, biological resources (vegetation, wildlife, fisheries, special status species, wetland/riparian areas), cultural resources, Native American concerns, land use (land use planning, public facilities, recreation, agricultural practices and prime and unique farmland), infrastructure, public health, waste management, visual resources, noise, social and economic
>
> [339]
>
> values, environmental justice, and cumulative impacts.

353. The Department's decision to incorporate the Federal EIS by reference in the State EIS is consistent with the intent of the Minnesota Environmental Policy Act (MEPA) to

[340]

reduce paperwork and delay through intergovernmental reviews and with the instruction in Minnesota Rules that "governmental units shall cooperate with federal agencies to the fullest extent possible to reduce duplication" between MEPA and the National Environmental Policy

[341]

Act (NEPA), 42 U.S.C. §§ 4321 to 4361.

354. The section of the Final EIS responding to the substantive comments on the Draft EIS provided a sufficient response to the substantive comments that were received that related to the scope of the EIS, in accordance with Minn. R. 4400.1700, subp. 9.

355. The Department followed all the procedures established for preparation of an EIS, including notification to the public and opportunities for submission of public comments. The Final EIS adequately addresses the environmental, social and economic impacts of the proposed transmission line project.

XIII. Conditions

356. In the Department's post hearing brief in this matter and an accompanying January 30, 2007, letter to the Administrative Law Judges from Deputy Commissioner Edward A. Garvey, the Department recognized that the transmission grid in the state and the region "is currently operating at or near capacity in many areas" and that the Applicants in the present case "appear to have shown that the proposed lines may benefit transmission reliability." The Department, however, stated that it could not recommend that the application be approved as filed because, in its view, the Applicants have failed to meet the legal need criteria, primarily due to shortcomings with respect to the issues of renewable energy and energy conservation. [342]

357. The Department indicated that the Applicants could amend the application and refile the application or the Commission could condition the application in such a way that it may be brought into legal compliance and be in the public interest. The Department recommended that at least five conditions be imposed:

a. the application should not be approved unless the Applicants develop and submit for Commission review a plan to offset the 4.7 million tons of CO2 emissions enabled by the proposed transmission lines;

b. the Commission require the Applicants to develop and issue a request for proposals for least 120 MW more of community-based energy development to be located in the counties that will host the proposed transmission facilities;

c. with respect to conservation, the Commission condition any approval of the project upon the Applicants complying with the least the following criteria:

(1) each generation and transmission (G & T) Applicant must agree to centralize regulatory reporting of conservation within the G & T;

(2) each G & T Applicant must agree to work with its members toward eliminating rate designs that promote energy growth; and

(3) each Applicant should establish a goal of achieving annual energy savings equaling 1.5 percent of forecasted energy sales, with such achievements to be part of the overall CO2 offset plan discussed above;

d. with respect to rate design, the Commission condition any approval on Otter

Tail power proposing to eliminate or phase out declining block rates in its next rate case due October 1, 2007; and

e. With respect to water issues, the Commission condition any approval upon the Applicants working with the state of South Dakota and the Minnesota Department of Natural Resources to resolve the issue regarding the water resource for the proposed Big Stone II generating unit and reporting the resolution to the Commission prior to the time that the proposed lines are energized.

The Department asserted that the imposition of these and other reasonable conditions "may be sufficient to rectify the failings in the proposal to make it possible to conclude that a conditioned [343] approval of the project is in the public interest."

358. The Public Utilities Commission has the authority to impose reasonable conditions in connection with Certificate of Need and Route Permit proceedings. Minn. Stat. § 216B.243, subd. 5, states that the issuance of the certificate of need "may be made contingent upon modifications required by the [C]ommission." Mirn. Stat. § 216E.03, subd. 10(b), similarly states that the Commission "shall issue a permit for the construction of a high-voltage transmission line specifying the design, routing, right-of-way preparation, and facility construction it deems necessary, and with any other appropriate conditions."

359. Because the MISO Open Access Transmission Tariff requires non-discriminatory access, MISO cannot give preference to a request based on fuel type or show a preference for wind in allocating firm usage of additional capability on the proposed transmission lines. Transmission service is to be available on a first-come, first-served basis, with no exceptions for particular sources. In addition, it is not possible to dedicate a transmission line on an integrated network to a sole use, such as wind energy, since there are no valves to redirect the flow of the [344] electrons. Accordingly, it would be in conflict with federal law to include a condition in the Certificate of Need reserving capacity on the proposed transmission lines for wind or any other [345] particular generation source. It is the understanding of the Administrative Law Judges that that is not what the Department is suggesting here.

360. Conditions similar to the Department's proposed condition relating to a requirement that the Applicants issue RFPs for least 120 MW more of community-based energy development have been imposed by the Commission in prior cases. For example, in a recent order in another proceeding, the Commission conditioned the granting of certificates of need to Xcel Energy for transmission lines in southwestern Minnesota on a number of conditions designed to maximize the likelihood that the certified lines would be used for their intended purpose of carrying wind generation. These conditions included a requirement that Xcel sign power purchase agreements with wind developers for a minimum of 675 MW of wind-generated electricity on the Buffalo Ridge, install a total of 825 MW of wind generation at Buffalo Ridge by the time the transmission lines become operational, make transmission service requests for network (firm) service to MISO for at least 825 MW of wind-generated power, and purchase at tariff rates all available small, locally-owned wind generation on Buffalo [346] Ridge up to a total of 60 megawatts.

361. Some of the proposed conditions may raise constitutional issues, such as the imposition of conditions relating to the construction or operation of Big Stone Unit II. In addition,

some of the proposed conditions may be affected by new legislation or rules relating to CO2 emissions.

362. The Applicants noted in their Proposed Findings of Fact that, since CMMPA and Heartland have both agreed to work with the Department to discuss ways in which their conservation efforts could be improved, it would be reasonable to include a condition in the CON recognizing that the two utilities and the Department would meet within the near future to discuss such efforts.

363. The Applicants also indicated in their Proposed Findings that, because Great River Energy has expressed a willingness to work with its member distribution cooperatives to discuss rate designs that might be promoting energy consumption, a CON condition requiring GRE to report to the Commission on its efforts to work with its members and the results of those efforts would be reasonable.

364. The question of what, if any, conditions should be imposed if the Certificate of Need and Routing Permits are granted is properly left to the discretion of the Commission in this matter.

Based on the foregoing Findings of Fact, the Administrative Law Judges make the following:

CONCLUSIONS

1. The Minnesota Public Utilities Commission and the Office of Administrative Hearings have jurisdiction over this matter pursuant to Minn. Stat. §§ 14.50, 216B.243, and 216E.03.

2. The Commission gave proper notice of the hearing in this matter, has fulfilled all relevant substantive and procedural requirements of law or rule, and has the authority to take the action proposed.

3. This proceeding concerns only the proposed construction in Minnesota of the Transmission Project. The permitting, construction, and operation of the proposed Big Stone Unit II generating plant are not at issue in this case.

4. The South Dakota PUC has no authority over transmission lines to be constructed in Minnesota. The Commission is not limited in its authority to approve, deny, or condition approval of the request of the Applicants for a Certificate of Need and Routing Permit in Minnesota. The Commission's lawful exercise of its discretion and application of Minnesota law to the proposed transmission lines to be located in Minnesota does not constitute illegal interference with the permitting decision issued by the South Dakota PUC.

5. The transmission lines proposed by the Applicants constitute "large energy facilities" within the definition set forth in Minn. Stat. § 216B.2421, and "high voltage transmission lines" within the meaning of Minn. Stat. §216E.03, subd. 2.

6. All of the Applicants meet the definition of "person" contained in Minn. Stat. § 216B.02, subd. 3, and Minn. Stat. § 216E.01, subd. 2.

7. Under Minn. Stat. § 216B.243, subds. 2 and 4, the Applicants must apply for and obtain a Certificate of Need from the Commission under Minn. Stat. §§ 216B.243 and 216C.05

to 216C.30, and route permits from the Commission under Minn. Stat. Ch. 216E, prior to construction of the transmission lines in Minnesota.

8. The Applicants have demonstrated compliance with all the criteria for issuance of a Certificate of Need under Minn. Stat. § 216B.243 and other applicable statutes and Minn. R. 7849.0120.

9. The Applicants have demonstrated compliance with all the criteria for a Route Permit for both transmission lines under Minn. Stat. §216E.03 and Minn. R. chap. 4400.

10. The Applicants failed to give meaningful consideration to the Mesaba Project as a supply option as required by Minn. Stat. § 216B.1694, subd. 2(a)(5). However, that failure may be excused because it is unlikely that energy from the Mesaba Project will be available when Big Stone II comes online. The Commission may wish to condition the Certificate of Need upon the Applicants making the Mesaba Project a supply option for a portion of their additional energy needs.

11. Neither the Full Faith and Credit clause nor the doctrine of issue preclusion require that the findings contained in the siting decision of the South Dakota PUC be given preclusive effect in this proceeding. Moreover, principles of comity among the states would not be violated if the Commission denied a Certificate of Need to the Applicants.

12. Application of the Minnesota Certificate of Need statute to the particular facts presented in this proceeding and an ultimate decision by the Commission to deny the Certificate of Need in this case would not violate the Commerce Clause of the United States Constitution.

13. During this proceeding, the Applicants and the PUC agreed to waive the provisions of Minn. Stat. § 216B.243, subd. 5, requiring the PUC to approve or deny a certificate of need within 12 months of the submission of the application.

14. Any of the foregoing Findings of Fact more properly designated as Conclusions of Law are hereby adopted as such. These Conclusions are reached for the reasons set forth in the Memorandum below, which is incorporated into these Conclusions by reference.

15. The citations to transcripts and exhibits and testimony in these Findings of Fact are not intended to indicate that all evidentiary support in the record has been cited.

Based upon the foregoing Conclusions, the Administrative Law Judges make the following:

RECOMMENDATION

IT IS HEREBY RESPECTFULLY RECOMMENDED that:

16. The Commission **GRANT** the Applicants' Petition for a Certificate of Need for the construction and operation of the Transmission Project.

17. The Commission **ISSUE** Routing Permits for the transmission lines (a 230 kV line from the South Dakota border to the Morris Substation and a 345 kV line from the South Dakota border to the Granite Falls Substation) along the route preferred by the Applicants and authorize construction of the lines, substations, and other associated facilities described in the applications, including a new site for the Canby Substation as described in the record.

18. The Commission consider imposing one or more of the conditions suggested by the Department.

19. The Commission consider requiring the Applicants to purchase a portion of their future energy and capacity needs from the Mesaba Project pursuant to Minn. Stat. § 216B.1694, subd. 2(a)(5).

20. The Commission find that the Final Environmental Impact Statement prepared by the Department is adequate.

Dated: August 15, 2007

s/Steve M. Mihalchick

STEVE M. MIHALCHICK
Administrative Law Judge

s/Barbara L. Neilson

BARBARA L. NEILSON
Administrative Law Judge

MEMORANDUM

Several rulings on legal issues have been incorporated in the Findings and Conclusions above and will not be repeated here. However, this Memorandum will address the issues raised by the parties that warrant more detailed discussion.

As a threshold matter, it is necessary to discuss several motions and defenses raised by various parties, and clarify the legal standards that apply to the present proceeding. The motions and defenses fall into two primary areas: (1) those seeking clarification of the nature of the current proceeding and exploring the interplay between the Minnesota CON law and the South Dakota PUC's issuance of a site permit regarding the Big Stone II plant; and (2) those seeking clarification of what, if any, environmental cost value should be assigned to carbon [347] dioxide in connection with the present proceeding.

I. Nature of the Current Proceeding and Interplay between Minnesota CON Proceeding and South Dakota Siting Decision

A. Background

In this consolidated proceeding, the Applicants seek a Certificate of Need and a Routing Permit for two proposed high-voltage transmission lines to be located in southwestern Minnesota. The lines would be built from points on the South Dakota-Minnesota border where they would connect to high voltage transmission lines that originate at the Big Stone power plants in South Dakota, to two termination points in Minnesota. In their application for the Certificate of Need, the Applicants indicate that the transmission lines are needed "[i]n order to accommodate the new generation facility [Big Stone unit II]" and to "expand the bulk transmission system in western Minnesota to enable the transmission grid to better transport power, including power generated by wind and other renewable energy sources, and to [348] increase reliability."

It is undisputed that both of the proposed transmission lines fall within the definition of "large energy facility" set forth in Minn. Stat. § 216B.2421, and the definition of "high voltage [349] transmission line" set forth in Minn. Stat. § 216E.01, subd. 4. Minn. Stat. § 216B.243, subd. 2, specifies that ""[n]o large energy facility shall be sited or constructed in Minnesota without the issuance of a certificate of need by the [PUC] pursuant to sections 216C.05 to 216C.30 [pertaining to energy planning and energy conservation] and this section and consistent with the criteria for assessment of need." Moreover, Minn. Stat. § 216E.03, subd.2, states that "[n]o person may construct a high-voltage transmission line without a route permit from the commission. A high-voltage transmission line may be constructed only along a route approved by the commission." It is also undisputed that all of the Applicants meet the definition of "person" under Minn. Stat. § 216B.02, subd. 3, and Minn. Stat. § 216E.01, subd. 2. As a result, prior to constructing the transmission lines in Minnesota, the Applicants must apply for and obtain a Certificate of Need and route permits from the PUC under applicable Minnesota law.

As discussed in the Findings of Fact and Conclusions above, the Minnesota statutes and rules require the Applicants, as part of demonstrating the need for the transmission lines, to demonstrate the need for the electricity the Applicants claim must come from Big Stone Unit II and to evaluate certain alternative sources for any such electricity. Accordingly, the Minnesota PUC has jurisdiction to consider and decide such issues.

In its December 19, 2005 Order Accepting the Application as Substantially Complete and Requiring Further Information, the PUC provided some guidance regarding what information it deemed to be relevant to this proceeding. The Order noted that the environmental organizations had argued that the application was incomplete because it did not contain adequate information on the human and environmental impacts of the proposed Big Stone II project or project alternatives, including demand-side management and renewable energy, and the Applicants had countered that an assessment of the risk of environmental costs and regulation on the proposed facility over the expected useful life of the plant, including a proposed means of allocating costs associated with that risk, was not relevant to the PUC's ultimate deliberations in this case since the generation facility was to be located in South Dakota and South Dakota had sole jurisdiction over the certificate of need for the facility. The PUC Order addressed these competing arguments as follows:

> The Commission believes that it is not necessary for the Application to contain the information identified by the Organizations. Although the Application is an important document, it is only part of a fairly extensive record that will be established for this proceeding, which, as indicated below, will include contested case hearings before an administrative law judge (ALJ). At the same time, however, the Commission does not accept the Applicants' further argument that the generation and demand-side information referred to by the Organizations is extraneous to the Commission's consideration of the merits of the Application. The need for the generating facility and the need for the transmission lines are inextricably linked. As a matter of logic, the transmission lines proposed to be constructed in Minnesota will not be needed where they are proposed if the Applicants have a more reasonable and prudent alternative generation site. And the proposed transmission lines will not be needed at all if the Applicants (due to demand-side management or any combination of other alternatives) do not need the electricity projected to be generated at the Big Stone, South Dakota facility.

[350]

Based upon Minn. Stat. § 216B.243, subds. 3 and 3a, Minn. R. 7849.0120, and the PUC's December 19, 2005, Order, it is evident that the matters relevant to this transmission line proceeding include whether the Applicants' demand for electricity cannot be met "more cost effectively" through demand side management, whether the Applicants' need for electricity is "otherwise justified," whether the Applicants made a reasonable study of renewable energy sources, and whether the Applicants have demonstrated that there is no reasonable renewable energy source, or combination thereof, for generating power that is less expensive than their chosen alternative, Big Stone II.

B. Applicability of Minn. Stat. § 216B.243, subd. 3(12)

In their Significant and Dispositive Motions, the Applicants seek clarification that Minn. Stat. § 216B.243, subd. 3(12), does not apply to this proceeding. That subdivision of the CON statute states that, *"if the applicant is proposing a nonrenewable generating plant,"* the PUC's evaluation of whether need has been shown by the applicant must include the "applicant's assessment of the risk of environmental costs and regulation *on that proposed facility* over the expected useful life of *the plant*, including a proposed means of allocating costs associated with [351]
that risk." The Department of Commerce agreed that this portion of the statute does not [352]
apply to the present case.

The Administrative Law Judges agree with the Applicants and the Department that Minn. Stat. § 216B.243, subd. 3(12) is not applicable here because the Applicants are not proposing a nonrenewable generating plant in this proceeding but simply certification of a large high-voltage transmission line that meets the definition of a large energy facility under 216B.2421, subd. 2, and Minnesota R. 7849.0100, subp. 14.

C. Jurisdiction of Minnesota PUC over Plant to be Located in South Dakota

Both the Applicants and the South Dakota Governor's Office of Economic Development (GOED) assert that the Minnesota PUC does not have statutory or regulatory jurisdiction over the Big Stone Unit II generating plant to be located in South Dakota and caution against allowing this proceeding to be transformed into one for a certificate of need for an out-of-state power plant. The Applicants and GOED assert that the PUC can only exercise jurisdiction within the borders of the state of Minnesota. The Applicants contend that, even if generation issues may have limited relevance in transmission certificate of need cases, they cannot be determinative in cases such as this where the generating facility to be interconnected is located out-of-state. The GOED claims that the Joint Intervenors are attempting to relitigate the same issues that were involved before the South Dakota PUC using the same witnesses, the same evidence, and the same arguments, and argues that it would be improper to allow the decision of the South Dakota PUC to be relitigated before the Minnesota PUC in this proceeding.

In response, the Department stressed that this case is not one seeking a certificate of need to construct an out-of-state power plant, but merely involves the proposed construction of high-voltage transmission lines in Minnesota. The Department pointed out that neither the PUC nor the Department has suggested that the PUC possesses jurisdiction over whether or not South Dakota allows construction in South Dakota of the proposed plant, and neither the PUC nor the Department intervened in the South Dakota permitting case regarding proposed Big

Stone Unit II. The Department agrees that whether or not generation is constructed in South Dakota is not within PUC's jurisdiction.

In the interests of clarity, the Administrative Law Judges reiterate that this case concerns only the proposed construction in Minnesota of high-voltage transmission lines that are defined under Minnesota law as "large energy facilities" and thus require issuance of a certificate of need by the Minnesota PUC as well as routing permits. The Minnesota statutes do not require that the Minnesota PUC issue a certificate of need for construction of a power plant in South Dakota. The construction and operation of Big Stone Unit II is not at issue in this case, nor is the propriety of the decision by the South Dakota PUC to issue a permit for the construction of Big Stone Unit II. By the same token, however, the South Dakota PUC has no authority over transmission lines to be constructed in Minnesota, and the Minnesota PUC is not limited in its authority to approve, deny, or condition approval of the Minnesota transmission line certificate of need request. The PUC's lawful exercise of its discretion and application of Minnesota law does not constitute illegal interference with South Dakota's generation permitting decision. Because no party has made any claim that the Minnesota PUC has jurisdiction over the construction or operation of an electric generating plant to be located in another state, there is no need to issue an order to that effect (as urged by the GOED).

D. Impact of the Siting Decision issued by the South Dakota PUC

The Applicants and the GOED also raised several other significant motions and defenses in connection with this proceeding. Several of these motions and defenses relate to the Final Decision and Order 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 Permit for the Construction of the Big Stone II Project, which was issued by the South Dakota PUC on July 21, 2006 (the "South [353]
Dakota PUC Decision"). Some background regarding the South Dakota proceeding is helpful in analyzing the issues raised by the parties.

In July of 2005, Otter Tail Power Company, on behalf of CMMPA, GRE, Heartland, MDU, SMMPA, and WMMPA through MRES, submitted an application to the South Dakota PUC under the South Dakota Energy Facility Permit Act (SDCL Chapter 49-41B), which governs energy conversion and transmission facilities. Under SDCL 49-41B-1, energy conversion [354]
facilities generally may not be constructed or operated in South Dakota without first [355]
obtaining a permit from the South Dakota PUC. In proceedings to obtain such a permit, the applicant bears the burden of proof to establish that:

(1) The proposed facility will comply with all applicable laws and rules;

(2) The facility will not pose a threat of serious injury to the environment nor to the social and economic condition of inhabitants or expected inhabitants in the siting area;

(3) The facility will not substantially impair the health, safety or welfare of the inhabitants; and

(4) The facility will not unduly interfere with the orderly development of the region with due consideration having been given the views of governing bodies of

[356]
affected local units of government.

[357]
The South Dakota PUC has adopted energy facility siting rules under Chapter 49-41B. Under South Dakota statutes, judicial review may be obtained of siting decisions issued by the
[358]
South Dakota PUC.

All parties in the South Dakota proceeding filed pre-filed testimony, and a formal evidentiary hearing was held on June 26-29, 2006. The intervenors included the Union of Concerned Scientists, Minnesotans for an Energy-Efficient Economy, the Izaak Walton League
[359]
of America – Midwest Office, and the Minnesota Center for Environmental Advocacy. The South Dakota PUC ultimately concluded that the Applicants had met their burden of proof under SDCL 49-41B-22 and were entitled to a permit as provided in SDCL 49-41B-25, subject to certain conditions. The specified conditions included, "The Applicants shall obtain and shall thereafter comply with all applicable federal, state and local permits, including but not limited to the Water Appropriation Permit, PSD Air Quality Construction Permit, Solid Waste Permit, and
[360]
Section 404 Permit." In accordance with the statutory requirements for issuance of the siting permit, the South Dakota PUC determined that the permit application complied with the applicable requirements of SDL Chapter 49-41B and ARSD 20:10:22; the Applicants sustained their burden of proving that the proposed facility will comply with all applicable laws and rules; the facility will not pose a threat of serious injury to the environment or to the social and economic conditions of inhabitants in the siting area; the facility will not substantially impair the health, safety or welfare of the inhabitants; and the project will not unduly interfere with the
[361]
orderly development of the region. The South Dakota PUC ordered that an Energy Conversion Facility Siting Permit be issued to Otter Tail Power for itself and on behalf of the Applicants, and construction of the Big Stone Unit II Project be authorized subject to certain
[362]
specified conditions. The South Dakota PUC's July 14, 2006, siting order acknowledged that its permit decision could be affected by a number of other agency decisions related to Big Stone II. In fact, South Dakota PUC made its siting permit approval conditional on Applicants'
[363]
receipt of all other state, federal and local permits.

The South Dakota PUC noted in the Decision that "SDCL Chapter 49-41B is not a certificate of convenience and necessity proceeding, and the Findings of Fact that the Commission has made in this proceeding regarding Applicants' description of need for the baseload generation to be provided by Big Stone Unit II pursuant to ARSD 20:10:22:08 are not intended to be nor have the effect of prospective findings of prudency that may arise in any
[364]
future rate proceeding involving such investments." The South Dakota PUC Decision was appealed on September 21, 2006, to the Circuit Court, Sixth Judicial District, Hughes County,
[365]
South Dakota.

Before constructing the transmission lines and Big Stone Unit II, the Applicants will need to obtain a Transmission Permit from the South Dakota PUC and a Prevention of Significant

Deterioration Construction Permit from the South Dakota Department of Environment and Natural Resources, along with several other permits from the Minnesota PUC, the Minnesota DNR, the Minnesota PCA, the Minnesota Department of Transportation, the U.S. [366]
Army Corps of Engineers, and local governmental units.

The Applicants and the GOED contend that, under the Full Faith and Credit clause of the United States Constitution and the judicial doctrine of issue preclusion, the Minnesota PUC is required to give preclusive effect to the determination of the South Dakota Public Utilities Commission that the Big Stone II generating plant is needed. Article IV, section 1 of the U.S. Constitution states that "Full Faith and Credit shall be given in each state to the public acts, records, and judicial proceedings of every other state." A judgment is entitled to Full Faith and [367]
Credit where it was "fully and fairly litigated and finally decided in the original court." In [368]
University of Tennessee v. Elliott, the United States Supreme Court found that the Full Faith and Credit clause extends to the decisions of state administrative agencies and emphasized that it is "sound policy to apply principles of issue preclusion to the fact-finding of administrative bodies acting in a judicial capacity" because preclusion "serves the value underlying general principles of collateral estoppel: enforcing repose."

[369]
In *Graham v. Special School District No. 1,* the Minnesota Supreme Court set forth a five-factor test under which the doctrine of collateral estoppel (issue preclusion) may apply to agency decisions. According to the Court, for collateral estoppel to apply:

> (1) the issue to be precluded must be identical to the issue raised in the prior agency adjudication;
>
> (2) the issue must have been necessary to the agency adjudication and properly before the agency;
>
> (3) the agency determination must be a final adjudication subject to judicial review;
>
> (4) the estopped party was a party or in privity with a party to the prior agency determination; and
>
> (5) the estopped party was given a full and fair opportunity to be heard on the [370]
> adjudicated issue.

The Applicants and GOED assert that the need for the Big Stone II generating unit is identical to the issue litigated before the South Dakota PUC. They contend that this issue was actively litigated and contested by the intervenors during the South Dakota PUC proceedings, based on information that is virtually identical to the information submitted in the present proceeding, and that the South Dakota PUC specifically ruled that the Big Stone II generation is needed. The Applicants emphasize that the South Dakota Decision contains six findings relating to regional needs (Findings 29-34) and 21 findings relating to each applicants' forecasted need for the additional baseload capacity and energy that Big Stone Unit II is [371]
designed to provide (Findings 35-56). They argue that this need issue was necessary to the decision by the South Dakota PUC; the determination of the South Dakota PUC is final and

is currently subject to judicial review; and the Joint Intervenors are the same Joint Intervenors who participated in the South Dakota PUC proceeding. They also assert that all parties, including the Joint Intervenors, had an adequate opportunity to litigate the need for the plant, the Applicants' conservation and demand-side management efforts, alternative energy resources to a supercritical coal burning facility, the potential impact of global warming and its connection to carbon dioxide emissions, the potential for future carbon dioxide regulation, and issues concerning air pollutant emissions and compliance with air quality standards during the South Dakota proceeding. As a result, the Applicants and GOED contend that the Joint Intervenors should not be allowed to relitigate the need for the Big Stone II generating plant considering possible demand-side and supply-side alternatives and carbon dioxide risk in the present case, and the Minnesota PUC must give preclusive effect to the South Dakota PUC's determination that the Big Stone unit II generating plant is needed, considering possible alternatives (including conservation) and carbon dioxide risk. Both the DOC and the Joint Intervenors argue in response that issue preclusion is not appropriate in the present proceeding..

After careful consideration of the parties' competing arguments, the Administrative Law Judges have concluded that the doctrine of issue preclusion is not applicable in this Certificate of Need/Routing Permit proceeding. Most importantly, issue preclusion is not appropriate under the first factor set forth in the *Graham* decision since the issues before the South Dakota PUC were not identical to those that are now before the Minnesota PUC. The subject matter is different. South Dakota was addressing the Generation Project; this proceeding is addressing the Transmission Project. Moreover, there has been no showing that the South Dakota legal criteria for determining whether a site permit should be issued are identical to the legal criteria required for a Minnesota certificate of need for transmission. To the contrary, it is evident that the statutory and regulatory criteria applied in the South Dakota proceeding are different from the Minnesota certificate of need criteria. The issues in the South Dakota proceeding revolved around such factors as whether the project will pose a threat of serious injury to the environment, substantially impair the health, safety, welfare, or social or economic conditions of inhabitants in the siting area, or unduly interfere with the orderly development of the region. In contrast, the Minnesota PUC must consider the factors set forth in Minn. Stat. § 216.243 in evaluating whether an applicant for construction of a large energy facility has shown that the "demand for electricity cannot be met more cost effectively through energy conservation and load management measures" and has "otherwise justified its need."

The factors to be evaluated by the PUC under Minn. Stat. § 216.243, subds. 3 and 3a, include the accuracy of the long-range energy demand forecasts on which the necessity for the facility is based; the effect of existing or possible energy conservation programs on long-term energy demand; the relationship of the proposed high-voltage transmission line to regional energy needs; promotional activities that may have given rise to the demand for the proposed facility; the benefits of the proposed facility, including protection or enhancement of environmental quality and increases in the reliability of the energy supply in Minnesota and the region; possible alternatives for satisfying the energy demand or transmission needs including potential for increased efficiency and upgrading of existing energy generation and transmission facilities, load-management programs, and distributed generation; other state, federal, and local policies and rules; any feasible combination of energy conservation improvements that can replace part or all of the energy to be provided and compete with it economically; the benefits of enhanced regional reliability, access, or deliverability, improvement in the robustness of the transmission system, or lower costs for Minnesota electric consumers; compliance with applicable provisions of sections 216B.1691 (renewable energy objectives) and 216B.2425, subdivision 7 (determination of transmission upgrades necessary to support development of

renewable energy resources required to meet renewable energy objectives); and whether the applicant has demonstrated that it has explored the possibility of generating power by means of renewable energy sources and has demonstrated that the alternative selected is less expensive (including environmental costs) than power generated by a renewable energy source under Minn. Stat. § 216.243, subd. 3a.

The issues before the South Dakota PUC differed from those before the Minnesota PUC at least in part because South Dakota's proceeding was not a certificate of need case. As [372] noted above, Finding No. 201 of the South Dakota PUC Decision emphasized that that proceeding was not a certificate of convenience and necessity proceeding. The Decision also noted that the findings of fact pertaining to the Applicants' description of need for the baseload generation to be provided by Big Stone Unit II had been made pursuant to an Administrative Rule that requires applicants in siting proceedings to "describe the purpose of the proposed [373] facility" and were not intended to govern in any future rate proceeding involving the prudency of the investment. The South Dakota PUC Decision thus explicitly acknowledged that the South Dakota PUC lacked authority in the siting proceeding to determine "need" for electric generation or transmission infrastructure. In contrast, in Minnesota CON proceedings seeking certification of large energy facilities, "need" is examined in the context of costs, both external and internal, alternatives, and state policy priorities for energy infrastructure additions. The South Dakota PUC did not apply identical or comparable standards in rendering its findings relating to "need" for Big Stone II generation unit or its associated transmission lines.

For the same reasons, the second factor set forth in *Graham* is also lacking here, since the issue of "need" in the context of the Minnesota statutory and regulatory standards was not necessary to the South Dakota adjudication or properly before the South Dakota PUC. In Attachment A to the South Dakota PUC Decision, the South Dakota PUC acknowledges that it adopted and incorporated virtually all of the Applicants' proposed findings of fact with the exception of certain modifications to reflect the Commission's understanding of the record and the addition of citations. The mere fact that the Applicants included among their proposed findings certain findings addressing "need" and that the South Dakota PUC adopted those findings does not, under the circumstances of this case, require that those findings be given preclusive effect.

Moreover, it appears that the factual basis on which the South Dakota PUC may have relied in making any "need," cost, or DSM findings is not identical to the factual basis presented in the Minnesota proceeding. Although some of the same evidence was presented in both proceedings, particularly by the Joint Intervenors, other evidence offered by the parties varied to a significant extent. For example, four of the Applicants that conducted capacity expansion modeling for their June 1, 2006, testimony in the Minnesota docket did not submit their modeling in the South Dakota siting permit case. In addition, due to the substantial increases in the projected costs of the Big Stone Unit II project, the majority of the Applicants conducted revised capacity expansion modeling in connection with the current case.

Finally, it would not be appropriate to remove the Minnesota PUC from its critical function in examining the factors set forth in the CON statute and rules to determine whether the transmission lines at issue here should be certified, and instead substitute a decision made by an agency in another state that is applying different statutory and regulatory criteria, lacks authority to enforce Minnesota's laws, and has no particular responsibility to protect Minnesota ratepayers or Minnesota resources. Minn. Stat. § 216B.243, subd. 2, states that no energy

facility shall be sited or constructed without the issuance of a certificate of need by the Minnesota PUC. Subdivision 3 states that "the commission shall evaluate" the listed criteria, and subdivision 3a states that the Applicants must demonstrate "to the commission's satisfaction" that they have explored the possibility of generating power by means of renewable energy sources and that the alternative selected is less expensive (including environmental costs) than power generated by a renewable energy source. The statute entrusts these decisions to the judgment of the Minnesota PUC and not to the judgment of regulators in other states.

Because there has no showing that the issues before the South Dakota PUC were identical to those before the Minnesota PUC, or that the findings in the South Dakota decision relating to such matters as cost, demand-side management, or "need" for the power were necessary to the South Dakota Decision and properly before the South Dakota PUC, neither the Full Faith and Credit clause nor the doctrine of issue preclusion requires that the South Dakota PUC's findings on the "need" for Big Stone Unit II be given preclusive effect in this proceeding.

The Applicants and GOED similarly argue that principles of comity among the states require that the Minnesota PUC defer to South Dakota on questions involving the need for and prudence of Big Stone Unit II. As explained in a recent Minnesota Court of Appeals decision:

> Judicial comity is "the respect a court of one state or jurisdiction shows to another state or jurisdiction in giving effect to the other's laws and judicial decisions. *See* Black's Law Dictionary 262 (7th ed. 1999). Comity is not a formal rule but rather [374] an informal policy of deference.

The Applicants assert that principles of comity would be violated if the Minnesota PUC were to deny a transmission certificate of need to the Applicants based on issues pertaining to the Big Stone Unit II generation project because the PUC would effectively be second-guessing the decision of the South Dakota agency that has direct authority over a generating station located in its state. They contend that such an approach could harm the citizens of South Dakota in obtaining electricity from a plant located in their state that has been determined to be in the public interest by their own state regulators. The Applicants emphasized that no party asserts that the transmission facilities located in Minnesota will actually cause any damage to Minnesota. They argue that the authority of the Minnesota PUC regarding generation issues is at best only indirect and derivative of its authority over the transmission facilities, and the Minnesota PUC should defer to the siting permit decision of the South Dakota PUC. The Department and the Joint Intervenors assert in response that principles of comity do not require the Minnesota PUC to adopt or defer to the South Dakota siting decision.

The Administrative Law Judges conclude that that there has been no showing that the Minnesota PUC is required by principles of comity to adopt the South Dakota siting decision as dispositive of the Minnesota certificate of need criteria. Comity is an informal policy of respect and deference to be applied in appropriate circumstances. It does not require that preemptive or preclusive effect to be given to a decision of another state agency where such an effect is not otherwise warranted. Because, as discussed above, the Minnesota PUC must address different issues under the Minnesota certificate of need statute than those considered by South Dakota, and the transmission lines directly involved in the Minnesota proceeding are obviously different than the generation plant involved in the South Dakota proceeding, the Applicants and the GOED have failed to demonstrate that principles of comity prevent the Minnesota PUC from applying the Minnesota statutes in determining whether a certificate of need should be granted

for the transmission lines.

E. Commerce Clause Issues

The Applicants and the GOED argue that the Commerce Clause of the U.S. Constitution [375] prohibits the Minnesota PUC from denying the certificate of need. The Applicants contend that refusal to issue the Applicants a CON based on objections to the generating plant previously approved by the South Dakota PUC would violate the negative or "dormant" aspect of the commerce clause that restrains state action hindering the national interest of free trade [376] among the states, under each of three different tests that have been developed by the courts.

First, the Applicants argue under that refusal to issue a certificate of need would constitute an impermissible direct regulation of interstate commerce that would amount to a *per se* violation of the Commerce Clause without the need to balance any in-state and interstate issues. They contend that this would exceed the incidental regulation of interstate commerce by the states that is permitted under Supreme Court precedent. Second, the Applicants assert that refusal to issue a certificate of need would amount to improper economic protectionism because it would discriminate against the use of coal for electric generation in favor of wind power and conservation. Because Minnesota has no coal resources but does have substantial wind resources which it is actively seeking to develop, and increased conservation efforts would help state contractors and developers, the Applicants argue that denial of the certificate of need based on generating concerns would benefit in-state interests while harming out-of-state interests. They assert that protectionism is prohibited under the Commerce Clause, whether purposeful or simply a practical effect, and that denial of the certificate of need would both block the flow of interstate commerce at the state's borders and patently discriminate against an out-of-state industry. Finally, the Applicants contend that, even if the Minnesota law is viewed as being evenhanded in its application and having only an incidental effect on interstate commerce, the burden imposed on interstate commerce exceeds the legitimate state interests served by the law. They argue that the transmission lines pose only a minor burden on Minnesota and, in fact, will benefit Minnesota because they will safely and reliably interconnect Big Stone II and allow access to major new wind power resources. They maintain that denial of the certificate of need in Minnesota would impose a palpable burden on interstate commerce. The Applicants therefore contend that the balance of interests therefore would tip strongly in favor of finding the commerce clause violation if the Minnesota PUC declines to issue a certificate of need.

The GOED similarly argues that a decision by the Minnesota PUC to deny the request for a certificate of need for the Minnesota portion of the interstate transmission lines based on issues concerning the Big Stone II generating plant--which is completely within South Dakota's jurisdiction and will supply power in interstate commerce--would be an improper regulation of interstate commerce. GOED asserts that, in essence, the Minnesota PUC would be requiring the Big Stone II co-owners to seek Minnesota approval for an out-of-state electric generating facility. GOED alleges that any Minnesota PUC decision contrary to the South Dakota PUC's decision would effectively invalidate the South Dakota decision to issue the permit for Big Stone II. Both the Department of Commerce and the Joint Intervenors oppose the commerce clause arguments made by the Applicants and the GOED.

Although an Administrative Law Judge lacks authority to declare a statute unconstitutional on its face because that power is vested in the judicial branch, an

Administrative Law Judge may decide a constitutional question involving the interpretation of a statute or its application to certain facts.[377] Because it appears that the arguments of the Applicants and the GOED in essence challenge the ability of the Minnesota PUC to apply the Minnesota CON statute and rules to the particular facts of this case involving transmission lines that will interconnect with a power plant proposed to be constructed in South Dakota, rather than pose a broad challenge to the constitutionality of the Minnesota statute on its face, the Administrative Law Judges conclude that they (and the Minnesota PUC) have proper authority to consider these arguments in the context of the present proceeding. Accordingly, the major arguments made by the parties are addressed below.

The literal words of the Commerce Clause merely grant authority to Congress to regulate commerce among the states, but it is well established that the Commerce Clause also reflects a negative or dormant aspect that imposes a direct limitation on the power of the States to discriminate against interstate commerce.[378] In *Wyoming v. Oklahoma,*[379] the U.S. Supreme Court noted that state statutes that clearly discriminate against interstate commerce will be struck down "unless the discrimination is demonstrably justified by a valid factor unrelated to economic protectionism." The Court described "economic protectionism" to mean "regulatory measures designed to benefit in-state economic interests by burdening out-of-state competitors."[380] The Court indicated that a "virtually *per se* rule of invalidity" under the Commerce Clause has been applied to state statutes that amount to simple economic protectionism.[381] The Court also noted that less strict scrutiny is appropriate in instances in which "a statute has only indirect effects on interstate commerce and regulates evenhandedly." In such cases, the Court has "examined whether the State's interest is legitimate and whether the burden on interstate commerce clearly exceeds the local benefits."[382]

Supreme Court precedent has also established that, in the absence of conflicting Congressional action, there is a "residuum of power" in the states to "make laws governing matters of local concern which nevertheless in some measure affect interstate commerce or even, to some extent, regulate it."[383] Accordingly, "not every exercise of state authority imposing some burden on the free flow of commerce is invalid."[384]

As a threshold matter, the Administrative Law Judges conclude that the application of the Minnesota CON statute under the facts of this case do not involve the type of impermissible direct regulation of interstate commerce that would amount to a *per se* violation of the Commerce Clause. Contrary to the arguments of the Applicants and the GOED, it does not appear that denial of the CON based on generating concerns would amount to improper economic protectionism by blocking the flow of interstate commerce at the state's borders or benefiting in-state wind power and conservation interests while discriminating against out-of-state coal generation interests. Even if the Minnesota PUC were to deny issuance of a CON, South Dakota would remain free to allow or not allow construction of the generation facility and to permit construction of other transmission lines within South Dakota. The certificate of need statute cannot reasonably be said to result in economic protection of Minnesota interests, since denial of the certificate of need may well benefit out-of-state entities such as Manitoba Hydro rather than Minnesota interests. Even if the statute were to benefit Minnesota wind interests,

the renewable preference set forth in Minnesota law would allow renewable resources located in South Dakota as well as Minnesota.

The Minnesota CON statute is nondiscriminatory and applies in a neutral fashion to those proposing large energy facilities. The CON statute applies equally to in-state and out-of-state applicants for such facilities; it does not impose greater burdens on out-of-state applicants. The statute does not distinguish between applicants that are investor-owned, cooperatively-owned, or municipally-owned, and applies both to proposals for transmission facilities and proposals for generation facilities. Unlike the situation presented in other cases arising under the Commerce Clause, the Minnesota statute does not reflect "an obvious effort to [385] saddle those outside the State" with most of the burden.

Because the Minnesota CON statute is evenhanded in its application and has at most an incidental effect on interstate commerce, a balancing test must be applied under relevant Supreme Court precedent to assess whether it is permissible under the Commerce Clause. The essential question is whether the CON statute serves legitimate local purposes that cannot [386] be adequately served by reasonable nondiscriminatory alternatives. The Administrative Law Judges conclude that it does, in fact, meet these requirements and thus does not violate the Commerce Clause.

As the Department and the Joint Intervenors emphasize, the Minnesota CON statute serves legitimate state interests in protecting natural resources, protecting ratepayers from potential after-the-fact rate increases, protecting facility owners from the potential financial impacts of cost disallowance, and protecting local communities and landowners from potential adverse impacts of the facilities to their properties. Although, as the Applicants point out, Minnesota does not have an interest in protecting the rate payers of non-Minnesota utilities such as MDU and Heartland, and Minnesota does not rate-regulate GRE, MRES, CMMPA, or SMMPA (which are all owned and controlled by their ratepayer constituents), Minnesota does have a legitimate interest in protecting Otter Tail's Minnesota ratepayers.

In any event, Minnesota's interests are not limited to those involving rates, nor are they solely limited to the impact of the proposed transmission lines. It is evident that a central purpose of the CON statute is to ensure that there is no unnecessary proliferation of large energy facilities in Minnesota. Because the natural resources of the state are limited, the CON statute is designed to first ensure that proposed large energy facilities cannot be avoided. Thus, there is a requirement that applicants for certificates of need for all large energy facilities show that demand for electricity cannot be met more cost effectively through energy conservation and load-management measures and otherwise justify their need. This is not an undue burden, or one that requires applicants to choose a more costly approach. If an applicant shows that more cost-effective DSM and more cost-effective renewable resources cannot meet the purported need for a proposed large energy facility project and that the project satisfies other statutory requirements, it is free to receive a certificate of need for the facility. The CON statute also reflects Minnesota's strong interest in prioritizing infrastructure for renewable energy sources by specifying that the PUC may not issue a certificate of need under this section for a large energy facility that transmits electric power generated by means of a nonrenewable energy source unless the applicant has demonstrated to the PUC's satisfaction that it has explored the possibility of generating power by means of renewable energy sources and the alternative selected is less expensive (including environmental costs) than power generated by a renewable energy source. Significant and legitimate state interests are served

by the Minnesota CON statute, and the burdens it imposes are not excessive.

As discussed above, the South Dakota siting permit is only one of a number of permits required for a project the magnitude of the proposed Big Stone II project, most of which do not fall under the jurisdiction of the South Dakota PUC (such as the need to obtain an air permit from the South Dakota Department of Environment and Natural Resources, a Dredge and Fill Permit from the U.S. Army Corps of Engineers, and a CON from the Minnesota PUC). The mere fact that the South Dakota PUC approved a site for the plant does not mean that it would be an improper intrusion for other governmental units to apply pertinent criteria and ultimately decide not to issue other authorizations for which they are responsible. The South Dakota PUC Decision in essence recognized this when it acknowledged that the granting of the siting permit was conditioned upon the Applicants' obtaining "all applicable federal, state and local permits."

The Minnesota CON statute and rules require that no proposed large energy facility be certified for construction unless the applicant shows that demand for electricity cannot be met more cost effectively through energy conservation and load-management and has otherwise
[387]
justified its need. In assessing whether the need showing has been sufficiently made, the statute directs that the Minnesota PUC evaluate such factors as the accuracy of the long-range energy demand forecasts, the effect of energy conservation programs, the relationship of the proposed transmission line to regional energy needs, benefits of the facility with respect to protection or enhancement of environmental quality and improvement in energy supply reliability, possible alternatives for satisfying transmission needs, the policies and rules of other state and federal agencies and local governments, feasible energy conservation improvements, benefits of enhanced regional access or deliverability, and whether the applicant showed that it explored the possibility of generating power by means of renewable energy sources and selected an alternative that is less expensive (including environmental costs) than power
[388]
generated by a renewable energy source. A decision by the Minnesota PUC to deny issuance of a CON for the transmission lines proposed in the present proceeding would simply recognize that the Applicants had not made all of the showings required by Minnesota law as a prerequisite to award of a CON. Such a decision would not place an unconstitutional burden on interstate commerce or reflect an improper attempt by Minnesota to impose its laws and regulations on activities outside Minnesota's borders.

Ultimately, the Administrative Law Judges believe that the legitimate state interests served by the CON statute exceed any incidental burden that may be imposed on interstate commerce by a decision to deny issuance of a CON, and that these interests cannot be adequately served by reasonable nondiscriminatory alternatives.

II. Environmental Cost Value for Carbon Dioxide:

A. Background

A major area of disagreement among the parties concerns what, if any, environmental cost value should be used by the Applicants for carbon dioxide emissions associated with the Big Stone II project. In 1993, the Legislature repealed 216B.164 (1991), which had required utilities to pay environmental costs directly to Qualifying Facilities as a component of the price paid for the purchase of energy and capacity, and enacted Minn. Stat. § 216B.2422, which placed consideration of environmental costs within the context of resource planning. Following passage of the statute, the PUC established a range of interim values for five emissions,

[389]
including carbon dioxide, and ordered the initiation of formal evidentiary hearings to set final environmental cost values. Following extensive evidentiary proceedings and consideration of findings and recommendations issued by an Administrative Law Judge, the PUC issued an Order in early 1997 that determined environmental cost values for a number of
[390]
power plant emissions, including emissions of CO2. On reconsideration, the PUC
[391]
determined that the CO2 values do not apply to generation located outside of Minnesota. The PUC also used a zero CO2 value for out-of-state generation in its latest update of the environmental cost values. See "Environmental Externalities Values Updated Through 2005," published on the PUC's website.

B. Recent Legislation

After the conclusion of the hearing in this matter, the Minnesota Legislature adopted the Next Generation Energy Act of 2007, which included a range of statutory amendments relating to renewable energy and demand-side management. Among other things, that Act amends Minn. Stat. § 216H.06 to include the following language:

> By January 1, 2008, the Public Utilities Commission shall establish an estimate of the likely range of costs of future carbon dioxide regulation on electricity generation. The estimate, which may be made in a commission order, must be used in all electricity generation resource acquisition proceedings. The estimates, and annual updates, must be made following informal proceedings conducted by the commissioners of commerce and pollution control that allow interested parties
> [392]
> to submit comments.

This Act resolves most of the parties' arguments with respect to the future establishment of CO2 costs. The Commission will establish, through an informal process, values to be used for the cost of future CO2 regulation.

C. Adequacy of the Applicants' Showing in the Present Proceeding

As discussed in the Findings above, Burns & McDonnell, an energy consulting firm retained by the Applicants, has conducted several studies to compare costs, performance, and emissions characteristics of a supercritical pulverized plant with several other alternatives. In each case, Burns & McDonnell concluded that the supercritical pulverized coal plant was the least cost option. The second study conducted by Burns & McDonnell (which considered subcritical pulverized coal, supercritical pulverized coal, natural gas fired combined cycle gas turbine, wind plus gas-fired combined cycle gas turbine, integrated coal gasification combined cycle, and a 100% biomass plant) included an analysis of carbon tax sensitivity. In that study, the high end of the environmental cost value set by the Commission for CO2 ($3.64/ton, applicable to generating facilities located in the Twin Cities) was assumed and applied to every ton of emissions of CO2 from those technologies with CO2 emissions. An additional study completed in October 2006 by Burns & McDonnell considered a 630 MW supercritical pulverized coal plant like Big Stone II, a 500 MW combined cycle gas turbine, and a combined cycle gas turbine in combination with market purchases of wind, and again concluded that Big Stone II was the least cost alternative. The Applicants also calculated the busbar costs for each generation alternative assuming that the Big Stone Unit II facility were located in Minnesota and the Applicants had to take into account the environmental cost value of $3.64 per ton of carbon

dioxide emitted. Once again, Big Stone II remained the least-cost alternative. Based upon the figures from Burns & McDonnell, the "break-even" point (i.e., the point at which the environmental cost associated with CO2 emissions would elevate the cost of a supercritical pulverized coal plant like Big Stone II to the level of the next lowest-cost alternative) is approximately $11.10 for investor-owned utilities and $21.70 for publicly owned utilities.

The record reflects a number of differing possibilities for an "appropriate" CO2 environmental cost value. For example, Xcel will be using a $9 figure in evaluating its next baseload resource alternative; Duke Power is using a carbon value of $7 in its proceeding before the North Carolina Utilities Commission for approval of 1600 MW of new coal generation; Dr. Rakow posited a possible figure of $7.90 per ton of carbon dioxide emitted; and Applicants' witness Thomas Hewson stated that his firm has advised utilities to use a $6 value beginning in 2013. All of these figures are lower than the break-even point. In contrast, Joint Intervenors' witness David Schlissel of Synapse asserted that the proper carbon risk value was much higher than those mentioned by the other witnesses--$19.10, applied to all tons of CO2 emitted. In light of the significant gap between the value urged by Schlissel and those suggested by others in this proceeding, the Administrative Law Judges are not persuaded that Schlissel's figure is a reasonable or appropriate environmental cost value.

Thus, under most assumptions made today on the cost of carbon control, the Applicants have shown that Big Stone II is the least cost alternative as compared to a CCGT alternative, a CCGT + wind alternative, and an IGCC alternative. Because the study showed that application of any reasonable CO2 value would not change the result, further analysis of the arguments of the parties is not necessary. While it may have been preferable for the Applicants to use a CO2 value in their capacity expansion modeling, the subsequent Burns & McDonnell study adequately addresses this issue and responds to the evidence presented. Accordingly, the Administrative Law Judges have recommended that the Commission find that the Applicants made an adequate showing relating to renewable generation alternatives.

S.M.M. and B.L.N.

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[1] Certificate of Need Application at 20 and Applicants' Exhibit 6 (Testimony of Ward Uggerud) at 8. The CON Application is in the record as Applicants' Exhibits 68-A and 68-B (public version) and Exhibits 69-A, and 69-B (trade secret version).

[2] CON Application at 21, Applicants' Exhibit 6 at 8, and Applicants' Exhibit 1 (Direct Testimony of Rod Scheel) at 4.

[3] CON Application at 23-24, and Applicants' Exhibit 8 (testimony of Richard Lancaster) at 4-5 and Exhibit 8-C.

[4] CON Application at 24 and Applicants' Exhibit 8 at 5.

[5] CON Application at 27 and Applicants' Exhibit 9 (Direct Testimony of Ray Wahle) at 5-9.

[6] CON Application at 27-28 and Applicants' Exhibit 9 at 9-10.

[7] CON Application at 28.

[8] DOC Exhibit 13 at 2, 4-5.

[9] CON Application at 30.

[10] CON Application at 31.

[11] CON Application at 29 and Applicants' Exhibit 11 (Direct Testimony of Andrea Stomberg) at 3-4.

[12] CON Application at 29.

[13] CON Application at 30.

[14] Applicants' Exhibit 11 at 3.

[15] CON Application at 30.

[16] The Cities of Madelia, Lake Crystal and New Ulm were listed in the CON as members, but are no longer. None of these three cities was ever a participant in the Big Stone Unit II Project. See CON Application at 23.

[17] CON Application at 22 and Applicants' Exhibit 12 (Direct Testimony of Stephen Michael Thompson) at 5.

[18] CON Application at 22.

[19] Applicants' Exhibit 12 at 5.

[20] CON Application at 22.

[21] CON Application at 22.

[22] Applicants' Exhibit 12 at 6.

[23] Applicants' Exhibit 12 at 16.

[24] CON Application at 25 and Applicants' Exhibit 13 (Direct Testimony of Mike McDowell) at 7-8. Madelia used to be part of CMMPA and is now part of Heartland.

[25] CON Application at 26 and Applicants' Exhibit 13 at 3-4.

[26] CON Application at 26.

[27] Second Prehearing Order dated February 15, 2006.

[28] Letter of March 15, 2006 and Third Prehearing Order dated April 18, 2006 at para. 4.

[29] Second Prehearing Order dated February 15, 2006.

[30] Third Prehearing Order dated April 18, 2006, at para. 6.

[31] Third Prehearing Order dated April 18, 2006, at para. 6; MISO Exhibit 1 (Direct Testimony of Eric Laverty).

[32] Third Prehearing Order dated April 18, 2006, at para. 6; FPL Exhibit FPL- 1.

[33] Third Prehearing Order dated April 18, 2006, at para. 6.

[34] Third Prehearing Order dated April 18, 2006, at para. 6; GOED Exhibits 1, 3A, 3B, and 3C.

[35] Third Prehearing Order dated April 18, 2006, at para. 5.

[36] Public Exhibits 8 - 10.

[37] Public Exhibits 19-70. The Office of Administrative Hearings posted all the comments that were received in writing on the Draft EIS on its webpage at http://www.oah.state.mn.us/cases/BigStone/index.html.

[38] These were also posted on the OAH website.

[39] DOC Exhibit 13 (DOC Exhibit 13 (Direct Testimony of Stephen Rakow)) at 14, fn. 4.

[40] Applicants' Exhibit 106, at 9.

[41] Applicants' Exhibit 19 at 10.

[42] Applicants' Exhibit 12 (CMMPA) at 12 and Applicants' Exhibit 21 (Heartland) at 13.

[43] GOED Exhibits 2 – 4.

[44] Applicants' Exhibit 32 (Supplemental Direct Testimony of Mark Rolfes) at 10. Big Stone Unit II was originally nominally sized at 600 MW, but in order to ensure 600 MW of generation during extreme summer conditions, the plant must be designed to operate at a higher nominal capacity under normal conditions. Thus, it was resized to have a nominal capacity of 630 MW during more average conditions. Applicants' Exhibit 72 (Rebuttal Testimony of Mark Rolfes) at 9.

[45] Observations of ALJ Mihalchick of site and maps.

[46] Applicants Exhibit 7 (Direct Testimony of Mark Rolfes) at 3.

[47] Applicants Exhibit 7 at 4.

[48] Applicants' Exhibit 26 at 5.

[49] Applicants' Exhibit 26 at 6.

[50] Applicants' Exhibit 26 (Direct Testimony of Terry Graumann) at 4.

[51] Applicants' Exhibit 26 at 6.

[52] Applicants' Exhibit 64 (Rebuttal Testimony of Terry Graumann) at 6; South Dakota PUC Final Decision and Order (July21, 2006), Ordering Paragraph 2.B at 33.

[53] Applicants' Exhibit 64 at 8-10.

[54] Minn. Laws 2006, ch. 201, codified at Minn. Stat. §§ 216B.68 to 216B.688.

[55] Applicants' Exhibit 64 at 6-10.

[56] Applicants' Exhibit 6 (Direct Testimony of Ward Uggerud) at 22.

[57] Applicants' Exhibit 65 (Rebuttal Testimony of Mark Rolfes).

[58] Applicants' Exhibit 62 at 40 (Rebuttal Testimony of Thomas Hewson).

[59] Applicants' Exhibit 64 at 1-4; Exhibit JI-9; and DOC Exhibit 13 (Direct Testimony of Stephen Rakow) at 71 and exhibit SRR-9.

[60] Applicants' Exhibit 72 (Rebuttal Testimony of Mark Rolfes) at 6-7; 3TrV. 81-85.

[61] Applicants' Exhibit 72 at 8-9; 3TrV. 33-34 (Rolfes); 4TrV. 71 (Trout).

[62] Rakow Rebuttal 10-11; 3 TrV. 70-79 (Rolfes); Rakow Rebuttal at 15-16; 14 TrV. 107-108 (Rakow).

[63] Applicants' Exhibit 27 (Direct Testimony of Dean Pawlowski) at 6; Applicants' Exhibit 34A (Supp. Direct Testimony of Bryan Morlock at Appendix A); DOC Exhibit 13 at 3.

[64]
Certificate of Need Application and the Route Permit Application.
[65]
Applicants' Exhibit 70 (the Route Permit Application).
[66]
Applicants' Exhibit 29 (Direct Testimony of Robert Krava) at 3-5.
[67]
Applicants' Exhibit 31 (Direct Testimony of Richard Johnson) at 3-4
[68]
CON Application at 73 and Applicants' Exhibit 31 at 3.
[69]
CON Application at 73 and Applicants' Exhibit 31 at 4.
[70]
Route Permit Application at 4.
[71]
Route Permit Application at 4.
[72]
Applicants' Exhibits 28 and 30 at 7-8.
[73]
See Finding No. 78.
[74]
First Supplement at 8 Table 20 revised; DOC Exhibit 13 at 8; Applicants' Exhibit 44 (Supplemental Direct Testimony of Dean Pawlowski) at 4-5; Applicants' Exhibit 72 (Rebuttal Testimony of Mark Rolfes) at 6 and e-mail from Tim Rogelstad to Stephen Rakow dated Dec. 26, 2006, attached to Applicants' Brief as Exhibit A.
[75]
Applicants' Exhibit 27 at 10.
[76]
Petition at Table 8; DOC Exhibit 13 at 3, fn. 1.
[77]
Order Accepting Application as Substantially Complete and Requiring Additional Information; Dec. 19, 2005; *In the Matter of the Application of Otter Tail Power Company and Others for Certification of Transmission Facilities in Western Minnesota;* PUC Docket No. CN-05-619, p. 8-9.
[78]
As discussed in the Memorandum, because the project at issue in this docket is transmission lines, not a generating plant, Clause (12) does not apply.
[79]
See also Minn. Stat. § 216B.243, subd. 3(11).
[80]
Minn. R. 7855.0100 sets forth the purpose of Minn. R. 7855.0120 as follows:

> The criteria for assessment of need shall be used by the commission in the determination of need for each proposed large energy facility that is subject to these rules. The factors listed under each of the criteria set forth at part 7855.0120 shall be evaluated to the extent that the commission deems them applicable and pertinent to each facility proposed pursuant to this chapter. The commission shall make a specific written finding with respect to each of the criteria.

[81]
Applicants' Brief at 14.
[82]
In the Matter of the Application of Northern States Power Company d/b/a Excel Energy for a Certificate of Need to Establish an Independent Spent Fuel Storage Installation at the Monticello Generating Plant, Docket No. E-002/CN-05-123, Order Granting Certificate of Need, October 23, 2006, at 7-10.
[83]
The Administrative Law Judges note that this statement is not entirely correct. The "Certificate of Need Statute" for large energy facilities is all of Minn. Stat. § 216B.243. It is actually Minn. Stat. § 216B.243, subd. 1, that authorizes the Commission to adopt assessment of need criteria and factors through rulemaking. In any event, the Commission has the statutory authority to adopt the rule.
[84]
See, e. g., Applicants' Brief at 14-15.
[85]
DOC Exhibit 13 at 10-17.

[86]
14 TrV. 62-63, 76-77, 140-141 (Rakow); Rakow Rebuttal at 29-30.
[87]
Applicants' Exhibit 59 (Rebuttal Testimony of John Knofczynski) at 3-5.
[88]
Applicants' Exhibit 23 (Direct Testimony of Peter Koegel) at 2-3.; Applicants' Exhibit 23 at 7 and Exhibit 23-B; Applicants' Exhibit 66 (Rebuttal Testimony of Peter Koegel) at 2-3; Applicants' Exhibit 96, p. 9.
[89]
Data are taken from Applicants' Exhibit 34-A. *See also* DOC Exhibit 10 (Direct Testimony of Hwikwon Ham) at 8.
[90]
DOC Exhibit 10 (Direct Testimony of Hwikwon Ham) at 7-33; DOC Exhibit 13 at 3; 14 TrV. at 8-10 (Ham).
[91]
Applicants' Exhibit 61 (Rebuttal Testimony of Hoa Nguyen) at 3-7.
[92]
Applicants' Exhibit 61 (Rebuttal Testimony of Hoa Nguyen) at 2-3.
[93]
Morlock is an Electrical Engineer and has been with Otter Tail since 1978. He has been supervising resource planning since 1986. Exhibit 15-A.
[94]
Applicants' Exhibits 55 at 5 and 55-A.
[95]
DOC Exhibit 14 at SRR-1.
[96]
DOC Exhibit 13 at 21.
[97]
Applicants' Proposed Findings, Finding No. 97.
[98]
Such projects are also referred to as "conservation improvement programs" (CIPs).
[99]
App. Br. at 57-58.
[100]
Davis Direct at 3; 13 TrV. 166-167 (Davis).
[101]
Joint Intervenors' Brief at 2.
[102]
In the Matter of the Application of the City of Hutchinson (Hutchinson Utilities Commission) For a Certificate of Need to Construct a Large Natural Gas Pipeline, unpublished, 2003 WL 22234703 (Minn. App.), Sept. 23, 2003.
[103]
GOED Exhibit 2, the Final Decision and Order of the South Dakota PUC, at Findings Nos. 57-68 and Attachment A.
[104]
CON Application, § 4.6 and Appendix K.
[105]
Davis Direct at 3-10.
[106]
Davis Direct at 11, 14-15.
[107]
Davis Direct at 11-12.
[108]
Davis Direct at 12; Applicants' Exhibit 61 (Rebuttal Testimony of Hoa Nguyen) at 8-11.
[109]
Applicants' Exhibit 61 (Rebuttal Testimony of Hoa Nguyen) at 8-11.
[110]
Applicants' Exhibit 12 at 13-15 and Exhibit 54 at 3.
[111]
Applicants' Exhibit 12 (Direct Testimony of Stephen Michael Thompson) at 10-11.
[112]
Applicants' Exhibit 56 (Rebuttal Testimony of Robert Davis) at 7-9.

[113] Applicants' Exhibit 54 (Rebuttal Testimony of Stephen Michael Thompson) at 4, 6, 9-10.

[114] Applicants' Exhibit 53 (Rebuttal Testimony of Mike McDowell) at 4 and 7; Applicants' Exhibit 59 (Rebuttal Testimony of John Knofczynski) at 12.

[115] Davis Direct at 13-14; Davis Rebuttal at 7.

[116] Pederson Rebuttal at 5.

[117] Nguyen Dec 1, 2006 Rebuttal at 61; 13 TrV. at 227 (Davis).

[118] Joint Intervenors Exhibit 5 (Direct Testimony of Timothy Woolf) at 4-7 and Tr. Vol. 9, p. 46, line 15. DOC Exhibit 9 (Rebuttal Testimony of Christopher Davis) at 2.

[119] 13 TrV. 229-230 (Davis).

[120] JI Exs. 5 at 1-2 and 5-A.

[121] JI Ex. 5 at 4-5 and Tables 1 and 2.

[122] JI Ex. 5 at 7 and 12. The reason Woolf calculated the low and medium benchmarks was so he could then calculate the incremental costs of DSM savings associated with each benchmark. JI Ex. 5, p. 6. As Woolf explained at the hearing, the first increment of savings at the lowest benchmark has the lowest cost, and costs rise with the higher increments of savings. T. Vol. 9, p. 78-80.

[123] JI Exh. 5-F; JI Exh. 5 at 30.

[124] C. Davis Rebuttal at 4; 13 TrV. at 221-222.

[125] C. Davis Rebuttal at 4.

[126] C. Davis Rebuttal at 6.

[127] Exhibit 9 (Rebuttal Testimony of Christopher Davis) at 2-3 and 12-13.

[128] C. Davis Rebuttal at 12.

[129] Applicants' Reply Brief at 14-16.

[130] C. Davis addressed promotional activities within the Applicants' conservation programs. DOC Exhibit 13 at 54-70.

[131] DOC Exhibit 13 at 61-62.

[132] DOC Exhibit 13 at 62 and 64-65.

[133] CON Application, Appendix B; CON Application at 40.

[134] CON Application at 40 and Appendix B and I.

[135] Transcript of August 2, 2007, Commission proceedings in E-6472/M-05-1993, at 157-163 and 238-240. The Commission's Order has not yet been issued.

[136] Minn. Stat. § 216B.1694, subd. 2(a)(1).

[137] Minn. Stat. § 216B.1694, subd. 2(a)(5).

[138] Excelsior Energy's Initial Brief.

[139] DOC Exhibit 13 at 34-35.

[140] Applicants' Exhibit 65 (Rebuttal Testimony of Mark Rolfes) at 1-2 and Tr. Vol. 3 at 93, line 13.

[141] Applicants' Exhibit 72 (Rebuttal Testimony of Mark Rolfes) at 9.

[142] Applicants' Exhibit 26 (Direct Testimony of Terry Graumann) at 4-5.

[143] CON Application at 83.

[144] CON Application at 85-86.

[145] CON Application, Appendix B at 75.

[146] CON Application at 44-48.

[147] See the Department's 2004 State Energy Policy and Conservation Report (Quad Report) at 15.

[148] CON Application, Table 7, at 87.

[149] DOC Exh. 18 (Rakow Surrebuttal Statement).

[150] CON Application at 121; Applicants' Exhibit 27 (Direct Testimony of Dean Pawlowski) at 7.

[151] CON Application at 110 and Applicants' Exhibit (Direct Testimony of Jason Weiers) at 17.

[152] Minn. Stat. § 216B.2426.

[153] DOC Exhibit 13 at 33-34.

[154] Final EIS at 56-74.

[155] Applicants' Exhibits 44 (Supplemental Direct Testimony of Dean Pawlowski) at 3-4; Exhibit 30 (Direct Testimony of Myron Rader) at 4 and Exhibit 30-A; Applicants' Exhibit 72 (Rebuttal Testimony of Mark Rolfes) at 6; and e-mail from Tim Rogelstad to Stephen Rakow dated Dec. 26 attached to Applicants' Brief as Appendix A.

[156] DOC Exhibit 13 at 47-53.

[157] Ham Direct at 6-7.

[158] MISO Ex. 1 at 17.

[159] MISO Ex. 1 at 17.

[160] MISO Ex. 1 at 18-19.

[161] *In the Matter of the Application of the City of Hutchinson (Hutchinson Utilities Commission) For a Certificate of Need to Construct a Large Natural Gas Pipeline*, unpublished, 2003 WL 22234703 (Minn. App.), Sept. 23, 2003.

[162] Applicants' Reply Brief at 30-31.

[163] *See* Finding No. 105.

[164] As noted in Finding No. 98, Minn. Stat. § 216B.243, subd. 3, also places the burden of proof upon the Applicants.

[165] See, Finding No. 122.

[166] Applicants' Exhibit 25 (Direct Testimony of Jeff Greig) at 3-4.

[167]
This report is included in the CON application as Appendix J.
[168]
Applicants' Exhibit 24-B.
[169]
Applicants' Exhibit 24 (Direct Testimony of Kiah Harris) at 5. The Department summarized each utility's next best resource in DOC Exhibit 13 at 33.
[170]
Revised Analysis of Baseload Generation Alternatives, Applicants' Exhibit 47-A.
[171]
Exhibit 15 at 8-11.
[172]
Nobody has contended that wind alone is a baseload resource. The Department of Commerce stated in its 2004 Quad Report: "The only major drawback of wind energy from an energy standpoint is that the wind energy is an intermittent resource – the wind does not blow, or blow consistently, throughout the day or throughout the year. As a result, wind energy, by itself, cannot be relied upon for baseload or peaking purposes – it cannot be "dispatched" (turned on or off as needed.)" Quoted in the CON Application at 95.
[173]
DOC Initial Br. at 40-46, DOC Reply Brief at 36.
[174]
App. Brief at 35.
[175]
CON Application, Appendix J, at 4.6, 4.8, and 4.13.
[176]
Busbar refers to the cost of power without transmission, distribution, and ancillary charges, effectively the cost of power at the plant substation. See Applicants' Exhibit 47 (Supplemental Direct Testimony of Jeffrey Greig) at 2.
[177]
Applicants' Exhibit 47-A; CON Application, Appendix J.
[178]
Order Affirming in Part and Modifying in Part Order Establishing Environmental Cost Values, Docket No. E-999/CI-93-583, July 2, 1997.
[179]
See Applicants' Exhibit 47-A.
[180]
Applicants' Exhibit 47 (Supplemental Direct Testimony of Jeffrey Greig) at 11.
[181]
Testimony of David Schlissel, Tr. Vol. 11, p. 14, lines 2-22.
[182]
Tr. Vol. 14, p. 69, lines 4-13.
[183]
DOC Ex. 14, p. 4, lines 9-11.
[184]
Tr. Vol. 11, p. 27, line 5 – p. 29, line 21.
[185]
Applicants' Exhibit 62 (Rebuttal Testimony of Thomas Hewson) at 5, lines 9-11.
[186]
Applicants' Exhibit 15 (Direct Testimony of Bryan Morlock) at 5; Exhibit 17 (Direct Testimony of Stan Selander) at 11; Exhibit 18 (Direct Testimony of Gerald Tielke) at 9; Exhibit 20 (Direct Testimony of Larry Anderson) at 7; and Exhibit 21 (Direct Testimony of John Knofczynski) at 14; and Tr. Vol. 6 at 12, lines 19-25 and p. 141, lines 13-21.
[187]
Applicants' Exhibit 66 (Rebuttal Testimony of Peter Koegel) at 4.
[188]
Rakow Rebuttal at 18-20; DOC Exh. 18 (Rakow Surrebuttal Statement).
[189]
Rakow Rebuttal at 12-15.
[190]
Rakow Rebuttal at 12-15.

[191] Rakow Rebuttal at 12-15, Joint Intervenors Exh. 3 at 49-50, 54-56 (Schlissel).

[192] 14 TrV. 79-80, 10 1-107 (Rakow) DOC Exh. 18 (Rakow Surrebuttal Statement).

[193] Rakow Rebuttal at 15-16; DOC Exh. 18 (Rakow Surrebuttal Statement); 14 TrV. 76-78, 107 (Rakow).

[194] Errata to JI Exhibit 3 (Schlissel).

[195] *See, e.g.* regarding tunneling generally, 6 TrV. at 80-81 (R. Davis).

[196] Rakow Rebuttal at 16-18; DOC Exh. 18, Rakow Surrebuttal Statement; 14 TrV. at 78, 108-112 (Rakow).

[197] Rakow Rebuttal at 20-24; DOC Exh. 18 (Rakow Surrebuttal Statement); 14 TrV. at 78-79, 114 (Rakow).

[198] DOC Exhibit 13 at 17; DOC Exh. 18 (Rakow Surrebuttal Statement); 14 TrV. at 77 (Rakow).

[199] 13 TrV. 168; Davis Direct at 38 and 42.

[200] C. Davis Direct at 42-43.

[201] C. Davis Direct at 47.

[202] DOC Ex. 10 and 11 (Direct of Ham) at 3; Tr. Vol. 14 at 85, 102-103, 132-137 (Rakow); DOC Exs. 10 and 11 (Direct of Ham) at 3-4.

[203] DOC Exs. 10 and 11 (Ham Direct) at 3-4, 7; 14 TrV. at 13-17 (Ham).

[204] DOC Exs. 10 and 11 (Ham Direct) at 5.

[205] MISO Ex. 1 (Laverty Direct) at 17.

[206] JI Exhibit 8 (Fagan Rebuttal) at 16.

[207] Applicants' Exhibit 2 (Direct Testimony of Timothy Rogelstad) and Exhibit 5 (Direct Testimony of Richard Gonzalez) and Testimony of Gonzalez at Tr. Vol. 13 at 24.

[208] DOC Exs. 10 and 11 (Ham Direct) at 6-7.

[209] DOC Ex. 6 at 41.

[210] DOC Ex. 6 at 41-45.

[211] DOC Ex. 6 at 41-45.

[212] DOC Ex. 6 at 41-45.

[213] DOC Ex. 6 at 115-116.

[214] DOC Ex. 6 at 115.

[215] Public Exhibits 3 (Worthington), 4 (Marshall), 12 (Sauk Centre), 13 (Benson), 16 (Granite Falls), 19 (Melrose), 26 (Willmar), and 32 (Alexandria).

[216] MISO Ex. 1 at 15.

[217] Applicant's Ex. 70 at 281-286.

[218] Applicant's Ex. 64 (Graumann Rebuttal) at 4-6.

[219]
The potential impacts under each criteria are reviewed in Applicant's Ex. 70 (the Route Permit Application). Table 75 at 231 –235 encompasses the Granite Falls routes and Table 23 at 112–115 encompasses the Morris routes.
[220]
DOC Ex. 6.
[221]
The Draft Federal EIS was available in May of 2006. See 71 Fed. Reg. 29148 (May 19, 2006).
[222]
Applicant's Ex. 30 (Rader Direct) at 3, 4.
[223]
DOC Ex. 6 at 80-81; Applicants' Ex. 70 at 66, 112, 231.
[224]
DOC Ex. 6 at 80.
[225]
DOC Ex. 6 at 30-31, -84; Applicants' Ex. 70 at 67, 73,112, 172.
[226]
DOC Ex. 6 at 32-34, 104-105; Applicants' Ex. 70 at 63-65, 112, 159-64, 231.
[227]
DOC Ex. 6 at 103-04 and App. H.
[228]
DOC Ex. 6 at 79.
[229]
Applicants' Ex. 70 at 44-48.
[230]
Findings 118-119, Findings of Fact, Conclusions and Order Issuing Route Permit, Docket No. 03-73-TR-Xcel (June 16, 2005), quoted in Applicants' Ex. 70 at 44 and DOC Ex. 6 at 93-94.
[231]
Id.
[232]
Applicants' Ex. 70, Table 5 at 47. The same information is also included in the Final EIS.
[233]
Applicants' Ex. 70, Table 6 at 48.
[234]
Applicants' Ex. 70, Table 4 at 46. These distances may to be at odds with the Applicants' statements that one home along Morris Route 1 was located within 100 feet of the route alignment, and eight homes were located within 300 feet of the route alignment. Perhaps the distance to the "route alignment" does not correspond with the distance to the actual "line."
[235]
Applicants' Ex. 70 at 48-49; DOC Ex. 6.at 95.
[236]
Applicants' Ex. 70 at 79 and 113, 232; DOC Ex. 6 at 104-105.
[237]
DOC Ex. 6 at 105.
[238]
DOC Ex. 6 at 115-116.
[239]
Applicants' Ex. 70 at 81, 113.
[240]
Applicants' Ex. 70 at 232.
[241]
Applicants' Exs. 64 (Prefiled Rebuttal Testimony of Graumann) at 4-6 and 64B (Nov. 29, 2006, letter from Nancy Werdel, NEPA Document Manager, U.S. Dept. of Energy to Graumann).
[242]
Applicants' Ex. 70 at 83-85, 113, 180-184, 233.
[243]
Applicants' Ex. 70 at 113, 232.
[244]
Applicants' Exhibit 45 (Supplemental Direct Testimony of Myron Rader) at 2-3. The new route is shown in Applicants' Exhibit 45-A.

[245] DOC Ex. 6 at 152-181; Applicants' Ex. 70 at 94-98, 114, 190-198, 234.
[246] Applicants' Ex. 70 at 94-98, 190-198.
[247] Applicants' Ex. 69A (Certificate of Need Application) at 110-121.
[248] MISO Ex. 1 at 15.
[249] Applicants' Ex. 70 at 111, 230 ; DOC Ex. 6 at 183.
[250] Applicants' Ex. 69A, Appendix B.
[251] Applicants' Ex. 30 (Rader Direct) at 3, 4; DOC Ex. 6 at 13.
[252] DOC Ex. 6 at 183-184.
[253] DOC Ex. 6 at 185; Applicants' Ex. 70 at 115 and 235.
[254] Applicants' Ex. 70 at 111-112.
[255] Applicants' Ex. 70 at 230-231.
[256] Applicants' Ex. 70 at 243, 250.
[257] Applicants' Ex. 70 at 250, 259.
[258] A map showing the new substation site is in the record as Applicants' Exhibit 28-A.
[259] Applicants' Exhibit 30 (Direct Testimony of Myron Rader) at 7.
[260] Public Exhibit 1.
[261] Canby Public Hearing, Transcript Vol. 8, at 65-68; Granite Falls Public Hearing, Transcript Vol. 10, at 36-47; Public Exhibit 89.
[262] Public Exhibits 76, 87, 88, 89, 90, 92, 96, 98, 100, 106, and 108.
[263] Ortonville Public Hearing, Transcript Vol. 6, at 41-45; Public Exhibit 75, 76, 89, 92, 93.
[264] Morris Public Hearing, Transcript Vol. 4, at 59.
[265] Canby Public Hearing, Transcript Vol. 7, at 39.
[266] Public Exhibit 92.
[267] Public Exs. 92, 100 and 102.
[268] Public Exs. 87, 90, 92, 93, 94, 96, 97, 98, 99, 100, 104.
[269] Public Exhibits 3, 4, 12, 13, 16, 19, 26, 32, 71, 72, 87, 90, 92.
[270] Benson Public Hearing, Transcript Vol. 1, at 53-54; Public Exhibit 12.
[271] Benson Public Hearing, Transcript Vol. 1, at 61-64.
[272] Benson Public Hearing, Transcript Vol. 1, at 60-61; Public Exhibit 12.
[273] Public Exhibit 89.

[274] Public Exhibit 20, at p 21.

[275] Morris Public Hearing, Transcript Vol. 3, at 44-47.

[276] Canby Public Hearing, Transcript Vol. 7, at 47-48.

[277] Public Exhibit 104.

[278] Canby Public Hearing, Transcript Vol. 7, at 65-68.

[279] Public Exhibit 1, Benson Public Hearing, Transcript Vol. 1, at 39; Canby Public Hearing, Transcript Vol. 7, at 57-59; Ortonville Public Hearing, Transcript Vol. 5, at 62; Public Exhibit 27; Canby Public Hearing, Transcript Vol. 7, at 38-41; Public Exhibit 107.

[280] Morris Public Hearing, Transcript Vol. 3, at 77-79; Public Exhibit 21.

[281] Public Exhibit 110.

[282] Granite Falls Public Hearing, Transcript Vol. 9, at 100.

[283] Public Exhibit 99.

[284] Morris Public Hearing, Transcript Vol. 3, at 36-37.

[285] Granite Falls Public Hearing, Transcript Vol. 9, at 44-46; Public Exhibits 36 and 37.

[286] Morris Public Hearing, Transcript Vol. 4, at 46-48.

[287] Public Exhibits 15 and 94.

[288] Granite Falls Public Hearing, Transcript Vol. 9, at 37-43, 95-96; Public Exhibits 35, 44.

[289] Morris Public Hearing, Transcript Vol. 4, at 65-67.

[290] Morris Public Hearing, Transcript Vol. 4, at 63-65.

[291] Public Exhibits 91, 95, 99, and 101.

[292] Morris Public Hearing, Transcript Vol. 3, at 51-54.

[293] Morris Public Hearing, Transcript Vol. 3, 72-74 (Ninneman), 76-77 (Graumann).

[294] Granite Falls Public Hearing, Transcript Vol. 9, at 46- 49.

[295] Public Exhibits 38 and 39.

[296] Granite Falls Public Hearing, Transcript Vol. 9, at 57-58.

[297] Standards of Performance for New and Existing Stationary Sources: Electric Utility Steam Generating Units; Final Rule, 70 Fed. Reg. 28606 (May 18, 2005) (amending 40 CFR Parts 60, 72, and 75).

[298] Granite Falls Public Hearing, Transcript Vol. 9, at 58-59.

[299] Granite Falls Public Hearing, Transcript Vol. 10, at 33; Public Exhibit 46.

[300] Granite Falls Public Hearing, Transcript Vol. 10, at 34, 47-62; Public Exhibits 47, 48 and 49.

[301] Granite Falls Public Hearing, Transcript Vol. 10, at 62-67.

[302] Granite Falls Public Hearing, Transcript Vol. 9, at 59-62 (Graumann).
[303] Morris Public Hearing, Transcript Vol. 4, at 69-70.
[304] Morris Public Hearing, Transcript Vol. 4, at 69-71.
[305] Morris Public Hearing, Transcript Vol. 4, at 71-72.
[306] Benson Public Hearing, Transcript Vol. 1, at 64-66; Public Exhibit 14.
[307] Benson Public Hearing, Transcript Vol. 1, at 67-68.
[308] Morris Public Hearing, Transcript Vol. 3, at 55-56.
[309] *See, e.g.,* Morris Public Hearing, Transcript Vol. 3, at 72 (Ninneman).
[310] Morris Public Hearing, Transcript Vol. 3, at 54-57.
[311] Morris Public Hearing, Transcript Vol. 3, at 73-74 (Schulte).
[312] Morris Public Hearing, Transcript Vol. 3, at 60-62.
[313] Morris Public Hearing, Transcript Vol. 3, at 61-71; Exhibit 20.
[314] December 8, 2006, letter to the Administrative Law Judges from Rep. McCollum.
[315] Public Exhibits 105 and 110.
[316] Morris Public Hearing, Transcript Vol. 4, at 35.
[317] Morris Public Hearing, Transcript Vol. 4, at 57.
[318] Morris Public Hearing, Transcript Vol. 4, at 58; see also.
[319] Morris Public Hearing, Transcript Vol. 4, at 59.
[320] See Transcript of October 16 hearing at 40-44; Applicants' Exhibit 64-B.
[321] Benson Public Hearing, Transcript Vol. 2, at 14-16 and 41-42.
[322] Granite Falls Public Hearing, Transcript Vol. 9, at 97-100.
[323] Benson Public Hearing, Transcript Vol. 2, at 17-18 and 43-44.
[324] Nov. 29, 2005, PUC Order at 1-2; DOC Ex. 4 (Direct Testimony of David E. Birkholz) at 2.
[325] DOC Exs. 4, 6.
[326] DOC Ex. 4, App. I.
[327] DOC Ex. 6, App. I at 6.
[328] DOC Ex. 6, App. I at 2.
[329] DOC Ex. 6, App. I at 2-3.
[330] DOC Exs. 4 at 4-5 and 6, App. I and J.
[331] DOC Ex. 4 at 6, App. I at 1-2.

[332]
DOC Exs. 4 at 3, 6. A Federal EIS is also required under NEPA because a federal agency, the Western Area Power Administration, owns the substations that the two proposed transmission lines will connect to in Minnesota – the Morris substation and the Granite Falls substation – and the Applicants require approval from the Western Area Power Administration to make these connections. Federal law requires preparation of an EIS before that authorization can be granted. The Draft Federal EIS was available in May of 2006. See 71 Fed. Reg. 29148 (May 19, 2006).

[333]
See Minn. R. 4410.7035.

[334]
"Responses to Substantive Comments on the Draft EIS," .DOC Ex. 6 at 200-204.

[335]
DOC Exs. 4 at 66 and 6 at 1-2.

[336]
When the Certificate of Need and the Route Permit proceedings are joined, as they were here, the procedures of chapter 4400 apply in conducting the environmental review. Minn. R. 4410.7060, subp. 3.

[337]
Joint Intervenors' Initial Post-Hearing Brief at 72-73; see also DOC Ex. 6, App. J (Oct. 30, 2006, letter to the Department from MCEA commenting on draft EIS) and Dec. 11, 2006, comments of the Joint Intervenors on Final EIS.

[338]
Minnesota R. 4400.1700, subp. 2.

[339]
71 Fed. Reg. 29618 (May 23, 2006).

[340]
Minn. Stat. § 116D.04, subd. 5a(9).

[341]
Minn. R. 4410.3900, subp. 1.

[342]
Jan. 30, 2007, letter from Deputy Commissioner Garvey to the Administrative Law Judges accompanying the Department's initial post-hearing brief, at 1; Department's Post-Hearing Brief at 88.

[343]
Jan. 30, 2007, Letter from Deputy Commissioner Garvey at 1-2; DOC's Post-Hearing Brief at 89-91.

[344]
MISO Ex. 1 (Direct Testimony of Eric Laverty) at 15-16.

[345]
The PUC recognized this limitation under federal law in the Certificates of Need it issued to Xcel Energy in 2003 for four transmission lines in the Buffalo Ridge area. *See In the Matter of the Application of Northern States Power Company d/b/a Xcel Energy for Certificates of Need for Four Large High Voltage Transmission Line Projects in Southwestern Minnesota*, PUC Docket No. E-002/CN-01-1958, Order Granting Certificates of Need Subject to Conditions (March 11, 2003). In that Order, the PUC noted, "Transmission is an interstate activity regulated by the Federal Energy Regulatory Commission. Under federal law, Xcel cannot reserve the proposed lines for wind generation; in fact, it cannot even reserve them for its own use, except under carefully defined circumstances. Access to the Company's transmission lines is determined by the terms of its federal open access transmission tariff, which must and does permit access on a non-discriminatory, first-come, first-served basis. The Company's transmission lines, and access to them, are controlled by the Midwest Independent System Operator (MISO), a neutral third party recognized as an appropriate administrator under federal law." *Id.* at 3.

[346]
In the Matter of the Application of Northern States Power Company d/b/a Xcel Energy for Certificates of Need for Four Large High Voltage Transmission Line Projects in Southwestern Minnesota, PUC Docket No. E-002/CN-01-1958, Order Granting Certificates of Need Subject to Conditions (March 11, 2003), at 15-25.

[347]
The Applicants initially filed a motion arguing that the Federal Power Act preempts the PUC from considering the need for the Big Stone II transmission lines (and therefore, in the present case, the need for the Big Stone II generation). DOC asserted in its reply brief (at pp. 8-11) that, while MISO has been given an important role in transmission planning, there is no express federal statutory authority supporting the Applicants' view that MISO has exclusive authority to determine whether the proposed transmission lines are needed. DOC also pointed out that MISO witness Eric Laverty testified that MISO itself has no regulatory authority, and MISO does not dispute the jurisdiction of the Minnesota PUC with respect to the CON and routing process. Tr. Vol. 7 at 47, 79. Because the Applicants withdrew this motion by letter dated February 12, 2007, the Administrative Law Judges do not express any view on this topic.

[348]
Ex. 69A at 1.
[349]
That statute defines "large energy facility" to include "any high-voltage transmission line with a capacity of 100 kilovolts or more and greater than 1,500 feet in length" and "any high-voltage transmission line with a capacity of 200 kilovolts or more with more than ten miles of its length in Minnesota or that crosses a state line." Minn. Stat. § 216B.2421, subd. 2(2) and (3).
[350]
PUC Order Accepting Application as Substantially Complete and Requiring Additional Information (Dec. 19, 2005) at 8-9.
[351]
Emphasis added.
[352]
DOC Reply Brief at 3, n. 7.
[353]
GOED Ex. 2.
[354]
"Energy conversion facility" is defined in SDCL 49-41B-2(5) to mean "any new facility, or facility expansion, designed for or capable of generation of one hundred megawatts or more of electricity, but does not include any wind energy facilities."
[355]
The South Dakota PUC may waive compliance with chapter 49-41B under certain circumstances involving urgency, disaster, or civil disorder. *See* SDCL 49-41B-23.
[356]
SDCL 49-41B-22.
[357]
See ARSD Chapter 20:10:22.
[358]
SDCL 49-41B-30.
[359]
GOED Ex. 2 at 1-2, 4. Apparently Wind on the Wires, who is one of the Joint Intervenors in the current Minnesota case, did not participate as an intervenor in the South Dakota case.
[360]
Id. at 33 (Decision and Order, ¶ 2(A)).
[361]
Id. at 31-33 (Conclusion of Law Nos. 4-7, 21).
[362]
Id. at 33 (Decision and Order).
[363]
Id.
[364]
Id. at 30-31 (Finding of Fact No. 201). ARSD 20:10:22:08 requires that the applicant describe the purpose of the proposed facility.
[365]
GOED Ex. 1 (Prefiled Direct Testimony of Delaine Kolbo) at 3.
[366]
Ex. 69A at 16-18.
[367]
Lyon Financial Services, Inc. v. Waddill, 625 N.W.2d 155, 158 (Minn. App. 2001), *citing Durfee v. Duke*, 375 U.S. 106, 111 (1963).
[368]
478 U.S. 788, 797-98 (1986).
[369]
472 N.W.2d 114, 115-16 (Minn. 1991).
[370]
472 N.W.2d at 116 (citations omitted).
[371]
Findings 29-34 in the South Dakota PUC Decision relate to projected need for power in the region. Finding 29 notes that, by the summer of 2011, the MAPP-US region is projected to have a capacity deficit of approximately 219 MW even if Big Stone Unit II is constructed and, without Big Stone unit II, the region will have a capacity deficit

of approximately 819 MW by 2011 and 2400 MW by 2014. Finding 31 states that MAPP-US installed capacity margins during the 1980s have been declining due to load growth in the region, and that continuing load growth will result in adequate generation capacity by 2011 unless additional resources are added. Findings 32-34 note that MAPP-Canada projects a 1,383 MW surplus in the summer season of 2011 and a 1,200 MW surplus in the 2011/2012 winter season, but the availability of such surpluses is limited. Findings 35-56 relate to forecasted need for additional baseload capacity and energy by each of the Applicants. Findings 38, 41, 44, 47, 51, 54, and 56 include findings that, based on the evidence provided regarding resource planning conducted by the Applicants, each Applicants' proposed share of Big Stone Unit II is a least-cost alternative.

[372]
GOED Ex. 2 at 33.

[373]
ARSD 20:10:22:08.

[374]
Medtronic, Inc. v. Advanced Bionics Corp., 630 N.W.2d 438, 449 (Minn. Ct. App. 2001). GOED points out that the Minnesota PUC noted in its 1997 order regarding the quantification of environmental costs that, "As a matter of interstate comity, in the process of establishing environmental cost values, the Commission believes it is reasonable to consider the concerns of other states, such as North Dakota and Wisconsin."

[375]
Article I, Section 8, Clause 3 of the U.S. Constitution (which specifies that the Congress shall have power "to regulate commerce with foreign nations, and among the several states, and with the Indian tribes").

[376]
Wyoming v. Ohio, 502 U.S. 437, 454 (1992).

[377]
G. Beck, M.B. Gossman, L. Nehl-Trueman, *Minnesota Administrative Procedure* § 11.5 (2d Ed. 1998). *See, e.g., Neeland v. Clearwater Memorial Hospital,* 237 N.W.2d 366, 368 (Minn. 1977); *Petterssen v. Commissioner of Employment Services,* 306 Minn. 542, 543, 236 N.W.2d 168, 169 (1975); *Starkweather v. Blair,* 245 Minn. 371, 394-95, 71 N.W.2d 869, 884 (1955); *In the Matter of Rochester Ambulance Service,* 500 N.W.2d 495 (Minn. Ct. App. 1993). *Accord Jackson County Education Association v. Grass Lake Community,* 95 Mich. App. 635, 641, 291 N.W.2d 53, 56 (1980).

[378]
See, e.g., New Energy Co. of Indiana v. Limbach, 486 U.S. 269, 273 (1988); *H.P. Hood & Sons, Inc. v. DuMond*, 336 U.S. 525, 534-35 (1949).

[379]
502 U.S. 437 (1992).

[380]
Id. at 454, citing *New Energy Co.*, 486 U.S. at 273-74, and Maine v. Taylor, 477 U.S. 131 (1986).

[381]
Id. at 454-55, quoting *Philadelphia v. New Jersey*, 437 U.S. 617, 624 (1978).

[382]
502 U.S. 455 at n.12, citing *Brown-Forman Distillers Corp. v. New York State Liquor Authority*, 476 U.S. 573, 579 (1986), and *Pike v. Bruce Church, Inc.*, 397 U.S. 137, 142 (1970).

[383]
Hunt v. Washington State Apple Advertising Commission, 432 U.S. 333, 350 (1977), quoting *Southern Pacific Co. v. Arizona ex rel Sullivan*, 2325 U.S. 761, 767 (1945).

[384]
Washington State Apple Advertising Commission, 432 U.S. at 349 (citations omitted).

[385]
See, e.g., Chemical Waste Management v. Hunt, 504 U.S. 332 (1992) (U.S. Supreme Court found violation of the Commerce Clause in a case in which a law enacted by Alabama imposed an additional fee for waste that was generated outside Alabama and disposed of at a commercial site in Alabama).

[386]
Chemical Waste Management v. Hunt, 504 U.S. 334 (1992).

[387]
Minn. Stat. § 216B.243, subds. 3 and 3a.

[388]
Id.

[389]
See PUC Order Establishing Interim Environmental Cost Values (March 1, 1994). The interim range of values for CO2 emissions adopted by the PUC was $5.99 – $13.60 per ton.

[390]
See Order Establishing Environmental Cost Values, PUC Docket No. E-999/CI-93-583 (January 3, 1997).
[391]
See Order Affirming in Part and Modifying in Part Order Establishing Environmental Cost Values, PUC Docket No. E-999/CI-93-583 (July 2, 1997).
[392]
Minn. Laws 2007, ch. 136, Art 5, Sec. 4.

Findings (under fuel costs)

Approximately 65 to 70 percent of the cost of fuel for the Big Stone plant is transportation cost (Uggerud p.8)

The cost assumptions for Big Stone II are predicated on the tariffed BNSF rate in place at the time of filing (Uggerud p. 80)

The tariffed BNSF rate has been under regulatory challenge by Ottertail during this time period so it is reasonable to believe that BNSF chose to not implement some of the dramatic price increases that other coal hauling utilities experienced. With the failure of Ottertail's rate case it is unlikely that this stability will remain in place.

Ottertail witness Uggerud believes the BNSF is essentially an unregulated monopoly (p. 81, 83).

According to witness Brautovich, BNSF spent over $600 million in 2006 and is on pace to spend $600 million in 2007 on capital expenditures to haul Powder River Basin coal (208). This is an increase of $300 million over, or a doubling of, 2005 spending, which was the previous average capital expenditure baseline (229-30). In addition, the workforce has expanded recently by thousands. (p. 208) In large part, this appears to be in response to the "catastrophic" coal supply problems that plagued the railroad in 2005-06.

Witness Brautovich believes these dramatic spending increases will find their way into tariffed rates (p. 232).

Demand for Powder River Basin coal over the BNSF is increasing (p. 212, 229).

Witness Bautvich declined to deny that rate increases could be as high as double digits, but indicated that transportation rates would be driven by the market for other sources (p. 239-240). We believe this means the BNSF intends in the future to capture a greater portion of the margin between the commodity price of coal and the delivered price of other higher priced fuel sources.

Last year's average BNSF rate increase was 11 percent (p. 244).

Given the foregoing, we believe the applicant has significantly miscalculated the future delivered price of fuel for Big Stone II. We find it is far more likely that Ottertail will be hit with rate increases that far exceed the 2.9 percent inflation factor used by company witnesses.

Findings (under fuel costs)

Approximately 65 to 70 percent of the cost of fuel for the Big Stone plant is transportation cost (Uggerud p.8)

The cost assumptions for Big Stone II are predicated on the tariffed BNSF rate in place at the time of filing (Uggerud p. 80)

The tariffed BNSF rate has been under regulatory challenge by Ottertail during this time period so it is reasonable to believe that BNSF chose to not implement some of the dramatic price increases that other coal hauling utilities experienced. With the failure of Ottertail's rate case it is unlikely that this stability will remain in place.

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