EXCELSIOR ENERGY

April 27, 2009

Burl W. Haar
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, MN 55101-2147

RE: In the Matter of a Petition by Excelsior Energy Inc. For Approval of a Power Purchase Agreement, Determination that the Clean Energy Technology is Likely to be a Least Cost Technology, and Establishment of a Clean Energy Technology Minimum Under Minn. Stat. 216B.1693

MPUC Docket No. E6472/M-05-1993

Dear Dr. Haar:

Enclosed for filing in the above docket, please find the following documents:

1. Excelsior Energy Inc.'s Motion to Suspend Proceedings;
2. Excelsior Energy Inc.'s Motion to Supplement the Record and Its Pending Petition for Rehearing, Reconsideration and Reargument, or in the Alternative Offer of Proof;
3. Affidavit of Thomas L. Osteraas;
4. Exhibit A to Affidavit of Thomas L. Osteraas; and
5. Exhibit B to Affidavit of Thomas L. Osteraas.

By copy of this letter, service of items 1–5 is made via E-Filing. For members of the full service list that Excelsior does not know to be enrolled for service via E-Filing, Excelsior is serving paper copies of items 1–3 above via U.S. Mail. Item 4 above, Boston Pacific Company's October 21, 2008 Report entitled *Responding to Commission Inquiries on Emissions Costs, Construction Costs and Fuel Costs*, and item 5 above, the Commission's March 17, 2009 order in Docket No. CN-05-619, are publicly available at the eDockets Search System, https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showeDocketsSearch&showEdocket=true, under docket number 05-619.

Sincerely,

/s/ Thomas L. Osteraas
Senior Vice President and General Counsel

Enclosure
cc: Service List

STATE OF MINNESOTA
BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

In the Matter of a Petition by Excelsior Energy Inc. For Approval of a Power Purchase Agreement, Determination that the Clean Energy Technology is Likely to be a Least Cost Technology, and Establishment of a Clean Energy Technology Minimum Under Minn. Stat. 216B.1693

MPUC Docket No.: E6472/M-05-1993

AFFIDAVIT OF SERVICE

STATE OF MINNESOTA)
) ss.
COUNTY OF HENNEPIN)

I, William Harrington, being first duly sworn, upon oath depose and state:

1. On April 27, 2009, I served the following documents to those persons listed on the attached Service List by E-Filing:

a. Excelsior Energy Inc.'s Motion to Supplement the Record and Its Pending Petition for Rehearing, Reconsideration and Reargument, or in the Alternative Offer of Proof;
b. Excelsior Energy Inc.'s Motion to Suspend Proceedings;
c. Affidavit of Thomas L. Osteraas;
d. Exhibit A to Affidavit of Thomas L. Osteraas; and
e. Exhibit B to Affidavit of Thomas L. Osteraas.

2. On April 27, 2009, I served the following documents to those persons listed on the attached Service List by U.S. Mail:

a. Excelsior Energy Inc.'s Motion to Supplement the Record and Its Pending Petition for Rehearing, Reconsideration and Reargument, or in the Alternative Offer of Proof;
b. Excelsior Energy Inc.'s Motion to Suspend Proceedings; and
c. Affidavit of Thomas L. Osteraas.

W Harrington
William Harrington

Subscribed and sworn to before me
on April 27, 2009.

Kathryn J. Osteraas
Notary Public

KATHRYN J. OSTERAAS
Notary Public-Minnesota
My Commission Expires Jan 31, 2010

Julia Anderson
MN Office of the Attorney General
1400 BRM Tower
445 Minnesota Street
St. Paul, MN 55101-2131

Christopher Anderson
Minnesota Power
30 West Superior Street
Duluth, MN 55802

Janet Anderson
MN Witness for Environmental Justice
1799 Sargent
St. Paul, MN 55105

Michael Beard
Regulated Industries Committee
100 Rev. Martin Luther King Jr. Blvd.
Room 577
St. Paul, MN 55155

Ingrid Bjorklund
Outland Renewable Energy
Suite 226
207 N. Chestnut St.
Chaska, MN 55318

William Blazar
MN Chamber of Commerce
400 Robert Street North
Suite 1500
St. Paul, MN 55101

Michael Bradley
Moss & Barnett
4800 Wells Fargo Center
90 South Seventh Street
Minneapolis, MN 55402

Jeff Burgess
Lignite Energy Council
1016 E. Owens Ave.
Bismarck, ND 58501

Christopher Clark
Xcel Energy
414 Nicollet Ave. - 5th Floor
Minneapolis, MN 55401

Steven Clemmer
Union of Concerned Scientists
2 Brattle Square
6th Floor
Cambridge, MA 02238

Sheryl Corrigan
Minnesota Pollution Control Agency
520 Lafayette Road North
St. Paul, MN 55155

Lisa Crum
Lindquist & Vennum
4200 IDS Center
80 South Eighth Street
Minneapolis, MN 55402

John Drawz
Fredrikson & Byron, P.A.
200 South 6th Street, Suite 4000
Minneapolis, MN 55402-1425

Sharon Ferguson
MN Department of Commerce
Suite 500
85 7th Place East
St. Paul, MN 55101-2198

Jason Flohrs
TwinWest Chamber of Commerce
Suite 170
10700 Old County Road 15
Plymouth, MN 55441

Mike Franklin
MN Chamber of Commerce
400 Robert Street North
Suite 1500
St. Paul, MN 55101

Edward Garvey
32 Lawton Street
St. Paul, MN 55102

Bruce Gerhardson
Otter Tail Power Company
P.O. Box 496
215 South Cascade Street
Fergus Falls, MN 56538

Elizabeth Goodpaster
Minnesota Center for Environmental Advocacy
26 East Exchange Street
Suite 206
St. Paul, MN 55101

Todd Guerrero
Lindquist & Vennum
4200 IDS Center
80 South Eighth Street
Minneapolis, MN 55402-2274

Burl Haar
MN Public Utilities Commission
Suite 350
121 East Seventh Place
St. Paul, MN 55101-2147

Scott Harris
Leonard, Street and Deinard
150 South Fifth Street
Suite 2300
Minneapolis, MN 55402

Annette Henkel
Minnesota Utility Investors
Suite 200
400 Robert Street North
St. Paul, MN 55101

Bruce Johnson
Office of Administrative Hearings
P.O. Box 64620
St. Paul, MN 55164

Chuck Kerr
Great Northern Power Development, L.P.
601 Jefferson Street, Suite 3600
Houston, TX 77002-7906

Michael Krikava
Briggs and Morgan
2200 IDS Center
80 South Eighth Street
Minneapolis, MN 55402

Jerry Larsen
HPC-LLC
Suite 6
1325 American Blvd. E.
Bloomington, MN 55402

Robert Lee
Mackall, Crounse & Moore, PLC
1400 AT&T Tower
901 Marquette Avenue
Minneapolis, MN 55402

John Lindell
OAG-RUD
900 BRM Tower
445 Minnesota Street
St. Paul, MN 55101

Alan Lukes
Great Northern Power Development, L.P.
1749 Pinto Place
Bismarck, ND 58503

Valerie Means
MN Office of the Attorney General
1400 BRM Tower
445 Minnesota Street
St. Paul, MN 55101-2131

Steve Mihalchick
Office of Administrative Hearings
P.O. Box 64620
St. Paul, MN 55164

David Moeller
Minnesota Power
30 West Superior Street
Duluth, MN 55802-2093

Thomas Osteraas
Excelsior Energy
11100 Wayzata Boulevard
Suite 305
Minnetonka, MN 55305

Carol Overland
Overland Law Office
P.O. Box 176
Red Wing, MN 55066

Steven Quam
Fredrikson & Byron, P.A.
200 South 6th Street, Suite 4000
Minneapolis, MN 55402-1425

Kevin Reuther
MN Center for Environmental Advocacy
Suite 206
26 East Exchange Street
St. Paul, MN 55101

Antone Rude
Great Northern Power Development, L.P.
10127 93rd Street NE
Monticello, MN 55362

Tom Sampson
City of Keewatin
Box 190
Keewatin, MN 55753

David Sasseville
Lindquist & Vennum
4200 IDS Center
80 South Eighth Street
Minneapolis, MN 55402-2274

Richard Savelkoul
Felhaber, Larson, Fenlon & Vogt
Suite 2100
444 Cedar Street
St. Paul, MN 55101

Robert Schulte
Schulte Associates LLC
15347 Boulder Pointe Road
Eden Prairie, MN 55347

Tore Simonsen
Clean Water Action Alliance of Minnesota
308 East Hennepin Avenue
Minneapolis, MN 55414

Mollie Smith
Fredrikson & Byron, P.A.
200 South 6th Street, Suite 4000
Minneapolis, MN 55402-1425

Byron Starns
Leonard, Street and Deinard
150 South Fifth Street
Suite 2300
Minneapolis, MN 55402

Eric Swanson
Winthrop & Weinstine, P.A.
225 South Sixth Street
Suite 3500
Minneapolis, MN 55402

SaGonna Thompson
Xcel Energy
414 Nicollet Mall, FSQ-4
Minneapolis, MN 55401-1993

STATE OF MINNESOTA
BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

In the Matter of a Petition by Excelsior Energy Inc. For Approval of a Power Purchase Agreement, Determination that the Clean Energy Technology is Likely to be a Least Cost Technology, and Establishment of a Clean Energy Technology Minimum Under Minn. Stat. 216B.1693.

MPUC Docket No.: E6472/M-05-1993

EXCELSIOR ENERGY INC.'S MOTION TO SUSPEND PROCEEDINGS

In order to ensure the protection of the public interest as contemplated by the Commission's August 30, 2007 Order in this proceeding, Excelsior Energy Inc. ("Excelsior") submits this motion to suspend this proceeding until the completion and full consideration of (1) currently pending or upcoming integrated resource plans ("IRPs") filed by Minnesota's largest electric utilities, including Xcel Energy, Minnesota Power, and Great River Energy, and (2) the Reliability Administrator's statewide assessment of Minnesota's power needs through 2025.

In its August 30, 2007 Order in this proceeding, the Commission stated that the "public interest requires it" to explore the potential for a statewide market for the power produced by the Mesaba Project.[1] Specifically, the Commission noted:

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[1] Minnesota Public Utilities Commission, Order Resolving Procedural Issues, Disapproving Power Purchase Agreement, Requiring Further Negotiations, and Resolving to Explore the Potential for a Statewide Market for Project Power Under Minn. Stat. §216B.1694, subd. [2(a)]5, In the Matter of the Petition by Excelsior Energy Inc. for Approval of a Power Purchase Agreement, MPUC Docket No. M-05-1993, Aug. 30, 2007, at 23.

> Resource plan filings are imminent from Xcel, Minnesota Power, and Great River Energy, three of the state's largest generators of electricity and purchasers of wholesale power. These resource plan proceedings should provide a good starting point for examining how Mesaba might contribute to meeting the state's intermediate and long-term power needs and how that contribution would affect rates, reliability, and other public-interest concerns. Another promising resource for this purpose will be the Reliability Administrator's assessment of Minnesota's power needs through 2025, required under the Next Generation Energy Act (Laws 2007, c. 136, art.4, § 16).[2]

The IRPs referenced in the August 30, 2007 Order as good "starting points" have yet to be completed, and the Reliability Administrator has not yet completed the assessment of Minnesota's power needs through 2025.

Development of any new baseload resource will take a decade or more of planning and the investment of tens of millions of dollars prior to the start of construction (or, in the case of any potential new nuclear development, longer than a decade and the investment of hundreds of millions of dollars prior to construction).[3] No utility in the State of Minnesota is currently working to develop any new baseload resources in Minnesota, and the pending IRPs and statewide need assessment may convince the Commission that it would be beneficial for the State to add a new baseload resource at some point during the next ten to fifteen years. The Mesaba Project is a viable, legislatively favored option to meet such future baseload need. Given the long lead-times and significant cost involved in developing a new baseload resource (particularly one that will be able to capture carbon dioxide using commercially available technologies) the Commission's view that the public interest requires it to explore a statewide

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[2] *Id*. at 23–24.

[3] *See, e.g., North and South Carolina Regulators Approve Lee Pre-Construction Costs,* World Nuclear News, June 10, 2008, http://www.world-nuclear-news.org/NN-South_Carolina_approves_pre-construction_costs_of_Lee_plant-1006085.html, noting that the North and South Carolina commissions have approved $230 million of cost recovery by Duke Energy to cover pre-construction costs in connection with Duke's proposed new Lee nuclear station. Duke filed its application for cost recovery in December, 2007 in order to ensure that Duke's proposed new Lee nuclear station could be an option to serve customer needs in the 2018 timeframe. As reported in the referenced article, in approving the request for $230 million in cost recovery the commission in South Carolina stated that it "agrees with Duke Energy Carolinas that preserving the option of new nuclear generation is valuable for the company's customers and for the future of the State of South Carolina, and therefore is in the public interest."

market for the Mesaba Project's power through completion of pending resource plans and full consideration of the statewide need assessment is even more powerful today than it was in 2007.

In addition to allowing the Commission to meaningfully explore the potential for a statewide market for output from the Mesaba Project, suspending this proceeding pending completion of the IRPs and full consideration of the statewide need assessment will also foster administrative efficiency. Failure to suspend this proceeding may ripen appellate issues that are currently not ripe, distracting all parties and the Commission with appeals that could be rendered moot should the Commission suspend this proceeding and delay final action until the Commission has before it additional information from the IRPs and statewide need assessment.

CONCLUSION

For the foregoing reasons, Excelsior respectfully requests that the Commission grant Excelsior's motion to suspend this proceeding pending completion of the IRPs and full consideration of the Reliability Administrator's statewide need assessment in order to allow the Commission to protect the public interest consistent with the conclusions contained in the August 30, 2007 Order, and to promote administrative efficiencies.

Dated: April 27, 2009

Respectfully submitted,

/s/ Byron E. Starns
Byron E. Starns, Esq.
LEONARD, STREET AND DEINARD
150 South Fifth Street, Suite 2300
Minneapolis, MN 55402
Telephone: (612) 335-1500

/s/ Thomas L. Osteraas
Thomas L. Osteraas, Esq.
Excelsior Energy Inc.
11100 Wayzata Blvd
Minnetonka, MN 55305

COUNSEL FOR EXCELSIOR ENERGY INC.

STATE OF MINNESOTA
BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

In the Matter of a Petition by Excelsior Energy Inc. For Approval of a Power Purchase Agreement, Determination that the Clean Energy Technology is Likely to be a Least Cost Technology, and Establishment of a Clean Energy Technology Minimum Under Minn. Stat. 216B.1693.	MPUC Docket No.: E6472/M-05-1993

EXCELSIOR ENERGY INC.'S MOTION TO SUPPLEMENT THE RECORD AND ITS PENDING PETITION FOR REHEARING, RECONSIDERATION AND REARGUMENT, OR IN THE ALTERNATIVE OFFER OF PROOF

PHASE 2

Pursuant to Minnesota Statutes Section 216B.27 and the Minnesota Rules Part 7829.3000, Excelsior submits this motion to supplement both the existing record in Docket No. M-05-1993 ("Mesaba Docket") and its October 14, 2008 Petition for Rehearing, Reconsideration, and Reargument ("October 14, 2008 Reconsideration Request"). As discussed below, Excelsior seeks to supplement the record in this proceeding to include (1) Boston Pacific Company's October 21, 2008 Report entitled *Responding to Commission Inquiries on Emissions Costs, Construction Costs and Fuel Costs* ("Boston Pacific Report") filed in Docket No. CN-05-619 ("Big Stone Docket");[1] and (2) the order recently issued by the Minnesota Public Utilities Commission

[1] *See* In the Matter of the Application of Otter Tail Power Company and Others for Certification of Transmission Facilities in Western Minnesota, Minnesota Public Utilities Commission ("MPUC") Docket No. CN-05-619.

("Commission") on March 17, 2009 ("Big Stone Order") in the Big Stone Docket.[2] This information, which only became available after the filing of Excelsior's October 14, 2008 Reconsideration Request, is directly relevant to the Commission's decision not to appoint an independent evaluator in the Mesaba Docket and further supports Excelsior's pending October 14, 2008 Reconsideration Request. Therefore, good cause exists to allow Excelsior to supplement the record and its October 14, 2008 Reconsideration Request with the report provided by the Commission's own independent expert, as well as the Commission's interpretation of that report as set forth in the Big Stone Order. In the alternative, Excelsior requests that the Boston Pacific Report and Big Stone Order be considered as an offer of proof.

I.
MOTION TO SUPPLEMENT

At the outset, Excelsior notes the unsolicited counsel provided by the Commission's independent expert, Boston Pacific:

> As to promoting new technologies, it is clear that just about everyone points to new technologies (demand- and supply-side) as needed to meet our overall goals. For example, if we want to stabilize prices or improve environmental performance, it is often said new technologies are needed. It is important here for the Commission to explicitly consider the effect of its decision ***as well as its decision-making process on new technologies; the decision-making process must invite and accommodate new players with new technologies.***[3]

The contrast is stark between the decision-making process in the Big Stone Docket, where an independent expert was appointed to evaluate a proposal involving utilities and conventional, old pulverized coal technology, and the decision-making

[2] The Boston Pacific Report and the Commission's Big Stone Order are attached to the Affidavit of Thomas L. Osteraas appended to this Motion.
[3] Boston Pacific, Report Responding to the Commission's Inquiries on Emissions Costs, Construction Costs, and Fuel Costs, Big Stone II Transmission Certificate of Need and Route Permit, MPUC Docket No. CN-05-619, Oct. 21, 2008, at 4, ll. 4–10 (emphasis added).

process in the Mesaba Docket, where Excelsior's request to appoint an independent expert to evaluate a legislatively preferred innovative, new clean coal technology was denied. The Minnesota legislature took concrete steps to encourage innovative new technologies when it enacted unprecedented legislation in 2003 inviting new players with new technologies to participate in Minnesota's energy future, and prescribing the proper scope of the Commission's review of innovative energy projects.[4]

The Commission's decision to appoint an independent expert in the Big Stone Docket[5] was prompted primarily by the Commission's desire to avoid blind reliance on complicated modeling opinion evidence presented by interested parties to the proceeding.[6] By failing to similarly appoint an independent expert in the Mesaba Docket the Commission had no choice but to rely on modeling opinion evidence of interested parties. Although not intended by the Commission, the disparate treatment of the "independent expert" issue between the Big Stone Docket and the Mesaba Docket unavoidably serves to discourage any new player with a new technology from seeking to help Minnesota meet the serious energy challenges that lie ahead.

A. Procedural Posture

In accordance with Minnesota Statutes Section 216B.27 and Minnesota Rules Part 7829.3000, on October 14, 2008 Excelsior timely sought rehearing, reconsideration, and

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[4] *See* Minn. Stat. §§ 216B.1693 and 216B.1694. For a concise description of the standards prescribed for the Commission in these statutes, see Exhibit EE 1137, Rebuttal Testimony of Jim Chen, Petition by Excelsior Energy Inc. for Approval of a Power Purchase Agreement, MPUC Docket No. E6472/M-05-1993, OAH Docket No. 12-2500-17260-2, Oct. 10, 2006, at 3–5, 17–28, 37–38.

[5] Minnesota Public Utilities Commission, Order Referring Case to Office of Administrative Hearings for Additional Evidentiary Proceedings, Big Stone II Transmission Certificate of Need and Route Permit, MPUC Docket No. CN-05-619, Aug. 7, 2008.

[6] Commissioner O'Brien noted during the Big Stone hearings, "What we have essentially before us now is a battle or a duel -- a battle of dual modeling. Their models are driven by their assumptions, the Applicants' models are driven by their assumptions, the Joint Intervenors' models are driven by their assumptions, and we're asked to pick from either model and either assumption…. I'd like to see if we can't move away from that paradigm." Transcript of Hearing, Big Stone II Transmission Certificate of Need and Route Permit, MPUC Docket No. CN-05-619, June 5, 2008, at 88, ll. 8–17.

reargument of the Commission's September 24, 2008 Order issued in Phase 2 of these proceedings. By its order dated December 9, 2008, the Commission granted Excelsior's petition for reconsideration, for procedural purposes, and held in abeyance further consideration of Excelsior's petition for reconsideration until after May 1, 2009.[7] Excelsior respectfully requests that the Commission allow Excelsior to supplement its October 14, 2008 Reconsideration Request, and allow Excelsior to supplement the record in the Mesaba Docket for the limited purpose of including the Boston Pacific Report and the Commission's recent Big Stone Order.

Minnesota's Rules of Civil Procedure are instructive in guiding the Commission's consideration of Excelsior's motion. Rules 59 ("New Trials") and 60 ("Relief from Judgment or Order") provide for the consideration of new material evidence that was not available "at trial." In the present case, the Boston Pacific Report and the Commission's Big Stone Order only became available on October 21, 2008 and March 17, 2009, respectively, after the record in this proceeding closed and after Excelsior submitted its October 14, 2008 Reconsideration Request. As discussed below, the information contained in the Boston Pacific Report and the Commission's related findings and conclusions in its Big Stone Order are directly relevant to the issues pending in the Mesaba Docket.

B. Good Cause Exists To Supplement the Record as the Evidence Is Relevant to This Docket and Was Previously Unavailable

In its October 14, 2008 Reconsideration Request, Excelsior noted that the Commission's rationale for appointing an independent expert to advise the Commission

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[7] Minnesota Public Utilities Commission, Order Granting Reconsideration for Procedural Purposes and Holding Further Consideration in Abeyance, Petition by Excelsior Energy Inc. for Approval of a Power Purchase Agreement, MPUC Docket No. M-05-1993, Dec. 9, 2008.

in the Big Stone proceeding applied with equal or greater force to the Mesaba proceeding.[8] The contents of the Boston Pacific Report, issued on October 21, a week after Excelsior filed its October 14, 2008 Reconsideration Request, and the Commission's interpretation of the Boston Pacific Report as reflected in the Commission's recently issued Big Stone Order, validate and affirm all of the reasons Excelsior has asked the Commission to reconsider its denial of Excelsior's request to appoint an independent expert in the Mesaba Docket.

In its Big Stone Order, the Commission summarized the core of Excelsior's argument for an independent expert in the Mesaba Docket with two important statements. First, confirming that any modeling input provided by an interested party is at risk of being unreliable, the Commission stated in the Big Stone Order, "Of course, a model's analysis is only as good as the assumptions that the parties put into it."[9] Second, confirming that an independent, third party expert directly advising the Commission is in the best position to provide unbiased evidence to the Commission, the Commission stated in the Big Stone Order, "[T]he balance of the evidence in the record persuades the Commission that the estimates offered by Boston Pacific are the most reliable in the record."[10]

[8] Excelsior Energy, Petition for Rehearing, Reconsideration, and Reargument of the September 24, 2008 Commission Order, Petition by Excelsior Energy Inc. for Approval of a Power Purchase Agreement, MPUC Docket No. M-05-1993, Oct. 14, 2008, at 1–3, 8–9.
[9] Minnesota Public Utilities Commission, Order Granting Certificate of Need With Conditions, Big Stone II Transmission Certificate of Need and Route Permit, MPUC Docket No. CN-05-619, Mar. 17, 2009, at 27.
[10] *Id*.

The Commission made the decision to seek the counsel of an independent evaluator in the Big Stone Docket "to ensure informed decision-making."[11] Excelsior respectfully requests that the Commission allow Excelsior to supplement the record in the Mesaba Docket and its October 14, 2008 Reconsideration Request to include the Boston Pacific Report and the Commission's Big Stone Order before the Commission considers the merits of the pending October 14, 2008 Reconsideration Request. The Boston Pacific Report and Big Stone Order demonstrate that an independent expert directly advising the Commission was necessary in the Big Stone Docket to ensure informed decision making and create a reliable evidentiary record to support the Commission's decision in a contentious, multi-year, highly litigated complex administrative proceeding involving complicated modeling and other opinion evidence from the parties about the cost effectiveness of a conventional, pulverized coal fired electric generating facility. Fundamental notions of due process and equal protection require that the same evidentiary standards be applied to the Mesaba Docket, a similarly contentious, multi-year, highly litigated complex administrative proceeding involving complicated modeling and other opinion evidence attempting to evaluate the cost effectiveness of a legislatively preferred, innovative new coal-fueled electric generating facility.

II.
OFFER OF PROOF

As discussed above, the Commission should permit Excelsior to supplement the record and its October 14, 2008 Reconsideration Request in the limited manner proposed. If the Commission nevertheless declines Excelsior's request, the Commission should

[11] Minnesota Public Utilities Commission, Order Referring Case to Office of Administrative Hearings for Additional Evidentiary Proceedings, Big Stone II Transmission Certificate of Need and Route Permit, MPUC Docket No. CN-05-619, Aug. 7, 2008, at 3.

accept the Boston Pacific Report and the Big Stone Order as an offer of proof in this proceeding.

III. CONCLUSION

For the foregoing reasons, the Commission should grant Excelsior's Motion to Supplement the Record and Its Petition for Rehearing, Reconsideration and Reargument.

Dated: April 27, 2009

Respectfully submitted,

/s/ Byron E. Starns
Byron E. Starns, Esq.
LEONARD, STREET AND DEINARD
150 South Fifth Street, Suite 2300
Minneapolis, MN 55402
Telephone: (612) 335-1500

/s/ Thomas L. Osteraas
Thomas L. Osteraas, Esq.
Excelsior Energy Inc.
11100 Wayzata Blvd
Minnetonka, MN 55305

COUNSEL FOR EXCELSIOR ENERGY INC.

STATE OF MINNESOTA
BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

In the Matter of a Petition by Excelsior Energy Inc. For Approval of a Power Purchase Agreement, Determination that the Clean Energy Technology is Likely to be a Least Cost Technology, and Establishment of a Clean Energy Technology Minimum Under Minn. Stat. 216B.1693.

MPUC Docket No.: E6472/M-05-1993

AFFIDAVIT OF THOMAS L. OSTERAAS

STATE OF MINNESOTA)
) ss.
COUNTY OF HENNEPIN)

I, Thomas L. Osteraas, being duly sworn, depose and state as follows:

1. I am Senior Vice President and General Counsel at Excelsior Energy Inc. ("Excelsior"). I make this Affidavit in Support of Excelsior's Motion to Supplement the Record and its Petition for Rehearing, Reconsideration and Reargument, or in the Alternative Offer of Proof.

2. Attached as Exhibit A to my affidavit is a true and correct copy of the Boston Pacific Company's October 21, 2008 Report entitled *Responding to Commission Inquiries on Emissions Costs, Construction Costs and Fuel Costs* filed in Docket No. CN-05-619, *In the Matter of the Application of Otter Tail Power Company and Others for Certification of Transmission Facilities in Western Minnesota*.

3. Attached as Exhibit B to my affidavit is a true and correct copy of the Commission's March 17, 2009 order in Docket No. CN-05-619.

Thomas L. Osteraas

Subscribed and sworn to before me
this 27th day of April, 2009.

Notary Public

WILLIAM E. HARRINGTON
Notary Public
Minnesota
Commission # 20210067
My Commission Expires January 31, 2010

BOSTON PACIFIC COMPANY, INC.

October 21, 2008

Mr. Burl Haar
Minnesota Public Utilities Commission
121 7th Place East, #350
St. Paul MN 55101

Dear Mr. Haar:

Enclosed please find one copy of Boston Pacific Company, Inc's Report entitled *Responding to Commission Inquiries on Emissions Costs, Construction Costs and Fuel Costs*. Boston Pacific very much appreciates the opportunity to submit this Report to the Commission.

Sincerely,

Craig R. Roach

Craig R. Roach

Frank Mossburg

Frank Mossburg

Enclosure

1100 New York Avenue, NW • Suite 490 East • Washington, DC 20005 • Tel: (202) 296-5520 • Fax: (202) 296-5531

REPORT RESPONDING TO THE COMMISSION'S INQUIRIES ON EMISSIONS COSTS, CONSTRUCTION COSTS, AND FUEL COSTS

Presented to

THE MINNESOTA PUBLIC UTILITIES COMMISSION

by

BOSTON PACIFIC COMPANY, INC.

Principal Authors:

Craig R. Roach, Ph.D.
Telephone: (202) 296-5520
Email: croach@bostonpacific.com

Frank Mossburg
Telephone: (202) 296-5520
Email: fmossburg@bostonpacific.com

Boston Pacific Company, Inc.
1100 New York Avenue, NW, Suite 490 East
Washington, DC 20005
Telephone: (202) 296-5520
Fax: (202) 296-5531

October 21, 2008

TABLE OF CONTENTS

I. BACKGROUND AND SUMMARY

A. Background

This Docket involves an application for a Certificate of Need for transmission lines in Western Minnesota by five applicants: Otter Tail Power Company, Montana-Dakota Utilities, Missouri River Energy Services, Central Minnesota Municipal Power Agency and Heartland Consumers Power District (collectively, "the Applicants").[1] Importantly, the transmission is tied to the construction of a new coal-fired power plant on the site of the existing Big Stone facility near Milbank, South Dakota; the new plant is referred to as Big Stone II.

The Applicants' choice of Big Stone II over other resource options is based on the results of capacity expansion and other modeling analyses. Intervenors have criticized the Applicants' analyses for, among other things, (a) failing to analyze an appropriate range of costs to comply with future carbon dioxide (CO_2) emissions regulations that may be imposed as a result of Federal legislation, (b) using inaccurate construction cost estimates for all resource options and (c) using inappropriate fuel price forecasts.

[1] Certificate of Need Application for Transmission Lines in Western Minnesota in MPUC Dkt No. CN-05-619 (September 30, 2005). The initial application included seven applicants; however, now there are only five.

Given these criticisms, Boston Pacific Company, Inc.[2] was engaged by the Minnesota Public Utilities Commission ("the Commission") to write a report addressing three questions related to the analyses in the Big Stone II application. The Commission specified the three questions as follows:

a. How passage of the greenhouse-gas regulation bills introduced in Congress to date would affect the cost of energy and power generated by a supercritical, pulverized-coal-fired plant such as Big Stone II?

b. What are the likely construction costs for a supercritical pulverized-coal-fired plant such as Big Stone II, constructed on a brownfield site, with an in-service date of approximately 2014-2015? In addition, what are the likely construction costs for an alternative wind generation system, with natural-gas-fired back-up, with a comparable capacity factor and in-service date? Finally, what are the likely construction costs for a natural-gas-fired plant with a comparable capacity factor and in-service date?

c. What are the likely delivered costs of natural gas and coal for power plants in the North Dakota/South Dakota/Minnesota area over the first fifteen years of the

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[2] Boston Pacific Company, Inc. was chosen for this effort, in part, because of its substantial experience as an Independent Evaluator or Monitor for power procurements across the country. These include recent engagements for procurements of unit contingent power in, for example, Oregon, Oklahoma, and the Virgin Islands as well as procurements for full requirements power in Delaware, the District of Columbia, Illinois, Maryland and New Jersey. Our experience also includes service as expert witnesses on resource decisions before State Commissions and FERC as well as power project development across the U.S. and in two dozen other countries around the world. Resumes and lists of testimony and publications are attached for the two principal authors of this report.

operation of any of the three generation systems described in (b), assuming the passage of climate-change regulation?[3]

Before presenting our answers to the Commission's three questions, it is important to state the context in which we believe the Commission's decision to approve or reject the Certificate of Need must be made. At the outset, note that, all across the U.S., State Commissions and the utilities they regulate are making important decisions about how the electricity needs of ratepayers will be met in the future. Minnesota is not alone. We take as a given that the goal for this decision-making is to get the best deal possible for ratepayers, and that, today, the deal must be defined in all its dimensions – price, risk, reliability, and environmental performance. Furthermore, to serve this goal, Commissions must meet two significant challenges: (a) manage uncertainty (or risk) and (b) promote new technologies.

With respect to managing risk, all decision makers face at least three big uncertainties as reflected in the three questions Boston Pacific was asked to address: (a) What will be the nature and cost of CO_2 (and other greenhouse gas) regulations? (b) What will be the construction costs for all the resource alternatives (demand-and-supply-side)? and (c) What will be the path for natural gas and coal prices? Given these uncertainties, no one can predict the future with precision so all resource options must be assessed under a range of futures to assure ratepayers will get the best deal possible no matter how the future unfolds. (To actually manage risks, Boston Pacific would go beyond <u>assessing</u>

[3] Minnesota Public Utilities Commission, *Request for Proposals* at p 1.

risk to actually assigning it to a party able to do something about it, but assignment of risk does not appear to be an explicit issue in this proceeding.)

As to promoting new technologies, it is clear that just about everyone points to new technologies (demand- and supply-side) as needed to meet our overall goals. For example, if we want to stabilize prices or improve environmental performance, it is often said new technologies are needed. It is important here for the Commission to explicitly consider the effect of its decision as well as its decision-making process on new technologies; the decision-making process must invite and accommodate new players with new technologies.

And, finally, we note that complicating matters further is the fact that the Federal Government has been slow to enact a national energy policy, leaving these decisions up to individual States. This increases the chances that neighboring States can make substantially different decisions on what is the best deal for ratepayers.

B. Summary of Findings

This report fits into the broader context explicitly because it focuses on whether risk was appropriately assessed. That is, do the Applicants appropriately assess risk by using a valid range of inputs regarding CO_2 emission costs, construction costs, and fuel prices?

In general we believe the range of emissions, construction, and fuel price inputs used in the Applicants' analyses were not appropriate; put another way, they were out of line with current "best practices" resource selection methodologies. Specifically, with respect to emissions costs, we found the Applicants' use of a \$0 to \$9 per ton CO_2 tax,[4] without escalation over time, to be far lower than the ranges justified for resource decisions today; the later use of a \$30 per ton tax was a good step forward but did not go far enough.[5]

We recommend analyzing resource choices under four different levels of CO_2 taxes: \$8, \$20, \$40 and \$60 per ton of CO_2, starting in 2012, and escalating with inflation thereafter. As detailed in the body of the report, our recommendation is supported by (a) recent market prices in greenhouse gas auctions worldwide, (b) a variety of cost estimates for proposed congressional legislation, (c) estimates of the CO_2 tax levels needed to actually reduce emission levels, and (d) the ranges of estimates used in a sample of actual Integrated Resource Plans (IRPs).

With respect to new construction costs, we understand that the Applicants' latest analysis used an estimate of \$2,545 per kW for the installed costs for Big Stone II.[6] This is below even the low end of our estimate of the possible range of installed costs for a

[4] Supplemental Prefiled Testimony of James Heidell in MPUC Dkt No. CN-05-619 (November 13, 2007) (hereinafter as "Heidell") at p 11, lines 5-7, Supplemental Prefiled Testimony of Bryan Morlock in MPUC Dkt No. CN-05-619 (November 13, 2007) (hereinafter as "Morlock") at p 16, lines 1-17, Supplemental Prefiled Testimony of J.P. Schumacher in MPUC Dkt No. CN-05-619 (November 13, 2007) (hereinafter as "Schumacher") at p 23, lines 4-18, Supplemental Prefiled Testimony of Robert L. Davis in MPUC Dkt No. CN-05-619 (November 13, 2007) (hereinafter as "Davis") at p 14, line 5 – p 15, line 5.
[5] Prefiled Rebuttal Testimony of Jeffrey J. Greig in MPUC Dkt No. CN-05-619 (January 16, 2008) (hereinafter as "Greig January 16, 2008") at p 5 line 17 – p 6 line 1.
[6] Supplemental Prefiled Testimony of Mark Rolfes in MPUC Dkt No. CN-05-619 (November 13, 2007) (hereinafter as "Rolfes") at p 4.

new coal-fired facility, which we would estimate to be from $2,600 per kW to $3,000 per kW; these are installed costs in nominal dollars for a new brownfield plant without interest during construction (IDC) or transmission integration costs.

For new gas-fired combined cycle facilities, the Applicants used $1,200 per kW to $1,795 per kW as their estimate of installed costs.[7] This is either at or above the high end of our estimates of the appropriate range of costs for new combined cycle facilities, even accounting for some Applicant's inclusion of transmission and IDC costs. In our view, the appropriate range is $1,000 to $1,200 per kW. For gas-fired combustion turbines our expected range of costs is $800 per kW to $1,100 per kW. The Applicants used a similar range of $870 to $1,098 per kW. Finally, the Applicants' cost estimates for wind turbines ($1,810 to $2,270 per kW) are generally in the right region, we would use a range of $2,000 to $2,200 per kW.

Equally important, while different Applicants had different construction cost estimates as discussed above, there was no effort to test a range of assumptions about construction costs in a unified capacity expansion model analysis to see if the resource decision changed with changes in those costs. This point is especially important in a case like this where we are not dealing with competitively-bid, pay-for-performance price offers or detailed fixed-price engineering, procurement, and construction (EPC) contracts. Here, the Applicants offer only an estimated cost so that ratepayers bear the risks that costs will be higher.

[7] Heidell at p 17, Davis at Ex – 117 A, Schumacher at p 4**.** Note that Heidell and Schumacher appear to have included IDC and transmission integration costs. Davis did not include IDC and it is unclear if his estimates included transmission. The current capital cost numbers used in Morlock's anlaysis are unclear.

With respect to fuel price forecasts, we believe that the Applicants' initial or "base case" estimates for coal and natural gas prices are reasonable given current market conditions and projections by other sources. However, we believe that the Applicants differed from a "best practice" analysis by not testing their results against a wide range of prices for natural gas. Based on historical volatility in natural gas futures, we would recommend that a range of natural gas prices be tested equal to plus and minus 25% around the base 2012 price of $8 per MMBtu.

II. ADDRESSING THE COMMISSION'S THREE QUESTIONS

A. Greenhouse Gas Regulation

The first question we were asked to address is how the passage of greenhouse gas regulation bills introduced in Congress would affect the cost of power generated at a coal-fired energy facility like Big Stone II. It is generally agreed that there will be some form of regulation of greenhouse gas emissions in the future, and that regulation will increase the cost of emitting CO_2. This is especially important to the resource choice here because a coal-fired power plant such as Big Stone II will emit about twice the amount of CO_2 of a new gas-fired combined-cycle facility. Moreover, renewable resources such as wind emit no CO_2. Therefore, any resource choice must take this potential cost into account.

The Applicants did attempt to examine the effect of future CO_2 costs in two ways. First in their capacity expansion modeling Applicants looked at resource selection using a range of costs from zero to \$9 per ton of CO_2.[8] Notably, this \$9 per ton cost was not escalated, meaning that it decreased in real (inflation-adjusted) terms over time.[9] Applicants' witness Greig also presented a "busbar" analysis comparing Big Stone II's likely annual cost (i.e. fuel costs, fixed and variable operating and maintenance charges, capital charges and emissions costs) versus that of a new gas-fired combined cycle and wind market purchases with a combined-cycle backup.[10] He reports that he examined CO_2 cost levels ranging from \$4 to \$30 per ton; again, we understand these were not escalated over time.[11]

While most agree that there will be some form of greenhouse gas regulation, they also agree it is quite difficult to predict an exact cost for CO_2 emissions in the future. To judge whether the Applicants assessed a reasonable range of costs, Boston Pacific reviewed three categories of information:

1. Market Prices for CO_2

[8] Heidell at p 11, lines 5-7, Morlock at p 16, lines 1-17, Schumacher at p 23, lines 4-18, Davis at p 14, line 5 – p 15, line 5.
[9] Ibid.
[10] Supplemental Prefiled Testimony of Jeffrey J. Greig in MPUC Dkt No. CN-05-619 (November 13, 2007) (hereinafter as "Greig November 13, 2007") at p 2, lines 1 - 11.
[11] Greig January 16, 2008 at p 5 line 17 – p 6 line 1.

The first category of information is current CO_2 allowance prices as traded in the open market. The purpose of examining this data is to see what parties are actually paying for allowances. CO_2 allowances were first issued and traded on a large scale in Europe. On October 17, 2008, the price for allowances for a December 2008 settlement date was priced at 21.68 Euros or about US $29 per ton on the European Climate Exchange.[12] The Exchange offers contracts through December 2014. Currently, prices for settlement increase as the years progress. On October 17th, contract prices for a December 2014 settlement date were 27.27 Euros or about US $37 per ton.[13]

In addition, a group of ten U.S. states, under the banner of the Regional Greenhouse Gas Initiative (RGGI) held the first U.S.-based auction for CO_2 allowances on September 25, 2008.[14] The market clearing price for that auction, in which six of the ten states participated, was $3.07 per ton.[15] This value is somewhat in line with futures prices on the Chicago Climate Exchange, where carbon emission allowances traded at about $2 per ton during the week of the RGGI Auction.[16]

The large discrepancy between European and American numbers is thought to be chiefly due to the basic forces of supply and demand; specifically, as the number of allowances offered for sale falls relative to the demand, prices will be higher. This

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[12] European Climate Exchange: (http://www.europeanclimateexchange.com/default_flash.asp). Translated to USD using market EUR/USD exchange rate as listed on October 17, 2008 by x-rates.com. http://www.x-rates.com/cgi-bin/hlookup.cgi.
[13] Ibid.
[14] Regional Greenhouse Gas Initiative "RGGI": (http://rggi.org/co2-auctions/results).
[15] Ibid.
[16] Chicago Climate Exchange: (http://www.chicagoclimatex.com/market/data/daily.jsf). Data retrieved for September 24, 2008.

dynamic was present in the early years of European climate markets, where too many allowances were issued, relative to the need, and the price of allowances collapsed.[17]

2. Cost Estimates for Proposed Legislation

A second category of information which we can examine is studies which attempt to estimate the cost impact of various pieces of proposed U.S. climate change legislation. Several key studies attempt to predict the effects of the Lieberman-Warner Climate Security Act of 2007 (S. 2191). Lieberman-Warner would establish a "cap and trade" system for emissions allowances.[18] Some allowances would be distributed and others auctioned off. The bill, with an amendment by Senator Boxer, was last considered by the Senate in June, and is still worth examining because (a) it is the only climate change bill to be reported out of committee, (b) it may return in some form at a later date, and (c) the "cap and trade" system with offset provisions and gradually declining annual emissions targets that it establishes is present in almost every other proposed climate change bill. For instance, the recent draft of the Dingell-Boucher bill also features a "cap and trade" system with a goal of reducing CO_2 emissions to 80% below 2005 levels by 2050.[19]

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[17] International Financial Services London (IFSL), *Carbon Markets & Emissions Trading* (June 2007) at p 3.
[18] Lieberman-Warner Climate Security Act of 2007 as introduced in the Senate on October 18, 2007 at Sec. 3 at p 8.
[19] VanNess Feldman Attorneys at Law, *Issue Alert: Representatives Dingell and Boucher Release Discussion Draft of Climate Change Legislation* (October 9, 2008) at p 1.

Studies of the impact of Lieberman-Warner show a broad range of possible cost impacts. Table One (attached for pullout) shows the predicted allowance price for the “base case” analyses of several important studies of the Lieberman-Warner bill.

As is evident from Table One, estimates of the cost of emissions allowances under this legislation vary greatly, ranging from (a) $21 to $48 a ton in 2015 and (b) from $46 to $86 a ton by 2030. This divergence in results is driven by differences in models and the assumptions used within each study. With this divergence there is certainly no one “right” allowance price estimate. However, an examination of these studies reveals to us what some of the key drivers of emission prices may be in the future.

First, differences in overall economic growth projections make a big difference. Lieberman-Warner, as other bills do, has certain emission targets for each year. If economic growth slows, there will be less pressure on generators to buy (or use) allowances since there will be less pressure to run power plants as demand growth slows. Because of this, studies which use more recent growth outlooks, which are less optimistic, generally show lower allowance prices. For example, the EPA’s study was based on an economic outlook from the EIA in 2006. Altering the inputs to roughly match 2008 EIA “baseline” emissions projections results in allowance prices of about $22-$35 per ton in 2015, about $5 to $7 lower than the two EPA estimates in Table One which reflect the 2006 economic growth projections.[20]

[20] Environmental Protection Agency (EPA), *EPA Analysis of the Lieberman-Warner Climate Securities Act of 2008* (March 14, 2008) (hereinafter as “EPA March 14, 2008”) at p 17 and 27.

Second, projections about the growth of nuclear power and renewables make a large difference. The more that utilities can depend on new nuclear and renewable technologies to fill their generation needs the less they will need allowances to support coal-, oil- and gas-fired generation. In the EIA Core analysis, 268 GW of new nuclear and 112 GW of new renewables construction is assumed.[21] If that construction pace is not achieved, and there is slower deployment of carbon capture and sequestration (CCS), the price of an allowance in 2020 moves from $30 to $44 per ton according to EIA.[22]

Third, the cost of and ability to use offsets instead of buying allowances is a major factor. Lieberman-Warner would have allowed up to 30% of emissions to be offset through a combination of domestic and foreign offsets. Restrictions on offset use will increase prices. For example, EPA's analysis found that removing offsets increased the price of an allowance from $51 in 2020 to $98.[23] When EIA removed just international offsets, the 2020 price of an allowance rose by $12 (from $30 to $42).[24]

While we focus here on Lieberman-Warner, since it progressed farther than other legislation and had more high-profile studies conducted on it, it is also worth mentioning that analysis of other climate change bills has shown a different range of results. The EPA's analysis of S. 280 (Lieberman-McCain) and S. 1766 (Bingaman-Specter) showed allowance prices around $12-$15 in 2015, rising to $25-$32 in 2030.[25] The generally

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[21] Energy Information Administration, *EIA Energy Market and Economic Impacts of S.2191, the Lieberman-Warner Climate Security Act of 2007* (April 2008) (hereinafter as "EIA April 2008") at p 24.
[22] Ibid. at Table ES2.
[23] EPA March 14, 2008 at p 27.
[24] EIA April 2008 at Table 3.
[25] Environmental Protection Agency (EPA), *EPA Analysis of The Climate Stewardship and Innovation Act of 2007* (July 16, 2007) (hereinafter as "EPA July 16, 2007") at p 24. Environmental Protection Agency

lower prices in these bills were due, in part, to the higher emissions caps in those bills combined with safety-valve prices for allowances.

Other studies have attempted to predict allowance prices by changing the question. Instead of asking "what will this legislation do to allowance prices" they ask "what would the price of allowances have to be in order to reduce emissions?" A 2006 report on the economics of climate change by the head of the British Government Economic Service (the "Stern Report") stated that reducing emissions to an acceptable level would result in a marginal cost of abatement of around \$25 to \$30 per ton of CO_2 emitted.[26] A recent report by McKinsey suggested a number of ways in which important reductions in emissions could be made, using an upper-end cost of \$50 as a target price.[27]

3. Estimates in Integrated Resource Plans

Clearly, the estimates discussed above show that there is no one "right" number when it comes to greenhouse gas emissions costs. How, then, are utilities supposed to make decisions about resource acquisition? In our opinion, the best practice is to analyze resource choices over a variety of emissions costs, with the goal of selecting resources that deliver low-cost supply under a range of emissions regulations. The low end of the range can be set around \$8, beginning in 2012, reflecting a relatively low-cost regime. The high end can be set at \$60 a ton, reflecting a bill with tighter emissions caps along

(EPA), *EPA Analysis of the Low Carbon Economy Act of 2007* (January 15, 2008) (hereinafter as "EPA January 15, 2008") at p 33.

[26] Sir Nicholas Stern, *The Economics of Climate Change: The Stern Review* (October 30, 2006) at p 304.

[27] McKinsey and Company, *Reducing U. S. Greenhouse Gas Emissions: How Much at What Cost?* (December 2007) at p xii.

with adverse outcomes such as limited development of new nuclear and renewable generation and limited ability to use offsets. Mid-range cases of $20 and $40 per ton should be examined as well. All costs should be escalated with inflation each year after 2012 and should be modeled as a tax. Emissions costs are typically modeled as a tax to all generation, because each bill has differences in allowance distribution among resources and among free allowances and auctions. Moreover, “free” allowances have an opportunity cost equal to the market price.

Boston Pacific’s recommended approach also is supported by a review of a sample of the latest Integrated Resource Plans (IRPs) from utilities around the country. In each of these plans the utility is trying to address the same key questions as in this proceeding: that is, what resources should we pursue given this uncertainty about greenhouse gas regulations? Note that IRPs are not just theoretical exercises. Ideally, for the sake of transparency, a utility will use the exact same analysis in a subsequent competitive procurement when evaluating actual offers, whether the bids were vetted through independent negotiations or competitive procurement.

Table Two (attached as pull out) shows the levels of emissions costs used in a sample of publicly available IRPs and presentations. It is not meant to be an exhaustive list, but is simply presented to show the general range of costs up for consideration. Looking at Table Two we can see that there is, again, a wide range of costs estimated, with the low end of the range set around zero to $10 per ton beginning in 2010-2012 timeframe. The higher end is at $55 per ton. There also are several in-between cases using from $20 to $40 per ton. Note that almost all of the costs escalate at some rate, typically roughly that of inflation or a bit more, year to year.

4. Conclusion

By only using estimates of up to $9 a ton (or even $30), unescalated, the Applicants have not performed what we would consider an appropriate ("best practices") analysis of emissions cost risk. Furthermore, the "busbar" analysis does not adequately serve the purpose of examining potential resource choices against changes in emissions costs. This risk should be measured within the context of a capacity expansion model, which will look at the effect of emissions costs on the utilities' entire fleet over a long-term horizon and select the best options for filling the utilities' need; the busbar analysis is a stand-alone analysis which does not consider how the facility in question would operate within the utility's system.

Resource choice must be assessed over a range of CO_2 taxes because future emissions costs will depend on a variety of factors from (a) the emissions targets in Federal Legislation to (b) the costs and availability of offsets to (c) the growth of nuclear and renewable sources of generation. We believe the best practice would be to test resource selection at $8, $20, $40 and $60 per ton of CO_2, starting in 2012 and escalating at inflation thereafter. The goal of these analyses will be to identify, if possible, a portfolio of resources that deliver low cost supply to ratepayers under a variety of greenhouse gas regimes. At a minimum, such an analysis will reveal the breakpoints; that is, what level of CO_2 tax switch the choice from one resource to another.

B. Construction Costs

The second question we have been asked to address deals with the construction costs for new supercritical coal-fired plants like Big Stone II. We also were asked to provide input regarding construction costs for new gas-fired combined cycle and combustion turbine facilities as well as new wind generation. This input is important because the construction cost of various technologies is a major driver in choosing which resource to pursue.

1. Our Judgment on Construction Costs

It is true, as has been mentioned often in this proceeding, that construction costs for new generation are rapidly escalating due to run ups in commodity prices (e.g. steel) and increased demand for specialized labor and equipment. According to the IHS CERA Power Capital Costs Index (PCCI), which measures the construction costs of new facilities, costs for building new power plants have more than doubled since 2000 and have risen 69 percent since 2005 alone.[28] We have seen this effect in our own work as monitors for unit-contingent baseload RFPs. Bidders have had great difficulty obtaining fixed-price commitments from engineering, procurement, and construction (EPC)

[28] IHS, *Construction Costs for New Power Plants Continue to Escalate: IHS CERA Power Capital Costs Index* (May 27, 2008) at http://energy.ihs.com/News/Press-Releases/2008/IHS-CERA-Power-Capital-Costs-Index.htm.

contractors. Because of ever-escalating construction costs, some RFPs now allow bidders utilizing new generation to tie their capacity prices to changes in broad market indices such as the Consumer Price Index (CPI) or the Producer Price Index (PPI) for metals during the financing or construction phases of project development.

The capital cost for Big Stone II, according to Applicants' witness Rolfes, is $2,545 per kW for the smallest possible potential size (500 MW).[29] This number is in nominal dollars and does not include transmission and interest during construction. This number is based on a 2006 Black and Veatch estimate, escalated by 6% per year to account for delays in construction and scaled to reflect the smaller plant design.[30]

Estimates of capital costs for other resources vary among the four Applicants' planners who utilized capacity expansion modeling.[31] Capital cost estimates for new natural-gas fired combined cycle units range from $1,200 to $1,795 per kW.[32] Those for new natural-gas fired combustion turbine units range from $870 to $1,098 per kW.[33] And capital costs estimates for new wind turbine construction range from $1,810 to $2,270 per kW.[34]

[29] Rolfes at p 4.
[30] Ibid. at p 4-5.
[31] Heartland did not use capacity expansion modeling, see, Supplemental Prefiled Testimony of John Knofczynski in MPUC Dkt No. CN-05-619 (November 13, 2007) (hereinafter as "Knofczynski") at p 6.
[32] Heidell at p 17, Davis at Ex – 117 A, Schumacher at p 4. Note that Heidell and Schumacher appear to have included IDC and transmission integration costs. Davis did not include IDC and it is unclear if his estimates included transmission. The current capital cost numbers used in Morlock's anlaysis are unclear.
[33] Ibid.
[34] Ibid.

With respect to the Applicants' installed cost estimate of $2,545 per kW, based on our experience, we would conclude that it is below the low end of the spectrum for a plant like Big Stone II. We would expect the facility to have installed cost somewhere in the $2,600 to $3,000 per kW range (in nominal dollars, excluding interest during construction and transmission upgrades). In contrast, the Applicants' ranges of estimates for gas-fired combined cycle generation costs ($1,200 to $1,795 per kW) appears to be above the likely range, even adjusting for the fact that some Applicants included transmission upgrades and interest during construction costs in their numbers. We would place the construction costs of a new combined cycle unit (again, in nominal dollars with no interest during construction and no transmission upgrades) at $1,000 to $1,200 per kW. For a combustion turbine, the Applicants' estimates of $870 to $1,098 per kW are more in line with our estimate of $800 to $1,100 per kW. Similarly, the Applicants' cost estimates for wind turbines ($1,810 to $2,270 per kW) are generally in the right region, we would place the range at about $2,000 to $2,200 per kW. Again, our CT and wind estimates are in nominal dollars and do not include IDC or transmission upgrades.

2. Estimates From a Sample of IRPs

Our judgments on the right range of installed cost to use are generally supported by a review of current, publicly available utility IRPs. Again, these IRPs are useful because utilities are attempting to address the same decision on resource choice that we are faced with today. Most IRPs show what the utility believes to be the installed capital costs plus the operating cost of different types of new generation. Table Three (attached as pullout) presents, for a select group of recent IRPs and IRP update presentations, the estimated installed cost for each technology as well as the year's dollar for the estimate.

From Table Three we can see the simple average estimate of installed cost (a) for a combined cycle plant is $1,008/kW, (b) for a combustion turbine it is $971 per kW, (c) for a coal plant it is $2,743 per kW and (d) for wind it is $2,134 per kW. To the best of our knowledge, these costs do not include interest during construction or transmission integration costs, although we cannot be completely certain as documentation for these numbers is sometimes incomplete. Further, these estimates are in real terms rather than nominal terms so we would expect them to be lower than our recommended ranges which are in nominal terms.

Note also the wide range of the estimates across technologies. Public Service Company of New Mexico, for example, provided an estimate for combined cycle which is very close to the average, but it has relatively low coal costs. While we cannot say for sure why this is, in our experience, in a rising cost market such as this, a utility's IRP estimates can sometimes become "stale" if they do not have up-to-the-minute cost numbers. This can lead to large jumps in estimates from one year to the next as updated costs estimate are updated. For example Portland General Electric, in its 2007 IRP priced a new coal plant at $1,785 per kW and a new gas combined cycle plant at $758 per kW.[35] As can be seen in the attached chart, they have revised those estimates one year later

[35] Portland General Electric, *Integrated Resource Plan 2009: Second Stakeholder Presentation & Discussion* (August 21, 2008) at slide 5.

numbers to $2,900 per kW and $1,300 per kW, respectively, for the coal- and the natural gas-fired plants.

We should note, too, that the Minnesota Commission's decision is made more difficult here because the Applicants are asking for approval of a project based upon cost estimates rather than a price offer vetted through competitive solicitation or even a detailed current price offer from an EPC contractor. In an IRP process which leads to a competitive procurement, there is less risk to ratepayers if a resource planner underestimates actual costs because the pass through of cost overruns is limited by a fixed or fixed-formula price offer. Here, however, there is substantial risk to ratepayers because Applicants are not promising to limit their cost recovery to their cost estimates.

3. Conclusion

Given this, we believe that the best practice for any analysis of resource choice would be to account for this significant risk. The Applicants did not. The decision-making process should, at a minimum, examine resource options with construction costs at the "low" and "high" points of the ranges of costs per kW which we listed above: (a) $2,600 to $3,000 per kW for coal; (b) $1,000 to $1,200 per kW for gas-fired combined cycle, (c) $800 to $1,100 per kW for gas-fired combustion turbines; and (d) $2,000 to $2,200 per kW for wind generation.

C. Fuel Prices

The third question we have been asked to address concerns the likely delivered price of natural gas and coal for power plants in the region over the first fifteen years of life for the power plants being evaluated. In this context, we were also asked to offer an opinion on the potential impacts of proposed climate change legislation on fuel prices. This is an important question because fuel costs are such a large portion of total plant costs, particularly for natural gas-fired facilities.

Each Applicant has its own estimate of natural gas prices that are used for the capacity expansion modeling, however, three of the five Applicants use prices that start in the $8 per MMBtu range around 2012 and escalate to the $12/MMBtu range around 2026.[36] This is about a 3% increase per year. The one exception is MDU, which has prices that start in the $11/MMBtu range in 2012.[37] For coal, most Applicants use a coal price of about $1.80/MMBtu around 2012 escalating to around $2.80/MMBtu in 2026.[38] The initial price translates into a delivered price for coal of about $32 per ton in 2012.[39]

In our opinion, the base fuel prices used by the Applicants are within a reasonable range. However, the Applicants failed to analyze the resource choice at a wide range of price projections for fuel prices. Because of the significant uncertainty surrounding gas

[36] Schumacher at p 6, Davis at Exhibit 117-F, Morlock at p 10-11. Heartland did not use capacity expansion modeling; instead, they compared Big Stone II against market purchases. See, Knofczynski at p 7 and 11.
[37] Heidell at p 16.
[38] Heidell at p 16, Schumacher at p 4, Davis at Exhibit 117-F.
[39] Assumes 8,800 btu/lb heat content.

prices it is necessary, in our opinion, to acknowledge the risk by analyzing the choice of resources at a range of different price levels. Applicants' failure to adequately analyze this risk means their analysis falls short of a best practice solution and could potentially lead to the selection of a less robust resource.

1. Futures Prices for Natural Gas

Support for our conclusions that the base prices are reasonable, and also that risk assessment is needed, comes from three sources. First, there are futures prices for natural gas. One well-respected source of future prices is the New York Mercantile Exchange (NYMEX). NYMEX is an important source of data because it includes futures contracts for coal, oil, and natural gas. Looking at the prices for these contracts can give us some idea of what the market expects prices to be in the near future. Indeed, by executing NYMEX futures contracts today, a power plant owner can lock in the price she or he will pay for natural gas in each month of each year for the next several years; a NYMEX contract is a guarantee of that price.

NYMEX prices for natural gas futures have been declining since spiking over this past summer. The average price for a year of natural gas futures spiked to roughly $12 per MMBtu on fears of supply shortages. Average prices for one year of gas are now around $8 per MMBtu for the time period of June 2009 through May 2012. Figure One (attached for pullout) shows this general trend by mapping average annual Henry Hub futures prices for the NYMEX exchange on each trade date from January 2007 to the present. That is, each line shows us, for a given trade date, the average price for one year of futures contracts, from June to May.

As can be seen, the annual futures prices clustered around the $8 per MMBtu line on trade dates from January 2007 to January 2008. Then futures prices began to rise reaching the $12 per MMBtu mark in summer 2008. The futures prices then fall back to about $8 per MMBtu. We believe that some of this price drop is attributable to expanded production from non-traditional gas supply sources. In particular, shale gas supply has rapidly grown over the past few years and some predict that shale gas could eventually supply almost half of the daily production in the U.S.[40] Those estimates are tempered by the fact that there are questions concerning the cost of extracting shale gas given recent downward price movements. Additionally, while LNG costs can be high because the U.S. competes with other countries, the fact that the U.S. has sizable storage capacity can also help to ease the price outlook; storage allows the U.S. to buy LNG when supply is plentiful and prices are low.[41]

The point here is that the view of market participants, as reflected in prices for NYMEX futures, supports the Applicants' use of a natural gas price in 2012 of $8 per MMBtu. However, the 2008 price spike shows there is volatility so a resource choice must be assessed over a range of natural gas prices.

[40] Navigant Consulting, *North American Natural Gas Supply Assessment* (July 4, 2008) prepared for the American Clean Skies Foundation at p 11.

[41] Federal Energy Regulatory Commission (FERC), *Staff Report: Gulf Coast Storms Exacerbate Tight Natural Gas Supplies; Already High Prices Driven Higher* (October 12, 2005) at p 3. FERC, *Winter 2005-2006 Energy Market Update Item No.: A-3* (March 16, 2006) at p 5 and 10.

2. Studies of Green House Gas Regulations

A second source of data that leads us to recommend the use of a range of fuel prices is the climate change studies referred to earlier in this report. While not all studies did so, several attempted to predict the effects of climate change legislation on fuel costs. Just as with CO_2 costs, the reports differ greatly on where gas prices would go in the future.

Driving the difference in numbers were many of the same forces which worked to create differing estimates of CO_2 allowance costs. For example, the more that renewable and nuclear technologies are used to generate electricity, in lieu of natural gas and coal technologies, the less price pressure will be on natural gas because there will be fewer electric generators buying natural gas to reduce CO_2 emissions. For example, in the EIA's Core scenario mentioned earlier, the natural gas price for utilities in 2020 was $7.52 per MMBtu. In another case in which the development of nuclear power plants, carbon capture and sequestration (CCS) for coal plants, and renewable generation were restricted, the price moved to $9.04/MMBtu, or about 20% higher than the core scenario.[42] Liberal offset and banking provisions, which will help reduce allowance costs and keep coal use economical, will also serve to reduce future gas prices. The EIA analysis showed that when international offsets were <u>not</u> <u>allowed</u>, the gas price in the case with restricted nuclear, renewables and CCS growth moves up even more to $11.68/MMBtu in 2020, or 55% above the core scenario.[43]

[42] EIA April 2008 at Table ES2.
[43] Ibid.

3. IRP Fuel Price Forecasts

The final source of data that supports both the $8 per MMBtu forecast, as well as the need to use a range of forecasts, is utility price predictions. Again, IRPs reveal how different utilities go about planning in the face of significant uncertainty. And, again, the general practice is to examine the resource choice at multiple fuel price levels. Table Four (attached for pullout) shows gas prices and price scenarios used in a selected group of IRPs. Table Four shows how utilities often test at least a “low” and a “high” case to assess resource choices in the face of gas price uncertainty. It must be noted that gas prices will vary by region for each utility. For example, utilities with access to relatively cheaper Rocky Mountain Basin gas will have a lower fuel cost than those with gas from, for example, the Sumas hub near Canada.

What is of interest to us is the range around that base forecast which is used for low and high natural gas price scenarios. The range in the five IRP forecasts shown, stated in percent above and below the base, are (a) plus 20% to minus 20%; (b) plus 43% to minus 29%, (c) plus 182% to minus 44%, (d) plus 32% to minus 27%, and (e) plus 45% to minus 12%. This variety gives us no clear guidance.

4. Coal Prices

While we focus on natural gas prices above, we should not ignore coal prices. While Powder River Basin (PRB) coal has a reasonably steady price historically, there could be price spikes and the cost of transportation could potentially increase. With respect to commodity prices, NYMEX offers a "swap" contract that is based off of the price of Powder River Basin coal at a certain date in the future. As of October 14th that price was $9.52 per ton for a November 2008 contract.[44] However, it is noteworthy that future months are significantly higher. The price in 2011 was $17.32 a ton.[45] With respect to transport, according to a statement made earlier this year, Ameren's transport rates, which had been about $8 per ton, to take coal about 1,000 miles, went up to $15 a ton in 2006.[46]

Significant here is that there is no futures market for transportation costs, which, as noted, make up a significant portion of delivered coal costs. According to the EIA, the transportation rate in 2001 for shipments to utilities in the West North Central Region was $8.24 a ton in 1996 dollars.[47] If we escalate that at 3% inflation to 2012 dollars, we get a transportation rate of $13.22/ton. Combining this with the current NYMEX swap price of $17.84 per ton (the current 2011 NYMEX price, plus one year of inflation at 3%) we get a total delivered price in 2012 of $31.06/ton, which translates to an energy price of about $1.76/MMBtu, about what the Applicants are using.[48]

[44] Nymex.com at http://www.nymex.com/QP_spec.aspx.
[45] Ibid.
[46] St. Louis Business Journal, *Ameren eyes Illinois coal to combat transport costs* (March 28, 2008) at http://stlouis.bizjournals.com/stlouis/stories/2008/03/31/story14.html.
[47] Energy Information Administration, *Coal Transportation: Rates and Trends* (September 17, 2004) at Table 3.04.
[48] Heidell at p 16, Schumacher at p 4, Davis at Exhibit 117-F. Assumes 8,800 btu/lb heat content.

5. Conclusion

In conclusion, the Applicants' fuel prices appear to be acceptable for a "base case" analysis. However, the fact that there was no assessment of the resource choice at a wide range of fuel price levels means that the analysis did not adequately assess the risk of fuel price changes. We would suggest that the Applicants should have, at a minimum, analyzed a "low" and "high" natural gas price.

We are open on the method used to establish the range. One approach would be to allow historical price volatility to dictate the range. Table Five (attached for pullout) displays average monthly futures prices for four fiscal years: (a) June 2008 to May 2009; (b) June 2009 to May 2010; (c) June 2010 to May 2011; and (d) June 2011 to May 2012. We will note that for all these four years, the expectation is that the average price will be about $8 per MMBtu which, again, matches the Applicants' base price forecast.

Table Five shows one measure of how futures prices varied around that annual average. The measure of variation is to state the futures price at the 95th and 5th percentile. These two fuel prices give us a high and low set of average annual futures prices actually seen in the futures market. So Table Five shows that these historical price data (a) reveal an average annual futures price of $7.97 per MMBtu, (b) an average high price of $10.06 per MMBtu or 26% higher than the average; and (c) an average low price of $5.95 per MMBtu or 25% below the average. Based on these historical data, we suggest that a range of plus and minus 25% be used around the $8 per MMBtu natural gas price forecast.

This concludes our report.

TABLES

TABLE ONE

COST OF A CO_2 ALLOWANCE UNDER LIEBERMAN-WARNER BILL (S. 2191)

Study	Year's Dollar	Dollars Per ton of CO2			
		2015	2020	2025	2030
EPA - Base Case S 2191-ADAGE Model [1]	2005	$29	$37	$48	$61
EPA - Base Case S 2191-IGEM Model [2]	2005	$40	$51	$65	$83
MIT - 15% Offsets and CCS Subsidy [3]	2005	$48	$58	$71	$86
EIA Core Case [4]	2006	$21	$30	$43	$61
CBO [5]	Nominal	$35	N/A	N/A	N/A
CRA International - With Banking Case [6]	2005	$48	$58	N/A	$84
Clean Air Task Force [7]	2005	N/A	$21	$31	$46

1. Environmental Protection Agency, *EPA Analysis of the Lieberman-Warner Climate Securities Act of 2008* (March 14, 2008). Applied Dynamic Analysis of the Global Economy (ADAGE) Model. s2191 Scenario at p 27.
2. Environmental Protection Agency, *EPA Analysis of the Lieberman-Warner Climate Securities Act of 2008* (March 14, 2008). Intertemporal General Equilibrium Model (IGEM). S2191 Scenario at p 27.
3. Paltsev et al., *Assessment of U.S. Cap-and-Trade Proposals*, MIT Joint Program on the Science and Policy of Global Change (April 2007) at Appendix D, p 21.
4. Energy Information Administration (EIA), *Energy Market and Economic Impacts of S.2191, the Lieberman-Warner Climate Security Act of 2007* (April 2008), Core Case.
5. Congressional Budget Office (CBO), *S. 2191 America's Climate Security Act of 2007* (April 10, 2008) at p 8, Table 2.
6. Charles River Associates (CRA) International Modeling data on S.2191 reported in *Insights from Modeling Analyses of the Lieberman-Warner Climate Security Act* by Pew Center on Global Climate Change (May 2008) at p 14-15.
7. Clean Air Task Force, *America's Climate Security Act of 2007 - Modeling Results from the National Energy Modeling System* (February 2008) Raw Data Download: (http://www.catf.us/publications/presentations/CATF_S2191_with_CAFE.xls)

TABLE TWO
EMISSIONS COSTS USED IN RESOURCE PLANS

Company	Levels Used in Modeling ($/ton)	Start Year for costs
Avista[1]	$23.46	2012
Xcel Energy - Northern States Power Company[2]	$9, $20, $40	2010
Xcel Energy - Public Service Company of Colorado[3]	$10,$20, $40	2010
Public Service Commission of Wisconsin[4]	$0, $22.66 (2006$)	N/A
Puget Sound Energy[5]	$27, $37, $55[6]	2012
Public Service Company of New Mexico[7]	$8, $20, $40, $53	2010
Portland General Electric[8]	$0, $7.72 (2010$), $10 (1990$), $25 (1990$), $40 (1990$)	N/A
NorthWestern Energy[9]	$9.57, $9.65	2010

1 Avista, Presentation entitled *Stochastic Analysis & Resource Portfolio Selection Modeling* presented by James Gall at the 2009 Integrated Resource Plan Technical Advisory Committee Meeting No. 2 (August 27, 2008) at slide 6. Number is expected value of results from stochastic modeling that considers a range of costs from $8.70 to $80.80.

2 Northern States Power Company, *2007 Minnesota Resource Plan* (December 14, 2007) at Chapter 4, p 4-4.

3 Public Service Company of Colorado, *2007 Colorado Resource Plan* (November 15, 2007) at Volume 1 - Sections 1.6 through 1.12 at p 1-57 and 1-68.

4 Public Service Commission of Wisconsin, *Strategic Energy Assessment Draft Report: Energy 2014* (September 2008) at p 20.

5 Puget Sound Energy, Presentation entitled *Draft Aurora Price Forecasts* presented by Villamor Gamponia at the 2009 IRP Advisory Group Meeting (August 19, 2008) at slide 6.

6 Note an additional "Backslide" scenario not listed in the table above states, "250 MW or greater $1.60/ton for 20% of total CO2" (Draft Aurora Price Forecasts at slide 6.)

7 Public Service Company of New Mexico, *Electric Integrated Resource Plan for the Period 2008-2027* (September 16, 2008) at p 99.

8 Portland General Electric, *2007 Integrated Resource Plan* (June 29, 2007) at p 198-200.

9 NorthWestern Energy, *2007 Electric Default Supply Resource Procurement Plan* (December 17, 2007) at p 47-49. A third case was also modeled. In this case it started at $9.57 only in 2016.

TABLE THREE
CONSTRUCTION COST ESTIMATES FROM RECENT PLANNING PROCESSES

Company	Year's Dollar	Capital Costs ($/kW)			
		CCCT	SCCT[9]	Coal	Wind
Avista[1]	2009	$900	$900	$3,000	$2,400
Xcel Energy - Public Service Company of Colorado[2]	2007	$766	$1,085	N/A	$1,645
Public Service Commission of Wisconsin[3]	2006	$875	$695	$2,965	$2,070
Puget Sound Energy[4]	2008	$1,257	$1,199	$2,878	$2,433
Public Service Company of New Mexico[5]	Dec. 2007	$1,002	$963	$2,065	$1,933
Portland General Electric[6]	2008	$1,300	$1,200	$2,900	$2,500
NorthWestern Energy[7]	2007	$894	$756	$2,395	$1,960
Idaho Power Company[8]	2007	$1,071	N/A	$3,000	N/A
Simple Average		$1,008	$971	$2,743	$2,134

1 Avista, Presentation entitled *2009 IRP Resource Assumptions* presented by John Lyons at the 2009 Integrated Resource Plan Technical Advisory Committee Meeting No. 2 (August 27, 2008) at slide 9.

2 Public Service Company of Colorado, *2007 Colorado Resource Plan* (November 15, 2007) at Volume 1 Table 1.7-1 and Volume 2 Table 2.9-10.

3 Public Service Commission of Wisconsin, *Strategic Energy Assessment Draft Report: Energy 2014* (September 2008) at p 22, Table 6.

4 Puget Sound Energy, Presentation entitled *Draft Aurora Price Forecasts* presented by Villamor Gamponia at the 2009 IRP Advisory Group Meeting (August 19, 2008) at slide 18.

5 Public Service Company of New Mexico, *Electric Integrated Resource Plan for the Period 2008-2027* (September 16, 2008) at p 83-84, Figure 7-3.

6 Portland General Electric, *Integrated Resource Plan 2009: Second Stakeholder Presentation & Discussion* (August 21, 2008) at slide 5.

7 NorthWestern Energy, *2007 Electric Default Supply Resource Procurement Plan* (December 17, 2007) at p 85, Table 6-5.

8 Idaho Power Company, *2008 Integrated Resource Plan UPDATE* (June 2008) at p 24, Figure 6.

9 When the IRPs listed more than one option for SCCT we choose the more fuel efficient option.

TABLE FOUR
SAMPLE OF NATURAL GAS PRICE FORECASTS

Company	Base Case Gas Price (2012) per MMBtu	Other Gas Price (2012) Scenarios per MMBtu
Xcel Energy - Northern States Power Company[1]	$7.90	Base Case +20% and -20%
Xcel Energy - Public Service Company of Colorado[2]	$7.00	Low: $5, High: $10
Public Service Company of New Mexico[3]	$8.25	$4.65, $11.63, $12.62, $17.44, $23.25
NorthWestern Energy[4]	$7.71	Low: $5.62, High: $10.18
Idaho Power Company[5]	$6.33	$5.57, $6.04, $9.18

1 Northern States Power Company, *2007 Minnesota Resource Plan* (December 14, 2007) at Chapter 7, Table 7-1.
2 Public Service Company of Colorado, *2007 Colorado Resource Plan* (November 15, 2007). Note, values are approximations. They are based on (a) Volume 1, Figures 1.7-1 and 1.8-6 and (b) Volume 1, p 1-67.
3 Public Service Company of New Mexico, *Electric Integrated Resource Plan for the Period 2008-2027* (September 16, 2008) at p 93, Figure 7-7.
4 NorthWestern Energy, *2007 Electric Default Supply Resource Procurement Plan* (December 17, 2007) at p 79, Table 6-2.
5 Idaho Power Company, *2008 Integrated Resource Plan UPDATE* (June 2008) at p 16, Table 6.

TABLE FIVE

AVERAGE OF MONTHLY NYMEX HENRY HUB FUTURES[1]

Contract Year[2]	Average Price	Percentile	
		95th	5th
June 08 - May 09	$8.27	$10.07	$5.97
June 09 - May 10	$8.07	$10.46	$5.69
June 10 - May 11	$7.69	$9.83	$5.32
June 11 - May 12	$7.85	$9.90	$6.82
Simple Average:	$7.97	$10.06	$5.95

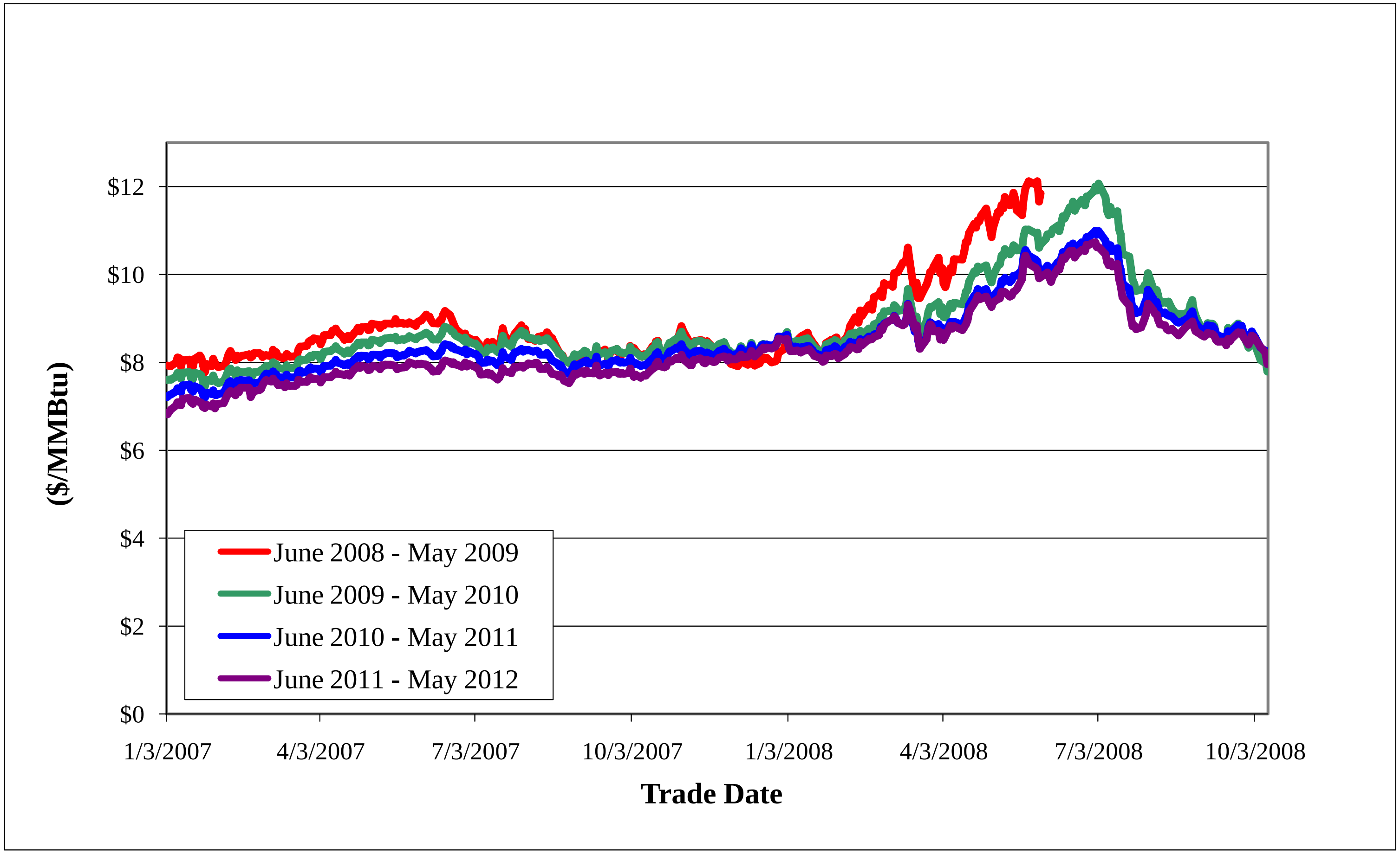
1 New York Mercantile Exchange "NYMEX" Data as of October 10, 2008 (http://www.nymex.com).

2 Trade dates from January 3, 2005 through October 10, 2008 were used in the Table above.

FIGURES

FIGURE ONE

NYMEX FUTURES PRICE FOR NATURAL GAS AT HENRY HUB [1]



1. New York Mercantile Exchange "NYMEX" Data as of October 10, 2008 (http://www.nymex.com)

RESUMES AND LISTS OF TESTIMONY AND PUBLICATIONS

CRAIG R. ROACH

Craig Roach has over thirty-two years of experience working on investments in, policies for, and litigation concerning the electricity, natural gas, and other energy businesses. Craig founded and incorporated Boston Pacific in Washington, DC in 1987.

Craig leads the Boston Pacific Team which has served since 2004 as the External Market Advisor (EMA) for the Southwest Power Pool Regional Transmission Organization (SPP RTO). As the EMA, the Boston Pacific Team is responsible for developing the Market Monitoring Plan and Market Power Mitigation Measures for the SPP RTO which have won Federal Energy Regulatory Commission (FERC) approval. The EMA also plays a significant role in market design for SPP's new real-time market which successfully started operations on February 1, 2007.

Craig also oversees the Boston Pacific Teams which manage and monitor major power auctions such as those in Illinois, New Jersey, Maryland, Delaware, and the District of Columbia. Boston Pacific also manages and monitors unit contingent solicitations such as those in Oregon, Oklahoma, and the U.S. Virgin Islands.

Craig has extensive experience as an expert witness on the electricity and natural gas businesses. He has provided testimony, affidavits or comments on thirty occasions before FERC, to twenty-two State Commissions (some on multiple occasions) plus two Canadian Provincial Boards, and a City Council. He also has served as an expert in arbitrations, in Federal Court, in State Court, and before a Congressional Subcommittee.

The great variety of topics in Craig's testimonies documents the breadth and depth of his experience in the electricity and natural gas businesses. He has served as an expert witness on issues such as market power (antitrust), electric industry restructuring, competitive bidding, transmission tariffs, ratemaking by both electric and gas utilities, finance for both competitive power suppliers and utilities, system reliability, prudence of power purchases, contract abrogation, mergers and acquisitions, and resource choice. His expertise also is reflected in the fact that he is a widely sought-after speaker.

In previous years, Boston Pacific also had extensive, hands-on experience supplementing the in-house asset transaction teams of our clients for power project development and acquisition. We have done so throughout the U.S. and in two dozen countries around the world.

Prior to founding Boston Pacific, Craig was a Project Manager with ICF Incorporated. While at ICF, Craig developed an engineering-economic model to forecast industrial fuel choice, assessed the impact of air pollution regulations on coal markets, and identified opportunities for coal exports to Asia and Europe.

From 1975 to 1979, Craig was a Principal Analyst for the U.S. Congressional Budget Office. He provided analyses on energy and environmental legislation through written reports and testimony to Congressional committees.

Craig holds a Ph.D. in Economics from the University of Wisconsin. His major field was Public Finance and his minor field was Energy Engineering. Craig earned his B.S. in Economics, *cum laude*, from John Carroll University. Craig currently serves on the Advisory Board to University of Wisconsin's Department of Economics.

LIST OF TESTIMONY AND OTHER PUBLICATIONS FOR CRAIG R. ROACH, Ph.D.

TESTIMONY

Testimony concerning the design of the 2008 RFP, Oklahoma Corporation Commission Cause No. PUD 200700418 [June 2008]. Filed as the Oklahoma Commission's Independent Evaluator.

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FRANK MOSSBURG

Frank has detailed experience in the design and monitoring of successful procurements of all types. He serves as the lead contact for several unit-contingent RFPs from PacifiCorp for the Oregon Commission, including the 2012 Baseload, 2008 All Source and 2008R-1 Renewables RFP. He also served as a lead writer for Boston Pacific's analysis of PacifiCorp's request for competitive bidding waiver to purchase the Chehalis plant. In these projects he has helped in all stages of the procurement, from analyzing and advising on the RFP design, to evaluating bids, to observing contract negotiations. He has appeared before the Commission on multiple occasions to provide recommendations regarding RFP design.

Frank is also the lead contact for the SOS procurements in the District of Columbia and Delaware, and the BGS Auction in New Jersey. For these engagements, he interacts with utilities, Commission Staff and bidders to design successful processes and assess the competitiveness of bids. He is also responsible for developing the technical analyses that we employ on these engagements, such as our benchmark models, and for leading analyses of utility-produced models and data. He has appeared formally and informally before Commissioners and Staff to explain how procurement results came to be.

In his initial tenure at Boston Pacific, prior to earning his MBA, Frank specialized in creating complicated valuation models from extremely large sets of data then summarizing his findings in clear and concise language. He worked with clients and law firms to develop and defend detailed analyses that could withstand the rigors of contentious litigation.

Frank has used massive databases to value assets on multiple occasions, creating new and unique models that account for each asset's special considerations. In one instance he worked with developers and experts to simulate alternate dispatch and contract scenarios to value the benefit of new power plant development. In another instance he collaborated with clients to value proposed "reverse tolling" agreements.

Frank's work also has extended to regulatory testing and studies. He designed the HHI analysis for Reliant Resources acquisition of Orion power. He has also conducted Hub-and-Spoke and Supply Margin Analysis tests which allowed major power producers the right to sell at market rates. He helped author Boston Pacific's report on market price volatility *Still Waters Run Deep.*

Frank has worked at IBM in their Business Consulting Services division. While there he helped manage the updating of a Navy cost database system while conducting process improvement actions to ensure a better and faster flow of information to military cost estimators. He also worked with personnel to answer questions and create custom data queries. Frank also had the opportunity to work at a boutique investment banking division which specialized in mergers and acquisitions in the electric and gas space.

Frank has also been a Director at Analysis Research Planning Corporation (ARPC). There he engaged in a variety of sophisticated analytical projects. In one instance he combined extensive historical data with a Monte Carlo simulation to forecast defense costs for a major pharmaceuticals manufacturer. He designed claims valuation models for Asbestos and Silica claimants using complicated regressions and coefficient balancing formulas to generate fair outcomes for thousands of claimants.

Frank graduated *cum laude* from the Wharton Undergraduate School of the University of Pennsylvania with a BS in Economics and a concentration in Finance. He received his MBA from the University of Virginia's Darden Graduate School of Business Administration.

BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

David C. Boyd	Chair
J. Dennis O'Brien	Commissioner
Thomas Pugh	Commissioner
Phyllis A. Reha	Commissioner
Betsy Wergin	Commissioner

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

ISSUE DATE: March 17, 2009

DOCKET NO. E-017, ET-6131, ET-6130, ET-6144, ET-6135, ET-10/CN-05-619

ORDER GRANTING CERTIFICATE OF NEED WITH CONDITIONS

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PROCEDURAL HISTORY

I. Phase 1: Initial Proceedings

On October 3, 2005, a consortium of seven Minnesota transmission owners – Central Minnesota Municipal Power Agency (CMMPA), Great River Energy (GRE), Heartland Consumers Power District (Heartland), Montana-Dakota Utilities Company (Montana-Dakota), Otter Tail Corporation d/b/a Otter Tail Power Company (Otter Tail), Southern Minnesota Municipal Power Agency (SMMPA), and Western Minnesota Municipal Power Agency (WMMPA) – filed an application for a certificate of need to build or upgrade existing transmission facilities in the southwestern part of the state, including the following:

- A line and associated facilities (the "Morris line") with the capacity to transmit 230 kilovolts (kV). This project would entail building a new line from Big Stone City, South Dakota, to Ortonville, Minnesota, and upgrading an existing line connecting Ortonville to Johnson Junction to Morris.

- An additional 345 kV transmission line and associated facilities (the "Granite Falls line"). This project would entail building a new line from Big Stone City to Canby, Minnesota, and upgrading an existing line from Canby to Granite Falls. The line would be operated at 230 kV until it was connected to a 345 kV line being built to transmit power generated from the strong winds along the Buffalo Ridge region of southwestern Minnesota and South Dakota.

While the applicants emphasize that the proposed lines would help strengthen the regional power grid in general, their primary rationale for the lines arises from the anticipated need to accommodate power from Big Stone Unit II, a coal-fueled power plant they plan to build adjoining the existing coal-fueled power plant in Big Stone, South Dakota (Big Stone Unit I). In addition, the applicants claim that their proposed lines would facilitate the transmission of electricity generated from wind turbines along the Buffalo Ridge.

On December 19, 2005, the Commission referred the application to the Office of Administrative Hearings for a contested case proceeding.[1] The Office of Administrative Hearings assigned Administrative Law Judges (ALJs) Steve M. Mihalchick and Barbara L. Neilson to preside over this matter. They conducted extensive public and evidentiary hearings with the participation of the following parties:

- The applicants;
- The Minnesota Department of Commerce (the Department);
- The Minnesota Center for Environmental Advocacy, the Union of Concerned Scientists, the Izaak Walton League – Midwest Office, Fresh Energy, and Wind on the Wires (collectively, the Joint Intervenors);
- Excelsior Energy Inc. (Excelsior);
- The Midwest Independent Transmission System Operator, Inc. (MISO);
- FPL Energy, Inc.;
- The Minnesota Municipal Utilities Association (MMUA); and
- The South Dakota Governor's Office of Economic Development (GOED).

The Administrative Law Judges also granted party status to other people for the limited purpose of addressing the Mesaba Project proposed by Excelsior.[2]

On December 1, 2006, the Department filed its Environmental Impact Statement (EIS).[3]

On August 16, 2007, the Administrative Law Judges filed their Findings of Fact, Conclusions of Law, and Recommendation (First ALJs' Report). They recommended that the Commission grant the requested certificate of need and consider imposing certain conditions recommended by the Department.

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[1] Notice and Order for Hearing (December 19, 2005), this docket.

[2] The Commission found that the proposed Mesaba Project – a generator using relatively new integrated gasification combined cycle technology – qualifies as an "innovative energy project" exempt from the certificate of need process pursuant to Minn. Stat. § 216B.1694. See *In the Matter of a Petition by Excelsior Energy Inc. For Approval of a Power Purchase Agreement Under Minn. Stat. § 216B.1694, Determination of Least Cost Technology, and Establishment of a Clean Energy Technology Minimum under Minn. Stat. § 216B.1693*, Docket No. E-6472/M-05-1993, Order Resolving Procedural Issues, Disapproving Power Purchase Agreement, Requiring Further Negations, and Resolving to Explore the Potential for a Statewide Market for Project Power Under Minn. Stat. § 216B.1694, subd. 5 (August 30, 2007).

[3] An Environmental Report (ER) is required for a certificate of need. Minn. Rules, parts. 7849.7010 - .7110. An Environmental Impact Statement (EIS) is required for the route permit. Minn. Rules, part 7849.5300. These documents may be combined. Minn. Rules, part 7849.7100. The Commission authorized this combination. See Order Agreeing to Combining the Environmental Report and the Environmental Impact Statement Documents (November 29, 2005), this docket.

By September 9, 2007, the applicants, Excelsior and the Joint Intervenors filed exceptions to the First ALJs' Report. By September 18 these parties had filed replies to exceptions.

On August 31, 2007, the applicants and the Department filed a "Settlement Agreement" proposing terms for resolving disputed issues among these parties.

II. Phase 2: Change in Applicants

On September 18, 2007 – before the Commission could act on the case – the applicants filed a letter stating that two of the original applicants, GRE and SMMPA, were withdrawing from the project.

On October 19, 2007, the Commission asked the Office of Administrative Hearings to conduct further evidentiary proceedings and offer further recommendations in light of these new facts and changed circumstances.[4]

On May 9, 2008, the Administrative Law Judges filed their Supplemental Findings of Fact, Conclusions of Law and Recommendation (Second ALJs' Report). This time they recommended denying the application, finding that the remaining applicants had failed to meet two statutory tests:

(1) They had not demonstrated, under Minn. Stat. § 216B.243, subd. 3, that their demand for electricity could not be met more cost-effectively through energy conservation and load management measures.[5]

(2) They had not demonstrated, under Minn. Stat. § 216B.243, subd. 3a, that they had explored obtaining power from renewable energy sources and found that power from the proposed Big Stone Unit II would be less expensive, including considerations of environmental costs.

The parties filed exceptions and replies to exceptions to the Administrative Law Judges' Report under the Commission's rules of practice and procedure, and presented oral argument.

III. Phase 3: Additional Evidentiary Proceedings

On August 7, 2008, the Commission again turned to the Office of Administrative Hearings to conduct expedited evidentiary proceedings to further develop the record regarding three issues in particular:

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[4] Order Recommencing Proceedings in the Office of Administrative Hearings (October 19, 2007), this docket.

[5] Conservation refers to practices that reduce the amount of energy consumed; a conservation program might, for example, encourage people to replace incandescent light bulbs with compact florescent bulbs or light-emitting diodes (LEDs). Load management refers to practices that alter when energy is consumed so as to reduce the cost of providing it. A load-management program might, for example, encourage people to run their appliances at night when the demand for energy is low, rather than during the day when demand is higher.

Carbon Regulation Costs - How would passage of the greenhouse-gas regulation bills introduced in Congress to date affect the cost of energy and power generated by a supercritical, pulverized-coal-fired plant such as Big Stone II? Bills introduced to date would include the 2003 McCain-Lieberman bill, the 2007 Bingaman-Specter bill, and the 2007 McCain-Lieberman bill.

Construction Costs - What are the likely construction costs for a supercritical, pulverized coal-fired plant such as Big Stone II, constructed on a brownfield site, with an in-service date around 2014-2015? What are the likely construction costs for an alternative wind generation system, with natural-gas-fired back-up, with a comparable capacity factor and in-service date? What are the likely construction costs for a natural-gas-fired plant with a comparable capacity factor and in-service date?

Natural Gas and Coal Costs - What are the likely delivered costs of natural gas and coal for power plants in the North Dakota/South Dakota/Minnesota area over the first fifteen years of the operation of any of the three generation systems described above, assuming the passage of climate-change regulation?[6]

To facilitate record development, the Commission retained the services of Boston Pacific Company, Inc. (Boston Pacific), a firm with experience evaluating and monitoring power procurement projects. Boston Pacific filed its report on the issues identified above on October 21, 2008.

The applicants, the Joint Intervenors and MISO filed rebuttal testimony on the report. On November 10, 2008, the Administrative Law Judges recommended striking testimony that exceeded the scope of that stage of the proceedings.[7]

On November 12-13, 2008, the Administrative Law Judges convened evidentiary hearings at which the Commissioners as well as the parties questioned the witnesses. Following evidentiary hearings, the Administrative Law Judges received briefs from the applicants, the Joint Intervenors and the Department's Office of Energy Security (OES or the Department).[8]

On December 23, 2008, the Administrative Law Judges filed their Summary of Testimony Received in Response to Report of Boston Pacific Company, Inc. (Third ALJs' Report).

The applicants, GOED, the Joint Intervenors, the North Dakota Industrial Commission and SummitWind, LLC filed comments.

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[6] Order Referring Case to Office of Administrative Hearings for Additional Evidentiary Proceedings (August 7, 2008), p. 3, this docket.

[7] Sixth Prehearing Order (November 10, 2008), this docket.

[8] On January 17, 2008, the Governor directed the Department of Commerce to organize an Office of Energy Security. 32 SR 1444-45 (January 28, 2008). Thereafter the OES participated in this matter on the Department's behalf.

On January 13, 2008, the Commission met to hear oral arguments from the parties.

This matter, in conjunction with the applicants' petition for a high voltage transmission line route permit,[9] came before the Commission on January 15, 2009. The Commission received final comments from a legislator and the parties. The record closed on this date.[10]

IV. The Parties and their Representatives

The applicants were represented by Todd J. Guerrero, Alan Mitchell and David L. Sasseville of Lindquist & Vennum PLLP, 80 South Eighth Street, Suite 4200 IDS Center, Minneapolis, Minnesota 55402; and by Peter S. Glaser of Troutman Sanders LLP, 401 Ninth Street, Suite 1000, Washington, DC.

The Department and its OES were represented by Julia E. Anderson, Assistant Attorney General, and Linda S. Jensen, Assistant Attorney General, of the Minnesota Office of the Attorney General, 1400 Bremer Tower, 445 Minnesota Street, St. Paul, Minnesota 55101.

The Joint Intervenors were represented by Elizabeth I. Goodpaster of the Minnesota Center for Environmental Advocacy, 26 East Exchange Street, Suite 206, St. Paul, Minnesota 55101.

MISO was represented by Christopher Sandberg of Lockridge, Grindal Nauen, P.L.L.P., 100 Washington Ave. S., Suite 2200, Minneapolis, Minnesota 55401.

Excelsior Energy Inc. was represented by Christopher Greenman, Assistant General Counsel, Excelsior Energy Inc., 11100 Wayzata Boulevard, Suite 305, Minnetonka, Minnesota 55305.

FINDINGS AND CONCLUSIONS

I. Procedural Matters

As noted above, the third phase of these proceedings began when the Commission asked the Office of Administrative Hearings to conduct expedited proceedings to further develop the record regarding carbon regulation costs, construction costs and fuel costs. The Commission's expert, Boston Pacific, filed testimony on these and related issues, and the parties responded to Boston Pacific's testimony.

The Joint Intervenors and OES object that the testimony filed by certain parties exceeds the scope of Boston Pacific's testimony. If this contested testimony were accepted the Joint Intervenors would want an opportunity to supplement the record on those issues. In their Sixth Prehearing Order (November 10, 2008) the Administrative Law Judges sustained these objections and recommended striking the following testimony:

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[9] *In the Matter of the Application of Otter Tail Power Company, and Others for a Route Permit for the Big Stone Transmission Project in Western Minnesota*, Docket No. E-017, ET-6131, ET-6130, ET-6144, ET-6135, ET-10/TR-05-1275.

[10] Minn. Stat. § 14.61, subd. 2.

- The November 6, 2008 prefiled testimony of MISO witness Eric Laverty, addressing how rejection of the applicants' proposed transmission line would affect MISO's planning, and affect parties seeking to interconnect with the transmission grid.

- The November 6, 2008 prefiled testimony of the applicants' witness Ward Uggerud – but only with respect to the testimony at page 12, line 20, through page 13, line 14, and Exhibits 141-A and 141-B – addressing the magnitude of alleged shortcomings in CMMPA's analysis of alternatives.

The Commission affirms the actions recommended by the Administrative Law Judges. The Commission asked the Administrative Law Judges to expedite developing the record on a few factual issues; the Commission did not intend for this phase to become an opportunity to re-litigate all the issues in the record to date. This contested evidence will be stricken.

II. The Big Stone II Proposal

A. The Applicants' Proposal

The applicants' proposal includes the following components:

1. A transmission line from the South Dakota border to Morris, Minnesota, traversing the counties of Big Stone and Stevens, and including the following:

    - A new 230 kV transmission line, continuing the new line from the Big Stone Plant in South Dakota, crossing the state line and extending approximately two miles to Ortonville, Minnesota.

    - Modifications to an existing 115 kV transmission line extending approximately 25 miles from Ortonville, Minnesota, to the switching station located in Johnson, Minnesota, then extending approximately 16 miles to the Morris substation near Morris, Minnesota, resulting in the entire line having a capacity of 230 kV.

    This project would also entail adding facilities to the Johnson Junction switching station and the Morris Substation, and removing approximately 1.2 miles of 115 kV transmission lines from the Ortonville substation.

2. A transmission line from the South Dakota border to Granite Falls, Minnesota, traversing Lac Qui Parle, Yellow Medicine and Chippewa counties, and including the following:

    - A new 345 kV transmission line, continuing the new line from the Big Stone Plant, South Dakota, crossing the state line and extending approximately 14 miles to Canby, Minnesota.

    - Modifications to an existing 115 kV transmission line extending approximately 39 miles from Canby, Minnesota, to the substation in Granite Falls, Minnesota, resulting in the entire line having a capacity of 345 kV.

> This project would also entail moving the Canby substation, and approximately one mile of 115 kV transmission line, a distance of one mile northeast from its current site.

Cost estimates for the transmission lines range from $110 million up to $267 million (in 2011 dollars).[11]

The applicants propose the new lines primarily for the purpose of transmitting power from the Big Stone Unit II generator to be built next to the current Big Stone Unit I generator in Grant County, South Dakota. As currently proposed, Unit II would generate between 500 and 580 MW using supercritical pulverized coal technology – operating at higher temperatures and pressures than conventional coal plants – thereby achieving higher efficiencies and lower carbon emissions than conventional coal plants. Unit II would be designed to serve as a base-load generator;[12] the applicants claim that Unit II would operate nearly 90% of the time, yet would permit operators to increase or decrease its output as system demand for electricity increases or decreases. The applicants estimate that building Unit II alone will cost between $1.3 billion and $1.4 billion.

The applicants are designing Unit II to facilitate modifying the plant in the future to capture and store some of the carbon that the plant would otherwise emit. According to the applicants, making Unit II "carbon capture retrofit ready" would not greatly increase the cost of the generator provided that they design this feature into the plant before construction begins.

B. The August 31, 2007 Settlement Agreement

As noted above, the applicants and the Department filed a settlement agreement setting forth terms under which these parties would recommend that the Commission grant the certificate of need. Changing circumstances prompted the Department to withdraw from the agreement. Nevertheless the applicants remain willing to abide by their obligations under the agreement.[13] Some of the Settlement Agreement's major provisions are summarized below, identified by section:

3.4 After Big Stone Unit II begins commercial operations, the Minnesota firms that have an equity stake in this project ("Minnesota Owners") will report 1) the actual capital costs of both the transmission lines and Big Stone Unit II, 2) the extent to which those costs differed from forecasts, and 3) the reasons for any difference.

3.5 The Minnesota Owners will report on the Big Stone II project's annual costs per megawatt-hour, including both the generator and transmission line costs.

3.6 When seeking cost recovery, the Minnesota Owners will set forth the costs of Big Stone Unit II and the transmission lines separately with supporting documents.

4 For the first four years of Big Stone Unit II's operations, the Minnesota Owners will cause the

[11] First ALJs' Report, Finding 44.

[12] A "base-load" generator is designed to operate almost continuously.

[13] See, for example, applicants' statement to Commission (January 15, 2009).

amount of carbon dioxide emitted elsewhere to be reduced by an amount equal to the amount of carbon dioxide emissions attributable to the generation of electricity at Big Stone Unit II for Minnesota customers, subject to conditions.

5 The Minnesota Owners will install mercury emissions control technology on both Big Stone Units I and II. They commit to installing certain specified technologies, as well as technologies "equivalent to what is required at large generating facilities in Minnesota" under the Mercury Emissions Reduction Act of 2006, Minn. Stat. §§ 216B.68 and 216B.688, as well as technologies "most likely to result in the removal of at least 90 percent of the mercury emitted from the units."

6 The Minnesota Owners agree to certain provisions designed to protect Big Stone Lake, the Minnesota River and the groundwater supply.

7 The Minnesota Owners acknowledge their duty to comply with Minn. Stat. § 216B.1691, the "Renewable Energy Standard," which provides for Minnesota utilities to acquire 25% of their retail customers' energy from renewable sources by 2025. The Minnesota Owners also agree to acquire roughly 3% of their retail customers' energy from "Community-Based Energy Developments" under Minn. Stat. § 216B.1612, subd. 5, which promotes small, community-based generators using renewable energy sources.

8 The Minnesota Owners acknowledge their duty to comply with Minn. Stat. §§ 216B.2401 and 216B.241, governing energy conservation, and to eliminate certain practices that arguably discourage efficient energy usage.

C. Additional terms

Beyond the terms of the Settlement Agreement, the applicants have agreed to abide by certain additional terms if the Commission grants the requested certificate of need – at least as long as the Big Stone II proposal continues to move forward. These conditions include the following:

1. The applicants will install equipment to reduce sulfur dioxide (SO_2) emissions from both Unit I and Unit II to one-seventh of the current level of SO_2 emissions from Unit I alone.

2. The applicants will explore the option of building Unit II using "ultra-supercritical" technology that would permit the plant to produce more energy per unit of carbon emitted. Preliminary studies indicate that this change would increase the plant's capital costs by $10 million, or roughly 1% of Big Stone Unit II's projected capital costs.

3. Otter Tail will provide updated capital cost estimates for the Big Stone II proposal prior to any Final Notice to Proceed and the final determination by owners to proceed with the project – at least with respect to the share of the plant intended for Otter Tail's Minnesota customers.

4. Otter Tail will make an informational filing in 2009 reviewing project contracting methodology so as to assure reasonable contracting methods.

5. Otter Tail will include certain information in its next resource plan filing.[14] Otter Tail agrees to submit information regarding two topics:

   a. Otter Tail's models offered in this docket. Specifically, Otter Tail agrees to provide detailed disclosure of the level(s) of carbon costs that Otter Tail assumed in its modeling.

   b. Its plans for the Hoot Lake Units 2 and 3. These are among Otter Tail's older and more polluting generators, dating from 1948 to 1964, and they are coming to the end of their scheduled service lives in 2017 or 2018. In its resource plan filing Otter Tail will discuss –

      - the generators' likely retirement dates,
      - the advantages and disadvantages of having generators at their location on the grid,
      - the potential for converting the generators to use natural gas or some other energy source that has fewer environmental consequences, and
      - options for renovation, pollution reduction, seasonal operation, and using the generators to "follow load" – that is, to respond to constant fluctuations in the supply and demand for electricity.

In addition, if the applicants elect not to build the Big Stone II project Otter Tail agrees to file as soon as practicable an alternative plan to acquire, in approximately the same time frame as the Big Stone II project, substitute base-load resources required for its Minnesota customers.

III. Legal Standard

Anyone seeking to build a transmission line that crosses into Minnesota with a capacity exceeding 100 kV,[15] or more than 1500 feet of transmission line within Minnesota with a capacity exceeding 200 kV,[16] must first obtain a "certificate of need" from this Commission.[17] Because the proposed 230 kV and 345 kV lines cross state lines and exceed these thresholds, the applicants must obtain a certificate of need before proceeding.

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[14] See Minn. Stat. § 216B.2422. In general, a resource plan filing contains a utility's analysis showing that its plans are likely to be the least-cost means, under a variety of circumstances, for reliably meeting the demand for electricity in its service area and achieving other objectives.

[15] Minn. Stat. § 216B.2421, subd. 2(3).

[16] Minn. Stat. § 216B.2421, subd. 2(2).

[17] Minn. Stat. § 216B.243.

While many statutes potentially bear on this matter,[18] Minn. Stat. § 216B.243 lists the principal factors the Commission must consider when determining whether a transmission line is needed. In particular, it bars the Commission from granting a certificate unless the applicants can demonstrate that the demand for electricity cannot be met more cost-effectively through conservation or load management, and is otherwise needed. Minn Stat. § 216B.243, subd. 3.

In addition, Minn. Stat. § 216B.243, subd. 3a, bars the Commission from granting a certificate of need for any 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.

(Emphasis added). As noted above, the applicants are seeking a certificate of need for transmission lines, and justify the need for the lines to a large extent on the need to manage the anticipated flow of electricity from the proposed Big Stone Unit II. This new generator will be powered by coal, a non-renewable fuel. Consequently § 216B.243, subd. 3a, applies to this case, and the Commission must consider, among other things, whether the applicants have shown to the Commission's satisfaction that Big Stone Unit II will provide power at lower cost, including environmental costs, than alternative sources of power derived from renewable sources of energy.[19]

Finally, Minnesota Rules Chapter 7849 requires the Commission to consider the following factors:

> 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
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> (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:

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[18] See, for example, Minn. Stat. §§ 216B.1612, subd. 5; 216B.1691; 216B.1694, subd. 2(a); 216B.2401; 216B.2422, subd. 4; 216B.2425; 216B.2426; and 216C.05 - .30.

[19] Second ALJs' Report, Findings 34 - 35.

(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 and local governments.

The parties have organized their discussion of these factors into three steps.[20]

- Demand: the extent to which the anticipated demand for electricity exceeds the applicants' anticipated capacity to serve it.[21]
- Conservation/load management: whether cost-effective load management and conservation measures will offset this excess demand.[22]

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[20] See, for example, Second ALJs' Report, Finding 22.

[21] See, for example, Minn. Stat. §§ 216B.2425; 216B.243, subd. 3; 216C.30; Minn. Rules, part 7849.0120.A(1), (3); 7849.0120.B(1).

[22] See, for example, Minn. Stat. §§ 216B.2401; 216B.243, subd. 3; 216C.05; Minn. Rules, part 7849.0120.A(2), (5).

- Supply alternatives: whether there are lower-cost sources of new electricity than the one proposed by the applicants.[23]

In evaluating an application for a certificate of need the Commission receives assistance from other state agencies. Where material facts are in dispute, for example, the Commission refers cases to the Office of Administrative Hearings to conduct a contested case proceeding.[24] And Minn. Rules Chap. 7849 provides for the Department to file an environmental review. As noted above, the Department has sought to fulfill its duties through the preparation of its Environmental Impact Statement.

Ultimately, the Commission acts on an application for a certificate of need by approving it, approving it with conditions, or reject it.[25]

IV. Reports of the Administrative Law Judges and Boston Pacific

A. First ALJs' Report

In their First Report the Administrative Law Judges concluded that the applicants had satisfied the relevant statutory and regulatory criteria for a certificate of need for their transmission line project. The Administrative Law Judges organized their discussion of these criteria in accordance with the framework of Minn. Rules, part 7849.0120:

- First, the Administrative Law Judges concluded that the applicants had demonstrated that "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." Minn Rules, part 7849.0120.A.[26] The record forecast more than enough demand for electricity to justify the proposed transmission lines. This demand is not the result of the applicants' promotional practices, and it cannot be cost-effectively met through existing facilities or planned facilities that do not require a certificate of need. And by replacing lines in existing rights-of-way, the proposal demonstrates an appropriate concern for making efficient use of existing resources.

- Second, the Administrative Law Judges concluded that the applicants have demonstrated that "a more reasonable and prudent alternative to the proposed facility has not been demonstrated by a preponderance of the evidence on the record." Minn Rules, part 7849.0120.B.[27] The applicants studied various alternatives to determine the appropriate size transmission lines to

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[23] See, for example, Minn. Stat. §§ 216B.1612, subd. 5; 216B.1691; 216B.1694; 216B.2426; 216B.243, subd. 3a; 216C.05; Minn. Rules, part 7849.0120.A(4), B, C.

[24] Minn. Rules, part 7829.1000.

[25] Minn Stat. §§ 216B.243, subd. 5; 216E.03, subd. 10(b).

[26] See generally First ALJs' Report, Findings 110 - 163.

[27] *Id.*, Findings 164 - 217.

build and when to build them; the cost of the proposed transmission lines is comparable to the cost of the alternatives. Because the applicants propose to build the new transmission lines by replacing existing transmission lines, and because some of these existing lines would need to be replaced shortly in any event, both the facilities themselves and the choice to build them will have little net effect on the natural or human environment. The applicants expect the proposed facilities to operate virtually continuously, enhancing the reliability of the transmission grid throughout the region for the next 40 years or more. Regarding plans for acquiring electricity from Big Stone Unit II, no party demonstrated another proposal to be more reasonable and prudent. And whatever other opportunities the applicants may have for obtaining electricity cost-effectively, the record demonstrates that the applicants are also justified in building transmission lines to obtain electricity from the proposed Big Stone Unit II.

- Third, the Administrative Law Judges concluded that the applicants have demonstrated "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." Minn Rules, part 7849.0120.C.[28] The proposed transmission lines would permit a greater flow of electricity to meet the growing demand for electricity discussed above. Increased transmission capacity would be especially helpful to the ethanol and wind-power industries in the region.[29] The Administrative Law Judges concluded that society would derive greater benefit from building the new lines than from refraining to build them.[30]

- Finally, the Administrative Law Judges found that "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 and local governments." Minn Rules, part 7849.0120.D.[31] To the contrary, the applicants are taking the necessary steps to comply with the requirements of various governmental agencies, including counties, cities, and other local governmental units; the Minnesota Department of Natural Resources, the Minnesota Pollution Control Agency, and other Minnesota agencies; state agencies in South Dakota; and various federal agencies such as the U.S. Department of Energy and the Corps of Engineers. The Administrative Law Judges found that the applicants are in the process of meeting the necessary requirements,[32] and no party has disputed this finding.

The Administrative Law Judges faulted the applicants for needlessly restricting consideration of conservation and load management programs. Nevertheless, the Administrative Law Judges concluded that the magnitude of the demand demonstrated by the applicants was sufficient to

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[28] *Id.*, Findings 218 - 234.

[29] *Id.*, Findings 229 - 231.

[30] *Id.*, Finding 228.

[31] *Id.*, Findings 235 - 237.

[32] *Id.*, Finding 237.

demonstrate that even aggressive conservation and load-management programs would not displace the need for an additional source of electricity.[33]

The Administrative Law Judges also concluded that the Environmental Impact Statement adequately addressed the environmental, social and economic effects of the proposed transmission line project,[34] and that the applicants had adequately fulfilled their duty to investigate acquiring electricity from Excelsior's Mesaba Project under Minn. Stat. § 216B.1694, subd. 5.[35] On this basis the Administrative Law Judges recommended granting the certificate of need.

B. Second ALJs' Report

Following further evidentiary proceedings triggered by the withdrawal of two applicants and certain statutory changes, the Administrative Law Judges issued a second report. In that report the Administrative Law Judges found as follows:

Applicant	**For how many MW has the applicant successfully demonstrated....**		
	demand?[36]	that demand cannot be met more cost-effectively through conservation, load management?	that demand cannot be met less expensively through renewable sources?
CMMPA	40-50 MW	40-50 MW	---
Heartland	30 MW	---	---
Montana-Dakota	---	---	---
MRES	160-175 MW	145 MW	145 MW
Otter Tail	170 MW	170 MW	---
Total	**400-425 MW**	**355-365 MW**	**145 MW**

Regarding the need to estimate the amount of electricity customers will demand, the Administrative Law Judges found that CMMPA, Heartland, MRES and Otter Tail had fulfilled this requirement, but that Montana-Dakota's forecasts were unreliable. Consequently Montana-Dakota could not demonstrate that it had demand for electricity that could not be met more cost effectively through energy conservation and load-management measures, as required by Minn. Stat. § 216B.243, subd. 3.[37]

[33] *Id.*, Findings 148 - 149.

[34] *Id.*, Findings 338 - 355.

[35] *Id.*, Conclusion 10.

[36] Second ALJs' Report, Findings 23, 38 (citing App. Exh. 131-A (Morlock rebuttal)).

[37] *Id.,* Finding 26.

Regarding conservation and load management, the Administrative Law Judges found that CMMPA, MRES and Otter Tail had demonstrated that their demand could not be met cost-effectively in this manner. But the Administrative Law Judges found that neither Heartland nor Montana-Dakota had adequately considered the extent to which these strategies might cost-effectively displace the need for electricity from the Big Stone II proposal. In addition, the Administrative Law Judges retracted their earlier conclusion that the magnitude of demand demonstrated by the applicants could compensate for an applicant's failure to adequately analyze conservation and load management alternatives.[38] To the contrary, the Administrative Law Judges concluded that the Applicants "as a whole" have not shown that their demand for electricity could be met at least in part more cost-effectively through conservation and load management, as required by Minn. Stat. § 216B.243, subd. 3.[39]

And regarding renewable sources of energy, the Administrative Law Judges found that only MRES had demonstrated that its demand could not be cost-effectively met in this manner. CMMPA, Heartland, Montana-Dakota and Otter Tail had failed to show that the Big Stone II proposal is less expensive (including environmental costs) than power generated from renewable sources, as required by Minn. Stat. § 216B.243, subd. 3a.

Significantly, the Administrative Law Judges found that Heartland's failure to use a capacity expansion model precluded a finding that it had fulfilled the statutory requirements for demonstrating need.[40] A capacity expansion model tests a large number of potential expansion plans under a given set of assumptions to determine a theoretical least-cost alternative.

And while all other applicants did use capacity expansion models, the Administrative Law Judges found that CMMPA, Montana-Dakota and Otter Tail incorporated unrealistic assumptions about carbon regulation, construction and fuel costs. And when these applicants provided additional analyses, they failed to use their capacity expansion models. According to the Administrative Law Judges, only MRES conducted an analysis sufficient to demonstrate that the Big Stone II proposal would be the least expensive way of serving its demand, as required by Minn. Stat. § 216B.243, subd. 3a.[41]

Because the applicants had not demonstrated a need for sufficient additional power that could not be served more cost-effectively through conservation, load management or alternative sources of supply, the Administrative Law Judges recommended denying the certificate of need.[42] But the Administrative Law Judges acknowledged the practical advantages of OES' recommendation to

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[38] *Id.*, Findings 29 - 31.

[39] *Id.*, Finding 33.

[40] First ALJs' Report, Finding 107; Second ALJs Report, Finding 36.

[41] Second ALJs' Report, Findings 80 - 83. This figure reflects 120 MW for MRES' member municipal utilities plus 25 MW to be provided to Hutchinson Utilities Commission under contract.

[42] *Id.*, Recommendation 1.

grant a certificate of need with conditions.[43] Consequently the Administrative Law Judges recommended that if the Commission were to grant a certificate of need, the Commission should impose the conditions recommended by OES.

C. Report of Boston Pacific

After reviewing the Second ALJs' Report and parties' reactions, the Commission retained Boston Pacific to provide expert testimony regarding three variables that strongly influence any analysis of the cost-effectiveness of the Big Stone II proposal: the costs of carbon emissions, construction and fuel. Boston Pacific concluded as follows:

> [T]he range of emissions, construction, and fuel price inputs used in the Applicants' analyses were not appropriate; put another way, they were out of line with current "best practices" resource selection methodologies. Specifically, with respect to emissions costs, we found the Applicants' use of a \$0 to \$9 per ton CO_2 tax, without escalation over time, to be far lower than the ranges justified for resource decisions today; the later use of a \$30 per ton tax was a good step forward but did not go far enough.
>
> We recommend analyzing resource choices under four different levels of CO_2 taxes: \$8, \$20, \$40 and \$60 per ton of CO_2, starting in 2012.....
>
> * * *
>
> With respect to new construction costs, we understand that the Applicants' latest analysis used an estimate of \$2,545 per kW for the installed costs for Big Stone II. This is below even the low end of our estimate of the possible range of installed costs for a new coal-fired facility, which we would estimate to be from \$2,600 per kW to \$3,000 per kW....
>
> * * *
>
> For new gas-fired combined cycle facilities, the Applicants used [a cost range that] is either at or above the high end of our estimates of the appropriate range of costs for new combined cycle facilities, even accounting for some Applicant's inclusion of transmission and [interest] costs. In our view, the appropriate range is \$1,000 to \$1,200 per kW. For gas-fired combustion turbines our expected range of costs is \$800 per kW to \$1,100 per kW. The Applicants used a similar range.... Finally, the Applicants' cost estimates for wind turbines (\$1,810 to \$2,270 per kW) are generally in the right region....
>
> * * *
>
> With respect to fuel price forecasts, we believe that the Applicants' initial or "base case" estimates for coal and natural gas prices are reasonable given current market conditions and projections by other sources. However, we believe that the Applicants differed from a "best practice" analysis by not testing their results against a wide range of prices for natural gas. Based on historical volatility in natural gas futures, we would recommend

[43] *Id.*, p. 43 (memorandum).

that a range of natural gas prices be tested equal to plus and minus 25% around the base 2012 price of $8 per MMBtu.[44]

Boston Pacific does not express an opinion about the merits of granting a certificate of need in general. If the Commission grants a certificate in reliance on the parties' cost estimates, however, Boston Pacific recommends that the Commission allocate the risk that costs exceed the estimated levels to the parties that made the estimates.[45]

D. Third ALJs' Report

Parties filed rebuttal evidence and analysis in response to the Boston Pacific Report.

The Administrative Law Judges issued a third report summarizing the report and testimony of Boston Pacific, as well as parties' rebuttal evidence and analysis. The Administrative Law Judges did not make any new findings, conclusions or recommendations.

V. Positions of the Parties

Based on the relevant factors, the parties propose various courses of action.

A. The Applicants

The applicants argue that they have provided abundant demonstration of the need for additional transmission and base-load generation capacity.

They note that the Big Stone II proposal has received approvals and endorsements from North Dakota, South Dakota, MISO and (provisionally) OES, and the proposed transmission lines have already been incorporated into various transmission studies.

The applicants argue that they have fulfilled the statutory and regulatory requirements for demonstrating need. They have documented that the proposed lines are needed not only to transmit power from the proposed Big Stone Unit II, but also to transmit power from wind turbines in southwestern Minnesota and to enhance system reliability. And Big Stone Unit II would help serve the applicants' forecasted demand as well as compensate for expiring power purchase contracts. Even the Administrative Law Judges acknowledged that the applicants have demonstrated demand for nearly 400 MW of new power in their service territories.

The applicants dispute the Administrative Law Judges' finding that only a capacity expansion model can provide a reliable comparison of resource alternatives. The applicants argue that no amount of alleged technical defects in the filings should distract the Commission from the fact that a large amount of new generation will be required – and that the only viable fuel choices at this

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[44] Boston Pacific report, pp. 5 - 7, citations omitted. "MMBtu" means one million British Thermal Units.

[45] *Id.*, pp 3-4, 20; Third ALJs' Report, pp. 44-45.

time are coal and natural gas, perhaps combined with wind turbines.[46] Given these dynamics, the applicants' levelized busbar analysis incorporating assumptions from Boston Pacific demonstrates that the proposed Big Stone Unit II would be the most cost-effective choice under a wide variety of circumstances.[47]

And, while other parties and the Administrative Law Judges found fault with the applicants' analysis, the applicants argue that no party has demonstrated a more cost-effective alternative to Big Stone Unit II for serving the demand for base-load power in the applicants' service territories.

Consequently the applicants recommend that the Commission grant the certificate of need for the proposed transmission lines subject to certain conditions set forth earlier in this Order. But the Applicants oppose the OES conditions listed above for conflicting with statute or exceeding the appropriate scope of this proceeding.

B. Joint Intervenors

The Joint Intervenors largely agree with the Administrative Law Judges' analysis and argue that the facts preclude the Commission from granting a certificate of need. They do not argue that the record demonstrates the merits of some resource plan other than the one proposed by the applicants. Nor do they deny that the applicants will need to acquire some new sources of electricity from fossil fuels.[48] But they argue that flaws in the applicants' justification for the Big Stone II project mean that the applicants have failed to bear their burden of proof in this matter.[49]

The Joint Intervenors focus on three flaws in particular. First, the Joint Intervenors argue that the current recession casts doubt on the applicants' forecasts of customer demand for electricity.

Second, the Joint Intervenors allege that the applicants used inappropriate models. In particular, the Joint Intervenors object to the applicants' "levelized busbar analysis" designed to demonstrate, based on construction cost estimates provided by Boston Pacific, that the Big Stone II proposal is cost-effective under a wide range of circumstances. Because a capacity expansion model permits a comparison of the broadest range of alternative resources within the context of a utility's system, the Joint Intervenors argue that no other model is adequate for determining whether conservation, load management or alternative sources could displace any of the need for the Big Stone II proposal.

Third, the Joint Intervenors allege that the applicants used estimates of carbon, construction and fuel costs that were unrealistically low, unrealistically stable over time, and in an unrealistically narrow range.

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[46] First ALJs' Report, Findings 202 - 209.

[47] Applicant Exh. 143 (testimony of Jeff Greig) and 144 (testimony of Mark Chupka)

[48] Third ALJs' Report, pp. 44.

[49] Second ALJs' Report, Finding 41.

C. OES

OES agrees with the Administrative Law Judges in many respects. OES concludes that CMMPA, Heartland, MRES and Otter Tail (provisionally) have collectively demonstrated customer demand for 380-395 MW of electricity, and that CMMPA, MRES and Otter Tail (provisionally) have demonstrated that between 355-365 MW of that demand cannot be served more cost-effectively through conservation and load management.

Unlike the Administrative Law Judges, however, OES concludes that the record is sufficient to demonstrate that the Big Stone II proposal is less expensive than power generated from renewable sources for Otter Tail – under certain conditions. Specifically, OES agrees that MRES has demonstrated its need for 145 MW of new generation from the Big Stone II proposal. And OES agrees that Otter Tail has, subject to conditions, demonstrated a demand for 170 MW that cannot be met more cost-effectively through conservation and demand-side management. But OES also finds that Otter Tail can, under certain conditions, demonstrate that acquiring electricity from the Big Stone II proposal is less expensive than other sources, including considerations of environmental costs. Combining MRES's demonstrated need for 145 MW with Otter Tail's need for 170 MW, OES concludes that the record demonstrates a need for 315 MW, more than enough to justify the proposed transmission lines.

The applicants have already agreed to some of OES's proposed conditions. For example, for the first four years of Big Stone Unit II's operations the applicants agree to purchase carbon offsets in proportion to the amount of carbon Unit II would emit in the process of providing power to Minnesota customers. But OES recommends the following conditions in addition:

- The applicants would waive their statutory right to seek a delay or variance from the duty a) to serve 25% of their Minnesota customers' demand through renewable sources of energy under Minn. Stat. § 216B.1691 (the Renewable Energy Standard), or b) to displace 1.5% of their Minnesota retail load though conservation under §§ 216B.2401 and 216B.241.

- Otter Tail would identify the carbon regulation costs it assumed as part of its capacity expansion modeling, and Otter Tail's ratepayers would not have to bear carbon regulation costs exceeding these levels.

- Otter Tail would identify the construction costs it assumed as part of its capacity expansion modeling, and Otter Tail's ratepayers would not have to bear construction costs exceeding this amount – or perhaps 110% of this amount. Alternatively, the Commission would clarify that the grant of a certificate of need provides no guarantee of cost recovery, and defer the issue of cost recover to a rate case.

- Otter Tail would discontinue its base-load operations at Hoot Lake consistent with the assumptions in its model; as a compliance filing, Otter Tail would submit a plan identifying the steps, costs and timeline for fulfilling this condition.

D. MISO

The Midwest Independent Transmission System Operator, Inc., administers the regional transmission grid under federal jurisdiction on behalf of its member transmission line owners. MISO's interest in this docket is promoting system reliability. MISO offers no opinion about the need for Big Stone Unit II, or about the choice of fuel for generating electricity.

From that perspective, MISO asks the Commission to permit the transmission lines to be built regardless of the fate of Big Stone Unit II. MISO argues that the regional power grid was designed to import roughly 50 MW, but the sudden growth of the wind power industry has created a demand to export thousands of MW. "This is just the opposite of what the transmission system in southwestern Minnesota was designed to handle, and the swing in direction in energy flow is just too much for the existing infrastructure."[50] MISO cites studies showing that the proposed transmission facilities are needed to transmit wind power to customers, consistent with state policy, even if Big Stone Unit II is never built.

Finally, MISO argues that the Administrative Law Judges' recommendation arguably reflects a mistaken impression of how the regional transmission grid operates.

E. South Dakota Governor's Office of Economic Development

South Dakota GOED argues that the preponderance of the evidence demonstrates the merits of permitting the Big Stone II proposal to proceed. Moreover, South Dakota GOED argues that this docket's focus on the merits of Big Stone Unit 2 – a plant that is to be built in South Dakota under South Dakota's regulatory jurisdiction – is misplaced, unwarranted, unwise and possibly unconstitutional.

F. North Dakota Transmission Authority

The North Dakota Transmission Authority asks the Commission to grant the requested certificate of need to facilitate power exports from North Dakota, and to enhance the reliability of the transmission grid.

G. Summit Wind, LLC

Summit Wind, LLC, a developer of wind turbine generator projects, would benefit from the creation of additional transmission capacity. In support of the Big Stone II proposal, Summit Wind argues that transmission capacity has not grown at the same pace as demand, that modern coal plants are less polluting than conventional coal plants, that demand for wind power is growing, and that increased transmission capacity will strengthen a utility's ability to acquire cheaper power.

H. Excelsior

Excelsior asks the Commission to consider the Mesaba Project as an alternative source of energy that does not require a certificate of need, under Minn. Rules, part 7849.0120.A(4).

In addition, Excelsior note that Minn. Stat. § 216B.1694(5) provides that an "innovative energy project" such as 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

[50] MISO Brief (January 31, 2007), p. 7.

> option for the generation facility, and 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.

Consequently Excelsior asks the Commission to grant a certificate of need only on the condition that the applicants enter into power purchase agreements for electricity from the Mesaba Project. Excelsior disputes the Administrative Law Judges' conclusion that the Mesaba Project would not be a suitable substitute for the Big Stone II proposal in the absence of any firm construction schedule. In any event, Excelsior argues that approval of the Big Stone II proposal need not preclude approval of power purchase agreements with Mesaba as well.

VI. Analysis

A. Threshold of Need

As an initial matter it is important to recognize, as the applicants and South Dakota GOED emphasize, that the Commission is engaged in analyzing the need for transmission facilities, not the need for Big Stone Unit II. While the applicants claim a need for 531 - 556 MW, this fact is only relevant in the current docket to the extent that it bears on the need for the proposed transmission facilities. In fact, the applicants can justify the need to expand transmission capacity by demonstrating need for at little as 150 MW of new power.[51]

Nevertheless, the Joint Intervenors argue that granting the certificate of need should depend upon each applicant demonstrating need for each MW it seeks. They note that the Administrative Law Judges found that the applicants "as a whole" failed to comply with Minn. Stat. § 216B.243, subd. 3,[52] even though CMMPA, MRES and Otter Tail had demonstrated compliance.[53]

The legal standard for determining need, however, is not whether applicant have demonstrated every megawatt of need they have claimed, but whether they have demonstrated enough need to justify the facilities they proposed to build. Consequently the Commission will decline to adopt the Administrative Law Judges' conclusion that the failure of certain applicants to bear their burden of proof can justify a conclusion that the applicants "as a whole" failed.

In the ensuing analysis, the Commission will consider the following:

- Demand – the extent to which the anticipated demand for electricity exceeds the applicants' anticipated capacity to serve it.
- Conservation/load management – whether cost-effective load management and conservation measures will offset this excess demand.

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[51] Second ALJs' Report, Finding 7, citing Department Exh. 26 (response to Information Request 105).

[52] *Id.*, Finding 33.

[53] *Id.*, Finding 27.

- Supply alternatives – whether the applicants' proposal is the least expensive source of new generation to serve the excess demand, even when environmental costs are considered.

In addition, the Commission will consider OES' proposals for imposing conditions on the certificate of need.

B. Demand

The first issue, then, is whether the record demonstrates that there is sufficient demand to justify new facilities. The Commission finds that the applicants in aggregate forecast sufficient demand for electricity to justify the proposed facilities.[54]

1. Demand within region

On a regional level, the applicants cite a number of sources demonstrating that growth of demand for generation and transmission has exceeded the growth of supply. Regarding the regional need for new sources of electricity, the applicants demonstrate that demand is expected to grow for the foreseeable future.[55] Each of Minnesota's investor-owned utilities forecasts a need for additional electricity in their resource plans,[56] and the region's capacity to generate or import electricity must expand to meet the region's continuing growth in demand, according to the Mid-Continent Area Power Pool (MAPP). MAPP is dedicated to promoting the reliability of the electrical system in the upper Midwest through coordinating the use of the generation and transmission resources of its member utilities. MAPP's most recent Load and Capability Report[57] predicted a regional capacity deficit of 568 MW by 2011 and 2400 MW by 2014.

Regarding the regional need for transmission lines, MISO – which administers the regional transmission grid – reports that developers in the region are seeking to add as much as 4000 MW of additional generating capacity from wind turbines, but the developers lack the capacity to transmit the resulting electricity to customers. While this amount of wind generation may initially appear large, the applicants calculate that Minnesota utilities will need between 5000 MW and 7000 MW of wind power to meet the Renewable Energy Standards. In response to this statutorily created demand, the applicants propose to expand the capacity of the Granite Falls line to provide additional capacity for wind power.

MISO also emphasizes that the growth in demand is taxing the transmission grid's reliability, and that adding the proposed transmission facilities would enhance the grid's reliability, reducing the risk of damaging current fluctuations and even blackouts.

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[54] *Id.*, Finding 23.

[55] First ALJs' Report, Findings 111 - 119.

[56] *Id.*, Finding 218.

[57] MAPP's Load and Capability Reports present two years of load and capability data, and then forecast the system load and capability for the next ten years. MAPP released its latest report in August 2006.

2. Demand within the applicants' service territories

The Administrative Law Judges found that CMMPA, Heartland, MRES and Otter Tail each successfully demonstrated the reasonableness of its own demand forecast, demonstrating an aggregate demand of 380-395 MW.[58] But the Joint Intervenors challenge this assessment, arguing that more recent news about the deepening economic recession calls into doubt conventional methods of forecasting demand.

The Commission finds the Administrative Law Judges' assessments persuasive and the applicants' forecasts reliable. The applicants must prepare for the contingency both that the economy slows and that the economy booms. Moreover, the applicants predict that the proposed facilities will remain in operation for at least 40 years. The applicants evaluate demand forecasts on the basis of longer-term trends. The Commission finds merit in these procedures and will not attempt to make adjustments to the demand forecasts to compensate for the current phase of the business cycle, or to anticipate the next one.

3. Demand within Otter Tail's service territory

OES supports the Administrative Law Judges' conclusions in general but raises questions about the assumptions underlying Otter Tail's forecast. That forecast relies on the assumption that Otter Tail would cease to obtain base-load power from its coal-fired Hoot Lake generators at the end of their service lives in 2017 or 2018. Otter Tail did not provide any analysis demonstrating its demand assuming the Hoot Late generators continue their current operations, and OES was unable to get Otter Tail's forecasting model to explore this alternative. Lacking any other basis upon which to evaluate Otter Tail's demand, OES recommends making this assumption an explicit condition for granting the certificate of need and recommends that the Commission direct Otter Tail to file plans for phasing out base-load operation of the Hoot Lake generators.

The applicants oppose OES's recommendation. They argue that any such condition should be addressed in a resource plan docket, and that the Commission should not needlessly constrain Otter Tail's options for dealing with unforeseen circumstances in the meantime. Beyond asking the Commission to reject OES's proposed condition, the applicants ask the Commission to refrain from ordering the closure of the Hoot Lake generators without plans (and approvals) for acquiring a substitute source of base-load power, and without plans for allocating responsibility for the costs among the three state jurisdictions in which Otter Tail operates.

The Administrative Law Judges found that it is reasonable for Otter Tail to replace its older plants with the more efficient and less polluting Big Stone Unit II, and therefore there is no reason to doubt that Otter Tail intends to close its Hoot Lake generators in the timeframe proposed.[59] But the Administrative Law Judges did not offer explicit recommendations on any of OES's proposed conditions.

The Commission finds merit in the concerns raised by OES and the applicants.

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[58] Second ALJs' Report, Finding 23.

[59] *Id.*, Finding 89.

Because the record demonstrating demand relies on the assumption that Otter Tail will phase out its reliance on the Hoot Lake generators, the Commission will incorporate that assumption into its Order. Consequently the certificate of need in this matter will be granted on the condition that Otter Tail cease operating Hoot Lake Units 2 and 3 as coal-fired generators no later than the end of 2018; the Commission will direct Otter Tail to file plans for implementing this condition.

Nevertheless, the Commission cannot preclude the possibility that changing circumstances may ultimately warrant continuing base-load operations at Hoot Lake. As the applicants observe, this matter will be addressed in Otter Tail's resources planning dockets. In that context, Otter Tail and any other party remain free to argue that continuing the operation of the Hoot Lake generators is necessary to meet the needs of Minnesota ratepayers cost-effectively. Of course environmental costs must be considered as part of any evaluation of cost-effectiveness.

C. Conservation/Load Management

The next step is to determine under Minn. Stat. § 216B.243, subd. 3, whether implementing cost-effective conservation and load management measures could address enough of the forecasted demand to eliminate the need for the proposed facilities. The Administrative Law Judges concluded that CMMPA, MRES and Otter Tail were able to demonstrate a continuing need for the Big Stone II proposal even after exhausting their cost-effective conservation and load management programs.[60] Because these applicants have an aggregate demand for 355-365 MW, far exceeding the threshold needed to justify the proposed transmission lines, the Commission finds that the requirements of § 216B.243, subd. 3, have been fulfilled.

In providing support for this analysis each applicant assumed, in accordance with Minn. Stat. § 216B.241, subd. 1c, that conservation programs would reduce forecasted demand from Minnesota retail customers by 1.5%. As a condition for granting a certificate of need OES recommends that the Commission direct the applicants not merely to make this assumption for modeling purposes, but to commit to achieving this level of savings in practice. Similar to OES's arguments regarding the Hoot Lake generators, OES recommends that the applicants be required to abide by their modeling assumptions. OES notes that the Administrative Law Judges also recommended that the applicants not be excused from meeting these goals.[61]

The applicants oppose this recommendation. They acknowledge that the statutes anticipate that they will achieve these conservation savings, and that they have committed in the Settlement Agreement to striving to achieve them. But they argue that the Legislature directs them to pursue this 1.5% conservation goal only to the extent that it is cost-effective to do so. Minn. Stat. § 216B.241, subd. 1c(f). According to the applicants, mandating conservation regardless of cost would be wasteful, and would frustrate the intent of the Legislature.

The Commission will decline OES's proposal. The Administrative Law Judges recommended that the Commission not excuse the applicants from their duty to comply with the 1.5% conservation

[60] *Id.*, Finding 27.

[61] *Id.*, Finding 17.

goal in this certificate of need proceeding[62] – that is, for purposes of estimating the need for the Big Stone II proposal. The Administrative Law Judges offered no recommendations for matters beyond the scope of this proceeding. And, while the Legislature directs the Commission to promote conservation "to the maximum reasonable extent,"[63] the Commission will not require parties to pursue conservation measures beyond the point where the cost exceeds the benefit.

The Commission clarifies, however, that neither this decision nor the eventual construction and operation of Big Stone Unit II will excuse the applicants from the duty to comply with the terms of the Conservation Improvement Program statutes, Minn Stat. § 216B.2401 and 216B.241.

D. Supply Alternatives

The final step is to determine whether the applicants can cost-effectively acquire enough electricity from some alterative source – including existing facilities and facilities that could be acquired without a certificate of need,[64] distributed generation[65] and generators using renewable sources of energy[66] – to eliminate the justification for the proposed facility.

In the Second ALJs' Report, the Administrative Law Judges concluded that only MRES had demonstrated that the Big Stone II proposal would the most cost-effective way of serving its customers. The Administrative Law Judges rejected the analyses performed by each of the other applicants on the grounds that it either 1) did not use a capacity expansion model or 2) did not use appropriate assumptions in the model. In particular, the Administrative Law Judges concluded that the applicants' assumptions about the cost of construction, carbon regulation and fuel were variously too low, within too narrow a range, and too stable over time. And when these parties filed subsequent analyses using different assumptions, the Administrative Law Judges rejected them because they were not based on their capacity expansion models.

A third phase of the proceeding then ensued, providing new evidence about models and the appropriate assumptions to include in them – and providing the Commission with a different perspective than the Administrative Law Judges had when they wrote the Second ALJs' Report. The Commission concludes that the applicants have appropriately considered alternative sources of electricity and the record demonstrates that the Big Stone II proposal is likely the least expensive option, even when environmental costs are considered.

1. Models

Given the myriad factors that must be weighed when determining whether to grant a certificate of need, parties use computer models to help them compare alternatives. The Joint Intervenors, OES

[62] *Id.*, Findings 17, 20.

[63] Minn. Stat. § 216B.03.

[64] Minn. Rules, part 7849.0120.A(4); Minn Stat. § 216B.1694, subd. 2(a).

[65] Minn Stat. § 216B.2426.

[66] Minn. Stat. §§ 216B.1612, subd. 5; 216B.2422, subd. 4; 216B.243, subd. 3 and 3a.

and ultimately the Administrative Law Judges favor capacity expansion models. These are resource planning computer models that compare the costs of thousands of scenarios, each entailing a different mix of resources – including energy conservation, load management and generation alternatives – to find the theoretical least-cost combination that will meet the applicant's demand. These models do not, however, make a determination about whether the theoretical least-cost combination can actually be implemented within a specified timeframe.

The applicants use such models, but have relied on other models as well – including a levilzed busbar cost analysis and a sensitivity analysis. A levelized busbar analysis permits a utility to compare similar types of resources (such as competing sources of firm base-load power), assuming the utility has already determined the needed type of resource and the timeframe for securing the resource. This analysis produces a single "level" cost in terms of dollars per kilowatt-hour ($/kWh) reflecting the expected cost of energy derived from that plant over the plant's service life.

While acknowledging the value of capacity expansion models, the Commission is not persuaded that these models have become the exclusive means by which a party can compare the cost of alternative sources of generation. First, the Commission notes the variety of analytical models, and the fact that technology is always changing.[67] Models that are deemed state-of-the-art at one point will be deemed outdated at later points. Consequently the Commission is reluctant to regard any one model as essential, or categorically dismiss all other models as having no probative value.

Second, different tasks call for different tools. The task of identifying an optimal resource plan may benefit from the full range of abilities a capacity expansion model provides. Given the number of possible resources and the number of variables relevant to selecting a resource, every change in assumptions is likely to produce a different optimal resource mix. In contrast, the task of evaluating the need for the proposed transmission lines is more straightforward.[68] For purposes of the current docket, a finding that the applicants should obtain 400 MW from the proposed Big Stone Unit II is equivalent to a finding that the applicants should obtain 300 MW or 500 MW; they all lead to the conclusion that the proposed transmission lines are justified.

For purposes of the current stage of the proceedings the Commission sought information about the relative costs of three alternative sources of base-load power: 1) a 500 MW generator such as Big Stone Unit II, 2) a comparably sized wind-powered generation system supplemented by generators fueled by natural gas, and 3) a comparably sized generator fueled by natural gas.[69] A levelized busbar analysis provides an appropriate tool for identifying circumstances under which one of these options becomes more cost-effective than another.[70]

Third, the Commission concludes that no model can substitute for the exercise of independent judgment. The Joint Intervenors offered a resource plan based on a capacity expansion model that

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[67] See Applicants Exh. 144 (testimony of Marc Chupka); Third ALJs' Report, pp. 11-16.

[68] *Id.*

[69] Order Referring Case to Office of Administrative Hearings for Additional Evidentiary Proceedings (August 7, 2008), this docket; see also First ALJs' Report, Findings 202 - 209.

[70] See Applicants Exh. 144 (testimony of Marc Chupka); Third ALJs' Report, pp. 11-16.

proposed that CMMPA acquire 200 MW – or 80% of its load – from wind power, backed up by 10 MW from gas turbines, in the next 12 years. The implausible nature of this portfolio serves as a reminder that no modeling technique should be regarded as either infallible or indispensable.

Consequently the Commission will decline to adopt the Administrative Law Judges' findings granting a privileged status to analyses performed by capacity expansion models;[71] the Commission will evaluate each analysis on its own merits on a case-by-case basis.

2. Model assumptions

Of course, a model's analysis is only as good as the assumptions that the parties put into it. In response to the concerns raised by OES, the Joint Intervenors and the Administrative Law Judges, the Commission sought expert testimony regarding certain assumptions that the applicants had included in their models.[72] That expert, Boston Pacific, generally confirmed what this Commission had heard from the Joint Applicants, OES and the Administrative Law Judges: some of the applicants' original assumptions regarding the cost of carbon regulation, construction and fuel were unrealistic, and consequently their analyses may not produce reliable results.

The applicants defend their choice of modeling assumptions. The applicants noted that both the Department and the Commission issued new positions regarding carbon regulation costs during the course of these proceedings.[73] While the Commission does not deny the challenges of developing appropriate cost estimates, the balance of the evidence in the record persuades the Commission that the estimates offered by Boston Pacific are the most reliable in the record.

Accordingly the applicants re-ran their levelized busbar analyses incorporating cost assumptions from within the ranges recommended by Boston Pacific. They compared the cost of 500 MW plant like Big Stone Unit II to two alternative sources of generation with comparable capacity: 1) generators powered by wind with supporting generators powered by natural gas, or 2) generators powered by natural gas alone.[74] This was consistent with the alternatives the Commission asked to have explored.[75] But even under assumptions favoring wind power – Congress extending the tax subsidy for wind power production, for example – the analysis showed that carbon regulation costs would need to reach $26/ton before the combined wind/gas alternative would become more cost-

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[71] See, for example, First ALJs' Report, Finding 107; Second ALJs' Report, Findings 36, 42, 59, 74.

[72] Order Referring Case to Office of Administrative Hearings for Additional Evidentiary Proceedings (August 7, 2008), this docket.

[73] See, for example, *In the Matter of Establishing an Estimate of the Costs of Future Carbon Dioxide Regulation on Electricity Generation Under Minnesota Statutes § 216H.06*, Docket No. E-999/CI-07-1199.

[74] Third ALJs' Report, p. 27.

[75] Order Referring Case to Office of Administrative Hearings for Additional Evidentiary Proceedings (August 7, 2008), p. 3, this docket.

effective than Big Stone Unit II.[76] And the analysis revealed no scenario in which the gas-powered generators alone proved to be more cost-effective than the Big Stone II proposal, even assuming the cost of carbon regulation reached $40/ton.

While Boston Pacific identifies a number of ways in which the applicants might have improved their analysis, Boston Pacific nevertheless finds their analysis to be constructive.[77] This analysis provides a basis for finding that the Big Stone II proposal is the least expensive way of serving the forecasted demand, as required by Minn. Stat. § 216B.243, subd. 3a, under reasonable assumptions.

3. Otter Tail's models and assumptions

Otter Tail uses a capacity expansion model that no other party employs. OES states that it was not able to explore this model with the same rigor that OES used regarding the other applicants' studies, could not replicate Otter Tail's results, and ultimately could not evaluate the reliability of Otter Tail's analysis. This is a source of concern to OES because Otter Tail is not only the party seeking the largest share of Big Stone Unit II's output, but Otter Tail is the only rate-regulated applicant. Thus OES was frustrated in its efforts to scrutinize the model and assumptions that most warranted scrutiny.

Consequently, while OES cannot conclude that Otter Tail's analysis is unreliable, OES advocates shielding Otter Tail's ratepayers from the risk of Otter Tail's modeling. That is, OES recommends that the Commission bar Otter Tail from recovering from its ratepayers construction and carbon regulation costs exceeding the amounts Otter Tail included in its capacity expansion model. If Otter Tail's construction and carbon regulation cost estimates prove to be accurate, Otter Tail's shareholders would incur no harm; but if those costs exceed Otter Tail's estimates, Otter Tail's shareholders would bear the cost of the excess.

The Commission appreciates the elegance of OES's recommendation for dealing with the uncertainty arising from Otter Tail's modeling. The Commission will therefore adopt this recommendation, but modify it to address procedural and substantive concerns.

Procedurally, the Commission will decline to decide in this docket questions that are more appropriately addressed in a rate-setting docket. OES argues that it is appropriate to advise the applicants about the consequences of their actions, thereby enabling them to make informed choices about how to proceed. The Commission agrees, yet the Commission cannot foresee with certainty how the facts of the current case will influence its decision in a later one. The Commission will therefore indicate to the parties how the Commission *intends* to balance the interests of ratepayers and shareholder in a future rate case. But these statements will not preclude any party from offering, nor the Commission from considering, contrary arguments in any future case in which Otter Tail seeks to recover its construction and carbon regulation costs.

Substantively, the Commission finds OES's recommendation needlessly restrictive. OES made its recommendation early in these proceedings as a means of managing uncertainty arising from the

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[76] Applicants' Exh. 146 (testimony of Jeffrey Greig).

[77] Third ALJs' Report, p. 19.

fact that Otter Tail's demonstration of need rested on Otter Tail's own modeling, which OES could not replicate. Since that time the applicants have submitted their levelized busbar analysis demonstrating that the Big Stone II proposal is justified under any reasonably foreseeable circumstance in which construction costs do not exceed the $2600 - $3000/kW range and carbon regulation costs do not exceed $26/ton. While this analysis does not eliminate the rationale for OES's proposal, it does warrant modifying the proposal accordingly.

The Commission will therefore adopt OES's recommendation, revised to reflect procedural and substantive concerns, as follows: The Commission hereby puts Otter Tail on notice of the Commission's present intention to shield Otter Tail's ratepayers from bearing any construction costs exceeding the $2600 - $3000/kW range and carbon regulation costs exceeding $26/ton, adjusted as appropriate for the passage of time, including inflation, arising from the Big Stone II proposal. In rendering this decision, however, the Commission does not preclude any party from advocating a contrary position, nor does the Commission pre-judge whether Otter Tail's ratepayers should bear construction or carbon regulation costs up to these levels. Those matters are more appropriately addressed in a future proceeding.

4. Analysis of facilities not requiring a certificate of need

Any new or upgraded transmission line exceeding 100 kV that crosses into Minnesota[78] requires a certificate of need.[79] And any new generator at the Big Stone location with an output exceeding 150 MW would require the addition of new transmission facilities with a capacity exceeding 115 kV.[80] Given that the demonstrated demand for new energy to serve Minnesota customers is well in excess of that threshold, the Commission finds that neither existing transmission facilities nor new facilities not requiring a certificate of need would displace the need for the transmission facilities being proposed by the applicants.

Excelsior Energy argues that transmission facilities should not be considered separate from substitute sources of generation, and notes that its proposed generator – the Mesaba Project – does not require a certificate of need.[81] However, the Administrative Law Judges concluded that the Mesaba Project is not a suitable substitute for Big Stone Unit II due to Mesaba's construction schedule.[82] Excelsior takes exception to this finding, arguing that the record did not address Mesaba's construction schedule. Excelsior proposes that, if the Commission grants a certificate of need, the Commission impose a condition directing the applicants to enter into a power purchase agreement with Excelsior.

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[78] Minn. Stat. § 216B.2421, subd. 2(3).

[79] Minn. Stat. § 216B.243.

[80] Second ALJs Report, Finding 7.

[81] The Commission has found that the proposed Mesaba Project – a generator using the relatively new integrated gasification combined cycle technology – qualifies as an "innovative energy project" exempt from the certificate of need process under Minn. Stat. § 216B.1694.

[82] First ALJs' Report, Findings 154 - 160; Conclusion 10.

There is little evidence in the record addressing the Mesaba Project's construction schedule – or indeed much else regarding the Mesaba Project. Excelsior offered no witnesses and filed no testimony. The applicants claim that they sought relevant information from Excelsior and, failing that,[83] they analyzed the possibility of acquiring electricity from a generator using similar technology to the Mesaba Project; this analysis demonstrated that the resource would be too expensive.[84] The Commission finds the applicants' analysis reasonable under the circumstances, and will not direct the applicants to enter into a power-purchase agreement with Excelsior as a condition for receiving a certificate of need.

5. Analysis of compliance with Minn. Stat. § 216B.1619 (Renewable Energy Standard)

In seeking to demonstrate that their proposal is more cost-effective than obtaining electricity from renewable sources, the applicants conducted analyses assuming that by 2025 they would acquire 25% of the electricity serving their retail customers in Minnesota from renewable sources, as provided by the Renewable Energy Standards, Minn. Stat. § 216B.1691, subd. 2a.[85]

As a condition for granting a certificate of need OES recommends that the Commission direct the applicants not merely to make this assumption for modeling purposes, but to waive their right to seek a modification or delay of these standards under Minn. Stat. § 216B.1691, subd. 2b. Similar to OES's arguments regarding the Hoot Lake generators, OES recommends that the applicants be required to abide by their modeling assumptions.

The applicants oppose this recommendation. They acknowledge that the statutes anticipate that they will acquire the specified amounts of energy from renewable sources, and that they have committed in the Settlement Agreement to pursuing this end. But they argue that the statute also permits the applicants to petition the Commission for a delay or variance when in the public interest. Issues such as cost, competitive dynamics, reliability, technical problems, permit delays, equipment shortages, transmission constraints and legal constraints may justify a deviation from the standards set forth in the statute.[86] Requiring the applicants to acquire a specified level of energy from renewable sources – even when contrary to the public interest – would be wasteful, and would frustrate the intent of the Legislature.

The Renewable Energy Standards already direct the applicants to meet targets for acquiring energy from renewable sources, and the applicants have committed themselves to pursuing that goal. In effect, it appears OES is asking this Commission to pre-judge the merits of any future argument that delaying or varying the standards might serve the public interest. The Commission finds it prudent to await such arguments before ruling on them. The Commission will therefore decline OES's proposal.

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[83] See Applicants' Brief (September 5, 2007), pp. 15-17.

[84] First ALJs' Report, Findings 197 - 208.

[85] Second ALJs' Report, Findings 42 - 48. Note that Montana-Dakota has no Minnesota retail customers.

[86] Minn. Stat. § 216B.1691, subd. 2b.

The Commission clarifies, however, that neither this decision nor the eventual construction and operation of Big Stone Unit II will excuse the applicants from the duty to comply with the terms of the Renewable Energy Standards.

VII. Commission Action

A. Completeness of Environmental Review

Commission rules establish the following procedures for environmental review:

- The Department gives notice to interested persons (7849.7050, subp. 1).
- The Department convenes a public meeting (7849.7050, subp. 3).
- The Department receives comments on scope of review (7849.7050, subp. 4).
- The Department issues a decision establishing the scope of review (7849.7050, subp. 7).
- The Department prepares environmental review documents (7849.7050, subp. 9).
- The Department files its environmental review documents (7849.7090, subp. 1).
- The Commission rules on the review's completeness (7849.7090, subp. 2).

Having reached the final step, the Commission must determine whether the environmental report and the record address the issues identified by the Department in its scoping decision. Having reviewed the Department's Environmental Impact Statement, the Commission concurs with the Administrative Law Judges that the EIS and the record as a whole do in fact adequately address the certificate of need issues identified in the scoping decision.[87]

B. Certificate of Need

In preparing recommendations for the Commission regarding both the applicants' certificate of need and route permit applications, the Administrative Law Judges presided over three evidentiary hearings and multiple public hearings. They reviewed the testimony of multiple witnesses and dozens of exhibits. They evaluated multiple rounds of initial and reply briefs. Their Reports include collectively more than 500 findings of fact and 20 conclusions, ultimately supporting various – sometimes conflicting – recommendations. Having examined the record and carefully considered the three Administrative Law Judges' Reports, the Commission concurs in the Administrative Law Judges' findings and conclusions – and will therefore accept, adopt and incorporate the relevant findings and conclusions – except as they are rejected herein or otherwise inconsistent with this Order.

In writing their Second ALJs' Report, the Administrative Law Judges ultimately found that the record did not demonstrate that the applicants had borne their burden to demonstrate that the proposed transmission lines are needed. This finding rested in large measure on the conclusions that 1) a capacity expansion model is necessary for comparing the cost-effectiveness of different supply options, and 2) the analyses underlying the applicants' arguments were based on inappropriate assumptions about the cost of construction, carbon regulation and fuels. The Administrative Law Judges nevertheless acknowledged the appeal of OES's proposal for addressing challenges by imposing conditions on the grant of the certificate of need:

[87] First ALJs' Report, Findings 338 - 355.

> The Office of Energy Security's approach may be the most practical solution. The proposed transmission lines are needed to some degree, and to the extent it is relevant, Big Stone II promises to be one of the most efficient and least polluting coal plants yet built. It will even reduce pollution from Big Stone I.[88]

This Commission identifies only two major points of difference between this Commission's findings and the findings of the Administrative Law Judges' reports. First, for the reasons set forth above, the Commission is not persuaded that a capacity expansion model provides the sole basis by which to evaluate the cost-effectiveness of competing supply options. Consequently the Commission declines to adopt the First ALJs' Report, Finding 107, and the Second ALJs' Report, Findings 36, 42, 59, and 74, to the extent that they suggest otherwise.

Second, this Commission has the benefit of the more realistic data on modeling assumptions as provided by Boston Pacific. The Commission retained these experts to explore the cost data assumptions that the Administrative Law Judges found questionable.

These two differences – regarding models and regarding cost data – largely account for the differences between the Commission and the Administrative Law Judges. Using a levelized busbar analysis that the Administrative Law Judges declined to consider, and analyzing cost data that the Administrative Law Judges did not yet have, the Commission arrives at different conclusions. Specifically the Commission is able to determine that, under a broad range of reasonable scenarios and subject to reasonable conditions, the Big Stone II proposal is more cost-effective than other alternatives.

On the basis of its analysis of the current record, and with due considerations of the conditions discussed herein, the Commission concludes that the requirements of Minn. Rules, part 7849.0120, have been fulfilled:

- First, the record shows that denying the application would probably impair the future adequacy, reliability, or efficiency of energy supply to the applicants, to the applicants' customers, or to the people of Minnesota and neighboring states. The Commission finds that the record demonstrates a demand for 380-395 MW within the applicants' service territories,[89] as well as a regional demand for 5000-7000 MW of wind power from southwest Minnesota to meet the Renewable Energy Standards.

- Second, the Big Stone II proposal is at least as reasonable and prudent as any other alternative demonstrated by a preponderance of the evidence on the record. No party claims to have demonstrated a more reasonable and prudent alternative for meeting the forecasted demand, or denies that the applicants will need to acquire at least some new sources of electricity generated from non-renewable fuels.[90]

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[88] Second ALJs' Report, pp. 43-44 (memorandum).

[89] *Id.*, Finding 23.

[90] Third ALJs' Report, pp. 44.

- Third, a preponderance of the evidence shows that the proposed facilities, or a suitable modification thereof, would benefit society in a manner compatible with protecting the natural and socioeconomic environments. The Commission finds that, under reasonable assumptions and subject to reasonable conditions, the Big Stone II proposal is the most cost-effective way to serve the forecasted demand.

- Finally, the record does not demonstrate that the design, construction, or operation of the proposed facility would fail to comply with those relevant policies, rules, and regulations of other state and federal agencies and local governments.

The Commission finds that between 355 - 365 MW of demand cannot be met more cost effectively through energy conservation and load-management measures, in fulfillment of Minn. Stat. § 216B.243, subd. 3. And the Commission finds that under reasonable assumptions the Big Stone II proposal is less expensive, including environmental costs, than power generated from other sources, in fulfillment of Minn. Stat. § 216B.243, subd. 3a.

For the foregoing reasons the Commission will reject Recommendation 1 in the Second ALJs' Report to deny the applicants' petition for a certificate of need, and will instead adopt the alternative recommendation to grant the requested certificate of need for transmission lines subject to conditions.

ORDER

1. The Commission affirms the Administrative Law Judges' Sixth Prehearing Order (November 10, 2008) and strikes –

   A. the November 6, 2008 prefiled testimony of Eric Laverty, and

   B. the November 6, 2008 prefiled testimony of Ward Uggerud at page 12, line 20, through page 13, line 14, and Exhibits 141-A and 141-B.

2. The December 1, 2006 Environmental Impact Statement prepared by the Office of Energy Security of the Minnesota Department of Commerce meets the requirements of applicable statutes and rules and is therefore adequate for purposes of issuing a certificate of need.

3. The Commission adopts the Administrative Law Judges' findings, conclusions and recommendations except as they are rejected herein or otherwise inconsistent with this Order and finds that the record supports granting a certificate of need with the conditions discussed herein. In particular, the Commission declines to adopt the following:

   A. The Administrative Law Judges' August 16, 2007 Findings of Fact, Conclusions of Law, and Recommendation (First ALJs' Report), Finding 107, and the Administrative Law Judges' May 9, 2008 Supplemental Findings of Fact, Conclusions of Law, and Recommendation (Second ALJs' Report), Findings 36, 42, 59, and 74, to the extent that they indicate that a capacity expansion model provides the sole basis by which to evaluate the cost-effectiveness of competing supply options.

B. The Second ALJs Report, Finding 33, to the extent it suggests that the applicants "as a whole" failed to demonstrate that their demand for electricity could not be met more cost-effectively by conservation and load management, even though Finding 27 acknowledges that three utilities with a combined demand of 355 - 365 MW had in fact made such a demonstration.

C. The first recommendation of the Second ALJs' Report.

4. The Commission hereby grants the applicants' request for a certificate of need for upgrading to 230 kV a transmission line and associated facilities from the South Dakota border to the Morris substation, and upgrading to 345 kV a transmission line and associated facilities from the South Dakota border to the Granite Falls substation. This certificate of need is granted subject to the following conditions that will continue to apply so long as the Big Stone II project moves forward:

A. The applicants shall abide by their commitments in the August 31, 2007 Settlement Agreement, consistent with this Order. An excerpt of the Settlement Agreement is attached..

B. The applicants shall make the proposed Big Stone Unit II generator carbon capture retrofit ready.

C. The applicants shall conduct a detailed assessment of the feasibility and prudence of building Big Stone Unit II using ultra-supercritical technology and shall report their conclusions to the Commission in 2009.

D. Otter Tail shall provide updated capital cost estimates for the Big Stone II proposal prior to any Final Notice to Proceed and the final determination by owners to proceed with the project – at least with respect to the 60 MW share intended for Otter Tail's Minnesota customers.

E. Otter Tail shall make an informational filing in 2009 reviewing project contracting methodology.

F. Otter Tail shall cease to operate the Hoot Lake generators as a coal-fired generating station no later than the end of 2018 unless it is determined through the development, discussion and approval of Otter Tail's resource plans that the continued operation of the Hoot Lake generators is necessary to meet the needs of Minnesota ratepayers cost-effectively, taking into consideration the environmental costs of the generators' continued operation.

5. This Order shall become effective immediately.

BY ORDER OF THE COMMISSION

Burl W. Haar

Burl W. Haar
Executive Secretary

(S E A L)

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SETTLEMENT AGREEMENT

HIGH VOLTAGE TRANSMISSION LINES-BIG STONE UNIT II

MINNESOTA PUBLIC UTILITIES COMMISSION DOCKET NO. CN-05-619

This Settlement Agreement ("Agreement") is executed by and between the electric utility companies set forth below and the Energy Planning and Advocacy function of the Minnesota Department of Commerce ("Department"). Together the aforementioned persons are regarded as the Parties ("Parties") to this Settlement Agreement ("Agreement"). The effective date of this Agreement is August 30, 2007 ("Effective Date"). The undersigned Parties recommend that the Minnesota Public Utilities Commission ("Commission") accept this Agreement and approve the Certificate of Need Application filed in the above matter, subject to this Agreement.

Certificate of Need Proceeding Background

A. On November 30, 2005, Otter Tail Power Company ("OTP"), Great River Energy ("GRE"), Missouri River Energy Services ("MRES") on behalf of Western Minnesota Municipal Power Agency, Montana-Dakota Utilities Co. ("MDU"), Southern Minnesota Municipal Power Agency ("SMMPA"), Central Minnesota Municipal Power Agency ("CMMPA"), and Heartland Consumers Power District ("HCPD") (hereinafter collectively referred to as "the Owners") applied to the Minnesota Public Utilities Commission ("Commission") for a Certificate of Need ("CON Proceeding") to construct two high voltage transmission lines located in Minnesota, Commission Docket No. CN-05-619, CON Application, Applicants' Exhibit 68A and 68B. The Owners with retail electric load in Minnesota are referred to as the "Minnesota Owners" and are as follows: Otter Tail Power Company, Great River Energy, Missouri River Energy Services, Southern Minnesota Municipal Power Agency, Central Minnesota Municipal Power Agency and Heartland Consumers Power District.

B. The high voltage transmission lines are proposed to connect a 630 MW supercritical, coal-fired power plant to be constructed near Big Stone City, South Dakota ("Big Stone Unit II"), adjacent to the existing Big Stone Unit I, to the transmission grid at substations located in Minnesota. The preferred option consists of a 230 kilovolt line that would run from the Big Stone 230 kV Substation in South Dakota to the Morris Substation near Morris, Minnesota, a distance of approximately 48 miles, approximately 43 miles of which would be within Minnesota (the "Morris Line"). A second line would run from a new substation at the Big Stone power plant to Granite Falls, Minnesota, a distance of approximately 90 miles, 54 miles of which would be within Minnesota (the "Granite Falls Line"). Although initially to be operated at 230kV, the Granite Falls Line would be constructed to 345 kV standards for the purpose of accommodating additional power, likely from wind generation units to be located in western Minnesota and eastern South Dakota. CON Application, Applicants' Exhibit 68A at page 72, attached as Appendix No. 1.

C. Big Stone Unit II is a supercritical, pulverized coal-fired generating plant to be built outside of Big Stone City, South Dakota, next to the existing Big Stone Unit I power plant. Big Stone Unit II is designed to have a nominal operating capacity of 630 MW (net).

Supplemental Direct Testimony of Mark Rolfes, Applicants' Exhibit 32, at page 10, attached as Appendix No. 2. Big Stone Unit II is designed to be a baseload facility. It will use sub-bituminous coal from the Powder River Basin in Wyoming and Montana, the same fuel presently being burned at Big Stone Unit I. CON Application, Applicants' Exhibit 68A, at page 74 and Direct Testimony of Mark Rolfes, Applicants' Exhibit 7, at pages 3-4, attached together as Appendix No. 3.

At the present time, each Owner's proposed share of Big Stone Unit II is as follows:

Owner	MW	Percent of Total BSII
MRES	157.5 MW	25.0 %
GRE	121.8 MW	19.33 %
MDU	121.8 MW	19.33 %
OTP	121.8 MW	19.33 %
SMMPA	49.35 MW	7.8 %
CMMPA	31.5 MW	5.0 %
HCPD	26.25 MW	4.2 %

The record in the CON Proceeding includes information showing that the costs for Big Stone Unit II are 10% to 18% lower than comparable lifetime costs for investor-owned utilities, and 29% to 44% lower for public power utilities compared to other baseload alternatives considered. These costs assume the following project features and are included in the CON Proceeding record (as cited below):

- Supercritical pulverized coal plant design as chosen by the Owners over alternatives for, among other reasons, its high fuel and operating efficiencies. Rebuttal Testimony of Mark Rolfes, Applicants' Exhibit 65, at pages 2-3, attached as Appendix No. 4, and Direct Testimony of Ward Uggerud, Applicants' Exhibit 6, at pages 13-14 and 21, attached as Appendix No. 5.

- Big Stone Unit II's estimated average fuel efficiency (heat rate) of 8,988 MMBtu/MWh, making it 20% more fuel-efficient (and thereby producing approximately 20% less carbon dioxide per unit of electric output) than existing regional coal plants. Rebuttal Testimony of Mark Rolfes, Applicants' Exhibit 65, at pages 1-2, attached as Appendix No. 6.

- Environmental wet scrubber equipment to serve both Big Stone Unit II and the existing Big Stone Unit I power plant, such that total SO_2 and NO_x emissions from the plant site including both units will not exceed current emissions of Big Stone Unit I alone, while site electric output will be more than doubled. Direct Testimony of Terry Graumann, Applicants' Exhibit 26, at pages 3-4, attached as Appendix No. 7.

- Optimized transmission lines with the Granite Falls Line built to 345 kV standards, rather than 230 kV standards that would otherwise be required to interconnect Big

Stone Unit II to the transmission grid. Together with other planned regional transmission developments, this will provide capacity for 800 MW - 1000 MW of future generation developments, likely renewable wind energy projects. Direct Testimony of Timothy Rogelstad, Applicants' Exhibit 2, at p. 4, and Dec. 5 Transcript at page 86 (Tim Rogelstad), attached as Appendix No. 8.

D. The Owners testified in the CON Proceeding that each utility's individual resource planning studies and proceedings have established a need for additional generation in the near future.

E. The Mid-Continent Area Power Pool (MAPP) 2006 Load and Capability Report predicts that continuing load growth in the Upper Midwest region will result in a deficit in summer 2011 for MAPP U.S. generating capacity even with the addition of Big Stone Unit II. Direct Testimony of Peter Koegel, Project Manager, MAPPCOR, Applicants' Exhibit 23, at page 6, attached as Appendix No. 9.

F. The Midwest Independent Transmission System Operator (MISO) testified in the CON Proceeding that the proposed transmission lines would benefit regional electric grid reliability in addition to providing optimal transmission interconnection facilities. Direct Testimony of Eric Laverty, MISO Exhibit 1, at pages 14-19, attached as Appendix No. 10.

G. The wholesale electricity generation market indicates that there is already a significant increase in the on-peak and off-peak wholesale prices of electricity; this situation supports the addition of transmission and new baseload resources as reasonable.

H. The Owners agree as part of this Agreement to install highly effective pollution control equipment to control emissions from both Big Stone Unit I and Unit II, to wit: emissions of sulfur dioxide (SO_2) from Big Stone Units I and II will be controlled by a common wet flue gas desulfurization system (i.e., wet scrubber). SO_2 emissions from both Big Stone Unit I and Big Stone Unit II are expected to be less than 15% of the present emissions from Unit I alone. Emissions of nitrogen oxides (NO_X) will also be reduced both by the use of a supercritical boiler and the installation of a selective catalytic reduction (SCR) NO_X emission control technology on Big Stone Unit II. The sum total of the Big Stone Unit I and Big Stone Unit II NO_X emissions will be equal to or less than Big Stone Unit I's historical NO_X emissions. Particulate matter will be controlled by a pulse-jet fabric filter, and Owners expect 99.9% removal. Direct Testimony of Terry Graumann, Applicants' Exhibit 26, at pages 3-4, attached as Appendix No. 7.

I. The Minnesota Owners have agreed to offset 100% of the emissions of carbon dioxide from the Big Stone Unit II that are attributable to the generation of electricity for Minnesota consumers, as described below. MDU, as the only non-Minnesota Owner, does not object to this provision.

J. Action by the State of Minnesota or the federal government to address the emissions of greenhouse gases such as carbon dioxide from power plants is anticipated within the timeframe required for construction of Big Stone Unit II.

K. The Owners submitted evidence in the CON Proceeding that they have considered and analyzed other alternative forms of generation including renewables, natural gas, and integrated gasification combined cycle, and additional demand-side alternatives including additional energy conservation and concluded these other alternatives are not capable of providing a baseload resource alone or are more expensive than the proposed Big Stone Unit II (including the consideration of reasonable costs imposed by future greenhouse gas regulation). The Owners contend such alternatives cannot be constructed within the timeframes required for the additional capacity and energy to be provided by Big Stone Unit II. Direct Testimony of Jeffrey Greig, Applicants' Exhibit 25, Direct Testimony of Kiah Harris, Applicants' Exhibit 24, CON Application, Applicants' Exhibit 68A, Appendix J, Supplemental Direct Testimony of Jeffrey Greig, Applicants' Exhibits 47 and 47A. Direct Testimony of Bryan Morlock (OTP), Applicants' Exhibit 15. Direct Testimony of Stan Selander (GRE), Applicants' Exhibit 17. Direct Testimony of Robert Davis (CMMPA), Applicants' Exhibit 22. Direct Testimony of Gerald Tielke (MRES), Applicants' Exhibit 18. Direct Testimony of Hoa Nguyen (MDU), Applicants' Exhibit 19. Direct Testimony of Larry Anderson (SMMPA), Applicants' Exhibit 20. Direct Testimony of John Knofczynski (Heartland), Applicants' Exhibit 21, collectively attached as Appendix No. 11.

L. The Minnesota Owners are subject to Minnesota's Renewable Energy Standard ("RES"), codified at 216B.1691, which was enacted after the close of the record in the CON Proceeding. Minn. Laws 2007, Ch. 3. As shown in Exhibit A, pursuant to that law, according to the current load forecasts of the Minnesota Owners, the Minnesota Owners will own or purchase more than 2600 GWh per year of renewable energy by the year 2012 (equivalent to approximately 750 MW of nameplate wind capacity at a 40% annual capacity factor) and approximately 5100 GWh per year of renewable energy by the year 2020 (equivalent to approximately 1460 MW of nameplate wind capacity at a 40% annual capacity factor). As discussed below, the Owners' decision to size the Granite Falls Line at 345 kV standards may allow additional renewable power to be delivered, which may assist the Minnesota Owners and other utilities in meeting the RES.

M. Recently enacted legislation in Minnesota imposes annual energy savings goals equivalent to 1.5 % of gross retail energy sales for each individual retail provider in Minnesota through energy conservation improvement programs and rate design, energy codes and appliance standards, programs designed to transform the market or change consumer behavior, energy savings resulting from efficiency improvements to the utility infrastructure and system, and other efforts to promote energy efficiency and energy conservation. Minn. Stat. §§ 216B.2401 and 216B.241, subd.1c. Achieving these goals would mean approximately 390 GWh per year of savings in Minnesota by the Minnesota Owners by the year 2020, as set forth in Exhibit B.

N. The high voltage transmission lines that are proposed to interconnect the Big Stone Unit II are intended to and likely will provide capacity for the transport of wind energy from South Dakota and North Dakota and southwestern Minnesota to the Twin Cities and other markets. See, e.g., Direct Testimony of Timothy Rogelstad, Applicants' Exhibit 2, at page 16, attached as Appendix No. 12.

O. The Commission's Wind Integration Study (Wind Integration Study, Dec. 2006), which shows the approximate cost to the transmission system of adding wind-sourced energy to the generation load in an amount roughly equal to 25% of Minnesota's electricity sales, includes in its base case the high voltage transmission lines in this docket. This information contributes to a showing of the importance of these transmission facilities to wind development in western Minnesota.

P. The Parties agree that Minnesota needs a diverse electric resource mix in the coming years, including additional renewables, additional energy conservation, and new conventional generation facilities. Recent actions by the Minnesota Legislature and Governor with regard to the RES and increased Conservation Improvement Program (CIP) goals are important elements in this future.

The Parties agree that a diverse and balanced resource plan including the Minnesota Owners' actions toward the RES, the increased CIP impacts, and Big Stone Unit II including the high voltage transmission lines proposed in the CON Proceeding, along with other resources is reasonable and prudent. In addition to its other benefits, Big Stone Unit II will help assure electric service reliability and reasonable costs for Minnesota consumers.

Q. The Parties acknowledge that the Administrative Law Judges, in their August 15, 2007 Findings of Fact, Conclusion of Law, and Recommendation, conclude that the Owners 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.

NOW THEREFORE, THE UNDERSIGNED PARTIES HEREBY ENTER INTO THIS AGREEMENT in Commission Docket No. CN-05-619 and recommend that the Commission issue a Certificate of Need for the proposed two high voltage transmission lines intended to interconnect the proposed Big Stone Unit II power plant in South Dakota to substations in Minnesota, subject to this Agreement.

1.0 JURISDICTION AND PARTIES

1.1 *Minnesota Public Utilities Commission Jurisdiction.* The Owners have applied to the Commission for a Certificate of Need and Route Permits for the two proposed high voltage transmission lines. The Commission does not have jurisdiction to require a Certificate of Need for Big Stone Unit II.

1.2 *South Dakota Public Utilities Commission Approval.* On July 21, 2006, the South Dakota Public Utilities Commission issued an Energy Conversion Facility Permit and Route Permit for the proposed Big Stone Unit II in South Dakota. On January 16, 2007, the South Dakota Public Utilities Commission issued its order granting a permit to construct the associated transmission facilities in South Dakota. The South Dakota Public Utilities Commission does not have jurisdiction over this Certificate of Need for large energy facilities, such as these proposed transmission lines in Minnesota.

1.3 *Department of Commerce.* The Minnesota Department of Commerce is an agency of the state of Minnesota with statutory authority to represent the public interest in certificate of need and other proceedings before the Commission. The Department provides two separate and distinct roles with two separate and distinct staffs. The Department's Energy Planning and Advocacy function and staff serve as the state agency charged with advocating for the public interest and is a party to this CON Proceeding and to this Agreement. The Department's Energy Facilities Permitting function and staff do not serve as an advocate or a party in either the CON Proceeding, or in the related Route Permit proceeding, Docket No. TR-05-1275, or in this Agreement. However, the Energy Facilities Permitting staff does serve as the facilitators of the processes required in route permitting proceedings as well as ensuring that the route permitting record is complete for the Commission's decision.

1.4 *Otter Tail Power Company.* Otter Tail Power Company (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. OTP provides electricity to over 128,000 customers throughout Minnesota, South Dakota, and North Dakota. Report and Recommendation of the Administrative Law Judges, August 15, 2007, at page 3, attached as Appendix No. 13.

1.5 *Great River Energy.* Great River Energy (GRE) is a not-for-profit 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. Report and Recommendation of the Administrative Law Judges, August 15, 2007, at page 4, attached as Appendix No. 14.

1.6 *Missouri Basin Municipal Power Agency d/b/a Missouri River Energy Services.* Missouri River Energy Services (MRES) is a not-for-profit body politic and public agency organized under Iowa law and existing under the intergovernmental cooperation laws of Iowa, Minnesota, North Dakota and South Dakota. MRES is the agent for Western Minnesota Municipal Power Agency (Western Minnesota). Western Minnesota is a municipal corporation and political subdivision of the State of Minnesota, and will hold title to ownership in the Big Stone Unit II and the high voltage transmission lines proposed in the CON Proceeding, and will sell to MRES its entitlement to the power, energy and transmission capability associated with the Big Stone Unit II project. CON Application, Applicants' Exhibit 68A, at page 27, attached as Appendix No. 15, and Report and Recommendation of the Administrative Law Judges, August 15, 2007, at page 5, attached as Appendix No. 16. In addition, although not an owner of the project, Hutchinson Utilities Commission has rights to the capacity and energy of Big Stone Unit

II through a power purchase agreement with MRES. Direct Testimony of Gerald Tielke, Applicants' Exhibit 18, at pages 18-20, attached as Appendix No. 17.

1.7 *Southern Minnesota Municipal Power Agency.* 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 has 18 municipally-owned member utilities. Report and Recommendation of the Administrative Law Judges, August 15, 2007, at page 5, attached as Appendix No. 18.

1.8 *Central Minnesota Municipal Power Agency.* 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 has 12 municipally-owned member utilities; all located in Minnesota. In addition, although not a member of CMMPA, the City of Willmar Municipal Utilities is participating in the Big Stone II project through the agency. Report and Recommendation of the Administrative Law Judges, August 15, 2007, at page 4, attached as Appendix No. 19.

1.9 *Heartland Consumers Power District.* Heartland Consumers Power District is a not-for-profit public corporation and political subdivision of the state of South Dakota, headquartered in Madison, South Dakota. Heartland supplies wholesale electric power and energy to 18 municipalities across eastern South Dakota, southwestern Minnesota, and northwestern Iowa. Report and Recommendation of the Administrative Law Judges, August 15, 2007, at page 8, attached as Appendix No. 20.

1.10 *Montana-Dakota Utilities Co.* Montana-Dakota Utilities Co. (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. MDU provides electric and natural gas services to approximately 250 communities in these states. Report and Recommendation of the Administrative Law Judges, August 15, 2007, at page 4, attached as Appendix No. 21.

2.0 RECOMMENDATION

2.1 *Compliance with Applicable Criteria.* The Parties hereby stipulate and agree that the record in this matter, as supplemented by this Agreement and all provisions hereof, along with the overarching new laws regarding energy efficiency and renewable energy combine to satisfy the Department's concerns expressed in the record pertaining to the applicable criteria for a Certificate of Need for the two proposed high voltage transmission lines, including those criteria set forth in Minnesota Statutes chapter 216B and Minnesota Rules chapter 7849.

2.2 *Recommendation.* The Parties jointly recommend that the Commission issue a Certificate of Need to the Owners for the two high voltage transmission lines proposed in the CON Proceeding, subject to this Agreement and all provisions hereof.

3.0 FACILITIES' COST AND COST RECOVERY

3.1 *Capital Cost of Transmission Lines.* The Owners estimate that the cost of the proposed high voltage transmission lines, including all substation costs with the exception of the 345 kV substation in South Dakota and the conversion of the Canby substation to 345 kV standards, is $109.8 million (in 2006 dollars), and not including costs for transmission facilities required to provide Delivery Service, for permitting, or for additional transmission studies and agreements. Report and Recommendation of the Administrative Law Judges, August 15, 2007, at pages 18-20, attached as Appendix 22. The CON Proceeding record indicates that the costs will increase by approximately 6% for each year that construction is delayed past the estimated in-service date.

3.2 *Capital Cost of Big Stone Unit II.* The cost of Big Stone Unit II, as presented by the Owners in the CON Proceeding, exclusive of transmission costs, was estimated to be $1.4 billion based on a April 2012 commercial operation date ("COD"). The record indicates that the costs will increase by approximately 6% for each year that construction is delayed past the estimated in-service date. Report and Recommendation of the Administrative Law Judges, August 15, 2007, at page 17, attached as Appendix No. 23. Attached as Appendix No. 24, is a schedule that shows the cost of Big Stone Unit II on a monthly basis up to and through a proposed commercial operation date of April 2012.

3.3 *Operating Costs.* The estimated levelized annual cost over the lifetime of Big Stone Unit II, assuming the first full year of operation and a January 2012 COD, ranges from $69.6 to $74.5 per MWh for investor-owned utilities, to $56.4 to $61.2 per MWh for public power utilities. Supplemental Direct Testimony of Jeffrey Greig, Applicants' Exhibit 47, at pages 11-12, attached as Appendix 25. The cost per unit of output from Big Stone Unit II, including costs for both the plant and its transmission, will vary among the Owners depending upon their financing arrangements, capital structure, and other factors. See, e.g., Revised Analysis of Baseload Generation Alternatives, Applicants' Exhibit 47A, attached as Appendix No. 26.

3.4 *Final Capital Costs.* Within fourteen (14) months of Big Stone Unit II's COD, the Minnesota Owners will file a written report with the Commission and the Department containing the actual capital costs of the high voltage transmission lines and Big Stone Unit II and comparing the actual costs with the estimated costs set forth above and explaining the reasons for any differences. Reporting the costs, as required in this paragraph, contributes to but does not fulfill the Owners' obligation to demonstrate that the actual capital costs were reasonably and prudently incurred for purposes of cost recovery as contemplated in section 3.6 below.

3.5 *Periodic Reports.* The Minnesota Owners will report to the Commission and the Department on the annual costs ($/MWh) for each Minnesota Owner based on actual costs for the preceding twelve months and levelized lifetime carrying charges on the actual investment in the project, including Unit II and the transmission lines. The first report shall be due within thirty days after the first anniversary of Big Stone Unit II COD, and the Minnesota Owners shall file such a report along with the reporting requirements set forth in section 3.4, for a period of four (4) additional years.

3.6 *Cost Recovery.* The commitments made or to be made by the Owners with respect to this Agreement are made on the expectation that OTP and MDU will obtain cost recovery from the state commissions having jurisdiction of all reasonable and prudent costs and expenditures through a rate case, tariff, rate rider, or other applicable cost or rate recovery mechanism.

Costs attributed to Big Stone Unit II or the proposed high voltage transmission lines shall be set forth separately and distinctly in all applicable cost recovery requests to the Commission, accompanied by supporting documentation.

3.7 *Department Support of Cost Recovery.* The Department will support OTP's recovery of all reasonable and prudent costs and expenditures as long as they are materially consistent with the costs described in sections 3.1, 3.2, and 3.3, and with costs reasonably attributable to the actions required by sections 4.0, 5.0, and 7.0 (unless otherwise recovered through a separate rate recovery mechanism).

4.0 OFFSETS OF GREENHOUSE GAS EMISSIONS

4.1 *100% of Minnesota-Attributable Emission Offsets.* Using the offset methods set forth in section 4.3, the Minnesota Owners agree to offset 100% of the carbon dioxide emissions attributable to the generation of electricity at Big Stone Unit II for customers in Minnesota. For the purposes of this Agreement, the portion of energy output from Big Stone Unit II attributable to a Minnesota Owner's Minnesota customers in a given time period will be the Minnesota Owner's share of the output of Big Stone Unit II expressed in MWh multiplied by the ratio that the Minnesota Owner's Minnesota retail electric energy obligations in that time period bears to the Minnesota Owner's total retail electric energy obligations in the time period.

For example, for a given time period:

$$EO_{MN} = EO_{TOTAL} \text{ X } \left[\frac{Retail_{MN}}{Retail_{TOTAL}} \right]$$

Where:

EO_{MN} = The portion of energy output (in MWh) from Big Stone II attributable to a Minnesota Owner's Minnesota customers;

EO_{TOTAL} = The Minnesota Owner's share of the output of Big Stone Unit II (in MWh);

$Retail_{MN}$ = The Minnesota Owner's Minnesota retail electric energy obligations (in MWh); and

$Retail_{TOTAL}$ = The Minnesota Owner's total retail electric energy obligations (in MWh).

4.2 *Timing and Calculation of Emissions to be Offset.*

4.2.1 *Offsets May Be Secured Ahead of Operations.* The Minnesota Owners may secure offsets using the methods in sections 4.3 at any time, but as soon as Big Stone Unit II begins commercial operation, the offsets must be made within one year of the emissions. The Minnesota Owners may secure offsets of future Big Stone Unit II carbon dioxide emissions prior to the COD of Big Stone Unit II, and may use offsets secured prior to the Unit's commercial operation date to offset future emissions.

4.2.2 *First Year of Operation.* Six months prior to the COD of Big Stone Unit II, the Minnesota Owners will forecast the amount of carbon dioxide that is projected to be emitted by Big Stone Unit II along with the Minnesota Owners' projected method(s) for obtaining offsets for carbon dioxide for the first twelve-months of operation and will request verification of the Minnesota Pollution Control Agency ("MPCA") of said emission and offset amounts, and will advise the Commission and Department of their actions.

4.2.3 *After Operations Have Begun.* As part of the Greenhouse Gas Management Plan under section 4.11, the Minnesota Owners will determine how many tons of carbon dioxide were emitted to generate electricity for their Minnesota customers in the previous twelve months and report this figure along with its estimated offset costs to the Commission, MPCA, and the Department. This amount will be the amount of carbon dioxide that will be used as the baseline forecast for offsets to be procured in the next ensuing twelve-month period, subject to reasonable adjustments based on actual operating history of Big Stone Unit II and other factors, as approved by the Commission.

4.2.4 *"Extra" Offsets Carry-Forward.* Any offsets obtained in one year that are greater than the emissions associated with serving customers in Minnesota for that year may be credited towards the offsets needed in the subsequent year or years unless they are sold, traded or otherwise transferred. In the event the credits are sold, traded, or otherwise transferred, any funds received from the sale by OTP (or any future utility or entity to which this Agreement applies and whose rates are regulated by the Commission) will be used for carbon offsets in subsequent years or credited to OTP's customers (or the customers of any future utility or entity to which this Agreement applies and whose rates are regulated by the Commission), as applicable.

4.2.5 *Emission Offset Calculation Termination.* The Minnesota Owners will continue the process set forth in sections 4.2.1 to 4.2.4 until this requirement is terminated pursuant to section 4.10.

4.3 *Offset Methods*. At the option of the Minnesota Owners, the carbon dioxide offsets required in section 4.1 may be achieved by any one or a combination of the following methods, with the goal being to achieve permanent (or at a minimum permanent during the entire specified time period the purchased credits are intended to apply), quantifiable, verifiable, and enforceable reductions in greenhouse gas emissions that would not otherwise have occurred:

a. Capture and sequestration;

b. Emission reductions in any of the Minnesota Owners' existing power plants or through other, verifiable efficiency improvements on the Minnesota Owners' systems that result in reductions in carbon dioxide emissions;

c. Trading on a recognized Greenhouse Gas ("GHG") exchange, consistent with section 4.4;

d. Purchases of carbon credits from a credible offset program, consistent with section 4.5;

e. Setting aside funds, consistent with section 4.6, in a separate, readily identifiable account on the Minnesota Owners' books of an amount equal to $10.00 per ton of carbon dioxide emissions;

f. Making investment in transmission that the Commission certifies will enhance renewable energy development, consistent with section 4.7;.

g. Adding renewable energy beyond any amount required by law, consistent with section 4.8;

h. Achieving energy efficiency savings beyond any amount required by law, consistent with section 4.9; or

i. Any other method the Commission concludes will result in economic offsets that will achieve permanent, quantifiable, verifiable, and enforceable reductions in greenhouse gas emissions that would not otherwise have occurred.

4.4 *Carbon Trading*. If the Minnesota Owners offset greenhouse gas emissions through an established carbon trading exchange pursuant to section 4.3(c) above, the Minnesota Owners will inform the Commission and the Department of the exchange(s) to be used. While the presumption is that any exchange recognized by a state or federal government is acceptable, the Minnesota Owners have the burden of proving that this offset option should be recognized as credible in Minnesota, with the exception that the Parties agree that the Oregon Climate Trust and the Chicago Climate Exchange (CCX) and its successors are already acceptable without further proof by the Minnesota Owners. Any profits, interest or carrying charges on the monies received by OTP (or by any future Minnesota-regulated utility to which this Agreement applies) from carbon trading will be credited to OTP's ratepayers (or the ratepayers of any Minnesota-regulated utility to which this Agreement applies) or be deposited into the carbon offset fund established in section 4.6.

4.5 *Purchase of Carbon Credits.* If the Minnesota Owners offset greenhouse gas emissions through the purchase of carbon credits pursuant to section 4.3(d), the Minnesota Owners will inform the Commission and the Department of the program to be used. The Minnesota Owners will show that the program chosen will result in permanent (or at a minimum permanent during the entire specified time period the purchased credits are intended to apply), verifiable, quantifiable and enforceable reductions in greenhouse gas emissions.

4.6 *Carbon Offset Fund.* If the Minnesota Owners offset their greenhouse gas (i.e., carbon dioxide) emissions through payment of a specified sum per ton of carbon dioxide emissions pursuant to section 4.3(e), the Owners will inform the Commission and the Department of their election to do so, amounts paid, amount of carbon dioxide offset in this manner, and of the specifics of the accounts established. Each Owner may elect to establish its own account, or two or more Minnesota Owners may join together to establish one account jointly. No one Owner shall be a party to more than one account.

4.6.1 *Use of Funds.* Funds set aside pursuant to section 4.3(e) above, and any interest or carrying charges earned thereon, must be used by the Minnesota Owners only for offset methods identified in section 4.3 or research and development projects supporting the offset methods identified in section 4.3 for use by the Minnesota Owners. The Minnesota Owners will advise the Commission and the Department of the expenditure of any of these funds and the balance of the account, in the Greenhouse Gas Management Plan submitted in accordance with section 4.11.

4.6.2 *Accounting Practices and Review.* The Minnesota Owners agree that any accounts established and any account activity pursuant to this section 4.6 will be subject to reasonable accounting methods and to review by the Commission and the Department.

4.7 *Transmission Investments for Renewables.* The Minnesota Owners may seek to obtain offsets of greenhouse gas (i.e., carbon dioxide) emissions for each of the years in which the Minnesota Owners' incremental investment in transmission facilities enhances either the quantity or timing of renewable energy development beyond that which would have otherwise occurred. The Minnesota Owners will ask the Commission to determine in a later proceeding the amount of offset credit, if any. The Minnesota Owners will file with the Commission a proposed offset credit method for purposes of this section 4.7 within two years following Commission approval of the Certificate of Need in this matter. The offset method may include the following formula: if a utility's fixed charge rate is 12% and the utility's aggregate investment in a single project or number of projects is $7,000,000, then the utility will have an annual carbon offset credit of 84,000 tons (calculated as $7,000,000 x 0.12 = $840,000/$10/ton = 84,000 tons of carbon offset).

4.8 *Renewable Energy Investments.* The Minnesota Owners will be eligible to obtain offsets of greenhouse gas (i.e., carbon dioxide) emissions for each of the calendar years in which the Minnesota Owners add renewable energy in amounts beyond that required by law. These amounts will be determined by comparing the actual renewable energy achieved in any calendar year with the renewable energy requirements under the RES. The Parties agree that the Minnesota Owners shall be eligible for offsets on a MWh for MWh basis for any renewable energy the Minnesota Owners generate or otherwise obtain in excess of those levels required by the Minnesota RES. The Minnesota Owners will report to the Commission, as part of the Greenhouse Gas Management Plan under section 4.11, the actual amount of offsets.

4.9 *Energy Efficiency Investments.* The Minnesota Owners will be eligible to obtain offsets of greenhouse gas (i.e., carbon dioxide) emissions for each of the calendar years in which the Minnesota Owners, their distribution member systems, or both, make energy efficiency improvements in amounts beyond that required by law. These amounts will be determined by comparing the actual energy efficiency (kWh) impacts achieved in a particular calendar year, as determined by the Commissioner of the Department of Commerce, with the energy efficiency savings required by applicable law. Based on this determination, the Parties agree that the Minnesota Owners shall be eligible for offsets on a MWh-for-MWh basis for any energy efficiency impacts the Minnesota Owners achieve in excess of those levels required by Minnesota law. The Minnesota Owners will report to the Commission, as part of the Greenhouse Gas Management Plan under section 4.11, the actual amount of offsets.

4.10 *Termination of Offset Requirement.* The Parties agree that the greenhouse gas emissions offset requirement of section 4.1 will continue until the earlier of (1) the date on which a Minnesota or federal greenhouse gas ("GHG") program intended to reduce the increase of GHG emissions has been implemented (and which program applies to GHG emissions from Big Stone Unit II), or (2) four (4) years after the Big Stone Unit II COD if a Minnesota or federal GHG program intended to reduce the increase of GHG emissions has not been adopted and implemented by that date. Upon the termination of the Minnesota Owners' greenhouse gas emissions offset obligations under this section 4.0, the Minnesota Owners are obligated to provide the offsets for any emissions occurring prior to the termination date that have not yet been offset. It is the Parties' understanding that the Minnesota Owners will not be obligated to offset GHG emissions under both a Minnesota and federal GHG program at the same time that the Minnesota Owners are required to make offsets under the terms of this Agreement. That is, the Minnesota Owners will be required to offset GHG emissions only according to the terms of this Agreement or either (1) a federal GHG program or (2) a Minnesota GHG program and provided the program applies to GHG emissions from Big Stone Unit II.

4.11 *Greenhouse Gas (GHG) Management Plan.* The Minnesota Owners agree that beginning fourteen (14) months from the Big Stone Unit II COD and annually thereafter until terminated according to section 4.10, the Minnesota Owners, individually or collectively, will submit a GHG Management Plan to the Commission, the MPCA, and the Department that will report the status of carbon dioxide offsets required under this Agreement in the previous year as well as any emissions occurring prior to the filing of the GHG Management Plan that have not yet been offset, and describe the Minnesota Owners' efforts to offset greenhouse gas emissions (i.e., carbon dioxide) in the upcoming year or years. The GHG Management Plan will also be used to verify GHG offsets that have been made in the past, and to review and approve the expenditure of funds as contemplated in section 4.1.

5.0 CONTROL OF MERCURY EMISSIONS

The Owners will control mercury emissions from Big Stone Unit I and Unit II through use of a wet scrubber and also through use of a pulse jet fabric filter. The Owners also agree to install such other control equipment so as to control emissions of mercury from both Big Stone Unit I and Unit II such that the control equipment is equivalent to what is required of certain large generating facilities in Minnesota (*i.e.*, Sherco, and Clay Boswell) under the Mercury Emission Reduction Act of 2006 (Minnesota Statutes §§ 216B.68 to 216B.688) and that is most likely to result in the removal of at least 90 percent of the mercury emitted from the units. The Owners agree to act in good faith to install such equipment as expeditiously as possible, but the parties recognize that given the construction schedule and commercial operation date of Big Stone Unit II, the Owners have until four (4) years after the commercial operation date of Big Stone Unit II for the Owners to achieve compliance with these requirements. On the same dates as required for the GHG Management Plan under section 4.11 above, or until the mercury control goal set forth in this section 5.0 is met, the Owners will also provide a report to the Commission and the Department on the progress of meeting the mercury control goal.

6.0 PROTECTION OF BIG STONE LAKE

Big Stone Lake is a treasured natural resource of both South Dakota and Minnesota. It is also important to the operation of the Big Stone Units I and II. As a result, the Owners understand the importance of not adversely affecting the long-term level or flow of the lake. Accordingly, the Owners agree to:

- utilize groundwater for drought protection at the Big Stone Unit II;

- provide to the South Dakota Department of Environment and Natural Resources ("SDDENR") and the Minnesota Department of Natural Resources ("MNDNR") by June 27, 2007 and will provide, on an on-going basis, all data used to evaluate the Veblen aquifer and the effect on Big Stone Lake of extended groundwater withdrawal;

- provide to the SDDENR and the MNDNR by June 27, 2007 and will provide, on an on-going basis, all data used to evaluate the effect on the Minnesota River of an extended period of withdrawal of water from Big Stone Lake;

- support the granting of party status to the Minnesota Department of Natural Resources before the South Dakota Water Management Board ("WMB") in its requested Water Permit No 6846-3; and

- perform tests on the groundwater supply to evaluate well production and impacts relative to the modeling conducted pursuant to Water Permit No. 6846-3, consistent with the Owners' actual construction schedule and process for Big Stone Unit II.

The Owners have participated in meetings between the staffs of the SDDENR and MNDNR to work through the data prior to the July 11, 2007 WMB hearing on Water Permit No. 6846-3.

If the groundwater tests performed by the Owners as part of its construction of Big Stone Unit II differ materially from the models relied on by the Owners in the Water Permit No. 6846-3 before the WMB, the Owners understand that the MNDNR may request and that the WMB may reconsider the terms and conditions of Water Permit No. 6846-3, should it be granted in the first place.

Finally, the Owners also believe that long-term management of Big Stone Lake can best be done through organized, frequent communications between the two states and urges the two states to establish such communications by December 31, 2007. To that end, the Owners agree when asked by the state agencies, to constructively participate in meetings to address the management of the Big Stone Lake water flow and level issues.

7.0 RENEWABLES

7.1 *Renewable Energy Standard.* The Minnesota Owners understand and are subject to Minnesota Statutes § 216B.1691 (2007), that direct utilities in Minnesota to obtain from renewable resources seven percent (7%) of their total retail electric sales to retail customers in Minnesota by the end of 2010; twelve percent (12%) by 2012; seventeen percent (17%) by 2016; 20 percent (20%) by 2020; and twenty-five percent (25%) by 2025. The Department expects that the Minnesota Owners will meet these obligations.

7.2 *Community-Based Energy Development.* The Minnesota Owners commit to own or procure from C-BED projects no less than twenty-four percent (24%) of their individual RES obligations for the year 2012 expressed on an annual energy basis, subject to commercially reasonable contract terms and price. The Minnesota Owners will achieve this level of C-BED energy output no later than four years following the Big Stone Unit II COD.

Although any C-BED qualified renewable technology may be used to fulfill this energy commitment, for purposes of illustration based on current load forecasts of the Minnesota Owners for the year 2012 this annual energy commitment would be equivalent to the output of 180 MW of C-BED wind energy projects, assuming an annual wind capacity factor of 40%. The actual amount of energy from C-BED projects will be determined by the Minnesota Owners' actual RES obligations in 2012, expressed on an annual energy basis. The actual megawatts of C-BED capacity will be based on the actual RES energy obligations of the Minnesota Owners in 2012, and on the types of qualifying C-BED projects chosen to fulfill this C-BED energy commitment.

The Minnesota Owners may fulfill this C-BED commitment either as individual utilities or in aggregate. All C-BED commitments will be accomplished as part of, and not in addition to, the Minnesota Owners' RES obligations.

In addition to this 24% of RES commitment, the Minnesota Owners will take reasonable steps to identify additional C-BED projects that can meet the Minnesota Owners' cost and reliability requirements to satisfy a portion of the Owners' RES obligations under Minnesota Statutes, section 216B.1691. The Minnesota Owners will file reports with the Department by July 1, of 2013 and 2018 describing how these C-BED commitments are being fulfilled.

8.0 ENERGY EFFICIENCY AND CONSERVATION

8.1 *Compliance with the Conservation Improvement Program Goal.* The Minnesota Owners understand and are subject to Minnesota Statutes §§ 216B.2401 and 216B.241 (2007). The Department expects that the Minnesota Owners will meet these obligations. By June 1, 2008, the Minnesota Owners will file with the Department a plan describing how each utility (and its members for GRE, SMMPA, MRES, and CMMPA) intends to meet its energy savings goal.

8.2 *Aggregated DSM.* SMMPA, CMMPA, MRES, and GRE will strive to aggregate the DSM filings of their respective Minnesota members. For example, SMMPA will strive to aggregate the DSM filings of its members, GRE its members, etc.

8.3 *Water Heater Incentives.* The Owners who have established electric water heater incentives greater than $50 per heater that are not part of a DSM program shall terminate such programs by July 1, 2008. The Minnesota Owners will work in good faith with any of their Minnesota members who also have such programs to eliminate such programs by July 1, 2010.

8.4 *Elimination of Block Rates.* OTP shall propose the phased elimination of its declining block rate program in its next Minnesota rate case.

9.0 GENERAL TERMS AND CONDITIONS

9.1 *Entire Agreement.* This Settlement Agreement constitutes the entire agreement and understanding between the Parties pertaining to the resolution of this matter.

9.2 *Not Precedential.* The Parties agree that no precedent is established by the resolution of issues made in this Agreement. The resolutions reached herein are for settlement purposes only and do not necessarily represent the positions the Parties would take in litigation, the Owners' respective Integrated Resource Plans (IRP), or otherwise. The Parties will not use this Agreement as evidence for impeachment of a party in any future proceeding before the Commission or for use in any other administrative or judicial body.

9.3 *Not Admissible.* Unless the Commission approves this Agreement, this Agreement, and any statements made in furtherance thereof, shall not be admissible in evidence in this proceeding or in any other administrative or judicial proceeding.

9.4 *Terms Binding on Project Participants*; *Assignment.* The commitments and obligations of the Owners have application to, and are binding on, only those individual Owners so long as the utility is an Owner of the Big Stone Unit II or otherwise has entitlement to the capacity and energy from Big Stone Unit II. No individual Owner is responsible for the obligations of any other individual Owner, unless the Owner agrees in writing to assume the obligations of another Owner or former Owner. Within thirty days of the execution of any changes to the ownership structure for either Big Stone Unit II or the transmission facilities at issue in this docket, the Owners will notify the Commission and the Department of the change and provide any regulatory filings that may be applicable to the change. This Agreement and all provisions hereof is binding upon and inure to the benefit of the Parties and their respective successors and assigns.

9.5 *Commission Action; No Construction.* In the event the Commission disapproves this Agreement or takes other action inconsistent with this Agreement, or changes materially the terms of this Agreement as a condition to its acceptance, or if the Commission does not approve the needed Route Permits for the proposed transmission facilities in Minnesota in Docket #TR-05-1275, or if the Big Stone Unit II generating plant is not constructed for any reason, all Parties retain the right to treat this Agreement as null and void, or to seek reconsideration to modify their positions. Each party shall notify the other parties and the Commission of its intention regarding this Agreement in such event.

9.6 *Amendment.* No amendment to this Agreement is effective unless in writing and signed by all the Parties.

9.7 *Preparation of the Agreem*ent. All parties to this Agreement have had the opportunity to participate in the drafting of the document. There shall be no legal presumption that any specific party was the drafter of any particular provision.

9.8 *Authority.* The signatory for each organization entering into this Agreement has the necessary authority to bind the party and agrees to be bound by the Agreement in the future.

9.9 *Counterparts.* This Agreement may be signed in counterparts.

STATE OF MINNESOTA)
)SS
COUNTY OF RAMSEY)

AFFIDAVIT OF SERVICE

I, Margie DeLaHunt, being first duly sworn, deposes and says:

That on the 17th day of March, 2009 she served the attached

ORDER GRANTING CERTIFICATE OF NEED WITH CONDITIONS.

MNPUC Docket Number: E-017,ET-6131,ET-6130, ET-6144, ET-6135, ET-10/CN-05-619

XX By depositing in the United States Mail at the City of St. Paul, a true and correct copy thereof, properly enveloped with postage prepaid

XX By personal service

XX By inter-office mail

to all persons at the addresses indicated below or on the attached list:

Commissioners
Carol Casebolt
Peter Brown
Eric Witte
Marcia Johnson
Kate Kahlert
Janet Gonzalez
Bret Eknes
Bob Cupit
Susan Mackenzie
Mary Swoboda
DOC Docketing
AG - PUC
Julia Anderson - OAG
John Lindell - OAG

Margie DeLaHunt

Subscribed and sworn to before me,

a notary public, this 17th day of

March, 2009

Mary Jo Jasicki
Notary Public

MARY JO JASICKI
NOTARY PUBLIC-MINNESOTA
MY COMMISSION EXPIRES
JANUARY 31, 2010

, ListID# 1 :

10:
MN PUC

Burl W. Haar
MN Public Utilities Commission
Suite 350
121 7th Place East
St. Paul MN 55101-2147

20:
Dept. of Commerce

Sharon Ferguson
MN Department Of Commerce
Suite 500
85 7th Place East
St. Paul MN 55101-2198

30:
Inter-Office Mail

Julia Anderson
MN Office Of The Attorney General
1400 BRM Tower
445 Minnesota Street
St. Paul MN 55101-2131

Matt Langan
MN Department of Natural Resources
500 Lafayette Road
St. Paul MN 55155-4025

John Lindell
OAG-RUD
900 BRM Tower
445 Minnesota Street
St. Paul MN 55101-2130

40:
Regular Postal Mail

Mark B. Bring
Otter Tail Corporation
215 South Cascade Street
PO Box 496
Fergus Falls MN 56538-0496

Christy Brusven
Fredrikson & Byron, P.A.
Suite 4000
200 South Sixth Street
Minneapolis MN 55402-1425

John E. Drawz
Fredrikson & Byron, P.A.
Suite 4000
200 South Sixth Street
Minneapolis MN 55402-1425

Elizabeth Goodpaster
MN Center for Environmental Advocacy
Suite 206
26 East Exchange Street
St. Paul MN 55101-1667

Todd J. Guerrero
Lindquist & Vennum, PLLP
4200 IDS Center
80 South Eighth Street
Minneapolis MN 55402-2274

E-017,ET-6131,ET-6130,ET-6144,ET-6135,ET-10/CN-05-619, ListID# 1 Otter Tail Power Company;

10:
MN PUC

Burl W. Haar
MN Public Utilities Commission
Suite 350
121 7th Place East
St. Paul MN 55101-2147

20:
Dept. of Commerce

Sharon Ferguson
MN Department Of Commerce
Suite 500
85 7th Place East
St. Paul MN 55101-2198

30:
Inter-Office Mail

Julia Anderson
MN Office Of The Attorney General
1400 BRM Tower
445 Minnesota Street
St. Paul MN 55101-2131

Karen Finstad Hammel
MN Office Of The Attorney General
1400 BRM Tower
445 Minnesota Street
St. Paul MN 55101-2131

John Lindell
OAG-RUD
900 BRM Tower
445 Minnesota Street
St. Paul MN 55101-2130

Steve M. Mihalchick
Office of Administrative Hearings
PO Box 64620
St. Paul MN 55164-0620

Barbara L. Neilson
Office of Administrative Hearings
PO Box 64620
St. Paul MN 55164-0620

40:
Regular Postal Mail

Lisa M. Agrimonti
Briggs And Morgan, P.A.
2200 IDS Center
80 South 8th Street
Minneapolis MN 55402

Thomas Erik Bailey
Briggs And Morgan
2200 IDS Center
80 South 8th Street
Minneapolis MN 55402

William A. Blazar
Minnesota Chamber Of Commerce
Suite 1500
400 Robert Street North
St. Paul MN 55101

Michael J. Bradley
Moss & Barnett
4800 Wells Fargo Center
90 South Seventh Street
Minneapolis MN 55402-4129

Kaela Brennan
McGrann Shea Anderson Carnival
Straughn & Lamb
800 Nicollet Mall, Suite 2600
Minneapolis MN 55402-7035

Kathleen M. Brennan
McGrann Shea Anderson Carnival
Straughn & Lamb, Chartered
800 Nicollet Mall, Suite 2600
Minneapolis MN 55402-7035

Mark B. Bring
Otter Tail Corporation
215 South Cascade Street
PO Box 496
Fergus Falls MN 56538-0496

Christy Brusven
Fredrikson & Byron, P.A.
Suite 4000
200 South Sixth Street
Minneapolis MN 55402-1425

Nicholas Chevance
Midwest Regional Office
National Park Svc., Dept. Of Interior
601 Riverfront Drive
Omaha NE 68102

Christopher Childs
WSCO
384 Hall Avenue
St. Paul MN 55107

Christopher Clark
Xcel Energy
5th Floor
414 Nicollet Mall
Minneapolis MN 55401-1993

John DiDonato
FPL Energy, LLC
700 Universe Blvd.
Mail Stop FEW/JB
Juno Beach FL 33408

John E. Drawz
Fredrikson & Byron, P.A.
Suite 4000
200 South Sixth Street
Minneapolis MN 55402-1425

John R. Dunlop, P.E.
American Wind Energy Association
Suite 300
448 Morgan Ave. S.
Minneapolis MN 55405-2030

Bob Elston
CMMPA
459 South Grove Street
Blue Earth MN 56013

Mike Franklin
Minnesota Chamber Of Commerce
Suite 1500
400 Robert Street North
St. Paul MN 55101

Darrell Gerber
Clean Water Action Alliance of Minnesota
308 Hennepin Ave. E.
Minneapolis MN 55414

Peter Glazer
Troutman Sanders, LLP
Suite 1000
401 9th Street N.W
Washington DC 20004

Elizabeth Goodpaster
MN Center for Environmental Advocacy
Suite 206
26 East Exchange Street
St. Paul MN 55101-1667

E-017,ET-6131,ET-6130,ET-6144,ET-6135,ET-10/CN-05-619, ListID# 1 Otter Tail Power Company;

Christopher Greenman
Excelsior Energy
Suite 305
11100 Wayzata Boulevard
Minnetonka MN 55305

Todd J. Guerrero
Lindquist & Vennum, PLLP
4200 IDS Center
80 South Eighth Street
Minneapolis MN 55402-2274

Valeie T. Herring
Briggs and Morgan, P.A.
2200 IDS Center
80 S. Eighth Street
Minneapolis MN 55402

Mark Hirsch
128 Marina View Road
Rockford MN 55373

Michael W. Koester
9649 Holley Circle NW
Coon Rapids MN 55433

Stephen G. Kozey
Midwest ISO
PO Box 4202
Carmel IN 45083-4202

Michael C. Krikava
Briggs And Morgan, P.A.
2200 IDS Center
80 South 8th Street
Minneapolis MN 55402

David R. Moeller
Minnesota Power
30 West Superior Street
Duluth MN 55802-2093

David D. Norgaard
Southwst Wind Counsulting LLC
1631 - 290th Avenue
Tyler MN 56178

Thomas L. Osteraas
Excelsior Energy
Suite 305
11100 Wayzata Boulevard
Minnetonka MN 55305

Carol Overland
Overland Law Office
P.O. Box 176
Red Wing MN 55066

Jeffrey C. Paulson
Jeffrey C. Paulson & Associates, Ltd.
Suite 325
7301 Ohms Lane
Edina MN 55439

Dean Pawlowski
Otter Tail Power Company
PO Box 496
215 S. Cascade St.
Fergus Falls MN 56537-0496

John C. Reinhardt
Laura A. Reinhardt
3552 26Th Avenue South
Minneapolis MN 55406

Christopher Sandberg
LOCKRIDGE GRINDAL NAUEN & HOLSTEIN
Suite 2200
100 Washington Avenue South
Minneapolis MN 55401

David Sasseville
Lindquist & Vennum
4200 IDS Center
80 South 8th Street
Minneapolis MN 55402-2274

Matthew J. Schuerger P.E.
Energy Systems Consulting Services, LLC
P.O. Box 16129
St. Paul MN 55116

Janet Shaddix Elling
Shaddix And Associates
9100 West Bloomington Freeway
Suite 122
Bloomington MN 55431

Paul R. Strong
P.O. Box 275
Ortonville MN 56278

Sandi Tabor
North Dakota Transmission Authority
P.O. Box 2277
1016 East Owens Avenue
Bismarck ND 58502-2277

Raymond J. Wahle
Missouri River Energy Services
3724 W. Avera Drive
PO Box 88920
Sioux Falls SD 57109-8920

Kevin Walli
Fryberger, Buchanan, Smith & Frederick
1st National Bank Building
332 Minnesota Street, Suite W1260
St. Paul MN 55101

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05-1275

BIG STONE

Lonnie Abrams
12323 Highway 27 West
Little Falls, MN 56345

Robert Amundson
23665 610th Avenue
Chokio, MN 56271

Dennis Anderson
2505 Willmar Ave. SW
Willmar, MN 56201

Robert Anderson
465 35th Avenue SW
Benson, MN 56215

Ron Anderson
PO Box 195
Milan, MN 56262

Scott Anderson
1303 East Bridge Street
Suite 130
Redwood Falls, MN 56283

Robynn Andracsek
Burns McDonnell
9400 Ward Parkway
Kansas City, MO 64114

Lori Andresen
3025 E Superior St
Duluth, MN 55812

Randy Ascheman
1930 20th Street SW
Appleton, MN 56208

Eldeen Baer
108 Orleans Avenue North
Canby, MN 56220

John Baker
655 150th Avenue SW
Appleton, MN 56208

Mike Bates
8 3rd St. South
Great Falls, MN 59401

Dale Beckmann
Westwood
7699 Anagram Dr.
Eden Prairie, MN 55344

Chuck Bell
Burns McDonnell
9400 Ward Parkway
Kansas City, MO 64114

Tom Belmont
38118 North Shore Drive
Battle Lake, MN 56515

Dale Berg
4006 220th Avenue
Clarkfield, MN 56223

Martin Bettmann
South Dakota PUC
500 E Capitol Ave
Pierre, SD 57501

David and Gladys Beyer
465 150th Avenue NW
Holloway, MN 56249

Chris Bibeau
2350 Main St.
Lino Lakes, MN 55038

David Birkholz
Minnesota Department of Commerce.
Energy Facility Permitting Siting and Routing
85 7th Place East Ste. 500
Saint Paul, MN 55101

Gary and Margaret Blahosky
113 Cantibury Road
Circle Pines, MN 55014

Velma Blomgren
49196 220th Street
Morris, MN 56267

Jon Boese
1160 20th Street NW
Holloway, MN 56249

John Boots
67437 County Hwy 14
Odessa, MN 56276

Christy Brusven
Fredrikson and Byron P.A.
200 South Sixth Street
Suite 4000
Minneapolis, MN 55402

R Buer
1113 Meadow Hills Ave
Madison, MN 56256

Nate Burmeister
61743 St. Hwy 28
Chokio, MN 56221

John Burmeister
61743 State Hwy 28
Chokio, MN 56221

Leon Carlson
PO Box 26
Olivia, MN 56277

Hali Carlson
NCC
89 Norman Drive
Kenora, Canada

Dale Champ
212 9th Avenue SE
Elbow Lake, MN 56531

Bryan Clark
1884 Hwy 40
Madison, MN 56256

Ivan Clark
R. W. Beck Inc.
1801 California Street
Suite 2800
Denver, CO 80202

Christopher Cole
911 West 4th Street
Morris, MN 56267

John Connolly
840 Hwy 12 SW
Danvers, MN 56231

Carol Cooper
26437 Galaxie Ave.
Farmington, MN 55024

Dave Crargmile
3600 140th Street
Boye, MN 56218

Emily Dalager
400 First Ave North
Suite 535
Minneapolis, MN 55401

Perry Davis
UEI
5201 East River Road
308
Minneapolis, MN 55421

Thomas Davis
1161 50th Ave.
Sherburn, MN 56171

Troy Denelsbect
2405 - 200th Street
Canby, MN 56220

LaVerne Dering
212 - 3rd Street North
Correll, MN 56227

Terri Dinesen
1623 9th Avenue
Granite Falls, MN 56241

Rose Doom
2902 240th Avenue
Canby, MN 56220

John Drawz
Fredrikson and Byron P.A.
200 South Sixth Street
Suite 4000
Minneapolis, MN 55402

Joseph Dudak
ITC Holdings
39500 Orchard Hill Place
Suite 200
Novi, MI 48375

Joseph Dudak
ITC Holdings
39500 Orchard Hill Place Drive
Suite 200
Novi, MI 48375

Joseph Dudak
ITC Holdings Corp.
27175 Energy Way
6th Floor
Novi, MI 48377

Cal Dufault
3409 Glynwater Trl NW
Prior Lake, MN 55372

Nate Duoss
Builders Association of the Twin Cities
2960 Centre Pointe Drive
Roseville, MN 55113

Gary Ehrenberg
180 200 Avenue SW
Appleton, M 56208

Richard Ehrenberg
41373 Co Hwy 25
Correll, MN 56227

Audie Ekas
70001 US Hwy 75
Odessa, MN 56276

Glenn Emmons
207 Rins Avenue South
Canby, MN 56220

Jennifer Engh
Cargill Inc.
15407 McGinty Road West
Wayzata, MN 55440

Jeffery Evans
Evans Consulting Services
PMB 145
1645 9th Ave. SE
Albany, OR 97322

Jim Falk
1170 Hwy 9 NE
Murdock, MN 56271

Andrew Falk
1170 Hwy 9 NE
Murdock, MN 56271

Patty Farmr
2471 240th Avenue
Canby, MN 56220

Ted Favirchild
2063 120th Street
Canby, MN 56220

Lori Frisk-Thompson
CMMPA
459 S Grove Street
Blue Earth, MN 56013

Rick Fuentes
Fresh Energy
408 St. Peter
Suite 220
St. Paul, MN 55102

Annalee Garletz
Assoc of MN Counties
125 Charles Avenue
St. Paul, MN 55103

Erica Gatzow
8 Meadow Lane
Morris, MN 56267

Darrell Gerber
Clean Water Action Alliance
308 E Hennepin Ave
Minneapolis, MN 55414

Karon Gerdes
7020 120th Ave. N.E.
Kerkhoven, MN 56252

Doug Gronholz
2355 20th NW
Appleton, Mn 56208

Don Groth
5420 135th St NW
Kerkhaven, MN 56252

Terry Grove
Capx
12300 Elm Creek Blvd.
Maple Grove, MN 55369

Glenn Guhud
2471 240th Avenue
Canby, MN 56220

Tom and Sandy Gunter
1060 120th Ave NE
Clara City, MN 56222

Arlan Gustafson
5110 230th Avenue
Granite Falls, MN 56241

Carl Haase
712 Bluff Street
Box 266
Graceville, MN 57240

Richard Haherman
4547 368th Avenue
Montevideo, MN 56265

Howard Hallman
58874 St. Hwy 28
Chokio, MN 56221

Harley Hamernon
325 20th Road
Benson, MN 56282

Eric Hansen
Pinnacle Engineering Inc.
11541 95th Avenue North
Maple Grove, MN 55369

John Hanson
Praesidis
7650 Courtney Campbell Cswy
Ste 240
Tampa, FL 33607

Roger Hanson
201 Garden Street
Duluth, MN 55812

David Hanson
1416 10th Street
Clarkfield, MN 56223

Doris Hanson
1147 4th Street
Boyd, MN 56241

Arden and Julnn Hanson
105 Buckeyes Drive
Montevideo, MN 56265

William Harmon
Jones Day
77 West Wacker Suite 3500
Chicago, Il 60601

Richard Sue Hauer
830 Hwy. 12 SE
DeGraff, MN 56271

Dan Haugen
Self-Employed
3343 Tyler St NE
Minneapolis, MN 55418

Joe Hauger
116 Baldwin Street
No. 7
Granite Falls, MN 56241

Tammy Jerry Heinrich
2664 201st Avenue
Madison, MN 56256

Gary Henneberg
445 130th Avenue SW
Holloway, MN 56249

Vince Herda
14910 Wellington Rd
Wayzata, MN 55391

Valerie Herring
Briggs and Morgan
2200 IDS Center
80 South 8th Street
Minneapolis, MN 55402

Judy Hoberg
435 Hwy 12 SW
Benson, MN 56215

Joseph Hocum
108 9th Street West
Canby, MN 56220

Arthur Hoeremen
557 4th Avenue
Ortonville, MN 56278

Bruce Hoernemann
71582 Cty Road 64
Ortonville, MN 56278

Tom Hoffman
1005 Oakwood Avenue
Benson, MN 56215

Virginia Homme
11007 - 810th Ave
Granite Falls, MN 56241

Barbara Hoyhtyes
110 Oscar Avenue
Canby, MN 56220

Jarrett Hubbard
Mn DOT Dist 8
2505 Transportation Road
Willmar, MN 56201

Tim Hunstad
HMG LLC
4165 Shorewood Trail
Medina, MN 55340

Wayne Hurley
West Central Initiative
1000 Western Ave.
Fergus Falls, MN 56537

D. Alex Iden
13040 60th Ave SW
Raymond, MN 56282

Kim Jergenson
1212 Parkside Drive
Marshall, MN 56258

George Johnson
SEH Inc.
3535 Vadnais Center Drive
Saint Paul, MN 55110

Gary Johnson
4767 330th
Montevideo, MN 56265

Bryan Kallhoff
1588 130th Street North
Canby, MN 56220

John Karstraup
2455 151st Street
Madison, MN 56256

Craig Kausting
1449 250th Street
Madison, MN 56256

Michael Kawlewski
Otter Tail Power Co
215 S Cascade St
PO Box 496
Fergus Falls, MN 56538

Cesia Kearns
Sierra Club
2327 E. Franklin Ave.
Ste. 1
Minneapolis, MN 55406

Cesia Kerns
2327 E. Franklin Avenue
Suite 2
Minnetonka, MN 55406

Carol Kopperud
401 LacQue Parle A
Canby, MN 56220

Stacy Kotch
Minnesota Department of
Transportation
395 John Ireland Blvd
Mailstop 678
St. Paul, MN 55155

Grant Krieger
1095 165th Avenue SE
Kerkhoven, MN 56252

Dick Kroger
2067 530th Street
Woodlake, MN 56297

Gordon Kruse
1430 110th Street North
Canby, MN 56220

John Larkey
12700 Whitewater Drive
Minnetonka, MN 55413

Art Larson
1610 230th Avenue
Canby, MN 56220

Gary Lentz
2148 620th Street
Echo, MN 56237

Rod Lindquist
1780 90th Street SE
Kerkhoven, MN 56252

David Little
West Central Tribune
2208 Trott Ave. SW
P.O. Box 839
Willmar, MN 56201

Brian Long
Ulteig Engineering Inc.
5201 East River Road
No. 308
Minneapolis, MN 55421

Linda Lumsden
None
4801 Fairhills Road West
none
Minnetonka, MN 55345

Harold Luthi
26490 Highway 59
Morris, MN 56267

Jacquline Maas
69266 430th Street
Odessa, MN 56276

Paula Maccabee
Just Change Consulting Law Offices
1961 Selby Avenue
St. Paul, MN 55104

Rene Maes III
UofM Morris
600 E. 4th Street
BOX 978
Morris, MN 56267

Pam Mansfield
1210 Hwy 12
Murdock, MN 56215

Curt Marcus
Marcus Financial
1609 NW 16th Ave
Willmar, MN 56201

James McKay
14301 Freeport Trail
Apple Valley, MN 55124

James Helen McNally
6105 Main
Chokio, MN 56221

Jolie McShane
AIR2 LLC
2345 York Road
Suite 102
Timonium, MD 21093

Brian Meloy
Leonard Street and Deinard
150 South 5th Street
Suite 2300
Minneapolis, MN 55402

John Mertens
Dakota County
14955 Galaxie Ave
Apple Valley, MN 55124

Charles Michael
Utility Management Corporation
16612 Saddle Horn Court
Eden Prairie, MN 55347

Chris Miguez
Universal Ensco
4848 Loop Central
Houston, TX 77081

Lewis Miller
109 8th Street West
Canby, MN 56220

Raymond Millett
511 20th North
Benson, MN 56215

Brian Mitchell
R. W. Beck Inc.
1380 Corporate Center Curve
Suite 305
St Paul, MN 55121

Alan Mitchell
Lindquist Vennum PLLP
4200 IDS Center
80 South Eighth Street
Minneapolis, MN 55402

Gordie Molenoon
6045 Kaniio Chip Line
Raymond, MN 56287

Kevin Molloy
MPCA
520 Lafayette Road N.
St. Paul, MN 55155

Steve Moorman
Babcock Wilcox
2096 Edgcumbe Road
Saint Paul, MN 55116

Dan Morrill
67702 280th Street
Clinton, MN 56225

Gordon Mueller
1123 390th Street
Ortonville, MN 56278

Mary Munn
Fond du Lac Reservation
1720 Big Lake Road
Cloquet, MN 55720

James Murphy
73483 County Hwy 13
Graceville, MN 56240

Bob Narem
14313 469th
Twin Brook, SD 57269

Day Neal
6080 60th Ave NE
Murdock, MN 56271

Duane Ninneman
PO Box 154
Ortonville, MN 56278

David Norgaard
Southwest Wind Consulting
1631 290th Ave.
Tyler, MN 56178

Gerry and Burt Nygren
228 North Grace Street
Ortinville, MN 56278

Mike O Donnell
Babcock Wilcox Company
20 South Van Buren Avenue
Barberton, Oh 44203

Bill Ogey
870 70th Street SW
Danvers, MN 56231

Brent Olson
68704 County Hwy 8
Ortonville, MN 56278

Carol Overland
Overland Law Office
P.O. Box 176
Red Wing, MN 55066

Jason Painter
ACES Power Marketing LLC
4140 West 99th Street
Carmel, IN 46032

Suzanne Pansch
38479 County Hwy 12
Ortonville, MN 56278

Todd Patza
1617 161st Avenue
Marietta, MN 50257

Dean Pawlowski
Otter Tail Power Co.
215 S. Cascade Street
Fergus Falls, MN 56538

Pearl and Ervin Pederson
Box 6108
Bellingham, MN 56212

Harold or Kyle Petersen
8090 Highway 40 NE
Murdock, MN 56271

Bradley Peterson
Flaherty Hood P.A.
525 Park Street
Suite 470
St. Paul, MN 55103

Kevin Peterson
Local Union 160
846 48th Avenue NW
Rochester, MN 55901

Robert Peterson
5280 Hwy 212
Granite Falls, MN 56241

Rep. Aaron Peterson
1439 Hwy 75
Madison, MN 56256

Gary Petrucci
2975 Co. Rd. 24
Long Lake, MN 55356

Paul Pillatzki
1895 255th Avenue West
Dawson, MN 56232

Angela Piner
HDR
701 Xenia Ave. South Suite 600
Minneapolis, MN 55416

Angela Piner
HDR
701 Xenia Ave. South
Suite 600
Minneapolis, MN 55416

Angela Piner
HDR Inc.
701 Xenia Avenue South
Suite 600
Minneapolis, MN 55416

Robert Porter
1916 Severn Grove Road
Annapolis, MD 21401

Jay Porter
American Transmission Company
PO Box 47
Waukesha, WI 53187

Mike Prukop
2486 170th Street
Canby, MN 56220

Lewis Rademach
3642 121st Avenue
Bellingham, MN 56212

Glen Radermacher
1477 - 330th Street
Bellingham, MN 56212

A. Radtter
65459 Co Hwy 14
Odessa, MN 56276

Dianne Radumacher
619 Cliff Street
Ortonville, MN 56278

Warren Ran
2100 30th Street NW
Appleton, MN 56208

Pam Rasmussen
Xcel Energy
P.O. Box 8
Eau Claire, WI 54702

Julie Rath
MN Valley Regional Rail Authority
PO Box 481
200 S Mill Street

Erin Jordahl Redlin
308 E. Hennepin Avenue
Minneapolis, MN 55414

Daniel Reed
701 8th Street NE
Buffalo, MN 55313

Ross Reiffenberge
304 22nd Street South
St. Cloud, MN 56301

TJ Rolfing
Holmes Murphy
600 S. Cliff Ave
Sioux Falls, SD 57104

Richard Rothaus
Trefoil Cultural and Environmental Heritage
1965 W. Highview Dr
Sauk Rapids, MN 56379

Erin Stojan- Ruccolo
Fresh Energy
408 St. Peter Street
Suite 220
St. Paul, MN 55102

Steve Rupp
1194 6th Street
Granite Falls, MN 56241

Ken Rupp
977 15th Street
Granite Falls, MN 56241

Kathy Ruppa
1060 Hwy 12 SW
Danvers, MN 56231

Brian Ruppe
1060 Hwy 12 SW
Danvers, MN 56231

Mam-Marie Sallah
Ener Information Administration
C O Department of Energy
1000 Independence Ave SW EI-53
Washington DC, 20585

Lila Salls
38742 State Hwy 7
Ortinville, MN 56278

Rick Sand
5223 Hwy 212
Granite Falls, MN 56241

Allen Saunders
555 10th Street S.E.
Benson, MN 56215

Benjamin Schaefer
Minnesota Department of Natural Resources
261 Highway 15 South
New Ulm, MN 56073

Carla Schellberg
38790 Co. Hwy 12
Ortonville, MN 56278

Keith and Mary Schirm
250 West Christenson
No. 3
Appleton, MN 56208

Wayne Schmidgolf
4 Bluebird Ct.
Morris, MN 56267

Ron Schmidt
43176 Co. Hwy 36
Correll, MN 56227

Ron Schneider
355 Lake Avenue North
Spicer, MN 56288

Anthony Schnitler
1160 20th NW
Davers, MN 56231

Kent Scholl
550 15th Street
Suite 1000
Denver, CO 80202

Michael Schrader
Ariztar Development LLC.
4616 East Pebble Ridge Road
Paradise Valley, AZ 85253

Bart Schultz
Houston Engineering Inc.
6901 East Fish Lake Road
Suite 140
Maple Grove, MN 55369

Bill Schuna
PO Box 111
Marshall, MN 56258

Roxanne Shekleton
1015 100th Street SE
Murdock, MN 56271

Dean Shurb
16281 140th Street NW
Sanburg, MN 56289

Lowell Simpson
14622 60th Avenue
Chokio, MN 56221

Galen Skjefte
2889 490th Street
Granite Falls, MN 56241

Phil Smith
MN DOC - MOES - Energy Information Center
85 7Th Place East
Suite 500
St Paul, MN 55101

John Sprangers
Planergy
710 Commerce Drive
Suite 205
Woodbury, MN 55125

Steven Stamp
1920 121Avemie
Marietta, MN 56257

Joe Stesig
1085 50th Street SW
Danvers, MN 56231

Esther Steuck
23036 590th Avenue
Chokio, MN 56221

Sean Stocker
Northwind Renewable Solutions
5 Whitney Lane
New Ulm, MN 56073

Jim Stone
1310 200th Avenue
Canby, MN 56220

Harold Strei
436 Eastvold Avenue
Ortonville, MN 56278

Gregory Stricherz
Foreign Ink Ltd.
5735 Washburn Avenue South
Minneapolis, MN 55410

Mary Jo Stueve
518 St. Joseph Avenue
PO Box 308
Graceville, MN 56240

Eric Swanson
Winthrop Weinstine P.A.
225 South Sixth Street
Suite 3500
Minneapolis, MN 55102

Jerry Swenson
1140 60th Avenue SE
DeGraff, MN 56271

Todd Tadych
American Transmission Company LLC
2 Fen Oak Court
Madison, WI 53718

R Taffe
40 Greenwood
Ortonville, MN 56278

Steven Thayer
510 150th Avenue SE
Kerkhaven, MN 56252

Jon Theisen
1592 100th Street North
Canby, MN 56220

Paul Theisen
1280 121st Avenue North
Canby, MN 56220

Greg Thompson
66995 County Hwy 10
Ortonville, MN 56278

Richard Thompson
34671 680th Avenue
Ortonville, MN 56278

Jim Thoreen
PO Box 530
Morris, MN 56267

Jim Threcses
2753 120th
Canby, MN 56220

Mitch Toftg
1110 130th Avenue SE
Kerkhoven, MN 56252

Lauren Trevisan
Sierra Club
408 C St NE
Washington, DC 20002

Amy Trygestad
Northland Concrete and Masonry
12026 Riverwood Drive
Burnsville, MN 55337

Emily Ulmer
Sierra Club
85 Second Street 2nd floor
San Francisco, CA 94105

Terry VanDerPel
235 7th Avenue
Granite Falls, MN 56241

Marlyn and Dorothy Vangness
42072 County Hwy 36
Correll, MN 56227

Jeffrey Vascoe
314 Hauffager Avenue
Canby, MN 56220

Todd Vesperman
US Army Corps of Engineers
190 Fifth St. East
St. Paul, MN 55101

Ingrid Vick
HDR Engineering Inc.
701 Xenia Avenue South
Suite 600
Minneapolis, MN 55416

Richard Vroman
3439 230th Steet
Milroy, MN 56263

Sandy Wadsworth
1101 East 145th Street
Burnsville, MN 55337

Tim Walsh
955 15th Avenue SE
Benson, MN 56215

Tom Walsh
705 100th St. S.E
DeGraff, MN 56271

J. Chuck Walters
68937 240th Street
Graceville, MN 56240

Bruce Wellendorf
36564 - 640th Street
Ortonville, MN 56278

Craig Wersing
590 30th St. SW
Danvers, MN 56208

Donald Wersing
590 30th Street SW
Danvers, MN 56231

Rita Wersinger
590 30th Street SW
Danvers, MN 56231

Tina Wexler
Aldridge Electric
844 E Rockland Road
Libertyville, IL 60048

Paul White
Project Resources Corp.
625 8th Ave. SE
Minneapolis, MN 55414

Don Wiese
60227 US Hwy 12
Correll, MN 56227

Don Wodek
ENSR Corporation
4500 Park Glen Road
Suite 210
St. Louis Park, MN 55416

Brian Wojtalenicz
139 N. Miles St.
Appleton, MN 56208

Robert Wolfington III
Marshall Independent
508 West Main
Marshall, MN 56258

Ben Wulff
67353 240th
Johnson, MN 56236

Pete Wyckoff
1111 Park Avenue
Morris, MN 56267

Dean Young
10121 120th Street NW
Pennock, MN 56279

Brian Zelenak
Xcel Energy
414 Nicollet Mall
7th Floor
Mpls, MN 55401

IUOE Local 49
2109 251st St
St. Cloud, Mn 56301

IUOE Local 49
128 Ridge Road
New London, MN 56361

Ulteig Engineers
3350 38th Ave S.
Fargo, ND 58104