Direct Testimony and Schedules
Laura McCarten

Before the South Dakota Public Utilities Commission
State of South Dakota

In the Matter of the Application of Northern States Power Company
for Authority to Increase Rates for Electric Service in South Dakota

Docket No. EL12-___
Exhibit___(LM-1)

Policy Testimony

June 29, 2012

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Schedules

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND OCCUPATION.

A. My name is Laura McCarten. I am Regional Vice President for Northern States Power Company (Xcel Energy or Company), a Minnesota corporation operating in South Dakota.

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND EXPERIENCE.

A. I began working for the Company in 1979 as a nuclear engineer, and spent several years in the Company's nuclear engineering department supporting the Prairie Island and Monticello nuclear power plants. Since the early 1990s, I have worked in several additional areas of the Company, including regulatory, special nuclear projects, electric and gas utility operations, and transmission. In my current position, I am responsible for regulatory, legislative, and media relations activities in South Dakota and North Dakota, and for legislative and media relations in Minnesota. I provide strategic leadership regarding the development and implementation of our initiatives to most effectively serve our retail customers and communities. My résumé is included as Exhibit___(LM-1), Schedule 1.

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. My testimony provides an overview of our Application, summarizing the need for a general electric rate increase and introduces the Company-sponsored witnesses. I also provide testimony regarding the Company's investments in

infrastructure improvements and key factors driving both this request and future challenges. Finally, I sponsor Exhibit No.___ (NSP-1), Statement Q, in Volume 1, which is a description of the Company's utility operations, offered in compliance with SD Admin. R. 20:10:13:101.

Q. PLEASE DESCRIBE HOW YOUR TESTIMONY IS ORGANIZED.

A. I present my testimony in the following sections:

- Overview;
- Case Drivers;
- Revenue Requirements;
- Addressing Future Challenges;
- Presentation of Witnesses; and
- Conclusion.

Q. ARE THERE ANY OTHER COMPONENTS OF THE COMPANY'S FILING THAT YOU WOULD LIKE TO HIGHLIGHT?

A. Yes. We are filing testimony, exhibits, and work papers in support of our request. In addition, we reviewed all South Dakota Public Utilities Commission (Commission) Rules and Orders from previous electric rate cases to ensure we have complied with all requirements. My Schedule 2, Exhibit___ (LM-1), lists the relevant Commission directives from the orders, the action the Company has taken to address each order directive, and the location in our rate case application of the Company's response.

II. OVERVIEW

Q. PLEASE SUMMARIZE THE COMPANY'S REQUEST IN THIS PROCEEDING.

A. Xcel Energy seeks authority from the Commission to increase our electric retail revenue by $19.4 million, or 11.5 percent. We base this request on a historical 2011 test year, adjusted for known and measurable changes over a 24-month period as allowed by the Commission's rules. The proposed revenue requirement reflects a return on equity (ROE) of 10.65 percent. Under our proposal, a residential customer using 750 kWh per month would see a monthly bill increase of about $10 per month or 12.7 percent.

Q. WHAT IS CAUSING THE NEED FOR RATE RELIEF AT THIS TIME?

A. This rate request is needed to support the Company's operations and fulfill our commitment to provide reliable, efficient and high quality service to our South Dakota customers. Despite our ongoing cost-control efforts, several factors have caused our 2011 costs to increase over 2010 levels, and are driving the need for rate relief, including the need to:

- Invest in capital projects necessary to maintain, improve and replace infrastructure on our system;
- Address increases in operating and maintenance (O&M) expenses, largely related to increased operating costs at generating facilities; and
- Comply with increasing regulatory requirements.

Nearly 75 percent of our request is due to new infrastructure investment and related capital costs. Operating and maintenance expenses, and economic and compliance trends account for a significant portion of the remainder. While we have worked hard to manage our costs, we have been unable to sufficiently offset these cost increases, largely because of the magnitude of required system

investments and a continued trend of nearly flat sales growth. Addressing this deficiency will allow us to maintain the high quality, reliable electric service expected by our customers and to preserve our financial integrity.

Even with the requested rate increase, I believe our customers will continue to receive great value, as we make prudent, cost-effective decisions to meet their current needs and be well-positioned for the future.

Going forward, I believe a phase-in rate plan may be effective at addressing the underlying challenges that have caused the need for frequent rate requests. While we are not filing a phase-in plan as part of this case, we look forward to beginning a parallel dialogue with Staff and other parties to address issues related to the interpretation and implementation of the new legislation. We will update the Commission on the results of our efforts during the course of this proceeding.

Q. WHY IS NSP FILING A RATE CASE WHEN THE COMMISSION ONLY RECENTLY MADE ITS DETERMINATION IN THE LAST CASE?

A. The previous case addressed actual costs in the 2010 test year and a portion of costs in 2011. This case is based on actual costs and revenues in 2011, which have increased since the 2010 test year. The majority of the cost increases we are facing are due to the significant level of investment to maintain, improve and replace the core local and regional utility infrastructure necessary to meet our customers' needs for reliable and economical electricity now and into the future. Additionally, our costs of service, including maintaining our existing system, as well as regulatory compliance, continue to increase. We have

implemented several cost control and efficiency initiatives that have helped to mitigate cost increases, but they have not eliminated cost increases altogether.

While our costs have increased, our revenues have not, reflecting the continuation of near flat sales. Economic metrics for 2011 and 2012 have shown some improvement, but sales have largely not reflected these improvements. Some areas, such as southern Sioux Falls, are experiencing stronger growth; however, overall sales are flat. In 2011, total retail sales grew by only 0.5 percent over 2010 sales on a weather-normalized basis. In the Commercial and Industrial class, weather-normalized sales in 2011 were at 2007 levels and lower than 2008 sales. Additionally, on the whole, we continued to see weak new customer additions.

III. CASE DRIVERS

Q. WHAT ARE THE MAJOR COST DRIVERS FOR THIS RATE CASE?

A. The chart below provides an overview of the major drivers for this rate increase request:

Major Cost Drivers

Drivers		Deficiency ($Millions)
Infrastructure		
Nuclear (inc. O&M)		$5.3
Other Generation and Amortizations (inc. O&M)		$3.0
Transmission (inc. O&M)		$1.0
Distribution (inc. O&M)		$1.8
Accounting and other A&G		$1.2
Transmission and Interchange Margins		$1.5
	Total Infrastructure	$13.8
Economic Trends		
Change in Cost of Capital		$4.1
Decommissioning		$0.9
Incentive Pay		($0.8)
Pension		$0.7
Retail Margins		($0.6)
Other Margins		$0.8
Property Taxes		($0.4)
	Total Economic Trends	$4.6
Regulatory Compliance		$1.1
	TOTAL	**$19.4**

As indicated above, infrastructure investments account for approximately $14 million of the proposed increase, with nuclear costs alone comprising 27 percent of the overall increase. The majority of the remaining increase is due to changes in the cost of capital, while other contributors include increased transmission expenses associated with increased interchange charges, higher demand costs and a slight increase in maintenance activity. These cost drivers

are further discussed in the Direct Testimony of Company Witness Mr. Thomas E. Kramer.

A. Infrastructure

Q. YOU INDICATED THAT MAINTAINING, IMPROVING, AND REPLACING COMPANY INFRASTRUCTURE IS A KEY DRIVER OF THIS REQUESTED RATE INCREASE. PLEASE EXPLAIN.

A. We continue the extensive capital investment in our system identified in our prior rate case in order to maintain safe and reliable service to our customers. The Company estimates that during the five-year period 2012-2016 it will invest approximately $5.9 billion, averaging approximately $1.18 billion per year over that five-year period.[1] Plant in-service additions for generation, transmission and distribution included in our rate request totaled $42.4 million before any known and measurable adjustments were considered. The Company is seeking recovery of an additional $22.6 million in plant in-service additions associated with 12 generation-related known and measurable projects. These investments in utility plant are long-term projects needed to provide safe and reliable service over our planning horizon and will continue to support economic growth in Sioux Falls and the State of South Dakota.

Q. WHY ARE THESE INFRASTRUCTURE INVESTMENTS NEEDED AT THIS TIME AND OF THIS MAGNITUDE?

A. The bulk of our infrastructure request is related to investments in maintaining, improving or expanding existing resources. These investments are not discretionary. Rather, we make strategic investments in our existing resources

[1] SEC Form 10-K, Xcel Energy, Inc, for the year ending December 31, 2011, at 73. Includes South Dakota, Minnesota and North Dakota jurisdictions.

to meet regulatory requirements, such as those enforced by the Nuclear Regulatory Commission (NRC) and the North American Electric Reliability Corporation (NERC), and to ensure that we maximize the value from our resources and continue to provide low-cost, reliable service.

For example, with respect to our Monticello and Prairie Island nuclear facilities, our current investments are needed to address maintenance and reliability requirements, as well as to support operations through the extended lives of the plants. The timing and scope of these investments is influenced by the licensing terms and operating requirements established by the NRC.

Q. PLEASE DESCRIBE THE GENERATION PROJECTS INCLUDED IN YOUR REQUEST.

A. Our request includes revenue associated with $4.5 million in capital for generation projects. The majority of the request is related to the life extension project at our Monticello nuclear generating plant and several smaller projects at our Prairie Island nuclear generating plant. In addition, we have ongoing projects at our Black Dog and Sherco facilities that are also included in this rate case.

For Monticello alone, we invested approximately $271 million in capital in 2011. This work included a large portion of the work necessary to implement our Life Cycle Management/Extended Power Uprate Project that will support continued operations through 2030 along with an additional 71 MW of capacity. The remaining LCM/EPU work is scheduled for final implementation in the Spring 2013 outage, and is currently budgeted at $291 million. Our 2013 investments in Monticello are included in the known and measurable adjustments in this case.

We also include costs for several smaller regulatory compliance projects and various improvements at our nuclear plants, such as warehouse consolidation and onsite storage cask management. Company witness Mr. Kramer discusses these projects in his testimony. Overall, our nuclear projects are necessary for continued operation of our nuclear plants. These plants provide substantial cost savings to our customers compared to alternative sources and, as emissions-free resources, will help us manage exposure to future environmental regulations.

In addition, we have made significant investments in our Black Dog and Sherco plants. We are replacing various exhaust components as a result of normal wear and tear over the past ten years at our Black Dog facility and replacing the high pressure steam turbine rotor and related equipment at Sherco. Mr. Kramer further addresses these investments in his Direct Testimony. Finally, the Company has not included in this rate request any new renewables additions to meet state renewable energy objectives and standards, as all standards and objectives are currently being met.

Q. ARE ANY OF THE COMPANY'S CAPITAL PROJECTS RELATED TO TRANSMISSION AND DISTRIBUTION?

A. Yes. We have included costs related to our investments in transmission and distribution systems to provide improved reliability and support customer needs. The transmission costs we have included in our request do not meet the criteria for recovery through the Transmission Cost Recovery rider, either because of the project specifications or in-service date.

We continue to invest in our local transmission and distribution network in South Dakota. In 2011, we invested approximately $8.5 million in local transmission and distribution improvements. For example, we completed and put into service the new Louise Avenue substation in Sioux Falls, which will serve the load in southern Sioux Falls and surrounding areas. This substation helps relieve load from Lincoln County substation and provides greater back-up capability.

Other major projects completed in 2011 include a transformer upgrade and breaker replacements at the Lincoln County substation; installation of a feeder tie, stepdown transformer and automated switch to improve reliability at Sioux Falls industrial parks; and voltage conversion and reconductoring to improve voltage and reliability in Tea. In addition, we have made several investments in system performance, including improved station equipment and additional system interconnections that will improve the operational capacity of our integrated system.

Q. HOW WILL THESE INFRASTRUCTURE INVESTMENTS BENEFIT YOUR SOUTH DAKOTA CUSTOMERS?

A. These investments support safe, reliable service to our customers. Maintaining and improving the operational characteristics of our system allows us to get the most out of our investment, reduces unplanned outages, and ultimately keeps costs low for customers.

In addition, Xcel Energy operates an integrated generation and transmission system to serve all our customers in the upper Midwest, including South Dakota, North Dakota, Minnesota, Wisconsin and Michigan. All of our

customers benefit by our planning and operation of an integrated system. Company assets needed to provide service to our customers in these states are part of a larger, interconnected network of assets owned by other public utilities, cooperatives, and municipal utilities. Connection with this larger, regional network of assets allows us to plan and operate our entire five-state system on an integrated basis. For example, we plan our fleet of generating plants on a total-system basis, as opposed to attempting to plan on a state-by-state or community-by-community basis. A large, integrated system allows the Company to: (1) reduce the total amount of generating resources needed to serve customers; (2) diversify the fleet of generating resources required to meet our customers' needs; and (3) lower costs and fuel volatility risks by spreading same over a substantially larger and diverse customer base.

For example, it would not be feasible for Xcel Energy to build and own nuclear power plants if we planned our system on a state-by-state basis. But from an integrated, multi-state perspective, a nuclear plant is economic and, thus, customers in South Dakota benefit from these low cost resources, both over the initial licensing period and over the extended period of operation enabled by the license extension and investments to replace, refurbish and upgrade equipment.

Q. ARE ALL OF THE INFRASTRUCTURE COSTS RELATED TO CAPITAL INVESTMENTS?

A. No, not all of the costs related to our infrastructure are capital investments; there is an O&M component as well. Approximately 19 percent of the rate request is related to O&M. Our O&M costs have increased largely due to increased operating costs at generating facilities.

B. Economic Trends

Q. PLEASE ELABORATE ON THE ECONOMIC TRENDS AND CONDITIONS THAT AFFECT YOUR BUSINESS.

A. Like all businesses, general economic trends have impacts on our Company. In 2011, we saw particular impacts in the areas of sales growth, pension and cost of capital, as described below.

Sales. Our sales growth significantly declined in 2009 relative to prior years, with a modest rebound in 2010 and 2011. However, sales are expected to grow more slowly than normal over the next few years. While total retail sales increased at an annual average rate of 3.4 percent between 2000 and 2008, we saw only 0.6 percent annual growth over the 2009 to 2011 period. We expect to see similar annual growth rates for 2012 and 2013. Slower sales growth diminishes our ability to offset cost increases and results in more frequent rate case filings, all else being equal.

Pension. This case includes a known increase for 2012 of $704,000 to reflect rising pension costs. As happened to many other pension programs, the value of our pension assets decreased during the financial crisis in 2008 and 2009. The significant 2008 asset loss is being phased into the pension expense calculation over five years, such that the full loss will not be recognized in amortization until 2013. This loss, coupled with a decrease in the discount rate, is expected to contribute to higher pension expenses through at least 2013. The Direct Testimony of Mr. Kramer provides additional detail on the amortization of the 2008 asset loss and our pension expense.

Cost of Capital. Our proposed increase includes the effects of the current economic conditions on the capital market. These effects are further addressed below and in Mr. James M. Coyne's Direct Testimony.

C. Regulatory Compliance Requirements

Q. PLEASE DESCRIBE THE COMPLIANCE COSTS DRIVING YOUR REQUEST.

A. We are continuing to face increasing regulatory requirements in many areas of our business. For example, the NRC has imposed new requirements on the operation of our nuclear generation plants. Recent standards imposed or expanded by the NRC focus on the safety and security at our plants, including additional fitness for duty standards, more stringent security rules, cyber-security rules, and fire protection and emergency preparedness requirements. The Direct Testimony of Mr. Kramer discusses two Monticello projects and one Prairie Island project related to new NRC fire protection requirements.

IV. REVENUE REQUIREMENTS

A. Historical Earnings

Q. YOUR MOST RECENT ELECTRIC RATE CASE WAS BASED ON A 2010 TEST YEAR WITH KNOWN AND MEASURABLE CHANGES IN 2011. BOTH YEARS WERE IMPACTED BY THE FINANCIAL DOWNTURN. HOW DID THE COMPANY PERFORM?

A. As discussed in greater detail in a subsequent section, we initiated several cost management initiatives in an attempt to mitigate the impact of low sales resulting from the financial downtown; however, those efforts were not sufficient to offset the low sales in those years. In 2010, we reported an actual return on equity of 2.95 percent and a weather-normalized return on equity of 2.64 percent for the South Dakota jurisdiction, much lower than our authorized return. For the historic test year of 2011, we reported an actual

return on equity of 4.16 percent and a weather-normalized return on equity of 3.9 percent, again much lower than our authorized return.

Economic factors are stabilizing and slowly improving, and our cost management efforts created efficiencies and cost controls that we continue to employ. Nonetheless, the need to continue to invest in our infrastructure and comply with regulatory requirements has resulted in increased costs.

B. Test Year

Q. WHAT TEST YEAR DOES THE COMPANY PROPOSE IN THIS CASE?

A. The test year is 2011, adjusted to normalize the test year, properly reflect regulatory requirements, and account for appropriate known and measurable changes. As discussed by Mr. Kramer in his Direct Testimony, we include $5.3 million of known and measurable changes for 24 months consistent with the Commission's rules. These known and measurable changes include projects placed in service in late 2011 and in 2012 or 2013 for the Monticello Nuclear Generating Plant, Prairie Island Generating Plant, Black Dog Generating Facility, and Sherburne County Generating Facility.

C. Rate of Return

Q. WHAT IS THE BASIS FOR THE COMPANY'S RECOMMENDED ROE OF 10.65 PERCENT?

A. Our proposed revenue requirement reflects an overall rate of return (ROR) on investment of 8.51 percent, based on an average common equity ratio of 52.89 percent and an ROE of 10.65 percent. Mr. Coyne provides a detailed analysis of the appropriate overall ROR and ROE for the Company.

Q. THE COMMISSION DECLINED TO ADOPT A 10.65 PERCENT ROE IN YOUR LAST CASE. PLEASE EXPLAIN WHY THE COMPANY PROPOSES THE SAME ROE HERE.

A. We acknowledge the short timeframe between the Commission's decision in our last case and the filing of this case. However, respectfully, we believe the data supports the 10.65 percent ROE recommended by Mr. Coyne. Mr. Coyne's analysis is consistent with the industry and meets the standard of comparability to other similar investments and would be sufficient to attract capital. We will continue to monitor and assess the market as this case proceeds and update our proposed ROE to reflect changes, if any.

Q. IS THE LEVEL OF ROE ESPECIALLY IMPORTANT IN LIGHT OF THE COMPANY'S PLAN FOR FUTURE INVESTMENTS?

A. Yes. An appropriate ROE and a supportive state regulatory framework are key contributors to our ability to raise significant capital at reasonable rates. Our plan of investment in generation, transmission and distribution will result in approximately $5.9 billion of expenditures between 2012 and 2016. We will need to turn to the capital markets to support the level of investment that is needed.

Given this magnitude of investment, we have a common interest with our regulators and customers in having the Commission set an appropriate ROE and allowing us a reasonable opportunity to earn that ROE. Absent these conditions, the cost of capital for the investments we need to make to serve our customers would be higher than otherwise necessary, increasing the rate impact on our customers.

Q. WHY IS IT IN THE INTEREST OF CUSTOMERS FOR THE COMPANY TO BE FINANCIALLY HEALTHY?

A. A healthy utility provides several benefits to customers, including lower cost of service, economic development, and job creation.

Lower cost of service. We will need to turn to the capital markets to support the level of investment that is needed to implement our infrastructure improvement plans. The cost at which we can obtain needed capital depends in large part on investors' perceived risk of investing with us and our expected return.

Economic development. A financially sound utility is able to make the infrastructure investments necessary to meet its customers' current and future needs and facilitate business development and expansion.

Job creation. With infrastructure investments comes the possibility for local employment opportunities over the short and long term, which benefits local communities.

D. Rate Design

Q. PLEASE DESCRIBE YOUR PROPOSED RATE DESIGN FOR THIS CASE.

A. The Company is not proposing significant changes to our current rate structures or the relationships between rate components. However, we are proposing changes to the voltage discounts that are a part of Commercial and Industrial demand tariffs. The Direct Testimony of Company witness Mr. Michael A. Peppin discusses these changes. Our other proposed changes are those necessary to implement the proposed test year 2011 revenue requirements, other technical and administrative updates necessary to keep the tariff structure current with that in the Company's other retail jurisdictions,

and limited changes in design to make our rates better reflect the cost of service.

V. ADDRESSING FUTURE CHALLENGES

Q. WHAT STEPS HAS THE COMPANY TAKEN TO CONTROL COSTS AND MINIMIZE THE NEED FOR RATE INCREASES?

A. In response to increasing costs and slow sales growth over the past several years, Xcel Energy Inc. and the NSP Companies have implemented aggressive cost control efforts to minimize the size of rate increases while continuing our efforts to provide quality service to our customers. For example, Xcel Energy has initiated and continued the following cost management efforts:

- Limited the rate of medical cost increases by increased employee cost-sharing requirements, benefit reductions and renegotiation of vendor contracts;
- Set aggressive targets for business units to further limit O&M expenses;
- Deployed new technologies to gain operational efficiency and reduce costs;
- Reduced travel and employee expenses by implementing new procedures and limitations; and
- Controlled supply chain costs by forming strategic supplier relationships.

Q. PLEASE DESCRIBE THESE COST MANAGEMENT EFFORTS.

A. We have limited the rate of medical cost increases through the implementation of cost-saving initiatives resulting from plan design changes, benefit reductions, and through prior renegotiation of vendor contracts. Our

employee benefit package is a high-deductible health plan with premiums, mandatory generic prescriptions when possible and mandatory mail-order for maintenance medications. As a result of continued cost-saving initiatives being implemented, active health care costs for NSPM decreased by $4.1M from 2010 to 2011. We continue to look for new ways to reduce health care and other cost increases.

We have also continued the travel and employee expense policies and limitations established in 2009. As a result, we maintained employee expenses at 2009 levels for 2011 and expect similar results in 2012. We have controlled supply chain costs by forming strategic supplier relationships with billing vendors, wood pole providers, power transformer providers and others, resulting in lowered costs for billing services and equipment. The reductions we have achieved in these areas are reflected in our costs of service.

We continue to pay close attention to O&M costs. Although we have been successful in reducing O&M in recent years, we recognize that some of these reductions are the result of deferral of actions into the future. In addition, with increased investment comes increased O&M expenses and we anticipate that these limits will not necessarily carry over into 2013.

Q. WHAT HAS THE COMPANY DONE TO HELP ITS CUSTOMERS REDUCE THEIR ENERGY COSTS?

A. In January 2012, the Company launched a suite of conservation and load management programs designed to help business and residential customers save energy and money. For example, residential customers can receive cash rebates for ground source heat pumps and discounted prices for compact

fluorescent bulbs at participating retailers. They can also receive bill discounts in exchange for allowing Xcel Energy to control central air conditioners and water heaters during times of peak demand. Business customers can receive cash rebates for installing more efficient lighting and bill discounts for curtailing load during peak times. Through these programs participating customers realize significant bill savings; non-participants also benefit from the system savings and reduced emissions. Our conservation and load management programs can reduce the need for additional infrastructure and the use of our existing infrastructure, saving all customers money. We look forward to increasing participation in our conservation and load management programs that benefit all of our customers.

Q. DOES THE COMPANY ANTICIPATE FILING ANOTHER RATE CASE IN 2013?

A. Yes, at this time another rate case seems likely. As I previously discussed, we are in the midst of an ongoing construction program that will require significant infrastructure investment each year out to 2016. Additionally, we are facing increased costs related to pensions and regulatory compliance. The stagnation in sales growth means that our revenues are not growing fast enough to cover our growing costs.

In this increasing cost and low sales growth environment, basing rates on a historical test year, even with known and measurable changes, generally results in revenues that lag current and future requirements. We are optimistic that the new phase-in rate plan authorized by SDCL §§ 49-34A-73 through 49-34A-78 will allow for a phase-in of rate increases to reflect rising costs of service due to major capital additions and purchased power costs. We look forward to working with the Commission and affected parties to identify how

best to proceed with such a plan and bring it forward for the Commission's review. We anticipate that we will work with parties and Commission staff over the next several months and will update the Commission on our work. We anticipate that potential issues can be addressed in such a way that would allow for a phase-in rate plan to be included in our next rate case filing.

Q. PLEASE DESCRIBE HOW A PHASE-IN RATE PLAN AS DEFINED UNDER S.D. CODIFIED LAWS § 49-34A-73 COULD ADDRESS THE FINANCIAL CHALLENGES FACING THE COMPANY?

A. A phase-in rate plan builds on the current, cost-based ratemaking model. However, instead of considering a snapshot of a utility's revenues and costs during a single historic test year, a phase-in rate plan considers planned investments that would have a material impact on rates.

House Bill 1121 amended S.D. Codified Laws § 49-34A-73 to expand the types of investments that may be eligible for inclusion in a phase-in rate plan and clarify the terms and conditions for a phase-in rate plan. Eligible costs include investments in fixed generation, transmission, and distribution assets, whether purchased or constructed; operations and maintenance expenses directly related to those fixed assets; real property; and new power purchases.

Q. PLEASE ELABORATE ON THE BENEFITS OF A PHASE-IN RATE PLAN.

A. A primary benefit of a phase-in rate plan is that it allows customers and regulators to have a more accurate picture of a utility's costs and rates over time. Under the current regulatory regime, there can be a significant gap between the time an infrastructure investment has been approved by regulators and when the costs appear on customers' bills. A phase-in plan can

facilitate better understanding of the rate impact of such significant investment decisions; even though cost-effective resources are selected in such processes, a phase-in plan can make the cumulative impact of such decisions more transparent to all stakeholders.

In addition, a phase-in plan can make the regulatory process itself less burdensome, reducing the number of rate cases that must be processed.

Q. DO YOU PROPOSE A NUCLEAR COST RECOVERY RIDER IN THIS CASE?

A. No. However, we continue to believe a rider may be the most appropriate mechanism for recovery of these costs, as a phase-in plan may not be best suited to address the unique circumstances of our nuclear investments. If we file for approval of such a rider, we would submit our proposal for the Commission's consideration in a separate docket.

VI. PRESENTATION OF WITNESSES

Q. WHO ARE THE WITNESSES FOR THE COMPANY IN THIS PROCEEDING?

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

- *Thomas E. Kramer*, who sponsors the overall revenue requirement for the rate case. Mr. Kramer sponsors the schedules supporting our income statement, rate base, revenue deficiency, and jurisdictional allocations.
- *James M. Coyne,* of Concentric Energy Advisors, who sponsors testimony on the ROE and ROR, including, capital structure, and the cost of debt.
- *Michael A. Peppin*, who sponsors our class cost of service study.

- *Steven V. Huso*, who sponsors the general rate design in this case and tariff changes.

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

VII. CONCLUSION

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. This rate request is needed to support infrastructure improvements to our system; address increases in O&M expenses, largely related to increased operating costs at generating facilities; and comply with increasing regulatory requirements. We provide excellent value to our South Dakota electric service customers as a result of our prudent development of a diverse, flexible and robust fleet of generation resources that will provide reliable, reasonably priced energy services to our customers both now and over the long term. Our requested increase in rates is necessary to allow the Company to continue to provide high quality, reliable electric service to our South Dakota customers and to preserve our financial integrity.

Q. PLEASE SUMMARIZE THE COMPANY'S REQUEST TO THE COMMISSION.

A. We respectfully request that the Commission approve:

- Our requested rate increase of $19.4 million, which is 11.5 percent of present retail revenues;
- An overall ROR on investment of 8.51 percent, based on an average common equity ratio of 52.89 percent and an ROE of 10.65 percent; and

- Our proposed rate design and tariffs.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.