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STATE OF NORTH DAKOTA

PUBLIC SERVICE COMMISSION

Northern States Power Company **Case No. PU-400-03-256**
2002 Electric Operations
Annual Report

AFFIDAVIT OF SERVICE BY CERTIFIED MAIL

STATE OF NORTH DAKOTA
COUNTY OF BURLEIGH

Sharon Helbling deposes and says that:

she is over the age of 18 years and not a party to this action and, on the **4th day of May, 2005,** she deposited in the United States Mail, Bismarck, North Dakota, **one** envelope with certified postage, return receipt requested, fully prepaid, securely sealed and each containing a photocopy of

Order

The envelope was addressed as follows

Dave Sederquist
Xcel Energy
P 0 Box 2747
Fargo **ND** 58108-2747
Cert. No. 7003 2260 0001 3517 9930

Each address shown is the respective addressee's last reasonably ascertainable post office address.

Sharon Helbling

Subscribed and sworn to before me
this **4th day of May, 2005**

Sandra L. Scott
Notary Public

SEAL

SANDRA L SCOTT
Notary Public
State of North Dakota
My Commission Expires June 11, 2010

APPROVED

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MOTION

May 3, 2005

Northern States Power Company
2002 Electric Operations
Annual Report

Case No. PU-400-03-256

I move the Commission approve the order to revise Northern States Power Company's performance-based regulation plan, Case No. PU-400-03-256.

STATE OF NORTH DAKOTA

PUBLIC SERVICE COMMISSION

Northern States Power Company
2002 Electric Operations
Annual Report

Case No. PU-400-03-256

ORDER

May 3, 2005

Preliminary Statement

On December 29, 2000, the Commission issued its Findings of Fact, Conclusions of Law and Order approving a performance based regulation (PBR) plan settlement agreement between the Northern States Power Company (NSP) and the Public Service Commission Staff (Staff) in Case No PU-400-00-195. The PBR plan became effective January 1, 2001, and will be in effect through December 31, 2005.

One of the provisions of the plan includes a mid-term review after the second year to make any necessary adjustments or refinements to the plan The review and related filings are documented in Case No. PU-400-03-256

The mid-term review included several meetings between NSP and Staff and informal hearings before the Commission.

On June 17, 2003, Staff filed a statement with the Commission that it had completed its financial review of NSP's 2001 and 2002 annual reports. In its report, Staff apprised the Commission of its findings including some perceived shortfalls in the existing performance measures.

On June 18, 2003, the Commission held an informal hearing to discuss Staff's recommendations The Commission instructed Staff to continue working with NSP to see if the issues could be resolved.

On October 15, 2003, the Staff filed a memo explaining that an agreement could not be reached with NSP Staff argued that the differences are philosophical in nature and can not be overcome In Staff's opinion, a PBR plan should encourage a company to exceed actual results obtained under traditional rate of return regulation NSP argues that the performance standards should have little to do with past performance and more to do with known and measurable industry standards Because the two positions are not compatible in this instance, no agreement could be reached

On December 16, 2003, NSP unilaterally filed proposed modifications to the existing PBR plan incorporating its new market driven standards

On February 10, 2004, Staff filed its objection to NSP's proposed modifications reiterating that any changes should be compared to historical results before agreeing to revise the PBR plan.

On February 25, 2004, an informal hearing was held to discuss the proposed revisions.

On September 20, 2004, the Commission received a revised modification proposal from NSP focusing on 1) its method of surveying customer satisfaction, (2) improving the annual rate change standard, and (3) establishing an exception threshold for addressing exogenous events.

On October 29, 2004, Staff filed a memo supporting NSP's revised modifications and recommending that the Commission approve the changes.

On January 19, 2005, NSP made a compliance filing reflecting the modifications agreed to by the Commission Staff and the Company for plan year 2005.

Discussion

As NSP's revised filing demonstrates, Staff and the Company have been working together to try and improve the existing plan for more than a year. NSP strongly advocates the use of external measurement criteria for establishing new PBR standards Staff is in agreement with that concept but believes the resulting standards do not include enough of a "stretch" factor for NSP.

The Commission believes changes that substantially affect the structure of the plan and the performance standards should not take place during the 5 year term of the performance plan Any significant changes to the plan will be considered when and if NSP decides to request an extension of the plan beyond 2005

The Commission appreciates NSP's revised proposal to modify the PBR plan. The revised proposal is evidence that the Company is trying to work with Staff even though there are some philosophical differences of opinion The revised proposal does not affect the structure of the plan but instead focuses on updating and calculating the performance measures The changes will also clarify the plan in respect to exogenous events.

In its revised proposal, NSP requests that its two customer satisfaction standards be developed around an 11-point scale rather than the existing 5-point scale and requests changes in the wording of its customer surveys. On page 7 of its filing, NSP reasons that the proposed changes make the surveys more intuitive, symmetrical, and consistent with internal and external benchmarks

NSP also proposes to change its rate management standard to make it more stable and meaningful. Currently, NSP's standard is based on the annual change in the residential rate for the lowest priced utility in the region. Because the standard is based on a single company, the year to year benchmark can vary significantly

The new rate management standard will be more stable because it uses a standard deviation calculation using all the utilities in the region Any performance outside one standard deviation will result in a reward or penalty Comparing NSP's rates from one year to the next against all the companies in the region will smooth out the fluctuations inherent in the existing benchmark

Currently, NSP's PBR plan includes language allowing NSP and the Commission Staff to request adjustment, suspension, or termination of the plan for exogenous events such as tax law changes, federal or state legislation, disasters etc. The revised plan requires that any such cost changes are passed through in rates if the impact is material to NSP's North Dakota electric operations. Materiality is determined to exist if the unusual event impacts NSP's earnings on common equity invested in North Dakota by more than 1 percentage point

Having considered this matter, the Commission finds that NSP's proposed changes to its PBR plan acceptable. Therefore, the Commission issues the following:

Order

The Commission orders

1. NSP's revised Petition for changes to its PBR plan is GRANTED

2. NSP's revised PBR plan is approved for plan year 2005.

3. The Commission's December 29, 2000 Findings of Fact, Conclusions of Law and Order in Case No PU-400-00-195 is supplemented by this decision.

PUBLIC SERVICE COMMISSION

Susan fald	**T.,.y Clark**	**Kevin Cramer**
Commi Ioner	**Commissioner**	**Commissioner**

Xcel Energy

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January 19, 2005

Illona A. Jeffcoat-Sacco, Executive Secretary
North Dakota Public Service Commission
State Capitol Building, Dept. 408
600 East Boulevard
Bismarck, ND 58505-0480

Re Commission request for a revised PLUS Plan compliance/description document reflecting the recently proposed modifications for 2005

Dear Ms. Jeffcoat-Sacco:

Enclosed is an original and 7 copies of a revised PLUS Plan compliance/description document reflecting the modifications agreed to by the Commission Staff and the Company for 2005

Proposed revisions to the PLUS Plan were originally filed with the Commission on December 16, 2003. A formal hearing was held on February 25 2004, and subsequent discussions between Staff and the Company led to a scaled down proposal that was filed on September 17, 2004.

Also included in this filing is a redline version of the main compliance document An electronic version of all documents has also been sent to the Commission

Let me know if you have any other questions or comments.

Sincerely,

David H. Sederquist

David H Sederquist
Sr Consultant, Regulation & Finance
Northern States Power Co d/b/a Xcel Energy

Enclosures

The PLUS Plan

A Performance-based Regulatory Framework

For
Northern States Power Company
Electric Operations
In
North Dakota

Effective January 1, 2001[1]

[1] Modified January 1, 2005.

Table of Contents

I. Introduction 3

II. Description of the PLUS Plan 3

A. Dynamic Authorized ROE Bandwidth 4

B. Revenue Sharing 4

C. Performance Standards 6

D. Changes in Base Rates 8

E. Regulatory Reporting and Review 12

F. Other PLUS Plan Considerations 13

G. Conditions for Suspension or Terminiation 14

Revenue Sharing Illustration Attachment A

Dynamic ROE Deadband Example Attachment B

Performance Indicators and Standards Attachment C

Utility Comparision Group Attachment D

PLUS Price Cap Decision Model Attachment E

Price Cap Factor Example Attachment F

2005 Plan Modifications Summary Attachment G

I. INTRODUCTION

On April 20, 2000, pursuant to N.D.C.0 49 02 02 and N.D C.C. 49.02.03, Northern States Power Company ("NSP" or "the Company") filed a performance-based regulation plan entitled ***Performance Linking*** *Utility* **Stakeholders** ("PLUS Plan" or "the Plan") with the North Dakota Public Service Commission ("NDPSC" or "Commission"). The PLUS Plan would modify the method of Commission regulation of NSP's retail electric rates and services in North Dakota consistent with the *Guidelines for Alternative Regulation Proposals* established by the NDPSC in Case No. PU-439-94-590 by order dated September 20, 1995.

After a hearing, the PLUS Plan, as modified by a Settlement Agreement between the Company and Commission Staff, was approved by the Commission by order dated December 29, 2000, as amended by supplemental order dated January 10, 2001. The orders required the Company to submit a PLUS Plan summary in compliance with the Settlement Agreement and orders.

On February _____, 2005, the Commission approved modifications to three of the performance indicators and the rate change criteria, effective January 1, 2005. Details of the revisions are included in this document.

II. DESCRIPTION OF THE PLUS PLAN

The key components of the approve PLUS Plan include 1) a dynamic "allowed ROE" range which can vary based on Company performance, 2) a revenue sharing mechanism, 3) establishment of service and operating performance standards, and 4) flexibility to adjust prices under specified circumstances, and 5) comprehensive annual reporting of the Plan results to the Commission by May 1st following the end of each Plan year. The individual components, as established by the Settlement Agreement and approved by the Commission orders, are as follows:

A. DYNAMIC AUTHORIZED ROE BANDWIDTH

An authorized baseline return on equity (ROE) of 12.0% is established. A range of +/- 100 basis points around the baseline ROE will represent an "acceptable authorized range" or "deadband" of earnings performance. Actual Company reported ROE for the Company's North Dakota electric operations which fall within this deadband are considered reasonably close to the baseline, and will not trigger any revenue sharing or rate adjustment (see Attachment A).

During the Plan term, the ROE deadband shall be subject to annual "basis point" adjustments depending on the Company's performance under each Plan performance standard, as provided herein. If the net performance basis points are positive (award), the upper end of the allowable ROE deadband increases. If the net performance points are negative (penalty), the lower end of the ROE deadband is decreased. The baseline does not change.

B. REVENUE SHARING

As stated previously, if the Company's reported actual earnings fall within the ROE deadband (as adjusted by the performance points) in a given Plan year, there will be no revenue sharing.

If the Company's actual reported earnings for any given Plan year exceed the ROE deadband, the corresponding revenue 'excess' will be calculated, and 50% of this dollar amount will be refunded to customers during the July billing cycle following the Plan year. Customers of record on March 31 following the Plan year will be issued refunds by bill credit prorated on the basis of their electric usage for the twelve months ending March 31.

If actual Company earnings are below the deadband, 50% of the corresponding revenue deficiency is recovered through a surcharge on the Company's electric rates effective no later than 24 months after the Plan year.

However, NSP will defer any reported fiscal year deficiency amount as a regulatory asset until the following Plan year revenue sharing amount -- if any -- is determined. If the prior year deficiency is fully offset by a current year reported revenue excess, the excess will be used to eliminate the regulatory asset, and no rate surcharge will be imposed. If the deficiency from the prior year is not fully offset, any remaining deficiency balance will be billed through a rate surcharge and collected over the remaining six-month period beginning July 1 of the year following the Plan fiscal reporting year, unless otherwise requested by either the Company or Commission Staff and approved by the Commission.

The customer share of any Plan refund or deficiency surcharge will be shown separately as a "performance-based dividend" or "performance-based surcharge", respectively, on customer bills. Plan dividends paid to customers or surcharges received will be excluded from the Company's regulated earnings statement for the Plan year in which the said dividends or surcharges are actually implemented.

Any deferred deficiency balance remaining at the end of the 5-year Plan term will first be considered as part of an on-going Plan, or alternatively, collected from customers through a surcharge.

Attachment B to this document provides an explanation of the dynamic ROE bandwidth and revenue sharing mechanisms provided in the PLUS Plan.

C. PERFORMANCE STANDARDS

The PLUS Plan takes a "comprehensive" approach to the utilization of performance measures and standards. NSP's performance will be measured by seven high level indicators within the areas of electric reliability, customer satisfaction, price, and employee safety. In the Plan, ranges of 'acceptable performance' are established around each performance standard. Performance results which are outside of PLUS's acceptable performance ranges will result in either an increase or decrease in the allowable ROE deadband. Each performance measure can adjust the ROE deadband by 25 basis points.

Three of the four performance areas have 2 indicators each, and hence have the ability to affect the baseline ROE and bandwidth up or down by 50 basis points, or 0.5% ROE. Safety has a single indicator with a total potential impact of 25 basis points, or 0.25%. The ROE impact of each measure is additive, meaning that it is possible for the combined effect on the baseline ROE of all seven measures to be anywhere from —1.75 % to +1.75 %, in increments of 0.25%.

Effective January 1, 2005, the PLUS Plan was amended to utilize the customer satisfaction measurement process the Company has established for all of its four operating companies. This change affected both the Relationship and Transaction surveys. In addition, the determination of the performance standard for the "rate change" indicator was also revised for 2005. See Attachment G for a description of these approved changes.

The following tables summarize the performance standards to be used in PLUS. Additional information on each measure is found in Attachment C.

RELIABILITY

Measure	''' ; Award Threshold	Target '	PeualtS,,„:1freSifold _ 7
CAIDI	< 75.6 minutes	89.0 minutes	> 102.4 minutes
SAIFI	< 0.77 outages/yr.	0.90 outages/yr.	> 1.04 outages/yr.

CUSTOMER SATISFACTION

Measure: . : r:::::	:. ,.AWargl-ThEelbldr	:il'::: :' 'Tiger.::	H"L(6311 _41iiiihokf.:':
Relationship survey satisfaction response %*	> 81.5%	78.5%	< 75.5%
Transaction survey satisfaction response %*	> 74.5%	71.5%	< 68.5%

PRICE

Measure *,	':''Awardtlireshoid	'Target :?	Penalty Threshold
Competitive Residential rate position	< 85% of target	peer group avg. res'1 rate/kWh	> 115% of target
Annual change in avg. Residential rate*	< (target-1 St. Dev.)	annual % change in avg. residential rate of the utility comparison group res'10	> (target+1 St. Dev.)

* Modified for 2005 Plan year See Attachment G

SAFETY

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OSHA incident rate	< 3 70	4.32	> 5.00

D. CHANGES IN BASE RATES

The PLUS Plan incorporates both inflationary and 'market price' factors in the calculation of the allowable rate change parameter, or "Price Cap Factor". The Plan thus ensures the Company's retail electric rates will, adjusted for inflation, decrease over the term of the Plan.

I. Factors Which Regulate Base Rate Changes

The PLUS Plan allows for the implementation of annual rate adjustments, depending on the following four factors-

- The Company's recently reported earnings levels;
- The Company's price position in the region;
- Average % residential price changes of the 'market' comparison group (see Attachment D);
- Percentage changes in the Consumer Price Index (adjusted by an efficiency target factor).

These four factors work together each year to freeze rates, limit rate increases, or in certain circumstances, mandate rate decreases. Attachment E is a graphical flowchart showing how these factors operate to determine base rate changes in the PLUS Plan.

a. Earnings Levels

Under the PLUS Plan, if the Company's reported ROE for its electric operations in North Dakota is higher than the ROE deadband midpoint less 100 basis points (1.0%), no rate increase is allowed in the following year, even if the inflation and comparison group price data support one. Conversely, price reductions supported by the CPI /comparison group price cap cannot be imposed if the Company's ROE is lower than the ROE deadband midpoint plus 1 0%.

b. Competitive Rate Position

Rate increases will not be allowed if the Company's average residential rate is higher than the comparison group average residential rate. Also, no decrease in rates will be required if the Company's average residential rate is lower than the comparison group's average residential rate.

c. Comparison Group Price Change

The annual percentage change in average residential rates for the seven state comparison group is calculated and used as the price cap factor for any rate change the Company may or must implement (unless inflation is even lower — see item # 4 below). Should the group average residential price decline, the Company is required to reduce its electric rates accordingly, unless reported actual ROE was deficient or the Company's actual rates were already less than the comparison group average, as discussed in items #1 and #2 above.

d. Inflation and Efficiency Target

To assure the Company's rates decline in real terms over the PLUS Plan period, the annual rate of inflation as measured by the Consumer Price Index (Urban) is also factored into the price cap formula. The CPI for the Plan reporting year is computed by averaging the annual CPIs reported at the end of each calendar quarter. The resulting average CPI rate is then multiplied by 60% (to reflect the Plan's "efficiency factor"). If the result is lower than the average comparison group residential price change percentage, the adjusted CPI factor replaces the average group price change percentage as the price cap factor for any Company rate change percentage. The amount of the rate change is thus limited to the lower of 1) the change in residential rates for the seven state mid-west market, or 2) 60% of the rate of inflation (CPI). See Attachment F for an example of this calculation.

2. Rate Change Procedure

Any proposed rate change allowed by the Plan would be reported to the Commission in the Company's Annual Regulated Earnings report on May 1 following the Plan year. To implement any permissive rate increase or mandatory rate reduction under PLUS, the Company will file a notice of rate change and the accompanying tariffs pursuant to N D.C.C. 49-05-05 not later than June 1.

The revised rates shall be effective on or after July 1 following the Plan year. Base rate changes will be across-the-board to all customer classes unless an alternative design is requested by the Company and approved by the Commission. The notice of rate change will not be suspended by the Commission under N.D.C.C. 49-05-06, but the revised rates shall be allowed to go into effect on the date proposed. If the Commission determines after investigation and hearing that the changed rates do not comply with the Plan terms as prescribed herein, the Commission may prospectively establish the rates it finds to be consistent with the Plan terms, and order a one-time billing true-up for the impact of the discrepancy since either the inception of the rate change or the previous 12 month period, whichever is less. Rates established consistent with the Plan are presumed just and reasonable, and non-discriminatory.

3. Materiality of Exogenous Events

Changes to base rates are subject to the rate change criteria and price cap mechanisms included in the Plan. There may be unusual and significant circumstances, however, where it is reasonable to make an exception to the Plan's rate normal rate change provisions. The Company proposes that should a specific and identifiable event, or combination of events, occur which causes a change in the costs of providing electric service (or collection of revenues) of such magnitude that there will be at least a 1.0% change in the North Dakota electric jurisdictional return on equity, an adjustment in rates will be required. Such an event may include but not be limited to governmentally imposed changes (tax law, etc.), a change in generally accepted accounting practices, industry restructuring, natural disasters, catastrophic loss, or terrorism. The corresponding adjustment to rates would be implemented within 90 days of the event or effective date of the mandate, unless otherwise agreed to by the Commission and Company.

E. REGULATORY REPORTING AND REVIEW

1. Annual Report

On or before May 1 of the year following the fiscal period being reviewed, the Company will file with the Commission a report showing:

- The Company's regulated electric earnings and return on equity (before and after any earnings sharing) in North Dakota for the fiscal year just completed;
- Summaries of operating revenue, expense, and regulated electric rate base,
- The Company's regulated capital structure including debt and equity ratios, cost of capital, and return on rate base;
- Calculation of baseline ROE and the authorized earnings bandwidth for the Plan review year;
- Annual results, awards, and penalties related to the Company's performance in the areas of reliability, price, customer satisfaction, and safety;
- Amount of revenues subject to sharing and the 'customer dividend' or surcharge;
- Comparison group average residential rates for the year in review;
- The calculation of the Price Cap Factor (CPI, comparison group rate changes);
- Proposed rate change percentages and typical bill impact for all customer classes.

2. Commission Review

Upon receipt of the PLUS earnings report in May, the Commission will perform its annual review, per existing Commission rules. A Staff report may be filed with the Commission. If none of the conditions for suspension of the Plan apply, any refunds, charges, and/or proposed rate adjustments allowed by the Plan and properly filed by the Company will go into effect on July 1.

F. OTHER PLUS PLAN CONDITIONS

The following conditions of the PLUS Plan will also apply:

I. Plan Term

The PLUS Plan commences on January 1, 2001. Except as provided herein, the PLUS Plan will remain in effect for a five year term ending December 31, 2005. Prior to July 1, 2005, the Company may file for an extension and/or modification of the Plan if so desired. Absent such a filing and a further order of the Commission extending the Plan, the PLUS Plan will automatically terminate on December 31, 2005.

2. Commission Interim Review

After the first two years of the term have been completed, the Commission may conduct an informal review hearing after May 1, 2003, to assess the Plan's results and discuss potential improvements. It is anticipated that the Commission and the Company will continue to have open communication and constructive dialogue during the plan term and, when necessary, agree to make general modifications or refine certain elements of the Plan.

3. *Fuel Clause Adjustment Mechanism*

The Company's Fuel Clause Adjustment ("FCA") will remain in effect during the PLUS Plan term and operate as it does currently to adjust customer bills for changes in fuel and purchased energy costs. The comparative price performance standards discussed previously will be calculated using total Residential revenue per kWh including the FCA adjustments in effect during the Plan reporting year.

4. *Demand Allocation Method*

For purposes of calculating the Company's jurisdictional expenses for each PLUS Plan reporting year, 36 months of historical demand data will be used to establish the Demand Allocation factor (known as D10). The Demand Allocation factor is used to assign production and transmission related costs and investment to the Company's retail electric jurisdictions in North Dakota, South Dakota and Minnesota. The use of a 36 month demand allocator is for financial reporting purposes under the Plan only. Use of a 36 month historic allocator for the Plan shall have no precedential effect in future electric rate increase applications after the Plan term expires or if the Plan is suspended or terminated

G. CONDITIONS FOR SUSPENSION OR TERMINATION OF PLAN

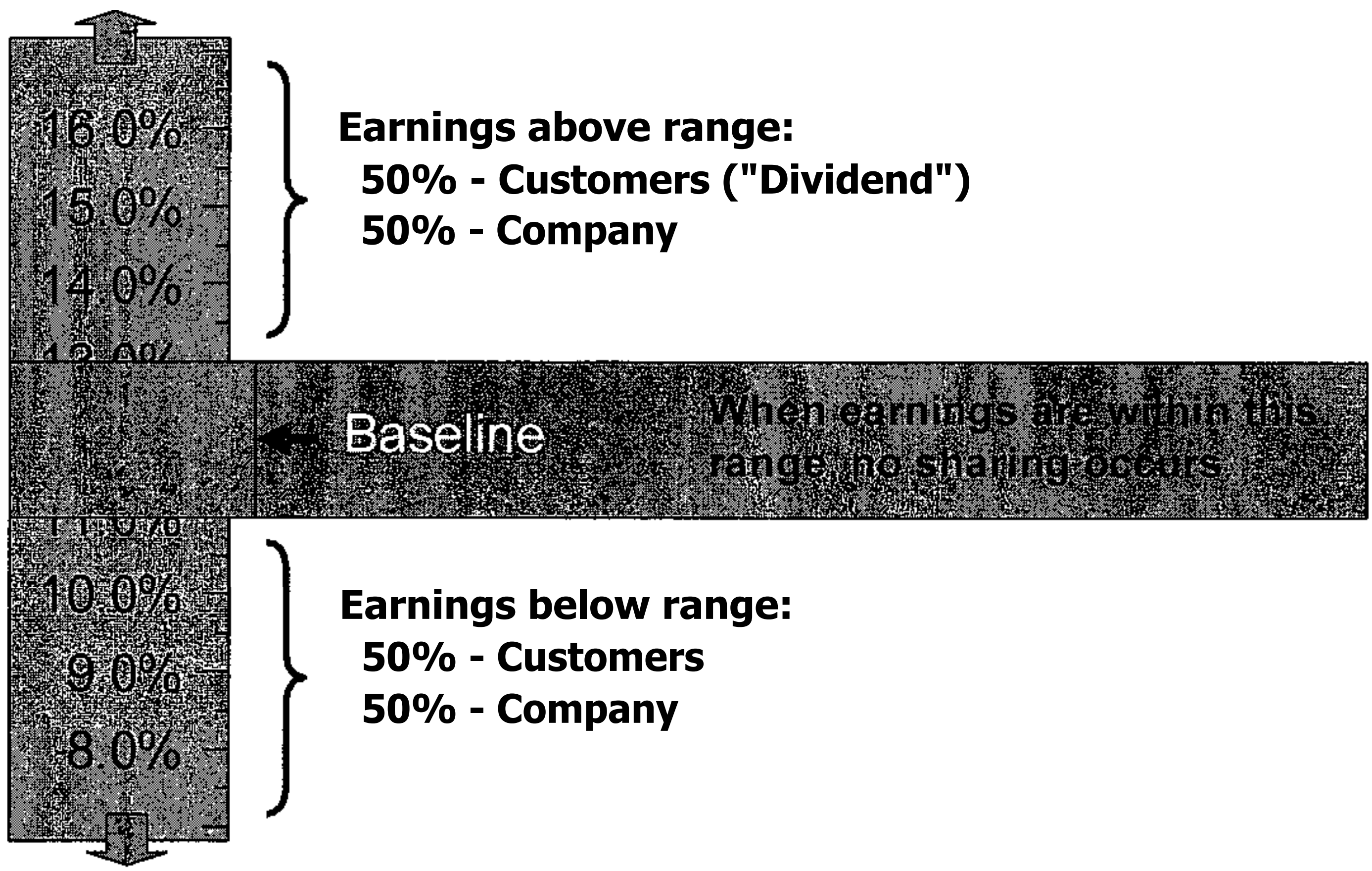
The Plan is intended to remain in effect for five years beginning January 1, 2001. However, the Company and Staff reserve the right to request adjustment, suspension, or termination of the Plan under the following events:

- Federal and/or state tax law changes;

- Passage of retail access legislation at either the federal or state level;
- Merger and acquisition events affecting the Company's structure and operations;
- Natural disasters affecting the Company's North Dakota electric operations (major storms, floods, etc.);
- Unusual events affecting the Company's operations (major generating plant failure, damage to major transmission or distribution lines, etc.); or
- Material and sustained earnings extremes (defined as returns on equity +/- 5.0% from the ROE deadband, prior to sharing).

It is anticipated the Commission and Company will make reasonable efforts to resolve any condition that could otherwise trigger a Company application or Commission motion to suspend the Plan before any decision to terminate operation of the Plan during the Plan term.

Revenue Sharing



Northern States Power Company dlb/a Xcel Energy
PLUS Plan Rate Changes
Performance-Adjusted Baseline ROE

Scenario 1: All 7 performance standards are exceeded

Since net result of performance points is positive, only the *upper limit* of the ROE deadband increases 7 X 25 points = 125 basis point adjustment

13%

12%

11%

Baseline ROE deadband

14 75%

12 88%

11.00%

ROE deadband if Company exceeds the acceptable performance ranges in all 7 measures.

Earnings above 14 75% are shared with customers, and Co may collect a surcharge only if earnings are less than 11 00% ROE A rate freeze is in effect if actual earnings are above 11 88% A rate decrease can be imposed if earnings are above 13 88%*

Scenario 2: None of the 7 performance standards are met.

Since net result of performance points is negative, only the *lower limit* of the ROE deadband decreases 7 X 25 points = 125 basis point adjustment

13%

12%

11%

Baseline ROE deadband

13 00%

11 13%

9 25%

ROE deadband tf Company does not achieve the acceptable performance range in any of the 7 perfor- mance measures

Earnings above 13 0% are shared with customers, and Co may collect a surcharge only if earnings are less than 9 25% ROE A rate freeze is in effect if actual earnings are above 10 13% A rate de- crease can be imposed if earnings are above 12 13%**

* The rate freeze threshold is equal to the baseline (12 88% in this example) minus 1 00%, or 11 88% Decreases can be imposed at 12 88%+1 0%, or 13 88%

**The rate freeze threshold is equal to the baseline (11 13% in this example) minus 1 00%, or 10 13% Decreases can be imposed at 11 13%+1 0%, or 12 13%

Northern States Power Co. d/b/a Xcel Energy
PLUS Plan Performance Standards
System Reliability (2 Indicators)

Performance Indicators

Outage Restoration Time (CAIDI) Measures the amount of time in minutes that a typical customer experiencing a sustained outage (5 minutes or more) was out of power Restoration time = # of customer-minutes interrupted / # of customers interrupted "CAIDI" stands for customer average interruption duration index

Outage Frequency (SAIFI) Measures the number of sustained outages that every 100 customers experience, on average, during the year Outage frequency = # of customer interruptions / # of customers served times 100 "SAIFI" stands for system average interruption frequency index

Performance Benchmarks

Reliability performance benchmarks were developed prior to the beginning of the 2001-2005 Plan term based on a consideration of historical results and trends for both the entire NSP (MN Co) system and the North Dakota jurisdiction

Year	NSP Co CAIDI	ND Junsd CAIDI	Average CAIDI	NSP Co SAIFI	ND Junsd SAIFI	Average SAIFI
1995	100.8	63 6		100	73	
1996	115 8	60 6		97	82	
1997	115 2	75 6		88	98	
1998	121 8	73 2		86	75	
1999	112 2	69 6		103	106	
Avg	113 2	68 5	90 8	95	87	91
Stipulated Benchmark			89 0			90

Performance Standards

The PLUS Plan range of acceptable performance for both the outage duration and frequency indicators will be +/- 15% around the benchmark

CAIDI Award < 75.7 min — Penalty > 102 **4** min

SAIFI Award < 77 outages — Penalty > **104** outages

(updated 12/31/04)

Northern States Power Co. d/b/a Xcel Energy
PLUS Plan Performance Standards
Customer Satisfaction (2 Indicators)

Performance Indicators

Relationship survey Measures the percent of randomly surveyed North Dakota customers who responded with a rating of 8, 9, or 10 (on a scale of 0 to 10) to the question "I'd like you to think in terms of your satisfaction with Xcel Energy. On a 0 to 10 scale where 10 means very satisfied and 0 means very dissatisfied, how would you rate your satisfaction with Xcel Energy?" The final PLUS result is determined by averaging the results of three separate surveys for the residential, small business, and large commercial customer classes, respectively

Transaction survey Of North Dakota customers that recently contacted our Call Center, this indicator measures the percent of those surveyed who responded with a rating of 8, 9, or 10 (on a scale of 0 to 10) to the question *"Thinking specifically of this recent interaction with Xcel Energy, from your first contact until your issue was resolved, how would you rate the service provided? (on a 0 to 10 scale, where 10 means very satisfied with how your entire transaction was handled and 0 means you were very dissatisfied)"* The final PLUS result is determined by averaging the results of two separate surveys for customers contacting Xcel Energy about 1) an electric service issue, or 2) their account

Performance Benchmarks

The customer satisfaction performance benchmark for 2005 was developed based on a consideration of historical results and trends.

Year	Relationship	Transaction
2002	76 0%	70 4%
2003	77 7%	74 5%
2004	81 8%	69 5%
Avg	78 5%	71 5%

Performance Standards

The PLUS Plan range of acceptable performance for both the Relationship and Transaction Surveys will be +1- 3 0% around the benchmark

Relationship Survey	Award > 81 5%	Penalty < 75 5%
Transaction Survey	Award > 74 5%	Penalty < 68 5%

Northern States Power Co. d/b/a Xcel Energy
PLUS Plan Performance Standards
Residential Rates (2 Indicators)

Performance Indicator

Competitive Position Measures Xcel Energy's average North Dakota residential electric rate against the average rate for a seven state, upper Midwest utility comparison group The average rate is computed by dividing total residential revenues by total residential electric sales (kWhs)

Annual Change in Residential Rate Measures the percent increase or decrease in Xcel Energy's average North Dakota residential electric rate (¢/kWh) over the prior year The change is compared to the annual percent change of the upper Midwest utility comparison group k

Performance Benchmark

The residential rate performance benchmark is developed each Plan year based on the average rate of an upper Midwest comparison group consisting of all electric investor-owned utilities in the states of ND, SD, MN, WI, MI, IA, and MT Results for 2001 — 2003 are shown below for informational purposes

Year	Comparison Group Rate	Xcel Energy ND Rate	Comp Group Rate Change	Xcel Energy ND Rate Chg
2001	768	6.53	3 71%	4 65%
2002	7 68	5 95	0 37%	-8 80%
2003	7.87	6 24	2 45%	4 90%

* Note make-up of the comparison group may change slightly from year to year due to mergers and/or rate data accessibility

Performance Standard

The PLUS Plan range of acceptable performance for the competitive position indicator will be +/- 15% around the benchmark The range of acceptable performance for the annual rate change indicator will be one standard deviation for the comparison group (excluding the two extreme utilities on each end of the change spectrum)

Memo - 2003 Standards

Competitive Position	Award < 6 69¢	Penalty > 9 05¢
Change in Rate*	Award < 4 2%	Penalty > 5 9%

Northern States Power Co. d/b/a Xcel Energy
PLUS Plan Performance Standards
Employee Safety (1 Indicator)

Performance Indicator

OSHA Incident Rate Measures the average number of Occupational Safety and Health Administration recordable safety incidents per 100 electric and electric support employees OSHA incidents include medical treatment cases, restricted work day injuries, lost workday injuries, and fatalities The OSHA incident rate = # of safety incidents times 200,000 hours divided by the number of productive labor hours Only North Dakota operations and employees are included in the PLUS Plan result

Performance Benchmark

The employee safety performance benchmark was developed prior to the 2001-2005 Plan term based on a consideration of historical results and trends reported by the Edison Electric Institute annual safety survey Data from the large utility category (> 7,000 employees) was used

Year	EEI Survey Group Avg
1994	4 83
1995	4 45
1996	4 20
1997	3 79
Avg	4 32

Performance Standard

The PLUS Plan range of acceptable performance for the OSHA Incident Rate will be +1- 15% around the benchmark

OSHA Incident Rate Award < 3 70 Penalty > 5 00

Northern States Power Company d/b/a Xcel Energy
PLUS Plan Performance Standards
Competitive Price -- Utility Comparison Group by State

Minnesota
Minnesota Power
Interstate Power
Otter Tail Power
Xcel Energy

Wisconsin
Wisconsin Energy
NW Wisconsin Electric
Wisconsin Power & Light
Wisconsin Public Service
Xcel Energy
Madison Gas & Electric

Montana
Black Hills Power & Light
Montana-Dakota Utilities
Montana Power

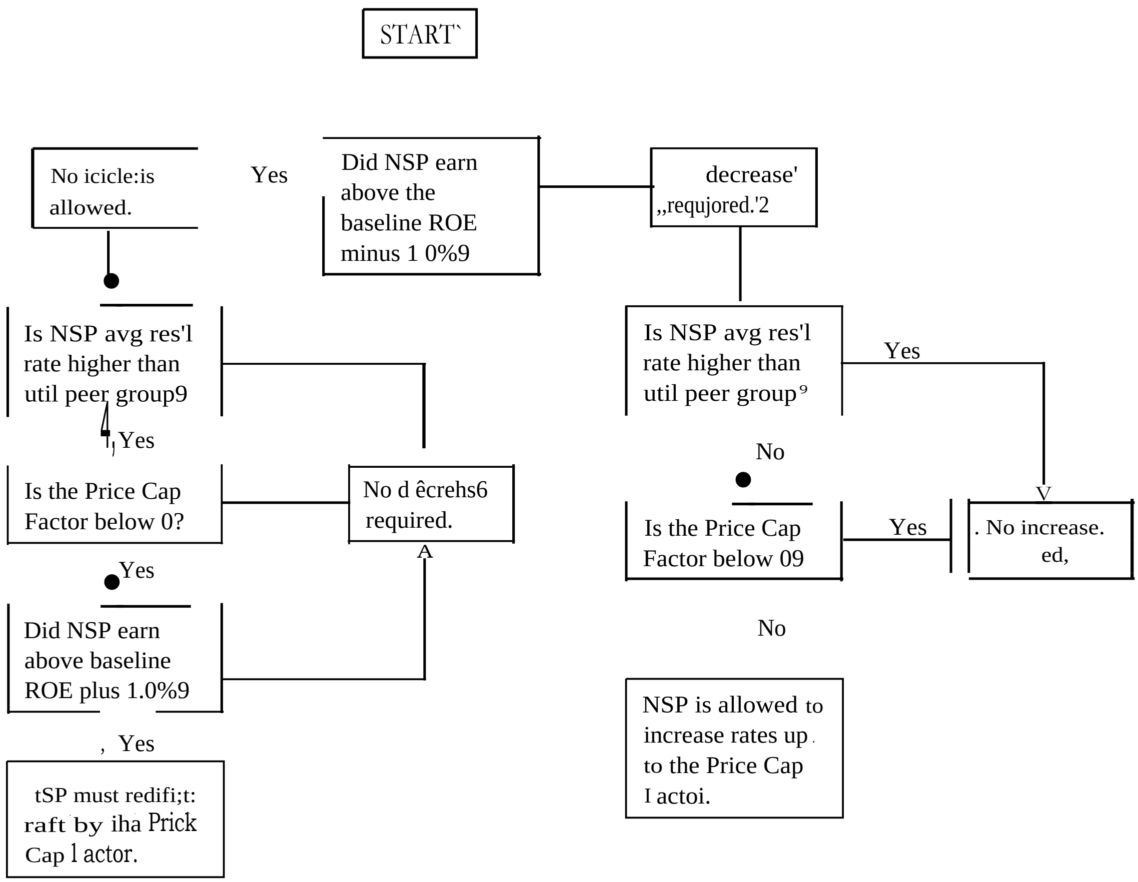
Iowa
MidAmerica Energy
IES Utilities
Interstate Power

Wyoming
PacifiCorp
PacifiCorp-Wyoming West
Montana-Dakota Utilities
Black Hills Power & Light
Cheyenne Light, Fuel, & Power

North Dakota
Montana-Dakota Utilities
Otter Tail Power
Xcel Energy

South Dakota
Montana-Dakota Utilities
Otter Tail Power
Xcel Energy
Northwest Public Service
Black Hills Power & Light
MidAmerica Energy

Decision Model for PLUS PBR Price Cap Mechanism



Price Cap Factor = lower of 1) the utility peer group average annual residential price change, and 2) CPI X 60%

Northern States Power Co. d/b/a Xcel Energy
Price Cap Factor
Sample Calculation

Line Item					
1	Utility comparison group annual change in average residential rate				2 45%
	Inflation (CPI)				
2	March	155 7	160 0	2 76%	
3	June	156 7	160 3	2 30%	
4	September	157 8	161 2	2.15%	
5	December	158 6	161 3	1 70%	
6	Average			2 23%	
7	Inflation adjusted by 40% efficiency commitment (60% X CPI)				1 34%
8	Price Cap Factor (lowest of line 1 and 7)				11 34%1

Note.

Other factors defined in the PLUS Plan relating to earnings and competitive price position need to be met before the Price Cap Factor can be applied to rates See Attachment

(updated 12/31/04)

2005 PLUS Plan Performance Standard Modifications

1. Customer Satisfaction Measurement

From 2001 through 2004, the PLUS Plan utilized two kinds of surveys for purposes of measuring customer satisfaction. The "Relationship" survey measured the percentage of randomly selected residential and business customers who give an 'excellent' or 'very good' response out of 5 worded choices in grading the Company's overall quality. The Plan score for the Relationship survey was an average of the percentage scores for each of the three customer class surveys (residential, small business, and large commercial)

The "Transaction" survey measured the percentage of customers who give an 'excellent' or 'very good' response (again, out of 5 worded choices) in grading the overall quality of a recent transaction the customer recently had with Xcel Energy. The types of customer contacts that were included in the transaction surveys were customer calls to start/stop electric service, report an outage, make credit/collection arrangements, discuss electric service issues, inquire about products and services, respond to an Xcel Energy notification, obtain usage information, report equipment damage, respond to a disconnect notice, discuss issues regarding utility poles, inquire about appliance repair, or ask for general information.

a. Survey Question and Response Scale

Currently, the relationship survey scores reflect the percentage of respondents who give Xcel Energy an 'excellent' or 'very good' rating out of the five established response choices on a question relating to "overall quality" of Xcel Energy products and services

"I'd like you to think of your entire relationship with Xcel Energy overall. Cons►denng everything, how would you rate the overall quality of products, services, and support you receive from Xcel Energy? Would you rate your overall experience as: excellent; very good, good, fair; or poor?

And, in the transaction satisfaction surveys, the current question is:

"Thinking specifically of this entire recent interaction with Xcel Energy, from the time you first contacted Xcel Energy until your issue was resolved, how would you rate the quality of service provided by Xcel Energy? Would you rate your overall experience as excellent; very good, good, fair; or poor?

The original PLUS Plan customer satisfaction standards were based on historic company-wide Company survey results from the previous three years (1998-2000). As contemplated in the original Plan settlement, these were updated in 2003 to reflect an additional two years (2001-2002) of results from North Dakota customers only.

Beginning in 2005, Xcel Energy proposes to focus on a slightly different survey question and utilize a different response scale to track customer satisfaction. Xcel Energy proposes to determine its PLUS relationship survey score by tracking and reporting the percentage of customers who give Xcel Energy a rating of 8, 9, or 10 (on a scale of 0 to 10) to the following question

"I'd like you to think in terms of your satisfaction with Xcel Energy. On a 0 to 10 scale where 10 means very satisfied and 0 means very dissatisfied, how would you rate your satisfaction with Xcel Energy?

Similarly, Xcel Energy would measure its "transaction "customer satisfaction performance by tracking and reporting the percentage of customers who give Xcel Energy a score of 8, 9, or 10 (on a scale of 0 to 10) to the following question

> *"Thinking specifically of this recent interaction with Xcel Energy, from your first contact until your issue was resolved, how would you rate the service provided? (on a 0 to 10 scale, where 10 means very satisfied with how your entire transaction was handled and 0 means you were very dissatisfied)*

Xcel Energy proposes this change because:

1 rating overall satisfaction is a more intuitive concept for customers than defining "overall quality";

2 an 11 point (0-10) scale using numerical ranking (as opposed to worded responses) provides more rating choices for respondents, and represents a more symmetrical set of responses than the current survey methodology;

3. rating customer satisfaction (as opposed to overall quality) with an 11 point scale (as opposed to a 5 point scale) is consistent with how the Company internally measures satisfaction in its other jurisdictions; and

4 the question is consistent with that used in the American Customer Service Index ("ACSI") from which external benchmarks can be obtained

b. Customer Satisfaction Standard

Consistent with the setting of the existing survey performance standards, the proposed Relationship and Transaction survey standards in 2005 would be based on the previous three-year average of Xcel Energy's satisfaction results in North Dakota Xcel Energy has been tracking results in North Dakota for the "customer satisfaction" question using the 11 point response scale since the company began using it across its 11 state service area in 2002. The North Dakota results are as shown below.

	Relationship	Transaction
2002	76 0%	70 4%
2003	77 7%	74 5%
2004	81.8%	69.5%
Avg.	78.5%	71.5%

Note 2004 reflects year to date results through July

Rounding the averages to the nearest half percent, the 2005 standards would be as shown below, using the same +/- 3% range in place currently.

Relationship.	< 75 5%	78 5%	> 81.5%
Transaction	< 68.5%	71 5%	> 74.5%

See Attachment A, pages 1 and 2 for more detailed information regarding the current and proposed survey standards The two survey standards will continue to carry a potential adjustment (reward and/or penalty) of 25 basis points to the authorized ROE deadband.

2. Improved Rate Management Standard

Unlike the Plan's other 5 performance indicators, the PLUS Plan currently uses external, regional rate data to establish new rate performance standards each year. A "competitive price" standard is set based on the most recent year's average residential rate (revenue per kwh) for a comparison group of about 30 mid-western utility jurisdictions. In addition, the PLUS Plan currently sets an annual 'rate management' standard based on the change in residential rates for the lowest priced utility in the peer group for the previous year

Currently, the two price standards are recalculated each Plan target year using utility price data compiled in an Edison Electric Institute publication entitled *Typical Bills and Average Rates Report,* issued twice per year. For purposes of the PLUS Plan, the "winter" edition reflecting the 12 month period ending December 31 st of the year just prior to the target year is used

Consistent with the competitive price standard, the proposed rate management standard in 2005 would be based on the change in the average residential rate for the utility jurisdictions shown in the calendar year **EEI** rate report. In addition to being consistent with the competitive price measure, using the utility group average from the prior year also mitigates volatility in the standard from year to year, is more representative of the general rate change trends in the regional "market", and it brings clarity to the standard. Because of this, the new standard will more effectively reward relatively favorable rate change, or penalize relatively unfavorable rate changes, than the current standard. See Attachment A, page 3 for more information regarding the proposed rate management standard.

The range of acceptable performance for this metric would be defined by one standard deviation (around the mean) of the changes in rates for each of the utilities in the comparison group. In years with higher variability, the range will be wider. In years when the "market" shows lower rate change variability, the range will be narrower. See attachment B for information relating to the standard deviation calculation

-1 To mitigate the impacts of extreme price fluctuations by individual utilities in the group, the two utilities with the highest increase and the highest decrease in average rates are removed from the group prior to calculation of the standard deviation

The price measure will continue to carry a potential reward and/or penalty of a 25 basis point adjustment to the authorized ROE deadband.

<u>The PLUS Plan</u>

A Performance-based Regulatory Framework

For
Northern States Power Company
Electric Operations
In
North Dakota

Effective January 1, 2001[1]

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[1] Modified January 1, 2005.

Table of Contents

I. Introduction 3

II. Description of the PLUS Plan 3

A. Dynamic Authorized ROE Bandwidth 4

B. Revenue Sharing 4

C. Performance Standards 6

D. Changes in Base Rates 8

E. Regulatory Reporting and Review 12

F. Other PLUS Plan Considerations 13

G. Conditions for Suspension or Terminiation 14

Revenue Sharing Illustration Attachment A

Dynamic ROE Deadband Example Attachment B

Performance Indicators and Standards Attachment C

Utility Comparision Group Attachment D

PLUS Price Cap Decision Model Attachment E

Price Cap Factor Example Attachment F

2005 Plan Modifications Summary Attachment G

~~NORTHERN STATES POWER COMPANY~~
~~PLUS PERFORMANCE-BASED REGULATION PLAN~~
~~EFFECTIVE JANUARY 1, 2001~~

I. INTRODUCTION

On April 20, 2000, pursuant to N.D.C.0 49.02.02 and N.D.C.C. 49.02.03, Northern States Power Company ("NSP" or "the Company") filed a performance-based regulation plan entitled ***Performance Linking Utility Stakeholders*** ("PLUS Plan" or "the Plan") with the North Dakota Public Service Commission ("NDPSC" or "Commission"). The PLUS Plan would modify the method of Commission regulation of NSP's retail electric rates and services in North Dakota consistent with the *Guidelines for Alternative Regulation Proposals* established by the NDPSC in Case No. PU-439-94-590 by order dated September 20, 1995.

After a hearing, the PLUS Plan, as modified by a Settlement Agreement between the Company and Commission Staff, was approved by the Commission by order dated December 29, 2000, as amended by supplemental order dated January 10, 2001. The orders required the Company to submit a PLUS Plan summary in compliance with the Settlement Agreement and orders.

On February , 2005, the Commission approved modifications to three of the performance indicators and the rate change criteria, effective January 1, 2005. Details of the revisions are included in this document.

II. DESCRIPTION OF THE PLUS PLAN

The key components of the approve LUS Plan include 1) a dynamic "allowed ROE" range which can vary based on Company performance, 2) a revenue sharing mechanism, 3) establishment of service and operating performance standards, and 4) flexibility to adjust prices under specified circumstances, and 5) comprehensive annual reporting of the Plan results to the Commission by May 1 st following the end of each Plan year. The individual components, as established by the Settlement Agreement and approved by the Commission orders, are as follows:

A. DYNAMIC AUTHORIZED ROE BANDWIDTH

An authorized baseline return on equity (ROE) of 12.0% is established. A range of +1- 100 basis points around the baseline ROE will represent an "acceptable authorized range" or "deadband" of earnings performance. Actual Company reported ROE for the Company's North Dakota electric operations which fall within this deadband are considered reasonably close to the baseline, and will not trigger any revenue sharing or rate adjustment (see Attachment A).

During the Plan term, the ROE deadband shall be subject to annual "basis point" adjustments depending on the Company's performance under each Plan performance standard, as provided herein. If the net performance basis points are positive (award), the upper end of the allowable ROE deadband increases. If the net performance points are negative (penalty), the lower end of the ROE deadband is decreased. The baseline does not change.

B. REVENUE SHARING

As stated previously, if the Company's reported actual earnings fall within the ROE deadband (as adjusted by the performance points) in a given Plan year, there will be no revenue sharing.

If the Company's actual reported earnings for any given Plan year exceed the ROE deadband, the corresponding revenue 'excess' will be calculated, and 50% of this dollar amount will be refunded to customers during the July billing cycle following the Plan year. Customers of record on March 31 following the Plan year will be issued refunds by bill credit prorated on the basis of their electric usage for the twelve months ending March 31.

If actual Company earnings are below the deadband, 50% of the corresponding revenue deficiency is recovered through a surcharge on the Company's electric rates effective no later than 24 months after the Plan year.

However, NSP will defer any reported fiscal year deficiency amount as a regulatory asset until the following Plan year revenue sharing amount -- if any -- is determined. If the prior year deficiency is fully offset by a current year reported revenue excess, the excess will be used to eliminate the regulatory asset, and no rate surcharge will be imposed. If the deficiency from the prior year is not fully offset, any remaining deficiency balance will be billed through a rate surcharge and collected over the remaining six-month period beginning July 1 of the year following the Plan fiscal reporting year, unless otherwise requested by either the Company or Commission Staff and approved by the Commission.

The customer share of any Plan refund or deficiency surcharge will be shown separately as a "performance-based dividend" or "performance-based surcharge", respectively, on customer bills. Plan dividends paid to customers or surcharges received will be excluded from the Company's regulated earnings statement for the Plan year in which the said dividends or surcharges are actually implemented.

Any deferred deficiency balance remaining at the end of the 5-year Plan term will first be considered as part of an on-going Plan, or alternatively, collected from customers through a surcharge.

Attachment B to this document provides an explanation of the dynamic ROE bandwidth and revenue sharing mechanisms provided in the PLUS Plan.

C. PERFORMANCE STANDARDS

The PLUS Plan takes a "comprehensive" approach to the utilization of performance measures and standards. NSP's performance will be measured by seven high level indicators within the areas of electric reliability, customer satisfaction, price, and employee safety. In the Plan, ranges of 'acceptable performance' are established around each performance standard. Performance results which are outside of PLUS's acceptable performance ranges will result in either an increase or decrease in the allowable ROE deadband. Each performance measure can adjust the ROE deadband by 25 basis points.

Three of the four performance areas have 2 indicators each, and hence have the ability to affect the baseline ROE and bandwidth up or down by 50 basis points, or 0.5% ROE. Safety has a single indicator with a total potential impact of 25 basis points, or 0.25%. The ROE impact of each measure is additive, meaning that it is possible for the combined effect on the baseline ROE of all seven measures to be anywhere from —1.75 % to +1.75 %, in increments of 0.25%.

<u>Effective January 1, 2005, the PLUS Plan was amended to utilize the customer satisfaction measurement process the Company has established for all of its four</u>

operating companies. This change affected both the Relationship and Transaction surveys. In addition, the determination of the performance standard for the "rate change" indicator was also revised for 2005. See Attachment G for a description of these approved changes.

The following tables summarize the performance standards to be used in PLUS. Additional information on each measure is found in Attachment C.

RELIABILITY

Measiirt	Award Iheesbold	;Target;	;,'Penalty,,Thresh Old
CAIDI	< 75.6 minutes	89.0 minutes	> 102 4 minutes
SAIFI	< 0.77 outages/yr.	0.90 outages/yr.	> 1.04 outages/yr.

CUSTOMER SATISFACTION

Measure	AWirclAifeshold':'	l'arget1-;	..-61141tklftCAibilit .=,:'
Relationship survey ~~positive satisfaction~~ response %*	> 847081.5%	847078.5%	< 787075.5%
Transaction survey ~~positive satisfaction~~ response %*	> 66,074.5%	6-37071.5%	< 60,068.5%

PRICE

144sllre	Amardx, 'OSIiiild	Tar at;	Penal
Competitive Residentialll pfic-erate position	< 85% of target	peer group avg. res'l pric-erate/kWh	> 115% of target
Annual change in ayg, Reslhdential avg, ppieerate*	< (target-.051 St. Dev.) 0440	annual % change in lewest-prieedavg, residential rate of the utility comparison group ~~avg. res'l pric-WIE-W43,~~	> (target+.051 St. Dev.) 0/kwh)

* Modified for 2005 Plan year See Attachment G

SAFETY

Measure	iiiid 6RfaCt	Target	‘P,'enaltY7ThikshOld:. :,
OSHA incident rate	< 3.70	4.32	> 5.00

D. CHANGES IN BASE RATES

The PLUS Plan incorporates both inflationary and 'market price' factors in the calculation of the allowable rate change parameter, or "Price Cap Factor". The Plan thus ensures the Company's retail electric rates will, adjusted for inflation, decrease over the term of the Plan.

1. Factors Which Regulate Base Rate Changes

The PLUS Plan allows for the implementation of annual rate adjustments, depending on the following four factors:

- The Company's recently reported earnings levels;
- The Company's price position in the region;
- Average % residential price changes of the 'market' comparison group (see Attachment D);
- Percentage changes in the Consumer Price Index (adjusted by an efficiency target factor).

These four factors work together each year to freeze rates, limit rate increases, or in certain circumstances, mandate rate decreases. Attachment E is a graphical flowchart showing how these factors operate to determine base rate changes in the PLUS Plan.

a. Earnings Levels

Under the PLUS Plan, if the Company's reported ROE for its electric operations in North Dakota is higher than the ROE deadband midpoint less 100 basis points (1.0%), no rate increase is allowed in the following year, even if the inflation and comparison group price data support one. Conversely, price reductions supported by the CPI /comparison group price cap cannot be imposed if the Company's ROE is lower than the ROE deadband midpoint plus 1.0%.

b. Competitive Rate Position

Rate increases will not be allowed if the Company's average residential rate is higher than the comparison group average residential rate. Also, no decrease in rates will be required if the Company's average residential rate is lower than the comparison group's average residential rate.

c. Comparison Group Price Change

The annual percentage change in average residential rates for the seven state comparison group is calculated and used as the price cap factor for any rate change the Company may or must implement (unless inflation is even lower — see item # 4 below). Should the group average residential price decline, the Company is required to reduce its electric rates accordingly, unless reported actual ROE was deficient or the Company's actual rates were already less than the comparison group average, as discussed in items #1 and #2 above.

d. Inflation and Efficiency Target

To assure the Company's rates decline in real terms over the PLUS Plan period, the annual rate of inflation as measured by the Consumer Price Index (Urban) is also factored into the price cap formula. The CPI for the Plan reporting year is computed by averaging the annual CPIs reported at the end of each calendar quarter. The resulting average CPI rate is then multiplied by 60% (to reflect the Plan's "efficiency factor"). If the result is lower than the average comparison group residential price change percentage, the adjusted CPI factor replaces the average group price change percentage as the price cap factor for any Company rate change percentage. The amount of the rate change is thus limited to the lower of 1) the change in residential rates for the seven state mid-west market, or 2) 60% of the rate of inflation (CPI). See Attachment F for an example of this calculation.

2. Rate Change Procedure

Any proposed rate change allowed by the Plan would be reported to the Commission in the Company's Annual Regulated Earnings report on May 1 following the Plan year. To implement any permissive rate increase or mandatory rate reduction under PLUS, the Company will file a notice of rate change and the accompanying tariffs pursuant to N.D.C.C. 49-05-05 not later than June 1.

The revised rates shall be effective on or after July 1 following the Plan year. Base rate changes will be across-the-board to all customer classes unless an alternative design is requested by the Company and approved by the Commission. The notice of rate change will not be suspended by the Commission under N.D.C.C. 49-05-06, but the revised rates shall be allowed to go into effect on the date proposed. If the Commission determines after investigation and hearing that the changed rates do not comply with the Plan terms as prescribed herein, the Commission may prospectively establish the rates it finds to be consistent with the Plan terms, and order a one-time billing true-up for the impact of the discrepancy since either the inception of the rate change or the previous 12 month period, whichever is less. Rates established consistent with the Plan are presumed just and reasonable, and non-discriminatory.

3. Materiality of Exogenous Events

Changes to base rates are subject to the rate change criteria and price cap mechanisms included in the Plan. There may be unusual and significant circumstances, however, where it is reasonable to make an exception to the Plan's rate normal rate change provisions. The Company proposes that should a specific and identifiable event, or combination of events, occur which causes a change in the costs of providing electric service (or collection of revenues) of such magnitude that there will be at least a 1.0% change in the North Dakota electric jurisdictional return on equity, an adjustment in rates will be required. Such an event may include but not be limited to governmentally imposed changes (tax law, etc.), a change in generally accepted accounting practices, industry restructuring, natural disasters, catastrophic loss, or terrorism. The corresponding adjustment to rates would be implemented within 90 days of the event or effective date of the mandate, unless otherwise agreed to by the Commission and Company.

E. REGULATORY REPORTING AND REVIEW

1. Annual Report

On or before May 1 of the year following the fiscal period being reviewed, the Company will file with the Commission a report showing:

- The Company's regulated electric earnings and return on equity (before and after any earnings sharing) in North Dakota for the fiscal year just completed;
- Summaries of operating revenue, expense, and regulated electric rate base;
- The Company's regulated capital structure including debt and equity ratios, cost of capital, and return on rate base;
- Calculation of baseline ROE and the authorized earnings bandwidth for the Plan review year;
- Annual results, awards, and penalties related to the Company's performance in the areas of reliability, price, customer satisfaction, and safety;
- Amount of revenues subject to sharing and the 'customer dividend' or surcharge;
- Comparison group average residential rates for the year in review;
- The calculation of the Price Cap Factor (CPI, comparison group rate changes);
- Proposed rate change percentages and typical bill impact for all customer classes.

2. Commission Review

Upon receipt of the PLUS earnings report in May, the Commission will perform its annual review, per existing Commission rules. A Staff report may be filed with the Commission. If none of the conditions for suspension of the Plan apply, any refunds, charges, and/or proposed rate adjustments allowed by the Plan and properly filed by the Company will go into effect on July 1.

F. OTHER PLUS PLAN CONDITIONS

The following conditions of the PLUS Plan will also apply:

1. Plan Term

The PLUS Plan commences on January 1, 2001. Except as provided herein, the PLUS Plan will remain in effect for a five year term ending December 31, 2005. Prior to July 1, 2005, the Company may file for an extension and/or modification of the Plan if so desired. Absent such a filing and a further order of the Commission extending the Plan, the PLUS Plan will automatically terminate on December 31, 2005.

2. Commission Interim Review

After the first two years of the term have been completed, the Commission may conduct an informal review hearing after May 1, 2003, to assess the Plan's results and discuss potential improvements. It is anticipated that the Commission and the Company will continue to have open communication and constructive dialogue during the plan term and, when necessary, agree to make general modifications or refine certain elements of the Plan.

3. Fuel Clause Adjustment Mechanism

The Company's Fuel Clause Adjustment ("FCA") will remain in effect during the PLUS Plan term and operate as it does currently to adjust customer bills for changes in fuel and purchased energy costs. The comparative price performance standards discussed previously will be calculated using total Residential revenue per kWh including the FCA adjustments in effect during the Plan reporting year.

4. Demand Allocation Method

For purposes of calculating the Company's jurisdictional expenses for each PLUS Plan reporting year, 36 months of historical demand data will be used to establish the Demand Allocation factor (known as D10). The Demand Allocation factor is used to assign production and transmission related costs and investment to the Company's retail electric jurisdictions in North Dakota, South Dakota and Minnesota. The use of a 36 month demand allocator is for financial reporting purposes under the Plan only. Use of a 36 month historic allocator for the Plan shall have no precedential effect in future electric rate increase applications after the Plan term expires or if the Plan is suspended or terminated

G. CONDITIONS FOR SUSPENSION OR TERMINATION OF PLAN

The Plan is intended to remain in effect for five years beginning January 1, 2001. However, the Company and Staff reserve the right to request adjustment, suspension, or termination of the Plan under the following events:

- Federal and/or state tax law changes;

- Passage of retail access legislation at either the federal or state level;
- Merger and acquisition events affecting the Company's structure and operations;
- Natural disasters affecting the Company's North Dakota electric operations (major storms, floods, etc.);
- Unusual events affecting the Company's operations (major generating plant failure, damage to major transmission or distribution lines, etc.); or
- Material and sustained earnings extremes (defined as returns on equity +/- 5.0% from the ROE deadband, prior to sharing).

It is anticipated the Commission and Company will make reasonable efforts to resolve any condition that could otherwise trigger a Company application or Commission motion to suspend the Plan before any decision to terminate operation of the Plan during the Plan term.

III Li OCT 2 9 2004 ED

Memo

ND PURLIC SERVICE COMMISSION
EXECUTIVE SECRETARY

To: Illona Jeffcoat-Sacco, Executive Secretary

From: Mike Diller, Director of Accounting se

Date: October 29, 2004

Re: NSP's Request to Revise PBR (Case No. PU-400-03-256)

On September 20, 2004, the commission received a revised proposal from Northern States Power Company requesting modifications to its existing performance-based regulation plan. **Staff is in agreement with the requested modifications and recommends that the commission approve the changes.**

As NSP's filing demonstrates, staff and the company have been working together to try and improve the existing plan for more than a year. NSP strongly advocates the use of external measurement criteria for establishing new PBR standards. Staff is in agreement with that concept but believes the resulting standards are too soft for a company like NSP. NSP's preferred standards do not include enough of a "stretch factor."

Because staff was unable to come to an agreement with the Company, the revised proposal represents a type of settlement to enact the portions for which there is agreement. Any wholesale changes to the plan will be argued later should NSP decide to seek an extension of the plan past 2005. The resulting changes to the plan are not all that substantial and could be characterized as "housekeeping" in nature.

In its revised proposal, NSP requests that its customer satisfaction standards be developed around an 11-point scale rather than the existing 5-point scale and argues to improve the wording of its customer surveys. On page 7 of its filing, NSP reasons that the proposed changes make the surveys more intuitive, symmetrical, and consistent with internal and external benchmarks. Staff does not oppose these changes.

NSP also argues for change of the rate management standard to make it more stable and meaningful. Currently, the standard is based on the annual change in the residential rate for the lowest priced utility in the region. Because it is based on one company, the year to year benchmark can vary significantly.

The new standard proposed in this filing sets the rate management standard using one standard deviation around the mean of the changes for all utilities in the region. Any performance outside the one standard deviation framework would result in either a reward or a penalty. Measuring the volatility of rates from one year to the next against all the companies in the region will smooth out the fluctuations which are inherent in the existing benchmark.

Last, the existing PBR plan includes language allowing NSP and commission staff to request adjustment, suspension, or termination of the PBR plan for exogenous events such as tax law changes, federal or state legislation, disasters etc. The new language in this proposal would require that any such costs are passed through in rates but only those events that impact North Dakota electric earnings on common equity by more than 1 percentage point.

Staff agrees with establishing a materiality benchmark for passing through exogenous costs and agrees that any such events meeting the benchmark will be passed through to customers.

Staff does not believe the changes incorporated in NSP's revised filing are significant to the plan as a whole and will prepare an order for commission approval. The order will require a compliance filing to incorporate the new language into the currently approved PBR plan.

Xcel Energy

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(701) 241-8632
dave sederquist@xcelenergy corn

September 17, 2004

Illona A. Jeffcoat-Sacco, Executive Secretary
North Dakota Public Service Commission
State Capitol Building, Dept. 408
600 East Boulevard
Bismarck, ND 58505-0480

Re: Revised PLUS Plan Modification Proposal

Dear Ms. Jeffcoat-Sacco:

Enclosed you will find for Commission review and approval an original and seven copies of Xcel Energy's *revised* modification proposal for its PLUS performance-based regulation plan.

The modifications included in this petition represent substantially fewer changes than what is currently pending before the Commission as part of the Company's original modification proposal, filed December 16, 2003. Since that filing, an informal hearing and a number of discussions have been conducted between the Company and North Dakota Public Service Commission Staff. The general consensus of those meetings has been to scale back the modifications sought, largely due to the fact that only one year remains in the initial five year term for the PLUS Plan.

Therefore, with this application, Xcel Energy proposes to revise its current modification proposal to focus on 1) changes to its method of surveying customer satisfaction, 2) improving the annual rate change standard, and 3) establishing an exception threshold for addressing exogenous events.

Please contact me if you have any questions about this application.

Sincerely,

David H. Sederquist
Sr. Consultant, Regulation & Finance

Enclosures

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STATE OF NORTH DAKOTA 11 SEP 2 0 2004
BEFORE THE
PUBLIC SERVICE COMMISSION

Northern States Power Company
d/b/a Xcel Energy

Case No.: PU-400-03-256

PROPOSED CHANGES To THE PLUS PLAN,
A PERFORMANCE-BASED REGULATION MODEL
BY NORTHERN STATES POWER COMPANY D/B/A XCEL ENERGY

I. INTRODUCTION

Pursuant to N.D Cent Codes § 49-02-03 and 49-02-04, Northern States Power Company d/b/a Xcel Energy ("Xcel Energy" or "the Company") hereby petitions the North Dakota Public Service Commission ("NDPSC" or "Commission") to approve proposed changes, contained herein, to the performance-based regulation ("PBR") plan, called the PLUS Plan ("PLUS" or "Plan"), that regulates its retail electric operations in North Dakota, to be effective January 1, 2005. The proposed modifications reflect a scaled back version of the modification application filed with the Commission on December 16, 2003. In summary, the changes proposed herein are designed to.

1. enhance the methodology used to survey customers and measure satisfaction,

2 improve the "rate management" measure by reducing volatility and more reasonably reflecting utility "market" data to establish the standard, and

3 define a threshold of materiality for purposes of making adjustments to the plan for certain exogenous events.

Other modifications the Company proposed in the December 16 application for establishing performance standards and adjusting the allowed earninas deadband and rate change threshold are withdrawn at this time. Xcel Energy reserves the option to reintroduce those provisions if and when the Company files for a PLUS Plan term extension in 2005.

II. BACKGROUND

On December 29, 2000, the Commission issued an order approving the PLUS Plan, as modified and agreed to by representatives of Xcel Energy and Commission Staff in a Final Settlement Agreement dated December 28, 2000. The PLUS Plan commenced on January 1, 2001, to be in effect for a five-year term ending December 31, 2005. The Company may file, prior to July 1, 2005, for an extension and/or modification of the Plan if so desired Absent such a filing and order of the Commission extending the Plan, the PLUS Plan will automatically terminate on December 31, 2005.

One of the provisions in the PLUS Plan was to conduct a "mid-term" review of the Plan after the first two years of the Plan's five year term had been completed. In the spring of 2003, the Commission opened a review docket to assess the outcomes thus far of PLUS and make any necessary or desired adjustments

The Company and Commission Staff held two discussion meetings to address various aspects of the Plan as it was applied during 2001 and 2002. On March 17, 2003, a meeting was held in Jamestown with representatives from the Staff, Xcel Energy, and OTP. Items discussed included the plan's rate changing process, performance standard development; changes to customer satisfaction surveying; modifying the dynamic allowed ROE deadband, and certain administrative provisions.

On May 20, 2003, the Commission conducted separate Periodic Information Exchange meetings with Xcel Energy and Otter Tail Power Company ("OTP") in which updates of the 2002 PBR results of both plans were given

On June 18, 2003, the Commission conducted an informal hearing on the PBR plans of Xcel Energy and OTP. Commission advised the Companies and Staff to continue to work on improvements to the Plans, with the intention of ensuring that modifications could be presented and approved in time for a January 1, 2004 implementation.

Another meeting between the Company and Commission Staff was held on July 24 th in Jamestown to discuss more specific Company proposals that had been developed since the March 17 meeting. Staff took the proposals under advisement at that time.

In September and October, various phone conversations and electronic document transmissions were conducted between Xcel Energy and Staff in an effort to reach agreement primarily on the performance standard setting methodology. A number of different proposals were discussed for establishing revised Plan standards for the 2004 and 2005 years Although the Company and Staff did not agree on all of the proposed revisions, progress was made in identifying parts of the Plan that could be improved and determining what industry benchmarks were available for use in the establishing performance standards.

On December 16, 2003, Xcel Energy filed a Plan modification proposal with the Commission. The Commission held a hearing on the application on February 25, 2004. At the hearing, the Company presented its rationale for proposing the various changes. The Commission determined that it would like to have an opportunity to review the industry data that was being used to establish the proposed industry-based performance standards. Xcel Energy began to assemble an informational filing to submit to the Commission.

On May 4, 2004, Xcel Energy reported its 2003 regulated electric earnings and operational performance under the PLUS Plan. In its report, the Company indicated that its good service performance and low rates, in combination with lower than authorized earnings, had qualified the company for a limited rate increase (1.4%) and one time deficiency sharing surcharge ($954,000).

A Staff review of the Company's jurisdictional financial report and subsequent discussions during the summer of 2004 between Company representatives and Staff led to an informal agreement that Xcel Energy would not propose changes to the performance standard and rate changing mechanisms in the Plan that would only be in effect for the one remaining year of the PLUS Plan term (2005) Company representatives and Staff informally agreed that significant changes of that nature should be heard as part of a future application, should one be filed, to renew the PLUS Plan or some form of it for another multi-year period.

The more limited Plan changes outlined in this filing regarding measurement of the customer satisfaction standard, the rate management standard, and the exception threshold represent incremental but needed changes, and are mutually agreeable to both Staff and the Company. All other terms of the original Plan as approved by the Commission and not addressed in this proposal will remain in force for the 2005 Plan year.

III. THE PROPOSED MODIFICATIONS WOULD SERVE THE PUBLIC INTEREST

The Company believes the modifications proposed here are consistent with the public interest and consistent with the Commission's 1995 Guidelines for Filing Alternative

Regulation Proposals. Xcel Energy believes the customer survey changes will minimize the administrative efforts and costs of assessing customer satisfaction, while producing more meaningful metrics comparable to those found in the industry. Changes to the rate management standard will produce a more stable and meaningful standard. Lastly, the establishment of an objective threshold for determining which events should trigger a Plan exception, adjustment, or suspension will help to alleviate potential disputes. Documentation in support of this is attached hereto

IV. PROPOSED MODIFICATIONS

1. **Customer Satisfaction Measurement**

The PLUS Plan presently utilizes two kinds of surveys for purposes of measuring customer satisfaction. The "Relationship" survey measures the percentage of randomly selected residential and business customers who give an 'excellent' or 'very good' response out of 5 worded choices in grading the Company's overall quality. The Plan score for the Relationship survey is an average of the percentage scores for each of the three customer class surveys (residential, small business, and large commercial).

The "Transaction" survey measures the percentage of customers who give an 'excellent' or 'very good' response (again, out of 5 worded choices) in grading the overall quality of a recent transaction the customer recently had with Xcel Energy. The types of customer contacts that are included in the transaction surveys include customer calls to start/stop electric service, report an outage, make credit/collection arrangements, discuss electric service issues, inquire about products and services, respond to an Xcel Energy notification, obtain usage information, report equipment damage, respond to a disconnect notice, discuss issues regarding utility poles, inquire about appliance repair, or ask for general information.

a. Survey Question and Response Scale

Currently, the relationship survey scores reflect the percentage of respondents who give Xcel Energy an 'excellent' or 'very good' rating out of the five established response choices on a question relating to "overall quality" of Xcel Energy products and services:

> *"I'd like you to think of your entire relationship with Xcel Energy overall. Considering everything, how would you rate the overall quality of products, services, and support you receive from Xcel Energy? Would you rate your overall experience as: excellent; very good; good; fair; or poor?*

And, in the transaction satisfaction surveys, the current question is:

> *"Thinking specifically of this entire recent interaction with Xcel Energy, from the time you first contacted Xcel Energy until your issue was resolved, how would you rate the quality of service provided by Xcel Energy? Would you rate your overall experience as: excellent; very good; good; fair; or poor?*

The original PLUS Plan customer satisfaction standards were based on historic company-wide Company survey results from the previous three years (1998-2000). As contemplated in the original Plan settlement, these were updated in 2003 to reflect an additional two years (2001-2002) of results from North Dakota customers only.

Beginning in 2005, Xcel Energy proposes to focus on a slightly different survey question and utilize a different response scale to track customer satisfaction. Xcel Energy proposes to determine its PLUS relationship survey score by tracking and reporting the percentage of customers who give Xcel Energy a rating of 8, 9, or 10 (on a scale of 0 to 10) to the following question:

"I'd like you to think in terms of your satisfaction with Xcel Energy. On a 0 to 10 scale where 10 means very satisfied and 0 means very dissatisfied, how would you rate your satisfaction with Xcel Energy?

Similarly, Xcel Energy would measure its "transaction "customer satisfaction performance by tracking and reporting the percentage of customers who give Xcel Energy a score of 8, 9, or 10 (on a scale of 0 to 10) to the following question:

"Thinking specifically of this recent interaction with Xcel Energy, from your first contact until your issue was resolved, how would you rate the service provided? (on a 0 to 10 scale, where 10 means very satisfied with how your entire transaction was handled and 0 means you were very dissatisfied)

Xcel Energy proposes this change because:

1. rating overall satisfaction is a more intuitive concept for customers than defining "overall quality";
2. an 11 point (0-10) scale using numerical ranking (as opposed to worded responses) provides more rating choices for respondents, and represents a more symmetrical set of responses than the current survey methodology;
3. rating customer satisfaction (as opposed to overall quality) with an 11 point scale (as opposed to a 5 point scale) is consistent with how the Company internally measures satisfaction in its other jurisdictions; and
4. the question is consistent with that used in the American Customer Service Index ("ACSI") from which external benchmarks can be obtained.

b. Customer Satisfaction Standard

Consistent with the setting of the existing survey performance standards, the proposed Relationship and Transaction survey standards in 2005 would be based on the previous three-year average of Xcel Energy's satisfaction results in North Dakota. Xcel Energy has been tracking results in North Dakota for the "customer satisfaction" question using the 11 point response scale since the company began using it across its 11 state service area in 2002. The North Dakota results are as shown below:

	Relationship	Transaction
2002	76.0%	70.4%
2003	77.7%	74.5%
2004	81.8%	69.5%
Avg.	78.5%	71.5%

Note 2004 reflects year to date results through July

Rounding the averages to the nearest half percent, the 2005 standards would be as shown below, using the same +/- 3% range in place currently.

Relationship	< 75.5%	78.5%	> 81 5%
Transaction	< 68.5%	71.5%	> 74.5%

See Attachment A, pages 1 and 2 for more detailed information regarding the current and proposed survey standards. The two survey standards will continue to carry a potential adjustment (reward and/or penalty) of 25 basis points to the authorized ROE deadband.

2. Improved Rate Management Standard

Unlike the Plan's other 5 performance indicators, the PLUS Plan currently uses external, regional rate data to establish new rate performance standards each year. A "competitive price" standard is set based on the most recent year's average residential rate (revenue per kwh) for a comparison group of about 30 mid-western utility jurisdictions. In addition, the PLUS Plan currently sets an annual 'rate management' standard based on the change in residential rates for the lowest priced utility in the peer group for the previous year.

Currently, the two price standards are recalculated each Plan target year using utility price data compiled in an Edison Electric Institute publication entitled *Typical Bills and Average Rates Report,* issued twice per year. For purposes of the PLUS Plan, the "winter" edition reflecting the 12 month period ending December 31[st] of the year just prior to the target year is used.

Consistent with the competitive price standard, the proposed rate management standard in 2005 would be based on the change in the average residential rate for the utility jurisdictions shown in the calendar year EEI rate report. In addition to being consistent with the competitive price measure, using the utility group average from the prior year also mitigates volatility in the standard from year to year, is more representative of the general rate change trends in the regional "market", and it brings clarity to the standard. Because of this, the new standard will more effectively reward relatively favorable rate change, or penalize relatively unfavorable rate changes, than the current standard. See Attachment A, page 3 for more information regarding the proposed rate management standard.

The range of acceptable performance for this metric would be defined by one standard deviation (around the mean) of the changes in rates for each of the utilities in the comparison group. In years with higher variability, the range will be wider. In years when the "market" shows lower rate change variability, the range will be narrower. See attachment B for information relating to the standard deviation calculation.

The price measure will continue to carry a potential reward and/or penalty of a 25 basis point adjustment to the authorized ROE deadband.

3. **Materiality of Exogenous Events**

Changes to base rates are subject to the rate change criteria and price cap mechanisms included in the Plan. There may be unusual and significant circumstances, however, where it is reasonable to make an exception to the Plan's rate normal rate change provisions. The Company proposes that should a specific and identifiable event, or combination of events, occur which causes a change in the costs of providing electric service (or collection of revenues) of such magnitude that there will be at least a 1 0% change in the North Dakota electric jurisdictional return on equity, an adjustment in rates will be required. Such an event may include but not be limited to governmentally imposed changes (tax law, etc.), a change in generally accepted accounting practices, industry restructuring, natural disasters, catastrophic loss, or terrorism. The corresponding adjustment to rates would be implemented within 90 days of the event or effective date of the mandate, unless otherwise agreed to by the Commission and Company.

[1] To mitigate the impacts of extreme price fluctuations by individual utilities in the group, the two utilities with the highest increase and the highest decrease in average rates are removed from the group prior to calculation of the standard deviation

4. Other Plan Criteria Are Not Changed

All other terms of the original Plan as approved by the Commission and not addressed in this proposal will remain in force for the 2005 Plan year.

VI. CONCLUSION

For the foregoing reasons, Northern States Power Company d/b/a Xcel Energy requests that the North Dakota Public Service Commission approve the proposed enhancements to the PLUS Plan to be effective January 1, 2005. The proposed modifications shall be effective for the 2005 Plan year, at which time the PLUS Plan will expire unless an extension or new plan is sought by the Company and approved by the Commission.

Please direct any questions regarding this Notice to Mr. Dave Sederquist at (701) 241-8632 or Mr. Jim Johnson at (612) 215-4592.

Respectfully Submitted,

By ______________________________
131 fflk,"

Kent T. Larson
Vice-President, Jurisdictional Relations

Date: September 16, 2004

Northern States Power Company d/b/a Xcel Energy
Electric Utility - North Dakota Jurisdiction
Proposed PLUS Plan Performance Standards for 2005
Price - Annual Change (average residential rate)

	Midwest Utility Group	2001	2002	2003	2004	2005
1	Average price change	3 7%	0 4%	2 5%		
2						

	Proposed Standard	2001	2002	2003	2004	2005
3	Standard	3.7%	0 4%	2.5%		
4	Standard Bandwidth (+/-)*	4 3%	6.7%	4 5%		
5	Award (<)	-0 6%	-6 3%	-2 1%		
6	Penalty (>)	8 0%	7.0%	7 0%		

	Current Standard	2001	2002	2003	2004	2005
7	Standard	35%	06%	37%		
8	Standard Bandwidth (+/-)	08%	08%	08%		
9	Award (<)	2 7%	-0 2%	2 9%		
10	Penalty (>)	4 3%	1 5%	4 5%		

	Xcel Energy Results	2001	2002	2003	2004	2005
11	Average price change	47%	-8.8%	49%		

* Reflects one standard deviation for the utility comparison group See Attachment B

Industry data resource Edison Electric Institute
Typical Bills and Average Rates Report
Group Investor-owned utilities serving ND, SD, MN, WY, WS, IA, and MT

Northern States Power Company d/b/a Xcel Energy
Electric Utility - North Dakota Jurisdiction
Proposed PLUS Plan Performance Standards for 2005
Customer Satisfaction - Transaction Surveys (% of customers ranking overall satisfaction with Company as 8, 9, or 10)

	Xcel Energy Results	2001*	2002	2003	2004	2005
1	% of customers at 8-10	na	70 4%	74.5%	69.5%	
2	Prey 3 yr Average					71.5%

	Proposed Standard	2001	2002	2003	2004	2005
3	Standard					71 5%
4	Standard Bandwidth (+/-)					30%
5	Award (>)					74 5%
6	Penalty (<)					68 5%

Current Standard (overall quality, top 2 of 5 pt. scale)

		2001	2002	2003	2004	2005
7	Standard	63 0%	63.0%	65 0%	65 0%	65.0%
8	Standard Bandwidth (+/-)	30%	30%	3.0%	3.0%	3 0%
9	Award (>)	66 0%	66 0°/0	68 0%	68 0%	68.0%
10	Penalty (<)	600%	600%	62 0%	62.0%	62.0%

	Xcel Energy Results	2001*	2002	2003	2004	2005
11	% of customers at 4, 5	70 6%	66.3%	68 2%	66 7%	

* Reflects 5 pt scale results, top 2 responses (No data exists for 11 pt scale responses)

Northern States Power Company d/b/a Xcel Energy
Electric Utility - North Dakota Jurisdiction
Proposed PLUS Plan Performance Standards for 2005
Price - Annual Change (average residential rate)

	Midwest Utility Group	2001	2002	2003	2004	2005
1	Change in avg residential rate	3 71%	0 37%	2.45%		
2						

	Proposed Standard	2001	2002	2003	2004	2005
3	Standard	3 71%	0.37%	2 45%		
4	Standard Bandwidth (+/-)*	3 22%	4 54%	3.33%		
5	Award (<)	0 49%	-4 17%	-0.88%		
6	Penalty (>)	693%	491%	5.78°k		

	Current Standard	2001	2002	2003	2004	2005
7	Standard	3 50%	0 65%	3.71%		
8	Standard Bandwidth (+1-)	0 83%	0 81%	0.81%		
9	Award (<)	2 67%	-0 16%	2.90%		
10	Penalty (>)	4.33%	1 46%	4 52%		

	Xcel Energy Results	2001	2002	2003	2004	2005
11	Change in avg residential rate	4 65%	-8 80%	4.90%		

* Reflects one standard deviation for the utility comparison group See Attachment B

Industry data resource Edison Electric Institute
Typical Bills and Average Rates Report
Group Investor-owned utilities serving ND, SD, MN, WY, WS, IA, and MT

PLUS Industry Benchmark Calculation
EEI Typical Bills and Average Rates Report
Average Residential RevenueIKwh and Annual Change in Res. Rev/Kwh

Average Residential Rate | **Annual Change in Residential Rate**

2001 Rank	Utility	Juris	2001 ¢/kwh	2001 Rank	Utility	Juris	2001 ¢/kwh	2000 0/kwh	Change
1	Ottertail Power Co.	ND	6.16	1	Montana-Dakota Utilities	Mont	7.35	7.44	-1.21%
2	Pacificorp -Wyoming East	Wyom	6.21	2	Black Hills Power & Light	SD	8.19	8.21	-0.24%
3	Ottertail Power Co.	SD	6.38	3	Black Hills Power & Light	Wyom	7.80	7.79	0.13%
4	Ottertail Power Co.	MN	6 52	4	Pacificorp -Wyoming West	Wyom	7.94	7.91	0.38%
5	***NSP***	***ND***	***6.53***	5	Superior Power & Light	Wisc	6 64	6 60	0.61°A
6	Superior Power & Light	Wisc	6 64	6	Montana-Dakota Utilities	Wyom	7.55	7.49	0.80%
7	Montana Power Company	Montar	6.75	7	Montana-Dakota Utilities	SD	8 86	878	091%
8	Montana-Dakota Utilities	ND	6.86	8	Ottertail Power Co	MN	6.52	6.44	1.24%
9	Minnesota Power	MN	7 00	9	Ottertail Power Co.	ND	6.16	6.08	1.32%
10	Montana-Dakota Utilities	Mont	7 35	10	NSP	MN	8.06	7.95	1.38%
11	Wisconsin Power & Light (A	Wisc.	7 49	11	Ottertail Power Co.	SD	6.38	6.29	1.43%
12	Wisconsin Public Service	Wisc	7 49	12	Montana-Dakota Utilities	ND	6.86	6.75	1.63%
13	MidAmerican Energy	SD	7.49	13	NSP	Wisc.	7.54	7.40	1.89%
14	Black Hills Power & Light	Mont	7.51	14	Minnesota Power	MN	7.00	6.84	2 34%
15	NSP	Wisc.	7 54	15	Northwest Public Service	SD	7.74	7.53	2.79%
16	Montana-Dakota Utilities	Wyom	7.55	16	IES Utilities (Alliant)	Iowa	8.85	8.60	2.91%
17	Northwest Public Service	SD	7.74	17	Interstate Power Co (Allian	Iowa	8 21	7.95	3 27%
18	Black Hills Power & Light	Wyom	7 80	18	MidAmerican Energy	SD	7 49	7.25	3.31%
19	Pacificorp -Wyoming West	Wyom	7 94	19	NSP	SD	8.09	7.83	3.32%
20	Cheyenne Light, Fuel, & Po	Wyom	7.99	20	Pacificorp -Wyoming East	Wyom	6.21	6.00	3.50%
21	NW Wisconsin Electric	Wisc	8 00	21	Black Hills Power & Light	Mont	7.51	7.24	3.73%
22	NSP	MN	8.06	22	Wisconsin Power & Light (A	Wisc.	7.49	7.18	4 32%
23	NSP	SD	8.09	23	Montana Power Company	Montar	615	6.46	4.49%
24	Black Hills Power & Light	SD	8.19	24	***NSP***	***ND***	***6.53***	***6.24***	4.65%
25	Interstate Power Co. (Alban	Iowa	8.21	25	Interstate Power Co (Alliant	MN	8 94	8.54	4.68%
26	Wisconsin Energy Co	Wisc	8.46	26	Madison Gas & Elec	Wisc.	9.26	8.84	4.75%
27	IES Utilities (Alliant)	Iowa	8.85	27	NW Wisconsin Electric	Wisc.	8.00	7.56	5.82%
28	Montana-Dakota Utilities	SD	8.86	28	Wisconsin Energy Co	Wisc	8 46	7 97	6 15%
29	Interstate Power Co.(Alliant	MN	8.94	29	Wisconsin Public Service	Wisc	7.49	7 00	7 00%
30	Madison Gas & Elec	Wisc.	9.26	30	Cheyenne Light, Fuel, & Po	Wyom	799	682	17.16%
31	MidAmerican Energy	Iowa	10.12	31	MidAmerican Energy	Iowa	10 12	8 49	19.20%
	'Average residential rate (¢/kwh):		7.68		'Average residential rate (0/kwh):		7.68	7.40	3 71%)
		St Dev:	0.93					St Dev	3.22%

Note: Highest and lowest rates in group were omitted for purposes of determining standard deviation

PLUS Industry Benchmark Calculation
EEI Typical Bills and Average Rates Report
Average Residential Revenue/Kwh and Annual Change in Res. Rev/Kwh

Average Residential Rate				**Annual Change in Residential Rate**						
2002 Rank	**Utility**	**Juris**	**2002 0/kwh**	**2002 Rank**	**Utility**	**Juris**	**2002 Clkwh**	**2001 0/kwh**	**Change**
1	***Xcel Energy***	***ND***	***5.95***	1	MidAmerican Energy	Iowa	8.67	10.12	-14.33%
2	Ottertail Power Co	ND	6 20	2	**Xcel *Energy***	***ND***	***595***	***6.53***	-8.88%
3	Pacificorp -Wyoming East	Wyom	6 37	3	Black Hills Power & Light	Mont	6 99	7.51	-6.92%
4	Ottertail Power Co	SD	6 43	4	Xcel Energy	SD	7.57	8.09	-6.43%
5	Superior Power & Light	Wisc.	6.43	5	Minnesota Power	MN	6.64	7.00	-5.14%
6	Ottertail Power Co.	MN	6.53	6	Xcel Energy	MN	7.68	8.06	-4.71%
7	Minnesota Power	MN	6.64	7	Superior Power & Light	Wisc.	6.43	6.64	-3.16%
8	Montana-Dakota Utilities	ND	6 77	8	Interstate Power & Light (All	Iowa	8.47	8.71	-2.76%
9	Northwest Public Service	Montar	6.90	9	MidAmerican Energy	SD	7.38	7.49	-1.47%
10	Black Hills Power & Light	Mont	6.99	10	Pacificorp -Wyoming West	Wyom	7.83	7.94	-1.39%
11	Montana-Dakota Utilities	Mont	7 33	11	Montana-Dakota Utilities	ND	6.77	6.86	-1.31%
12	MidAmerican Energy	SD	7 38	12	Black Hills Power & Light	Wyom	7 71	7 80	-1 15%
13	Xcel Energy	SD	7 57	13	Montana-Dakota Utilities	SD	8 80	8 86	-0 68%
14	Xcel Energy	Wisc	7 60	14	Black Hills Power & Light	SD	8.14	8 19	-0.61%
15	Montana-Dakota Utilities	Wyom	7 62	15	Montana-Dakota Utilities	Mont	7 33	7.35	-0 27%
16	Xcel Energy	MN	7 68	16	Ottertail Power Co	MN	6 53	6.52	0 15%
17	Black Hills Power & Light	Wyom	7.71	17	Wisconsin Energy Co.	Wisc	8.51	8 46	0.59%
18	Pacificorp -Wyoming West	Wyom	7.83	18	Ottertail Power Co.	ND	6.20	6.16	0.65%
19	Wisconsin Power & Light (A	Wisc.	7.94	19	Ottertail Power Co	SD	6 43	6.38	0.78%
20	Black Hills Power & Light	SD	8.14	20	Xcel Energy	Wisc.	7.60	7 54	0.80%
21	Wisconsin Public Service	Wisc	8 30	21	Montana-Dakota Utilities	Wyom	7.62	7.55	0.93%
22	Interstate Power & Light (All	Iowa	8 47	22	Interstate Power Co (Alliant	MN	9 10	8.94	1 79%
23	Northwest Public Service	SD	8 49	23	Northwest Public Service	Montar	6 90	6.75	2 22%
24	Wisconsin Energy Co.	Wisc.	8.51	24	Pacificorp -Wyoming East	Wyom	6 37	621	2.58%
25	NW Wisconsin Electric	Wisc.	8,56	25	Madison Gas & Elec	Wisc	9 69	9.26	4.64%
26	MidAmerican Energy	Iowa	8.67	26	Wisconsin Power & Light (A	Wisc	7.94	7.49	6.01%
27	Montana-Dakota Utilities	SD	8 80	27	NW Wisconsin Electric	Wisc.	8.56	8.00	7.00%
28	Interstate Power Co.(Alliant	MN	9.10	28	Northwest Public Service	SD	8.49	7.74	9.69%
29	Madison Gas & Elec	Wisc.	9.69	29	Wisconsin Public Service	Wisc	8 30	7 49	10 81%
30	Cheyenne Light, Fuel, & Po	Wyom	9.87	30	Cheyenne Light, Fuel, & Po	Wyom	9.87	7.99	23.53%
	'Average residential rate (0/kwh):		7.68		'Average residential rate (10/kwh):		7.68	7.65	0.37%I
		St Dev	1 02					St Dev:	4 54%

Note. Highest and lowest rates in group were omitted for purposes of determining standard deviation.

PLUS Industry Benchmark Calculation
EEI Typical Bills and Average Rates Report
Average Residential Revenue/Kwh and Annual Change in Res. Rev/Kwh

Average Residential Rate

2003 Rank	Utility	Juris	2003 st/kwh
1	***Xcel Energy***	***ND***	***6.24***
2	Ottertail Power Co	ND	643
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	669
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	Montar	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	MidAmencan 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 (0/kwh):		7.87
		St Dev.	1.08

Annual Change in Residential Rate

2003 Rank	Utility	Juris	2003 Olkwh	2002 ¢/kwh	Change
1	Northwestern Energy	SD	7.92	8.49	-6 71%
2	Pacificorp -Wyoming West	Wyom	7.38	7.83	-5.75%
3	Xcel Energy	Wisc.	7.52	7.60	-1.05%
4	Cheyenne Light, Fuel, & Po	Wyom	9.83	9.87	-0.41%
5	Black Hills Power & Light	Wyom	7.68	7.71	-0.39%
6	MidAmencan Energy	Iowa	8 65	8.67	-0.23%
7	Montana-Dakota Utilities	Mont	7.33	7.33	0 00%
8	Black Hills Power & Light	SD	8.14	8.14	0.00%
9	NW Wisconsin Electric	Wisc.	8.57	8.56	0.12%
10	Montana-Dakota Utilities	ND	683	677	0 89%
11	Montana-Dakota Utilities	SD	888	880	0 91%
12	Interstate Power Co.(Alliant	MN	9 20	9.10	1.10%
13	Minnesota Power	MN	6 73	6.64	1.36%
14	Superior Power & Light	Wisc.	6.52	6.43	1.40%
15	Montana-Dakota Utilities	Wyom	7.73	7.62	1.44%
16	MidAmencan Energy	SD	7 52	7.38	1.90%
17	Xcel Energy	MN	7.84	7.68	2.08%
18	Pacificorp -Wyoming East	Wyom	6.51	6.37	2.20%
19	Ottertail Power Co.	MN	6 69	6.53	2.45%
20	Ottertail Power Co.	SD	6.63	6.43	3.11%
21	Xcel Energy	SD	7.84	7.57	3.57%
22	Ottertail Power Co.	ND	6.43	6.20	3.71%
23	Wisconsin Energy Co.	Wisc.	8.87	8.51	4.23%
24	Wisconsin Public Service	Wisc	8.66	8.30	4.34%
25	***Xcel Energy***	***ND***	***6.24***	***5.95***	4.87%
26	Interstate Power & Light (All	Iowa	8.90	8.47	5.08%
27	Black Hills Power & Light	Mont	7.38	6 99	5 58%
28	Madison Gas & Elec	Wisc	10.64	969	9 80%
29	Northwestern Energy	Montar	7 74	6.90	12.17%
30	Wisconsin Power & Light (A	Wisc.	9.32	7.94	17.38%
	Average residential rate (0/kwh):		7.87	7.68	2.45%)
				St Dev:	3.33%

Note Highest and lowest rates in group were omitted for purposes of determining standard deviation.

Xcel Energy

RECEIVED
MAR 1 5 2004
ND PUBLIC SERVICE COMMISSION
EXECUTIVE SECRLTARY

302 Great Northern Drive
P O Box 2747
Fargo, ND 58108-2747
(701) 241-8632
ave sederquist@xcelenergy corn

March 12, 2004

Mona A. Jeffcoat-Sacco, Executive Secretary
North Dakota Public Service Commission
State Capitol Building, Dept. 408
600 East Boulevard
Bismarck, ND 58505-0480

Re. Case No. PU-400-03-256 (PLUS Plan Modification Proposal)

Dear Ms. Jeffcoat-Sacco:

Pursuant to the Company's December 16, 2003 PLUS Plan modification application, Northern States Power Company d/b/a Xcel Energy hereby wishes to amend the effective date of its proposed changes to the plan from January 1, 2004 to January 1, 2005.

On February 25, 2004 the North Dakota Public Service Commission held an informal hearing on the proposed revisions to the performance standards in the PLUS Plan. It was evident in the discussion at the hearing that more time would be necessary for the Commission to review and respond to the industry benchmarking data and other aspects of the petition. The consensus among those present was that in the remauung months of 2004 further progress in investigating the proposal could be made, with a Commission decision made in time for new standards to be in effect for 2005.

In this regard, the Company respectfully requests that the Commission provide more specific direction regarding the procedural schedule in this case, and/or other informational needs that it believes would facilitate better understanding.

Currently, Xcel Energy is assembling a data filing which it will soon submit to the Commission. The information will include the industry reliability, customer satisfaction, price, and worker safety data along with the calculations used to derive the proposed PLUS standards. The industry benchmarking data was a key focal point of the discussion during the February 25th hearing. We hope that providing more information in this regard will provide the basis for further discussion at a future hearing.

Please contact me (701-241-8632) if you have any questions or suggestions.

Sincerely,

David H. Se erquist
Sr. Consultant, Regulation & Finance

Enclosures

10 PU-400-03-256 noes 1

'Request t: amend Chen tisk, date of
Proposed chances from 1-1 04 lo 1-1-05
by i,orlheir, Mates er t_,omhiny

03/15'1/04

INFORMAL HEARING AGENDA

February 25, 2004

PU-400-03-256	Northern States Power Company 2002 Electric Operations Annual Report (Consideration of PBR Revision)

P U. 400-03-256 Pages 0

Informal hearing held

by Pub' . Service E..ornmission

02/25/200A

1.1). ACX

Memo

FEB I $ 2004

To: Commissioners, PUD, and Legal

From: Mike Diller 4

Date: February 10, 2004

Re: Informal Hearing February 25, 2004 (Case No. PU-400-03-256)

The staff has written two previous memorandums dated June 17, 2003 and October 15, 2003 concerning its 2-year review of NSP's performance based regulation plan. After the first memo, the commission instructed staff to work with the Company to see if settlement could be reached. No settlement was reached and staff issued its second memo stating that it had concluded its review.

On December 16, 2003, NSP unilaterally filed proposed modifications to its PBR plan for 2004 and 2005. The fact that we are now in the second month of 2004 is not an implementation problem, by itself, since the revisions would weaken the overall performance standards and NSP's employees are likely under the assumption that the old standards still apply.

As stated previously, settlement has not occurred because of a fundamental difference in what both parties think is the purpose of PBR.

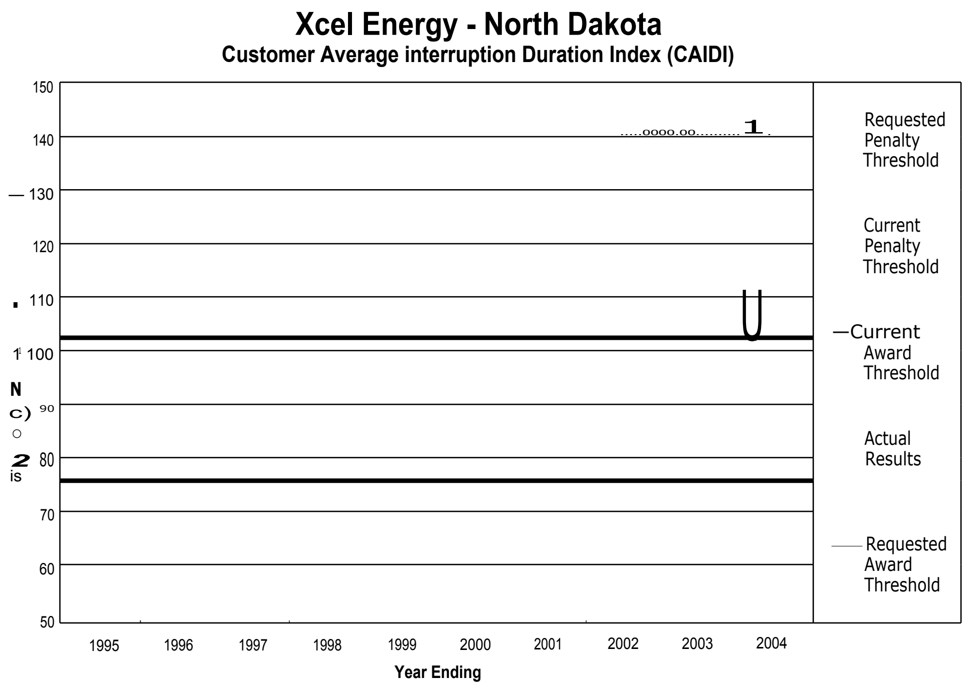
Staff believes that the purpose of moving from traditional rate of return regulation to performance based ratemaking is to encourage NSP to perform at a higher level of service. Higher performance levels are then rewarded through higher earnings potential. Conversely, lower performance levels under PBR result in penalties and lower earnings potential.

NSP on the other hand, believes for the most part, that it does not matter how NSP is performing in comparison to the past. It only matters whether NSP is beating the market place. The market place, in general, being represented by the performance standards that are developed from information reported to the Edison Electric Institute by participating electric companies in the region.

Staff appreciates the effort that NSP has made to tie the performance standards to the market. We support the direction that the Company has taken. However, the significant disparity between historical performance levels and the recommended standards by NSP will not provide an adequate incentive for continued or better service in the future. Staff is concerned that the weaker standards could provide a perverse incentive for the company to manage down its performance rather than strive for higher levels of service. Instead, the gathered information should be used to develop standards which require better service for higher earnings potential.

Because of the differences in philosophy, staff remains opposed to the revisions as proposed by NSP. Following are some graphical representations of the seven performance standards of PBR along with additional comments to help explain staff's concerns.

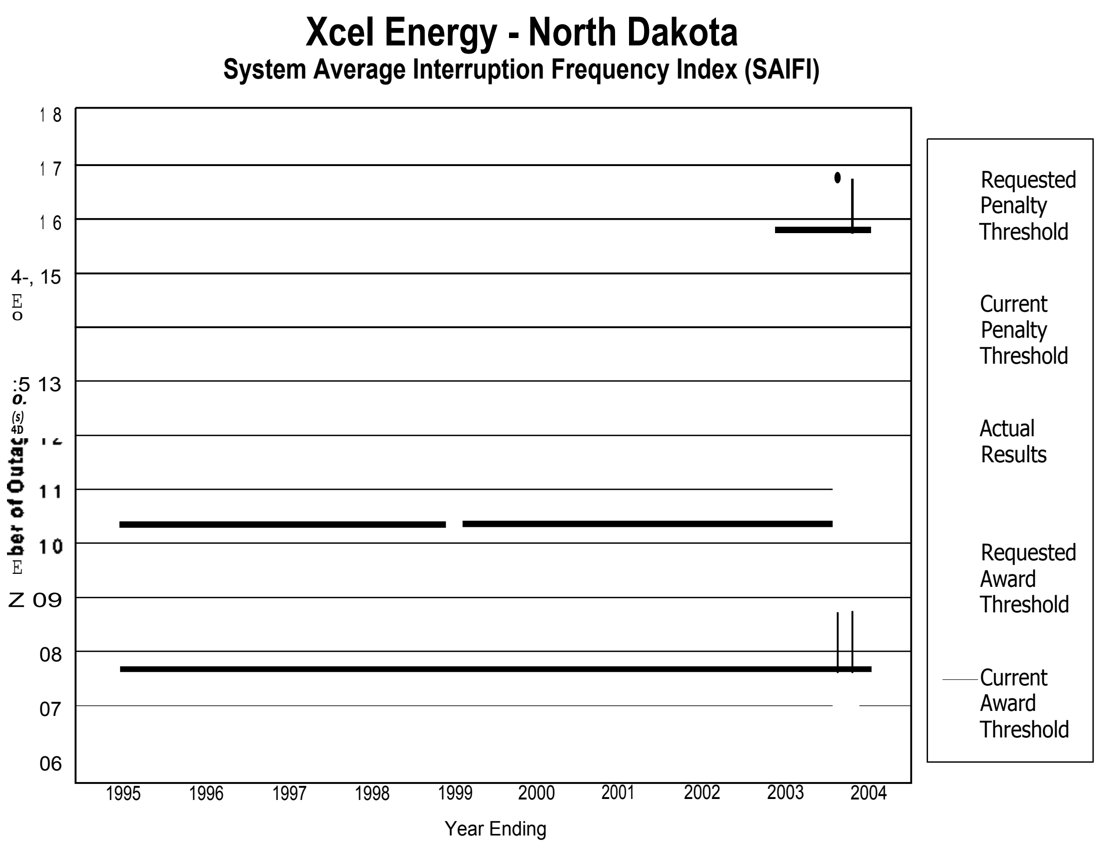
CAIDI (Average Length of Outage Duration)
With regard to the Customer Average Interruption Duration Index standard, NSP proposes an award threshold of 74.6 minutes for 2004 compared to the existing threshold of 75.7 making it slightly more difficult to achieve an award. Actual results have fallen between 60 and 75.6 minutes during the past 8 years. The proposed threshold for incurring a penalty is more than 130 minutes. Following is a graphical representation of actual results compared to the current and proposed standards.



SAIFI (Number of Outages per Year per Customer)

With regard to the System Average Interruption Frequency Index standard, NSP proposes an outage award threshold of .87 times per customer for 2004 compared to the existing threshold of .77. Actual results have fallen between .73 and 1.09 during the past 8 years. The recommended threshold for incurring a penalty is more than 1.5 times per customer.

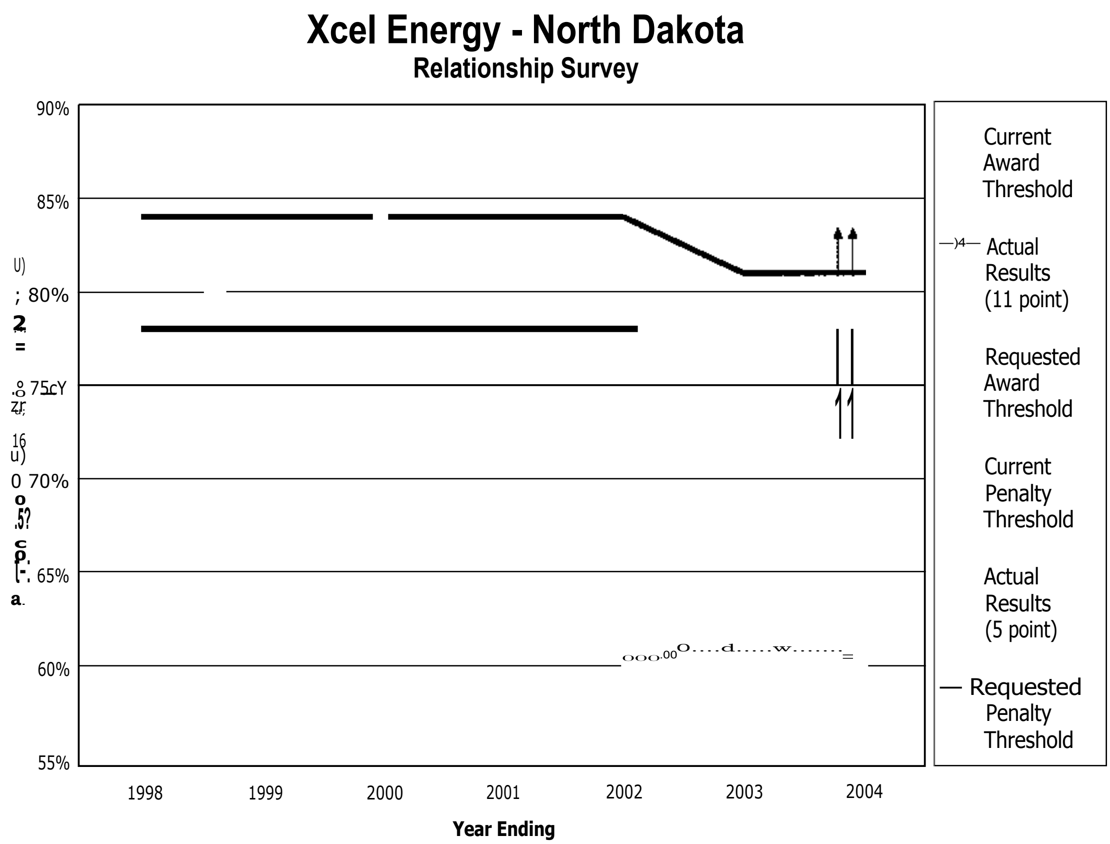
Following is a graphical representation of actual results compared to the current and proposed standards.



Relational Survey
With regard to the relational survey standard, NSP proposes to change its method of survey from a 5 point to an 11 point customer response scale for a number of reasons including that it is consistent with the method used by the University of Michigan in conducting its national survey. The University's resulting American Customer Service Index (ACSI) provides the benchmark for NSP's proposed relational standard. Again, the requested standard appears to nearly eliminate the chance of incurring a penalty.

Please note that there are two actual results lines depicting the history of both the 5 point and 11 point survey results.

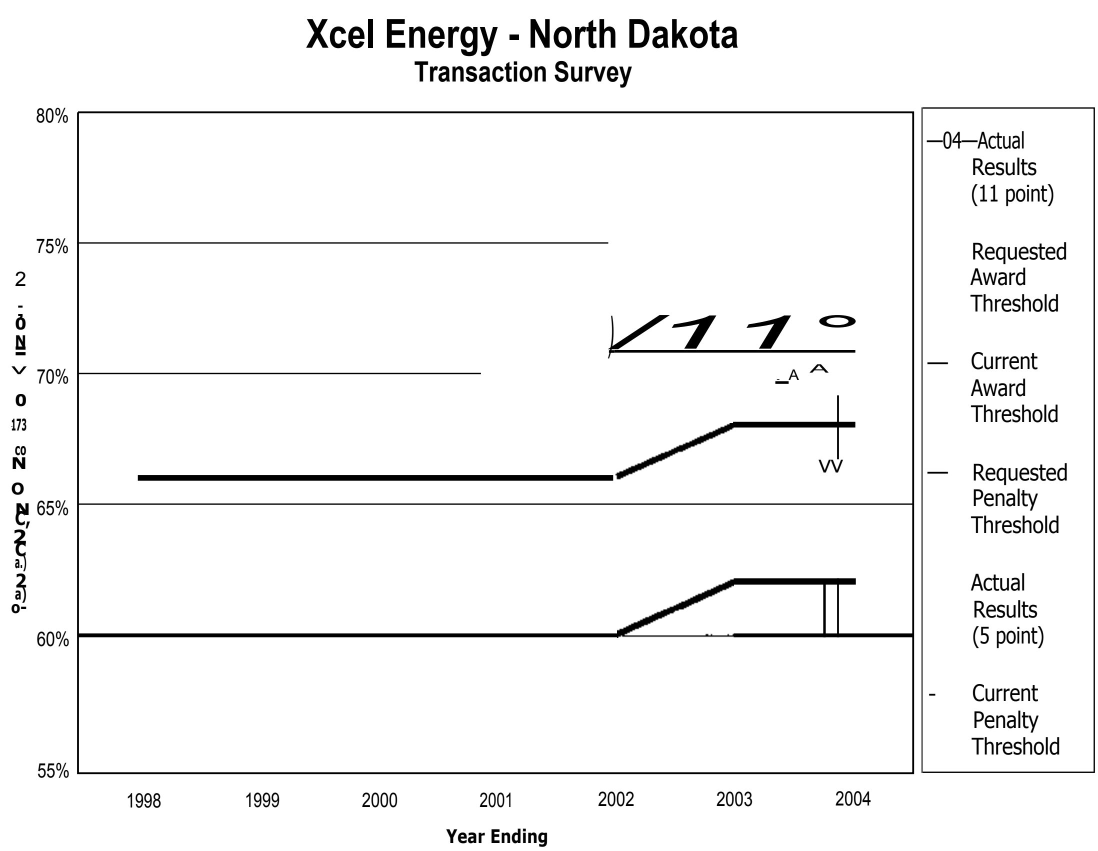
Following is a graphical representation of actual results compared to the current and proposed standards.



<u>Transactional Survey</u>
With regard to the transactional survey standard for customers who contacted NSP or came into contact with NSP crews, NSP proposes to change its method of survey from a 5 point to an 11 point customer response scale. The change is consistent with the relational survey change but there is currently no existing external data for making industry comparisons. Therefore, NSP advocates using a 3 year rolling average of actual NSP North Dakota results to replace the current fixed standard.

The 5 point and 11 point results are blended together to develop NSP's new requested thresholds. Please note that there are two actual results lines depicting the historical results of both the 5 point and 11 point surveys.

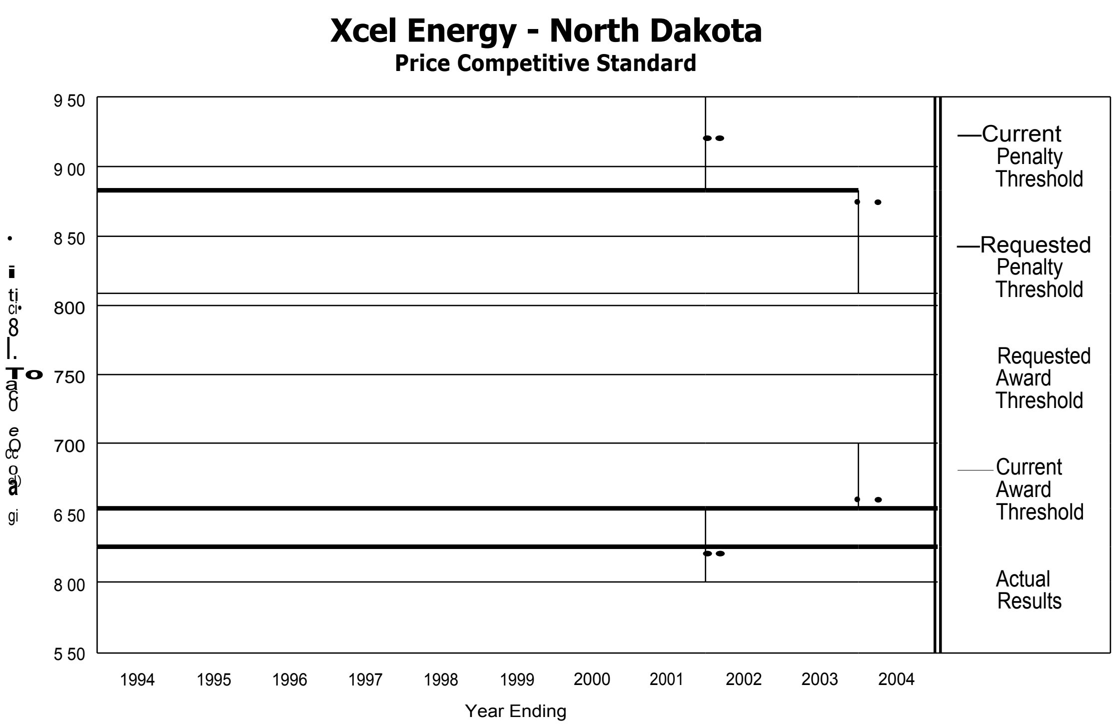
Following is a graphical representation of actual results compared to the current and proposed standards.



Price Competitive Standard

With regard to the price competitive standard, NSP proposes an award and penalty threshold using a .75 standard deviation calculation from the 3-year industry average of residential prices in the region. The current standard compares NSP's prices each year to the average prices in the region for the same year. The existing award and penalty thresholds are determined by adding or subtracting 15% to the industry average. The new proposal appears to weaken the award threshold and strengthen the penalty threshold--though the penalty side for all practical purposes is out-of-play. Retroactively applied, actual results for the past 9 years have been at or better than the current award threshold standard.

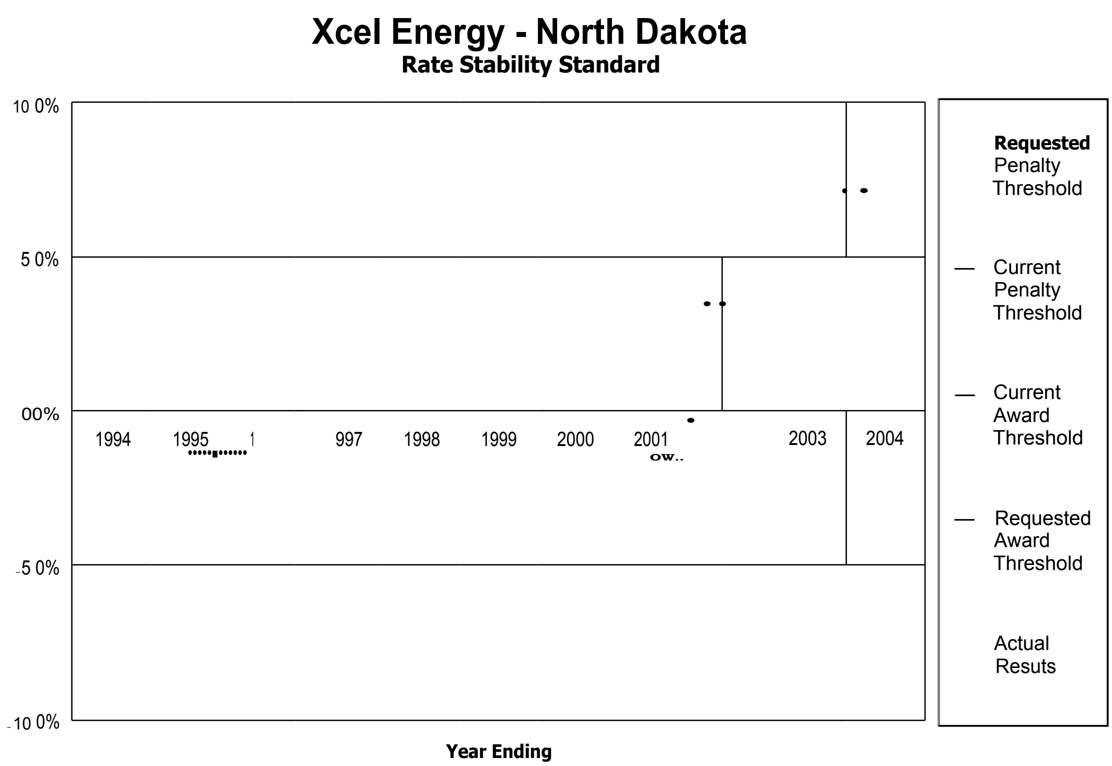
Following is a graphical representation of actual results compared to the current and proposed standards.



Price Stability Standard

With regard to the price stability standard, NSP proposes an award and penalty threshold using a .75 standard deviation calculation of the 3 year rolling average of the percentage change in the regions average annual residential price change. The current standard is based off of the price change of the lowest priced utility in the region and can be quite volatile from one year to the next. The 3 year rolling average removes some of that volatility.

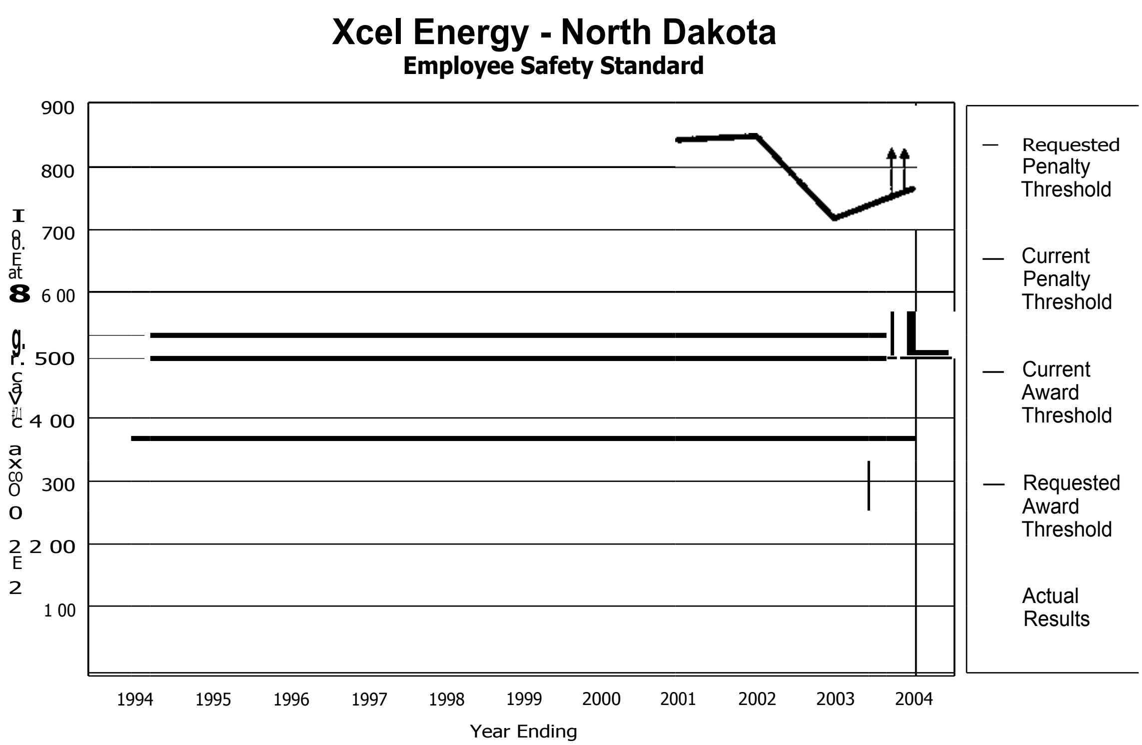
Following is a graphical representation of actual results compared to the current and proposed standards.



<u>Employee Safety</u>

With regard to the employee safety standard, NSP's proposal would make achieving an award a little more difficult and the chance of incurring a penalty for poor performance a lot more unlikely. Actual results for the past 9 years have ranged from 1.99 to 5.64 incidents per year per 100 employees. Under the current plan, the award threshold is set at 3.7 and the penalty threshold at 5. NSP proposes an award threshold at 3.44 and a penalty threshold of 7.65 for 2004.

Following is a graphical representation of actual results compared to the current and proposed standards.



<u>Other Proposed Revisions</u>

Staff does not oppose NSP's improved ROE deadband or its revenue sharing mechanism PROVIDED that the performance standards better match historical performances with proper incentives to improve service under **PBR.** Staff also agrees with limiting rate changes for exogenous events to only those impacting ROE by more than one percentage point.

Staff looks forward to discussing this case at the informal hearing on February 25, 2004.

Xcel Energy

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(701) 241-8632
dave sederquist@xcelenergy corn

December 16, 2003

Jon Mielke, Executive Secretary
North Dakota Public Service Commi sion
State Capitol Building, Dept. 408
600 East Boulevard
Bismarck, ND 58505-0480

Re: Modifications to the PLUS Plan for 2004 and 2005

Dear Mr. Mielke:

Enclosed you will find for Commission review and approval an original and seven copies of Xcel Energy's proposed modifications to its PLUS performance-based regulation plan.

The modifications advanced in this petition represent the culmination of a substantial amount of industry data research and plan design work. In addition, various meetings and discussions have been conducted between the Company and North Dakota Public Service Commission Staff in conjunction with the PBR mid-term review docket (Case No. PU-400-03-256). While it was hoped that the Company's proposals would be formally filed well m advance of the 2004 plan year, the Company still anticipates that the changes would still be applicable for both the 2004 and 2005 plan years if and when approved by the Commission

Please contact me if you have any questions about this application.

Sincerely,

David H. Sederquist
Sr. Consultant, Regulation & Finance

Enclosures

DEC I 7 2003

STATE OF NORTH DAKOTA
BEFORE THE '
PUBLIC SERVICE COMMISSION

Northern States Power Company
d/b/a Xcel Energy

"Case Nb7PU-400:0T-256

PROPOSED CHANGES To THE PLUS PLAN, A PERFORMANCE-BASED REGULATION MODEL BY NORTHERN STATES POWER COMPANY D/B/A XCEL ENERGY

I. INTRODUCTION

Pursuant to N.D. Cent. Codes § 49-02-03 and 49-02-04, Northern States Power Company d/b/a Xcel Energy ("Xcel Energy" or "the Company") hereby petitions the North Dakota Public Service Commission ("NDPSC" or "Commission") to approve proposed changes, contained herein, to the performance-based regulation ("PBR") plan, called the PLUS Plan ("PLUS" or "Plan"), that regulates its electric operations in North Dakota, to be effective January 1, 2004. The proposed modifications will improve the methods for establishing performance standards, surveying customer satisfaction, and simplifying the mechanics of the adjustable authorized earnings deadband and revenue sharing mechanisms.

II. BACKGROUND

On September 20, 1995 the Commission issued a document entitled "Guidelines for Filing Alternative Regulation Proposals" ("Guidelines")[1]. The Guidelines set forth both

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[1] See Case No. PU-439-94-590

goals and criteria for alternative regulation proposals. It is included in this application as Attachment A.

On April 20, 2000, the Company filed a "Proposal for a Performance-Based Regulation Plan" ("Petition") asking the Commission to approve the Company's proposed performance based regulation ("PBR") plan, called the "PLUS" plan ("Plan"), for purposes of regulating the Company's retail electric operations in North Dakota. The key components of PLUS include

1) a "dynamic allowed ROE" range which adjusts the level of "authorized" ROE up or down based on Company performance;
2) a revenue sharing mechanism;
3) establishment of service performance standards; and
4) provisions to adjust prices — with caps — under specified circumstances.

The Petition stated the Plan would create an alternative form of regulation, with economic signals similar to those found in competitive markets, for the Company's electric operations in North Dakota as contemplated by the Guidelines. The Company asserted in its original petition that:

- The PLUS Plan framework met the stated goals and criteria identified by the Commission alternative regulation guidelines.
- The PLUS Plan would be an appropriate regulatory model because it provides benefits to customers which extend beyond traditional cost-based regulation, while at the same time ensuring that the Company's North Dakota electric rates are just

and reasonable, and the Company's operations have the opportunity to maintain financial strength.

- The PLUS Plan would be a more effective than traditional cost-based regulation in promoting a balanced emphasis on utility efficiency, service quality, and economic development in North Dakota, while maintaining the basic customer protections typically provided by traditional regulation.
- The PLUS Plan would provide an automatic, pre-defined mechanism to pass the benefits of a financially healthy utility on to its stakeholders. Unlike traditional, cost-based regulation, which can be slow and adversarial, the PLUS Plan offers an efficient, win/win approach to utility regulation. PLUS places the regulatory focus more on operational and economic results and less on regulatory processes.
- As restructuring of the electric industry evolves, performance based regulation is expected to play a role in facilitating industry changes to foster a more competitive, service-oriented electricity market. The PLUS regulatory model would simulate a competitive market by creating meaningful incentives and economic signals that promote high quality service and low cost.
- Since PLUS offers the Company the potential to achieve above-average returns on its North Dakota electric business (if the Company's performance exceeds the performance standards set forth in the plan), PLUS would create an additional incentive for the Company to invest its limited capital resources in_North Dakota (other things being equal).

On December 29, 2000, the Commission issued an order approving the PLUS Plan, as modified and agreed to by representatives of Xcel Energy and Commission Staff in a Final Settlement Agreement dated December 28, 2000. The PLUS Plan commenced on January 1, 2001, to be in effect for a five-year term ending December 31, 2005. Prior to July 1, 2005, the Company may file for an extension and/or modification of the Plan if so desired. Absent such a filing and a further order of the Commission extending the Plan, the PLUS Plan will automatically terminate on December 31, 2005.

One of the provisions in the PLUS Plan was to conduct a "mid-term" review of the Plan after the first two years of the Plan's five year term had been completed. In the spring of 2003, the Commission opened a review docket to assess the outcomes thus far of PLUS and make any necessary or desired adjustments.

On May 20, 2003, the Commission conducted separate Periodic Information Exchange meetings with Xcel Energy and Otter Tail Power Company ("OTP") in which updates of the 2002 PBR results of both plans were given.

On June 18, 2003 the Commission conducted an informal hearing on the PBR plans of Xcel Energy and OTP. Commission advised the Companies and Staff to continue to work on improvements to the Plans, with the intention of ensuring that modifications could be presented and approved in time for a January 1, 2004 implementation.

The Company and Commission Staff held two discussion meetings during the summer to address various aspects of the Plan as it was applied during 2001 and 2002. On March 17, 2003, a meeting was held in Jamestown with representatives from the Staff, Xcel Energy, and OTP. Items discussed included the plan's rate changing process; performance standard development; changes to customer satisfaction surveying; modifying the dynamic allowed ROE deadband; and certain administrative provisions.

A follow-up meeting was held on July 24th at the same site to discuss more specific Company proposals that had been developed since the initial meeting. Staff took the proposals under advisement at that time.

In September and October, various phone conversations and electronic document transmissions were conducted between Xcel Energy and Staff in an effort to reach agreement primarily on the performance standard setting methodology. A number of different proposals were discussed for establishing revised Plan standards for the 2004 and 2005 years. Although the Company and Staff did not agree on all of the proposed revisions, progress was made in identifying parts of the Plan that could be improved and determining what industry benchmarks were available for use in the establishing performance standards.

Paragraph 1(A) of the Final Settlement Agreement in Case No. PU-400-00-195 provides that "Prior to July 1, 2005, the Company may file for [a]...modification of the Plan if so desired." The proposed modifications being submitted here for the 2004 and 2005 Plan periods are thus not contrary to the approved Final Settlement Agreement. [2]

III. THE PROPOSED MODIFICATIONS WOULD SERVE THE PUBLIC INTEREST

Based on the research data, testimony, and working sessions, the Company believes the modifications proposed here are consistent with the public interest and consistent with the Commission's Guidelines for Filing Alternative Regulation Proposals.

[2] The Commission Staff is, of course, free to support or oppose Commission approval of the proposed modifications

In addition, Xcel Energy believes the changes maintain incentives for the Company to maintain or improve the quality of service and reasonableness of rates for North Dakota electric customers, and will support the safe and reliable electric infrastructure and the financial viability of the Company. Documentation in support of this is attached hereto.

IV. PROPOSED MODIFICATIONS

1. Dynamic, Industry-Benchmarked Performance Standards

The Company proposes to implement a method for establishing service and operational performance standards that 1) utilizes industry performance benchmarks and 2) establishes new standards on an annual basis. By using external utility industry performance results to set standards for six of the Plan's seven performance indicators [3] the Plan is better able to define "best in class" performance for purposes of determining whether Xcel Energy's performance merits adjustments to its level of allowed earnings.

Under this approach, a legitimate benchmarking resource is used to obtain industry results for the most recent 3 year period for each applicable performance indicator. These annual results are then averaged to determine the Plan benchmark for the upcoming year. By establishing a range based on 75% of one standard deviation (this calculation is discussed later in the petition), the PLUS standards establish utility performance levels for the upper and lower quartile of the industry comparison group.

The current standards for the Plan's reliability, customer satisfaction, and safety indicators were negotiated prior to the Plan's implementation and are fixed. Of these, only the safety standard reflected a consideration of external benchmarking data. 1995

[3] The single exception is the Company's "transaction" customer satisfaction indicator (survey), for which there is no applicable industry benchmark

to 1999 data was used to establish the current performance standards for these measures. Presently, only the Plan's price standards are reset each year using regional utility rate data.

This change in the standard setting process for 2004 and 2005 is designed to produce the following Plan improvements:

- By simulating the "competitive market" model, provides a "real world" definition of what constitutes excellent (upper quartile), acceptable, or poor service;
- Ensures that annual PLUS performance standards stay current with performance trends in the industry; e.g., if the universe of comparison companies improve their services, the Company must continue to improve to be rewarded under the Plan.
- Implementing an annual standard setting process based on empirical data is a more objective, streamlined, and relevant approach than periodic negotiations between the Company and Staff (or unilateral filings by either the Company or Staff which may lead to lengthy disputed regulatory proceedings).

The specifics of the proposed modifications to the Plan performance standards for the 2004 and 2005 periods are as follows:

A. <u>Reliability</u>

For measuring reliability, the PLUS Plan continues to focus on two indicators widely used in the electric utility industry for measuring electric service reliability:

1) customer average interruption duration index ("CAIDI"), and
2) system average interruption frequency index ("SAIFI").

With these indicators, the Company is measured on how well it minimizes the occurrence of outages and the time it takes to restore power. As described in the original PLUS Plan application, annual results for each reliability measure are "normalized" to exclude unusual events such as storm-related outages (lightning, ice, wind), floods, extreme heat, sabotage, etc.

No changes are being proposed in the reliability indicators themselves. However, as shown in Attachment B, pages 1 and 2, standards for CAIDI and SAIFI in 2004 (and similarly in 2005) would be based on the rolling three year average CAIDI and SAIFI for utilities participating in the annual Edison Electric Institute ("EEI") Reliability Study. Because the EEI report is typically unavailable until the 4 th quarter *following* the results year; the most recent three year period which can be used to determine the upcoming target year's standard in a reasonable time will not include the prior year. Hence, the EEI study data from 2000 to 2002 would be used for purposes of establishing the Company's CAIDI and SAIFI standards for 2004. The Company believes use of current industry "comparable group" data is more meaningful as a measure of the Company's reliability performance than a negotiated fixed standard based on aged company data. Calibrating allowed ROE adjustments with performance in the upper or lower quartile among other utilities is consistent with how competitive markets function.

As is currently the case, the potential reward and/or penalty for each reliability indicator would remain a 25 basis point adjustment to the authorized ROE deadband.

B. Customer Satisfaction

The PLUS Plan presently utilizes two kinds of surveys for purposes of measuring customer satisfaction. The "Relationship" survey measures the percentage of randomly selected residential and business customers who give an 'excellent' or 'very good' response out of 5 choices in grading the Company's overall quality. The Plan score for the Relationship survey is an average of percent scores for each of the three customer class surveys (residential, small business, and large commercial).

The "Transaction" survey measures the percentage of customers who give an 'excellent' or 'very good' response (again, out of 5 choices) in grading the overall quality of a recent transaction the customer recently had with Xcel Energy. The types of customer contacts that are included in the transaction surveys include customer calls for general information, to start/stop electric service, to report an outage, credit/collection arrangements, electric service issues, inquiries about products and services offered, line locations, responding to an Xcel Energy notification, to obtain usage information, to report equipment damage, responding to a disconnect notice, issues regarding utility Poles, and appliance repair inquiries.

Currently, the relationship survey scores reflect the percentage of respondents who give Xcel Energy an 'excellent' or 'very good' rating out of five established response choices on a question relating to the "overall quality" of Xcel Energy products and services:

> *"I'd like you to think of your entire relationship with Xcel Energy overall. Considering everything, how would you rate the overall quality of products,*

services, and support you receive from Xcel Energy? Would you rate your overall experience as: excellent; very good; good; fair; or poor?

And, in the transaction satisfaction surveys, the current question is:

'Thinking specifically of this entire recent interaction with Xcel Energy, from the time you first contacted Xcel Energy until your issue was resolved, how would you rate the quality of service provided by Xcel Energy? Would you rate your overall experience as: excellent; very good; good; fair; or poor?

The original PLUS customer satisfaction standards were based on historic company-wide Company survey results from the previous three years (1998-2000). As contemplated in the original Plan settlement, these were revised in 2003 to reflect an additional two years (2001-2002) of results from North Dakota customers only.

Beginning in 2004, Xcel Energy proposes to focus on a slightly different survey question and utilize a different response scale to track customer satisfaction. Xcel Energy will now determine its relationship survey score by tracking and reporting the percentage of customers who give Xcel Energy a score of 8, 9, or 10 (on a scale of 0 to 10) to the following question:

"I'd like you to think in terms of your satisfaction with Xcel Energy. On a 0 to 10 scale where 10 means very satisfied and 0 means very dissatisfied, how would you rate your satisfaction with Xcel Energy?

Similarly, Xcel Energy will measure its "transaction "customer satisfaction performance by tracking and reporting the percentage of customers who give Xcel Energy a score of 8, 9, or 10 (on a scale of 0 to 10) to the following question:

'*Thinking specifically of this recent interaction with Xcel Energy, from your first contact until your issue was resolved, how would you rate the service provided? (on a 0 to 10 scale, where 10 means very satisfied with how your entire transaction was handled and 0 means you were very dissatisfied)*

Xcel Energy proposes this change because:

1. "overall satisfaction" is an easier concept for customers to relate to and define than "overall quality";
2. the 11 point scale using number rankings provides more rating choices for respondents, and represents a more symmetrical set of responses than the current survey methodology;
3. the question is consistent with that used in the American Customer Service Index ("ACSI") from which external benchmarks can be obtained; and
4. rating "satisfaction" (as opposed to "quality") with an 11 point scale (as opposed to a 5 point scale) is consistent with how the Company currently measures satisfaction in its other jurisdictions, and it is more consistent with the survey scale employed by OTP in its PBR plan.

As indicated in Attachment B, page 3, and consistent with the setting of other Plan performance standards, standards for the Relationship surveys in 2004 and 2005 would be based on the three year average for utilities participating in the annual American Customer Service Index ("ACSI") study, administrated by the University of Michigan School of Business. The ACSI results are available in August within the results year (focusing on the results for the 1st and 2nd quarters of the year). Hence, the most recent three year period for industry data will include the year just prior to the PLUS target year. Data from the ACSI study is available beginning in 2001, so 2001 to 2003 data will be used for purposes of establishing a standard for 2004.

Since there is no comparable external benchmark for the Transaction Survey scores, by default the PLUS Plan will continue to rely solely on past Xcel Energy (North Dakota jurisdiction) results to establish the standard. Results from the most recent 3 year period will be used (see Attachment B, page 4).

As is currently the case, each of the two survey standards will carry a potential adjustment (reward and/or penalty) of 25 basis points to the authorized ROE deadband.

C. Price

Unlike the Plan's other 5 performance indicators, the PLUS Plan currently uses external, regional rate data to establish new performance standards each year. A "competitive price" standard is set based on the most recent year's average residential rate (revenue per kwh) for a comparison group of about 30 mid-western utility jurisdictions. In addition, the PLUS Plan currently sets an annual 'rate management' standard based on the change in residential rates for the lowest priced utility in the peer group.

Currently, the price standard is calculated for each Plan target year using utility price data compiled in an Edison Electric Institute publication entitled *Typical Bills and Average Rates Report,* issued twice per year. For purposes of the PLUS Plan, the "winter" edition reflecting the 12 month period ending December 31st of the year just prior to the target year is used.

As shown in Attachment B, pages 5 and 6, and consistent with the methodology being proposed for the other Plan performance indicators, standards for the competitive rate and rate management indicators in 2004 and 2005 would be based on the three year average residential rate for the utility jurisdictions shown in the calendar year EEI rate report. Besides being consistent with the methodology used in setting the other performance standards, using results from the prior three years will also mitigate volatility in the price standard from year to year and thereby encourage rate stability. The EEI report is typically available within the 1 st quarter following each results year. Thus, the three year period for industry data would include the year previous to the target year, but the standard will not be final until March or April of the target year. This means that data from 2001-2003 will be used for purposes of establishing the 2004 standard.

The use of a 3 year average annual percent price change for the entire utility comparison group for purposes of establishing the annual rate management standard will eliminate the wide fluctuations currently seen in the standard from year to year, and will be more representative of the general rate change trend's in the region.

Each of the two price measures will continue to carry a potential reward and/or penalty of a 25 basis point adjustment to the authorized ROE deadband.

D. Employee Safety Standard

The PLUS Plan's safety indicator is the Occupational Safety and Health Administration ("OSHA") incident rate, a commonly used metric throughout the utility industry. The OSHA incident rate essentially measures the annual number of OSHA reportable safety incidents per 100 employees. The PLUS safety standard is currently a fixed number based primarily on 1994 to 1997 historical OSHA results for the largest group of utilities (more than 7,000 employees) participating in the annual Edison Electric Institute safety survey.

As shown in Attachment B, page 7, the proposed OSHA standard in 2004 and 2005 would be based on the three year average for Group 5 utilities (less than 1,000 employees) participating in the EEI safety survey. Use of Group 5 benchmark data is more appropriate than Group 1 (> 7,000 employees) data because Xcel Energy's North Dakota electric jurisdiction, with about 125 electric-oriented employees, is far smaller than the Group 5 company size criteria. In addition, since Xcel Energy's North Dakota jurisdiction relies on corporate staffing for much of its back office, administrative, engineering, and call center functions, the ratio of office personnel to field personnel in Xcel Energy's North Dakota operations is lower than what most stand alone utility companies in Group 5 would experience. The lower ratio of office personnel -- who are typically more insulated from the safety risks that field employees face -- would mean that it would generally be more difficult for Xcel Energy (North Dakota jurisdiction) to achieve equal or better OSHA incident results than the group of utilities in the < 1,000 employee category, all other things being equal.

The EEI report is available in late spring following the most recent results year. Because of this delay, and the need to be able to communicate to employees early in the target year what the new PLUS safety standard will be, the most recent three year period for industry data would not include the year just previous to the target year. For purposes of establishing the 2004 standard, external OSHA data from 2000-2002 will be used.

Consistent with the other Plan performance standards, the employee safety measure will carry a potential reward and/or penalty of a 25 basis point adjustment to the authorized ROE deadband.

2. Improved Performance Standard Bandwidths

For the first three years of the PLUS Plan (2001-2003), the standard or "range of acceptable performance" (i.e., performance deemed as acceptable, which results in neither an award or penalty) attached to each of the seven performance indicators was determined by multiplying the given performance midpoint or target by 85% and 115%. Performance within these bandwidth limits is defined by the Plan as 'meeting the standard', and no performance points are assigned. The +/- 15% calculation was considered by all parties to be reasonable for purposes of defining acceptable ranges of performance, although it was somewhat arbitrary.

For 2004 and 2005, Xcel Energy proposes that the acceptable performance bandwidths be determined mathematically each year by computing the standard deviation associated with the utility results for each year of the previous three year period[4]. Specifically, the range would be established by adding and subtracting from each industry performance benchmark 75% of the *average* standard deviation of the three years of external industry data. Since one standard deviation from the average will capture approximately 68% of the utilities in the sample (leaving 16% of the utilities

[4] For the Transaction survey measure, the standard deviation of the three years of historical Xcel Energy -- North Dakota jurisdiction results is computed to determine the performance standard range

in each of the award and penalty categories), multiplying by 75% ensures that the standard captures 50% of the utilities in the standard (and 25% in each of the award and penalty categories). Implementing this approach will:

- Improve the definition of award and/or penalty level performance to mean results that are generally in the upper and/or lower quartile for the industry.
- Provide mathematical consistency in the width of the standard (i.e., acceptable performance ranges) for all Plan indicators;
- Ensure the performance standards reflect changes in the variability of utility performance results over time.

The following table summarizes the estimated [5] Plan standards for 2004 using the new standard deviation methodology, and compares these ranges to the existing 2003 PLUS standards. See Attachment B for a more detailed schedule of the calculation of each indicator's standard deviation:

[5] Some measures will require data from the 2001-2003 three year period in order to establish a final 2004 performance target Since final 2003 data is not available at this time, an estimate of 2003 results has been factored into the calculation of the standards for those indicators

TABLE 1

Measure	2003 PLUS - Standard	2004 Top-Quartile Standard*	2002 XCel„ ' Energy Result
Outage Duration*	75.6 to 102.4 min.	74.6 to 134.2 min':	74.3 min.
Outage Frequency*	0.77 to 1.04 per customer	-, 0.87 to 1.58 , per customer	1.09 incidents
Relationship Customer Satisfaction	81.0% to 75.0%	75.4% to 63.6%	76.0%
Transactional Customer Satisfaction**	68.0% to 62.0%	74.5% to 69.2%	70.5%
Competitive Rates	6.53¢ to 8.83¢	6:95¢ td'8'.42¢	5.95 0
Rate Stability	1.7% to 3.4% increase	2.3% decrease to 5.7% increases ,	8.9% decrease
OSHA Rate	3.70 to 5.00	, 3.44 to 7.65	3.11 incidents

* Standard based on the statistical derivation of upper and lower quartile performance for the applicable industry comparison group.

3. Improved ROE Deadband & Revenue Sharing Mechanism

The PLUS Plan "baseline" allowed Return on Equity ("ROE") is currently 12.0%. An ROE deadband of +1- 1.0% is established around the baseline for purposes of defining the allowed or acceptable ROE for the Company should it meet all performance standards in a given year.

As previously discussed, this allowed ROE deadband is subject to annual adjustments depending on the Company's performance relative to each Plan performance standard. Currently, if net performance points earned in a given year are positive (net award), only the upper end of the ROE deadband increases. If the net performance points earned are negative (net penalty), only the lower end of the ROE deadband is decreased (see Attachment C).

The Company proposes that for 2004 and 2005, performance points earned by the Company — whether negative or positive -- would adjust *both* the upper and lower limits of the ROE deadband equally. In other words, the entire ROE deadband representing the "authorized" earnings amount (and within which no revenue sharing occurs) will move up with excellent performance and move down with poor perforMance (see Attachment C, page 2).

As is currently the case, if the Company's actual reported earnings for any given Plan year exceeds the deadband, 50% of the corresponding revenue 'sufficiency' would be refunded to customers during the July billing cycle of the following year. The proposed modification, however, would enhance the incentives to meet or exceed the performance standards. For example, by moving the entire range down for substandard performance (rather than leaving the upper limit unaffected) the likelihood of refunds to customers is increased since all earnings above the bandwidth are to be shared. On - the other hand, moving the whole bandwidth up when performance exceeds Plan standards (rather than leaving the lower limit fixed) increases the Company's chances to secure at least partial recovery of costs when revenues are deficient (i.e., earnings are below the allowed ROE bandwidth commensurate with performance). Besides being more straightforward, this approach is also more symmetrical than one that only moves the upper or lower limit of the ROE bandwidth.

Also, the Plan currently requires that refunds be made to customers of record on March 31 following the fiscal results year. As part of this proposal, the Company would commit to having customers of record on a date *as close as possible* to July 1 (and no more than 60 days prior to July 1) be issued refunds. Refunds would be administered as bill credits prorated on the basis of electric usage for the twelve months ending on that date.

4. Simpler Base Rate Change Criteria

A. Rate Increase Criteria

Currently, the PLUS Plan requires that specific criteria be met before any changes to base rates are allowed. For example, the Company is only allowed to increase rates if all of the following conditions exist:

1) its most recently reported ROE is more than 100 basis points (i.e., 1.0% ROE) below the performance-adjusted ROE deadband *midpoint;*
2) the Company's average residential rates in the most recent Plan year are lower than the utility peer group average residential rate; and
3) the price cap factor is greater than 0.0%.

If all of these conditions are met, the Company may increase rates by an overall percentage not to exceed the Plan price cap factor (which is based on the lower of the utility comparison group average rate change and 60% of inflation).

Pursuant to this proposal, the first Plan criteria would be changed to read:

1) its most recently reported ROE is lower than both 11.0% and the lower limit of the adjusted ROE deadband

B. Rate Freeze Conditions

If one or more of the above conditions fails to be true, the PLUS plan requires base rates to remain unchanged for the following year, unless a rate decrease is in order, as described below.

C. Required Rate Decrease Criteria

The PLUS Plan currently *requires* the Company to *reduce* its retail electric rates if all of the following conditions exist:

1) its most recently reported ROE is higher than the performance-adjusted ROE deadband midpoint plus 100 basis points;
2) the Company's average residential rates in the most recent Plan year are higher than the PLUS utility peer group average residential rate; and
3) the Price Cap Factor is below 0.0%.

Pursuant to this proposal, the first Plan criteria would be changed to read:

1) its most recently reported ROE is higher than both 13.0% and the upper limit of the adjusted ROE deadband

This approach to base rate change criteria works in tandem with the revised dynamic ROE deadband methodology that moves the *whole* ROE bandwidth as dictated by the Company's performance. Also, by eliminating the use of "ROE deadband midpoint plus or minus 100 basis points" as the earnings threshold, the Plan is also simpler to understand and explain. In essence, if a utility performs poorly and causes the ROE deadband to shift downward, the utility will more likely be required to refund excess earnings, freeze rates, or even reduce rates than under the current method. If the utility is meeting or exceeding performance standards, but is experiencing revenue deficiencies, it will have an improved capacity to adjust rates upward to bring earnings more in line with the excellent performance level. See Attachment C for more information regarding the rate change earnings threshold.

5. Term/Extension of Plan

The Company does not propose to modify the term of the PLUS Plan in this application. As originally approved, the PLUS Plan will remain in effect through December 31, 2005. Prior to July 1, 2005, the Company may file for an extension and/or further modification of the Plan if so desired. Such a filing may include an adjustment to rates to be effective on or before the extended Plan commencement date (if other than January 1, 2006). Absent such a filing and an order from the Commission approving extension, the PLUS Plan will automatically terminate on December 31, 2005.

6. Other Terms and Conditions

A. Exogenous Events.

Generally, Plan changes to base rates are subject to the rate change criteria and price cap mechanisms included in the Plan. However, any increases or decreases in costs of electric service amounting to at least a 1.0% change in ROE which is caused by governmentally imposed changes in taxes and/or accounting practices shall be implemented within 60 days of the effective date of the change.

All other terms of the original Plan as approved by the Commission and not addressed in this proposal remain in force.

VI. CONCLUSION

For the foregoing reasons, Northern States Power Company d/b/a Xcel Energy requests that the North Dakota Public Service Commission approve the proposed enhancements to the PLUS Plan to be effective January 1, 2004. The proposed modifications shall be effective for the 2004 and 2005 Plan years, at which time the PLUS Plan will expire unless an extension is sought by the Company and approved by the Commission.

Please direct any questions regarding this Notice to Mr. Dave Sederquist at (701) 241-8632 or Mr. Jim Johnson at (612) 215-4592.

Respectfully Submitted,

By: ____________________

Kent T. Larson
State Vice-President

Date: December 16, 2003

PUBLIC SERVICE COMMISSION

STATE OF NORTH DAKOTA

Public Service Commission
Incentive Regulation-Electric
Investigation

Case No. PU-439-94-590

GUIDELINES FOR FILING
ALTERNATIVE REGULATION PROPOSALS

September 20, 1995

The Commission wants North Dakota consumers to receive reliable electric service at the lowest reasonable rates. To further that purpose, the Commission will consider proposals for alternative forms of regulation.

The Commission and interested parties have been meeting in workshop and public input settings to discuss different types of regulation for electric companies during the past several months. Based on those discussions, proposals should promote the following goals

1 **Promote Utility Efficiencies:** Regulatory signals should encourage short and long term cost optimization, streamlined operating procedures, improved employee productivity, and increased pricing efficiency.

2. **Align Customer and Shareholder Interests:** Utilities and their customers should share in benefits obtained through improved efficiency and innovative techniques.

3. **Maintain/Improve Customer Service:** Safety, reliability, and customer service and satisfaction should be maintained or improved over current levels, and customers should experience lower, non-discriminatory rates than they would with the current regulatory framework.

4. **Allow Utilities to be Flexible:** Utilities must be able to respond to customers' specific needs.

5 **Minimize Regulatory Costs:** Regulation should focus more on results (overall performance) rather than processes and allow increased flexibility in management decisions. This will reduce the need for some filings, hearings, and other regulatory proceedings and enable utilities to respond more quickly and creatively to changing business conditions.

6. **Improve Public Participation:** Opportunities for public input should be enhanced.

Proposals should also meet the following criteria:

1. **Comprehensive:** Adopt plans that keep the focus on the overall economics of operating the utility and serving customers. The plans should also avoid potential for overemphasis on specific aspects of the utility operation

2. **Administratively Simple:** Adopt plans that are straightforward, using easily measured data. Plans should include measurable and verifiable processes that avoid arguments by parties in assessing results to provide a basis for evaluating the success of the plan.

3. **Easily Communicated:** Adopt plans that utility employees understand so that actions to make improvements occur. The goal of alternative plans is to improve performance above the level that would have been achieved without the plan. It takes actions by utility employees to make this happen. Plans should also contain mechanisms that inform customers about plans and their benefits.

4. **Balanced:** Adopt plans that are symmetrical in terms of the rewards and penalties offered. In a competitive market, good performance is rewarded and poor performance is penalized.

5. **Flexible:** Adopt utility specific plans that provide flexibility both in terms of the ability to modify plans to improve effectiveness and in terms of the utility's ability to be responsive to customers in increasingly competitive situations.

The Commission would also like any proposals to reflect the following considerations:

1. That a utility should not assume that its existing rate base will be the base to which the alternative rate proposal will apply. The utility must show that the base rates--calculated on a cost-of-service basis--are just and reasonable at the start of the alternative mechanism.

2. That the proposal will be for a limited period of time and for an experimental purpose only. Each plan should include a review date and a rationale for that date. The Commission will consider the time period proposed in conjunction with the plan.

3 That during the period of the experiment, the plan will provide for a periodic review of the utility's profits by the Commission, which profits will be adjusted, if necessary, pursuant to criteria defined in the plan.

4. That the proposal will enable the Commission to judge the success of the experiment at its completion.

5. In adopting these guidelines, the Commission will not permit companies to violate the Territorial Integrity Act.

PUBLIC SERVICE COMMISSION

Bruce Hagen **Commissioner**	**Susan E. Wefald** **President**	**Leo M. Reinbold** **Commissioner**

Northern States Power Company d/b/a Xcel Energy
Electric Utility -North Dakota Jurisdiction
Proposed PLUS Plan Performance Standards for 2004, 2005
Reliability - Outage Duration (number of minutes typical customer is without power during a sustained outage)

	Industry Benchmark	1998	1999	2000	2001	2002	2003	2004	2005
1	Average CAIDI for group	86 3	108 1	976	104 4	1112			
2	Standard Deviation	35 5	59 5	37 0	35 1	47 1			
3	Rolling 3 yr avg CAIDI			97 3	103 4	104 4			
4	Rolling 3 yr avg Std Deviation			440	439	398			

	Xcel Enerav Results	1998	1999	2000	2001	2002	2003*	2004	2005
5	CAIDI	73 2	69 6	75 6	66 6	74 3	60 0		

	Proposed Standard	1998	1999	2000	2001	2002	2003	2004	2005
7	Industry Benchmark					973	103 4 [	1044]	
8	Bandwidth (+/- 0 75 Std Dev's)					33 0	32 9	29 8	
	Resulting Standard								
9	Award (<)					64 3	70 5	74 6	
10	Penalty (>)					130 3	136 3	134 2	

	Current Standard	2001	2002	2003
11	Standard	89 0	89 0	89 0
12	Standard Bandwidth (+/-)	15%	15%	15%
13	Award (<)	75 6	75 7	75 7
14	Penalty (>)	102 4	102 4	102 4

# of Std Deviations to construct PLUS Performance Standard **0.75**

• 2003 Xcel Energy actual reflects estimate based on year to date results through November for Xcel Energy Industry result is not known at this time

Industry data resource Edison Electric Institute
Annual Reliability Report
Group all participating utilities (number of utilities has varied from 45 to 64 in last 5 years)

Northern States Power Company d/b/a Xcel Energy
Electric Utility - North Dakota Jurisdiction
Proposed PLUS Plan Performance Standards for 2004, 2005
Reliability - Outage Frequency (number of sustained outages experienced by a typical customer during the year)

	Industry Benchmark	1998	1999	2000	2001	2002	2003	2004	2005
1	Average SAIFI for group	1 38	1 21	1 15	1 29	1 22			
2	Standard Deviation	0 85	0 49	0 43	0 52	0 46			
3	Rolling 3 yr avg SAIFI			1 25	1 22	1 22			
4	Rolling 3 yr avg Std Deviation			0 59	0 48	0 47			

	Xcel Energy Results	1998	1999	2000	2001	2002	2003*	2004	2005
5	SAIFI	0 75	1 06	0 75	0 90	1 09	0 90		

	Proposed Standard	1998	1999	2000	2001	2002	2003	2004	2005
7	Industry Benchmark					1 25	1 22	1 22	
8	Bandwidth (+/- 0 75 Std Dev's)					044	036	035	
	Resulting Standard								
9	Award (<)					0 80	0 86	0 87	
10	Penalty (>)					1 69	1 58	1.58	

	Current Standard	2001	2002	2003
11	Standard	0 90	0 90	0 90
12	Standard Bandwidth (+/-)	15%	15%	15%
13	Award (‹)	0 77	0 77	0 77
14	Penalty (>)	1 04	1 04	1 04

# of Std Deviations to construct PLUS Performance Standard 0.75

* 2003 actual reflects forecast based on year to date results through November for Xcel Energy Industry result is not known at this time and an estimate is provided for illustrative purposes only

Industry data resource Edison Electric Institute
Annual Reliability Report
Group all participating utilities (number of utilities has varied from 45 to 64 in last 5 years)

Northern States Power Company d/b/a Xcel Energy
Electric Utility - North Dakota Jurisdiction
Proposed PLUS Plan Performance Standards for 2004, 2005
Customer Satisfaction - Relationship Surveys (% of customers ranking overall satisfaction with Company as 8, 9, or 10)

	Industry Benchmark	1998	1999	2000	2001	2002	2003	2004	2005
1	% of customers at 8-10				67 4%	70 3%	70 8%		
2	Standard Deviation				10 3%	7 2%	6 3%		
3	Rolling 3 yr avg % at 8-10				67 4%	68 9%	69 5%		
4	Rolling 3 yr avg Std Deviation				10 3%	8 7%	7 9%		

	Xcel Enerav Results	1998	1999	2000	2001	2002*	2003*	2004	2005
5	% of customers at 8-10	79 0%	80 7%	84 3%	70 1%	76 0%	76 9%		

	Proposed Standard	1998	1999	2000	2001	2002	2003	2004	2005
7	Industry Benchmark					67 4%	68 9%	69 5%j	
8	Bandwidth (+/- 0 75 Std Dev's)					7 7%	6 5%	5 9%	
	Resulting Standard								
9	Award (<)					75 1%	754%	754%	
10	Penalty (>)					59 7%	62 3%	63 6%	

	Current Standard (overall quality, top 2 of 5 Pt. scale)	2001	2002	2003
11	Standard	81 0%	81 0%	78 0%
12	Standard Bandwidth (+/-)	3 0%	3 0%	3 0%
13	Award (>)	840%	840%	81 0%
14	Penalty (<)	780%	780%	75 0%

# of Std Deviations to construct PLUS Performance Standard 0.75

' Reflects 11 pt scale results, top 3 responses Prior years reflect 5 pt scale, top 2 responses 2003 actual reflects year to date results through October for Xcel Energy

Industry data resource University of Michigan's School of Business National Quality Center
American Customer Satisfaction Index (ACSI) National Survey
Group Participation includes approximately 30 utilites across the nation

Northern States Power Company d/b/a Xcel Energy
Electric Utility - North Dakota Jurisdiction
Proposed PLUS Plan Performance Standards for 2004, 2005
Customer Satisfaction - Transaction Surveys (% of customers ranking overall satisfaction with transaction 8, 9, or 10)

	Xcel Enerav Results	1998	1999	2000	2001	2002	2003	2004	2005
1	% of customers at 8-10	59 5%	62 5%	65 0%	70 6%	70 5%	74 5%		
2	Standard Deviation				3 4%	2 6%	1 9%		
3	Rolling 3 yr avg % at 8-10	No industry data exists for comparable transaction survey results Xcel results are used			660%	687%	719%		
4	Rolling 3 yr avg Std Deviation				34%	30%	26%		

	Xcel Enerav Results	1998	1999	2000	2001	2002*	2003*	2004	2005
5	% of customers at 8-10	59 5%	62 5%	65 0%	70 6%	70 5%	74 5%		

	Proposed Standard	1998	1999	2000	2001	2002	2003	2004	2005
7	Industry Benchmark					66 0%	68 7%	71 9%	
8	Bandwidth (+1- 0 75 Std Dev's)					3 4%	3 0%	26%	
	Resulting Standard								
9	Award (<)					69 4%	71 7%	74 5%	
10	Penalty (>)					62 7%	65 7%	692%	

	Current Standard (overall quality, top 2 of 5 pt. scale)	2001	2002	2003
11	Standard	630%	630%	650%
12	Standard Bandwidth (+1-)	30%	30%	30%
13	Award (>)	660%	660%	680%
14	Penalty (<)	600%	600%	620%

# of Std Deviations to construct PLUS Performance Standard **1 00**

* Reflects 11 pt scale results, top 3 responses Pnor years reflect 5 pt scale, top 2 responses 2003 actual reflects forecast based on year to date results through October for Xcel Energy There are no industry results to benchmark at this time, so Xcel Energy results are used to set the standard Due to this, one st dev of Xcel Energy histoncal results is used to establish performance standard

Industry data resource None

Northern States Power Company d/b/a Xcel Energy
Electric Utility - North Dakota Jurisdiction
Proposed PLUS Plan Performance Standards for 2004, 2005
Price - Competitiveness (average residential rate in ft)

	Industry Benchmark	1998	1999	2000	2001	2002	2003*	2004	2005
1	Average price for group	7 31	7 35	7 42	7 68	7 68	7 70		
2	Standard Deviation	0 95	0 87	0 81	0 93	1 02	1 00		
3	Rolling 3 yr avg price			7 36	7 48	7 59	7 69		
4	Rolling 3 yr avg Std Deviation			088	087	092	098		

	Xcel Enemy Results	1998	1999	2000	2001	2002	2003*	2004	2005
5	Average price	607	611	624	653	595	630		

	Proposed Standard	1998	1999	2000	2001	2002	2003	2004	2005
7	Industry Benchmark				7 36	7 48	7 59	7 69	
8	Bandwidth (+/- 0 75 Std Dev's)				0 66	0.65	0 69	0 74	
	Resulting Standard								
9	Award (<)				6 70	6 83	6 90	6 95	
10	Penalty (>)				8 02	8 13	8 28	8 42	

	Current Standard	2001	2002	2003
11	Standard	7 68	7 68	7 70
12	Standard Bandwidth (+/-)	15%	15%	15%
13	Award (<)	6 53	6 53	6 55
14	Penalty (>)	883	883	886

# of Std Deviations to construct PLUS Performance Standard 0 75

• 2003 Xcel Energy 'actual reflects forecast based on year to date results through November for Xcel Energy Industry result is not known at this time and an estimate is provided for illustrative purposes only

Industry data resource Edison Electric Institute
Typical Bills and Average Rates Report
Group Investor-owned utilities serving ND, SD, MN, WY, WS, IA, and MT

Northern States Power Company d/b/a Xcel Energy
Electric Utility - North Dakota Jurisdiction
Proposed PLUS Plan Performance Standards for 2004, 2005
Price - Annual Change (average residential rate in 0)

	Industry Benchmark	1998	1999	2000	2001	2002	2003*	2004	2005
1	Average price change for group	1 4%	0 9%	0 5%	3 7%	0 4%	1 0%		
2	Standard Deviation	3 1%	3 5%	3 1%	4 3%	6 7%	5 0%		
3	Rolling 3 yr avg price change			0 9%	1 7%	1 5%	1 7%		
4	Rolling 3 yr avg Std Deviation			32%	36%	47%	53%		

	Xcel Eneray Results	1998	1999	2000	2001	2002	2003*	2004	2005
5	Average price change	3 6%	0 7%	2 1%	4 6%	-8 9%	5 9%		

	Proposed Standard	1998	1999	2000	2001	2002	2003	2004	2005
7	Industry Benchmark				0 9%	1 7%	1 5%	[7— 1 7%1	
8	Bandwidth (+/- 0 75 Std Dev's)				2 4%	2 7%	3 5%	4 0%	
	Resulting Standard								
9	Award (<)				-1 5%	-1 0%	-2 0%	-23%	
10	Penalty (>)				34%	44%	51%	5 7%	

	Current Standard	2001	2002	2003
11	Standard	34%	06%	50%
12	Standard Bandwidth (+/-)	08%	08%	08%
13	Award (<)	26%	-02%	42%
14	Penalty (>)	4 2%	1 4%	5 9%

# of Std Deviations to construct PLUS Performance Standard **0** 75

* 2003 Xcel Energy actual reflects forecast based on year to date results through November for Xcel Energy Industry result is not known at this time and an estimate is provided for illustrative purposes only

Industry data resource Edison Electric Institute
Typical Bills and Average Rates Report
Group Investor-owned utilities serving ND, SD, MN, WY, WS, IA, and MT

Northern States Power Company d/b/a Xcel Energy
Electric Utility - North Dakota Jurisdiction
Proposed PLUS Plan Performance Standards for 2004, 2005
Worker Safety - (number of OSHA incidents per 100 workers in a year)

	Industry Benchmark	1998	1999	2000	2001	2002	2003	2004	2005
1	Average OSHA rate for group 5	5 78	6 94	5 53	4 78	6 32			
2	Standard Deviation	3 46	3 08	3 11	2 27	3 03			
3	Rolling 3 yr avg OSHA rate		651	608	516	554			
4	Rolling 3 yr avg Std Deviation		257	322	269	280			

	Xcel Enemy Results	1998	1999	2000	2001	2002	2003*	2004	2005
5	Average OSHA rate	361	241	401	448	311	325		

	Proposed Standard	1998	1999	2000	2001	2002	2003	2004	2005
7	Industry Benchmark				651	608	5 16 {	5 54	
8	Bandwidth (+/- 0 75 Std Dev's)				1 93	241	202	210	
	Resulting Standard								
9	Award (<)				458	367	314	344	
10	Penalty (>)				843	849	718	7 65	

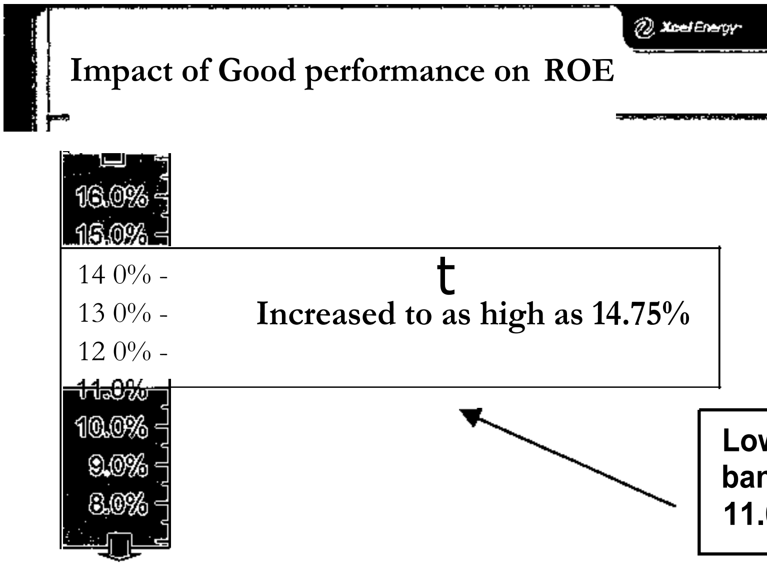
	Current Standard	2001	2002	2003
11	Standard	4 32	4 32	4 32
12	Standard Bandwidth (+/-)	15%	15%	15%
13	Award (<)	370	370	370
14	Penalty (>)	5 00	5 00	5 00

# of Std Deviations to construct PLUS Performance Standard **0.75**

• 2003 actual reflects forecast based on year to date results through November for Xcel Energy Industry result is not known at this time and an estimate is provided for illustrative purposes only

Industry data resource Edison Electric Institute Human Resources Information Center
Annual Safety Survey
Group Participating Level 5 (less than 1,000 employees) utilities (8-12)

Current Mechanism — Dynamic Allowed ROE Deadband

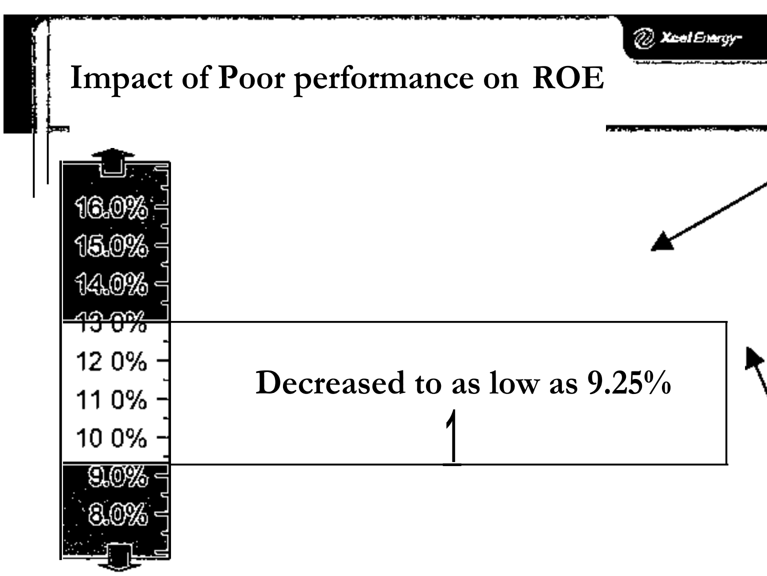


Best-case scenario: Company exceeds all 7 standards and the upper allowed ROE limit is increased by 1.75% to 14.75%

Lower limit of ROE bandwidth stays fixed at 11.0%

If performance exceeds the standards (see above), actual financial benefits exist only if the company is earning above 13.0% (since the Company is then allowed to retain more of its earnings). If the Company is earning below 13.0%, there is no difference in actual financial benefits between exceeding all 7 standards and exceeding none of them.

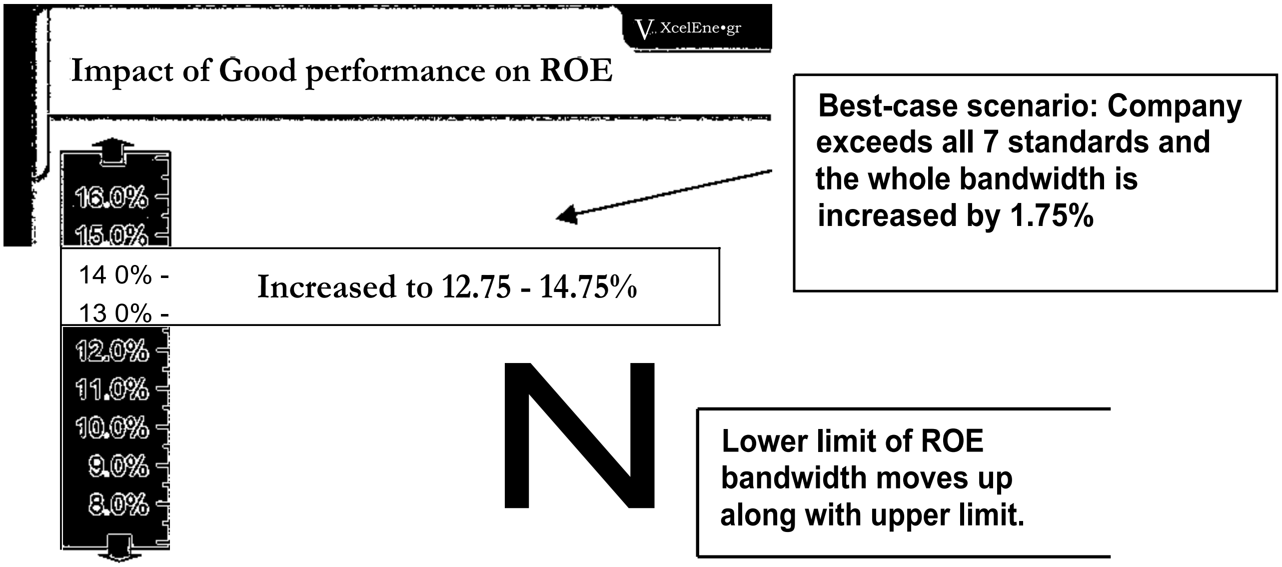
If performance is poor (see below), actual financial penalties are blunted because the Company can still earn as high as 13.0% without being required to refund anything to customers. Refunds are only required if earnings exceed 13.0%.



Worst-case scenario: Company fails to meet any of the 7 standards, and the lower limit is decreased 1.75%.

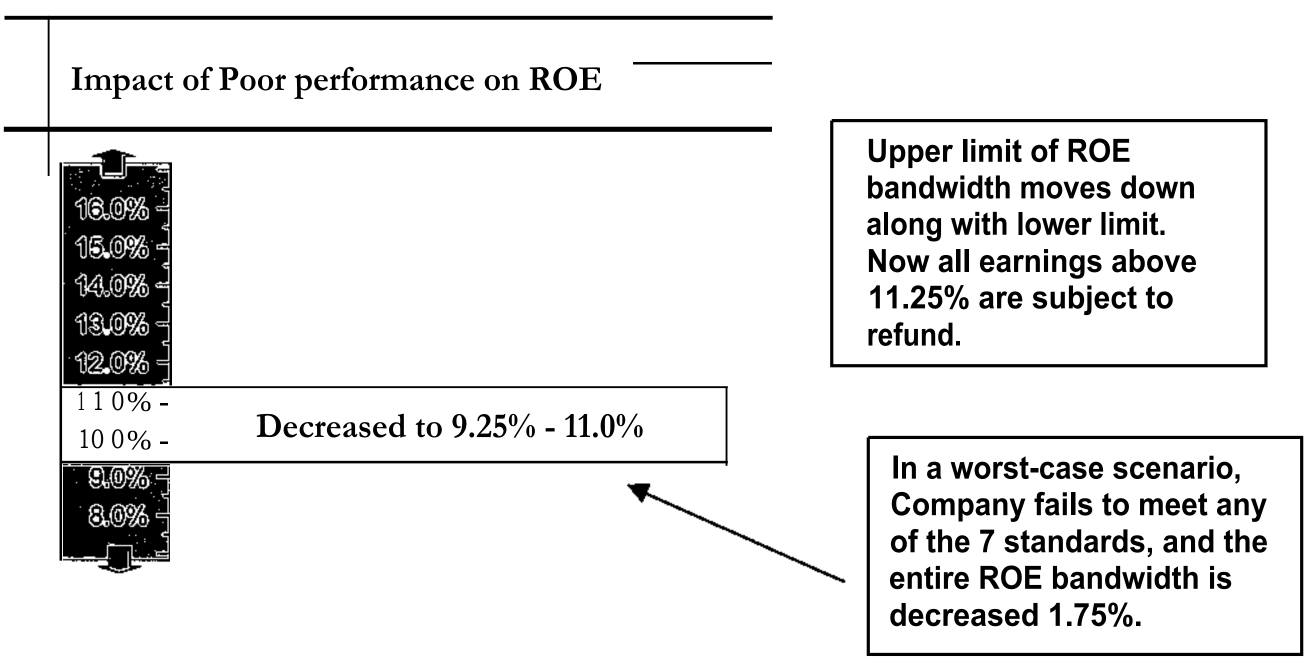
Upper limit of ROE bandwidth stays fixed at 13.0%. Earnings aren't subject to refund unless they exceed 13.0%, which is the same outcome as if all 7 standards were met.

Proposed Mechanism - Dynamic Allowed ROE Deadband



If performance is exceeding the standards (see above), direct financial benefits are proportional to the number of performance standards exceeded. The Company is allowed to retain more "high" earnings while being allowed to recover part of any earnings below the deadband.

If performance is not meeting the standards (see below), financial penalties are more effective because the Company is subject to more customer refunds for every standard it fails to meet.



Public Service Commission
State of North Dakota

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Memo

To: Commissioners

From: Mike Diller **Ofr**

Date: October 15, 2003

Re: NSP PBR 2-year Review (Case No. PU-400-03-256)

On June 17, 2003, I submitted a memo on behalf of staff describing the concerns staff has with NSP's existing PBR plan. The concerns are not with the reporting aspect of the plan but instead the performance standards used to determine the benchmark earnings levels allowed. See memo for refresher of details.

On June 18, 2003, the commission held an informal hearing to discuss staffs recommendations. Since then, staff has continued to work with NSP to see if the issues could be resolved.

Staff appreciates the hard work done by NSP in securing the necessary information and for staying fully engaged throughout the process.

Staff and NSP have not been able to agree on improving the existing standards. The failure to agree was not because we didn't try. Many different options were explored. However, the differences between staff and NSP were too great to overcome. The differences arise out of different perspectives on what a performance-based regulation plan should achieve. In staffs view, a PBR plan should encourage a company to exceed actual results obtained under traditional rate of return regulation. From NSP's perspective, the plan should reward or penalize NSP based on industry standards and should have little or nothing to do with past performance levels. NSP believes it is unfair -- and ultimately counter-productive -- to require a utility to meet or exceed performance levels that are already among the best in the industry.

Both perspectives have merit. NSP developed a target-setting approach that factors in both an industry benchmark and the company's most recent

5 **PU-400-03-256** Pages 2

NSP PBR 2-Year Review Memo

by Public Service Commission by Mike Diller

10/20/2003

performance trends to accommodate both sides. However, staff remains uncertain as to the validity of the industry benchmarks and is not persuaded that the new proposed targets will result in improved performance from the company. NSP's new approach would lower the standards for 6 of the 7 performance measures.

Staff is not opposed to NSP's market approach--provided that the industry standards are relative to NSP. I believe the industry data related to price of service and worker safety is clean enough that staff might be able to agree to performance standards outside the confines of actual results. With regard to price, the standards are simply based on residential revenues divided by residential sales to arrive at a cost per kWh. The OSHA reporting requirements are standardized for what constitutes an injury and therefore reporting differences should be minimal between electric companies.

While staff is fairly comfortable with price and safety reporting and comparability between companies, staff is not so convinced with the remaining standards pertaining to outages and customer satisfaction. The outage reporting can be greatly affected by each company's storm normalization approach. Some companies exclude outages that last more than 24 hours. Others exclude outages using a standard deviation calculation. Some companies make no storm adjustments at all and report all outages. With regard to the customer satisfaction standards, there is no external data for transactional survey results comparisons and the comparability of relationship studies between companies is suspect. In staff opinion, relationship survey results could vary significantly depending on a company's structure and other affiliated services outside the electric operations. For instance, it is likely that customers will not delineate between NSP's high natural gas prices and its electric service when rating their feelings towards NSP's electric operations and so on.

In the end analysis, staff is not set against NSP's notion of market measurements as long as there is a fair bit of assurance that the industry data can be fairly applied to NSP. Without that comfort level, any agreement would be arbitrary and should give way to benchmarking based on NSP's own historical results.

Unless the commission gives further direction, the staff is finished with its 2-year review of NSP's PBR plan and recommends no change at this time.

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INFORMAL HEARING AGENDA

June 18, 2003

PU-2805-03-231	Otter Tail Corporation 2002 Annual Report
PU-400-03-256	Northern States Power Company 2002 Electric Operations Annual Report

3 **PU-2805-03-231** Pages 0

Informal Hearing held

by Public Service Commission

06/18/2003

4 **PU-400-03-256** Pages 0

Informal Hearing held

by Public Service Commission

06/182003

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Memo

JUN 1 8 2003

DP:
EXECUTIVE SECRETARY

To: Commissioners

From: Mike Diller

Date: June 17, 2003

Re: PBR Review (Case No. PU-400-03-256)
Northern States Power Company

I have completed my review of NSP's 2001 and 2002 financial reports to the commission as well as how the plan is working and where improvements need to be made.

Before beginning, I understand that you will not have much time to digest the memo before the informal meeting. However, we knew going into the project that the time line would be very difficult. The meeting will be exploratory in nature and not intended to decide all facets of the case. Instead, this memo kicks off what may result in other meetings to finalize any changes in the plan that can be agreed to. I look forward to discussing these ideas with you and receiving any direction you may feel appropriate.

Financial Review

With regard to the first two financial reports under PBR, I have reviewed the revenue, expense and rate base levels in comparison to years past including allocation factors used to allocate costs to North Dakota. Staff issued data requests for explanations of any abnormal cost deviations. The responses were reviewed and follow-up discussions were held with Dave Sederquist.

Staff noted no exceptions other than an overstated accumulated deferred income tax balance reported in 2001. Because accumulated deferred income taxes are ratepayer-supplied capital, it reduces rate base or the investment necessary to provide service. As a result of the overstatement, rate base was understated resulting in a higher reported return on investment than actually occurred. Because the mistake benefited ratepayers, no further procedures were deemed necessary.

The staff was also concerned with the preliminary report of Fraudwise, a division of Eide Bailly **LLP.** Fraudwise was hired by Minnesota's Attorney General's Office to look into the allegations of under reporting outage durations. Staff was concerned that, if the allegations were true, the North Dakota's reported outage durations would be under reported resulting in a financial benefit to NSP through PBR for falsely exceeding its outage duration performance standard. NSP presented information at its last PIE meeting indicating changes that have been made to facilitate a better reconciliation of field reports with the called in information.

Based on its annual reports, NSP reported that it exceeded its outage duration standard for both 2001 and 2002 resulting in an increase in its allowed rate of return on equity of 25 basis points. Under PBR, any earnings above the ROE bandwidth are shared equally between ratepayers and the company. Even if the outage standard were removed from PBR and the awards taken away, the lower ROE bandwidth would have still been higher than reported earnings for both years and no refunds required. Therefore, staff will continue to monitor the eventual findings of the Minnesota commission but no further review of record keeping is necessary at this time.

Impact of PBR

PBR is intended to link earnings with performance through the rewards and penalties associated with its various performance standards. To this end, staff asked NSP to identify specific instances where PBR has impacted the decisions of its management. NSP responded that PBR had contributed to the following actions:

- The establishment of an improvement team in the fall of 2002 to address customer satisfaction performance that was below PLUS plan standards (relationship surveys);

- Formation of a 2003 North Dakota reliability plan to identify the feeders that contributed the most to 2002 outage frequency (SAIFI);

- Modification of a transmission pole replacement plan in the Grand Forks area to avoid the necessity of an extended outage to numerous customers;

- Establishment of a company-wide reliability problem solving team in 2001 to reduce electric delivery average interruption duration time;

- Utilization of the PLUS Plan safety standard in monthly safety advisory group meetings to promote safe work practices;

- Communicating the PLUS Plan in Xcel Energy's annual report to shareholders, at North Dakota shareholder advisory meetings, and to Wall Street analysts to convey the Company's desire to implement performance based regulation in its other utility jurisdictions; and

- Inclusion of PLUS standards with Minnesota (NSP) and Colorado (PSCo) regulatory reporting requirements.

Staff believes that the principal of connecting performance with earnings potential remains a very sound regulatory practice. PBR appears to be affecting NSP's North Dakota operations as well as its operations in other states.

Potential Improvements to PBR

Due to time constraints, staff has not had time to flesh out possible improvements to PBR with the Company. The following suggestions are therefore preliminary and intended to begin discussions to improve the existing plan.

Competitive Position Within Region

The current price standard of the competitive position of NSP relative to the regional average is pretty much a slam-dunk. Retroactively applying the standard results in NSP exceeding the standard 8 of the last 9 years and barely missing the reward in the remaining year. A standard that is too easy to meet or one that is too hard to meet does little to spur on greater achievement. NSP is one of the lowest cost providers in the region so perhaps a slam-dunk is agreeable to the commission. Perhaps there should be no sharing of profits with ratepayers and unlimited earnings so long as the other standards of reliability, safety and customer satisfaction are met. On the other hand, why diminish what NSP can achieve by providing a "gimme" for its competitive position performance measure.

I suggest that we look at setting the standard on some percentage of the regional average. For example, during the years 1994 to 2002, NSP's competitive position relative to the regional average has not deviated more than 3.1 percentage points from 81.9% to 85% (excluding 77.5% for 2002). Why not set the competitive position standard at the latest 5-year average before 2002 of 83.6% plus or minus 1 percentage point? Such a change would bring the competitive position standard back into play and encourage even lower prices in the future. Retroactively applying such a standard would have resulted in 3 awards and 2 penalties for the past 9 years.

Rate Stability

The price standard of rate stability as compared to the price change of the lowest priced utility in the region is quite volatile. Staff explored using the 5 lowest companies rather than using the price change of the lowest priced utility but similar volatility was observed. Staff also tried to develop some kind of percentage relationship as discussed in the competitive position price standard but found little correlation there as well. Even though the current practice of comparing NSP's price change to that of the lowest utility in the region (2nd lowest if NSP is the lowest cost provider in the region) is volatile, the unpredictability of the standard is not all bad. If you apply the current standard backwards for eight years, NSP would have earned a reward for 4 years, a penalty for 3 years. The standard regularly comes into play giving the company reason to concentrate on its fuel costs and rates in general. At this time, staff is not able to identify a better method to apply for purposes of the rate stability standard.

Outage Duration

The outage duration standard has resulted in a reward for NSP for both 2001 and 2002. Applying the standard retroactively to 1995 results in 5 awards and no penalties. The 3-year average and 5-year average of actual results is right around 72 minutes whereas the standard is set at 89 with a bandwidth reaching from 75.7 minutes to 102.4 minutes. It appears that little effort is required to earn a reward. Again, it seems logical that any standard too easy or too hard to meet would be counterintuitive to the desired outcome. Staff recommends that the standard be tightened up to encourage greater effort in this area. If the commission adopted the latest 3-year average of 72 2 with a bandwidth of 2% on either side (instead of 15%) the standard would come into play more often and demand closer attention by NSP. Retroactively applying such a standard would result in 4 awards and 3 penalties during the past 8 years.

Frequency of Outage

The average outage frequency of .9 per customer per year appears to be on target with recent results. Retroactively applying it would result in 3 rewards and 2 penalties for the past 8 years. The commission could increase the play of this standard by reducing the bandwidth from 15% to 5%. A retroactive application of such would result in 4 awards and 3 penalties during the past 8 years. The current standard appears reasonable and not a high priority for change with staff.

Relationship and Transaction Surveys

Staff has not done enough work in this area to make a recommendation.

Worker Safety

NSP's incident rate per 100 employees is quite volatile ranging from a low of 1.99 and a high of 5.64 during the past 9 years. The industry average has been steadily declining during the past 9 years to a low of 3.15 for 2001. While NSP's results have been volatile, its average results compared to the industry average are 98%.

Retroactively applying the existing standard of 4.32 plus or minus 15% results in 4 awards and 1 penalty during the past 9 years. The standard initially set using industry averages was reasonable when PBR was initiated but the industry averages have improved a lot and the standard needs adjusting. Staff recommends that the standard be adjusted each year using last years average for Group 1 utilities with more than 7,000 employees with a bandwidth of plus or minus 5%. Retroactively applying such a standard would have resulted in 3 awards and 2 penalties during the past 8 years.

Customer of Record

Staff is not opposed to changing the "customers of record" from March 31 to "as close to July 1 as possible." This will ease the burden of finding people, who have left the system, to payout any dividends resulting from PBR.

Performance Dividend
Evidently such a description of a customer refund causes people to wonder if they should declare the money as taxable income. Staff is not opposed to using a more non-descript name such as "refund" to avoid such questions.

Exogenous Events
The plan should be modified to only include events that impact earnings by more than 1 ROE percentage point or some such agreed upon threshold. This will eliminate the current requirement that any increase or decrease in exogenous events be passed on to consumers regardless of materiality.

Moving Dead-Band
There was some talk between staff and NSP regarding doing away with the ROE anchor If you remember, the dead-band slides up or down depending on performance but one side of the dead-band remains fixed or anchored. For example, if NSP's net awards are a positive 50 basis points, the dead-band remains fixed at the bottom but stretches the top of the dead-band out 50 basis points. The anchored dead-band was developed out of concern for the near impossibility of a rate reduction and a quite possible rate increase given the terms of the PBR plan. The anchoring was an attempt to balance the scales. In order to move away from anchoring, we would need to develop a more balanced mechanism making rate decreases just as likely as rate increases.

C: Bernadeen Brutlag, Otter Tail Power Company
Dave Sederquist, Northern States Power Company
Illona Jeffcoat-Sacco, Director of PUD
Bill Binek, Commission Counsel

Xcel Energy

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JUN 10 2003
ND PUBLIC SERVICE COMMISSION
PUBUC UTILITIES DIVISION

June 5, 2003

Mike Diller, Director of Accounting
North Dakota Public Service Commission
State Capitol Building, Dept. 408
600 East Boulevard
Bismarck, ND 58505-0480

Re: Case No. PU-400-03-256 (PLUS Plan 2-year Review)

Dear Mr. Diller:

Attached are the responses to your Requests For Information related to the review of Xcel Energy's PLUS performance-based regulation plan in North Dakota. Thank you for allowing ample time for the Company to provide this information.

Please call or email me if you have any questions regarding this response.

Sincerely,

D Sederquist

David H. Sederquist
Sr. Consultant, Regulation/Finance

Enclosures

2 PU-400-03-256 cages

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Northern States Power d/b/a Xcel Energy
Case No : PU-400-03-256
Response To: Mike Diller — Request For Information 1
Date Received: May 14, 2003

Question:

Please explain why the North Dakota accumulated deferred income tax balance increased by $11 million in 2001 and then decreased by $8 million in 2002.

Response:

An analysis of accumulated deferred taxes during the 2000 to 2002 period has revealed an oversight in the reporting of the 2001 amount. In 2001, the decommissioning-related portion of accumulated deferred taxes ("ADT") was inadvertently excluded from the total ADT shown in the annual report of North Dakota electric earnings, thereby overstating the average ADT balance by $8,007,000.

Deferred taxes associated with the Company's decommissioning funding are "negative" because there is only book expense with the tax deductions for this cost not occurring until actual decommissioning payments are made at the end of the service life of the Company's nuclear facilities.

Had the decommissioning portion of ADT been included, the amount for 2001 would have been $38,450,000, not $46,457,000 as shown on page 5 of the 2001 PLUS Plan report. This ADT amount for 2001 is reasonably consistent with the levels for 2000 and 2002, given the inherent variability of deferred taxes from one year to the next:

(000's)	2000	2001	2002
Accum. Def. Taxes	$35,190	$38,450	$38,280

Response By: Lloyd A. Dallman
Title: Sr. Accounting/Financial Analyst
Department: Capital Asset Accounting
Telephone: 715-839-2606
Date: June 5, 2003

Northern States Power d/b/a Xcel Energy
Case No: PU-400-03-256
Response To: Mike Diller
Date Received: May 14, 2003

Request For Information 2

Question:

Explain the large variances in expense levels for 2000 through 2002 for the following accounts groups.

a) Customer Billing
b) Customer Service
c) Sales and Marketing
d) Administrative and General
e) Depreciation

Response:

The following table shows the annual North Dakota expenses for the classifications identified in Request For Information No 2:

(000's)	2000	2001	2002
Customer Billing	$2,870	$2,990	$3,530
Customer Service	$997	$33	$192
Sales & Marketing	$709	$185	$91
Admin & General	$10,250	$9,432	$7,561
Depreciation	$16,830	$19,682	$19,204
Total Operating Expenses	$2,136,070	$2,295,288	$2,126,281

The amounts shown above reflect information from page E-2 in the 2000 ND earnings report, and page 4 in the 2001 and 2002 PLUS Plan report to the Public Service Commission (the "Commission"). The North Dakota expense for each classification represents the sum of: 1) directly incurred North Dakota jurisdiction expenses; and, 2) portion of Northern States Power (NSP) amounts allocated to North Dakota.

Following the merger of "Old NSP" and New Century Energies, Inc. (NCE) in August 2000 to form Xcel Energy Inc., the merged company started the process of integrating the different accounting and financial management systems of Old NSP and NCE. Also, during this time the company began operating as a registered holding company subject to Securities and Exchange Commission rules regulating the allocation of corporate services costs to the operating companies, and most "corporate" functions were placed in the Xcel Energy Services Inc. ("XES") "service company" within the Xcel Energy Inc. system. The significant changes involved in this transition, which is still ongoing to a certain extent, resulted in material reclassifications of costs among the major FERC cost categories. Also, the integration of financial systems imposed limitations with respect to examining finer levels of cost detail and maintaining cost comparability with prior years. This affected primarily the 2001 FERC classifications.

For example, many expenses previously charged directly to the Customer Service and Sales and Marketing functional classes (FERC accounts) prior to the merger were initially charged by XES to Administrative and General accounts during the first year of merged operations. Beginning in 2002, efforts were made by XES to move to a more direct approach to FERC cost charging. The differences in the NSP Company and North Dakota portions of selected FERC functional classes reflect primarily the various stages of transition to a single, consolidated financial management system at Xcel Energy.

It is important to note that while variances occurred within specific FERC classes of costs, total North Dakota operating expenses remained relatively consistent from 2000 through 2002. This is indicative of the fact that while the merging of the Company's accounting systems and changes in financial processes had varying affects on individual FERC classifications of cost, the *overalljurisdictzonal* treatment of total operating costs is reasonable and consistent with historical experience.

An important consideration in comparing annual depreciation expenses is that North Dakota jurisdictional depreciation expenses represented between 5.6% and 6.1% of the NSP totals between 2000 and 2002. Minor variability in the North Dakota percentage can be attributed to annually changing allocation factors (such as the Demand Allocator) that are applied to the various functional classes of depreciation expense. However, due to the magnitude of the total Company depreciation expense, even small variations in the allocating percentages can have a significant nominal impact on expenses allocated to North Dakota

One component of depreciation that is not allocated is decommissioning costs. Depreciation expenses reflected a decrease in decommissioning funding when comparing 2002 to 2001. This decrease is due to a one-time adjustment in 2001 for an under-funding of external decommissioning in 2000 for North Dakota in the amount of $326,665.

Response By:	Jeff Robinson; Lisa H. Perkett
Title:	Manager, Revenue Analysis; Manager, Capital Asset Accounting
Department:	Revenue Analysis; Capital Asset Accounting
Telephone.	612-330-5912; 612-330-6950
Date:	June 5, 2003

Northern States Power d/b/a Xcel Energy

Case No : PU-400-03-256

Response To: Mike Diller

Request For Information 3

Date Received: May 14, 2003

Question:

Explain the large variances in North Dakota's allocated share of expenses for 2000 through 2002 for the following account groups:

a) Customer Service
b) Sales and Marketing
c) Deferred Income Taxes

Response:

The following table shows the annual North Dakota share of the total Northern States Power (NSP) expenses for the classifications identified in Request For Information No. 3:

	2000	2001	2002
Customer Service	2 0%	0.1`)/0	0.3%
Sales & Marketing	11.1%	6.6%	6.5%
Deferred Income Taxes	23 2%	29 7 %	6 .0 %
Total Operating Expenses	5.7%	5.7%	5.7%

The percentages shown above reflect information from page E-2 in the 2000 North Dakota jurisdictional earnings report, and page 4 in the 2001 and 2002 PLUS Plan report to the Public Service Commission (the "Commission"). The North Dakota share represents the sum of: 1) directly incurred North Dakota expenses, and, 2) amounts of NSP or XES costs allocated to the North Dakota jurisdiction, shown as a percentage of Company total incurred expense

As discussed in the response to Request For Information No. 2, the merging of Old NSP and New Century Energies, Inc. (NCE) financial management systems, as well as the beginning of operations as a registered holding company with a service company contributed to operating expense shifts among the various FERC functional classes. It is not feasible for the Company to determine, at a more detailed level, the specific areas in which these shifts took place or why.

As similarly noted in the response to Request For Information No. 2, while variances can be seen among specific FERC classes of costs, the North Dakota allocation of overall Company operating costs remained consistent from 2000 through 2002 at 5 7%. Again, this is indicative of the fact that while changes to the Company's accounting processes and systems had varying affects on FERC classifications of costs, the *overall junsdictzonal* allocation of total operating costs remained reasonable and consistent compared to historical experience.

Finally, it is not necessarily typical for deferred income taxes to be consistent from year to year primarily because book to tax timing differences can change significantly. The significant turnaround in deferred taxes between 2001 and 2002 are directly related to book to tax differences (Schedule M-Items) and a State of Minnesota tax change For 2001, the tax deductions were greater than the book deductions by $9,240,474 compared to 2002 when the book deductions were greater than the tax deductions by $57,528,981. Tax deductions are accelerated wherever possible and book deductions are usually level over time This net change of $66,769,455 is attributable to the fact that the book deductions are now greater than the tax deductions.

In 2001 the State of Minnesota changed their tax rules for ACRS property, vintages 1981 to 1987. This rule change, allowed the Minnesota State tax depreciation to follow the Federal tax depreciation rules for the ACRS property. The affect of this change produced a one time "catch up" in tax depreciation This additional tax depreciation dampened the impact of book depreciation for 2001, creating an atypical reduction in taxable income. At 2002 things returned to form, with book depreciation increasing over tax depreciation. In conclusion these two events most represent the cause for the unusual swing in deferred taxes between 2001 and 2002.

Response By: Jeff Robinson; Lisa H. Perkett
Title: Manager, Revenue Analysis, Manager, Capital Asset Accounting
Department: Revenue Analysis; Capital Asset Accounting
Telephone. 612-330-5912, 612-330-6950
Date: June 5, 2003

Northern States Power d/b/a Xcel Energy
Case No.: PU-400-03-256
Response To: Mike Diller Request For Information 4
Date Received: May 14, 2003

Question.

Explain how PBR has affected NSP's operations in general and any specific instances where PBR impacted decisions of management

Response:

The Company has long recognized the importance of measuring and managing its performance in delivering good customer service, achieving high system reliability, maintaining a low cost/price structure, and ensuring employee and public safety. In fact, our history of measuring and achieving good operational results was an important factor in moving to performance-based regulation in North Dakota. Many of the key performance indicators used by Old NSP in the past have now been included in the design of the Company's PLUS Plan ("PLUS", or the "Plan").

The adoption of the PLUS Plan gave the Company the opportunity to reinforce the existing performance objectives with its employees. The Plan has intensified the Company's focus on performance by directly linking operational plans and work results to financial results. During the two years PLUS has been in operation, employees have been regularly updated as to how individual achievements impact customer service, reliability, safety, and ultimately, the financial results of our North Dakota electric operations. This has been communicated through employee gatherings, safety meetings, the posting of PLUS scorecards, and newsletter articles.

Despite the fact that the Plan has only been in existence for two years, employee awareness of how regulation works under PLUS has influenced decision-making. The Plan, in concert with other important decision-making factors, has contributed to a number of specific actions, including:

- The establishment of an improvement team in the fall of 2002 to address customer satisfaction performance that was below PLUS plan standards (relationship surveys);

- Formation of a 2003 North Dakota reliability plan to identify the feeders that contributed the most to 2002 outage frequency (SAIFI);
- Modification of a transmission pole replacement plan in the Grand Forks area to avoid the necessity of an extended outage to numerous customers;
- Establishment of a company-wide reliability problem solving team in 2001 to reduce electric delivery average interruption duration time
- Utilization of the PLUS Plan safety standard in monthly safety advisory group meetings to promote safe work practices;
- Communicating the PLUS Plan in Xcel Energy's annual report to shareholders, at North Dakota shareholder advisory meetings, and to Wall Street analysts to convey the Company's desire to implement performance based regulation in its other utility jurisdictions; and
- Inclusion of PLUS standards with Minnesota (NSP) and Colorado (PSCo) regulatory reporting requirements monitored by the company

Perhaps one of the most important changes brought about by the PLUS Plan is that it has provided a vehicle for formally reporting the Company's service and operational performance to regulators, customers, and the public. Through the Plan's comprehensive annual report of performance, earnings, and rate information, the Commission is informed of the Company's performance in areas that might not otherwise be reported In addition, local media outlets have also communicated the results of the PLUS Plan to the public. See Attachment 4A.

Response By: David H. Sederquist
Title: Sr. Consultant, Regulation/Finance
Department: North Dakota Jurisdiction
Telephone. 701-241-8632
Date: June 5, 2003

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Xcel keeps rates stable

By Gerry Gilmour
ggilmour@forumcomm coin

Xcel Energy is holding the line on North Dakota electric rates this year, according to a company official.

Dave Sederquist, senior regulatory and financial analyst for the company in Fargo, Monday said the company's average residential rate of 5.95 cents per kilowatt remains the lowest among 30 investor-owned utilities operating in the seven-state area of North Dakota, South Dakota, Minnesota, Wisconsin, Iowa, Montana and Wyoming.

Sederquist said Xcel avoided a rate increase despite the state of North Dakota's new PLUS Plan. Developed by the North Dakota Public Service Commission, the "performance-based regulation" PLUS Plan establishes utility performance standards in the areas of reliability, customer satisfaction, electric prices and worker safety.

When a company meets or exceeds state standards, the state increases the company's allowed earnings. A poor performance pulls down a company's allowed earnings

"Philosophically, this seemed to be the way to go," said Mike Diller, director of accounting for the North Dakota PSC "The better they do, the more money they make."

Xcel Energy earned a 13 15 percent return on equity in 2002 through its electric operations in the state

XCEL Page C3

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The Forum 5/14/03

Ea,. Mel s aere ana arouna the world must be assured that their products won't be rejected simply because they used biotechnology," she said.

EU officials questioned the action, saying it will further damage trade relations already strained by the U.S.

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XCEL: Company met five of seven PLUS standards

From Page C1

"We saw the best of both worlds We had a good financial year and our performance was good," Sederquist said.

Xcel Energy met or exceeded five of seven PLUS Plan performance standards in 2002. Outage restoration time, worker safety, and customer satisfaction measurements also met or exceeded plan targets. The company failed to meet its outage frequency and overall satisfaction standards

Xcel Energy — a publicly traded company with operations in 12 Western and Midwestern states — serves 84,600 electric customers in the Fargo, Grand Forks and Minot areas of North Dakota. The company also serves natural gas customers in Fargo-Moorhead and Grand Fork-East Grand Forks, Minn.

Readers can reach Forum Business Reporter Gerry Gilmour at (701) 241.5560

Northern States Power d/b/a Xcel Energy
Case No.: PU-400-03-256
Response To: Mike Diller — Request For Information 5
Date Received: May 14, 2003

Question:

Provide all NSP responses to the Minnesota Attorney General's report on Xcel's service quality reporting.

Response

On October 22, 2002, the Minnesota Public Utilities Commission (MPUC) directed the Minnesota Department of Commerce (the "Department") and the Minnesota Office of the Attorney General — Residential Utilities Division (OAG) (together, the "State Agencies") to engage an auditor to examine the service quality records that formed the basis for Xcel Energy's reliability reporting in Minnesota. Toward that end, the State Agencies engaged a firm by the name of Fraudwise to conduct such an audit

On March 10, 2003, the State Agencies jointly filed with the MPUC a preliminary report from Fraudwise (this is assumed to be the "Attorney General's report" referenced in this request). The State Agencies asked the MPUC for direction regarding the scope and continuation of the audit.

On March 27, 2003, Xcel Energy filed a proposal with the MPUC suggesting that any action on the preliminary report be held in abeyance for thirty days to allow the Company to work with Fraudwise and the State Agencies

On April 3, 2003, the MPUC rejected the Company's proposal and ordered the continuation of the audit. The Company has not made any further response to the Fraudwise preliminary report.

Response By: Megan J. Hertzler
Title: Sr. Attorney
Department: General Counsel
Telephone: 612-215-4589
Date. June 5, 2003

Northern States Power d/b/a Xcel Energy
Case No.: PU-400-03-256
Response To: Mike Diller — Request For Information 6
Date Received: May 14, 2003

Question:

Provide any internal changes made to correct reporting procedures or practices as a result of the Attorney General's investigation.

Response:

Prior to the service quality investigation in Minnesota, Xcel Energy had two different processes for documenting service outages: the process used in the Twin Cities Metro region; and the process used in the Xcel Energy northern territories, which includes North Dakota With the advent of the investigation, the Company decided to develop a common standard for service outage documentation to be implemented throughout the Xcel Energy northern territories.

In early October of 2002, a team of managers from the Xcel Energy northern territories (including managers from North Dakota) was formed to:

1 Examine and define roles and responsibilities for personnel involved in the process;
2 Identify the geographic and organizational differences between the Twin Cities Metro region and the other regions in Xcel Energy's northern territories, and how those differences impacted our processes for outage response and reporting;
3. Develop a common method to capture information for outage reporting;
4. Outline a process for documenting data discrepancies and changes; and
5. Create process diagrams for use by the various regions

Prior to the implementation of a common method, North Dakota followed the following process, which was also used in all of Xcel Energy's northern (non-metro) territories:

> The dispatcher directed the field responder(s) via radio and logged all activities in DDS (our dispatch tool) and filed the data to REMS (our

reporting database). Paper records from the field might be submitted if supplemental information was noted. Under this process, the dispatcher created all official records that recorded the history of the service outage.

In November of 2002, the process was changed in North Dakota (and non-metro Minnesota regions) to formally institute the consistent use of a field paper record. Under the common method, the following process is used:

> Field responder records pertinent outage information on a paper document ("trouble ticket"). The dispatcher records information given to him by the field responder(s) over the radio or phone during and immediately after restoration of the outage. A management employee checks the computer database (REMS) record and the paper record from the field to make sure that all common data in both records match. If there is a reason to deviate from the field record, the management employee is to document the reason and file as part of the official paper record.

Since implementation of these processes, the Company has periodically audited its compliance with these processes to ensure consistent application. These changes in processes and our compliance with these processes provide a more significant audit trail for reviewing the data that support our reliability performance. We believe that these changes also provide a higher level of confidence in the reliability data the Company reports to regulators in both Minnesota and North Dakota

This process was presented to the Commission during the Company's last PIE meeting on May 20, 2003. See Attachment 6A for the flowchart of this process

Response By: Dennis P. Branca
Title: Director, Emergency Response and Dispatch
Department Emergency Response and Dispatch
Telephone: 612-330-6412
Date• June 5, 2003

Northern States Power d/b/a Xcel Energy
Case No: PU-400-03-256
Response To: Mike Diller Request For Information 7
Date Received: May 14, 2003

Question:

Indicate any differences in the procedures or practices of service quality reporting that existed before the investigation, or that now exists between the Minnesota and North Dakota jurisdictions, if any.

Response:

With respect to regulatory reporting, the Company submits outage frequency (SAIFI) and duration (CAIDI) results for its North Dakota operations to the Public Service Commission on an annual basis in its PLUS Plan report. Also included in the PLUS report are results of customer satisfaction surveys (relationship and transaction based), average residential rate information, and employee safety results (OSHA incidence rate). There has been no change in the reporting of this information as a result of the investigation.

In Minnesota, prior to the investigation Xcel Energy reported service quality data, including reliability data, to the Minnesota Public Utilities Commission (MPUC) on a quarterly basis. With the advent of this investigation and pursuant to related orders issued by the MPUC, reliability data is now provided on a monthly basis.

The information reported in Minnesota includes:

- Electric reliability (SAIDI, SAIFI, CAIFI)
- Gas reliability (interruption duration, hits per 100 miles of pipe,
- Mislocates
- Customer service (telephone response time, customer complaints, meter reading and billing)

Currently, Xcel Energy provides electric reliability data to the MPUC in a variety of ways, including

- Actual results without reflecting partial outage restorations

- Actual results reflecting partial outage restorations[i]
- Normalized to exclude storms and other unusual events
- Normalized for storms, unusual events and public damage

Response By: David H Sederquist
Title: Sr. Consultant, Regulatory/Finance
Department: North Dakota Jurisdiction
Telephone: 701-241-8632

Date: June 5, 2003

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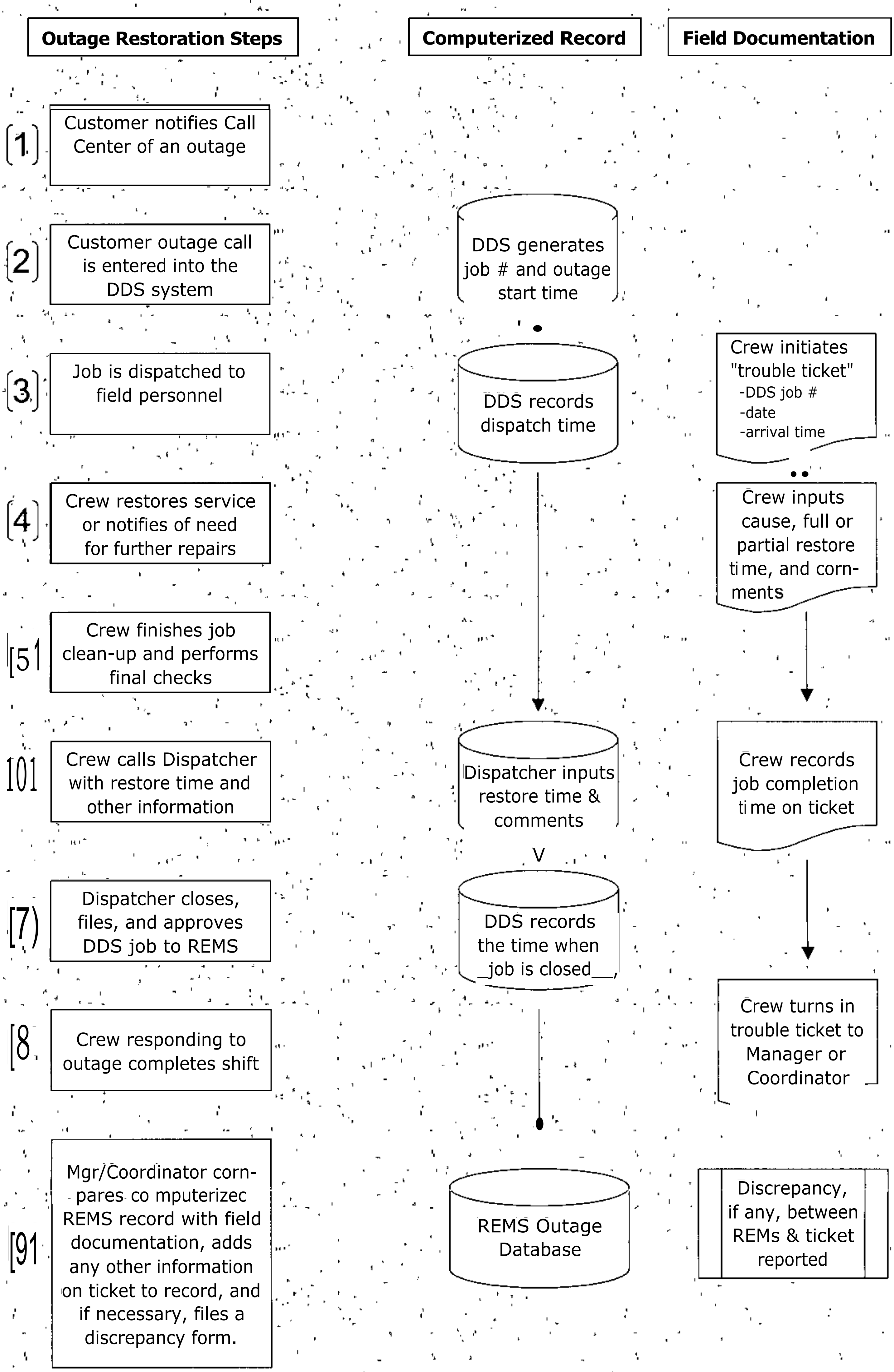
[i] In reflecting partial restorations, the various times when service is restored to subsets of customers affected by a single outage event are recorded For example, if 1,000 customers lose power because a major distribution line fails, service may be restored to half of them after one hour by switching their service to an alternative distribution line The remaining 500 customers have their power restored after two hours, when the line that failed is repaired and returned to service The Company first provided a separate SAIDI calculation with and without partial restoration in its February 28, 2003, Service Quahty Compliance Report for MPUC Docket Nos E,G002/PA-99-1031, E,G002/CI-02-1346, and E,G002/CI-97-863

Xcel Energy Outage Process Flow chart **Attachment 6A**



DDS44= Distribution Dispatch-System
REMS = Reliability Monitoring System

Xcel *Energy*

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May 8, 2003

RECEIVED
MAY 9 2003
ND PUBLIC SERVICE COMMISSION
PUBLIC UTILITIES DIVISION

Jon Mielke, Executive Secretary
North Dakota Pubhc Service Commission
State Capitol Building, Dept. 408
600 East Boulevard
Bismarck, ND 58505-0480

Re: XCEL ENERGY 200x REPORTS OF REGULATED EARNINGS FOR ITS NORTH DAKOTA ELECTRIC AND GAS OPERATIONS

Dear Mr. Mielke:

Enclosed you will find eight bound copies of Xcel Energy's annual reports of 2002 regulated electric and gas earnings in North Dakota.

An electronic version of this report was sent to you last Thursday, May 1. Thank you for allowing us the extra time to print and deliver these hardcopies.

Please contact me if you have any questions or comments

Sincerely,

DAVID H. SEDERQUIST
SR. CONSULTANT, REGULATION/FINANCE

Enclosures

2002

Regulatory Report
Of Electric Utility Operations

for

Northern States Power Company
d/b/a Xcel Energy

North Dakota Jurisdiction

Utilizing

The PLUS Plan

Performance-Based Regulation Model

Submitted to the
North Dakota Public Service Commission
May 1, 2003

Table of Contents

	Page
Executive Summary	2
Return on Equity	3
Operating Income	4
Rate Base	5
Cost of Capital	6
Baseline Return on Equity	7
Shared Earnings	8
Price Cap Factor	9
Operating and Financial Statistics	10
System Reliability Performance	Appendix A
Customer Satisfaction Performance	Appendix B
Electric Rate Performance	Appendix C
Workforce Safety Performance	Appendix D
Utility Comparison Group	Appendix E
Affiliated Transactions	Appendix F

Executive Summary

Financial Results			2002
1	Return on Equity (ROE) (page 3, line 10):		13.15%
2	Return on Rate Base (ROR) (page 3, line 5):		9.72%
3	Rate Base (000's) (page 5, line 15):		$151,502
4	Common Equity Ratio (page 6, line 5):		48.97%
5	ROE deadband (page 7, lines 6, 7)'	11.00% 13 50%	
6	ROE deadband midpoint (page 7, line 8):	12.25%	

Utility Performance		Result	Perf Pts.
7	Annual Outage Duration per Customer (min.) (Appendix A)'	74.3	25
8	Annual Outage Frequency per Customer (Appendix A):	1 09	-25
9	Relationship Survey Score (Appendix B)	77.0%	-25
10	Transaction Survey Score (Appendix B)	66.0%	0
11	Average Residential Rate -- ¢/kWh (Appendix C):	5.95	25
12	Change in Residential Rate -- ¢/kWh (Appendix C):	-0 57	25
13	Workforce Safety -- OSHA Incident Rate (Appendix D)	3.11	25
		Total Points:	**50**

PLUS Plan Customer Dividend Information		
14	Total Customer Dividend (or deferred charge) (000's) (page 8, line 7):	**$0.00**
15	Typical residential customer dividend (or deferred charge):	$0.00

Proposed Rate Changes		Proposed %	Avg. Mo.
	Effective 7/ 2003 — Pnce Increase Cap 0 00%	Rate Change	Bill Impact
16	Residential without space heat (page 9, lines 9 and 14):	0.00%	$0.00
17	Residential with space heat (page 9, lines 10 and 15):	0.00%	$0.00
18	Small commercial & industrial (page 9, lines 11 and 16):	0.00%	$0.00
19	Large commercial & industrial (page 9, lines 12 and 17):	0.00%	$0.00
20	PSHL/Mun. Auth (page 9, lines 13 and 18):	0.00%	$0.00
21	Total proposed annual revenue increase (page 9, line 19):	0.00%	$0

Other Miscellaneous		2002
22	Electric retail sales -- mWh (page 10, line 6)'	2,047,352
23	Peak demand -- Mw (page 10, line 7):	369,093
24	Customers (page 10, line 13)'	84,747

Return on Equity (ROE)
(000's)

	Before Revenue Sharing	**2002 Amount**
1	Operating Income from Electric Operations (page 4, line 20)	$14,720
2	Shared Earnings (page 8, line 7) X 50%	$0
3	Adjusted Operating Income (line 1- line 2)	$14,720
4	Average Regulated Rate Base (page 5, line 15)'	$151,502
5	Rate of Return on Rate Base (ROR) (line 3 / line 4)'	9.72%
6	Less Weighted Cost of Debt (page 6, line 3):	3.28%
7	Less Weighted Cost of Preferred Stock (page 6, line 4):	0.00%
8	Weighted Return on Equity (line 5 - line 6 - line 7):	6.44%
9	% of Equity in Capital Structure (page 6, line 5):	48.97%
10	'Return on Equity (ROE) before Revenue Sharing (line 8 / line 9):	13.15%1

After Revenue Sharing

11	Shared After-Tax Earnings (page 8, line) X 50%	$0
12	Adjusted Operating Income (line 1- line 11):	$14 720
13	Adjusted Rate of Return on Rate Base (ROR) (line 12 / line 4).	9.72%
14	Adjusted Weighted Return on Equity (line 5 - line 6 - line 7):	6.44%
15	Return on Equity (ROE) after Revenue Sharing (line 8 / line 9):	13.15%1

Normalized

16	ROE before earnings sharing and reflecting normal weather:	12.98%

Operating Income
(000's)

Line Item		2002 Total NSP	2002 ND Juris.	ND %	2001 ND Juris.	Annual Change
	Operating Revenues:					
1	Residential	$737,647	$43,906	6.0%	$45,701	-3.9%
2	Small Comm. & Ind	$780,221	$53,543	6 9%	$54,223	-1.3%
3	Large Comm & Ind.	$427,994	$12,482	2.9%	$13,038	-4.3%
4	Str. Lighting/Municipal	$25,434	$1,530	6.0%	$8,299	-81.6%
5	Interchange/Other Oper	$409,000	$23,802	5 8%	$22,430	6.1%
6	Total Revenues:	$2,380,296	$135,262	5.7%	$143,691	-5 9%
	Operating Expenses:					
7	Production	$1,123,559	$65,646	5.8%	$75,323	-12 8%
8	Transmission	$94,215	$5,456	5.8%	$4,731	15.3%
9	Distribution	$81,124	$3,713	4.6%	$4,345	-14.5%
10	Customer Billing	$46,379	$3,530	7.6%	$2,990	18.1°/0
11	Customer Service	$60,253	$192	0.3%	$33	481.8%
12	Sales & Marketing	$1,406	$91	6.5%	$185	-50.8%
13	Admin. & General	$133,483	$7,561	5 7%	$9,432	-19.8%
14	Depreciation	$335,509	$19,204	5.7%	$19,682	-2.4%
15	Property Taxes	$101,391	$4,849	4.8%	$5,449	-11.0%
16	Other General Taxes	$45,392	$2,394	5.3%	$2,653	-9.8%
17	Income Taxes	$158,571	$11,194	7.1%	$7,112	57 4%
18	Deferred Income Taxes	($55,0011	($3,288)	6.0%	($770)	327 0%
19	Total Expenses:	$2,126,281	$120,542	5.7%	$131,165	-8.1%
20	'Regulated Operating Income	$254,015	$14,720	5.8%	$12,526	17.5%1

Notes

Regulated operating income shown above does not reflect any shared earnings adjustments

Rate Base
(000's)

Line Item		2002 Total NSP	2002 ND Juris.	ND %	2001 ND Juris.	Annual Change
1	Plant in Service	$8,107,453	$454,015	5.6%	$443,124	2.5%
2	Accumulated Depreciation	$4,654,873	$270,915	5.8%	$257,572	5.2%
3	Net Plant in Service	$3,452,580	$183,100	5.3%	$185,552	-1 3%
4	Plant Held for Future Use	$0	$0	*	$0	*
5	Construct Work in Progress	$42,658	$2,089	4.9%	$1,992	4.9%
6	Materials and Supplies	$94,417	$5,603	5.9%	$5,926	-5.5%
7	Fuel Inventory	$30,115	$1,820	6.0%	$1,491	22.1%
8	Prepayments	$19,602	$1,181	6.0%	$1,092	8.2%
9	Customer Deposits	($750)	($253)	33 7%	($178)	42 1%
10	Unamortized Expenses	$6	$6	100.0%	$6	0.0%
11	Cash Working Capital	$0	$0		$0	*
12	Non-Plant Assets	($62,111)	($3,764)	6.1%	($3,959)	-4 9%
13	Total Other Rate Base	$123,937	$6,682	5.4%	$6,370	4.9%
14	Less Accum. Deferred Taxes	($650,058)	($38,280)	5.9%	($35,190)	8.8%
15	!Total Average Rate Base	$2,926,459	$151,502	5.2%	$156,732	-3.3%

Cost of Capital
(000's)

2002

Line	Item	Amount	% of Total	Cost	Weighted Cost
1	Long-Term Debt	$1,589,740	43 95%	6.98%	3.07%
2	Short-Term Debt	$255,975	7 08%	2.97%	0 21%
3	Total Debt	$1,845,715	51 03%		3.28%
4	Preferred Stock	$0	0.00%	0 00%	0.00%
5	Common Equity	$1,771,064	48 97%	13.15%	6.44%
6	Total Equity	$1,771,064	48.97%		
7	Total Capital	$3,616,779	100.00%		9.72%

Baseline Return on Equity

Baseline Return on Equity

Line		
1	Baseline ROE	12.00%
2	Baseline ROE deadband upper limit (line 1 + 1 0%):	13.00%
3	Baseline ROE deadband lower limit, (line 1 -1 0%):	11.00%

Performance-Adjusted Return on Equity Deadband

4	PLUS performance award points (Appendices A - D):	50
5	ROE deadband adjustment (01% per award point in line 4):	0.50%
6	**Upper limit on ROE Deadband:**	**13.50%**
7	**Lower limit on ROE Deadband**	11.00%
8	ROE Deadband midpoint (used in price cap cntena - see Section 9, lines 8a, 8b)	12.25%

Note If deadband adjustment (line 5) is > 0, it is added to the baseline deadband upper limit (line 2)

If the deadband adjustment is < 0, it is subtracted from the baseline deadband lower limit (line 3)

Shared Earnings
(000's)

Line	Item		
1	Operating income from electric operations (page 4, line 20)		$14,720
2	Debt expense and preferred equity dividends:		
	a Regulated average rate base (page 5, line 15):	$151,502	
	b. Weighted cost of debt (page 6, line 3)	3.28%	
	c. Weighted preferred equity cost (page 6, line 4).	0.00%	
	d. Debt & pref. equity costs (line 2a X (line 2b+line 2c))*		$4,967
3	Actual common equity earnings (line 1- line 2d):		$9,753
4	Common equity earnings range allowed by ROE deadband:		
	a. Regulated average rate base (page 5, line 15)	$151,502	
	b. Equity ratio (page 6, line 5)•	48.97%	
	c. Equity portion of average rate base (line 4a X line 4b)*	$74,187	
	d. Upper limit ROE and earnings (line 4c X upper ROE limit):	13.50%	$10,015
	e Lower limit ROE and earnings (line 4c X lower ROE limit):	1 1. 00%	$8,161
5	Actual common equity earnings over (under) ROE deadband (line 3 - line 4d or 4e):		$0
6	Pre-tax multiplier (1 / {1-tax rate}) Tax rate: 39.61%	1.6559	
7	Pretax amount to share (line 5 X line 6):		$0
	a. Customer dividend [deferred charge] (50% of line 7):	$0	
	b. Retained by company (line 7 - line 7a):	$0	

Cumulative Results

Total PLUS Plan Customer Dividends issued (2001-2002):	$0
Current balance of deferred Service Cost Recovery account':	$0

1 Indicates pending surcharge balance, excluding future offsets

Price Cap Factor

Line Item

Line	Item				Value
1	Utility comparison group change in res'l ¢/kwh (Appendix E):				0.37%
	inflation (CPI)	2001	2002	Change	
2	March	176.2	178 8	1.48%	
3	June	178.0	179.9	1.07%	
4	September	178.3	181.0	1 51%	
5	December	176.6	180.9	2.43%	
6	Average:			1.62%	
7	Inflation reduced by "efficiency commitment" adj. (so% x CPI):				0.97%(
8	Maximum rate increase allowed				0 00%1

Lower of line 1 and line 7, or 0 0% if

a line 1,7 >0, and {Xcel ROE > midpt ROE-1°/0 or Xcel rates > group avg }

b. line 1,7 <0, and {Xcel ROE < midpt R0E+1% or Xcel rates < group avg }

Line	**Proposed Rate Changes** -Effective July 1, 2003	Rate Change
9	Residential without space heat	0.00%
10	Residential with space heat	0.00%
11	Small commercial & industrial	0.00%
12	Large commercial & industrial	0.00%
13	Str. Lgt/Municipal	0.00%

Line	**Average Monthly Bill Impact**	2003 Projected Avg. Monthly Bill	Proposed Change to Monthly Bill
14	Residential without space heat	$47.39	$0.00
15	Residential with space heat	$70.05	$0 00
16	Small commercial & industrial	$397.70	$0.00
17	Large commercial & industrial	$47,095.83	$0.00
18	Str. Lgt/Municipal	$524.86	$0.00
19	IEstimated total annual revenue increase:	0.00%	$0

Selected Operating and Financial Statistics

Line	Electric Sales (ND) [mWh's]	2002	2001	Annual Change	% Change
1	Residential	737,573	700,199	37,374	5 34%
3	Small commercial & industrial+B22	965,437	966,034	-597	-0 06%
4	Large commercial & industrial	319,618	293,034	26,584	9.07%
5	PSHUSPA/Interdepartmental	24,724	24,822	-98	-0.39%
6	Total	2,047,352	1,984,089	63,263	3.19%
7	Coincident Peak Demand (ND)	369,093	384,229	-15,136	-3 94%
		(Aug)	(Sept)		
	Electric Customers (ND)				
8	Residential	72,974	72,805	169	0.23%
10	Small commercial & industrial	11,472	11,298	174	1.54%
11	Large commercial & industrial	27	24	3	12.50%
12	PSHUSPA/Interdepartmental	274	271	3	1.11%
13	Total	84,747	84,398	349	0.41%
	ND Customer Statistics				
14	Average ¢/Kwh charge	5.44	6.11	-0.67	-10.93%
15	Ave. residential mo. usage -Kwh	842	801	41	5.09%
16	Ave. residential mo. bill	$50 14	$52.31	($2.17)	-4.15%
	Jurisdictional Cost Allocators				
17	36CP Demand	5.8472%	5.7242%	0.1230%	2.15%
18	Energy Requirements	6.0441%	5.9735%	0.0706%	1.18%
19	Customers	6.4926%	6.5479%	-0.0553%	-0.84%
	Xcel Energy Corporate Financial Data				
20	Earnings per Share	($5.82)	$2.30	($8.12)	-353.04%
21	Earnings to Fixed Charges	-1.8	2.1		
22	S&P Bond Rating	BBB-	BBB+		
23	Book Value per Common Share	$11.70	$17.91	($6.21)	-34.67%
24	Market Price - High	$28.49	$30.35	($1.86)	-6.13%
25	Market Price - Low	$5.12	$24.19	($19.07)	-78.83%

System Reliability Performance

Outage Duration

Measure: For a typical customer experiencing an outage during the year, this is the average amount of time the customer was without power during the outage.

Measure	PLUS Standard	2002 Result
(Minutes)	89.0	74.3

	Standard	Award
15% better than target	75.6	25 points
Acceptable range:		0 points
15% worse than target:	102.4	25 points

Points
25

!Outage Frequency

Measure: The average number of outages that a typical customer experienced during the year.

Measure	PLUS Standard	2002 Result
(Minutes)	0.90	1.09

	Standard	Award
15% better than target:	0 77	25 points
Acceptable range:		0 points
15% worse than target:	1.04	25 points

Points
-25

ITotal Reliability Award Points: 0

Note Results reflect storm-normalized data Also, outages included in above measures are sustained (i e , longer than 5 minutes) outages only

Customer Satisfaction Performance

Relationship Surveys

Measure: Percent of survey respondents who rank Xcel Energy's products and services either "excellent" or "very good" (top 2 responses on a 5 point scale).

Measure	PLUS Standard	2002 Result			Res 79% SCI 79% LCI 74%
giving top two	81%	77%			
		Standard	Award		Points
3 % better than target		84%	25 points		
Acceptable range:			0 points		-25
3 % worse than target		78%	25 points		

(Transaction Surveys

Measure: Percent of survey respondents who rank Xcel Energy's products and services either "excellent" or "very good" (top 2 responses on a 5 point scale).

Measure	PLUS Standard	2002 Result			Res 66% SCI 66%
% giving top two	63.0%	66.0%			
		Standard	Award		Points
3 % better than target		66.0%	25 points		
Acceptable range:			0 points		0
3 % worse than target		60.0%	25 points		

'Total Cust. Satisfaction Award Points: -251

Note Relationship survey score reflects average of three random surveys of residential, commercial, and large commercial customers in North Dakota Transaction surveys are conducted with customers who contact the company's call center or request restoration of service following an outage

Electric Rate Performance

!Competitive Position

Measure: Residential revenues divided by kWh sales to arrive at an average unit price.
Target is based on the annual comparison group res'l average (see Appendix C).

Measure	PLUS Standard	2002 Result
(¢/Kwh)	7.68	5 95

	Standard	Award	Points
15% better than target	6.53	25 points	
Acceptable range		0 points	25
15% worse than target	8 83	25 points	

'Rate Stability

Measure: Change in average revenue per kWh's from the prior year. Target based on
change of lowest priced utility in the comparison group from previous year.

Measure	PLUS Standard	2002 Result
(¢/Kwh)	0.04	-0.57
	OtterTail Power Co (ND)	

	Standard	Award	Points
15% better than target	-0.01	25 points	
Acceptable range:		0 points	25
15% worse than target	0.09	25 points	

'Total Rates Award Points: 501

Workforce Safety Performance

OSHA Incident Rate

Measure. Number of safety related incidents per 100 employees.

Measure	PLUS Standard	2002 Result		Points
OSHA	4.32	311		
	Standard	Award		Points
15% better than target:		3.70	25 points	
Acceptable range:			0 points	25
15% worse than target:		5.00	25 points	

Total Safety Award Points: 25

Grand Total Performance Award Points: 501

Utility Comparison Group
Average Residential Revenue!Kwh

IOU's in North Dakota, South Dakota, Montana, Wyoming, Minnesota, Iowa, Wisconsin

2002 Rank	Utility	Jurisdiction	2002 it/kwh	2001 Okwh	Change
1	**Xcel *Energy***	***ND***	***5.95***	***6.53***	***-8.9%***
2	Ottertail Power Co.	ND	6.20	616	0.6%
3	Pacificorp -Wyoming East	Wyom	6.37	621	2.6%
4	Ottertail Power Co.	SD	6.43	6.38	0 8%
5	Superior Power & Light	Wisc	6.43	6 64	-3.2%
6	Ottertail Power Co.	MN	6.53	6.52	0.2%
7	Minnesota Power	MN	6.64	7.00	-5.1%
8	Montana-Dakota Utilities	ND	6.77	6.86	-1.3%
9	Northwest Public Service	Montana	6.90	6.75	2.2%
10	Black Hills Power & Light	Mont	6.99	7.51	-6.9%
11	Montana-Dakota Utilities	Mont	7.33	7.35	-0.3%
12	MidAmerican Energy	SD	7.38	7 49	-1 5%
13	Xcel Energy	SD	7.57	8.09	-6.4%
14	Xcel Energy	Wisc.	7.60	7.54	0.8%
15	Montana-Dakota Utilities	Wyom	7.62	7.55	0.9%
16	Xcel Energy	MN	7.68	8.06	-4.7%
17	Black Hills Power & Light	Wyom	7.71	7.80	-1.2%
18	Pacificorp -Wyoming West	Wyom	7.83	7.94	-1.4%
19	Wisconsin Power & Light (Alliant)	Wisc.	7.94	7.49	6.0%
20	Black Hills Power & Light	SD	8.14	8.19	-0.6%
21	Wisconsin Public Service	Wisc.	8.30	7.49	10.8%
22	Interstate Power & Light (Alliant)	Iowa	8.47	8.71	-2.8%
23	Northwest Public Service	SD	8.49	7.74	9.7%
24	Wisconsin Energy Co	Wisc.	8.51	8.46	0 6%
25	NW Wisconsin Electric	Wisc.	8.56	8.00	7 0%
26	MidAmerican Energy	Iowa	8.67	10 12	-14 3%
27	Montana-Dakota Utilities	SD	8.80	8.86	-0.7%
28	Interstate Power Co.(Alliant)	MN	9.10	8.94	1.8%
29	Madison Gas & Elec	Wisc.	9.69	9.26	4 6%
30	Cheyenne Light, Fuel, & Power	Wyom	9.87	7.99	23.5%
	!Average residential rate (¢/kwh):		7.68	7.65	0.37%1

Source: Typical Residential, Commercial, and Industrial Bills, Edison Electric Instit Winter, 2003

Note NW Public Service in Montana was formerly Montana Power Co , Interstate P&L rate in Iowa reflects all Alliant service areas in Iowa (previously IES and Interstate operations were listed separately)

Affiliated Transactions

Line #	Affiliate Name	General Description of Services Rendered/Supplied	ND Jurisdiction Allocation Expense[2]	Revenue[3]
1	Northern States Power Company (Wis.)	Electric and Gas Utility	4,712,102	12,936,884
3	Public Service of Colorado	Electric and Gas Utility	12,403	101,406
4	Southwestern Public Service	Electric Utility	289	3,565
5	Cheyenne Light Fuel and Power	Electric and Gas Utility		
6	Black Mountain Gas	Gas Utility		4,826
7	United Power and Land	Real estate holdings	185,930	25,799
8	Reddy Kilowatt Corp	Owns tradmark rights for Reddy Kilowatt and Reddy Flame		
10	The NRG Group	Operates and develops independent power supplies	(201,452) (4)	407,659
11	Eloigne Company	Affordable housing investment program	-	95
12	Viking Gas Transmission Company	Natural gas transportation	421,317	24,279
13	Energy Master International	National energy service company		
14	Seren Innovations, Inc.	Energy mgmt , security control & bus info through communications networks		4,276
15	Xcel Energy Services	Xcel Energy Inc service company	11,891,793	
16	e' prime	Natural energy service company	99,532	12,622
17	Natrogas Inc.	Retail propane supplier		1,133
18	Nuclear Mgmt Company	Regional nuclear facilities management	12,116,507	
20	Utility Engineering	Engineering services	360,383	6,091

Notes:

(1) The amounts allocated to North Dakota electric and gas jurisdictions represent an estimate based on an overall allocation factor applied to all of the revenues and expenses for each affiliate To derive the actual amounts by junsdiction would require an allocation by transaction by account number and would require significant analysis and expense to perform

(2) Expense to North Dakota electric and gas junsdictions Revenue to affiliate for services provided to NSP (Mn) by affiliate

(3) Revenue to North Dakota electric and gas junsdictions Expense to the affiliate for services provided to the affiliate by NSP (MN)

(4) The revenue paid by NSP (MN) to NSP's affiliate NRG is the net of fuel and miscellaneous service expenses paid to NRG of $1,244,966 and incentives paid by NRG Resource Recovery to NSP (MN) for burning RDF at NSP (MN)'s Red Wing and Wilmarth generating plants, $4,347,762

PH-460-03-358

SENDER: *COMPLETE THIS SECTION*

- Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired.
- Print your name and address on the rever e so that we can return the card to you
- Attach this card to the back of the mailpiece, or on the front if space permits.

1 Article Addressed to

X

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COMPLETE THIS SECTION ON DELIVERY

A. Signature

X 4

❑ Agent
❑ Addressee

B Received by *(Panted Name)*

C DatOf Delivery

D Is delivery a dress different from item 1? ❑ Yes

If YES, enter delivery address below ❑ No

3. Service Type

aCeitified ❑ Express Mail
❑ Registered ❑ Return Receipt for Merchandise
❑ Insured Mail ❑ C 0 D.

4 Restricted Delivery? *(Extra Fee)* ❑ Yes

2. Article Number *(Transfer from service labe0* 7003 2260 0001 3517 9930

PS Form 3811, February 2004 Domestic Return Receipt 102595-02-M-1540