Appendix D

Electric Utility Annual Report

This Report was submitted to the Minnesota Department of Commerce on July 1, 2004, in accordance with Minn. Rules 7610.0100 - 7610.0700.

The forecast information in this report does not necessarily correspond to information being provided in the current Resource Plan.

Minnesota Electric Utility Annual Report – July 2004

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Item J	Energy Delivered to Ultimate Consumers by County
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7610.0120 REGISTRATION.

Any electric utility that commences operations in the state shall file a registration statement with the commissioner within 30 days after commencing operation. Each registration statement shall be on forms issued by the commissioner and shall contain the name and headquarter address of the utility, the type of utility, the names and addresses of all officers of the utility, and the name, address, and telephone number of a person who may be contacted for information about the utility. Registration statements must be updated as a part of each utility's annual report.

Please update this registration statement annually.

Utility Name Northern States Power Company d/b/a Xcel Energy	Federal ID No. 41-1967505
Address 414 Nicollet Mall	City, State, Zip Code Minneapolis, MN 55401
Telephone (include area code) (612) 330-5500	Utility Type: ☐ Private ☒ Public ☐ Co-op
Utility Officers (list name, title, and address if different from above): See following page.	
Contact Name Teresa Kowles	Title Regulatory Case Specialist
Telephone (612) 330-5785	
Contact Address 414 Nicollet Mall	City, State, Zip Code Minneapolis, MN 55401
Contact Email Address teresa.j.kowles@xcelenergy.com	
Name of Person Preparing Forms Various	Preparer's Title
Date July 2004	

7610.0150 FEDERAL OR STATE DATA SUBSTITUTION.

Upon written request by any utility, the commissioner may allow it to substitute data provided to the federal government or another state agency in lieu of data required by these parts if the data required by both agencies is substantially the same.

Federal Agency	Form Number	Form Title	Filing Cycle Monthly	Filing Cycle Yearly	Filing Cycle Other
See following section 7610.0170.					

7610.0120 Registration – Officers

Chairman and Chief Executive Officer	Wayne H. Brunetti
President and Chief Operating Officer	Richard C. Kelly
Vice President and General Counsel	Gary R. Johnson
Vice President and Chief Financial Officer	Benjamin G.S. Fowke III
Vice President and Corporate Secretary	Cathy J. Hart
President – Commercial Enterprises	Paul J. Bonavia
Vice President and Chief Information Officer	Raymond E. Gogel
Chief Administrative Officer and Chief Human Resources Officer	Cynthia L. Lesher
President – Customer and Field Operations	Patricia K. Vincent
President – Energy Supply	David M. Wilks

7610.0170 – Federal Reports Filed by Utilities

Federal Agency	Form No.	Form Title	Cycle
Federal Energy Regulatory Commission	Form 1	Annual Report of Major Electric Utilities, Licensees and Others	Yearly
Federal Energy Regulatory Commission		Twenty Largest Electric Customers	Yearly
Federal Energy Regulatory Commission	Form 714	Annual Electric Control and Planning Area Report	Yearly
Securities Exchange Commission	Form 10-K	Annual Financial Statements	Yearly
Securities Exchange Commission	Form 10-Q	Quarterly Financial Statements	Quarterly
Securities Exchange Commission	Form 8-K	Disclosure of Interim Events	Periodic
Securities Exchange Commission	Form 11-K	Employee Stock Ownership Plan	Yearly
Securities Exchange Commission	Form 3	Initial Disclosures for Statement of Changes in Beneficial Ownership of Securities	Yearly
Securities Exchange Commission	Form 4	Statement of Changes in Beneficial Ownership of Securities	Yearly
Securities Exchange Commission	Form S	Registration Statements	Periodic
U.S. Department of Energy	EIA-759	Monthly Power Plant Report	Monthly
U.S. Department of Energy	EIA-826	Monthly Electric Sales & Revenue Report with State Distributions	Monthly
U.S. Department of Energy	EIA-860	Annual Electric Generator Report	Yearly
U.S. Department of Energy	EIA-861	Annual Electric Utility Report	Yearly

7610.0170 – Federal Reports Filed by Utilities (continued)

Federal Agency	Form No.	Form Title	Cycle
Internal Revenue Service	Form 990	Return of Organization Exempt from Income Tax	Yearly
Internal Revenue Service	Form 1120	Corporate Income Tax Return	Yearly
Internal Revenue Service	Form 5500	Annual Return/Report of Employee Benefit Plan	Yearly
Federal Energy Regulatory Commission	Form 2056	Statement of Generation in kWh for Hydropower – Annual Charges for Project	Yearly
Federal Energy Regulatory Commission	Form 561	Interlocking Directorships or Conflict of Interest	Yearly
U.S. Department of Energy	EIA-767	Steam Electric Plant Operation and Design Report	Yearly
Federal Energy Regulatory Commission	Form 423	Monthly Cost and Quality of Fuels for Electric Plants	Monthly
Securities Exchange Commission	U-5S	PUHCA Report	Yearly
Securities Exchange Commission	U-13-60	PUHCA Report	Yearly
Securities Exchange Commission	U-9C-3	PUHCA Report	Quarterly
Securities Exchange Commission	Rule 24 Certificate	PUHCA Report	Quarterly

7610.0600 B – Names, Addresses, and Electricity Consumed by Largest Customers

[TRADE SECRET DATA]

This information is being submitted separately.

7610.0600 D – Sales for Resale and Purchases from Other Utilities

See the following pages from Xcel Energy's 2003 FERC Form 1.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/30/2004	Dec. 31, 2003

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
LF - for long-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	City of Ada	RQ	474	N/A	N/A	N/A
2	City of Buffalo	RQ	475	N/A	N/A	N/A
3	City of Fairfax	RQ	477	N/A	N/A	N/A
4	City of Granite Falls	RQ	530	N/A	N/A	N/A
5	City of Kasota	RQ	478	N/A	N/A	N/A
6	City of Kasson	RQ	479	N/A	N/A	N/A
7	City of Melrose	RQ	486	N/A	N/A	N/A
8	City of Sioux Falls	RQ	484	N/A	N/A	N/A
9	Northern States Power Co. (Wisconsin)	RQ	363	N/A	N/A	N/A
10	Blue Earth Light & Water Department	OS	470	N/A	N/A	N/A
11	Delano	OS	470	N/A	N/A	N/A
12	Glencoe	OS	470	N/A	N/A	N/A
13	Janesville Municipal Utilities	OS	470	N/A	N/A	N/A
14	Kenyon Municipal Utilities	OS	470	N/A	N/A	N/A
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			0	0	0

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.

AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)

5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.

6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)
demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.

7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.

8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.

9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401, line 24.

10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
9,073	79,767	166,520	4,516	250,803	1
88,784	348,463	3,549,648	8,554	3,906,665	2
3,266	2,173	129,019	1,954	133,146	3
7,148	207,396	164,081	60,810	432,287	4
3,239	17,657	134,167	753	152,577	5
27,522	137,234	1,118,415	4,913	1,260,562	6
75,227	229,586	2,500,686	11,299	2,741,571	7
41,412	398,492	1,085,611	3,983	1,488,086	8
5,738,565		155,823,333		155,823,333	9
1,594		75,503		75,503	10
27,644		1,005,976		1,005,976	11
47,751		1,746,009		1,746,009	12
6,167		218,206		218,206	13
9,850		342,051		342,051	14
5,994,236	1,420,768	164,671,480	96,782	166,189,030	
6,959,465	1,581,170	224,462,003	238,331	226,281,504	
12,953,701	3,001,938	389,133,483	335,113	392,470,534	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/30/2004	Dec. 31, 2003

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Lake Crystal Public Utilities	OS	470	N/A	N/A	N/A
2	City of Madelia	OS	481	N/A	N/A	N/A
3	Mountain Lake Municipal	OS	470	N/A	N/A	N/A
4	Sleepy Eye Public Utility	OS	470	N/A	N/A	N/A
5	Truman Municipal	OS	470	N/A	N/A	N/A
6	City of Windom	OS	455	N/A	N/A	N/A
7	North Central Power Company, Inc.	OS	459	N/A	N/A	N/A
8	Northwestern Wisconsin Electric Company	OS	451	N/A	N/A	N/A
9	City of Springfield	OS		N/A	N/A	N/A
10	Aquila Inc. d/b/a Aquila Networks	OS	[illegible]	N/A	N/A	N/A
11	Aquila Energy Marketing Company	OS	[illegible]	N/A	N/A	N/A
12	AEP Energy Marketing	OS	[illegible]	N/A	N/A	N/A
13	Alliant Energy Corporate Services Inc.	OS	MAPP No. 2	N/A	N/A	N/A
14	Ameren Energy Inc.	OS	MAPP No. 2	N/A	N/A	N/A
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			0	0	0

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/30/2004	Dec. 31, 2003

SALES FOR RESALE (Account 447) (Continued)

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7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
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10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
6,879	-143	284,670		284,527	1
16,258	100,197	562,514	9,035	671,746	2
9,717		325,206		325,206	3
6,647	27,035	248,123		275,158	4
8,050		330,441		330,441	5
22,133	114	759,461		759,575	6
21,775	25,550	1,053,826		1,079,376	7
193,327	787,950	4,528,115	514	5,316,579	8
	3,647			3,647	9
7,540		296,695		296,695	10
68,349		2,789,947		2,789,947	11
32,554		1,119,918		1,119,918	12
74,456		3,308,480		3,308,480	13
35,296		1,113,540		1,113,540	14
5,994,236	1,420,768	164,671,480	96,782	166,189,030	
6,959,465	1,581,170	224,462,003	238,331	226,281,504	
12,953,701	3,001,938	389,133,483	335,113	392,470,534	

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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Ames Municipal Electric System	OS	MAPP No. 2	N/A	N/A	N/A
2	Associated Electric Cooperative	OS	[illegible]	N/A	N/A	N/A
3	Basin Electric Power Cooperative	OS	MAPP No. 2	N/A	N/A	N/A
4	Black Hills Power & Light	OS	[illegible]	N/A	N/A	N/A
5	BP Energy Company	OS	WSPP No. 6	N/A	N/A	N/A
6	Central Minnesota Municipal Power Agenc	OS	[illegible]	N/A	N/A	N/A
7	Cinergy Services, Inc.	OS	[illegible]	N/A	N/A	N/A
8	Cargill-Alliant LLC	OS	[illegible]	N/A	N/A	N/A
9	CLECO Power LLC	OS		N/A	N/A	N/A
10	Consolidated Water Power Company	OS	MAPP No. 2	N/A	N/A	N/A
11	Constellation Power Source, Inc.	OS	WSPP No. 6	N/A	N/A	N/A
12	Coral Power LLC	OS	[illegible]	N/A	N/A	N/A
13	Detroit Edison Company	OS	[illegible]	N/A	N/A	N/A
14	Duke Energy Trading & Marketing LLC	OS	[illegible]	N/A	N/A	N/A
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			0	0	0

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/30/2004	Dec. 31, 2003

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.

AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)

5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.

6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)
demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.

7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.

8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.

9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see Instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401, line 24.

10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
11		1,359		1,359	1
952,471		26,281,644		26,281,644	2
1,350		123,385		123,385	3
788		21,709		21,709	4
34,400		1,900,600		1,900,600	5
319		23,240		23,240	6
45,753	1,264	1,617,473		1,618,737	7
8,333		194,585		194,585	8
45		1,785		1,785	9
269,976		11,719,953	8,400	11,728,353	10
2,683		136,053		136,053	11
1,600		73,200		73,200	12
7,700		271,100		271,100	13
1,600		52,100		52,100	14
5,994,236	1,420,768	164,671,480	96,782	166,189,030	
6,959,465	1,581,170	224,462,003	238,331	226,281,504	
12,953,701	3,001,938	389,133,483	335,113	392,470,534	

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/30/2004	Year of Report Dec. 31, 2003

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
LF - for long-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	DTE Energy Trading, Inc.	OS	WSPP No. 6	N/A	N/A	N/A
2	Dynegy Power Marketing, Inc.	OS	WSPP No. 6	N/A	N/A	N/A
3	Edison Mission Marketing & Trading Inc.	OS	[illegible]	N/A	N/A	N/A
4	Empire District Electric Company	OS	WSPP No. 6	N/A	N/A	N/A
5	Entergy-Koch Trading, LP	OS	WSPP No. 6	N/A	N/A	N/A
6	Entergy Services Inc.	OS	NSP No. 4,5	N/A	N/A	N/A
7	Exelon Generation Company LLC	OS	[illegible]	N/A	N/A	N/A
8	Grand River Dam Authority	OS	WSPP No. 6	N/A	N/A	N/A
9	City of Granite Falls	OS		N/A	N/A	N/A
10	Great River Energy	OS	[illegible]	N/A	N/A	N/A
11	GEN-SYS Energy	OS	MAPP No. 2	N/A	N/A	N/A
12	Golden Spread Electric Cooperative, Inc	OS	WSPP No. 6	N/A	N/A	N/A
13	Hutchinson Utilities Commission	OS	434	N/A	N/A	N/A
14	Kansas City Power & Light Company	OS	[illegible]	N/A	N/A	N/A
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			0	0	0

Name of Respondent	This Report Is:	Date of Report	Year of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr) 04/30/2004	Dec. 31, 2003

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.
AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.
4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)
demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401, line 24.
10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
2,975		85,800		85,800	1
27,338		832,240		832,240	2
4,274		106,165		106,165	3
1,300		46,645		46,645	4
1,600		59,000		59,000	5
2,469		71,947		71,947	6
9,002		268,218		268,218	7
300		10,800		10,800	8
2,587		110,239		110,239	9
177,575		2,374,672		2,374,672	10
30,970		1,059,569		1,059,569	11
		64,299		64,299	12
27		1,398		1,398	13
50,067		1,576,170		1,576,170	14
5,994,236	1,420,768	164,671,480	96,782	166,189,030	
6,959,465	1,581,170	224,462,003	238,331	226,281,504	
12,953,701	3,001,938	389,133,483	335,113	392,470,534	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/30/2004	Dec. 31, 2003

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
LF - for long-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Klickitat Public Utility District	OS		N/A	N/A	N/A
2	Lincoln Electric System	OS	[illegible]	N/A	N/A	N/A
3	Lighthouse Energy Trading Company, Inc.	OS	[illegible]	N/A	N/A	N/A
4	LG&E Energy Marketing, Inc.	OS	WSPP No. 6	N/A	N/A	N/A
5	Montana-Dakota Utilities	OS	[illegible]	N/A	N/A	N/A
6	Morgan Stanley Capital Group Incorporat	OS	WSPP No.6	N/A	N/A	N/A
7	MidAmerican Energy Company	OS	[illegible]	N/A	N/A	N/A
8	Madison Gas & Electric Company	OS	MAPP No. 2	N/A	N/A	N/A
9	Manitoba Hydro	OS	MAPP No. 2	N/A	N/A	N/A
10	Minnesota Municipal Power Agency	OS	MAPP No. 2	N/A	N/A	N/A
11	Minnesota Power Inc.	OS	[illegible]	N/A	N/A	N/A
12	Minnkota Power Cooperative	OS	MAPP No. 2	N/A	N/A	N/A
13	Muscatine Power & Water	OS	MAPP No. 2	N/A	N/A	N/A
14	Missouri River Energy Services	OS	MAPP No. 2	N/A	N/A	N/A
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			0	0	0

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/30/2004	Dec. 31, 2003

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.
AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.
4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)
demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401, line 24.
10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
375		11,425		11,425	1
1,679		80,173		80,173	2
6,348		163,300		163,300	3
76,500		2,129,708		2,129,708	4
11,143		473,218		473,218	5
25		1,175		1,175	6
9,172		491,349		491,349	7
3,444		85,017		85,017	8
3,048,207	83,600	103,313,172		103,396,772	9
132,212		4,617,911		4,617,911	10
860		51,818		51,818	11
4,794		221,959		221,959	12
230		9,912		9,912	13
561		22,942		22,942	14
5,994,236	1,420,768	164,671,480	96,782	166,189,030	
6,959,465	1,581,170	224,462,003	238,331	226,281,504	
12,953,701	3,001,938	389,133,483	335,113	392,470,534	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/30/2004	Dec. 31, 2003

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Northern Indiana Public Service Company	OS	NSP No. 5	N/A	N/A	N/A
2	Nebraska Public Power District	OS	[illegible]	N/A	N/A	N/A
3	New York Independent System Operator	OS	FERC Vol No 2	N/A	N/A	N/A
4	NorthPoint Energy Solutions	OS	[illegible]	N/A	N/A	N/A
5	NorthWestern Energy, LLC	OS	MAPP No. 2	N/A	N/A	N/A
6	Northwestern Public Service Company	OS	MAPP No. 2	N/A	N/A	N/A
7	OGE Energy Resources, Inc.	OS	WSPP No. 6	N/A	N/A	N/A
8	Omaha Public Power District	OS	[illegible]	N/A	N/A	N/A
9	Otter Tail Power Company	OS	[illegible]	N/A	N/A	N/A
10	PJM Interconnection LLC	OS	[illegible]	N/A	N/A	N/A
11	Public Service Company of Colorado	OS	[illegible]	N/A	N/A	N/A
12	Public Service Company of New Mexico	OS	WSPP No. 6	N/A	N/A	N/A
13	Powerex Corporation	OS	MAPP No. 2	N/A	N/A	N/A
14	Rainbow Energy Marketing Corporation	OS	[illegible]	N/A	N/A	N/A
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			0	0	0

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/30/2004	Dec. 31, 2003

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.

AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)

5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.

6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.

7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.

8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.

9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last-line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401, line 24.

10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
800		8,000		8,000	1
4,029		233,616		233,616	2
8,031		319,984		319,984	3
9,717		264,960		264,960	4
295		21,229		21,229	5
75		6,807		6,807	6
2,400		100,000		100,000	7
6,373		297,027		297,027	8
298,294		9,779,381	31,230	9,810,611	9
9,004		403,180		403,180	10
13,820		372,022		372,022	11
100		4,500		4,500	12
50		2,000		2,000	13
13,102		430,486		430,486	14
5,994,236	1,420,768	164,671,480	96,782	166,189,030	
6,959,465	1,581,170	224,462,003	238,331	226,281,504	
12,953,701	3,001,938	389,133,483	335,113	392,470,534	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/30/2004	Dec. 31, 2003

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
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LF - for long-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Saskatchewan Power Corporation	OS	NSP No. 4	N/A	N/A	N/A
2	Southern Minnesota Municipal Power Agen	OS	MAPP No. 2	N/A	N/A	N/A
3	South Plains Electric Cooperative	OS	NSP No. 6	N/A	N/A	N/A
4	Southwestern Public Service Company	OS	[illegible]	N/A	N/A	N/A
5	Split Rock Energy LLC	OS	[illegible]	N/A	N/A	N/A
6	SRP Marketing	OS		N/A	N/A	N/A
7	The Energy Authority	OS	[illegible]	N/A	N/A	N/A
8	TransAlta Energy Marketing (U.S.) Inc.	OS	[illegible]	N/A	N/A	N/A
9	Tenaska Power Services Company	OS	[illegible]	N/A	N/A	N/A
10	Tennessee Valley Authority	OS	[illegible]	N/A	N/A	N/A
11	TXU Portfolio Management Company LP	OS	[illegible]	N/A	N/A	N/A
12	Utah Association of Municipal Power Sys	OS	WSPP No. 6	N/A	N/A	N/A
13	UtiliCorp United Inc.	OS	NSP No. 4, 5	N/A	N/A	N/A
14	Utilities Plus	OS	MAPP No. 2	N/A	N/A	N/A
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			0	0	0

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/30/2004	Dec. 31, 2003

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.

AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)

5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.

6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)
demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.

7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.

8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.

9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,line 24.

10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
14,050		434,204		434,204	1
17,965		891,077		891,077	2
5		115		115	3
1,573		50,926		50,926	4
169,266		6,598,671		6,598,671	5
415		13,750		13,750	6
19,068		795,048		795,048	7
1,150		47,950		47,950	8
50		4,000		4,000	9
44,658		1,681,790		1,681,790	10
329		8,725		8,725	11
30,388		1,124,356		1,124,356	12
1,250		77,325		77,325	13
1,228		52,164		52,164	14
5,994,236	1,420,768	164,671,480	96,782	166,189,030	
6,959,465	1,581,170	224,462,003	238,331	226,281,504	
12,953,701	3,001,938	389,133,483	335,113	392,470,534	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/30/2004	Dec. 31, 2003

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW): Average Monthly NCP Demand (e)	Actual Demand (MW): Average Monthly CP Demand (f)
1	Wisconsin Electric Power Company	OS	[illegible]	N/A	N/A	N/A
2	Wisconsin Public Power Incorporated	OS	[illegible]	N/A	N/A	N/A
3	Wisconsin Public Service Corporation	OS	[illegible]	N/A	N/A	N/A
4	Western Area Power Administration	OS	[illegible]	N/A	N/A	N/A
5	Westar Energy	OS	[illegible]	N/A	N/A	N/A
6	West Texas Municipal Power Agency	OS	NSP No. 6	N/A	N/A	N/A
7	Miscellaneous accounting adjustment					
8						
9	Footnote for Total Dollars and MWH's					
10						
11						
12						
13						
14						
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			0	0	0

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/30/2004	Dec. 31, 2003

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.
AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.
4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)
demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last-line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401, line 24.
10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE: Demand Charges ($) (h)	REVENUE: Energy Charges ($) (i)	REVENUE: Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
151,017		4,712,859		4,712,859	1
11,322		608,127	120,988	729,115	2
362,640	551,956	7,372,882	120,988	8,045,826	3
13,819		495,812		495,812	4
39,558		1,716,712		1,716,712	5
184,574		4,665,210		4,665,210	6
			-52,824	-52,824	7
					8
					9
					10
					11
					12
					13
					14
5,994,236	1,420,768	164,671,480	96,782	166,189,030	
6,959,465	1,581,170	224,462,003	238,331	226,281,504	
12,953,701	3,001,938	389,133,483	335,113	392,470,534	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/30/2004	Dec. 31, 2003

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Alliant Energy Corporate Service Inc.	OS	2	N/A	N/A	N/A
2	Albert & Meredith Kellen/Annua	OS		N/A	N/A	N/A
3	Alvina Vandersluis/Annual Wind	OS		N/A	N/A	N/A
4	Ameren Cilco	OS		N/A	N/A	N/A
5	Ameren Energy Inc.	OS	6, 2	N/A	N/A	N/A
6	Amerex Power LTD	OS		N/A	N/A	N/A
7	American Electric Power Marketing	OS	6, 2	N/A	N/A	N/A
8	APB Financial	OS		N/A	N/A	N/A
9	Aquila Inc. DBA Aquila Networks	OS	6	N/A	N/A	N/A
10	Aquila Merchant Services, Inc.	OS	2, 6	N/A	N/A	N/A
11	Associated Electric Cooperative Inc.	OS	6	N/A	N/A	N/A
12	Barron Light & Water Dept.	OS	103	N/A	N/A	N/A
13	Black Hills Power & Light	OS	2, 6	N/A	N/A	N/A
14	Blue Earth Light & Water Department	OS	485	N/A	N/A	N/A
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/30/2004	Dec. 31, 2003

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses; or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
25,315				771,574		771,574	1
					9,951	9,951	2
					10,058	10,058	3
225				8,025		8,025	4
93,032				3,462,631		3,462,631	5
					2,386	2,386	6
89,374				3,391,345		3,391,345	7
					498	498	8
87,109			4,197,501	8,394		4,205,895	9
297,274				14,865,633		14,865,633	10
102,948				4,828,523		4,828,523	11
252				16,472		16,472	12
3,502				378,271		378,271	13
472				7,109		7,109	14
12,164,524	167,517	19,899	138,593,920	402,478,160	213,825	541,285,905	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/30/2004	Dec. 31, 2003

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Buffalo Ridge 1	OS		N/A	N/A	N/A
2	Buffalo Ridge 2	OS		N/A	N/A	N/A
3	Buffalo Ridge 3	OS		N/A	N/A	N/A
4	Byllesby Hydro	OS		N/A	N/A	N/A
5	Central Illinois Light Company	OS		N/A	N/A	N/A
6	Central Minnesota Municipal Pwr Agency	OS	470, 2	N/A	N/A	N/A
7	Chad & Kristin Pater/Annual WI	OS		N/A	N/A	N/A
8	Cargill-Alliant LLC	OS		N/A	N/A	N/A
9	City of Hastings	OS	2	N/A	N/A	N/A
10	Cinergy Services, Inc.	OS		N/A	N/A	N/A
11	Consolidated Water	OS	2	N/A	N/A	N/A
12	DL Windy Acres	OS		N/A	N/A	N/A
13	Dynegy Power Marketing Inc.	OS	6	N/A	N/A	N/A
14	Eau Galle Renewable Energy Co. Inc.	OS	IPP	N/A	N/A	N/A
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/30/2004	Dec. 31, 2003

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
60,866				3,440,775	126,278	3,567,053	1
293,780				11,309,887		11,309,887	2
321,588				7,563,088		7,563,088	3
8,727			169,901	206,414		376,315	4
154				200		200	5
325			-12,500	24,375		11,875	6
					14,496	14,496	7
43,411				1,768,870		1,768,870	8
19,588			564,576	263,497		828,073	9
11,016				280,167		280,167	10
1,300				104,000		104,000	11
54				1,792		1,792	12
560,523			1,600,345	18,623,861		20,224,206	13
1,421				91,557		91,557	14
12,164,524	167,517	19,899	138,593,920	402,478,160	213,825	541,285,905	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/30/2004	Dec. 31, 2003

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Edison Mission Marketing & Trading Inc	OS	2, 6	N/A	N/A	N/A
2	Eric & Gail Petersen/Annual Wi	OS		N/A	N/A	N/A
3	Erpelding	OS		N/A	N/A	N/A
4	Entergy-Koch Power Marketing Corp.	OS	6	N/A	N/A	N/A
5	Empire District	OS	6	N/A	N/A	N/A
6	Exelon Generation Company LLC	OS	2, 6	N/A	N/A	N/A
7	Ford Motor Co.	OS	IPP	N/A	N/A	N/A
8	Garwin McNeilus Windfarm LLC	OS		N/A	N/A	N/A
9	Gen-Sys Energy	OS	2	N/A	N/A	N/A
10	George & Rosemarie Kallemeyna/A	OS		N/A	N/A	N/A
11	Great River Energy	OS	2	N/A	N/A	N/A
12	Harold & Gertrude Jasper/Annua	OS		N/A	N/A	N/A
13	Hennepin Energy Resource Recovery	OS	IPP	N/A	N/A	N/A
14	Hutchinson Utilities Commission	OS	434	N/A	N/A	N/A
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/30/2004	Dec. 31, 2003

PURCHASED POWER (Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
91,235				3,072,763		3,072,763	1
					5,146	5,146	2
					38,045	38,045	3
1,150				45,100		45,100	4
280				14,400		14,400	5
4,073				124,523		124,523	6
25,734				465,403		465,403	7
60,854				1,953,269		1,953,269	8
48,906				1,743,344		1,743,344	9
					28,432	28,432	10
149,200	58,765			2,884,528		2,884,528	11
					14,216	14,216	12
205,378			8,205,006	1,980,137		10,185,143	13
9				400		400	14
12,164,524	167,517	19,899	138,593,920	402,478,160	213,825	541,285,905	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/30/2004	Dec. 31, 2003

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Intercontinential Exchange	OS		N/A	N/A	N/A
2	Kansas City Power & Light Co.	OS	2, 6	N/A	N/A	N/A
3	Kas Brothers Wind Farm	OS	IPP	N/A	N/A	N/A
4	Lac Courte Oreilles Band of Lake Super	OS		N/A	N/A	N/A
5	Landfill Power Flying Cloud	OS		N/A	N/A	N/A
6	Lighthouse Energy Trading Co.	OS	2	N/A	N/A	N/A
7	Lincoln Electric System	OS	2, 6	N/A	N/A	N/A
8	Louisville Gas & Electric Co.	OS	6	N/A	N/A	N/A
9	Manitoba Hydro	OS	357, 2	N/A	N/A	N/A
10	Mid-American Energy Co.	OS	2, 6	N/A	N/A	N/A
11	Mid Continent Area Power Pool	OS		N/A	N/A	N/A
12	Missouri River	OS	2	N/A	N/A	N/A
13	Minnesota Methane LLC	OS		N/A	N/A	N/A
14	MN Municipal Power Agency	OS	2, 3	N/A	N/A	N/A
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/30/2004	Dec. 31, 2003

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
					72	72	1
133,077				4,436,919		4,436,919	2
4,275				185,996		185,996	3
				96,000		96,000	4
13,699			269,907	316,424		586,331	5
				-100,800		-100,800	6
25				480		480	7
3,134				94,138		94,138	8
4,038,909			59,218,414	80,316,328		139,534,742	9
524,836			3,049,998	18,699,604		21,749,602	10
	3,322	12,848					11
560				33,600		33,600	12
23,957			392,923	646,123		1,039,046	13
215,820			50,200	9,562,266		9,612,466	14
12,164,524	167,517	19,899	138,593,920	402,478,160	213,825	541,285,905	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/30/2004	Dec. 31, 2003

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	MN Power	OS	2	N/A	N/A	N/A
2	Minnkota Power Cooperative	OS	2,284,334,502	N/A	N/A	N/A
3	Midwest Independent System Operator	OS		N/A	N/A	N/A
4	Montana-Dakota Utilities Co.	OS	2	N/A	N/A	N/A
5	New Corp. Resources	OS		N/A	N/A	N/A
6	Neshonoc Hydro	OS		N/A	N/A	N/A
7	Nebraska Public Power	OS	2, 6	N/A	N/A	N/A
8	Northern Shore Mining Company	OS		N/A	N/A	N/A
9	NAE/Gassiz Beach LLC	OS		N/A	N/A	N/A
10	NAE/Lakota Ridge	OS		N/A	N/A	N/A
11	NAE/Metro Wind LLC	OS		N/A	N/A	N/A
12	NAE/North Shaoktan LLC	OS		N/A	N/A	N/A
13	NAE/Ruthton Ridge LLC	OS		N/A	N/A	N/A
14	NAE/Shaokatan Hills LLC	OS		N/A	N/A	N/A
	Total					

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
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7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
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9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
633,575			2,529,371	20,031,377		22,560,748	1
329,422			11,886,976	4,262,141		16,149,117	2
	67,788	7,048					3
167,444				4,949,382		4,949,382	4
				47,340		47,340	5
1,952			162,019	234,146		396,165	6
274				21,718		21,718	7
162,745			6,387,360	2,607,735		8,995,095	8
5,670				223,695		223,695	9
30,764				1,545,895		1,545,895	10
963				37,897		37,897	11
38,589				1,370,726		1,370,726	12
49,786				1,969,706		1,969,706	13
36,794				1,670,330		1,670,330	14
12,164,524	167,517	19,899	138,593,920	402,478,160	213,825	541,285,905	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/30/2004	Dec. 31, 2003

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	NAE/Shaokatan	OS		N/A	N/A	N/A
2	NSP Energy Marketing	OS		N/A	N/A	N/A
3	Oklahoma Gas & Electric Co.	OS	6	N/A	N/A	N/A
4	Olsen Wind Farm	OS		N/A	N/A	N/A
5	Omaha Public Power District	OS	2, 6	N/A	N/A	N/A
6	Otter Tail Power Co.	OS		N/A	N/A	N/A
7	Paul A Erschens & Lisa L Ersch	OS		N/A	N/A	N/A
8	Pine Bend Landfill LLC	OS		N/A	N/A	N/A
9	PJM Interconnection LLC	OS	5	N/A	N/A	N/A
10	Public Service Co of New Mexico	OS	6	N/A	N/A	N/A
11	Public Service Co of Colorado	OS	1	N/A	N/A	N/A
12	Rainbow Energy Marketing Corp.	OS	2, 6	N/A	N/A	N/A
13	Rainy River Energy Corp.	OS	2, 6	N/A	N/A	N/A
14	Rapidan Hydro	OS		N/A	N/A	N/A
	Total					

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
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7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
3,750				300,787		300,787	1
	15,354	3					2
35				14,190		14,190	3
4,082				118,646		118,646	4
53,853			613,229	2,025,562		2,638,791	5
1,133,928			141,521	42,919,292		43,060,813	6
					23,621	23,621	7
93,666			1,903,418	3,011,972		4,915,390	8
16,737				692,943		692,943	9
28,627				1,482,993		1,482,993	10
40,665				1,725,902		1,725,902	11
159,418				5,752,076		5,752,076	12
800				40,600		40,600	13
7,501			497,899	68,740		566,639	14
12,164,524	167,517	19,899	138,593,920	402,478,160	213,825	541,285,905	

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/30/2004	Dec. 31, 2003

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Reliant Energy Services Inc.	OS	2, 6	N/A	N/A	N/A
2	Select Energy, Inc.	OS	2, 6	N/A	N/A	N/A
3	S & P Windfarm	OS		N/A	N/A	N/A
4	Sebastian G Schwing & Beverly	OS		N/A	N/A	N/A
5	Southern MN Municipal Power Agency	OS	2	N/A	N/A	N/A
6	South Plains Electric Coop	OS		N/A	N/A	N/A
7	Southwestern Public Service Co.	OS	1	N/A	N/A	N/A
8	Split Rock Energy	OS	2, 6	N/A	N/A	N/A
9	St Cloud Hydro	OS		N/A	N/A	N/A
10	The Energy Authority	OS	2, 6	N/A	N/A	N/A
11	University of Minnesota	OS		N/A	N/A	N/A
12	Western Area Power Administration	OS	2, 6	N/A	N/A	N/A
13	Westar Energy	OS	2, 6	N/A	N/A	N/A
14	Westridge Windfarm	OS		N/A	N/A	N/A
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/30/2004	Dec. 31, 2003

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
			-200,000			-200,000	1
22,394				788,597		788,597	2
111				3,706		3,706	3
					11,342	11,342	4
6,803				219,686		219,686	5
5				115		115	6
18,685				1,083,689		1,083,689	7
260,308				11,177,078		11,177,078	8
38,268			1,614,878	370,029		1,984,907	9
16,534			300,000	642,178		942,178	10
31,515				64,515		64,515	11
75,530	22,288			2,753,283		2,753,283	12
410,866			768,600	13,619,525		14,388,125	13
939				31,455		31,455	14
12,164,524	167,517	19,899	138,593,920	402,478,160	213,825	541,285,905	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/30/2004	Dec. 31, 2003

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Wisconsin Electric Power Co.	OS	319	N/A	N/A	N/A
2	Wisconsin Public Power Inc.	OS	2, 447	N/A	N/A	N/A
3	Wisconsin Public Power Service Corp.	OS	2	N/A	N/A	N/A
4	Woodstock Hills LLC	OS	IPP	N/A	N/A	N/A
5	Windcurrent Farms	OS		N/A	N/A	N/A
6	Koch Refinery	OS	IPP	N/A	N/A	N/A
7	B & K Energy Systems	OS		N/A	N/A	N/A
8	Bernard & Janet Bouman/Annual	OS		N/A	N/A	N/A
9	Bison Windfarm	OS		N/A	N/A	N/A
10	Boeve Windfarm	OS		N/A	N/A	N/A
11	Carron City Court House	OS		N/A	N/A	N/A
12	Central Valley Electric	OS		N/A	N/A	N/A
13	CG Windfarm	OS		N/A	N/A	N/A
14	Coral Power	OS	2, 6	N/A	N/A	N/A
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/30/2004	Dec. 31, 2003

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES MegaWatt Hours Received (h)	POWER EXCHANGES MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	COST/SETTLEMENT OF POWER Energy Charges ($) (k)	COST/SETTLEMENT OF POWER Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
10,155				327,902		327,902	1
125				3,705		3,705	2
35,027				1,804,037		1,804,037	3
26,702				1,288,372		1,288,372	4
2,800				93,800		93,800	5
			4,533,915	31,087,215		35,621,130	6
67				2,249		2,249	7
					4,204	4,204	8
1,347				45,121		45,121	9
2,864				95,911		95,911	10
				374		374	11
1,607				47,340		47,340	12
273				9,134		9,134	13
34,400				1,926,400		1,926,400	14
12,164,524	167,517	19,899	138,593,920	402,478,160	213,825	541,285,905	

7610.0600 E – Current Minnesota Electric Rate Schedules

Following are Xcel Energy's electric rate schedules in effect between June 1, 2003 and June 1, 2004, and monthly power cost adjustments for the same period.

Northern States Power Company d/b/a Xcel Energy
Retail Fuel Clause Adjustment (FCA) – Minnesota
June 2003 – June 2004

Billing Month	Fuel Clause Adjustment ¢ per kWh
June 2003	0.579
July 2003	0.618
August 2003	0.637
September 2003	0.180
October 2003	0.459
November 2003	0.123
December 2003	0.061
January 2004	-0.001
February 2004	0.197
March 2004	0.178
April 2004	-0.204
May 2004	0.412
June 2004	0.365

Minnesota Electric Rates

Northern States Power Company

MPUC No. 2

AVAILABILITY

Available to any residential customer for domestic purposes only in a single private residence and qualifying farm customers.

RATE

	Standard	Electric Space Heating
Customer Charge per Month	$4.59	$6.09
Energy Charge per kWh		
June - September	$0.075894	$0.075894
Other Months	$0.065894	$0.054254

RESOURCE ADJUSTMENT

Bills are subject to the adjustments provided for in the Fuel Clause Rider, the Conservation Improvement Program Adjustment Rider, the Environmental Improvement Rider and the State Energy Policy Rate Rider. N

PROPERTY TAX ADJUSTMENT

The above energy charge includes a $0.000502 / kWh reduction, to reflect a property tax change.

MONTHLY MINIMUM CHARGE

Customer Charge.

SURCHARGE

In certain communities, bills are subject to surcharges provided for in a Surcharge Rider.

LATE PAYMENT CHARGE

Any unpaid balance over $10.00 is subject to a 1.5% late payment charge or $1.00, whichever is greater, after the date due. The charge may be assessed as provided for in the General Rules and Regulations, Section 3.5.

LOW INCOME ENERGY DISCOUNT

Energy discount is available to qualified low income customers under this schedule subject to the provisions contained in the Low Income Energy Discount Rider.

OTHER PROVISIONS

This schedule is also subject to provisions contained in Underground Service Rider and in Rules for Application of Residential Rates.

AVAILABILITY

Available to any residential customer for domestic purposes only in a single private residence and qualifying farm customers.

RATE

	Standard	Electric Space Heating
Customer Charge per Month	$6.59	$8.09
On Peak Period Energy Charge per kWh		
June - September	$0.144469	$0.144469
Other Months	$0.117407	$0.090318
Off Peak Period Energy Charge per kWh	$0.033656	$0.033656

RESOURCE ADJUSTMENT

Bills are subject to the adjustments provided for in the Fuel Clause Rider, the Conservation Improvement Program Adjustment Rider, the Environmental Improvement Rider and the State Energy Policy Rate Rider. N

PROPERTY TAX ADJUSTMENT

The above energy charge includes a $0.000502 / kWh reduction, to reflect a property tax change.

MONTHLY MINIMUM CHARGE

Customer Charge.

SURCHARGE

In certain communities, bills are subject to surcharges provided for in a Surcharge Rider.

LATE PAYMENT CHARGE

Any unpaid balance over $10.00 is subject to a 1.5% late payment charge or $1.00, whichever is greater, after the date due. The charge may be assessed as provided for in the General Rules and Regulations, Section 3.5.

LOW INCOME ENERGY DISCOUNT

Energy discount is available to qualified low income customers under this schedule subject to the provisions contained in the Low Income Energy Discount Rider.

(Continued on Sheet No. 5-3)

DEFINITION OF PEAK PERIODS

The on peak hours shall be a 12 hour block of continuous hours as selected by customer from options listed below. On peak hours shall begin at the same time for each of the on peak days, which are Monday through Friday, except the following holidays: New Year's Day, Good Friday, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day. When a designated holiday occurs on Saturday, the preceding Friday will be designated a holiday. When a designated holiday occurs on Sunday, the following Monday will be designated a holiday. The off peak period is defined as all other hours. Definition of on peak and off peak period is subject to change with change in Company's system operating characteristics.

CHOICE OF PEAK PERIODS

Customer may choose one of three optional peak periods and must maintain the choice for a minimum of one year. The three on peak periods have the following beginning and ending hours:

Option	Beginning Hour	Ending Hour	Maximum Customer Limitation
1	8:00 a.m.	8:00 p.m.	500
2	9:00 a.m.	9:00 p.m.	No Limit
3	10:00 a.m.	10:00 p.m.	500

Off peak hours are times not specified as on peak hours.

One year after initial choice of peak period, customer may change peak period selection. Such change is allowed only once per year and is subject to the Service Processing Charge, as specified in the General Rules and Regulations, Section 1, GENERAL SERVICE RULES.

OPTIONAL TRIAL SERVICE

Customers may elect time of day service for a trial period of three months. If a customer chooses to return to non-time of day service after the trial period, the customer will pay a charge of $20.00 for removal of time of day metering equipment.

(Continued on Sheet No. 5-4)

TERMS AND CONDITIONS OF SERVICE

1. Customer selecting the above time of day rate schedule will remain on this rate for a period of not less than 12 months, except as provided under Optional Trial Service. While served under this schedule, the Residential Service rate is not available.

2. This schedule is also subject to provisions contained in Rules for Application of Residential Rates.

3. Time of Day Metering Charge per Month Option (Closed): For any customer who prior to November 1, 1988, elected to pay a non-refundable payment of $310.00 in lieu of the time of day metering charge, the monthly customer charge is reduced by $2.00. C

AVAILABILITY

Available to any residential customer for domestic purposes only in a single private residence where service is provided through underground facilities.

RATE

	Standard	Electric Space Heating
Customer Charge per Month	$6.59	$8.09
Energy Charge per kWh		
June - September	$0.075894	$0.075894
Other Months	$0.065894	$0.054254

RESOURCE ADJUSTMENT

Bills are subject to the adjustments provided for in the Fuel Clause Rider, the Conservation Improvement Program Adjustment Rider, the Environmental Improvement Rider and the State Energy Policy Rate Rider. N

PROPERTY TAX ADJUSTMENT

The above energy charge includes a $0.000502 / kWh reduction, to reflect a property tax change.

MONTHLY MINIMUM CHARGE

Customer Charge.

SURCHARGE

In certain communities, bills are subject to surcharges provided for in a Surcharge Rider.

LATE PAYMENT CHARGE

Any unpaid balance over $10.00 is subject to a 1.5% late payment charge or $1.00, whichever is greater, after the date due. The charge may be assessed as provided for in the General Rules and Regulations, Section 3.5.

LOW INCOME ENERGY DISCOUNT

Energy discount is available to qualified low income customers under this schedule subject to the provisions contained in the Low Income Energy Discount Rider.

OTHER PROVISIONS

This schedule is also subject to provisions contained in Rules for Application of Residential Rates.

AVAILABILITY
Available to any residential customer for domestic purposes only in a single private residence where service is provided through underground facilities.

RATE

	Standard	Electric Space Heating
Customer Charge per Month	$8.59	$10.09
On Peak Period Energy Charge per kWh		
June - September	$0.144469	$0.14446
Other Months	$0.117407	$0.090318
Off Peak Period Energy Charge per kWh	$0.033656	$0.033656

RESOURCE ADJUSTMENT
Bills subject to the adjustments provided for in the Fuel Clause Rider, the Conservation Improvement Program Adjustment Rider, the Environmental Improvement Rider and the State Energy Policy Rate Rider. N

PROPERTY TAX ADJUSTMENT
The above energy charge includes a $0.000502 / kWh reduction, to reflect a property tax change.

MONTHLY MINIMUM CHARGE
Customer Charge.

SURCHARGE
In certain communities, bills are subject to surcharges provided for in a Surcharge Rider.

LATE PAYMENT CHARGE
Any unpaid balance over $10.00 is subject to a 1.5% late payment charge or $1.00, whichever is greater, after the date due. The charge may be assessed as provided for in the General Rules and Regulations, Section 3.5.

LOW INCOME ENERGY DISCOUNT
Energy discount is available to qualified low income customers under this schedule subject to the provisions contained in the Low Income Energy Discount Rider.

(Continued on Sheet No. 5-7)

DEFINITION OF PEAK PERIODS

The on peak hours shall be a 12 hour block of continuous hours as selected by customer from options listed below. On peak hours shall begin at the same time for each of the on peak days, which are Monday through Friday, except the following holidays: New Year's Day, Good Friday, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day. When a designated holiday occurs on Saturday, the preceding Friday will be designated a holiday. When a designated holiday occurs on Sunday, the following Monday will be designated a holiday. The off peak period is defined as all other hours. Definition of on peak and off peak period is subject to change with change in Company's system operating characteristics.

CHOICE OF PEAK PERIODS

Customer may choose one of three optional peak periods and must maintain the choice for a minimum of one year. The three on peak periods have the following beginning and ending hours:

Option	Beginning Hour	Ending Hour	Maximum Customer Limitation
1	8:00 a.m.	8:00 p.m.	500
2	9:00 a.m.	9:00 p.m.	No Limit
3	10:00 a.m.	10:00 p.m.	500

Off peak hours are times not specified as on peak hours.

One year after initial choice of peak period, customer may change peak period selection. Such change is allowed only once per year and is subject to the Service Processing Charge, as specified in the General Rules and Regulations, Section 1, GENERAL SERVICE RULES.

OPTIONAL TRIAL SERVICE

Customers may elect time of day service for a trial period of three months. If a customer chooses to return to non-time of day service after the trial period, the customer will pay a charge of $20.00 for removal of time of day metering equipment.

(Continued on Sheet No. 5-8)

TERMS AND CONDITIONS OF SERVICE

1. Customer selecting the above time of day rate schedule will remain on this rate for a period of not less than 12 months, except as provided under Optional Trial Service. While served under this schedule, the Residential Service - Underground rate is not available.

2. This schedule is also subject to provisions contained in Rules for Application of Residential Rates.

3. Time of Day Metering Charge per Month Option (Closed): For any customer who prior to November 1, 1988, elected to pay a non-refundable payment of $310.00 in lieu of the time of day metering charge, the monthly customer charge is reduced by $2.00. C

AVAILABILITY
Available to residential and commercial customers with permanently connected interruptible loads of up to 50 kW which would be under Company control. The types of loads served would include dual fuel space heating, water heating, and other loads subject to Company approval.

RATE

Customer Charge	$3.29
Energy Charge per kWh	
June - September	
Standard	$0.036122
Optional - Residential	$0.075894
Optional - Commercial	$0.075754
Other Months	$0.036122

OPTIONAL ENERGY CHARGE
This option is available to customers with heat pump installations for non-interruptible service during June through September billing months.

RESOURCE ADJUSTMENT
Bills subject to the adjustments provided for in the Fuel Clause Rider, the Conservation Improvement Program Adjustment Rider, the Environmental Improvement Rider and the State Energy Policy Rate Rider. N

PROPERTY TAX ADJUSTMENT
The above energy charge includes a $0.000512 / kWh reduction, to reflect a property tax change.

MONTHLY MINIMUM CHARGE
Customer Charge.

SURCHARGE
In certain communities, bills are subject to surcharges provided for in a Surcharge Rider.

LATE PAYMENT CHARGE
Any unpaid balance over $10.00 is subject to a 1.5% late payment charge or $1.00, whichever is greater, after the date due. The charge may be assessed as provided for in the General Rules and Regulations, Section 3.5.

(Continued on Sheet No. 5-10)

TERMS AND CONDITIONS OF SERVICE

1. The controllable load shall be permanently wired, separately served and metered, and at no time connected to facilities serving customer's firm load.

2. The duration and frequency of interruptions shall be at the discretion of Company. Interruption will normally occur at such times:
   a. When Company is required to use oil-fired generation equipment or to purchase power that results in equivalent production cost.
   b. When Company expects to establish an annual system peak demand, or
   c. At such times when, in Company's opinion, the reliability of the system is endangered.

3. Customer selecting Energy Controlled Service (Non-Demand Metered) must have a Company approved electric space heating system and must remain on this service for a minimum term of one year.

4. Customer selecting Energy Controlled Service (Non-Demand Metered) must be prepared for interruptions that will last longer than 12 hours per occurrence. Company shall not be liable for any loss or damage caused by or resulting from any interruption of service.

5. Electricity must be the primary source of energy for dual fuel space heating installations. Customer must have available alternative energy sources capable of supplying up to 30% of the annual heating needs during any heating season.

6. Customer's water heating system served under this rate must be designed and sized to be capable of providing customer's hot water needs for the full duration of the potential interruption periods.

7. Customer must furnish and install an NSP approved electric meter socket to accept Energy Controlled Service (Non-Demand Metered). Company reserves the right to inspect and approve the installation.

8. The rate contemplates that this service will utilize existing facilities with no additional major expenditures. Customer shall reimburse Company for any expenditures for facilities necessary to serve this load which would not otherwise be required to serve customer's load.

AVAILABILITY

Available to any customers for controlled loads which will be energized only for the time period between 10:00 p.m. to 6:30 a.m. daily.

RATE

	Residential	Commercial & Industrial
Customer Charge per Month		
Secondary Voltage		
Single Phase	$3.29	$8.39
Three Phase	–	$12.39
Primary Voltage	–	$60.39
Transmission Transformed	–	$60.39
Transmission	–	$60.39
Energy Charge per kWh		
Secondary Voltage	$0.028522	$0.025381
Primary Voltage	–	$0.024881
Transmission Transformed	–	$0.024481
Transmission	–	$0.024081

RESOURCE ADJUSTMENT

Bills are subject to the adjustments provided for in the Fuel Clause Rider, the Conservation Improvement Program Adjustment Rider, the Environmental Improvement Rider and the State Energy Policy Rate Rider. N

PROPERTY TAX ADJUSTMENT

The above energy charge includes a $0.000512 / kWh reduction for Residential customers and a $0.000456 / kWh reduction for Commercial customers, to reflect a property tax change.

MONTHLY MINIMUM CHARGE

For all customers, the minimum charge shall be the applicable commercial and industrial customer charge.

SURCHARGE

In certain communities, bills are subject to surcharges provided for in a Surcharge Rider.

LATE PAYMENT CHARGE

Any unpaid balance over $10.00 is subject to a 1.5% late payment charge or $1.00, whichever is greater, after the date due. The charge may be assessed as provided for in the General Rules and Regulations, Section 3.5.

(Continued on Sheet No. 5-12)

TERMS AND CONDITIONS OF SERVICE

1. Limited Off Peak Service shall be separately served and metered and must at no time be connected to facilities serving customer's other loads.

2. Company will not be liable for any loss or damage caused by or resulting from any interruption of service.

3. Customer selecting Limited Off Peak Service must remain on this service for a minimum term of one year, unless customer transfers to another interruptible service rate.

4. Customer has the option of directly controlling own load or allowing Company load control. If customer chooses Company load control, customer must:
   a. Provide a load-break switch or circuit breaker equipped with electronic trip and close circuits allowing for remote operation of customer's switch or circuit breaker by Company,
   b. Wire the trip and close circuits into a connection point designated by Company to allow installation of remote control equipment by Company, and
   c. Provide a continuous 120 volt AC power source at the connection point for operation of Company's remote control equipment.

5. A charge of $0.20 per kWh shall be applied to non-authorized energy used outside of the energized time period specified in this tariff. If this energy use occurs during three or more billing months, the Company reserves the right to remove customer from Limited Off Peak Service.

6. The rate contemplates that this service will utilize existing facilities with no additional major expenditures. Customer shall reimburse Company for any expenditures for facilities necessary to serve this load which would not otherwise be required to serve customer's load.

1. The Residential Service, Residential Service - Underground, Residential Time of Day Service, and Residential Time of Day Service - Underground rates are the only rates available to residential customers for domestic purposes in a single private residence. Energy Controlled Service (Non-Demand Metered), Limited Off Peak Service, and Automatic Protective Lighting Service rate schedules are also available to qualifying residential customers.

2. Normal service under the Residential Service, Residential Service - Underground, Residential Time of Day Service, and Residential Time of Day Service - Underground rate schedules is single phase service rendered through one meter. Three phase service or service through more than one meter will be provided upon a one-time payment of an amount to reimburse Company for the additional investment. If customer is served through more than one meter, each meter will be separately billed.

3. Electric space heating charges are applicable only when customer's electric space heating equipment is used as customer's primary heating source.

4. The Residential Service - Underground and Residential Time of Day Service - Underground rate schedules will apply where the underground facilities are owned by Company, and Company has not been fully reimbursed for the added cost of such underground facilities.

5. Standby and Supplementary Service is available for any residential customer subject to the provisions in the General Rules and Regulations, Section 2.4. The Company's meter will be ratcheted to measure the flow of power and energy from Company to customer only.

6. A customer using electric service for domestic and non-domestic purposes jointly may combine such use through one meter on such rates as are available to general service customers.

7. The Residential Service and Residential Time of Day Service rate schedules are available to farm installations which were served on the separate Farm Service rate schedule prior to its cancellation on November 1, 1988. Residential Service and Residential Time of Day Service to these qualifying farm customers is limited to 120/240 volts single phase service rendered through one meter. Motors and other equipment which interfere with service to neighboring customers and all transformer type welding machines larger than 25 kilovolt-amperes are not permitted as part of this service.

AVAILABILITY
Available to all types of customers except for municipal street lighting purposes.

RATE

Designation of Lamp	Monthly Rate Per Unit
Area Units	
100W High Pressure Sodium	$6.88
175W Mercury (1)	$6.88
250W High Pressure Sodium	$12.63
400W Mercury (1)	$12.63
Directional Units	
250W High Pressure Sodium	$14.28
400W Mercury (1)	$14.28
400W High Pressure Sodium	$18.78
1,000W Mercury (1)	$29.53

(1) Available to existing installations only.

ENERGY CREDITS
A merger credit of $0.000381 and property tax credit of $0.000507 shall be applied per kWh.

SERVICE INCLUDED IN RATE
Company shall own, operate, and maintain the lighting unit including the fixture, lamp, ballast, photoelectric control, mounting brackets, and all necessary wiring. Company shall furnish all electric energy required for operation of the unit.

RESOURCE ADJUSTMENT
Bills are subject to the adjustments provided for in the Fuel Clause Rider, the Conservation Improvement Program Adjustment Rider, the Environmental Improvement Rider and the State Energy Policy Rate Rider. N

SURCHARGE
In certain communities, bills are subject to surcharges provided for in a Surcharge Rider.

LATE PAYMENT CHARGE
Any unpaid balance over $10.00 is subject to a 1.5% late payment charge or $1.00, whichever is greater, after the date due. The charge may be assessed as provided for in the General Rules and Regulations, Section 3.5.

(Continued on Sheet No. 5-15)

TERM OF AGREEMENT

Agreement shall be for a term of three years. If not then terminated by at least 30 days' written notice by either party, the agreement shall continue until so terminated.

TERMS AND CONDITIONS OF SERVICE

1. Service available subject to the provisions for Automatic Protective Lighting Service of the General Rules and Regulations, Section 5.4.

2. The lamp shall be lighted and extinguished by a photoelectric control furnished by the Company. The hours of burning shall be from approximately one-half hour after sunset until one-half hour before sunrise, every night.

3. If illumination of a lamp is interrupted and said illumination is not resumed within 72 hours from the time Company receives notice thereof from customer, one-thirtieth of the monthly compensation for such unit shall be deducted for each night of non-illumination after such notice is received.

4. Company reserves the right to discontinue service if equipment is abused.

5. Company will convert mercury vapor lighting units to high pressure sodium upon failure of the mercury vapor ballast.

AVAILABILITY
Available to any non-residential customer for single or three phase electric service.

RATE
Customer Charge per Month $6.88

Energy Charge per kWh

June - September	$0.075836
Other Months	$0.065836

RESOURCE ADJUSTMENT
Bills are subject to the adjustments provided for in the Fuel Clause Rider, the Conservation Improvement Program Adjustment Rider, the Environmental Improvement Rider and the State Energy Policy Rate Rider. N

PROPERTY TAX ADJUSTMENT
The above energy charge includes a $0.000456 / kWh reduction, to reflect a property tax change.

MONTHLY MINIMUM CHARGE
Customer Charge.

SURCHARGE
In certain communities, bills are subject to surcharges provided for in a Surcharge Rider.

LATE PAYMENT CHARGE
Any unpaid balance over $10.00 is subject to a 1.5% late payment charge or $1.00, whichever is greater, after the date due. The charge may be assessed as provided for in the General Rules and Regulations, Section 3.5.

TERMS AND CONDITIONS OF SERVICE
Company shall install a demand meter for a customer when:

1. Customer's connected load is estimated to be 20 kW or greater,
2. Customer is served single phase and has a service entrance capacity greater than 200 amperes,
3. Customer is served three phase at 120/208 or 120/240 volts and has a service entrance capacity greater than 200 amperes,
4. Customer is served three phase at 240/480 or 277/480 volts and has a service entrance capacity greater than 100 amperes, or
5. Customer's average monthly kWh use for four consecutive months exceeds 3,500 kWh.

(Continued on Sheet No. 5-22)

TERMS AND CONDITIONS OF SERVICE (Continued)

If a demand meter is installed in accordance with the above, the customer may remain on the Small General Service schedule as long as customer's maximum demand is less than 25 kW. When the customer achieves an actual maximum demand of 25 kW or greater, the customer will be placed on the General Service schedule in the next billing month. A customer with a billing demand of less than 25 kW for 12 consecutive months will be given the option of returning to the Small General Service schedule.

SMALL GENERAL TIME OF DAY SERVICE
RATE CODE A12 (METERED) AND
RATE CODE A18 (NON-METERED)

AVAILABILITY
Available to any non-residential customer for single or three phase electric service supplied through one meter.

RATE
Customer Charge per Month $8.88

Energy Charge per kWh	Oct-May	Jun-Sep
On Peak Period Energy	$0.099690	$0.119683
Off Peak Period Energy	$0.031190	$0.031190
Constant Hourly Energy	$0.055165	$0.062162

RESOURCE ADJUSTMENT
Bills are subject to the adjustments provided for in the Fuel Clause Rider, the Conservation Improvement Program Adjustment Rider, the Environmental Improvement Rider and the State Energy Policy Rate Rider. N

PROPERTY TAX ADJUSTMENT
The above energy charge includes a $0.000456/ kWh reduction, to reflect a property tax change.

MONTHLY MINIMUM CHARGE
Customer Charge.

SURCHARGE
In certain communities, bills are subject to surcharges provided for in a Surcharge Rider.

LATE PAYMENT CHARGE
Any unpaid balance over $10.00 is subject to a 1.5% late payment charge or $1.00, whichever is greater, after the date due. The charge may be assessed as provided for in the General Rules and Regulations, Section 3.5.

DEFINITION OF PEAK PERIODS
The on peak period is defined as those hours between 9:00 a.m. and 9:00 p.m. Monday through Friday, except the following holidays: New Year's Day, Good Friday, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day. When a designated holiday occurs on Saturday, the preceding Friday will be designated a holiday. When a designated holiday occurs on Sunday, the following Monday will be designated a holiday. The off peak period is defined as all other hours. Definition of on peak and off peak period is subject to change with change in Company's system operating characteristics.

(Continued on Sheet No. 5-24)

OPTIONAL TRIAL SERVICE
Customers may elect time of day service for a trial period of three months. If a customer chooses to return to non-time of day service after the trial period, the customer will pay a charge of $25.00 for removal of time of day metering equipment.

TERMS AND CONDITIONS OF SERVICE

1. Customer selecting the above time of day rate schedule will remain on this rate for a period of not less than 12 months. While served under this schedule, the Small General Service rate is unavailable.

2. Company shall install a demand meter for a customer when:
   a. Customer's connected load is estimated to be 20 kW or greater,
   b. Customer is served single phase and has a service entrance capacity greater than 200 amperes,
   c. Customer is served three phase at 120/208 or 120/240 volts and has a service entrance capacity greater than 200 amperes,
   d. Customer is served three phase at 240/480 or 277/480 volts and has a service entrance capacity greater than 100 amperes, or
   e. Customer's average monthly kWh use for four consecutive months exceeds 3,500 kWh.

   If a demand meter is installed in accordance with the above, the customer may remain on the Small General Time of Day Service schedule as long as customer's maximum demand is less than 25 kW. When the customer achieves an actual maximum demand of 25 kW or greater, the customer will be placed on the General Time of Day Service schedule in the next billing month. A customer with a billing demand of less than 25 kW for 12 consecutive months will be given the option of returning to the Small General Time of Day Service schedule.

3. Optional Metering Service: Optional metering is available subject to the provisions in the General Rules and Regulations, Section 1.5, for the following applications:
   a. Kilowatt-hour Metered Service: For applications where a non-time of day meter is used, the time of day metering charge will be waived and the monthly customer charge for each location is $6.88. R
   b. Unmetered Service: For applications where no metering is installed, the monthly customer charge for each location is $5.58. If requested by Company, the customer agrees to receive one or more combined bills for all their unmetered service locations. For purposes of applying the appropriate customer service charge, one customer service charge shall be applied for every point of delivery. A point of delivery shall be any location where a meter would otherwise be required under this schedule. R

TERMS AND CONDITIONS OF SERVICE (Continued)

3. Optional Metering Service (Continued)

c. Low Wattage Unmetered Service: For applications where customer owns and operates multiple electronic devices in at least 500 locations within Company's Minnesota electric service area. Such electronic devices are: 1) individually located at each point of delivery, 2) rated at less than 400 Watts, and 3) operated with a continuous and constant load level year round. Each individual electronic device must not in any way interfere with Company operations and service to adjacent customers. This optional metering service is not applicable to electric service for traffic signals, civil defense, or lighting. Company reserves the right to evaluate customer requests for this optional metering service to determine eligibility.

The monthly fixed charge under this optional metering service shall be $0.25 per device for devices with a rating of 100 Watts or less. For devices with a rating over 100 Watts but less than 400 Watts, the monthly fixed charge shall be $1.05 per device. The customer charge shall equal the sum of the fixed charges for customer's low wattage devices in service plus $0.39 low income discount program R
cost recovery surcharge for the billing month.

In place of metered usage for each device, customer will be billed for the predetermined energy usage in kWh per device. The energy charge shall equal the sum of the predetermined energy usage for customer's low wattage devices in service for the billing month multiplied by the Constant Hourly Energy Charge applicable for the billing month.

Customer shall contract for this optional metering service through an electric service agreement with Company.

EFFECTIVE IN
Minneapolis and St. Paul

AVAILABILITY
Available to any commercial or industrial customer for Direct Current Service only where and to the extent now used.

RATE

Customer Charge per Month	$6.88	
Demand Charge per Month per kW of Connected Load	$2.75	
	Oct-May	Jun-Sep
Energy Charge per kWh	$0.065862	$0.075862

RESOURCE ADJUSTMENT
Bills are subject to the adjustments provided for in the Fuel Clause Rider, the Conservation Improvement Program Adjustment Rider, the Environmental Improvement Rider and the State Energy Policy Rate Rider. N

PROPERTY TAX ADJUSTMENT
The above energy charge includes a $0.000456 / kWh reduction, to reflect a property tax change.

MONTHLY MINIMUM CHARGE
Customer Charge and Demand Charge.

SURCHARGE
In certain communities, bills are subject to surcharges provided for in a Surcharge Rider.

LATE PAYMENT CHARGE
Any unpaid balance over $10.00 is subject to a 1.5% late payment charge or $1.00, whichever is greater, after the date due. The charge may be assessed as provided for in the General Rules and Regulations, Section 3.5.

DETERMINATION OF CONNECTED LOAD FOR PURPOSES OF THIS SCHEDULE
The nameplate rating shall be the basis of determining the connected load and shall be assumed to be one kW for each hp of nameplate rating. In any case, where there is reasonable doubt as to correctness of manufacturer's rating or where insufficient or no rating exists, the Company may fix the rating by test. For billing purposes, the demand shall be rounded to the nearest 0.1 kW.

AVAILABILITY
Available to any non-residential customer for general service.

RATE

Customer Charge per Month	$22.04	
Service at Secondary Voltage	Oct-May	Jun-Sep
Demand Charge per Month per kW	$6.61	$9.26
Energy Charge per kWh	$0.033054	
Energy Charge Credit per Month per kWh All kWh in Excess of 400 Hours Times the Billing Demand	$0.0070	

	January - December	
Voltage Discounts per Month	Per kW	Per kWh
Primary Voltage	$0.95	$0.0005
Transmission Transformed Voltage	$1.75	$0.0009
Transmission Voltage	$2.35	$0.0013

RESOURCE ADJUSTMENT
Bills are subject to the adjustments provided for in the Fuel Clause Rider, the Conservation Improvement Program Adjustment Rider, the Environmental Improvement Rider and the State Energy Policy Rate Rider. N

PROPERTY TAX ADJUSTMENT
The above energy charge includes a $0.000429 / kWh reduction, to reflect a property tax change.

SURCHARGE
In certain communities, bills are subject to surcharges provided for in a Surcharge Rider.

LATE PAYMENT CHARGE
Any unpaid balance over $10.00 is subject to a 1.5% late payment charge or $1.00, whichever is greater, after the date due. The charge may be assessed as provided for in the General Rules and Regulations, Section 3.5.

(Continued on Sheet No. 5-27)

5.2 GENERAL EXTENSION (Continued)

Refundable payments will be in the amount determined by subtracting from the total estimated installation the anticipated revenue adjusted by the revenue factor, as set forth in Section 5.1, STANDARD INSTALLATION. For each additional customer served directly from the original contracted extension within five years from the date of its completion, the person who made the advance payment will receive refunds based on the revenue to be received from the additional customer served from the extension and the costs required to serve such customer. The total of such refunds will in no event exceed the total advance payment. Refunds will be made only for line extensions on private property to a single customer served directly from the original contracted facilities.

5.3 SPECIAL FACILITIES

A. Definitions

For the purposes of Section 5.3 and the City Requested Facilities Surcharge Rider, the following definitions apply:

1. "Distribution Facilities" are defined as all primary and secondary voltage wires, poles, insulators, transformers, fixtures, cables, trenches, ductlines, and other associated accessories and equipment, including substation equipment, rated 35kV class and below, whose express function and purpose is for the distribution of electrical power from the Company's distribution substation directly to residential, commercial, and/or industrial customers. Distribution Facilities exclude all facilities used primarily for the purpose of transferring electricity from a generator to a substation and/or from one substation to another substation. As such, Distribution Facilities serve only customers on the primary and secondary rates of the Company.

2. "Transmission Facilities" are defined as all poles, towers, wires, insulators, transformers, fixtures, cables, and other associated structures, accessories and equipment, including substation equipment, rated 25kV class and above, whose express function and purpose is the transmission of electricity from a generator to a substation or substations, and from one substation to another.

3. "Municipality" is defined as any one of the following entities: a county, a city, a township or other unit of local government.

4. "City" is defined as either a statutory city or a home rule charter city consistent with Minn. Stat. Sections 410.015 and 216B.02, Subd. 9.

(Continued on Sheet No. 6-27.1)

5.3 SPECIAL FACILITIES (Continued)

A. Definitions (Continued)

5. "Standard Facilities" are those facilities whose design or location constitute the reasonable and prudent, least-cost alternative that is consistent with the existing electric system configuration, will meet the needs of the Company's customers and will maintain system reliability and performance under the circumstances. In determining the design or location of a "Standard Facility", the Company shall use good utility practices and evaluate all of the circumstances surrounding the proposal, including (i) public and employee safety in the installation, operation and maintenance of the facility, (ii) compliance with the National Electrical Safety Code, other applicable engineering standards and electric utility norms and standards, (iii) electric system reliability requirements, (iv) the presence, age, condition and configuration of existing facilities in the affected area, (v) the presence and size of existing right-of-way in the affected area, (vi) existing topology, soil, spacing, and any environmental limitations in the specific area, (vii) existing and reasonably projected development in the affected area, (viii) installation, maintenance, useful life and replacement cost factors, and (ix) other relevant factors under the particular circumstances. N

6. "Special Facilities" are non-standard facilities or the non-standard design or location of facilities as provided in Section 5.3(B).

7. "Excess Expenditure" is defined as the total reasonable incremental cost for construction of Special Facilities, including: the value of the un-depreciated life of existing facilities being removed and removal costs less salvage; the fully allocated incremental labor costs for design, surveying, engineering, construction, administration, operations or any other activity associated with said project; the incremental easement or other land costs incurred by the Company; the incremental costs of immediately required changes to associated electric facilities, including backup facilities, to ensure reliability, structural integrity and operational integrity of electric system; the incremental taxes associated with requested or ordered Special Facilities; the incremental cost represented by accelerated replacement cost if the Special Facility has a materially shorter life expectancy than the standard installation; the incremental material cost for all items associated with said construction, less salvage value of removed facilities, and any other prudent costs incurred by Company directly related to the applicable Special Facilities. N

(Continued on Sheet No. 6-27.2)

5.3 SPECIAL FACILITIES (Continued)

B. General Rule

1. When the Company is requested by a customer, group of customers, developer, or Municipality to provide types of service that result in an expenditure in excess of the Company designated standard service installation as provided under Section 5.1, STANDARD INSTALLATION, or designated standard Distribution Facilities or Transmission Facilities under Section 5.3 (A)(5) the requesting customer, group of customers, developer, or Municipality will be responsible for such Excess Expenditure, unless otherwise required by law. Common examples of Special Facilities include duplicate service facilities, special switching equipment, special service voltage, three phase service where single phase service is adequate, excess capacity, capacity for intermittent equipment, trailer park distribution systems, underground installations to wood poles, conversion from overhead to underground service, specific area undergrounding, other special undergrounding, location and relocation or replacement of existing Company facilities. T

2. When requested under Section 5.3 (B)(1) the Company will evaluate the circumstances and determine the Standard Facility(ies) that would be appropriate to the particular situation. From this evaluation, the Company will determine the facilities design/configuration for the proposed project that meets the definition of a Standard Facility. This design/configuration shall constitute the Standard Facility for purposes of determining the Excess Expenditure associated with any requested or ordered Special Facility, including a Special Facility subject to a City Requested Facilities Surcharge or other rate surcharge. N

3. Subject to the requirements of applicable law, and subject to the Company's previously scheduled or emergency work, the Company will initially install Special Facilities or will replace, modify or relocate to a Company-approved location or route its existing Distribution Facilities or Transmission Facilities (a) upon the request of a customer, a group of customers, developer, or upon request or lawful order of a Municipality if the Company determines the requested or ordered Special Facilities will not adversely affect the reliability, structural integrity, ability to efficiently expand capacity or operational integrity of the Company's Distribution Facilities or Transmission Facilities; and (b) the requesting or ordering customer, group of customers, developer, or Municipality arranges for payment of the Excess Expenditures under Section 5.3(E)(1) or 5.3(E)(2), or a requesting or ordering City elects that the Excess Expenditures for undergrounding of Distribution Facilities be recovered by surcharge under Section 5.3(E)(3). N

(Continued on Sheet No. 6-28)

5.3 SPECIAL FACILITIES (Continued)

C. Special Facilities In Public Right-Of-Way

1. Whenever a Municipality as a governing body of public right-of-way orders or requests the Company to replace, modify or relocate its existing Distribution Facilities or Transmission Facilities located by permit in said public right-of-way to the extent necessary to avoid interference with construction on said public right-of-way, such facilities will be replaced, modified or relocated at Company expense, provided the construction is the Standard Facility(ies) installation designated by the Company. N

2. If the Municipality requests or orders a facility other than the standard facility(ies) determined under 5.3(C)(1), the Company will provide the Municipality notification of the Excess Expenditure compared to the Standard Facility. If the Municipality requests or orders a type of construction with cost in excess of the Company designated standard construction, recovery of such Excess Expenditures will be subject to Section 5.3(E).

3. Except in emergencies, the Company has no obligation to commence initial construction of new Special Facilities, or to commence construction for replacement, modification, reconstruction or relocation of existing facilities, until the Company receives a permit, or other written authorization, from the Municipality (or its designee) having jurisdiction over use of the applicable public right-of-way, authorizing the construction at a Company-approved reasonable location within the public right-of-way or at a location established by lawful order of the Municipality.

4. The Company reserves the right to require an order from a Municipality if the Company determines the requested Special Facilities constitute an improvement primarily for the benefit of a landowner or other group and only an incidental benefit to public use of the right-of-way. The Company also reserves the right to challenge the lawfulness of a Municipality's order. N

D. Underground Facilities Requirements

The following provisions apply when replacing overhead facilities with underground facilities:

1. The customer, at customer's expense, must engage an electrician to adapt the customer's electrical facilities to accept service from Company underground facilities.

2. The Company will allow reasonable time for the customer to make the necessary alterations to their facilities, before removal of the existing overhead facilities. The customer, group of customers, developer or Municipality must provide Company reasonable notice of the undergrounding request so Company may efficiently plan and install such facilities. N

(Continued on Sheet No. 6-29)

AVAILABILITY
Available to any non-residential customer for general service.

RATE

Customer Charge per Month	$25.04	
Service at Secondary Voltage	Oct-May	Jun-Sep
Demand Charge per Month per kW		
On Peak Period Demand	$6.61	$9.26
Off Peak Period Demand in Excess of On Peak Period Demand	$2.35	$2.35
Energy Charge per kWh		
On Peak Period Energy	$0.038707	
Off Peak Period Energy	$0.028243	
Energy Charge Credit per Month per kWh		
All kWh in Excess of 400 Hours Times the On Peak Period Billing Demand, Not to Exceed 50% of Total kWh	$0.0070	

	January - December	
Voltage Discounts per Month	Per kW	Per kWh
Primary Voltage	$0.95	$0.0005
Transmission Transformed Voltage	$1.75	$0.0009
Transmission Voltage	$2.35	$0.0013

RESOURCE ADJUSTMENT
Bills are subject to the adjustments provided for in the Fuel Clause Rider, the Conservation Improvement Program Adjustment Rider, the Environmental Improvement Rider and the State Energy Policy Rate Rider. N

PROPERTY TAX ADJUSTMENT
The above energy charge includes a $0.000429 / kWh reduction, to reflect a property tax change.

SURCHARGE
In certain communities, bills are subject to surcharges provided for in a Surcharge Rider.

LATE PAYMENT CHARGE
Any unpaid balance over $10.00 is subject to a 1.5% late payment charge or $1.00, whichever is greater, after the date due. The charge may be assessed as provided for in the General Rules and Regulations, Section 3.5.

(Continued on Sheet No. 5-30)

5.3 SPECIAL FACILITIES (Continued)

E. Special Facilities Payments

N

1. Where the requesting or ordering party is required to prepay or agrees to prepay or arrange payment for Special Facilities, the requesting or ordering party shall execute an agreement or service form pertaining to the installation, operation and maintenance, and payment of the Special Facilities. Payments required will be made on a non-refundable basis and may be required in advance of construction unless other arrangements are agreed to in writing by the Company. The facilities installed by the Company shall be the property of the Company. Any payment by a requesting or ordering party shall not change the Company's ownership interest or rights. N T N N

Payment for Special Facilities may be required by either, or a combination, of the following methods as prescribed by the Company: a single charge for the costs incurred or to be incurred by the Company due to such a special installation or a monthly charge being one-twelfth of Company's annual fixed costs necessary to provide such a special installation. The monthly charge will be discontinued if the special facilities are removed or if the requester eventually qualifies for the originally requested Special Facilities. T

2. Where Special Facilities are requested or ordered by a Municipality which is not a City, or in circumstances other than those addressed in Section 5.3(E)(3), and payment is not made or arranged by the Municipality, the Company may seek approval of the Commission to allow the Excess Expenditures to be the responsibility of the Company's customers residing within the Municipality and may seek approval by the Commission pursuant to Minn. Stat. Chap. 216B to allow recovery of such expenditures from those customers through a rate surcharge or other method. T

N

Company will provide notice to an affected Municipality of any miscellaneous rate filing by Company under Minn. Stat. Sect. 216B.16, Subd. 1, to establish a Special Facilities surcharge applicable to customers in such Municipality. Customers in the applicable Municipality will be notified of (a) the implementation of the Special Facilities surcharge through either a bill message or bill insert during the month of implementation of such surcharge, and (b) any change in the surcharge. N

Continued on Sheet No. 6-29.2)

SPECIAL FACILITIES (Continued)

E. Special Facilities Payments (Continued)

3. Where undergrounding of Distribution Facilities as a Special Facility is ordered by a City, and payment for excess expenditure is not made or arranged by the City, the Excess Expenditures will be recovered from the Company's customers located in the City through a rate surcharge set forth in Section 5.3 (F) and the City Requested Facilities Surcharge Rider subject to the following conditions:

   a. The Company shall provide written notice to the City containing the following:

      i. the estimated total excess expenditures required for the designated City undergrounding project and an estimate of the resulting surcharge;

      ii. notice to the City Clerk that the City has sixty (60) days from its receipt of the notice to file with the Commission an objection to the proposed surcharge under Minnesota Statutes 216B.17 or other applicable law. The notice shall contain a brief statement of facts and tariff or other legal authority on which the Company bases its right to surcharge the ratepayers located in the City.

   b. Within the sixty (60) day period noticed by the Company, the City may give written notice to the Company of its intention to pay all, a portion or none of the estimated Excess Expenditures, or otherwise enter into an agreement with the Company regarding payment of any Excess Expenditures. If the City does not respond in writing within the sixty (60) days, it is deemed to have elected not to pay any portion of the Excess Expenditures and will have waived its right to object to the Company's right to surcharge ratepayers in the City for the Excess Expenditures. Such failure, however, is not a waiver of the City's right to object to the Company's Excess Expenditures surcharged to ratepayers in the City, which objection may be exercised pursuant to other applicable law.

   c. A rate surcharge set forth in Section 5.3(F) and the City Requested Facilities Surcharge Rider may be used to recover the excess Expenditures of Distribution Facilities when such projects are initiated and controlled by a city even if the city does not act within its police powers to require the undergrounding project to be completed and the City and Company mutually agree in writing to using such a surcharge.

(Continued on Sheet No. 6-29.3)

SPECIAL FACILITIES (Continued)

E. Special Facilities Payments (Continued)

d. The City may bring its objection to the proposed surcharge to the Commission by filing a statement of objection with the Commission and serving the Company within sixty (60) days. An objection proceeding shall not halt or delay the project, except for good cause shown. Notice and implementation of the surcharge shall be stayed until the Commission or a court of competent jurisdiction issues a final order or judgment.

e. Nothing in this tariff is intended to establish or limit the rights of a Company customer that is a member of the class of customers surcharged or proposed to be surcharged from pursuing its rights under applicable law.

f. Customers in the applicable City will be notified of: (i) the implementation of a City Requested Facilities Surcharge either through a bill message or a bill insert during the month preceding the month the surcharge is commenced; and (ii) any change in a preexisting surcharge. The Company shall provide the Department and City the proposed notice to customers no less than sixty (60) days prior to the first day of the month in which the Company intends to notify customers of the surcharge. N

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(Continued on Sheet No. 6-29.4)

SPECIAL FACILITIES (Continued)

F. Costs of Special Facilities Recovered by City Requested Facilities Surcharge N

1. The Excess Expenditure required for any Special Facility undergrounding of Distribution Facilities requested or ordered by a City shall be subject to surcharge in accordance with the provisions of this section and the City Requested Facilities Surcharge (CRFS) Rider, if the City does not prepay or otherwise arrange payment. The surcharge shall commence on such date as determined by the Company, but no earlier than the first full billing month following at least 60 days notice to the applicable City of the planned implementation date of a surcharge.

2. City Project Tracker Account. The Company will establish a City Project Tracker Account for the applicable City in order to track project cost recovery through customer collections. The initial balance in the Tracker Account will be the Company-determined Excess Expenditure for the applicable Special Facilities. Excess Expenditures for subsequent, additional City requested or ordered Special Facilities may be added to the Tracker Account balance at any time to the extent additional Excess Expenditures are incurred by Company. The Tracker Account balance shall be determined as follows:

   a. The total Excess Expenditure ("EE") for each City Special Facility undergrounding project to be recovered through a CRFS surcharge. The EE will be adjusted to reflect actual Company costs and any direct payments made by the City for the designated construction project;

   b. Plus the Carrying Charge ("CC") on the unrecovered or over-recovered monthly balance in the Tracker Account based on the overall rate of return from the Company's most recent electric general rate case decision; and

   c. Less the Recovered Project Costs ("RPC") equal to the actual monthly amounts billed to customers in the applicable city through the CRFS Rider, subject to subsequent reductions to account for uncollectibles, refunds and correction of erroneous billings. N

(Continued on Sheet No. 6-29.5)

SPECIAL FACILITIES (Continued)

F. Costs of Special Facilities Recovered by City Requested Facilities Surcharge (Continued)

N

3. The Company may delay implementation of a surcharge for a City Project Tracker Account until the minimum surcharge amount provided in the CRFS Rider is reached. Any under or over recovery of the Tracker Account balance in the last month of the final Recovery Period will be expensed. The Company will limit over-recoveries to no more than $0.05 per customer at the time the Tracker Account is terminated.

4. Record Access and Reporting Requirements. The Company's records associated with a City's Tracker Account shall be available for inspection by such City at reasonable times. If requested by a City, the Company shall provide a report on the status and balance of the City Project Tracker Account as follows:

   a. whenever Excess Expenditures for requested or ordered Distribution Facilities undergrounding are added to the Tracker Account for a designated or new City project,

   b. on or before the last business day of the month following the final month of the Recovery Period, or

   c. annually if the Recovery Period is greater than 12 months.

5. The surcharge for a particular Special Facility Distribution Facilities undergrounding project may be of a different design than set forth in the City Requested Facilities Surcharge Rider if approved in advance by Commission order in response to a rate filing by the Company under Minn. Stat. Section 216B.16, or in response to a complaint filed by the applicable City under Minn. Stat. Section 216B.17.

N

DEFINITION OF PEAK PERIODS

The on peak period is defined as those hours between 9:00 a.m. and 9:00 p.m. Monday through Friday, except the following holidays: New Year's Day, Good Friday, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day. When a designated holiday occurs on Saturday, the preceding Friday will be designated a holiday. When a designated holiday occurs on Sunday, the following Monday will be designated a holiday. The off peak period is defined as all other hours. Definition of on peak and off peak period is subject to change with change in Company's system operating characteristics.

DETERMINATION OF ON PEAK PERIOD DEMAND

The actual on peak period demand in kW shall be the greatest 15 minute load for the on peak period during the month for which the bill is rendered. The adjusted demand in kW for billing purposes shall be determined by dividing the actual on peak demand by the power factor expressed in percent but not more than 90%, multiplying the quotient so obtained by 90%, and rounding to the nearest whole kW. In no month shall the on peak period demand to be billed be considered as less than the current month's adjusted on peak period demand in kW, or 50% of the greatest monthly adjusted on peak period demand in kW during the preceding 11 months. In no month shall the on peak billing demand be greater than the value in kW determined by dividing the kWh sales for the billing month by 75 hours per month.

The greatest monthly adjusted on peak period demand in kW during the preceding 11 months shall not include the additional demand which may result from customer's use of standby capacity contracted for under the Standby Service Rider.

DETERMINATION OF OFF PEAK PERIOD DEMAND IN EXCESS OF ON PEAK PERIOD DEMAND

The actual off peak period demand in kilowatts shall be the greatest 15 minute load for the off peak period during the month for which the bill is rendered rounded to the nearest whole kW. In no month shall the off peak period demand for billing purposes be considered as less than the current month's actual off peak period demand in kW, or 50% of the greatest monthly actual off peak period demand in kW during the preceding 11 months.

The greatest monthly actual off peak period demand in kW during the preceding 11 months shall not include the additional demand which may result from customer's use of standby capacity contracted for under the Standby Service Rider.

The off peak period demand in excess of on peak period demand in kW to be billed shall be determined by subtracting the billing on peak period demand from the actual off peak period demand as defined above only if the off peak period demand is greater.

(Continued on Sheet No. 5-31)

POWER FACTOR
For three phase customers with services above 200 amperes, or above 480 volts, the power factor for the month shall be determined by permanently installed metering equipment. For all single phase customers and three phase customers with services 200 amperes or less, a power factor of 90% will be assumed.

COMPETITIVE SERVICE
Competitive Service is available under this schedule subject to the provisions contained in the Competitive Service Rider.

STANDBY SERVICE
Standby Service is available under this schedule subject to the provisions contained in the Standby Service Rider.

MINIMUM DEMAND TO BE BILLED
The monthly minimum on peak period billing demand shall not be less than provided above.

SPLIT SERVICE
When approved by Company, customer's service may be split between General Service and General Time of Day Service rates. Only Company approved storage space cooling and storage space heating equipment qualifies for the General Time of Day Service portion of a split service installation. The thermal storage equipment shall be permanently wired, separately served and metered, and at no time connected to the general service portion of the split service installation. Each portion of customer's split service installation will be considered separately for all other rate application purposes.

OPTIONAL TRIAL SERVICE
Customers may elect time of day service for a trial period of three months. If a customer chooses to return to non-time of day service after the trial period, the customer will pay a charge of $35.00 for removal of time of day metering equipment.

(Continued on Sheet No. 5-32)

TERMS AND CONDITIONS OF SERVICE

1. Alternating current service is provided at the following nominal voltages:
   a. Secondary Voltage: Single or three phase from 208 volts up to but not including 2,400 volts,
   b. Primary Voltage: Three phase from 2,400 volts up to but not including 69,000 volts,
   c. Transmission Transformed Voltage: Three phase from 2,400 volts up to but not including 69,000 volts, where service is provided at the Company's disconnecting means of a distribution substation transformer, or
   d. Transmission Voltage: Three phase at 69,000 volts or higher.

   Service voltage available in any given case is dependent upon voltage and capacity of Company lines in vicinity of customer's premises.

2. Transmission Transformed Service is available only to customers served by an exclusively dedicated distribution feeder. Customer will be responsible for the cost of all facilities necessary to interconnect at the Company's disconnecting means of a distribution substation transformer.

3. Transmission Service is available at transmission voltage, subject to the terms and conditions contained in the Company's General Rules and Regulations, Section 5.1(B).

4. Customer selecting the above time of day rate schedule will remain on this rate for a period of not less than 12 months.

5. If a customer has a billing demand of less than 25 kW for 12 consecutive months, the customer will be given the option of returning to the Small General Time of Day Service schedule.

6. Optional Metering Service: Optional metering is available subject to the provisions in the General Rules and Regulations, Section 1.5, for the following applications:
   a. Kilowatt-hour Metered Service: For applications where a non-time of day meter is used, the time of day metering charge will be waived and the monthly customer charge for each location is $21.65.
   b. Unmetered Service: For applications where no metering is installed, the monthly customer charge for each location is $15.10. If requested by Company, the customer agrees to receive one or more combined bills for all their unmetered service locations. For purposes of applying the appropriate customer service charge, one customer service charge shall be applied for every point of delivery. A point of delivery shall be any location where a meter would otherwise be required under this schedule.

AVAILABILITY

Available to any non-residential customer for general service who agrees to control demand to a predetermined level whenever required by Company. Availability is restricted to customers with a minimum controllable demand of 50 kW.

RATE

Customer Charge per Month	$47.04	
Service at Secondary Voltage		
Energy Charge per kWh	$0.033054	
Energy Charge Credit per Month per kWh		
All kWh in Excess of 400 Hours	$0.0070	
Times the Sum of All Billing Demands		
Demand Charge per Month per kW	Oct-May	Jun-Sep
Firm Demand	$6.61	$9.26
Controllable Demand		
Option A	$4.30	$4.69
Option B	$3.71	$6.36
	January - December	
Voltage Discounts per Month	Per kW	Per kWh
Primary Voltage	$0.95	$0.0005
Transmission Transformed Voltage	$1.75	$0.0009
Transmission Voltage	$2.35	$0.0013

RESOURCE ADJUSTMENT

Bills are subject to the adjustments provided for in the Fuel Clause Rider, the Conservation Improvement Program Adjustment Rider, the Environmental Improvement Rider and the State Energy Policy Rate Rider. N

PROPERTY TAX ADJUSTMENT

The above energy charge includes a $0.000429 / kWh reduction, to reflect a property tax change.

SURCHARGE

In certain communities, bills are subject to surcharges provided for in a Surcharge Rider.

(Continued on Sheet No. 5-34)

LATE PAYMENT CHARGE

Any unpaid balance over $10.00 is subject to a 1.5% late payment charge or $1.00, whichever is greater, after the date due. The charge may be assessed as provided for in the General Rules and Regulations, Section 3.5.

DETERMINATION OF DEMAND

Maximum Actual Demand in kW shall be the greatest 15 minute load during the billing month.

Adjusted Demand in kW for billing purposes shall be determined by dividing the maximum actual demand in kW by the power factor expressed in percent but not more than a 90% power factor and multiplying the quotient so obtained by 90% and rounding to the nearest whole kW.

Predetermined Demand shall be specified and agreed to by the customer and Company. Customer's adjusted demand must not exceed the predetermined demand level (PDL) during a control period.

Standard PDL customers must agree to a fixed demand level and limit load to that level during a control period.

Optional PDL customers must agree to reduce demand by a fixed amount during a control period. Customer's PDL will be the monthly adjusted demand less the fixed load reduction. Customers selecting the Optional PDL after September 28, 1995, must be equipped with backup generation to provide the fixed load reduction.

Firm Demand for the billing month shall be the lesser of predetermined demand or adjusted demand, except in months when customer fails to control load to predetermined demand level when requested by Company. In these months, firm demand shall be the adjusted demand established during the control period.

Controllable Demand shall be the difference between customer's adjusted demand during the billing month and the greater of predetermined demand or firm demand, but never less than zero.

Minimum Demand to be billed each month shall not be less than the current month's adjusted demand in kW.

POWER FACTOR

The power factor for the month shall be determined by permanently installed metering equipment.

(Continued on Sheet No. 5-35)

ANNUAL MINIMUM DEMAND CHARGE

The annual minimum demand charge shall be no less than six times the average monthly firm demand charge per kW times the predetermined demand, plus six times the average monthly controllable demand charge per kW times the maximum controllable demand.

COMPETITIVE SERVICE

Competitive Service is available under this schedule subject to the provisions contained in the Competitive Service Rider or the Competitive Market Rider.

OTHER PROVISIONS

Peak Controlled Service (Closed) is also subject to provisions contained in Rules for Application of Peak Controlled Tiered Services and Peak Controlled Services (Closed).

TERMS AND CONDITIONS OF SERVICE

1. Alternating current service is provided at the following nominal voltages:
   a. Secondary Voltage: Single or three phase from 208 volts up to but not including 2,400 volts,
   b. Primary Voltage: Three phase from 2,400 volts up to but not including 69,000 volts,
   c. Transmission Transformed Voltage: Three phase from 2,400 volts up to but not including 69,000 volts, where service is provided at the Company's disconnecting means of a distribution substation transformer, or
   d. Transmission Voltage: Three phase at 69,000 volts or higher.

   Service voltage available in any given case is dependent upon voltage and capacity of Company lines in vicinity of customer's premises.

2. Transmission Transformed Service is available only to customers served by an exclusively dedicated distribution feeder. Customer will be responsible for the cost of all facilities necessary to interconnect at the Company's disconnecting means of a distribution substation transformer.

3. Transmission Service is available at transmission voltage, subject to the terms and conditions contained in the Company's General Rules and Regulations, Section 5.1(B).

AVAILABILITY

Available to any non-residential customer for general service who agrees to control demand to a predetermined level whenever required by Company. Availability is restricted to customers with a minimum controllable demand of 50 kW.

RATE

Customer Charge per Month	$50.04		R
Service at Secondary Voltage			
Energy Charge per kWh			
On Peak Period Energy	$0.038707		
Off Peak Period Energy	$0.028243		
Energy Charge Credit per Month per kWh			
All kWh in Excess of 400 Hours Times the Sum of All On Peak Period Billing Demands, Not to Exceed 50% of Total kWh	$0.0070		

Demand Charge per Month per kW	Oct-May	Jun-Sep
On Peak Period Demand		
Firm Demand	$6.61	$9.26
Controllable Demand		
Option A	$4.30	$4.69
Option B	$3.71	$6.36
Off Peak Period Demand in Excess of On Peak Period Demand	$2.35	$2.35

	January - December	
Voltage Discounts per Month	Per kW	Per kWh
Primary Voltage	$0.95	$0.0005
Transmission Transformed Voltage	$1.75	$0.0009
Transmission Voltage	$2.35	$0.0013

(Continued on Sheet No. 5-37)

RESOURCE ADJUSTMENT
Bills are subject to the adjustment provided for in the Fuel Clause Rider, the Conservation Improvement Program Adjustment Rider, the Environmental Improvement Rider and the State Energy Policy Rate Rider. N

PROPERTY TAX ADJUSTMENT
The above energy charge includes a $0.000429 / kWh reduction, to reflect a property tax change.

SURCHARGE
In certain communities, bills are subject to surcharges provided for in a Surcharge Rider.

LATE PAYMENT CHARGE
Any unpaid balance over $10.00 is subject to a 1.5% late payment charge or $1.00, whichever is greater, after the date due. The charge may be assessed as provided for in the General Rules and Regulations, Section 3.5.

DEFINITION OF PEAK PERIODS
The on peak period is defined as those hours between 9:00 a.m. and 9:00 p.m. Monday through Friday, except the following holidays: New Year's Day, Good Friday, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day. When a designated holiday occurs on Saturday, the preceding Friday will be designated a holiday. When a designated holiday occurs on Sunday, the following Monday will be designated a holiday. The off peak period is defined as all other hours. Definition of on peak and off peak period is subject to change with change in Company's system operating characteristics.

DETERMINATION OF DEMAND
Actual On Peak Period Demand in kW shall be the greatest 15 minute load for the on peak period during the billing month.

Adjusted On Peak Period Demand in kW for billing purposes shall be determined by dividing the actual on peak demand by the power factor expressed in percent but not more than 90%, multiplying the quotient so obtained by 90%, and rounding to the nearest whole kW.

Actual Off Peak Period Demand in kW shall be the greatest 15 minute load for the off peak period during the billing month rounded to the nearest whole kW. In no month shall the off peak period demand for billing purposes be considered as less than the current month's actual off peak period demand in kW.

Off Peak Period Demand in Excess of On Peak Period Demand in kW to be billed shall be determined by subtracting the billing on peak period demand from the actual off peak period demand only if the off peak period demand is greater.

(Continued on Sheet No. 5-38)

DETERMINATION OF DEMAND (Continued)

Predetermined Demand shall be specified and agreed to by the customer and Company. Customer's adjusted on peak demand must not exceed the predetermined demand level (PDL) during a control period.

Standard PDL customers must agree to a fixed demand level and limit load to that level during a control period.

Optional PDL customers must agree to reduce demand by a fixed amount during a control period. Customer's PDL will be the monthly adjusted on peak demand less the fixed load reduction. Customers selecting the Optional PDL after September 28, 1995, must be equipped with backup generation to provide the fixed load reduction.

Firm Demand for the billing month shall be the lesser of predetermined demand or adjusted on peak period demand, except in months when customer fails to control load to predetermined demand level when requested by Company. In these months, firm demand shall be the adjusted on peak period demand established during the control period.

Controllable Demand shall be the difference between customer's adjusted on peak period demand during the billing month and the greater of predetermined demand or firm demand, but never less than zero.

Minimum On Peak Demand to be billed each month shall not be less than the current month's adjusted on peak period demand in kW.

POWER FACTOR

The power factor for the month shall be determined by permanently installed metering equipment.

ANNUAL MINIMUM DEMAND CHARGE

The annual minimum demand charge shall be no less than six times the average monthly firm demand charge per kW times the predetermined demand, plus six times the average monthly controllable demand charge per kW times the maximum controllable demand.

COMPETITIVE SERVICE

Competitive Service is available under this schedule subject to the provisions contained in the Competitive Service Rider or the Competitive Market Rider.

(Continued on Sheet No. 5-39)

OTHER PROVISIONS

Peak Controlled Time of Day Service (Closed) is also subject to provisions contained in Rules for Application of Peak Controlled Tiered Services and Peak Controlled Services (Closed).

TERMS AND CONDITIONS OF SERVICE

1. Alternating current service is provided at the following nominal voltages:
   a. Secondary Voltage: Single or three phase from 208 volts up to but not including 2,400 volts.
   b. Primary Voltage: Three phase from 2,400 volts up to but not including 69,000 volts.
   c. Transmission Transformed Voltage: Three phase from 2,400 volts up to but not including 69,000 volts, where service is provided at the Company's disconnecting means of a distribution substation transformer, or
   d. Transmission Voltage: Three phase at 69,000 volts or higher.

   Service voltage available in any given case is dependent upon voltage and capacity of Company lines in vicinity of customer's premises.

2. Transmission Transformed Service is available only to customers served by an exclusively dedicated distribution feeder. Customer will be responsible for the cost of all facilities necessary to interconnect at the Company's disconnecting means of a distribution substation transformer.

3. Transmission Service is available at transmission voltage, subject to the terms and conditions contained in the Company's General Rules and Regulations, Section 5.1(B).

AVAILABILITY

Available to any non-residential customer for general service who agrees to control demand to a predetermined level whenever required by Company. Availability is restricted to customers with a minimum controllable demand of 50 kW.

RATE

Customer Charge per Month	$47.04	
Service at Secondary Voltage		
Energy Charge per kWh	$0.033054	
Energy Charge Credit per Month per kWh		
All kWh in Excess of 400 Hours Times the Sum of All Billing Demands	$0.0070	
Demand Charge per Month per kW	Tier 1	Tier 2
Firm Demand		
June - September	$9.26	$9.26
Other Months	$6.61	$6.61
Controllable Demand (Jan-Dec)		
Level A: < 65% PF	Not Available	$4.43
Level B: ≥ 65% and < 85% PF	$3.49	$4.09
Level C: ≥ 85% PF	$2.99	$3.69

	January - December	
Voltage Discounts per Month	Per kW	Per kWh
Primary Voltage	$0.95	$0.0005
Transmission Transformed Voltage	$1.75	$0.0009
Transmission Voltage	$2.35	$0.0013

RESOURCE ADJUSTMENT

Bills are subject to the adjustments provided for in the Fuel Clause Rider, the Conservation Improvement Program Adjustment Rider, the Environmental Improvement Rider and the State Energy Policy Rate Rider. N

PROPERTY TAX ADJUSTMENT

The above energy charge includes a $0.000429 / kWh reduction, to reflect a property tax change.

(Continued on Sheet No. 5-41)

SURCHARGE

In certain communities, bills are subject to surcharges provided for in a Surcharge Rider.

LATE PAYMENT CHARGE

Any unpaid balance over $10.00 is subject to a 1.5% late payment charge or $1.00, whichever is greater, after the date due. The charge may be assessed as provided for in the General Rules and Regulations, Section 3.5.

DEFINITION OF PERFORMANCE FACTOR (PF)

Performance factor is defined in percentage terms as the average of the July and August calendar month unadjusted maximum controllable demand occurring from 1:00 p.m. to 7:00 p.m. on weekdays, or which has been permanently shifted out of normal control period times, divided by the unadjusted maximum annual controllable demand. Customers claiming permanent load shifts must provide verification to Company, based on NSP's established criteria.

DETERMINATION OF DEMAND

Maximum Actual Demand in kW shall be the greatest 15 minute load during the billing month.

Adjusted Demand in kW for billing purposes shall be determined by dividing the maximum actual demand in kW by the power factor expressed in percent but not more than a 90% power factor and multiplying the quotient so obtained by 90% and rounding to the nearest whole kW.

Predetermined Demand shall be specified and agreed to by the customer and Company. Customer's adjusted demand must not exceed the predetermined demand level (PDL) during a control period.

Standard PDL customers must agree to a fixed demand level and limit load to that level during a control period.

Optional PDL customers must agree to reduce demand by a fixed amount during a control period. Customer's PDL will be the monthly adjusted demand less the fixed load reduction. Customers selecting the Optional PDL must either be equipped with back-up generation to provide the fixed load reduction or have a specific load that can be separately sub-metered and has an annual load factor of 90% or greater.

(Continued on Sheet No. 5-42)

DETERMINATION OF DEMAND (Continued)

Firm Demand for the billing month shall be the lesser of predetermined demand or adjusted demand, except in months when customer fails to control load to predetermined demand level when requested by Company. In these months, firm demand shall be the adjusted demand established during the control period.

Controllable Demand shall be the difference between adjusted demand during the billing month and the greater of predetermined demand or firm demand, but never less than zero.

Minimum Demand to be billed each month shall not be less than the current month's adjusted demand in kW.

POWER FACTOR

The power factor for the month shall be determined by permanently installed metering equipment.

ANNUAL MINIMUM DEMAND CHARGE

The annual minimum demand charge shall be no less than six times the average monthly firm demand charge per kW times the predetermined demand, plus six times the controllable demand charge per kW times the maximum controllable demand.

TIER 1 PEAK CONTROLLED SCHEDULE L INTERRUPTION

Tier 1 Peak Controlled Schedule L Interruption option is available on experimental basis under this schedule subject to the provisions contained in the Experimental Tier 1 Peak Controlled Schedule L Interruption Rider.

COMPETITIVE SERVICE

Competitive Service is available under this schedule subject to the provisions contained in the Competitive Service Rider or the Competitive Market Rider.

OTHER PROVISIONS

Peak Controlled Tiered Service is also subject to provisions contained in Rules for Application of Peak Controlled Tiered Services and Peak Controlled Services (Closed).

(Continued on Sheet No. 5-43)

TERMS AND CONDITIONS OF SERVICE

1. Alternating current service is provided at the following nominal voltages:
   a. Secondary Voltage: Single or three phase from 208 volts up to but not including 2,400 volts,
   b. Primary Voltage: Three phase from 2,400 volts up to but not including 69,000 volts,
   c. Transmission Transformed Voltage: Three phase from 2,400 volts up to but not including 69,000 volts, where service is provided at the Company's disconnecting means of a distribution substation transformer, or
   d. Transmission Voltage: Three phase at 69,000 volts or higher.

   Service voltage available in any given case is dependent upon voltage and capacity of Company lines in vicinity of customer's premises.

2. Transmission Transformed Service is available only to customers served by an exclusively dedicated distribution feeder. Customer will be responsible for the cost of all facilities necessary to interconnect at the Company's disconnecting means of a distribution substation transformer.

3. Transmission Service is available at transmission voltage, subject to the terms and conditions contained in the Company's General Rules and Regulations, Section 5.1(B).

AVAILABILITY

Available to any non-residential customer for general service who agrees to control demand to a predetermined level whenever required by Company. Availability is restricted to customers with a minimum controllable demand of 50 kW.

RATE

Customer Charge per Month	$50.04		R
Service at Secondary Voltage			
Energy Charge per kWh			
On Peak Period Energy	$0.038707		
Off Peak Period Energy	$0.028243		
Energy Charge Credit per Month per kWh			
All kWh in Excess of 400 Hours Times the Sum of All On Peak Period Billing Demands, Not to Exceed 50% of Total kWh	$0.0070		

Demand Charge per Month per kW	Tier 1	Tier 2
On Peak Period Demand		
Firm Demand		
June - September	$9.26	$9.26
Other Months	$6.61	$6.61
Controllable Demand (Jan-Dec)		
Level A: < 65% PF	Not Available	$4.43
Level B: ≥ 65% and < 85% PF	$3.49	$4.09
Level C: ≥ 85% PF	$2.99	$3.69
Off Peak Period Demand in Excess of On Peak Period Demand (Jan-Dec)	$2.35	$2.35

	January - December	
Voltage Discounts per Month	Per kW	Per kWh
Primary Voltage	$0.95	$0.0005
Transmission Transformed Voltage	$1.75	$0.0009
Transmission Voltage	$2.35	$0.0013

(Continued on Sheet No. 5-45)

RESOURCE ADJUSTMENT
Bills are subject to the adjustments provided for in the Fuel Clause Rider, the Conservation Improvement Program Adjustment Rider, the Environmental Improvement Rider and the State Energy Policy Rate Rider. N

PROPERTY TAX ADJUSTMENT
The above energy charge includes a $0.000429 / kWh reduction, to reflect a property tax change.

SURCHARGE
In certain communities, bills are subject to surcharges provided for in a Surcharge Rider.

LATE PAYMENT CHARGE
Any unpaid balance over $10.00 is subject to a 1.5% late payment charge or $1.00, whichever is greater, after the date due. The charge may be assessed as provided for in the General Rules and Regulations, Section 3.5.

DEFINITION OF PEAK PERIODS
The on peak period is defined as those hours between 9:00 a.m. and 9:00 p.m. Monday through Friday, except the following holidays: New Year's Day, Good Friday, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day. When a designated holiday occurs on Saturday, the preceding Friday will be designated a holiday. When a designated holiday occurs on Sunday, the following Monday will be designated a holiday. The off peak period is defined as all other hours. Definition of on peak and off peak period is subject to change with change in Company's system operating characteristics.

DEFINITION OF PERFORMANCE FACTOR (PF)
Performance factor is defined in percentage terms as the average of the July and August calendar month unadjusted maximum controllable demand occurring from 1 p.m. to 7 p.m. on weekdays, or which has been permanently shifted out of normal control period times, divided by the unadjusted maximum annual controllable demand. Customers claiming permanent load shifts must provide verification to Company, based on NSP established criteria.

DETERMINATION OF DEMAND
Actual On Peak Period Demand in kW shall be the greatest 15 minute load for the on peak period during the billing month.

Adjusted On Peak Period Demand in kW for billing purposes shall be determined by dividing the actual on peak demand by the power factor expressed in percent but not more than 90%, multiplying the quotient so obtained by 90%, and rounding to the nearest whole kW.

Actual Off Peak Period Demand in kW shall be the greatest 15 minute load for the off peak period during the billing month rounded to the nearest whole kW. In no month shall the off peak period demand for billing purposes be considered as less than the current month's actual off peak period demand in kW.

(Continued on Sheet No. 5-46)

DETERMINATION OF DEMAND (Continued)

Off Peak Period Demand in Excess of On Peak Period Demand in kW to be billed shall be determined by subtracting the billing on peak period demand from the actual off peak period demand only if the off peak period demand is greater.

Predetermined Demand shall be specified and agreed to by the customer and Company. Customer's adjusted on peak demand must not exceed the predetermined demand level (PDL) during a control period.

Standard PDL customers must agree to a fixed demand level and limit load to that level during a control period.

Optional PDL customers must agree to reduce demand by a fixed amount during a control period. Customer's PDL will be the monthly adjusted on peak demand less the fixed load reduction. Customers selecting the Optional PDL must either be equipped with back-up generation to provide the fixed load reduction or have a specific load than can be separately sub-metered and has an annual load factor of 90% or greater.

Firm Demand for the billing month shall be the lesser of predetermined demand or adjusted on peak period demand, except in months when customer fails to control load to predetermined demand level when requested by Company. In these months, firm demand shall be the adjusted on peak period demand established during the control period.

Controllable Demand shall be the difference between adjusted on peak demand during the billing month and the greater of predetermined demand or firm demand, but never less than zero.

Minimum On Peak Demand to be billed each month shall not be less than the current month's adjusted on peak period demand in kW.

POWER FACTOR

The power factor for the month shall be determined by permanently installed metering equipment.

ANNUAL MINIMUM DEMAND CHARGE

The annual minimum demand charge shall be no less than six times the average monthly firm demand charge per kW times the predetermined demand, plus six times the controllable demand charge per kW times the maximum controllable demand.

(Continued on Sheet No. 5-47)

TIER 1 ENERGY CONTROLLED SERVICE

Tier 1 Energy Controlled Service is available under this schedule only to customers that were taking service on the Energy Controlled Service (Closed) tariff on or before March 31, 1994, subject to the provisions contained in the Tier 1 Energy Controlled Service Rider.

TIER 1 PEAK CONTROLLED SCHEDULE L INTERRUPTION

Tier 1 Peak Controlled Schedule L Interruption option is available on experimental basis under this schedule subject to the provisions contained in the Experimental Tier 1 Peak Controlled Schedule L Interruption Rider.

COMPETITIVE SERVICE

Competitive Service is available under this schedule subject to the provisions contained in the Competitive Service Rider or the Competitive Market Rider.

OTHER PROVISIONS

Peak Controlled Tiered Time of Day Service is also subject to provisions contained in Rules for Application of Peak Controlled Tiered Services and Peak Controlled Services (Closed).

TERMS AND CONDITIONS OF SERVICE

1. Alternating current service is provided at the following nominal voltages:
   a. Secondary Voltage: Single or three phase from 208 volts up to but not including 2,400 volts,
   b. Primary Voltage: Three phase from 2,400 volts up to but not including 69,000 volts,
   c. Transmission Transformed Voltage: Three phase from 2,400 volts up to but not including 69,000 volts, where service is provided at the Company's disconnecting means of a distribution substation transformer, or
   d. Transmission Voltage: Three phase at 69,000 volts or higher.

   Service voltage available in any given case is dependent upon voltage and capacity of Company lines in vicinity of customer's premises.

2. Transmission Transformed Service is available only to customers served by an exclusively dedicated distribution feeder. Customer will be responsible for the cost of all facilities necessary to interconnect at the Company's disconnecting means of a distribution substation transformer.

3. Transmission Service is available at transmission voltage, subject to the terms and conditions contained in the Company's General Rules and Regulations, Section 5.1(B).

1. Customer has the responsibility of controlling own load to predetermined demand level.

2. Customer must allow Company to inspect and approve the load control installation and equipment provided by customer.

3. If controlled demand is 10,000 kW or larger, Company may require customer to:
   a. Provide auxiliary contacts for remote indication of position of switch or circuit breaker used to control demand and wire auxiliary contacts into a connection point designated by Company,
   b. Install the remote breaker indication equipment provided by Company, and
   c. Provide a continuous 120 volt AC power source at the connection point for operation of the Company remote breaker indication equipment.

4. Company will endeavor to give customer one hour notice of commencement of control period, and as much additional notice as is practical. However, control period may be commenced without notice should Company determine such action is necessary.

5. Failure to Control Charge: An additional charge of $8.00 ($10.00 for Tier 1) per kW will apply during each Company specified control period to the amount by which customer's maximum adjusted demand exceeds their predetermined demand level. After three such customer failures to control load to their predetermined demand level, Company reserves the right to increase the predetermined demand level, or transfer customer to General Service or General Time of Day Service and apply the cancellation charge specified in customer's Electric Service Agreement.

6. The duration and frequency of control periods shall be at the discretion of Company. Control periods will normally occur when:
   a. Company expects a reasonable possibility of system load levels surpassing the level for which NSP has sufficient accredited capacity under the Mid-Continent Area Power Pool Agreement, including reserve requirements, or
   b. In Company's opinion, the reliability of the system is endangered.

   Peak Controlled Tiered Service - Tier 2 and Peak Controlled Service (Closed) customers will be separated into two groups by Company with control periods applicable to one or both groups. Customer groups are determined by geographical location and equivalent total controllable load. Control periods will apply to both customer groups at times of the highest forecast system load levels. Control periods at other high load times may apply to only one of the customer groups. Customer groups will be defined as subject to control periods on either even or odd numbered days.

(Continued on Sheet No. 5-49)

7. Customer must execute an Electric Service Agreement with Company which will include:

Peak Controlled Tiered Service - Tier 1

a. A minimum initial 10 year term of service which includes a one year trial period and a three year cancellation notice effective after the initial term of service,
b. The predetermined demand level, which may be revised subject to approval by Company,
c. Minimum demand charge differential,
d. Maximum 150 hours of interruption,
e. Cancellation charge terms, and
f. Control period notice.

Peak Controlled Tiered Service - Tier 2 and Peak Controlled Service (Closed)

a. A minimum initial five year term of service which includes a one year trial period and a six month cancellation notice effective after the initial term of service,
b. The predetermined demand level, which may be revised subject to approval by Company,
c. Minimum demand charge differential,
d. Maximum 80 hours of interruption,
e. Cancellation charge terms, and
f. Control period notice.

8. Peak Controlled Tiered Service customers choosing the Tier 1 rate option will be subject to an additional monthly charge for a Company approved and installed two-way communications system. The system equipment allows NSP to determine remotely customer load levels and to notify customers of control periods.

9. Minimum controllable demand during the Company's peak season shall be 50 kW.

10. Company shall not be liable for any loss or damage caused by or resulting from any interruption of service.

11. Company will determine, at a service location designated by Company, the number of services supplied. Customers requesting special facilities will be charged the additional costs incurred for such facilities.

(Continued on Sheet No. 5-50)

12. Customers choosing the predetermined demand level option requiring a fixed demand reduction will be subject to an additional charge for metering and billing when additional metering equipment is necessary. The additional charge is $11.00 per month for an application using a single meter in close proximity to customer's service point. The additional charge for more complex applications will be based on the actual costs of the specific application.

13. Company will maintain firm demand charge rates at the General Service and General Time of Day Service levels, whichever is applicable.

14. Any customer with generating equipment which is operated in parallel with Company must comply with all requirements associated with parallel operations as specified in the General Rules and Regulations of the Company.

15. Any load served by customer generation during Company requested control periods must be served by Company at all other times.

16. Customers selecting Peak Controlled Tiered Services will normally remain at a specific performance factor level for a minimum of one year, subject to the Company's discretion. The Company may transfer customers between performance factor levels following verification of a customer's performance, as defined in the applicable rate schedule and as specified in the customer's Electric Service Agreement. This rate contemplates that increases in summer controllable demand, which thereby affect a customer's performance factor level, will be at sufficient consumption levels to yield a July and August calendar month load factor of 34% or greater. The Company reserves the right to limit the customer's eligibility to be on a higher performance factor level due to the above restriction.

AVAILABILITY

Available to any non-residential customer for general service who agrees to control demand to a predetermined level whenever required by Company. Availability is restricted to customers with a minimum controllable demand of 50 kW.

RATE

Customer Charge per Month	$50.04		R
Service at Secondary Voltage			
Energy Charge per kWh			
Firm On Peak Period Energy	$0.038707		
Firm Off Peak Period Energy	$0.028243		
Controllable On Peak Period Energy	$0.036088		
Controllable Off Peak Period Energy	$0.027261		
Control Period Energy	$0.054090		
Energy Charge Credit per Month per kWh			
All kWh in Excess of 400 Hours Times the Sum of All On Peak Period Billing Demands, Not to Exceed 50% of Total kWh	$0.0070		

Demand Charge per Month per kW	Oct-May	Jun-Sep
On Peak Period Demand		
Firm Demand	$6.61	$9.26
Controllable Demand	$4.09	$4.48
Off Peak Period Demand in Excess of On Peak Period Demand	$2.35	$2.35

	January - December	
Voltage Discounts per Month	Per kW	Per kWh
Primary Voltage	$0.95	$0.0005
Transmission Transformed Voltage	$1.75	$0.0009
Transmission Voltage	$2.35	$0.0013

(Continued on Sheet No. 5-52)

RESOURCE ADJUSTMENT

Bills are subject to the adjustments provided for in the Fuel Clause Rider, the Conservation Improvement Program Adjustment Rider, the Environmental Improvement Rider and the State Energy Policy Rate Rider. N

PROPERTY TAX ADJUSTMENT

The above energy charge includes a $0.000429 / kWh reduction, to reflect a property tax change.

SURCHARGE

In certain communities, bills are subject to surcharges provided for in a Surcharge Rider.

LATE PAYMENT CHARGE

Any unpaid balance over $10.00 is subject to a 1.5% late payment charge or $1.00, whichever is greater, after the date due. The charge may be assessed as provided for in the General Rules and Regulations, Section 3.5.

DEFINITION OF PEAK PERIODS

The on peak period is defined as those hours between 9:00 a.m. and 9:00 p.m. Monday through Friday, except the following holidays: New Year's Day, Good Friday, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day. When a designated holiday occurs on Saturday, the preceding Friday will be designated a holiday. When a designated holiday occurs on Sunday, the following Monday will be designated a holiday. The off peak period is defined as all other hours. Definition of on peak and off peak period is subject to change with change in Company's system operating characteristics.

DETERMINATION OF DEMAND

Actual On Peak Period Demand in kW shall be the greatest 15 minute load for the on peak period during the billing month.

Adjusted On Peak Period Demand in kW for billing purposes shall be determined by dividing the actual on peak demand by the power factor expressed in percent but not more than 90%, multiplying the quotient so obtained by 90%, and rounding to the nearest whole kW.

Actual Off Peak Period Demand in kW shall be the greatest 15 minute load for the off peak period during the billing month rounded to the nearest whole kW. In no month shall the off peak period demand for billing purposes be considered as less than the current month's actual off peak period demand in kW.

(Continued on Sheet No. 5-53)

DETERMINATION OF DEMAND (Continued)

Off Peak Period Demand in Excess of On Peak Period Demand in kW to be billed shall be determined by subtracting the billing on peak period demand from the actual off peak period demand only if the off peak period demand is greater.

Predetermined Demand shall be specified and agreed to by the customer and Company. Customer's adjusted on peak demand must not exceed the predetermined demand level during a control period.

Firm Demand for the billing month shall be the lesser of predetermined demand or adjusted on peak period demand, except in months when customer fails to control load to predetermined demand level when requested by Company. In these months, firm demand shall be the adjusted on peak period demand established during the control period.

Controllable Demand shall be the difference between customer's adjusted on peak period demand during the billing month and the greater of predetermined demand or firm demand, but never less than zero.

Minimum On Peak Demand to be billed each month shall not be less than the current month's adjusted on peak period demand in kW.

POWER FACTOR

The power factor for the month shall be determined by permanently installed metering equipment.

ANNUAL MINIMUM DEMAND CHARGE

The annual minimum demand charge shall be no less than six times the average monthly firm demand charge per kW times the predetermined demand, plus six times the average monthly controllable demand charge per kW times the maximum controllable demand.

COMPETITIVE SERVICE

Competitive Service is available under this schedule subject to the provisions contained in the Competitive Service Rider or the Competitive Market Rider.

(Continued on Sheet No. 5-54)

TERMS AND CONDITIONS OF SERVICE

1. Alternating current service is provided at the following nominal voltages:
   a. Secondary Voltage: Single or three phase from 208 volts up to but not including 2,400 volts,
   b. Primary Voltage: Three phase from 2,400 volts up to but not including 69,000 volts,
   c. Transmission Transformed Voltage: Three phase from 2,400 volts up to but not including 69,000 volts, where service is provided at the Company's disconnecting means of a distribution substation transformer, or
   d. Transmission Voltage: Three phase at 69,000 volts or higher.

   Service voltage available in any given case is dependent upon voltage and capacity of Company lines in vicinity of customer's premises.

2. Transmission Transformed Service is available only to customers served by an exclusively dedicated distribution feeder. Customer will be responsible for the cost of all facilities necessary to interconnect at the Company's disconnecting means of a distribution substation transformer.

3. Transmission Service is available at transmission voltage, subject to the terms and conditions contained in the Company's General Rules and Regulations, Section 5.1(B).

4. Customer has the responsibility of controlling own load to predetermined demand level.

5. Customer must allow Company to inspect and approve the load control installation and equipment provided by customer.

6. If controlled demand is 10,000 kW or larger, Company may require customer to:
   a. Provide auxiliary contacts for remote indication of position of switch or circuit breaker used to control demand and wire auxiliary contacts into a connection point designated by Company,
   b. Install the remote breaker indication equipment provided by Company, and
   c. Provide a continuous 120 volt AC power source at the connection point for operation of the Company remote breaker indication equipment.

7. Company will endeavor to give customer one hour notice of commencement of control period, and as much additional notice as is practical. However, control period may be commenced without notice should Company determine such action is necessary.

(Continued on Sheet No. 5-55)

TERMS AND CONDITIONS OF SERVICE (Continued)

8. Failure to Control Charge: Except as provided for under Control Period Energy Service described below, the following charges will apply in any month customer fails to control load to predetermined demand level:
   a. An additional charge of $10.00 per kW will apply during each Company specified control period to the amount by which customer's maximum adjusted demand exceeds their predetermined demand level, and
   b. Control period energy charge will apply to the energy used during the control period which is associated with the customer's controllable demand.

   After three such customer failures to control load to their predetermined demand level, Company reserves the right to increase the predetermined demand level or remove customer from Energy Controlled Service (Closed) and apply the cancellation charge specified in customer's Electric Service Agreement.

9. The duration and frequency of interruption periods shall be at the discretion of Company. Interruption periods will normally occur at such times when:
   a. Company is required to use oil-fired generation equipment or to purchase power that results in equivalent production cost,
   b. Company expects a reasonable possibility of system load levels surpassing the level for which NSP has sufficient accredited capacity under the Mid-Continent Area Power Pool Agreement, including reserve requirements, or
   c. In Company's opinion, the reliability of the system is endangered.

10. Customer shall execute an Electric Service Agreement with Company which will include:
   a. A minimum initial five year term of service which includes a one year trial period and a six month cancellation notice effective after the initial term of service,
   b. The predetermined demand level, which may be revised subject to approval by Company,
   c. Minimum demand charge differential,
   d. Maximum 300 hours of interruption,
   e. Cancellation charge terms, and
   f. Control period notice.

(Continued on Sheet No. 5-56)

TERMS AND CONDITIONS OF SERVICE (Continued)

11. Minimum controllable demand during the Company's peak season shall be 50 kW.

12. Company shall not be liable for any loss or damage caused by or resulting from any interruption of service.

13. Company will determine, at a service location designated by Company, the number of services supplied. Customers requesting special facilities will be charged the additional costs incurred for such facilities.

14. Company will maintain firm demand charge rates for Energy Controlled Service (Closed) at the General Time of Day Service level.

15. Any customer with generating equipment which is operated in parallel with Company must comply with all requirements associated with parallel operations as specified in the General Rules and Regulations of the Company.

16. Any load served by customer generation during Company requested control periods must be served by Company at all other times.

(Continued on Sheet No. 5-57)

CONTROL PERIOD ENERGY SERVICE

AVAILABILITY

Available to Energy Controlled Service (Closed) customers for supply of controllable demand related energy during control periods. The control period energy charge will apply when the Company is required to use oil-fired generation equipment or to purchase power that results in equivalent production costs. Control Period Energy Service will not be available when Company expects system peak load conditions or during system emergencies.

RATE

The control period energy charge will apply to all controllable demand related energy used during the control period.

TERMS AND CONDITIONS OF SERVICE

1. Control Period Energy Service will be available provided such service will not adversely affect firm service to any customer.

2. Company reserves the right to refuse or control the supply of Control Period Energy Service if its capacity is not adequate to furnish such service.

3. All other provisions of the Energy Controlled Service (Closed) rate schedule not in conflict with Control Period Energy Service shall apply.

4. Company notice of commencement of control period will include notice of availability of Control Period Energy Service.

EXPERIMENTAL DESIGN
The experimental period will end December 31, 2004. Participation is limited to 300,000 kW, based on historical or expected average monthly on peak demand of customers. Company reserves the right to revise this rate schedule and the method for determination of hourly prices.

AVAILABILITY
Available to non-residential customers with a minimum anticipated average monthly on peak demand of 1,000 kW. The controllable service option is available to customers with a minimum controllable load of 500 kW, who agree to control load to a predetermined level whenever required by Company.

CONTRACT
Customers must contract for this service through an electric service agreement with Company. Contract period will normally be for one year, but may not extend past the experimental period.

RATE

Customer Charge per Month	$500.39	R
Demand Charge per Month per kW		
Access Demand	$5.23	
Distribution Demand by Voltage		
Secondary	$2.00	
Primary	$1.15	
Transmission Transformed	$0.50	
Transmission	$0.00	
Energy Charge per kWh	Variable by Hour	
Energy Charge Credit per Month		
Base Year Average Monthly Credit Amount times Sales Factor Adjustment		
Energy Charge Voltage Discounts per kWh		
Primary	$0.0005	
Transmission Transformed	$0.0009	
Transmission	$0.0013	

(Continued on Sheet No. 5-59)

ENERGY CHARGE

Hourly energy charges are derived from the energy charge in the General Service rate schedule, adjusted for Fuel Clause Rider revision effective December 1, 2004.

PRICE COMMUNICATION

Prior to 4:00 p.m. each day, Company will provide customers the hourly real-time prices effective from midnight to midnight the following day. Multiple day-ahead prices may also be provided. If Company is responsible for not providing hourly prices by the specified time, the lesser of two days of hourly prices will be applicable, as determined by the non-weighted average hourly prices for both days. In this instance, the comparison day for billing is the most recent prior day with or without an on peak period as specified in the Definition of Peak Period, whichever is applicable.

RESOURCE ADJUSTMENT

Bills are subject to the adjustments provided for in the Fuel Clause Rider, the Conservation Improvement Program Adjustment Rider, the Environmental Improvement Rider and the State Energy Policy Rate Rider. N

SURCHARGE

In certain communities, bills are subject to surcharges provided for in a Surcharge Rider.

LATE PAYMENT CHARGE

Any unpaid balance over $10.00 is subject to a 1.5% late payment charge or $1.00, whichever is greater, after the date due. The charge may be assessed as provided for in the General Rules and Regulations, Section 3.5.

DEFINITION OF PEAK PERIOD

The on peak period is defined as those hours between 9:00 a.m. and 9:00 p.m. Monday through Friday, except the following holidays: New Year's Day, Good Friday, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day. When a designated holiday occurs on Saturday, the preceding Friday will be designated a holiday. When a designated holiday occurs on Sunday, the following Monday will be designated a holiday. The off peak period is defined as all other hours. Definition of on peak and off peak period is subject to change with change in Company's system operating characteristics.

POWER FACTOR

The power factor for the month shall be determined by permanently installed metering equipment.

(Continued on Sheet No. 5-60)

POWER FACTOR ADJUSTMENT

The demand adjustment for power factor is determined by dividing actual demand by the billing month average power factor expressed in percent but not more than 90%, and multiplying the quotient so obtained by 90%.

BASE YEAR

The 12 months immediately prior to service with this rate. Load characteristics from the base year period may be adjusted if not representative of expected loads, subject to Company approval.

SALES FACTOR ADJUSTMENT

The sales factor adjustment is determined by dividing customer's annual kWh sales from the preceding contract year by customer's annual kWh sales from the base year. The sales factor adjustment is 1.0 during customer's initial contract year.

DETERMINATION OF DEMAND

Actual On Peak Period Demand in kW is the greatest 15 minute on peak period load during the billing month.

Access Demand in kW is customer's actual on peak period demand from the corresponding month in the base year, adjusted for the current billing month's power factor, then multiplied by the sales factor adjustment. Access demand is rounded to the nearest whole kW for billing.

Distribution Demand in kW shall be the greatest 15 minute load that occurred during the past 12 months, including the month for which the bill is rendered. Distribution demand is adjusted for power factor and rounded to the nearest whole kW. Additional demand that may result from customer's use of contracted standby or supplemental capacity is not included in the determination of distribution demand.

CONTROLLABLE SERVICE OPTION

Controllable Service Credit is the applicable controllable demand credit times the monthly controllable demand.

Controllable Demand Credit per Month per kW

		Jun-Sep	Other Months
Level A:	< 65% PF	$4.30	$1.65
Level B:	≥ 65% and < 85% PF	$4.65	$2.00
Level C:	≥ 85% PF	$5.00	$2.35

(Continued on Sheet No. 5-61)

CONTROLLABLE SERVICE OPTION (Continued)

Controllable Demand in kW is the difference between access demand for the billing month and predetermined demand.

Predetermined Demand shall be specified and agreed to by the customer and Company. Customer's demand, adjusted for power factor, must not exceed the predetermined demand level (PDL) during a control period.

Performance Factor (PF) is defined in percentage terms as the average of the July and August calendar month unadjusted maximum controllable demand occurring from 1:00 p.m. to 7:00 p.m. on weekdays, divided by the unadjusted maximum annual controllable demand. Customer's base year billing history or representative load characteristics will be used to determine customer's performance factor. Customers will normally remain at a specific performance factor level for a minimum of one year, subject to the Company's discretion. The Company reserves the right to determine customer's eligibility for performance factor levels and may transfer customers between levels following verification of a customer's performance.

Controllable Service Terms and Conditions

1. Company will endeavor to give customer one hour notice of commencement of control period.

2. An additional charge of $8.00 per kW for failure to control will apply during each Company specified control period to the amount that customer's maximum power factor adjusted on peak demand exceeds their predetermined demand level.

3. The duration and frequency of control periods shall be at the discretion of Company. Control periods will normally occur when Company expects a reasonable possibility of system load levels surpassing the level for which NSP has sufficient accredited capacity under the Mid-Continent Area Power Pool Agreement, including reserve requirements, or when in Company's opinion, the reliability of the system is endangered. Customers will be separated into two groups by Company with control periods applicable to one or both groups. Customer groups are determined by geographical location and equivalent total controllable load. Control periods will apply to both customer groups at times of the highest forecast system load levels. Control periods at other high load times may apply to only one of the customer groups. Customer groups will be defined as subject to control periods on either even or odd numbered days.

(Continued on Sheet No. 5-62)

CONTROLLABLE SERVICE OPTION (Continued)

Controllable Service Terms and Conditions (Continued)

4. Maximum duration of all control periods specified by Company will be 80 hours per year.

5. Customer may revise predetermined demand level subject to approval by Company.

6. Company shall not be liable for any loss or damage caused by or resulting from any interruption of service.

7. Any customer with generating equipment that is operated in parallel with Company must comply with all requirements associated with parallel operations as specified in the General Rules and Regulations of the Company.

8. Any load served by customer generation during Company requested control periods must normally be served by Company.

COMPETITIVE SERVICE

Competitive service is available under this schedule subject to the provisions contained in the Competitive Service Rider. Competitive service is also available with the controllable service option under this schedule subject to the provisions contained in the Competitive Market Rider.

STANDBY SERVICE

Standby service is available under this schedule subject to the provisions contained in the Standby Service Rider.

TERMS AND CONDITIONS OF SERVICE

1. Alternating current service is provided at the following nominal voltages:
   a. Secondary Voltage: Single or three phase from 208 volts up to but not including 2,400 volts,
   b. Primary Voltage: Three phase from 2,400 volts up to but not including 69,000 volts,
   c. Transmission Transformed Voltage: Three phase from 2,400 volts up to but not including 69,000 volts, where service is provided at the Company's disconnecting means of a distribution substation transformer, or
   d. Transmission Voltage: Three phase at 69,000 volts or higher.

   Service voltage available in any given case is dependent upon voltage and capacity of Company lines in vicinity of customer's premises.

(Continued on Sheet No. 5-63)

TERMS AND CONDITIONS OF SERVICE (Continued)

2. Transmission Transformed Service is available only to customers served by an exclusively dedicated distribution feeder. Customer will be responsible for the cost of all facilities necessary to interconnect at the Company's disconnecting means of a distribution substation transformer.

3. Transmission Service is available at transmission voltage, subject to the terms and conditions contained in the Company's General Rules and Regulations, Section 5.1(B).

4. Company will provide, install, and maintain equipment necessary to communicate real-time prices to customers. Customer will provide for a dedicated telephone line service approved by Company.

5. Customer will pay a cancellation charge for contract cancellation prior to the end of a contract period. The cancellation charge is $2,000.00, plus the difference between customer's bills recalculated using customer's previous rate schedule and this rate schedule if such difference is greater than zero.

DAY-TYPE
Separate energy charges are defined for each of eight day-types. Company will normally designate the applicable day-type for each day by 4:00 p.m. of the preceding day. If Company has not designated the applicable day by 4:00 p.m., the day-type will be the same as the last designated day-type, unless Company later designates a lower cost day-type.

CONTRACT
Customers must contract for this service through an Electric Service Agreement with Company. Contract period will normally be for one year, but may not extend past December 31, 2006.

RESOURCE ADJUSTMENT
Bills are subject to the adjustments provided for in the Fuel Clause Rider, the Conservation Improvement Program Adjustment Rider, the Environmental Improvement Rider and the State Energy Policy Rate Rider. N

SURCHARGE
In certain communities, bills are subject to surcharges provided for in a Surcharge Rider.

LATE PAYMENT CHARGE
Any unpaid balance over $10.00 is subject to a 1.5% late payment charge or $1.00, whichever is greater, after the date due. The charge may be assessed as provided for in the General Rules and Regulations, Section 3.5.

PEAK PERIOD HOURS DEFINITION
Peak period hours are the nine hours between 9:00 a.m. and 6:00 p.m. for day-types 1, 2, 3, 4, 5, and 6. No peak period hours are applicable for day-types 7 and 8.

STABILITY FACTOR ADJUSTMENT
Day-type energy charges will be adjusted by a stability factor to compensate for departures from the normal distribution of day-types. The average day-type energy charge, weighted with system loads, will be determined for actual and normal day-types. Stability factors of no more than five percent will be implemented following an annualized differential that exceeds two percent, and discontinued after the differential for the preceding 12 months is less than one percent. Customers will be notified of the effective date and amount of any stability factor adjustment before that adjustment is implemented, changed or discontinued. No stability factor adjustment will apply to customers receiving this service for fewer months than used to determine the adjustment.

POWER FACTOR
The power factor for the month shall be determined by permanently installed metering equipment. Company may require customer to install Company-approved equipment to maintain a power factor of not less than 90%.

(Continued on Sheet No. 5-66)

AVAILABILITY

Available for year-round illumination of public streets, parkways, and highways by High Pressure Sodium (HPS) or Metal Halide electric lamps in luminaires supported on poles, where the facilities for this service are furnished by Company. Underground Service under this schedule is limited to areas having a Company owned underground electric distribution system.

RATE

Designation of Lamp	Monthly Rate Per Luminaire Overhead	Underground	Decorative Underground	Purchase Option
70W High Pressure Sodium	$8.79	$14.49	–	–
100W High Pressure Sodium	$8.94	$14.84	$19.29	$5.54
150W High Pressure Sodium	$10.24	$16.79	$20.94	$6.54
250W High Pressure Sodium	$13.94	$20.09	$24.39	$8.59
400W High Pressure Sodium	$17.79	$23.09	$27.54	$12.04
175W Metal Halide	$12.69	$20.49	$25.19	$8.89
250W Metal Halide	$15.99	$22.79	$27.19	$10.19
400W Metal Halide	$19.79	$25.54	$29.94	$12.94
1,000W Metal Halide	$29.04	$35.79	$40.19	$23.19

PURCHASE OPTION SURCHARGE

A monthly surcharge per luminaire of 0.2% applies to the amount the purchase price exceeds $1,200.

ENERGY CREDITS

A merger credit of $0.000381 and property tax credit of $0.000507 shall be applied per kWh.

RESOURCE ADJUSTMENT

Bills are subject to the adjustments provided for in the Fuel Clause Rider, the Conservation Improvement Program Adjustment Rider, the Environmental Improvement Rider and the State Energy Policy Rate Rider. N

SURCHARGE

In certain communities, bills are subject to surcharges provided for in a Surcharge Rider.

LATE PAYMENT CHARGE

Any unpaid balance over $10.00 is subject to a 1.5% late payment charge or $1.00, whichever is greater, after the date due. The charge may be assessed as provided for in the General Rules and Regulations, Section 3.5.

OTHER PROVISIONS

This schedule is also subject to provisions contained in Rules for Application of Street Lighting Rates.

AVAILABILITY

Available for year-round illumination of public streets, parkways, and highways by electric lamps in luminaires supported on wood poles, where the facilities for this service are furnished by Company. Service is limited to existing installations being served under this schedule.

RATE

Designation of Lamp	Number of Lamps per Luminaire	Monthly Rate per Luminaire Overhead
200W High Pressure Sodium	1	$12.66

ENERGY CREDITS

A merger credit of $0.000381 and property tax credit of $0.000507 shall be applied per kWh.

RESOURCE ADJUSTMENT

Bills are subject to the adjustments provided for in the Fuel Clause Rider, the Conservation Improvement Program Adjustment, the Environmental Improvement Rider, and the State Energy Policy Rate Rider. N

SURCHARGE

In certain communities, bills are subject to surcharges provided for in a Surcharge Rider.

LATE PAYMENT CHARGE

Any unpaid balance over $10.00 is subject to a 1.5% late payment charge or $1.00, whichever is greater, after the date due. The charge may be assessed as provided for in the General Rules and Regulations, Section 3.5.

OTHER PROVISIONS

This schedule is also subject to provisions contained in Rules for Application of Street Lighting Rates.

AVAILABILITY

Available for year-round illumination of public streets, parkways, and highways by electric lamps mounted on standards where customer owns Company approved ornamental street lighting system complete with standards, luminaires with globes, lamps, and other appurtenances, together with all necessary cables extending between standards and to point of connection to Company's facilities as designated by Company. Availability to new lighting systems is restricted to lights maintained by Company.

RATE

Designation of Lamp	Monthly Rate per Luminaire
100W Mercury	$2.29
175W Mercury	$3.34
250W Mercury	$4.44
400W Mercury	$7.09
700W Mercury	$12.04
1,000W Mercury	$16.79
50W High Pressure Sodium	$1.24
70W High Pressure Sodium	$1.49
100W High Pressure Sodium	$2.04
150W High Pressure Sodium	$2.89
200W High Pressure Sodium	$3.84
250W High Pressure Sodium	$4.99
400W High Pressure Sodium	$7.49
750W High Pressure Sodium	$13.29
1,000W High Pressure Sodium	$17.24
55W Low Pressure Sodium	$1.39
1,000W Metal Halide	$17.29

ENERGY CREDITS

A merger credit of $0.000381 and property tax credit of $0.000507 shall be applied per kWh.

RESOURCE ADJUSTMENT

Bills are subject to the adjustments provided for in the Fuel Clause Rider, the Conservation Improvement Program Adjustment Rider, the Environmental Improvement Rider and the State Energy Policy Rate Rider. N

SURCHARGE

In certain communities, bills are subject to surcharges provided for in a Surcharge Rider.

(Continued on Sheet No. 5-77)

LATE PAYMENT CHARGE

Any unpaid balance over $10.00 is subject to a 1.5% late payment charge or $1.00, whichever is greater, after the date due. The charge may be assessed as provided for in the General Rules and Regulations, Section 3.5.

OTHER PROVISIONS

This schedule is also subject to provisions contained in Rules for Application of Street Lighting Rates.

AVAILABILITY

Available for year-round illumination of public streets, parkways, and highways by electric lamps mounted on standards where customer owns and maintains an ornamental street lighting system complete with standards, luminaires with globes, lamps, photocells, and other appurtenances, together with all necessary cables extending between standards and to point of connection to Company's meter as designated by Company.

RATE

Customer Charge per Meter per Month	$7.00
Energy Charge per kWh	$0.044766

RESOURCE ADJUSTMENT

Bills are subject to the adjustments provided for in the Fuel Clause Rider, the Conservation Improvement Program Adjustment Rider, the Environmental Improvement Rider and the State Energy Policy Rate Rider. N

PROPERTY TAX ADJUSTMENT

The above energy charge includes a $0.000507 / kWh reduction, to reflect a property tax change.

SURCHARGE

In certain communities, bills are subject to surcharges provided for in a Surcharge Rider.

LATE PAYMENT CHARGE

Any unpaid balance over $10.00 is subject to a 1.5% late payment charge or $1.00, whichever is greater, after the date due. The charge may be assessed as provided for in the General Rules and Regulations, Section 3.5.

CONDITIONS OF SERVICE

The customer owns and maintains ornamental street lighting system including underground cables, posts, lamps, ballasts, photocells, and glassware. Ballasts shall provide a power factor of at least 90% and photocells shall conform to specified daily operating schedule. Company furnishes energy only at central metered distribution points designated by Company. The daily operating schedule of the lamps shall be from approximately one-half hour after sunset until one-half hour before sunrise.

AVAILABILITY
Available for year round illumination of public streets, parkways, and highways by electric lamps mounted on standards where customer owns an ornamental street lighting system complete with standards, luminaires with globes, lamps, and other appurtenances, together with all necessary cables extending between standards and to point of connection to Company's facilities as designated by Company. Service is limited to existing installations being served under this schedule.

RATE

Designation of Lamp		Number of Lamps per Luminaire	Monthly Rate per Luminaire - AN
2,500 Lumen Incandescent		1	$5.01
6,000 Lumen Incandescent		1	$8.71
10,000 Lumen Incandescent		1	$12.16
15,000 Lumen Incandescent		1	$16.51
F72HO	Fluorescent	1	$4.66
F72HO	Fluorescent	2	$6.06
F72HO	Fluorescent	4	$10.61
F72EHO	Fluorescent	1	$6.21
F72EHO	Fluorescent	2	$9.36
F72EHO	Fluorescent	4	$16.81

ENERGY CREDITS
A merger credit of $0.000381 and property tax credit of $0.000507 shall be applied per kWh.

RESOURCE ADJUSTMENT
Bills are subject to the adjustments provided for in the Fuel Clause Rider, the Conservation Improvement Program Adjustment Rider, the Environmental Improvement Rider and the State Energy Policy Rate Rider. N

SURCHARGE
In certain communities, bills are subject to surcharges provided for in a Surcharge Rider.

LATE PAYMENT CHARGE
Any unpaid balance over $10.00 is subject to a 1.5% late payment charge or $1.00, whichever is greater, after the date due. The charge may be assessed as provided for in the General Rules and Regulations, Section 3.5.

OTHER PROVISIONS
This schedule is also subject to provisions contained in Rules for Application of Street Lighting Rates.

AVAILABILITY

Available to the City of St. Paul for furnishing, maintaining, and operating certain electrical connections, lines, and appurtenances thereto, and supplying electric current for city street lighting.

RATE

Designation of Lamp	Monthly Rate per Luminaire
100W High Pressure Sodium	$4.74
150W High Pressure Sodium	$5.54
250W High Pressure Sodium	$8.04

ENERGY CREDITS

A merger credit of $0.000381 and property tax credit of $0.000507 shall be applied per kWh.

RESOURCE ADJUSTMENT

Bills are subject to the adjustments provided for in the Fuel Clause Rider, the Conservation Improvement Program Adjustment Rider, the Environmental Improvement Rider and the State Energy Policy Rate Rider. N

SURCHARGE

In certain communities, bills are subject to surcharges provided for in a Surcharge Rider.

LATE PAYMENT CHARGE

Any unpaid balance over $10.00 is subject to a 1.5% late payment charge or $1.00, whichever is greater, after the date due. The charge may be assessed as provided for in the General Rules and Regulations, Section 3.5.

OTHER PROVISIONS

This schedule is also subject to provisions contained in Rules for Application of Street Lighting Rates.

AVAILABILITY

Available for year-round illumination of existing public telephone booths at various locations served through street lighting circuits.

RATE

Customer Charge per Month	$3.01
For Each 10 Watts or Fraction Thereof in Excess of 100 Watts of Connected Load per Booth per Month	$0.301279

RESOURCE ADJUSTMENT

Bills are subject to the adjustments provided for in the Fuel Clause Rider, the Conservation Improvement Program Adjustment Rider, the Environmental Improvement Rider and the State Energy Policy Rate Rider. N

SURCHARGE

In certain communities, bills are subject to surcharges provided for in a Surcharge Rider.

LATE PAYMENT CHARGE

Any unpaid balance over $10.00 is subject to a 1.5% late payment charge or $1.00, whichever is greater, after the date due. The charge may be assessed as provided for in the General Rules and Regulations, Section 3.5.

1. SERVICE INCLUDED IN RATE

a. *Street Lighting System Service*

Overhead, Underground, Decorative Underground
Company shall own, operate, and maintain the overhead and underground street lighting systems using Company's standard street lighting equipment.

Purchase Option.
Customer shall purchase from Company the entire ornamental street lighting system including underground cables, posts, lamps, ballasts, starters, photocells, and glassware and transfer ownership to the Company. The street lighting system shall be Company approved and include a lamp type and wattage combination that corresponds to an existing Purchase Option rate. Company shall furnish all electric energy necessary to operate the street lighting system, shall make all lamp and glassware renewals, clean the glassware, light and extinguish all lamps, make all ballast and starter renewals, and furnish all the materials and labor necessary for these services. Company shall also repair all damaged equipment for 25 years from the installation date. After 25 years, Company will repair damaged equipment when the damage is not associated with the age of the street lighting system. If in the Company's opinion, the condition of the street lighting system is such that replacement or significant renovation of the system is necessary, the customer shall have two options:

(1) the customer must either transfer to the appropriate Company purchased rate if available, or
(2) reimburse Company for the installed cost of a replacement system or a Company approved renovation of the existing system.

b. *Street Lighting Energy Service*
The customer owns and maintains entire ornamental street lighting system including underground cables, posts, lamps, ballasts, photocells, and glassware. Ballasts shall provide a power factor of at least 90% and photocells shall conform to specified daily operating schedule. Company furnishes energy only at central distribution points designated by Company. See individual street lighting contracts for terms and conditions not covered herein.

(Continued on Sheet No. 5-83)

1. SERVICE INCLUDED IN RATE (Continued)

c. *City of St. Paul - Multiple Overhead*
City owns and maintains lamp units, lamps, photocells, and glassware. Company owns and maintains distribution system, including hangers and furnishes energy at the lamp unit. Ballasts shall provide a power factor of at least 90% and photocells shall conform to specified daily operating schedule

2. DAILY OPERATING SCHEDULE
The daily operating schedule of lamps shall be from approximately one-half hour after sunset until one-half hour before sunrise.

3. OUTAGES
If illumination from any lamp is interrupted and said illumination is not resumed within 72 hours from the time Company receives notice thereof from customer, one-thirtieth of the monthly energy related rate for such lamp shall be deducted for each night of non-illumination after such notice is received.

4. SPECIAL SERVICES

a. *Street Lighting System Service (Closed)*

Temporary Disconnection of Service (Street lighting facilities remain in place.)
When requested by the customer, Company will temporarily disconnect service to individual street lighting units provided the customer pays a monthly facilities charge equal to the regular monthly rate less the product of the average monthly kWh for the lighting unit and the energy charge from the Street Lighting Energy Service - Metered rate schedule. The customer must pay a charge of $25.00 to disconnect or reconnect each lighting unit.

Termination of Street Lighting Facilities
When requested by the customer, except for Purchase Option lighting service, Company will remove all or a portion of a street lighting system and cease billing. The customer must pay estimated termination costs for the removal and undepreciated value of facilities, less any salvage value, if the number of lights requested to be removed in any 12 month period exceeds 5% of the municipality's leased street lighting system

(Continued on Sheet No. 5-84)

4. SPECIAL SERVICES (Continued)

b. *Street Lighting Energy Service*

Daily Operating Schedule Option
Reduced hours of operation from the standard daily operating schedule is available under the applicable commercial and industrial rate, subject to the following provisions:

(1) customer must install a meter socket at the service point, and
(2) customer shall provide all maintenance to lighting units and identify the lighting units with Company approved markings.

Disconnection of Service
During the period between customer disconnection and reconnection of street lighting units, Company will cease billing provided the disconnection is made on the line side of the lighting unit ballast. Customer disconnection not on the line side will require the customer to pay a charge to compensate for the lighting unit ballast core loss. When requested by the customer, Company will disconnect or reconnect street lighting units provided the customer pays a charge of $25.00 for the disconnection or reconnection of each lighting unit. The customer must identify all disconnected street lighting units with Company approved markings.

AVAILABILITY

Available to municipal owned water works and municipal sewage systems for operation of pumping and treatment plants.

(Rate schedule applied separately to each delivery point.)

RATE

	Oct-May	Jun-Sep
Customer Charge per Month	$7.39	$7.39
Energy Charge per kWh	$0.060332	$0.070332

RESOURCE ADJUSTMENT

Bills are subject to the adjustments provided for in the Fuel Clause Rider, the Conservation Improvement Program Adjustment Rider, the Environmental Improvement Rider and the State Energy Policy Rate Rider. N

PROPERTY TAX ADJUSTMENT

The above energy charge includes a $0.000793 / kWh reduction, to reflect a property tax change.

MONTHLY MINIMUM CHARGE

Customer Charge.

SURCHARGE

In certain communities, bills are subject to surcharges provided for in a Surcharge Rider.

LATE PAYMENT CHARGE

Any unpaid balance over $10.00 is subject to a 1.5% late payment charge or $1.00, whichever is greater, after the date due. The charge may be assessed as provided for in the General Rules and Regulations, Section 3.5.

INSTALLATION OF DEMAND METERS

The Company shall install a demand meter for a customer when:

1. Customer's connected load is estimated to be 20 kW or greater, or
2. Customer is served single phase and has a service entrance capacity greater than 200 amperes, or
3. Customer is served three phase at 120/208 or 120/240 volts and has a service entrance capacity greater than 200 amperes, or
4. Customer is served three phase at 240/480 or 277/480 volts and has a service entrance capacity greater than 100 amperes, or
5. Customer's average monthly kWh use for four consecutive months exceeds 3,500 kWh.

(Continued on Sheet No. 5-86)

INSTALLATION OF DEMAND METERS (Continued)

If a demand meter is installed in accordance with the above, the customer may remain on the Small Municipal Pumping Service schedule as long as customer's maximum demand is less than 25 kW. When the customer achieves an actual maximum demand of 25 kW or greater, the customer will be placed on the Municipal Pumping Service schedule in the next billing month. Customers with a billing demand of less than 25 kW for 12 consecutive months will be given the option of returning to the Small Municipal Pumping Service schedule.

AVAILABILITY
Available to municipal owned water works and municipal sewage systems for operation of pumping and treatment plants.

(Rate schedule applied separately to each delivery point.)

RATE

Customer Charge per Month	$22.04	
	Oct-May	Jun-Sep
Service at Secondary Voltage		
Demand Charge per Month per kW	$6.56	$9.21
Energy Charge per kWh	$0.033034	
Energy Charge Credit per Month per kWh All kWh in Excess of 400 Hours Times the Billing Demand	$0.0070	

	January - December	
Voltage Discounts per Month	Per kW	Per kWh
Primary Voltage	$0.95	$0.0005

RESOURCE ADJUSTMENT
Bills are subject to the adjustments provided for in the Fuel Clause Rider, the Conservation Improvement Program Adjustment Rider, the Environmental Improvement Rider and the State Energy Policy Rate Rider. N

PROPERTY TAX ADJUSTMENT
The above energy charge includes a $0.000793 / kWh reduction, to reflect a property tax change.

SURCHARGE
In certain communities, bills are subject to surcharges provided for in a Surcharge Rider.

LATE PAYMENT CHARGE
Any unpaid balance over $10.00 is subject to a 1.5% late payment charge or $1.00, whichever is greater, after the date due. The charge may be assessed as provided for in the General Rules and Regulations, Section 3.5.

(Continued on Sheet No. 5-88)

DETERMINATION OF DEMAND
The adjusted demand in kW for billing purposes shall be determined by dividing the maximum actual demand in kW by the power factor expressed in percent but not more than a 90% power factor and multiplying the quotient so obtained by 90% and rounding to the nearest whole kW. In no month shall the demand to be billed be considered as less than the current month's adjusted demand in kW nor greater than the value in kW determined by dividing the kWh sales for the billing month by 75 hours per month.

MAXIMUM DEMAND
The maximum actual demand in kW shall be the greatest 15 minute load during the month for which bill is rendered.

POWER FACTOR
For three phase customers with services above 200 amperes, or above 480 volts, the power factor for the month shall be determined by permanently installed metering equipment. For all single phase customers and three phase customers with services 200 amperes or less, a power factor of 90% will be assumed.

MINIMUM DEMAND TO BE BILLED
The monthly minimum billing demand shall not be less than provided above.

TERMS AND CONDITIONS OF SERVICE
Alternating current service is provided at the following nominal voltages:
1. Secondary Voltage: Single or three phase from 208 volts up to but not including 2,400 volts, or
2. Primary Voltage: Three phase from 2,400 volts up to but not including 69,000 volts.

AVAILABILITY

Available for power service for the operation of municipal fire and civil defense warning sirens having a rated capacity not in excess of 25 horsepower.

RATE

Per Month per Horsepower of Connected Capacity $0.59

MONTHLY MINIMUM CHARGE

Net per Month $2.95

LATE PAYMENT CHARGE

Any unpaid balance over $10.00 is subject to a 1.5% late payment charge or $1.00, whichever is greater, after the date due. The charge may be assessed as provided for in the General Rules and Regulations, Section 3.5.

CONNECTION

Under the above rate, the Company will make no extension for service other than a normal service span. Where conditions are such that a long service connection or extra transformer capacity, or both, are necessary, the customer shall either pay the entire cost of such extra equipment or pay a monthly facilities charge based on such costs.

The circuit serving the siren must be in conduit from the entrance to the motor with an enclosed entrance switch box, which may be sealed and operated from an external appliance.

OPTIONAL

In case the customer already has a service connection of sufficient capacity to permit operation of the siren without unduly disturbing conditions on the Company's nearby circuits, the siren may be connected at the option of the customer on the load side of the customer's existing meter and the commercial rate applied to the total load.

EFFECTIVE FOR
United States Government acting through the Corps of Engineers.

AVAILABILITY
Available for operation of the St. Anthony Falls Lower Lock and Dam and Upper Lock which is in excess of the service to be supplied without charge under provisions of Article 11 of Federal Power Commission Order issued April 30, 1963, for License Project No. 2056.

KIND OF SERVICE
Three phase, 60 cycle alternating at the following nominal voltages:

Lower Lock and Dam	4,160 volts
Upper Lock	13,800 volts

RATE
Monthly Demand Charge per kW

Demand Which is in Excess of the Demand to be Furnished Without Charge	$5.23

Annual Energy Charge per kWh

Energy Supplied During the Contract Year in Excess of the Annual Energy Consumption to be Furnished Without Charge	$0.033290

RESOURCE ADJUSTMENT
Bills are subject to the adjustments provided for in the Fuel Clause Rider, the Conservation Improvement Program Adjustment Rider, the Environmental Improvement Rider and the State Energy Policy Rate Rider. N

DETERMINATION OF DEMAND
The demand in kW shall be the greatest 15 minute load during the month for which bill is rendered.

SPECIFIED ELECTRICAL QUANTITIES TO BE FURNISHED WITHOUT CHARGE

	Monthly kW Demand	Contract Year kWh
Lower Lock and Dam	375	480,000
Upper Lock	300	370,000

FUEL CLAUSE ADJUSTMENT (FCA)

There shall be added to or deducted from the monthly bill a Fuel Clause Adjustment (FCA). The FCA is calculated by multiplying the monthly applicable billing kilowatt hours (kWh) by a prorated Fuel Clause Adjustment Factor (FCAF) based on the number of billing days in each calendar month. The FCAF is equal to the Current Period Cost of Energy plus the Energy Cost True-up Factor less the Base Cost of Energy of $0.01075 and rounded to the nearest $0.00001 per kWh.

EXEMPTION

For customers participating in Company's Windsource Program under the Voluntary Renewable and High-Efficiency Energy Purchase Rider, the applicable billing kilowatt hours for FCA shall be reduced by the elected Voluntary Renewable Adjustment energy blocks.

In the event customer's metered energy use is lower than the subscribed energy blocks, the applicable billing kilowatt hours for FCA for that month is zero.

CURRENT PERIOD COST OF ENERGY

The Current Period Cost of Energy per kWh is defined as the sum of the following costs forecasted to be incurred during the calendar month, divided by the kWh sales forecasted for the same month:

1. The cost of fossil, nuclear, biomass, wood, and refuse-derived fuel (RDF) consumed in the Company's generating stations as recorded in Accounts 151 and 518.

2. The net energy cost of purchases as recorded in Account 555, exclusive of capacity or demand charges, irrespective of the designation assigned to such transaction, when such energy is purchased on an economic dispatch basis.

3. The actual identifiable fossil, nuclear, biomass, wood, and refuse-derived fuel (RDF) costs associated with energy purchased for reasons other than identified in (2) above and expenditures entered into or made by the Company to satisfy the wind and biomass mandates contained in sections 216B.2423 and 216B.2424, or to develop renewable energy sources from the account section 116C.779 as these amounts recorded in Account 407.3.

4. The net energy cost of purchases from a qualifying facility, as that term is defined in 18 C.F.R. Part 292 and Minn. Rule 7835.0100, Subp. 19, as amended, and the net cost of energy (and capacity if purchased on an energy output basis) purchases from any facility utilizing wind energy conversion systems for the generation of electric energy, whether or not those purchases occur on an economic dispatch basis.

5. Less the fuel-related costs recovered through intersystem sales.

(Continued on Sheet No. 5-91.1)

FUEL CLAUSE ADJUSTMENT (FCA)

There shall be added to or deducted from the monthly bill a Fuel Clause Adjustment (FCA). The FCA is calculated by multiplying the monthly applicable billing kilowatt hours (kWh) by a prorated Fuel Clause Adjustment Factor (FCAF) based on the number of billing days in each calendar month. The FCAF is equal to the Current Period Cost of Energy plus the Energy Cost True-up Factor less the Base Cost of Energy of $0.01354 and rounded to the nearest $0.00001 per kWh. R

EXEMPTION

For customers participating in Company's Windsource Program under the Voluntary Renewable and High-Efficiency Energy Purchase Rider, the applicable billing kilowatt hours for FCA shall be reduced by the elected Voluntary Renewable Adjustment energy blocks.

In the event customer's metered energy use is lower than the subscribed energy blocks, the applicable billing kilowatt hours for FCA for that month is zero.

CURRENT PERIOD COST OF ENERGY

The Current Period Cost of Energy per kWh is defined as the sum of the following costs forecasted to be incurred during the calendar month, divided by the kWh sales forecasted for the same month:

1. The cost of fossil, nuclear, biomass, wood, and refuse-derived fuel (RDF) consumed in the Company's generating stations as recorded in Accounts 151 and 518.

2. The net energy cost of purchases as recorded in Account 555, exclusive of capacity or demand charges, irrespective of the designation assigned to such transaction, when such energy is purchased on an economic dispatch basis.

3. The actual identifiable fossil, nuclear, biomass, wood, and refuse-derived fuel (RDF) costs associated with energy purchased for reasons other than identified in (2) above and expenditures entered into or made by the Company to satisfy the wind and biomass mandates contained in sections 216B.2423 and 216B.2424, or to develop renewable energy sources from the account section 116C.779 as these amounts recorded in Account 407.3.

4. The net energy cost of purchases from a qualifying facility, as that term is defined in 18 C.F.R. Part 292 and Minn. Rule 7835.0100, Subp. 19, as amended, and the net cost of energy (and capacity if purchased on an energy output basis) purchases from any facility utilizing wind energy conversion systems for the generation of electric energy, whether or not those purchases occur on an economic dispatch basis.

5. Less the fuel-related costs recovered through intersystem sales.

(Continued on Sheet No. 5-91.1)

CURRENT PERIOD COST OF ENERGY (CONTINUED)

6. Less purchased power cost for the Windsource® Program as recorded in Federal Energy Regulatory Commission (FERC) account 555.

The kWh sales shall be all kWh forecasted to be sold excluding intersystem sales.

ENERGY COST TRUE-UP FACTOR

The Energy Cost True-up Factor is calculated by dividing the Energy Cost True-up Amount by the kWh sales forecasted for the calendar month. The Energy Cost True-up Amount is the balance of the prior months' unrecovered or over-recovered cumulative actual energy costs.

APPLICATION

Applicable to bills for electric service provided under the Company's retail rate schedules.

RIDER

There shall be included on each non-exempt customer's monthly bill a Conservation Improvement Program Adjustment which shall be the applicable Conservation Improvement Program Adjustment factor multiplied by the customer's monthly bill for electric service before any applicable adjustments, city surcharge, or sales tax. C

N For customer accounts granted exemption by the Commissioner of the Minnesota Department of Commerce (or successor agency) from Conservation Improvement Program (CIP) costs pursuant to Minn. Stat. 216B.241, the Conservation Improvement Program Adjustment shall not apply. Instead, each monthly bill will include the appropriate Conservation Improvement Program Exemption Adjustment which reflects the lower CIP cost responsibility applicable to exempt customer accounts. N

DETERMINATION OF CONSERVATION IMPROVEMENT PROGRAM ADJUSTMENT FACTOR

The Conservation Improvement Program Adjustment factor shall be the quotient obtained by dividing the Recoverable Conservation Improvement Program Expense by the Projected Retail Revenues for a designated recovery period. The factor may be adjusted annually with approval of the Minnesota Public Utilities Commission.

Recoverable Conservation Improvement Program (CIP) Expense shall be the conservation program expense not recovered through base rates as determined from the CIP Tracker account balance for a designated period. All costs appropriately charged to the CIP Tracker Account shall be eligible for recovery through this Rider and all revenues received from the CIP adjustment shall be credited to the CIP Tracker Account.

Projected Retail Revenues shall be the estimated revenues from projected retail sales for the designated recovery period excluding revenues resulting from adjustments, city surcharges, or sales taxes.

DETERMINATION OF CONSERVATION IMPROVEMENT PROGRAM EXEMPTION ADJUSTMENT N

The Conservation Improvement Program Exemption Adjustment applicable to exempt customer accounts shall be a credit as necessary for the authorized annual exemption period determined by multiplying total billing energy by the Conservation Cost Recovery Charge (CCRC) established in the Company's last general rate case, adjusted for any Conservation Improvement Program cost responsibility approved by the Minnesota Public Utilities Commission. Customer accounts granted exemption by a decision of the Commissioner of the Department after the beginning of a calendar year shall be credited for any CIP collections billed after January 1st of such year. N

A surcharge will be included in the monthly customer bills in Minnesota communities in an amount equal to any franchise gross earnings or other fee, permit or usage fee, excise, city sales or other charge or tax now or hereafter imposed upon Company by a community, whether by ordinance, franchise or otherwise, applicable to electric service supplied by Company to a customer.

UNDERGROUND SERVICE RIDER (CLOSED)

AVAILABILITY

Available to Residential Service customers who were taking service under the underground residential distribution clause on May 15, 1974. Service under this Rider will not be available to such an existing customer who on or after May 15, 1974, elects to take service under another applicable rate for which he qualifies. Service under this Rider will not be available to a successor customer or a new installation.

RIDER

For service through underground facilities which are installed, owned, and maintained by Company, a charge of $2.00 will be added to the monthly bill for a period of not to exceed 30 years from date of installation. In lieu of the monthly charge, a non-refundable payment of $220.00 may be made at any time. Such payment for any residence served hereunder shall apply to that residence only and shall relieve the customer and any successor customer at that residence of any obligation to pay a monthly underground charge thereafter.

LOW INCOME ENERGY DISCOUNT RIDER

Section No. 5
Original Sheet No. 95
Relocated from MPUC No. 1 Sheet No. 5-8

AVAILABILITY

Available to any residential customer who is certified and receiving assistance from the Low Income Home Energy Assistance Program (LIHEAP) during the federal fiscal year. Customers must receive certification annually through Community Action Agencies or authorized LIHEAP agencies to be eligible for this discount Rider.

RATE

For average daily use up to the first 10.0 kWh, energy is billed at 50% of the applicable energy charge. For all energy in excess of the 10.0 kWh average daily use, the energy is billed according to the applicable energy charge.

For qualified customers on Residential Time of Day Service or Residential Time of Day Service - Underground, 50% of the applicable on peak and off peak energy charges will be applied to the corresponding average on peak daily use up to 5 kWh and average off peak daily use up to 5 kWh in computing the discount amount.

TERMS AND CONDITIONS OF SERVICE

1. Customer must maintain an active account registered under customer's name with the Company to be eligible for this discount Rider.

2. Customers receiving assistance from LIHEAP with electric service through one meter for domestic and non-domestic purposes jointly may be eligible for this Discount Rider subject to Company's verification and approval. The Company shall determine the kWh use that is for domestic purposes. This Discount Rider only applies to kWh use for domestic purposes.

3. If only one household in a duplex dwelling who shares electric service jointly with another household through one meter is receiving assistance from LIHEAP, the qualified customer is eligible to receive the discount under this Rider based on one-half of the total usage by the two households registered on the meter.

4. Qualified customers are only eligible to receive an energy discount under this Rider at one residential location at any one time and the discount only applies to a qualified customer's permanent primary residence. This Rider will not be available when, in the opinion of the Company, the customer's accommodation or occupancy is of temporary nature.

(Continued on Sheet No. 5-96)

TERMS AND CONDITIONS OF SERVICE (Continued)

5. The discount shall be prospective and may not be applicable to past due bills or non-electric services.

6. An annual application and eligibility declaration is required for each request for service under this Rider. Without declaration of continuing eligibility, the discount ends in the September calendar month of each year.

7. It is the customer's responsibility to notify the Company if there is a change of address or eligibility status.

8. Discounts will be credited to the eligible customer bills one billing month after Company's receipt of notification of LIHEAP certification. The applicable discount under this Rider will be retroactive to the October billing month during that same LIHEAP fiscal year. For the 1994 LIHEAP fiscal year, the applicable discount will become effective January 1, 1995.

9. Refusal or failure of a customer or agencies to provide documentation of eligibility acceptable to the Company may result in removal from this Rider.

10. Customers may be rebilled for periods of ineligibility under the applicable rate schedule.

11. This Rider shall meet the conditions of Minnesota Statutes, Chapter 216B.16, Subd. 14 on low income discount rates.

AVAILABILITY

Available to Residential Service and Residential Service - Underground customers with:

1. Company controlled central air conditioning, or
2. Company controlled heat pumps receiving Energy Controlled Service (Non-Demand Metered) with optional non-interruptible service during June through September.

Company controlled electric water heating is also available to residential customers with a controlled central air conditioner or heat pump, except electric water heaters served with the Energy Controlled Service (Non-Demand Metered) rate schedule. Availability is limited to customers located in areas which are within the operating range of radio control transmitters.

RIDER

Residential Central Air Conditioning. A 15% discount will apply to the energy charge up to a maximum of 4,000 kWh per month during the billing months of June through September.

Residential Electric Water Heating. A 2% discount will apply to energy charges up to a maximum of 4,000 kWh per month during each billing month provided total energy use is not less than 300 kWh.

TERMS AND CONDITIONS OF SERVICE

1. The duration and frequency of interruptions will be determined by Company. Air conditioning will be cycled on a schedule of 15 minutes on and 15 minutes off in any 30 minute portion of a load management period. Air conditioning interruptions will normally occur on high demand days during summer months. Water heating interruptions will normally occur on high demand days during summer and winter months. Interruption will normally be based on meeting peak demands and system economic dispatch requirements of Company. However, interruption may also occur at times when, in the Company's opinion, the reliability of the system may be at risk. Air conditioning and water heating interruptions will not normally occur during the observation day of the following holidays: New Year's Day, Good Friday, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day. The interruptions C
as described above, will be made so as to benefit native load and may occur up to a maximum of 300 C
hours per calendar year. C

2. Company shall not be liable for any loss or damage caused by or resulting from any interruption of service.

3. To be eligible for this service, customer must agree to Company load control for a minimum term of one year.

(Continued on Sheet No. 5-98)

TERMS AND CONDITIONS OF SERVICE (Continued)

4. The storage capacity of the water heater shall be 40 gallons or more in order to be eligible for this service.

5. The residential central air conditioning energy charge discount for Energy Controlled Service (Non-Demand Metered) customers will also apply to their standard service energy charge.

6. Rider availability for heat pump installations is limited to those sized for summer cooling requirements, as determined by Company.

AVAILABILITY
Available to non-residential customers with Company controlled central air conditioning. Availability is restricted to customers with single and/or dual stage air conditioning units.

RIDER
A $5.00 per ton per month credit shall be applied to customer's bill during each of the four summer billing months (June through September).

TERMS AND CONDITIONS OF SERVICE
1. The duration and frequency of interruptions will be determined by the Company. Single stage air conditioners will be cycled on a schedule of 15 minutes on and 15 minutes off in any 30 minute portion of a load management period. Dual stage air conditioners will be allowed to have the first stage run without interruption while the second stage will be shut off for the entire load management period. Air conditioning interruptions will normally occur on high demand days during summer months. Interruption will normally be based on meeting peak demands and system economic dispatch requirements of Company. However, interruption may also occur at times when, in the Company's opinion, the reliability of the system may be at risk. Air conditioning interruptions will not normally occur during the observation day of the following holidays: New Year's Day, Good Friday, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day. The interruptions as described above, will be made so as to benefit native load and C
may occur up to a maximum of 300 hours per calendar year. C

2. Company shall not be liable for any loss or damage caused by or resulting from any interruption of service.

3. To be eligible for this service, customer must be on Small General Service, Small General Time of Day Service, General Service, or General Time of Day Service and customer must agree to Company load control for no less than one year.

4. Rider will not be available to customers that have an air conditioning system which significantly exceeds summer cooling requirements, as determined by Company.

5. Company will normally control every air conditioning unit at the customer's building. Subject to Company approval, customers may exclude individual air conditioning units from Company control where those units serve either a sufficiently isolated area within a building or a separate building.

6. Availability is limited to customers located within the operating range of radio control transmitters.

7. Those air conditioning units that the Company is not able to install equipment on will be excluded.

AVAILABILITY

Available to any non-residential customer who has an alternative source of electric energy supply which normally serves all or a portion of the customer's electrical load requirements and who desires use of the Company's electric service for temporary backup or maintenance power. Under this service the Company will provide a permanent service connection to supply the customer's contracted load in accordance with the provisions in the General Rules and Regulations, Section 2.4.

RESERVATION FEES

	Firm Standby		
	Unscheduled Maintenance	Scheduled Maintenance	Non-Firm Standby
Customer Charge per Month	$17.39	$17.39	$17.39
Demand Charge per Month per kW of Contracted Standby Capacity			
Secondary Voltage Service	$3.25	$3.15	$2.35
Primary Voltage Service	$2.30	$2.20	$1.40
Transmission Transformed Voltage Service	$1.50	$1.40	$0.60
Transmission Voltage Service	$0.90	$0.80	$0.00
Annual Allowed Grace Period of Unscheduled Use of Standby Service for Exemption from Demand Usage Rates (Hours per kW of Contracted Standby Capacity)	964	964	0

USAGE RATES

Demand Charge per Month per kW of Standby Capacity Used. Capacity actually used under this Rider will be charged at the same demand rate as contained in the base tariff to which this Rider is attached.

Energy Charge per kWh of Standby Energy Used. Energy actually used under this Rider will be charged at the same energy rate as contained in the base tariff to which this Rider is attached.

RESOURCE ADJUSTMENT

Bills are subject to the adjustments provided for in the Fuel Clause Rider, the Conservation Improvement Program Adjustment Rider, the Environmental Improvement Rider and the State Energy Policy Rate Rider. N

(Continued on Sheet No. 5-102)

AVAILABILITY
Available to any General Service customer whose maximum monthly demand occurs during the usage months of April, May, October, or November. Typical applications would be agricultural grain drying and handling loads.

RATE
The General Service rate provisions apply except the adjusted demands established during the usage months of April, May, October, and November are not included in determining the 50% demand ratchet contained in the General Service determination of demand provision.

TERMS AND CONDITIONS OF SERVICE

1. The customer's usage months for this Rider must be contained by the following meter reading schedule. The two month fall season begins no earlier than the billing cycle 11 meter reading date in mid-September and ends no later than the billing cycle 10 meter reading date in mid-December. The two month spring season begins no earlier than the billing cycle 11 meter reading date in mid-March and ends no later than the billing cycle 10 meter reading date in mid-June.

2. Customer must compensate Company for the costs associated with local distribution facilities required to serve customer load during the months of April, May, October, and November, which is in excess of customer's base load during the remaining months.

TERMS AND CONDITIONS OF SERVICE (Continued)

3. The Company's meter will be ratcheted to measure the flow of power and energy from Company to customer only.

4. Company will not be obligated to supply Standby Service to back-up a customer's generator at a level in excess of the Standby capacity for which customer has contracted. This restriction in no way limits the amount of load for which a customer may require service from the Company under the base tariff to which this Rider is attached.

5. Customer will be liable for all damages allowed by law to the extent caused by customer's use of Standby power in excess of contracted Standby capacity.

6. Company will require customer to contract for additional Standby and Supplemental capacity if the customer exceeds the contract amount in any three of the preceding 12 months.

7. Customer will annually furnish documentation to Company confirming the maximum capacity and reliability of the power source for which customer requires Standby Service. The Company and the customer will review the actual output and performance of the power source relative to the capacity nominated for Standby Service in the Electric Service Agreement. If this review shows a significant and consistent shortfall between the power source's actual performance and the nominated capacity due to factors reasonably within the customer's control, the Company will notify the customer of its intent to refuse to provide Standby Service. Upon receipt of such notice, the customer may agree to reduce the Standby Service nomination in its Electric Service Agreement or to take such action as necessary to operate the power source at or reasonably near the nominated Standby Service capacity. If the customer's power source does not operate at or reasonably near that level during the 12 months immediately following the Company's notice, the Company may refuse to provide Standby Service until such time as the customer agrees to reduce its Standby Service nomination or provide the Company with documentation demonstrating the power source's actual performance at or reasonably near the nominated Standby Service capacity for a trial period of three consecutive months.

8. Customer will remain on Standby Service for a period of not less than 12 months.

(Continued on Sheet No. 5-104)

SURCHARGE
In certain communities, bills are subject to surcharges provided for in a Surcharge Rider.

LATE PAYMENT CHARGE
Any unpaid balance over $10.00 is subject to a 1.5% late payment charge or $1.00, whichever is greater, after the date due. The charge may be assessed as provided for in the General Rules and Regulations, Section 3.5.

DETERMINATION OF DEMAND
For billing purposes, the customer demand for this Standby Service Rider will be determined separately from the billing demand determined under the tariff to which this Rider applies. For purposes of applying the Reservation Fee, the demand will be the quantity specified in the customer's Electric Service Agreement as the maximum amount of Standby Service the Company is obligated to supply. This quantity may be different between the summer and winter seasons. For applying the Usage Rate, the demand will be the smaller of the following two amounts: (1) the amount of the Standby capacity contracted for by the customer minus the actual demand supplied by the customer's own generating facilities, but not less than zero, or (2) the amount of actual capacity supplied by the Company. This amount of used Standby service demand will be determined independent of and will have no effect on the billing demand of the customer under their base tariff including any demand ratchet provisions of that base tariff.

TERMS AND CONDITIONS OF SERVICE
1. Standby Service Rider is applicable to any non-residential customer who requires 40 kW or more of Standby capacity from the Company. Standby Service may not be used by a customer to serve controllable demand that is subject to interruption as determined by the Company under the Company's controllable service schedules, however, customer will always be permitted to implement demand side load reductions or use alternative generation capacity when necessary, due to full or partial outage of the customer's generator, instead of using Standby Service from the Company. C

2. Customer will execute an Electric Service Agreement with the Company which will specify:
   a. Type of Standby Service elected by the customer and the base tariff that this Rider is attached to and under which demand and energy rates will be selected during months Standby power is used.
   b. The total Standby capacity requirements for which Company will be providing Standby power and to which the Standby Service reservation fee applies as well as the expected level of firm service the customer will take, even if that level is zero.

(Continued on Sheet No. 5-103)

TERMS AND CONDITIONS OF SERVICE (Continued)

11. In the event any portion of the capacity associated with the additional capacity costs or MAPP after-the-fact purchase costs incurred by the Company and attributable to the customer under Section 10 above are subsequently used to satisfy the Company's MAPP requirements for the Company's customers, the peak demand charges under Section 10 shall be discounted with respect to that portion subsequently used by the Company's customers.

12. The Company shall provide notice to the Standby customers when peak load conditions are expected to occur through the same means that the Company notifies interruptible customers of the potential interruption.

13. Company will install and charge customer for the metering necessary, as determined by the Company, to allow for proper billing of the separate base tariff and Standby Rider demands and grace period identified above. Customer shall reimburse the Company for the costs of installing, operating, and maintaining these meters and any other facilities required to serve the customer's Standby load. Such required additional equipment shall include the metering equipment used to measure the electrical output of the customers' alternative source of electric energy supply. In particular, the Company will install a meter that measures the flow of power and energy from the customer's own generating facility. If, as a result of the customer's construction and installation of their generating facility, it is more practical or economical for the customer to install some or all of the metering equipment required, the customer may be permitted to do so subject to Company's approval of an installation plan for such equipment.

(Continued on Sheet No. 5-106)

TERMS AND CONDITIONS OF SERVICE (Continued)

9. Customer will be allowed annually a grace period as specified above for use of unscheduled Standby Service without incurring additional demand charges for use of Standby Service. Use of this grace period will be measured in terms of Standby energy used by customer with the maximum amount of grace energy being the hours specified above times the contracted Standby capacity. After the grace period has been exhausted and customer uses unscheduled Standby Service, the customer shall pay the Usage Rates instead of the Reservation Fees as listed above. In a billing month, when customer uses Standby Service, the base tariff billing demand and the Standby Service billing demand will be determined individually. The base tariff billing demand will be the greatest 15 minute load determined after separating Standby Service usage from the total metered demands. The time of this determined greatest 15 minute demand may or may not be at the same time when Standby Service is used. Billed demand charges for usage of Standby Service will be in addition to the billed demand charges for the base tariff as just described.

10. Notwithstanding the grace period noted in Section 9 above, in the event customer requires unscheduled Standby Service at the times of Company's system peak hours in which the Company would have insufficient accredited capacity under the Mid-Continent Area Power Pool (MAPP) Agreement, if not for additional capacity purchases, and the Company incurs additional capacity costs as a result of such unscheduled Standby Service, customer shall pay peak demand charges for the month in which such unscheduled Standby Service occurs and for each of the five succeeding months instead of the above listed demand charges, or the demand charges under Section 9 above. Such peak demand charges shall be based upon the following:

   a. If customer has notified Company of an unscheduled outage at least three hours prior to Company's system peak hour, such peak demand charges shall be based on one-sixth of any additional capacity costs incurred by the Company as a result of the unscheduled outage. Such additional capacity costs shall not include any MAPP after-the-fact capacity purchase costs incurred by the Company.

   b. If customer has not notified the Company of any unscheduled outage at least three hours prior to the Company's system peak hour, such peak demand charges shall be based on one-sixth of any additional capacity costs or MAPP after-the-fact purchase costs incurred by the Company as a result of the unscheduled outage. The demand for billing purposes for the succeeding five months shall be equal to the demand placed on the system during the time of the Company's system peak hour.

(Continued on Sheet No. 5-105)

ADDITIONAL TERMS AND CONDITIONS OF SERVICE FOR NON-FIRM STANDBY OPTION

1. Non-firm standby rates are available to customers who agree to use Standby Service only by prearrangement with the Company.

2. Company makes no guarantee that Standby Service will be available to Non-Firm Standby Service customers; however, the Company will make reasonable efforts to provide Standby Service whenever possible.

3. Customer must request use of Standby Service and receive approval from the Company prior to actually using Standby Service.

4. Use of Standby Service without prior approval by the Company shall subject the Non-Firm Standby Service customer to the following:
   a. General Service or General Time of Day Service monthly demand charges for the unapproved Standby Service used in a given month, plus
   b. Firm Standby Service unscheduled maintenance option reservation fees for six months prior to the month in which unapproved use of Standby Service occurred.

5. If unapproved use of Standby Service occurs twice in any 12 month period, the Company reserves the right to convert the Non-Firm Standby Service customer to Firm Standby Service.

6. Non-Firm Standby Service customers will remain on Non-Firm Standby Service for a period of not less than five years which includes a one year trial period.

ADDITIONAL TERMS AND CONDITIONS OF SERVICE WITH FIRM STANDBY SCHEDULED MAINTENANCE

1. Scheduled maintenance rates are available to Standby Service customers who agree to schedule maintenance of their power source during qualifying scheduled maintenance periods.

2. Qualifying Scheduled Maintenance Periods

   <u>Customers With 40 kW to 10,000 kW of Contracted Standby Capacity.</u> Maintenance must occur within the calendar months of April, May, October, and November. Customer must provide Company with written notice of scheduled maintenance prior to the beginning of the maintenance period. C

   <u>Customers With Greater Than 10,000 kW of Contracted Standby Capacity.</u> Maintenance must occur at a time period mutually agreed to by Company and customer. These time periods will normally not include those times when Company expects system seasonal peak load conditions to occur, and at those times when Company is required to use oil-fired generation equipment or to purchase power that results in equivalent production costs. Customer shall provide an annual projection of scheduled maintenance to the Company. Customer shall be allowed changes or additions to this projection upon notice to the Company based on the following schedule:

Outage Length	Required Notice
Less than 48 hours	24 hours
2 days to 30 days	7 days
Over 30 days	90 days

3. The duration of qualifying scheduled maintenance periods may not exceed a total of six weeks in any 12 month period.

4. An additional charge shall apply if customer does not comply with all terms and conditions for qualifying scheduled maintenance periods. The additional charge shall be determined by calculating the additional charges which would have applied if customer were billed on the Unscheduled Maintenance Option for the period extending back to the customer's last scheduled maintenance period.

5. General Service or General Time of Day Service demand charges shall not apply to use during qualifying scheduled maintenance periods. Further, qualifying scheduled maintenance period time and energy will not count against the grace period.

(Continued on Sheet No. 5-107)

RESOURCE ADJUSTMENT

Bills are subject to the adjustments provided for in the Fuel Clause Rider, the Conservation Improvement Program Adjustment Rider, the Environmental Improvement Rider and the State Energy Policy Rate Rider. N

SURCHARGE

In certain communities, bills are subject to surcharges provided for in a Surcharge Rider.

LATE PAYMENT CHARGE

Any unpaid balance over $10.00 is subject to a 1.5% late payment charge or $1.00, whichever is greater, after the date due. The charge may be assessed as provided for in the General Rules and Regulations, Section 3.5.

DETERMINATION OF SUPPLEMENTAL DEMAND

For billing purposes, the customer demand for this Supplemental Service Rider will be determined separately from the billing demand determined under the tariff to which this Rider applies. For purposes of applying the Reservation Fee, the demand will be the quantity specified in the customer's Electric Service Agreement as the maximum amount of Supplemental Service the Company is obligated to supply. This quantity may be different between the summer and winter seasons. For applying the Usage Rate, as referenced in Section 10 below of this Rider, the Supplemental Demand will be the maximum actual demand (as adjusted for power factor) that is supplied by the Company to serve that portion of the customer's load, up to the contracted Supplemental Capacity, not served by the customer's alternative source of electric energy supply. This amount of used Supplemental Service Demand will be determined independent of and will have no effect on the billing demand of the customer under their base tariff.

DETERMINATION OF SUPPLEMENTAL ENERGY

Supplemental Energy shall be that portion of the customer's total energy requirements provided by the Company to supplement the customer's generation. Supplemental Energy shall be calculated hourly, and shall be the lesser of:

1. The Supplemental Capacity for which the customer has contracted, or
2. The Supplemental Capacity for which the customer has contracted less generation output above the Standby capacity for which the customer has contracted (as defined in the Standby Service Rider), but not less than zero.

(Continued on Sheet No. 5-110)

AVAILABILITY

Available to any non-residential customer who has an alternative source of electric energy supply which has an output that is variable and dependent on the thermal load characteristics of the customer and, therefore, serves all or a portion of the customer's electrical load requirements for a portion of the time and who requires use of the Company's electric service for supply of energy at other times. The normal expectation of this Rider is that the customer will contract for the firm portion of their backup supply from the Company under the Standby Service Rider and will contract for the interruptible and variable portion under this Rider. Each customer request for service under this Rider will be evaluated on a customer specific basis to determine eligibility. Under this service, the Company will provide a permanent service connection to supply the customer's contracted load in accordance with the provisions in the General Rules and Regulations, Section 2.4.

RESERVATION FEES

Customer Charge per Month	$17.39	R
Demand Charge per Month per kW of Contracted Supplemental Service		
Secondary Voltage Service	$3.15	
Primary Voltage Service	$2.20	
Transmission Transformed Voltage Service	$1.40	
Transmission Voltage Service	$0.80	

USAGE RATES

Demand Charge per Month per kW of Supplemental Capacity Used. There will be no demand charge for capacity actually used under this Rider except if that capacity is used during one of the Company's peak controlled interrupt periods. In such case, the demand will be charged as described below.

Energy Charge per kWh of Supplemental Energy Used. Energy actually used under this Rider during acceptable time periods will be charged at the same energy rate as contained in the base tariff to which this Rider is attached except if that energy is used during one of the Company's energy controlled or peak controlled interrupt periods. In such case, the energy will be charged as described below.

(Continued on Sheet No. 5-109)

TERMS AND CONDITIONS OF SERVICE (Continued)

4. Company will not be obligated to supply Supplemental Service to backup a customer's generator at a level in excess of the Supplemental Capacity for which customer has contracted. This restriction in no way limits the amount of load for which a customer may require service from the Company under the base tariff to which this Rider is attached.

5. Customer will be liable for all damages allowed by law to the extent caused by customer's use of Supplemental power in excess of contracted Supplemental Capacity.

6. Company will require customer to contract for additional Supplemental Capacity if the customer exceeds the contract amounts in any three of the preceding 12 months.

7. Customer will annually furnish documentation to Company confirming the maximum capacity and reliability of the power source for which customer requires Supplemental Service. Company and customer will review actual output and performance of the power source relative to the capacity nominated for Supplemental Service in the Electric Service Agreement. If this review shows a significant and consistent shortfall between the power source's actual performance and the nominated capacity due to factors reasonably within customer's control, Company will notify customer of its intent to refuse to provide Supplemental Service. Upon receipt of such notice, customer may agree to reduce the Supplemental Service nomination in its Electric Service Agreement or to take such action as necessary to operate the power source at or reasonably near the nominated Supplemental Service Capacity. If customer's power source does not operate at or reasonably near that level during the 12 months immediately following Company's notice, Company may refuse to provide Supplemental Service until such time as customer agrees to reduce its Supplemental Service nomination or provide Company with documentation demonstrating the power source's actual performance at or reasonably near the nominated Supplemental Service for a trial period of three consecutive months.

8. Customer will remain on Supplemental Service for a period of not less than 12 months.

9. Customer will be allowed to take Supplemental Energy from the Company at any time, up to the maximum contracted level of Supplemental Demand, without incurring any usage demand charges except during the periods listed below.

(Continued on Sheet No. 5-112)

TERMS AND CONDITIONS OF SERVICE

1. This Supplemental Service Rider is applicable to any non-residential customer who requires 40 kW or more of backup capacity from the Company. Supplemental Service may not be used by a customer to serve controllable demand that is subject to interruption as determined by the Company under the Company's controllable service schedules, however, customer will always be permitted to implement demand side load reductions or use alternative generation when necessary, due to full or partial outage of the customer's generator, instead of using Supplemental Service from the Company. The Company and customer will develop and attach to the Electric Service Agreement, a load control procedure for the customer that will clearly define the customer's demand side load reductions or alternative generation capacity use that, if achieved during control periods, will avoid any Supplemental Demand Usage Rate charges being incurred. This will specifically state that when customer has been notified that a peak control period has been initiated, in addition to any load reductions customer must make under the terms of the controllable load portion of the Electric Service Agreement, customer's demand served by Company must be reduced by an amount equal to the difference between actual generator output and contracted Supplemental Capacity. Additionally, the customer demand served by Company shall not increase during the peak control period. If customer fails at either of these requirements, customer will incur Supplemental usage charges as defined in Section 10 below. C

2. Customer will execute an Electric Service Agreement with the Company which will specify:
   a. Type of Standby Service elected by the customer under the Standby Service Rider and the base tariff that these Riders are attached to and under which demand and energy rates will be selected during months Standby and/or Supplemental power is used,
   b. The individual and total capacity requirements for which Company will be providing Standby and Supplemental power and to which the Reservation Fees apply, and
   c. The expected initial level of firm service the customer will take under their base tariff, even if that level is zero, as well as any expected changes in load over the term of the agreement.

3. The Company's meter will be ratcheted to measure the flow of power and energy from Company to customer only.

(Continued on Sheet No. 5-111)

TERMS AND CONDITIONS OF SERVICE (Continued)

11. In the event any portion of the capacity associated with the additional capacity costs or MAPP after-the-fact purchase costs incurred by the Company and attributable to the customer under Section 10 above are subsequently used to satisfy the Company's MAPP requirements for the Company's customers, the peak demand charges under Section 10 shall be discounted with respect to that portion subsequently used by the Company's customers.

12. The Company shall provide notice to the Supplemental Service customers when peak load conditions are expected to occur through the same means that the Company notifies interruptible customers of the potential interruption.

13. Company will install and charge customer for the metering necessary, as determined by the Company, to allow for proper billing of the separate base tariff, Standby Service Rider and Supplemental Service Rider demands. Customer shall reimburse the Company for the costs of installing, operating, and maintaining these meters and any other facilities required to serve the customer's Supplemental load. Such required additional equipment shall include the metering equipment used to measure the electrical output of the customers' alternative source of electric supply. In particular, the Company will install a meter that measures the flow of power and energy from the customer's own generating facility. If, as a result of the customer's construction and installation of their generating facility, it is more practical or economical for the customer to install some or all of the metering equipment required, customer may be permitted to do so subject to Company's approval of an installation plan for such equipment.

(Continued on Sheet No. 5-114)

TERMS AND CONDITIONS OF SERVICE (Continued)

10. In the event customer requires Supplemental Service during one of the Company's energy control periods, customer will pay for the Supplemental Energy used during the energy control period at the applicable control period energy rate as listed in Company's Energy Controlled Service tariff. In the event customer requires Supplemental Service during one of the Company's peak control periods, as defined in the Rules for Application of Peak Controlled Tiered Services and Peak Controlled Services (Closed), customer will pay for the Supplemental Energy used during the peak control period at twice the applicable control period energy rate as listed in Company's Energy Controlled Service tariff plus pay a fee of $10.00 per kW of maximum Supplemental Capacity used during the peak control period. However, if this use occurs at the times of Company's system peak hours in which the Company would have insufficient Accredited Capacity under the Mid-Continent Area Power Pool (MAPP) Agreement, if not for additional capacity purchases, and the Company incurs additional capacity costs as a result of such Supplemental Service used by customer, customer shall pay peak demand charges for the month in which such Supplemental Service use occurs and for each of the five succeeding months instead of the above listed demand charges and/or Reservation Fees. Such peak demand charges shall be based upon the following:

a. If customer has notified Company of the need to use Supplemental Service at least three hours prior to Company's system peak hour, such Supplemental Peak Demand charges shall be based on one-sixth of any additional capacity costs incurred by the Company as a result of using Supplemental Service. Such additional capacity costs shall not include any MAPP after-the-fact capacity purchase costs incurred by the Company.

b. If customer has not notified the Company of any need for Supplemental Service at least three hours prior to the Company's system peak hour, such Supplemental Peak Demand charges shall be based on one-sixth of any additional capacity costs or MAPP after-the-fact purchase costs incurred by the Company as a result of using Supplemental Service. The demand for billing purposes for the succeeding five months shall be equal to the Supplemental Demand placed on the system during the time of the Company's system peak hour.

(Continued on Sheet No. 5-113)

AVAILABILITY

Availability is restricted to customers who were taking service on the Energy Controlled Service (Closed) tariff on or before March 31,1994.

RATE

The rates and provisions of Tier 1 of the Peak Controlled Tiered Time of Day Service schedule shall apply except that the on peak and off peak energy charges for secondary voltage are replaced as follows:

Energy Charge per kWh		
Firm On Peak Period Energy	$0.038707	R
Firm Off Peak Period Energy	$0.028243	R
Controllable On Peak Period Energy	$0.036088	R
Controllable Off Peak Period Energy	$0.027261	R
Control Period Energy	$0.054090	

PROPERTY TAX ADJUSTMENT

The above energy charge includes a $0.000429 / kWh reduction, to reflect a property tax change.

TERMS AND CONDITIONS OF SERVICE

1. Customers choosing service under this rider are restricted to the Standard PDL (predetermined demand level) option, agreeing to a fixed demand level and limiting load to that level during a control period.

2. Failure to Control Charge: Except as provided for under Control Period Energy Service described below, the following charges will apply in any month customer fails to control load to predetermined demand level:
   a. An additional charge of $10.00 per kW will apply during each Company specified control period to the amount by which customer's maximum adjusted demand exceeds their predetermined demand level, and
   b. The control period energy charge will apply to the energy used during the control period which is associated with the customer's controllable demand.

After three such customer failures to control load to their predetermined demand level, Company reserves the right to increase the predetermined demand level or remove customer from Tier 1 Energy Controlled Service Rider and apply the cancellation charge specified in customer's Electric Service Agreement.

3. The duration and frequency of interruption periods shall be at the discretion of Company. Interruption periods will normally occur at such times when:
   a. Company is required to use oil-fired generation equipment or to purchase power that results in equivalent production costs,
   b. Company expects a reasonable possibility of system load levels surpassing the level for which NSP has sufficient accredited capacity under the Mid-Continent Area Power Pool Agreement, including reserve requirements, or
   c. In Company's opinion, the reliability of the system is endangered.

(Continued on Sheet No. 5-116)

ADDITIONAL TERMS AND CONDITIONS FOR SCHEDULED MAINTENANCE

1. Supplemental Service customers shall schedule maintenance of their power source during qualifying scheduled maintenance periods.

2. Qualifying Scheduled Maintenance Periods

   Customers With 40 kW to 10,000 kW of Contracted Standby and Supplemental Capacity. Maintenance must occur within the calendar months of April, May, October, and November. Customer must provide Company with written notice of scheduled maintenance prior to the beginning of the maintenance period. C

   Customers With Greater Than 10,000 kW of Contracted Standby and Supplemental Capacity. Maintenance must occur at a time period mutually agreed to by Company and customer. These time periods will normally not include those times when Company expects system seasonal peak load conditions to occur, and at those times when Company is required to use oil-fired generation equipment or to purchase power that results in equivalent production costs. Customer shall provide an annual projection of scheduled maintenance to the Company. Customer shall be allowed changes or additions to this projection upon notice to the Company based on the following schedule:

Outage Length	Required Notice
Less than 48 hours	24 hours
2 days to 30 days	7 days
Over 30 days	90 days

3. The duration of qualifying scheduled maintenance periods may not exceed a total of six weeks in any 12 month period.

4. An additional charge shall apply if customer does not comply with all terms and conditions for qualifying scheduled maintenance periods. The additional charge shall be determined by calculating the additional charges which would have applied if customer were billed on the Unscheduled Maintenance Option for the period extending back to the customer's last scheduled maintenance period.

5. General Service or General Time of Day Service demand charges shall not apply to use during qualifying scheduled maintenance periods.

AVAILABILITY

Available to no more than five non-residential customers on an experimental basis for general service subject to provisions in the General Rules and Regulations, Section 2.5. Availability is restricted to customers with a minimum billing demand of 5,000 kW and average monthly load factor over a 12 month period of not less than 80%. The rate contemplates that this service will utilize existing facilities with no additional major expenditures. This experimental rate is available for a period of two years. After the two year experimental period, NSP will conduct a study to review the effectiveness of this rider. With the Commission's approval, NSP may offer this rider to the commercial and industrial customers permanently after the two year experimental period. All provisions of regular service schedules continue to apply except as indicated in this Rider.

RATE

The applicable retail energy charge.

DETERMINATION OF DEMAND

Base Demand level shall be specified and agreed to by the customer and Company. Customer's contracted base demand level must not be greater than 125% of the annual maximum demand.

ncremental Demand shall be determined by subtracting the actual demand from the contracted base demand.

DETERMINATION OF DEMAND FREE POWER ENERGY

The maximum demand free power energy supplied in any billing month shall be the contracted incremental demand times 20.

TERMS AND CONDITIONS OF SERVICE

1. Experimental Demand Free Power Service Rider will apply to any customer who requires 1,000 kWh or more of energy from Company each time the Rider is exercised during designated period.

2. Customer must maintain at least 90% lagging power factor during the term of the agreement.

3. Customer will execute an Electric Service Agreement with Company which will specify:
   a. Base demand level,
   b. Incremental demand,
   c. Monthly maximum demand free power energy, and
   d. Annual maximum demand.

(Continued on Sheet No. 5-118)

TERMS AND CONDITIONS OF SERVICE (Continued)

4. Customer's Electric Service Agreement with Company will include a maximum of 300 hours of interruption per year.

5. All other provisions of Tier 1 of the Peak Controlled Tiered Time of Day Service schedule not in conflict with the Tier 1 Energy Controlled Service Rider shall apply.

CONTROL PERIOD ENERGY SERVICE

AVAILABILITY

Available to Tier 1 Energy Controlled Service Rider customers for supply of controllable demand related energy during control periods. The control period energy charge will apply when the Company is required to use oil-fired generation equipment or to purchase power that results in equivalent production costs. Control Period Energy Service will not be available when Company expects system peak load conditions or during system emergencies.

RATE

The control period energy charge will apply to all controllable demand related energy used during the control period.

TERMS AND CONDITIONS OF SERVICE

1. Control Period Energy Service will be available provided such service will not adversely affect firm service to any customer.

2. Company reserves the right to refuse or control the supply of Control Period Energy Service if its capacity is not adequate to furnish such service.

3. All other provisions of the Tier 1 Energy Controlled Service Rider not in conflict with Control Period Energy Service shall apply.

4. Company notice of commencement of control period will include notice of availability of Control Period Energy Service.

AREA DEVELOPMENT RIDER

Section No. 5
Original Sheet No. 119
Relocated from MPUC No. 1 Sheet No. 5-26

AVAILABILITY

Available to new or existing demand metered customers located in Area Development Zones whose proper Standard Industrial Classification (SIC) is manufacturing or wholesale trade and who qualify for other development incentives offered by local government entities. The availability of this Rider is limited to specific Area Development Zones that meet the criteria listed below as set forth by the Commission.

ZONE DESIGNATION

Area Development Zones in the seven county Twin Cities' metropolitan area (Anoka, Carver, Dakota, Hennepin, Ramsey, Scott, and Washington Counties) must be located within one of the cities lying within the "Fully Developed Area" as classified by the Metropolitan Council in the document entitled "Metropolitan Development and Investment Framework (December 1988)" that has experienced a decline in combined employment in manufacturing and wholesale trade between 1980 and the most recent year for which data are available as published by the Minnesota Department of Economic Security. Eligible communities are Bloomington, Columbia Heights/Hilltop, Crystal, Fridley, Golden Valley, Hopkins, Minneapolis, New Brighton, Roseville, South St. Paul, St. Louis Park, and St. Paul. Area Development Zones in cities located outside the seven county Twin Cities' metropolitan area must be located in a city with a minimum population of 25,000 based on the most recent U.S. Census of Population and must be located in a county (or counties) that have experienced a decline in combined employment in manufacturing and wholesale trade between 1987 and the most recent year for which data are available as published by the Minnesota Department of Economic Security. The Area Development Zone must be an existing or proposed industrial park with a minimum size of ten acres. The maximum total number of active zones at any time is 18; the maximum number of active zones in the seven county Twin Cities' metropolitan area is 15. The maximum number of active zones in any community is three. A zone can be "decertified" and a new Area Development Zone established at any time as long as there are no more than three Area Development Zones in a community at any point in time.

RATE

The rates and provisions of the customer's regular rate schedule shall apply except monthly demand charges for customer's Qualified Billing Demand shall be reduced as follows:

Years	Percent Reduction
1 - 3	50%
4	30%
5	20%
6	0%

(Continued on Sheet No. 5-120)

TERMS AND CONDITIONS OF SERVICE (Continued)

4. Demand free power may not be available during Company designated system high load period or system emergency.

5. Customer must request from Company the use of demand free power, the time its to be used and its duration at least 24 hours in advance. Shorter notices may be available at Company's discretion.

6. Company will confirm the schedule of demand free power to the customer as soon as possible after the customer request is made. Confirmed schedules may be canceled during Company designated system high load period or system emergency.

7. Customer will annually furnish documentation to Company confirming the base demand level established is still valid. Company will adjust customer's base demand level upward if customer's load growth is confirmed over a 12 month period.

ENERGY EFFICIENCY

For service taken on this Rider, the Company will conduct an energy audit and inform the customer of the conservation programs available from the Company.

ELECTRIC SERVICE AGREEMENT

Any customer taking service under this Area Development Rider shall execute an Electric Service Agreement, or amend their existing Electric Service Agreement, with the Company for a period of six years beginning on the effective date on which the customer commences taking service under this Rider; however, customers who began service under the Pilot Area Development Rider before June 28, 1995, with Electric Service Agreement terms of five years, will not be required to amend or modify those agreements. Such Electric Service Agreements (new or amended) shall state the increased or new load level of the customer as well as the customer's obligation to continue to purchase all of their electric power and electric energy from the Company during the term of the agreement.

QUALIFIED BILLING DEMAND

The portion of the customer's billing demand which qualifies for reduced demand charges.

New Customers. The total billing demand of new customers shall be defined as Qualified Billing Demand.

Existing Customers. The billing demand in excess of customer's base billing demand shall be defined as qualified billing demand. The base billing demand for each month will be calculated by averaging the monthly billing demands from the two year period immediately preceding the customer's application for this Rider.

NEW CUSTOMERS

To be considered a new customer for the purpose of this Rider, an applicant must demonstrate one of the following:

1. That business has not been conducted at the premises for at least three monthly billing periods prior to application,
2. That the predecessor customer is in bankruptcy and the applicant has obtained the business in a liquidation of assets sale,
3. Customer's activities are largely or entirely different in nature from that of the previous customer, or
4. If the activities are not so different, that the owner(s), operator(s), or manager(s) are substantially different.

EXISTING CUSTOMERS

Existing customers who materially increase their use of electric service may qualify for service under this Rider, provided such material increase is the result of the addition of equipment, or expansion of the customer's facility or operations. The customer shall notify the Company in writing and document the basis for the material increase in its use of electric service. Following such notification, the Company will review the customer's monthly billing demands. If the billing demands for each of the next three consecutive months exceed that from the comparable monthly period of the preceding year by at least 25%, the customer will be eligible thereafter to receive service under this Rider.

RIGHT TO REFUSE SERVICE

The Company reserves the right to refuse applicants for service under this Rider if it determines that significant additional capital expenditures will be required to provide service to that applicant. In such cases, an applicant may be able to qualify for service by making a non-refundable contribution to compensate for the significant additional capital costs incurred by the Company to supply service to the applicant.

(Continued on Sheet No. 5-121)

TERMS AND CONDITIONS OF SERVICE (Continued)

5. A rate under this Rider shall meet the conditions of Minnesota Statutes, Section 216B.03, Reasonable Rate, for other customers in this same customer class.

6. Unless the Commission determines that it would be in the public interest, a rate under this Rider shall not compete with district heating or cooling provided by a district heating utility defined by Minnesota Statutes, Section 216B.166, Subdivision 2, Paragraph (c).

7. A rate offered under this Rider may not be offered to a customer in which the Company has a financial interest greater than 50%.

REGULATORY REVIEW

The rate offered under this Rider will be effective on an interim basis after filing by Company of the proposed rate with the Commission and upon the date specified in the Electric Service Agreement. If the Commission does not approve the rate, Company may seek to recover the difference in revenues between the interim competitive rate and the standard tariff from the customer who was offered the competitive rate.

The Commission has the authority to approve, modify, or reject a rate under this Rider. If the Commission approves the competitive rate, it becomes effective as agreed to by the Company and customer. If the competitive rate is modified by the Commission, the Commission shall issue an order modifying the competitive rate subject to the approval of the Company and the customer. Each party has ten days in which to reject the proposed modification. If no party rejects the proposed modifications, the Commission's order becomes final. If either party rejects the Commission's proposed modifications, the Company on its behalf or on the behalf of the customer, may submit to the Commission a modified version of the Commission's proposal. The Commission shall accept or reject the modified version within 30 days. If the Commission rejects the competitive rate, it shall issue an order indicating the reasons for the rejection.

COMPETITIVE SERVICE RIDER

AVAILABILITY

Available at Company's discretion to commercial and industrial customers that have electric service requirements which are subject to effective competition. Effective competition exists if a customer is located in Company's service territory and has the ability to obtain its energy requirements from an energy supplier not rate regulated by the Minnesota Public Utilities Commission.

RATE

Standard service rate provisions apply except the level of the demand and/or energy charges may be decreased for each customer based on a consideration of customer's load characteristics and lowest cost competitive energy supply.

TERMS AND CONDITIONS OF SERVICE

1. Customer must provide Company with information which documents that customer is not likely to take service provided by any other electric tariff available from Company.

2. Minimum load served under this Rider is 500 kW.

3. Customer must execute an Electric Service Agreement with Company which will include:
   a. The minimum rate under this Rider, which will recover at least the incremental cost of providing service, including the cost of incremental capacity that is to be added while the rate is in effect and any applicable on peak or off peak differential,
   b. The maximum possible rate reduction possible under this Rider, which will not exceed the difference between the standard tariff and the cost to the customer of the lowest cost competitive energy supply,
   c. The term of service under this Rider, which must be no less than one year and no longer than five years,
   d. The size of the load served under this Rider,
   e. An annual minimum charge to fully recover distribution costs, and
   f. Verification that customer has been fully informed of the availability of energy audits. If no energy audit is performed for customer, an explanation of why an energy audit was not necessary will be included.

4. The Company, within a general rate case, is allowed to seek recovery of the difference between the standard tariff and this Rider times the usage level during the test year period.

(Continued on Sheet No. 5-123)

ENERGY EFFICIENCY

For service taken on this Rider, the Company will conduct an energy audit as provided for in its demand side management program, and inform the customer of the conservation and load management programs available from the Company.

REGULATORY REVIEW

The Commission has the authority to approve, modify, or reject a rate developed under this Rider. Therefore, application of the rate agreed to between the Company and a customer under this Rider is subject to Commission approval.

AVAILABILITY

Available at Company's discretion to demand metered controlled service customers that have electric service requirements which qualify under the Competitive Market Conditions described below.

RATE

Controllable service rate provisions apply except the level of the demand and/or energy charges may be discounted for qualified customers.

QUALIFIED BILLING DEMAND AND/OR BILLED ENERGY

The portions of the customer's billing demand and/or billed energy as described below which qualify for discounted charges.

New Customers. The total billing demand and/or billed energy of new customers may be defined as qualified for discounted charges.

Existing Customers. The billing demand and/or billed energy in excess of customer's base billing demand and/or base billed energy may be defined as qualified for discounted charges. The base billing demand and/or base billed energy for each month will be determined by considering the billing demands and/or billed energy for a representative period preceding the application of this Rider.

COMPETITIVE MARKET CONDITIONS

Rate discounts will be determined individually and specified in an Electric Service Agreement with the customer for customers who meet the following qualifications:

1. The market for customer's energy requirements is competitive. Customer must provide evidence of the competitive nature of the market for its electric energy requirements which at a minimum would include one of the following:
   a. The existence of direct competitor(s) in customer's own product/service market who obtain electric energy from another utility at a lower cost than NSP's comparable electric service, or
   b. The existence of a directly substitutable energy source.

2. Customer's production process is energy intensive. Customer must provide evidence that its electric energy costs are at least 10% of their total production costs.

3. Customer will make new capital investments in production equipment which uses electricity as its primary energy source in an amount equal to or greater than $750.00 per kW of qualified billing demand.

(Continued on Sheet No. 5-125)

RESOURCE ADJUSTMENT
Bills are subject to the adjustments provided for in the Fuel Clause Rider and in the Conservation Improvement Program Adjustment Rider and the State Energy Policy Rate Rider. N

SURCHARGE
In certain communities, bills are subject to surcharges provided for in a Surcharge Rider.

LATE PAYMENT CHARGE
Any unpaid balance over $10.00 is subject to a 1.5% late payment charge or $1.00, whichever is greater, after the date due. The charge may be assessed as provided for in the General Rules and Regulations, Section 3.5.

TERMS AND CONDITIONS OF SERVICE
1. Tier 1 Peak Controlled Schedule L Interruption Rider will apply each time the rider is exercised by a customer during a designated billing period.

2. Customers choosing service under this rider are restricted to the Tier 1 and Standard PDL options of the Peak Controlled Tiered Service or Peak Controlled Tiered Time of Day Service rate schedules. Any rider otherwise available to the customer not in conflict with this rider shall also be available to the customer.

3. Failure to control charges do not apply to customers on this rider requesting Company supply of energy during peak control periods. All other provisions of Tier 1 of the Peak Controlled Tiered Service and Peak Controlled Tiered Time of Day Service rate schedules not in conflict with this rider shall apply.

4. The duration and frequency of interruption periods shall be at the discretion of Company. Interruption periods will normally occur when Company expects a reasonable possibility of system load levels surpassing the level for which NSP has sufficient accredited capacity under the MAPP Agreement, including reserve requirements, or when in Company's opinion the reliability of the system is endangered.

5. The customer shall provide to Company a threshold price for energy under MAPP Schedule L below which customer shall automatically purchase energy instead of being interrupted. Above that threshold level, Company shall notify customer of the price in advance for customer to determine their willingness to purchase. Advance notification and Peak Control Period Schedule L Energy arrangement under this rider shall be via telephone, facsimile, or other electronic communication device as specified in the customer's Electric Service Agreement. All costs for the equipment necessary to accomplish these notifications and arrangements shall be paid for by the customer.

(Continued on Sheet No. 5-128)

AVAILABILITY

Availability is restricted to customers who are taking Peak Controlled Tiered Service or Peak Controlled Tiered Time of Day Service. Customers choosing service under this rider are restricted to the Tier 1 and Standard PDL (predetermined demand level) options and shall agree to allow the Company to interrupt customer's load to a predetermined level within 10 minutes notice whenever required by Company during a peak control interrupt period or in emergency situations. Availability is also restricted to customers with a minimum controllable demand of 3,000 kW. Participation is limited to 100,000 kW of controllable demand. Participation limits may be exceeded if part of a customer's controllable load is within the participation limit, subject to Company approval.

CONTRACT

Customers must contract for this service rider through an electric service agreement with Company. Contract period will normally be for 24 months. Customer's controllable demand also requires certification as defined in MAPP's (Mid-Continent Area Power Pool) Certified Interruptible Demand certification process.

RATE

Peak Control Period Schedule L

Energy Charge per kWh

Secondary Voltage Service	MAPP Schedule L Energy Rate Plus $0.0013	R
Primary Voltage Service	MAPP Schedule L Energy Rate Plus $0.0008	R
Transmission Transformed Voltage Service	MAPP Schedule L Energy Rate Plus $0.0004	
Transmission Voltage Service	MAPP Schedule L Energy Rate	

MAPP Schedule L Energy Rate is the composite energy rate per kWh determined under MAPP Service Schedule L, Interruptible Load Replacement Energy Service.

DETERMINATION OF PEAK CONTROL PERIOD SCHEDULE L ENERGY

For each control period in which customer has arranged in advance with Company for the supply of controllable demand-related energy, the Peak Control Period Schedule L Energy in kilowatt-hours shall be the customer's contracted Certified Interruptible Demand in kilowatts times the duration of Company's declared Schedule L peak control period in hours.

(Continued on Sheet No. 5-127)

APPLICABILITY
Applicable to bills for electric service provided under the Company's retail rate schedules in a City requesting or ordering the installation of non-standard underground Distribution Facilities. The Excess Expenditure costs for these Special Facilities are to be collected from customers located within such City in accordance with the provisions in the General Rules and Regulations, Section 5.3, SPECIAL FACILITIES. N

RATE
In each applicable City, there shall be included in the monthly minimum billing on each customer's bill a separately itemized surcharge line item determined in accordance with this Rider entitled City Requested Special Facilities. The City Requested Special Facilities Surcharge shall not be subject to current month billing adjustments or City surcharges and shall be subject to any applicable sales taxes.

DETERMINATION OF CITY REQUESTED FACILITIES SURCHARGE
The City Requested Special Facilities Surcharge for each applicable City project shall be calculated by determining a Class Facilities Surcharge to be applied to the Average Monthly Customers in the designated City such that the total Excess Expenditure plus carrying charges in the City Project Tracker Account are recovered over the designated Recovery Period.

Average Monthly Customers shall be the projected average number of active customers in each applicable customer classification located in the City for the designated Recovery Period.

Class Facilities Surcharge shall be the surcharge amount for each applicable customer classification determined in accordance with the Rules for Application.

City Project Tracker Account is a regulatory asset account representing the sum of the following:

(1) The total Excess Expenditures for each Distribution Facilities undergrounding project in such City,

(2) Monthly carrying charges on the under recovered or over recovered monthly balance in the City Project Tracker Account based on the overall rate of return from the Company's most recent electric general rate case decision,

(3) Less the recovered project costs collected to date through the applicable City's Facilities Surcharge.

Recovery Period is the number of months the City Requested Special Facilities Surcharge shall be applied to bills for a designated City project determined in accordance with the Rules for Application.

Excess Expenditures shall be determined in accordance with the provisions in the General Rules and Regulations, Section 5.3. N

(Continued ion Sheet No. 5-132)

TERMS AND CONDITIONS OF SERVICE (Continued)

6. Unless customer has arranged with Company in advance for the supply of controllable demand related energy during the control period, upon 10 minute notification from the Company, customer's controllable load shall be curtailed via Company initiated automatic control for a duration as required by the Company.

7. Customers taking service under this rider will require certification of the controllable demand level for each MAPP season in compliance with the MAPP Schedule L requirement. Customer will cooperate fully and assist in the preparation of the information necessary for the certification filing to MAPP.

RULES FOR APPLICATION (Continued)

6. The Class Facilities Surcharges may be adjusted annually and in the last 6 months of the Recovery Period to more closely recover the balance remaining in the City Project Tracker Account. N

7. Subject to the limits on monthly surcharge amounts set forth above, the Class Facilities Surcharges may also be increased at any time, with notice as provided in Section 5.3 of the General Rules and Regulations, in order to recover Excess Expenditures associated with additional Distribution Facilities undergrounding projects requested or ordered by City. N

RULES FOR APPLICATION

1. The Recovery Period shall not commence until the City Requested Facilities Surcharge to be applied to bills is at least $0.25 per customer per month. A surcharge of $0.25 up to and including $1.00 per customer regardless of customer class may be applied for a Recovery Period of exactly one month (e.g., a one-time surcharge). N

2. For a Recovery Period greater than one month, the Class Facilities Surcharge per month per customer in each non-residential customer class for any month in which a Residential Class Facilities Surcharge is applicable shall be as follows:

   a. Commercial & Industrial (C&I), Street Lighting and Municipal – Non-Demand Billed: Equal to the Residential Class Facilities Surcharge.

   b. Small C&I and Small Municipal – Demand Billed: Three times the Residential Class Facilities Surcharge.

   c. Large C&I – Demand Billed: Four times the Residential Class Facilities Surcharge.

   However, whenever the Non-residential Class Facilities Surcharges to be billed exceed the Customer Charge applicable on a customer account, the Class Facilities Surcharge for that account shall be equal to such Customer Charge.

3. A Residential Class Facilities Surcharge of $0.25 up to and including $1.00 per Residential customer per month will be applied each month whenever the City Project Tracker Account balance to be collected allows for a Recovery Period of 36 months or less.

4. A Residential Class Facilities Surcharge of over $1.00, up to and including $4.50, per Residential customer per month will be applied each month for a Recovery Period of 36 months whenever the City Project Tracker Account balance is uncollectable at a Residential Class Facilities Surcharge level of $1.00 or less, provided that the surcharge amount for any Residential class customer account receiving a Low Income Energy Discount shall not exceed $1.00 per month.

5. A Residential Class Facilities Surcharge of $4.50 per Residential customer per month for a Recovery Period of 36 months up to and including 60 months will be applied only when necessary to recover the City Project Tracker Account balance, provided a surcharge of $4.50 may be collected pending Commission action on a Company petition or City complaint to modify the design of the rate surcharge for a specific project which cannot be recovered in 60 months. N

(Continued on Sheet No. 5-133)

N

AVAILABILITY

This rider is available on a voluntary basis and is limited to customers who are eligible for the Western Area Power Administration ("Western" or "WAPA") Bill Crediting Program.

TERM OF SERVICE

Service under this rider shall be for a period not less than 90 days.

PRICING METHODOLOGY

The WAPA Bill Credit shall be calculated as specified in the Commission approved Bill Crediting Agreement between the customer and the Company.

BILL DETERMINATION

The WAPA Bill Credit will be applied to the customer's standard monthly bill rendered after each monthly billing period.

SPECIAL PROVISIONS

1. Eligibility for the Program, and thus this Rider, is determined by the customer and Western, and not by Xcel Energy.

2. If there is a change in the legal identity of the customer receiving service under this Rider, credit under this Rider shall be terminated unless Xcel Energy, Western and the customer determine otherwise.

3. Changes are subject to the Agreement for Bill Crediting arrangements between Xcel Energy, Western and the customer, a copy of which is contained in Section 7 of this Electric Rate Book.

RULES AND REGULATIONS

Service under this Rider is subject to orders of the Minnesota Public Utilities Commission and to the General Rules and Regulations section of this Electric Rate Book.

N

AVAILABILITY

Available to any customer who elects to apply an adjustment to blocks of electric energy usage to contribute to the development of renewable and high-efficiency energy resources. N

RIDER

Voluntary Renewable Adjustment must be elected in blocks of 100 kWh up to customer's average monthly metered electric energy use per month. The Adjustment will add $2.00 per 100 kWh block elected per billing month. This charge of $2.00 per 100 kWh block shall be applied as an adjustment to customer's bill under the standard retail tariff each billing month according to the number of energy block(s) purchased. The customer may nominate renewable energy in 100 kWh blocks up to their average monthly usage based on the prior twelve months of usage. This Adjustment is not subject to Fuel Clause Rider but is subject to Conservation Improvement Program (CIP) Adjustment, any other applicable adjustments and surcharges including city surcharge, or sales tax. The Voluntary Renewable Adjustment will appear on the bill as "Windsource Program." Amounts collected pursuant to the Adjustment will be expended on a program, filed with the Commission, to develop renewable and high efficiency energy resources. The Adjustment charge does not represent the purchase of 100 kWh blocks of renewable energy.

TERMS AND CONDITIONS OF SERVICE

1. The minimum subscription and to be billed each month is one 100 kWh block. Residential customers must agree to be on the program for a minimum of 12 consecutive months. For non-residential customers the minimum subscription period is three years. After the minimum period customer could continue month to month thereafter or terminate the subscription with 30 days notice.

2. In the event customer's metered energy use is lower than the subscribed energy blocks, the additional charge of the last 100 kWh block will be prorated accordingly. For customers on time of day tariffs the prorates are based on total on-peak and off-peak kWh use in similar manner.

3. The discounts under Residential Controlled Air Conditioning and Water Heating Rider and Commercial and Industrial Controlled Air Conditioning Riders are not applicable to the charges under this Rider.

4. The Company will maintain accounting of the monthly balance of total revenues collected under the Adjustment and the expenses associated with offering this Adjustment, including the renewable energy purchases, marketing and other costs for this program. The Company will submit reports to the Commission each May 1, or as otherwise ordered in relation to the tracker accounting.

5. This Rider is provided to satisfy the conditions of Minnesota Statutes, Chapter 216B.169, subd.2 related to renewable and high-efficiency energy rate options. The sales arrangements of renewable energy from the Windsource program supplies are such that the power supply is sold only once to retail customers. N

APPLICATION

Applicable to bills for electric service provided under the Company's retail rate schedules. N

RIDER

There shall be included on each customer's monthly bill a State Energy Policy Rate Rider which shall be the applicable State Energy Policy Rate Rider factor multiplied by the customer's monthly kWh electric consumption.

DETERMINATION OF STATE ENERGY POLICY RATE FACTOR

The applicable State Energy Policy Rate Rider shall be the quotient obtained by dividing the annual State Energy Policy Tracker amount by the annual forecasted kWh sales. The factor may be adjusted annually with approval of the Minnesota Public Utilities Commission.

Residential	$0.000156 per kWh
Commercial	$0.000156 per kWh

Recoverable State Energy Policy Rate Expense

All costs appropriately charged to the State Energy Policy Tracker account shall be eligible for recovery through this Rider, and all revenues received from the State Energy Policy adjustment portion of the Resource Adjustment shall be credited to the State Energy Policy Tracker account. N

APPLICATION

N

Applicable to bills for electric service provided under the Company's retail rate schedules.

RIDER

There shall be included on each customer's monthly bill an Environmental Improvement Rider (EIR) adjustment. For all but demand-billed customers, the adjustment shall be the Full EIR Energy Adjustment Factor multiplied by the customer's monthly billing kWh for electric service. For demand-billed customers, the adjustment shall be the Reduced EIR Energy Adjustment Factor multiplied by the customer's monthly billing kWh for electric service, plus the EIR Demand Adjustment Factor multiplied by the customer's monthly kW billing demand. These EIR adjustments shall be calculated before city surcharge and sales tax.

DETERMINATION OF EIR ADJUSTMENT FACTORS

The Full EIR Energy Adjustment Factor shall be the quotient obtained by dividing the forecasted balance of the EIR Tracker Account by the forecasted retail sales for the calendar year. The Reduced EIR Energy Adjustment Factor shall be the Full EIR Energy Adjustment Factor multiplied by 50%. The EIR Demand Adjustment Factor shall be the difference between the Full and Reduced factors, multiplied by the class load factor of 52.5% and multiplied by 730 hours in an average month. All factors shall be rounded to the nearest $0.00001 per kWh. The EIR Adjustment Factors may be adjusted annually with approval of the Minnesota Public Utilities Commission (Commission). The EIR Adjustment Factors shall apply to bills rendered on and after January 1st of the year.

Recoverable EIR Costs shall be the annual revenue requirements associated with emissions reduction projects (a) not recovered through base rates, (b) recorded in the EIR Tracker Account for the designated period, and (c) determined by the Commission to be eligible for recovery under this Rider pursuant to the terms of the Settlement Agreement approved by the Commission on March 8, 2004. A standard model will be used to calculate the total forecasted revenue requirements for eligible projects for the designated period. All costs appropriately charged to the EIR Tracker Account shall be eligible for recovery through this Rider, and all revenues recovered from the EIR Adjustment shall be credited to the EIR Tracker Account.

Forecasted retail sales shall be the estimated retail electric sales for the designated recovery period.

TRUE-UP

For each 12-month period ending December 31, a true-up adjustment to the EIR Tracker Account will be calculated reflecting the difference between the EIR Adjustment recoveries and the revenue requirements for such period. The true-up adjustment shall be calculated and recorded by no later than May 1 of the following calendar year and will be included in calculating the EIR Adjustment Factor for each customer group effective with the start of the next designated recovery period. No carrying cost shall be applied. N

SCHEDULE 1. IDENTIFICATION

SURVEY CONTACTS: Persons to contact with question about this form

RESPONSE DUE DATE: Please submit by April 30th following the close of calendar year

Contact Name

First: Alyssa   Last: Pogue

Title: Financial Analyst

Telephone: 612 330 7920 Ext: FAX: 612 330 6542   Email: alyssa.r.pogue@xcelenergy.com

REPORT FOR: Northern States Power Co   13781

REPORTING PERIOD: 2003

Supervisor Name

First: Jacqueline   Last: Reecy

Title: Director of External Reporting

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1	Legal Name of Industry Participant	Northern States Power Co Submission Status/Date: Re-Submitted 05/06/2004
2	Current Address of Principal Business Office	ATTN: Alyssa Pogue 414 Nicollet Mall Minneapolis MN 55401
3	Preparer's Legal Name Operator (if different than line 1)	
4	Current Address of Preparer's Office (if different than line 2)	
5	Type of Ownership and Function	☐ Federal ☐ Political Subdivision ☐ Municipal Marketing Authority ☐ Cooperative ☐ Independent Power Producer or Qualifying Facility ☐ State ☐ Municipal ☒ Investor-Owned ☐ Power Marketer (or Energy Service Provider)

REPORT FOR: Northern States Power Co   13781

REPORT PERIOD ENDING: 2003

SCHEDULE 2, PART A. GENERAL INFORMATION

7610.0600 Item F – Annual Electric Utility Report

Following is Xcel Energy's 2003 Federal Form EIA-861.

REPORT FOR: Northern States Power Co 13781

REPORT PERIOD ENDING: 2003

SCHEDULE 2, PART A. GENERAL INFORMATION

LINE NO.		
1	North American Electric Reliability Council (Check all the Regional Councils in which your Organization conducts operations)	[ ] ECAR [ ] MAAC [ ] NPCC [ ] WSCC [ ] ERCOT [ ] MAIN [ ] SERC [ ] FRCC [x] MAPP [ ] SPP
2	(For EIA Use Only) Identify the North American Electric Reliability Council where you are physically located	MAPP
3	Enter Control Area Operator(s) Responsible for Your Oversite	Northern States Power Co 13781
4	Did Your Company Operate Generating Plants(s)?	[x] Yes [ ] No
5	Identify The Activities Your Company Was Engaged In During The Year (Check were appropriate)	[x] Generation from company owned plant [x] Transmission [x] Buying transmission services on other electrical system [x] Distribution using owned/leased electric wires [ ] Buying distribution on other electrical system [x] Wholesale power marketing [x] Retail power marketing [x] Bundled Services (electricity plus other services)
6	Highest Hourly Electrical Peak System Demand	Summer (Megawatts): 7,834 Winter (Megawatts): 5,994
7	Did Your Company Operate Alternative-Fueled Vehicles During the Year? or Does Your Company Plan to Operate Such Vehicles During the Coming Year?	[x] Yes [ ] No
	If "Yes", Please Provide Additional Contact Information	Name: Rob Streeter Title: Fleet Asset Consultant Telephone: 612 - 630 - 4704 Fax: - - Email:

REPORT FOR: Northern States Power Co 13781

REPORT PERIOD ENDING: 2003

SCHEDULE 2. PART B ENERGY SOURCES AND DISPOSITION					
	ENERGY SOURCES	MEGAWATTHOURS		DISPOSITION OF ENERGY	MEGAWATTHOURS
1	Net Generation	36,086,341	11	Retail Sales to Ultimate Consumers	34,145,453
2	Purchases from Electricity Suppliers	12,164,524	12	Sales For Resale	12,953,701
3	Exchanged Received (In)	167,517	13	Energy Furnished Without Charge	
4	Exchanged Delivered (Out)	19,899	14	Energy Consumed By Respondent Without Charge	41,233
5	Exchanged Net	147,618	15	Energy Consumed By Facility (Independent Power Producer or Qualifying Facility)	
6	Wheeled Received (In)	3,350,885			
7	Wheeled Delivered (Out)	3,273,616	16	Total Energy Losses	669,163
8	Wheeled Net	77,269			
9	Transmission by Others Losses (Negative Number)	-666,202			
10	Total Sources (sum of lines 1, 2, 5, 8 & 9)	47,809,550	17	Total Disposition (sum of lines 11, 12, 13, 14, 15 & 16)	47,809,550

REPORT FOR: Northern States Power Co 13781

REPORT PERIOD ENDING: 2003

SCHEDULE 2, PART C. CUSTOMER SERVICE PROGRAM

Green Pricing programs allow customers to purchase power generated from renewable resources and to pay for renewable energy development. Provide the number of customers in these programs by state and customer class.

Net Metering programs allow customers to sell excess power they generate back to the electrical grid to offset consumption. Provide the number of customers in these programs by state and customer class.

		NUMBER OF CUSTOMER BY CUSTOMER CLASS				
STATE	TYPE OF CUSTOMER SERVICE PROGRAM (a)	RESIDENTIAL (b)	COMMERCIAL (c)	INDUSTRIAL (d)	TRANSPORTATION (e)	TOTAL (d)
MN	Green Pricing	5,575				5,575
	Net Metering	53	1			54
	Green Pricing					
	Net Metering					
	Green Pricing					
	Net Metering					
	Green Pricing					
	Net Metering					
	Green Pricing					
	Net Metering					
	Green Pricing					
	Net Metering					
	Green Pricing					
	Net Metering					
	Green Pricing					
	Net Metering					

REPORT FOR: Northern States Power Co 13781

REPORT PERIOD ENDING: 2003

SCHEDULE 3. ELECTRIC OPERATING REVENUE

LINE NO.	TYPE OF OPERATING REVENUE OR COST	THOUSAND DOLLARS	
1	Electric Operating Revenue From Retail Sales To Ultimate Customers (Schedule 4, Parts A and B)	2,053,278	
2	Revenue From Unbundled (Delivery) Customers (Schedule 4, Part C)		
3	Electric Operating Revenue from Sale for Resale	148,087	
4	Electric Credits / Other Adjustments		
5	Other Electric Operating Revenue	277,066	
6	Total Electric Operating Revenue (sum of lines 1, 2, 3, 4 and 5)	2,478,431	

REPORT FOR: Northern States Power Co 13781

REPORT PERIOD ENDING: 2003

SCHEDULE 4, PART -A . RETAIL SALES TO ULTIMATE CUSTOMERS. FULL SERVICE - ENERGY AND DELIVERY SERVICE (BUNDLED)

STATE / TERRITORY	MN	RESIDENTIAL (a)	COMMERCIAL (b)	INDUSTRIAL (c)	TRANSPORTATION (d)	TOTAL (e)
Revenue (thousand dollars)		665173	751237	419773	0	1836183
Megatwatthours		8482572	12547929	9387479	0	30417980
Number of Customers		1038393	124846	611	0	1163850
STATE	ND					
Revenue (thousand dollars)		46571	53908	13474	0	113953
Megatwatthours		745836	1001057	323157	0	2070050
Number of Customers		73333	11835	26	0	85194
STATE	SD					
Revenue (thousand dollars)		43075	45878	14189	0	103142
Megatwatthours		549483	792481	315459	0	1657423
Number of Customers		63298	9353	22	0	72673
STATE						
Revenue (thousand dollars)						
Megatwatthours						
Number of Customers						
STATE						
Revenue (thousand dollars)						
Megatwatthours						
Number of Customers						

REPORT FOR: Northern States Power Co 13781

REPORT PERIOD ENDING: 2003

SCHEDULE 4, PART-B. RETAIL SALES TO ULTIMATE CUSTOMERS. ENERGY ONLY (WITHOUT DELIVERY SERVICE)

STATE / TERRITORY	RESIDENTIAL (a)	COMMERCIAL (b)	INDUSTRIAL (c)	TRANSPORTATION (d)	TOTAL (e)
Revenue (thousand dollars)					
Megatwatthours					
Number of Customers					
STATE					
Revenue (thousand dollars)					
Megatwatthours					
Number of Customers					
STATE					
Revenue (thousand dollars)					
Megatwatthours					
Number of Customers					
STATE					
Revenue (thousand dollars)					
Megatwatthours					
Number of Customers					
STATE					
Revenue (thousand dollars)					
Megatwatthours					
Number of Customers					

REPORT FOR: Northern States Power Co 13781

REPORT PERIOD ENDING: 2003

SCHEDULE 4, PART -C. RETAIL SALES TO ULTIMATE CUSTOMERS. DELIVERY ONLY SERVICE (AND ALL OTHER CHARGES)

STATE / TERRITORY	MN	RESIDENTIAL (a)	COMMERCIAL (b)	INDUSTRIAL (c)	TRANSPORTATION (d)	TOTAL (e)
Revenue (thousand dollars)		0	0	0	0	0
Megatwatthours		0	0	0	0	0
Number of Customers		0	0	0	0	0
STATE						
Revenue (thousand dollars)						
Megatwatthours						
Number of Customers						
STATE						
Revenue (thousand dollars)						
Megatwatthours						
Number of Customers						
STATE						
Revenue (thousand dollars)						
Megatwatthours						
Number of Customers						
STATE						
Revenue (thousand dollars)						
Megatwatthours						
Number of Customers						

[illegible]

REPORT FOR: Northern States Power Co 13781

REPORT PERIOD ENDING: 2003

SCHEDULE 5. DEMAND - SIDE MANAGEMENT INFORMATION

LINE NO.		
1	Do you have company administered Demand-Side Management Programs? (check Yes or No)	[x] Yes [ ] No
2	If your Demand-Side Management activities are reported on Schedule 5 of another company identify the company	

NOTE: If you answered "No" to line 1 or another Company Reports your Demand-Side Management Activities on their Schedule 5, do not complete the rest of this Schedule.

[illegible]

	ENERGY EFFICIENCY	RESIDENTIAL (a)	COMMERCIAL (b)	INDUSTRIAL (c)	TRANSPORTATION (d)	RESIDENTIAL (e)	COMMERCIAL (f)	INDUSTRIAL (g)	TRANSPORTATION (h)
3	Energy Effects (megawatthours)	6,820	39,924	195,827		264,[illegible]74	1,845,803	1,156,382	
4	Actual Peak Reduction (megawatts)	7	10	42		147	426	265	
	LOAD MANAGEMENT								
5	Energy Effects (megawatthours)	535	1,341	895		6,231	21,081	16,622	
6	Potential Peak Reduction (megawatts)	20	20	12		267	425		
7	Actual Peak Reduction (megawatts)	20	20	12		267	425		

[illegible]

8	Direct Cost - Energy Efficiency	29,219
9	Direct Cost - Load Management	7,259
10	Indirect Costs	5,530
11	Total Cost (sum of lines 8,9, and 10)	42,008

[illegible]

12	Have there been any major changes to your Demand-Side Management programs (e.g., terminated programs, new information or finacing programs or a shift to programs with dual load building objective and energy efficiency objectives), program tracking proceduers, program evaluation or reporting methods that impact the demand-side management data reported on this schedule? check Yes or No)	[ ] Yes [x] No
13	Does your company currently have a program to increase the amount of "price responsive" customer load, (i.e., load that responds dynamically to higher or lower prices for wholesome electricity)? (check Yes or No)	[ ] Yes [x] No
14	If the answer to line 13 is "Yes", please disclose the number of participating customer class. Residential: Commercial: Industrial: Other:	

REPORT FOR: Northern States Power Co 13781

REPORT PERIOD ENDING: 2003

SCHEDULE 6. DISTRIBUTION SYSTEM INFORMATION

If your company owns a distribution system, please identify the names of the counties(parish, etc.) by State in which the electric wire/equipment are located.

LINE NO.	STATE (US Postal Abbreviation) (a)	COUNTY (Parish, Etc.) (b)	LINE NO.	STATE (US Postal Abbreviation) (a)	COUNTY (Parish, Etc.) (b)
1	MN - Anoka		21	MN - Lyon	
2	MN - Benton		22	MN - McLeod	
3	MN - Blue Earth		23	MN - Meeker	
4	MN - Brown		24	MN - Mower	
5	MN - Carver		25	MN - Murray	
6	MN - Chippewa		26	MN - Nicollet	
7	MN - Chisago		27	MN - Nobles	
8	MN - Clay		28	MN - Norman	
9	MN - Dakota		29	MN - Olmsted	
10	MN - Dodge		30	MN - Pine	
11	MN - Douglas		31	MN - Pipestone	
12	MN - Faribault		32	MN - Polk	
13	MN - Freeborn		33	MN - Pope	
14	MN - Goodhue		34	MN - Ramsey	
15	MN - Hennepin		35	MN - Redwood	
16	MN - Houston		36	MN - Renville	
17	MN - Kandiyohi		37	MN - Rice	
18	MN - Lac Qui Parle		38	MN - Rock	
19	MN - Le Sueur		39	MN - Scott	
20	MN - Lincoln		40	MN - Sherburne	

REPORT FOR: Northern States Power Co 13781

REPORT PERIOD ENDING: 2003

SCHEDULE 6. DISTRIBUTION SYSTEM INFORMATION

LINE NO.	STATE (US Postal Abbreviation) (a)	COUNTY (FOREIGN) (b)
41	MN - Sibley	
42	MN - Stearns	
43	MN - Steele	
44	MN - Todd	
45	MN - Wabasha	
46	MN - Waseca	
47	MN - Washington	
48	MN - Watonwan	
49	MN - Wilkin	
50	MN - Winona	
51	MN - Wright	
52	MN - Yellow Medicine	
53	ND - Cass	
54	ND - Grand Forks	
55	ND - McHenry	
56	ND - Traill	
57	ND - Ward	
58	SD - Hanson	
59	SD - Hutchinson	
60	SD - Lake	
61	SD - Lincoln	
62	SD - McCook	
63	SD - Miner	
64	SD - Minnehaha	
65	SD - Moody	
66	SD - Sanborn	
67	SD - Turner	

REPORT FOR: Northern States Power Co 13781

REPORT PERIOD ENDING: 2003

SCHEDULE 7. FOOTNOTES

SCHEDULE (a)	PART (b)	LINE NO. (c)	COLUMN (d)	NOTES (e)

REPORT FOR: Northern States Power Co 13781

REPORT PERIOD ENDING: 2003

EIA-861 ERROR LOG

Schedule	Part	State	Error No.	Error Description/Override Comment	Type	Override
						☐

7610.0600 I - Electric Use by Minnesota Residential Space Heating Users

Each utility shall provide actual data on the number of residential electric space heating customers and units it serves in Minnesota and the total megawatt-hours of electricity sold to these users in the past calendar year. If a utility cannot provide actual data, estimates will be accepted but must be identified as such.

A residential electric space heating customer or unit means any residential customer or unit which uses electricity as a source of space heating throughout the entire premises from permanently installed electric heating equipment.

Col. 1 – Provide the number of Minnesota residential electrical space heating customers at years end. Apartments, public housing projects, and senior citizen housing should be considered residential.

Col. 2 – Provide the number of Minnesota residential units which were served with electric space heating at years end. The total for Column 2 will be larger than Column 1 if the utility serves multiple housing structures or apartments heated with electricity which it counts as "1" customer, but which in reality contain multiple housing units. Apartments public housing projects, and senior citizen housing should be considered residential.

Col. 3 – The total megawatt hours of electricity these residential space heating customers and units used.

	COL. 1 No. of Residential Electrical Space Heating Customers	COL. 2 No. of Res. Units Served with Elec. Space Heating	COL. 3 Total MWH Used by These Customers and Units
PAST YEAR 2003	28,335	N/A	384,953

7610.0600 J - Energy Delivered to Ultimate Consumers by County

ENERGY DELIVERED TO ULTIMATE CONSUMERS BY COUNTY IN 2003

Include all energy delivered to ultimate consumers as well as public buildings and/or municipal functions even if no charge is levied for deliveries to public buildings and/or municipal functions. (Do not include station use.)

County Code	County	MWH Delivered to Ultimate Consumers	County Code	County	MWH Delivered to Ultimate Consumers
01	Aitkin		44	Mahnomen	
02	Anoka	1,023,675	45	Marshall	
03	Becker		46	Martin	
04	Beltrami		47	Meeker	32,337
05	Benton	686,469	48	Mille Lacs	
06	Big Stone		49	Morrison	
07	Blue Earth	635,521	50	Mower	1,716
08	Brown	2,180	51	Murray	36,919
09	Carlton		52	Nicollet	102,916
10	Carver	431,554	53	Nobles	
11	Cass		54	Norman	1,446
12	Chippewa	100,420	55	Olmstead	29,848
13	Chisago	163,870	56	Otter Tail	
14	Clay	48,430	57	Pennington	
15	Clearwater		58	Pine	
16	Cook		59	Pipestone	71,476
17	Cottonwood		60	Polk	
18	Crow Wing		61	Pope	59,287
19	Dakota	2,837,287	62	Ramsey	5,520,883
20	Dodge	88,068	63	Red Lake	
21	Douglas	10,591	64	Redwood	37,552
22	Faribault	5,795	65	Renville	72,217
23	Fillmore		66	Rice	511,144
24	Freeborn	9,282	67	Rock	1,037
25	Goodhue	395,829	68	Roseau	
26	Grant		69	St. Louis	
27	Hennepin	12,313,279	70	Scott	431,455
28	Houston	33,780	71	Sherburne	195,227
29	Hubbard		72	Sibley	70,663
30	Isanti		73	Stearns	1,141,670
31	Itasca		74	Steele	15,474
32	Jackson		75	Stevens	
33	Kanabec		76	Swift	
34	Kandiyohi	75,173	77	Todd	1,774
35	Kittson		78	Traverse	
36	Koochiching		79	Wabasha	63,935
37	Lac Que Parle	565	80	Wadena	
38	Lake		81	Waseca	144,240
39	Lake of the Woods		82	Washington	2,043,245
40	Le Sueur	55,325	83	Watonwan	6,501
41	Lincoln	825	84	Wilkin	891
42	Lyon	35,420	85	Winona	438,406
43	McLeod	61,881	86	Wright	348,940
			87	Yellow Medicine	21,564

Note: Sales by county excludes sales to municipal customers.

GRAND TOTAL (of both columns) 30,417,982

(Should equal "Megawatt-hours" column total on Page 7A)

7610.0600 J – Electricity Delivered To Ultimate Consumers In Minnesota Service Area In 2003

INSTRUCTIONS

The energy use classifications employed in this schedule are defined or clarified below for those classifications, which may not be self-explanatory.

FARM, INCLUDING IRRIGATION AND DRAINAGE PUMPING -- In order to facilitate reporting this classification of energy, farm may be defined in accordance with respondent's own interpretation. For guidance, the Bureau of the Census' definition of a farm may for the purposes herein be redefined briefly as a tract of land which produces or has the potential for the production of agricultural goods totaling $1,000 or more, annually; the land operated by each tenant, renter, cropper, or manager is considered a separate farm. Respondent should report farms served rather than farm dwellings served in the column for number of customers. Estimates should be furnished for this classification if exact information is not available.

NONFARM-RESIDENTIAL--Energy supplied for nonfarm-residential purposes. Include seasonal homes and cottages. Where electric energy was supplied through a single meter for both residential and commercial purposes include it in one or the other, according to its principal use. Exclude energy supplied to farm customers.

COMMERCIAL--Energy supplied to small commercial and industrial power accounts.

INDUSTRIAL--Energy supplied to large commercial and industrial power accounts, including mining accounts.

STREET AND HIGHWAY LIGHTING--Energy supplied for street and highway lighting.

ALL OTHER--Energy delivered for ultimate consumption that does not fall within any of the specific classifications listed in this schedule. Included in this group should be deliveries for municipal water pumping; military camps and bases; and public buildings such as schools, police stations, post offices, and government offices. Do not include sales for resale.

Classification of Energy Delivered to Ultimate Consumers[1] (include energy used during the year for irrigation and drainage pumping) – CALENDAR MONTH BASIS	Number Customers at End of Year[2]	Megawatt-hours (round to nearest MWH)[3]	Revenue[4]
Farm	NA	NA	NA
Nonfarm-residential...(Total Residential)	1,043,231	8,482,572	665,172,716
Small Commercial and Industrial	120,223	12,300,171	726,771,969
Large Commercial and Industrial	595	9,387,479	419,773,762
Street and highway lighting	2,712	129,473	17,111,040
All other*	2,149	361,591	17,659,868
Total Energy Delivered to Ultimate Consumers	1,168,910	30,661,286	1,846,489,355

[1]Exclude station use, distribution losses, and unaccounted for energy losses from this table altogether.
[2]Report number of farms, residences, commercial establishments, etc., and not the number of meters where different.
[3]This column total should equal the grand total in the previous section on total deliveries by county.
[4]This column total will be used for the Renewable Energy Assessment and should not include revenues from sales for resale.

Note: Municipal Sales Component 7 243,305 10,303,332

*Includes Other Sales to Public Authority, Inter-departmental sales, and municipals.

7610.0310 – Historical Data and Forecast

7610.0320 – Forecast Documentation

7610.0310, item A. SYSTEM FORECAST OF ANNUAL ELECTRIC CONSUMPTION BY ULTIMATE CONSUMERS

In the space below, provide actual data for your entire system for the past year, your estimate for the present year and all future forecast years. Please remember that the number of customers should reflect the number of customers at years end not the number of meters.

			FARM	TOTAL RESIDENTIAL	SMALL C&I (< 1000 Kw)	MINING*
PAST YEAR	2003	NO. OF CUST'S	NA	1,379,851	175,484	NA
		MWH's	NA	11,662,067	16,579,354	NA
PRESENT YEAR	2004	NO. OF CUST'S	NA	1,395,475	178,395	NA
		MWH's	NA	11,847,727	16,821,001	NA
1st FORECAST YR	2005	NO. OF CUST'S	NA	1,411,393	180,950	NA
		MWH's	NA	12,056,428	17,115,936	NA
2nd FORECAST YR	2006	NO. OF CUST'S	NA	1,427,307	183,498	NA
		MWH's	NA	12,309,391	17,434,706	NA
3rd FORECAST YR	2007	NO. OF CUST'S	NA	1,446,300	186,505	NA
		MWH's	NA	12,596,904	17,796,488	NA
4th FORECAST YR	2008	NO. OF CUST'S	NA	1,460,213	188,786	NA
		MWH's	NA	12,888,447	18,155,233	NA
5th FORECAST YR	2009	NO. OF CUST'S	NA	1,473,880	191,008	NA
		MWH's	NA	13,156,855	18,477,697	NA
6th FORECAST YR	2010	NO. OF CUST'S	NA	1,488,623	193,447	NA
		MWH's	NA	13,480,101	18,861,434	NA
7th FORECAST YR	2011	NO. OF CUST'S	NA	1,502,683	195,774	NA
		MWH's	NA	13,779,564	19,223,531	NA
8th FORECAST YR	2012	NO. OF CUST'S	NA	1,514,662	197,804	NA
		MWH's	NA	14,077,068	19,587,362	NA
9th FORECAST YR	2013	NO. OF CUST'S	NA	1,527,230	199,928	NA
		MWH's	NA	14,375,131	19,942,336	NA
10th FORECAST YR	2014	NO. OF CUST'S	NA	1,540,108	202,088	NA
		MWH's	NA	14,686,083	20,308,300	NA
11th FORECAST YR	2015	NO. OF CUST'S	NA	1,552,992	204,253	NA
		MWH's	NA	15,010,198	20,668,152	NA
12th FORECAST YR	2016	NO. OF CUST'S	NA	1,565,222	206,329	NA
		MWH's	NA	15,333,008	21,028,404	NA
13th FORECAST YR	2017	NO. OF CUST'S	NA	1,576,813	208,310	NA
		MWH's	NA	15,614,546	21,353,263	NA
14th FORECAST YR	2018	NO. OF CUST'S	NA	1,587,575	210,172	NA
		MWH's	NA	15,884,905	21,665,421	NA

7610.0310, item C. PEAK DEMAND BY ULTIMATE CONSUMERS AT TIME OF ANNUAL SYSTEM PEAK (IN MW'S)

LAST YR PEAK DAY	NA	3,074	3,113	NA

* Mining needs to be reported as a separate category only if annual sales are greater than 1,000 GWH. Otherwise, include mining in the INDUSTRIAL category.

7610.0310, item A. SYSTEM FORECAST OF ANNUAL ELECTRIC CONSUMPTION BY ULTIMATE CONSUMERS (Continued)

		LARGE C&I (> or = 1000 Kw)	ST. AND HWY. LIGHTING	OTHER (incl. Municipals)	SYSTEM TOTALS (Should equal col.1 + col. 2 on p.10)
PAST YEAR 2003	NO. OF CUST'S.	753	3,784	2,827	1,562,699
	MWH's	11,443,959	177,054	954,165	40,816,600
PRESENT YEAR 2004	NO. OF CUST'S.	793	4,339	2,856	1,581,858
	MWH's	11,902,791	180,144	1,018,632	41,770,295
1st FORECAST YR 2005	NO. OF CUST'S.	805	4,503	2,855	1,600,506
	MWH's	12,118,704	180,618	1,039,960	42,511,646
2nd FORECAST YR 2006	NO. OF CUST'S.	815	4,668	2,856	1,619,144
	MWH's	12,329,130	180,905	1,060,241	43,314,373
3rd FORECAST YR 2007	NO. OF CUST'S.	826	4,869	2,856	1,641,356
	MWH's	12,555,660	181,008	1,076,214	44,206,273
4th FORECAST YR 2008	NO. OF CUST'S.	836	5,007	2,856	1,657,698
	MWH's	12,790,521	181,008	1,095,535	45,110,745
5th FORECAST YR 2009	NO. OF CUST'S.	843	5,142	2,856	1,673,729
	MWH's	13,010,370	181,008	1,102,427	45,928,357
6th FORECAST YR 2010	NO. OF CUST'S.	854	5,293	2,856	1,691,073
	MWH's	13,257,556	181,008	1,102,427	46,882,525
7th FORECAST YR 2011	NO. OF CUST'S.	863	5,436	2,856	1,707,612
	MWH's	13,499,186	181,008	1,102,427	47,785,716
8th FORECAST YR 2012	NO. OF CUST'S.	870	5,554	2,856	1,721,746
	MWH's	13,741,172	181,008	1,102,441	48,689,051
9th FORECAST YR 2013	NO. OF CUST'S.	876	5,682	2,856	1,736,572
	MWH's	13,986,504	181,008	1,102,427	49,587,405
10th FORECAST YR 2014	NO. OF CUST'S.	882	5,814	2,856	1,751,748
	MWH's	14,228,338	181,008	1,102,427	50,506,156
11th FORECAST YR 2015	NO. OF CUST'S.	888	5,947	2,856	1,766,936
	MWH's	14,453,490	181,008	1,102,427	51,415,275
12th FORECAST YR 2016	NO. OF CUST'S.	893	6,073	2,856	1,781,373
	MWH's	14,680,905	181,008	1,102,441	52,325,766
13th FORECAST YR 2017	NO. OF CUST'S.	898	6,190	2,856	1,795,067
	MWH's	14,902,748	181,008	1,102,427	53,153,992
14th FORECAST YR 2018	NO. OF CUST'S.	903	6,298	2,856	1,807,804
	MWH's	15,120,062	181,008	1,102,427	53,953,824

7610.0310, item C. PEAK DEMAND BY ULTIMATE CONSUMERS AT TIME OF ANNUAL SYSTEM PEAK (IN MW'S)

LAST YR PEAK DAY	1,933	0	161	8,281

7610.0310, item D. PEAK DEMAND BY MONTH FOR THE LAST CALENDAR YEAR

	PEAK (In MW's)		PEAK (In MW's)		PEAK (In MW's)
JANUARY	6,371	MAY	5,892	SEPTEMBER	7,296
FEBRUARY	6,236	JUNE	7,760	OCTOBER	6,128
MARCH	5,954	JULY	7,863	NOVEMBER	6,136
APRIL	5,755	AUGUST	8,281	DECEMBER	6,497

7610.0310, item A. MINNESOTA ONLY FORECAST OF ANNUAL ELECTRIC CONSUMPTION BY ULTIMATE CONSUMERS

In the space below, provide actual data for your **Minnesota service area only,** for the past year, your best estimate for the present year and all future forecast years. The definition shall be the same as those used in 7610.0310, item A on the firs page of this report. Please remember that the number of customers should reflect the actual number of customers the utility has in that category at years end not the number of meters.

		TOTAL RESIDENTIAL	SMALL COMM & IND	MINING*
*PAST YEAR 2003	NO. OF CUSTS.	1,043,231	120,223	NA
	MWH's	8,482,571	12,300,171	NA
PRESENT YEAR 2004	NO. OF CUSTS.	1,053,796	122,254	NA
	MWH's	8,629,233	12,484,743	NA
1st FORECAST YR 2005	NO. OF CUSTS.	1,065,313	124,056	NA
	MWH's	8,787,966	12,695,593	NA
2nd FORECAST YR 2006	NO. OF CUSTS.	1,076,939	125,854	NA
	MWH's	8,983,917	12,930,617	NA
3rd FORECAST YR 2007	NO. OF CUSTS.	1,091,597	128,115	NA
	MWH's	9,213,786	13,200,977	NA
4th FORECAST YR 2008	NO. OF CUSTS.	1,101,454	129,663	NA
	MWH's	9,445,429	13,458,878	NA
5th FORECAST YR 2009	NO. OF CUSTS.	1,111,138	131,158	NA
	MWH's	9,660,039	13,686,120	NA
6th FORECAST YR 2010	NO. OF CUSTS.	1,122,032	132,876	NA
	MWH's	9,926,575	13,966,578	NA
7th FORECAST YR 2011	NO. OF CUSTS.	1,132,419	134,492	NA
	MWH's	10,173,749	14,229,126	NA
8th FORECAST YR 2012	NO. OF CUSTS.	1,140,953	135,826	NA
	MWH's	10,418,731	14,492,424	NA
9th FORECAST YR 2013	NO. OF CUSTS.	1,150,163	137,253	NA
	MWH's	10,668,851	14,746,406	NA
10th FORECAST YR 2014	NO. OF CUSTS.	1,159,735	138,722	NA
	MWH's	10,929,306	15,007,306	NA
11th FORECAST YR 2015	NO. OF CUSTS.	1,169,382	140,201	NA
	MWH's	11,204,056	15,265,477	NA
12th FORECAST YR 2016	NO. OF CUSTS.	1,178,455	141,596	NA
	MWH's	11,477,547	15,523,261	NA
13th FORECAST YR 2017	NO. OF CUSTS.	1,186,958	142,903	NA
	MWH's	11,715,399	15,749,177	NA
14th FORECAST YR 2018	NO. OF CUSTS.	1,194,699	144,096	NA
	MWH's	11,941,900	15,965,375	NA

* Mining needs to be reported as a separate category only if annual sales are greater than 1,000 GWH. Otherwise, include mining in the INDUSTRIAL category.

7610.0310, item A. MINNESOTA ONLY FORECAST OF ANNUAL ELECTRIC CONSUMPTION BY ULTIMATE CONSUMERS (Continued)

			LARGE COMM & IND	ST. AND HWY LIGHTING	OTHER (incl. Municipals)	TOTAL-MN ONLY (should equal column 1 on page 10)
PAST YEAR	2003	NO. OF CUST'S.	595	2,712	2,149	1,168,910
		MWH's	9,387,479	129,473	361,591	30,661,286
PRESENT YEAR	2004	NO. OF CUST'S.	632	3,254	2,178	1,182,114
		MWH's	9,777,122	131,933	416,209	31,439,240
1st FORECAST YR	2005	NO. OF CUST'S.	643	3,404	2,178	1,195,594
		MWH's	9,953,169	132,026	430,607	31,999,361
2nd FORECAST YR	2006	NO. OF CUST'S.	652	3,554	2,179	1,209,178
		MWH's	10,124,730	132,061	446,427	32,617,751
3rd FORECAST YR	2007	NO. OF CUST'S.	662	3,744	2,179	1,226,297
		MWH's	10,304,358	132,102	461,125	33,312,349
4th FORECAST YR	2008	NO. OF CUST'S.	671	3,872	2,179	1,237,839
		MWH's	10,484,041	132,102	480,233	34,000,683
5th FORECAST YR	2009	NO. OF CUST'S.	677	3,997	2,179	1,249,149
		MWH's	10,651,002	132,102	487,339	34,616,602
6th FORECAST YR	2010	NO. OF CUST'S.	687	4,138	2,179	1,261,912
		MWH's	10,839,211	132,102	487,339	35,351,805
7th FORECAST YR	2011	NO. OF CUST'S.	695	4,273	2,179	1,274,058
		MWH's	11,023,383	132,102	487,339	36,045,698
8th FORECAST YR	2012	NO. OF CUST'S.	702	4,383	2,179	1,284,043
		MWH's	11,206,619	132,102	487,351	36,737,226
9th FORECAST YR	2013	NO. OF CUST'S.	708	4,502	2,179	1,294,805
		MWH's	11,391,741	132,102	487,339	37,426,438
10th FORECAST YR	2014	NO. OF CUST'S.	714	4,626	2,179	1,305,976
		MWH's	11,570,198	132,102	487,339	38,126,251
11th FORECAST YR	2015	NO. OF CUST'S.	720	4,751	2,179	1,317,233
		MWH's	11,734,511	132,102	487,339	38,823,485
12th FORECAST YR	2016	NO. OF CUST'S.	725	4,869	2,179	1,327,824
		MWH's	11,899,669	132,102	487,351	39,519,929
13th FORECAST YR	2017	NO. OF CUST'S.	730	4,979	2,179	1,337,749
		MWH's	12,059,769	132,102	487,339	40,143,786
14th FORECAST YR	2018	NO. OF CUST'S.	735	5,079	2,179	1,346,788
		MWH's	12,217,745	132,102	487,339	40,744,460

7610.0310, item B. FORECAST OF ANNUAL SYSTEM CONSUMPTION AND GENERATION DATA

	Column 1	Column 2	Column 3	Column 4
	CONSUMPTION BY ULTIMATE COMSUMERS IN MINNESOTA MWH 7610.0310 B(1)	CONSUMPTION BY ULTIMATE COMSUMERS OUTSIDE OF MINNESOTA MWH 7610.0310 B(2)	RECEIVED FROM OTHER UTILITES MWH 7610.0310 B(3)	DELIVERED FOR RESALE MWH 7610.0310 B(4)
PAST YEAR 2003	30,661,286	10,155,314	10,102,000	4,820,000
PRESENT YEAR 2004	31,439,240	10,331,056	10,496,797	4,475,465
1st FORECAST YR 2005	31,999,361	10,512,285	10,217,000	3,377,000
2nd FORECAST YR 2006	32,617,751	10,696,621	11,068,000	3,387,000
3rd FORECAST YR 2007	33,312,349	10,893,924	12,187,000	3,539,000
4th FORECAST YR 2008	34,000,683	11,110,062	11,930,000	3,368,000
5th FORECAST YR 2009	34,616,602	11,311,755	13,058,000	2,496,000
6th FORECAST YR 2010	35,351,805	11,530,720	13,776,000	2,286,000
7th FORECAST YR 2011	36,045,698	11,740,017	14,051,520	2,256,282
8th FORECAST YR 2012	36,737,226	11,951,825	14,332,550	2,226,950
9th FORECAST YR 2013	37,426,438	12,160,967	14,619,201	2,198,000
10th FORECAST YR 2014	38,126,251	12,379,906	14,911,585	2,169,426
11th FORECAST YR 2015	38,823,485	12,591,791	15,209,817	2,141,223
12th FORECAST YR 2016	39,519,929	12,805,838	15,514,013	2,113,388
13th FORECAST YR 2017	40,143,786	13,010,206	15,824,294	2,085,913
14th FORECAST YR 2018	40,744,460	13,209,364	16,140,780	2,058,797

NOTE: Column 1 plus Column 2 should equal Column 5 minus Column 6 minus Column 4 plus Column 3.

7610.0310, item B. FORECAST OF ANNUAL SYSTEM CONSUMPTION AND GENERATION DATA (Continued)

	Column 5 TOTAL ANNUAL NET GENERATION MWH 7610.0310 B(5)	Column 6 TRANSMISSION LINE SUBSTATION AND DISTRIBUTION LOSSES MWH 7610.0310 B(6)	Column 7 TOTAL WINTER CONSUMPTION MWH 7610.0310 B(7)	Column 8 TOTAL SUMMER CONSUMPTION MWH 7610.0310 B(8)
PAST YEAR 2003	38,451,397	2,916,797	19,749,671	20,893,772
PRESENT YEAR 2004	39,731,561	3,982,598	20,095,439	21,529,803
1st FORECAST YR 2005	39,725,297	4,053,651	20,459,778	21,930,049
2nd FORECAST YR 2006	39,763,013	4,129,640	20,837,910	22,345,340
3rd FORECAST YR 2007	39,772,103	4,213,830	21,245,729	22,805,745
4th FORECAST YR 2008	40,848,345	4,299,600	21,718,003	23,254,839
5th FORECAST YR 2009	39,743,278	4,376,921	22,109,713	23,682,897
6th FORECAST YR 2010	39,859,989	4,467,463	22,542,424	24,182,001
7th FORECAST YR 2011	40,543,197	4,552,719	23,005,025	24,636,958
8th FORECAST YR 2012	41,221,759	4,638,308	23,459,358	25,088,834
9th FORECAST YR 2013	41,889,392	4,723,188	23,874,783	25,561,386
10th FORECAST YR 2014	42,574,213	4,810,216	24,328,713	26,031,246
11th FORECAST YR 2015	43,242,984	4,896,302	24,772,957	26,496,412
12th FORECAST YR 2016	43,907,691	4,982,550	25,236,814	26,948,707
13th FORECAST YR 2017	44,476,654	5,061,042	25,636,872	27,383,378
14th FORECAST YR 2018	45,008,618	5,136,777	26,036,724	27,790,849

7610.0310 Item E – Firm Purchases SUMMER						
	Manitoba Hydro	BEPC	OPPD	GRE	WAPA	Total
2003	350	50	35	75	2	512
2004	350	50		75	2	477
2005	350	50		75	2	477
2006	350	50		75	2	477
2007	350	50		75	2	477
2008	350	50		75	2	477
2009	350	50		75	2	477
2010	350	50		75	2	477
2011	350	50		75	2	477
2012	350	50		75	2	477
2013	350	50		75	2	477
2014	350	50		75	2	477
2015	200	50		75	2	327
2016	200	50		75	2	327
2017		50		75	2	127
2018		50		75	2	127

7610.0310 Item E – Firm Purchases WINTER				
	GRE	BEPC	WAPA	Total
2003	75	50	2	127
2004	75	50	2	127
2005	75	50	2	127
2006	75	50	2	127
2007	75	50	2	127
2008	75	50	2	127
2009	75	50	2	127
2010	75	50	2	127
2011	75	50	2	127
2012	75	50	2	127
2013	75	50	2	127
2014	75	50	2	127
2015	75	50	2	127
2016	75	50	2	127
2017	75	50	2	127
2018	75	50	2	127

7610.0310 Item E – Firm Sales SUMMER				
	Municipals	Total		
2003	15	15		
2004		0		
2005		0		
2006		0		
2007		0		
2008		0		
2009		0		
2010		0		
2011		0		
2012		0		
2013		0		
2014		0		
2015		0		
2016		0		
2017		0		
2018		0		

7610.0310 Item E – Firm Sales WINTER				
	Municipals	Manitoba Hydro	Total	
2003	15	350	365	
2004	15	350	365	
2005	15	350	365	
2006	15	350	365	
2007	15	350	365	
2008	15	350	365	
2009	15	350	365	
2010	15	350	365	
2011	15	350	365	
2012	15	350	365	
2013	15	350	365	
2014	15	350	365	
2015	15	200	215	
2016	15		15	
2017	15		15	
2018	15		15	

7610.0310 Item F – Participation Purchases SUMMER

	All Source	Biomass	MPC Coyote	Otter Tail	Non Utility	Man Hydro	United Power Assoc	OPPD	CMMPA	Aquila	AEMC	DYPM	MEC	TEA	WEI	MP	Total
2003			100	75	381	760	50	10	25		255	100	150	20	61	100	2087
2004			100	75	385	700	50		25	235			150		61		1781
2005	171	10	100		385	500	50										1216
2006	675	60	100		385	500	50										1770
2007	971	95	100		385	500	50										2101
2008	971	95	100		385	500	50										2101
2009	971	95	100		385	500											2051
2010	971	95	100		385	500											2051
2011	971	95	100		345	500											2011
2012	971	95	100		345	500											2011
2013	971	95	100		345	500											2011
2014	971	95	100		342	500											2008
2015	971	95	100		342												1508
2016	971	95			342												1408
2017	971	95			334												1400
2018	971	95			301												1367

7610.0310 Item F – Participation Purchases WINTER							
	All Source	Biomass	Non Utility	Manitoba Hydro	CMMPA	MP	Total
2003			396	500	25	100	1023
2004			396	500			896
2005	171		396	500			1067
2006	675	60	396	500			1631
2007	971	95	396	500			1962
2008	971	95	396	500			1962
2009	971	95	396	500			1962
2010	971	95	396	500			1962
2011	971	95	356	500			1922
2012	971	95	356	500			1922
2013	971	95	356	500			1922
2014	971	95	353				1419
2015	971	95	353				1419
2016	971	95	350				1416
2017	971	95	312				1378
2018	971	95	312				1378

7610.0310 Item F – Participation Sales SUMMER					
	Total				
2003	0				
2004	0				
2005	0				
2006	0				
2007	0				
2008	0				
2009	0				
2010	0				
2011	0				
2012	0				
2013	0				
2014	0				
2015	0				
2016	0				
2017	0				
2018	0				

7610.0310 Item F – Participation Sales WINTER				
		United		
	Otter Tail	Power Assoc	Melrose	Total
2003	75	50		125
2004		50	3	53
2005		50		50
2006		50		50
2007		50		50
2008		50		50
2009		50		50
2010				0
2011				0
2012				0
2013				0
2014				0
2015				0
2016				0
2017				0
2018				0

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7610.0310 Item G - Load and Generation Capacity
Expressed in Megawatts

	Past Year 2003		Present Year 2004		1st Forecast Year 2005		2nd Forecast Year 2006		3rd Forecast Year 2007		4th Forecast Year 2008		5th Forecast Year 2009		6th Forecast Year 2010	
	summer	winter	summer	winter	summer	winter	summer	winter	summer	winter	summer	winter	summer	winter	summer	winter
(1) seasonal maximum demand	8281	6653	8278	6657	8434	6722	8598	6793	8796	6872	8972	6952	9126	7024	9301	7108
(2) schedule L purchased at the time of seasonal system demand	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
(3) seasonal system demand	8281	6653	8278	6657	8434	6722	8598	6793	8796	6872	8972	6952	9126	7024	9301	7108
(4) annual system demand	8281	8281	8278	8278	8434	8434	8598	8598	8796	8796	8972	8972	9126	9126	9301	9301
(5) seasonal firm purchases - total	512	127	477	127	477	127	477	127	477	127	477	127	477	127	477	127
(6) seasonal firm sales - total	15	365	0	365	0	365	0	365	0	365	0	365	0	365	0	365
(7) seasonal adjusted net demand (3-5+6)	7784	6891	7801	6895	7957	6960	8121	7031	8319	7110	8495	7190	8649	7262	8824	7346
(8) annual adjusted net demand (4-5+6)	7784	8519	7801	8516	7957	8672	8121	8836	8319	9034	8495	9210	8649	9364	8824	9539
(9) net generating capability	7273	7732	7259	7671	7744	8232	7749	8237	7749	8237	7994	8482	8046	8534	8046	8534
(10) participation purchases - total	2087	1023	1781	896	1216	1067	1770	1631	2101	1962	2101	1962	2051	1962	2051	1962
(11) participation sales - total	0	125	0	53	0	50	0	50	0	50	0	50	0	50	0	0
(12) adjusted net capability (9+10-11)	9360	8630	9040	8514	8960	9249	9519	9818	9850	10149	10095	10394	10097	10446	10097	10496
(13) net reserve capacity obligation	1168	1278	1170	1277	1194	1301	1218	1325	1248	1355	1274	1382	1297	1405	1324	1431
(14) total firm capacity obligation (7+13)	8952	8169	8971	8172	9151	8261	9339	8356	9567	8465	9769	8572	9946	8667	10148	8777
(15) surplus (+) or deficit (-) capacity (12-14)	408	461	69	342	-191	988	179	1461	283	1683	325	1822	150	1779	-51	1719

7610.0310 Item G - Load and Generation Capacity
Expressed in Megawatts

	7th Forecast Year 2011		8th Forecast Year 2012		9th Forecast Year 2013		10th Forecast Year 2014		11th Forecast Year 2015		12th Forecast Year 2016		13th Forecast Year 2017		14th Forecast Year 2018	
	summer	winter	summer	winter	summer	winter	summer	winter	summer	winter	summer	winter	summer	winter	summer	winter
(1) seasonal maximum demand	9470	7188	9639	7268	9786	7347	9951	7429	10115	7509	10279	7590	10429	7663	10572	7734
(2) schedule L purchased at the time of seasonal system demand	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
(3) seasonal system demand	9470	7188	9639	7268	9786	7347	9951	7429	10115	7509	10279	7590	10429	7663	10572	7734
(4) annual system demand	9470	9470	9639	9639	9786	9786	9951	9951	10115	10115	10279	10279	10429	10429	10572	10572
(5) seasonal firm purchases - total	477	127	477	127	477	127	477	127	327	127	327	127	127	127	127	127
(6) seasonal firm sales - total	0	365	0	365	0	365	0	365	0	215	0	15	0	15	0	15
(7) seasonal adjusted net demand (3-5+6)	8993	7426	9162	7506	9309	7585	9474	7667	9788	7597	9952	7478	10302	7551	10445	7622
(8) annual adjusted net demand (4-5+6)	8993	9708	9162	9877	9309	10024	9474	10189	9788	10203	9952	10167	10302	10317	10445	10460
(9) net generating capability	8046	8534	8046	8534	8046	8534	8046	8534	8046	8534	8046	8534	8046	8534	8046	8534
(10) participation purchases - total	2011	1922	2011	1922	2011	1922	2008	1419	1508	1419	1408	1416	1400	1378	1367	1378
(11) participation sales - total	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
(12) adjusted net capability (9+10-11)	10057	10456	10057	10456	10057	10456	10054	9953	9554	9953	9454	9950	9446	9912	9413	9912
(13) net reserve capacity obligation	1349	1456	1374	1482	1396	1504	1421	1528	1468	1530	1493	1525	1545	1548	1567	1569
(14) total firm capacity obligation (7+13)	10342	8882	10536	8988	10705	9089	10895	9195	11256	9127	11445	9003	11847	9099	12012	9191
(15) surplus (+) or deficit (-) capacity (12-14)	-285	1573	-480	1468	-649	1367	-842	757	-1703	825	-1991	946	-2402	813	-2599	721

7610.0310 Item H – Additions and Retirements
Expressed in Megawatts

	Additions	Retirements
Present Year 2004		45
1st Forecast Year 2005	480	
2nd Forecast Year 2006		
3rd Forecast Year 2007		
4th Forecast Year 2008	515	270
5th Forecast Year 2009	439	386
6th Forecast Year 2010		
7th Forecast Year 2011		
8th Forecast Year 2012		
9th Forecast Year 2013		
10th Forecast Year 2014		
11th Forecast Year 2015		
12th Forecast Year 2016		
13th Forecast Year 2017		
14th Forecast Year 2018		

Xcel Energy
Peak Demand and Annual Electric Consumption Forecast
7610.0320 – Subparts 1, 2, 3, 4 and 5

Subpart 1 – Forecast Methodology

A. OVERALL METHODOLOGICAL FRAMEWORK

Xcel Energy prepared its forecast by major customer class and jurisdiction, using a variety of statistical and econometric techniques. Xcel Energy has five jurisdictions: Minnesota, North Dakota, South Dakota which comprise the legal entity Northern States Power-Minnesota and Wisconsin and Michigan which comprise the legal entity Northern States Power-Wisconsin. The overall methodological framework is "model oriented". The forecast is referred to as the Native Energy and Peak Demand Forecast (August 2003).

B. SPECIFIC ANALYTICAL TECHNIQUES

1. Econometric Analysis. Xcel Energy used econometric analysis to develop jurisdictional MWh sales forecasts at the customer meter of the following:
   a. Residential without Space Heating
   b. Residential with Space Heating
   c. Small Commercial and Industrial
   d. Large Commercial and Industrial

   Trend analysis was used for the "Other" sectors, which includes Public Street and Highway Lighting, Other Sales to Public Authorities, Interdepartmental sales, and Municipals (firm Wholesale).
2. Judgment. Judgment is inherent to the development of any forecast. Whenever possible, Xcel Energy tries to use quantitative models to structure its judgment in the forecasting process.
3. Loss Factor Methodology. Loss factors by legal entity were used to convert the sales forecasts developed in section B.1 into system energy requirements (at the generator).
4. Peak Demand Forecast. Econometric analysis was used to develop a total system Mw demand forecast for the entire forecast period.

C. RELATIONSHIP OF SPECIFIC TECHNIQUES TO PRODUCE FORECAST

The MWh sales forecast was developed for each customer class and jurisdiction based on the techniques discussed in section B.1. Summing the various jurisdictional class forecasts yields the total system sales forecast. A monthly loss factor is applied to convert MWh sales to MWh native energy requirements. An econometric model was developed to forecast MW peak demand for the Xcel Energy North system, using independent variables such as native energy requirements, peak producing weather, seasonal and binary variables.

1. Sales Forecasts. Sales forecasts are estimates of MWh levels measured at a customer meter. They do not include line or other losses.

2. Native Energy Requirement Forecasts. Native energy requirements are measured at the generator and include line and other losses. Xcel Energy creates native energy requirements based on the sales forecasts. A system loss factor for each legal entity, developed based on average historical losses, was applied to the sales forecast to calculate total losses. The sum of the MWh sales and losses equal native energy requirements.
3. Peak Demand Forecasts. Xcel Energy estimates peak demand using an econometric model with native energy requirements, weather, seasonal and binary series as independent variables.

D. STATISTICAL ANALYTICAL TECHNIQUES AND MODELS USED

1. Residential Econometric Models. Xcel Energy's sales to the residential sectors represent about 29 percent of its total retail electric sales in 2002. Residential sales are divided into with and without space heating customer classes for each jurisdiction. Ordinary Least Squares models using historic data were developed for each residential sector. A variety of independent variables were used in the model, including:
   - Number of customers
   - Personal income
   - Price of electricity, residential class
   - Actual heating and temperature humidity index (THI) degree days
   - Binary seasonal variables
2. Small Commercial and Industrial Econometric Models. The small commercial and industrial sector represents about 41 percent of Xcel Energy's retail electric sales in 2002. The models are ordinary least squares regressions using historic data. The models include a combination of variables, including the following:
   - Number of small commercial and industrial customers
   - Price of electricity, small commercial and industrial class
   - Gross State Product for respective jurisdiction
   - Actual heating and temperature humidity index (THI) degree days
   - Indicator variables (i.e. billing system conversion)
3. Large Commercial and Industrial Econometric Models. Sales to the large commercial and industrial sector represent about 29 percent of Xcel Energy's retail electric sales in 2002. The models are OLS regressions using historic data and a combination of variables, including the following:
   - Regional employment by sector
   - Price of electricity, large commercial and industrial class
   - Actual heating and temperature humidity index (THI) degree days
   - Indicator variables such as billing system conversion, etc.
4. Municipals. The municipal class is forecast using separate trend analysis at the individual customer level for the Minnesota Company and Wisconsin Company. The forecast of these municipal customers only includes those that Xcel Energy is committed to serve, i.e., only the firm wholesale customer usage.
5. Others. This sector includes Public Street and Highway Lighting (PSHL), Sales to Public Authorities (OSPA) and Interdepartmental (IDS) sales. Because this class represents a

very small portion of the total sales, trend analysis was used and very little growth was forecast.

6. Peak Demand Model. An econometric model was developed to forecast base peak demand for the entire planning period. The model includes a combination of variables, including the following:
    - Native energy requirements
    - Peak-producing weather by month
    - Monthly binary variables

E. FORECAST CONFIDENCE LEVELS

Xcel Energy developed probability distributions around total MWh native energy requirements and Mw peak demand. Using an upper and lower bandwidth produced by the modeling software used to create the peak demand and native energy forecast, an annual standard error for each model was determined and confidence levels established.

Over the last five years, annual peak demand and electric consumption deviation from expected levels is within an acceptable range.

F. METHODOLOGY STRENGTHS AND WEAKNESSES

The strength of the process Xcel Energy used for this forecast is the richness of the information obtained during the analysis. Xcel Energy's econometric forecasting models are based on sound economic and statistical theory. Historical modeling and forecast drivers are based on economic and demographic variables that are easily measured and analyzed. The use of models by class and jurisdiction gives greater insight into how Xcel Energy's system is growing and should enable better decisions in the areas of generation, transmission, marketing, conservation, and load management.

Regarding accuracy, forecasts of this duration are inherently uncertain. Planners and decision makers must be keenly aware of the inherent risk of the forecasts and develop plans that are robust over a wide range of future outcomes.

G. METHODOLOGY CHANGES

The methodology used by Xcel Energy to create native energy and peak demand forecasts has transitioned from a "top-down" approach to a "bottom-up" method. In forecasts prior to the 2002 Integrated Resource Plan, Xcel Energy created a total system MWh sales estimate by class and allocated to the various jurisdictions. In response to comments from Department of Commerce staff regarding the 2000 Integrated Resource Plan, and in an effort to standardize methodologies across its entire service territory, Xcel Energy has developed independent class models for each jurisdiction. In addition, Xcel Energy now has one set of models for the entire forecast period, eliminating the need to calibrate its long-term planning forecast to its short-term financial forecast.

Subpart 2 – Database for Forecasts

A. DATA DEFINITIONS AND SOURCES

The following is a list of definitions of the variables considered in Xcel Energy's econometric models.

Jurisdiction Abbreviations

M or MN	State of Minnesota
N or ND	State of North Dakota
S or SD	State of South Dakota
W or WI	State of Wisconsin
Mi or MI	State of Michigan

Monthly MWh Sales Series

ERX(Juris)	Residential without space heating for given jurisdiction
ERH(Juris)	Residential with space heating for given jurisdiction
ESC(Juris)	Small commercial and industrial for given jurisdiction
ELC(Juris)	Large commercial and industrial for given jurisdiction

Monthly Customer Series

NRX(Juris)	Residential without space heating for given jurisdiction
NRH(Juris)	Residential with space heating for given jurisdiction
NSC(Juris)	Small commercial and industrial for given jurisdiction
NLC(Juris)	Large commercial and industrial for given jurisdiction

Monthly Price per MWh Series

PRX(Juris)	Residential without space heating for given jurisdiction
PRH(Juris)	Residential with space heating for given jurisdiction
PSC(Juris)	Small commercial and industrial for given jurisdiction
PLC(Juris)	Large commercial and industrial for given jurisdiction

Monthly Economic and Demographic Series

(Juris)HH	Number of Households in given jurisdiction
(Juris)GSP	Gross State Product for given jurisdiction
EEA_(Juris)	Total non-farm employment in given jurisdiction
EM_(Juris)	Total manufacturing employment in given jurisdiction
EnonM_(Juris)	Total non-manufacturing employment in given jurisdiction
YP96@(Juris)	Personal income in given jurisdiction

Monthly Weather Variables

H65(Suffix)	HDD base 65 deviation from normal for given jurisdiction
H35(Suffix)	HDD base 35 deviation from normal for given jurisdiction
T65(Suffix)	THI DD base 65 deviation from normal for given jurisdiction
T75(Suffix)	THI DD base 75 deviation from normal for given jurisdiction

Monthly Binary Variables

Jan	Binary variable for the month of January
Feb	Binary variable for the month of February
Mar	Binary variable for the month of March
Apr	Binary variable for the month of April
May	Binary variable for the month of May
Jun	Binary variable for the month of June
Jul	Binary variable for the month of July
Aug	Binary variable for the month of August
Sep	Binary variable for the month of September
Oct	Binary variable for the month of October
Nov	Binary variable for the month of November
Dec	Binary variable for the month of December
CSS(month)	Binary variable representing change in billing system in 1996

Xcel Energy used internal and external data to create its MWh sales forecast.

Historical MWh sales are taken from Xcel Energy's internal company records, fed by its billing system. An electric price series for each customer class was developed by calculating revenue per Mwh also based on billing information for each jurisdiction.

Weather data (dry bulb temperature and dew points) are collected from a local meteorologist and the National Oceanic and Atmospheric Administration (NOAA) for the Minneapolis/St. Paul, Fargo, Sioux Falls, and Eau Claire areas. The heating degree-days and THI degree-days were calculated internally based on this weather data.

Economic and demographic data was obtained from the Bureau of Labor Statistics, U.S. Department of Commerce, and the Bureau of Economic Analysis. Typically they are accessed from Global Insights, Inc. data banks, and reflect the most recent values of those series at time of modeling.

B. DATA ADJUSTMENTS

1. Weather Adjustments. Xcel Energy adjusted its weather data to reflect billing schedules. Therefore, the weather data corresponds exactly with the billing month schedule.

2. Economic Adjustments. All price data and related economic series were deflated to 1996 constant dollars.

Subparts 3 and 4 – Assumptions and Special Information

Most of the data used in Xcel Energy's forecasting process has already been discussed in a general way. Descriptions and citations of sources for most data sets have been mentioned within this documentation under different sections.

Xcel Energy believes that its process is a reasonable and workable one to use as a guide for its future energy and load requirements. The underlying assumptions used to prepare Xcel Energy's 2002 Long Range median forecast are as follows:

1. Demographic Assumption. Population or household projections are essential in the development of the long-range forecast. The forecasts of customers are derived from population and household projections provided by Global Insights, Inc., and reviewed by Xcel Energy staff. Xcel Energy customer growth mirrors demographic growth over the forecast period.

2. Electric Price Assumption. Xcel Energy incorporates estimates of resource adjustments in its price forecast, and anticipates little price-induced substitution between electric and natural gas or oil.

3. Weather Assumption. Xcel Energy assumed "normal" weather in the forecast horizon. Normal weather is defined as the average weather pattern over the 20-year period from 1983-2002. The variability of weather is an important source of uncertainty. Xcel Energy's energy and peak demand forecasts are based on the assumption the normal weather conditions will prevail in the forecast horizon. Weather-related demand uncertainties are not treated explicitly in this forecast.

4. Loss Factor Assumptions. The loss factors are important to convert the sales forecast to energy requirements. Xcel Energy uses a historic average loss factor for each legal entity, and assumes it will not change in the future.

Subpart 5 – Forecast Coordination

Xcel Energy reports its energy and peak demand forecasts to the Mid-Continent Area Power Pool (MAPP) as a requirement of membership. MAPP then combines the forecasts of all its member utilities. Xcel Energy also reports its forecast to the Wisconsin Public Service Commission as part of its Strategic Energy Assessment (SEA) process. In this process, the Wisconsin portion of the total Xcel Energy system load is combined with other Wisconsin electric utilities to form a statewide Wisconsin forecast.

Xcel Energy
2004 Jurisdictional Annual Reports
System Net Energy Requirements (MWh), Summer and Winter Peak Demand (Mw)

Year	Net Energy Requirements (MWh)	Net Summer Peak (Mw)	Net Winter Peak (Mw)
2004	45,752,894	8,278	6,657
2005	46,565,294	8,434	6,722
2006	47,444,010	8,598	6,793
2007	48,420,104	8,796	6,872
2008	49,410,346	8,972	6,952
2009	50,305,279	9,126	7,024
2010	51,349,989	9,301	7,108
2011	52,338,436	9,470	7,188
2012	53,327,361	9,639	7,268
2013	54,310,591	9,786	7,347
2014	55,316,375	9,951	7,429
2015	56,311,576	10,115	7,509
2016	57,308,318	10,279	7,590
2017	58,215,035	10,429	7,663
2018	59,090,603	10,572	7,734
2019	59,938,328	10,709	7,802
2020	60,818,490	10,853	7,873
2021	61,658,364	11,012	7,941
2022	62,465,752	11,171	8,006

Average Annual Growth Rate, 2004-2022:

% growth:	**1.7%**	**1.7%**	**1.0%**

Table Xcel-1
Xcel Energy
System Net Energy Requirements (MWh)

Year	Semi-Low (MWh)	Median (MWh)	Semi-High (MWh)
2004	44,487,921	45,752,894	47,017,866
2005	45,264,167	46,565,294	47,866,428
2006	46,103,338	47,444,010	48,784,688
2007	47,028,973	48,420,104	49,811,234
2008	47,957,625	49,410,346	50,863,064
2009	48,794,956	50,305,279	51,815,600
2010	49,762,947	51,349,989	52,937,030
2011	50,671,043	52,338,436	54,005,827
2012	51,583,282	53,327,361	55,071,437
2013	52,491,845	54,310,591	56,129,342
2014	53,423,457	55,316,375	57,209,289
2015	54,345,266	56,311,576	58,277,888
2016	55,265,082	57,308,318	59,351,551
2017	56,098,117	58,215,035	60,331,950
2018	56,902,554	59,090,603	61,278,648
2019	57,679,179	59,938,328	62,197,479
2020	58,482,051	60,818,490	63,154,933
2021	59,241,988	61,658,364	64,074,740
2022	59,966,707	62,465,752	64,964,797

Average Annual Growth Rate, 2004-2022:

% growth:	**1.7%**	**1.7%**	**1.8%**

Note: Semi-Low and Semi-High Scenarios reflect an 80%/20% Confidence Level

Table XCEL-2
Xcel Energy
System Net Summer Peak (MW)

Year	Semi-Low (MW)	Median (MW)	Semi-High (MW)
2004	8,004	8,278	8,552
2005	8,141	8,434	8,728
2006	8,281	8,598	8,915
2007	8,449	8,796	9,144
2008	8,596	8,972	9,348
2009	8,723	9,126	9,529
2010	8,867	9,301	9,736
2011	9,004	9,470	9,936
2012	9,141	9,639	10,138
2013	9,266	9,786	10,305
2014	9,409	9,951	10,492
2015	9,551	10,115	10,679
2016	9,692	10,279	10,865
2017	9,821	10,429	11,037
2018	9,944	10,572	11,200
2019	10,061	10,709	11,357
2020	10,185	10,853	11,521
2021	10,318	11,012	11,705
2022	10,452	11,171	11,891

Average Annual Growth Rate, 2003-2021:

% growth:	**1.5%**	**1.7%**	**1.8%**

Note: Semi-Low and Semi-High Scenarios reflect an 80%/20% Confidence Level

Table XCEL-2
Xcel Energy
System Base Summer Peak (MW)

Year	Semi-Low (MW)	Median (MW)	Semi-High (MW)
2004	8,869	9,173	9,476
2005	9,029	9,355	9,681
2006	9,194	9,546	9,898
2007	9,381	9,766	10,152
2008	9,542	9,960	10,377
2009	9,685	10,132	10,580
2010	9,843	10,326	10,809
2011	9,995	10,512	11,030
2012	10,145	10,698	11,251
2013	10,284	10,861	11,437
2014	10,440	11,041	11,642
2015	10,595	11,220	11,846
2016	10,747	11,398	12,048
2017	10,888	11,561	12,235
2018	11,022	11,718	12,414
2019	11,150	11,868	12,587
2020	11,286	12,027	12,767
2021	11,431	12,199	12,967
2022	11,576	12,373	13,170

Average Annual Growth Rate, 2004-2022:

% growth:	**1.5%**	**1.7%**	**1.8%**

Note: Semi-Low and Semi-High Scenarios reflect an 80%/20% Confidence Level

Table XCEL-3
Xcel Energy
System Net Winter Peak (MW)

Year	Semi-Low (MW)	Median (MW)	Semi-High (MW)
2004	6,533	6,657	6,780
2005	6,590	6,722	6,854
2006	6,650	6,793	6,936
2007	6,715	6,872	7,028
2008	6,782	6,952	7,121
2009	6,852	7,024	7,195
2010	6,935	7,108	7,281
2011	7,013	7,188	7,363
2012	7,091	7,268	7,445
2013	7,168	7,347	7,526
2014	7,247	7,429	7,610
2015	7,326	7,509	7,692
2016	7,405	7,590	7,775
2017	7,476	7,663	7,850
2018	7,545	7,734	7,922
2019	7,612	7,802	7,992
2020	7,681	7,873	8,065
2021	7,747	7,941	8,135
2022	7,811	8,006	8,201

Average Annual Growth Rate, 2004-2022:			
% growth:	**1.0%**	**1.0%**	**1.1%**

Notes: Winter Peak = MAPP Winter Peak season, 2004 is 2004-2005 winter peak.
Semi-Low and Semi-High Scenarios reflect an 80%/20% Confidence Level

7610.0400 – Present Facilities

Following are data sheets on Xcel Energy's power plants and generating units.

POWER PLANT AND GENERATING UNIT DATA REPORT 2003

A. Plant Data

Plant Name	Utility Name	Date
United Hospital	Northern States Power Company d/b/a Xcel Energy	6/25/2004

Plant Address	City	State	Zip Code	County
333 North Smith Avenue	St. Paul	MN	55102	

Plant ID#	# of Units	Contact Person	Telephone
	3	Toni Martinez	(720)497-2012

B. Individual Generating Unit Data

Unit id #	Status	Type	Year Installed	Energy Source	Net Generation (MWHR)
All	USE	IC	1992		(171)
Plant Total					(171)

C. Individual Unit Capability Data

Unit id #	Capacity (MW)		Capacity Factor	Operating Availability	Forced Outage Rate (%)
	Summer	Winter			
All	4.77	4.77			
0					
0					
0					
Plant Total	4.77	4.77			

D. Fuel Used

Unit id #	Primary Fuel Use				Secondary Fuel Use		
	Fuel Type	Quantity	Unit of Measure	BTU Content	Fuel Type	Quantity	Unit of Measure
All	oil	3281	gallons				
0							
0							
0							
Plant Total		3281					

POWER PLANT AND GENERATING UNIT DATA REPORT 2003

A. Plant Data

Plant Name	Utility Name	Date
United Health Care	Northern States Power Company d/b/a Xcel Energy	6/25/2004

Plant Address	City	State	Zip Code	County
711 Douglas Avenue	Golden Valley	MN	55403	

Plant ID#	# of Units	Contact Person	Telephone
	2	Toni Martinez	(720)497-2012

B. Individual Generating Unit Data

Unit id #	Status	Type	Year Installed	Energy Source	Net Generation (MWHR)
Both	USE	IC	1993		(45)
Plant Total					(45)

C. Individual Unit Capability Data

Unit id #	Capacity (MW)		Capacity Factor	Operating Availability	Forced Outage Rate (%)
	Summer	Winter			
Both	3.66	3.66			
0					
0					
0					
Plant Total	3.66	3.66			

D. Fuel Used

Unit id #	Primary Fuel Use				Secondary Fuel Use		
	Fuel Type	Quantity	Unit of Measure	BTU Content	Fuel Type	Quantity	Unit of Measure
Both	oil	399	gallons				
0							
0							
0							
Plant Total		399					

POWER PLANT AND GENERATING UNIT DATA REPORT 2003

A. Plant Data

Plant Name	Utility Name	Date
Alliant Tech Systems	Northern States Power Company d/b/a Xcel Energy	6/25/2004

Plant Address	City	State	Zip Code	County
600 2nd Street NE	Hopkins	MN	55343	

Plant ID#	# of Units	Contact Person	Telephone
	2	Toni Martinez	(720)497-2012

B. Individual Generating Unit Data

Unit id #	Status	Type	Year Installed	Energy Source	Net Generation (MWHR)
Both	USE	IC	1993		(65)
Plant Total					(65)

C. Individual Unit Capability Data

Unit id #	Capacity (MW)		Capacity Factor	Operating Availability	Forced Outage Rate (%)
	Summer	Winter			
Both	1.67	1.67			
0					
0					
0					
Plant Total	1.67	1.67			

D. Fuel Used

Unit id #	Primary Fuel Use				Secondary Fuel Use		
	Fuel Type	Quantity	Unit of Measure	BTU Content	Fuel Type	Quantity	Unit of Measure
Both	oil	1441	gallons				
0							
0							
0							
Plant Total		1441					

POWER PLANT AND GENERATING UNIT DATA REPORT 2003

A. Plant Data

Plant Name	Utility Name	Date
Bayfront	Northern States Power, a Wisconsin Corporation, d/b/a Xcel Energy	6/25/2004

Plant Address	City	State	Zip Code	County
122 North 14th Ave. West	Ashland	WI	54806	Ashland

Plant ID#	# of Units	Contact Person	Telephone
	3	Toni Martinez	(720)497-2012

B. Individual Generating Unit Data

Unit id #	Status	Type	Year Installed		Energy Source	Net Generation (MWHR)
4	use	st	1948			
5	use	st	1950			
6	use	st	1956			
Plant Total						296,712

C. Individual Unit Capability Data

Unit id #	Capacity (MW) Summer	Winter	Capacity Factor	Operating Availability	Forced Outage Rate (%)
4	22.3	17.5			
5	22.6	17.2			
6	28.0	22.3			
Plant Total	72.9	57.0	46.40%	100.00%	0.00%

D. Fuel Used

Unit id #	Primary Fuel Use				Secondary Fuel Use		
	Fuel Type	Quantity	Unit of Measure	BTU Content	Fuel Type	Quantity	Unit of Measure
all	coal	135,498	tons	9,830			
all	wood	157,357	tons	5,809			
all	gas	78,709	mcf	1,006			
Plant Total							

mcf = 1000 cf

POWER PLANT AND GENERATING UNIT DATA REPORT 2003

A. Plant Data

Plant Name	Utility Name	Date
Wissota	Northern States Power, a Wisconsin Corporation, d/b/a Xcel Energy	6/25/2004

Plant Address	City	State	Zip Code	County
Route 6 Box 31	Chippewa Falls	WI	54729	

Plant ID#	# of Units	Contact Person	Telephone
	6	Toni Martinez	(720)497-2012

B. Individual Generating Unit Data

Unit id #	Status	Type	Year Installed	Energy Source	Net Generation (MWHR)
1	use	hc	1917		
2	use	hc	1917		
3	use	hc	1917		
4	use	hc	1917		
Plant Total	see next page				

C. Individual Unit Capability Data

Unit id #	Capacity (MW)		Capacity Factor	Operating Availability	Forced Outage Rate (%)
	Summer	Winter			
1	6.04	6.04	41.06%	100.00%	0.00%
2	6.23	6.23	52.02%	100.00%	0.00%
3	6.08	6.08	44.52%	100.00%	0.00%
4	6.08	6.08	53.64%	99.06%	1.46%
Plant Total	see next page				

D. Fuel Used

Unit id #	Primary Fuel Use				Secondary Fuel Use		
	Fuel Type	Quantity	Unit of Measure	BTU Content	Fuel Type	Quantity	Unit of Measure
All	hyd						
Plant Total		0					

POWER PLANT AND GENERATING UNIT DATA REPORT 2003

A. Plant Data

Plant Name	Utility Name	Date
Wissota	Northern States Power, a Wisconsin Corporation d/b/a Xcel Energy	6/25/2004

Plant Address	City	State	Zip Code	County
Route 6 Box 31	Chippewa Falls	WI	54729	

Plant ID#	# of Units	Contact Person	Telephone
	6	Toni Martinez	(720)497-2012

B. Individual Generating Unit Data

Unit id #	Status	Type	Year Installed	Energy Source	Net Generation (MWHR)
5	use	chi	1917		
6	use	hc	1917		
Plant Total					109,836

C. Individual Unit Capability Data

Unit id #	Capacity (MW) Summer	Capacity (MW) Winter	Capacity Factor	Operating Availability	Forced Outage Rate (%)
5	5.87	5.87	41.32%	98.35%	0.00%
6	5.87	5.87	29.01%	100.00%	0.00%
0					
0					
Plant Total	36.17	36.17			

D. Fuel Used

Unit id #	Primary Fuel Use: Fuel Type	Quantity	Unit of Measure	BTU Content	Secondary Fuel Use: Fuel Type	Quantity	Unit of Measure
All	hyd						
Plant Total		0					

POWER PLANT AND GENERATING UNIT DATA REPORT 2003

A. Plant Data

Plant Name	Utility Name	Date
White River	Northern States Power, a Wisconsin Corporation, d/b/a Xcel Energy	6/25/2004

Plant Address	City	State	Zip Code	County
		WI	54806	Ashland

Plant ID#	# of Units	Contact Person	Telephone
	2	Toni Martinez	(720)497-2012

B. Individual Generating Unit Data

Unit id #	Status	Type	Year Installed	Energy Source	Net Generation (MWHR)
1	use	hc	1907		
2	use	hc	1907		
Plant Total					4,171

C. Individual Unit Capability Data

Unit id #	Capacity (MW)		Capacity Factor	Operating Availability	Forced Outage Rate (%)
	Summer	Winter			
1	0.4	0.3	7.73%	54.59%	67.89%
2	0.4	0.3	42.53%	99.90%	0.12%
0					
0					
Plant Total	0.8	0.6			

D. Fuel Used

Unit id #	Primary Fuel Use				Secondary Fuel Use		
	Fuel Type	Quantity	Unit of Measure	BTU Content	Fuel Type	Quantity	Unit of Measure
All	hyd						
Plant Total		0					

*Capacity Factor, Operating Availability, and Forced Outage is based on the first 8 months of the year.

POWER PLANT AND GENERATING UNIT DATA REPORT 2003

A. Plant Data

Plant Name	Utility Name	Date
Wheaton	Northern States Power, a Wisconsin Corporation, d/b/a Xcel Energy	6/25/2004

Plant Address	City	State	Zip Code	County
Route 2	Eau Claire	WI	54701	

Plant ID#	# of Units	Contact Person	Telephone
	6	Toni Martinez	(720)497-2012

B. Individual Generating Unit Data

Unit id #	Status	Type	Year Installed	Energy Source	Net Generation (MWHR)
1	use	gt	1973		
2	use	gt	1973		
3	use	gt	1973		
4	use	gt	1973		
Plant Total	Continued on next page				

C. Individual Unit Capability Data

Unit id #	Capacity (MW) Summer	Capacity (MW) Winter	Capacity Factor	Operating Availability	Forced Outage Rate (%)
1	56.73	71.40	3.18%	100.00%	0.00%
2	64.09	80.69	3.14%	25.49%	74.51%
3	55.76	71.40	3.50%	37.39%	59.64%
4	56.49	71.40	2.08%	16.51%	82.77%
Plant Total	Continued on next page				

D. Fuel Used

Unit id #	Primary Fuel Use				Secondary Fuel Use		
	Fuel Type	Quantity	Unit of Measure	BTU Content	Fuel Type	Quantity	Unit of Measure
Plant Total	See next page						

POWER PLANT AND GENERATING UNIT DATA REPORT 2003

A. Plant Data

Plant Name	Utility Name	Date
Wheaton	Northern States Power, a Wisconsin Corporation, d/b/a Xcel Energy	6/25/2004

Plant Address	City	State	Zip Code	County
Route 2	Eau Claire	WI	54701	

Plant ID#	# of Units	Contact Person	Telephone
	6	Toni Martinez	(720)497-2012

B. Individual Generating Unit Data

Unit id #	Status	Type	Year Installed	Energy Source	Net Generation (MWHR)
5	use	gt	1973		
6	use	gt	1973		
Plant Total					79,558

C. Individual Unit Capability Data

Unit id #	Capacity (MW)		Capacity Factor	Operating Availability	Forced Outage Rate (%)
	Summer	Winter			
5	60.85	78.21	0.59%	7.42%	92.58%
6	61.47	80.21	0.82%	26.77%	70.23%
0					
0					
Plant Total	355.39	453.31			

D. Fuel Used

Unit id #	Primary Fuel Use				Secondary Fuel Use		
	Fuel Type	Quantity	Unit of Measure	BTU Content	Fuel Type	Quantity	Unit of Measure
All	fo2	1,700,005	gal	139,891	ng	990,053	kcf
Plant Total							

*Capacity Factor, Operating Availability, and Forced Outage is based on the first 8 months of the year.

POWER PLANT AND GENERATING UNIT DATA REPORT **2003**

A. Plant Data

Plant Name	Utility Name	Date
Thornapple	Northern States Power, a Wisconsin Corporation, d/b/a Xcel Energy	6/25/2004

Plant Address	City	State	Zip Code	County
	Ladysmith	WI	54848	

Plant ID#	# of Units	Contact Person	Telephone
	2	Toni Martinez	(720)497-2012

B. Individual Generating Unit Data

Unit id #	Status	Type	Year Installed		Energy Source	Net Generation (MWHR)
1	use	hc	1929			
2	use	hc	1929			
Plant Total						7,213

C. Individual Unit Capability Data

Unit id #	Capacity (MW)		Capacity Factor	Operating Availability	Forced Outage Rate (%)
	Summer	Winter			
1	0.78	0.78	29.93%	97.80%	2.29%
2	0.79	0.79	16.30%	68.20%	4.31%
0					
0					
Plant Total	1.6	1.6			

D. Fuel Used

Unit id #	Primary Fuel Use				Secondary Fuel Use		
	Fuel Type	Quantity	Unit of Measure	BTU Content	Fuel Type	Quantity	Unit of Measure
All	hyd						
Plant Total		0					

*Capacity Factor, Operating Availability, and Forced Outage is based on the first 8 months of the year.

POWER PLANT AND GENERATING UNIT DATA REPORT 2003

A. Plant Data

Plant Name	Utility Name	Date
Trego	Northern States Power, a Wisconsin Corporation, d/b/a Xcel Energy	6/25/2004

Plant Address	City	State	Zip Code	County
	Trego	WI	54888	

Plant ID#	# of Units	Contact Person	Telephone
	2	Toni Martinez	(720)497-2012

B. Individual Generating Unit Data

Unit id #	Status	Type	Year Installed	Energy Source	Net Generation (MWHR)
1	use	hc	1927		
2	use	hc	1927		
Plant Total					7,595

C. Individual Unit Capability Data

Unit id #	Capacity (MW) Summer	Winter	Capacity Factor	Operating Availability	Forced Outage Rate (%)
1	0.9	0.9	68.39%	98.85%	1.14%
2	0.52	0.52	24.70%	94.37%	2.12%
0					
0					
Plant Total	1.4	1.4			

D. Fuel Used

Unit id #	Primary Fuel Use				Secondary Fuel Use		
	Fuel Type	Quantity	Unit of Measure	BTU Content	Fuel Type	Quantity	Unit of Measure
All	hyd						
Plant Total		0					

*Capacity Factor, Operating Availability, and Forced Outage is based on the first 8 months of the year.

POWER PLANT AND GENERATING UNIT DATA REPORT 2003

A. Plant Data

Plant Name	Utility Name	Date
Superior Falls	Northern States Power, a Wisconsin Corporation, d/b/a Xcel Energy	6/25/2004

Plant Address	City	State	Zip Code	County
East 112 Lake Road	Ironwood	MI	49938	

Plant ID#	# of Units	Contact Person	Telephone
	2	Toni Martinez	(720)497-2012

B. Individual Generating Unit Data

Unit id #	Status	Type	Year Installed	Energy Source	Net Generation (MWHR)
1	use	hc	1917		
2	use	hc	1917		
Plant Total					9,890

C. Individual Unit Capability Data

Unit id #	Capacity (MW)		Capacity Factor	Operating Availability	Forced Outage Rate (%)
	Summer	Winter			
1	0.95	0.75	63.42%	85.34%	2.30%
2	0.90	0.70	71.45%	94.63%	0.10%
0					
0					
Plant Total	1.9	1.5			

D. Fuel Used

Unit id #	Primary Fuel Use				Secondary Fuel Use		
	Fuel Type	Quantity	Unit of Measure	BTU Content	Fuel Type	Quantity	Unit of Measure
All	hyd						
Plant Total		0					

*Capacity Factor, Operating Availability, and Forced Outage is based on the first 8 months of the year.

POWER PLANT AND GENERATING UNIT DATA REPORT 2003

A. Plant Data

Plant Name	Utility Name	Date
St. Croix Falls	Northern States Power, a Wisconsin Corporation, d/b/a Xcel Energy	6/28/2004

Plant Address	City	State	Zip Code	County
	St. Croix Falls	WI	54024	

Plant ID#	# of Units	Contact Person	Telephone
	8	Toni Martinez	(720)497-2012

B. Individual Generating Unit Data

Unit id #	Status	Type	Year Installed	Energy Source	Net Generation (MWHR)
1	use	hc	1905		
2	use	hc	1905		
3	use	hc	1905		
4	use	hc	1905		
Plant Total	see next page				

C. Individual Unit Capability Data

Unit id #	Capacity (MW)		Capacity Factor	Operating Availability	Forced Outage Rate (%)
	Summer	Winter			
1	3.29	3.29	50.32%	82.44%	17.38%
2	2.99	2.99	57.62%	85.51%	0.00%
3	2.99	2.99	42.51%	91.15%	0.00%
4	2.99	2.99	46.93%	87.60%	6.89%
Plant Total	see next page				

D. Fuel Used

Unit id #	Primary Fuel Use				Secondary Fuel Use		
	Fuel Type	Quantity	Unit of Measure	BTU Content	Fuel Type	Quantity	Unit of Measure
All	hyd						
Plant Total		0					

POWER PLANT AND GENERATING UNIT DATA REPORT 2003

A. Plant Data

Plant Name	Utility Name	Date
St. Croix Falls	Northern States Power, a Wisconsin Corporation, d/b/a Xcel Energy	6/25/2004

Plant Address	City	State	Zip Code	County
	St. Croix Falls	WI	54024	

Plant ID#	# of Units	Contact Person	Telephone
	8	Toni Martinez	(720)497-2012

B. Individual Generating Unit Data

Unit id #	Status	Type	Year Installed	Energy Source	Net Generation (MWHR)
5	use	hc	1910		
6	use	hc	1910		
7	use	hc	1923		
8	use	hc	1923		
Plant Total					109,813

C. Individual Unit Capability Data

Unit id #	Capacity (MW) Summer	Capacity (MW) Winter	Capacity Factor	Operating Availability	Forced Outage Rate (%)
5	2.99	2.99	58.82%	68.85%	0.02%
6	3.09	3.09	66.81%	72.48%	0.00%
7	3.19	3.19	48.82%	72.47%	0.03%
8	2.99	2.99	41.92%	66.35%	0.00%
Plant Total	24.52	24.52			

D. Fuel Used

Unit id #	Primary Fuel Use				Secondary Fuel Use		
	Fuel Type	Quantity	Unit of Measure	BTU Content	Fuel Type	Quantity	Unit of Measure
All	hyd						
Plant Total		0					

*Capacity Factor, Operating Availability, and Forced Outage is based on the first 8 months of the year.

POWER PLANT AND GENERATING UNIT DATA REPORT 2003

A. Plant Data

Plant Name	Utility Name	Date
Riverdale	Northern States Power, a Wisconsin Corporation, d/b/a Xcel Energy	6/25/2004

Plant Address	City	State	Zip Code	County
		WI	54025	St. Croix

Plant ID#	# of Units	Contact Person	Telephone
	2	Toni Martinez	(720)497-2012

B. Individual Generating Unit Data

Unit id #	Status	Type	Year Installed	Energy Source	Net Generation (MWHR)
1	use	hc	1905		
2	use	hc	1905		
Plant Total					3,546

C. Individual Unit Capability Data

Unit id #	Capacity (MW) Summer	Capacity (MW) Winter	Capacity Factor	Operating Availability	Forced Outage Rate (%)
1	0.32	0.32	23.19%	99.37%	0.14%
2	0.28	0.28	21.85%	97.67%	2.29%
0					
0					
Plant Total	0.60	0.60			

D. Fuel Used

Unit id #	Primary Fuel Use: Fuel Type	Quantity	Unit of Measure	BTU Content	Secondary Fuel Use: Fuel Type	Quantity	Unit of Measure
1	hyd						
2							
0							
0							
Plant Total		0					

*Capacity Factor, Operating Availability, and Forced Outage is based on the first 8 months of the year.

POWER PLANT AND GENERATING UNIT DATA REPORT 2003

A. Plant Data

Plant Name	Utility Name	Date
Saxon Falls	Northern States Power, a Wisconsin Corporation, d/b/a Xcel Energy	6/25/2004

Plant Address	City	State	Zip Code	County
	Saxon	WI	54559	

Plant ID#	# of Units	Contact Person	Telephone
	2	Toni Martinez	(720)497-2012

B. Individual Generating Unit Data

Unit id #	Status	Type	Year Installed	Energy Source	Net Generation (MWHR)
1	use	hc	1913		
2	use	hc	1913		
Plant Total					9,061

C. Individual Unit Capability Data

Unit id #	Capacity (MW)		Capacity Factor	Operating Availability	Forced Outage Rate (%)
	Summer	Winter			
1	0.70	0.55	52.99%	93.75%	0.04%
2	0.80	0.65	68.22%	94.03%	0.04%
0					
0					
Plant Total	1.55	1.2			

D. Fuel Used

Unit id #	Primary Fuel Use				Secondary Fuel Use		
	Fuel Type	Quantity	Unit of Measure	BTU Content	Fuel Type	Quantity	Unit of Measure
Both	hyd						
Plant Total		0				0	

*Capacity Factor, Operating Availability, and Forced Outage is based on the first 8 months of the year.

POWER PLANT AND GENERATING UNIT DATA REPORT 2003

A. Plant Data

Plant Name	Utility Name	Date
Big Falls	Northern States Power, a Wisconsin Corporation, d/b/a Xcel Energy	6/25/2004

Plant Address	City	State	Zip Code	County
		WI	54563	Rusk

Plant ID#	# of Units	Contact Person	Telephone
	3	Toni Martinez	(720)497-2012

B. Individual Generating Unit Data

Unit id #	Status	Type	Year Installed	Energy Source	Net Generation (MWHR)
1	use	hc	1922		
2	use	hc	1922		
3	use	hc	1925		
Plant Total					30,189

C. Individual Unit Capability Data

Unit id #	Capacity (MW)		Capacity Factor	Operating Availability	Forced Outage Rate (%)
	Summer	Winter			
1	2.39	2.39	54.23%	99.93%	0.00%
2	2.39	2.39	57.81%	99.95%	0.00%
3	2.59	2.59	23.63%	99.91%	0.00%
0					
Plant Total	7.37	7.37			

D. Fuel Used

Unit id #	Primary Fuel Use				Secondary Fuel Use		
	Fuel Type	Quantity	Unit of Measure	BTU Content	Fuel Type	Quantity	Unit of Measure
1	hyd						
2	hyd						
3	hyd						
0							
Plant Total		0					

*Capacity Factor, Operating Availability, and Forced Outage is based on the first 8 months of the year.

POWER PLANT AND GENERATING UNIT DATA REPORT 2003

A. Plant Data

Plant Name	Utility Name	Date
Angus Anson	Northern States Power Company d/b/a Xcel Energy	6/25/2004

Plant Address	City	State	Zip Code	County
RFD 2 Box 352	Sioux Falls	SD	57101	

Plant ID#	# of Units	Contact Person	Telephone
	2	Toni Martinez	(720)497-2012

B. Individual Generating Unit Data

Unit id #	Status	Type	Year Installed	Energy Source	Net Generation (MWHR)
2	use	gt	1994		
3	use	gt	1994		
Plant Total					100,396

C. Individual Unit Capability Data

Unit id #	Capacity (MW)		Capacity Factor	Operating Availability	Forced Outage Rate (%)
	Summer	Winter			
2	106.0	128.0	5.42%	99.08%	0.00%
3	105.5	128.0	3.97%	76.65%	3.44%
0					
0					
Plant Total	211.5	256.0			

D. Fuel Used

Unit id #	Primary Fuel Use				Secondary Fuel Use		
	Fuel Type	Quantity	Unit of Measure	BTU Content	Fuel Type	Quantity	Unit of Measure
Both	ng	1,351,297	mcf	1,005	fo2	366,372	gal
Plant Total		1,351,297				366,372	

mcf = 1000 cf

POWER PLANT AND GENERATING UNIT DATA REPORT 2003

A. Plant Data

Plant Name	Utility Name	Date
Pathfinder	Northern States Power Company d/b/a Xcel Energy	6/25/2004

Plant Address	City	State	Zip Code	County
RFD 2 Box 352	Sioux Falls	SD	57101	

Plant ID#	# of Units	Contact Person	Telephone
	1	Toni Martinez	(720)497-2012

B. Individual Generating Unit Data

Unit id #	Status	Type	Year Installed	Energy Source	Net Generation (MWHR)
1	RET	ST	1969		
Plant Total					(1,396)

C. Individual Unit Capability Data

Unit id #	Capacity (MW)		Capacity Factor	Operating Availability	Forced Outage Rate (%)
	Summer	Winter			
1	0.0	0.0	0.00%	0	100.00%
0					
0					
0					
Plant Total	0.0	0.0	0	0	1

D. Fuel Used

Unit id #	Primary Fuel Use				Secondary Fuel Use		
	Fuel Type	Quantity	Unit of Measure	BTU Content	Fuel Type	Quantity	Unit of Measure
1	ng	0	mcf	1000			
Plant Total		0					

mcf = 1000 cf

Retired Unit

POWER PLANT AND GENERATING UNIT DATA REPORT 2003

A. Plant Data

Plant Name	Utility Name	Date
Menomonie	Northern States Power, a Wisconsin Corporation, d/b/a Xcel Energy	6/25/2004

Plant Address	City	State	Zip Code	County
	Menomonie	WI	54751	

Plant ID#	# of Units	Contact Person	Telephone
	2	Toni Martinez	(720)497-2012

B. Individual Generating Unit Data

Unit id #	Status	Type	Year Installed	Energy Source	Net Generation (MWHR)
1	use	hc	1958		
2	use	hc	1958		
Plant Total					25,604

C. Individual Unit Capability Data

Unit id #	Capacity (MW) Summer	Capacity (MW) Winter	Capacity Factor	Operating Availability	Forced Outage Rate (%)
1	2.66	2.66	54.43%	99.97%	0.00%
2	2.72	2.72	53.41%	99.92%	0.00%
0					
0					
Plant Total	5.38	5.38			

D. Fuel Used

Unit id #	Primary Fuel Use				Secondary Fuel Use		
	Fuel Type	Quantity	Unit of Measure	BTU Content	Fuel Type	Quantity	Unit of Measure
All	hyd						
Plant Total		0					

*Capacity Factor, Operating Availability, and Forced Outage is based on the first 8 months of the year.

POWER PLANT AND GENERATING UNIT DATA REPORT 2003

A. Plant Data

Plant Name	Utility Name	Date
Ladysmith	Northern States Power, a Wisconsin Corporation, d/b/a Xcel Energy	6/25/2004

Plant Address	City	State	Zip Code	County
	Ladysmith	WI	54848	

Plant ID#	# of Units	Contact Person	Telephone
	3	Toni Martinez	(720)497-2012

B. Individual Generating Unit Data

Unit id #	Status	Type	Year Installed	Energy Source	Net Generation (MWHR)
1	use	hc	1940		
2	use	hc	1940		
3	use	hc	1983		
Plant Total					9,083

C. Individual Unit Capability Data

Unit id #	Capacity (MW) Summer	Capacity (MW) Winter	Capacity Factor	Operating Availability	Forced Outage Rate (%)
1	0.87	0.87	42.79%	99.97%	0.00%
2	0.81	0.81	46.61%	93.40%	0.00%
3	1.10	1.10	33.89%	99.93%	0.00%
0					
Plant Total	2.78	2.78			

D. Fuel Used

Unit id #	Primary Fuel Use Fuel Type	Quantity	Unit of Measure	BTU Content	Secondary Fuel Use Fuel Type	Quantity	Unit of Measure
All	hyd						
Plant Total		0					

*Capacity Factor, Operating Availability, and Forced Outage is based on the first 8 months of the year.

POWER PLANT AND GENERATING UNIT DATA REPORT 2003

A. Plant Data		
Plant Name Jim Falls	Utility Name Northern States Power, a Wisconsin Corporation, d/b/a Xcel Energy	Date 6/25/2004

Plant Address	City	State	Zip Code	County
	Jim Falls	WI	54748	

Plant ID#	# of Units	Contact Person	Telephone
	3	Toni Martinez	(720)497-2012

B. Individual Generating Unit Data					
Unit id #	Status	Type	Year Installed	Energy Source	Net Generation (MWHR)
1	use	hc	1988		
2	use	hc	1988		
3	use	hc	1986		
Plant Total					104,441

C. Individual Unit Capability Data					
Unit id #	Capacity (MW)		Capacity Factor	Operating Availability	Forced Outage Rate (%)
	Summer	Winter			
1	27.96	27.96	25.99%	97.96%	2.04%
2	28.26	28.26	26.40%	100.00%	0.00%
3	0.50	0.50	45.10%	98.11%	1.87%
0					
Plant Total	56.72	56.72			

D. Fuel Used							
Unit id #	Primary Fuel Use				Secondary Fuel Use		
	Fuel Type	Quantity	Unit of Measure	BTU Content	Fuel Type	Quantity	Unit of Measure
All	hyd						
Plant Total		0					

*Capacity Factor, Operating Availability, and Forced Outage is based on the first 8 months of the year.

POWER PLANT AND GENERATING UNIT DATA REPORT 2003

A. Plant Data

Plant Name	Utility Name	Date
Holcombe	Northern States Power, a Wisconsin Corporation, d/b/a Xcel Energy	6/25/2004

Plant Address	City	State	Zip Code	County
	Holcombe	WI	54745	

Plant ID#	# of Units	Contact Person	Telephone
	3	Toni Martinez	(720)497-2012

B. Individual Generating Unit Data

Unit id #	Status	Type	Year Installed	Energy Source	Net Generation (MWHR)
1	use	hc	1950		
2	use	hc	1950		
3	use	hc	1950		
Plant Total					79,815

C. Individual Unit Capability Data

Unit id #	Capacity (MW)		Capacity Factor	Operating Availability	Forced Outage Rate (%)
	Summer	Winter			
1	11.7	11.7	30.22%	96.73%	0.00%
2	11.7	11.7	36.62%	99.42%	0.00%
3	11.7	11.7	28.23%	94.97%	0.00%
0					
Plant Total	35.13	35.13			

D. Fuel Used

Unit id #	Primary Fuel Use				Secondary Fuel Use		
	Fuel Type	Quantity	Unit of Measure	BTU Content	Fuel Type	Quantity	Unit of Measure
All	hyd						
Plant Total		0					

*Capacity Factor, Operating Availability, and Forced Outage is based on the first 8 months of the year.

POWER PLANT AND GENERATING UNIT DATA REPORT 2003

A. Plant Data

Plant Name	Utility Name	Date
Hayward	Northern States Power, a Wisconsin Corporation, d/b/a Xcel Energy	6/25/2004

Plant Address	City	State	Zip Code	County
	Hayward	WI	54806	

Plant ID#	# of Units	Contact Person	Telephone
	1	Toni Martinez	(720)497-2012

B. Individual Generating Unit Data

Unit id #	Status	Type	Year Installed	Energy Source	Net Generation (MWHR)
1	use	hc	1925		
Plant Total					1,491

C. Individual Unit Capability Data

Unit id #	Capacity (MW)		Capacity Factor	Operating Availability	Forced Outage Rate (%)
	Summer	Winter			
1	0.2	0.2	17.05%	99.48%	0.06%
0					
0					
0					
Plant Total	0.2	0.2			

D. Fuel Used

Unit id #	Primary Fuel Use				Secondary Fuel Use		
	Fuel Type	Quantity	Unit of Measure	BTU Content	Fuel Type	Quantity	Unit of Measure
1	hyd						
Plant Total		0					

*Capacity Factor, Operating Availability, and Forced Outage is based on the first 8 months of the year.

POWER PLANT AND GENERATING UNIT DATA REPORT 2003

A. Plant Data

Plant Name	Utility Name	Date
French Island	Northern States Power, a Wisconsin Corporation, d/b/a Xcel Energy	6/25/2004

Plant Address	City	State	Zip Code	County
South End of Bainbridge	LaCrosse	WI		

Plant ID#	# of Units	Contact Person	Telephone
	4	Toni Martinez	(720)497-2012

B. Individual Generating Unit Data

Unit id #	Status	Type	Year Installed	Energy Source	Net Generation (MWHR)
1	use	st	1969		76,057
2	use	st	1969		
3	use	gt	1974		7,966
4	use	gt	1974		
Plant Total					84,023

C. Individual Unit Capability Data

Unit id #	Capacity (MW)		Capacity Factor	Operating Availability	Forced Outage Rate (%)
	Summer	Winter			
1	14.00	15.00	31.20%	80.75%	12.15%
2	14.00	15.00	35.93%	89.15%	3.51%
3	72.03	93.62	51.00%	99.86%	0.00%
4	73.34	93.38	61.00%	96.76%	2.68%
Plant Total	173.37	217			

D. Fuel Used

Unit id #	Primary Fuel Use				Secondary Fuel Use		
	Fuel Type	Quantity	Unit of Measure	BTU Content	Fuel Type	Quantity	Unit of Measure
1 - 2	wood	58,008	tons	6933	ref	52,484	tons
1 - 2	ng	3,101	mcf	1,006			
3 - 4	fo2	1,022,783	gal	139,998			
Plant Total							

mcf = 1000 cf

*Capacity Factor, Operating Availability, and Forced Outage is based on the first 8 months of the year.

POWER PLANT AND GENERATING UNIT DATA REPORT 2003

A. Plant Data

Plant Name	Utility Name	Date
Flambeau	Northern States Power, a Wisconsin Corporation, d/b/a Xcel Energy	6/25/2004

Plant Address	City	State	Zip Code	County
	Park Falls	WI	54552	

Plant ID#	# of Units	Contact Person	Telephone
	1	Toni Martinez	(720)497-2012

B. Individual Generating Unit Data

Unit id #	Status	Type	Year Installed	Energy Source	Net Generation (MWHR)
1	use	gt	1969		
Plant Total					4,968

C. Individual Unit Capability Data

Unit id #	Capacity (MW) Summer	Capacity (MW) Winter	Capacity Factor	Operating Availability	Forced Outage Rate (%)
1	14.08	19.50	4.32%	100.00%	0.00%
0					
0					
0					
Plant Total	14.08	19.5	4.32%	100.00%	0.00%

D. Fuel Used

Unit id #	Primary Fuel Use: Fuel Type	Quantity	Unit of Measure	BTU Content	Secondary Fuel Use: Fuel Type	Quantity	Unit of Measure
1	ng	83,269	mcf	1,009	fo2	58,760	gal
Plant Total		83,269				58,760	

mcf = 1000 cf

*Capacity Factor, Operating Availability, and Forced Outage is based on the first 8 months of the year.

POWER PLANT AND GENERATING UNIT DATA REPORT 2003

A. Plant Data

Plant Name	Utility Name	Date
Dells	Northern States Power, a Wisconsin Corporation, d/b/a Xcel Energy	6/25/2004

Plant Address	City	State	Zip Code	County
Forest Street	Eau Claire	WI	54701	

Plant ID#	# of Units	Contact Person	Telephone
	7	Toni Martinez	(720)497-2012

B. Individual Generating Unit Data

Unit id #	Status	Type	Year Installed	Energy Source	Net Generation (MWHR)
1	use	hc	1923		
2	use	hc	1924		
3	use	hc	1930		
4	use	hc	1930		
Plant Total	see next page				

C. Individual Unit Capability Data

Unit id #	Capacity (MW) Summer	Capacity (MW) Winter	Capacity Factor	Operating Availability	Forced Outage Rate (%)
1	2.34	2.34	33.75%	93.24%	6.76%
2	1.19	1.19	34.62%	100.00%	0.00%
3	1.29	1.29	36.28%	100.00%	0.00%
4	1.29	1.29	31.21%	100.00%	0.00%
Plant Total	see next page				

D. Fuel Used

Unit id #	Primary Fuel Use				Secondary Fuel Use		
	Fuel Type	Quantity	Unit of Measure	BTU Content	Fuel Type	Quantity	Unit of Measure
All	hyd						
Plant Total		0					

POWER PLANT AND GENERATING UNIT DATA REPORT 2003

A. Plant Data

Plant Name	Utility Name	Date
Dells	Northern States Power, a Wisconsin Corporation, d/b/a Xcel Energy	6/25/2004

Plant Address	City	State	Zip Code	County
Forest Street	Eau Claire	WI	54701	

Plant ID#	# of Units	Contact Person	Telephone
	7	Toni Martinez	(720)497-2012

B. Individual Generating Unit Data

Unit id #	Status	Type	Year Installed	Energy Source	Net Generation (MWHR)
5	use	hc	1930		
6	use	hc	1916		
7	use	hc	1907		
Plant Total					36,416

C. Individual Unit Capability Data

Unit id #	Capacity (MW) Summer	Winter	Capacity Factor	Operating Availability	Forced Outage Rate (%)
5	1.19	1.19	45.03%	97.34%	0.00%
6	0.59	0.59	43.11%	93.41%	6.59%
7	0.69	0.69	38.88%	91.64%	8.36%
Plant Total	8.58	8.58			

D. Fuel Used

Unit id #	Primary Fuel Use				Secondary Fuel Use		
	Fuel Type	Quantity	Unit of Measure	BTU Content	Fuel Type	Quantity	Unit of Measure
All	hyd						
Plant Total		0					

POWER PLANT AND GENERATING UNIT DATA REPORT 2003

A. Plant Data

Plant Name	Utility Name	Date
Saxon Falls	Northern States Power, a Wisconsin Corporation, d/b/a Xcel Energy	6/25/2004

Plant Address	City	State	Zip Code	County
	Saxon	WI	54559	

Plant ID#	# of Units	Contact Person	Telephone
	2	Toni Martinez	(720)497-2012

B. Individual Generating Unit Data

Unit id #	Status	Type	Year Installed	Energy Source	Net Generation (MWHR)
1	use	hc	1913		
2	use	hc	1913		
Plant Total					9,061

C. Individual Unit Capability Data

Unit id #	Capacity (MW)		Capacity Factor	Operating Availability	Forced Outage Rate (%)
	Summer	Winter			
1	0.70	0.55	52.99%	93.75%	0.04%
2	0.80	0.65	68.22%	94.03%	0.04%
0					
0					
Plant Total	1.55	1.2			

D. Fuel Used

Unit id #	Primary Fuel Use				Secondary Fuel Use		
	Fuel Type	Quantity	Unit of Measure	BTU Content	Fuel Type	Quantity	Unit of Measure
Both	hyd						
Plant Total		0				0	

*Capacity Factor, Operating Availability, and Forced Outage is based on the first 8 months of the year.

POWER PLANT AND GENERATING UNIT DATA REPORT 2003

A. Plant Data

Plant Name	Utility Name	Date
Cedar Falls	Northern States Power, a Wisconsin Corporation, d/b/a Xcel Energy	6/25/2004

Plant Address	City	State	Zip Code	County
	Menomonie	WI	54751	

Plant ID#	# of Units	Contact Person	Telephone
	3	Toni Martinez	(720)497-2012

B. Individual Generating Unit Data

Unit id #	Status	Type	Year Installed	Energy Source	Net Generation (MWHR)
1	use	hc	1910		
2	use	hc	1911		
3	use	hc	1915		
Plant Total					35,770

C. Individual Unit Capability Data

Unit id #	Capacity (MW)		Capacity Factor	Operating Availability	Forced Outage Rate (%)
	Summer	Winter			
1	2.50	2.50	42.18%	99.95%	0.03%
2	2.28	2.28	57.71%	99.95%	0.02%
3	2.33	2.33	51.60%	99.96%	0.02%
0					
Plant Total	7.11	7.11			

D. Fuel Used

Unit id #	Primary Fuel Use				Secondary Fuel Use		
	Fuel Type	Quantity	Unit of Measure	BTU Content	Fuel Type	Quantity	Unit of Measure
All	hyd						
Plant Total		0					

*Capacity Factor, Operating Availability, and Forced Outage is based on the first 8 months of the year.

POWER PLANT AND GENERATING UNIT DATA REPORT 2003

A. Plant Data

Plant Name	Utility Name	Date
Chippewa Falls	Northern States Power, a Wisconsin Corporation, d/b/a Xcel Energy	6/28/2004

Plant Address	City	State	Zip Code	County
	Chippewa Falls	WI	54729	

Plant ID#	# of Units	Contact Person	Telephone
	6	Toni Martinez	(720)497-2012

B. Individual Generating Unit Data

Unit id #	Status	Type	Year Installed	Energy Source	Net Generation (MWHR)
1	use	hc	1928		
2	use	hc	1928		
3	use	hc	1928		
4	use	hc	1928		
Plant Total					54,661

C. Individual Unit Capability Data

Unit id #	Capacity (MW)		Capacity Factor	Operating Availability	Forced Outage Rate (%)
	Summer	Winter			
1	3.79	3.79	38.73%	100.00%	0.00%
2	3.89	3.89	30.90%	100.00%	0.00%
3	3.89	3.89	31.67%	100.00%	0.00%
4	3.89	3.89	32.90%	100.00%	0.00%
Plant Total					

D. Fuel Used

Unit id #	Primary Fuel Use				Secondary Fuel Use		
	Fuel Type	Quantity	Unit of Measure	BTU Content	Fuel Type	Quantity	Unit of Measure
All	hyd						
Plant Total		0					

POWER PLANT AND GENERATING UNIT DATA REPORT 2003

A. Plant Data

Plant Name	Utility Name	Date
Chippewa Falls	Northern States Power, a Wisconsin Corporation, d/b/a Xcel Energy	6/28/2004

Plant Address	City	State	Zip Code	County
	Chippewa Falls	WI	54729	

Plant ID#	# of Units	Contact Person	Telephone
	6	Mary Dupre	(612) 337.2101

B. Individual Generating Unit Data

Unit id #	Status	Type	Year Installed	Energy Source	Net Generation (MWHR)
5	use	hc	1928		
6	use	hc	1928		
Plant Total					54,661

C. Individual Unit Capability Data

Unit id #	Capacity (MW) Summer	Capacity (MW) Winter	Capacity Factor	Operating Availability	Forced Outage Rate (%)
5	2.39	2.39	37.19%	100.00%	0.00%
6	2.89	2.89	21.18%	75.50%	24.50%
Plant Total	20.74	20.74			

D. Fuel Used

Unit id #	Primary Fuel Use: Fuel Type	Quantity	Unit of Measure	BTU Content	Secondary Fuel Use: Fuel Type	Quantity	Unit of Measure
All	hyd						
Plant Total							

*Capacity Factor, Operating Availability, and Forced Outage is based on the first 8 months of the year.

POWER PLANT AND GENERATING UNIT DATA REPORT 2003

A. Plant Data

Plant Name	Utility Name	Date
Cornell	Northern States Power, a Wisconsin Corporation, d/b/a Xcel Energy	6/25/2004

Plant Address	City	State	Zip Code	County
P O Box 827	Cornell	WI	54732	

Plant ID#	# of Units	Contact Person	Telephone
	4	Toni Martinez	(720)497-2012

B. Individual Generating Unit Data

Unit id #	Status	Type	Year Installed	Energy Source	Net Generation (MWHR)
1	use	hc	1976		
2	use	hc	1976		
3	use	hc	1976		
4	use	hc	1976		
Plant Total					67,715

C. Individual Unit Capability Data

Unit id #	Capacity (MW)		Capacity Factor	Operating Availability	Forced Outage Rate (%)
	Summer	Winter			
1	10.33	10.33	10.55%	22.58%	56.55%
2	10.69	10.69	37.47%	81.19%	0.00%
3	11.43	11.43	34.57%	92.95%	0.00%
4	0.54	0.54	51.04%	80.60%	7.31%
Plant Total	32.99	32.99			

D. Fuel Used

Unit id #	Primary Fuel Use				Secondary Fuel Use		
	Fuel Type	Quantity	Unit of Measure	BTU Content	Fuel Type	Quantity	Unit of Measure
All	hyd						
Plant Total		0					

*Capacity Factor, Operating Availability, and Forced Outage is based on the first 8 months of the year.

POWER PLANT AND GENERATING UNIT DATA REPORT 2003

A. Plant Data

Plant Name	Utility Name	Date
Apple River	Northern States Power, a Wisconsin Corporation, d/b/a Xcel Energy	6/25/2004

Plant Address	City	State	Zip Code	County
	Somerset	WI	54025	

Plant ID#	# of Units	Contact Person	Telephone
	4	Toni Martinez	(720)497-2012

B. Individual Generating Unit Data

Unit id #	Status	Type	Year Installed	Energy Source	Net Generation (MWHR)
1	use	hc	1900		
2	use	hc	1900		
3	use	hc	1900		
4	ret	hc	1900		
Plant Total					18,255

C. Individual Unit Capability Data

Unit id #	Capacity (MW)		Capacity Factor	Operating Availability	Forced Outage Rate (%)
	Summer	Winter			
1	0.8	0.8	33.00%	49.43%	0.04%
2	1.1	1.1	92.68%	99.76%	0.10%
3	1.1	1.1	72.73%	94.49%	5.47%
4					
Plant Total	2.93	2.93			

D. Fuel Used

Unit id #	Primary Fuel Use				Secondary Fuel Use		
	Fuel Type	Quantity	Unit of Measure	BTU Content	Fuel Type	Quantity	Unit of Measure
All	hyd						
Plant Total		0					

*Capacity Factor, Operating Availability, and Forced Outage is based on the first 8 months of the year.

POWER PLANT AND GENERATING UNIT DATA REPORT 2003

A. Plant Data

Plant Name	Utility Name	Date
Hennepin Island	Northern States Power Company d/b/a Xcel Energy	6/28/2004

Plant Address	City	State	Zip Code	County
	Minneapolis	MN	55414	Hennepin

Plant ID#	# of Units	Contact Person	Telephone
	5	Toni Martinez	(720)497-2012

B. Individual Generating Unit Data

Unit id #	Status	Type	Year Installed	Energy Source	Net Generation (MWHR)
1	use	hc	1954		
2	use	hc	1954		
3	use	hc	1954		
4	use	hc	1954		
Plant Total					

C. Individual Unit Capability Data

Unit id #	Capacity (MW)		Capacity Factor	Operating Availability	Forced Outage Rate (%)
	Summer	Winter			
1	2.40	2.40	57.65%	97.19%	2.40%
2	2.35	2.35	0.00%	0.00%	100.00%
3	2.30	2.30	59.09%	100.00%	0.00%
4	2.30	2.30	34.93%	60.49%	0.00%
Plant Total					

D. Fuel Used

Unit id #	Primary Fuel Use				Secondary Fuel Use		
	Fuel Type	Quantity	Unit of Measure	BTU Content	Fuel Type	Quantity	Unit of Measure
1-5	Hyd	All					
Plant Total							

POWER PLANT AND GENERATING UNIT DATA REPORT 2003

A. Plant Data

Plant Name	Utility Name	Date
Hennepin Island	Northern States Power Company d/b/a Xcel Energy	6/28/2004

Plant Address	City	State	Zip Code	County
	Minneapolis	MN	55414	Hennepin

Plant ID#	# of Units	Contact Person	Telephone
	5	Toni Martinez	(720)497-2012

B. Individual Generating Unit Data

Unit id #	Status	Type	Year Installed	Energy Source	Net Generation (MWHR)
5	use	hc	1955		
Plant Total					56,872

C. Individual Unit Capability Data

Unit id #	Capacity (MW)		Capacity Factor	Operating Availability	Forced Outage Rate (%)
	Summer	Winter			
5	2.70	2.70	52.55%	100.00%	0.00%
Plant Total	12.05	12.05			

D. Fuel Used

Unit id #	Primary Fuel Use				Secondary Fuel Use		
	Fuel Type	Quantity	Unit of Measure	BTU Content	Fuel Type	Quantity	Unit of Measure
All	Hydro						
Plant Total							

mcf = 1000 cf

*Capacity Factor, Operating Availability, and Forced Outage is based on the first 8 months of the year.

POWER PLANT AND GENERATING UNIT DATA REPORT 2003

A. Plant Data

Plant Name	Utility Name	Date
West Faribault	Northern States Power Company d/b/a Xcel Energy	6/25/2004

Plant Address	City	State	Zip Code	County
	Faribault	MN	55021	Rice

Plant ID#	# of Units	Contact Person	Telephone
	2	Toni Martinez	(720)497-2012

B. Individual Generating Unit Data

Unit id #	Status	Type	Year Installed	Energy Source	Net Generation (MWHR)
2	use	gt	1965		
3	use	gt	1965		
Plant Total					55

C. Individual Unit Capability Data

Unit id #	Capacity (MW) Summer	Capacity (MW) Winter	Capacity Factor	Operating Availability	Forced Outage Rate (%)
2	16.90	0.00	0.08%	0.24%	99.76%
3	14.70	0.00	0.07%	100.00%	0.00%
0					
0					
Plant Total	31.6	0			

D. Fuel Used

Unit id #	Primary Fuel Use				Secondary Fuel Use		
	Fuel Type	Quantity	Unit of Measure	BTU Content	Fuel Type	Quantity	Unit of Measure
Both	ng	13,276	mcf	1,010			
Plant Total		13,276					

mcf = 1000 cf

*Capacity Factor, Operating Availability, and Forced Outage is based on the first 8 months of the year.

POWER PLANT AND GENERATING UNIT DATA REPORT 2003

A. Plant Data

Plant Name	Utility Name	Date
Key City	Northern States Power Company d/b/a Xcel Energy	6/25/2004

Plant Address	City	State	Zip Code	County
P O Box 1090	Mankato	MN	56001	Blue Earth

Plant ID#	# of Units	Contact Person	Telephone
	4	Toni Martinez	(720)497-2012

B. Individual Generating Unit Data

Unit id #	Status	Type	Year Installed	Energy Source	Net Generation (MWHR)
1	use	gt	1969		
2	use	gt	1969		
3	use	gt	1969		
4	use	gt	1969		
Plant Total					2,647

C. Individual Unit Capability Data

Unit id #	Capacity (MW)		Capacity Factor	Operating Availability	Forced Outage Rate (%)
	Summer	Winter			
1	15.40	19.50	0.46%	100.00%	0.00%
2	15.20	19.50	0.45%	100.00%	0.00%
3	15.90	19.50	0.63%	100.00%	0.00%
4	16.50	19.50	0.72%	100.00%	0.00%
Plant Total	63.00	78.00			

D. Fuel Used

Unit id #	Primary Fuel Use				Secondary Fuel Use		
	Fuel Type	Quantity	Unit of Measure	BTU Content	Fuel Type	Quantity	Unit of Measure
All	ng	55,666	mcf	1,002			
Plant Total		55,666				0	

mcf = 1000 cf

POWER PLANT AND GENERATING UNIT DATA REPORT 2003

A. Plant Data

Plant Name	Utility Name	Date
Inver Hills	Northern States Power Company d/b/a Xcel Energy	6/25/2004

Plant Address	City	State	Zip Code	County
3185 117th Street	Inver Grove Height	MN	55077	Dakota

Plant ID#	# of Units	Contact Person	Telephone
	8	Toni Martinez	(720)497-2012

B. Individual Generating Unit Data

Unit id #	Status	Type	Year Installed	Energy Source	Net Generation (MWHR)
1	use	gt	1972		
2	use	gt	1972		
3	use	gt	1972		
4	use	gt	1972		
Plant Total	Continued on next page				

C. Individual Unit Capability Data

Unit id #	Capacity (MW) Summer	Capacity (MW) Winter	Capacity Factor	Operating Availability	Forced Outage Rate (%)
1	61.5	71.40	3.97%	95.38%	0.00%
2	58.1	71.40	3.18%	12.83%	63.47%
3	58.9	71.40	3.62%	96.04%	0.00%
4	60.7	71.40	3.59%	100.00%	0.00%
Plant Total	Continued on next page				

D. Fuel Used

Unit id #	Primary Fuel Use: Fuel Type	Quantity	Unit of Measure	BTU Content	Secondary Fuel Use: Fuel Type	Quantity	Unit of Measure
Plant Total	See next page						

POWER PLANT AND GENERATING UNIT DATA REPORT 2003

A. Plant Data

Plant Name	Utility Name	Date
Inver Hills	Northern States Power Company d/b/a Xcel Energy	6/25/2004

Plant Address	City	State	Zip Code	County
3185 117th Street	Inver Grove Height	MN	55077	Dakota

Plant ID#	# of Units	Contact Person	Telephone
	8	Toni Martinez	(720)497-2012

B. Individual Generating Unit Data

Unit id #	Status	Type	Year Installed	Energy Source	Net Generation (MWHR)
5	use	gt	1972		
6	use	gt	1972		
7	use	ic	1994		
8	use	ic	1994		
Plant Total					109,599

C. Individual Unit Capability Data

Unit id #	Capacity (MW) Summer	Capacity (MW) Winter	Capacity Factor	Operating Availability	Forced Outage Rate (%)
5	58.9	71.40	3.00%	92.76%	7.24%
6	61.0	71.40	3.93%	100.00%	0.00%
7	1.8	1.83			
8	1.8	1.83			
Plant Total	362.8	432.1			

D. Fuel Used

Unit id #	Primary Fuel Use				Secondary Fuel Use		
	Fuel Type	Quantity	Unit of Measure	BTU Content	Fuel Type	Quantity	Unit of Measure
1-6	ng	1,352,369	mcf	1,010	fo2	1,901,571	gal
Plant Total	ng	1,352,369	mcf		fo2	1,901,571	gal

mcf = 1000 cf

POWER PLANT AND GENERATING UNIT DATA REPORT 2003

A. Plant Data

Plant Name	Utility Name	Date
Granite City	Northern States Power Company d/b/a Xcel Energy	6/25/2004

Plant Address	City	State	Zip Code	County
	St. Cloud	MN	56301	Sherburne

Plant ID#	# of Units	Contact Person	Telephone
	4	Toni Martinez	(720)497-2012

B. Individual Generating Unit Data

Unit id #	Status	Type	Year Installed	Energy Source	Net Generation (MWHR)
1	use	gt	1969		
2	use	gt	1969		
3	use	gt	1969		
4	use	gt	1969		
Plant Total					3,768

C. Individual Unit Capability Data

Unit id #	Capacity (MW) Summer	Capacity (MW) Winter	Capacity Factor	Operating Availability	Forced Outage Rate (%)
1	14.75	19.35	0.27%	22.90%	74.63%
2	15.47	19.80	0.74%	54.62%	42.33%
3	15.55	19.80	0.77%	24.80%	75.20%
4	15.61	19.80	0.60%	47.42%	52.58%
Plant Total	61.38	78.75			

D. Fuel Used

Unit id #	Primary Fuel Use				Secondary Fuel Use		
	Fuel Type	Quantity	Unit of Measure	BTU Content	Fuel Type	Quantity	Unit of Measure
All	ng	76,751	mcf	1,006	fo2	7,656	gal
Plant Total		76,751				7,656	

mcf = 1000 cf

POWER PLANT AND GENERATING UNIT DATA REPORT 2003

A. Plant Data

Plant Name	Utility Name	Date
Blue Lake	Northern States Power Company d/b/a Xcel Energy	6/25/2004

Plant Address	City	State	Zip Code	County
1200 70th Street	Shakopee	MN	55379	Scott

Plant ID#	# of Units	Contact Person	Telephone
	4	Toni Martinez	(720)497-2012

B. Individual Generating Unit Data

Unit id #	Status	Type	Year Installed	Energy Source	Net Generation (MWHR)
1	use	gt	1974		
2	use	gt	1974		
3	use	gt	1974		
4	use	gt	1974		
Plant Total					11,182

C. Individual Unit Capability Data

Unit id #	Capacity (MW) Summer	Winter	Capacity Factor	Operating Availability	Forced Outage Rate (%)
1	41.60	55.60	0.77%	100.00%	0.00%
2	42.60	56.60	0.97%	100.00%	0.00%
3	40.80	54.80	0.79%	37.85%	62.15%
4	52.10	66.10	1.11%	25.07%	74.93%
Plant Total	177.1	233.1			

D. Fuel Used

Unit id #	Primary Fuel Use				Secondary Fuel Use		
	Fuel Type	Quantity	Unit of Measure	BTU Content	Fuel Type	Quantity	Unit of Measure
All	fo2	1,550,513	gal	138,000			
Plant Total		1,550,513					

POWER PLANT AND GENERATING UNIT DATA REPORT 2003

A. Plant Data

Plant Name	Utility Name	Date
Minnesota Valley	Northern States Power Company d/b/a Xcel Energy	6/25/2004

Plant Address	City	State	Zip Code	County
Highway 212	Granite Falls	MN	56241	

Plant ID#	# of Units	Contact Person	Telephone
	1	Toni Martinez	(720)497-2012

B. Individual Generating Unit Data

Unit id #	Status	Type	Year Installed	Energy Source	Net Generation (MWHR)
3	stb	st	1953		379
Plant Total					379

C. Individual Unit Capability Data

Unit id #	Capacity (MW) Summer	Capacity (MW) Winter	Capacity Factor	Operating Availability	Forced Outage Rate (%)
3	45.4	47.2			
0					
0					
0					
Plant Total	45.4	47.2	0.00%	0.00%	0.00%

D. Fuel Used

Unit id #	Primary Fuel Use				Secondary Fuel Use		
	Fuel Type	Quantity	Unit of Measure	BTU Content	Fuel Type	Quantity	Unit of Measure
3	bit	248	tons	12,619	ng	3,018	mcf
					fo2	1,201	gal
Plant Total		248					

mcf = 1000 cf

Retired Unit

POWER PLANT AND GENERATING UNIT DATA REPORT **2003**

A. Plant Data

Plant Name	Utility Name	Date
Prairie Island	Northern States Power Company d/b/a Xcel Energy	6/25/2004

Plant Address	City	State	Zip Code	County
1717 Wakonade Drive E	Welch	MN	55089	Goodhue

Plant ID#	# of Units	Contact Person	Telephone
	2	Toni Martinez	(720)497-2012

B. Individual Generating Unit Data

Unit id #	Status	Type	Year Installed	Energy Source	Net Generation (MWHR)
1	use	nc	1973		4,596,252
2	use	nc	1974		4,241,066
Plant Total					8,837,318

C. Individual Unit Capability Data

Unit id #	Capacity (MW) Summer	Capacity (MW) Winter	Capacity Factor	Operating Availability	Forced Outage Rate (%)
1	523	547	98.26%	98.31%	1.69%
2	523	545	90.66%	91.96%	0.55%
0					
0					
Plant Total	1046	1092			

D. Fuel Used

Unit id #	Primary Fuel Use				Secondary Fuel Use		
	Fuel Type	Quantity	Unit of Measure	BTU Content	Fuel Type	Quantity	Unit of Measure
1	nuc	48,162,940	mbtu				
2	nuc	44,592,120	mbtu				
0							
0							
Plant Total		92,755,060					

POWER PLANT AND GENERATING UNIT DATA REPORT 2003

A. Plant Data

Plant Name		Utility Name		Date
Monticello		Northern States Power Company d/b/a Xcel Energy		6/25/2004
Plant Address	**City**	**State**	**Zip Code**	**County**
Old Hwy 152 NW	Monticello	MN	55362	Wright
Plant ID#	**# of Units**	**Contact Person**		**Telephone**
	1	Toni Martinez		(720)497-2012

B. Individual Generating Unit Data

Unit id #	Status	Type	Year Installed	Energy Source	Net Generation (MWHR)
1	use	nc	1971		4,576,510
Plant Total					4,576,510

C. Individual Unit Capability Data

Unit id #	Capacity (MW) Summer	Capacity (MW) Winter	Capacity Factor	Operating Availability	Forced Outage Rate (%)
1	569.10	595.60	91.65%	90.82%	0.18%
0					
0					
0					
Plant Total	569.1	595.6	91.65%	90.82%	0.18%

D. Fuel Used

Unit id #	Primary Fuel Use: Fuel Type	Quantity	Unit of Measure	BTU Content	Secondary Fuel Use: Fuel Type	Quantity	Unit of Measure
1	nuc	47,781,386	mbtu				
0							
0							
0							
Plant Total		47,781,386					

POWER PLANT AND GENERATING UNIT DATA REPORT 2003

A. Plant Data

Plant Name	Utility Name	Date
Allen S. King	Northern States Power Company d/b/a Xcel Energy	6/25/2004

Plant Address	City	State	Zip Code	County
210 N. 10th Ave	Bayport	MN	55003	Washington

Plant ID#	# of Units	Contact Person	Telephone
	1	Toni Martinez	(720)497-2012

B. Individual Generating Unit Data

Unit id #	Status	Type	Year Installed	Energy Source	Net Generation (MWHR)
1	use	st	1968		3,431,730
Plant Total					3,431,730

C. Individual Unit Capability Data

Unit id #	Capacity (MW)		Capacity Factor	Operating Availability	Forced Outage Rate (%)
	Summer	Winter			
1	573	583	74.20%	82.25%	1.36%
Plant Total	573	583	74.20%	82.25%	1.36%

D. Fuel Used

Unit id #	Primary Fuel Use				Secondary Fuel Use		
	Fuel Type	Quantity	Unit of Measure	BTU Content	Fuel Type	Quantity	Unit of Measure
1	sub	1,832,020	tons	9,388	ng	16,206	mcf
Plant Total		1,832,020				16,206	

POWER PLANT AND GENERATING UNIT DATA REPORT **2003**

A. Plant Data

Plant Name	Utility Name	Date
Red Wing	Northern States Power Company d/b/a Xcel Energy	6/25/2004

Plant Address	City	State	Zip Code	County
801 East 5th Street	Red Wing	MN	55066	Goodhue

Plant ID#	# of Units	Contact Person	Telephone
	2	Toni Martinez	(720)497-2012

B. Individual Generating Unit Data

Unit id #	Status	Type	Year Installed	Energy Source	Net Generation (MWHR)
1	use	st	1949		
2	use	st	1949		
Plant Total					111,317

C. Individual Unit Capability Data

Unit id #	Capacity (MW)		Capacity Factor	Operating Availability	Forced Outage Rate (%)
	Summer	Winter			
1	11.50	12.40	68.82%	75.92%	9.66%
2	10.90	11.70	64.92%	75.99%	12.65%
0					
0					
Plant Total	22.4	24.1			

D. Fuel Used

Unit id #	Primary Fuel Use				Secondary Fuel Use		
	Fuel Type	Quantity	Unit of Measure	BTU Content	Fuel Type	Quantity	Unit of Measure
1	ref	61,130	tons	5,565	ng	13,926	mcf
2	ref	57,195	tons	5,565	ng	16,084	mcf
0							
0							
Plant Total		118325				30010	

mcf = 1000 cf

*Capacity Factor, Operating Availability, and Forced Outage is based on the first 8 months of the year.

*Primary Fuel Use and Secondary Fuel Use is based on the first 8 months of the year.

POWER PLANT AND GENERATING UNIT DATA REPORT 2003

A. Plant Data

Plant Name	Utility Name	Date
Sherburne County	Northern States Power Company d/b/a Xcel Energy	6/25/2004

Plant Address	City	State	Zip Code	County
13999 Industrial Blvd	Becker	MN	55308	Sherburne

Plant ID#	# of Units	Contact Person	Telephone
	3	Toni Martinez	(720)497-2012

B. Individual Generating Unit Data

Unit id #	Status	Type	Year Installed	Energy Source	Net Generation (MWHR)
1	use	st	1976		4,894,323
2	use	st	1977		4,374,304
3	use	st	1987		3,747,019
Plant Total					13,015,646

C. Individual Unit Capability Data

Unit id #	Capacity (MW) Summer	Capacity (MW) Winter	Capacity Factor	Operating Availability	Forced Outage Rate (%)
1	715.00	719.95	78.14%	96.56%	2.96%
2	706.00	710.14	70..73%	89.20%	1.66%
3	521.56	525.10	82.86%	95.75%	1.41%
0					
Plant Total	1942.56	1955.19			

D. Fuel Used

Unit id #	Primary Fuel Use: Fuel Type	Quantity	Unit of Measure	BTU Content	Secondary Fuel Use: Fuel Type	Quantity	Unit of Measure
1	sub	2,938,848	tons	8,706	fo2	118,837	gal
2	sub	2,588,493	tons	8,719	fo2	160,874	gal
3	sub	2,187,527	tons	8,759	fo2	364,380	gal
0							
Plant Total		7714868				644091.4079	

NSP Portion of Sherburne Unit number 3

POWER PLANT AND GENERATING UNIT DATA REPORT 2003

A. Plant Data

Plant Name	Utility Name	Date
Wilmarth	Northern States Power Company d/b/a Xcel Energy	6/25/2004

Plant Address	City	State	Zip Code	County
P O Box 1090	Mankato	MN	56001	Blue Earth

Plant ID#	# of Units	Contact Person	Telephone
	2	Toni Martinez	(720)497-2012

B. Individual Generating Unit Data

Unit id #	Status	Type	Year Installed	Energy Source	Net Generation (MWHR)
1	use	st	1948		
2	use	st	1951		
Plant Total					123,474

C. Individual Unit Capability Data

Unit id #	Capacity (MW)		Capacity Factor	Operating Availability	Forced Outage Rate (%)
	Summer	Winter			
1	9.80	10.40	69.04%	84.51%	7.27%
2	9.70	10.30	71.91%	84.25%	8.75%
0					
0					
Plant Total	19.5	20.7			

D. Fuel Used

Unit id #	Primary Fuel Use				Secondary Fuel Use		
	Fuel Type	Quantity	Unit of Measure	BTU Content	Fuel Type	Quantity	Unit of Measure
1	ref	93,722	tons	5,364	ng	15,118	mcf
2	ref	99,307	tons	5,364	ng	15,738	mcf
0							
0							
Plant Total		193029					

mcf = 1000 cf

POWER PLANT AND GENERATING UNIT DATA REPORT 2003

A. Plant Data

Plant Name	Utility Name	Date
Riverside	Northern States Power Company d/b/a Xcel Energy	6/25/2004

Plant Address	City	State	Zip Code	County
3100 Marshall St NE	Minneapolis	MN	55418	Hennepin

Plant ID#	# of Units	Contact Person	Telephone
	2	Toni Martinez	(720)497-2012

B. Individual Generating Unit Data

Unit id #	Status	Type	Year Installed	Energy Source	Net Generation (MWHR)
7	use	st	1987		857,531
8	use	st	1964		1,550,432
Plant Total					2,407,963

C. Individual Unit Capability Data

Unit id #	Capacity (MW)		Capacity Factor	Operating Availability	Forced Outage Rate (%)
	Summer	Winter			
7	150.55	155.22	65.26%	84.82%	8.00%
8	236.50	239.90	74.86%	91.39%	1.77%
Plant Total	387.05	395.12			

D. Fuel Used

Unit id #	Primary Fuel Use				Secondary Fuel Use		
	Fuel Type	Quantity	Unit of Measure	BTU Content	Fuel Type	Quantity	Unit of Measure
7	sub	540,333	tons	9155	ng	31,670	mcf
					fo2	26,524	gal
8	sub	781,226	tons	9155	fo2	36,227	gal
Plant Total		1321559					

mcf = 1000 cf

POWER PLANT AND GENERATING UNIT DATA REPORT 2003

A. Plant Data

Plant Name	Utility Name	Date
High Bridge	Northern States Power Company d/b/a Xcel Energy	6/25/2004

Plant Address	City	State	Zip Code	County
501 Shepard Road	St. Paul	MN	55102	Ramsey

Plant ID#	# of Units	Contact Person	Telephone
	3	Toni Martinez	(720)497-2012

B. Individual Generating Unit Data

Unit id #	Status	Type	Year Installed	Energy Source	Net Generation (MWHR)
4	retired	st	1944		(10,858.00)
5	use	st	1956		640,297
6	use	st	1959		858,194
Plant Total					1,487,633

C. Individual Unit Capability Data

Unit id #	Capacity (MW) Summer	Capacity (MW) Winter	Capacity Factor	Operating Availability	Forced Outage Rate (%)
4	0	0	0	0.0	0.0
5	97.30	98.40	73.83%	90.97%	0.00%
6	172.80	173.80	56.96%	72.97%	3.74%
Plant Total	270.1	272.2			

D. Fuel Used

Unit id #	Primary Fuel Use: Fuel Type	Quantity	Unit of Measure	BTU Content	Secondary Fuel Use: Fuel Type	Quantity	Unit of Measure
4		0					
5	sub	395,330	tons	8913	ng	18,470	mcf
6	sub	480,000	tons	8913	ng	130,030	mcf
Plant Total		875,330				148,500	

mcf = 1000 cf

POWER PLANT AND GENERATING UNIT DATA REPORT 2003

A. Plant Data

Plant Name	Utility Name	Date
Black Dog	Northern States Power Company d/b/a Xcel Energy	6/25/2004

Plant Address	City	State	Zip Code	County
1400 E. Black Dog Road	Burnsville	MN	55337	Dakota

Plant ID#	# of Units	Contact Person	Telephone
	4	Toni Martinez	(720)497-2012

B. Individual Generating Unit Data

Unit id #	Status	Type	Year Installed	Energy Source	Net Generation (MWHR)
2	use	st	1954		103,143
3	use	st	1955		589,942
4	use	st	1960		867,218
5	use	gt	2002		245,536
Plant Total					1,805,839

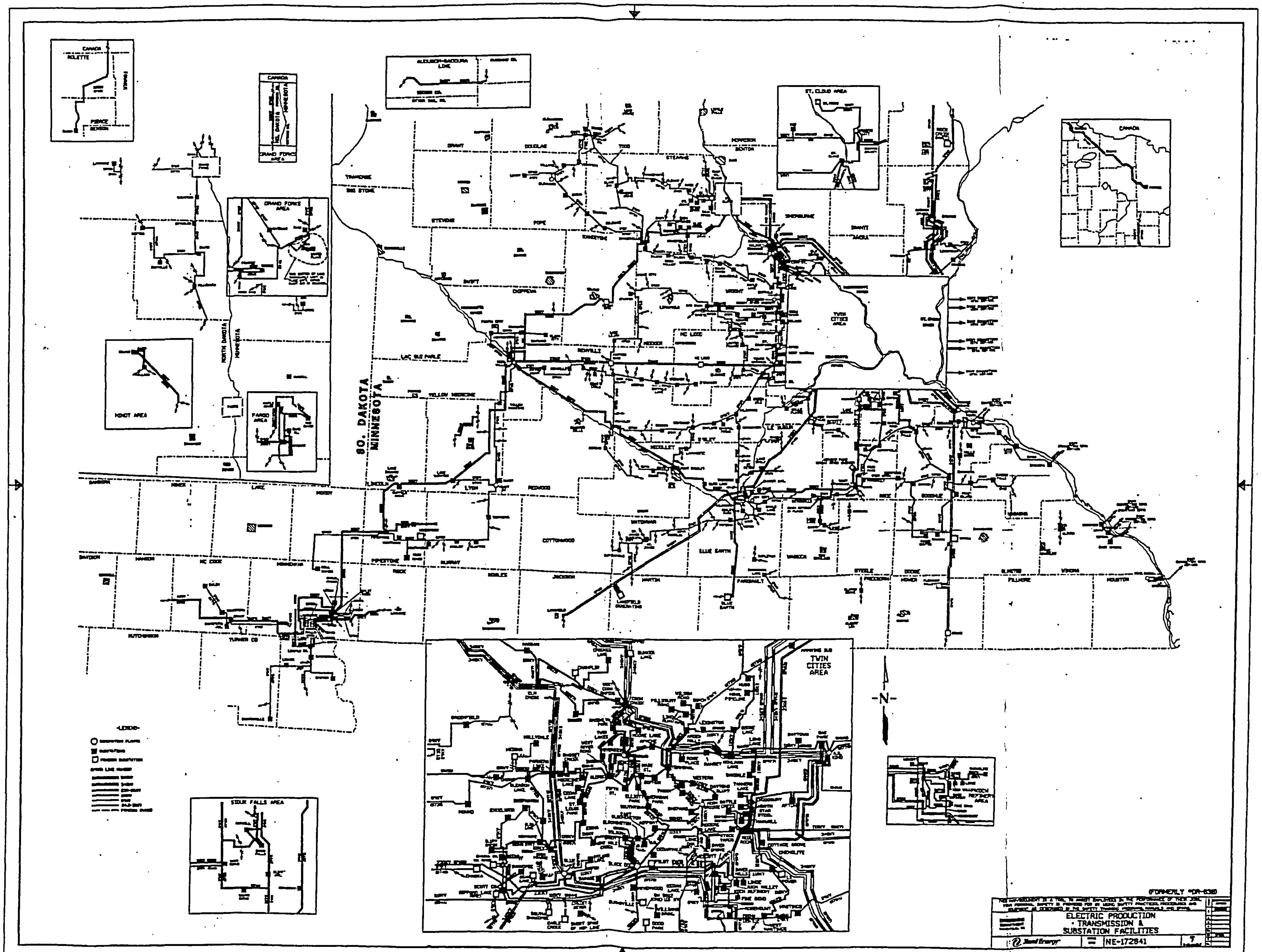
C. Individual Unit Capability Data

Unit id #	Capacity (MW)		Capacity Factor	Operating Availability	Forced Outage Rate (%)
	Summer	Winter			
2	102.96	99.97	12.97%	52.69%	31.90%
3	106.80	88.00	78.71%	91.96%	4.17%
4	172.40	173.20	60.73%	73.64%	19.35%
5	177.18	221.52	73.83%	25.21%	0.00%
Plant Total	559.34	582.69			

D. Fuel Used

Unit id #	Primary Fuel Use				Secondary Fuel Use		
	Fuel Type	Quantity	Unit of Measure	BTU Content	Fuel Type	Quantity	Unit of Measure
2							
3	sub	382,174	tons	8561	ng	113,331	mcf
4	sub	536,540	tons	8561	ng	163,699	mcf
5					ng	2,984,882	mcf

mcf = 1000 cf



SO. DAKOTA
MINNESOTA
NORTH DAKOTA
TWIN CITIES AREA
SIOUX FALLS AREA
MINOT AREA
FARGO AREA
GRAND FORKS AREA
ST. CLOUD AREA
CANADA
-N-
ELECTRIC PRODUCTION
• TRANSMISSION &
SUBSTATION FACILITIES
NE-172841

7610.0410 – Future Facility Additions
7610.0420 – Future Facility Retirements

On May 3, 2002, Xcel Energy submitted a petition to the Minnesota Public Utilities Commission ("Commission") and the Minnesota Pollution Control Agency ("MPCA") proposing a package of projects to be completed over the next seven years at three of its generating plants in the Minneapolis-St. Paul metropolitan area.[1] On March 8, 2004, the Commission issued an order approving the Company's proposal, with certain clarifications and subject to the terms of the settlement agreement the Company reached with several parties to the proceeding. These voluntary projects are designed to reduce air emissions through rehabilitation and/or repowering of metro area coal plants. As a result of these proposed improvements, generating capacity of these three plants is expected to increase by a total of approximately 298 MW. Details related to the three plants affected by this plan are provided below.

High Bridge
Location: St. Paul, Minnesota
Retirements: Existing units # 5 and # 6, approximately 270 MW
Additions: Two new units, approximately 515 MW
Scheduled in-service date: May 2008

Riverside
Location: Minneapolis, Minnesota
Retirements: Existing units # 7 and # 8, approximately 386 MW
Additions: Two new units, approximately 439 MW
Scheduled in-service date: May 2009

King
Location: Stillwater, Minnesota
Retirements: None
Additions: Work will result in the restoration of approximately 60 MW to existing unit
Scheduled in-service date: May 2007

Peaking capacity additions are currently under construction at Xcel Energy's Blue Lake power plant located in Shakopee, Minnesota,[2] and at the Anson power plant, located in Sioux Falls, South Dakota. Both plants currently exist as peaking generation sites and will have additional natural gas fired simple cycle combustion turbines added to them. The additions will include two units at the Blue lake plant and one unit at the Anson

[1] Docket No. E002/M-02-633.
[2] The Commission's Order Granting Certificate of Need for the Blue Lake plant expansion project was issued on June 25, 2004, in Docket No. E002/CN-04-76.

plant. The two-unit capacity addition to the Blue Lake plant is approximately 320 MW and the single unit capacity addition to the Anson plant is approximately 160 MW. The additions to each plant are scheduled to be completed and in-service for the summer of 2005.

Xcel Energy retired unit # 3 at the Minnesota Valley Power Plant located in Granite Falls, Minnesota in May of 2004. The unit was originally constructed in 1953 and was designed to operate on both coal and natural gas. The generating capacity of the unit was 45 MW.

The Company has no other specific plans for facility retirements during this reporting period. The condition of Xcel Energy's generating equipment is monitored, and as the age increases, an evaluation of continued operation is periodically performed.

Xcel Energy proposes to fulfill future electric generating resource needs through both a competitive bidding process and new generation projects. The specific generation technology and location of future generation facilities will be determined through our resource planning process and through the competitive bidding process. Xcel Energy filed its most recent Resource Plan with the Commission on December 2, 2002.[3] On September 10, 2003, the Company filed an update to the Resource Plan. On November 10, 2003, Xcel Energy filed a notice of changed circumstances affecting the Resource Plan and requested that the Commission allow the Company to withdraw its 2002 Resouce Plan. The Commission issued an order permitting the withdrawal of the 2002 Resource Plan on March 9, 2004.

Following is the Executive Summary from Xcel Energy's 2002 Resource Plan and copies of the additional Resource Plan documents listed above.

[3] Docket No. E002/RP-02-2065.

In this Resource Plan, we present many scenarios for consideration. The significant number of scenarios evaluated is indicative of the amount of potential variability and risk we see in this planning period. Therefore, we present analysis of the effects of: variability in the future demand for electricity; various renewable energy scenarios; and various nuclear power scenarios. We also examine the potential impacts various environmental strategies could have on the Minnesota's economy and power supply decisions.

Demand-Side Management

As in our most recent Plan, we anticipate that it will become increasingly difficult to cost-effectively acquire additional DSM on our system. While demand-side management offers a number of advantages to our system and our customers, it can also pose implementation issues, particularly as we begin to saturate the market for particular technologies.

At present, however, we have met the aggressive goals adopted in the 2000 Resource Plan. We believe it is appropriate to continue to operate under these goals at this time, and seek Commission approval for continuation of these goals in our current Plan.

Fossil-Fuel Resources

Xcel Energy currently has 3,758 MW (summer rating) of coal-fired generation on our system. With respect to this existing fleet, we recently completed the conversion of Black Dog Units 1 and 2 from coal to natural gas. During the upcoming planning period, we expect that more change will occur within our coal fleet through the Emissions Reduction Proposal, which would convert the High Bridge and Riverside plants from coal to natural gas in 2008 and 2009 and substantially refurbish the King Plant with new pollution control equipment in 2007. We have assumed that all other coal plants continue to operate through the planning horizon without any major changes in O&M expenses or capital commitments. We will, however, continue to make incremental improvements at existing plants when cost effective.

With respect to natural gas-fired generation, Xcel Energy currently has 1,277 MW of on our system, including 987 MW of combustion turbines and 290 MW of combined cycle plant. We have assumed all these plants operate through the planning horizon without any major changes in O&M expenses or capital commitments.

Nuclear Generation and Its Alternatives

Xcel Energy's current resource mix includes the Prairie Island ("PI") and Monticello nuclear plants. Minnesota law limits the amount of spent nuclear fuel storage at these plants, such that the PI plant will need to shut down in 2007 without legislative action. Monticello may operate until end of license (2010), but would not have the capability of seeking license extension (required to be filed in 2005). Therefore, electricity supply issues in the middle part of the planning period will be largely influenced by whether nuclear generation will continue to be part of the state's resource mix.

Our Plan provides information regarding the status of initiatives to provide storage and disposal of spent nuclear fuel and analysis of the options available to Minnesota policymakers regarding nuclear generation and its alternatives. Our analysis indicates that an electricity future that includes nuclear resources is preferable to one that requires shutdown of these facilities. The Plan provides detail on the options Xcel Energy will present to the Minnesota Legislature in the 2003 Session.

Spent Fuel Storage: Since our last Resource Plan, Congress authorized the Department of Energy's ("DOE") permanent spent fuel repository at Yucca Mountain, Nevada. While this milestone is significant, the repository will not be available to address the needs of PI and Monticello during the planning period. Although less promising than reported in our previous Resource Plan, Private Fuel

Storage ("PFS") solution remains a potential interim solution. PFS anticipates that the Nuclear Regulatory Commission ("NRC") will issue a license for the facility in 2003, such that the storage facility could be operating by the end of 2005. The project will continue to face political and legal challenges, as well as uncertainty as to whether it can attract sufficient customers. The progress on Yucca Mountain may cause many utilities to defer to the Yucca site rather than using off-site, interim storage. While we continue to believe PFS is a viable initiative and we intend to continue to pursue development of the project, we can no longer make planning decisions under the assumption that it will exist. Given the status of both the federal and private initiatives, the Minnesota Legislature will need to resolve the future of nuclear generation in this state absent a 2007 out-of-state spent nuclear fuel solution. We will present our analysis and potential options for consideration by the 2003 Minnesota Legislatures.

Steam Generator Replacement: Our analysis indicates that Prairie Island can produce power more economically if steam generators are replaced. However, it would not be economical to invest in new steam generators if the plant must shut down in 2007 due to spent fuel storage limitations. The most advantageous course is to replace steam generators in Unit 1 in 2004. We have taken incremental steps to preserve our ability to do that. However we have reached a point at which a decision whether to continue must be made. That decision necessarily depends on spent nuclear fuel decisions to be made by the legislature.

Relicensing: Applications must be made to the NRC five or more years before the current licenses expire and the work to prepare applications takes approximately two years. Therefore, Xcel Energy must decide soon whether to continue the process of application preparation for relicensing for the Monticello plant, or alternatively commence decommissioning planning. To date, 26 nuclear power plant licensees have made application for 20-year extensions to their operating licenses; 26 others have announced their intention to apply. Licenses have been renewed at five nuclear generating plant sites.

In this resource plan we examine a variety of alternatives to replace Prairie Island should it become necessary. Xcel Energy has received bids for the replacement of Prairie Island in a special competitive bidding process designed for that purpose. We anticipate finishing the selection process soon and continuing through the rest of the process as expeditiously as possible to preserve our ability to replace Prairie Island if necessary. The bids available to us consist of new gas- and coal-based generating plants. All require substantial transmission investments to ensure system reliability as the result of the significant change in the operating dynamics of the grid resulting from the absence of Prairie Island.

In addition, we have explored the feasibility of repowering Prairie Island as a natural gas fired facility. While nuclear power plants have been repowered, such a conversion has never been done seamlessly. Rather, gas conversion has only taken place after decommissioning is well advanced, several years after operations cease. Repowering does not appear to be a replacement option but may be a strategy to consider in order to make use of the site's infrastructure in the future.

Our comparative analysis of the replacement alternatives and continued operation indicates that the cost of electricity will be more economical with nuclear generation than without it. We also found the emission of fossil fuel related pollutants and green house gases to be lower with a nuclear generating component in our resource mix. We believe the risks associated with nuclear generation are manageable. We also conclude that the difference in the amount of spent nuclear fuel produced as the result of early shutdown is small and does nothing to address the fundamental responsibilities we as a nation have to properly manage and dispose of radioactive wastes. However, if Minnesota does not agree, we are prepared to pursue the resources necessary to replace our nuclear generating plants.

Renewable Energy

Xcel Energy's use of renewable energy is expected to increase during the planning period. We anticipate that biomass facilities developed pursuant to 1994 Minnesota legislation will begin to operate during this period. We anticipate that additional wind resources will be procured under the All-Source Bidding processes, both underway and planned. Due to the relative costs of various renewable energy resources, we expect that most renewable energy additions will be wind. We continue to believe that All-Source Bidding is the most appropriate means for determining additions to our resource mix, including renewable energy.

Other developments regarding renewable energy since our last Resource Plan include: adoption of renewable energy objectives by the Minnesota Legislature; implementation of a tariff for small wind producers to allow for streamlined connection to our distribution system; approval of our green-pricing offering; and awards of the first round of funding under the Renewable Development Fund, which has selected 19 projects for grants totaling $16 million for renewable energy projects.

Environment

Xcel Energy's fossil-fueled plants continue to comply with environmental regulations. Since our last Resource Plan, we have implemented several pollution-control equipment installations at our plants, submitted a voluntary mercury reduction plan, and proposed significant projects at the King, High Bridge, and Riverside plants under the Emissions Reduction Rider statute.

There is uncertainty in predicting the future of environmental compliance regulations. Consequently, we modeled various scenarios of potential future regulations to assess their impacts. This analysis shows that independent actions of either Minnesota or the United States will have more of a detrimental impact on the state's economy than operation under international environmental agreements would have. In addition, we provide various analyses in compliance with the

Commission's Order in our most recent Resource Plan regarding alternative environmental scenarios.

Transmission Impacts Associated with Generation Decision Making

Like other utilities in the country, Xcel Energy's transmission system is operating with very little excess capacity. Major improvements will be necessary as generation is added and customer demands continue to grow. The new market created by Open-Access transmission tariffs have increased the volume of transactions often to the point of raising the transmission network loading to its limits, such that line-loading relief and curtailment procedures are implemented more frequently than ever before. Implementation of RTOs, the start-up of MISO, and anticipated operation of TRANSLink pose transitional issues that impact resource planning and acquisition. Managing through these transitions as efficiently and effectively as possible will be important. Close monitoring of these transitions will be needed.

Legislative and Regulatory Changes have been made that require a separate Minnesota Transmission Planning proceeding. Minnesota transmission providers must now file a report on November 1 of odd numbered years outlining the system deficiencies their planning must address and potential solutions. The inaugural State Transmission Planning Report was filed November 1, 2001, and rulemaking is underway to guide future transmission planning dockets.

In this Resource Plan we provide a general discussion of the transmission implications associated with the generation decision making discussed throughout the plan. New high voltage transmission lines will be needed to support just about any large generation addition to the system. The actual requirements are very dependent on the specific site, size and operating characteristics of the proposal.

In general, small increments of additional electric power can probably be delivered within the Twin Cities metropolitan area without significant transmission investments. However, large units, approaching 400 – 500 MW in size, will probably require new transmission lines so that the added electrical power can be injected at more than one point in the interconnected electrical grid. Remote large generators (for example wind or coal-based plants in the Dakotas or additional purchases from Canada) will require new longer, and therefore more expensive, high-voltage transmission lines.

Distributed Generation

Much work has been completed since the last Resource Plan to facilitate the addition of distributed generation resources on our system. Key among these include implementation of our tariff for projects 2 MW and under, and the work to establish generic state standards for projects sized up to 10 MW. Straightforward processes to connect distributed resources to our system are important to encouraging their development.

While we do not expect that distributed generation will provide a significant portion of our resource needs in the near future, we are working to support its implementation. In this chapter, we provide a summary of the pilot projects underway as part of our approved Conservation Improvement Plan.

Conclusion

Xcel Energy appreciates this opportunity to present this Resource Plan to the parties and decision makers. We believe that a successful Resource Plan will allow us to successfully manage our resources through risk and uncertainty and ensure that we have ample, viable resources available to meet our customers' needs. Our five-year action plan focuses on managing through this period to ensure continued reliable, economic, environmentally sound service to our customers.

We look forward to discussion of our action plan with key stakeholders and decision makers. We recognize that others may view these issues differently and come to different conclusions. We welcome the opportunity to engage in a dialogue of these issues and work toward ensuring continued reliable, economical, and environmentally sound energy for our customers.

Xcel Energy

414 Nicollet Mall
Minneapolis, Minnesota 55401-1993

September 10, 2003

Burl W. Haar
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, MN 55101

RE: 2002 RESOURCE PLAN SUBMITTAL
DOCKET NO. E002/RP-02-2065

Dear Dr. Haar:

Enclosed is an original and 15 copies of Northern States Power Company d/b/a Xcel Energy's ("Xcel Energy") Update to our 2002 Resource Plan filed December 2, 2003. This plan hinged on significant decisions that were under examination by Legislators in the 2003 session and the Minnesota Public Utilities Commission suspended further activity on this plan pending completion of the legislative session. We have carefully considered the impact of new legislation and resolution of several keys uncertainties since this plan was filed and submit our update to the 2002 Resource Plan and recommended course of action. We look forward to working with stakeholders on these important issues as outlined in our update.

Copies of this filing have been served on the Department of Commerce and the Office of the Attorney General – Residential Utilities Division and members of the Environmental Quality Board as well as those on our current service list in this docket. Please call me at (612) 330-6125 if you have any questions regarding this filing.

Sincerely,

JUDY M. POFERL
DIRECTOR REGULATORY ADMINISTRATION

Enclosures
c: Service List

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

LeRoy Koppendrayer	Chair
Marshall Johnson	Commissioner
Phyllis Reha	Commissioner
Gregory Scott	Commissioner

IN THE MATTER OF NORTHERN STATES POWER COMPANY D/B/A XCEL ENERGY'S APPLICATION FOR RESOURCE PLAN APPROVAL 2003-2017

DOCKET NO. E002-RP-02-2065

UPDATE TO 2002 RESOURCE PLAN

INTRODUCTION

Northern States Power Company d/b/a Xcel Energy ("Xcel Energy" or "Company") submits to the Minnesota Public Utilities Commission ("Commission" or "MPUC") this update to our 2002 Resource Plan filed on December 2, 2002. The Commission's March 18, 2003 notice suspended the original comment period in this Docket to allow for the completion of the 2003 legislative session which was expected to provide key direction for the future of additional dry cask storage at the Prairie Island and Monticello nuclear generating units.

With the legislative session completed and new energy legislation adopted, Xcel Energy committed in correspondence dated June 12, 2003 to provide this update as a starting point for further consideration of our 2002 Resource Plan. A number of the issues and uncertainties identified in that plan were addressed by the Legislature, including authorization to expand dry cask storage sufficient to allow our Prairie Island plant to continue operating to the end of its current federal license in 2013/14.

OVERVIEW OF UPDATED PLAN AND REQUESTED COMMISSION ACTION

As discussed in more detail below, the Company seeks Commission approval of:

- *The withdrawal of the pending Resource Plan and a filing date of no later than November 1, 2004 for our next resource plan.* Significant changes have occurred since the filing of our plan in December of 2002 and with the passage of time we believe several issues key to development of our resource plans going forward would benefit from refreshed analysis. Re-filing next fall will provide us time to work through key issues with stakeholders – such as contingency needs and acquisition processes for coal-fired generation – prior to the filing of the next plan. Further, this timing would correspond well to a potential future filing related to our nuclear facilities, specifically, a potential filing for additional storage capacity at the Monticello nuclear plant. We detail the basis for this requested timing further below.

- *A Request for Proposals in 2005 for new resources needed toward the end of the decade.* This bid is the sole element of our 5-year action plan that requires action prior to the completion of a 2004 Resource Plan proceeding. We believe the remainder of our action plan can be addressed in a new filing and provide further discussion below. As presented in our plan, a 2005 RFP would seek to obtain 450 MW of supply in the 2011 - 2013 time frame. As is always the case, Xcel Energy constantly reevaluates its resource acquisition requirements and bidding schedule in light of new developments. If conditions warrant a change in our plans prior to the next cycle of Resource Planning the Company would update the Commission as provided for in the Commissions Rules and recommend actions to appropriately address the changing circumstances and needs.

Other issues for this resource plan, such as conservation goals and compliance with the renewable energy requirements, should be able to proceed according to the Commission's 2000 Resource Plan Order until the next resource plan cycle is completed. We also detail our compliance with the new Renewable Energy Objective established by the 2003 Legislature below, and believe that no action is needed to ensure continued compliance in the near future. Additional time to evaluate the impact of this objective on our system and design future plans for compliance would benefit from ongoing research, the results of which can then be incorporated into a 2004 plan filing.

Therefore, the Company respectfully requests that the Commission:

- Accept this plan update and allow comments and replies from interested parties,

- Approve our original proposal to issue a Request for Proposal for acquisition of up to 450 MW of supply in the 2011-2013 timeframe, and

- Require the filing of a new resource plan no later than November 1, 2004.

We have organized the remainder of this update into the following sections:

- *Bid Schedule,* which provides a discussion of our requested 2005 RFP for 450 MW in the 2011-2013 timeframe.

- *Contingency Issues*, which provides additional discussion regarding the risks during the planning period, some options to consider for addressing these risks through contingency planning and resources, and our proposal for future consideration of these issues.

- *Coal Acquisition Issues*, which provides an assessment of the lessons learned from our recent All-Source Bid process with respect to acquisition of baseload coal generation and proposes an approach for additional work to address these issues.

- *Renewable Energy Objective*, provides the Commission with the required bi-annual report on Xcel Energy's compliance with the newly-revised renewable energy objectives under Minn. Stat. § 216B.1691.

- *Nuclear Issues*, which provides an overview of the nuclear-related actions taken by the 2003 Legislature and their impact on this and future Resource Plans.

- *Natural Gas Issues*, which assesses the impact of the short-term increased volatility of the natural gas market on our plan.

- *Future Filing Schedule*, which proposes a schedule for future consideration of these issues in a new Resource Plan to be filed no later than November 1, 2004.

- *Five-Year Action Plan*, which updates our proposed action plan consistent with the recommendations in this filing.

PLAN UPDATE

A. BID SCHEDULE

In our original five-year action plan, we proposed to initiate an all-source bidding process in 2005 for up to 450 MW of generation to be in service in the 2011-13 timeframe. Since that time, we announced our selection of resources in the 2001 All-Source bid process, where we selected approximately 800 MW of capacity as opposed to the 1000 MW sought by the solicitation. Further, as we have continued to gain experience with the process, we have come to appreciate the complexities and time consuming nature of bid evaluation including working through the transmission evaluation process now operated by the Midwest Independent System Operator ("MISO").

If the Commission accepts our recommendation to file a new resource plan in 2004, Xcel Energy does not recommend that the next generation acquisition program be deferred until the completion of that process, late in 2005.

Because of the amount of time necessary to conduct the bid process and construct many types of large power generation projects, we request authorization to launch the bid process in 2005 and seek approximately 450 MW of new, reliable capacity in the 2011-13 timeframe. Such an approach to the bid would provide us flexibility in the planning period and should help ensure that resources are available to meet customer needs. We would anticipate that the solicitation would be structured similar to our ongoing 2001 All-Source Request For Proposal process (Docket No. E002/M-01-1618).

While we propose to issue an RFP prior to the outcome of a new 2004 Resource Plan cycle we would expect that the planning process would be complete or nearly so prior to the completion of the bidding process. Such a sequence of events would provide the opportunity to consider and incorporate any pertinent outcomes of the planning process in the final stages of evaluation in bidding.

Xcel Energy constantly monitors market conditions and other issues that may affect the level of resource commitments necessary to reliably meet our customer's demand for electricity. The Company will continue to do so in the interim between now and the next resource plan proceeding. Should market conditions or other events warrant any changes to our bidding plans we would notify the Commission of our changed circumstances as is provided for in Resource Planning Rules (Minnesota Rules Chapter 7843.0500 Subpart 5.)

B. Contingency Issues

Our original resource plan identified a number of risks during the planning period. The 2003 Legislature addressed a number of those issues with its adoption of legislation regarding nuclear waste storage. However, a number of issues surrounding our mid- to long-term resource strategy remain. These include:

- *Emissions Reduction Proposal*. In a separate proceeding (Docket No. E-002/M-02-633), the Commission is considering whether to authorize Xcel Energy to implement its three-plant emissions reduction proposal under Minn. Stat. § 216B.1692. If approved, our proposal will provide over 1500 MW of long-term capacity, including a net increase of 300 MW, for our system.[1] While the 2003 legislature determined that the Company's entire proposal constitutes a qualifying project and all upgrades eligible for rider recovery, the Commission retains authority to determine whether the approximately $1 billion cost of the proposal is in the best interest of ratepayers when taking into account the emissions reductions associated with the proposal. If our proposal is rejected or substantially delayed, we could experience a 300 MW shortfall in capacity by 2009.

- *2001 All-Source RFP Uncertainty.* We recently selected seven projects for final contract negotiations in our 2001 All-Source solicitation, including *one existing and two new* natural gas projects totaling over 600 MW, 450 MW of new wind generation from three developers, and a 115 MW of system purchase from existing generation resources. Our plan assumes that the Company will be successful in completing its purchases under the RFP process. However, no purchase is complete at this time and consequently the Commission has not yet had the opportunity to review and approve any proposals. The possibility exists that one or more of the proposals may not result in contract(s). Moreover, selection of five new projects with five different developers introduces a possibility that one or more of those new plants may not be completed.

- *Monticello Relicensing.* The Monticello nuclear plant's license expires in 2010. Because it may take several years to obtain an extension should that be the course chosen, Xcel Energy must decide soon whether to pursue relicensing. However, regardless of that decision, there is uncertainty regarding the future of Monticello and we need to determine a plan for replacing Monticello's capacity if a new license is not pursued or granted. We anticipate making a filing with the Commission in late 2004 or early 2005 to address that decision and, if appropriate, seek the required Certificate of Need for additional storage capacity.

Our 2002 plan proposed to establish an acquisition strategy for up to 500 MW of potential additional generation as a hedge against these and other identified uncertainties. We continue to believe that a contingency plan is important. We would welcome the opportunity to work with the Department and other stakeholders to

[1] If approved by the Commission, the Emission Reduction Proposal will result in installation of state-of-the-art pollution control equipment at our 571 MW coal-fired King plant and conversion from coal to natural gas and expansion of our High Bridge (515 MW) and Riverside (439 MW) plants.

potentially design new and innovative ways to develop resources and hedge some of the risks and unknowns that impact our resource decisions.

There are two primary approaches that could be used to secure contingent resources: through a bidding acquisition process or through Company-built resources. Through the Prairie Island contingent bid process, Xcel Energy has gained experience relative to this discussion. Our experience indicates that:

- *Covering contingencies in the bidding process can be difficult and expensive to manage.* We found substantial commonality in bidder refusal to put significant capital at risk without assurance that it would recover its costs. Thus, bidders insisted upon substantial withdrawal payments in exchange for allowing the option to terminate the contract after funds were expended. Depending upon when the contingency was exercised, it essentially would have resulted in payment in the hundreds of millions of dollars, without giving Xcel Energy ownership. Indeed, the termination payments for some bids were so high at later stages of development that it made termination an impractical outcome.
- *Bidders may be less interested in contingency bid processes than traditional acquisition processes.* While our 2001 All Source RFP drew interest from about 30 bidders comprising almost 40 bids, the Prairie Island Contingent RFP saw only eight bids.

Another approach to managing supply adequacy risks is to consider Company-built generation to meet contingency needs. The Company has access to sites where additional capacity could be added quickly and incrementally as needed, provided upfront permitting and regulatory approvals are obtained. Such an approach may offer an effective and appropriate alternative to the bidding process for this type of resource, which by definition needs to offer flexibility to meet rapidly changing needs. We believe the discussion could benefit from additional development of this concept for consideration as an alternative to bidding for these resources.

There may be other ways to structure resource plan decision making and bidding processes for contingency resources that address these issues. We would like the opportunity to further explore these issues with stakeholders.

C. Coal Acquisition Issues

As described in our original plan, Xcel Energy projects that in the later years of the planning horizon we will need significant additional baseload resources. Between 2010 and 2015, our Strategist computer model indicates that approximately 1800 MW of baseload generation is needed (450 MW in 2010, 450 MW in 2012, and 900 MW in

2015). Meeting these needs with coal-fired generation resources would appear to cost substantially less ($154 Million) than gas-fired generation resources.

However, the length of time necessary to develop coal-fired plants (typically five to eight years or more, depending upon the type of resource) makes it difficult to compare these resources with other options. We found in our 2001 All-Source bidding process that terms and conditions required by vendors to develop coal-based projects were substantially different from those to develop other resources, making direct comparison difficult and making it less likely a coal project would be selected.

Based on this experience, we believe it is appropriate to consider whether a new approach is needed to ensure fair evaluation and timely acquisition of coal-fired, baseload resources. The cost analysis above indicates that it would be well worth the effort to explore these issues, given the potential overall lower cost of these resources compared to other options. Alternative approaches to consider include separate solicitations for baseload resources or staged development of a multi-unit resource over time, potentially with Company involvement in either the development or ultimate ownership of the facility. It may be that Company involvement up-front in a project is necessary to ensure such projects can be successfully developed.

We do not have a specific recommendation to advance at this time regarding this issue. Rather, we propose to work with the Department and stakeholders to consider this issue and potentially develop alternative approaches to acquiring such resources that will maximize ratepayer value and an efficient, timely, and cost-effective process. The results of this work would be presented in our next Resource Plan filing.

In addition, the 2003 Legislature adopted provisions regarding a potential coal-fired plant to be located in northeast Minnesota. The Legislature granted the project, known as Mesaba Energy, a number of rights, including the right to be considered in future resource selections. There are a number of issues to be worked through regarding implementation of these provisions. While the Legislature gave this project certain advantages to facilitate its implementation, at present there is still considerable uncertainty as to whether the project will be successfully developed and become operational.

We propose to continue working with the Mesaba project as directed by the 2003 legislation. We expect to have significant additional information regarding this initiative by the time of our next Resource Plan filing.

D. Renewable Energy Objective

The 2003 Legislature adopted amendments made to the Renewables Energy Objective ("REO") contained in Minn. Stat. 216B.1691. The revised statute specifies what technologies comply with the requirement[2] and the amount each utility is to obtain. For Xcel Energy, the renewable energy objective is a requirement, tempered however, in that the deployment of renewables is subject to satisfaction of least cost planning requirements and cannot jeopardize electrical system reliability. Xcel Energy is required in 2005 to meet 1 percent of its retail sales in Minnesota with electricity produced at power plants using eligible renewables fuels. The requirement increases by one percent each year reaching 10 percent by 2015.

The statute requires that of the renewable energy amount, 0.5% is required to be generated by eligible biomass generation by 2005, increasing to 1% of the renewable energy amount by 2010. In addition to that requirement, Xcel Energy is required to "enter into a power purchase agreement by January 1, 2004 for ten to 20 MW of biomass energy and capacity at an all-inclusive price not to exceed $55 per megawatt-hour". Finally, the legislature has required that Xcel Energy deploy an additional 300 MW of nameplate capacity of wind energy capacity by 2010. This 300 MW requirement is in addition to the wind energy capacity Xcel Energy was "required by law or commission order as of May 1, 2003" and is subject to the system reliability contingency.

Subdivision 3 of this section of the statute requires utilities to provide a report to the Commission in Resource Plans concerning progress toward the Renewable Energy Objectives, including:

- The status of the utility's renewable energy mix relative to the good faith objective,
- Efforts taken to meet the objective,
- Any obstacles encountered or anticipated in meeting the objective, and
- Potential solutions to the obstacles.

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[2] Resources eligible to be counted toward the REO include technologies that generate electricity using solar power, wind power, hydro-power (at plants with less than 60 MW of production capacity), hydrogen, and biomass. Included in the definition of biomass is mixed municipal waste and refuse-derived fuel. After 2010, the hydrogen used to produce electricity must come from other renewable resources. Resources mandated in the 1994 Prairie Island legislation (Session Laws 1994, Chapter 641) cannot be counted toward the REO. Waste combustion at the Hennepin County Energy Recovery Center does not qualify toward the REO.

We provide this information below.

Xcel Energy's Compliance with the REO

Xcel Energy has the resources in place or already committed to comply with the REO requirements in 2005 and could be well positioned to comply through late in the decade, subject to the least-cost planning and system reliability conditions provided in the statute. The Commission will determine our actual position as it addresses issues surrounding REO compliance measurement over the next several months in a separate docket just underway.

In our 2002 Resource Plan filing, we forecast that electric energy consumption in Xcel Energy's Upper Midwest service territory will grow at a rate of 1.6% per year. In 2002, Xcel energy retail customers in Minnesota used 29,675,319 MWh of electricity. The table below illustrates the REO requirements by year for Xcel Energy assuming electric retail sales increase at the same 1.6% rate.

XCEL ENERGY'S REO TARGETS Minnesota Jurisdiction			
	Actual Retail sales	Projected Retail Sales (1.6% G.R.)	REO Target (1.6% G.R.)
2002	29,675,319		
2003		30,150,124	
2004		30,632,526	
2005		31,122,647	311,226
2006		31,620,609	632,412
2007		32,126,539	963,796
2008		32,640,563	1,305,623
2009		33,162,812	1,658,141
2010		33,693,417	2,021,605
2011		34,232,512	2,396,276
2012		34,780,232	2,782,419
2013		35,336,716	3,180,304
2014		35,902,103	3,590,210
2015		36,476,537	3,647,653

In 2002 Xcel Energy produced or purchased approximately 2,700,000 MWh of electricity from REO eligible resources.

XCEL ENERGY'S RENEWABLE GENERATION AND PURCHASES
2002

	MW	MWh
Refuse Derived Fuel	72.10	297,478
Hydro	299.67	1,279,137
Wind	302.00	921,007
Biomass	65.20	220,408
TOTAL	738.97	2,718,030

Approximately 180 MW of additional wind-powered generation has been contracted for and is under development in 2003. We anticipate at least 60 additional MW from small wind developers in the next few years and we recently announced the selection of three wind projects totaling 450 MW. In addition the 2003 legislation authorizing spent fuel storage at Prairie Island also requires power purchase contracts for more biomass and another 300 MW of wind power.

After excluding production from 825 MW of wind powered generation and mandated biomass resources, we estimate that existing resources and those under negotiation will provide approximately 2 million megawatt hours of electricity which would meet the REO requirements through the 2009 or 2010 time frame.. This calculation assumes existing levels of short-term purchases from renewables based generators will continue at 2002 levels. It also does not account for the expiration of Refuse Derived Fuel contracts in 2007 that provide REO compliant fuel for the Red Wing and Wilmarth plants.

Xcel Energy will be meeting the early year requirements of Minn. Stat. 216B.1691. Because the Commission is considering in a new docket issues such as counting of resources, multiple credits and other issues, it is difficult to assess precisely what Xcel Energy's REO status will be as time passes. It appears that Xcel Energy will meet the REO standard through the latter part of the decade with a combination of existing and committed resources and other newly legislated requirements. We anticipate that we will continue to add renewable resources to our power supply portfolio as long as it is consistent with least-cost planning and reliability considerations.

Obstacles that we may encounter in future renewable development on our system include:

- *Saturation issues with respect to additional wind development.* Xcel Energy has development commitments underway that will result in wind powered generation reaching nearly 10 percent of its total production capacity. The penetration of wind power could rise to 15 percent or more depending on the strategy used to meet our remaining REO obligation. The intermittent nature of wind creates issues on our system with respect to load following, regulation, and the operation of our baseload coal and nuclear plants that must be carefully evaluated.
- *Transmission issues.* The characteristics of wind turbines and their location pose issues for the operation and design of the transmission system. Further, additional resources of any kind will likely require significant additional transmission development, which is operating at near capacity. Transmission facilities are typically difficult to site and construct.
- *Cost issues.* While wind costs continue to decline and, together with federal production tax credits, have become cost competitive, the cost of other renewable resources remain high relative to more traditional resources. After including the cost associated with the two issues above it is not clear how many additional resources will be acquired under the legislative standard that they meet least-cost planning requirements.

Significant study work is under way to address cost and reliability factors that will help us further define the boundaries of renewables development on our system. We expect to use this work as we develop plans for addressing the REO requirement. A more meaningful resource planning analysis will result if we can take the time to incorporate the results of this ongoing work. We believe that can be done with a new resource plan filing in the fall of 2004.

E. NUCLEAR ISSUES

Our original plan identified significant issues concerning continued operation of Xcel Energy's Prairie Island and Monticello nuclear plants. Prairie Island needs added on-site storage for spent nuclear fuel to continue operating beyond 2007; Monticello's operating license expires in 2010. Our plan discussed in detail the issues surrounding the future of nuclear generation as part of our energy supply mix.

The 2003 Legislature significantly clarified Minnesota's policy regarding nuclear generation. By enacting 2003 Minn. Laws (1st Special Session), Ch. 11, the Legislature authorized sufficient spent nuclear fuel storage to allow Xcel Energy to operate Prairie Island to the end of its current operating license. The statute also provides a process for securing additional spent nuclear fuel storage capacity in the event the Company pursues relicensing of either of its nuclear plants. These developments clarify a significant issue concerning available resources during the later years of the planning horizon. We briefly discuss the implications of this legislation on our Resource Plan below.

1. *Prairie Island Operations*

The 2003 legislation resolves the near to mid-term issues concerning continued generation at Prairie Island, including our ability to operate the plant until 2013/14, the expiration of the current operating license; the process by which we would secure additional capacity in the event we seek relicensing of the plant from the Nuclear Regulatory Commission; resolution of the contingency bid process, allowing us to close that separate proceeding (Docket E002-M-01-1480).

In addition, the 2003 legislation clarifies our approach to continued operation at Prairie Island. As discussed in our original filing, Prairie Island can produce more power more economically if its two steam generators are replaced. Allowing this plant to operate through the end of its license makes it economically attractive to replace the steam generator in Unit 1. We continue to believe the most advantageous course is to replace the generators for Unit 1 in 2004 and will continue to take the steps necessary to do so.

2. *Relicensing Issues*

As described in our Resource Plan filing, relicensing a nuclear plant is a time-consuming process that calls for significant and thoughtful consideration. The issue will first arise at Monticello, whose operating license will expire in 2010. This plant has been a reliable, low-cost energy producer, and our analysis to date indicates it could continue to operate economically and reliably into the foreseeable future. Because the Nuclear Regulatory Commission ("NRC") requires any application for relicensing be submitted 5 years in advance of the scheduled end of license, the Company needs make an application for Monticello in 2005 if we want to pursue this option.

The decision whether to seek relicensing implicates several important issues for the Commission's consideration. At the time Monticello's operating license runs out, so will its spent fuel storage space. Without the assurance that the Private Fuel Storage ("PFS") interim storage facility in Utah will be successfully developed, Monticello will need additional dry storage to bridge to a Yucca Mountain solution or to decommission. A decision to go forward with Monticello relicensing will involve evidence of storage availability at a PFS prior to 2010 or regulatory approval to install an on site Independent Spent Fuel Storage Installation.

The Company has elected to continue the studies needed to make a determination whether to pursue relicensing of Monticello. If after the completion of these studies the Company elects to pursue an application with the NRC, we will also make appropriate submissions to the Commission, both in terms of a Resource Plan to reflect this decision and application for a Certificate of Need for additional storage capacity. During the coming months, the Company also intends to develop a plan to address the risk that Monticello may not operate beyond 2010. Depending on final corporate decision on whether or not to move forward with relicensing at Monticello, such filings would be appropriate to make in late 2004, given the timing of the relicensing process.

F. NATURAL GAS ISSUES

The natural gas market has experienced increased volatility and higher prices since the original filing, and general concerns regarding availability and supply have been raised on a national level. The Commission has set a technical conference on natural gas issues in conjunction with its consideration of our Emissions Reduction Proposal to gain additional information regarding this situation.

We believe that our original Resource Plan filing adequately addressed natural gas issues. We ran a number of scenarios testing our plan against various gas price assumptions, including high-cost scenarios. Current projections of future gas prices remain in the range of our base case assumptions, particularly with respect to the period in which new gas-fired facilities would come on line. Therefore, we do not believe any additional analysis of natural gas issues is required in this planning cycle. To the extent that natural gas prices rise beyond what we assumed only reinforces the analysis presented in our resource plan. In out years of the planning period the *Strategist* analysis found that base load coal resources were more economical additions. Higher gas prices only amplify that result. We would continue to assess the situation and address any updated conditions in our next Resource Plan filing.

G. FUTURE FILING SCHEDULE

As demonstrated in the discussion of issues above, the Company believes that, other than approval of an RFP in 2005 to meet projected customer needs in the 2011-2013 timeframe, most of the issues yet to be resolved would benefit from additional analysis and consultation with parties to be successfully resolved. These issues include the process for securing resources to address the risks present in the planning period and considering options for securing baseload resources for our system. Further, the timing of an application for additional storage to accommodate a potential Monticello relicensing would need to occur in late 2004, as would a plan for addressing the loss of Monticello capacity if relicensing is either not pursued or ultimately denied.

Taken together, the Company believes that it would be most efficient for the Commission to approve our proposal for a 2005 bid for 450 MW of capacity and require a new Resource Plan filing no later than November 2004. In the event that changing circumstances require any action prior to this time, the Company would make a filing pursuant to Minn. Rule 7543.0500, Subd. 5 to inform the Commission of the significant change and if necessary initiate a proceeding to consider remedy.

H. UPDATED FIVE-YEAR ACTION PLAN

Our original filing proposed a five-year action plan, in compliance with the Commission's rules. To assist in putting our update in context, we provide that action plan and update it as discussed above. Most of the issues have been resolved or would benefit considerably from additional work incorporating key information being developed in the next few months. Thus we recommend further consideration of resource plans be deferred to a new 2004 Resource Plan filing. Such action would not jeopardize our power supply as long as a 2005 RFP filing is authorized.

- *Continue to aggressively pursue the conservation and load management goals established in the 2000 Resource Plan Proceeding.* We propose to continue pursuing the goals established by the Commission in our last Resource Plan.

- *Obtain Commission approval of the Manitoba Hydro 500-MW contract.* The Commission approved this contract in December 2002. The matter has been appealed to the Minnesota courts; however, the contract is currently in effect pending appeal. The Company will continue to pursue implementation of this contract to ensure our customer needs are met.

- *Complete the 2001 All-Source Bidding process in 2003.* We announced selections totaling approximately 800 MW of capacity. We are currently negotiating contracts with vendors and will file them for approval with the Commission once completed. In the event that contracts are not reached or other circumstances develop affecting the selected resources, we will inform the Commission and recommend the appropriate action plans. These purchases require no action within the Resource Planning Docket.

- *Obtain approval of our Emissions Reduction Proposal.* This matter is pending before the Commission. We hope to have a Commission decision on this matter later this year. That outcome will help clarify the level of generation capacity yet needed late in the decade.

- *Seek resolution of the future of nuclear generation in Minnesota by the legislature in 2003.* The 2003 Legislature adopted legislation that significantly clarified this issue and provides direction for future proceedings. The Company will be making decisions in coming months whether to pursue extending operation of the Monticello plant beyond 2010. That analysis will help inform our resource acquisition strategy going forward.

- *Initiate an All-Source Bidding process in 2005 for up to 450 MW of generation to be in service between 2011 and 2013.* As discussed above, this solicitation is the sole element of our 5 year plan we do not believe should wait for a new Resource Plan. To ensure a reliable power supply it would be prudent to get the next solicitation process underway. However, the results of the next resource plan cycle can be incorporated into final stages of the bidding process.

- *Continue to closely monitor and manage the transition to new market and regulatory structures.* We continue this effort. Since the filing of our original plan, we submitted an application to participate in TRANSLink, an independent transmission company approved by the Federal Energy Regulatory Commission ("FERC") to operate within MISO. That proceeding is pending before the Commission, awaiting an update from the Companies. In addition, we continue to advocate before FERC on various transmission issues regarding MISO and FERC policies, and participate in discussions with the state agencies on these topics through the MISO stakeholder meetings.

We had also identified and analyzed a number of contingency issues in our original plan. Many of these have been resolved, as discussed below.

- *If continued operation of our nuclear plants is not the State's preferred option, seek legislation expediting the Prairie Island alternative and begin the solicitation process in the 2003 – 2004 timeframe for replacement of Monticello's output in 2010.* After the 2003 Legislature approved additional storage at Prairie Island, the Company terminated the contingent bid process. As noted above, we believe it would most appropriate to address the future of Monticello and corresponding contingencies in our next Resource Plan.

- *Establish an acquisition strategy for up to 500 MW of potential additional generation to as a hedge against the uncertainties and risks during this planning period.* We continue to believe contingency planning is important and necessary. As discussed above, we believe that alternative approaches to a contingent bid process may be appropriate. While we raised the issue in our 2002 filing we did not make a specific proposal. We would like the opportunity to explore these issues with stakeholders and address the issue in our next Resource Plan.

- *Conduct a competitive solicitation program for up to 100 MW of biomass generation resources as a backstop so that we can respond quickly should current market conditions create difficulty for pending biomass projects.* We made a filing offering such a process to the Commission in Docket No. E002/M-03-306. Since then, several issues with respect to our current biomass contracts have been resolved, either by the Commission or the Legislature. At present, such a bid process does not appear necessary. Issues regarding our future compliance with the REO can be addressed in the next Resource Plan. We will have the benefit of the Commission's actions regarding compliance measurement by that time as well as the results of important study work underway. Reexamining issues related to renewables in the next planning cycle will not jeopardize compliance with REO requirements.

- *Conduct periodic assessments to consider the combined impacts of the many events that will be occurring on our system.* We will continue to carefully monitor developments affecting our system. To the extent that we need to act in response to any development in a way not addressed by this Resource Plan, we will file with the Commission under Minn. Rule 7543.0500, Subd. 5 a notice of changed circumstance. Appropriate regulatory action can be taken if necessary.

As shown, we believe that a number of issues in our pending Resource Plan have been resolved, a number of issues at the center of future resource plans would benefit from new information being developed over coming months, and additional time to incorporate new information does not jeopardize our power supply provided a 2005 RFP can get underway in the interim. Consequently, we believe it is appropriate for the Commission to act to close this proceeding by approving our proposed 2005 bid and directing us to file a new Resource Plan no later than November 2004.

CONCLUSION

Xcel Energy respectfully requests that the Commission authorize the Company to develop and implement a 2005 bidding process to solicit approximately 450 MW of reliable capacity. The Company will work with Staff and the Parties to design an RFP process for this solicitation that meets the Commission's guidelines and requirements. We also request that the Commission approve a filing date of no later than November 1, 2004 for us to address issues including the Monticello nuclear plant, contingency planning, and acquisition of baseload resources. Such a schedule will allow us time to conduct the necessary analysis and engage in discussions with stakeholders prior to making a specific plan proposal.

Dated: September 10, 2003

Northern States Power Company
d/b/a Xcel Energy

By: James Alders

JAMES ALDERS
MANAGER REGULATORY PROJECTS

Xcel Energy℠

414 Nicollet Mall
Minneapolis, Minnesota 55401-1993

November 10, 2003

Burl W. Haar
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, MN 55101-2147

RE: NOTICE OF CHANGING CIRCUMSTANCES AFFECTING RESOURCE PLANNING
DOCKET NOS. E002/PR-00-787, E002/RP-02-2065 AND E002/M-01-1618

Dear Dr. Haar:

Enclosed are the original and 15 copies of a filing by Northern States Power Company d/b/a Xcel Energy notifying the Commission of changing circumstances affecting our Resource Plans as provided by Minnesota Rules Chapter 7843.0500, Subpart 5.

In our filing we identify market conditions and transmission issues affecting our ability to make short-term power purchases and our ability to successfully complete the All-Source acquisition program. As a result, we have reduced our estimates of power plant capacity available to us in 2005 by approximately 500 megawatts. To compensate for the potential shortfall we intend to pursue the development of three combustion turbines at existing Company plant sites.

This filing includes information that may be of interest to those participating in our Resource Plan dockets and Bidding Docket. Accordingly, we have provided copies of this filing to those on those service lists, attached.

Please call me at (612) 330-6732 if you have any questions regarding this filing.

Sincerely,

James Alders

JAMES R. ALDERS
MANAGER, REGULATORY PROJECTS

Enclosures
c: Service List

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

LeRoy Koppendrayer	Chair
Marshall Johnson	Commissioner
Kenneth Nickolai	Commissioner
Phyllis Reha	Commissioner
Gregory Scott	Commissioner

DOCKET NO. E002/RP-00-787
E002/RP-02-2065

NOTIFICATION OF CHANGED
CIRCUMSTANCES AFFECTING
RESOURCE PLANNING

INTRODUCTION

Northern States Power Company d/b/a Xcel Energy ("Xcel Energy" or "Company") submits to the Minnesota Public Utilities Commission ("Commission") this notification of changing circumstances that are affecting the Company's Resource Plan. Minnesota Rules Chapter 7843.0500, Subpart 5 instructs the utility to inform the Commission in the event it encounters changed circumstances that may have a significant effect on it's Resource Plan.

In recent weeks and months, Xcel Energy has encountered significant challenges in ensuring that adequate production capacity is available to meet the summer peak demand for electricity in our upper Midwest service territory. Limitations and constraints on the transmission system along with the evolution of the administration of the transmission system have created increasing uncertainty in our ability to make shorter-term power purchases that we have traditionally relied upon to help cover peak electrical demand and reserve obligations. As a result we have reduced our estimates of available short-term power by approximately 300 megawatts in 2005.

The Company continues to work with developers to complete the acquisition of resources from the 2001 All-Source bidding program and to supplement those resources with other purchases. We believe that we will be able to acquire at least as much production capacity from developers as was included on the All-Source Finalist

List. However, because of the complexities of negotiating over 800 megawatts of power purchase contracts including issues related to transmission access we anticipate a delay in some of the acquisitions. Accordingly, we have reduced our estimate of new All-Source purchases that will be available in 2005 by approximately 200 megawatts. The Company plans to submit successfully negotiated power purchase contracts to the Commission for review and approval over the next several months.

In our 2002 Resource Plan filing we introduced the concept that there was increasing uncertainty in our plan due to a number of factors. We identified the need to plan for approximately 500 megawatts of generation to reduce the risks associated with our reliance on the wholesale market and other factors. The issues that caused us to raise the concern in our resource plan have developed more quickly than we anticipated. Immediate action is necessary to address reliability risks associated with potential shortfalls in generating capacity in 2005.

To compensate for these changing circumstances, the Company intends to seek authorization to construct 3 combustion turbines, or nearly 500 MW of peaking duty production capacity, on the Xcel Energy system, to be placed in service by the summer of 2005. The Company intends to make application for a Certificate of Need for two combustion turbines at the Blue Lake generating plant site as soon as possible, early in December. We will also be pursuing permits for the addition of a combustion turbine unit at the Anson generating plant site near Sioux Falls.

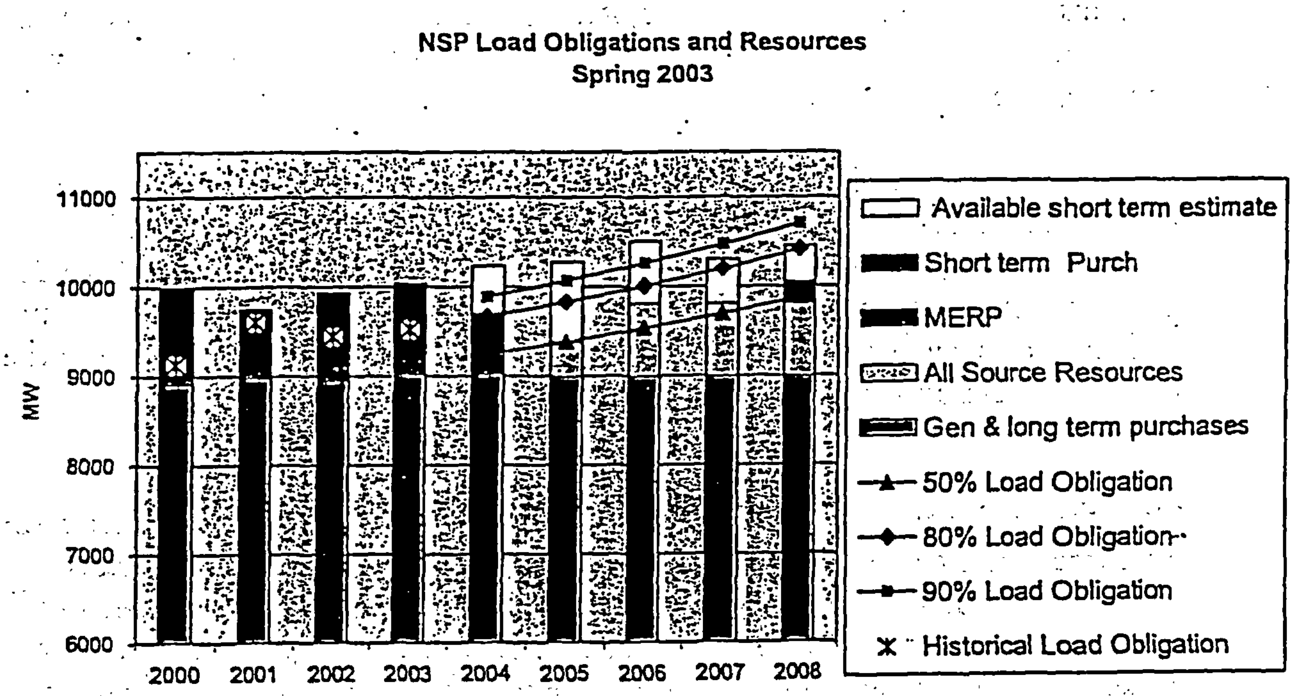
BACKGROUND

Traditionally, Xcel Energy has relied on a combination of Company owned generating capacity, long-term power purchases, and short-term seasonal power purchases to meet the demand for electricity in our five state upper Midwest service territory. To ensure that adequate generating resources are available to reliably meet the demand for electricity in the region, the Mid-Continent Area Power Pool has a long-standing reliability standard for its members. All power suppliers serving customers in the MAPP region must have sufficient accredited generation capacity to provide 15% reserves above their actual summer peak demand.

The test of compliance with MAPP requirements is done after-the-fact, but arrangements for generation must be made before the actual peak demand is known. The arrangements are therefore made based on a forecast of peak demand and, as with any forecast, there is considerable uncertainty in what actual peak demand levels will be.

In order to ensure that the actual demand and reserve obligations can be met, the Company has traditionally made long term purchases and capacity additions to meet a median forecasts and then has augmented those resources with short term seasonal purchases to cover to an 80th to 90th percentile forecast. In that way, the risk that demand will exceed available resources is minimized in a cost effective manner.

The figure below illustrates how the Company planned to use the combination of existing generation facilities, long-term purchases, new All-Source purchases and short-term seasonal purchases to meet its forecasted peak demand and reserve generation obligations. The figure illustrates the forecast demand and resource picture as it existed in the spring and early summer of this year, as we were making All-Source Bidding selections. We anticipated that the combination of existing (owned and purchased) and All-Source resources would meet the median forecast and that short-term purchases would increase generating capacity to the 90% level. The graph also shows historical coverage for reference.



*Load forecasts include 15% reserve obligation

THE AVAILABILITY OF SHORT TERM POWER PURCHASES HAS BECOME MORE UNCERTAIN.

Recently, we have encountered conditions in the regional market that lead us to conclude that we can no longer rely on the same level of short-term power purchases as in the past. This trend was identified in past resource plan filings but is occurring sooner than anticipated.

Through the summer of 2003, we have planned for and successfully secured 800 to 1100 megawatts of short-term power purchases to be delivered during the summer peak demand season along with the required firm transmission rights to deliver the contracted electricity. Our initial plan for the years 2004 and 2005 anticipated similar levels of short-term power purchases would be available. However because of concern about increasing demands on the transmission system and changes in the administration of the transmission system, our plan conservatively included an expectation of reduced availability of short-term power purchases starting with a reduction to 700 megawatts in 2006.

Several events since the filing of the All-Source finalist list have made us reconsider that expectation. While the generation resources appear to be available in the region, there is growing concern that transmission capacity is no longer available to deliver power from other systems to the NSP load. Accordingly we have reduced our estimates of available short-term power that can be successfully delivered to the Xcel Energy system by about 300 megawatts in 2005.

Over the past five years, approximately 400 to 500 megawatts of our short-term purchases were made from utilities to the south of the NSP system. Excess generation resources and transmission availability from the south had been sufficient to make these purchases an excellent source of economic capacity for our system. Entering 2003, we had no reason to believe that this situation would change in the near term. Therefore, in early 2003, when we began our short-term purchase planning for 2004 and 2005, we continued to assume that the resources originating from utilities to the south would be available. As early as November of 2002, we submitted requests for transmission service to the Midwest Independent System Operator for 200 megawatts to be delivered during the 2003 summer season. MISO notified us these requests would require system impact studies.

To ensure adequate capacity coverage for 2003, we requested monthly firm transmission while MISO studied the annual request. The principal difference between monthly and annual firm transmission service is that annual transmission reservations establish a transmission access right that can be preserved from year to year or rolled over. MISO authorized the monthly transmission at the same time that it was studying the annual request in more detail.

However, during the summer of 2003, Xcel Energy began experiencing refusals of other monthly transmission requests to facilitate day-to-day power transactions from the south. While these monthly transmission reservations did not impact the production capacity purchases for 2003, they did restrict economical electric energy purchases, an indication that transmission availability was tightening sooner than anticipated.

On September 4, 2003 we received the results of the system impact study from MISO for the annual transmission request submitted in November of 2002. The study identified numerous constraints that would limit our ability to acquire firm annual transmission access from the south. Among others, MISO identified that transfers from the south were constrained by the Quad Cities limitation on the Mid-American system, part of the transmission network at the Iowa Illinois border. We then authorized MISO to conduct a Facility Study to identify the transmission improvements necessary to overcome the constraints. MISO is currently working on this study and we expect the results in the spring of 2004.

Additionally, in early October 2003, the earliest time allowed by MISO procedures, we made new monthly firm transmission requests for power purchases from the south for the summer season of 2004. MISO immediately denied those requests. We expect we will receive similar results for 2005.

In summary, based on these transmission access developments, we conclude that we cannot depend on short-term power purchases to the same degree as in the past. To complicate matters further the power system experienced its largest blackout ever on August 14th of this year. We are concerned that the transmission system will be more conservatively administered until significant improvements are made and thus long distance power purchases may decline further.

FERC and MISO procedures and tariffs provide for the rollover of certain transmission rights from one year to the next. While we are limited in the amount of power that can be delivered from the south, we continue to believe we can secure enough power for the 2004 summer season from other sources, using rollover transmission rights and unconstrained transmission paths, to cover peak demand and reserve reliability requirements to the 85th to 90th percentile forecast probability.

However, because of the significant uncertainty in the regional transmission capacity picture in 2005 and beyond, we believe it is no longer prudent to rely as heavily on short-term seasonal power purchases from distant utilities to meet our reliability obligations. We will continue to pursue purchases as they are available but can no longer count on their availability for the foreseeable future. Thus we have reduced our estimates of short-term capacity availability by approximately 300 megawatts in 2005.

LONGER TERM POWER PURCHASES HAVE BEEN DELAYED

Some of the same transmission constraint issues encountered in our efforts to secure short-term seasonal power supplies have presented challenges in our 2001 All-Source long-term resource acquisition program. We continue to believe we will successfully secure over 800 megawatts of production capacity as the result of the program, however, due to "work arounds" necessary to address transmission constraints we have reduced our estimate of power available in 2005.

In June of this year the Company announced its selection of 7 finalists in the 2001 All-Source, long term, resource acquisition program. Those selections were:

- a 100 MW purchase from the Minnesota Power system,
- a 250 MW purchase from Reliant from an existing plant in Illinois,
- a 240 MW purchase from Calpine from a gas combined cycle plant to be built in Wisconsin,
- a 155 MW purchase from TransCanada from a gas combustion turbine unit to be built near Hutchinson, Minnesota, and
- three power purchases totaling 450 MW of nameplate capacity from wind farms on Buffalo Ridge and in south-central Minnesota

Shortly after the announcement of the finalists, preparations for contract negotiation and preliminary discussions began. Preparations included contacting bidders, incorporating project details into the model purchased power agreement, and continued due diligence on project development. While all of the finalist bidders initially identified in their proposals 2005 in service dates, the Company anticipated it would be difficult to complete the as yet undeveloped projects by 2005. However the Company expected to complete negotiations and make purchases from at least the Minnesota Power proposal and the Reliant Illinois proposal, both existing generation, beginning in 2005. The negotiations are on going and significant issues in addition to those discussed here are present in each.

On August 6, 2003, Minnesota Power informed us that they were completing negotiations with another utility to dedicate the capacity and energy that was the subject of their All-Source proposal to Xcel Energy. Xcel Energy and Minnesota Power spent some time discussing if the all-source bid could be completed or a substitute arrangement could still be made. On August 25, Minnesota Power notified Xcel Energy that it had executed the long-term transaction with another utility and formally withdrew their All-Source bid.

During preparations for negotiations with two of the other bidders, it became apparent that the Quad Cities limitation, which prevented MISO from approving the short-term transmission requests from the resources to the south, might also prevent long-term purchases from the Reliant facility and from the Calpine project in Wisconsin. Xcel Energy had expected that mitigation efforts and the use of certain transmission paths would enable the deliveries, but it became apparent that these arrangements would not ensure delivery. Xcel Energy confirmed this concern and began the process of trying to work around the transmission constraint to enable the long-term transactions.

In order to facilitate delivery to the NSP system, Calpine has expressed a willingness to change the location of their project to a site near Mankato, Minnesota, a location previously considered in the Prairie Island contingent bidding program. We are continuing to negotiate a contract with Calpine based on the new location, however, as anticipated, the project's in-service date will be delayed until at least 2006. As part of our effort to address the emerging limitations in short term power purchases Calpine and Xcel Energy are discussing the purchase of about 100 megawatts of additional power production capacity. By adding the capability of increasing flue gas temperatures with what is known as "duct firing", additional production capacity can be added to the project.

The Reliant facility in Illinois is existing and therefore cannot be developed in a different location. Reliant has expressed a willingness to complete the negotiation process for a power purchase that would be contingent upon cost-effective transmission improvements necessary to eliminate the Quad Cities constraint. We are investigating the facility improvements that would be required to overcome the constraints. However, it is very unlikely that this matter will be resolved in time to accommodate power deliveries in 2005 or 2006.

Negotiations concerning TransCanada's 155-megawatt combustion turbine proposal to be located near Hutchinson, Minnesota have been difficult, particularly around the allocation of risk during the development phase. It is not clear that the parties can overcome these issues. TransCanada estimates their facility could be in service by late 2005.

Negotiations with the selected wind farm developers are also well underway. The Company is negotiating in service dates for the two projects to be located on Buffalo Ridge to coincide with the completion of the transmission improvements necessary to reliably deliver their output. We anticipate a 2005 or 2006 in service date for the third project proposed in the south central part of the state. Regardless of the actual in service dates for these wind projects, they will not add appreciably to the total accreditable production capacity on our system.

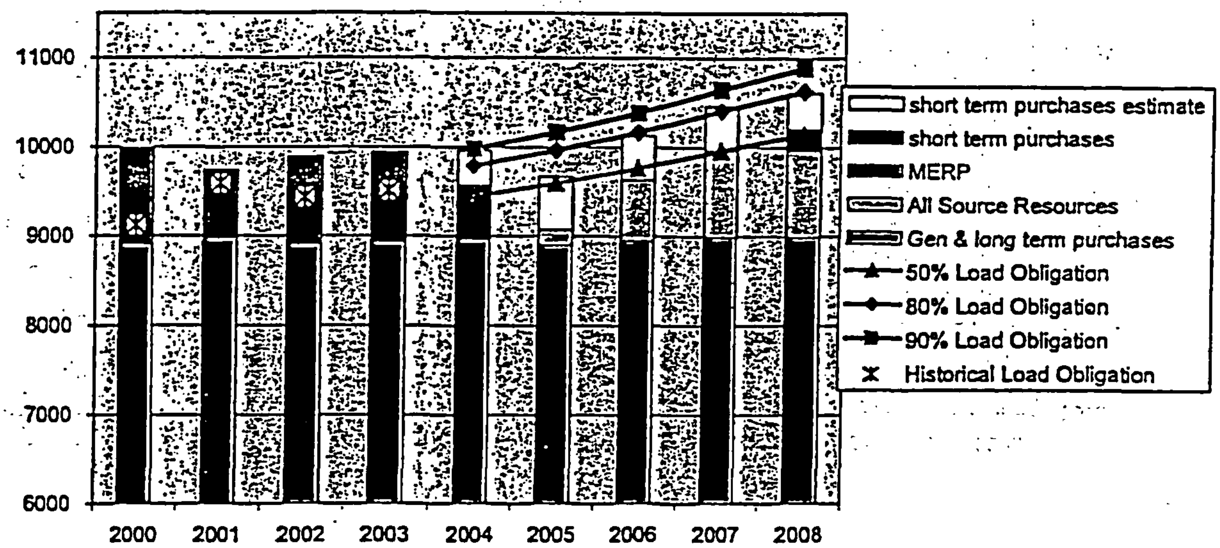
The net effect of these bidding issues has been to reduce the expected resources from the All-Source process available by 2005. The most significant changes are the Minnesota Power withdrawal and the difficulty with the 250 MW purchase from the Reliant Illinois facility. At best, the Reliant purchase will likely be delayed by two or more years. If the necessary transmission improvements are too expensive or delays are too long, the purchase may not be completed.

In response to these changes, Xcel Energy revisited the shortlist of bidders in the All-Source program to determine if any viable proposals remained that could address the issues that had developed, with an emphasis on 2005 availability. After some initial screening, contacts were made with three bidders. As the result of the effort, discussions are underway with Rainy River regarding the purchase of 157 megawatts from a peaking facility in Superior, Wisconsin. Rainy River holds all permits and construction authorizations for the facility and has expressed a willingness to complete the project by the summer of 2005. We are attempting to negotiate a contract that would let them proceed, however, as with any complex power purchase agreement, significant issues will need to be negotiated.

Xcel Energy continues to seek other potential sources of power from All-Source developers and others as part of our efforts to ensure reliable service.

The effects of both the short-term power availability issues and the changing circumstances affecting the All-Source acquisition program are portrayed in the figure below. In addition, some adjustments in the graph have been made to reflect the Company's most recent forecast analysis completed in August. The new 90th percentile forecast is approximately 100 megawatts higher in 2005 than the spring '03 forecast. The graph also includes changes to reflect potential delays in the Fibrominn and NGP biomass projects.

NSP Load Obligations and Resources
October 2003

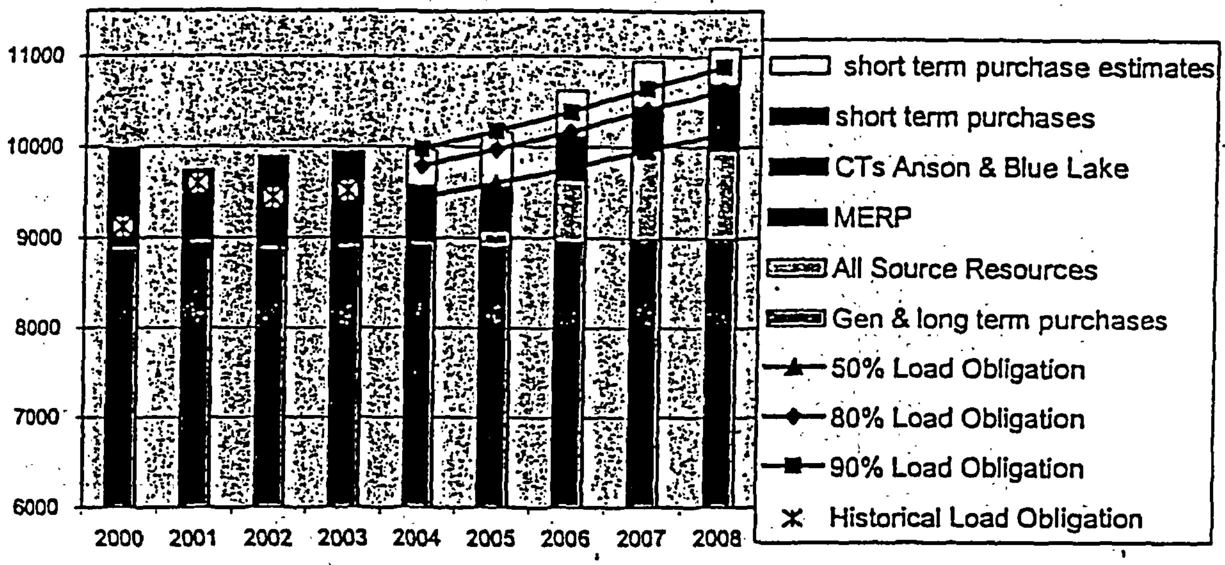


The net effect of these emerging and changing circumstances is that there is significant risk that Xcel Energy will not be able to secure adequate power supply resources to cover peak demand and associated reserve obligations to the 80th to 90th percentile probability level in 2005. Said another way, there is significant risk that the reliability of our power supply could decline.

XCEL ENERGY PROPOSES TO ADD 485 MEGAWATTS OF PEAKING CAPACITY

Xcel Energy believes the best way to address this potential shortfall or decline in system reliability is to add peaking facilities located on the company's own transmission system as soon as possible. Accordingly, the Company intends to develop two combustion turbines at the Blue Lake peaking plant site in Shakopee, Minnesota and add one combustion turbine at the Anson site near Sioux Falls, South Dakota. By developing the units ourselves we maximize the likelihood that the units will be in service by the summer of 2005. In addition, we have investigated the current market for combustion turbines and believe the projects can be developed at costs competitive with and perhaps better than the All-Source outcomes. The most recent power supply estimate with the addition of three combustion turbines added to the Xcel Energy system in 2005 is shown in the graph below.

NSP Load Obligations and Resources
November 2003



In order to meet a 2005 in service date, we estimate that construction must begin no later than the fall of 2004. The Blue Lake proposal requires a Certificate of Need from the Commission, a Site Permit from the Environmental Quality Board, and air quality permits form the Pollution Control Agency. We believe that the regulatory process can be completed in the remaining 10 months. However, the schedule is aggressive and will require the consideration of three separate agency approvals in parallel. We intend to do everything possible to facilitate the review of our proposal and we stand ready to work with the regulatory authorities to move through the process expeditiously. Toward that end, we intend to make an application to the Commission for a Certificate of Need for the Blue Lake Combustion Turbines by early December and site and air quality applications shortly thereafter. We would like to make clear that we are not asking agencies to prejudge the suitability or merits of our proposal. Rather, we would like to explore ways in which we can move through the process expeditiously so that, should the Commission concur with our assessment, a 2005 in service date can be achieved.

We respectfully request no action be taken in the Resource Planning venue at this time. It appears to us that the best way to proceed is to get the matter quickly before the Commission in a Certificate of Need filing. The Commission will also have the opportunity to act as power purchase agreements are brought for approval.

Dated: November 7, 2003

Northern States Power Company
d/b/a Xcel Energy

By: James Alders
JAMES ALDERS
MANAGER REGULATORY PROJECTS

FILE COPY

BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

LeRoy Koppendrayer	Chair
Marshall Johnson	Commissioner
Ken Nickolai	Commissioner
Phyllis A. Reha	Commissioner
Gregory Scott	Commissioner

RECEIVED
MAR 10 2004

In the Matter of Northern State Power Company d/b/a Xcel Energy's Application for Approval of its 2003-2017 Resource Plan

ISSUE DATE: March 9, 2004

DOCKET NO. E-002/RP-02-2065

ORDER PERMITTING WITHDRAWAL OF RESOURCE PLAN AND REQUEST TO ISSUE RFP

PROCEDURAL HISTORY

On December 2, 2002, Northern State Power Company d/b/a Xcel Energy (Xcel or the Company) filed its 2003-2017 Resource Plan.

On March 14, 2003, the Department of Commerce (DOC) requested that the date for filing initial comments be delayed until the conclusion of the 2003 legislative session due to the Legislature's consideration of issues related to Xcel's Prairie Island and Monticello plants.

On March 18, 2003, the Commission issued a notice suspending the initial and reply comment periods.

On June 12, 2003, Xcel filed a summary of legislative action in the 2003 legislative session and the impact of certain legislation on its open dockets. In reference to the present docket, Xcel proposed making a filing within a month that would restate its preferred resource plan, assess the impact of the new legislation on various components of its resource plan, and make recommendations on how to address the issues.

On September 10, 2003, Xcel filed an update to its Resource Plan filed on December 2, 2002. Xcel requested that it be allowed to withdraw the pending Resource Plan and file its next Resource Plan no later than November 1, 2004. Xcel also requested approval to issue a Request for Proposals (RFP) in 2005 to obtain 450 MW of supply in the 2011-2013 time frame.

On October 20, 2003, the DOC filed comments recommending approval.

On October 20, 2003, the Izaak Walton League of America - Midwest Office (IWLA), Minnesotans for an Energy-Efficient Economy (ME3), and Minnesota Center for Environmental Advocacy (MCEA) (collectively, Environmental Intervenors) filed joint comments.

On November 10, 2003, Xcel filed a Notice of Changed Circumstances affecting this Resource Planning docket.

On November 12, 2003, Xcel filed reply comments.

On February 10, 2004, Xcel filed a request to withdraw its September 10, 2003 request for approval to issue a RFP in 2005 to obtain 450 MW of supply in the period 2011-2013.

This matter came before the Commission on February 12, 2004.

FINDINGS AND CONCLUSIONS

I. Xcel's Request to Withdraw its Pending Resource Plan

The Company filed its pending Resource Plan for the 2003-2017 period in December of 2002. This filing identified significant issues concerning the continued operation of the Company's Prairie Island and Monticello nuclear plants..

Since that filing, the 2003 Legislature authorized, among other things, sufficient spent nuclear fuel storage to allow Xcel to operate Prairie Island to the end of its current operating license in 2013 (Unit 1) and 2014 (Unit 2). The Legislature also provided a process by which Xcel could secure additional capacity if it sought relicensing of the plant, and provided a resolution of the contingency bid process.[1]

Xcel argued that besides this legislative action there have been other significant events that need to be represented in the Company's long range planning. Some of these include Xcel's Metropolitan Emissions Reduction Proposal (MERP)[2], Xcel's January 16, 2004 application for a Certificate of Need for two combustion turbines at the Blue Lake generating plant site,[3] and Xcel's intention to pursue permits for the addition of a combustion turbine unit at the Anson generating plant site near Sioux Falls.

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[1] 2003 Minn. Laws (1st Special Session), Ch. 11.

[2] *In the Matter of a Petition by Xcel Energy for Approval of a Three-Plant Emissions Reduction Proposal and Rate Rider to Recover Costs*, Docket No. E-002/M-02-633.

[3] *In the Matter of the Application of Northern States Power Company (d/b/a Xcel Energy) for a Certificate of Need for a Large Electric Generating Facility*, Docket E-002/CN-04-76.

Xcel recommended that its next resource plan should be submitted on or before November 1, 2004. It argued that this date would be reasonable given the complexity of the issues that need to be considered and evaluated.

Finally, Xcel agreed that other issues such as conservation goals and compliance with renewable energy requirements would proceed according to the Commission's 2000 resource plan order [4] until the next resource plan cycle was completed.

II. Xcel's request to Withdraw its Request to authorize a 2005 RFP in this Proceeding

In September 2003 Xcel requested permission to withdraw its 2002 Resource Plan filing. At the same time Xcel requested that the Commission authorize a 2005 RFP for new resources. At hearing, Xcel requested that its request to authorize a 2005 RFP be withdrawn.

Xcel proposed that rather than request approval of a 2005 RFP at this time, Xcel would provide the Commission with a re-evaluation of the need for the next solicitation at least 90 days before filing an RFP. Xcel anticipated that such a filing would not occur until after its next resource plan is filed.

III. Parties' Positions

At hearing, no party opposed Xcel's requests to withdraw its 2002 resource plan filing or to withdraw its request for an RFP authorization for 2005.

A. The DOC.

On the issue of the Company's request to withdraw its resource plan previously filed, the DOC stated that Xcel's 2002 Resource Plan did not raise significant issues that required immediate Commission action. The most important decision, the near-term future operation of the Prairie Island Nuclear Generating plant was decided by the 2003 Minnesota Legislature.

Further, the DOC concluded that no law or rule prohibits Xcel from withdrawing its 2003-2017 Resource Plan.

Finally, the DOC stated that Xcel's request to withdraw its pending resource plan would not unduly limit the Commission's ability to shape the Company's future resource acquisitions.

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[4] *In the Matter of Northern States Power Company's Application for Approval of its 2000-2014 Resource Plan*, Docket No. E-002/RP-00-787, ORDER APPROVING XCEL ENERGY'S 2000-2014 RESOURCE PLAN, AS MODIFIED, August 29, 2001.

B. The Environmental Intervenors

The Environmental Intervenors argued that Xcel should be required to resubmit its resource plan in July 2004. It argued that a July date was workable and would be consistent with Minnesota Rules, which require a utility to submit a proposed resource plan biennially on July 1.[5]

IV. Commission Action

The Commission will approve Xcel's request to withdraw its Resource Plan for the period 2003 to 2017, which it filed in December 2002. Given the complexity of resource planning, the Commission will accept the Company's request to refile by November 1, 2004. That will provide the Company with ample time to prepare its plan.

The Commission will vary the two-year interval filing provision of Minn. Rules, Part 7843, Subp.2 to extend the date for the Company's filing to November 1, 2004. The Commission finds that the requirements for granting a variance pursuant to Minn. Rules, Part 7829.3200 are met in this case.

- In view of the legislation recently passed and the other significant matters that need to be considered in the Company's resource planning, and considering the time necessary to prepare a resource plan, it would impose an excessive burden upon Xcel to require it to refile its resource plan before November 1, 2004.

- Granting the time necessary to incorporate the items identified in this Order into a solid resource plan is in the public interest.

- Finally, since the filing date is set by Commission rule and not by statute, extending that deadline does not violate a standard imposed by law.

The Commission also will allow Xcel to withdraw its request for authorization for a 2005 RFP for new resources. The Commission is in agreement with the parties that the need for such a solicitation should be reevaluated prior to the submission of an RFP. Xcel has agreed to do so at least 90 days prior to filing an RFP with the Commission.

In addition, the Commission recognizes the difficulties and shortcomings in the current bid process, including difficulty in securing new resources in a timely manner, and agrees that discussions between the Company and stakeholders to re-examine the competitive bidding process are in order. For this reason the Commission will order that discussions, between the Company and stakeholders, including the DOC and Commission staff, on the competitive bidding process and the use of other processes for acquiring baseload as well as other resources should begin as soon as possible.

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[5] Minn. Rules Part 7843.0300, subp.2.

As part of the discussions, the Commission believes that information from other jurisdictions on the success or difficulties of the bidding process in other areas may aid in determining whether the problems herein are specific to Minnesota or are of a broader nature. Such information may also aid in determining what is successful in the bidding process and what is not. For these reasons, the Commission will request that the DOC conduct an analysis of the bidding process as used in other jurisdictions to inform the stakeholder process about what is successful and what is not as it relates to baseload acquisitions and other acquisitions.

Finally, the Commission will require Xcel to address in its next resource plan filing the issue of the incremental additions of natural gas facilities on its system. The Commission notes its concern about the potential long run impact of the Company's natural gas projects and directs the Company to provide support for what it considers to be the appropriate level of incremental natural gas facility additions over the planning period.

ORDER

1. Xcel's request to withdraw its pending resource plan is hereby granted. The current resource plan docket (E-002/RP-02-2065) shall be held open for information requests and any other actions required as a result of the Commission's decisions herein.

2. The Commission grants a variance from the two-year requirement of Minnesota Rules, part 7843.0300, subp. 2, and designates November 1, 2004 as the filing date for Xcel's next Resource Plan. Xcel shall re-file, in the November 2004 Resource Plan, any filing requirements from the Commission's August 29, 2001 Resource Plan Order, in Docket No. E-002/RP-00-787, and any other filing requirements that were included in the 2003-2017 Resource Plan in response to Commission directives.

3. Xcel's request to withdraw its earlier proposal for approval to issue an RFP in 2005 is hereby granted. Xcel shall provide the Commission with the Company's re-evaluation of the need for the next solicitation at least 90 days prior to filing its next RFP with the Commission.

4. Xcel shall fully meet, in a timely manner, all outstanding ordering requirements, which apply to the next RFP and all source bid, including those required in the Commission's March 6 and November 19, 2003 Orders in Docket No. E-002/M-01-1618.

5. Xcel shall immediately begin stakeholder discussions to re-examine the competitive bidding process, the use of the competitive bidding process, and the use of other processes for acquiring baseload and other resources. The first step shall be the establishment of a roadmap for these discussions, including among other issues the timing and number of meetings, issues to be discussed, and stakeholders to be represented. This roadmap shall be filed with the Commission, for informational purposes, by March 31, with stakeholder

meetings to begin shortly thereafter. Department and Commission staff shall be included in these meetings.

6. The Commission requests that the DOC conduct an analysis of the bidding process as used in other jurisdictions to inform the stakeholder process of successes and failures in other jurisdictions, as they relate to both baseload and other kinds of acquisitions.

7. Xcel shall, in the November 2004 resource plan filing, address the issue of what it considers the appropriate level of natural gas fired facilities on its system over the planning period. At a minimum, Xcel shall include the following in its filing:

   a. existing natural gas facilities;
   b. currently planned facilities (e.g. MERP project, proposed Blue Lake facilities, 2001 all source bid projects fueled by natural gas);
   c. any other proposals for projects fueled by natural gas within the local region and the MAPP region during the forecast period;
   d. projected demand on the system over the planning period;
   e. A list or plan of viable options for meeting natural gas capacity needs;
   f. the projected growth rate of the total demand for natural gas in these regions; and
   g. to the extent Xcel intends to rely on other companies to provide the pipeline capacity for projects, Xcel shall provide estimates, along with supporting documentation, of these costs and capacity increase needs.

8. Xcel shall report back to the Commission in writing on the results of the MISO Facility Study (referenced in the Company's November 10 filing) and its implications for future resource acquisitions, within 20 days of receiving the study.

9. This Order shall become effective immediately.

BY ORDER OF THE COMMISSION

Carl Caselotti, for

Burl W. Haar
Executive Secretary

(S E A L)

This document can be made available in alternative formats (i.e., large print or audio tape) by calling (651) 297-4596 (voice), or 1-800-627-3529 (MN relay service).

7610.0430 Fuel Requirements and Generation by Fuel Type

		Nuclear	Nuclear	Coal	Coal	RDF	RDF	Natural Gas	Natural Gas	Oil	Oil	Hydro
		1000 Mbtu	1000 MWhr	1000 Ton	1000 MWhr	1000 Ton	1000 MWhr	1000 mcf	1000 MWhr	1000 Gallon	1000 MWhr	1000 MWhr
Past Year	2003	140,536	13,413	12,725	21,780	373	235	5,035	473	4,234	29	57
Present Year	2004	135,011	12,692	12,526	21,557	381	235	4,940	601	980	10	86
1st Forecast Year	2005	136,968	13,167	12,475	20,814	379	252	10,936	1,134	38	3	86
2nd Forecast Year	2006	140,726	13,533	12,194	20,297	389	259	9,980	1,078	34	2	86
3rd Forecast Year	2007	138,533	13,316	11,888	19,811	375	249	10,258	1,124	62	5	86
4th Forecast Year	2008	135,760	13,052	12,316	20,673	385	256	11,851	670	27	2	86
5th Forecast Year	2009	142,321	13,686	11,044	18,614	388	258	19,400	540	18	1	86
6th Forecast Year	2010	136,661	13,138	10,857	18,286	384	256	26,471	573	21	1	86
7th Forecast Year	2011	89,262	8,526	11,312	19,017	366	244	27,732	607	24	2	86
8th Forecast Year	2012	90,146	8,610	11,419	19,252	381	253	29,569	701	22	2	86
9th Forecast Year	2013	90,121	8,608	11,500	19,372	364	243	31,275	723	22	2	86
10th Forecast Year	2014	45,720	4,367	11,846	19,948	387	258	44,702	1,140	23	2	86
11th Forecast Year	2015	-	-	11,808	19,910	408	272	50,084	1,415	29	2	86
12th Forecast Year	2016	-	-	11,730	19,756	408	272	41,213	1,063	26	2	86
13th Forecast Year	2017	-	-	11,696	19,697	407	271	37,285	835	24	2	86
14th Forecast Year	2018	-	-	11,699	19,702	407	271	40,323	933	42	3	86

7610.0500 – Transmission Lines

7160.0500 TRANSMISSION LINES

Subpart 1. Existing Transmission Lines Over 200 kV

A map is included at the end of this section.

Design Voltage	Size of Conductor	Type of Conductor	D.C. or A.C. (specify)	Location of D.C. Terminals or A.C. substations	Length in MN (miles)
500 kV	3-1192	ACSR	A.C.	Forbes (MPC)-Manitoba Hydro Interconnection	203.79
500 kV	3-1192	ACSR	A.C.	Chisago Co.-MPL	61.56
345 kV	2-795	ACSR	A.C.	King-Red Rock	24.97
345 kV	2-795	ACSR	A.C.	Parkers Lake-Prairie Island	33.09
	2-954	ACSR	A.C.		34.17
	2312	ACSR	A.C.		0.22
345 kV	2-795	ACSR	A.C.	King-Terminal	23.00
345 kV	2-954	ACSR	A.C.	Monticello-Parkers Lake	37.16
345 kV	2-954	ACSR	A.C.	Prairie Island-Adams	2.42
	2-795	ACSR	A.C.		73.87
345 kV	2-795	ACSR	A.C.	Chisago Co.-Coon Creek	26.18
	2-954	ACSR	A.C.		31.56
345 kV	2-795	ACSR	A.C.	King-St. Croix River	19.26
345 kV	2-795	ACSR	A.C.	Blue Lake-Lakefield Junction	127.88
345 kV	2-954	ACSR	A.C.	Sherburne Co.-Terminal	43.50
	2-795	ACSR	A.C.		13.73
345 kV	2-954	ACSR	A.C.	Sherburne Co.-CU Connection	33.26
345 kV	2-795	ACSR	A.C.	Prairie Island-Red Rock	29.44
	2-954	ACSR	A.C.		2.57

Continued next page

Design Voltage	Size of Conductor	Type of Conductor	D.C. or A.C. (specify)	Location of D.C. Terminals or A.C. substations	Length in MN (miles)
345 kV	2-795	ACSR	A.C.	Prairie Island-Red Rock	29.44
	2-954	ACSR	A.C.		2.57
345 kV	2-795	ACSR	A.C.	Parkers Lake-Blue Lake	14.86
345 kV	2-795	ACSR	A.C.	Blue Lake-Red Rock	31.16
345 kV	2-954	ACSR	A.C.	Sherburne Co.-Monticello	5.78
345 kV	2-954	ACSR	A.C.	Sherburne Co.-Coon Creek	43.50
345 kV	2-1192	ACSR	A.C.	Sherburne Co.-CPA Interconnection	10.55
345 kV	2-795	ACSR	A.C.	Chisago Co.-King	6.61
	2-954	ACSR	A.C.		31.56
345 kV	2-954	ACSR	A.C.	Parkers Lake-CU Connection	9.64
230 kV	795	ACSR	A.C.	Black Dog-Minnesota Valley-WAPA (Granite Falls)	116.78
230 kV	795	ACSR	A.C.	Red Rock-Rush City (UPA)-MP&L Co.	66.55
	1272	ACSR	A.C.		13.82
230 kV	795	ACSR	A.C.	Wilmar-Paynsville	29.74
230 kV	795	ACSR	A.C.	Audubon-Badoura	38.31

Subpart 2. Transmission Line Additions

A map is included at the end of this section.

Design Voltage	Size of Conductor	Type of Conductor	D.C. or A.C. (specify)	Location of D.C. Terminals or A.C. substations	Date	Length in MN (miles)
230 kV	795	ACSR	A.C.	Blue Lake- Granite Falls tap	2005	0.8
345 kV	795	ACSR	A.C.	Calpine Generation- Wilmarth**	2006	0.2
345 kV	2-954	ACSR	A.C.	Split Rock (SD) - Lakefield Jct.*	2007	80

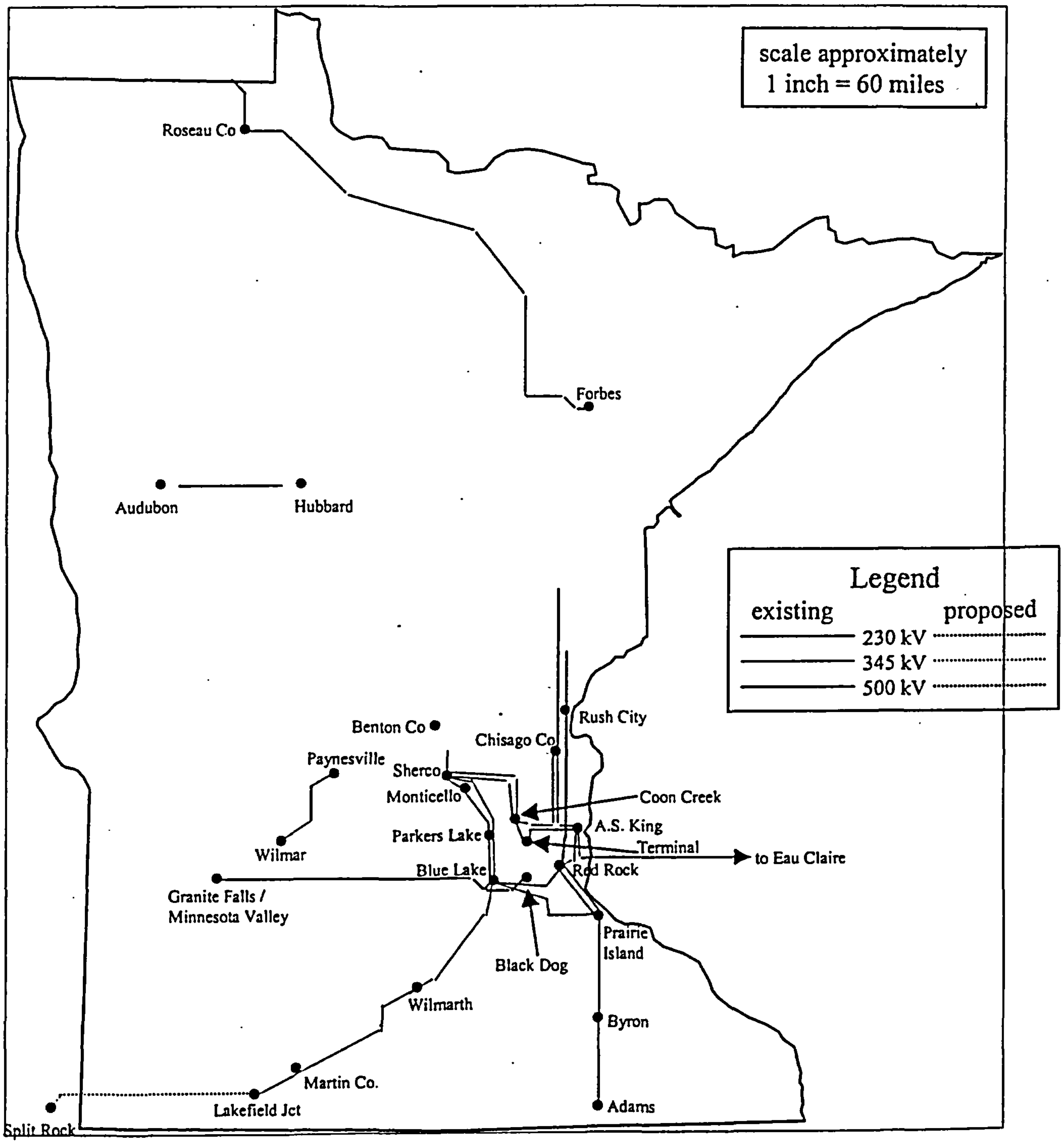
*Project associated with anticipated wind generation developments in SW Minnesota. Certificate of need approved by the Minnesota PUC in March 2003. Construction pending Minnesota EQB route designation.

**Xcel Energy has been requested to connect a steam generator planned to be located next to Xcel Energy's Wilmarth substaion to the to the Wilmarth 345 kV substation. Design is pending

Subpart 3. Transmission Line Retirements

Xcel Energy will operate the Blue Lake-Black Dog portion of the Granite Falls- Black Dog 230 kV line at 115 kV beginning spring of 2005

NSP Existing and Proposed Transmission System
State of Minnesota
(Lines Above 200 kV)



7610.0600, item A. 24-HOUR PEAK DAY DEMAND

Each utility shall provide the following information for the last calendar year:

A table of the demand in megawatts by the hour over a 24-hour period for:

1. the 24-hour period during the summer season when the megawatt demand on the system was the greatest; and
2. the 24-hour period during the winter season when the megawatt demand on the system was the greatest.

(Use the table to the right)

Note: This data reflects the peak demand day after interruptions. The peak demand including interruption was 8,908 Mw on August 18, 2003.

TIME OF DAY	DATE: 8/20/2003 MW USED ON SUMMER PEAK DAY	DATE: 12/11/2003 MW USED ON WINTER PEAK DAY
0100	• 5,795	• 4,517
0200	• 5,432	• 4,354
0300	• 5,247	• 4,299
0400	• 5,125	• 4,299
0500	• 5,183	• 4,438
0600	• 5,390	• 4,753
0700	• 5,990	• 5,450
0800	• 6,399	• 5,964
0900	• 6,724	• 5,934
1000	• 6,963	• 5,932
1100	• 7,311	• 5,929
1200	• 7,589	• 5,897
1300	• 7,693	• 5,819
1400	• 8,004	• 5,785
1500	• 8,208	• 5,754
1600	• 8,232	• 5,694
1700	• **8,281**	• 6,047
1800	• 8,229	• 6,475
1900	• 8,190	• **6,497**
2000	• 8,084	• 6,357
2100	• 8,037	• 6,245
2200	• 7,761	• 5,956
2300	• 7,139	• 5,524
2400	• 6,467	• 5,010

A. 7610.0700

Quarterly Report of Electricity Delivered to Ultimate Consumers in Minnesota, 2003

	1st Quarter			2nd Quarter			3rd Quarter			4th Quarter		
SIC Code	Number of Customers	Sales (Mwh)	Revenue (000 $)	Number of Customers	Sales (Mwh)	Revenue (000 $)	Number of Customers	Sales (Mwh)	Revenue (000 $)	Number of Customers	Sales (Mwh)	Revenue (000 $)
SLS01T09	3,644	80,344	4,330	3,252	43,583	2,827	3,295	56,255	3,910	3,287	50,160	2,961
SLS10T19	2,958	114,996	5,394	2,917	53,233	3,346	2,846	59,165	4,151	2,841	55,639	3,230
SLS20	714	286,972	13,177	1,025	297,680	14,775	1,009	330,768	18,159	991	301,272	13,832
SLS21	6	676	36	6	605	36	6	421	30	6	593	33
SLS22	58	4,812	256	72	7,530	434	70	8,131	512	70	7,347	389
SLS23	145	2,540	163	141	2,522	178	137	2,891	224	140	3,242	218
SLS24	446	38,557	1,948	437	47,093	2,485	435	48,660	2,918	417	43,616	2,111
SLS25	161	5,066	324	157	4,510	306	154	4,729	368	152	4,149	262
SLS26	229	185,860	7,273	253	193,822	7,552	246	223,688	9,090	248	221,530	7,721
SLS27	1,136	124,245	6,310	1,106	138,035	7,597	1,075	152,177	9,238	1,046	138,192	6,862
SLS28	335	149,832	6,177	353	162,104	7,232	349	181,176	8,955	358	165,892	6,845
SLS29	131	282,432	9,617	193	323,666	13,132	183	334,078	14,221	185	324,504	5,074
SLS30	651	135,292	6,425	651	143,668	7,172	642	154,164	8,533	668	143,283	6,568
SLS31	41	6,697	341	44	7,226	386	44	7,214	448	44	6,441	325
SLS32	330	45,953	2,153	316	51,422	2,422	307	54,114	2,798	301	55,797	2,365
SLS33	174	163,086	6,799	171	181,360	7,870	169	176,285	8,024	171	163,289	6,519
SLS34	890	110,235	5,797	888	110,534	6,246	868	123,712	7,747	856	112,277	5,806
SLS35	1,312	200,624	9,470	1,282	184,584	9,673	1,265	197,594	11,619	1,258	178,661	8,599
SLS36	550	106,653	4,927	543	113,169	5,702	531	135,067	7,461	514	124,311	5,728
SLS37	141	14,980	753	132	12,537	728	132	15,448	980	129	16,382	848
SLS38	471	105,815	5,008	488	113,380	5,891	473	128,961	7,366	469	111,806	5,259
SLS39	618	28,236	1,606	570	20,702	1,349	548	23,784	1,722	545	20,687	1,225
SLS40	823	12,752	656	925	7,042	415	924	7,237	458	929	5,849	282
SLS41	356	9,935	492	336	8,195	434	337	8,769	520	329	7,759	387
SLS42	1,674	40,230	2,077	1,529	29,187	1,674	1,477	31,933	2,029	1,469	29,527	1,565
SLS43	277	10,605	528	271	9,153	514	266	11,403	696	269	9,153	475
SLS44	146	1,007	67	141	1,084	83	140	1,578	126	136	1,281	90
SLS45	720	47,372	2,053	701	46,439	2,240	671	53,373	2,778	667	43,560	1,926
SLS46	48	18,807	850	7	916	66	6	2,111	125	6	961	67
SLS47	405	20,188	900	340	17,910	863	330	18,811	1,024	324	16,975	760
SLS48	4,221	65,149	3,084	4,909	70,491	3,573	5,848	87,596	4,847	5,769	81,646	3,845
SLS49	1,306	58,855	2,797	1,230	70,529	3,691	1,217	86,653	4,862	1,212	72,011	3,304
SLS50	2,615	75,359	4,215	2,526	66,515	4,199	2,440	69,525	5,004	2,403	59,574	3,547
SLS51	1,630	63,539	3,397	1,418	52,041	3,023	1,382	58,226	3,737	1,365	52,809	2,856
SLS52	1,143	32,583	1,687	1,143	37,778	2,165	1,119	43,335	2,724	1,113	35,846	1,911
SLS53	640	116,943	5,480	619	96,858	5,212	600	116,642	6,894	573	98,448	4,854
SLS54	1,792	168,619	7,663	1,685	177,183	8,747	1,646	200,319	10,881	1,617	174,134	7,872
SLS55	2,354	82,571	4,368	2,394	84,097	4,839	2,378	93,962	5,983	2,349	84,467	4,441

SLS56	7	13,433	812	957	15,686	1,027	922	18,946	1,342	894	15,049	2
SLS57	1,266	29,258	1,652	1,236	32,180	1,998	1,214	39,441	2,673	1,211	32,925	1,860
SLS58	4,520	147,810	8,263	4,401	154,447	9,573	4,313	192,776	12,833	4,302	152,804	8,725
SLS59	5,102	104,188	5,748	4,949	116,226	7,042	4,803	144,193	9,471	4,765	116,268	6,406
SLS60	783	37,009	1,909	704	28,485	1,644	700	32,824	2,082	697	27,972	1,504
SLS61	170	4,544	249	160	4,834	287	152	5,429	355	150	4,789	256
SLS62	78	5,378	283	66	894	59	64	968	69	64	691	43
SLS63	139	21,349	1,032	106	3,585	213	104	4,258	276	104	3,187	179
SLS64	814	14,839	814	780	19,490	1,109	772	26,307	1,599	757	18,023	971
SLS65	20,606	492,150	25,939	21,061	546,010	31,734	20,791	638,260	40,922	20,813	559,330	29,904
SLS66	1	40	2	1	33	2	1	31	3	1	47	2
SLS67	269	14,068	741	257	9,991	609	247	11,672	779	225	8,782	502
SLS68	0	0	0	0	0	0	0	0	0	0	0	0
SLS69	8	196	11	7	187	11	7	218	14	6	209	10
SLS70	842	83,268	4,110	879	73,900	4,000	862	92,589	5,407	857	72,557	3,614
SLS71	0	1	0	0	0	0	0	0	0	0	0	0
SLS72	3,099	29,590	1,915	2,997	27,398	1,995	2,943	32,862	2,622	2,893	26,171	1,744
SLS73	4,009	74,689	4,094	3,892	77,553	4,628	3,855	92,761	6,048	3,877	79,362	4,281
SLS74	6	42	3	6	28	3	6	21	3	5	5	2
SLS75	3,115	48,451	2,889	3,022	37,581	2,540	2,954	38,859	2,947	2,934	33,992	2,137
SLS76	845	5,564	378	813	4,448	345	790	4,961	422	773	4,104	290
SLS77	8	13	1	8	13	1	7	18	1	7	4	0
SLS78	371	8,153	487	411	10,525	676	399	13,000	924	329	7,980	477
SLS79	3,098	66,037	3,737	2,966	70,938	4,532	2,965	97,573	6,742	2,935	75,738	4,411
SLS80	2,956	172,492	8,298	2,965	187,368	10,056	2,947	243,616	14,085	2,936	191,063	9,432
SLS81	426	4,596	260	412	2,430	180	401	3,156	252	398	2,333	162
SLS82	2,158	316,212	15,650	2,205	312,019	17,317	2,218	318,032	19,533	2,206	335,621	17,027
SLS83	1,090	27,157	1,545	1,078	29,798	1,879	1,039	37,201	2,551	1,047	28,617	1,654
SLS84	115	7,905	402	105	9,415	518	105	11,450	671	105	8,783	446
SLS85	0	0	0	0	0	0	0	0	0	0	0	0
SLS86	3,713	67,422	4,220	3,582	51,920	3,855	3,525	61,744	4,994	3,551	53,290	3,666
SLS87	994	24,920	1,366	959	20,209	1,273	928	23,035	1,607	910	18,891	1,095
SLS88	161	1,002	59	165	563	43	158	601	50	167	590	40
SLS89	1,769	34,159	1,860	1,687	23,101	1,467	1,684	25,472	1,799	1,709	23,510	1,378
SLS90	16	23	2	14	14	1	14	20	2	14	5	0
SLS91	1,038	51,834	2,594	1,741	56,408	3,194	1,777	67,777	4,155	1,759	56,323	2,907
SLS92	542	25,917	1,220	467	24,197	1,245	451	28,934	1,610	460	25,793	1,240
SLS93	36	8,640	402	31	7,728	404	29	7,970	460	31	7,497	362
SLS94T99	20,048	318,324	17,389	20,170	237,136	15,284	20,935	297,562	21,169	21,700	303,553	17,580
TOTAL	120,469	5,259,090	258,934	120,431	5,185,121	279,821	120,647	5,924,512	351,634	120,818	5,318,928	256,161

NOTE: Due to accounting adjustments, the sum of revenues by SIC code may not match the final reported revenues.

A. 7610.0700
Quarterly Report of Electricity Delivered to Ultimate Consumers Outside Minnesota, 2003

	1st Quarter			2nd Quarter			3rd Quarter			4th Quarter		
SIC Code	Number of Customers	Sales (Mwh)	Revenue (000 $)	Number of Customers	Sales (Mwh)	Revenue (000 $)	Number of Customers	Sales (Mwh)	Revenue (000 $)	Number of Customers	Sales (Mwh)	Revenue (000 $)
SLS01T09	1,288	18,022	1,071	1,377	15,201	977	1,434	18,790	1,240	1,448	17,636	1,094
SLS10T19	1,660	12,704	830	1,666	11,538	793	1,666	13,206	960	1,667	12,327	842
SLS20	402	140,474	6,228	401	146,620	6,499	407	155,787	7,423	397	151,850	6,562
SLS21	11	30	2	11	29	2	11	32	2	13	25	4
SLS22	15	1,273	72	14	1,076	65	17	1,269	76	15	1,064	67
SLS23	62	2,708	161	61	2,647	166	63	3,255	213	62	2,451	144
SLS24	363	39,057	2,102	366	37,450	2,044	361	37,076	2,098	362	36,301	1,781
SLS25	84	2,624	167	83	2,450	160	82	2,583	175	80	2,441	145
SLS26	42	78,202	2,925	43	73,770	2,773	45	79,280	3,063	46	98,730	3,364
SLS27	259	11,556	655	260	11,683	692	252	14,194	877	249	12,858	756
SLS28	70	14,537	685	67	14,476	687	76	15,288	770	69	15,917	832
SLS29	25	8,224	315	24	6,263	285	25	7,222	319	25	9,271	419
SLS30	187	56,462	2,443	191	58,529	2,584	186	58,569	2,735	185	58,990	2,508
SLS31	10	494	26	10	461	25	8	492	27	8	449	29
SLS32	144	11,744	601	147	11,706	630	148	12,550	700	145	12,821	648
SLS33	28	10,116	540	28	10,309	538	28	9,640	537	28	11,126	656
SLS34	210	35,505	1,815	214	33,288	1,719	214	36,074	1,936	213	34,241	1,649
SLS35	374	59,820	3,030	375	61,056	3,119	376	70,071	3,700	371	62,926	3,116
SLS36	125	36,216	1,647	130	38,463	1,767	133	40,612	1,916	138	38,267	1,732
SLS37	62	7,343	387	60	6,685	365	58	6,640	376	55	6,152	322
SLS38	36	4,332	212	38	4,670	235	38	5,447	281	39	5,494	364
SLS39	133	8,855	478	138	8,996	489	140	10,517	584	140	9,857	491
SLS40	571	3,525	197	569	1,456	99	573	1,347	98	577	1,413	91
SLS41	140	1,746	104	141	1,430	85	136	1,544	94	137	1,483	86
SLS42	1,461	26,224	1,342	1,470	22,167	1,204	1,478	26,625	1,460	1,459	24,930	1,177
SLS43	207	3,951	202	206	4,597	248	206	5,889	336	204	4,533	240
SLS44	88	951	54	90	733	51	96	761	54	94	733	48
SLS45	445	3,513	188	445	2,800	158	448	3,171	183	442	2,892	192
SLS46	32	3,178	128	31	2,864	120	32	2,709	122	33	2,832	114
SLS47	124	1,049	64	120	845	54	117	966	63	116	908	68
SLS48	2,034	22,711	1,165	2,021	22,018	1,158	2,034	25,713	1,411	2,021	22,508	1,177
SLS49	1,249	25,989	1,253	1,247	26,059	1,301	1,242	30,058	1,529	1,261	30,387	1,464
SLS50	900	19,880	1,154	892	17,469	1,069	891	20,005	1,298	882	18,681	1,107
SLS51	915	27,678	1,556	895	26,582	1,531	876	30,847	1,815	868	28,804	1,549
SLS52	613	17,280	938	605	17,065	952	600	19,938	1,150	589	18,346	959
SLS53	431	32,849	1,607	446	33,363	1,746	451	42,291	2,311	439	35,939	1,830
SLS54	732	67,493	3,089	723	68,393	3,227	721	78,326	3,874	739	72,679	3,292
SLS55	1,461	37,744	2,044	1,450	34,900	1,959	1,445	39,050	2,301	1,442	36,369	1,942

SLS56	2	4,608	281	361	4,245	275	357	5,300	353	346	4,321	2
SLS57	527	6,353	390	523	5,946	388	506	7,360	498	515	6,078	402
SLS58	2,663	68,076	3,906	2,656	70,587	4,230	2,646	91,257	5,609	2,664	73,359	4,173
SLS59	2,376	32,999	1,913	2,352	30,870	1,914	2,355	38,069	2,467	2,359	31,544	1,914
SLS60	687	28,163	1,404	690	26,007	1,379	683	31,649	1,781	684	26,949	1,381
SLS61	105	3,066	154	108	2,874	157	105	3,464	198	105	2,851	152
SLS62	53	840	45	49	735	41	45	953	54	45	750	41
SLS63	84	2,930	145	84	2,849	153	82	3,541	203	82	3,059	156
SLS64	560	4,724	282	546	4,618	282	539	6,017	383	529	4,897	296
SLS65	8,365	74,503	4,298	8,326	58,706	3,662	8,236	67,542	4,406	8,208	61,671	4,159
SLS66	4	19	1	4	9	1	4	9	1	4	14	1
SLS67	82	1,138	65	85	1,102	67	92	1,387	88	88	1,239	78
SLS68	0	0	0	0	0	0	0	0	0	0	0	0
SLS69	2	145	9	2	122	7	2	73	4	3	105	7
SLS70	977	40,432	2,088	974	28,351	1,605	977	37,773	2,163	966	29,315	1,595
SLS71	1	0	0	1	0	0	1	0	0	1	0	0
SLS72	1,508	9,434	659	1,502	9,036	646	1,506	10,473	792	1,511	8,735	609
SLS73	1,277	15,202	853	1,275	14,091	841	1,313	17,089	1,077	1,320	15,382	926
SLS74	1	0	0	1	0	0	0	0	0	0	0	1
SLS75	1,931	15,119	988	1,942	11,716	823	1,949	12,213	913	1,969	11,883	794
SLS76	525	2,239	159	523	1,765	136	518	1,969	158	507	1,711	126
SLS77	3	1	0	3	1	0	3	1	0	3	0	0
SLS78	127	2,101	129	119	1,936	134	115	2,641	183	116	1,758	124
SLS79	1,706	25,380	1,449	1,716	21,511	1,358	1,717	27,025	1,799	1,747	23,603	1,431
SLS80	1,594	101,949	4,741	1,592	104,808	5,136	1,589	134,190	6,788	1,597	109,474	5,171
SLS81	316	2,022	126	310	1,641	110	312	2,188	154	314	1,741	109
SLS82	1,087	103,929	5,534	1,090	97,462	5,474	1,094	98,565	5,738	1,083	110,196	6,017
SLS83	424	8,477	497	428	7,840	493	430	10,003	656	433	8,165	501
SLS84	71	1,158	68	76	1,230	74	73	1,242	81	72	937	61
SLS85	1	1	0	1	0	0	1	0	0	0	0	0
SLS86	2,086	19,608	1,316	2,090	16,942	1,254	2,089	20,897	1,604	2,092	18,329	1,298
SLS87	397	17,808	803	397	16,126	750	393	17,978	859	398	16,938	714
SLS88	135	803	50	163	893	57	185	1,045	66	198	924	57
SLS89	687	7,336	424	685	5,988	375	700	6,968	461	732	6,476	399
SLS90	36	382	22	36	329	20	35	398	25	33	357	20
SLS91	627	7,971	461	631	7,621	453	647	9,876	579	658	7,798	482
SLS92	377	10,012	512	379	9,632	526	380	11,454	643	378	9,557	498
SLS93	33	290	16	34	281	18	34	320	20	32	309	24
SLS94T99	6,097	81,172	4,567	6,151	78,123	4,428	6,377	92,444	5,344	6,571	86,851	4,798
TOTAL	54,8[illegible]7	1,556,449	79,832	54,960	1,486,100	78,843	55,204	1,701,207	94,255	55,421	1,591,907	81,648

NOTE: Due to accounting adjustments, the sum of revenues by SIC code may not match the final reported revenues.