MINNESOTA DEPARTMENT OF PUBLIC SERVICE

Volume V

Direct Testimony and Exhibit of
Geoffrey Crandell
MSB Energy Associates
DSM Potential

Direct Testimony and Exhibit of
David Schoengold
MSB Energy Associates
Comparison of Alternatives

Before the
Minnesota Public Utilities Commission

Northern States Power Company
Docket No. E002/CN-91-19

September 30, 1991

DIRECT TESTIMONY AND EXHIBIT OF

GEOFFREY CRANDELL

MINNESOTA DEPARTMENT OF PUBLIC SERVICE

* * *

BEFORE THE

MINNESOTA PUBLIC UTILITIES COMMISSION

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NORTHERN STATES POWER COMPANY

DOCKET NO. E002/CN-91-19

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Q. Please state your name and business address.

A. My name is Geoffrey C. Crandall. My business address is 7507 Hubbard Avenue, Suite 200, Middleton, Wisconsin 53562.

Q. What is your occupation?

A. I am a principal and an energy-efficiency specialist with MSB Energy Associates, Inc., a consulting firm specializing in regulatory issues, including energy conservation and load management, the environment, and integrated resource planning methods. I have been employed by MSB since January, 1990. In that time I have advised clients in Colorado, District of Columbia, Georgia, Hawaii, Illinois, Louisiana, Maine, Maryland, Massachusetts, Michigan, Minnesota, New Jersey, North Carolina, Ohio, Ontario, Pennsylvania, and Wisconsin on least-cost planning, energy efficiency and load-management resources.

I was employed by the Michigan Public Service Commission (MPSC) from 1974 until January 1990. My responsibilities at the MPSC included the development, implementation, evaluation, monitoring and modification of energy efficiency and load management resource options (hereafter referred to as "demand-side management" or "DSM" for convenience) resource options for the industrial, commercial, residential and institutional sectors.

Q. What is your educational background and professional experience?

A. I graduated from Western Michigan University with a Bachelor of Science degree in Pre-Law and Business in 1974. In addition, I have attended courses and seminars at Michigan State University Graduate School, Western Michigan University Graduate School, University of Wisconsin, and Wayne State University in federal taxation, accounting, management, and the economics of utility regulation. I have successfully completed the National Conference of States on Building Codes and Standards Energy Auditor examination.

In June 1988, I testified before the United States House of Representatives' Committee on Science, Space and Technology, Subcommittee on Energy Research and Development regarding promotion of energy efficiency, research and development, development and commercialization of energy-efficiency technologies and renewable energy. In August 1991, I testified before the United States House of Representatives' Committee on Science, Space and Technology Subcommittee on Investigations and Oversight on integrated resource planning and demand-side management as it relates to Consumers' Power Company.

I represented the Michigan Public Service Commission Staff on two interdepartmental task forces assembled at the direction of the Governor:

- the Energy Assurance Program Low-Income Weatherization Monitoring Committee, and
- the Petroleum Escrow Violation (Exxon Oil Overcharge) Committee.

I was a member of the Michigan Electricity Options Study research task force.

I was directly involved in and supervised the Michigan Public Service Commission staff research on and implementation of load management and energy-efficiency resources in the residential, commercial, institutional and industrial sectors. I was responsible for pilot and full-scale programs totalling approximately $250 million.

In August 1987 I lectured on utility demand-side management and low-income weatherization programs at a national workshop conducted by the Center for Community Futures held in Boston, Massachusetts.

In September 1987 I spoke on industrial energy efficiency at the Ninth Annual Industrial Energy Symposium in Houston, Texas, sponsored by Texas A & M University.

I spoke on energy efficiency and least-cost planning at all three National Least-Cost Utility Planning Conferences sponsored by the U.S. Department of Energy and the National Association of Regulatory Utility Commissioners (NARUC) held in Aspen, Colorado in April 1988, in Charleston, South Carolina in September 1989, and in Santa Fe, New Mexico in April 1991.

I lectured on energy efficiency and conservation at the Michigan State University Graduate School of Public Utilities - NARUC federal/state regulators' summer course on utility regulation in August 1988, 1989 and 1990.

From 1987 through 1989, I served as the Chairman of the NARUC Energy Conservation Subcommittee.

In January and March of 1990 I lectured at two regional workshops in Newport, Rhode Island and Little Rock, Arkansas on least-cost planning, sponsored by the United States Department of Energy and NARUC.

Q. Have you previously testified before the Minnesota Public Utilities Commission?

A. On May 13, 1991 I submitted pre-filed testimony regarding Minnesota PUC Docket E002/GR-91-001. I was not cross- examined because my testimony was bound into the record after stipulation by all parties to the case. I have testified in approximately twenty cases in eleven other jurisdictions (see DPS Exhibit No.____(GCC-1, Schedule 1)).

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to make an assessment of the quantity of peak demand reduction (MW) and energy savings (GWh) that could be achieved through implementation of various load-management and energy-efficiency technologies and programs (collectively referred to as "demand-side management," or simply "DSM") within the service territory of Northern States Power Company (NSP). In addition, my purpose is to identify the costs of acquiring these potential energy resources. Providing equivalent energy services to NSP's customers through use of energy-efficient technologies is among the alternatives to additional storage capability for spent fuel at the Prairie Island Nuclear Power Plant that are evaluated by the Minnesota Department of Public Service (DPS) witness David Schoengold and described in his testimony.

Q. What are NSP's estimates of the amount of peak demand reduction and energy savings that will be achieved through Company DSM programs?

A. NSP estimates that it can achieve peak demand reductions of 1098 MW by 1995, 1519 MW by 2000, 1830 MW by 2005 and 2083 MW by 2010 for its entire system. Corresponding to these reductions, the Company estimates that the cumulative annual energy savings from new Company-influenced DSM will be 746 GWh by 1995, 1440 GWh by 2000, 1992 GWh by 2005, and 2463 GWh by 2010 for the entire NSP system (see DPS Exhibit ____ (GCC-1, Schedule 2)).

Q. Are you familiar with studies of the DSM potential for the NSP system and/or service area ?

A. Yes, there are several studies of the DSM potential for the NSP service territory. Electric Power Software in May 1989 completed a study titled, "Northern States Power Company-Minnesota, Demand-Side Potentials Study, Volumes 1-13," which examined all sectors (residential, commercial and industrial). Xenergy, Inc. in April 1990 completed a study titled, "Northern

States Power Company, Commercial and Industrial, Demand-Side Management Potential, Volumes 1-4," which examined only the commercial and industrial sectors. The studies by Electric Power Software and by Xenergy, Inc. are cited as the basis for the Company's DSM projections.

PLC, Inc. in June 1988 completed a study titled, "Conservation Potential in the State of Minnesota," prepared for the Minnesota Department of Public service.

Q. Please describe the objectives, methodology and findings of "Northern States Power Company-Minnesota, Demand-Side Potentials Study," by Electric Power Software.

A. The main objectives of this study were, as stated on page 1, Volume 1, to:

1. Identify and define major customer market segments in the residential, commercial and industrial sectors;

2. Identify significant demand-side measures and the end uses they affect;

3. Define and evaluate cost-effective demand-side alternatives based on demand-side measures identified and customer market segments defined;

4. Evaluate the system impacts of selected demand-side alternatives to aid in the assessment of current NSP Minnesota demand-side plans;

5. Provide direction for future work and continued refinement of the process developed and various assumptions used.

After compiling the necessary data on market segments, end-uses, DSM technologies, costs, and the NSP system, the model "DS Manager," developed by the Electric Power Research Institute (EPRI), was used to evaluate system impacts of selected DSM technologies and programs.

The results of this study, as given in the section "Integrated Results," Volume 1 show that the "summer maximum available" peak reductions are approximately 1350 MW by 1995 and 1450 MW by 2010. These data, according to DPS Information Request 405 (see DPS Exhibit ____ (GCC-1, Schedule 3)), "...best represent a maximum achievable potential for NSP's programs involving the measures assessed..." A comparable graph of maximum achievable potential for energy savings (GWh) is provided with DPS Information Request 406 and shows that the maximum achievable potential energy savings to be approximately 1400 GWh by 1995 and 2300 GWh by 2010 (see DPS Exhibit ____ (GCC-1, Schedule 4)).

From these estimates of "maximum available" peak reductions and energy savings, values for the "likely NSP-achievable potential" are given. According to the Company in DPS Information Request 405, these "likely NSP-achievable values" are "somewhat less" than the maximum available values because of various "economic and awareness" factors and "logistical and other constraints" that affect program implementation over time. The values for "likely NSP-achievable potential" are approximately 500 MW by 1995 and 800 MW by 2010 for peak demand reduction, and 500 GWh by 1995 and 1200 GWh by 2010 for energy savings.

It is important to note that this study is for the NSP Minnesota Company, not for the combined Minnesota and Wisconsin NSP companies.

Q. Please describe the objectives, methodology and findings of "Northern States Power Company, Commercial and Industrial, Demand-Side Management Potential," by Xenergy, Incorporated.

A. The Xenergy study is based on detailed energy audits of a large sample (over 1000) of NSP's commercial and industrial customers. Its objectives were to provide customers with detailed recommendations for reducing energy costs and usage and to obtain data on usage patterns, equipment inventories, and operating characteristics in order to estimate the DSM potential among the Company's commercial and industrial sectors.

This study identified 337 MW of technically feasible peak reduction measures and nearly 1700 GWh of energy savings potential. These values represent 12.4 per cent of demand (MW) and 12.2 per cent of energy (MWh) for the C&I market segments upon which the study authors drew their conclusions. It is important to note that this population of the C&I market segments does not represent the entire C&I population of the NSP combined system. DPS Exhibit ____ (GCC-1, Schedule 5) gives a comparison between the population statistics for the Xenergy study and the NSP system, in addition to a summary of the results of this study.

The "technical potential" is defined as "those measures that show a simple 10-year payback for the individual customer based on the total costs for purchase, installation and operation of a given technology and the total value of life-cycle energy savings." These results were not presented in either a $/kW or $/kWh equivalent for specific technologies.

Q. Please describe the objectives, methodology and findings of "Conservation Potential in the State of Minnesota," by PLC, Incorporated.

A. The objective of the study, as stated on page 1 of Volume 1, was to examine the potential "for cost-effective electric end-use efficiency improvements by seven Minnesota utilities," which includes NSP.

The estimates of potential savings are based on evaluation of the costs of demand-side options compared to supply-side options. This study estimates the technical potential for demand-side management for Minnesota, which was found to be 52 per cent of current usage. This study was a good starting point for interested parties to identify and understand the potential for energy efficiency in Minnesota.

Q. Can you explain the differences between the PLC study and the studies by Xenergy and Electric Power Software?

A. The PLC, Inc. study addresses exclusively the maximum technical potential for energy efficiency in Minnesota. This study was limited in scope and breadth due to available financial resources, and was not able to account for a number of factors that will reduce this amount of maximum technical potential to the achievable potential, namely:

1. This estimate is based on an avoided cost of energy of $0.088/kWh (which is considerably higher than the Electric Power Software and Xenergy avoided cost estimates), making larger amounts of energy efficiency cost-effective.

2. This estimate assumes all technologies are replaced in the short-term, which does not account for replacement on a life-cycle basis.

3. There is no accounting for a "ramping-up" of programs and technologies. Any utility program will build up market penetration over time to a saturation level that will likely be less than the total potential. The PLC study assumes that maximum saturations are achieved in the short-term.

4. Technologies are used in this estimate which were not fully commercially available at the time of the study (1988), but were assumed to become so in the early 1990s. Some of these technologies may fail to

become commercially available, and therefore may not be available for adoption by consumers.

5. Utility administrative, marketing, and other program costs are not included.

The PLC, Inc. study shows the maximum technical potential of DSM that could be achieved under optimal conditions. It provides a benchmark against which to evaluate progress towards greater energy efficiency for Minnesota.

Q. Based on your review of the studies by Xenergy, Inc. and Electric Power Software (EPS), do you believe these studies accurately depict the DSM potential within the NSP service territory?

A. No, I do not. I believe these studies underestimate the amount of DSM that is cost-effective.

Q. Why do you think these studies underestimate this potential?

A. I believe that the study by EPS assumes low market penetration for the DSM technologies that were evaluated. The Company's own estimates of the achievable amounts of peak reduction and energy savings show the EPS estimates to be low. The Company estimates of the achievable amount of load- management and energy savings are closer to what EPS describes as "maximum achievable" than what EPS describes as "likely achievable."

I believe the results from Xenergy as given document a higher DSM potential than indicated by the Company's response to DPS Information Request 58 (see DPS Exhibit ____ (GCC-1, Schedule 7)) and other Company filings. When seen as the percent savings of the population studied, the Xenergy study shows an energy-efficiency potential within the commercial sector of 15.4 per cent of total use and 7.5 per cent within the industrial sector (see DPS Exhibit ____ (GCC-1, Schedule 5)). If these values are extrapolated to the entire NSP commercial and industrial sectoral energy use in 1990, energy savings would equal 2400 GWh by the year 2000 for the commercial and industrial sectors alone. Corresponding peak demand reductions are 14.3 per cent within the commercial sector and 8.6 per cent within the industrial sector. The combined commercial and industrial DSM savings for the Xenergy study are 12.4 per cent peak savings and 12.2 per cent energy savings. These Xenergy estimates differ significantly from NSP projections, which are 3.3 per cent energy savings from Company-influenced DSM by 2000 and 16 per cent peak demand reduction by 2000.

Even the authors of the Xenergy study believe that their findings are low. This is especially true for the industrial sector (which comprises the largest customer segment of NSP energy sales). Specifically, the authors on page 1-3-22 of Volume 1 state, "It should be noted that in-depth studies of particular processes will result in greater potential in the industrial sector." Of the 337 MW identified in this study of the technical potential, 261 MW (77 per cent of the total) come from the commercial sector. This follows from the composition of the sample population utilized by this study, which is 59 per cent commercial and 41 per cent industrial. These values are in stark contrast to the combined total energy sales for the commercial (including municipal) and industrial sectors in 1990, which is only 30 per cent commercial and 70 per cent industrial (i.e. 59 per cent vs 30 per cent commercial and 41 per cent vs 70 per cent industrial. See DPS Exhibit ____ (GCC-1, Schedule 5)).

Overall, while I believe that the Xenergy study provides an end-use analysis and screening of DSM options, (which is necessary for effective utilization of DSM resources), I note several factors that contribute to what I believe to be a low estimate of the DSM potential for the NSP system. I found that the cost estimates for certain technologies (e.g reduction of lighting levels and installation of high- efficiency ballasts) are high compared to similar types of analyses that have been conducted for other states and regions. It is also important to note that the costs used in the Xenergy study reflect 1988 prices. Many new energy-efficient technologies, especially for lighting, are becoming less costly. This trend can be expected to continue as consumer demand grows and production and availability of these technologies increase. This in turn will make greater amounts of DSM resources more cost-effective than indicated by the Xenergy study.

I also note inclusion of a load-building technology within this study. Specifically, on page 1-3-21, Table 10, of the Executive Summary, Xenergy identifies 5,300 kW of load building that would occur at time of peak, should NSP take the actions identified to encourage fuel-switching that converts customers from non-electric air-conditioning to electric air-conditioning. This "DSM" option runs directly counter to a DSM peak reduction strategy and would further exacerbate growth of NSP's summer peak.

Q. Have you independently analyzed the DSM potential for the NSP-system?

A. Yes, I have.

Q. What is your estimate of the size and costs of the Company-influenced DSM potential?

A. I estimate that 5400 GWh at an average delivered cost of $0.022/kWh is achievable by the year 2010, and that a 2400 MW peak demand reduction is achievable by 2010.

Q. What is the basis for your estimate?

A. My estimates are based on the best-available data, studies and analyses from numerous sources. These specifically include data submitted by NSP-Wisconsin (NSPW) in Wisconsin Advance Plan Six (Wis-AP6); data, studies and analyses prepared for the Electric Power Research Institute; the Michigan Department of Commerce (the Michigan Electric Options Study); the American Council for an Energy-Efficient Economy; the New York State Energy Research and Development Authority; and research completed by the United States Department of Energy, Oak Ridge National Laboratory.

Q. Please explain what your estimates are.

A. My results indicate that approximately 2800 GWh of energy savings can be achieved by 1995, 4100 GWh by 2000, 5200 GWh by 2005, and 5400 GWh by 2010; and that 1100 MW of peak demand reduction can be achieved by 1995, 1900 MW by 2000, 2300 MW by 2005, and 2400 MW by 2010.

Q. How did you derive these estimates?

A. I used several analytical approaches. First I examined the DSM target values for NSPW from 1991-2010 and the total costs for Company DSM-influenced programs (including customers' net costs and all utility costs) to estimate the cost per delivered unit of saved energy over this period. The target values (in percent) were then applied to the entire NSP system, and I estimated that this amount of Company-influenced DSM could be delivered at equivalent costs to those projected by NSP-Wisconsin.

Q. What other analyses did you perform to substantiate this amount of DSM potential within the NSP system?

A. In addition to the NSP-Wisconsin studies, I analyzed data from numerous studies of the DSM potential in other states and regions. I relied on "Michigan

Electricity Options Study, Final Report," prepared for the Michigan Department of Commerce, October 1987; "The Achievable Conservation Potential in New York State from Utility Demand-Side Management Programs," prepared for the New York State Energy Research and Development Authority, November 1990; "Impact of Demand-Side Management on Future Customer Electricity Demand: An Update," prepared for the Electric Power Research Institute, September 1990; "Efficient Electricity Use: Estimates of Maximum Energy Savings," also prepared for the Electric Power Research Institute, March 1990; and "Possible Effects of Electric-Utility DSM Programs, prepared by the Oak Ridge National Laboratory, January 1991.

Costs and savings estimated in these studies were compared to the NSP system and form the basis for my estimates of the DSM potential for the NSP system, which are presented in DPS Exhibit ____ (GCC-1, Schedule 2).

Q. Is the amount of DSM potential you have identified enough to entirely offset the potential loss of generation from the Prairie Island nuclear units, should the Commission deny the certificate?

A. No, it is not. Annual generation from PI was 7633 GWh in 1990, at a capacity factor of 83 per cent and average production cost of $0.015/kWh. Peak capacity is 1050 MW. My estimate for potential annual energy savings is 5400 GWh at an average delivered cost of $0.022/kWh. My estimate of peak demand reductions is 2400 MW. It is also important to note that this amount of energy savings and peak demand reduction is clearly achievable by the year 2010, should NSP choose to pursue this resource option. To fully offset the NSP power (MW) and energy (GWh) demands in the time frame of this case would require achieving the equivalent generation of PI by <u>1995</u>, an amount greater than my estimate of the potential by the year <u>2010</u>, at an average cost of $0.022/kWh.

Q. How does your estimate of the potential amount of achievable energy savings (GWh) compare to NSP's current targets?

A. I believe that the NSP estimate for the amount of achievable energy savings by the year 2010 is off by a factor of two. My analysis documents that approximately double the amount of energy savings currently projected for the entire NSP system is achievable by 2010. NSP's current energy conservation target for the year 2010 for the entire system is 4.5 per cent (annual GWh savings) compared to base forecasts. NSP-Wisconsin has established a more aggressive target, which is 9.2 per cent savings of the base forecast, and I believe that this amount is achievable for the entire NSP system.

Q. How does this target level of peak demand reduction (MW) compare to compare to NSP's current targets?

A. My estimate is only slightly higher than the Company's current target (2400 MW compared to 2083 MW).

Q. In addition to your analyses described earlier, have you analyzed how NSP's current DSM targets and your proposed targets compare to those of other electric utilities in the United States?

A. Yes. As shown in DPS Exhibit ____ (GCC-1, Schedule 6), NSP's current targets for the entire system are lower than those of a number of utilities that Oak Ridge National Laboratory has identified as considering DSM a bona fide resource option. If the Commission and NSP system adopts my recommended targets, which are equal to NSP-Wisconsin's targets, it would put NSP at the forefront of utilities across the nation. These higher targets may appear ambitious to NSP-Minnesota. However, I believe them to be realistic, given the analyses from the NSP-Wisconsin system and from other electric utilities throughout the United States.

Q. Does this complete your testimony?

A. Yes, it does.

EXHIBIT OF

GEOFFREY CRANDELL

MINNESOTA DEPARTMENT OF PUBLIC SERVICE

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BEFORE THE

MINNESOTA PUBLIC UTILITIES COMMISSION

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NORTHERN STATES POWER COMPANY

DOCKET NO. E002/CN-91-19

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SEPTEMBER 30, 1991

Previous Testimony
by Geoffrey C. Crandall

Case No. U-5531, (8/77), Consumers' Power Company electric rate increase application; I served as the Staff Witness and recommended that the Applicant initiate the Residential Electric Customers' Information program.

Case No. U-6743, (3/81), Michigan Consolidated Gas Company (MRCS); I served as the Staff policy witness and recommended that the Commission approve a surcharge to cover all reasonable and prudent costs associated with Applicant's implementation of the Michigan Residential Conservation Services Program (MRCS).

Case No. U-6819, (6/81), Michigan Power Company-Gas (MRCS); I served as the Staff policy witness and described the basis for the program and the expected level of activity, recommending that the Commission approve a surcharge to cover all reasonable and prudent costs associated with Applicant's implementation of the MRCS Program.

Case No. U-6787, (6/81), Michigan Gas Utilities Company (MRCS); I served as the Staff policy witness and described the basis for the program and the expected level of activity, recommending that the Commission approve a surcharge to cover all reasonable and prudent costs associated with the implementation of the MRCS Program.

Case No. U-6820, (6/81), Michigan Power Company-Electric (MRCS); I served as the Staff policy witness and reviewed the Applicant's request to operate the MRCS Program. Although not mandated by federal law, Applicant chose to operate the program in conjunction with its other services offered to residential gas customers. I recommended the establishment of a surcharge to cover all reasonable and prudent costs associated with the operation of that program.

Case No. U-5451-R (10/82), Michigan Consolidated Gas Company (ZIP); I served as the Staff policy witness and described the Staff's position regarding Applicant's proposed adjustment of surcharge level. I also recommended that the eligibility criteria for customers be adjusted to more accurately reflect proper fuel consumption and to include customers who would be likely to realize a seven-year return on their investment by installing flue-modification devices in conjunction with Applicant's financing program.

Case No. U-6743-R, (10/82), Michigan Consolidated Gas Company (MRCS); I served as the Staff policy witness regarding the Applicant's proposed expenses and revenues, as well as the reasonableness of activity and expense levels in the company's projected period.

Case No. U-7341 (12/84), Detroit Edison Company, Request for Authority for Certain Non-Utility Business Activities; I represented the Staff's position during settlement discussions and sponsored the settlement agreement.

Case No. U-6787-R, (3/84), Michigan Gas Utilities Company (MRCS); I served as the Staff witness regarding the Applicant's proposed expenses and revenues. This also included a review of the company's future expenses associated with the Energy-Assurance Program, the Specialized Unemployed-Energy Analyses, and the Michigan Business Energy-Efficiency Program expenses.

Case No. U-8528, (3/87), Commission's own Motion on the Costs, Benefits, Goals and Objectives of Michigan's utility conservation programs; I represented the Staff on the costs and savings of conservation programs and the other benefits of existing programs, and I described alternative actions available to the Commission relative to future energy-conservation programs and services and other conservation policy matters.

Case No. U-8871, et al., (4/88), Midland Cogeneration Venture Limited Partnership. For approval of capacity charges contained in a power-purchase agreement with Consumers' Power Company. I served as the Staff witness on Michigan Conservation potential and reasonably-achievable programs that could be operated by Consumers' Power Company, and so testified to the potential impact of these conservation programs on the Company's request for use of its converted nuclear-plant cogeneration project. I also recommended levels of demand-side management potential for the Commercial, Industrial and Institutional sectors in Consumers' Power service territory.

Case No. U-9172, (1/89), Consumers' Power Company, Power-Supply Cost-Recovery Plan and Authorization of Monthly Power-Supply Cost-Recovery Factors for 1989. I served as Staff witness on the Conservation potential and reasonably-achievable programs that could be operated by Consumers' Power Company. I also testified to the potential impact of these conservation programs on the Company's fuel and purchase practices, its five-year forecast and the fuel factor. I also recommended levels of demand-side management potential for the Commercial, Industrial and Institutional sectors in Consumers' Power service territory as an offset to its more-expensive outside and internally-generated power. I also suggested that CPCO vigorously pursue conservation, demand-side management research, planning and program implementation.

Case No. U-9263, (4/89), Consumers' Power Company requests to amend its gas rate schedule to modify its rule on central metering. I served as a Staff witness on the conservation effect of converting from individual metered apartment to a master meter. I suggested that the Commission continue its moratorium on the master meters, due to the adverse energy-conservation and efficiency impact.

Case No. E-100 (1/90) North Carolina Public Service Commission proceeding on review of the Duke Power Company's least-cost utility plan. I testified on behalf of the North Carolina Consumers' Council regarding utility energy-efficiency and demand-side management programs and the concept of profitability and implementation of demand-side management programs.

Case No. 889 (1/90) Public Service Commission of the District of Columbia. I testified on behalf of the Government of the District of Columbia in the Potomac Electric Power Company's application for an increase in its retail rates (general rate case). I sponsored testimony regarding the design and implementation and overall appropriateness of PEPCO's existing and proposed energy-efficiency and conservation programs.

Case No. 889 (4/90) Public Service Commission of the District of Columbia. I provided supplemental direct testimony and testified on behalf of the Government of the District of Columbia in the Potomac Electric Power Company's application for an increase in its retail rates (general rate case). I prepared and offered supplemental testimony regarding a more-detailed review of PEPCO's existing pilot and full-scale energy-efficiency and conservation programs. I offered suggestions and recommendations for a future direction for PEPCO to pursue in order to implement more cost-effective and higher-impact energy-efficiency and conservation programs.

Case No. ICC Docket 90-004 and 90-0041 (6/90) Illinois Commerce Commission proceeding to adopt an electric-energy plan for Central Illinois Light Company (CILCO). I testified on behalf of the State of Illinois, Office of Public Counsel and the Small-Business Utility Advocate. I reviewed the CILCO electric least-cost plan filing and the conservation and load-management programs proposed in its filing. I sponsored testimony regarding my analysis of the proposed programs, and offered alternative programs for the Company's and the Commission's consideration.

Case No. D.P.U. 90-55 (6/90) Commonwealth of Massachusetts Department of Public Utilities. I testified on behalf of the Commonwealth of Massachusetts, Division of Energy Resources. I reviewed and analyzed Boston Gas' proposed energy- conservation programs that were submitted for pre-approval in its main rate case. In addition, I suggested that it might consider implementation of other natural-gas energy- efficiency programs, and not award an economic incentive for energy-efficiency and conservation programs until minimum program-implementation standards are satisfied.

Case No. U-9346 (6/90) Michigan Public Service Commission. I testified on behalf of the Michigan Community Action Agency Association. I reviewed and analyzed the Consumers' Power Company rate-case filing related to energy-efficiency and demand-side management programs. I proposed alternative energy-efficiency programs and recommended program budgets and a cost-recovery mechanism.

Case No. 89-193; 89-194; 89-195; and 90-001 (6/90) Maine Public Utilities Commission. I testified on behalf of the Maine Public Advocate's Office. I reviewed the appropriateness of Bangor Hydro-Electric Company's existing energy-efficiency and demand-side management programs in the context of BHE's main rate case and request for approval to construct the Basin Mills Hydro-Electric dam. I reviewed the overall resource plan and suggested alternative programs to strengthen the energy-efficiency and demand-side management resource efforts.

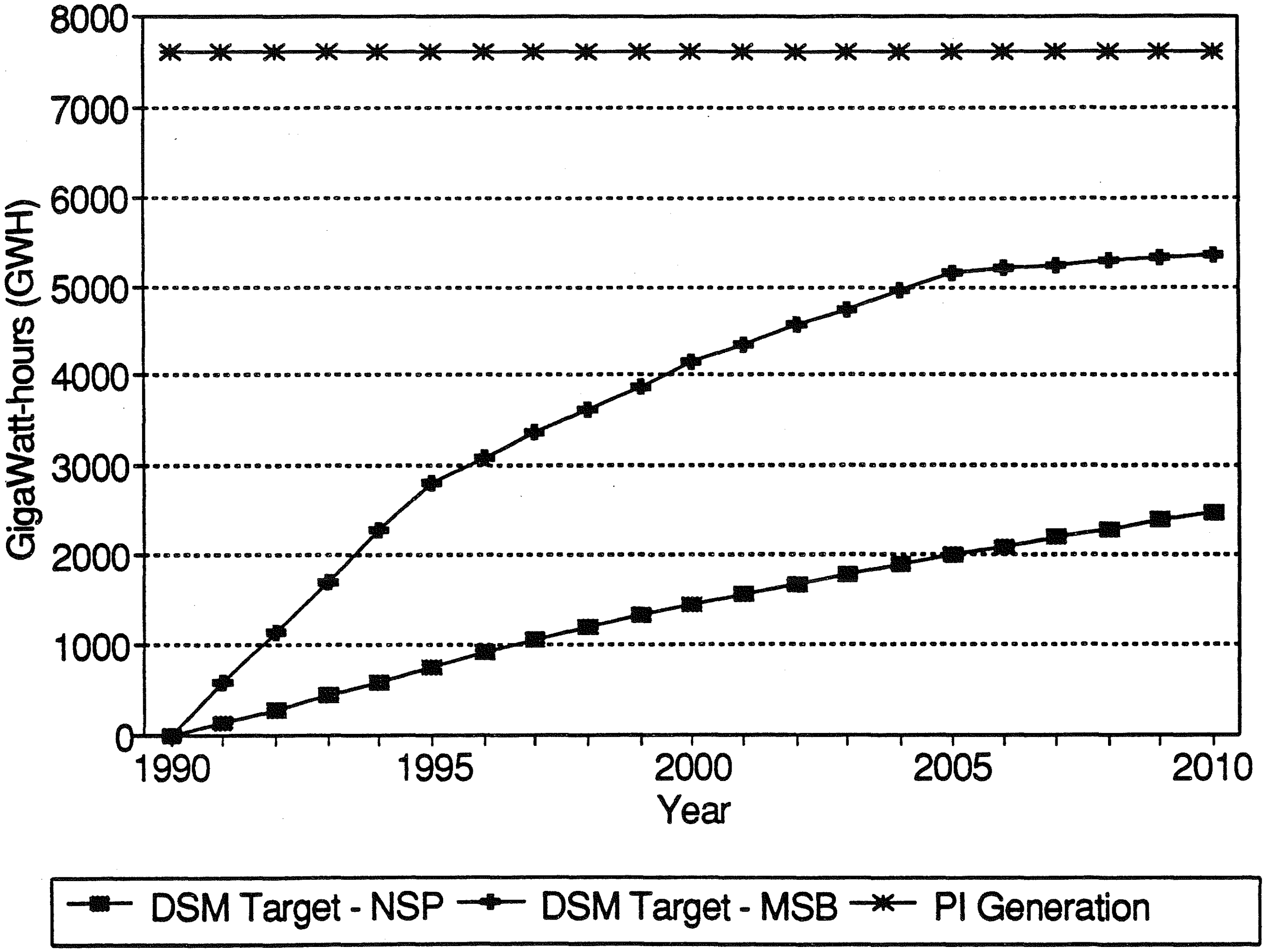
Case No. 6617 (4/91) Hawaii Public Utility Commission. I testified on behalf of the Hawaii Division of Consumer Advocacy. I described what demand-side management resources are, why they should be included in the integrated resource planning process, and proposed the implementation of several pilot projects in Hawaii along with guidelines for the pilot programs.

Case No. E002/GR-91-001 (5/91) Minnesota Public Utilities Commission. I filed testimony on behalf of Minnesotans for an Energy Efficient Economy. I assessed the DSM programs being operated or proposed by Northern States Power Company and made recommendations as to ways in which NSP could improve its DSM efforts.

Case No. 905 (6/91) Public Service Commission of the District of Columbia. I testified on behalf of the District of Columbia Energy Office. I responded to the energy-efficiency and load management aspects of Potomac Electric Company's filing and made several recommendations for DC-PSC action.

Case No. 6690-UR-106 (9/91) Public Service Commission of Wisconsin. I requested the Commission to increase the WPSCo commitment to energy efficiency and increase its DSM budget. I further requested that the Commission direct WPSCo to employ leasing as a DSM program delivery mechanism in combination with other actions and design an aggressive door-to-door, direct installation leasing program.

DSM Targets Compared to PI Generation



Question:

Refer to "Northern States Power Company Minnesota, Demand-Side Potentials Study. Volume 1: Project Summary." Electric Power Software, 5/89

Refer to figures entitled "NSP MN Demand-side Potentials Study, reduction in System Peak Demands" (Figure 1) and (on same page) "NSP MN Demand-side Potentials Study, Reduction in Annual System Energy Sales" (Figure 2).

On Figure 1, explain precisely what each plotted series of data represents (i.e., does the "summer max. avail." represent total technical potential? Do the "summer" and "winter" series represent the achievable potentials? How are these defined [i.e., criteria for "achievable"])?

Response:

As stated in the SUMMARY section of Volume 1, the "summer max. avail." curve shows the maximum achievable impacts for the measures studied, given the criteria of economic payback and relative customer awareness as described in the summary. Therefore, the "summer max. avail." does not represent the maximum technical potential. Instead, that curve indicates the maximum potential impact if the entire "target" population (those believed to be unaware of the measure prior to NSP's program existence) installs all stated measures having a 0.9 or better total resource benefit/cost ratio. The data best represent a maximum achievable potential for NSP's programs involving the measures assessed, for several reasons. First, the estimates do not take credit for efforts likely to happen anyway (those customers assumed aware of the measure would likely not be as influenced by NSP's program and could be "free riders"). Second, the estimates assume economic resource planning by NSP (i.e. that DSM would be economically balanced against other electric resources). Third, no non-commercialized technologies are assumed to penetrate the market with significant impact during the study period.

The <u>likely</u> NSP-achievable potential is represented by the "summer" and "winter" curves on the chart. These likely achievable amounts are somewhat less than the maximum achievable potential because of the above-mentioned economic and awareness factors, plus logistical and other constraints not related to economics or awareness that affect program implementation over a period of time. These factors are applied to the maximum potential estimates in order to obtain the likely achievable impact on which NSP set its 1000 mw DSM goal.

Response By: Mark Thornsjo
Title: Administrator, Demand-Side Planning
Department: Electric Marketing

Northern States Power Company
Docket No. E002/CN-91-19

September 10, 1991
Proprietary

DPS Information Request 406

DPS Exhibit No. ______
(GCC-1)
Schedule 4
Page 1 of 2

Question:

Refer to "Northern States Power Company Minnesota, Demand-Side Potentials Study. Volume 1: Project Summary." Electric Power Software, 5/89

Refer to figures entitled "NSP MN Demand-side Potentials Study, reduction in System Peak Demands" (Figure 1) and (on same page) "NSP MN Demand-side Potentials Study, Reduction in Annual System Energy Sales" (Figure 2).

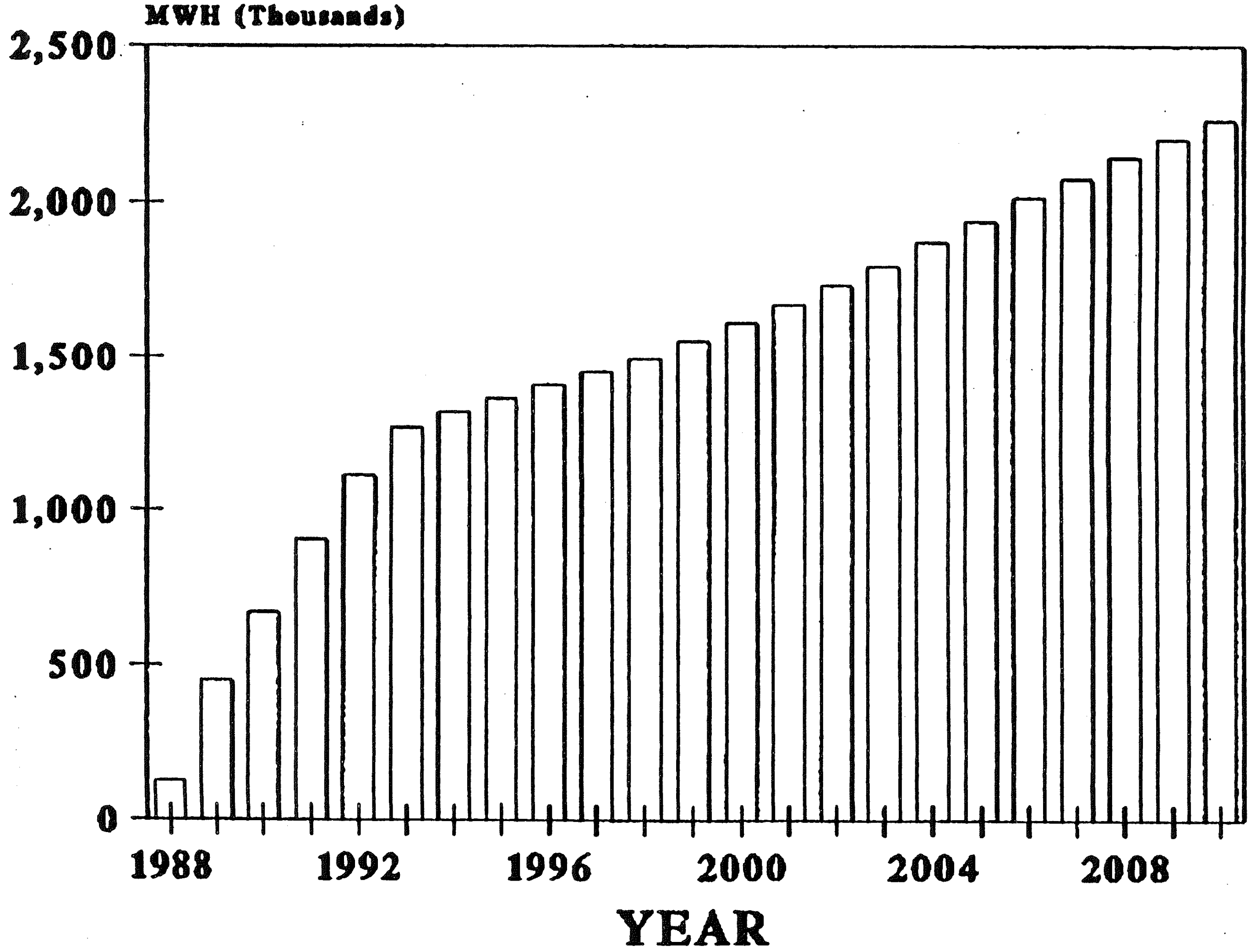
On Figure 2, what does this plot of energy savings represent? If this plot represents achievable potential, provide a plot and/or data series of maximum technical potential.

Response:

Figure 2 presents the likely achievable potential. The energy impacts corresponding to the maximum achievable potential are provided in the enclosed chart.

Response By: Mark Thornsjo
Title: Administrator, Demand-Side Planning

NSP MN DEMAND-SIDE POTENTIALS STUDY
406 (ANNUAL ENERGY REDUCTION)



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ANALYSIS OF COMMERCIAL AND INDUSTRIAL ENERGY CONSERVATION POTENTIAL PERFORMED BY XENERGY, INC. FOR NSP

SUMMARY OF RESULTS

Population Statistics (1988 Data)	Total Use (MWH)	Savings Potential (MWH)	%
TOTAL	13,843,008	1,688,081	12.2%
INDUSTRIAL	5,682,900	428,173	7.5%
COMMERCIAL	8,160,108	1,259,908	15.4%
	Peak Demand (MW)	Savings Potential (MW)	
TOTAL	2711	337	12.4%
INDUSTRIAL	885	76	8.6%
COMMERCIAL	1826	261	14.3%

NSP-SYSTEM STATISTICS 1990	(MWH)
TOTAL COMM & IND	24,360,379
Industrial	17,145,474
Commercial and Municipal	7,214,905

COMPARISON OF DSM TARGETS FOR SELECTED UTILITIES
All targets as a percent of base forecast for the year indicated.

	1995	2000	2005	2010
PEAK DEMAND REDUCTION:				
NSP-SYSTEM	13.1%	16.0%	17.1%	17.6%
NSP-WISCONSIN	13.5%	19.2%	21.1%	20.4%
NSP-MINNESOTA	13.0%	15.5%	16.5%	17.2%
ANNUAL ENERGY SAVINGS:				
NSP-SYSTEM	1.9%	3.3%	4.0%	4.5%
NSP-WISCONSIN	6.9%	8.9%	9.7%	9.2%
NSP-MINNESOTA	1.0%	2.3%	3.0%	3.7%
OTHER US UTILITIES				
ANNUAL ENERGY SAVINGS:				
SOUTHERN CALIFORNIA EDISON		13.0%		
TAUNTON MUNICIPAL		11.1%		
LONG ISLAND LIGHTING COMPANY		9.0%		
CONSOLIDATED EDISON		8.1%		
ROCHESTER GAS & ELECTRIC		7.3%		
SEATTLE CITY LIGHT		7.0%		
NORTHEAST UTILITIES		7.0%		
COMMONWEALTH ELECTRIC		6.9%		
PUGET POWER		6.8%		
NEW ENGLAND ELECTRIC		6.6%		
PACIFIC GAS & ELECTRIC		6.0%		
WISCONSIN ELECTRIC POWER		6.2%		
WISCONSIN POWER & LIGHT		6.4%		8.8%
MADISON GAS & ELECTRIC		7.2%		8.6%

Sources: E. Hirst, "Possible Effects of Electric-Utility DSM Programs, 1990 to 2010," Oak Ridge National Laboratory, ORNL/CON-312.
Also, Wisconsin Advance Plan 6.

Northern States Power Company (Minn)
Docket No. E002/CN-91-19
DPS Information Request No. 58

Question

DEPT. OF PUBLIC SERVICE

Please provide your best estimate of the cost to replace the generating capacity of Prairie Island with energy conservation. This estimate should include a study of all current and potential conservation measures. The study should include an examination of the following:

a. probability of baseload electric conservation with enough reliability to replace Prairie Island (1,050 MW).

b. technical feasibility of baseload electric conservation.

c. anticipated penetration rates of current and potential conservation projects.

d. anticipated saturation rates of current and potential conservation projects.

e. estimated marketing efforts to achieve 1050 MW of baseload energy conservation.

f. estimated level of consumer behavior modification and probability of such modification necessary to achieve 1050 MW of baseload energy conservation.

g. relevant local and national studies conducted by credible sources on the potential for baseload energy conservation.

h. probability of maintaining the necessary baseload conservation efforts throughout the life of the Prairie Island operating license.

i. estimated effect on future certificates of need for electric generation, i.e. estimated need for additional capacity to meet the projected needs of the NSP service territory.

j. NSP's best estimate of environmental externalites (costs --$/kw, $/kwh) associated with nuclear, coal-fired, gas-fired, oil-fired, and hydro-powered electricity generation.

k. technical feasibility of alternative supply sources, ie., wind, solar, and biomass.

l. estimated per unit cost of alternative supply sources.

Response:

NSP does not find it is feasible to replace Prairie Island -- which has a winter capacity of 1060 MW, annual energy production of 7633 GWH (1990), and a capacity factor of 83% -- with baseload conservation. What NSP can, and will, do by 2010 is market essentially all the available conservation which NSP can directly influence, which is projected to reduce demand by 558 MW and energy by 1930 GWH/year. This cumulative conservation in the year 2010 will equate to a "capacity" or load factor of 40%. Clearly, the load factor of the available conservation is substantially lower than that of a baseload plant and, as such, cannot be considered as an equal generating resource.

To substantiate this, NSP references a 1988-1989 Commercial & Industrial DSM Potential Study conducted with the assistance of Xenergy, Inc. In this study, described in Appendix 1 of the Application, extensive energy audits of over 1,000 commercial and industrial (C&I) customers were conducted, accounting for 20% of the C&I sectors' 1988 total usage of 13,843 GWHs. These audits were conducted to determine what the potential and technical feasibility were for conservation measures in the NSP territory.

The audit results provided the baseline customer profiles and conservation recommendations for determining the available technical and economic conservation potential. With these results, NSP considered the penetration, saturation, modification of customer behavior and marketing efforts needed to achieve the identified conservation measures.

This study, along with the results of another study conducted during the same time frame (also described in Appendix 1; both studies' documentation reports have been provided to the DPS) are the basis for NSP's long range forecast of NSP-influenced conservation impacts. Essentially, all of the impacts identified would have to be achieved to meet these forecast estimates.

As indicated in the study reports, the C&I Potential Study revealed that today 337 MWs and nearly 1,700 GWHs of conservation from C&I were technically feasible, with under a ten-year simple economic payback. As reported in the potential study, these measures would cost about $500 million, exclusive of NSP's marketing costs. Air conditioning impacts totalled 102 MWs, leaving 235 MWs of intermediate- and baseload-equivalent conservation. Over 90% of the 235 MWs is lighting conservation, which has a load factor of 40-45%. Because of this fact, most conservation cannot be equated to a baseload generating facility.

Indeed, another perspective on this finding can be shown by plotting the revised impacts according to their load pattern, i.e. by type and time of day. Doing so shows about 94 MWs and 824 GWHs/year of purely "baseload" impact. This is less than 1/3 the total conservation demand impact and about 1/2 the energy impact identified in the study. Thus, in order to accomplish 94 MWs of conservation baseload impact, more than three times the demand impact and twice the energy impact must be achieved. Thus, the participant cost of measures needed to achieve a 94 MW/824 GWH-yr impact would be about $330 million (this excludes NSP's marketing costs, added below. It also excludes $170 million for extensive weatherization (which would reduce consumption by 1 MW) from the total $500 million original measure cost estimate. The participant cost in 1988$ (the study time frame) is about $3500/KW, or $0.04/KWH assuming an average 10-year life of measures. Adding in NSP's current, base-load-weighted marketing program cost of about $938/KW or $0.019/KWH ($375/KW program cost/40% conservation load factor in the year 2010; and $0.0075/KWH/40% conservation load factor in the year 2010) brings the total resource cost for the 94 MWs of impact to over $4438/KW and nearly $0.06/KWH.

An additional consideration is economics and related "free market" impacts. In developing the C&I Potential Study, NSP assumed that measures with a simple payback of up to ten years were technically and economically feasible. When asked, customers indicated explicit plans to implement 17 of the 337 MWs of the conservation measures identified. However, in light of their stated payback criteria for conservation measures, 136 MWs would qualify. Thus, while customers in the short-term plan few actions, a substantial amount of conservation is economically attractive and could be achieved without any special utility marketing effort. At least some of this free market impact is believed to be captured in NSP's base (without NSP-influenced conservation and load management) energy forecast. Because NSP's DSM goal focuses on the impacts NSP can influence, the identified technical potential for which NSP can claim credit is thus reduced. These findings add to the difficulty of NSP influencing a sufficient block of energy to displace existing baseload generating capacity. The related likelihood of maintaining such a block of energy conservation over a 13 year period is low, because of the continuing changes customers make in their equipment and the continuing pressure in the market place to minimize up-front costs. Continued reselling of conservation would be needed.

NSP's current energy forecast, as presented in the Advance Forecast Report to the Minnesota Environmental Quality Board and the Department of Public Service, states that, even with given forecasted conservation efforts, a need for future generation still remains -- for peaking capacity in the mid '90s and baseload capacity in the late '90s. Therefore, to both replace Prairie Island <u>and</u> meet current forecasted demand growth needs, NSP would have to achieve over 1600 MWs of baseload conservation, 27% of NSP's system peak, within nine years. Because of conservation's relatively low load factor, however, achieving this level of baseload impact would require substantially greater amounts of <u>overall</u> conservation -- perhaps 2-3 times the 1600 MW of baseload impact, or 3200 - 4800 MW total. Again, this extreme impact would have to be 100% achieved in 9 years, a feat which NSP considers to be both technically and logistically impossible.

When analyzing enviromental externalities for conservation measures, NSP uses a willingness-to-pay factor of $0.003 cents per KWH saved for the years 1991 through 2002 inflated at 4% each year. Beginning in the year 2003, NSP adds an externality factor of $0.0088 to this amount. This amount and its timing are based on additional coal-fired generation pollution abatement NSP may need to implement given the new Clean Air Act requirements. The environmental externalities associated with nuclear, gas-fired, oil-fired, and hydro-powered electricity generation are not estimated for conservation analysis. The coal externalities cost acts as a surrogate for all fossil-fuel generation source externalities.

Renewable energy sources such as wind, solar, and biomass have been extensively studied by electric utilities nationwide, including NSP. In fact, NSP has sponsored an extensive wind resource assessment effort in Minnesota and Wisconsin, and has studied solar water heating. Wind and photovoltaic systems are available now, although technological advancements are expected to continue to reduce their cost and improve performance. Site-related factors limit the viability of wind and solar development; and operation of wind and solar plants is limited by resource availability (e.g. wind speed, sunshine) and the cost of energy storage needed to provide higher reliability.

The technology to burn wood is well developed and is similar to coal-fired steam plants. Wood and other biomass resources are available on a dispersed basis, and therefore tend to be incompatible with large central electric generation facilities. Nonetheless, NSP burns wood waste at its Bayfront and French Island plants in Wisconsin. Wood provides 70% to 100% of fuel input to two of three boilers at Bayfront. At French Island, NSP burns a 50/50% mixture of RDF (Refuse Derived Fuel) and waste wood. Development of biomass resources, in small increments, has been proposed and studied by non-utility generators, but such projects were not found to be economical.

Based on current information, NSP believes the practical potential for future development of these technologies is much less than NSP's future need for additional generating resources. Development of renewable resources will continue to be studied as part of NSP's resource planning process, however, and where found to be desirable, such development will defer or replace a portion of the fossil fuel-fired generating additions needed because of load growth on NSP's system. Adding renewable resources will not affect the continued need to maintain NSP's existing generating resources, such as the Prairie Island plant.

The following are representative of the capital costs (exclusive of O&M costs) of alternative supply systems. These costs were used in Wisconsin Advance Plan 6 joint studies, in which NSP participated.

		Capital Cost (1990$)
Wind:	Installed in 1990	$1050/Kw
	Installed in 1995	$935-$990/Kw
	Installed in 2005	$890-$935/Kw
Photovoltaic: (Solar)	Installed in 1990	$5000/Kw
	Installed in 1995	$1750-$3150/Kw
	Installed in 2005	$1150-$1750/Kw
Wood-Fired Steam Plant		$1500-$2000/Kw

NSP does not have per unit cost estimates from biomass applications, other than a wood-fired steam plant. The cost estimates for wind and solar are for peak output; that is, they do not include storage costs.

Response by: Mark Thomsjo
Title: Administrator, Demand-Side Planning
Department: Electric Marketing

Response by: Dave Grover
Title: Senior Planning Engineer
Department: Electric Supply and Transmission Planning

DIRECT TESTIMONY AND EXHIBIT OF

DAVID SCHOENGOLD

MINNESOTA DEPARTMENT OF PUBLIC SERVICE

* * *

BEFORE THE

MINNESOTA PUBLIC UTILITIES COMMISSION

* * *

NORTHERN STATES POWER COMPANY

DOCKET NO. E002/CN-91-19

* * *

SEPTEMBER 30, 1991

Direct Testimony of
David Schoengold
Minnesota Department of Public Service

* * *

Before The

Minnesota Public Utilities Commission

* * *

Northern States Power Company

Docket No. E002/CN-91-19

* * *

September 30, 1991

Prepared Testimony of
David Schoengold
Before the Minnesota Public Utilities Commission
In Docket E-002/CN-91-19

Q. Please state your name and business address.

A. My name is David Schoengold. My business address is MSB Energy Associates, Inc., 7507 Hubbard Avenue - Suite 200, Middleton, Wisconsin 53562-3135.

Q. Please describe your educational background and experience in utility regulation.

A. I received a BA degree in physics from Rutgers University in 1966. I have graduate level course work in physics and computer science at the University of Chicago. From 1974 through 1990 I was employed by the Wisconsin Public Service Commission in the energy planning area, initially as an analyst and since 1981 as the director of systems analysis. My staff's responsibilities as the director of systems analysis included forecasting, fuel forecasting, transmission planning, electric supply planning, renewable resources, integrated least-cost planning, and natural gas planning. During my tenure at the Wisconsin PSC I had major responsibility for Advance Plans 1 through 5, studies of the use of efficiency and renewable resources as an alternative to conventional electricity supply, and many other related planning studies.

I am also one of the founders of MSB Energy Associates, Inc. a consulting firm which was formed in 1988 to offer planning advice to electric and gas utilities, utility commissions, public counsels, and others interested in regulatory matters. Since March 1990 I have been a full-time employee of this firm. Among the projects which I have been involved in for MSB Energy Associates are integrated resource planning collaboratives in Vermont, Connecticut, and Massachusetts, transmission planning studies in New Jersey, South Carolina, and Arizona, a study of the City of Chicago's franchise options, integrated resource planning studies for Illinois, Ohio, Hawaii, Ontario, and Pennsylvania, and several studies of electric utility avoided costs. In addition I was involved in the preparation of a series of regional least-cost planning workshops put on under the auspices of the National Association of Regulatory Utility Commissioners. I have testified in the District of Columbia, Illinois, Wisconsin, Michigan, and West Virginia.

Q. For whom are you testifying today?

A. I am testifying on behalf of the Minnesota Department of Public Service.

Q. What is the purpose of your testimony today?

A. I intend to address the economics of the decision to add additional spent fuel storage capability to the Prairie Island Nuclear Power Plant.

Q. Do you have any exhibits to support your testimony?

A. Yes. I am sponsoring DPS Exhibit ____ (DS-1). This exhibit is a report prepared by MSB Energy Associates, Inc. for the Minnesota Department of Public Service which explores the costs and benefits of various alternatives for dealing with the spent fuel situation at Prairie Island. This report identifies the major alternatives under consideration, the cost elements which must be included in evaluating the economics of each of those alternatives, and the overall cost differentials between alternatives.

Q. Were you personally responsible for this report?

A. I was responsible for the overall production of the report. Portions of the report are the responsibility of other members of the Minnesota DPS team. Specifically, MHB Technical Associates was responsible for the estimates of the externality costs of the spent fuel storage facility, Geoffrey Crandall of MSB was responsible for the estimates of the cost and availability of energy conservation and other demand-side alternatives, and the Minnesota DPS was responsible for estimates of the capital and operating costs of the spent fuel storage facility and for estimates of the externality costs of continued operation of the Prairie Island Nuclear Plant. I was responsibility for estimates of the system operating and capital cost impacts of the alternatives, the environmental externality costs of operations of the existing system (except for the nuclear plant externalities), and for developing the overall differential costs of the alternatives.

Q. Please describe the alternatives which were considered in your analysis.

A. Our analysis considered five major alternatives, one of which has two sub-alternatives.

The alternatives are as follows:

1. Build a storage facility and continue to run Prairie Island
2. Do not build a storage facility. Retire Prairie Island and build new generating capacity to replace the lost capacity. Do not add additional conservation beyond that already planned.
    a. The new capacity added is peaking capacity with a low capital cost and high operating cost.
    b. The new capacity added is coal-fired base load capacity with a high capital cost and a low operating cost.
3. Do not build a storage facility. Instead, rely on 1000 MW of baseload equivalent additional conservation to reduce customer loads so that the energy which would have been generated by Prairie Island is not required.
4. Build a storage facility and continue to run Prairie Island. At the same time, implement 1000 MW of baseload equivalent additional conservation. Under this alternative the additional conservation

will enable NSP to back off the operation of other plants on its system rather than replace Prairie Island.

5. Build a storage facility and continue to run Prairie Island. At the same time, implement an aggressive conservation program. Under this alternative the additional conservation will enable NSP to back off the operation of other plants on its system rather than replace Prairie Island. However, in this alternative we have not included enough conservation (1000 MW of baseload equivalent) to be able to replace Prairie Island.

Q. Do alternatives 3 and 4 include enough conservation to fully replace Prairie Island?

A. Yes.

Q. Hasn't Northern States Power claimed that there is not enough conservation available to fully replace Prairie Island?

A. Yes, it has. As Mr. Crandall demonstrates in his testimony, our analysis has also concluded that sufficient conservation to replace Prairie island is unlikely to be achievable in the time frame under consideration. In view of this conclusion, our alternatives 3 and 4 must be viewed, not as achievable scenarios at this time, but rather as studies of the sensitivity of our conclusions to the possibility of significantly greater conservation than we have been able to identify at this time.

Q. How does the amount of conservation included in alternative 5 compare to what NSP has included in its planning?

A. As Mr. Crandall discusses in his testimony, our alternative 5 has a great deal more conservation than NSP has included in its planning.

Q. In various documents filed in this case there have been suggestions that NSP reduce generation at its Prairie Island Plant in order to extend the life of the spent fuel storage while additional conservation is being developed. Does your report address this alternative?

A. Not directly. However, this approach would be a variation of my alternative 3 which calls for immediate conservation to replace Prairie Island. If my alternative 3 can be shown to be cost effective, the Prairie Island stretch out would also be cost-effective. Similarly, if my alternative 3 is not cost-effective, neither would the stretch out alternative be.

Q. Northern States Power in its application discusses various alternatives for increasing spent fuel storage capacity. Have you addressed these alternatives in your report?

A. Not directly. We have accepted NSP's claim that the proposal is the most cost-effective way of increasing spent fuel storage. Other more costly alternatives would reduce the cost-effectiveness of alternative 1.

Q. Can you discuss the conclusions which you include in DPS Exhibit ____ (DS-1)?

A. Yes. Basically we have concluded that the cost of increasing the spent fuel storage capacity is small compared to the benefits which would accrue from the continued operation of the Prairie Island Nuclear Plant. These benefits are primarily the reduced operating cost of generating power on the NSP system. We have also concluded that an aggressive conservation program, even though it is unlikely to produce enough conservation to replace Prairie island, is cost-effective at this time.

Q. In concluding that the benefits of continuing the operation of Prairie Island are greater than the costs aren't you ignoring the externality costs of nuclear power?

A. No. We have included in our analysis best case and worst case estimates of the externality cost of operating the spent fuel storage facility and continuing to operate Prairie Island. We have also included two separate estimates of the externality cost of air pollutant emissions from the NSP coal, oil, and gas fired plants.

Q. Have you factored into your conclusion the widespread public opposition to the continued operation of the Prairie Island Nuclear Plant?

A. No I have not. Public opposition is not a factor which can be readily evaluated in an economic analysis. It is a political issue which the Commission as a politically empowered decision making body must consider. As I stated in DPS Exhibit ____ (DS-1), the differential cost of retiring Prairie Islan/d, while high, is not so high that to pay it would lead to a major public policy disaster. Even with the higher cost Northern States Power would continue to have very reasonable electric rates. The commission will have to determine whether the perceived benefits of retiring Prairie Island now are worth the cost of so doing.

Q. Does this complete your testimony?

A. Yes, it does.

EXHIBIT OF

DAVID SCHOENGOLD

MINNESOTA DEPARTMENT OF PUBLIC SERVICE

* * *

BEFORE THE

MINNESOTA PUBLIC UTILITIES COMMISSION

* * *

NORTHERN STATES POWER COMPANY

DOCKET NO. E002/CN-91-19

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SEPTEMBER 30, 1991

DPS Exhibit ____ (DS-1).

Prairie Island Spent Fuel Storage Facility

A Report to the Minnesota Department of Public Service on the Costs and Benefits of Alternative Courses of Action

Prepared by MSB Energy Associates, Inc.
September 26, 1991

Prairie Island Spent Fuel Storage Facility

A Report to the Minnesota Department of Public Service on the Costs and Benefits of Alternative Courses of Action

Prepared by MSB Energy Associates, Inc.

The Problem

Northern States Power Company will have to retire the Prairie Island Nuclear Power Plant in 1995 if something isn't done to provide additional storage capability for the spent fuel. The retirement can be delayed for a bit if the operations of Prairie Island are cut back, but the bottom line is that the plant needs some type of increased spent fuel storage to continue to operate. The problem is to identify and evaluate the costs and benefits of the various alternatives from which NSP can choose.

The major alternatives which NSP has are to add to the spent fuel storage (someplace -- the actual site, whether at Prairie Island or an off-site facility does not significantly affect the costs or benefits, though it may affect who receives the impact of the environmental externalities) or to retire the units and serve the load which they would have served through some other means. That other means can be demand-side management, purchased power, new generating facilities, or increased use of the existing system (up to a point). Each alternative has a different set of costs and benefits. Some of the costs and benefits overlap between alternatives, but there are major differences between all of them.

For analytical purposes we have identified five major alternatives, with several sub-alternatives under them. In the next section we have tried to identify the comparative costs and benefits connected with each alternative. The section is set up so that only costs appear. When comparing alternatives, benefits for one scenario are the absence of costs which would appear in another scenario. By identifying all of the costs for each alternative being considered (to the extent possible), the total costs for each alternative can be compared and differentials calculated. As we will discuss later, not all of the scenarios are achievable, but are shown for analytical purposes anyway.

The Alternatives

The five major alternatives we have identified are as follows:

1. Build a storage facility and run Prairie Island

2. Do not build a storage facility. Retire Prairie Island and build new generating capacity to replace the lost capacity. Do not add additional conservation beyond that already planned. There are two sub-alternatives under this alternative. In one the new capacity will be peaking capacity built primarily for the purpose of insuring system reliability. In this sub-alternative NSP is expected to rely on the existing base- and intermediate-load capacity to provide most of the energy which Prairie Island would have provided. In the other sub-alternative, the new capacity is assumed to be coal-fired base load capacity to replace the lost base-load capacity of Prairie Island.

3. Do not build a storage facility. Instead, rely on 1000 MW of additional baseload equivalent conservation to reduce customer loads so that the energy which would have been generated by Prairie Island is not required. There are variations of this alternative which call for different timings of conservation implementation, but none of these variations significantly affect the identification and evaluation of costs and benefits of this approach. As discussed later in this report, we do not believe this is an achievable alternative at this time.

4. Build a storage facility and continue to run Prairie Island. At the same time, implement the same 1000 MW of additional baseload equivalent conservation as in Alternative 3. Under this alternative the additional conservation will enable NSP to back off the operation of other plants on its system rather than replace Prairie Island. As with Alternative 3, we do not believe this is an achievable alternative at this time.

5. Adopt an aggressive conservation program. However, the aggressive conservation program we have identified will not achieve enough conservation in the necessary time frame to enable the retirement of Prairie Island. Instead, use the aggressive conservation program to back off the use of other facilities on the NSP system. This alternative includes the building of the storage facility and the continued operation of Prairie Island.

The Cost Elements

The costs connected with each alternative are listed below. We have included direct utility costs, costs which would be born directly by the utility customers, and the externality costs of each action. The framework is structured so as to be able to separate costs into discrete units which can be combined to evaluate different alternatives.

Alternative 1

- Capital cost of the storage facility
- Operating cost of the storage facility
- Decommissioning cost of the storage facility
- Operating cost of the NSP system with Prairie Island (fuel and O&M, including fixed O&M for Prairie Island)
- Externality costs of operating NSP system with Prairie Island
- Externality costs of operating the storage facility
- Externality costs of decommissioning the storage facility

Alternative 2

- Operating costs of the NSP system without Prairie Island with new capacity (including fixed O&M for new capacity). This will vary depending on whether the new capacity being considered is base-load or peaking capacity.
- Capital cost of new capacity needed to replace Prairie Island. The costs will be different depending on whether the new capacity is to be base-load or peaking capacity.
- Externality costs of operating the NSP system without Prairie Island and with new replacement capacity
- Externality costs of building the replacement capacity

Alternative 3

- Operating cost of the existing system without Prairie Island and without the load which conservation displaces
- Direct cost of the conservation (both utility paid and participant paid)
- Program costs for implementing the conservation programs including monitoring and evaluation costs
- Any externality costs related to the conservation options

- Externality costs of operating the NSP system at reduced load without Prairie Island

Alternative 4

- Capital cost of the storage facility
- Operating cost of the storage facility
- Decommissioning cost of the storage facility
- Operating cost of the NSP system at reduced load with Prairie Island (including Prairie Island fixed O&M)
- Credit for capacity which would not need to be built because of the additional conservation
- Externality costs of operating the NSP system at reduced load with Prairie Island
- Externality costs of operating the storage facility
- Externality costs of decommissioning the storage facility
- Direct cost of the conservation (both utility paid and participant paid)
- Program costs for implementing the conservation programs
- Any externality costs related to conservation

Alternative 5

- The cost elements for Alternative 5 are the same as for Alternative 4. Since Alternative 5 includes less conservation than Alternative 4, the total conservation cost is less. So is the capacity credit.

The Cost of the Storage Facility

NSP has considered a number of different alternatives for increasing the spent fuel storage capacity. These include both on-site and off-site facilities. For the purpose of analyzing the costs and benefits of increasing storage, the option selected is not particularly critical. NSP claims to have selected the lowest cost alternative which is practical and meets regulatory requirements. It will serve in this analysis as a reasonable proxy for the costs and benefits of any storage facility.

The Minnesota Department of Public Service has provided us with a best case and a worst case estimate of the cost to construct and operate the spent fuel storage facility. We have analyzed the impact of both. According to the DPS, the cost is more likely to be closer to the best case than to the worst case estimate.

Operating Costs of the NSP System

The operating costs for the NSP system were modeled for the various alternatives using a production cost computer model. This model considers the loads on the system and the plants available to meet those loads, and dispatches the available plants in the most economic manner while recognizing system operating constraints which might interfere with economic dispatch. The model attempts to track the actions of the system operators. Use of a production cost model enables us to determine which plants will be called on to generate extra energy if the Prairie Island plant must be shut down. The model also enables us to determine which plants will generate less energy if there is additional conservation.

Six individual cases were modeled which match the alternatives discussed above (alternative 2 required two separate model runs depending on whether the new capacity added to replace Prairie Island was assumed to be peaking or base-load capacity). The cases were modeled beginning in 1995 and running through 2012 (the last year for which forecast and planning data were available. Operating costs were extrapolated through 2014. The model we used also enables us to keep track of the air pollutant emissions for the various alternatives.

The production cost runs were based on data filed by NSP in the Wisconsin Advance Plan 6 proceeding. In Wisconsin's advance plan proceeding, a long range planning docket, NSP is required to file long range forecasts of expected customer demand and energy use, and the system expansions planned to meet these forecasts. As part of the filing NSP is also required to file projections of costs and operating parameters for its system. These filings in Wisconsin date from March 1991 so they have been checked against the latest NSP supplied data in order to determine whether any changes were necessary.

The operating cost savings which accrue to NSP from continued operations of the Prairie Island units are significantly less than they would be for many other utilities. This is because NSP is ideally situated to be able to get inexpensive coal from the western coal fields, inexpensive economy energy from utilities located in the Plains states, and inexpensive purchased power from Manitoba Hydro. Even with NSP's locational advantages, there is still a significant increase in operating costs when power which had been generated by Prairie Island is produced elsewhere on the system.

Capital Costs of Replacement Capacity

In alternative 2 (retire Prairie Island, no additional conservation) new capacity is required in order to maintain system reliability. Two sub-alternatives were considered. In one the replacement capacity is peaking capacity added purely to maintain system reliability and not to provide any significant amounts of energy. In the other the replacement capacity is assumed to be base-load coal in order to provide inexpensive energy to replace the energy lost from Prairie Island. In the Advance Plan 6 filings referenced above NSP has provided its estimate of the cost of both peaking and base-load capacity. For the purposes of this case we have assumed the costs of new capacity which NSP is projecting.

In alternatives 4 and 5 additional conservation is included while the Prairie Island units continue to operate. This additional conservation has capacity value to NSP, both as capacity which can be sold and as a way of deferring some of the capacity which NSP is planning to build during the planning period. The same peaking capacity cost used in alternative 2 is used as a credit in alternatives 4 and 5.

Availability of Demand-side Management Resources

The amounts of energy efficiency and load management (collectively referred to as "demand-side management", or simply "DSM") that are available within the NSP service territory are ambiguous due to the nature of DSM resources. The potential for DSM is the sum of literally thousands of individual changes in technology and customer behavior. A study of the maximum technical potential for DSM in Minnesota estimated this potential to be 52% of current electricity use. This amount should be considered an upper limit as it represents an amount available under several optimal assumptions.

The "achievable" amount of DSM resources is defined as the amount of DSM resources that can be expected to be achieved through the combined efforts of individual energy customers and the Company to implement cost-effective DSM options. NSP estimates that the cumulative impacts of its DSM programs will reduce peak demands by approximately 2000 MW and annual energy demand by 2500-2700 GWh by the year 2010.[1] We estimate that there is a much larger achievable DSM potential within the NSP service territory than these amounts, especially for reducing annual energy demand. We estimate that approximately 5400 GWh of annual energy savings and approximately 2400 MW of peak demand reduction are achievable by the year 2010. We believe that these levels of DSM are realistic targets for the NSP system considering utility costs, levels of customer participation, and the Company's ability to development, implement and administer the necessary DSM programs.

Our estimates of the DSM potential for NSP are based on the best-available data and research studies from numerous sources.[2] We first examined the DSM target values for NSP-Wisconsin from 1991-2010 and the total costs for Company DSM programs (including customers' net costs and all utility costs) to estimate the cost per delivered unit of saved energy over this period. The target values (in percent) were then applied to the entire NSP system. In addition to analysis of NSP-Wisconsin DSM plans, we analyzed data from numerous studies of the DSM potential in other states and regions. The costs and savings estimated in these studies were compared to the NSP system, and form the basis of our estimates of the DSM potential for the NSP system.

Our estimate of the amount of achievable DSM for the NSP system is not sufficient to totally offset the potential loss of generation from the Prairie Island nuclear units should the decision be made to retire these units rather than build the dry cask storage facility. While there are theoretically enough DSM resources available to offset the potential loss of generation from the Prairie Island nuclear units, we do not think that this amount could be realistically achieved in the time frame of this case at reasonable costs, as discussed further below.

Costs of Demand-Side Management

The cost of a demand-side management option is the sum of the costs of investment, operation and maintenance of a given technology, and any utility costs incurred to implement the technology, which include marketing, incentive payments, program development, and program administration. This cost varies from option to option. When aggregated over all utility-influenced DSM options, an average delivered cost of DSM can be estimated. We estimate that for the 5400 GWh of DSM resources we have identified as achievable for the NSP system, this average cost is $0.022/kWh.

DSM resources face increasing marginal costs similar to other resources. Utility planners need to balance the costs of DSM resources against supply-side resources. In addition they must consider the availability and feasibility of utilizing various resource options. Our estimate of the amount and cost of DSM resources for the NSP system takes the view of a utility planner who must work within a number of constraints towards achieving a certain level of DSM. Our target levels of DSM are more aggressive than existing Company targets, but we believe our target levels and the associated costs are reasonable and achievable.

Externalities

In this case, as in any other case concerning electric power options, there is a large set of externality costs which must be considered. This set includes the emissions from the utility system, the radiation and radioactive waste related issues, the political aspects of any decision involving nuclear power, and other related issues. There are externality costs connected with all of the alternatives under consideration. If NSP is denied authority to construct the spent fuel storage facility and must shut down the Prairie Island units, replacement power will need to come from some other source. This source (or multiple sources) may be other power supply options or conservation options. None of these alternatives are completely free in themselves of externality costs. To the extent that other power supply options are called on there will be increases in the emission of air pollutants such as SO_2, NOx, and CO_2. If new supply facilities are required there will be the impacts of constructing those facilities.

The externalities to be considered for the various alternatives differ. We discussed above the general categories of externalities which apply to the various alternatives. Below we specify in more detail what types of externalities (both positive and negative) fall in these categories.

- Externalities from operating the NSP system
  - Emissions from the fossil-fueled plants
  - Radiation emissions from the nuclear units
  - Continued generation of spent nuclear fuel and other waste
  - Consumptive and non-consumptive water use
- Externalities from building and operating the storage facility
  - Construction impacts
  - Construction employment
  - Air, land, and water use impacts
- Externalities from decommissioning the storage facility
  - Handling and transportation of radioactive materials
  - Extremely long-lived radioactive wastes
- Externalities from building and operating replacement capacity
  - Construction impacts
  - Construction employment
  - Land and water use
  - Air pollutant emissions
  - Increased use of imported fuels (if peakers are built)
- Externalities from increased use of conservation
  - Manufacturing impacts from conservation materials
  - Employment to build and install conservation materials
  - Inside air quality
  - Reduced dependence on fossil fuels and imported fuels

Unfortunately, listing the externalities related to the various alternatives does not make it easy to factor them into the decision. Different people will have different views of the relative value and importance of different externalities. While there is a lot of interest nationally in trying to quantify externalities and convert them to dollar terms which can be factored directly into the analysis, this effort is at an early stage.

The greatest amount of effort recently has been put into monetizing the costs of air emissions. The Massachusetts Department of Public Utilities has adopted estimates of the costs of the major air pollutants (Massachusetts Department of Public Utilities Order D.P.U. 89-239, August 31, 1990, page 85). In the same docket the Massachusetts DPU stated that it was also important to develop similar costs for other externalities. Such work has not been completed at this time. The Clean Air Act with its establishment of the right to trade SO2 emission allowances has established a market which will presumably set a market value to the right to emit SO2. This market is not, however, in place yet and estimates as to the value of allowances in the market vary widely. We have relied on our best estimate of the market value of SO2 allowances as an alternative to the Massachusetts DPU values.

We have relied on the work of MHB Technical Associates for estimating the externality costs connected with the spent fuel storage facility. We have relied on the work of the Department of Public Service for estimating the externality costs of continued operation of the Prairie Island units. We have best case and worst case estimates for these costs and have used both in our analysis. The Department believes that the costs are more likely to be closer to the best case than to the worst case estimates.

The Analysis

The results of the analysis we have done are shown in the tables at the end of the report. We have included the costs of individual elements as well as the totals. Certain costs which are common between the cases (for example, fixed operations and maintenance costs at existing plants other than Prairie Island) were not included since they will drop out of the calculation of cost differentials. All costs are shown in the tables as differences from the base case which represents our joint estimate of the cost of NSP's proposal. Differentials are shown for the individual cost elements as well as totals. Costs are expressed in net present value discounted to 1995. 1995 is used as the base year for discounting because that is the year in which the major cost impacts of whatever alternative is chosen would begin. Costs are also annualized to get a measure of the year-by-year cost differences.

The Decision

It is clear from looking at the costs of the various alternatives that, based purely on the direct costs to the utility and its customers, the benefits of building the spent fuel storage facility outweigh the costs. While we believe that there is a great deal more cost-effective conservation available than NSP is including in its planning, we have not been able to identify enough achievable conservation to replace Prairie Island. However, for sensitivity purposes we included an analysis of the impacts of enough conservation to replace Prairie Island. Even in this case the benefits obtained by using the conservation to back down the operations of more costly plants while continuing to operate Prairie Island would be greater still.

When we look beyond the direct cost to the utility and its customers the question becomes less clear. The externality costs of continued use of nuclear power are uncertain. There are unresolved questions relating to the long-term handling of nuclear material which make it almost impossible to evaluate the externality costs. A further difficulty is that, under standard economic analysis techniques, costs which occur more than some 40 to 50 years in the future have almost no impact, no matter how large those costs are. When we are considering impacts (such as those connected with nuclear fuel storage) which have lives of potentially hundreds of thousands of years, the idea that these don't matter after the first 50 years doesn't seem to hold up. While the calculations may seem to show that result, most decision makers -- particularly those with a public perspective -- find such a conclusion unacceptable.

While the dollar benefits from continued operation of Prairie Island are fairly large they must be put into a larger perspective. NSP sells over 35,000,000,000 kWh per year with annual revenues (from electricity sales) of over 1.6 billion dollars. Each additional $100,000,000 per year in costs is equivalent to a rate increase of 6.25% or less than 0.3 cents per kWh. Even with such an increase the NSP electric rates would still be low. The Commission will have to decide whether the benefits of reducing the continued buildup of radioactive wastes is worth cost increases of this magnitude.

COSTS FOR ALTERNATIVES UNDER CONSIDERATION

Description of Alternatives

Alternative 1	NSP proposal (Base Case)
Alternative 2a	Retire Prairie Island in 1995 Replace with peakers
Alternative 2b	Retire Prairie Island in 1995 Replace with base load
Alternative 3	Retire Prairie Island in 1995 Replace with 1000 MW of baseload equivalent conservation Note - This does not appear to be an achievable scenario at this time.
Alternative 4	Build fuel storage casks and maintain Prairie Island Add 1000 MW of additional baseload equivalent conservation Note - This does not appear to be an achievable scenario at this time.
Alternative 5	Build fuel storage casks and maintain Prairie Island Add an aggressive conservation program

Basic Assumptions

Inflation Rate	5.0%
Discount Rate	10.0%
Capital Cost (Base Load)	$145.00/kW-Yr (1990$)
Capital Cost (Peakers)	$35.00/kW-Yr (1990$)
Cost of ISFSI (NPV to 1995 in 1990 dollars) Including Capital, Operating, and Decommissioning Costs	$34,000,000 (best case) $78,000,000 (worst case)

Cost of Conservation	\$0.022 per kWh (1990\$)
Utility Fuel Costs	As Provided by NSP
Cost of Air Emissions (From Massachusetts DPU Order 89-239)	\$0.75 per lb of SO_2 (1989\$) \$3.25 per lb of NO_x \$2.00 per lb of TSP \$0.011 per lb of CO_2
Alternative Cost of Air Emissions	\$500 per ton of SO_2 (1990\$) (Estimated value of allowances under the Clean Air Act trading provisions)
Health and Safety Costs of the ISFSI (NPV to 1995 in 1990 Dollars)	\$27,800 (best case) \$78,000 (worst case)
Environmental Cost of Running Prairie Island (NPV to 1995 in 1990 Dollars)	\$513,300,000 (best case) \$5,052,700,000 (worst case)
Period of Analysis	1995 to 2014

COST ELEMENTS
(All costs are presented in millions of 1990 dollars, net present valued to 1995)

Differential Operating Costs (Compared to Alternative 1)

Alternative 1	Base
Alternative 2a	$2,867
Alternative 2b	$488
Alternative 3	($1,733)
Alternative 4	($2,198)
Alternative 5	($881)

Differential Spent Fuel Cask Capital and Operating Costs (compared to Alternative 1)

Alternative 1	Base
Alternative 2a	($34) (best case)
	($78) (worst case)
Alternative 2b	($34) (best case)
	($78) (worst case)
Alternative 3	($34) (best case)
	($78) (worst case)
Alternative 4	Base
Alternative 5	Base

Differential Capital Costs for Generating Capacity (Compared to Alternative 1)

Alternative 1	Base
Alternative 2a	$466
Alternative 2b	$1,932
Alternative 3	Base
Alternative 4	($466)
Alternative 5	($172)

Differential Costs of Conservation (Compared to Alternative 1)

Alternative 1	Base
Alternative 2a	Base
Alternative 2b	Base
Alternative 3	$2,563
Alternative 4	$2,563
Alternative 5	$745

Differential Costs of Air Emissions (Compared to Alternative 1)
(Assuming Massachusetts DPU Order 89-239 Costs)

Alternative 1	Base
Alternative 2a	$5,209
Alternative 2b	$5,071
Alternative 3	($722)
Alternative 4	($6,415)
Alternative 5	($1,828)

Differential Costs of Air Emissions (Compared to Alternative 1)
(Assuming $500 per Ton of SO2)

Alternative 1	Base
Alternative 2a	$167
Alternative 2b	$167
Alternative 3	($25)
Alternative 4	($231)
Alternative 5	($64)

Differential Costs of Prairie Island Operations Related Externalities (Compared to Alternative 1)

Alternative 1	Base
Alternative 2a	($513) (best case) ($5,053) (worst case)
Alternative 2b	($513) (best case) ($5,053) (worst case)
Alternative 3	($513) (best case) ($5,053) (worst case)
Alternative 4	Base
Alternative 5	Base

Differential Costs of Storage Facility Related Externalities (Compared to Alternative 1)

Alternative 1	Base
Alternative 2a	($0.023) (best case) ($0.430) (worst case)
Alternative 2b	($0.023) (best case) ($0.430) (worst case)

Alternative 3	($0.023) (best case)
	($0.430) (worst case)
Alternative 4	Base
Alternative 5	Base

TOTAL DIFFERENTIAL COSTS
(All costs are presented in millions of 1990 dollars, net present valued to 1995)

Assuming Massachusetts DPU Emission Costs

Alternative 1	Base
Alternative 2a	$7,995 (best case)
	$3,411 (worst case)
Alternative 2b	$6,944 (best case)
	$2,360 (worst case)
Alternative 3	($439) (best case)
	($5,023) (worst case)
Alternative 4	($6,516)
Alternative 5	($2,136)

Assuming SO2 at $500 per Ton

Alternative 1	Base
Alternative 2a	$2,953 (best case)
	($1,631) (worst case)
Alternative 2b	$2,040 (best case)
	($2,544) (worst case)
Alternative 3	$258 (best case)
	($4,326) (worst case)
Alternative 4	($332)
Alternative 5	($372)

Including No Externality Costs (Direct Costs Only)

Alternative 1	Base
Alternative 2a	$3,299 (best case)
	$3,255 (worst case)
Alternative 2b	$2,386 (best case)
	$2,342 (worst case)
Alternative 3	$796 (best case)

	$752 (worst case)
Alternative 4	($101)
Alternative 5	($308)

ANNUALIZED DIFFERENTIAL COSTS
(Annualized costs are in millions of 1990 dollars beginning in 1995)
(Based on an estimate of approximately $7.50 per year per $100 NPV

Assuming Massachusetts DPU Emission Costs

Alternative 1	Base
Alternative 2a	$600 per year (best case)
	$256 per year (worst case)
Alternative 2b	$521 per year (best case)
	$177 per year (worst case)
Alternative 3	($33) per year (best case)
	($376) per year (worst case)
Alternative 4	($488) per year
Alternative 5	($160) per year

Assuming SO2 at $500 per Ton

Alternative 1	Base
Alternative 2a	$221 per year (best case)
	($122) per year (worst case)
Alternative 2b	$153 per year (best case)
	($191) per year (worst case)
Alternative 3	$19 per year (best case)
	($324) per year (worst case)
Alternative 4	($25) per year
Alternative 5	($28) per year

Including No Externality Costs (Direct Costs Only)

Alternative 1	Base
Alternative 2a	$243 per year (best case)
	$244 per year (worst case)
Alternative 2b	$179 per year (best case)
	$176 per year (worst case)
Alternative 3	$60 per year (best case)
	$56 per year (worst case)
Alternative 4	($8) per year
Alternative 5	($23) per year

NOTES:

1. Different amounts of cumulative energy savings due to NSP's DSM programs are reported by NSP. In the "NSP Certificate of Need Application, Volume 1," April 29, 1991, the Company states its long-term DSM goals will "..total 2000 MW and 2700 gigawatt-hours annually by *2016* (sic - should be *2010*)." According to NSP's response to DPS Information Request 412, September 10, 1991, the amount of energy savings attributable to Company DSM programs is 2463 GWh by 2010 and 2918 GWh by 2015.

2. Sources include: "Northern States Power Company-Minnesota, Demand-Side Potentials Study, Volumes 1-13," Electric Power Software, May 1989; "Northern States Power Company, Commercial and Industrial, Demand-side Management Potential, Volumes 1-4," Xenergy, Inc., April 1990; "Conservation Potential in the State of Minnesota," PLC, Inc., June 1988; "The Achievable Conservation Potential in New York State From Utility Demand-Side Management Programs," American Council for an Energy-Efficient Economy and New York State Energy Office, November 1990; "The Michigan Electricity Options Study, Final Report," Michigan Department of Commerce, October 1987; "Impact of Demand-Side Management on Future Customer Electricity Demand: An Update," Barakat and Chamberlin, Inc. for the Electric Power Research Institute (EPRI), September 1990; "Efficient Electricity Use: Estimates of Maximum Energy Savings," Barakat and Chamberlin, Inc. for EPRI March, 1990; "Possible Effects of Electric-Utility DSM Programs, 1990 to 2010," Eric Hirst, Oak Ridge National Laboratory, January 1991; and, "Advance Plan 6: D5 - Northern States Power Company Technical Support Document," joint filing to the Wisconsin Public Service Commission, March 1, 1991.

EXHIBIT OF

DAVID SCHOENGOLD

MINNESOTA DEPARTMENT OF PUBLIC SERVICE

* * *

BEFORE THE

MINNESOTA PUBLIC UTILITIES COMMISSION

* * *

NORTHERN STATES POWER COMPANY

DOCKET NO. E002/CN-91-19

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SEPTEMBER 30, 1991

DPS Exhibit ____ (DS-1)

Prairie Island Spent Fuel Storage Facility

A Report to the Minnesota Department of Public Service

on the Costs and Benefits of Alternative Courses of Action

Prepared by MSB Energy Associates, Inc.
September 26, 1991