Direct Testimony and Schedules
Kent T. Larson

Before the North Dakota Public Service Commission
State of North Dakota

In the Matter of the Application of
Northern States Power Company, a Minnesota Corporation

For Authority to Increase Rates for
Electric Service in North Dakota

Case No. PU-07-___
Exhibit 4

Policy Testimony

December 7, 2007

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I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Kent T. Larson. My business address is 414 Nicollet Mall, Minneapolis, Minnesota 55401.

Q. BY WHOM ARE YOU EMPLOYED AND WHAT IS YOUR POSITION?

A. I am Regional Vice President, North at Northern States Power Company, ("Xcel Energy" or "the Company") a Minnesota corporation operating in North Dakota. My resume is included as Exhibit___(KTL-1), Schedule 1.

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND EXPERIENCE.

A. From 1997 to 2000, I was Chief Executive and Managing Director, Dakotas for the former Northern States Power Company, and in 2001, I was named State Vice President for Minnesota and the Dakotas for the newly formed Xcel Energy Inc. I became Vice President of Jurisdictional Relations in 2004, with varying levels of responsibility for governmental, regulatory, and community affairs in ten of the states served by the Xcel Energy Inc. operating companies. In 2006, Xcel Energy Inc. increased its jurisdictional focus by reorganizing by operating companies, and I was named Vice President, Customer and Community Relations for Xcel Energy Inc., and subsequently Regional Vice President, North. In all the positions I have held since 1997, except for a one-year period, I have had management responsibility for public affairs and jurisdictional financial results for the Company's natural gas and electric utility operations in North Dakota.

Q. For whom are you testifying?

A. I am testifying on behalf of Xcel Energy.

Q. What is the purpose of your testimony in this proceeding?

A. I will provide an overview of this Application, summarizing the need for this general electric rate increase and introducing the Company-sponsored witnesses and exhibits. I will also provide policy testimony regarding Xcel Energy's plans to refurbish or repower three of its primary coal generation plants, and I will discuss our efforts to promote economic vitality in our North Dakota service areas.

II. CASE OVERVIEW

Q. Please summarize the Company's Notice of Change in Rates for Electric Service.

A. With this Notice of Change in Rates (the "Notice" or "proposal") Xcel Energy gives notice to the North Dakota Public Service Commission (the "Commission") of a proposal to increase its electric revenue by $20.5 million, or 13.95 percent, based on a forecasted 2008 test year. Unless the Commission suspends these proposed rates, they will go into effect January 6, 2008.

The proposed rates reflect an overall rate of return on investment of 9.20 percent, based on an equity ratio of 51.77 percent and a rate of return on equity ("ROE") of 11.50 percent. This ROE is somewhat less than the 12.0% baseline ROE most recently approved by the Commission in December 2000 as part of the PLUS performance-based regulation case ("PLUS Plan"), and it is equal to the 11.50 percent granted in the last electric rate case order issued by the Commission in April 1993 (Case No. PU-400-92-399).

With this proposal, a residential customer using 750 kWh per month would see a monthly bill increase of $7.59 per month.

Should the Commission suspend this proposal, the Company respectfully requests Commission approval of the Alternative Petition for Interim Rate proposing an 11.49 percent across-the-board interim rate increase to be effective on February 5, 2008, and applied to the various bill components, except for the Fuel Clause Adjustment ("FCA"). The proposed Interim rates will result in an increase of about $7.20 per month for a residential customer using 750 kWh.

Q. ARE YOU ALSO REQUESTING SOME CHANGES IN RATE POLICY IN THIS PROCEEDING?

A. Yes. In addition to the typical rate case issues of cost recovery, we propose two initiatives in this proceeding that will address regulatory matters of current interest to the Commission. Also, there are two other items being pursued in separate filings with the Commission, and I mention them here because of their significance and potential impacts on our rates in the near future. Together, these four key proposals are:

- *Wholesale Margin Sharing.* Changes in the wholesale electricity marketplace have made it increasingly difficult to forecast annual margins on wholesale transactions. Consequently, including a projected level of wholesale margins as a credit to the test year cost of service will likely result in base rates that do not accurately reflect *actual* wholesale margins. As discussed in the Direct Testimony of Mr. Allen Krug, the Company proposes in this proceeding to exclude from the test year any projection of wholesale margins when setting base rates and to instead share (through the Company's proposed Fuel Cost Rider ("FCR")) 85 percent of the actual margins with customers. Sharing these margins aligns the interests of customers and the Company and eliminates the risk to both customers and the Company of margin forecasting uncertainty.

- *MISO Schedule 16 and Schedule 17 Costs.* Currently, the Commission has approved, on an interim basis, the recovery of Midwest Independent Transmission System Operator ("MISO") Schedule 16 and 17 costs through the existing FCA. While the Company believes recovering Schedule 16 and 17 costs through the FCA is a reasonable approach, we note that the Commission expressed a preference in Case No. PU-05-131 concerning Ottertail Power Company to have these types of costs recovered in base rates. Therefore we have included these costs in our base rates for the test year in this proceeding. Mr. Steve Buening provides Direct Testimony supporting the recovery of these costs.
- *Amortization of nuclear outage costs.* In a separate application filed with the Commission, the Company has proposed an accounting change to mitigate the significant annual variability in nuclear plant outage costs. While the 2008 test year filed with this rate case includes the North Dakota allocation of actual costs of two scheduled re-fueling outages, the Company's alternative accounting proposal seeks deferral and

monthly amortization of annual outage costs over the term of each respective unit's re-fueling outage cycle (typically 18 to 24 months). The advantage of such an approach is that a fairly level amount of nuclear outage costs can be determined and included in the test year, ensuring a better match between revenues and expense going forward. If this method were approved for us in this rate case it would reduce our revenue requirement by approximately $173,000. We are willing to work with the Commission on this matter to facilitate implementation of this accounting change and the appropriate rate case adjustment. Ms. Anne Heuer further describes this accounting proposal in her Direct Testimony.

- *Implementation of Demand Side Management Programs.* The Company has offered load management service rates in North Dakota for its electric customers since the early 1990's, including Residential Controlled Air Conditioning and Water Heating, Commercial and Industrial Controlled Air Conditioning, and Peak and Energy Controlled Services. In January, the Company will propose an expanded set of electric Demand Side Management ("DSM") programs in a separate filing outside of this rate case. In that petition, we will present for the Commission's review an estimated DSM budget of over $800,000 for 2008, and a proposal to reach over 50,000 customers and achieve an estimated demand and energy savings of 4,000 kilowatts and 3,000,000 kilowatt-hours respectively. The Company will propose these additional electric energy conservation options in North Dakota to help customers manage their energy costs by offering them more energy conservation incentives and educational materials on decreasing their electric usage and resulting monthly electric bills. Because we will be filing this DSM proposal in a separate proceeding, no DSM costs have been included in the test year for this case. Instead, the DSM filing in January will propose a stand-alone program cost recovery and financial incentive mechanism.

Q. WERE THERE ANY COMPLIANCE ITEMS FROM THE PREVIOUS RATE CASE ORDERS THAT YOU WOULD LIKE TO IDENTIFY?

A. Yes. Exhibit (KTL-1), Schedule 2 to my Direct Testimony lists the relevant Commission directives from the orders in the previous rate case, the action the Company has taken to address each order directive, and the location in this rate case application of the Company's compliance response. I should mention that compliance items relating to energy conservation programs were not addressed in this current rate filing, but will be addressed in the Company's DSM application that will be filed separately in January 2008.

III. COMPANY OVERVIEW

Q. PLEASE REVIEW THE ORGANIZATIONAL STRUCTURE OF XCEL ENERGY.

A. Xcel Energy Inc. (the "Holding Company"), a registered holding company under the Public Utility Holding Company Act, was formed by the merger of the former Northern States Power Company and New Century Energies, Inc. The North Dakota Commission approved this merger in Case No. PU-400-99-418. Xcel Energy provides electric and natural gas service to customers in eight states through four utility operating companies, as shown in the table below:

Operating Company	States Served
Northern States Power Company, a Minnesota corporation	Minnesota, North Dakota, South Dakota
Northern States Power Company, a Wisconsin corporation	Wisconsin, Michigan
Public Service Company, a Colorado corporation	Colorado
Southwest Public Service, a New Mexico corporation	Texas, New Mexico

In November 2005, the Holding Company reorganized management along operating company lines to strengthen its focus on the unique regulatory, economic, and customer characteristics of the various states it serves. As one of four utility operating company subsidiaries of the Holding Company, the Company focuses on electric and natural gas utility operations in both Minnesota and North Dakota, and electric operations in South Dakota.

Q. COULD YOU PLEASE DESCRIBE THE COMPANY'S ELECTRIC UTILITY BUSINESS?

A. Yes. Today, the operating companies of Xcel Energy Inc. serve approximately 3.3 million electric customers in eight states. Of these, about 86,000 customers are located in 27 communities and townships located in and near the cities of Fargo, Grand Forks, and Minot, North Dakota. About 86 percent of our North Dakota electric customers are residential, and 14 percent are in the commercial and industrial classes. Approximately 36 percent of our annual electric retail sales are to residential customers, while 64 percent are commercial and industrial sales.

Xcel Energy has about 104 employees either dedicated strictly to North Dakota electric operations or working in an electric support area such as engineering, project design, warehousing, garage, meter department, and others located in the Fargo, Grand Forks, and Minot service centers. Another 18 employees work in our natural gas operations in North Dakota. These service centers are also supported by the Company's operational employees as well as Xcel Energy Services Inc. (the "Service Company") employees located in Colorado, Minnesota, and Wisconsin.

IV. RECENT HISTORY OF RATE INCREASES

Q. HOW LONG HAS IT BEEN SINCE THE LAST ELECTRIC RATE CASE?

A. The last electric rate case (Case No. PU-400-92-399) was filed in 1992.

Q. WHY IS THE COMPANY ASKING FOR A RATE INCREASE NOW?

A. The Company has not filed a comprehensive electric base rate increase application in North Dakota in over fifteen years (since Case No. PU-400-92-399). In fact, since we received a $1.2 million increase in 1994 (intended to recover remainder of costs only partially reflected in the 1993 test year), electric base rates in North Dakota have actually been reduced four times:

- A $3.6 million decrease to residential rates in 1994 as a condition to a Settlement Agreement reached in our Demand Allocation factor correction proceeding (Case No. PU-400-94-514);
- A $0.8 million decrease to commercial and industrial rates to complete resolution of Case No. PU-400-94-514;

- A one-time reduction of $736,000 for residential customers and a $124,000 base rate reduction for commercial customers in 1999 (Case No. PU-400-98-356) to flow through savings negotiated in our purchased power agreement with the Manitoba Hydro Electric Board; and
- A $260,000 reduction in 2001 following the Xcel Energy Inc. merger proceeding (Case No. PU-400-99-418).

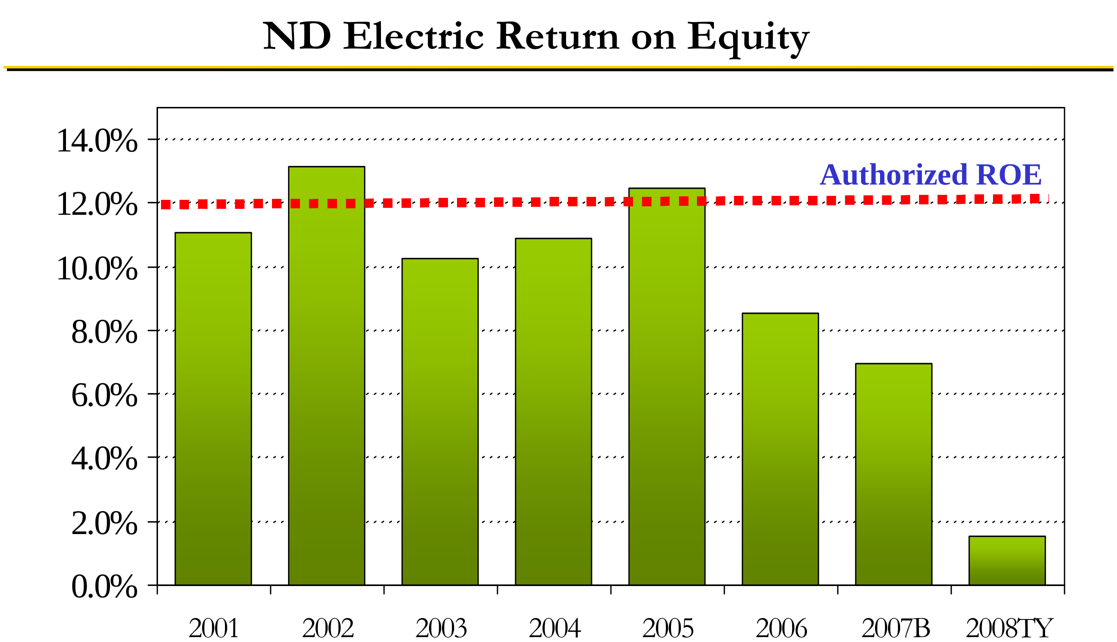
During this same period, the Company also implemented two small price-cap regulated increases -- a $1.6 million (1.4 percent) increase in July 2004 and a $1.9 million (1.6 percent) increase in July 2005 – as part of the PLUS Plan performance-based regulation framework. However, these increases were limited to 60 percent of the rate of inflation, which is likely far less than the average rate increase awarded to utilities in an upper Midwest comparison group for the same period. Even today, Xcel Energy's base rates (excluding fuel recovery) in North Dakota are essentially the same as they were after the Commission's last rate case order in 1993. Yet, the Company has experienced increases in the cost of providing service to our customers, particularly in recent years as we reinvest in our operations and transmission infrastructure. We can no longer continue to provide safe reliable service to our customers without reflecting these increases in the cost of such service in our rates.

Q. HOW DOES THE AMOUNT OF THE COMPANY'S PROPOSAL COMPARE TO ITS LAST ELECTRIC RATE CASE?

A. The 13.95 percent increase we are requesting in this proposal is greater than the prior request in our last electric rate case. We acknowledge that this rate application represents a significant increase in its North Dakota electric rates, and we understand that our customers are already challenged with significant increases in all of their energy costs. We appreciate these concerns and assure the Commission that we carefully considered the decision to come in for an electric rate increase.

However, since the Company has earned well below its authorized level in 2006 and is expecting to see its regulated electric earnings erode even further in 2007 and 2008 (See Chart 1 below), we have determined that an increase in our electric rates can no longer be avoided.

CHART 1



Q. HAS THE COMPANY TRIED TO MANAGE ITS COSTS TO AVOID THE NEED FOR THIS ELECTRIC RATE CASE PROCEEDING?

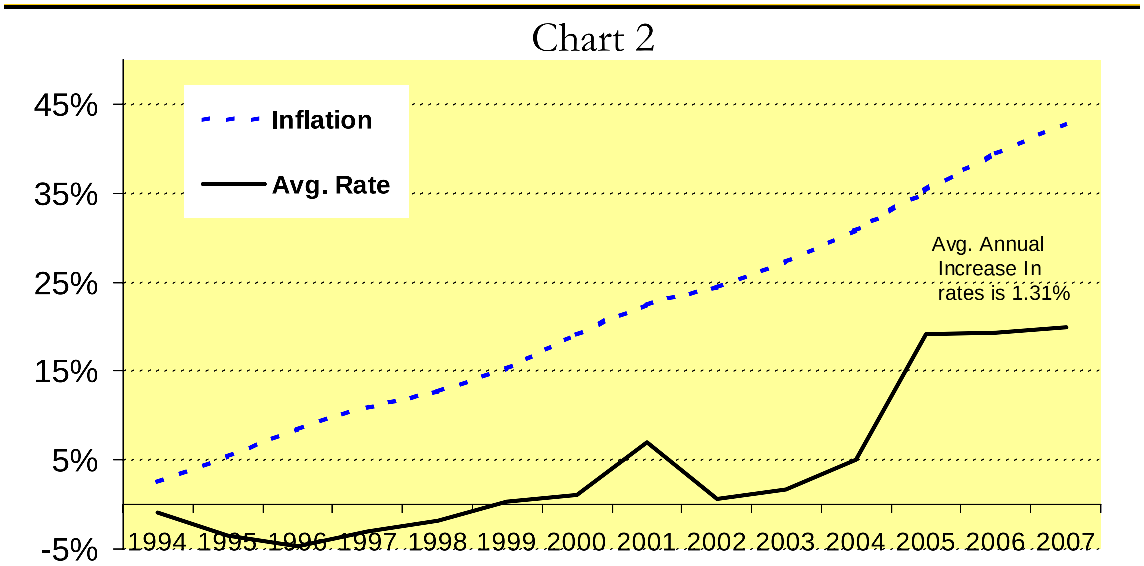
A. Yes. Since the last electric rate case, we have undertaken many efforts to prudently manage our costs. For example, Xcel Energy has realized significant administrative savings and greater purchasing power as a result of the Commission-approved merger of the former Northern States Power Company and New Century Energies Inc. in 2000. The Company has also aggressively utilized new technologies to improve service and reduce costs. Examples include the company-wide installation of a new customer service and billing system, a new project management system, automated electric and gas meters, and mobile data terminals that provide faster and more accurate information flow between the field and company planners and engineers.

The Company's current efforts to refurbish, repower, and extend the lives of its existing coal and nuclear power plants will also generate significant cost savings over the next two or three decades, relative to the costs of securing the necessary capacity and energy resources on the market or with new plants.

Finally, by establishing stringent expenditure budget targets, consolidating functions, and standardizing processes the Company has been able to keep its operating costs low over the past fifteen years. In fact, the North Dakota jurisdictional expenses for distribution, customer service, sales, and administrative and general functions reflected in the 2008 Test Year have only increased, on average, 0.7 percent annually during this 15 year period compared to the 1993 Test Year used in the last electric rate case. This low level of annual increase is noteworthy, given the fact that the Company is not immune to significant cost increases faced by all businesses during this period, such as employee health care costs and material costs.

Q. HOW HAVE THESE EFFORTS TO CONTAIN COSTS BENEFITED YOUR CUSTOMERS?

A. By prudently managing our costs, we were able to avoid coming in for a comprehensive increase in our electric rates for fifteen years. During this time, our rates have remained competitive when compared to both overall inflation levels and the comparable rates of other regional utilities. (*See* Exhibit ___ (KTL-1), Schedule 3 attached to my Direct Testimony showing the PLUS Plan comparison of residential rates for the five-year period from 2001 to 2005, and for comparison purposes, 2006 data has been added.) Since 1993 -- even taking into account significant increases in fuel and purchased energy costs -- our current average price for electric service has only increased at an average annual rate of about 1.3 percent - roughly half the rate of inflation during that same period (see Chart 2 below).



Q. WHY WEREN'T THE "PLUS" PERFORMANCE-BASED REGULATION PLAN INCREASES SUFFICIENT TO AVOID THE NEED FOR THIS RATE REQUEST?

A. First, I want to say that we greatly appreciate the increases to our revenues allowed under the Commission-approved PLUS Plan in 2004 and 2005. These increases were critical in avoiding an earlier electric rate case filing. However, the PLUS Plan increases (1.4 percent in 2004 and 1.6 percent in 2005) were designed to mitigate earnings deficiencies that were evident in 2002 and 2003, and were not sufficient to further postpone the need for the current filing. In addition, the amount of the allowed increases was a function of inflationary and regional utility price trend factors incorporated into the PLUS Plan price cap mechanism. The purpose of the limiting price cap was to incent the Company to find cost savings and efficiency improvements, not necessarily to enable the Company to recover all of its cost of service. As such, even though the increases helped the Company to defer filing an overall electric rate increase application until now, they did not reflect either the Company's current or projected cost structures in North Dakota. Furthermore, the PLUS Plan was never designed to recover the costs of significant and non-recurring generation and transmission investments, such as are occurring now and will continue into the foreseeable future. For these reasons, the Company needed to file this request for rate relief.

Q. CAN YOU EXPLAIN WHY THIS RATE CASE IS SO IMPORTANT TO THE COMPANY AND HOW IT WILL BENEFIT YOUR CUSTOMERS?

A. Yes, I can. Xcel Energy needs to remain financially strong so it can continue to meet our customers' energy needs with new infrastructure going forward. To be financially strong, we need to earn the authorized return on equity in each of our jurisdictional regulated utility operations, including North Dakota. While we have prudently managed our costs and avoided a general base rate increase for our electric operations over the last 15 years, current rate levels are not adequate to support the level of investment and operating costs necessary to: provide reliable electric service and maintain our leadership in areas such as state and local economic development and community support.

Strong financial performance is particularly important in times of substantial investment plans, such as we have today. To continue to attract capital investment on reasonable terms, it is essential that we have a revenue stream sufficient to cover the costs of our additional capital investments. Otherwise, investors will demand higher returns to compensate for what is perceived as higher risks related to their investment.

V. NEED FOR RATE RELIEF

Q. WHAT IS CREATING THE NEED FOR A RATE INCREASE AT THIS TIME?

A. In addition to the length of time since our last rate case and general increases in our cost to provide electric service described earlier in my Direct Testimony, there are three primary drivers of our rate proposal:

- Increasing investments in our generation assets, including the completion in 2008 of two (out of a series of three) significant coal power plant rehabilitation and repowering projects;
- Increasing costs at our nuclear power plants, including new investments to extend the lives of these plants an additional 20 years; and
- Increasing investment in our transmission infrastructure.

Q. PLEASE IDENTIFY THE POWER PLANT REHABILITATION PROJECTS INCLUDED IN THIS PROPOSAL.

A. Until fairly recently, Xcel Energy had not added any new baseload generating facilities to its fleet since the last electric rate case filing in 1992. In 2005, however, the Company began construction on a series of rehabilitation and repowering projects at three of its oldest but most strategic coal plants located in the Minneapolis/St. Paul metropolitan area: the Allen S. King ("King"), High Bridge, and Riverside plants. The refurbishing of these plants will extend their lives by another 25 years or more, and add over 400 MW of net dependable capacity to the full and medium baseload capability of the Company's generating fleet without the addition of significant new transmission infrastructure.

The 2008 test year in this case reflects a full year of the North Dakota allocation of the rebuilt King plant, completed in May of 2007, and a partial year of service of the repowered High Bridge plant, which goes into service May 2008. The Riverside Plant is scheduled to go into service in May 2009, and as such, costs for this repowering project are not included in this rate case.

Q. PLEASE DESCRIBE THE REHABILITATION OF THE KING PLANT.

A. The King plant, built in 1968, is a valuable generation source for Xcel Energy. It is located in Oak Park Heights, Minnesota on the St. Croix River. Before the rehabilitation, the King plant was a single-unit, coal-fired generating plant with a net dependable capacity of 504 MW. It provided baseload electric service, operating 24 hours a day, seven days a week. The plant burned low-sulfur Wyoming or Montana coal and petroleum coke.

This "work horse" plant is strategically situated near our major load centers and is located on a major interface with the transmission system. The continuation of base load generation at King is important not only because it is a low-cost resource, but also because it provides important system benefits and avoids the need for costly new transmission that would be time-consuming and costly to construct.

In order to preserve this strategic asset, the Company embarked on a project to rehabilitate the existing electric generation equipment. The rehabilitation project encompassed replacement of the steam turbine, upgrading of the boiler, circulating water system modifications, coal handling upgrades, auxiliary electric system upgrades, and other equipment refurbishment, along with state-of-the-art pollution control equipment. These upgrades increased the net dependable capacity of the plant by 60 MW, and returned the plant to its original design capacity (which had been lost in the 1970s when the plant switched from Illinois coal to low-sulfur coal).

The new air quality control system includes selective catalytic reduction and an overfire air system for nitrogen oxide (NOx) reduction, flue gas scrubbers for control of sulfur dioxide (SO_2) emissions, and fabric filters for control of particulate matter.

King is the first of the three power plant rehabilitation projects to be completed, because it is the most vital of the three plants to our system. The plant's eastern Minnesota location supports stability of the regional transmission system. The near 40 year-old unit was also in the greatest need of upgrades to ensure operating reliability and protect system security. The King boiler was one of only a few remaining boilers in the nation of its type and vintage that had not been rehabilitated in recent years. The following are some of the King rehabilitation project statistics:

Location: Oak Park Heights, Minnesota
Original in-service date: 1968
Fuel source: Coal
Project cost: $480.2 million
Capacity improvement: 60 megawatt increase
Expected Capacity Factor improvement: 74% to 82%
Projected emissions reductions:

- 91% Sulfer Dioxide (SO_2);
- 89% Nitrogen Oxide (NOx);
- 20% Particulate;
- 20% Mercury.

In-service date: May 2007;
Projected book life: 2032 (25 years).

Q. WOULDN'T CONSTRUCTING A NEW COAL PLANT BE A MORE COST-EFFECTIVE ALTERNATIVE?

A. No. At a combined cost of approximately $480.2 million for capacity of 564 MW, our customers will receive long-term base load capacity for only about $851/kW installed (including the use of and support for existing transmission facilities). This cost is much lower than the cost of building or buying new base load generation.[1] Furthermore, the cost differential may be higher because any new plant would likely require more extensive transmission upgrades. In other words, by rehabilitating the King plant our customers will

[1] According to documents filed with the North Dakota Commission in Case No. PU-06-481, cost estimates for the 630 MW Big Stone II power plant proposed in South Dakota were approximately $1.6 billion, or $2,540 per kW.

receive the benefits of an essentially new power plant at a fraction of the price, and one that is prepared to meet environmental standards well into the future.

Q. PLEASE DESCRIBE IN MORE DETAIL THE REPOWERING OF THE HIGH BRIDGE PLANT.

A. The High Bridge plant, originally built in 1924, was a coal-fired generating plant located in downtown St. Paul, Minnesota on the Mississippi River with four remaining operating units. Units 3 and 4 were only used to produce steam for a nearby manufacturer, and were not a part of the Company's rate base. Units 5 and 6 had a net dependable capacity of 243 MW. The plant burned low-sulfur, sub-bituminous Western coal.

A new natural gas-fired combined-cycle facility with two combustion turbines, corresponding heat recovery steam generators, and a new steam turbine has been installed in a new structure located at the southwest corner of the existing plant site. The facility will use the existing circulating water supply and return from the river, and take advantage of existing transmission infrastructure to expand generation at this strategic location.

Because the High Bridge project called for an entirely new facility, the existing High Bridge plant operated until the new units were built. Currently, testing of the new combined cycle plant is underway. When complete, the original plant will be demolished, along with accompanying structures, including the 565-foot-high stack. The following are some of the High Bridge project statistics:

Location: Downtown St. Paul

Original in-service date: 1924
Fuel source: Converted from Coal to Natural gas
Project cost (est.): $388.5 million
Capacity improvement: 272 megawatt increase
Expected Capacity Factor improvement: 52% to 63%
Projected emissions reductions:

- 100% SO_2;
- 97% NOx;
- 100% particulates;
- 100% mercury.

In-service date: May 2008;
Projected book life: 2033 (25 years).

Q. WHAT IS THE INSTALLED COST OF THE NEW COMBINED CYCLE PLANT AT THE HIGH BRIDGE SITE?

A. The installed cost of the new 515 MW High Bridge combined cycle plant will be approximately $389 million, which equates to about $755/kW installed. This cost is competitive with current market estimates of the cost to install this type of generation plus associated transmission, particularly when one considers this price tag also includes the cost of retiring the existing coal plant. This low cost was accomplished in part because the Company was able to achieve tremendous savings --- about 40% --- in the acquisition of the combustion and steam turbines. This was accomplished through the secondary market by taking advantage of an oversupply of turbines resulting from orders for generation projects of other utilities that never came to fruition.

Q. PLEASE DESCRIBE THE COMPANY'S PLANS TO REPOWER THE RIVERSIDE PLANT.

A. In 2009 Xcel Energy is also planning to repower our Riverside plant located in Northeast Minneapolis on the Mississippi River. Built in 1911, Riverside is the oldest coal-fired plant in the Xcel Energy system and it currently has a net dependable capacity of 360 MW. Low-sulfur, sub-bituminous Western coal is burned in the two remaining units (7 and 8) at the plant, which have undergone several maintenance activities in recent years to improve operating efficiency and reduce emissions. Although Riverside was originally built nearly 100 years ago, these upgrades have left the plant in better condition than either King or High Bridge plants, so it was most cost-effective to make this the third and final project in this series of plant rehabilitations.

In their current configuration, nevertheless, Units 7 and 8 at Riverside have a remaining life of less than 10 years. This project will replace the existing coal-fired Unit 7 with a natural gas combined-cycle arrangement with two combustion turbines and corresponding heat recovery steam generators. After the new turbines and steam generators are constructed, Unit 7 will be temporarily taken out of service to install new steam lines from the heat recovery boilers. Steam produced in the heat recovery boilers will be used to drive the existing Unit 7 steam turbine. Throughout construction, Unit 8 will continue to operate in its current fashion until the new units are fully operational, after which it will be retired and demolished.

When completed, Riverside will have a net dependable capacity rating of 439 MW, representing an increase in capacity of 79 MW. This capacity rating is less than the capacity of the new High Bridge facility because of the utilization of the smaller, existing equipment at Riverside. However, it still represents the most cost-effective design for this particular plant site. Like High Bridge, the refurbished Riverside facility will allow the Company to maintain and expand, in an environmentally responsible way, generating capacity in a strategic urban area where vital transmission infrastructure already exists. The following are some of the Riverside project statistics:

Location: Northeast Minneapolis
Original in-service date: 1911
Fuel source: Converted from Coal to Natural gas
Project cost (est.): $273.1 million
Capacity improvement: 79 megawatt increase
Expected Capacity Factor change: 67% to 62%
Projected emissions reductions:

- 100% SO_2;
- 99% NOx;
- 100% Particulate;
- 100% Mercury.

In-service date: May 2009;
Projected book life: 2034 (25 years).

Q. ARE THERE COSTS FROM THE RIVERSIDE REPOWERING THAT ARE INCLUDED IN THIS RATE CASE?

A. No. The investment-related and operating costs of repowering Riverside Plant will be reflected in 2009, along with the remaining 4 months of costs from the High Bridge project that are not captured in the 2008 test year in this case.

Q. WHAT ARE THE BENEFITS OF REFURBISHING AND REPOWERING THESE POWER PLANTS?

A. These projects were undertaken to produce a number of significant benefits to ratepayers and the public:

- When complete, these projects will add 411 MW of net dependable capacity to the Company's generating fleet, without the addition of significant new transmission infrastructure. This will be done at a very competitive cost when weighed against the costs of building a new plant, particularly considering the low cost of extending the useful life of the 564 MW baseload King Plant. Expanding capacity within the Minneapolis/St. Paul metro load center relieves transmission constraints and minimizes the risk of major transmission network disruptions that can have regional impacts.
- Through these rehabilitation projects, the operating lives of these aging generating facilities will be extended at least another 25 years and likely longer. This is important since continuing to run the High Bridge and Riverside plants as coal-fired plants was no longer a viable option. In order to extend the lives of these plants, they needed to be repowered. In addition, the stability of the transmission system was planned with the assumption that our major existing facilities – or at least the sites they are located - would continue to be utilizede.
- The resulting increase in dispatch and operational flexibility will improve the Company's ability to adapt to changes in load requirements and meet reserve requirements, allowing other low cost plants like the Company's flagship Sherco Plant to run more consistently, as baseload plants are designed to operate.
- Emissions of sulfur dioxide (SO_2), nitrogen oxide (NOx), and particulates from these plants will be drastically reduced with the installation of state-of-the-art pollution control equipment and plant conversions from coal to natural gas, a fuel source better suited for the

densely populated locations of these plants. In addition a number of other pollutants including antimony, arsenic, beryllium, cadmium, chromium, cobalt, hydrogen chloride, hydrogen fluoride, manganese, mercury, nickel, and selenium will be substantially reduced or even eliminated.

- The efficiency of strategic Company sites will be optimized and significant cost savings will result from the redevelopment of existing generation and transmission facilities already in close proximity to the Company's major load centers. This reduces the need for additional import capability (with significant transmission upgrades), eliminates the need for new intrusions in the metro area that major new transmission would create, and provides energy stability because additional generation is available in the right configuration to support the transmission network. In fact, had King plant not been rehabilitated, some sort of base load generation would have been required at or near that location to keep the grid stable.
- The diversity of Company-owned generation will be enhanced with the increased contribution of natural gas-fired sources to the Company's total supply portfolio. Diversity provides price risk protection for consumers, as no single source of fuel is depended on to meet electricity needs. The current contribution of clean-burning natural gas to the Company's generating capacity will increase from 7 percent to approximately 20 percent after all three rehabilitation projects are completed (though it will decline again in the near future due to additional wind generation resources planned).

- The costs to comply with future environmental requirements will be reduced. Because the rehabilitation projects needed to be undertaken at this time, there was no reasonable option to address these requirements later. When the industry is forced to respond to new regulations, the related construction costs to comply will undoubtedly increase due to mandated implementation schedules and escalated demands on labor and materials.

Q. HAVE THERE BEEN ANY OTHER SIGNIFICANT NEW RESOURCES THE COMPANY HAS INVESTED IN SINCE YOUR LAST GENERAL ELECTRIC RATE CASE?

A. Yes. Xcel Energy placed a 162 MW, combined cycle generation unit at its Black Dog plant into service in 2002 at a cost of $113 million. In addition to supplying needed capacity, this project also created regional environmental benefits. In 2005, the Company invested about $100 million to install two natural gas fired combustion turbines at its Blue Lake peaking plant near Shakopee, Minnesota. The additional units added 160 MW of capacity to the existing 225 MW of oil-fired capacity. Also in 2005 and at a cost of about $64 million, the Company completed installing a new natural gas-fired, 160 MW unit at its 223 MW Angus C. Anson peaking plant in Sioux Falls, South Dakota. In total, we have constructed more than 600 MWs of new capacity since our last electric rate application.

Xcel Energy is also planning to construct and own a 100 MW wind farm in 2008. The project will consist of 67 1.5 MW turbines, and will be located near Grand Meadow, Minnesota.

In addition to our own construction of generation facilities, we have also entered into power purchase agreements ("PPAs") like the one with Mankato Energy Center effective January 1, 2006. The increased costs related to this contract have been partially offset by other capacity cost reductions, including a contract renewal with the Manitoba Hydro Electric Board effective May of 2005. Nonetheless, we have experienced a significant net increase in purchased capacity costs that are not recovered in current base rates or the FCA.

Q. GIVEN THE PRICE VOLATILITY OF NATURAL GAS, PLEASE ADDRESS CONCERNS ABOUT INCREASING THE USE OF THIS FUEL TO GENERATE ELECTRICITY.

A. Natural gas price volatility is a concern for many utilities, but our generation portfolio is varied and is not natural gas-heavy. Another factor that helps to mitigate price swings in the natural gas market is that our Minnesota and North Dakota service area has access to Canadian natural gas and Mid-Continent natural gas through four different pipelines running through the area. Pricing is competitive and Xcel Energy doesn't have to worry about being held captive by one supplier.

In addition, the Company's natural gas fired power plants are located in the MISO (Midwest Independent Transmission System Operator) region, and the power generated from natural gas at the High Bridge and Riverside plants will only be dispatched if the price is competitive.

Q. WHAT ARE THE INCREASES IN NUCLEAR RELATED COSTS THAT ARE INCLUDED IN THIS RATE CASE?

A. Xcel Energy has made and continues to make significant investments to maintain and improve our existing nuclear generating fleet. Expenditures include those made to secure plant license renewal at Prairie Island, dry fuel storage at both Monticello and Prairie Island, life cycle extensions at both plants, and power capacity increases. In 2004, we invested approximately $170 million in new steam generators and reactor vessel heads for Unit 1 at our Prairie Island nuclear plant, which supplies our lowest-cost energy. While significant expenditures are being made to increase capacity and upgrade critical infrastructure components, the Company anticipates saving our customers approximately $1 billion over the next 20-25 years compared to the cost of shutting the plants down and replacing them with other forms of generation. Mr. Charley Bomberger further discusses our nuclear production costs in his Direct Testimony.

Q. WHAT ARE THE INCREASES TO TRANSMISSION RELATED COSTS THAT ARE INCLUDED IN THIS RATE CASE?

A. Although there was much national discussion in recent years about the alleged lack of investment in new transmission, the Company has continued to invest in transmission facilities where needed to:

- improve system performance;
- provide interconnection of new or expanded generation facilities; and
- deliver new wind energy resources to its primary load centers.

In 2003, we placed into service a 56 mile, 230 kV transmission line from near Rugby, North Dakota, to an interconnection with Manitoba Hydro at the U.S. Canadian border, at a cost of $13.8 million. Mr. Walt Grivna discusses more recent transmission investments in his Direct Testimony in this proceeding.

Q. WHAT ARE THE IMPLICATIONS OF THE COMPANY'S SIGNIFICANT GENERATION AND TRANSMISSION PROJECT CAPITAL OUTLAYS?

A. Xcel Energy's five year capital expenditure projections indicate, on average, it will invest about $1.0 billion annually on system infrastructure. These growing capital requirements mean we will be accessing the marketplace with greater frequency to attract the financing (either debt or equity as appropriate) required to fund our ongoing investment program. Under these circumstances, it is critical that the Company be in a healthy financial position to attract this capital on reasonable terms.

VI. ECONOMIC DEVELOPMENT AND COMMUNITY SUPPORT

Q. WHAT EFFORTS HAS THE COMPANY MADE TO STRENGTHEN THE NORTH DAKOTA COMMUNITIES IN WHICH IT SERVES?

A. In our last electric rate case the Commission encouraged the Company to promote economic development. Xcel Energy contributes in excess of $130,000 annually directly targeted to economic development organizations for dues and contributions. In 1999, Xcel Energy provided a $50,000 economic development grant to fund a feasibility study and development plan to transform 55 acres of open land near North Dakota State University into a technology research park which is expected to create more than 600 quality jobs. In 2003, Xcel Energy announced an additional pledge of $150,000 to assist with the start-up operating expenses of a technology-focused business incubator. The Company has also granted over $100,000 towards the University of North Dakota Tech Park project since 1999.

Strong, broad-based support from Xcel Energy also helped to lead the 59th Legislative Assembly to approve $20 million of state resources toward the development of Centers of Excellence located on or near the campuses of the North Dakota University System. This funding leveraged more than $70 million in additional monies for research and development. In May 2007, the Governor signed a bill authorizing another $20 million toward projects occurring over the next two years. Currently, Xcel Energy personnel are members of the boards of the area economic development corporations in each of Fargo, Grand Forks, and Minot as well as the state-wide North Dakota Economic Foundation Board.

With respect to the energy industry here in North Dakota, we have worked hard to promote wind generation within the state. The Company partnered with a wind developer to establish our first wind resource in the state, a 12 MW project near Velva, North Dakota. Most recently, we announced our intentions to build or buy an additional 200 MW of wind generation located in North Dakota by the year 2011.

We have also devoted significant funding and effort to community care, as we acknowledge that we are only as strong as the communities we serve. In 2007, the Xcel Energy Foundation granted $162,000 in corporate funding to charitable organizations in North Dakota. The Foundation targets funds to projects that support education, stronger communities, and arts and cultural activities. During our 2006 United Way campaign, North Dakota employees (of which nearly 3 out of 4 contribute) and retirees raised $23,128, and because our Foundation matches employee and retiree contributions dollar-for-dollar, our total contribution exceeded $46,256 for United Way charities. In addition, Xcel Energy employees in North Dakota regularly volunteer for various community projects and programs throughout the year. Our Foundation also supports these employee volunteer efforts by awarding $500 to any project that has a team of at least 6 employee participants, and by donating $5 per hour for individual donations of time to qualifying non-profit organizations.

VII. PRESENTATION OF WITNESSES

Q. PLEASE REVIEW THE WITNESSES THE COMPANY IS SPONSORING IN THIS PROCEEDING.

A. In addition to my Policy Testimony, the Company sponsors the following witnesses:

- *Anne Heuer*, who sponsors the overall revenue requirement for the rate case. Ms. Heuer sponsors the schedules supporting our income statement, rate base, revenue deficiency, and jurisdictional allocations. Her schedules incorporate and reflect the recommendations of a number of our witnesses, including the cost of capital and sales forecast.
- *Jannell Marks*, who sponsors the sales forecast used in Ms. Heuer's determination of the revenue deficiency.
- *Dr. James H. VanderWeide,* Professor of Finance and Economics at Duke University, the Fuqua School of Business, who sponsors testimony on the appropriate return on common equity.
- *Charles Bomberger*, who sponsors our Nuclear Operations costs.

- *Marvin E. McDaniel, Jr.*, who sponsors the Company compensation and incentive pay plans.
- *Walter Grivna*, who sponsors Xcel Energy's transmission planning and investment costs.
- *Stephen Beuning,* who sponsors our proposal to recover MISO Schedule 10 and Schedules 16 and 17 costs in base rates.
- *Allen Krug,* who sponsors our wholesale margin sharing proposal.
- *Phillip Zins*, who sponsors our class cost of service study, rate design objectives, and selected rate design and tariff changes.
- *Steven Huso*, who sponsors the general rate design in this case.

Together, these witnesses provide the information and advocacy needed to evaluate and approve our Application.

VIII. CONCLUSION

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. Xcel Energy has been a leader among electric utilities, both regionally and nationally. As demonstrated by the performance results reported under the PLUS Plan, we have made significant accomplishments in achieving high levels of customer satisfaction, maintaining low rates, keeping our system reliable, and maintaining a safe work environment. We are committed to the communities in North Dakota that we serve. We are proud of our support of economic development initiatives in the state, and we look forward to remaining an industry leader and a critical player in the State of North Dakota.

To do so, the Company requires an overall rate increase of 13.95 percent to recover our prudent costs of service and have an opportunity to earn a reasonable rate of return, based on a forecasted 2008 test year. While we have exercised cost-conscious and effective management during rapidly changing market conditions, we are not able to fully offset the costs related to investments in our generation and transmission infrastructure. This rate increase is needed to help provide strong financial results needed to attract the capital required to fund additional energy infrastructure. We propose to recover costs through rate designs that fairly and appropriately allocate costs to the various customer classes, and propose initiatives that address the differing financial impacts of various resource options. These initiatives will benefit both customers and the Company in the long run.

Therefore, the Company respectfully requests that the Commission approve:

- Our requested rate increase of 13.95 percent,
- A rate of return of 9.20 percent, which includes a rate of return on equity of 11.5 percent;
- Our proposed rate design and tariffs;
- Our proposed sharing mechanism for wholesale margins; and
- Our transfer of MISO Day 2 Schedule 16 and 17 costs from the Fuel Clause Adjustment to base rates.

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Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

STATE OF NORTH DAKOTA
BEFORE THE
PUBLIC SERVICE COMMISSION

In the Matter of the Application of Northern States Power Company, a Minnesota Corporation For Authority to Increase Rates for Electric Service in North Dakota	))))	Case No. PU-07-___

AFFIDAVIT OF
Kent T. Larson

I, the undersigned, being duly sworn, depose and say that the foregoing is the Direct Testimony of the undersigned, and that such Direct Testimony and the exhibits or schedules sponsored by me to the best of my knowledge, information and belief, are true, correct, accurate and complete, and I hereby adopt said testimony as if given by me in formal hearing, under oath.

Kent T Larson
____
Kent T. Larson

Subscribed and sworn to before me, this 6th day of December, 2007.

Sandra Ann Bjorstrom
____
Notary Public

SANDRA ANN BJORSTROM
NOTARY PUBLIC
MINNESOTA
My Commission Expires 01/31/2011

Mr. Kent T. Larson
Regional Vice President, North
414 Nicollet Mall, Minneapolis, MN 55401

CURRENT RESPONSIBILITIES

Leadership and management of Xcel Energy's customer and community relations, local government and community affairs for Minnesota. Overall business management of North Dakota and South Dakota jurisdictions.

PREVIOUS EMPLOYMENT

Regional Vice President, North	Xcel Energy	2006 -
Vice President, Jurisdictions	Xcel Energy Services Inc.	2004-2005
State Vice President, MN and Dakotas	Xcel Energy Services Inc	2001-2004
State Vice President, MN		2000-2001
Chief Executive and Managing Director - Dakotas	Northern States Power Company	1997-2000
Director, Sales – MN		1994-1997
Manager, White Bear Lake Area		1992-1994
Manager, Operations – South Dakota		1990-1992
Engineering and Engineering Leadership		1982-1990

EDUCATION

- Master of Business Administration, University of St. Thomas, 1985
- Bachelor of Science, Electrical Engineering, Iowa State University 1981
- Registered Professional Engineer – Minnesota – Current

PROFESSIONAL

- Board of Directors, American Gas Association (2001-2007)
- Chair, Minneapolis Regional Chamber of Commerce (2007)
- Vice-chair, University Enterprise Laboratories (2004-2007)
- Trustee, Hamline University (2007)

PREVIOUS TESTIMONY

North Dakota PSC	Northern States Power Company	Case No. PU-06-525 (natural gas rates)
North Dakota PSC	Northern States Power Company	Case No. PU-400-04-578 (natural gas rates)
North Dakota PSC	Northern States Power Company	Case No. PU-400-99-418 (merger filing)

FILING REQUIREMENT COMPLIANCE TABLE

Application of Northern States Power Company, a Minnesota Corporation, for Authority to Increase Rates for Electric Service in North Dakota	))))	Case No. PU-400-07-____

	Information Required Under Commission Orders To Be Affirmatively Addressed Or To Be Used To Determine Cost of Service In This Filing	**Section and page of Application**
Docket Number /Name of Order	**Name of Proceeding**	
PU-400-92-399	**Request by Northern States Power Company for Increase in Electric Rates**	
Order on Reconsideration, 4/7/93	The Company should consider expanding its economic development efforts to include a loan and grant program, as well as other assistance.	Kent Larson's Direct Testimony
Findings of Fact, Conclusions of Law and Order, 12/15/92 Finding 79	The Company is urged to aggressively pursue bringing in low income households to the demand side management programs; and to investigate a comprehensive tree-planting program as part of its demand side management. The Company should report on these suggestions in its next rate filing.	The Company plans to file a separate DSM proposal.

	Information Required Under Commission Orders To Be Affirmatively Addressed Or To Be Used To Determine Cost of Service In This Filing	**Section and page of Application**
Finding 111	In its next rate case NSP should provide an appropriate compensation comparison for labor with the industry in general.	A request to remove this requirement is pending before the Commission
Finding 115	Long-term incentive compensation was treated as a shareholder expense.	Ann Heuer Direct Testimony, long-term costs excluded.
Finding 128	Charitable contributions were disallowed.	Ann Heuer Direct Testimony, 50% recovery requested based on past Commission decisions.
Finding 130	Only organizational dues related to ND electric operations were included.	Ann Heuer Direct, consistent with this decision.
Finding 166	The Company should file both embedded class cost of service study and long run incremental class cost of service studies with its next rate application.	A request to remove this requirement is pending before the Commission
Finding 172	NSP should file an alternate embedded class cost of service study illustrating a splitting of the commercial/industrial class with its next rate application.	Phil Zins Direct Testimony

PLUS Industry Benchmark Calculation
EEI Typical Bills and Average Rates Report
Average Residential Revenue/Kwh and Annual Chang

Average Residential Rate

2001 Rank	Utility	Juris	2001 ¢/kwh
1	Ottertail Power Co.	ND	6.16
2	Pacificorp -Wyoming East	Wyom	6.21
3	Ottertail Power Co.	SD	6.38
4	Ottertail Power Co.	MN	6.52
5	*Xcel Energy*	*ND*	*6.53*
6	Superior Power & Light	Wisc.	6.64
7	Montana Power Company	Montan	6.75
8	Montana-Dakota Utilities	ND	6.86
9	Minnesota Power	MN	7.00
10	Montana-Dakota Utilities	Mont	7.35
11	Wisconsin Power & Light (A	Wisc.	7.49
12	Wisconsin Public Service	Wisc.	7.49
13	MidAmerican Energy	SD	7.49
14	Black Hills Power & Light	Mont	7.51
15	Xcel Energy	Wisc.	7.54
16	Montana-Dakota Utilities	Wyom	7.55
17	Northwest Public Service	SD	7.74
18	Black Hills Power & Light	Wyom	7.80
19	Pacificorp -Wyoming West	Wyom	7.94
20	Cheyenne Light, Fuel, & Po	Wyom	7.99
21	NW Wisconsin Electric	Wisc.	8.00
22	Xcel Energy	MN	8.06
23	Xcel Energy	SD	8.09
24	Black Hills Power & Light	SD	8.19
25	Interstate Power Co. (Alliant	Iowa	8.21
26	Wisconsin Energy Co.	Wisc.	8.46
27	IES Utilities (Alliant)	Iowa	8.85
28	Montana-Dakota Utilities	SD	8.86
29	Interstate Power Co.(Alliant)	MN	8.94
30	Madison Gas & Elec	Wisc.	9.26
31	MidAmerican Energy	Iowa	10.12
	Average residential rate (¢/kwh):		7.68

PLUS Industry Benchmark Calculation
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Average Residential Rate

2002 Rank	Utility	Juris	2002 ¢/kwh
1	*Xcel Energy*	*ND*	*5.95*
2	Ottertail Power Co.	ND	6.20
3	Pacificorp -Wyoming East	Wyom	6.37
4	Ottertail Power Co.	SD	6.43
5	Superior Power & Light	Wisc.	6.43
6	Ottertail Power Co.	MN	6.53
7	Minnesota Power	MN	6.64
8	Montana-Dakota Utilities	ND	6.77
9	Northwest Public Service	Montan	6.90
10	Black Hills Power & Light	Mont	6.99
11	Montana-Dakota Utilities	Mont	7.33
12	MidAmerican Energy	SD	7.38
13	Xcel Energy	SD	7.57
14	Xcel Energy	Wisc.	7.60
15	Montana-Dakota Utilities	Wyom	7.62
16	Xcel Energy	MN	7.68
17	Black Hills Power & Light	Wyom	7.71
18	Pacificorp -Wyoming West	Wyom	7.83
19	Wisconsin Power & Light (A	Wisc.	7.94
20	Black Hills Power & Light	SD	8.14
21	Wisconsin Public Service	Wisc.	8.30
22	Interstate Power & Light (All	Iowa	8.47
23	Northwest Public Service	SD	8.49
24	Wisconsin Energy Co.	Wisc.	8.51
25	NW Wisconsin Electric	Wisc.	8.56
26	MidAmerican Energy	Iowa	8.67
27	Montana-Dakota Utilities	SD	8.80
28	Interstate Power Co.(Alliant)	MN	9.10
29	Madison Gas & Elec	Wisc.	9.69
30	Cheyenne Light, Fuel, & Po	Wyom	9.87

Average residential rate (¢/kwh):	7.68

PLUS Industry Benchmark Calculation
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Average Residential Rate

2003 Rank	Utility	Juris	2003 ¢/kwh
1	*Xcel Energy*	*ND*	*6.24*
2	Ottertail Power Co.	ND	6.43
3	Pacificorp -Wyoming East	Wyom	6.51
4	Superior Power & Light	Wisc.	6.52
5	Ottertail Power Co.	SD	6.63
6	Ottertail Power Co.	MN	6.69
7	Minnesota Power	MN	6.73
8	Montana-Dakota Utilities	ND	6.83
9	Montana-Dakota Utilities	Mont	7.33
10	Black Hills Power & Light	Mont	7.38
11	Pacificorp -Wyoming West	Wyom	7.38
12	MidAmerican Energy	SD	7.52
13	Xcel Energy	Wisc.	7.52
14	Black Hills Power & Light	Wyom	7.68
15	Montana-Dakota Utilities	Wyom	7.73
16	Northwestern Energy	Montan	7.74
17	Xcel Energy	MN	7.84
18	Xcel Energy	SD	7.84
19	Northwestern Energy	SD	7.92
20	Black Hills Power & Light	SD	8.14
21	NW Wisconsin Electric	Wisc.	8.57
22	MidAmerican Energy	Iowa	8.65
23	Wisconsin Public Service	Wisc.	8.66
24	Wisconsin Energy Co.	Wisc.	8.87
25	Montana-Dakota Utilities	SD	8.88
26	Interstate Power & Light (All	Iowa	8.90
27	Interstate Power Co.(Alliant)	MN	9.20
28	Wisconsin Power & Light (A	Wisc.	9.32
29	Cheyenne Light, Fuel, & Po	Wyom	9.83
30	Madison Gas & Elec	Wisc.	10.64

Average residential rate (¢/kwh): 7.87

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Average Residential Rate

2004 Rank	Utility	Juris	2004 ¢/kwh
1	*Xcel Energy*	*ND*	*6.51*
2	Ottertail Power Co.	ND	6.66
3	Pacificorp -Wyoming East	Wyom	6.82
4	Superior Power & Light	Wisc.	6.84
5	Ottertail Power Co.	SD	6.90
6	Ottertail Power Co.	MN	6.96
7	Minnesota Power	MN	7.11
8	Montana-Dakota Utilities	ND	7.19
9	Pacificorp -Wyoming West	Wyom	7.29
10	Montana-Dakota Utilities	Mont	7.37
11	MidAmerican Energy	SD	7.50
12	Xcel Energy	Wisc.	7.56
13	Black Hills Power & Light	Wyom	7.74
14	Montana-Dakota Utilities	Wyom	7.90
15	Xcel Energy	MN	8.05
16	Xcel Energy	SD	8.10
17	Northwestern Energy	SD	8.16
18	Black Hills Power & Light	SD	8.22
19	Northwestern Energy	Montan	8.23
20	NW Wisconsin Electric	Wisc.	8.61
21	MidAmerican Energy	Iowa	8.67
22	Montana-Dakota Utilities	SD	9.09
23	Wisconsin Energy Co.	Wisc.	9.13
24	Interstate Power Co.(Alliant)	MN	9.42
25	Cheyenne Light, Fuel, & Po	Wyom	9.44
26	Wisconsin Public Service	Wisc.	9.58
27	Wisconsin Power & Light (A	Wisc.	9.61
28	Interstate Power & Light (All	Iowa	9.86
29	Madison Gas & Elec	Wisc.	11.12

Average residential rate (¢/kwh): 8.13

PLUS Industry Benchmark Calculation
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Average Residential Rate

2005 Rank	Utility	Juris	2005 ¢/kwh
1	Ottertail Power Co.	ND	6.82
2	Superior Power & Light	Wisc.	6.84
3	Pacificorp -Wyoming East	Wyom	6.97
4	Minnesota Power	MN	6.98
5	Montana-Dakota Utilities	ND	7.03
6	Ottertail Power Co.	SD	7.09
7	Pacificorp -Wyoming West	Wyom	7.17
8	Ottertail Power Co.	MN	7.19
9	*Xcel Energy*	*ND*	*7.24*
10	Montana-Dakota Utilities	Mont	7.35
11	MidAmerican Energy	SD	7.38
12	Black Hills Power & Light	Wyom	7.70
13	Black Hills Power & Light	Mont	7.81
14	Montana-Dakota Utilities	Wyom	7.92
15	Xcel Energy	Wisc.	7.97
16	Northwestern Energy	SD	8.09
17	Black Hills Power & Light	SD	8.17
18	NW Wisconsin Electric	Wisc.	8.57
19	MidAmerican Energy	Iowa	8.59
20	Xcel Energy	MN	8.60
21	Northwestern Energy	Mont	8.73
22	Xcel Energy	SD	8.75
23	Montana-Dakota Utilities	SD	8.91
24	Interstate Power Co.(Alliant)	MN	9.55
25	Wisconsin Energy Co.	Wisc.	9.70
26	Wisconsin Public Service	Wisc.	10.23
27	Wisconsin Power & Light (A	Wisc.	10.35
28	Cheyenne Light, Fuel, & Po	Wyom	10.39
29	Interstate Power & Light (All	Iowa	10.78
30	Madison Gas & Elec	Wisc.	12.30

Average residential rate (¢/kwh):	8.37

PLUS Industry Benchmark Calculation
EEI Typical Bills and Average Rates Report
Average Residential Revenue/Kwh and Annual Chang

Average Residential Rate

2006 Rank	Utility	Juris	2006 ¢/kwh
1	Superior Power & Light	Wisc.	7.02
2	Minnesota Power	MN	7.07
3	Ottertail Power Co.	ND	7.22
4	*Xcel Energy*	*ND*	*7.32*
5	Montana-Dakota Utilities	Mont	7.33
6	Montana-Dakota Utilities	ND	7.36
7	Ottertail Power Co.	SD	7.36
8	Pacificorp	Wyom	7.41
9	Ottertail Power Co.	MN	7.53
10	MidAmerican Energy	SD	7.60
11	Black Hills Power & Light	Wyom	7.63
12	Montana-Dakota Utilities	Wyom	8.01
13	Black Hills Power & Light	SD	8.14
14	Black Hills Power & Light	Mont	8.35
15	Northwestern Energy	SD	8.58
16	MidAmerican Energy	Iowa	8.66
17	Xcel Energy	SD	8.66
18	Northwestern Energy	Mont	8.94
19	Xcel Energy	MN	9.16
20	Montana-Dakota Utilities	SD	9.16
21	Xcel Energy	Wisc.	9.26
22	Interstate Power Co.(Alliant)	MN	10.05
23	NW Wisconsin Electric	Wisc.	10.65
24	Wisconsin Energy Co.	Wisc.	10.69
25	Cheyenne Light, Fuel, & Po	Wyom	10.93
26	Wisconsin Public Service	Wisc.	11.08
27	Wisconsin Power & Light (A	Wisc.	11.08
28	Interstate Power & Light (All	Iowa	11.53
29	Madison Gas & Elec	Wisc.	13.49

Average residential rate (¢/kwh): 8.87