

RADEY | THOMAS | YON | CLARK

Attorneys & Counselors at Law

FIRM CONTACT: J. Terry Deason

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**RESPONSE TO NORTH DAKOTA PUBLIC SERVICE COMMISSION'S
REQUEST FOR PROPOSAL
RFP NUMBER: 408.06.11.003**

Introduction

Based in Tallahassee, Florida, Radey Thomas Yon & Clark, P.A. (RTYC) is an AV-rated firm consisting of twelve lawyers and one non-lawyer consultant who practice regularly before a variety of state agencies and in all Florida state and federal courts. Our practice areas include public utility law, telecommunications, administrative practice and administrative litigation, complex civil and commercial litigation (including class action defense), labor and employment law, corporate law and business transactions, and insurance regulation. We are also firmly committed to having a positive impact on our community by supporting many local and national causes with our time and financial backing.

There are ten shareholder attorneys, all of whom are AV-rated by Martindale-Hubbell, two associate attorneys, two paralegal assistants and one non-lawyer special consultant with expertise in public utilities matters. Our firm is large enough to staff the most complex cases but also small enough to avoid the institutional inertia and inflated expense that tends to beset even middle-sized firms.

RTYC emphasizes providing service to clients that is efficient and dedicated. Success for clients is our success. We vigorously marshal the facts and law in a cost-effective manner to achieve clients' objectives. Our efforts reflect a shared dedication to excellence, integrity, humanity, and community.

Confirmation

RTYC confirms that it will comply with all applicable provisions of RFP Number: 408.06.11.003 and that it has no conflicts of interest that prevent it from meeting all requirements of the RFP.

Understanding of the Project

RTYC understands that Montana-Dakota Utilities Co. and Otter Tail Power Company have made application to the North Dakota Public Service Commission (NDPSC) for an advance determination of prudence of an air quality control system at the Big Stone Generating Station. This application was filed pursuant to Title 49 of the North Dakota Century Code and applicable rules and regulations of the NDPSC.

Applicants assert that it is a prudent course of action to add the air quality control system to comply with the Federal Clean Air Act and the South Dakota Required Haze Implementation Plan. Applicants estimate the cost of adding the air quality control system to be \$489,397,400 with an accuracy of plus or minus 20 percent. Applicants also seek authority to install additional mercury emissions control equipment in anticipation of new requirements pursuant to the Environmental Protection Agency's proposed rule concerning hazardous air pollutants for coal-fired power plants. The estimated cost for the mercury control equipment is \$5,012,700.

RTYC is familiar with the Big Stone Generating Plant, a 475 megawatt (MW) coal-fired power plant located near Milbank, South Dakota. RTYC was retained by the NDPSC to assist in the review to build Big Stone II, a 630 MW ultra super-critical coal-fired plant proposed to be built adjacent to the existing Big Stone Generating Plant. (Case Nos. PU-06-481 and PU-06-482)

RTYC's assistance spanned the first proposed Big Stone II Generating Plant (630 MW) and a scaled down version (500 or 580 MW) that was subsequently proposed in early 2008. RTYC, through its special consultant, J. Terry Deason, made an exhaustive review and filed testimony in the cases on behalf of the NDPSC advocacy staff. Mr. Deason identified deficiencies in the applicant's case which needed further clarification. Mr. Deason recommended approval with certain specified conditions and within recommended parameters. The NDPSC granted an advance determination of prudence for Big Stone II on August 27, 2008. On September 11, 2009, Otter Tail Power Company withdrew from the Big Stone II project and on November 2, 2009 the remaining co-owners announced the termination of the Big Stone II project.

RTYC understands that the applications concerning proposed environmental upgrades to the existing Big Stone Generating Plant currently pending before the NDPSC will by necessity have to address many issues (many akin to those addressed in the Big Stone II cases). Among them will be:

- The need for the capacity and energy to be produced by the Big Stone Generating Plant
- The completeness and reasonableness of the applicants integrated resource plans
- The reasonableness of the cost projections submitted by the applicants
- The nature and reasonableness of assumptions supporting the need of the capacity and energy and the capital and operating costs of the environmental upgrades
- The results of sensitivity analyses with varying assumptions
- The operating efficiency of the plant as proposed
- The continued availability and projected price of coal for the Big Stone Generating Plant
- The impacts of the upgrades on reliability
- An analysis of alternatives if the environmental upgrades are not made
- The cost effectiveness of making substantial improvements to a plant that was originally constructed in 1975
- The availability of financing of the upgrades and the associated risks and costs

- Impact on the financial integrity of the applicants
- The impacts and risks of potential regulations to regulate carbon dioxide and other greenhouse gasses
- Implications for the transmission grid of proceeding or not proceeding with the environmental upgrades
- Whether the proposed environmental upgrades are in the best interests of the applicants' customers

As was the case for RTYC's participation in Case Nos. PU-06-481 and PU-06-482, RTYC understands that there will be a schedule to complete all necessary research, data requests, witness interviews, and independent analysis in time to prepare and file testimony on a date certain, which in this case is anticipated to be November 4, 2011. RTYC further understands that a hearing is contemplated for mid December, 2011 and it will be necessary for Mr. Deason to appear as a witness at that time. RTYC commits that it has the resources and expertise needed to meet this schedule.

Methodology Used for the Project

RTYC proposes to plan and implement a methodology to timely and completely meet the requirements of the RFP and provide quality and well-supported testimony that will be in the customers' best interests. RTYC will fulfill its requirements in an independent manner with no preconceived conclusions concerning the prudence of the applicants' proposed environmental upgrades. To that end, RTYC proposes to:

- Thoroughly review the testimony of the applicants, all supporting exhibits and their integrated resource plans.
- Research similar issues from other jurisdictions and the factual basis of other decisions to test the reasonableness of the applicants' positions and cost estimates.
- Prepare data requests and conduct interviews of applicants' witnesses and key managers on issues as presented and as they emerge through RTYC's research and review.
- Conduct at least bi-weekly conference calls with key advocacy staff members to report status of the project and gain input as issues become more defined. This is a measure to provide added quality assurance.
- Provide draft testimony to advocacy staff by October 25, 2011. Discuss draft testimony with advocacy staff and make edits and revisions as necessary. This is a measure to

provide added quality assurance. (All proposed edits and revisions will be reviewed by Mr. Deason and incorporated only if he deems them to be appropriate.)

- File final testimony and exhibits by November 4, 2011.
- Provide assistance to advocacy staff in plans to litigate the case and assist in preparing cross examination questions as needed by advocacy staff.
- Present and defend testimony and recommendations at hearing in December 2011.
- Assist advocacy staff with post-hearing activities, review transcripts and exhibits as needed, and assist in preparation of post-hearing brief as needed.

Having participated in the litigation of many complex regulatory proceedings, RTYC is fully aware that proceedings such as an advance determination of prudence can be complex and require the adaptability and flexibility of participants to thoroughly and effectively litigate their respective positions. RTYC acknowledges this reality and commits to work with advocacy staff as needs arise to most effectively utilize the resources and expertise that RTYC provides, within the budget established for this project.

Experience and Qualifications

Curricula vitae of all key professionals who would be expected to work on the application of Montana-Dakota Utilities Company and Otter Tail Power Company for Advance Determination of Prudence are **attached**. These professionals are listed below, along with a summary of the types of matters in which each professional is expected to become involved.

Susan F. Clark, shareholder. Ms. Clark is a former Florida Public Service Commissioner and Chairman, former Chair of the National Association of Utility Commissioners Electricity Committee, and also former General Counsel of the FPSC. Ms. Clark has served as counsel in numerous Florida regulatory matters. She leads and coordinates the firm's team of public utility regulatory professionals and will serve in a quality control capacity for this project.

Terry Deason, non-lawyer special consultant. Mr. Deason is also a former FPSC Commissioner and twice served as FPSC Chairman. Mr. Deason provides special expert consulting services to public utilities and state regulatory bodies in Florida and in other states, including serving as an expert witness in contested proceedings. Mr. Deason is expected to be the lead professional on this case, analyze all issues, and provide expert testimony as needed.

Attached to this response is a complete list of need determination cases in which Mr. Deason participated while a Commissioner on the Florida Public Service Commission. In Florida, need determination cases require a review of utilities' integrated resource plans, conservation efforts, projections of peak demands, reliability impacts, transmission needs, fuel costs, operating efficiencies and an overall determination of cost effectiveness and whether

Travel	<u>15,000</u>
	\$133,900

Note:

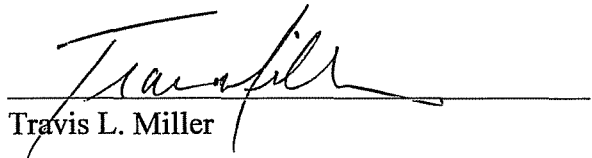
RTYC retains the right to allocate the actual hours spent on the project among the three above listed professionals as needed to meet deadlines and provide quality analysis and testimony. RTYC does commit to meet all requirements of the RFP at a cap on all direct labor of \$118,900. Any hours incurred beyond this cap will be billed at zero cost. Travel costs will be billed at actual cost up to a cap of \$15,000. Any travel costs incurred over the \$15,000 cap will not be billed. Any travel in excess of the three budgeted trips will be billed at actual cost.

Letters of Reference

In lieu of letters of reference from previous clients, RTYC requests that its work in Case Nos. PU-06-481 and PU-06-482 be considered as an expression of RTYC's experience, quality of review, understanding of issues relevant to this project, and its ability to perform and meet deadlines. Attached to this response are copies of the Direct Testimony of Terry Deason Dated, May 31, 200 and Supplemental Direct Testimony of Terry Deason dated April 7, 2008.

Offeror's Certification

This offer is being made in compliance with the requirements of RFP Number: 408.06.11.003 and will be valid for at least 60 days from its submission.


Travis L. Miller



Shareholder

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AV Rated



Practice Areas:

- Energy, Telecommunications, Water and Wastewater and Public Utility Law

Shareholder, Radey Thomas Yon & Clark, P.A.

301 South Bronough Street, Suite 200, Tallahassee, Florida

April 2003 to present

Primary area of practice is energy and telecommunications law and utility regulation, including electric, telecommunications and water and wastewater industries. Practice includes advice, counsel and representation before state and federal legislative, regulatory and executive bodies, as well as various state and federal courts.

Shareholder, Katz, Kutter, Alderman, Bryant and Yon, P.A.

106 East College Avenue, Suite 1200, Tallahassee, Florida

August 2000 to April 2003

Primary area of practice is energy and telecommunications law and utility regulation, including electric, telecommunications and water and wastewater industries.

Commissioner, Florida Public Service Commission

2540 Shumard Oak Boulevard, Tallahassee, Florida

Commissioner August 1991 to August 2000; Chairman 1995-1996

The Florida Public Service Commission is charged with the responsibility of economic regulation of Florida's investor-owned utility companies. Public Service Commissioners are required to be knowledgeable in public affairs, laws, economics, accounting, engineering, finance, natural resource conservation, energy and other areas relating to the duties and responsibilities

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of the Commission. As part of this collegial body, Commissioners must preside over contested matters, rulemaking and declaratory statement proceedings within the Commission's jurisdiction. Commissioners also participate in shaping state and federal regulatory law and policy by issuing written comments and through their participation in National Association of Regulatory Utility Commissioners and other professional organizations. Commissioners are responsible for making executive-level decisions relating to the structure and operation of the Commission.

General Counsel, Florida Public Service Commission
April 1988 to August 1991

Served as the Commission's chief legal counsel. Supervised the Commission's legal personnel consisting of 27 attorneys and 12 administrative/secretarial positions. Assisted in the coordination of interagency and legislative liaison functions. Represented the Commission in all state and federal courts, including numerous cases before the Florida Supreme Court. Participated in the development of Commission policies relating to cogeneration and conservation in the electric industry, restructuring of the telecommunications industry to accommodate competition, and streamlining regulation of water and wastewater utilities.

**Deputy General Counsel/Director of Division of Appeals,
Florida Public Service Commission**
October 1983 to April 1988

Head of the Division of Appeals, which included five attorneys and three administrative/secretarial positions. The Division's assignments included: legislative, rulemaking and appellate functions; federal/state liaison functions; providing legal advice to Commissioners; and handling in-house legal matters such as negotiating and drafting service and purchasing contracts and providing legal advice on personnel matters. Participated in the development of Commission policies on telephone access charges, customer premise equipment and inside wire, and territorial boundaries for electric utilities.

Associate General Counsel, Florida Public Service Commission
October 1980 to October 1983

Acted as staff counsel and advisor to Commissioners in proceedings before Commission and in state courts and the Division of Administrative Hearings. Participated in several rate cases in electric, telephone and water and sewer industries. Lead counsel in Southern Bell Rate Case, 1982. Participated in development of Commission rules on practice and procedure and appropriate levels of CIAC for water and sewer companies.

Staff Attorney, Joint Administrative Procedures Committee

120 Holland Building, Tallahassee, Florida 32301

August 1977 to October 1980

Reviewed agency action and rulemaking pursuant to the Administrative Procedure Act and advised agencies, legislators and citizens regarding the requirements and provisions of the Act. Drafted legislation relating to administrative procedures. Assignments included the Departments of Agriculture and Consumer Services, Business Regulation, Highway Safety and Motor Vehicles, and Professional Regulation.

Staff Attorney, Florida Senate Legislative Services

404 Capitol, Tallahassee, Florida 32301

October 1974 to August 1977

Prepared legislation and amendments for State Senators. Rendered advice and provided legal research in support of legislation. Prepared Revisor's Bill for Florida Environmental Reorganization Act of 1975. Assisted in Finance and Tax Committee on tax legislation.

PROFESSIONAL ASSOCIATIONS, MEMBERSHIPS, AND AWARDS:

- Florida Bar, *Member* since 1974
- U.S. District Court Northern, Middle and Southern Districts of Florida
- U.S. Court of Appeals 4th Circuit
- U.S. Supreme Court
- EPRI (formerly the Electric Power Research Institute), 2002-2006 *Board of Directors*
- Florida Trend Magazine's Annual Listing of Florida Legal Elite, 2005, 2006, & 2007
- 2008 selected as Super Lawyer by *Florida Super Lawyers Magazine*
- Netcommunications Advisory Board, 2001-2002
- Southeast Compact Commission for Low-Level Radioactive Waste Management
Alternate Commissioner
- National Association of Regulatory Utility Commissioners (NARUC), 1997-2000
Chair, Committee on Electricity
- National Association of Regulatory Utility Commissioners (NARUC), 1997-2000
Chair, Ad Hoc Committee on Electric Industry Restructuring
- National Association of Regulatory Utility Commissioners (NARUC), 1992-2000
Member, Committee on Electricity
- National Association of Regulatory Utility Commissioners (NARUC) *Member, Subcommittee on Nuclear Issues-Waste Disposal*

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- National Association of Regulatory Utility Commissioners (NARUC) *Member, Subcommittee on Strategic Issues*
- National Association of Regulatory Utility Commissioners (NARUC), 1997-2000
Member, Executive Committee
- National Association of Regulatory Utility Commissioners (NARUC), 1995-1997 *Vice Chair, Subcommittee on Nuclear Issues-Waste Disposal*
- National Association of Regulatory Utility Commissioners (NARUC), 1991-1992
Member, Committee on Energy Conservation
- National Association of Regulatory Utility Commissioners (NARUC), 1988-1991
Member, Staff Subcommittee on Law
- Nuclear Electric Insurance Limited, 1999-2000 *NARUC Representative*
- Consortium for Electric Reliability Technology Solutions, 2000 *Member, Board of Directors*
- Electric Power Research Institute Advisory Council, 1992-2002 *Member*
- North American Electric Reliability Council, 1997-2000 *NARUC Representative*
- National Council on Competition, 1998-2000 *Member, Steering Committee*
- Southeastern Association of Regulatory Utility Commissioners, 1991-2000 *Member*
- Nuclear Waste Strategy Coalition, 1993-2000 *Member*
- Telecommunications Taxation Task Force, 1996-1997 *Member*
- Association of Agency General Counsels, 1989-1991 *Chair*
- The Florida Bar, Administrative Law Section *Member*
- The Florida Bar, Government Lawyers Section *Member*
- The Florida Bar *Member, Public Utilities Law Committee*
- Brogan Museum of Art and Science, *President 2004, Board of Directors 2000-2007*

EDUCATION

Juris Doctor Degree, University of Florida, June 1974
Bachelor of Arts in Political Science, University of Florida, June 1971

TESTIMONIES

- Town of Belleair v. Florida Power Corporation, Case No. 0006487CI-20 - testified in arbitration in connection with case; June 11, 2003.
- Florida Power Corporation d/b/a Progress Energy Florida, Inc., Docket No. SC03-1-000, Federal Regulatory Commission - filed written testimony in case; April 2, 2003.
- City of Winter Park Florida v. Florida Power Corporation, Case No. 01-CI-01-4558-39 - testified in arbitration in connection with case; December 2002.
- Before The U.S. House of Representatives Senate Energy and Natural Resources Committee; July 15, 1999: Essential Elements of Federal Legislation.

- Before The U.S. House of Representatives Commerce Committee - Energy and Power Sub Committee; March 18, 1999.
- Remarks For Commerce Committee Hearing On Electric Industry Restructuring; October 21, 1997.
- Before The U.S. House of Representatives Committee on Commerce Subcommittee on Energy and Power: Electricity: Reliability and Competition; June 19, 1997.
- Testimony Regarding Electric Industry Restructuring Before The U.S. House of Representatives Committee On Commerce, Field Hearing; April 14, 1997.
- Testimony Regarding Competitive Change in the Electric Power Industry Before The U.S. Senate Committee on Energy And Natural Resources; July 11, 1996.

SPEECHES, PRESENTATIONS AND ARTICLES

- Presentation to the House Committee on Energy on Energy Efficiency; January 9, 2008.
- Presentation on the regulatory perspective on the Evolution of Telecommunications Competition at Florida Telecommunications Industry Association's 100th Annual Convention in Sarasota, Florida; June 25, 2007.
- Panel Moderator at NARUC Western Conference of Utility Commissioners on Energy Efficiency and Conservation in Park City, Utah; June 11, 2007.
- Panel Moderator on issues regarding construction of new nuclear plants at SEARUC convention in Little Rock, Arkansas; June 5, 2007.
- Presentation at the Florida Chapter of the Federal Communications Bar Association/ PURC/Florida Bar Public Utilities Law Committee's 2006 Florida Telecom and Energy Legislative Update - Siting; November 16, 2006.
- Presentation at the Southeast Utility Commissioners Dialogue with the Investment Community; October 3, 2006.
- Presentation to the 2006 Eastern NARUC Utility Rate School; September 11, 2006.
- Presentation at the Edison Electric Institute's 2006 Spring Legal Conference-Ringfencing Activities in the States; Naples, Florida, April 11, 2006.
- Presentation before the Florida Senate Judiciary Committee on Street Lighting; February 9, 2005.
- Presentation before the Florida Senate Committee on Communications & Public Utilities on securitization-hurricane damage cost recovery; January 25, 2005.
- Presentation before the Florida House of Representatives Utilities & Telecommunications Committee on securitization-hurricane damage cost recovery; January 11, 2005.
- Presentation on the Florida Energy Law: Electric Industry Regulatory Statutes and Policy; Florida Public Service Commission/Federal Energy Regulatory Commission Technical Conference; September 15, 2003.

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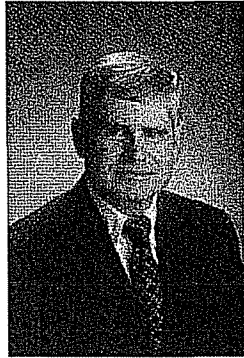
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- Article: "Let Deregulation Proceed;" Utility Business; July 18, 2001.
- "RTO's: The October Filings" Keynote address EEI Conference in Washington, D.C.; November 2 and 3, 2000.
- "Technological Changes Affecting the Need for Regulation" - Moderated Panel Discussion at World Forum on Energy Regulation; Montreal, Quebec, Canada, May 23, 2000.
- Presentation: "NARUC Positions on Electric Industry Restructuring Legislation" - National Energy Marketers Association's Conference; Washington, D.C., April 17, 2000.
- Presentation: "Overview of Steps Taken Toward a Peninsular Florida Transco to Date" - Federal Energy Regulatory Commission's Workshop on Regional Transmission Organizations; Atlanta, Georgia, April 6, 2000.
- Presentation: "Regulatory Review: Federal and State Update" - 13th Annual Utility Mergers and Acquisitions Symposium, New York, New York, January 31, 2000.
- Presentation: "Is There a Role for Regulation in Economic Development?" - 1999 Regional Economic Symposium; Sandestin, Florida, October 26, 1999.
- Presentation to the Federal Energy Regulatory Commission's Regional ISO Conference; Orlando, Florida, June 8, 1998.
- "New Rules of the Road" - 1998 Strategic Marketing Conference; Orlando, Florida, April 30, 1998.

RADEY THOMAS YON CLARK

Attorneys & Counselors at Law



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Special Consultant (Non-lawyer)

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Practice Areas:

- Energy, Telecommunications, Water and Wastewater and Public Utilities

Education:

- United States Military Academy at West Point, 1972
- Florida State University, B.S., 1975, Accounting, summa cum laude
- Florida State University, Master of Accounting, 1989

Professional Experiences:

- Florida Public Service Commission, Commissioner, 1991 - 2007
- Florida Public Service Commission, Chairman, 1993 - 1995, 2000 - 2001
- Office of the Public Counsel, Chief Regulatory Analyst, 1987 - 1991
- Florida Public Service Commission, Executive Assistant to the Commissioner, 1981 - 1987
- Office of the Public Counsel, Legislative Analyst II and III, 1979 - 1981
- Ben Johnson Associates, Inc., Research Analyst, 1978 - 1979
- Office of the Public Counsel, Legislative Analyst I, 1977 - 1978
- Quincy State Bank Trust Department, Staff Accountant and Trust Assistant, 1976 - 1977

Professional Associations and Memberships:

- National Association of Regulatory Utility Commissioners (NARUC), 1993 - 1998, *Member, Executive Committee*
- National Association of Regulatory Utility Commissioners (NARUC), 1999 - 2006, *Board of Directors*

Terry Deason, Special Consultant (Non-lawyer)

- National Association of Regulatory Utility Commissioners (NARUC), 2005-2006, *Member, Committee on Electricity*
- National Association of Regulatory Utility Commissioners (NARUC), 2004 - 2005, *Member, Committee on Telecommunications*
- National Association of Regulatory Utility Commissioners (NARUC), 1991 - 2004, *Member, Committee on Finance and Technology*
- National Association of Regulatory Utility Commissioners (NARUC), 1995 - 1998, *Member, Committee on Utility Association Oversight*
- National Association of Regulatory Utility Commissioners (NARUC) 2002 *Member, Rights-of-Way Study*
- Nuclear Waste Strategy Coalition, 2000 - 2006, *Board Member*
- Federal Energy Regulatory Commission (FERC) South Joint Board on Security Constrained Economic Dispatch, 2005 - 2006, *Member*
- Southeastern Association of Regulatory Utility Commissioners, 1991 - 2006, *Member*
- Florida Energy 20/20 Study Commission, 2000 - 2001, *Member*
- FCC Federal/State Joint Conference on Accounting, 2003 - 2005, *Member*
- Joint NARUC/Department of Energy Study Commission on Tax and Rate Treatment of Renewable Energy Projects, 1993, *Member*
- Bonbright Utilities Center at the University of Georgia, 2001, *Bonbright Distinguished Service Award Recipient*



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Practice Areas:

- Energy Law
- Labor & Employment Law
- Administrative Law
- Commercial Litigation

Professional Experience:

- Radey Thomas Yon & Clark, P.A., Associate, 2005 - present
- Radey Thomas Yon & Clark, P.A., Law Clerk, 2005
- U.S. District Court, Northern District of Florida, Intern, 2004
- Radey Thomas Yon & Clark, P.A., Summer Associate, 2004
- University of Missouri - Columbia, Procurement/Materials Management, Assistant Director and Senior Buyer, 1992-97
- State of Missouri, Division of Purchasing, Buyer, 1990-92
- University of Missouri-Columbia, Teaching Assistant, 1989-90

Professional Associations and Memberships:

- Tallahassee Women Lawyers, 2007-Present
- The Florida Bar, 2005
- U.S. District Court, Northern District of Florida, 2005
- U.S. District Court, Middle District of Florida, 2009
- U.S. Court of Appeals, Eleventh Circuit, 2010
- American Bar Association
- Phi Kappa Phi Legal Fraternity, 2005-Present
- Rotary Club of Tallahassee, 2010-Present
- Mizzou Alumni Association, 2011-Present
- Certified Professional Public Buyers, 1995-2000

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Education:

- Juris Doctor, Florida State University College of Law, Tallahassee, Florida, 2005
 - Honor: Summa Cum Laude; ranked 2nd in graduating class of 274
 - Book Awards: Property I, Property II, Legal Writing & Research I, Legal Writing & Research II, Foreign Relations Law, Florida Administrative Practice, Energy Law Seminar
 - *Florida State University Law Review*
 - Florida State University Moot Court
 - Order of the Coif
 - Outstanding Appellate Advocate, awarded by the Florida Supreme Court, Moot Court Final Four Competition, Fall 2003
 - Order of the Barristers

- Masters of Business Administration, University of Missouri - Columbia, 1990
 - Emphasis: Personnel Management
- Bachelors of Science in Business Administration, University of Missouri - Columbia, 1988
 - Emphasis: Marketing

Awards:

- Super Lawyers Florida - Rising Star - 2011
- Super Lawyers Florida - Rising Star - 2010

Reported Cases:

- *Tunnell v. Crosby*, 657 F.Supp.2d 1263(N.D. Fla. 2009)

Published Articles:

- *Single Wage Base or Not? Administering Client-Based Workers' Comp*, PEO Insider, December 2007/January 2008 (with Donna Blanton)

EXHIBIT _____

Need Determination Dockets in which Commissioner Deason participated:

- In re: Petition for determination of need for Seminole Generating Station Unit 3 electrical power plant in Putnam County, by Seminole Electric Cooperative, Inc., Docket No. 060220-EC, Florida Public Service Commission, 2006 (750 MW supercritical pulverized coal plant).
- In re: Petition for determination of need for West County Units 1 and 2 electrical power plants in Palm Beach County by Florida Power & Light Company, Docket No. 060225-EI, Florida Public Service Commission, 2006 (two 1300 MW combined cycle units).
- In re: Petition for determination of need for Hines 4 power plant in Polk County by Progress Energy Florida, Inc., Docket No. 040817-EI, Florida Public Service Commission, 2004 (517MW combined cycle unit).
- In re: Petition for determination of need for expansion of electrical cogeneration power plant in Palm Beach County, by Florida Power & Light Company and New Hope Power Partnership, Docket No. 040766-EI, Florida Public Service Commission 2004 (70 MW steam turbine electric generator).
- In re: Petition to determine need for an electrical power plant in Martin County by Florida Power and Light Company, Docket No. 020262-EI, Florida Public Service Commission, 2002-04 (789 MW additions to existing combustion turbine units).
- In re: Petition to determine need for an electrical power plant in Manatee County by Florida Power & Light Company, Docket No. 020263-EI, Florida Public Service Commission, 2002-04 (1,100MW combined cycle unit).
- In re: Petition for determination of need of Hines Unit 3 power plant, Docket No. 020953-EI, Florida Public Service Commission, 2002-03 (582MW combined cycle unit).
- In re: Petition for determination of need for an electrical power plant in Lake County by Panda Leesburg Power Partners, L.P., Docket No. 000288-EU, Florida Public Service Commission, 2000-01 (1000MW combined cycle unit).
- In re: Petition for determination of need for an electrical power plant in St. Lucie County by Panda Midway Power Partners, L.P., Docket No. 000289-EU, Florida Public Service Commission, 2000-01 (1000MW combined cycle unit).
- In re: Petition for determination of need for an electrical power plant in St. Lucie County by Duke Energy St. Lucie, L.L.C., Docket No. 000612-EU, Florida Public Service Commission, 2000-01 (608MW combined cycle unit).

- In re: Petition for determination of need for an electrical power plant in Okeechobee County by Okeechobee Generating Company L.L.C., Docket No. 991462-EU, Florida Public Service Commission, 1999-01 (550 MW combined cycle unit).
- In re: Petition for determination of need for the Osprey Energy Center in Polk County by Seminole Electric Cooperative and Calpine Construction Finance Company, L.P., Docket No. 001748-EC, Florida Public Service Commission, 2000-01 (529MW combined cycle unit).
- In re: Petition for determination of need of Hines Unit 2 Power Plant by Florida Power Corporation, Docket No. 001064-EI, Florida Public Service Commission, 2000-01 (530MW combined cycle unit).
- In re: Joint Petition for determination of need for an electrical power plant in Volusia County by the Utilities Commission, City of New Smyrna Beach, Florida, and Duke Energy New Smyrna Beach Power Company, Ltd., L.L.P., Docket No. 981042-EM, Florida Public Service Commission, 1998-99 (514MW combined cycle unit).
- In re: Petition to determine need for existing Tiger Bay Electrical Power Plant and nominal electrical capacity increase to that plant by Florida Power Corporation, Docket No. 971059-EI, Florida Public Service Commission, 1997 (increase of 12MW of steam electric capacity).
- In re: Petition to determine need for electrical power plant in St. Marks, Wakulla County, by City of Tallahassee, Docket No. 961512-EM, Florida Public Service Commission, 1996-97, (250MW combined cycle unit).
- In re: Petition for determination of need for proposed electrical power plant to be located in Hardee and Polk Counties by Seminole Electric Cooperative, Inc., Docket No. 931212-EC, Florida Public Service Commission, 1993-94 (440MW combined cycle unit).
- In re: Petition to determine need for electrical power plant (Okeechobee County Cogeneration Facility) by Nassau Power Corporation, Docket No. 920769-EQ, Florida Public Service Commission, 1992-94 (75+ MW cogeneration).
- In re: Joint Petition to determine need for electric power plant to be located in Okeechobee County by Florida Power and Light Company and Cypress Energy Partners, L.P., Docket No. 920520-EQ, Florida Public Service Commission, 1992-94 (MW unavailable).
- In re: Petition of Ark Energy, Inc. and CSW Development for determination of need for electrical power plant to be located in Okeechobee County, Florida, Docket No. 920761-EQ, Florida Public Service Commission, 1992-94 (866MW combined cycle unit).
- In re: Petition of Ark Energy, Inc. and CSW Development I for approval of contract for the sale of capacity and energy to Florida Power & Light Company, Docket No. 920762-EQ, Florida Public Service Commission, 1992-94.

- In re: Petition of Nassau Power Corporation for approval of contract for the sale of capacity and energy to Florida Power & Light Company, Docket No. 920783-EQ, Florida Public Service Commission, 1992-94.
- In re: Petition of Nassau Power Corporation to determine need for electrical power plant (Amelia Island Cogeneration Facility), Docket No. 910816-EQ, Florida Public Service Commission, 1991-92 (MW unavailable).
- In re: Petition for determination of need for a proposed electrical power plant and related facilities in Polk County by Tampa Electric Company, Docket No. 910883-EI, Florida Public Service Commission, 1991-93 (220 MW integrated gasification combined cycle unit).
- In re: Petition for determination of need for proposed electrical power plant and related facilities Polk County Units 1-4, by Florida Power Corporation, Docket No. 910759-EI, Florida Public Service Commission, 1991-1992. (940 MW-four combined cycle units).

**BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF NORTH DAKOTA**

In the Matter of the Application of) Case No. PU-06-481
Otter Tail Corporation, d/b/a)
Otter Tail Power Company, for an)
Advance Determination of Prudence)
For the Big Stone II Generating Plant)

In the Matter of the Application of)
MONTANA-DAKOTA UTILITIES CO., a) Case No. PU-06-482
Division of MDU Resources Group, Inc.,)
For an Advance Determination of)
Prudence of Montana-Dakota's)
Participation & Ownership Interest in the)
Big Stone II Generating Station)

DIRECT TESTIMONY

OF

TERRY DEASON

Special Consultant

Radey Thomas Yon & Clark

May 31, 2007

1 **BEFORE THE NORTH DAKOTA PUBLIC SERVICE COMMISSION**

2 **DIRECT TESTIMONY OF TERRY DEASON**

3 **Q: Please state your name and business address.**

4 A: My name is Terry Deason. My business address is 301 South Bronough St., Suite
5 200, Tallahassee, Florida 32301.

6 **Q: By whom are you employed, and in what capacity?**

7 A: I am employed by the firm Radey Thomas Yon and Clark as a Special Consultant
8 specializing in energy, telecommunications, water and wastewater and public utilities.

9 **Q: What is your educational background?**

10 A: I received a BS in Accounting, summa cum laude, from Florida State University
11 in 1975, and a Master of Accounting in 1986 from Florida State University.

12 **Q: What is your employment history?**

13 A: Other than a year and a half in the banking industry immediately following
14 graduation, my entire professional career has been in the field of public utility regulation.
15 I have held a number of positions in this field ranging from consumer advocate to
16 Commissioner on the Florida Public Service Commission. I most recently finished my
17 fourth term on the Florida Public Service Commission on January 1, 2007. I served in
18 that capacity for a total of 16 years and served as chairman on two separate occasions. A
19 more complete account of my education, work experience and professional associations
20 is contained in Exhibit No. ____ (JTD-1).

21 **Q: Have you submitted testimony in other utility regulatory proceedings?**

1 A: Yes, I have. A list of the dockets in which I have previously testified is contained
2 in Exhibit No. ___ (JTD-2).

3 **Q: Do you have any relevant experience dealing with siting and prudence**
4 **determinations for electric generating facilities?**

5 A: Yes, I have. Under Florida Law, any generating facility which utilizes a steam
6 cycle and is greater than 75 MWs must come before the Florida Public Service
7 Commission for a Need Determination. A Need Determination case is quite
8 comprehensive and includes a review of a utility's demand forecasts, its Integrated
9 Resource Plan, its conservation and Demand Side Management (DSM) programs, its
10 overall generating portfolio and whether the proposed generating unit is the most cost-
11 effective alternative available. Over the last 16 years, I have sat on 25 Need
12 Determination Cases involving more than 14,000 MWs of proposed generating capacity.
13 A complete list of these dockets is contained in Exhibit No. ___ (JTD-3). In addition to
14 Need Determinations, Florida Law requires all public utilities in Florida, including
15 Investor-Owned Utilities (IOUs), Municipals and Cooperatives, to annually submit Ten-
16 Year Site Plans (TYSP) to the Florida Public Service Commission for review. As the
17 name implies, each utility is required to forecast its demand needs and how that demand
18 is to be met over a ten-year planning horizon. While the TYSPs are not docketed cases,
19 the Florida Commission is required to review them for their suitability for planning
20 purposes. The Commission's review includes such matters as accuracy of demand
21 forecasts, conservation and DSM programs, fuel diversity and reliability of fuel supply

1 considerations and transmission adequacy. I have participated in each of these annual
2 reviews for the last 16 years.

3 **Q: On whose behalf are you appearing?**

4 A: I am presenting testimony on behalf of the advocacy staff of the North Dakota
5 Public Service Commission.

6 **Q: What is the purpose of your testimony?**

7 A: The purpose of my testimony is to present the results of my review of the Big
8 Stone II generating plant being proposed by Otter Tail Power Company and Montana-
9 Dakota Utilities Company (MDU). My review was conducted from an overall regulatory
10 policy perspective. My goal is to offer assistance that will be helpful to the North Dakota
11 Public Service Commission in making its decision on the pending applications.

12 **Q: What was the extent of your review?**

13 A: I read the testimony of all company witnesses, reviewed their exhibits and
14 reviewed the Power Plant Site Evaluation Study presented by Otter Tail. I prepared three
15 separate sets of Data Requests submitted to Otter Tail and reviewed the responses. I
16 visited Otter Tail's offices in Fergus Falls along with Mr. Mike Diller during the week of
17 April 9, 2007. During that week we were given the opportunity to interview company
18 personnel familiar with Big Stone II.

19 **Q: Was your review limited to North Dakota specific information?**

20 A: No, it was not. I also reviewed publicly available information from the Energy
21 Information Administration, the Federal Energy Regulatory Commission (FERC), the
22 Midwest Independent Transmission System Operator (MISO), the Surface Transportation

1 Board and the United States Environmental Protection Agency. I also reviewed open or
2 recently concluded cases, similar to the Big Stone II applications, in three other states:
3 Florida, Nevada and North Carolina.

4 **Q: Will you please summarize your overall understanding of the Big Stone II project?**

5 A: Big Stone II, as currently proposed, is a 630 MW supercritical pulverized coal
6 unit using state of the art technologies for both its thermal generation and its pollution
7 control systems. It is proposed to be constructed at the existing site of Big Stone I and
8 share common facilities at that location. It will burn Powder River Basin (PRB) coal that
9 will be delivered by the Burlington Northern Santa Fe (BNSF) Railway Company. It will
10 be interconnected using existing transmission corridors with increased transmission
11 infrastructure to meet MISO requirements. Big Stone II will be jointly owned by seven
12 participants with Otter Tail and MDU each owning 19.3%.

13 **Q: Please describe supercritical generating technology.**

14 A: Supercritical technology employs higher operating pressures providing increased
15 efficiencies, which result in greater fuel economy and reduced emissions. Supercritical is
16 a proven and reliable generating technology. There are currently more than 160
17 supercritical units operating in the United States, representing 15% of total fossil-fuel
18 capacity. Based upon my research, it appears to be the technology of choice for large
19 (greater than 500 MWs) baseload generating units.

20 **Q: What was the process utilized by Otter Tail and MDU that resulted in their**
21 **applications for Big Stone II?**

1 A: The exact process utilized by any given utility to conclude there is a need for new
2 generation capacity will obviously vary from utility to utility. However, there are general
3 steps common to most utilities and these steps were utilized by both Otter Tail and MDU.

4 **Q: What is the first step in this process?**

5 A: The first step is an Integrated Resource Plan (IRP) which continually projects
6 future demand, monitors existing generating resources and evaluates the resources (both
7 demand side and supply side) needed to meet future demand which exceeds existing
8 resources. The goal is to achieve an optimal mix of demand and supply side resources to
9 meet future demand with a reasonable reserve margin.

10 Both MDU and Otter Tail have undertaken integrated resource planning. MDU's
11 IRP is based on a 1987 Order of the North Dakota Public Service Commission, while
12 Otter Tail's is based on Minnesota requirements. Both plans rely on the traditional least
13 cost approach to resource planning. A summary of the more relevant portions of MDU's
14 IRP is contained in Exhibit No. ___ (JTD-4). A similar summary for Otter Tail is
15 contained in Exhibit No. ___ (JTD-5). Both of these exhibits were prepared in
16 consultation of Ms. Annette Bendish of the North Dakota Staff.

17 **Q: Was a Request for Proposal (RFP) process used by MDU?**

18 A: Yes. MDU issued an RFP for a baseload resource beginning in 2011. Only two
19 responses were received. One did not meet the requirements of the RFP and the other
20 had deliverability problems with no real cost advantage over Big Stone II.

21 **Q: Was a RFP process used by Otter Tail?**

1 A: Yes, as described in Exhibit ___ (JTD-5), Otter Tail's only response was from the
2 Manitoba Hydro Electric Board (MHEB). The proposals did not meet Otter Tail's need
3 for long-term dispatchable baseload generation.

4 **Q: How was the site for the needed baseload generation selected?**

5 A: Otter Tail retained Burns & McDonnell to conduct a Power Plant Site Evaluation
6 Study. The purpose of the study was to identify a preferred site within the states of
7 Minnesota, North Dakota and South Dakota for a new coal-fired generating plant. The
8 study was quite comprehensive, beginning with 38 preliminary site areas that were
9 narrowed to six specific candidate sites. Each of the six candidate sites were then
10 subjected to a rigorous numerical screening process based on six categories: 1) Air
11 Impacts; 2) Water Supply; 3) Environmental; 4) Fuel Supply; 5) Transmission; and 6)
12 Other.

13 **Q: What was the result of the numerical screening process?**

14 A: Big Stone was selected as the preferred site with a numerical score of 397.7. The
15 preferred alternative site was determined to be Utica Junction with a score of 383.3.

16 **Q: Was Coyote Station evaluated as one of the six candidate sites?**

17 A: Yes, it was. Coyote Station received a score of 339.6, but was eliminated because
18 of "serious flaws" concerning air quality and transmission issues. The air quality concern
19 is based on Coyote's proximity to two Class I Prevention of Significant Deterioration
20 (PSD) areas: Theodore Roosevelt National Park (73 miles) and Lostwood National
21 Wildlife Refuge (94 miles). The transmission concern is based on the fact that the
22 existing transmission system does not have the capacity for additional power exports out

1 of the North Dakota Lignite Mining area. The study concludes that the necessary
2 transmission upgrades to accommodate the 600 MWs at Coyote Station would be “very
3 expensive.” The study did not attempt to quantify the exact costs.

4 The study gave Coyote a score of “2” for the category addressing Class I Area
5 Proximity. This was the lowest score given for this category, while Big Stone received a
6 “5,” the highest score possible. The study gave Coyote a score of “1” for the category
7 addressing transmission system impacts, the lowest possible score. Big Stone received a
8 “4” for this category.

9 **Q: Was a sensitivity analysis performed as part of the Site Evaluation Study?**

10 **A:** Yes, it was. Six different sensitivities were performed, by giving each of the six
11 screening categories a double weighting and reducing each of the remaining five
12 screening category weights proportionately, so that the total weight for all categories
13 would still equal 100%. In each one of the sensitivities, Big Stone had an overall ranking
14 of either 1 or 2, with the best overall average rank of 1.43. Coyote performed poorly in
15 the sensitivities with an overall average rank of 3.86. This lower ranking was primarily
16 influenced by the air quality sensitivity and the transmission sensitivity, where Coyote
17 received the lowest possible rank of 6.

18 An interesting sensitivity for Coyote was the fuel sensitivity where Coyote
19 received a relatively high rank of 2. I believe this results because Coyote is the only
20 candidate site that has significant potential for fuel delivery competition. The existence
21 of significant fuel delivery competition would be a strategic advantage of the Coyote site.

1 **Q: Did the Site Evaluation study attempt to quantify the impact of fuel delivery**
2 **competition?**

3 A: The study gave an overall weighting of 6.67% out of 100% to this category and
4 then gave a score of from 1 to 5 to each candidate site. No attempt beyond this was made
5 to quantify the impact of fuel delivery competition.

6 **Q: Are you aware of any attempts in other jurisdictions to quantify the impact of fuel**
7 **delivery competition?**

8 A: Yes, I am. Florida Power and Light Company (FPL) in its Report on Clean Coal
9 Generation concluded that a lack of competition (e.g., having access to only one port, or
10 having access to only one railroad) would result in a significantly higher delivered price
11 for coal. The Report quantified the net present value of the additional cost to be \$383
12 million. This amount was calculated in relation to FPL's pending application to build
13 two 980 MW ultra supercritical coal units in Glades County, Florida. FPL concluded that
14 without fuel delivery competition, the calculated \$435 million savings of the ultra
15 supercritical coal units as compared to an all-gas alternative would be reduced to only
16 \$52 million. This caused FPL to further conclude: "It is therefore very important that a
17 robust competitive coal transportation plan be established prior to making a final decision
18 to implement clean coal generation."

19 I do not vouch for FPL's \$435 million calculation. I realize it is for two units
20 comprising 1,960 MWs of capacity compared to Big Stone II's 630 MW. I further
21 realize that transportation costs represent a higher proportion of overall fuel costs for FPL
22 than for MDU or Otter Tail, and that FPL has the potential for waterborne transportation

1 alternatives which are not available to MDU and Otter Tail. The reference to FPL's
2 Report is given merely to demonstrate the potential significance of the lack of fuel
3 delivery competition and to give an example of an effort to actually quantify it.

4 **Q: Within the Site Evaluation Study, did you review the specific scores given to Coyote**
5 **for each of the category weightings?**

6 A: Yes, I did. There were three specific scores given that I believe merit further
7 consideration.

8 First, Coyote received the lowest possible score of "1" for Potential Airspace
9 Restrictions. This score was given based only on the distance to the nearest airport,
10 which in Coyote's case is 1.8 miles from the Beulah Airport. However, given that
11 Coyote is a brownfield site and that the Beulah Airport runway is oriented east-west
12 while Coyote is located due south of the airport, this low score may not be warranted.
13 The Site Evaluation Study concluded that it is unlikely there would be any airspace
14 restrictions that would limit the height of additional structures such as chimneys at
15 Coyote.

16 Second, Coyote received the lowest possible score of "1" for Surface Water
17 Proximity. This score was given based only on the distance from the site area to a
18 potential water source, which in Coyote's case is 26 miles from Lake Sakakawea.
19 However, given that Coyote is a brownfield site with an existing supply pipeline with
20 adequate capacity and that the water supply is adequate without significant impacts on
21 other water users, this low score may not be warranted.

1 Third, Coyote received the lowest possible score of "1" for Highway Access.
2 This score was given based only on the distance to a U.S. or Interstate Highway, which in
3 Coyote's case is 25 miles to Interstate 94. However, given that Coyote is an existing
4 generating site with access provided by State Highway 49, this low score may not be
5 warranted.

6 **Q: Did you perform a sensitivity analysis in regard to the three scores you just**
7 **referenced?**

8 A: Yes, I did. For ease of reference, I prepared a spreadsheet showing the
9 weightings for all categories and the corresponding scores for each of the six candidate
10 sites, as originally contained in the Site Evaluation Study. The total scores for each
11 candidate site may differ slightly due to rounding. This spreadsheet is attached to my
12 testimony as Exhibit No. __ (JTD-6).

13 For the specific scores I discuss above, I changed the score from "1" to "5" and
14 recalculated the total score. This recalculation is attached to my testimony as Exhibit
15 No. __ (JTD-7). This recalculation shows that Coyote attains a score of 385.1, the second
16 highest score and only slightly below Big Stone II's 397.7. If more weight were given to
17 Fuel Delivery Competition this disparity is further reduced. Giving equal weight to Rail
18 Line/Mine Proximity and Fuel Delivery Competition would reduce Big Stone II's
19 advantage over Coyote to less than 5 points. This recalculation is shown on Exhibit No.
20 __ (JTD-8).

21 **Q: What do you conclude from these sensitivity recalculations?**

1 A: Sensitivities are meaningful in evaluating impacts of changed assumptions or
2 inputs in complex calculations. However, it is difficult to draw hard and fast conclusions
3 from sensitivities.

4 I do believe that the sensitivities show that Coyote should remain a viable
5 candidate site for future generation expansion plans. I do acknowledge that Coyote has
6 serious issues with proximity to Class I PSD areas as well as serious transmission
7 concerns. However, Coyote offers a strategic advantage with its potential for fuel
8 delivery competition.

9 Coyote's proximity to Class I PSD areas is a significant challenge, but one which
10 deserves greater scrutiny in future site evaluations. While proximity is a good initial
11 screen, there are other considerations beyond mere proximity. A Class I PSD increment
12 is the maximum allowable increase in concentration from new emissions that is allowed
13 to occur above a baseline concentration for a given pollutant. The allowable increments
14 are not stagnant and can be affected by changes at other source emitters and changes in
15 pollution control technology.

16 Coyote also faces significant challenges on the transmission side. Like Class I
17 PSD areas, transmission is not a stagnant consideration. In fact, the transmission analysis
18 for Big Stone II shows that its location will enable greater flows from west to east.
19 Therefore, if Big Stone II and its transmission is built along with the Cap-X 2020
20 transmission infrastructure, the existing transmission constraints for Coyote may be
21 substantially mitigated. This possibility merits further review for any future generation
22 expansion.

1 Q: Did MDU and Otter Tail engage in a review of available generating technologies
2 and analyze their cost impacts?

3 A: Yes, they did. MDU retained PA Consulting Corporation to perform a base case
4 generation expansion plan which concluded that MDU's participation in Big Stone II
5 yielded the lowest cost expansion option. The results are presented in MDU's Generation
6 Expansion Plan Analysis dated October 2, 2006 and are discussed by Mr. Heidell in his
7 testimony.

8 MDU, Otter Tail and the other Co-Owners retained Burns & McDonnell to
9 evaluate several generation alternatives, including pulverized coal, wind plus combined
10 cycle natural gas, integrated coal gasification combined cycle (IGCC) and 50 MW of
11 biomass. This evaluation concludes that 630 MWs of supercritical pulverized coal is the
12 lowest cost option. The results are presented in two reports: Analysis of Baseload
13 Generation Alternatives dated September 2005 and Revised Analysis of Baseload
14 Generation Alternatives dated October 2, 2006.

15 Q: Did you review these reports?

16 A: Yes, I did. All of the reports are quite comprehensive and involve intricate
17 modeling with forecasted assumptions and corresponding economic and engineering
18 inputs. The Burns & McDonnell reports also contain sensitivity analyses including high
19 and low cases for fuel costs and capital costs. I placed a greater emphasis on reviewing
20 the Revised Burns & McDonnell report as it contains more current information and more
21 specific information relevant to Big Stone II as proposed. I reviewed the PA Consulting
22 Report as corroborative to the Burns & McDonnell reports.

1 Q: **Please summarize your understanding of the Revised Burns & McDonnell report.**

2 A: The Revised Burns & McDonnell Report narrows the focus to three alternatives:
3 630 MW Supercritical Pulverized Coal (BS II); 500 MW Natural Gas Fired Combined
4 Cycle Gas Turbine (CCGT); and 500 MW Gas Fired Combined Cycle Gas Turbine plus
5 Wind (CCGT+Wind). The report shows the levelized busbar costs for each alternative
6 both on an Investor Owned Utility (IOU) basis and a Public Power basis. In each case,
7 BS II is the clear winner on a busbar cost basis, with little difference between the busbar
8 costs for the CCGT and the CCGT+Wind alternatives. The degree to which BS II is cost
9 effective is greater for the Public Power scenario than for the IOU scenario. This is
10 because BS II is more capital intensive and Public Power benefits from a lower cost of
11 capital. BS II's cost advantage in the IOU scenario is \$11.16/MWh (\$69.62/MWh vs.
12 \$80.78/MWh for CCGT+Wind). This cost advantage shrinks substantially as
13 sensitivities are run regarding the Wind Production Tax Credit (PTC) and a carbon
14 dioxide (CO₂) environmental cost value.

15 Q: **Does a busbar cost analysis include all costs?**

16 A: A busbar cost analysis is quite comprehensive and includes capital costs,
17 Operating and Maintenance (O&M) costs and fuel costs (but not fuel inventories). There
18 was some ambiguity as to whether it included Interest During Construction (IDC). In
19 response to Data Request No. 11 of the 2nd Set, Otter Tail indicates that the busbar costs
20 do include IDC. The busbar cost analysis does not include transmission costs.

21 Q: **Is a busbar cost analysis a good tool to evaluate alternative generation technologies?**

1 A: It is certainly a good tool but must be tempered with other policy concerns and
2 strategic considerations. It should be viewed with an understanding of the assumptions
3 and projected inputs on which it is based. And obviously, transmission costs and impacts
4 must also be considered.

5 **Q: What are the more important inputs utilized by Burns & McDonnell in the revised**
6 **busbar cost analysis?**

7 A: There are many different inputs which have a meaningful impact on the revised
8 busbar cost analysis and which give insight into the reasonableness of the busbar cost
9 results. I will categorize the more meaningful of these inputs into the following
10 categories for ease of discussion: Wind Inputs; Construction Inputs; Operating Inputs;
11 Fuel Inputs; Financial Inputs; and Other Assumptions.

12 **Q: What are the wind inputs?**

13 A: The original input for wind purchases was \$50/MWh in 2011 without
14 consideration of the PTC. When the revised analysis was updated for 2006 costs, the
15 new wind farm costs were estimated to be \$40/MWh in 2006 with the PTC. This amount
16 was escalated by 2.5% per year to result in a \$46.39 cost in 2012. Recognizing that the
17 impact of the PTC should be \$20/MWh or higher, the resulting cost of wind in 2012 was
18 estimated at \$66/MWh. This amount was conservatively reduced to \$60/MWh for use in
19 the busbar cost analysis. It is Burns & McDonnell's position that both the 2.5% annual
20 escalation rate and the \$60/MWh cost are conservative inputs.

21 Whether the \$60/MWh cost for wind in 2012 is in fact conservative is dependent
22 on both the annual escalation rate and the continuation or discontinuation of the PTC. In

1 regard to the PTC, Otter Tail, in response to Data Request No. 16 of the 2nd Set, stated
2 that a general consensus belief is that the PTC will receive an extension beyond 2008 but
3 that it will be completely gone by approximately 2013. In any event there is a sensitivity
4 analysis assuming a continuation of the PTC included in the Burns & McDonnell
5 analysis.

6 In regard to the 2.5% annual escalation rate, this input is particularly significant
7 because the cost of wind is assumed to be purchases as opposed to actual ownership of
8 the resource. It is not clear why the wind option was assumed to be purchases,
9 particularly when Otter Tail is actively engaged in acquiring ownership interests in wind
10 generation. Of particular interest is the wind assumption used by Mr. Heidell in MDU's
11 Generation Expansion Plan Analysis. Mr. Heidell used a capital cost of \$1,500/KW for
12 wind in 2006 and deescalated it to \$1,200/KW in 2011. Even though the Burns &
13 McDonnell study is measuring the cost of wind purchases and Mr. Heidell is apparently
14 modeling the cost of wind ownership, there seems to be an inconsistency in the direction
15 of wind costs. Perhaps the wind purchases are assumed to follow the marginal cost of
16 generation which is heavily influenced by natural gas prices. Nevertheless, there appears
17 to be an inconsistency between the two reports which should be explained.

18 Another potential inconsistency between Mr. Heidell and the Burns & McDonnell
19 report is the assumed capacity factor for wind generation. Mr. Heidell assumes a 22%
20 capacity credit for summer months. Burns & McDonnell assumes wind will supply
21 enough energy to displace a 40% capacity factor on the CCGT operations. These two
22 assumptions are not measuring the exact same parameter. One is measuring capacity and

1 the other is measuring an amount of energy displacement and stating it in terms of an
2 overall capacity factor. Therefore, there may be no inconsistency at all. If the 40%
3 capacity factor used by Burns & McDonnell is in fact generous, it would only make BS
4 II's cost advantage over the CCGT+Wind option that much more conservative. The
5 differences in these two assumed parameters should be explained.

6 Another significant assumption concerning the CCGT+Wind alternative is the
7 need for the wind portion to be "backed-up" by an equivalent amount of CCGT
8 generation on a MW-to-MW basis. This means that the wind portion is assumed to
9 provide no capacity benefits. This appears to be inconsistent with Mr. Heidell's
10 assumption that wind provides a 22% capacity credit for the summer months. I
11 understand that Otter Tail is a winter peaking utility and it is not clear that wind would
12 provide capacity in the winter months. If wind does provide capacity, a lesser amount of
13 CCGT capacity would be needed to be paired with the wind alternative. This scenario
14 would cause the CCGT+Wind to have a slightly lower busbar cost.

15 **Q: What are the construction related inputs which materially impact the busbar cost**
16 **analysis?**

17 **A:** The most obvious and significant input is the estimated capital cost expressed in
18 \$/KW. In the original busbar cost analysis the capital cost for BS II was estimated to be
19 \$1,800/KW in 2011. This was revised upward in the revised busbar analysis to \$2,168 in
20 2012, an increase of over 20%. Even at this much higher capital cost level, the revised
21 busbar analysis still shows BS II to be the more cost-effective alternative.

1 In its April 19, 2007 response to Data Request No. 10 of the 2nd Set, Otter Tail
2 indicates that the revised busbar analysis reflects the latest estimates. However, in an
3 interview with Mr. Rolfes on April 10, 2007, he indicated that the capital costs used in
4 the revised busbar cost analysis would need to be updated to reflect a later inservice date
5 for BS II. He indicated that the capital costs would need to be increased by 6.5% (13
6 months @ 6% per annum). If this is done, the resulting capital cost for BS II would be
7 approximately \$2,300/KW. This increase would have a more material impact on BS II's
8 resulting busbar cost, since capital costs comprise such a greater portion of BS II's
9 overall costs. This coupled with the fact that the capital cost of the CCGT+Wind
10 alternative is assumed to only escalate at 2.5% per year, could have a material effect on
11 the busbar costs of BS II as compared to the CCGT+Wind alternative. Whether the
12 impact would be material enough to change the conclusion that BS II is the lower cost
13 alternative is unclear. I believe MDU and Otter Tail need to clarify the impact of BS II's
14 increasing capital cost estimates.

15 Another significant construction related input is the estimated construction period
16 of 48 months for BS II. This certainly may be achievable, but is likely optimistic. To the
17 extent the actual construction time is within the assumed 48 months, there is a lesser
18 potential for increase in materials and labor. In addition, the impact of IDC would be
19 minimized and the benefits of asset-backed sales and lower fuel costs would be achieved
20 sooner. To the extent construction takes longer than 48 months; there would be greater
21 upward pressure on costs and postponement of anticipated benefits. Managing the

1 construction time will be particularly challenging given the growing demand that
2 numerous other proposed coal units will place on available resources.

3 **Q: How many other coal plants will be under construction?**

4 A: I do not know the exact number, but I have read reports that the United States is
5 entering an acute period of increased coal generation development. I have also seen
6 projections for as many as 45 coal plants to be under construction during the 2008 to
7 2013 timeframe. With so much competing activity, delays in the delivery of major
8 equipment or difficulties in obtaining adequate skilled labor for a project the size of BS II
9 may occur. I understand there already are backlogs in specialty fabrication facilities,
10 including steam turbines, boilers and fuel handling equipment. The availability and cost
11 of skilled labor may also be affected by construction related to refineries, post-Katrina
12 activities and an overall aging of the work force.

13 **Q: What are the operating inputs which materially impact the busbar cost analysis?**

14 A: There are two operating parameters of particular interest: capacity factor and heat
15 rate. Capacity factor is the percentage of time the plant is expected to be available for
16 generation, taking into account both forced outages and unforced (maintenance) outages.
17 For a baseload unit such as BS II, it is critically important that it have a high capacity
18 factor. A high capacity factor means the relatively high capital costs are actually
19 achieving the anticipated savings in lower fuel and operating costs. In fact, the sensitivity
20 analysis shown in the original busbar cost analysis shows capacity factor to have an
21 extremely large impact on BS II's resulting busbar cost, second only to BS II's capital

1 costs. For purposes of the busbar cost analysis an overall capacity factor of 88% was
2 assumed. I believe the 88% capacity factor is a conservative assumption.

3 The heat rate is a measure of the thermal efficiency of the plant and is stated in
4 terms of Btu/KWh. The lower the heat rate value, the greater the efficiency. The original
5 busbar cost analysis used a heat rate of 9,369 which was changed to 9,095 for the revised
6 busbar analysis. The 9,095 is a conservative value as Mr. Rolfes indicates the current
7 projected heat rate for BS II is 8,988 Btu/KWh. To the extent an actual heat rate closer to
8 Mr. Rolfes' projection is actually achieved, the lower the resulting busbar costs.

9 **Q: What are the fuel cost inputs which materially impact the busbar cost analysis?**

10 A: Fuel costs may very well be the single most significant input in a busbar cost
11 analysis which compares coal-based generation technologies with gas-based generation
12 technologies. Fuel costs may also be the most difficult input to forecast.

13 The revised busbar cost analysis assumes a delivered price of PRB coal of
14 \$1.71/MMBtu in 2010 escalated at 2.9% per year. The original busbar cost analysis
15 utilized an escalation rate of 2.0% per year. Given that the transportation component
16 exceeds the commodity portion of the delivered price of PRB coal and that there is
17 uncertainty concerning future transportation costs for PRB coal, increasing the overall
18 escalation rate is probably justified. Mr. Heidell used an escalation rate of 2.5% for coal
19 in his analysis, indicating that the 2.9% escalation is conservative. The \$1.71/MMBtu
20 cost of coal in 2010 is essentially the same as that used by Mr. Heidell of \$1.68/MMBtu
21 in 2010.

22 **Q: What about the natural gas cost inputs?**

1 A: Predicting future prices of natural gas is inherently uncertain, particularly over a
2 long-term horizon which is necessary in evaluating alternative generation technologies.
3 There are many uncontrollable drivers that influence the price of natural gas: expected
4 worldwide economic growth and worldwide demand; North American natural gas
5 demand and production; the worldwide supply and demand for Liquefied Natural Gas;
6 the geopolitics of many regions of the world; and the potential for new environmental
7 requirements. While it is difficult to predict the price of natural gas, it can be the single
8 most important factor in justifying the relatively high capital costs of a solid fuel
9 generating plant like BS II.

10 The revised busbar cost analysis assumes a delivered price of natural gas of
11 \$7.60/MMBtu in 2011 with a 3.0% annual escalation rate. The original busbar cost
12 analysis used a 2.5% annual escalation rate. Mr. Heidel did not use a constant escalation
13 rate in his analysis. Rather, he utilized PA Consulting's long-term consensus gas forecast
14 which predicts gas price reductions in the early years followed by escalating increases in
15 the later years. Mr. Heidel's forecast is consistently lower than that used by Burns &
16 McDonnell. It is unclear whether Mr. Heidel's forecast is a commodity-only forecast or
17 if it also includes transportation costs. The Burns & McDonnell forecast includes
18 transportation at \$0.40/MMBtu and then escalates it by 3.0% per year. A comparison of
19 the two natural gas price forecasts is shown in Exhibit No. __ (JTD-9).

20 Q: **Why is there a difference in the two natural gas price forecasts?**

21 A: As I said earlier, predicting natural gas prices is inherently uncertain so it is not
22 surprising that knowledgeable people will have different forecasts. However, Mr.

1 Heidell's forecast is consistently lower than that used by Burns & McDonnell in its
2 revised busbar cost analysis. Part of this difference could be attributable to transportation
3 costs. Nevertheless, the differences are quite large, greater than 20% in many years, and
4 they are consistent in their magnitude and their direction of deviation.

5 **Q: Could these differences impact the conclusions of the revised busbar cost analysis?**

6 A: Yes, it is possible. The original busbar cost analysis contained sensitivity
7 analyses for a number of inputs, including fuel costs. The fuel cost sensitivity was for
8 both a high cost and a low cost case, at 10% above and below the forecasted values.
9 Even in the low fuel cost case, the busbar cost of BS II was still lower than that of the
10 gas-based alternatives. However, there was no fuel cost sensitivity presented in the
11 revised busbar cost analysis. It is not clear whether a fuel cost sensitivity was performed
12 for the revised busbar cost analysis and, if it was, what it showed. Even if it was
13 performed, I would assume it would have been done for the 10% sensitivity case. The
14 difference between the Burns & McDonnell forecast and the PA Consulting forecast
15 exceed 20% in most years. I believe MDU and Otter Tail should explain the differences
16 in the gas forecasts and determine the potential impacts on the revised busbar cost results,
17 if any.

18 **Q: What are the financial inputs which materially impact the busbar cost analysis?**

19 A: There are essentially three major categories of financial inputs that materially
20 impact the busbar cost analysis: cost of capital; forecasted lives; and tax considerations.
21 Assumptions for these inputs are distinguished between the IOU case and the Public
22 Power case. I will concentrate on the IOU assumptions.

1 The revised busbar cost analysis assumes an interest rate of 7.5% on debt and a
2 cost of equity capital of 12.0%. These rates combined with an assumed 50%/50% debt to
3 equity ratio results in an overall cost of capital rate of 9.75%. The 9.75% is used as the
4 discount rate in the model used to calculate the busbar costs.

5 The busbar cost analysis is based on a 20-year economic model analysis. It also
6 assumes a book life of 30 years and a tax life of 20 years. The effective tax rate (for
7 IOU's only) is assumed to be 40%.

8 **Q: Are the financial inputs used in the revised busbar cost analysis appropriate?**

9 A: I generally agree that the financial inputs used are appropriate for modeling
10 purposes, as is the case in the revised busbar cost analysis. In many cases, I believe the
11 financial inputs used are not only appropriate, but are actually conservative. Obviously,
12 inputs that are appropriate for modeling busbar costs may not be appropriate for other
13 purposes such as ratemaking.

14 **Q: Will you specifically address the cost of capital inputs?**

15 A: Yes, I will. First, let me say that a company's cost of capital is specific to that
16 company and is based on many qualitative as well as quantitative considerations. It is
17 beyond the scope of this testimony to fully explore all of those considerations. However,
18 I have made some general observations which indicate that it is not necessary, for
19 purposes of this testimony, to distinguish possible differences between MDU and Otter
20 Tail. My review indicates that the two companies share many similarities.

21 Besides their close geographic proximity, they both have substantial interests in
22 non-utility lines of business. While MDU, in terms of total assets is larger on a

1 consolidated basis, Otter Tail's regulated electric business is larger, in terms of both net
2 plant and income, than MDU's regulated electric business. MDU and Otter Tail have
3 other similarities including equity ratio, interest coverage and bond rating. These and
4 other financial comparisons are shown in Exhibit No. ____ (JTD-10).

5 The assumed 7.5% interest rate appears conservative. Both MDU and Otter Tail
6 have strong financial indicators with the apparent ability to access the capital markets on
7 reasonable terms. The companies' existing interest costs compare favorable to the
8 assumed 7.5%. The current yields on A3 rated electric utility debt with an approximate
9 20-year maturity are averaging around 6%. While markets can change, it is reasonable to
10 assume that the necessary debt to construct Big Stone II should be available at a rate at or
11 below 7.5%. To the extent debt can be acquired considerably less than 7.5%, the
12 resulting busbar cost of Big Stone II will also be less.

13 While the companies' current consolidated equity ratios are substantially greater
14 than 50%, it should be recognized that these are consolidated equity ratios reflecting
15 substantial non-regulated businesses. Also, electric capital expenditures are forecasted to
16 greatly exceed historical averages. Therefore, substantial amounts of debt in excess of
17 historical levels will have to be acquired for Big Stone II. A 50%/50% debt to equity
18 ratio is reasonable under these circumstances.

19 The use of a 12% return on equity is also reasonable. This return is not out of line
20 when compared to returns historically granted. I believe it is reasonable given the
21 financial stress that an undertaking the size of Big Stone II will have on the electric
22 operations of MDU and Otter Tail. While the actual return on equity will be the product

1 of a future rate proceeding, the use of 12% for the busbar cost analysis is certainly
2 reasonable.

3 **Q: Are the forecasted lives used in the busbar cost analysis reasonable?**

4 A: Yes, they are. The busbar cost analysis assumes an economic term of 20 years.
5 This is a reasonable term to use when comparing competing generation alternatives.
6 Certainly the impacts of any years beyond 20 would have a lesser significance on a net
7 present value basis and would introduce greater uncertainties in forecasted inputs.
8 However, the true economic life of a plant like Big Stone II is anticipated to be much
9 greater than 20 years, probably by a factor of two. This means that assuming all other
10 things (like relative fuel and operating costs) being equal, a unit like Big Stone II should
11 generate savings well beyond the 20 year planning horizon. This phenomenon is known
12 as "end effects" and is referenced by Mr. Heidell in his testimony. To the extent the end
13 effects materialize, the busbar cost of Big Stone II would be less over its actual economic
14 life.

15 The busbar cost analysis also assumes a book life of 30 years and a tax life of 20
16 years. The 30-year book life is certainly conservative. Mr. Heidell used a book life of 40
17 years. The difference in the book life and the tax life would generate deferred income
18 taxes in the early years that would eventually reverse over the life of the unit. It is not
19 clear whether the busbar cost analysis includes the beneficial effects of the deferred taxes.
20 I assume it does not since the simplified capital structure assumption is a 50%
21 equity/50% debt. To the extent deferred taxes are not considered, it would yield a
22 conservative result. If deferred taxes were considered and all other things held equal, Big

1 Stone II (given its higher capital costs) would have an even lower busbar cost relative to
2 other generation alternatives.

3 **Q: Are there other assumptions which impact the busbar cost analysis?**

4 A: Yes, there are two other assumptions which merit some brief discussion.

5 First, the busbar cost analysis assumes that the construction of each alternative is
6 executed under an Engineer-Procure-Construct (EPC) Contract. Under this approach a
7 single contract is entered into which covers all aspects from initial design to final
8 construction. This is a reasonable assumption to make when comparing competing
9 generation alternatives. However, an EPC Contract is not the basis upon which Otter Tail
10 and the other Co-owners plan to proceed if Big Stone II is approved. In an interview
11 conducted April 10, 2007, Mr. Rolfes indicated that multiple contracts will be pursued for
12 Big Stone II with Black & Veatch acting as Construction Manager. This should allow for
13 more control and more competition from vendors, resulting in lower costs. To the extent
14 multiple contracts are pursued and costs are lower, it should have a greater benefit for Big
15 Stone II relative to the other generating alternatives.

16 Second, the busbar cost analysis assumes no gypsum sales from Big Stone II.
17 This is certainly the conservative approach to take and avoids having to make
18 assumptions about quantities and prices in the gypsum market. However, in reality,
19 gypsum sales should provide some revenue to help offset some of the costs of Big Stone
20 II. Obviously, gypsum revenue would not be available from any of the other generating
21 alternatives.

1 Q: Are there other considerations which go beyond the limitations of a busbar cost
2 analysis?

3 A: Yes, there are. By definition, busbar costs do not include transmission costs.
4 Obviously, transmission is an extremely important consideration which I will discuss
5 later in my testimony. Also, significant is the manner in which Big Stone II would fit
6 into MDU and Otter Tail's generation fleet and how it would be dispatched in relation to
7 other units. Also potentially significant is the possibility of Big Stone II facilitating
8 additional asset-backed sales either from Big Stone or other generating units within
9 MDU's and Otter Tail's systems.

10 Q: Why are asset-backed sales an important consideration?

11 A: Asset-backed sales provide a benefit to the selling utility by providing additional
12 revenue above the marginal costs of generation, thus providing a contribution toward
13 fixed costs. These sales also provide a benefit to the buying utility by displacing higher
14 cost generation.

15 Different jurisdictions have different policies when it comes to asset-backed sales.
16 I am familiar with Florida's system of sharing the gains between customers and
17 stockholders. This provides an incentive for companies to pursue such sales, thus
18 benefiting themselves and their customers.

19 I understand that MDU has a similar arrangement that was part of a negotiated
20 settlement whereby there is an 85%/15% sharing between customers and stockholders.
21 To the extent Big Stone II were to facilitate additional asset-backed sales, this would be a
22 significant benefit to MDU's customers. I understand that Otter Tail does not have a

1 sharing requirement but is recognizing these sales in their financial reporting of regulated
2 operations.

3 **Q: What is your understanding of the interconnection requirements of Big Stone II?**

4 A: Big Stone II would be connecting at the same location as Big Stone I, which is in
5 Otter Tail's control area. MISO has the responsibility to process interconnection requests
6 and to evaluate impacts on the grid. Otter Tail took the lead in performing an
7 interconnection study and submitting it to the MISO. The study identified two primary
8 options for achieving interconnection, the preferred alternative being a new upgraded line
9 from Big Stone to Morris, Minnesota, and a new line from Big Stone to Granite Falls,
10 Minnesota. The Big Stone to Morris line would be designed to operate at 230 kV while
11 the Big Stone to Granite Falls line would be designed to operate at either 230 kV or 345
12 kV. The Big Stone to Morris line would utilize an existing transmission corridor.

13 **Q: Are there requirements beyond interconnection?**

14 A: Yes, there are. To determine the deliverability of the power from Big Stone II to
15 the loads of the various Co-owners, a delivery service study was performed by Otter Tail
16 and submitted to the MISO. This study identified facility upgrades which would
17 generally enhance the overall grid and more specifically enable the output to be delivered
18 to the intended recipients. The result of the delivery service study did not change the
19 conclusion of the interconnection study.

20 **Q: What is the anticipated cost of all transmission facilities associated with Big Stone**
21 **II?**

1 A: Transmission planning and costing is a dynamic process. It is a constant
2 evaluation of the effects of changes to the system and of synergies that will most cost-
3 effectively meet changing needs. Therefore, anticipated costs will change over time.
4 Nevertheless, the latest cost projection for Big Stone II's transmission, including costs
5 relating to interconnection, delivery, contingencies and escalation is approximately \$215
6 million. This amount includes cost escalations to 2012 and recognizes \$35 million of
7 savings for delivery service facilities. The original transmission cost estimate was \$238
8 million.

9 **Q: Are there other cost savings possible?**

10 A: Yes, there is always the possibility that other savings (or increases) will be
11 identified. There also is the likelihood that some of Big Stone II's transmission cost will
12 be shifted to others. MISO has a Regional Economic Criteria Benefit tariff on file with
13 the FERC where other MISO members pay a portion of certain transmission
14 enhancements. A preliminary analysis performed by Otter Tail indicates that others
15 would be allocated about \$8 million of Big Stone II's transmission costs, assuming the
16 transmission line from Big Stone to Granite Falls is constructed and operated as proposed
17 at 345 kV.

18 **Q: How does the cost of Big Stone II's transmission compare to the cost of transmission**
19 **from 600 additional MWs at Coyote Station?**

20 A: This question was posed to Mr. Rogelstad in an interview conducted on April 11,
21 2007. He indicated that an interconnection study for Coyote Station was not performed.
22 He offered as a surrogate the results of a preliminary study for the interconnection of 600

1 MWs of additional capacity at Center, North Dakota. This study shows interconnection
2 costs substantially greater than those estimated for Big Stone II. To my knowledge, no
3 studies were performed for delivery costs at any location other than Big Stone II.

4 **Q: Is Center a good surrogate for estimating the cost of additional transmission for**
5 **Coyote?**

6 A: Yes, I believe it is. A Transmission System Impact Study performed as part of
7 the Lignite Vision 21 Project shows that the cost of transmission for Coyote is within \$4
8 million of that needed for Center. These results were reported in February, 2001.

9 **Q: Are there constraints that limit the amount of energy which can be exported out of**
10 **North Dakota?**

11 A: Yes, in his testimony, Mr. Rogelstad refers to the North Dakota Export
12 transmission constraint, which also includes a portion of western Minnesota and eastern
13 South Dakota. He also refers to the transient stability problem that arises when large
14 amounts of generation are connected to distant loads with less than optimal transmission.
15 Contingency analyses show that in those circumstances the tripping of a single
16 transmission line can cause severe voltage swings, sometimes resulting in separation and
17 outages.

18 **Q: Would the transmission requirements for Big Stone II mitigate this constraint?**

19 A: Yes, while the transmission requirements for Big Stone II are consistent with the
20 addition of 630 MWs and are designed to allow the energy to be transmitted to the
21 intended recipients, the addition of Big Stone II will have a beneficial effect on the ability
22 of the entire system to transmit energy from west to east.

1 Under existing circumstances, Big Stone I provides a beneficial effect. Without
2 Big Stone I, the west-to-east capability of the system is reduced by 350 MWs. With the
3 addition of Big Stone II, the beneficial effect is further increased. It is estimated that with
4 Big Stone II up to 500 MWs of generation could be added in North Dakota and that the
5 transient stability performance of the system would meet current reliability standards.

6 **Q: Is this conclusion supported by MISO?**

7 A: I am not aware of any attempts by MISO to estimate the amount of additional
8 export capability Big Stone II would create. However, MISO is keenly aware of the
9 west-to-east constraint. MISO recently evaluated 1300 MWs of transmission service
10 requests, excluding Big Stone II, in a general west-to-east direction. This evaluation
11 shows a need for additional transmission capacity and identified a number of individual
12 constraints on the system. In testimony filed on behalf of MISO in Minnesota, MISO
13 stated:

14 *The Big Stone upgrades in conjunction with the Cap-X 2020 proposed*
15 *lines resolved 61 constraints in a study that analyzed 1300 MW of*
16 *transmission service plus the 600 MW of Big Stone. The upgrades in and*
17 *of themselves did not single-handedly remove those constraints, but rather*
18 *the integration of the plans of the Big Stone upgrades to those proposed in*
19 *Cap-X 2020 resolved the constraints.*

20 MISO went on to conclude that the transmission upgrades associated with Big
21 Stone II would be used and useful even without Big Stone II's 630 MWs of additional
22 capacity.

1 Q: **Would the construction of Big Stone II take transmission capacity away from**
2 **potential wind generators?**

3 A: The addition of Big Stone II would not take away any existing transmission
4 capacity that may exist for wind. Any generating capacity expansion requires adequate
5 transmission capacity to match it and Big Stone II is not exempt from this requirement.

6 There already exists a long queue of potential wind generators seeking
7 interconnection. MISO has concluded that the 345 kV portion of the Big Stone II
8 facilities along with the Cap-X line from Brookings to the Twin Cities would enable
9 more wind generation to interconnect. Therefore, it is conceivable, that Big Stone II
10 would be assisting the development of more wind generation, not taking away from it.

11 Q: **Did MISO take a position on Big Stone II before the Minnesota Public Utilities**
12 **Commission?**

13 A: Yes, MISO took the position that Big Stone II transmission should be approved.

14 Q: **What will be the coal requirements for Big Stone II, if approved?**

15 A: Big Stone II would burn sub-bituminous coal from the PRB, similar to what Big
16 Stone I has been burning since 1995. Big Stone II is being designed to burn 8400 Btu/lb
17 coal, but could also burn fuel with a higher heat content.

18 Big Stone I currently burns approximately 2 million tons of coal annually. Big
19 Stone II would be expected to burn approximately 2.5 million tons annually. A historical
20 summary of Big Stone I's coal usage is shown in Exhibit No __ (JTD-11).

21 Q: **Would Big Stone II be able to burn fuels other than coal, similar to Big Stone I?**

1 A: Yes, but probably not to the extent of Big Stone I. Big Stone I has burned a
2 variety of "opportunity fuels" that have included tire-derived fuel and waste corn and
3 seeds. There are a variety of independent suppliers of such fuels, which are delivered by
4 truck. The prices paid for such fuels are generally 70% or less than that paid for the
5 plant's primary fuel. Big Stone II would be able to burn some biomass fuels on a limited
6 basis.

7 **Q: Has Otter Tail entered into any contracts or bid solicitations for coal supply for Big**
8 **Stone II?**

9 A: No, Otter Tail has not yet done so. Given that Big Stone II is only in its
10 preliminary approval stage, it would be premature and perhaps impractical to require
11 fully negotiated fuel supply contracts. It is my understanding that if Big Stone II is
12 approved, Otter Tail would issue RFPs to those mines that can supply coal to the correct
13 specifications, similar to what is currently done for Big Stone I. However, it is
14 imperative that the current economic evaluation of Big Stone II contain reasonable
15 estimates of future fuel costs. The projected cost of coal for Big Stone II is shown in
16 Exhibit No.__(JTD-12).

17 **Q: Are the projected costs of coal shown in this exhibit consistent with the projected**
18 **costs in the revised busbar cost analysis?**

19 A: Yes, I believe so with one clarification. The revised busbar cost analysis begins
20 with the 2010 estimated cost of \$1.71/MMBtu and escalates it by 2.9%. It is not clear
21 whether this is a constant escalation rate or an average escalation rate. The projected cost
22 shown in Exhibit No.__(JTD-12) is not based on a constant escalation rate, but still

1 reflects an overall annual escalation rate of 2.9%. I have added two columns to Exhibit
2 No.__(JTD-12) to show the differences that result from using a constant 2.9% escalation
3 rate. For ease of reference, these additional columns are shown in Exhibit No.__(JTD-
4 13). The differences are not great but do show lower escalated values in the earlier years
5 compared to greater escalated values in the later years. This would tend to show a
6 slightly lower busbar cost on a net present value basis.

7 **Q: Do you believe these differences are material?**

8 A: No, I do not. Unless there is a severe distortion between the earlier and later
9 years, it should make no material difference whether the escalation rate is constant or an
10 annual average.

11 **Q: Is the 2.9% escalation rate appropriate?**

12 A: Forecasting fuel costs is difficult. While forecasting the costs of natural gas may
13 be the most challenging, coal presents its own set of problems. Coal is generally not a
14 worldwide or even a national commodity. It tends to be based on regional markets where
15 users have a limited ability to switch from one region to another. Regional prices tend to
16 be set by the marginal cost of production to satisfy demand. While production costs for
17 PRB coal are generally less, demand has been steadily increasing. Another complicating
18 factor for PRB coal is transportation costs. For western sub-bituminous coal, rail
19 transportation costs represent about 60% of overall cost, while it is only about 25% for
20 eastern bituminous.

21 Given these uncertainties, I believe a 2.9% escalation rate is reasonable. It is just
22 slightly lower than the recent actual escalation experienced at Big Stone I and is in line

1 with recent forecasts from the Energy Information Administration. While it is slightly
2 higher than the 2.5% escalation rate by Mr. Heidell, I believe it is reasonable given the
3 uncertainty of rail transportation costs.

4 Obviously, the higher the escalation rate used in the busbar cost analysis, the
5 higher the confidence that Big Stone II is the most cost-effective alternative. If Big Stone
6 II is approved and the actual cost of coal is less, the savings would be even greater.

7 **Q: What if Big Stone II is approved and the actual escalation rate of coal is greater**
8 **than forecasted?**

9 A: The actual escalation rate could be higher or lower. If it is higher, Big Stone II
10 would not be as cost-effective, holding all other factors equal. However, in all likelihood,
11 if coal costs escalate greater than forecasted then natural gas costs would also escalate
12 greater than forecasted. The true test of Big Stone II's cost effectiveness would be its
13 overall operating costs compared to the overall operating costs of the other alternatives,
14 which are highly dependent on natural gas costs. The question for today is whether the
15 2.9% escalation rate is reasonable. For our purposes, I believe it is.

16 **Q: Why is the rail transportation of coal such a critical concern?**

17 A: The transportation component of any fuel is an important concern. However, for
18 PRB coal it is even more critical. On an absolute basis, transportation exceeds the
19 commodity portion of the overall cost of PRB coal. Beyond that, transportation adds a
20 level of uncertainty both in the cost and its reliability of delivery.

21 **Q: Why is the cost of rail transportation for Big Stone II such a critical concern?**

1 A: There is no competition for this service and thus no competitive pressure to keep
2 these costs down. The section of Otter Tail's 2006 Annual Report discussing Risk
3 Factors identifies this and states:

4 *We are a captive rail shipper of the Burlington Northern Santa Fe*
5 *Railroad for shipments of coal to our Big Stone and Hoot Lake plants,*
6 *making us vulnerable to increased prices for coal transportation from a*
7 *sole supplier.*

8 Earlier in my testimony I discussed the strategic advantage of having fuel delivery
9 competition. Unfortunately, this is not an option for Big Stone.

10 **Q: Have there been efforts to mitigate this risk factor?**

11 A: Yes, to MDU's and Otter Tail's credit, they have pursued relief from the Surface
12 Transportation Board (STB). This action was prompted by a 38% increase in their
13 freight rates from 1999 to 2000. They sought a favorable rate with a 20-year term that
14 would be based on a least-cost replacement standard to simulate a competitive rate. The
15 STB rejected this standard and used a cross-subsidy test under which the rate was found
16 to not only be permissible but also subject to further potential increases. This decision
17 was appealed to the 8th Circuit Court of Appeals where the STB decision was reaffirmed
18 on May 1, 2007.

19 **Q: Have there been reliability problems with the delivery of coal to Big Stone I?**

20 A: Yes, there have been. The delivery disruptions got so severe that there were
21 generation curtailments which began on March 11, 2006, and lasted through May 4,
22 2006. On March 11, 2006, the normal 30-day supply of coal had been depleted to only

1 10 days, while the train cycle times had increased by more than 20%. The initial
2 curtailments were to 70% of full load and on April 6 there were further curtailments to
3 45% of full load. It is estimated that 115,000 MWhs of generation were lost due to the
4 supply disruptions.

5 **Q: What has caused the supply disruptions from the PRB?**

6 A: There were many reasons that contributed to the problem. One of the most
7 obvious was structural failures of rail roadbeds triggered by a combination of coal dust
8 and unusually wet weather. Another significant factor was the record growth of coal
9 production from the region. The Energy Information Administration (EIA) reports that
10 coal production in the Western Region, primarily from mines in Wyoming and Montana,
11 increased by 800% from 1973 to 2003. This was followed by three record production
12 years from 2003 to 2006. By 2006, the Western Region accounted for over 53% of total
13 U.S. coal production.

14 **Q: Have the railroads responded to the increase in production?**

15 A: The EIA reports that both the BNSF Railway Company and the Union Pacific
16 Railroad have made substantial improvements that address both the need to strengthen
17 the existing system and to increase its capacity. Mr. Brautovich addresses BNSF's
18 efforts in this overall effort as well as efforts to address Big Stone II's specific needs.

19 **Q: If Big Stone II is approved, what, if anything, can the co-owners do to address**
20 **potential coal delivery problems?**

21 A: The options available may be limited. First, the co-owners do not have the option
22 of negotiating with a competing carrier. And based upon responses to data requests and

1 interviews with knowledgeable individuals at Otter Tail, it does not appear that
2 negotiating performance guarantees with BNSF Railway Company is a viable option.

3 There are a number of internal operational measures the co-owners could
4 undertake, however, to enhance the timely and efficient delivery of coal. First, cycle
5 times should be closely monitored. Cycle time is the amount of time that it takes a train
6 to move from the load point, through loaded transit, unloading, and unloaded transit back
7 to placement for loading again. This is important as a measure of equipment utilization
8 when owned or leased railcars are being used. This also gives an early indication of rail
9 congestion and possible future shipment slow downs.

10 Second, there should be a forecasted schedule of train loadings for each month
11 and for each set of equipment, based upon the burn requirements for each plant. This
12 schedule should be communicated to the railroad. The loadings should be monitored to
13 determine if the schedule is being met. If the schedule is not being met, there should be
14 an effort to coordinate with the railroad to speed up cycle times or place more train sets in
15 service.

16 Third, there should be a system to manage train deliveries. In most cases the
17 generating plant must move coal away from the unloading area before it can unload the
18 next train. This becomes more critical if a train arrives within a short time of the
19 previous unloading. It is important to monitor the expected times of arrival as scheduled
20 and compare them to the actual times of arrival. Moving coal out of the way
21 unnecessarily when a train arrives late is costly and delaying trains from unloading when
22 they arrive early is poor utilization of rail equipment.

1 Fourth, there should be a target number of cars per unit train and enough railcars
2 to hit those targets plus maintenance spares. The actual number of cars per train should
3 be monitored to verify that the targets are being met.

4 **Q: Does Otter Tail use these measures for the delivery of coal to Big Stone I?**

5 A: The operational measures I just described should be part of an overall coal
6 delivery management system. I believe Otter Tail undertook many of these measures in
7 response to the earlier delivery problems at Big Stone I. They may also be part of Otter
8 Tails' ongoing coal delivery procedures. I believe Otter Tail should indicate if this is the
9 case, how these measures fit into their overall management system and whether there is
10 any formalized reporting of these measures. If Otter Tail plans not to engage in these
11 practices for Big Stone II, I believe they should explain why.

12 **Q: If approved, would Big Stone II use light weight aluminum railcars?**

13 A: I am not sure of the type of rail cars planned for Big Stone II. It may not be
14 possible to determine which railcars would serve which plant. It is my understanding that
15 there would be a common coal-handling facility for both Big Stone I and Big Stone II,
16 creating cost savings and adding to their overall efficiency.

17 To the extent additional railcars would be needed to serve the additional coal
18 requirements of Big Stone II, I believe the use of light weight aluminum railcars should
19 be considered. There would be a trade-off between cost and capacity that would need to
20 be considered. However, the cost may be justified, particularly considering past coal
21 delivery problems at Big Stone I.

22 **Q: What is the significance of using aluminum railcars?**

1 A: The significance is basically twofold. First, the per ton shipping rate is less for
2 aluminum railcars than that for steel railcars. According to the BNSF Tariff, the savings
3 is slightly more than 5%. Second, an aluminum railcar can carry 121 tons on average
4 compared to 100 tons on average for a steel railcar. If congestion on the system persists,
5 getting more tons per train set may be crucial in maintaining adequate inventories.

6 **Q: Is there any other measure that could be taken to minimize the effect of potential**
7 **coal delivery problems?**

8 A: Yes, the coal inventory level could be increased. It is my understanding that Big
9 Stone II would have a target inventory of 30 days burn, which should be adequate under
10 most circumstances. However, as planned, it would be possible to have up to 45 days of
11 inventory on site.

12 **Q: Would there be a cost associated with increasing the amount of fuel inventory?**

13 A: Yes, there is an end-of-year inventory tax collected by South Dakota, there could
14 be some additional Operation and Maintenance (O&M) expenses and there is also the
15 potential for some coal quality degradation. There also would be the carrying costs of the
16 additional inventory.

17 **Q: What would be the amount of the carrying costs on the additional inventory?**

18 A: This is largely dependent upon the cost of coal you assume. Assuming a
19 delivered cost of PRB coal of \$30/ton, I calculated the additional inventory to be slightly
20 over \$3 million. MDU and Otter Tail would each be responsible for 19.33% of this
21 amount or approximately \$600,000 each. The carrying cost of this amount, including

1 income taxes, would be less than \$100,000 per year. These calculations are shown in
2 Exhibit No. __ (JTD-14).

3 **Q: Would a 45-day inventory of coal have prevented the earlier curtailments at Big**
4 **Stone I?**

5 A: A 45-day inventory would probably not have totally prevented the curtailments.
6 However, it is reasonable to conclude that it would have mitigated the degree of
7 curtailments. My calculations show that Big Stone I experienced curtailments equal to
8 approximately 23 days of full load capacity (26 days at 30% curtailment and 28 days at
9 55% curtailment). These curtailments were begun when the inventory had been depleted
10 to a level of 10 days burn.

11 **Q: What was the cost of purchasing replacement power to cover the curtailments at Big**
12 **Stone I?**

13 A: According to Otter Tail's response to Data Request No. 8 of the 3rd Set, the cost
14 of replacement power itself was in a range of \$2.1 million to \$2.8 million. The
15 incremental costs (those costs over what Big Stone's costs would have been assuming no
16 curtailments) were in a range of \$1.0 million to \$1.7 million.

17 **Q: If Big Stone II is approved, what level of coal inventory should it maintain?**

18 A: My understanding is that Big Stone II would have a target inventory of 30 days
19 burn, like Big Stone I. I also understand that the Engineering and Operating Committee
20 for Big Stone I has on occasion increased the target level to address supply concerns. I
21 believe Big Stone II should be no different. In light of the recent supply disruptions, I
22 believe that the target level should once again be reviewed to determine if a higher target

1 is cost justified. Given the high cost of replacement power, having a higher inventory
2 may be justified even if the likelihood of future curtailments is remote.

3 **Q: What agreements have MDU and Otter Tail entered into to govern the development**
4 **and operation of Big Stone II?**

5 A: MDU, Otter Tail and the other Co-owners have entered into three agreements, the
6 Participation Agreement, the O&M Agreement and the Joint Facilities Agreement.
7 Northwestern Corporation, one of the co-owners of the existing Big Stone I Plant, is also
8 a signatory to the Joint Facilities Agreement.

9 **Q: Have you reviewed these agreements?**

10 A: Yes, I have. The agreements address matters in great detail and address numerous
11 contingencies. The operating parameters are generally patterned after the Big Stone I
12 agreement.

13 The Participation Agreement is an agreement to jointly develop, finance,
14 construct, own and manage Big Stone II. It includes provisions which obligate the parties
15 to obtain financing and pay their share of costs. It also addresses withdrawal rights due
16 to higher than anticipated project costs. Amendments extend these rights until June 2007.
17 The Participation Agreement establishes a Coordinating Committee and an Engineering
18 and Operating Committee to manage all aspects of Big Stone II and to supervise the plant
19 operator. Decisions at the Engineering and Operating Committee have to be unanimous.
20 Other matters are addressed by the Coordination Committee for resolution.

21 The O&M Agreement designates Otter Tail as the operator of Big Stone II. The
22 operator is required to provide staff and resources for the development, design, financing,

1 construction and operation of Big Stone II. The other Co-owners are required to
2 reimburse Otter Tail for their allocated share of these costs. In addition to the recovery of
3 all costs associated with being the operator, Otter Tail also receives a \$500,000 per year
4 fee as operator. Under the agreement, it is permissible for Otter Tail to share this fee
5 with its employees. Otter Tail is the designated operator for at least the first five years.

6 The Joint Facilities Agreement provides for the transfer of certain real property
7 and easements from Big Stone I participants to Big Stone II participants. It also provides
8 for the shared use of certain equipment and facilities and for the allocation of associated
9 costs.

10 **Q: What facilities would be shared between Big Stone I and Big Stone II?**

11 A: There would be many different facilities that could be shared now and perhaps
12 even more in the future. Sharing the facilities would provide significant cost savings.
13 Three of the most significant would be coal handling facilities, water intake facilities and
14 the wet scrubber.

15 **Q: Does Big Stone I currently have a wet scrubber?**

16 A: No, it does not. If Big Stone II is approved, it is contemplated that a common wet
17 scrubber would be installed for both units. This would create a tremendous cost savings
18 for Big Stone I. It is estimated that a wet scrubber can be added with enough capacity to
19 scrub both units at an incremental cost of only 60% of scrubbing Big Stone II alone. The
20 incremental cost of the scrubber would be allocated to big Stone I. The wet scrubber as
21 designed would remove 98% of SO₂ and would collect the fly ash. It would also create

1 SO₂ allowances. It also could potentially allow both Big Stone I and Big Stone II to look
2 at higher sulfur coal as a future fuel supply.

3 **Q: How would you characterize the risk of proceeding with Big Stone II?**

4 A: Adding coal-fired base load generation like Big Stone II presents a myriad of
5 uncertainties and thus risks. However, these risks must be weighed against the
6 advantages of this type of generation. One should also evaluate the risks of not
7 proceeding.

8 **Q: What are the significant areas of uncertainty associated with Big Stone II?**

9 A: I have discussed various areas of uncertainty in answers to previous questions. I
10 will attempt to summarize them here.

11 First is the uncertainty of the timing of the benefits. It is important to recognize
12 that the higher capital costs of Big Stone II would be incurred at the outset while the
13 anticipated benefits, such as lower and more stable fuel costs, would be realized
14 gradually over the plant's operating life. There would be a commitment to higher capital
15 costs with the expectation, but no guarantee, that the commitment would create savings in
16 the long-term.

17 Second is the uncertainty of the various fuel price forecasts and whether the fuel
18 price differential between coal and natural gas narrows or widens in the future. To the
19 extent the differential narrows the cost advantage of Big Stone II would diminish.

20 Third is the uncertainty concerning the price and reliability of rail transportation
21 for PRB coal. This could have a material impact on the fuel price differential discussed
22 previously and the overall availability of the unit.

1 Fourth is the uncertainty of the actual operating performance of the plant in terms
2 of efficiency (heat rate) and availability (availability factor). While there is some level of
3 uncertainty here, I tend to discount it for Big Stone II. Supercritical technology is
4 proven to be both efficient and reliable, assuming coal is available.

5 Fifth is the uncertainty of currently unknown but potential future environmental
6 regulations. Such regulations could significantly increase the capital and O&M expenses
7 of Big Stone II. The actual impact would depend on the form, extent and timing of those
8 new regulations and the market's response to them.

9 Sixth is the uncertainty of the actual capital cost of constructing Big Stone II.
10 Longer construction times create a potential for the cost of equipment, materials and
11 labor to change significantly. Other planned coal plants could also impact these costs.

12 And seventh is the uncertainty of the financial stresses Big Stone II could have on
13 MDU's and Otter Tail's financial health. For MDU, Big Stone II would approximately
14 double its existing amount of net electric plant. For Otter Tail, it would be an increase of
15 over 50%. These are significant increases and, even after recognizing the benefits on fuel
16 costs, would almost certainly necessitate future rate relief.

17 **Q: Are these uncertainties unique to Big Stone II?**

18 A: No, not at all. All of the areas of uncertainty, with the possible exception of PRB
19 coal deliveries, would also apply to other generating alternatives. It is a question of to
20 what extent. A high capital cost alternative like Big Stone II simply makes the
21 uncertainties more critical.

22 **Q: What are the risks of not proceeding with Big Stone II?**

1 A: If no new generation were pursued, both MDU and Otter Tail would be subject to
2 the prices and availability of power on the market. While relying on the market can be
3 successful for part of a utility's need in the short term, it would not be a good long term
4 strategy. There would be too much price risk and potential adverse impacts on reliability.

5 If Big Stone II were not pursued and some alternative generating technology
6 pursued in its place there would still be a myriad of risks specific to that alternative. If
7 the alternative were gas-based, there would be significant risks associated with the price
8 and availability of natural gas. And based upon the best information we have available at
9 this time, the alternative would most likely be at a higher cost than Big Stone II. In
10 addition, the strategic benefits of Big Stone II would be foregone.

11 Q: **What are the strategic benefits of Big Stone II?**

12 A: In answers to previous questions I have discussed various aspects of the benefits
13 that Big Stone II would bring. I will summarize them here.

14 First, Big Stone II is based on a proven, reliable and efficient technology with low
15 emission rates.

16 Second, Big Stone II is planned for an existing brownfield site with substantial
17 infrastructure already in place and minimal environmental impacts. There will be the
18 ability to share common facilities and to cost-efficiently install a wet scrubber which also
19 benefits Big Stone I. The scrubber also enables the possibility for sales of gypsum.

20 Third, Big Stone II would be owned by a group of utilities. No single co-owner
21 could undertake a project the size of Big Stone II. By participating, MDU and Otter Tail
22 could gain the benefits and efficiencies of a large base-load unit that otherwise would not

1 be available to them. As operator, Otter Tail would also receive an annual \$500,000 fee
2 above its incremental costs.

3 Fourth, Big Stone II would be dispatchable and add to the reliability of MDU's
4 and Otter Tail's systems. It also could act as back-up generation for future wind projects.

5 Fifth, Big Stone II would enhance the possibility of asset-backed sales with their
6 accompanying benefits.

7 Sixth, Big Stone II would burn a domestic fuel in plentiful supply. It would have
8 a relatively stable supply of fuel in terms of price and availability. This would be in
9 contrast to the price of natural gas which can be priced high on a Btu basis and is prone to
10 sharp fluctuations.

11 Seventh, Big Stone II would enhance the reliability of the transmission grid and
12 increase the potential for export capabilities out of North Dakota. This potentially could
13 allow for additional generation, wind or coal, to be constructed within North Dakota.

14 And eighth, the projected life of Big Stone II would be 40 plus years. Depending
15 on future costs of other generation, this could provide substantial "end effect" benefits.

16 **Q: Should Big Stone II be approved and given an advanced determination of**
17 **prudence?**

18 **A:** I believe Big Stone II should be approved with some needed clarifications and
19 subject to some potential conditions.

20 **Q: What are the needed clarifications?**

21 **A:** As discussed earlier in my testimony, there are a number of ambiguities or
22 inconsistencies within the revised busbar cost analysis that need an explanation. First

1 there are some inconsistencies on wind costs and assumptions including capacity factor
2 and the need for back-up. I discuss these on pages 14 through 16 of my testimony.
3 Second is the impact of Big Stone II's latest capital cost forecast in relation to the capital
4 costs of other alternatives and the resulting busbar cost differentials. I discuss this on
5 pages 16 and 17 of my testimony. Third is the differences in the forecasts of natural gas
6 prices. I discuss this on pages 19 through 21.

7 Based upon my review, I doubt these ambiguities and inconsistencies would
8 change the conclusion of the revised busbar cost analysis that Big Stone II is the lowest
9 cost alternative. However, this is not something that I can confirm. I would invite Otter
10 Tail to address these matters and confirm whether the conclusion of the revised busbar
11 cost analysis is still valid.

12 **Q: Are there other clarifications needed?**

13 A: Yes, I believe Otter Tail should clarify to the Commission how they propose to
14 treat any additional asset-backed sales that may result from the addition of Big Stone II. I
15 also believe Otter Tail should clarify whether Coyote Station would remain a potential
16 site for future expansion plans and what impacts, positive or negative, Big Stone II would
17 have on the prospects of future generation in North Dakota.

18 **Q: What are the conditions you suggest for granting the advance prudence
19 determination for Big Stone II?**

20 A: There are five conditions I suggest the Commission consider before granting an
21 advance determination of prudence. While these conditions are not necessarily required,

1 I believe they would be helpful to the Commission in carrying out its on-going regulatory
2 oversight.

3 First is a simple requirement to make periodic informational filings on the
4 progress of obtaining all necessary approvals, permits and licenses from other regulatory
5 bodies and an indication when construction commences.

6 My second suggested condition is a reporting requirement as contemplated by
7 Section 49-05-16 of the North Dakota Century Code. At or shortly prior to construction
8 commencement, Otter Tail should file a forecasted budget by year for all construction
9 related costs. Within the budget should be information on the results of RFPs (subject to
10 confidentiality protections) for all major components of the plant. This first report should
11 be followed by at least annual updates with an analysis of deviations between actual and
12 budget and explanations of changes in forecasts for future years. If at any time the co-
13 owners determine that the prudence, economic viability or continuation of the project is
14 in jeopardy, there should be an immediate filing indicating the reasons for such
15 determination.

16 Given that the deliverability of coal is fundamentally critical to the success of Big
17 Stone II, my third suggested condition involves coal delivery and management. At pages
18 37 and 38 of my testimony I describe operational measures that can be undertaken to
19 better manage the delivery of coal. These measures may already be part of Otter Tail's
20 management system. If they are, I believe there should be a confirmation of this. If they
21 are not, Otter Tail should either confirm that they will be incorporated for Big Stone II or
22 explain why they are inappropriate. If these measures are to be utilized, I believe the

1 accompanying information and management reports produced should be available for
2 periodic review by the Commission.

3 My fourth suggested condition also addresses coal deliverability. I believe Otter
4 Tail should be required to conduct a study of the number of rail cars necessary to serve
5 Big Stone II and do a cost/benefit analysis of whether any additional rail cars should be
6 light weight aluminum railcars. The results of this study should be filed with the
7 Commission in sufficient time before the commercial operation of Big Stone II so as to
8 enable Commission review of the report.

9 My fifth and final suggested condition involves coal inventory. Given that the
10 cost of maintaining coal inventory above 30 days may be less than the adverse
11 consequences of potential generation curtailments, I believe Otter Tail should perform a
12 study which calculates the cost of having a higher inventory level. The cost should be
13 compared to the cost and likelihood of curtailments from inadequate fuel deliveries. The
14 results of the study along with Otter Tail's recommendations should be filed with the
15 Commission in sufficient time before the commercial operation of Big Stone II so as to
16 enable Commission review of the study and its conclusions.

17 **Q: Does this conclude your testimony?**

18 **A:** Yes, it does.

Exhibit No. ____ (JTD-1)
2 pages

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- Florida Public Service Commission, Chairman, 1993 - 1995, 2000 - 2001
- Office of the Public Counsel, Chief Regulatory Analyst, 1987 - 1991
- Florida Public Service Commission, Executive Assistant to the Commissioner, 1981 - 1987
- Office of the Public Counsel, Legislative Analyst II and III, 1979 - 1981
- Ben Johnson Associates, Inc., Research Analyst, 1978 - 1979
- Office of the Public Counsel, Legislative Analyst I, 1977 - 1978
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- National Association of Regulatory Utility Commissioners (NARUC), 2004 - 2005, *Member, Committee on Telecommunications*
- National Association of Regulatory Utility Commissioners (NARUC), 1991 - 2004, *Member, Committee on Finance and Technology*
- National Association of Regulatory Utility Commissioners (NARUC), 1995 - 1998, *Member, Committee on Utility Association Oversight*
- National Association of Regulatory Utility Commissioners (NARUC) 2002 *Member, Rights-of-Way Study*
- Nuclear Waste Strategy Coalition, 2000 - 2006, *Board Member*
- Federal Energy Regulatory Commission (FERC) South Joint Board on Security Constrained Economic Dispatch, 2005 - 2006, *Member*
- Southeastern Association of Regulatory Utility Commissioners, 1991 - 2006, *Member*
- Florida Energy 20/20 Study Commission, 2000 - 2001, *Member*
- FCC Federal/State Joint Conference on Accounting, 2003 - 2005, *Member*
- Joint NARUC/Department of Energy Study Commission on Tax and Rate Treatment of Renewable Energy Projects, 1993, *Member*
- Bonbright Utilities Center at the University of Georgia, 2001, *Bonbright Distinguished Service Award Recipient*

Exhibit No. ____ (JTD-2)

1 page

EXHIBIT _____

Dockets in which Mr. Deason testified:

- In re: Application of Southern States Utilities, Inc. for a rate increase in Marion County, Docket No. 880520-WS, Florida Public Service Commission, 1988-89.
- In re: Petition of Florida Power & Light Company for authority to increase its rates and charges, Docket No. 810002-EU, Florida Public Service Commission, 1981.
- In re: Petition of Florida Power Corporation for authority to increase its rates and charges, Docket No. 800119-EU, Florida Public Service Commission, 1980-81.
- In re: Petition of Tampa Electric Company for authority to increase its rates and charges, Docket No. 800011-EU, Florida Public Service Commission, 1980-81.
- In re: Petition of Gulf Power Company for an increase in its rates and charges, Docket No. 800001-EU, Florida Public Service Commission, 1980-82.
- In re: Petition of General Telephone Company of Florida to increase certain rates and charges, Docket No. 790084-TP, Florida Public Service Commission, 1979.
- In re: Application of Florida Public Utilities Company-Marianna Division to increase its rates and charges, Docket No. 770652-EU, Florida Public Service Commission, 1977-78.

Exhibit No. ____ (JTD-3)

3 pages

EXHIBIT _____

Need Determination Dockets in which Commissioner Deason participated:

- In re: Petition for determination of need for Seminole Generating Station Unit 3 electrical power plant in Putnam County, by Seminole Electric Cooperative, Inc., Docket No. 060220-EC, Florida Public Service Commission, 2006 (750 MW supercritical pulverized coal plant).
- In re: Petition for determination of need for West County Units 1 and 2 electrical power plants in Palm Beach County by Florida Power & Light Company, Docket No. 060225-EI, Florida Public Service Commission, 2006 (two 1300 MW combined cycle units).
- In re: Petition for determination of need for Hines 4 power plant in Polk County by Progress Energy Florida, Inc., Docket No. 040817-EI, Florida Public Service Commission, 2004 (517MW combined cycle unit).
- In re: Petition for determination of need for expansion of electrical cogeneration power plant in Palm Beach County, by Florida Power & Light Company and New Hope Power Partnership, Docket No. 040766-EI, Florida Public Service Commission 2004 (70 MW steam turbine electric generator).
- In re: Petition to determine need for an electrical power plant in Martin County by Florida Power and Light Company, Docket No. 020262-EI, Florida Public Service Commission, 2002-04 (789 MW additions to existing combustion turbine units).
- In re: Petition to determine need for an electrical power plant in Manatee County by Florida Power & Light Company, Docket No. 020263-EI, Florida Public Service Commission, 2002-04 (1,100MW combined cycle unit).
- In re: Petition for determination of need of Hines Unit 3 power plant, Docket No. 020953-EI, Florida Public Service Commission, 2002-03 (582MW combined cycle unit).
- In re: Petition for determination of need for an electrical power plant in Lake County by Panda Leesburg Power Partners, L.P., Docket No. 000288-EU, Florida Public Service Commission, 2000-01 (1000MW combined cycle unit).
- In re: Petition for determination of need for an electrical power plant in St. Lucie County by Panda Midway Power Partners, L.P., Docket No. 000289-EU, Florida Public Service Commission, 2000-01 (1000MW combined cycle unit).
- In re: Petition for determination of need for an electrical power plant in St. Lucie County by Duke Energy St. Lucie, L.L.C., Docket No. 000612-EU, Florida Public Service Commission, 2000-01 (608MW combined cycle unit).

- In re: Petition for determination of need for an electrical power plant in Okeechobee County by Okeechobee Generating Company L.L.C., Docket No. 991462-EU, Florida Public Service Commission, 1999-01 (550 MW combined cycle unit).
- In re: Petition for determination of need for the Osprey Energy Center in Polk County by Seminole Electric Cooperative and Calpine Construction Finance Company, L.P., Docket No. 001748-EC, Florida Public Service Commission, 2000-01 (529MW combined cycle unit).
- In re: Petition for determination of need of Hines Unit 2 Power Plant by Florida Power Corporation, Docket No. 001064-EI, Florida Public Service Commission, 2000-01 (530MW combined cycle unit).
- In re: Joint Petition for determination of need for an electrical power plant in Volusia County by the Utilities Commission, City of New Smyrna Beach, Florida, and Duke Energy New Smyrna Beach Power Company, Ltd., L.L.P., Docket No. 981042-EM, Florida Public Service Commission, 1998-99 (514MW combined cycle unit).
- In re: Petition to determine need for existing Tiger Bay Electrical Power Plant and nominal electrical capacity increase to that plant by Florida Power Corporation, Docket No. 971059-EI, Florida Public Service Commission, 1997 (increase of 12MW of steam electric capacity).
- In re: Petition to determine need for electrical power plant in St. Marks, Wakulla County, by City of Tallahassee, Docket No. 961512-EM, Florida Public Service Commission, 1996-97, (250MW combined cycle unit).
- In re: Petition for determination of need for proposed electrical power plant to be located in Hardee and Polk Counties by Seminole Electric Cooperative, Inc., Docket No. 931212-EC, Florida Public Service Commission, 1993-94 (440MW combined cycle unit).
- In re: Petition to determine need for electrical power plant (Okeechobee County Cogeneration Facility) by Nassau Power Corporation, Docket No. 920769-EQ, Florida Public Service Commission, 1992-94 (75+ MW cogeneration).
- In re: Joint Petition to determine need for electric power plant to be located in Okeechobee County by Florida Power and Light Company and Cypress Energy Partners, L.P., Docket No. 920520-EQ, Florida Public Service Commission, 1992-94 (MW unavailable).
- In re: Petition of Ark Energy, Inc. and CSW Development for determination of need for electrical power plant to be located in Okeechobee County, Florida, Docket No. 920761-EQ, Florida Public Service Commission, 1992-94 (866MW combined cycle unit).
- In re: Petition of Ark Energy, Inc. and CSW Development I for approval of contract for the sale of capacity and energy to Florida Power & Light Company, Docket No. 920762-EQ, Florida Public Service Commission, 1992-94.

- In re: Petition of Nassau Power Corporation for approval of contract for the sale of capacity and energy to Florida Power & Light Company, Docket No. 920783-EQ, Florida Public Service Commission, 1992-94.
- In re: Petition of Nassau Power Corporation to determine need for electrical power plant (Amelia Island Cogeneration Facility), Docket No. 910816-EQ, Florida Public Service Commission, 1991-92 (MW unavailable).
- In re: Petition for determination of need for a proposed electrical power plant and related facilities in Polk County by Tampa Electric Company, Docket No. 910883-EI, Florida Public Service Commission, 1991-93 (220 MW integrated gasification combined cycle unit).
- In re: Petition for determination of need for proposed electrical power plant and related facilities Polk County Units 1-4, by Florida Power Corporation, Docket No. 910759-EI, Florida Public Service Commission, 1991-1992. (940 MW-four combined cycle units).

Exhibit No. ____ (JTD-4)

3 pages

Integrated Resource Plan Review

Montana-Dakota

Montana-Dakota used an end-use forecasting model to develop a long-range (20-year) electric load forecast for Montana-Dakota's Integrated System which includes its service territories in Montana, North Dakota, and South Dakota.

Demand Side Management (DSM)

Montana-Dakota's DSM program includes programs such as load management, new uses of electricity, strategic conservation, electrification, and adjustments in market share. For an activity to be classified under DSM it must result from direct intervention on the part of the utility. In its IRP Montana-Dakota evaluated 12 residential programs and seven commercial programs. To determine whether a program is beneficial, Montana-Dakota relies on a benefit/cost ratio for the Ratepayer Test and the Societal Benefit Test. The Ratepayer Test includes all of the quantifiable benefits and costs of a given program and its impact on all ratepayers. The Societal Benefit Test measure the net costs of a management program based on its total costs including both the participant's and the utility's costs as well as including environmental externalities and excluding tax credit benefits.

Power Supplier Assumptions

A utility discount rate of 7.4 percent was used for the analysis. The discount rate is the weighted average cost of capital, based on the capital structure and associated interest rates forecasted for the long-range planning of resource needs for Montana-Dakota. The annual transmission and distribution losses represent an average of the losses that have occurred on Montana-Dakota's system. Montana-Dakota used 7.88 percent for residential and commercial program evaluations.

Analysis Procedure

Five programs were selected to be evaluated on a qualitative basis (Energy Star partner, commercial energy audits, continue load management rates, home energy audits, proper A/C sizing training seminars.) Montana-Dakota's DSM Model was used as the evaluation tool for the remaining 13 programs (promote Energy Star® applicants (4), high efficiency A/C residential, high efficiency A/C commercial, residential A/C cycling, refrigerator round-up, residential geo-thermal heat pump, electric heat incentives/promotion, commercial lighting T-8 retrofit, commercial lighting – LED exit, commercial A/C cycling)

Feasible Programs

The DSM programs that Montana-Dakota found feasible were:

Residential Programs:

- Promote Energy Star® refrigerators
- Promote Energy Star® high-efficiency central air conditioners
- Promote residential central air conditioner cycling
- Promote residential refrigerator round-up
- Promote uncontrolled electric heat (in North Dakota only)

Commercial Programs:

- Promote Energy Star® high-efficiency central air conditioners
- Propose high-efficiency lighting (T-8 retrofit)
- Promote commercial central air conditioner cycling

Montana-Dakota cannot implement all of the feasible DSM programs so two alternative options were packaged for consideration.

Option A:

Energy Star® Partnership

Promote uncontrolled electric heat (in North Dakota only)

Promote Energy Star® high-efficiency residential central air conditioners

Propose high-efficiency lighting (T-8 retrofit)

Option B:

Energy Star® Partnership

Promote uncontrolled electric heat (in North Dakota only)

Promote residential central air conditioner cycling

Promote commercial central air conditioner cycling

Montana-Dakota implemented the programs outlined in Option A in 2006.

Supply-Side Resource Plan

Resource Plan

In 2001 Montana-Dakota started planning for a baseload coal-fired plant. Montana-Dakota states that its IRP relies on the "least cost" IRP approach but also takes into consideration factors which are not captured in a strict least cost analysis. Montana-Dakota states that it also considered

- The benefits resulting from wholesale sales of off-peak energy provided by coal-fired, baseload units.
- Societal changes in environmental obligations due to changes in laws and regulations as well as changes in consumer attitude, which cannot be monetarily quantified.
- The possibility of new large load developing in Montana-Dakota's service territory from economic development efforts.
- Renewable resources, especially wind energy development. Total costs for wind turbines are depended on governmental incentives notwithstanding, wind energy investments result in relatively high costs for consumers.

For these reasons, Montana-Dakota states that it is proposing a supply-side resource plan that will consider economic, societal, governmental, and customer issues.

Existing and Committed Resources

In addition to its own generation, Montana-Dakota receives power from the Western Area Power Administration under Bill Crediting Program Arrangements and purchasing peak capacity from NorthPoint Energy and Northern States Power Company as part of its existing and committed resources. The agreement to purchase power from the Antelope Valley Station expired October 31, 2006.

Future Baseload Capacity

In its IRP Montana-Dakota states that it was pursuing four options with other utilities or partners:

- A 175 MW coal plant near Gascoyne, North Dakota to be on-line in 2010
- Part ownership of a 600 MW coal plant addition at the existing Big Stone plant near Big Stone, South Dakota to be on-line in 2011
- Part ownership of a 600-1200 MW coal project being considered for construction in one of five locations in the upper Midwest to be on-line in 2012 or later (The Resource Coalition), and
- Purchase of power from other utilities or from the energy market.

Big Stone II Unit

In April 2001, Otter Tail Power Company suggested developing a business plan for a second generating unit at Big Stone, South Dakota. The Big Stone II partners are still in the process of applying for a Certificate of Need with the Minnesota Public Service Commission for the construction of transmission facilities associated with the unit that will be constructed in Minnesota.

Resource Coalition Unit

In August 2003 Montana-Dakota joined a group of utilities known as the Resource Coalition to study the feasibility of a jointly owned coal-fired plant and potentially 100 MW of wind energy. The coalition members are Basin Electric Power Cooperative, Heartland Consumers Power District, Minnkota Electric Cooperative, Missouri Basin Power Agency, and Montana-Dakota. The Coalition has selected five potential plant sites for study: Gascoyne, North Dakota; Mobridge, South Dakota; Modale, Iowa; Stanton, North Dakota; and Yankton, South Dakota. Transmission, fuel supply, and other studies are underway for all sites.

Bridge Power

On January 9, 2004, Montana-Dakota signed a Participation Power Purchase/Sale Agreement with Omaha Public Power District (OPPD) to purchase the following amounts of capacity and associated energy:

- 70 MW for November and December 2006
- 80 MW for 2007
- 90 MW for 2008 and
- 100 MW for 2009 and 2010

The agreement was contingent on Montana-Dakota and OPPD securing confirmed firm transmission service to deliver power from OPPD's system to Montana-Dakota's customer load. The OPPD agreement was cancelled on December 31, 2004 because Montana-Dakota and OPPD could not secure the needed firm transmission service.

October 2004 Request for Proposals

On October 25, 2004 Montana-Dakota issued a request for proposals for the purchase of 70 to 100 MW of capacity and associated energy from November 1, 2006 through December 31, 2010. Three proposals were received. Of these, only one was a qualified bid and only offered a small portion of the needed capacity.

Exhibit No. ____ (JTD-5)

2 pages

Integrated Resource Plan Review

Otter Tail Power Company

Existing Resources

Current Otter Tail capacity resources are about 60% coal-fired in the winter and 65% in the summer. Almost two-thirds of the summer season capacity was from Manitoba Hydro.

Hydro

Otter Tail has six units located at five dams on the Otter Tail River and two units located at dam on the outlet of Lake Bemidji. The units on the Otter Tail River are FERC jurisdictional.

Peaking Facilities

Otter Tail has two fuel oil-fired combustion turbines at Jamestown and a third at Lake Preston, South Dakota. Prior to the 2003 summer season Otter Tail brought on-line a new dual-fuel combustion turbine. There are two internal combustion diesel units located at the Hoot Lake Steam Plant and one at Big Stone. A 2,000 kW diesel unit was installed at Otter Tail's System Control Center to serve as a standby generator for the facility, in accordance with NERC reliability criteria.

Otter Tail has worked with several customers who desire to install small diesel generators for back-up emergency power.

Baseload Resources

Otter Tail has partial or full ownership of five coal-fired generators located at three plants – Hoot Lake #1, 2, and 3, Big Stone, and Coyote Station.

Radio Load Management System

Otter Tail has an extensive radio load management system that is used to control annual peak demand and reduce the need for new generating capacity. The latest load management capability forecast was developed in 2002. Since then Otter Tail has undertaken a multi-year project to replace all load management equipment, transmitter and receivers.

Transactions

Otter Tail receives 2MW of capacity as payment from Minnkota Power Cooperative for control area services provided by Otter Tail. A capacity purchase of 50 MW from Manitoba Hydro has been executed from May 1, 2000 to April 30, 2010.

DSM Programs

The IRP only outlines projects that are part of the Company's Conservation Improvement Plan in effect in Minnesota.

Potential Resources

Capacity Purchases

Otter Tail contacted area utilities and other known entities within the region close to the Company's service territory to explore the potential to purchase long-term capacity and energy. To those entities that indicate having available resources or the expectation of available resources, a written Request for Proposal was issued. The only proposals received were from Manitoba Hydro Electric Board (MHEB).

Excelsior Energy was contacted in late 2003 to seek proposals from the planned coal gasification project in northern Minnesota, both by telephone and by issuance of an RFP. They declined to make a proposal.

Otter Tail received three proposals from MHEB in response to an RFP issued to them for baseload and peaking capacity proposals. The proposals included a variety of megawatts of capacity, energy availability, and options for load following service.

Supply-side Generation

The group of utilities involved in the Big Stone II plant investigated a number of baseload generation technologies including sub-critical pulverized coal, super-critical pulverized coal, atmospheric circulating fluidized bed combustion coal, integrated gasification combined cycle, and large natural gas-fired combined cycle. The group has selected a 600 MW super-critical pulverized coal-fired facility.

The IRP also evaluated phosphoric acid fuel cell, wind, hydro, pumped storage hydro, solar photovoltaic, anaerobic digestion, landfill gas, microturbines, biomass, geothermal, and conservation for its modeling.

Preferred Resource Plan

The Otter Tail preferred resource plan in the IRP is the plan selected by the IRP-Manager model with one change. The model selected an LM6000 for implementation in 2011. Otter Tail's review of the IRP-Manager base plan indicated the model elected more capacity in 2011 than is needed. According to the IRP the LM6000 could possibly be delayed until 2013, resulting in a cost savings to customers. The model selected 20 MW of wind in 2012 in addition to the wind manually implemented in the model, if the total cost to Otter Tail is 3 cents/kWh or less, flat cost, over the life of the installation. The model also selected 120 MW of the Big Stone II Plant. This was the maximum it was allowed to select. The IRP-Manager selected two small IGCC units for implementation in 2018 for reserve margin and energy needs.

As of the date of the IRP, Otter Tail had filed for approval of the 70.5 MW Enbridge Wind Farm. There is no mention of 40.5 MW in Cavalier County.

Otter Tail has identified three transmission projects that will result in reduction in transmission line losses. These three projects are the Appleton-Canby 41.6 kV to 115 kV update. Fargo-Mapleton 41.6 kV to 115 kV uprate, and the Audubon-Detroit Lakes-Frazee-Perham-Rush Lake 41.6 kV to 115 kV uprate.

Exhibit No. ____ (JTD-6)

1 page

Big Stone II
Site Evaluation Summary

<u>Major Category/Criterion</u>	<u>Weight</u>	<u>Big Stone II</u>		<u>Coyote</u>		<u>Dickenson</u>		<u>Fargo</u>		<u>Glenham</u>		<u>Utica</u>	
		<u>Rank</u>	<u>Score</u>	<u>Rank</u>	<u>Score</u>	<u>Rank</u>	<u>Score</u>	<u>Rank</u>	<u>Score</u>	<u>Rank</u>	<u>Score</u>	<u>Rank</u>	<u>Score</u>
Air Impacts	15.00%												
Proximity to Class I Area	10.71%	5	53.6	2	21.4	4	42.8	5	53.6	3	32.1	5	53.6
Potential Airspace Restrictions	4.29%	3	12.9	1	4.3	2	8.6	1	4.3	5	21.5	5	21.5
Water Supply	20.00%												
Surface Water Proximity	5.71%	5	28.6	1	5.7	3	17.1	3	17.1	5	28.6	3	17.1
Surface Water Supply Potential	14.29%	3	42.9	5	71.5	3	42.9	1	14.3	5	71.5	5	71.5
Environmental	15.00%												
Socioeconomics	2.22%	1	2.2	3	6.7	5	11.1	5	11.1	2	4.4	2	4.4
Land Use Compatibility	3.33%	5	16.7	5	16.7	1	3.3	3	10	3	10	3	10
Protected Species Impacts	1.11%	5	5.6	5	5.6	3	3.3	4	4.4	3	3.3	3	3.3
Noise Impacts	5.56%	5	27.8	5	27.8	1	5.6	4	22.2	5	27.8	3	16.7
Wetlands	2.78%	3	8.3	4	11.1	1	2.8	5	13.9	4	11.1	2	5.6
Fuel Supply	20.00%												
Rail Line/Mine Proximity	11.11%	5	55.6	5	55.6	4	44.4	2	22.2	1	11.1	3	33.3
Fuel Delivery Competition	6.67%	1	6.7	5	33.4	3	20	1	6.7	1	6.7	1	6.7
Reagent Delivery	2.20%	2	4.4	2	4.4	4	8.9	3	6.7	3	6.7	1	2.2
Electric Transmission	20.00%												
Proximity to Interconnection Point	2.67%	5	13.4	5	13.4	5	13.4	2	5.3	4	10.7	5	13.4
Expected System Impacts	17.33%	4	69.3	1	17.3	3	52	4	69.3	2	34.7	5	86.7
Other	10.00%												
Highway Access	1.25%	5	6.3	1	1.3	4	5	3	3.8	4	5	3	3.8
Land Availability	6.25%	5	31.3	5	31.3	3	18.8	5	31.3	5	31.3	5	31.3
Common Facilities/Staff	2.50%	5	12.5	5	12.5	1	2.5	1	2.5	1	2.5	1	2.5
Total	100.00%		398.1		340		302.5		298.7		319		383.6

Exhibit No. ____ (JTD-7)

1 page

Big Stone II
Site Evaluation Summary

<u>Major Category/Criterion</u>	<u>Weight</u>	<u>Big Stone II</u>		<u>Coyote</u>		<u>Dickenson</u>		<u>Fargo</u>		<u>Glenham</u>		<u>Utica</u>	
		<u>Rank</u>	<u>Score</u>	<u>Rank</u>	<u>Score</u>	<u>Rank</u>	<u>Score</u>	<u>Rank</u>	<u>Score</u>	<u>Rank</u>	<u>Score</u>	<u>Rank</u>	<u>Score</u>
Air Impacts	15.00%												
Proximity to Class I Area	10.71%	5	53.6	2	21.4	4	42.8	5	53.6	3	32.1	5	53.6
Potential Airspace Restrictions	4.29%	3	12.9	5	21.5	2	8.6	1	4.3	5	21.5	5	21.5
Water Supply	20.00%												
Surface Water Proximity	5.71%	5	28.6	5	28.6	3	17.1	3	17.1	5	28.6	3	17.1
Surface Water Supply Potential	14.29%	3	42.9	5	71.5	3	42.9	1	14.3	5	71.5	5	71.5
Environmental	15.00%												
Socioeconomics	2.22%	1	2.2	3	6.7	5	11.1	5	11.1	2	4.4	2	4.4
Land Use Compatibility	3.33%	5	16.7	5	16.7	1	3.3	3	10	3	10	3	10
Protected Species Impacts	1.11%	5	5.6	5	5.6	3	3.3	4	4.4	3	3.3	3	3.3
Noise Impacts	5.56%	5	27.8	5	27.8	1	5.6	4	22.2	5	27.8	3	16.7
Wetlands	2.78%	3	8.3	4	11.1	1	2.8	5	13.9	4	11.1	2	5.6
Fuel Supply	20.00%												
Rail Line/Mine Proximity	11.11%	5	55.6	5	55.6	4	44.4	2	22.2	1	11.1	3	33.3
Fuel Delivery Competition	6.67%	1	6.7	5	33.4	3	20	1	6.7	1	6.7	1	6.7
Reagent Delivery	2.20%	2	4.4	2	4.4	4	8.9	3	6.7	3	6.7	1	2.2
Electric Transmission	20.00%												
Proximity to Interconnection Point	2.67%	5	13.4	5	13.4	5	13.4	2	5.3	4	10.7	5	13.4
Expected System Impacts	17.33%	4	69.3	1	17.3	3	52	4	69.3	2	34.7	5	86.7
Other	10.00%												
Highway Access	1.25%	5	6.3	5	6.3	4	5	3	3.8	4	5	3	3.8
Land Availability	6.25%	5	31.3	5	31.3	3	18.8	5	31.3	5	31.3	5	31.3
Common Facilities/Staff	2.50%	5	12.5	5	12.5	1	2.5	1	2.5	1	2.5	1	2.5
Total	100.00%		398.1		385.1		302.5		298.7		319		383.6

Exhibit No. ____ (JTD-8)

1 page

Big Stone II
Site Evaluation Summary

<u>Major Category/Criterion</u>	<u>Weight</u>	<u>Big Stone II</u>		<u>Coyote</u>		<u>Dickenson</u>		<u>Fargo</u>		<u>Glenham</u>		<u>Utica</u>	
		<u>Rank</u>	<u>Score</u>	<u>Rank</u>	<u>Score</u>	<u>Rank</u>	<u>Score</u>	<u>Rank</u>	<u>Score</u>	<u>Rank</u>	<u>Score</u>	<u>Rank</u>	<u>Score</u>
Air Impacts	15.00%												
Proximity to Class I Area	10.71%	5	53.6	2	21.4	4	42.8	5	53.6	3	32.1	5	53.6
Potential Airspace Restrictions	4.29%	3	12.9	5	21.5	2	8.6	1	4.3	5	21.5	5	21.5
Water Supply	20.00%												
Surface Water Proximity	5.71%	5	28.6	5	28.6	3	17.1	3	17.1	5	28.6	3	17.1
Surface Water Supply Potential	14.29%	3	42.9	5	71.5	3	42.9	1	14.3	5	71.5	5	71.5
Environmental	15.00%												
Socioeconomics	2.22%	1	2.2	3	6.7	5	11.1	5	11.1	2	4.4	2	4.4
Land Use Compatibility	3.33%	5	16.7	5	16.7	1	3.3	3	10	3	10	3	10
Protected Species Impacts	1.11%	5	5.6	5	5.6	3	3.3	4	4.4	3	3.3	3	3.3
Noise Impacts	5.56%	5	27.8	5	27.8	1	5.6	4	22.2	5	27.8	3	16.7
Wetlands	2.78%	3	8.3	4	11.1	1	2.8	5	13.9	4	11.1	2	5.6
Fuel Supply	20.00%												
Rail Line/Mine Proximity	8.90%	5	44.5	5	44.5	4	35.6	2	17.8	1	8.9	3	26.7
Fuel Delivery Competition	8.90%	1	8.9	5	44.5	3	26.7	1	8.9	1	8.9	1	8.9
Reagent Delivery	2.20%	2	4.4	2	4.4	4	8.9	3	6.7	3	6.7	1	2.2
Electric Transmission	20.00%												
Proximity to Interconnection Point	2.67%	5	13.4	5	13.4	5	13.4	2	5.3	4	10.7	5	13.4
Expected System Impacts	17.33%	4	69.3	1	17.3	3	52	4	69.3	2	34.7	5	86.7
Other	10.00%												
Highway Access	1.25%	5	6.3	5	6.3	4	5	3	3.8	4	5	3	3.8
Land Availability	6.25%	5	31.3	5	31.3	3	18.8	5	31.3	5	31.3	5	31.3
Common Facilities/Staff	2.50%	5	12.5	5	12.5	1	2.5	1	2.5	1	2.5	1	2.5
Total	100.00%		389.2		385.1		300.4		296.5		319		379.2

Exhibit No. ____ (JTD-9)

1 page

Natural Gas Price Forecasts

<u>Year</u>	<u>Burns & McDonnell</u>		<u>PA Consulting</u>	
	<u>Price</u>	<u>Escalation</u>	<u>Price</u>	<u>Escalation</u>
	<u>\$/MMBtu</u>	<u>Rate</u>	<u>\$/MMBtu</u>	<u>Rate</u>
2011	7.60		6.58	
2012	7.83	3.0%	6.53	(-).8%
2013	8.06	3.0%	6.77	3.7%
2014	8.31	3.0%	6.90	1.9%
2015	8.55	3.0%	6.92	0.3%
2016	8.81	3.0%	7.10	2.6%
2017	9.08	3.0%	7.21	1.5%
2018	9.35	3.0%	7.39	2.5%
2019	9.63	3.0%	7.77	5.1%
2020	9.92	3.0%	8.06	3.7%
2021	10.21	3.0%	8.38	4.0%
2022	10.52	3.0%	8.69	3.7%
2023	10.84	3.0%	9.00	3.6%
2024	11.16	3.0%	9.34	3.8%
2025	11.50	3.0%	9.70	3.9%

Exhibit No. ____ (JTD-10)

1 page

Comparison of Selected Financial Statistics
As of December 31, 2006
(In millions where applicable)

	<u>MDU</u>	<u>Otter Tail</u>
Consolidated Total Assets	\$4,904	\$1,259
Net Electric Plant	\$320	\$561
Net Income from Electric Operations	\$14.4	\$24.2
Consolidated Equity Ratio	65%	64%
Consolidated Interest Coverage	6.3x	6.2x

Covenants Restrictions

Maximum Debt Ratio	65%	60%
Minimum Coverage	2.5x	1.5x

Moody's Bond Rating	A3	A3
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Average Per Year

Electric Capital Expenditures

Actual 2004-2006	28.3	30.0
* Projected	144.7	155.2

*2007-2009 for MDU

*2007-2011 for Otter Tail

Exhibit No. ____ (JTD-11)

1 page

Big Stone I Coal Usage

Year	BS I \$/ton	BS I Btu/lb	BS I \$/MMBtu	Type of Fuel	Source of Fuel
1990	14.083	6096	1.155	Lignite	Gascoyne Mine
1991	13.719	6026	1.138	Lignite	Gascoyne Mine
1992	13.862	6034	1.149	Lignite	Gascoyne Mine
1993	13.279	6060	1.096	Lignite	Gascoyne Mine
1994	13.224	6049	1.093	Lignite	Gascoyne Mine
1995	14.624	9033	0.809	Lignite/ Subbituminous	Gascoyne Mine/Absaloka/ Spring Creek
1996	16.847	8990	0.937	Subbituminous	Absaloka/Spring Creek
1997	15.946	8685	0.918	Subbituminous	Absaloka/Spring Creek
1998	16.186	8728	0.927	Subbituminous	Absaloka/Spring Creek
1999	16.244	8642	0.940	Subbituminous	Absaloka/Spring Creek
2000	17.349	8456	1.026	Subbituminous	Cordero Complex/Coal Creek
2001	17.933	8425	1.064	Subbituminous	Cordero Complex
2002	22.748	8549	1.330	Subbituminous	Eagle Butte/Belle Ayr
2003	23.259	8551	1.360	Subbituminous	Eagle Butte/Belle Ayr
2004	24.095	8518	1.414	Subbituminous	Eagle Butte/Belle Ayr
2005	26.084	8687	1.501	Subbituminous	Cordero/Black Thunder
2006	25.882	8538	1.516	Subbituminous	Cordero/Black Thunder

Exhibit No. ____ (JTD-12)

1 page

Big Stone II Coal Projections

Year	BSP II \$/ton	BSP II Btu/lb	BSP II \$/MMBtu	% Change
2010	28.668	8400	1.706	
2011	29.055	8400	1.729	1.35%
2012	29.854	8400	1.777	2.78%
2013	30.449	8400	1.812	1.97%
2014	31.286	8400	1.862	2.76%
2015	32.722	8400	1.948	4.62%
2016	33.578	8400	1.999	2.62%
2017	34.463	8400	2.051	2.60%
2018	35.487	8400	2.112	2.97%
2019	36.948	8400	2.199	4.12%
2020	38.083	8400	2.267	3.09%
2021	39.266	8400	2.337	3.09%
2022	40.371	8400	2.403	2.82%
2023	41.508	8400	2.471	2.83%
2024	42.678	8400	2.54	2.79%
2025	43.882	8400	2.612	2.83%

Exhibit No. ____ (JTD-13)

1 page

Big Stone II Coal Projections

Year	BSP II \$/ton	BSP II Btu/lb	BSP II \$/MMBtu	% Change	* BSP II \$/MMBtu	Difference from Projection
2010	28.668	8400	1.706		1.706	0
2011	29.055	8400	1.729	1.35%	1.755	0.026
2012	29.854	8400	1.777	2.78%	1.806	0.029
2013	30.449	8400	1.812	1.97%	1.859	0.047
2014	31.286	8400	1.862	2.76%	1.913	0.051
2015	32.722	8400	1.948	4.62%	1.968	0.020
2016	33.578	8400	1.999	2.62%	2.025	0.026
2017	34.463	8400	2.051	2.60%	2.084	0.033
2018	35.487	8400	2.112	2.97%	2.144	0.032
2019	36.948	8400	2.199	4.12%	2.207	0.008
2020	38.083	8400	2.267	3.09%	2.271	0.004
2021	39.266	8400	2.337	3.09%	2.336	-0.001
2022	40.371	8400	2.403	2.82%	2.404	0.001
2023	41.508	8400	2.471	2.83%	2.474	0.003
2024	42.678	8400	2.540	2.79%	2.546	0.006
2025	43.882	8400	2.612	2.83%	2.619	0.007

* at constant 2.9% escalation

Exhibit No. ____ (JTD-14)

1 page

Carrying Costs on Additional Coal Inventory
at Big Stone II

2.5 million tons/year
÷ 365 days/year
6,849 tons/day
x 15 days additional inventory
102,740 tons of additional inventory
x \$30 /ton cost of coal
\$3.082 million of additional inventory
x 19.33% ownership share
\$595,800 cost of inventory for MDU/Otter Tail
x 11.25% rate of return (plus income taxes)*
\$67,028 carrying costs

* assumes: 7.5% cost of debt
12.0% cost of equity
50% equity/50% debt
40% tax rate

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF NORTH DAKOTA

In the Matter of the Application of) Case No. PU-06-481
Otter Tail Corporation, d/b/a)
Otter Tail Power Company, for an)
Advance Determination of Prudence)
For the Big Stone II Generating Plant)

In the Matter of the Application of)
MONTANA-DAKOTA UTILITIES CO., a) Case No. PU-06-482
Division of MDU Resources Group, Inc.,)
For an Advance Determination of)
Prudence of Montana-Dakota's)
Participation & Ownership Interest in the)
Big Stone II Generating Station)

SUPPLEMENTAL
DIRECT TESTIMONY

OF

TERRY DEASON

Special Consultant

Radey Thomas Yon & Clark

April 7, 2008

SUPPLEMENTAL DIRECT TESTIMONY OF TERRY DEASON

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BEFORE THE NORTH DAKOTA PUBLIC SERVICE COMMISSION

SUPPLEMENTAL DIRECT TESTIMONY OF TERRY DEASON

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I. INTRODUCTION

Q: Please state your name and business address.

A: My name is Terry Deason. My business address is 301 South Bronough St., Suite 200, Tallahassee, Florida 32301.

Q: By whom are you employed, and in what capacity?

A: I am employed by the firm Radey Thomas Yon and Clark as a Special Consultant specializing in energy, telecommunications, water and wastewater and public utilities.

Q: Did you previously submit testimony in this proceeding?

A: Yes. I submitted testimony on behalf of the advocacy staff of the North Dakota Public Service Commission, along with 14 exhibits, on May 31, 2007.

II. PURPOSE AND BACKGROUND

Q: What is the purpose of your supplemental testimony?

A: The purpose of my supplemental testimony is to present the results of my review of the modified applications, from Otter Tail Power Company (Otter Tail) and Montana-Dakota Utilities Company (MDU) (the applicants), for advance determination of prudence for the Big Stone II Generating Station.

Q: What necessitated the modifications to the original applications?

A: The modifications were made as a result of two participants, Great River Energy and Southern Minnesota Municipal Power Agency, withdrawing from the project. These

1 withdrawals, along with a delay in the certificate of need case in Minnesota, affected both
2 the size and the timing of Big Stone II.

3 **Q: Based upon your review, what is your understanding of the current proposal**
4 **regarding Big Stone II?**

5 A: The applicants have determined that a down-sized version of Big Stone II, either
6 500 MWs or 580MWs, is the most cost-effective alternative available to meet their needs
7 for baseload generation in 2013. The applicants' supplemental case describes their
8 reasons, along with updated analyses, for this determination.

9 **Q: What were the design and operating characteristics of Big Stone II as originally**
10 **proposed?**

11 A: Big Stone II was originally proposed to be a 630 MW supercritical pulverized
12 coal unit using state of the art technologies for both its thermal generation and its
13 pollution control systems. It was proposed to be constructed at the existing site of Big
14 Stone I and share common facilities at that location. It was to burn Powder River Basin
15 (PRB) coal that was to be delivered by the Burlington Northern Santa Fe Railway
16 Company (BNSF). It was to be interconnected using existing transmission corridors with
17 increased transmission infrastructure to meet Midwest Independent System Operator
18 (MISO) requirements. Big Stone II was to be jointly owned by seven participants with
19 Otter Tail and MDU each owning 19.3%, or approximately 120 MWs each.

20 **Q: Have any of these design and operating characteristics changed?**

21 A: The size of Big Stone II, along with the number of participants and their
22 respective ownership interests, has now changed. Otter Tail is now proposing an

1 ownership interest in the range of 120 MWs to 133 MWs. MDU is now proposing an
2 ownership interest of 133 MWs. The other major design and operating characteristics of
3 Big Stone II essentially remain unchanged, i.e. the technology, location, fuel source and
4 interconnection requirements remain the same.

5 **Q: What were your earlier recommendations for Big Stone II as originally proposed?**

6 A: I earlier reviewed Otter Tail's and MDU's need for additional baseload
7 generation, the Power Plant Site Evaluation Study and the applicants' cost studies for Big
8 Stone II and other generation alternatives. Within the cost studies, I reviewed numerous
9 inputs and assumptions and classified them within six categories: Wind Inputs;
10 Construction Inputs; Operating Inputs; Fuel Inputs; Financial Inputs; and Other
11 Assumptions. I also reviewed Big Stone II's interconnection requirements and its coal
12 delivery and management systems. Within my overall review, I also identified risk
13 factors and strategic considerations for various generation alternatives. I concluded that
14 Big Stone II, as originally proposed, should be approved subject to further clarifications
15 of potential ambiguities within the cost studies and subject to five conditions. The five
16 conditions addressed reporting requirements and coal delivery and inventory
17 management.

18 **III. REVIEW OF INPUTS**

19 **Q: Did you once again review the inputs and assumptions used by the applicants for**
20 **Big Stone II and other generation alternatives?**

21 A: Yes, I did. In addition to the applicants' prefiled supplemental testimony, I
22 reviewed the applicants' responses to 62 data requests submitted to them on March 20

1 and March 24, 2008. I will discuss relevant inputs and assumptions according to the six
2 categories that I used in my initial review.

3 **Q: What did your review reveal concerning wind inputs?**

4 A: The Burns & McDonnell study, sponsored by Otter Tail, modeled wind as a
5 purchased resource with availability sufficient to displace the equivalent of a 40%
6 capacity factor of a combined cycle gas turbine plant (CCGT). The study continued to
7 use a \$40/MWh cost for wind with the federal production tax credit (PTC) in place.
8 Without the PTC, it was assumed that the cost of wind would be \$20/MWh higher. The
9 study also used a 5.0% annual escalation rate. No transmission costs for wind were
10 included.

11 MDU's expansion plan sponsored by Mr. Heidell did not model wind purchases,
12 but rather assumed a capital cost of wind of \$2,000/kW. This is a 67% increase over the
13 assumed capital cost of wind in the previous study. Mr. Heidell used two different
14 capacity factors for wind, 52% in scenarios I and II, and 38% in Scenarios III and IV. He
15 also assumed two different PTC expiration dates, January 1, 2013, for Scenarios I and II,
16 and January 1, 2009, for Scenarios III and IV. Like the Burns & McDonnell study, Mr.
17 Heidell did not include the cost of transmission system upgrades for wind resources.

18 **Q: What did your review reveal concerning construction inputs?**

19 A: Otter Tail's assumed cost of a down-sized Big Stone II was based upon its earlier
20 estimate of a 630 MW plant. This cost was scaled down using factors from the Electric
21 Power Research Institute (EPRI) and escalated for the delayed in-service date to result in
22 assumed costs of \$1.272 billion (\$2,545/kW) for a 500 MW unit and \$1.411 billion

1 (2,434/kW) for a 580 MW unit. The assumed cost of a 500 MW CCGT plant remained
2 the same as the earlier study at \$674/kW. These costs do not include transmission costs
3 nor an allowance for funds used during construction (AFUDC). The escalation rate used
4 for a supercritical coal unit was 6%, and for a CCGT it was 5%.

5 Mr. Heidell used the same construction costs for the down-sized Big Stone II, but
6 included transmission line costs and interest during construction (AFUDC). For a 120
7 MW CCGT unit, Mr. Heidell assumed a cost of \$1,795/kW.

8 **Q: What did your review reveal concerning operating inputs?**

9 A: My review did not reveal any significant changes for operating inputs, other than
10 some increase in the operating and maintenance costs per MWh.

11 **Q: What did your review reveal concerning fuel inputs?**

12 A: Otter Tail used a similar cost of PRB coal as it did in its earlier study,
13 \$1.74/MMBtu now versus \$1.71/MMBtu earlier. However, Otter Tail increased the
14 escalation rate from 2.9% to 3.5%. For natural gas, Otter Tail increased the cost from
15 \$7.60/MMBtu in 2011 to \$8.31/MMBtu in 2012 and kept the same escalation rate of
16 3.0%. Within this cost is an assumed transportation cost of \$0.40 MMBtu. The
17 commodity price of the gas is based upon the October 2007 New York Mercantile
18 Exchange (NYMEX) futures price for Henry Hub natural gas supply in 2012.

19 MDU also increased its assumed cost of coal, but no explanation was given by
20 Mr. Heidell. A comparison of MDU's original and updated coal cost assumptions is
21 shown in Exhibit No. ___(JTD-15). A comparison of Otter Tail's assumed cost of coal to
22 that of MDU is shown in Exhibit No. ___(JTD-16).

1 MDU's updated cost of natural gas is now based on the long-term Department of
2 Energy (DOE) Energy Information Administration (EIA) natural gas forecast, as adjusted
3 by MDU's in-house experience. MDU's earlier forecast of natural gas was based on PA
4 Consulting's consensus natural gas forecast. No reason was provided for this change in
5 methodology. A comparison of MDU's original and updated forecasts of the commodity
6 price of natural gas is shown in Exhibit No. ___(JTD-17). A comparison of Otter Tail's
7 forecasted commodity cost of natural gas to that of MDU is shown in Exhibit
8 No. ___(JTD-18).

9 MDU, like Otter Tail, also added a transportation cost to its commodity price of
10 natural gas to result in a delivered cost of natural gas. For Scenarios I and II, MDU used
11 a transportation cost based on the South Dakota Intrastate Pipeline Company (SDIP)
12 tariff. For Scenarios III and IV, MDU used a lower transportation cost to determine
13 whether a hypothetical reduction in gas transportation costs makes natural gas fired
14 generation more attractive. However, MDU's assumed transportation component for all
15 scenarios is much higher than the \$0.40 MMBtu assumed by Otter Tail. A comparison of
16 MDU's assumed cost of delivered natural gas to that of Otter Tail is shown in Exhibit
17 No. ___ (JTD-19) for MDU's Scenarios I and II and No. ___ (JTD-20) for Scenarios III
18 and IV.

19 **Q: What did your review reveal concerning Financial Inputs?**

20 **A:** My review did not reveal any significant changes in Otter Tail's financial inputs.
21 Mr. Heidell indicated that he updated the cost-of-capital assumptions used for Scenarios

1 III and IV. In response to Data Request No. 61, he clarified that he reduced the cost of
2 capital to 7.61%.

3 **Q: Did your review reveal any other notable inputs, assumptions or considerations?**

4 A: Yes, there are two. First is the recognition of potential off-system power sales
5 from Big Stone II. I discussed off-system sales (asset-backed sales) in my previous
6 testimony and identified it as an item needing additional clarification. At that time, the
7 applicants provided the requested clarifications in their rebuttal case. In their updated
8 case, MDU has now included off-system sales (in Scenario IV) and has quantified the
9 estimated benefit at \$72 million on a net present value (NPV) basis. In response to Data
10 Request No. 39, MDU explained the methodology used to make this estimate. Mr.
11 Heidell concludes that the potential for off-system sales is a benefit for proceeding with
12 Big Stone II, but that Big Stone II is not dependent on off-system sales to make it the
13 choice of their expansion plan.

14 The second consideration is transmission requirements. The physical
15 transmission requirements for Big Stone II remain essentially the same, regardless of
16 whether Big Stone II is sized at 500 MWs or 630MWs. The cost of the required
17 transmission has been updated from \$238 million to \$249 million. Due to this increase
18 and the downsizing of Big Stone II, the per kW cost of transmission increases by \$120,
19 from \$378 to \$498 (at 500 MW size).

20 **IV. FINDINGS AND CLARIFICATIONS**

21 **Q: What are your findings for Big Stone II as currently proposed?**

1 A: Based upon my review and subject to a number of additional clarifications, Big
2 Stone II has been shown by the applicants to be a cost-effective alternative to meet their
3 baseload generation needs. However, the case for Big Stone II is not as compelling as
4 when it was originally proposed and its risk factors have increased.

5 **Q: Why do you conclude that Big Stone II is a cost-effective alternative to meet the**
6 **applicants' baseload generation needs?**

7 A: First, let me reemphasize that there are areas which I believe need further
8 clarification from the applicants. If these clarifications are provided and they sufficiently
9 address the areas of concern, then I would conclude that Big Stone II is a cost-effective
10 alternative. This conclusion is based upon my review of the costs and operating
11 characteristics of Big Stone II and those of other baseload alternatives, as presented by
12 the applicants in their supplemental case.

13 The applicants' supplemental case essentially uses the same approaches used
14 earlier to justify Big Stone II as a 630 MW unit. The downsized version of Big Stone II
15 is essentially the same as the earlier version, only smaller. It would utilize the same
16 supercritical technology, which has proven to be efficient and reliable. It would continue
17 to operate with low heat rates, high availability factors, and low emissions rates. It would
18 continue to be owned by a group of utilities to achieve economies of scale that none of
19 the individual utilities could accomplish on their own. It would continue to be located at
20 an existing site and have the ability to cost-effectively share common facilities. It would
21 continue to be a dispatchable resource and enhance the possibility of additional off-
22 system sales for the benefit of the applicants' ratepayers. And it would enhance the

1 reliability of the transmission grid and potentially increase export capabilities out of
2 North Dakota.

3 **Q: What are the clarifications that are needed before it can be concluded that Big Stone**
4 **II is a cost-effective alternative to meet the applicants' baseload generation needs?**

5 A: First, let me state the obvious. The time to review the revised case and file
6 supplemental testimony has been short. This is not a criticism. I understand the need for
7 this case to be expedited so that the applicants' need for baseload generation may be
8 timely addressed. However, the short time frame has allowed only one round of data
9 requests to be submitted. Therefore, ambiguities or potential inconsistencies, which
10 possibly could have been adequately addressed during a longer data collection process,
11 must now be identified in testimony. I invite the applicants to provide the needed
12 clarifications in their rebuttal testimony so that I and the advocacy staff can review them
13 prior to hearing.

14 The areas needing additional clarification can be summarized as follows:

- 15 • Wind PTC and fixed costs;
- 16 • Capital costs;
- 17 • Fuel forecasts and escalations;
- 18 • Project financing; and
- 19 • Environmental compliance costs.

20 **Q: What are the variables affecting wind generation?**

21 A: The viability of wind generation as a component of a baseload generation
22 expansion plan is dependent on many variables. Two of the most significant are PTC

1 assumptions and capacity factors. MDU addresses these variables in its response to Data
2 Request No. 45. Another consideration is fixed operating costs, which MDU addresses in
3 its response to Data Request No. 62.

4 **Q: Why is the PTC an important consideration?**

5 A: The PTC can substantially reduce the cost of wind generation. Otter Tail assumes
6 that the levelized cost of purchased power is reduced by a third with the PTC, from a cost
7 of \$60/MWh without the PTC to a cost of \$40/MWh with the PTC. Otter Tail goes on to
8 calculate a levelized busbar cost of wind plus CCGT, both with and without the PTC.
9 With the PTC, the wind plus CCGT alternative is only 2.6% higher than the cost of Big
10 Stone II, \$88.55 per MWh for wind plus CCGT compared to \$86.27 per MWh for Big
11 Stone II. Without the PTC, the differential is \$11.37 per MWh or 13.2%. The
12 significance of the PTC is apparent.

13 **Q: What needs to be clarified in Otter Tail's approach?**

14 A: What is unclear within Otter Tail's approach is the timing of the impact on costs
15 of assuming a discontinuation of the PTC. It is unclear when the discontinuation is
16 assumed to be effective. It is also unclear whether the cost to purchase wind would
17 increase by \$20 per MWh immediately or gradually increase over time. I believe Otter
18 Tail should identify the timing of its assumption, why the timing assumed is appropriate
19 and how it impacts the determination of the levelized busbar costs.

20 **Q: Does MDU's approach differ from Otter Tail's?**

21 A: Yes, instead of modeling wind as purchases, MDU modeled wind as a capital
22 project, at an assumed cost of \$2,000 per kW in 2006 dollars. This is an \$800/kW

1 increase over the value used by Mr. Heidell in his previous testimony and is further
2 addressed in MDU's response to Data Request No. 58.

3 All of Mr. Heidell's expansion plan scenarios assume discontinuation of the PTC,
4 effective either January 1, 2009 (Scenarios III and IV) or January 1, 2013 (Scenarios I
5 and II). Big Stone II is chosen as part of the expansion plan in all scenarios. However,
6 according to Mr. Heidell's results, extending the PTC by four years (along with an
7 assumed higher wind capacity factor) materially impacts the NPV margin by which Big
8 Stone II is the preferred alternative. Under Scenarios I and II, the NPV margin by which
9 Big Stone II is the preferred alternative is within a range of \$12 million to \$33 million or
10 only 0.6% to 1.5% of the NPV of the next best expansion plan without Big Stone II.
11 Thus, the PTC (and the assumed wind capacity factor) can have a material impact on the
12 relative cost-effectiveness of a wind alternative.

13 **Q: What needs to be clarified within MDU's approach?**

14 **A:** What is unclear is if an assumed continuation of the PTC beyond four years
15 would result in a lesser or no amount of Big Stone II being chosen as part of the
16 expansion plan. Mr. Heidell states that an extension of the PTC is likely but that a
17 permanent extension remains uncertain. I believe MDU should clarify if an extension
18 longer than four years would change the generation expansion plan and why such an
19 extension should or should not be considered. MDU should also address whether the
20 resulting wind generation would cause operational and reliability problems for MDU's
21 system. Another area needing clarification is the assumptions shown in Mr. Heidell's
22 Table 4. The assumed capital, fixed and variable costs for wind remain the same

1 regardless of whether the PTC is present or not. I believe MDU should explain why the
2 existence of non-existence of the PTC has no impact on these assumed costs.

3 **Q: In your previous answer, you identified wind capacity factor as an important**
4 **determinant. Did you review the assumed wind capacity factors used by the**
5 **applicants?**

6 A: Yes, I did and I also submitted a number of data requests concerning wind
7 capacity factors and cost assumptions.

8 Mr. Heidell conservatively assumed a wind capacity factor of 52% in Scenarios I
9 and II. In Scenarios III and IV, he reduced it to 38%, just below Otter Tail's assumed
10 40% capacity factor. The reasons for these capacity factors and overall wind costs are
11 explained in testimony. And in the confidential response to Data Request Nos. 28 and
12 29, these assumptions are further explained and compared to actual wind projects. My
13 review concludes that the information submitted is sufficient without the need for further
14 clarification.

15 **Q: What clarifications are needed for capital costs?**

16 A: The applicants "scaled down" the original cost estimate of a 630 MW unit to
17 result in the updated capital costs for a 500 MW unit and a 580 MW unit. To be
18 conservative, the applicants used the same construction time frame of 62 months from the
19 time of final permits and continued to use the higher contingency factor of 13.5%.

20 The use of the EPRI scaling factors and how Big Stone II compares to other
21 supercritical units is more fully addressed in the responses to Data Request Nos. 23, 24
22 and 25. These responses confirm that the scaling is a linear function. What is unclear is

1 whether the scaling adequately factors the proportional higher costs of a smaller unit. For
2 example, when Big Stone II was designed to be a 630 MW unit, it was represented to be
3 the most cost-effective size and incorporated the best matching of components to achieve
4 its higher efficiencies and cost-effectiveness. With that level of costs being the starting
5 point, it is possible that there is some residual of this optimal sizing such that the scaled-
6 down costs are not truly representative of actual construction costs of a smaller unit and
7 its reconfiguration of smaller sized components. The comparison of Big Stone II to a
8 "scaled-down" version of Duke Energy's 800 MW Cliffside unit (response to Data
9 Request No. 25) indicates that the costs of Big Stone II are not artificially understated.
10 The cost comparisons to other supercritical units shown in the response to Data Request
11 No. 24 also support this conclusion. Nevertheless, I believe the applicants should clarify
12 how the scaling factors do not result in understated cost estimates and how the scaled-
13 down costs of Big Stone II match the configuration of components to be utilized.

14 **Q: Are there any other capital cost items which need clarification?**

15 A: Yes, there are two and they both arise from differences in assumptions and
16 approaches used by the applicants.

17 Otter Tail's Updated Economic Evaluation assumes the cost of a 500 MW CCGT
18 plant to be \$674/kW, while Mr. Heidell assumes a \$1,795/kW cost for a 120 MW
19 combined cycle plant. This is a large disparity. It could be explained by the difference
20 in the size of the two assumed units. If the disparity in costs is explained by the size of
21 the units, Mr. Heidell should explain why he did not use a larger combined cycle unit for

1 comparison purposes. If the disparity is not explained by the difference in size, Mr.
2 Heidell should explain why his higher assumed cost is appropriate.

3 The other difference is in the approach used for AFUDC. Otter Tail's busbar
4 costs do not include AFUDC, while Mr. Heidell included AFUDC in his scenarios. Since
5 Big Stone II is a high capital cost alternative, including AFUDC would be the more
6 conservative approach. In its confidential responses to Data Request Nos. 21 and 22,
7 Otter Tail quantifies the impact of AFUDC on the per kW cost of Big Stone II. I believe
8 Otter Tail should explain why AFUDC was excluded and determine the materiality of its
9 exclusion on the revised busbar costs.

10 **Q: Are any clarifications needed for coal forecasts and escalations?**

11 A: Based upon my review and the applicants' responses to data requests, I have
12 identified no coal cost assumptions which need further clarification. Both Otter Tail and
13 MDU increased their projected cost of coal from their earlier estimates. Otter Tail also
14 increased its assumed escalation rate from 2.9% to 3.5%, which I believe is a
15 conservative assumption. The conservative nature of this assumption is further supported
16 by the confidential response to Data Request No. 14. MDU's coal cost forecast appears
17 to use an annual escalation factor of approximately 3.0%. The resulting cost forecasts for
18 coal by MDU and Otter Tail are very similar. There are essentially no differences in the
19 early years with only slight differences in the later years, probably due to the different
20 escalation rates. Refer to Exhibit No. ___ (JTD-16) for a side-by-side comparison.

21 **Q: How did the applicants forecast the price of natural gas?**

1 A: Otter Tail and MDU each used different approaches with both resulting in
2 increased forecasted natural gas costs. Otter Tail used the NYMEX futures prices for gas
3 supply in 2012 with a 3% escalation rate. Otter Tail's approach is more fully explained
4 in its response to Data Request No. 33. MDU's forecast is based upon the high scenario
5 cost from EIA, as adjusted by MDU's in-house experience. MDU's approach is more
6 fully explained in its response to Data Request No. 56. While MDU does not expressly
7 state its assumed escalation rate, it appears to be approximately 4%.

8 A comparison of Otter Tail's and MDU's forecasted commodity cost of gas is
9 shown in Exhibit No. ___ (JTD-18). This comparison shows their forecasts for the
10 commodity cost of gas to be quite similar, with Otter Tail's forecast being higher in the
11 early years and MDU's forecast being higher in the later years. Only in the later years,
12 does the difference grow to more than \$0.40 MMBtu, probably because of MDU's higher
13 escalation rate.

14 **Q: Are these differences significant?**

15 A: I do not consider these differences to be material for long-term planning purposes.
16 Predicting future prices of natural gas is inherently uncertain, particularly over a long-
17 term horizon which is necessary in evaluating alternative generation technologies. There
18 are many uncontrollable drivers that influence the price of natural gas: expected
19 worldwide economic growth and worldwide demand; North American natural gas
20 demand and production; the worldwide supply and demand for Liquefied Natural Gas;
21 the geopolitics of many regions of the world; and the potential for new environmental
22 requirements, particularly carbon dioxide regulation.

1 **Q: Did the applicants' gas forecasts factor in potential impacts from carbon dioxide**
2 **regulations?**

3 A: No, they did not. This question was posed to the applicants and they confirmed
4 that their forecasts did not explicitly consider the potential impacts of carbon dioxide
5 regulations. It is unclear, however, whether MDU's assumed escalation rate was
6 influenced by potential carbon dioxide regulations.

7 **Q: What effect would carbon dioxide regulations have on natural gas?**

8 A: While there is speculation as to the degree such regulations would affect natural
9 gas prices, they would certainly cause greater demand to be placed on existing natural gas
10 supplies, at least in the short run. This would certainly place upward pressure on prices.
11 In fact, I believe this is already being manifested to some degree by the number of coal
12 units which have been cancelled and partially replaced by additional gas-fired generation.
13 To the extent the applicants' gas forecasts do not consider the impact of potential carbon
14 dioxide regulations, they may very well be conservative.

15 **Q: Are there differences in the applicants' assumed transportation cost for natural**
16 **gas?**

17 A: Yes, and in two of the scenarios the difference is quite large. Otter Tail used a
18 conservative transportation cost of \$0.40/MMBtu. For Scenarios I and II, MDU used a
19 transportation cost based on the SDIP tariff, which is forecasted to be as high as
20 \$3.99/MMBtu. To test the sensitivity of using a lower cost of delivered natural gas,
21 MDU reduced the transportation component in Scenarios III and IV to a range of
22 \$0.65/MMBtu to \$1.14/MMBtu. In response to Data Request No. 31, MDU provides

1 historical transportation costs incurred for its combustion turbine units, which average
2 \$1.17/MMBtu.

3 **Q: How does MDU's assumed cost of delivered natural gas compare to Otter Tail's?**

4 A: These comparisons are shown in Exhibit Nos. ___ and ___ (JTD-19 and JTD-20).
5 Even in JTD-20, which uses MDU's lower transportation costs, MDU's assumed cost of
6 delivered natural gas is equal to or higher than Otter Tail's assumed cost in every year.

7 **Q: Are these differences significant?**

8 A: In the early years, the differences are not material. However, in the later years the
9 differences are larger and only escalate. I do not know whether they are significant
10 enough to affect MDU's conclusion that Big Stone II is the most cost-effective baseload
11 alternative. Given the difficulties and uncertainties in making long term forecasts of a
12 volatile commodity like natural gas, MDU's forecast is probably as valid as Otter Tail's.
13 However, I believe MDU should provide an additional sensitivity analysis at Otter Tail's
14 assumed gas costs or explain why Otter Tail's assumptions would not apply to MDU's
15 use of gas-fired generation alternatives.

16 **Q: How would the applicants finance the construction of Big Stone II?**

17 A: Neither of the applicants has secured financing at this early stage. The actual
18 financing used would depend upon the capital markets and the companies' financial
19 position at the time a decision is made to go forward with Big Stone II (or any other
20 alternative generation project). However, the applicants have made assumptions
21 concerning the financing in their cost studies and expansion models.

22 **Q: What are those assumptions?**

1 A: Otter Tail's financing assumptions have not changed. Otter Tail assumes a
2 50%/50% debt/equity ratio with a 7.5% cost of debt and a 12% return on equity. This
3 results in an overall cost of capital of 9.75%. Otter Tail also assumes an effective tax rate
4 of 40%.

5 MDU has updated its cost of capital to 7.61%. MDU also assumes a 50%/50%
6 debt/equity ratio. However, MDU assumes an 11% cost of equity and a 6.5% cost of
7 debt, with a downward adjust to recognize the tax deduction of interest on the debt. The
8 assumed tax rate is 35%.

9 **Q: Why is MDU's cost of capital lower than Otter Tail's?**

10 A: MDU's assumed cost of capital is 214 basis points lower than Otter Tail's.
11 MDU's lower cost of equity accounts for 50 basis points and the lower cost of debt
12 accounts for another 50 points of the difference. The remaining 114 points are due to the
13 adjustment for the interest tax deduction ($6.5\% \times .50 \times .35 = 1.14\%$ or 114 points).

14 **Q: Is MDU's approach correct?**

15 A: It is true that the interest on debt is tax deductible and effectively lowers the after-
16 tax cost of debt. However, the return earned on equity capital is taxable and effectively
17 raises the after-tax cost of equity. The correctness of MDU's approach would depend on
18 the structure of MDU's expansion model and how it accounts for the income taxes on
19 equity capital and the income tax deduction for interest expense. I believe that MDU
20 should explain how its expansion model accounts for income taxes and confirm to the
21 Commission that the true (after-tax) cost of equity capital is recognized when comparing
22 alternative generation expansion plans.

1 **Q: Are MDU's 11% return on equity and its 6.5% cost of debt appropriate?**

2 A: I cannot conclude that they are inappropriate. However, Otter Tail's assumptions
3 are more conservative and provide a greater assurance that a capital-intensive generating
4 unit, such as Big Stone II, is truly the more cost-effective alternative. This is particularly
5 true given the greater scrutiny capital markets are giving to projects with higher carbon
6 dioxide emission profiles. In response to Data Request No. 13, MDU acknowledges that
7 this greater level of scrutiny could place upward pressure on the cost of debt and equity,
8 but concludes that its assumed cost of capital is still reasonable. Nevertheless, I believe
9 MDU should confirm to the Commission that the results of its expansion plan remain the
10 same, even with an assumed higher cost of capital, or in the alternative provide greater
11 assurance that its assumed capital costs are appropriate in today's capital markets.

12 **Q: You referenced a greater degree of scrutiny that capital markets are giving to
13 projects with higher carbon dioxide emission profiles. Can you further explain this?**

14 A: Yes. An article entitled "Banks to Consider Environmental Impact" appeared in
15 the February 4, 2008 issue of the Wall Street Journal. This article was the basis for a
16 series of questions posed to the applicants within Data Request No. 13. In response to
17 this Data Request, Otter Tail provided more information on "The Carbon Principles"
18 adopted by Citi, JPMorgan Chase and Morgan Stanley. The signatory banks agreed to
19 follow an Enhanced Diligence process for high carbon dioxide emitting technologies.
20 Within "The Carbon Principles" is the following statement:

21 *Due to evolving climate policy, investing in CO₂-emitting fossil fuel*
22 *generation entails uncertain financial, regulatory and certain*

1 *environmental liability risks. It is the purpose of the Enhanced Diligence*
2 *process to assess and reflect these risks in the financing considerations for*
3 *certain fossil fuel generation.*

4 **Q: Does this mean that financing will be unavailable for projects such as Big Stone II?**

5 A: No, not at all. It means that such projects will receive greater scrutiny “in a
6 process aimed at providing banks and their power industry clients with a consistent
7 roadmap for reducing the regulatory and financial risks associated with greenhouse gas
8 emissions.” There is explicit recognition that investment will be needed in conventional
9 or advanced generating facilities, which may include natural gas, coal and nuclear
10 technologies.

11 **Q: Will the greater scrutiny result in a higher cost of capital for projects with a higher**
12 **carbon dioxide emissions profile?**

13 A: This may be possible. However, I believe it will depend on what the higher level
14 of scrutiny reveals. If it reveals a process whereby all alternatives, including energy
15 efficiency and low-carbon technologies, are fairly considered and their relative carbon
16 risks are considered and mitigated, then the impact on capital costs should be minimized.

17 **Q: How can the risks be mitigated?**

18 A: Until such time as the rules for carbon reduction are adopted and their impacts
19 quantified and understood, both utilities and their customers are exposed to greater risks.
20 This is particularly true for utilities which are faced with the need to add capacity at this
21 time of uncertainty. A major way to mitigate the risk is to engage in a thorough open
22 process to fairly evaluate all alternatives and their relative risks, such as what this

1 Commission is currently undertaking. And after the process is complete, a degree a
2 regulatory certainty should provide needed assurances to the capital markets.

3 **Q: Do potential carbon dioxide regulations have ramifications beyond financing risks?**

4 A: Yes, they could have a material impact on the cost-effectiveness of a relatively
5 high carbon emitting unit, such as Big Stone II, compared to one with a lesser carbon
6 profile, such as wind or CCGT.

7 **Q: Do you believe the costs to mitigate carbon dioxide emissions to be an environmental
8 externality?**

9 A: I have no opinion as to the legal definition of an environmental externality. From
10 an economic and regulatory perspective, carbon dioxide costs continue to be externalized
11 in many jurisdictions. However, in many other jurisdictions, they have been or are
12 currently in the process of being internalized. And even though there is not a national
13 policy or program in place requiring reductions in carbon dioxide emissions, most believe
14 one is imminent. Its imminence is evident by concerns expressed by the investment
15 community and decisions in many jurisdictions to cancel or defer proposed coal units.
16 Otter Tail's expert in coal prices, L.E. Peabody & Associates, also believes that some
17 form of carbon dioxide regulation will be enacted in the 2010 to 2015 time period
18 (Response to Data Request No. 15).

19 **Q: Do you believe it would be appropriate for this Commission to consider the impacts
20 of potential carbon dioxide regulations?**

1 A: Again, I express no opinion on the Commission's legal authority to do so.
2 However, from a regulatory policy perspective, carbon dioxide costs should be
3 considered for at least two reasons.

4 First, the choice of the appropriate type of generation to add will have significant
5 cost considerations for decades to come. This is particularly true for a capital-intensive
6 option such as Big Stone II. The decision to make such a large long-term investment
7 should be made with the best information available. This should include even the
8 speculative and as of yet unquantified costs of carbon dioxide emission reductions.

9 Second, as discussed previously, the possibility of carbon dioxide regulations has
10 resulted in actions by the investment community. Therefore, at least for the financing
11 aspects, one could argue that carbon dioxide costs are being internalized based upon their
12 perceived risks. To help mitigate these risks, regulation should openly consider their
13 impacts and demonstrate that any generation or efficiency alternative pursued is the most
14 cost-effective when all costs are considered. This should provide a degree of regulatory
15 certainty which should facilitate acquisition of the needed financing under the best terms
16 available.

17 **Q: What form will potential carbon dioxide regulations take?**

18 A: Unfortunately, this question does not have a definitive answer at this time. There
19 is much speculation that the regulations will be based upon a cap and trade system. Even
20 if a cap and trade system is ultimately implemented, there would be questions concerning
21 the level and timing of the caps, the amount of free allowances and how they would be

1 distributed, whether domestic and international offsets would be allowed, and whether
2 there would be a safety value mechanism should the cost of allowances rise too high.

3 **Q: Have the applicants considered the impacts of potential carbon dioxide regulations?**

4 A: As stated in Mr. Uggerud's testimony, the applicants did not explicitly include the
5 costs (or a risk value) for carbon dioxide regulation. However, he did reference an
6 assumed \$9/ton carbon dioxide tax used in their Minnesota Certificate of Need
7 proceeding. This \$9/ton tax was applied to all tons of carbon dioxide emitted even
8 though there may be free allowances permitted in pending legislation. Inclusion of the
9 \$9/ton carbon dioxide tax did not change the results of Otter Tail's Updated Economic
10 Evaluation of Baseload Generation Alternatives.

11 **Q: Does this updated evaluation address carbon dioxide costs?**

12 A: Yes, in a limited fashion. This study, sponsored by Mr. Greig, quantifies the
13 break-even carbon dioxide cost values at which Big Stone II's busbar cost would be equal
14 to the busbar cost of the CCGT plus wind alternative.

15 **Q: What are these break-even values?**

16 A: For the 500 MW Big Stone II, the break-even is \$12.10/ton with continuation of
17 the PTC. Without the PTC, the value is \$24.40/ton. For the 580 MW Big Stone II, the
18 break-even values would be approximately \$3/ton higher. It is my understanding that
19 these values do not consider any free allowances that may be available under a cap and
20 trade approach.

21 **Q: Which of these break-even values is more relevant?**

1 A: I believe they are all relevant for the purposes that they were calculated.
2 However, the break-even values assuming discontinuation of the PTC may be more
3 relevant when considering the long-term cost-effectiveness of competing generation
4 technologies.

5 **Q: Why do you believe the break-even values without the PTC may be more relevant in**
6 **the long-term?**

7 A: The PTC was established in the Energy Policy Act of 1992 as an incentive,
8 beyond those already available within the market, to promote the production of
9 renewable energy. It has been successful even though it has been allowed to periodically
10 lapse by Congress and has never been extended for more than two years at a time. If
11 carbon dioxide regulations are put in place with a cap and trade scheme, it could be
12 argued that there would be enough incentive within the ensuing market for wind energy
13 without the need for a PTC. Of course, predicting what Congress may or may not do is
14 tenuous.

15 **Q: What will be the per ton cost of carbon dioxide emission allowances?**

16 A: The cost will depend on the structure of the regulations and the market reactions
17 to them, including the variables I mentioned earlier. In the longer term, such things as
18 the availability and cost of carbon capture and storage technologies and the deployment
19 of new nuclear generation will also have an impact.

20 I am aware of an analysis by the Environmental Protection Agency (EPA) of the
21 Lieberman-Warner bill which predicts a range of \$29 to \$40 per ton in 2015, increasing
22 to \$61 to \$83 in 2030. After considering the impacts of the Energy Independence and

1 Security Act of 2007, the EPA revised its predictions downward to \$22 to \$25 per ton in
2 2015 and \$46 to \$73 per ton in 2030. The EPA cautioned that there are many
3 uncertainties affecting the outcomes of its analysis.

4 **Q: Assuming the EPA's predictions are correct, how would they affect the relative cost-**
5 **effectiveness of Big Stone II?**

6 A: Once again, it would depend upon the assumptions made. However, according to
7 Mr. Greig's break-even analysis and Otter Tail's response to Data Request No. 12, Big
8 Stone II has a substantial cushion within which it would remain the most cost-effective
9 choice for baseload generation. Only at the upper bounds of the EPA's range would big
10 Stone II's cost-effectiveness be placed in doubt.

11 **Q: In your earlier testimony you stated that the price of natural gas can be the single**
12 **most important factor in justifying the relatively high costs of a solid fuel generating**
13 **plant like Big Stone II. Is this still your testimony?**

14 A: Yes, it is. In fact, the potential impacts of future carbon dioxide regulations can
15 be expressed in terms of a break-even cost of natural gas. This is done through a dispatch
16 cost comparison at various assumed costs of carbon dioxide emission allowances.

17 This was the subject of Data Request No. 11. As Otter Tail's response indicates,
18 Big Stone II would continue to be the first or one of the first units dispatched over a
19 broad range of assumed carbon dioxide emissions costs. The break-even point for natural
20 gas varies from a low of \$2.18 for the case with no carbon dioxide emissions costs to a
21 high of \$6.37 for the case with \$30/ton carbon dioxide costs with no free allowances. In
22 other words, before Big Stone II's dispatch order would be jeopardized, the cost of

1 natural gas would have to fall to \$6.37/MMBtu at the higher end of the assumed carbon
2 dioxide emissions costs. The \$6.37/MMBtu compares to the applicants' projected cost of
3 natural gas of \$8.96/MMBtu. And the applicants' projected costs of natural gas do not
4 consider the impacts of carbon dioxide regulations. If they were considered, the
5 projected cost of natural gas would probably be higher.

6 **Q: Are there any needed clarifications for the impacts of potential carbon dioxide**
7 **regulations?**

8 A: No, the applicants have provided all requested information in this regard and I
9 have not identified the need for any additional clarifications. However, if Big Stone II is
10 approved, I believe there should be a requirement on the applicants to monitor the
11 developments in the carbon dioxide debate and to routinely report them to the
12 Commission. I would also recommend that before construction begins, that the
13 applicants file an updated confirmation as to the cost-effectiveness of Big Stone II in light
14 of the best information then available concerning the anticipated costs of carbon dioxide
15 emission allowances.

16 **Q: Are any other clarifications needed with regard to environmental compliance costs?**

17 A: Yes. On March 14, 2008, the U.S. Court of Appeals for the District of Columbia
18 Circuit granted a motion which requires a maximum achievable control technology
19 standard to be used for emission controls at new power plants, likely requiring at least a
20 90% mercury removal rate. This was the subject of Data Request No. 35. Otter Tail
21 provided a comprehensive response to the data request. However, it was unclear whether
22 this recent development concerning mercury removal would go beyond what the

1 applicants have already agreed to do in their Settlement Agreement with the Minnesota
2 Department of Commerce and whether there would be any additional costs not already
3 included in Big Stone II's capital and operating costs. Otter Tail should so clarify and
4 identify the impacts of any additional costs, if applicable.

5 **V. SUMMARY AND RECOMMENDATIONS**

6 **Q: You have identified a number of areas needing additional clarification. Can you**
7 **please summarize them?**

8 A: Yes, I will do so by general subject area.

9 Wind PTC and fixed costs:

- 10 • Otter Tail's assumptions concerning the timing of PTC discontinuation;
- 11 • The effect (if any) on MDU's expansion plan of a PTC extension beyond four
12 years and any operational or reliability problems resulting therefrom; and
- 13 • The effect (if any) of a discontinuance of the PTC on the assumed fixed and
14 variable costs found in Table 4 of Mr. Heidell's supplemental testimony.

15 Capital costs:

- 16 • The effect of EPRI's scaling factors on the cost of Big Stone II as actually
17 configured with smaller components;
- 18 • The relative differences in the per kW cost of a CCGT plant assumed by Otter
19 Tail and MDU; and
- 20 • The effect on Otter Tail's relative busbar costs by including AFUDC.

21 Fuel forecasts and escalations:

- 1 • The sensitivity on MDU's expansion plan of using Otter Tail's assumed cost of
2 delivered natural gas; or
- 3 • An explanation why the use of Otter Tail's assumed cost of delivered natural gas
4 would be inappropriate for MDU's gas-fired generation alternatives.

5 Project financing:

- 6 • An explanation of how MDU's expansion model accounts for the income tax
7 effect of the sources of capital within MDU's assumed cost of capital; and
- 8 • The effect on MDU's expansion plan by using a higher cost of capital; or
- 9 • An explanation of why MDU's assumed cost of capital is appropriate in today's
10 capital markets.

11 Environmental compliance costs:

- 12 • Identification and explanation of the impacts of any mercury removal costs not
13 already considered within Big Stone II's assumed capital and operating costs.

14 **Q: In your earlier testimony, you recommended five conditions before granting an**
15 **advance prudence determination for Big Stone II. Would those conditions continue**
16 **to apply?**

17 A: Yes, they would. I would also add the condition that the applicants continue to
18 monitor potential carbon dioxide regulations and that an updated confirmation of Big
19 Stone II's cost-effectiveness be filed prior to the commencement of construction.

20 **Q: Are you recommending an entirely new review before construction were to begin?**

21 A: No, not at all. I am merely recognizing that the applicants have an ongoing
22 obligation to their stockholders and customers to continually monitor any developments

1 in the carbon dioxide debate. My recommendation is to have the applicants report to the
2 Commission on these developments and the impacts they may or may not have on the
3 continuing viability of the Big Stone II project. In fact, this requirement could probably
4 be incorporated within my second condition. This condition requires the filing of budget
5 information and an ongoing obligation to report on any developments which affect the
6 economic viability of the project.

7 **Q: Does this conclude your testimony?**

8 A: Yes, it does.

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MDU's Assumed Cost of Coal for Big Stone II
\$/MMBtu

Year	Original Forecast	Updated Forecast	Percent Change
2010	1.68	1.76	4.76%
2011	1.72	1.81	5.23%
2012	1.76	1.86	5.68%
2013	1.81	1.92	6.08%
2014	1.85	1.98	7.03%
2015	1.90	2.04	7.37%
2016	1.95	2.10	7.69%
2017	1.99	2.16	8.54%
2018	2.04	2.22	8.82%
2019	2.10	2.29	9.05%
2020	2.15	2.36	9.77%
2021	2.20	2.43	10.45%
2022	2.26	2.50	10.62%
2023	2.31	2.58	11.69%
2024	2.37	2.66	12.24%
2025	2.43	2.74	12.76%

Comparison of Assumed Cost of Coal for Big Stone II
\$/MMBtu

Year	MDU Updated Forecast	Offer Tail Updated Forecast	Difference
2010	1.76	1.74	0.02
2011	1.81	1.80	0.01
2012	1.86	1.86	0.00
2013	1.92	1.93	-0.01
2014	1.98	1.99	-0.01
2015	2.04	2.06	-0.02
2016	2.10	2.13	-0.03
2017	2.16	2.21	-0.05
2018	2.22	2.29	-0.07
2019	2.29	2.37	-0.08
2020	2.36	2.45	-0.09
2021	2.43	2.53	-0.10
2022	2.50	2.62	-0.12
2023	2.58	2.72	-0.14
2024	2.66	2.81	-0.15
2025	2.74	2.91	-0.17
Average	2.21	2.28	-0.06

**MDU's Assumed Commodity Cost of Natural Gas
\$/MMBtu**

Year	Original Forecast	Updated Forecast	Percent Change
2010	6.78	7.70	13.57%
2011	6.58	7.88	19.76%
2012	6.53	8.00	22.51%
2013	6.77	8.18	20.83%
2014	6.90	8.49	23.04%
2015	6.92	8.80	27.17%
2016	7.10	9.20	29.58%
2017	7.21	9.56	32.59%
2018	7.39	9.94	34.51%
2019	7.77	10.33	32.95%
2020	8.06	10.73	33.13%
2021	8.38	11.15	33.05%
2022	8.69	11.59	33.37%
2023	9.00	12.05	33.89%
2024	9.34	12.52	34.05%
2025	9.70	13.01	34.12%

**Comparison of Assumed Commodity Cost of Natural Gas
\$/MMBtu**

Year	MDU Updated Forecast	Otter Tail Updated Forecast	Difference
2010	7.70		
2011	7.88		
2012	8.00	8.31	-0.31
2013	8.18	8.56	-0.38
2014	8.49	8.82	-0.33
2015	8.80	9.08	-0.28
2016	9.20	9.35	-0.15
2017	9.56	9.63	-0.07
2018	9.94	9.92	0.02
2019	10.33	10.22	0.11
2020	10.73	10.53	0.20
2021	11.15	10.84	0.31
2022	11.59	11.17	0.42
2023	12.05	11.50	0.55
2024	12.52	11.85	0.67
2025	13.01	12.20	0.81
Average	9.95	10.14	0.11

**Comparison of Assumed Cost of Delivered Natural Gas
\$/MMBtu**

Year	MDU Updated Forecast*	Other Tail Updated Forecast	Difference
2010	10.85		
2011	11.12		
2012	11.34	8.71	2.63
2013	11.62	8.96	2.66
2014	12.03	9.22	2.81
2015	12.45	9.48	2.97
2016	12.96	9.75	3.21
2017	13.43	10.03	3.40
2018	13.92	10.32	3.60
2019	11.97	10.62	1.35
2020	12.42	10.93	1.49
2021	12.89	11.24	1.65
2022	13.38	11.57	1.81
2023	13.89	11.90	1.99
2024	14.42	12.25	2.17
2025	14.97	12.60	2.37
Average	12.73	10.54	2.44

* For Scenarios I and II

**Comparison of Assumed Cost of Delivered Natural Gas
\$/MMBtu**

Year	MDU Updated Forecast*	Offer Tail Updated Forecast	Difference
2010	8.41		
2011	8.61		
2012	8.75	8.71	0.04
2013	8.96	8.96	0.00
2014	9.29	9.22	0.07
2015	9.63	9.48	0.15
2016	10.05	9.75	0.30
2017	10.43	10.03	0.40
2018	10.84	10.32	0.52
2019	11.25	10.62	0.63
2020	11.69	10.93	0.76
2021	12.14	11.24	0.90
2022	12.60	11.57	1.03
2023	13.09	11.90	1.19
2024	13.60	12.25	1.35
2025	14.12	12.60	1.52
Average	10.84	10.54	0.63

* For Scenarios III and IV