414 Nicollet Mall
Minneapolis, Minnesota 55401

March 30, 2011

The Honorable Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, DC 20426

RE:
Northern States Power Company, a Minnesota corporation,
Docket No. ER11-____-000
Northern States Power Company, a Wisconsin corporation,
Docket No. ER11-____-000
Interchange Agreement – Annual Update and E-Tariff Submission
Revised Tariff Pages Effective January 1**,** 2011

Dear Ms. Bose:

Pursuant to Section 205 of the Federal Power Act,[1] Section 35.13 of the regulations of the Federal Energy Regulatory Commission ("FERC" or the "Commission"),[2] and Order No. 714,[3] Northern States Power Company, a Minnesota corporation ("NSPM") and Northern States Power Company, a Wisconsin corporation ("NSPW) (jointly the "NSP Companies"), submit an electronic tariff filing of the "Restated Agreement to Coordinate Planning and Operations and Interchange Power and Energy between Northern States Power Company (Minnesota) and Northern States Power Company (Wisconsin)" (hereafter "Interchange Agreement" or "Agreement").

The NSP Companies are submitting the proposed revisions under two docket numbers because NSPM is the designated filing party for the Interchange Agreement for purposes of the e-Tariff rules, and NSPW is submitting a concurrence record, as required by Order No. 714.

As discussed below, a complete copy of the Interchange Agreement is being submitted in e-Tariff format. However, the proposed revised tariff sheets include only the following revised exhibits:

[1] 16 U.S.C. § 824d (2006).
[2] 18 C.F.R. § 35.13 (2009).
[3] *Electronic Tariff Filings*, Order No. 714, 124 FERC ¶ 61,270 (Sept. 19, 2008) ("E-Tariff Final Rule").

Exhibits VII, VIII, and IX
Exhibit V
Exhibit V, Schedule 11

Pursuant to Section 14.2 of the Interchange Agreement, Exhibits VII, VIII, and IX are not subject to automatic adjustment and may only be changed by a Section 205 filing. In addition to required updates to Exhibits VII, VIII, and IX, we also propose administrative updates to Exhibit V and Exhibit V, Schedule 11 for notation corrections and heading modifications. The NSP Companies propose the revised tariff sheets be effective January 1, 2011, and request any waiver necessary for the tariff sheets to be effective on the date requested.

A. Background

NSPM is, inter alia, an investor-owned Minnesota corporation engaged in the business of generating, transmitting, distributing, and selling electric power and energy and related services in the States of Minnesota, North Dakota, and South Dakota. NSPW is, inter alia, an investor-owned Wisconsin corporation engaged in the business of generating, transmitting, distributing, and selling electric power and energy and related services in the States of Wisconsin and Michigan. The NSP Companies are both wholly-owned utility operating company subsidiaries of Xcel Energy Inc. Xcel Energy Services Inc. ("XES") is the service company for the Xcel Energy holding company system, and represents the Xcel Energy Operating Companies in proceedings before the Commission.[4]

The Interchange Agreement is a formula rate which provides for charges between NSPM and NSPW for certain electric production and transmission costs related to the NSP Companies' integrated electric system (the "NSP System"). Pursuant to the terms of the Agreement, the NSP Companies annually update certain exhibits to the Interchange Agreement.[5] In the 2001 annual filing, the NSP Companies restated the Interchange Agreement in tariff sheet format pursuant to Order No. 614. The Restated Interchange Agreement was accepted for filing by letter order dated March 20, 2001 in Docket No. ER01-1014-000, effective January 1, 2001. The 2010 annual update was submitted on February 22, 2010 and accepted for filing effective January 1, 2010, by letter order dated March 31, 2010 in Docket No. ER10-785-000.

In this annual filing, the NSP Companies submit the annual updates to the designated exhibits, but also submit a complete copy of the Interchange Agreement as an electronic tariff filing, because this is the first time the NSP Companies have filed a change to the Interchange Agreement since the effective date of the Commission's e-Tariff filing rule. The NSP Companies have decided to place the Interchange Agreement in each NSP Company's respective Market Tariffs database because the Interchange Agreement addresses, inter alia, production costs. Compliance with the e-Tariff final Rule is described further in section D below. The Interchange Agreement provisions proposed to be changed are described in Section B.

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[4] The other Xcel Energy Operating Companies are Public Service Company of Colorado and Southwestern Public Service Company.
[5] *See* Article XIV of the Interchange Agreement.

B. Statement of Nature, Basis and Reasons for Revised Tariff Sheets

1. Proposed Tariff Revisions

The annual filing of revised Exhibits VII, VIII and IX is required by Article XIV of the Interchange Agreement which states:

> 14.2 Features Not Automatically Adjusting. It is the intent of the Parties that the values and data specified in Exhibits VII, VIII, IX and X shall not be subject to automatic adjustment and may be changed only by filing revised sheets as a rate change under the Federal Power Act. The Parties contemplate that a revised Exhibit VIII will be filed annually at the end of each calendar year to specify the projected average monthly peak demands for the succeeding calendar year, but that if the projected demands are not available before commencement of the calendar year to which they apply, they may be filed as soon in that calendar year as feasible, with a request, in which all Parties shall concur, that they be made effective as of the first day of the calendar year.

The restatement of Exhibit VII without change is permitted by Exhibit V, Schedule 6, which states in pertinent part:

> If, for whatever reason, FERC ceases to issue or fails to issue a quarterly adjusted generic rate of return on common equity effective for November 1 of a year,[6] the NSP Companies shall file with FERC by December 15 of the year either a revised Exhibit VII or the existing Exhibit VII with a request that it be allowed to become effective as of January 1 of the following year. The rate of return on common equity proposed in a filing shall be in the NSP Companies' sole discretion. NSP shall bear the burden of justifying any increase or decrease in the rate of return on common equity. The NSP Companies shall request that any determination by FERC on such filing shall be made effective as of January 1 of the year following the filing, and the NSP Companies shall make such payments among themselves as may be required to adjust billings for sales made on or after the effective date of the determination.

Article XIV of the Interchange Agreement, states:

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[6] At the time of the certain settlement agreements regarding the 1984 Interchange Agreement, the Commission applied a policy of establishing the rate of return on common equity for electric utilities using a formula approach. *See Generic Determination of Rate of Return on Common Equity for Public Utilities*, Docket No. RM84-15-000, Order No. 420, issued May 20, 1985. The 1984 agreement, as amended, thus referred to this process. The Commission has long since ceased this practice.

> 14.1 Automatically adjusting Features. It is the intent of the Parties that Exhibits I, II, III, IV, V and VI of this Interchange Agreement establish formula-type procedures for developing the amounts of power and energy sales and the unit rates charged for such sales and that the amounts developed under the formula-type procedures set out in those exhibits will adjust automatically from time to time as provided in the exhibits and that no filings will be made at the Federal Energy Regulatory Commission or any successor agency to reflect such automatic adjustments. It is the further intent of the Parties that any change in the formula-type procedures set out in the above specified exhibits shall be filed as a rate change under the Federal Power Act.

Section C of this transmittal letter (below) discusses the proposed revisions to the Interchange Agreement tariff pages in more detail. Clean and redline versions of the Interchange Agreement revised tariff sheets effective January 1, 2011 are included with this filing as an attachment in the XML package. Appendix B shows the projected impact on the costs to be allocated to each of the NSP Companies in 2011.

C. Proposed Revised Tariff Sheets Effective January 1, 2011

1. Exhibit VII - Specification of Rate of Return on Common Equity

Exhibit VII sets forth a specification of the rate of return on common equity to determine the overall cost of capital. The NSP Companies are restating the existing Exhibit VII because the Commission has ceased to issue a quarterly adjusted generic rate of return on common equity. The NSP Companies only bear the burden of justifying an increase or decrease in the rate of return on common equity. Here, the NSP Companies are proposing no change to the rate of return on common equity for 2011 from the level accepted in Docket No. ER10-785-000, so a statement of impact on each of the NSP Companies is not required.

2. Exhibit VIII – Specification of Average Monthly Peak Demands

Exhibit VIII sets forth the specification of average monthly coincident peak demands for calendar year 2011 for each of the NSP Companies. These coincident peak demands were determined using the same methodology as the previous Exhibit VIII accepted in Docket No. ER10-785-000. Coincident peak demands are based upon three years' data consisting of 18 months of actual and 18 months of projected peak demands.

Enclosed with this filing as Appendix B, Page 1 is the calculation of the 2011 36-month coincident peak demand ratios for each of the NSP Companies. These demand ratios are based on the average monthly coincident peak demands for calendar years 2009-2011 as set forth in Exhibit VIII. Appendix B, Page 2, is a statement of the impacts of these coincident peak demands on each of the NSP Companies. While Appendix B provides support of certain calculations in the Interchange Agreement, it is not part of the Interchange Agreement and thus does not need to be filed in e-Tariff format.

3. <u>Exhibit IX – Specification of Depreciation Rates</u>

Exhibit IX sets forth a specification of the depreciation rates currently approved for the NSP Companies. The Minnesota Public Utilities Commission ("MPUC"), the North Dakota Public Service commission ("NDPSC") and the South Dakota Public Utilities Commission ("SDPUC") approved NSP-Minnesota's currently effective depreciation rates in the following dockets: MPUC Docket No. E,G002/D-10-173, Annual Review of Remaining Lives 2010, order dated June 16, 2010; MPUC Docket No. E,G002/D-07-1528, Average Service Life and Vintage Group Depreciation Studies for 2007, order dated September 22, 2008; MPUC Docket No. E002/GR-08-1065, Application for Authority to Increase Electric Rates in Minnesota, order dated October 23, 2009; NDPSC Case No. PU-07-776, Application for Authority to Increase Rates for Electric Service in North Dakota, order dated December 31, 2008; and SDPUC Docket No. EL-09-009, Application for Authority to Increase Electric Rates in South Dakota, order dated January 12, 2010. The Public Service Commission of Wisconsin ("PSCW") approved NSP-Wisconsin's depreciation rates in Docket No. 4220-DU-106, order dated December 13, 2007.

The NSP Companies also modified the description of the depreciation rates presented in Exhibit IX to explain that the depreciation rates are composite depreciation rates. Exhibit IX previously provided composite depreciation rates, but the NSP Companies believe the expanded description more accurately describes the rates included on this exhibit. These descriptive changes have no impact on the depreciation rates, but rather are intended to provide a more accurate exhibit heading.

Also enclosed with this filing as Appendix B, Page 3 is a statement of the impacts of the depreciation rates on each of the NSP Companies.

4. <u>Exhibit V – Formula Type Procedures for Development of Demand Related Costs</u>

Line number corrections have been made to line references included in the procedures outlined in Exhibit V. These corrections are administrative in nature and have no impact on the development of demand related costs.

5. <u>Exhibit V, Schedule 11 – Insurance Expense</u>

Insurance expense is included in the development of demand related costs. FERC Account 924, Property Insurance related to production and transmission facilities is included the development of demand related costs. Certain nuclear liability insurance is included in FERC Account 925, Injuries and Damages and, because it is directly related to nuclear production, should also be included in the quantification of total insurance expense. Therefore, the Company is making a modification to Exhibit V, Schedule 11 to include FERC Account 925.

D. E-Tariff Compliance

1. Designated Filer

On September 19, 2008, the Commission issued its e-Tariff Final rule, which requires public utilities to file all tariffs and tariff revisions electronically beginning on April 1, 2010. The e-Tariff Final Rule directs, inter alia, that when multiple utilities are party to the same tariff (a "joint tariff"), the parties may designate one utility as the designated filer of the baseline tariff filing.[7] The non-designated utility is required to submit as its baseline filing a tariff section that provides the appropriate name of the tariff and identifies the utility that is designated filing for the joint tariff.

Under the Commission's e-tariff filing rules, entities desiring to submit e-tariff filings first must register on the Commission's website to obtain a Company Identifier (one of the required data elements to enter the Commission's e-tariff filing web page and submit an e-tariff filing). However, "Northern States Power Companies" (or "NSP Companies") is not an entity that is qualified to register for a Company ID under the Commission's rules, and as such may not submit e-tariff filings. Therefore, the NSP Companies have chosen NSPM as the party that will submit the Interchange Agreement. NSPW is submitting a tariff record that will identify the Interchange Agreement filed by NSPM as a tariff to which NSPW is a party.

2. Explanation of Formatting Changes to Currently Effective Tariff

In addition to the proposed revised tariff sheets described in Section C of this transmittal letter, the NSP Companies have made certain formatting changes to the Interchange Agreement. These changes affect only the format of the tariff and do not in any way affect the rates, terms and conditions of the tariff. These types of changes are permitted by the e-Tariff Final Rule. Notably, the NSP Companies have elected to file their tariff as a section-based tariff, instead of continuing the former sheet-based format. In the process of this conversion, the NSP Companies have altered the tariff's text flow and pagination. A detailed explanation of the various formatting changes that were made to the tariff is provided in the table in Appendix A.

E. Request for Acceptance for Filing of Agreement, Request for Waiver

The NSP Companies request the Commission accept the revised tariff sheets for filing effective January 1, 2011. The NSP Companies request a waiver of the Commission's notice

[7] *See E-Tariff Final Rule* at pp 63, 97.

requirements pursuant to Part 35, if necessary, as well as any other waivers which may be necessary for the revised tariff sheets to be accepted for filing effective on the date requested.[8]

In *Central Hudson Gas* & *Electric Corporation,*[9] the Commission stated that it would generally grant waivers of the 60-day prior notice requirement for uncontested filings that do not change rates.

Based upon the above, a waiver is appropriate for this filing for the following reasons:

(1) the Interchange Agreement is a longstanding formula rate that only affects the allocation of system costs between two affiliated and regulated electric utilities;

(2) the revised tariff sheets will not directly impact the rates charged to wholesale or retail electric customers of the NSP Companies until more than sixty days after filing;[10]

(3) Section 14.2 of the Interchange Agreement specifically contemplates that revisions may be filed after the start of a calendar year if the projected demands are not available before commencement of the calendar year to which they apply, as occurred here; and

(4) Accepting the tariff changes on the date requested will allow the charges between the NSP Companies to reflect the updated cost allocation formulas for the entire 2011 fiscal year.

F. Contents of Filing; Notice; Service

1. NSPM Filing

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[8] *See* Prior Notice and Filing Requirements under Part II of the Federal Power Act, Docket No PL93-2-002, which states that a waiver of the 60 day notice period will be granted for certain amendments to pre-existing rate schedules. Specifically, the NSP Companies request waiver of the provisions of Exhibit V of the Agreement, found on Original Sheet No 30, which by its terms would have required the annual update to Sheet No. 48 be submitted by December 15, 2010.

[9] 60 FERC, 61,106 (1992), *reh'g denied* 61 FERC¶ 61,089 (1992).

[10] In Docket No. ER10-992-000, NSPW filed to establish a cost-based formula production rate for sales to its ten (10) wholesale requirements customers. The formula rate would include costs allocated to NSPW under the Interchange Agreement as a component of the formula rate, subject to an after the fact true-up. The Commission accepted the NSPW formula rate for filing effective June 1, 2010, subject to refund and settlement judge procedures. *Northern States Power Company (Wisconsin)*, 131 FERC ¶ 61,188 (2010). NSPW, the wholesale customers and Commission staff recently agreed to a settlement in principle, which NSPW anticipates filing in April 2011. The revisions to the Interchange Agreement proposed here would not affect the calculation of the rates to the NSPW wholesale customers until July 1, 2011, more than sixty days after filing. The changes would also affect the true-up to 2011 actual costs, effective in 2012. The formula rate process established in Docket No. ER10-992 will allow the NSPW wholesale customers to review and potentially challenge the inclusion of costs included in the formula.

Pursuant to the Commission's filing requirements and in compliance with the e-Tariff Final Rule, the NSPM filing contains:

a. this transmittal letter, which includes

   i. Appendix A, Table of Formatting Changes;

   ii. Appendix B, Comparison of Costs

   iii. Appendix C, the NSPW Certificate of Concurrence;

   iv. Appendix D, the Service List for this filing;

b. clean and redlined copies of the Interchange Agreement; and

c. RTF and plain text versions of the relevant tariff records.

2. NSPW Filing

Pursuant to the Commission's filing requirements and in compliance with the e-Tariff Final Rule, the NSPW filing contains:

a. this transmittal letter, which includes

   i. Appendix A, Table of Formatting Changes;

   ii. Appendix B, Comparison of Costs

   iii. Appendix C, the NSPW Certificate of Concurrence;

   iv. Appendix D, the Service List, the service list for this filing;

b. a clean copy of a tariff record that identifies the Interchange Agreement as a joint tariff and NSPM as the designated filing utility for the joint tariff; and

c. RTF and plain text versions of the relevant tariff records.

A copy or notice of this filing will be sent by mail or e-mail to: (i) all State Commissions with jurisdiction over the NSP Companies, and (ii) all affected customers, notifying them where they can download or access a copy of this compliance filing. Appendix D provides the list of State Commissioner and customers to be served notice. The NSP Companies will also provide a courtesy copy of this filing to Ms. Penny Murrell, Director of the Division of Electric Power Regulation – Central. Pursuant to 18 C.F.R. § 35.2(d), a copy of this filing will be available for public inspection at the offices of NSPM at 414 Nicollet Mall, Minneapolis, Minnesota; and NSPW's office at 1414 W. Hamilton Avenue, Eau Claire, Wisconsin.

G. Correspondence and Communications

Please send all communications and correspondence in this docket to:

For NSP-Minnesota:

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Manager, Revenue Analysis
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For NSP-Wisconsin:

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Eau Claire, WI 54702-0008

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414 Nicollet Mall – 5th Floor
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H. **Conclusion**

The NSP Companies thus respectfully request the Commission accept the revised tariff sheets to the Interchange Agreement for filing effective January 1, 2011.

Please direct any questions regarding this filing to Mr. Jeff Hafner (612-330-7622), Ms. Anne E. Heuer (612-330-6181) or Mr. James P. Johnson (612-215-4592).

Sincerely,

/s/ *Scott M. Wilensky*

Scott M. Wilensky
Vice President, Regulatory and Resource Planning

Xcel Energy Services Inc., on behalf of
Northern States Power Company, a Minnesota corporation and
Northern States Power Company, a Wisconsin corporation

Enclosures

Appendix A

Item	Formatting Change
1	Removed Order No. 614 designations in headers and footers and added general headers
2	Original page/section breaks removed and new logical page breaks applied where applicable
3	Removed page numbers
4	Removed pages that said “This page has intentionally been left blank.”
5	Minor formatting corrections (e.g., spacing, underlines, and margins) for consistency

Specification of Average Monthly Coincidental Peak Demands

2011 Calendar Year

		Minnesota Company			Wisconsin Company		
Year/Month		Peak Demand MW	Transmission Loss Multiplier	Distribution Level Demand MW	Peak Demand MW	Transmission Loss Multiplier	Distribution Level Demand MW
January 2009	A	5,663	0.968	5,482	1,173	0.960	1,126
February	A	5,424	0.968	5,251	1,126	0.960	1,081
March	A	5,151	0.968	4,987	1,048	0.960	1,006
April	A	4,701	0.968	4,550	1,013	0.960	972
May	A	5,956	0.968	5,766	999	0.960	959
June	A	7,098	0.968	6,871	1,388	0.960	1,332
July	A	6,279	0.968	6,078	1,117	0.960	1,072
August	A	6,862	0.968	6,643	1,251	0.960	1,201
September	A	5,994	0.968	5,802	1,071	0.960	1,028
October	A	4,858	0.968	4,703	985	0.960	946
November	A	5,093	0.968	4,930	1,027	0.960	986
December 2009	A	5,756	0.968	5,572	1,163	0.960	1,116
Total 2009		68,836		66,634	13,361		12,827
January 2010	A	5,569	0.968	5,390	1,103	0.960	1,059
February	A	5,305	0.968	5,135	1,062	0.960	1,020
March	A	4,868	0.968	4,712	987	0.960	948
April	A	4,842	0.968	4,687	963	0.960	924
May	A	7,157	0.968	6,928	1,263	0.960	1,212
June	A	7,049	0.968	6,823	1,262	0.960	1,212
July	F	7,052	0.968	6,826	1,330	0.960	1,277
August	F	7,072	0.968	6,846	1,312	0.960	1,259
September	F	6,727	0.968	6,511	1,272	0.960	1,221
October	F	5,131	0.968	4,967	1,022	0.960	981
November	F	5,484	0.968	5,308	1,108	0.960	1,063
December 2010	F	5,804	0.968	5,618	1,233	0.960	1,183
Total 2010		72,059		69,753	13,916		13,359
January 2011	F	5,695	0.968	5,513	1,226	0.960	1,177
February	F	5,558	0.968	5,380	1,181	0.960	1,134
March	F	5,331	0.968	5,160	1,024	0.960	983
April	F	5,104	0.968	4,940	1,077	0.960	1,034
May	F	6,126	0.968	5,930	1,089	0.960	1,045
June	F	7,238	0.968	7,007	1,393	0.960	1,337
July	F	7,266	0.968	7,033	1,368	0.960	1,313
August	F	7,277	0.968	7,045	1,357	0.960	1,302
September	F	6,887	0.968	6,666	1,312	0.960	1,260
October	F	5,228	0.968	5,060	1,040	0.960	999
November	F	5,589	0.968	5,411	1,129	0.960	1,083
December 2011	F	5,922	0.968	5,733	1,261	0.960	1,210
Total 2011		73,222		70,878	14,455		13,877
3 Three Total		214,117	0.968	207,265	41,732	0.960	40,062
			2011 CP Ratio	0.838019		2011 CP Ratio	0.161981

A = Actual
F = Forecast

Northern States Power Company
Interchange Agreement
Comparison of Costs - Present and Proposed Rate Schedules
Allocation of 2011 Estimated Demand Costs, at Authorized, and Proposed Peaks

	2011 Estimated Demand Costs		
	NSP-M	**NSP-W**	**System**
Production	Demand Costs	Demand Costs	Demand Costs
Fixed Charges-Demand	$597,877,901	$34,657,285	$632,535,186
Fixed Portion of O & M & Capacity Purchases	622,435,265	21,815,878	644,251,143
Total	$1,220,313,166	$56,473,163	$1,276,786,329
Transmission			
Fixed Charges	$211,092,506	$53,113,419	$264,205,925
Fixed Portion of O & M	44,036,104	10,573,597	54,609,701
Net Transmission Expense & Wheeling Revenues	1,929,756	n/a	1,929,756
Total	$257,058,366	$63,687,016	$320,745,382
Total Estimated Demand Costs	$1,477,371,532	$120,160,179	$1,597,531,711

	Allocate 2011 Demand Costs Using 2010 Authorized CP's		
	NSP-M	**NSP-W**	**System**
Coincident Peak Ratios (CP's)			
Authorized Transmission Loss Rate	3.20%	4.00%	
Authorized Demand Loss Multipliers	0.968	0.960	
2010 Authorized CP Ratio	0.836422	0.163578	1.000000
Net Costs using 2010 Authorized CP's - Production	$1,067,932,175	$208,854,154	$1,276,786,329
Net Costs - using 2010 Authorized CP's - Transmission	268,278,494	52,466,888	320,745,382
Total Allocated Demand Costs @ Authorized CP's	$1,336,210,669	$261,321,042	$1,597,531,711

	Allocate 2011 Demand Costs Using 2011 Proposed CP's		
Coincident Peak Ratios (CP's)			
Authorized Transmission Loss Rate	3.20%	4.00%	
Authorized Demand Loss Multipliers	0.968	0.960	
2011 Proposed CP Ratio	0.838019	0.161981	1.000000
Net Costs using 2011 Proposed CP's - Production	$1,069,971,203	$206,815,126	$1,276,786,329
Net Costs - using 2011 Proposed CP's - Transmission	268,790,724	51,954,658	320,745,382
Total Allocated Demand Costs @ Proposed CP's	$1,338,761,927	$258,769,784	$1,597,531,711

	Change In Cost of Service		
	NSP-M	**NSP-W**	**System**
Change in Ratios	0.00160	(0.00160)	(0.00000)
Change in Production	$2,039,028	($2,039,028)	($0)
Change in Transmission	512,230	(512,230)	0
Total Change in Cost of Service	$2,551,258	($2,551,258)	($0)

Northern States Power Company
Interchange Agreement
Comparison of Costs - Present and Proposed Rate Schedules
Effect On 2011 Budget

		NSP(M)	NSP(W)	Present Depreciation Rates		
Coincident Peaks Ratio		0.838019	0.161981			
				NSP-M	**NSP-W**	**System**
Production						
NSP-M to NSP-W		$168,070,143		$140,845,973	$27,224,170	$168,070,143
NSP-W to NSP-M		$11,555,407		$9,683,651	$1,871,756	$11,555,407
	Total Production	$179,625,550		$150,529,624	$29,095,926	$179,625,550
Transmission						
NSP-M to NSP-W		$46,322,310		$38,818,976	$7,503,334	$46,322,310
NSP-W to NSP-M		$14,064,495		$11,786,314	$2,278,181	$14,064,495
	Total Transmission	$60,386,805		$50,605,290	$9,781,515	$60,386,805
Distribution						
NSP-M to NSP-W		$102,153		$85,606	$16,547	$102,153
NSP-W to NSP-M		$11,563		$9,690	$1,873	$11,563
	Total Distribution	$113,716		$95,296	$18,420	$113,716
General System Control						
NSP-M to NSP-W		$1,343,257		$1,125,675	$217,582	$1,343,257
NSP-W to NSP-M		$0		$0	$0	$0
	Total General System Control	$1,343,257		$1,125,675	$217,582	$1,343,257
	Total	$241,469,328		$202,355,885	$39,113,443	$241,469,328

			Proposed Depreciation Rates		
			NSP-M	**NSP-W**	**System**
Production					
NSP-M to NSP-W		$157,512,168	$131,998,190	$25,513,978	$157,512,168
NSP-W to NSP-M		$11,823,131	$9,908,008	$1,915,123	$11,823,131
	Total Production	$169,335,299	$141,906,198	$27,429,101	$169,335,299
Transmission					
NSP-M to NSP-W		$45,286,406	$37,950,869	$7,335,537	$45,286,406
NSP-W to NSP-M		$13,437,600	$11,260,964	$2,176,636	$13,437,600
	Total Transmission	$58,724,006	$49,211,833	$9,512,173	$58,724,006
Distribution					
NSP-M to NSP-W		$102,153	$85,606	$16,547	$102,153
NSP-W to NSP-M		$11,563	$9,690	$1,873	$11,563
	Total Distribution	$113,716	$95,296	$18,420	$113,716
General System Control					
NSP-M to NSP-W		$1,343,257	$1,125,675	$217,582	$1,343,257
NSP-W to NSP-M		$491,648	$412,011	$79,638	$491,649
	Total General System Control	$1,834,905	$1,537,686	$297,220	$1,834,906
	Total	$230,007,926	$192,751,013	$37,256,914	$230,007,927

			Change In Cost of Service		
			NSP-M	**NSP-W**	**System**
Production					
NSP-M to NSP-W		($10,557,975)	($8,847,783)	($1,710,192)	($10,557,975)
NSP-W to NSP-M		$267,724	$224,357	$43,367	$267,724
	Total Production	($10,290,251)	($8,623,426)	($1,666,825)	($10,290,251)
Transmission					
NSP-M to NSP-W		($1,035,904)	($868,107)	($167,797)	($1,035,904)
NSP-W to NSP-M		($626,895)	($525,350)	($101,545)	($626,895)
	Total Transmission	($1,662,799)	($1,393,457)	($269,342)	($1,662,799)
Distribution					
NSP-M to NSP-W		$0	$0	$0	$0
NSP-W to NSP-M		$0	$0	$0	$0
	Total Distribution	$0	$0	$0	$0
General System Control					
NSP-M to NSP-W		$0	$0	$0	$0
NSP-W to NSP-M		$491,648	$412,011	$79,638	$491,649
	Total General System Control	$491,648	$412,011	$79,638	$491,649
	Total	($11,461,402)	($9,604,872)	($1,856,529)	($11,461,401)

Appendix C

CERTIFICATE OF CONCURRENCE

This is to certify that Northern States Power Company, a Wisconsin corporation, assents to and concurs in the joint rate schedule described below, which Northern States Power Company, a Minnesota corporation, has filed in its Market Tariffs e-tariff database.

Rate Schedule:

Northern States Power Companies
Interchange Agreement

Northern States Power Company, a Wisconsin corporation and a wholly owned subsidiary of Xcel Energy Inc.

By: /s/ Donald F. Reck

Title: Director, Government and Regulatory Affairs, Xcel Energy Services Inc.

Dated: March 30, 2011

<u>Service List of State Commissions and Impacted Customers</u>

Dr. Burl W. Haar
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, MN 55101

Mr. Darrell Nitschke
Executive Secretary and Director of Administration
North Dakota Public Service Commission
State Capital
600 East Boulevard
Bismarck, ND 58505-0480

Ms. Sandra J. Paske
Secretary to the Commission
Public Service Commission of Wisconsin
P.O. Box 7854
Madison, WI 53707-7854

Ms. Mary Jo Kunkle
Executive Secretary
Michigan Public Service Commission
P.O. Box 30221
Lansing, MI 48909

Ms. Patricia Van Gerpen
Executive Director
South Dakota Public Utilities Commission
500 East Capitol Avenue
Pierre, SD 57501

Ms. Penny Murrell, Director
Division of Tariffs and Market Development (Central)
Federal Energy Regulatory Commission
888 First Street N.E.
Washington, DC 20426

Bangor Municipal Utility
Mr. Steve Baker, Manager
106 15th Ave. N.
P.O. Box 130
Bangor, WI 54814

Barron Light & Water Department
Mr. Rick Jari, Utility Manager
1303 East Division Avenue
Barron, WI 54812

Medford Electric Utility
Mr. Mike Frey, Electric Utility Manager
639 South 2nd Street
Medford, WI 54451-0360

Bloomer Electric Company
Mr. Pete Paulson, Superintendent
1503 Main Street
Bloomer, WI 54724

Trempealeau Municipal Utilities
Travis Cooke, Village Administrator
24455 East 3rd Avenue
PO Box 247
Trempealeau, WI 54661

Cadott Light & Water Department
Ms. Lila McConville, Village President
110 East Central
PO Box 40
Cadott, WI 54727

Wakefield Municipal Utility
John Siira, City Administrator
311 Sunday Lake Street
Wakefield, MI 49968

Cornell Electric Utility
Mr. Dave DeJongh, City Administrator
222 Main Street
PO Box 796
Cornell, WI 54732

Rice Lake Utilities
Mr. Scott Reimer, General Manager
320 W. Coleman Street
Rice Lake, WI 54868

Anita Gallucci
Boardman Law Firm
PO Box 927
Madison, WI 53701-0927

Spooner Municipal Utilities
Mr. Wayne Fischer, Utilities Manager
515 Summit Avenue
PO Box 548
Spooner, WI 54801

CERTIFICATE OF SERVICE

I hereby certify that on this 30th day of March 2011, a copy of the foregoing document will be served by First Class U.S. Mail upon all persons shown on the attached service list of State Commissions.

/s/

____

Lindsey Didion
Xcel Energy Services Inc.
414 Nicollet Mall
Minneapolis, MN 55401

Cover Page Version: 0.0.0 Effective: 1/1/2011

Agreement Version: 0.0.0 Effective: 1/1/2011

RESTATED AGREEMENT TO
COORDINATE PLANNING AND OPERATIONS AND
INTERCHANGE POWER AND ENERGY
Between
NORTHERN STATES POWER COMPANY
and
NORTHERN STATES POWER COMPANY (Wisconsin)

Restated January 16, 2001
Restates Agreement Dated September 17, 1984, As Amended

RESTATED AGREEMENT TO
COORDINATE PLANNING AND OPERATIONS AND
INTERCHANGE POWER AND ENERGY
Between
NORTHERN STATES POWER COMPANY
And
NORTHERN STATES POWER COMPANY (Wisconsin)

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RESTATED
AGREEMENT TO COORDINATE PLANNING AND OPERATIONS
AND
INTERCHANGE POWER AND ENERGY

ARTICLE I
Recitals

1.1 THIS RESTATED AGREEMENT, hereinafter referred to as the Interchange Agreement, is made this 16th day of January, 2001, by and among NORTHERN STATES POWER COMPANY, a Minnesota corporation, hereinafter referred to as "NSP (Minn)"; and NORTHERN STATES POWER COMPANY, a Wisconsin corporation, hereinafter referred to as "NSP (Wis)."

1.2 WHEREAS, the parties to this Agreement, hereinafter called "Parties" or "NSP Companies" collectively, or "Party" singularly, are the owners and operators of electric generation and transmission facilities (hereinafter called "power supply facilities") and are engaged in the business of providing electric power and energy at retail and wholesale; and

1.3 WHEREAS, NSP (Minn) and NSP (Wis) are utility operating company subsidiaries of Xcel Energy Inc; and

1.4 WHEREAS, the Parties for many years have coordinated the planning and operation of their power supply facilities under various coordinating agreements, including the "Coordinating Agreement Among Northern States Power Company (Minnesota) and Northern States Power Company (Wisconsin)" ("1982 Contract") and the "Agreement to Coordinate Planning and Operations and Interchange Power and Energy Between Northern States Power Company (Minnesota) and Northern States Power Company (Wisconsin)" dated September 17, 1984 ("1984 Contract"); and

1.5 WHEREAS, the object of the coordination among the Parties has been to plan and operate their power supply facilities as an integrated electric system; and

1.6 WHEREAS, such integrated system planning and operation provides benefits to the Parties and their respective customers, including opportunities for:

A. The construction of new generation and transmission facilities of optimum size to produce maximum economies of scale for the Parties' combined electric system as a whole;

B. The economical use of capacity and energy available from variations in load patterns resulting from the diversity of loads imposed by the respective Parties;

C. The utilization of the seasonal and diversity patterns of other utilities not contiguous to each of the respective Parties for the outlet of surplus capacity and energy which may be available from time to time, together with the opportunity, because of such variation in seasons and diversity of loads, to acquire capacity and energy from other utilities and thus avoid or defer the construction of generating capacity to meet seasonal loads;

D. The pooling of reserves to reduce the magnitude of reserve capacity required by the respective Parties in order to assure reliable service to their respective customers;

E. Improvement in the reliability of electric service through the use of transmission interconnections which provide the respective Parties with the opportunity to call upon one another as well as other utilities with which they, or any of them, are interconnected to provide backup service in case of emergencies or breakdowns in excess of the reserves carried by the respective Parties; and

F. The provision of the most economical energy for the customers of the respective Parties by use of a centralized economic dispatch system.

1.7 WHEREAS, the Parties having planned and operated their power supply facilities as an integrated system, it is fitting that each should bear the same unit cost of power supply as the others; and

1.8 WHEREAS, under the 1982 Contract the unit cost of power supply was equalized among the Parties through sales of power and energy among the Parties as set out in the contract; and

1.9 WHEREAS, the Parties desire to continue to plan and operate their power supply facilities on an integrated system basis and, through sales among themselves, to equalize their unit power supply costs; and

1.10 WHEREAS, the rates under which the sales of power and energy were made among the Parties under the 1984 Contract were formula rates stated in generalized terms; and

1.11 WHEREAS, the Parties' desire to provide for greater specificity in the formula rates under which the sales among themselves are made and to perfect and refine the cost of service procedures contained in the formula rates; and

1.12 WHEREAS, NSP(Minn) is the successor public utility to the rights and obligations of Northern States Power Company (Minnesota) under the 1984 Contract;

1.13 NOW, THEREFORE, in consideration of the foregoing and the mutual covenants and agreements hereinafter stated, the Parties agree and contract as follows:

ARTICLE II
Objectives of Interchange Agreement

The objectives of this Interchange Agreement are (1) to provide the contractual basis for the continued planning and operation of the power supply facilities of the Parties in such a manner as to achieve the maximum possible economies consistent with the highest practicable reliability of service and (2) to provide the basis for determining the amounts of power and energy needed to be sold among the Parties and the charges for such sales in order to equalize the Parties' unit costs of power supply.

ARTICLE III
Definitions

3.1 "Sales of power and energy" are the sales of power in kilowatts and the sales of energy in kilowatt-hours made under this Interchange Agreement by each Party to the other Party.

3.2 "Generation facilities" are those facilities of the Parties which produce power and energy and introduce it into the transmission facilities.

3.3 "Transmission facilities" are all facilities which serve a transmission function.

3.4 "Power supply facilities" consist of both generation and transmission facilities as defined above.

3.5 A Party's "system" refers to the system of power supply facilities which it owns. Where the context indicates such intent, "system" refers to the combined system of power supply facilities of all Parties.

ARTICLE IV
Coordinating Committee

Coordinating Committee. The Parties shall establish a committee to be known as the Coordinating Committee to coordinate planning and operations among themselves. Each of the Parties shall designate, in writing, two persons who are to act as its representatives on the committee. The Coordinating Committee shall be responsible for the following:

A. Coordinating the planning and design of generation and transmission facilities to be installed by the Parties in the ensuing 10 year period;

B. Coordinating the operation and maintenance of generation and transmission facilities of the Parties;

C. Administering procedures for determining the amounts of power and energy sold among the Parties In accordance with the provisions of this Interchange Agreement.

D. Administering the development of monthly charges under the formula rates contained in this Interchange Agreement; and

E. Such other matters as the Coordination Committee may determine to be necessary or desirable in order to carry out the purposes of this Interchange Agreement.

The Coordinating Committee shall select a chairman and vice-chairman from its members, and the chairman, or in his absence the vice-chairman, shall convene meetings of the committee from time to time as deemed appropriate. The chairman and the vice chairman shall not be employees of the same Party.

ARTICLE V
Planning

The Parties agree that their power supply facilities shall be planned and developed on the basis that their combined individual systems constitute an integrated electric system and that the objective of their planning shall be to maximize the efficiency and reliability of the system as a whole.

ARTICLE VI
Interconnection Systems

6.1 Transmission Facilities. The Parties shall maintain adequate Interconnections between their respective systems which will permit interchange of electric power and energy pursuant to this Interchange Agreement.

6.2 Associated System Facilities. Each Party shall provide in its system facilities for such telemetering, load control, communication, and relay protection as is necessary for the proper operation of the interconnected systems.

ARTICLE VII
Operation and Maintenance

7.1 Operation. The interconnected systems of the Parties shall be operated in continuous synchronism and in coordination with each other. If the synchronous operation of the systems becomes interrupted because of reasons beyond the control of any Party or because of scheduled construction or maintenance, the Parties shall cooperate to remove the cause of the interruption as soon as practicable and restore the systems to normal operating condition.

7.2 Service Conditions. It is intended that no Party shall be obligated to deliver reactive power to any other Party or to receive reactive power from any other Party when to do so may introduce objectionable operating conditions on the system of any Party. It is recognized that in order to assure adequate service and economical use of the facilities of the Parties' systems it may be necessary from time to time to establish operating procedures for carrying reactive power loads of one system by the other.

7.3 Recognition of Flow of Power and Energy. It is recognized by the Parties that their respective electric systems are and will be directly or indirectly interconnected with electric systems owned or operated by others, that the flow of power and energy among the systems of the Parties will in part be controlled by the physical and electrical characteristics of the facilities involved and the manner in which they are operated, and that part of the power and energy being delivered under this Interchange Agreement may flow through such other systems rather than through the facilities of the Parties.

Each Party shall at all times cooperate with other interconnected systems in establishing arrangements which may be necessary to relieve any hardship on other systems caused by energy flows from deliveries hereunder.

7.4 Correction of Trouble. In the event that the interconnected operation of the systems herein contemplated results in trouble on any Party's system including, but not limited to, interruptions, grounds, communication interference, unreasonable surges, or objectionable voltage fluctuations, where such trouble is caused by the method of operation or the facilities employed by another Party, its customers, or fourth party suppliers connected to its lines, such trouble shall be corrected by the Party on or through whose system it originates within a reasonable time after written notice thereof.

7.5 Emergency Service from a Third Party. In the event of an emergency on a Party's system the other Party shall procure emergency service from other systems which may be available. Any Party procuring such service shall be the sole judge of its ability to supply emergency service.

ARTICLE VIII
Metering

8.1 Metering. Suitable metering equipment shall be installed for determining the flow of power and energy among the Parties. The ownership of and responsibility for metering equipment shall be determined by the Parties. Any Party may at any time install and maintain duplicate meters at its own expense.

8.2 Meter Readings. Each Party shall read its meters at times to be agreed upon and promptly forward such registrations to the other Party.

8.3 Meter Tests, Accuracy, and Adjustments. Each meter shall be tested periodically and maintained in an accurate condition by the Party owning the meter in accordance with rules prescribed by regulatory bodies having jurisdiction thereof. Adjustments of any meter readings for meter error shall not extend beyond 60 days previous to day on which inaccuracy is discovered. Should any metering equipment at any time fail to register, or should the registration thereof be so erratic as to be meaningless, the quantities of power and energy delivered shall be determined from the best information available.

ARTICLE IX
Sales

9.1 Amount of Sales. The Parties shall sell power and energy to each other in amounts that will allow them to achieve equal unit costs of power supply. The amount of power sold by each Party to the other Party in each billing month shall be determined as set out in Exhibit I hereto. The amount of energy sold by each Party to the other Party in each billing month shall be determined as set out in Exhibit II hereto.

9.2 Character of Service. Power and energy sold hereunder shall be delivered as three-phase alternating current, at a frequency of approximately 60 Hz with such variations from nominal voltages as may be mutually established from time to time.

9.3 Continuity of Delivery. Power and energy sold hereunder shall be furnished continuously except for interruptions or curtailments in service caused by an uncontrollable force, or by operation of devices installed for system protection, or by the necessary installation, maintenance, repair, and replacement of facilities. Such interruptions or reductions in service shall not constitute a breach of this Interchange Agreement, and no Party shall be liable to the other for damages resulting there from. Except in case of emergency, each Party shall give reasonable advance notice of temporary interruptions or curtailments in service necessary for such installations, maintenance, repair, and replacement of facilities, and shall attempt to schedule such interruptions or curtailments as convenient for all Parties.

9.4 Environmental and Renewable Energy Credits. All Environmental and Renewable Energy Credits related to the sale of power and energy under this Interchange Agreement shall be allocated to the parties on an energy basis in conformity with the net energy requirements of each state for which it provides electric service. The parties shall own or be entitled to claim all Environmental and Renewable Energy Credits allocated to them.

"Environmental and Renewable Energy Credits" are defined as any contractual right to the full set of non-energy attributes, including any and all credits, benefits, emissions reductions, offsets and allowances, howsoever titled, directly attributable to a specific amount of capacity or electric energy generated from an Eligible Renewable Energy Resource, including any and all environmental air quality credits, benefits, emissions reductions, offsets, allowances or other benefits as may be created or under any existing or future statutory or regulatory scheme (federal, state or local) by virtue of or due to the facility's actual energy production or the facility's energy production capability because of the facility's environmental or renewable characteristics or attributes, including any Environmental and Renewable Energy Credits or similar rights arising out of or eligible for consideration in the Midwest Renewable Energy Tracking System Program ("M-RETS") or the Michigan Renewable Energy Certification System ("MIRECS").

"Eligible Renewable Energy Resource" is defined as any resource that qualifies as a renewable energy resource eligible to be certified to receive, claim, own or use Renewable Energy Credits pursuant to the protocols and procedures developed and approved by any state served by NSP (Minn) or NSP (Wis) and tracked by M-RETS, MIRECS, or a comparable tracking program.

ARTICLE X
Charges

10.1 Compensation General Principle. The objective of the charges provided for herein is to compensate the Party selling power and energy for its full fixed costs including return and its full variable costs of producing and transmitting the power and energy.

10.2 Monthly Charges. The Parties selling power and energy under this Interchange Agreement shall charge the unit rates for power (dollars per kilowatt) developed each month pursuant to Exhibit III hereof and the unit rates for energy (mills per kilowatt-hour) developed each month pursuant to Exhibit IV hereof. The unit rate for power for each Party shall be applied to the number of kilowatts of power sold by the Party pursuant to Paragraph 9.1 hereof in the billing month, and the unit rate for energy for each Party shall be applied to the number of kilowatt-hours sold by that Party pursuant to that Paragraph.

10.3 True-up for Payments for Power. The unit rates for power developed pursuant to Exhibit III hereof shall initially be developed on the basis of estimated data for the calendar year. When actual cost data are available, the total annual costs shall be redetermined and the total annual payment by each Party shall be adjusted to reflect the actual cost data. The specification of average monthly coincidental peak demands specified in Exhibit VIII shall not, however, be adjusted to actual data in the true-up process. The adjustment shall be accomplished by a surcharge or credit, whichever is appropriate, on the next statement prepared under Paragraph 10.4 hereof. The estimated data for the calendar year used to develop the unit rates for power may be adjusted from time to time to reflect significant revisions in estimates.

10.4 Statements. As promptly as practicable after the first day of each calendar month, the Parties shall cause to be prepared a statement setting forth the transactions and charges between the Parties during the preceding month in such detail and with such segregations as may be needed for operating records or for settlements under the provisions of this Interchange Agreement. The statement shall set forth in detail the charges and credits to each Party and the net balance due.

10.5 Method of Settlement. The Party or Parties owing a net balance due, as set forth in the monthly statement, shall pay the net balance due within 10 days of the date of the statement.

ARTICLE XI
General Provisions

11.1 Reports and Information. Each Party shall, upon request, furnish to the other Party such reports and information concerning its system operations as are reasonably necessary to enable each member of the Operating Committee to make an informed judgment on all matters considered by the Committee.

11.2 Uncontrollable Force. No Party shall be considered to be in default in respect of any obligation hereunder if prevented from fulfilling such obligation by reason of an uncontrollable force. The term "uncontrollable force" shall include, among others, such causes as failure of facilities, flood, earthquake, storm, lightning, fire, epidemic, war, riot, civil disturbance, labor disturbance, sabotage, delay in receiving supplies and materials, collision, or restraint or order of court or public authority having jurisdiction, or other causes beyond the control of the Party affected, and which by exercise of due diligence and foresight could not reasonably have been avoided. Any Party unable to fulfill any obligation by reason of an uncontrollable force shall remove said inability with reasonable dispatch; except that the settlement of strike or labor disturbance shall be entirely within the discretion of the Party incurring the strike or disturbance.

11.3 Indemnity. Each Party agrees to defend, indemnify, and hold harmless the other Party against any and all claims, liability, loss, damage, or expense caused by or resulting from the negligent acts or omissions of the indemnifying Party, its employees or agents in connection with the performance of this Interchange Agreement.

11.4 Waivers. Any waiver at any time by a Party of its rights with respect to default of this Interchange Agreement or with respect to any other matter arising in connection with this Interchange Agreement, shall not be deemed a waiver with respect to any subsequent default or matter. Any delay, short of the statutory period of limitation, in asserting of enforcing any right under this Interchange Agreement, shall not be deemed a waiver of such rights.

11.5 Right of Access. Each Party shall give authorized agents and employees of any other Party the right to enter its premises at all reasonable times for the purpose of reading or checking meters, for constructing, testing, repairing, renewing, exchanging, or removing any or all of such other Party's equipment which may be located on the property of the Party or performing any work incident hereto.

11.6 Successors and Assigns. This Interchange Agreement shall inure to the benefit of, and shall bind, the successors of the Parties hereto but shall not be assigned by any Party without first securing written consent of the other Party.

11.7 Limitation as to Third Parties. The signatories hereto shall be the only Parties in interest to this Interchange Agreement. This Interchange Agreement is not intended to and shall not grant rights of any character whatsoever in favor of any person, corporation, association, or entity other than the Parties, and the obligations herein assumed by the Parties are solely for the use and benefit of the Parties. Nothing herein contained shall be construed as permitting or vesting in any person, corporation, association, or entity other than the Parties, any rights hereunder or in any of the electric facilities owned by the Parties or the use thereof.

11.8 Independent Contractors. It is agreed among the Parties that by entering into this Interchange Agreement providing for coordinated planning and operation of their systems, the Parties shall not become partners, but as to each other and to third persons, the Parties shall remain independent contractors in all matters relating to this Agreement.

11.9 Notices. Any notices, demands, or requests, required or authorized by this Interchange Agreement, shall be deemed properly given if mailed postage prepaid, as follows:

For NSP (Minn) President Minnesota Jurisdiction Northern States Power Company 414 Nicollet Mall Minneapolis, MN 55401	For NSP (Wis): President Wisconsin Jurisdiction Northern States Power Company (Wisconsin) 1414 West Hamilton Avenue P.O. Box 8 Eau Claire, WI 54702-0008

The designation of the persons to be notified or the address of such person may be changed at any time by similar notice.

11.10 Regulatory Approval. This Interchange Agreement and all obligations hereunder are subject to the regulation of the Federal Energy Regulatory Commission and any other regulatory body or governmental authority having jurisdiction thereof.

11.11 The interpretation and performance of this Interchange Agreement shall be in accordance with and controlled by the laws of the State of Minnesota.

ARTICLE XII

Termination of Existing Agreements

The following agreements are terminated as of the date that this Interchange Agreement is permitted to become effective as a rate schedule under Section 205 of the Federal Power Act.

A. Coordinating Agreement, dated April 23, 1982.

B. Amendment to Coordinating Agreement, Article 7.09, Determination of Return on Investment, dated October 29, 1982.

C. Agreement to Coordinate Planning and Operations and Interchange Power and Energy, dated September 17, 1984, as amended.

Termination of the foregoing agreements shall have no effect on unpaid bills or other liabilities which may have accrued as of the date of termination.

ARTICLE XIII
Term of Agreement

This Restated Interchange Agreement shall become effective January 1, 2001, or the date that it is permitted to become effective as a rate schedule under Section 205 of the Federal Power Act. The contract may be terminated by either Party giving the other Party five years written notice. The Interchange Agreement may be terminated at any time by mutual agreement of the Parties. The applicable provisions of the Interchange Agreement shall continue in effect after termination to the extent necessary to provide for final billings and adjustment.

ARTICLE XIV

Features of Interchange Agreement Subject to Automatic Adjustment Under Formula Provisions and Features Subject to Adjustment Only by Filing Under Federal Power Act

14.1 Automatically Adjusting Features. It is the intent of the Parties that Exhibits I, II, III, IV, V and VI of this Interchange Agreement establish formula-type procedures for developing the amounts of power and energy sales and the unit rates charged for such sales and that the amounts developed under the formula-type procedures set out in those exhibits will adjust automatically from time to time as provided in the exhibits and that no filings will be made at the Federal Energy Regulatory Commission or any successor agency to reflect such automatic adjustments. It is the further intent of the Parties that any change in the formula-type procedures set out in the above specified exhibits shall be filed as a rate change under the Federal Power Act.

14.2 Features Not Automatically Adjusting. It is the intent of the Parties that the values and data specified in Exhibits VII, VIII, IX, and X shall not be subject to automatic adjustment and may be changed only by filing revised sheets as a rate change under the Federal Power Act. The Parties contemplate that a revised Exhibit VIII will be filed annually at the end of each calendar year to specify the projected average monthly peak demands for the succeeding calendar year, but that if the projected demands are not available before the commencement of the calendar year to which they apply, they may be filed as soon in that calendar year as feasible, with a request, in which each Party shall concur, that they be made effective as of the first day of the calendar year.

14.3 Example of Development of Unit Rates. Exhibit III and IV illustrate in detail the development of the unit rates for power and energy sales. It is the Intent of the Parties that no material change in the procedures used to develop the unit rates will be made without filing a revised Exhibit III and IV illustrating the change as a rate change under the Federal Power Act.

IN WITNESS WHEREOF, the Parties have caused this instrument to be executed by their respective authorized officials as of the day and year first above written.

ATTEST	NORTHERN STATES POWER COMPANY
By Catherine J. Cleveland	By Gary R. Johnson
	Title:

NORTHERN STATES POWER COMPANY
(WISCONSIN)

By Jerome L. Larson

Title:

Exhibits Version: 0.0.0 Effective: 1/1/2011

Exhibits

Exhibit I	-	Formula-type Procedures for Development of Amounts of Power Sales
Exhibit II	-	Formula-type Procedures for Development of Amounts of Energy Sales
Exhibit III	-	Formula-type Procedures for Development of Unit Rates for Power Sales
Exhibit IV	-	Formula-type Procedures for Development of Unit Rates for Energy Sales
Exhibit V	-	Formula-type Procedures for Development of Demand Related Costs
Exhibit VI	-	Formula-type Procedures for Development of Energy Related Costs
Exhibit VII	-	Specification of Rate of Return on Common Equity
Exhibit VIII	-	Specification of Average Monthly Peak Demands
Exhibit IX	-	Specification of Depreciation Rates
Exhibit X	-	Specification of Demand and Energy Classification of Production Expenses

FORMULA TYPE PROCEDURES FOR DEVELOPMENT OF AMOUNTS OF POWER SALES

The Monthly amounts of sales of power by each Party to the other Party shall be determined as follows:

A - NSP(Minn) Power Sales (PS) to NSP(Wis):

$$\text{PS to NSP(Wis)} = \text{NSP(Minn) Demand} \times \frac{\text{NSP(Wis) Demand}}{\text{System Demand}}$$

B - NSP(Wis) Power Sales (PS) to NSP(Minn):

$$\text{PS to NSP(Minn)} = \text{NSP(Wis) Demand} \times \frac{\text{NSP(Minn) Demand}}{\text{System Demand}}$$

Where:

"PS" is the amount of power sold in MW by the selling Party to the purchasing Party in the billing month.

"Demand" is each Party's billing demand in MW's based on the average of 36 Monthly Coincident Peaks; including 18 months on historical peaks and 18 months of forecasted peak data for the year of application. The measured monthly coincident peak demands shall be adjusted by a Transmission Loss Multiplier. Historical peak data may be adjusted to reflect known significant load changes over 10 MW by agreement of the Parties.

"Transmission Loss Multipliers" are equal to:

0.968 for NSP(Minn)
0.960 for NSP(Wis)

"System Demand" equals NSP(Minn) Demand + NSP(Wis) Demand

Exhibit VIII shows an example of the development of the power sales.

FORMULA TYPE PROCEDURES FOR DEVELOPMENT OF AMOUNTS OF POWER SALES

The monthly amounts of sales of energy by each Party to the other Party shall be determined as follows:

A - NSP(Minn) Energy Sales (ES) to NSP(Wis):

$$\text{ES to NSP(Wis)} = \text{NSP(Minn) Energy Requirements} \times \frac{\text{NSP(Wis) Energy Requirements}}{\text{System Energy Requirements}}$$

B - NSP(Wis) Energy Sales (ES) to NSP(Minn):

$$\text{ES to NSP(Minn)} = \text{NSP(Wis) Energy Requirements} \times \frac{\text{NSP(Minn) Energy Requirements}}{\text{System Energy Requirements}}$$

Where:

"ES" is the amount of energy sold in Mwh's by the selling Party to the purchasing Party in the billing month.

"Energy Requirements" are each Party's billing requirements in Mwh's for the previous month. The measured monthly energy requirements shall be adjusted by a Transmission Loss Multiplier.

"Transmission Loss Multipliers" are equal to:

0.967 for NSP(Minn)
0.938 for NSP(Wis)

"System Demand" equals NSP(Minn) Demand + NSP(Wis) Demand

"System Energy Requirements" equals the total of NSP(Minn) and NSP(Wis) Energy Requirements.

FORMULA TYPE PROCEDURES FOR DEVELOPMENT OF AMOUNTS OF POWER SALES

The monthly unit rates for the sales of megawatts of power by each Party to the other Party shall be determined as follows:

A - NSP(Minn) Demand Rate for sales to NSP(Wis):

$$\text{DR to NSP(Wis)} = \frac{\text{NSP(Minn) Demand Costs}}{\text{NSP(Minn) Demand}}$$

B - NSP(Wis) Demand Rate for sales to NSP(Minn):

$$\text{DR to NSP(Minn)} = \frac{\text{NSP(Wis) Demand Costs}}{\text{NSP(Wis) Demand}}$$

Where:

"DR" is the monthly unit demand rate (rate in dollars per MW) for power sales by each Party to other Parties.

"Demand Costs" are the demand related costs developed for each Party for the billing month under Exhibit V.

"Demand" is each Party's billing demand in MW's based on the average of 36 Monthly Coincident Peaks; including 18 months of historical peaks and 18 months of forecasted peak data for the year of application. The measured monthly coincident peak demands shall be adjusted by a Transmission Loss Multiplier. Historical peak data may be adjusted to reflect known significant load changes over 10 MW by agreement of the Parties.

"Transmission Loss Multipliers" are equal to:

0.968 for NSP(Minn)
0.960 for NSP(Wis)

FORMULA TYPE PROCEDURES FOR DEVELOPMENT OF AMOUNTS OF POWER SALES

The monthly unit rates for the sales of megawatts of power by each Party to the other Party shall be determined as follows:

A - NSP(Minn) Energy Rates for sales to NSP(Wis):

$$\text{ER to NSP(Wis)} = \frac{\text{NSP(Minn) Energy Costs}}{\text{NSP(Minn) Energy Requirements}}$$

B - NSP(Wis) Energy Rates for sales to NSP(Minn):

$$\text{ER to NSP(Minn)} = \frac{\text{NSP(Wis) Energy Costs}}{\text{NSP(Wis) Energy Requirements}}$$

Where:

"ER" is the monthly unit energy rate (rate in dollars per Mwh) for energy sales from each Party to the other Parties.

"Energy Costs" are each Party's energy costs for the billing month, including the carrying costs on Electric Production Fuel Stock balances recorded in FERC Accounts 151 and 152 included at 100 percent of the average of the monthly balances in the accounts.

"Energy Requirements" are each Party's billing requirements in MWH's for the previous month. The measured monthly energy requirements shall be adjusted by a Transmission Loss Multiplier.

"Transmission Loss Multipliers" are equal to:

0.967 for NSP(Minn)
0.938 for NSP(Wis)

FORMULA TYPE PROCEDURES FOR DEVELOPMENT OF DEMAND RELATED COSTS

The demand related cost used in Exhibit III shall be those developed on line 23 of this exhibit.

	DEVELOPMENT OF RATE BASE	NSP(Minn)	NSP(Wis)
1.	Electric Plant in Service (Sched. 1)		
2.	Accumulated Provision for Depreciation (Sched. 2)		
3.	Net Electric Plant in Service		
4.	Deduct: Accumulated Deferred Income Taxes (Sched. 3)		
5.	Add: Plant Held for Future Use (Sched. 4)		
6.			
7.	Rate Base (Total lines 1 through 6)		

COST OF SERVICE - DEMAND RELATED

A. Fixed Charges on Investment

8. Return on Rate Base at Specified Rate of Return (Sched. 6)
9. Income Taxes (Sched. 7)
10. Depreciation & Amortization Expense (Sched. 8)
11. Deferred Income Taxes (Sched. 9)
12. Property Taxes (Sched. 10)
13. Insurance (Sched. 11)
13.1 Carrying Cost on Demand-Related Deferred Nuclear Refueling Outage Costs
14. Total Fixed Charges (Total lines 8 through 13.1)

B. Fixed Power Production and Regional Market Expense

15. Fixed Operating and Maintenance Expense (Sched. 12 and 12.1)
16. Net Purchased Power Demand Costs (Sched. 13)
17. Production System Control & Load Dispatching (Sched. 14)
18. Credits for Production Related Services (Sched. 16)
19. Total Fixed Power Production Expense (Total lines 15 through 18)

C. Fixed Transmission Expense

20. Operation and Maintenance Expense (Sched. 15)
21. Credits for Transmission Related Services (Sched. 17)
22. Total Fixed Transmission Expense (Total lines 20 through 21)
23. Total Month's Demand Related Costs (Total lines 14, 19 and 22)

ELECTRIC PLANT IN SERVICE

Electric Plant In Service included for the determination of charges among the Parties shall include the average monthly balances of gross plant at original cost. The following FERC Accounts shall be included:

1. Intangible Plant Investment
   Water power relicensing investment recorded in FERC Account 302.

2. Production Plant Investment
   Production plant investment recorded in FERC Accounts 310 through 346.

3. Nuclear Fuel Plant Investment
   Nuclear fuel investment included in FERC Accounts 120.2, 120.4 and 120.6.

4. Transmission Plant Investment
   Transmission plant investment recorded in FERC Accounts 350 through 359. Transmission substations having facilities which jointly serve the transmission and distribution functions are inventoried and priced according to the function served. The original cost value of the distribution facilities are excluded from these accounts for the purpose of this Agreement.

5. Distribution Substation Plant Investment
   Distribution substation plant investment recorded in FERC Accounts 360, 361 and 362. Distribution substations having facilities which jointly serve the distribution and transmission functions are inventoried and priced according to the function served. The original cost value of only the facilities which serve a transmission function are included for the purposes of this Agreement.

6. General Plant Investment
   System control and load dispatching plant investment recorded in FERC Account 397. System control and load dispatching equipment is analyzed as to the function it serves. The original cost value of the equipment serving the production and transmission functions is included for the purposes of this Agreement.

ACCUMULATED PROVISION FOR DEPRECIATION

Accumulated Provision for Depreciation for Electric Plant in Service and Nuclear Fuel is recorded in FERC Accounts 108 and 120.5, respectively. Accumulated provision for amortization of electric utility plant is recorded in FERC Account 111.

These accounts are classified to the production, nuclear fuel, transmission, distribution and general functions of plant and the amounts are calculated based upon the original cost of the plant. The annual charge to the accumulated provisions for depreciation reflects the annual depreciation provisions, book cost of plant retired, cost of removal and salvage credit.

ACCUMULATED DEFERRED INCOME TAXES

Accumulated Deferred Income Taxes included in FERC Accounts 190 and 281-283 are classified to the production, nuclear fuel, transmission, distribution and general plant functions in the same detail as the original cost of the plant in service.

PLANT HELD FOR FUTURE USE - LAND

Land Plant Held for Future Use if recorded in FERC Account 105. The amounts included to determine the charges among the Parties shall include those amounts related to the production and transmission functions. These amounts shall be included at 100% of the average monthly balances as recorded on the Company's books and records.

OTHER

The proceeds of U.S. Environmental Protection Agency (EPA) emission allowance auctions recorded in FERC 411.8 and collected by either company shall be allocated annually as a credit to such Party's Demand Costs in Exhibit III.

In the event either Party experiences a new type of cost not anticipated by this Exhibit V, the cost shall be allocated as a Demand Cost or Energy Cost in a manner consistent with the FERC Uniform System Accounts in effect from time to time.

RETURN ON RATE BASE

The return on rate base shall be the overall rate of return developed from the long term debt and preferred stock costs (if any) determined according to this schedule and the rate of return on equity specified in Exhibit VII. The capital structure for NSP(Minn) and NSP(Wis) and the appropriate cost rates shall be determined for each calendar year in the following steps:

The debt and preferred stock (if any) of NSP (Minn) and NSP(Wis) is directly assigned to each company. The cost rates for these components of the capital structure are the actual cost rates of each company's debt and preferred stock (if any) determined in accordance with FERC regulatory principles. The retained earnings portion of each company's common equity is also directly assigned to the such company. Each company's equity capital shall equal total capitalization less the debt and preferred stock (if any) directly assigned. The return on equity derived pursuant to this Schedule G and provided for in Exhibit VII is used as the cost of the subsidiary's retained earnings.

Unless otherwise agreed and accepted for filing by FERC, the cost rate for common equity for NSP(Minn) and NSP(Wis) will be equal. The capitalization ratios and cost rates for debt and preferred stock (if any) will be distinct between companies based on their specific level and cost of financing.

Equity Return:

By December 15 of each year, the NSP Companies shall file a revised Exhibit VII containing a rate of return on common equity equal to the quarterly adjusted generic return on common equity promulgated by FERC for effectiveness on November 1 of that year. See, *Generic Determination of Rate of Return on Common Equity for Public Utilities*, Docket No. RM84-15-000, Order No. 420, issued May 20, 1985. No filing shall be required if the quarterly adjusted generic rate of return effective on November 1 is the same as the quarterly adjusted generic rate of return effective on November 1 of the previous year. In making such filing, the NSP Companies shall request that the revised Exhibit VII shall be made effective as of January 1 of the year following the filing and shall request waiver of the 60 day notice-of-filing period to achieve such effective date. After the revised Exhibit VII has been allowed to become effective, the NSP Companies shall make such payments among themselves as may be required to adjust billings for sales made on and after the date that the filing is permitted to become effective. Such payments among the NSP Companies shall be with interest at the rate provided in the Commission's regulations.

Within 30 days of the filing of a revised Exhibit VII, the NSP Companies shall have the right to petition the Commission for a determination that the NSP Companies' risks are sufficiently above or below industry average risks to warrant a rate of return on common equity above or below the generic rate of return on common equity contained in such filing. The proponent of any departure from the generic rate of return on common equity contained in the filing shall bear the burden of justifying the departure.

If the Commission after hearing on the record finds that a departure is justified, it shall establish a just and reasonable rate of return on common equity for the pertinent calendar year. Such rate of return on common equity shall be made retroactively effective as of January 1 of the pertinent calendar year, and the NSP Companies shall make such payments among themselves as may be required to adjust billings for sales made on and after that date to the rate of return on common equity determined by the Commission for the calendar year.

If, for whatever reason, FERC ceases to issue or fails to issue a quarterly adjusted generic rate of return on common equity effective for November 1 of a year, the NSP Companies shall file with FERC by December 15 of the year either a revised Exhibit VII or the existing Exhibit VII with a request that it be allowed to become effective as of January 1 of the following year. The rate of return on common equity proposed in a filing shall be in the NSP Companies' sole discretion. NSP shall bear the burden of justifying any increase or decrease in the rate of return on common equity. The NSP Companies shall request that any determination by FERC on such filing shall be made effective as of January 1 of the year following the filing, and the NSP Companies shall make such payments among themselves as may be required to adjust billings for sales made on or after the effective date of the determination. Such payments among the NSP Companies shall be with interest at the rate provided in the Commission's regulations.

COMPUTATION OF FEDERAL AND STATE INCOME TAXES

The Federal and State Income Taxes shall be computed as follows:

1. Required Return on Rate Base (Schedule 6)
2. Add: Book Depreciation and Amortization (Schedule 8)
3. Provision for Deferred Income Taxes (Schedule 9)
4. Deduct: Investment Tax Credit Flow Through (Schedule 7, Page 3 of 3)
5. Income Tax Depreciation (Schedule 7, Page 3 of 3)
6. Interest Expense (Schedule 7, Page 3 of 3)
7. Preferred Dividend Credit (if any) (Schedule 7 Page 3 of 3)

8. Income Tax Base

9. Preliminary Income Taxes @ Income Tax Conversion Factor (1)

10. Deduct: Investment Tax Credit Flow Through (Line 4)
11. Preferred Dividend Credit (Line 7)

12. Federal and State Income Taxes

(1) $\frac{\text{Composite Tax Rate (2)}}{\text{1 - Composite Tax Rate (2)}}$ = Income Tax Conversion Factor

(2) Composite Federal and State Income Tax Rate as determined in accordance with Schedule 7, Page 2 of 3.

DETERMINATION OF FEDERAL AND STATE COMPOSITE INCOME TAX RATES

Let:
F = Federal Income Tax Rate
M = Minnesota State Income Tax Rate
D = North Dakota State Income Tax Rate
S = South Dakota State Income Tax Rate
W = Wisconsin State Income Tax Rate
MI = Michigan State Single Business Tax Rate
N = Net Income After Net Deductions But Before Income Taxes

NSP Company (Minnesota)

Only Minnesota and Federal Income Taxes:
M = ______________ (N)
F = ______________ (N)
M + F = _______________ (N)

Only North Dakota and Federal Income Taxes:
F = ______________ (N)
D = ______________ (N)
F + D = _______________ (N)

Only South Dakota and Federal Income Taxes:
S + F = _______________ (N)

NSP Company (Minnesota): Combined Minnesota, North Dakota, South Dakota
M + D + S + F = _______________ (N)

NSP Company (Wisconsin):

Wisconsin, Michigan and Federal Income Taxes
W = ______________ (N)
MI = ______________ (N)
F = ______________ (N)
W +MI+ F = _______________ (N)

Notes:
1. Investment Tax Credit and Surtax Credits are ignored in all formulas.
2. State Income Taxes are deductible from Federal Taxable Income.
Federal Income Tax is deductible from North Dakota Taxable Income.
Federal Income Tax is not deductible from Minnesota or Wisconsin Taxable Income.

DEDUCTIONS FOR COMPUTATION OF FEDERAL AND STATE INCOME TAXES

Investment Tax Credit Flow Through

The Investment Tax Credit Flow Through is recorded in FERC Account 411.4. The amounts included for the calculation of income taxes are those amounts attributable to the plant investment related to the production, nuclear fuel, transmission, distribution and general plant as functionalized.

Income Tax Depreciation

Income Tax Depreciation allowable for the calculation of Federal and State income taxes is based upon the plant investment related to production, nuclear fuel, transmission, distribution and general plant as functionalized.

Interest Expense

Interest costs associated with debt recorded in FERC Accounts 221-224 is used to calculate the embedded cost of debt. The embedded cost of debt times the debt ratio as determined on Exhibit V, Schedule 6, applied to the rate base determines the interest expense deduction for income taxes.

Preferred Dividend Credit

A Preferred Dividend Credit (if any) is allowed on certain preferred stock issues in accordance with Section 247 of the Internal Revenue Code. This credit is reflected in the calculation of income taxes.

DEPRECIATION AND AMORTIZATION EXPENSE

Depreciation expense and depreciation expense for asset retirement costs are recorded in FERC Account 403 and 403.1, respectively by the plant functional classifications. Depreciation rates used to calculate the depreciation expense for the original cost of plant as classified by functions for this Agreement are shown on Exhibit IX - Specification of Depreciation Rates.

Amortization expense included to determine the charges among the Parties are recorded in FERC Accounts 404, 405, 406, and 407.

PROVISION FOR DEFERRED INCOME TAXES

The Provision for Deferred Income Taxes is recorded in FERC Accounts 410.1 and 411.1, amounts debited and amounts credited, respectively. The Companies have segregated the deferred income taxes by functional classification in the same detail as the original cost of plant investment.

PROPERTY TAXES

The Property Tax expense or taxes in lieu of property taxes are recorded in FERC Account 408.1. Each Company has segregated its taxes by functional classification in the same detail as the original cost of plant investment.

INSURANCE EXPENSE

The Insurance Expense is recorded in FERC Accounts 924 and 925. Insurance expense included is related to the production plant and transmission and distribution substations in the same manner as the original cost of the plant investment for these facilities.

FIXED PRODUCTION OPERATING AND MAINTENANCE EXPENSE

Production Operating and Maintenance Expenses are recorded in FERC Accounts 500 through 554 and 557. The expenses recorded in these accounts are determined to be demand related in accordance with the FERC Demand and Energy Classification of Production Expenses - Exhibit X.

FIXED REGIONAL MARKET OPERATING AND MAINTENANCE EXPENSE

Production Operating and Maintenance Expenses are recorded in FERC Accounts 575 through 576. The expenses recorded in these accounts are determined to be demand related as billed.

NET PURCHASED POWER DEMAND COSTS

Purchased Power Demand Costs as billed are recorded in FERC Account 555 - Purchased Power. Firm Power Sales Demand Charges made to eligible non-associated entities are recorded in FERC Account 447 - Revenue from Sales for Resale. The net amount of these demand charges and credits is included as the Net Purchased Power Demand costs.

PRODUCTION SYSTEM CONTROL AND LOAD DISPATCHING EXPENSE

Production System Control and Load Dispatching expense is recorded in FERC Account 556. 100% of these power supply expenses is included to determine the charges under the Agreement in accordance with the FERC Demand and Energy Classification of Production Expenses - Exhibit X.

TRANSMISSION OPERATION AND MAINTENANCE EXPENSE

Transmission Operation and Maintenance expenses are recorded in FERC Accounts 560 through 573. 100% of these expenses is considered fixed or demand related.

CREDITS FOR PRODUCTION-RELATED SERVICES

Revenue for Production-Related Services is recorded in FERC Accounts 454 - Rent From Electric Property and 456 - Other Operating Revenue. These Revenues are credited to production operating and maintenance expenses.

CREDITS FOR TRANSMISSION RELATED SERVICES

Revenue from Transmission Related Service is recorded in FERC Accounts 454 – Rent from Electric Property and 456 - Other Operating Revenue. These revenues are credited to transmission operating and maintenance expenses.

FORMULA TYPE PROCEDURES FOR DEVELOPMENT OF
ENERGY RELATED COSTS

The energy-related costs used in Exhibit IV shall be those developed on Line 5 of this exhibit.

	NSP (Minn)	NSP(Wis)
1. Fuel Expenses (Schedule 1)		
2. Variable Production and Regional Market Operating, and Maintenance Expense (Schedule 2 and 2.1)		
3. Net Purchased Power Energy Costs (Schedule 3)		
4. Carrying Cost on Fuel Stocks		
4.1 Carrying Cost on Energy-Related Deferred Nuclear Refueling Outage Costs		
5. Total Energy Related Costs (Total lines 1 through 4.1)		

FUEL EXPENSES

Fuel Expenses are recorded in FERC Accounts 501, 518 and 547. 100% of fuel expenses is included as a variable expense in accordance with the FERC Classification of Production Expenses - Exhibit X.

VARIABLE PRODUCTION OPERATING AND MAINTENANCE EXPENSES

Production Operating and Maintenance expenses are recorded in FERC Accounts 500 through 554 and 557. The expenses recorded in these accounts are determined to be energy related in accordance with the FERC Demand and Energy Classification of Production Expenses - Exhibit X.

VARIABLE REGIONAL MARKET OPERATING AND MAINTENANCE EXPENSES

Regional Market Operating and Maintenance expenses are recorded in FERC Accounts 575 through 576. The expenses recorded in these accounts are determined to be energy related as billed.

NET PURCHASED POWER ENERGY COSTS

Purchased Power Energy Costs as billed are recorded in FERC Account 555 - Purchased Power. Firm power energy sales are recorded in Account 447 - Revenue from Sales for Resale. The net amount of these energy charges and credits is included as the Net Purchased Power Energy costs.

SPECIFICATION OF RATE OF RETURN ON COMMON EQUITY

The rate of return on common equity to determine the overall cost of capital as developed in accordance with Exhibit V, Schedule 6, is 11.47%.

SPECIFICATION OF AVERAGE MONTHLY COINCIDENTAL PEAK DEMANDS

Calendar Year 2011 Contract Year

Monthly Coincidental Peak Demands (KW)

		NSP (Minn)	NSP (Wis)	***Total System***
2009	January	5663	1173	6836
	February	5424	1126	6550
	March	5151	1048	6199
	April	4701	1013	5714
	May	5956	999	6955
	June	7098	1388	8486
	July	6279	1117	7396
	August	6862	1251	8113
	September	5994	1071	7065
	October	4858	985	5843
	November	5093	1027	6120
	December	5756	1163	6919
	Total	68,836	13,361	82,197
2010	January	5569	1103	6672
	February	5305	1062	6367
	March	4868	987	5855
	April	4842	963	5805
	May	7157	1263	8420
	June	7049	1262	8311
	July	7052	1330	8382
	August	7072	1312	8384
	September	6727	1272	7998
	October	5131	1022	6153
	November	5484	1108	6591
	December	5804	1233	7037
	Total	72,059	13,916	85,974
2011	January	5695	1226	6921
	February	5558	1181	6738
	March	5331	1024	6355
	April	5104	1077	6180
	May	6126	1089	7215
	June	7238	1393	8631
	July	7266	1368	8634
	August	7277	1357	8634
	September	6887	1312	8199
	October	5228	1040	6268
	November	5589	1129	6718
	December	5922	1261	7183
	Total	73,222	14,455	87,677

Agreement to Coordinate Planning and Operations and Interchange Power and Energy **Exhibit IX**

SPECIFICATION OF COMPOSITE DEPRECIATION RATES 2011 CONTRACT YEAR

The following annual composite depreciation rates are calculated based on the most recent actual depreciation expense accruals and plant balances. The actual depreciation expense is calculated based on the most recent remaining life depreciation studies certified by the respective State Commissions for NSP (Minn) and NSP (Wis). Even though individual depreciation lives may not have changed from the previous year, these are composite rates and a change in plant balances could cause a change in the rate by FERC Account.

NSP (Minn)

FERC ACCOUNT		DESCRIPTION	ANNUAL DEPRECIATION RATE PERCENT
PRODUCTION			
E311	STEAM	Structures and Improvements	1.66%
E312	STEAM	Boiler Plant Equipment	3.19%
E314	STEAM	Turbogenerator Units	3.59%
E315	STEAM	Accessory Electric Equipment	3.45%
E316	STEAM	Miscellaneous Power Plant Equipment	2.27%
E302	NUCLEAR	Franchises & Consents	3.27%
E321	NUCLEAR	Structures and Improvements	1.46%
E322	NUCLEAR	Reactor Plant Equipment	2.10%
E323	NUCLEAR	Turbogenerator Units	2.38%
E324	NUCLEAR	Accessory Electric Equipment	1.43%
E325	NUCLEAR	Miscellaneous Power Plant Equipment	1.22%
E325	NUCLEAR	Decommissioning Minnesota Jurisdiction	0.00%
E325	NUCLEAR	Decommissioning South Dakota Jurisdiction	0.00%
E325	NUCLEAR	Decommissioning FERC Wisconsin Jurisdiction	0.00%
E325	NUCLEAR	Decommissioning North Dakota Jurisdiction	0.71%
E325	NUCLEAR	Decommissioning Wisconsin Jurisdiction	0.00%
E302	HYDRO	Franchises & Consents	3.74%
E331	HYDRO	Structures and Improvements	0.95%
E332	HYDRO	Reservoirs, Dams and Water	2.73%
E333	HYDRO	Water Wheels, Turbines & Generators	4.34%
E334	HYDRO	Accessory Electric Equipment	2.48%
E335	HYDRO	Miscellaneous Power Plant Equipment	1.23%
E340.1	OTHER	Wind Rights	3.66%
E341	OTHER	Structures and Improvements	2.75%
E342	OTHER	Fuel Holders, Producers & Accessories	3.88%
E344	OTHER	Generators	3.04%
E345	OTHER	Accessory Electric Equipment	3.26%
E346	OTHER	Miscellaneous Power Plant Equipment	2.79%

Agreement to Coordinate Planning and Operations and Interchange Power and Energy **Exhibit IX**

TRANSMISSION

E352	Structures and Improvements	2.13%
*E352	Structures and Improvements-Prod.	2.47%
E353	Station Equipment	2.56%
*E353	Station Equipment-Prod.	2.57%
E354	Towers and Fixtures	2.36%
*E354	Towers and Fixtures-Prod.	0.81%
E355	Poles and Fixtures	2.42%
*E355	Poles and Fixtures-Prod.	2.37%
E356	Overhead Conductors & Devices	3.03%
*E356	Overhead Conductors & Devices-Prod.	2.76%
E357	Underground Conduit	1.80%
E358	Underground Conductors & Devices	2.48%

DISTRIBUTION

E361	Structures and Improvements	2.86%
*E361	Structures and Improvements-Prod.	2.89%
E362	Station Equipment	2.87%
*E362	Station Equipment-Prod.	2.89%
E364	Poles, Towers and Fixtures	4.70%
E365	Overhead Conductors and Devices	3.69%
E366	Underground Conduit	1.95%
E367	Underground Conductor and Devices	2.28%
E368	Line Transformers	2.82%
E368	Line Capacitors	3.99%
E369	Overhead Services	3.35%
E369	Underground Services	3.36%
E370	Meters	6.67%
E370.1	Meters-Old	4.99%
E373	Street Lighting and Signal Systems	4.75%

GENERAL - ELECTRIC

E303	Intangible Plant – 5 Year	20.00%
E390	Structures and Improvements	2.22%
E391	Office Furniture and Equipment	5.56%
E391	Network Equipment	25.00%
E392	Transportation Equipment – Auto	18.00%
E392	Transportation Equipment – Light Truck	9.00%
E392	Transportation Equipment – Trailers	9.00%
E392	Transportation Equipment – Heavy Trucks	7.92%
E393	Stores Equipment	5.00%
E394	Tools, Shop and Garage Equipment	6.67%
E394	Hand Held Meter Readers	20.00%
E395	Laboratory Equipment	10.00%
E396	Power Operated Equipment	9.00%
E397	Communication Equipment	11.11%
E397	Communication Equipment-AMR	6.67%
E398	Miscellaneous Equipment	6.67%

Agreement to Coordinate Planning and Operations and Interchange Power and Energy **Exhibit IX**

SPECIFICATION OF COMPOSITE DEPRECIATION RATES

NSP(Wis):

FERC ACCOUNT		DESCRIPTION	ANNUAL DEPRECIATION RATE PERCENT
PRODUCTION			
E311	STEAM	Structures and Improvements	2.38%
E312	STEAM	Boiler Plant Equipment	3.12%
E314	STEAM	Turbogenerator Units	3.07%
E315	STEAM	Accessory Electric Equipment	3.46%
E316	STEAM	Miscellaneous Power Plant Equipment	3.09%
E302	HYDRO	Franchises & Consents	3.49%
E331	HYDRO	Structures and Improvements	2.81%
E332	HYDRO	Reservoirs, Dams & Water	2.68%
E333	HYDRO	Water Wheels, Turbines & Generators	3.15%
E334	HYDRO	Accessory Electric Equipment	2.83%
E335	HYDRO	Miscellaneous Power Plant Equipment	2.51%
E341	OTHER	Structures and Improvements	1.64%
E342	OTHER	Fuel Holders, Producers & Accessories	3.67%
E343	OTHER	Prime Movers	1.57%
E344	OTHER	Generators	2.55%
E345	OTHER	Accessory Electric Equipment	3.33%
E346	OTHER	Miscellaneous Power Plant Equipment	6.86%
TRANSMISSION			
E352		Structures and Improvements	2.52%
*E352		Structures and Improvements-Prod.	2.17%
E353		Station Equipment	3.16%
*E353		Station Equipment-Prod.	3.29%
E354		Towers and Fixtures	2.30%
E355		Poles and Fixtures	2.98%
E356		Overhead Conductors & Devices	3.12%
E357		Underground Conduit	.25%
E358		Underground Conductors & Devices	.35%
E359		Roads and Trails	2.50%

DISTRIBUTION

E361	Structures and Improvements	2.56%
*E361	Structures and Improvements-Prod.	2.63%
E362	Station Equipment	3.10%
*E362	Station Equipment-Prod.	3.14%
E364	Poles, Towers and Fixtures	4.30%
E365	Overhead Conductors and Devices	3.44%
E366	Underground Conduit	2.62%
E367	Underground Conductor and Devices	2.58%
E368	Line Transformers	2.99%
E368	Line Transformers/Other	2.99%
E368	Line Capacitors	3.01%
E369	Overhead Services	4.34%
E369	Underground Services	4.36%
E370	Meters	4.58%
E370.1	Meters-Old	5.35%
E370.2	Meters-AMR	7.20%
E371	Customer Installations	.17%
E373	Street Lighting	6.41%

ELECTRIC GENERAL

E303	Intangible Plant – 5 year	20.00%
E390	Structures and Improvements	2.86%
E391	Office Furniture and Equipment	5.00%
E391	Network Equipment	25.00%
E392	Transportation Equipment – Auto	12.86%
E392	Transportation Equipment – Light Truck	12.86%
E392	Transportation Equipment – Heavy Truck	9.00%
E393	Stores Equipment	5.00%
E394	Tools, Shop and Garage Equipment	5.00%
E395	Laboratory Equipment	5.00%
E396	Power Operated Equipment	7.50%
E397	Communication Equipment	6.67%
E397	Communication Equipment-EMS	9.09%
E398	Miscellaneous Equipment	5.00%

SPECIFICATIONS OF DEMAND AND ENERGY
CLASSIFICATION OF PRODUCTION EXPENSES

Uniform System of Accounts Account No.	Description	Classification Demand	Classification Energy
	Steam Power Generation Operation		
500	Operation Supervision and Engineering	X	
501	Fuel		X
502	Steam Expenses	X	
503	Steam from other sources		X
504	Steam transferred - CR		X
505	Electric Expenses	X	
506	Miscellaneous steam power expenses	X	
507	Rents	X	
509	Allowances		X
	Maintenance		
510	Supervision and engineering		X
511	Structures	X	
512	Boiler plant		X
513	Electric plant		X
514	Miscellaneous steam plant	X	
	Nuclear Power Generation Operation		
517	Operation supervision and engineering	X	
518	Fuel		X
519	Coolants and water	X	
520	Steam expenses	X	
523	Electric expenses	X	
524	Miscellaneous nuclear power expenses	X	
525	Rents	X	
	Maintenance		
528	Supervision and engineering		X
529	Structures	X	
530	Reactor plant equipment		X
531	Electric plant		X
532	Miscellaneous nuclear plant	X	

Agreement to Coordinate Planning and Operations and Interchange Power and Energy **Exhibit X**

SPECIFICATIONS OF DEMAND AND ENERGY
CLASSIFICATION OF PRODUCTION EXPENSES

Uniform System of Accounts Account No.	Description	Classification Demand	Classification Energy
	Hydraulic Power Generation Operation		
535	Operation supervision and engineering	X	
536	Water for power	X	
537	Hydraulic expenses	X	
538	Electric expenses	X	
539	Miscellaneous hydraulic power expenses	X	
540	Rents	X	
	Maintenance		
541	Supervision and engineering	X	
542	Structures	X	
543	Reservoirs, dams and waterways	X	
544	Electric plant		X
545	Miscellaneous hydraulic plant	X	
	Other Power Generation Operation		
546	Operation Supervision and Engineering	X	
547	Fuel		X
548	Generation expenses	X	
549	Miscellaneous other power generation	X	
550	Rents	X	
	Maintenance		
551	Supervision and engineering	X	
552	Structures	X	
553	Generating and electric equipment	X	
554	Miscellaneous other power generation plant	X	
	Other Power Supply Expenses		
555	Purchased power		As Billed
556	System control and load dispatching	X	
557	Other expenses		As Billed

Exhibits

FORMULA TYPE PROCEDURES FOR DEVELOPMENT OF AMOUNTS OF POWER SALES

The Monthly amounts of sales of power by each Party to the other Party shall be determined as follows:

A - NSP(Minn) Power Sales (PS) to NSP(Wis):

$$\text{PS to NSP(Wis)} = \text{NSP(Minn) Demand} \times \frac{\text{NSP(Wis) Demand}}{\text{System Demand}}$$

B - NSP(Wis) Power Sales (PS) to NSP(Minn):

$$\text{PS to NSP(Minn)} = \text{NSP(Wis) Demand} \times \frac{\text{NSP(Minn) Demand}}{\text{System Demand}}$$

Where:

"PS" is the amount of power sold in MW by the selling Party to the purchasing Party in the billing month.

"Demand" is each Party's billing demand in MW's based on the average of 36 Monthly Coincident Peaks; including 18 months on historical peaks and 18 months of forecasted peak data for the year of application. The measured monthly coincident peak demands shall be adjusted by a Transmission Loss Multiplier. Historical peak data may be adjusted to reflect known significant load changes over 10 MW by agreement of the Parties.

"Transmission Loss Multipliers" are equal to:

0.968 for NSP(Minn)
0.960 for NSP(Wis)

"System Demand" equals NSP(Minn) Demand + NSP(Wis) Demand

Exhibit VIII shows an example of the development of the power sales.

FORMULA TYPE PROCEDURES FOR DEVELOPMENT OF AMOUNTS OF POWER SALES

The monthly amounts of sales of energy by each Party to the other Party shall be determined as follows:

A - NSP(Minn) Energy Sales (ES) to NSP(Wis):

$$\text{ES to NSP(Wis)} = \text{NSP(Minn) Energy Requirements} \times \frac{\text{NSP(Wis) Energy Requirements}}{\text{System Energy Requirements}}$$

B - NSP(Wis) Energy Sales (ES) to NSP(Minn):

$$\text{ES to NSP(Minn)} = \text{NSP(Wis) Energy Requirements} \times \frac{\text{NSP(Minn) Energy Requirements}}{\text{System Energy Requirements}}$$

Where:

"ES" is the amount of energy sold in Mwh's by the selling Party to the purchasing Party in the billing month.

"Energy Requirements" are each Party's billing requirements in Mwh's for the previous month. The measured monthly energy requirements shall be adjusted by a Transmission Loss Multiplier.

"Transmission Loss Multipliers" are equal to:

0.967 for NSP(Minn)
0.938 for NSP(Wis)

"System Demand" equals NSP(Minn) Demand + NSP(Wis) Demand

"System Energy Requirements" equals the total of NSP(Minn) and NSP(Wis) Energy Requirements.

FORMULA TYPE PROCEDURES FOR DEVELOPMENT OF AMOUNTS OF POWER SALES

The monthly unit rates for the sales of megawatts of power by each Party to the other Party shall be determined as follows:

A - NSP(Minn) Demand Rate for sales to NSP(Wis):

$$\text{DR to NSP(Wis)} = \frac{\text{NSP(Minn) Demand Costs}}{\text{NSP(Minn) Demand}}$$

B - NSP(Wis) Demand Rate for sales to NSP(Minn):

$$\text{DR to NSP(Minn)} = \frac{\text{NSP(Wis) Demand Costs}}{\text{NSP(Wis) Demand}}$$

Where:

"DR" is the monthly unit demand rate (rate in dollars per MW) for power sales by each Party to other Parties.

"Demand Costs" are the demand related costs developed for each Party for the billing month under Exhibit V.

"Demand" is each Party's billing demand in MW's based on the average of 36 Monthly Coincident Peaks; including 18 months of historical peaks and 18 months of forecasted peak data for the year of application. The measured monthly coincident peak demands shall be adjusted by a Transmission Loss Multiplier. Historical peak data may be adjusted to reflect known significant load changes over 10 MW by agreement of the Parties.

"Transmission Loss Multipliers" are equal to:

0.968 for NSP(Minn)
0.960 for NSP(Wis)

Agreement to Coordinate Planning and Operations and Interchange Power and Energy **Exhibit IV**

FORMULA TYPE PROCEDURES FOR DEVELOPMENT OF AMOUNTS OF POWER SALES

The monthly unit rates for the sales of megawatts of power by each Party to the other Party shall be determined as follows:

A - NSP(Minn) Energy Rates for sales to NSP(Wis):

$$\text{ER to NSP(Wis)} = \frac{\text{NSP(Minn) Energy Costs}}{\text{NSP(Minn) Energy Requirements}}$$

B - NSP(Wis) Energy Rates for sales to NSP(Minn):

$$\text{ER to NSP(Minn)} = \frac{\text{NSP(Wis) Energy Costs}}{\text{NSP(Wis) Energy Requirements}}$$

Where:

"ER" is the monthly unit energy rate (rate in dollars per Mwh) for energy sales from each Party to the other Parties.

"Energy Costs" are each Party's energy costs for the billing month, including the carrying costs on Electric Production Fuel Stock balances recorded in FERC Accounts 151 and 152 included at 100 percent of the average of the monthly balances in the accounts.

"Energy Requirements" are each Party's billing requirements in MWH's for the previous month. The measured monthly energy requirements shall be adjusted by a Transmission Loss Multiplier.

"Transmission Loss Multipliers" are equal to:

0.967 for NSP(Minn)
0.938 for NSP(Wis)

FORMULA TYPE PROCEDURES FOR DEVELOPMENT OF DEMAND RELATED COSTS

The demand related cost used in Exhibit III shall be those developed on line 23 of this exhibit.

	DEVELOPMENT OF RATE BASE	NSP(Minn)	NSP(Wis)
1.	Electric Plant in Service (Sched. 1)		
2.	Accumulated Provision for Depreciation (Sched. 2)		
3.	Net Electric Plant in Service		
4.	Deduct: Accumulated Deferred Income Taxes (Sched. 3)		
5.	Add: Plant Held for Future Use (Sched. 4)		
6.			
7.	Rate Base (Total lines 1 through 6)		

COST OF SERVICE - DEMAND RELATED

A. Fixed Charges on Investment

8. Return on Rate Base at Specified Rate of Return (Sched. 6)
9. Income Taxes (Sched. 7)
10. Depreciation & Amortization Expense (Sched. 8)
11. Deferred Income Taxes (Sched. 9)
12. Property Taxes (Sched. 10)
13. Insurance (Sched. 11)
13.1 Carrying Cost on Demand-Related Deferred Nuclear Refueling Outage Costs
14. Total Fixed Charges (Total lines 8 through 13.1)

B. Fixed Power Production and Regional Market Expense

15. Fixed Operating and Maintenance Expense (Sched. 12 and 12.1)
16. Net Purchased Power Demand Costs (Sched. 13)
17. Production System Control & Load Dispatching (Sched. 14)
18. Credits for Production Related Services (Sched. 16)
19. Total Fixed Power Production Expense (Total lines 15 through ~~17~~18)

C. Fixed Transmission Expense

20. Operation and Maintenance Expense (Sched. 15)
21. Credits for Transmission Related Services (Sched. 17)
22. Total Fixed Transmission Expense (Total lines ~~19~~20 through 21)
23. Total Month's Demand Related Costs (Total lines 14, ~~18~~19 and 22)

ELECTRIC PLANT IN SERVICE

Electric Plant In Service included for the determination of charges among the Parties shall include the average monthly balances of gross plant at original cost. The following FERC Accounts shall be included:

1. Intangible Plant Investment
   Water power relicensing investment recorded in FERC Account 302.

2. Production Plant Investment
   Production plant investment recorded in FERC Accounts 310 through 346.

3. Nuclear Fuel Plant Investment
   Nuclear fuel investment included in FERC Accounts 120.2, 120.4 and 120.6.

4. Transmission Plant Investment
   Transmission plant investment recorded in FERC Accounts 350 through 359. Transmission substations having facilities which jointly serve the transmission and distribution functions are inventoried and priced according to the function served. The original cost value of the distribution facilities are excluded from these accounts for the purpose of this Agreement.

5. Distribution Substation Plant Investment
   Distribution substation plant investment recorded in FERC Accounts 360, 361 and 362. Distribution substations having facilities which jointly serve the distribution and transmission functions are inventoried and priced according to the function served. The original cost value of only the facilities which serve a transmission function are included for the purposes of this Agreement.

6. General Plant Investment
   System control and load dispatching plant investment recorded in FERC Account 397. System control and load dispatching equipment is analyzed as to the function it serves. The original cost value of the equipment serving the production and transmission functions is included for the purposes of this Agreement.

ACCUMULATED PROVISION FOR DEPRECIATION

Accumulated Provision for Depreciation for Electric Plant in Service and Nuclear Fuel is recorded in FERC Accounts 108 and 120.5, respectively. Accumulated provision for amortization of electric utility plant is recorded in FERC Account 111.

These accounts are classified to the production, nuclear fuel, transmission, distribution and general functions of plant and the amounts are calculated based upon the original cost of the plant. The annual charge to the accumulated provisions for depreciation reflects the annual depreciation provisions, book cost of plant retired, cost of removal and salvage credit.

ACCUMULATED DEFERRED INCOME TAXES

Accumulated Deferred Income Taxes included in FERC Accounts 190 and 281-283 are classified to the production, nuclear fuel, transmission, distribution and general plant functions in the same detail as the original cost of the plant in service.

PLANT HELD FOR FUTURE USE - LAND

Land Plant Held for Future Use if recorded in FERC Account 105. The amounts included to determine the charges among the Parties shall include those amounts related to the production and transmission functions. These amounts shall be included at 100% of the average monthly balances as recorded on the Company's books and records.

<u>OTHER</u>

The proceeds of U.S. Environmental Protection Agency (EPA) emission allowance auctions recorded in FERC 411.8 and collected by either company shall be allocated annually as a credit to such Party's Demand Costs in Exhibit III.

In the event either Party experiences a new type of cost not anticipated by this Exhibit V, the cost shall be allocated as a Demand Cost or Energy Cost in a manner consistent with the FERC Uniform System Accounts in effect from time to time.

RETURN ON RATE BASE

The return on rate base shall be the overall rate of return developed from the long term debt and preferred stock costs (if any) determined according to this schedule and the rate of return on equity specified in Exhibit VII. The capital structure for NSP(Minn) and NSP(Wis) and the appropriate cost rates shall be determined for each calendar year in the following steps:

The debt and preferred stock (if any) of NSP (Minn) and NSP(Wis) is directly assigned to each company. The cost rates for these components of the capital structure are the actual cost rates of each company's debt and preferred stock (if any) determined in accordance with FERC regulatory principles. The retained earnings portion of each company's common equity is also directly assigned to the such company. Each company's equity capital shall equal total capitalization less the debt and preferred stock (if any) directly assigned. The return on equity derived pursuant to this Schedule G and provided for in Exhibit VII is used as the cost of the subsidiary's retained earnings.

Unless otherwise agreed and accepted for filing by FERC, the cost rate for common equity for NSP(Minn) and NSP(Wis) will be equal. The capitalization ratios and cost rates for debt and preferred stock (if any) will be distinct between companies based on their specific level and cost of financing.

Equity Return:

By December 15 of each year, the NSP Companies shall file a revised Exhibit VII containing a rate of return on common equity equal to the quarterly adjusted generic return on common equity promulgated by FERC for effectiveness on November 1 of that year. See, *Generic Determination of Rate of Return on Common Equity for Public Utilities*, Docket No. RM84-15-000, Order No. 420, issued May 20, 1985. No filing shall be required if the quarterly adjusted generic rate of return effective on November 1 is the same as the quarterly adjusted generic rate of return effective on November 1 of the previous year. In making such filing, the NSP Companies shall request that the revised Exhibit VII shall be made effective as of January 1 of the year following the filing and shall request waiver of the 60 day notice-of-filing period to achieve such effective date. After the revised Exhibit VII has been allowed to become effective, the NSP Companies shall make such payments among themselves as may be required to adjust billings for sales made on and after the date that the filing is permitted to become effective. Such payments among the NSP Companies shall be with interest at the rate provided in the Commission's regulations.

Within 30 days of the filing of a revised Exhibit VII, the NSP Companies shall have the right to petition the Commission for a determination that the NSP Companies' risks are sufficiently above or below industry average risks to warrant a rate of return on common equity above or below the generic rate of return on common equity contained in such filing. The proponent of any departure from the generic rate of return on common equity contained in the filing shall bear the burden of justifying the departure.

If the Commission after hearing on the record finds that a departure is justified, it shall establish a just and reasonable rate of return on common equity for the pertinent calendar year. Such rate of return on common equity shall be made retroactively effective as of January 1 of the pertinent calendar year, and the NSP Companies shall make such payments among themselves as may be required to adjust billings for sales made on and after that date to the rate of return on common equity determined by the Commission for the calendar year.

If, for whatever reason, FERC ceases to issue or fails to issue a quarterly adjusted generic rate of return on common equity effective for November 1 of a year, the NSP Companies shall file with FERC by December 15 of the year either a revised Exhibit VII or the existing Exhibit VII with a request that it be allowed to become effective as of January 1 of the following year. The rate of return on common equity proposed in a filing shall be in the NSP Companies' sole discretion. NSP shall bear the burden of justifying any increase or decrease in the rate of return on common equity. The NSP Companies shall request that any determination by FERC on such filing shall be made effective as of January 1 of the year following the filing, and the NSP Companies shall make such payments among themselves as may be required to adjust billings for sales made on or after the effective date of the determination. Such payments among the NSP Companies shall be with interest at the rate provided in the Commission's regulations.

COMPUTATION OF FEDERAL AND STATE INCOME TAXES

The Federal and State Income Taxes shall be computed as follows:

1. Required Return on Rate Base (Schedule 6)
2. Add: Book Depreciation and Amortization (Schedule 8)
3. Provision for Deferred Income Taxes (Schedule 9)
4. Deduct: Investment Tax Credit Flow Through (Schedule 7, Page 3 of 3)
5. Income Tax Depreciation (Schedule 7, Page 3 of 3)
6. Interest Expense (Schedule 7, Page 3 of 3)
7. Preferred Dividend Credit (if any) (Schedule 7 Page 3 of 3)

8. Income Tax Base

9. Preliminary Income Taxes @ Income Tax Conversion Factor (1)

10. Deduct: Investment Tax Credit Flow Through (Line 4)
11. Preferred Dividend Credit (Line 7)

12. Federal and State Income Taxes

(1) $\frac{\text{Composite Tax Rate (2)}}{\text{1 - Composite Tax Rate (2)}}$ = Income Tax Conversion Factor

(2) Composite Federal and State Income Tax Rate as determined in accordance with Schedule 7, Page 2 of 3.

DETERMINATION OF FEDERAL AND STATE COMPOSITE INCOME TAX RATES

Let: F = Federal Income Tax Rate
M = Minnesota State Income Tax Rate
D = North Dakota State Income Tax Rate
S = South Dakota State Income Tax Rate
W = Wisconsin State Income Tax Rate
MI = Michigan State Single Business Tax Rate
N = Net Income After Net Deductions But Before Income Taxes

NSP Company (Minnesota)

Only Minnesota and Federal Income Taxes:
M = ______________ (N)
F = ______________ (N)
M + F = _______________ (N)

Only North Dakota and Federal Income Taxes:
F = ______________ (N)
D = ______________ (N)
F + D = _______________ (N)

Only South Dakota and Federal Income Taxes:
S + F = _______________ (N)

NSP Company (Minnesota): Combined Minnesota, North Dakota, South Dakota
M + D + S + F = _______________ (N)

NSP Company (Wisconsin):

Wisconsin, Michigan and Federal Income Taxes
W = ______________ (N)
MI = ______________ (N)
F = ______________ (N)
W +MI+ F = _______________ (N)

Notes: 1. Investment Tax Credit and Surtax Credits are ignored in all formulas.

2. State Income Taxes are deductible from Federal Taxable Income.
Federal Income Tax is deductible from North Dakota Taxable Income.
Federal Income Tax is not deductible from Minnesota or Wisconsin Taxable Income.

DEDUCTIONS FOR COMPUTATION OF FEDERAL AND STATE INCOME TAXES

Investment Tax Credit Flow Through

The Investment Tax Credit Flow Through is recorded in FERC Account 411.4. The amounts included for the calculation of income taxes are those amounts attributable to the plant investment related to the production, nuclear fuel, transmission, distribution and general plant as functionalized.

Income Tax Depreciation

Income Tax Depreciation allowable for the calculation of Federal and State income taxes is based upon the plant investment related to production, nuclear fuel, transmission, distribution and general plant as functionalized.

Interest Expense

Interest costs associated with debt recorded in FERC Accounts 221-224 is used to calculate the embedded cost of debt. The embedded cost of debt times the debt ratio as determined on Exhibit V, Schedule 6, applied to the rate base determines the interest expense deduction for income taxes.

Preferred Dividend Credit

A Preferred Dividend Credit (if any) is allowed on certain preferred stock issues in accordance with Section 247 of the Internal Revenue Code. This credit is reflected in the calculation of income taxes.

DEPRECIATION AND AMORTIZATION EXPENSE

Depreciation expense and depreciation expense for asset retirement costs are recorded in FERC Account 403 and 403.1, respectively by the plant functional classifications. Depreciation rates used to calculate the depreciation expense for the original cost of plant as classified by functions for this Agreement are shown on Exhibit IX - Specification of Depreciation Rates.

Amortization expense included to determine the charges among the Parties are recorded in FERC Accounts 404, 405, 406, and 407.

PROVISION FOR DEFERRED INCOME TAXES

The Provision for Deferred Income Taxes is recorded in FERC Accounts 410.1 and 411.1, amounts debited and amounts credited, respectively. The Companies have segregated the deferred income taxes by functional classification in the same detail as the original cost of plant investment.

PROPERTY TAXES

The Property Tax expense or taxes in lieu of property taxes are recorded in FERC Account 408.1. Each Company has segregated its taxes by functional classification in the same detail as the original cost of plant investment.

INSURANCE EXPENSE

The Insurance Expense is recorded in FERC Accounts 924 and 925. Insurance expense included is related to the production plant and transmission and distribution substations in the same manner as the original cost of the plant investment for these facilities.

FIXED PRODUCTION OPERATING AND MAINTENANCE EXPENSE

Production Operating and Maintenance Expenses are recorded in FERC Accounts 500 through 554 and 557. The expenses recorded in these accounts are determined to be demand related in accordance with the FERC Demand and Energy Classification of Production Expenses - Exhibit X.

FIXED REGIONAL MARKET OPERATING AND MAINTENANCE EXPENSE

Production Operating and Maintenance Expenses are recorded in FERC Accounts 575 through 576. The expenses recorded in these accounts are determined to be demand related as billed.

NET PURCHASED POWER DEMAND COSTS

Purchased Power Demand Costs as billed are recorded in FERC Account 555 - Purchased Power. Firm Power Sales Demand Charges made to eligible non-associated entities are recorded in FERC Account 447 - Revenue from Sales for Resale. The net amount of these demand charges and credits is included as the Net Purchased Power Demand costs.

PRODUCTION SYSTEM CONTROL AND LOAD DISPATCHING EXPENSE

Production System Control and Load Dispatching expense is recorded in FERC Account 556. 100% of these power supply expenses is included to determine the charges under the Agreement in accordance with the FERC Demand and Energy Classification of Production Expenses - Exhibit X.

TRANSMISSION OPERATION AND MAINTENANCE EXPENSE

Transmission Operation and Maintenance expenses are recorded in FERC Accounts 560 through 573. 100% of these expenses is considered fixed or demand related.

CREDITS FOR PRODUCTION-RELATED SERVICES

Revenue for Production-Related Services is recorded in FERC Accounts 454 - Rent From Electric Property and 456 - Other Operating Revenue. These Revenues are credited to production operating and maintenance expenses.

CREDITS FOR TRANSMISSION RELATED SERVICES

Revenue from Transmission Related Service is recorded in FERC Accounts 454 – Rent from Electric Property and 456 - Other Operating Revenue. These revenues are credited to transmission operating and maintenance expenses.

FORMULA TYPE PROCEDURES FOR DEVELOPMENT OF ENERGY RELATED COSTS

The energy-related costs used in Exhibit IV shall be those developed on Line 5 of this exhibit.

	NSP (Minn)	NSP(Wis)
1. Fuel Expenses (Schedule 1)		
2. Variable Production and Regional Market Operating, and Maintenance Expense (Schedule 2 and 2.1)		
3. Net Purchased Power Energy Costs (Schedule 3)		
4. Carrying Cost on Fuel Stocks		
4.1 Carrying Cost on Energy-Related Deferred Nuclear Refueling Outage Costs		
5. Total Energy Related Costs (Total lines 1 through 4.1)		

FUEL EXPENSES

Fuel Expenses are recorded in FERC Accounts 501, 518 and 547. 100% of fuel expenses is included as a variable expense in accordance with the FERC Classification of Production Expenses - Exhibit X.

VARIABLE PRODUCTION OPERATING AND MAINTENANCE EXPENSES

Production Operating and Maintenance expenses are recorded in FERC Accounts 500 through 554 and 557. The expenses recorded in these accounts are determined to be energy related in accordance with the FERC Demand and Energy Classification of Production Expenses - Exhibit X.

VARIABLE REGIONAL MARKET OPERATING AND MAINTENANCE EXPENSES

Regional Market Operating and Maintenance expenses are recorded in FERC Accounts 575 through 576. The expenses recorded in these accounts are determined to be energy related as billed.

NET PURCHASED POWER ENERGY COSTS

Purchased Power Energy Costs as billed are recorded in FERC Account 555 - Purchased Power. Firm power energy sales are recorded in Account 447 - Revenue from Sales for Resale. The net amount of these energy charges and credits is included as the Net Purchased Power Energy costs.

SPECIFICATION OF RATE OF RETURN ON COMMON EQUITY

The rate of return on common equity to determine the overall cost of capital as developed in accordance with Exhibit V, Schedule 6, is 11.47%.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy **Exhibit VIII**

SPECIFICATION OF AVERAGE MONTHLY COINCIDENTAL PEAK DEMANDS

Calendar Year ~~2010~~2011 Contract Year

Monthly Coincidental Peak Demands (KW)

		NSP (Minn)	NSP (Wis)	Total System
~~2008~~2009	January	~~5771~~5663	~~1182~~1173	~~6953~~6836
	February	~~5655~~5424	~~1245~~1126	~~6900~~6550
	March	~~5282~~5151	~~1087~~1048	~~6369~~6199
	April	~~4897~~4701	~~1020~~1013	~~5917~~5714
	May	~~4967~~5956	~~950~~999	~~5917~~6955
	June	~~6793~~7098	~~1208~~1388	~~8001~~8486
	July	~~7351~~6279	~~1273~~1117	~~8624~~7396
	August	~~7208~~6862	~~1197~~1251	~~8405~~8113
	September	~~6170~~5994	~~1316~~1071	~~7486~~7065
	October	~~5012~~4858	~~1036~~985	~~6048~~5843
	November	~~5412~~5093	~~1082~~1027	~~6494~~6120
	December	~~5912~~5756	~~1258~~1163	~~7170~~6919
	Total	~~70,430~~68,836	~~13,854~~13,361	~~84,284~~82,197
~~2009~~2010	January	~~5716~~5569	~~1173~~1103	~~6889~~6672
	February	~~5471~~5305	~~1126~~1062	~~6597~~6367
	March	~~5199~~4868	~~1048~~987	~~6247~~5855
	April	~~4744~~4842	~~1013~~963	~~5757~~5805
	May	~~5995~~7157	~~999~~1263	~~6994~~8420
	June	~~7158~~7049	~~1388~~1262	~~8546~~8311
	July	~~6296~~7052	~~1152~~1330	~~7448~~8382
	August	~~6913~~7072	~~1258~~1312	~~8171~~8384
	September	~~6815~~6727	~~1293~~1272	~~8108~~7998
	October	~~5200~~5131	~~1040~~1022	~~6240~~6153
	November	~~5509~~5484	~~1112~~1108	~~6621~~6591
	December	~~5810~~5804	~~1232~~1233	~~7042~~7037
	Total	~~70,826~~72,059	~~13,834~~13,916	~~84,660~~85,974
~~2010~~2011	January	~~5678~~5695	~~1192~~1226	~~6870~~6921
	February	~~5520~~5558	~~1185~~1181	~~6705~~6738
	March	~~5230~~5331	~~1083~~1024	~~6313~~6355
	April	~~5025~~5104	~~1087~~1077	~~6112~~6180
	May	~~5943~~6126	~~1099~~1089	~~7042~~7215
	June	~~7178~~7238	~~1360~~1393	~~8538~~8631
	July	~~7179~~7266	~~1360~~1368	~~8539~~8634
	August	~~7193~~7277	~~1345~~1357	~~8538~~8634
	September	~~6896~~6887	~~1302~~1312	~~8198~~8199
	October	~~5218~~5228	~~1055~~1040	~~6273~~6268
	November	~~5536~~5589	~~1137~~1129	~~6673~~6718
	December	~~5853~~5922	~~1249~~1261	~~7102~~7183
	Total	~~72,448~~73,222	~~14,455~~14,455	~~86,903~~87,677

Agreement to Coordinate Planning and Operations and Interchange Power and Energy | **Exhibit IX** ~~**Page 1 of 7**~~

SPECIFICATION OF COMPOSITE DEPRECIATION RATES ~~2010~~2011 CONTRACT YEAR

The following annual composite depreciation rates are calculated based ~~up~~on the most recent actual depreciation expense accruals and plant balances. The actual depreciation expense is calculated based on the most recent remaining life depreciation studies ~~and~~ certified by the respective State Commissions for NSP (Minn) and NSP (Wis). Even though individual depreciation lives may not have changed from the previous year, these are composite rates and a change in plant balances could cause a change in the rate by FERC Account. ~~are used to determine the annual depreciation expense accruals for purposes of this Agreement:~~

NSP (Minn)

FERC ACCOUNT		DESCRIPTION	ANNUAL DEPRECIATION RATE PERCENT
PRODUCTION			
E311	STEAM	Structures and Improvements	~~3.08%~~1.66%
E312	STEAM	Boiler Plant Equipment	~~2.93%~~3.19%
E314	STEAM	Turbogenerator Units	~~2.75%~~3.59%
E315	STEAM	Accessory Electric Equipment	~~3.17%~~3.45%
E316	STEAM	Miscellaneous Power Plant Equipment	~~2.26%~~2.27%
E302	NUCLEAR	Franchises & Consents	~~4.26%~~3.27%
E321	NUCLEAR	Structures and Improvements	~~1.40%~~1.46%
E322	NUCLEAR	Reactor Plant Equipment	2.10%
E323	NUCLEAR	Turbogenerator Units	~~2.17%~~2.38%
E324	NUCLEAR	Accessory Electric Equipment	~~1.38%~~1.43%
E325	NUCLEAR	Miscellaneous Power Plant Equipment	~~1.04%~~1.22%
E325	NUCLEAR	Decommissioning Minnesota Jurisdiction	0.00%
E325	NUCLEAR	Decommissioning South Dakota Jurisdiction	~~1.50%~~0.00%
E325	NUCLEAR	Decommissioning FERC Wisconsin Jurisdiction	0.00%
E325	NUCLEAR	Decommissioning North Dakota Jurisdiction	0.71%
E325	NUCLEAR	Decommissioning Wisconsin Jurisdiction	0.00%
E302	HYDRO	Franchises & Consents	3.74%
E331	HYDRO	Structures and Improvements	0.95%
E332	HYDRO	Reservoirs, Dams and Water	~~2.66%~~2.73%
E333	HYDRO	Water Wheels, Turbines & Generators	~~0.95%~~4.34%
E334	HYDRO	Accessory Electric Equipment	~~2.35%~~2.48%
E335	HYDRO	Miscellaneous Power Plant Equipment	1.23%
E340.1	OTHER	Wind Rights	~~4.00%~~3.66%
E341	OTHER	Structures and Improvements	~~2.67%~~2.75%
E342	OTHER	Fuel Holders, Producers & Accessories	~~1.26%~~3.88%
E344	OTHER	Generators	~~4.12%~~3.04%
E345	OTHER	Accessory Electric Equipment	~~4.04%~~3.26%
E346	OTHER	Miscellaneous Power Plant Equipment	~~1.47%~~2.79%

TRANSMISSION

E352	Structures and Improvements	~~2.22%~~2.13%
*E352	Structures and Improvements-Prod.	2.47%
E353	Station Equipment	~~2.63%~~2.56%
*E353	Station Equipment-Prod.	2.57%
E354	Towers and Fixtures	~~2.50%~~2.36%
*E354	Towers and Fixtures-Prod.	0.81%
E355	Poles and Fixtures	~~2.44%~~2.42%
*E355	Poles and Fixtures-Prod.	2.37%
E356	Overhead Conductors & Devices	~~3.10%~~3.03%
*E356	Overhead Conductors & Devices-Prod.	2.76%
E357	Underground Conduit	~~1.82%~~1.80%
E358	Underground Conductors & Devices	~~2.50%~~2.48%

~~**Agreement to Coordinate Planning and Operations and Interchange Power and Energy**~~ ~~**Exhibit IX Page 2 of 7**~~

DISTRIBUTION

E361	Structures and Improvements	~~2.89%~~2.86%
*E361	Structures and Improvements-Prod.	2.89%
E362	Station Equipment	~~2.89%~~2.87%
*E362	Station Equipment-Prod.	2.89%
E364	Poles, Towers and Fixtures	~~4.75%~~4.70%
E365	Overhead Conductors and Devices	~~3.71%~~3.69%
E366	Underground Conduit	~~2.00%~~1.95%
E367	Underground Conductor and Devices	~~2.29%~~2.28%
E368	Line Transformers	~~2.81%~~2.82%
E368	Line Capacitors	~~4.00%~~3.99%
E369	Overhead Services	~~3.38%~~3.35%
E369	Underground Services	~~3.38%~~3.36%
E370	Meters	~~5.00%~~6.67%
E370.1	Meters-Old	~~6.67%~~4.99%
E373	Street Lighting and Signal Systems	~~4.80%~~4.75%

GENERAL - ELECTRIC

E303	Intangible Plant – 5 Year	20.00%
E390	Structures and Improvements	2.22%
E391	Office Furniture and Equipment	5.56%
E391	Network Equipment	25.00%
E392	Transportation Equipment – Auto	18.00%
E392	Transportation Equipment – Light Truck	9.00%
E392	Transportation Equipment – Trailers	9.00%
E392	Transportation Equipment – Heavy Trucks	7.92%
E393	Stores Equipment	5.00%
E394	Tools, Shop and Garage Equipment	6.67%
E394	Hand Held Meter Readers	20.00%
E395	Laboratory Equipment	10.00%
E396	Power Operated Equipment	9.00%
E397	Communication Equipment	11.11%
E397	Communication Equipment-AMR	6.67%
E398	Miscellaneous Equipment	6.67%

SPECIFICATION OF COMPOSITE DEPRECIATION RATES

NSP(Wis):

FERC ACCOUNT		DESCRIPTION	ANNUAL DEPRECIATION RATE PERCENT
PRODUCTION			
E311	STEAM	Structures and Improvements	~~2.31%~~2.38%
E312	STEAM	Boiler Plant Equipment	~~3.03%~~3.12%
E314	STEAM	Turbogenerator Units	~~3.00%~~3.07%
E315	STEAM	Accessory Electric Equipment	~~3.45%~~3.46%
E316	STEAM	Miscellaneous Power Plant Equipment	~~3.50%~~3.09%
E302	HYDRO	Franchises & Consents	~~3.51%~~3.49%
E331	HYDRO	Structures and Improvements	~~2.75%~~2.81%
E332	HYDRO	Reservoirs, Dams & Water	2.68%
E333	HYDRO	Water Wheels, Turbines & Generators	~~3.03%~~3.15%
E334	HYDRO	Accessory Electric Equipment	~~2.77%~~2.83%
E335	HYDRO	Miscellaneous Power Plant Equipment	~~3.75%~~2.51%
E341	OTHER	Structures and Improvements	~~1.26%~~1.64%
E342	OTHER	Fuel Holders, Producers & Accessories	~~3.70%~~3.67%
E343	OTHER	Prime Movers	~~1.51%~~1.57%
E344	OTHER	Generators	~~2.33%~~2.55%
E345	OTHER	Accessory Electric Equipment	~~2.42%~~3.33%
E346	OTHER	Miscellaneous Power Plant Equipment	~~7.03%~~6.86%
TRANSMISSION			
E352		Structures and Improvements	~~2.63%~~2.52%
*E352		Structures and Improvements-Prod.	2.17%
E353		Station Equipment	~~3.29%~~3.16%
*E353		Station Equipment-Prod.	3.29%
E354		Towers and Fixtures	2.30%
E355		Poles and Fixtures	~~3.00%~~2.98%
E356		Overhead Conductors & Devices	~~3.13%~~3.12%
E357		Underground Conduit	~~2.63%~~.25%
E358		Underground Conductors & Devices	~~2.75%~~.35%
E359		Roads and Trails	2.50%

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DISTRIBUTION

E361	Structures and Improvements	~~2.63%~~2.56%
*E361	Structures and Improvements-Prod.	2.63%
E362	Station Equipment	~~3.14%~~3.10%
*E362	Station Equipment-Prod.	3.14%
E364	Poles, Towers and Fixtures	~~4.29%~~4.30%
E365	Overhead Conductors and Devices	~~3.43%~~3.44%
E366	Underground Conduit	~~2.63%~~2.62%
E367	Underground Conductor and Devices	~~2.57%~~2.58%
E368	Line Transformers	~~3.00%~~2.99%
E368	Line Transformers/Other	~~3.00%~~2.99%
E368	Line Capacitors	~~3.00%~~3.01%
E369	Overhead Services	~~4.33%~~4.34%
E369	Underground Services	~~4.33%~~4.36%
E370	Meters	~~4.55%~~4.58%
E370.1	Meters-Old	5.35%
E370.2	Meters-AMR	~~6.67%~~7.20%
E371	Customer Installations	~~7.92%~~.17%
E373	Street Lighting	~~6.47%~~6.41%

ELECTRIC GENERAL

E303	Intangible Plant – 5 year	20.00%
E390	Structures and Improvements	2.86%
E391	Office Furniture and Equipment	5.00%
E391	Network Equipment	25.00%
E392	Transportation Equipment – Auto	12.86%
E392	Transportation Equipment – Light Truck	12.86%
E392	Transportation Equipment – Heavy Truck	9.00%
E393	Stores Equipment	5.00%
E394	Tools, Shop and Garage Equipment	5.00%
E395	Laboratory Equipment	5.00%
E396	Power Operated Equipment	7.50%
E397	Communication Equipment	6.67%
E397	Communication Equipment-EMS	9.09%
E398	Miscellaneous Equipment	5.00%

SPECIFICATIONS OF DEMAND AND ENERGY
CLASSIFICATION OF PRODUCTION EXPENSES

Uniform System of Accounts Account No.	Description	Classification Demand	Classification Energy
	Steam Power Generation Operation		
500	Operation Supervision and Engineering	X	
501	Fuel		X
502	Steam Expenses	X	
503	Steam from other sources		X
504	Steam transferred - CR		X
505	Electric Expenses	X	
506	Miscellaneous steam power expenses	X	
507	Rents	X	
509	Allowances		X
	Maintenance		
510	Supervision and engineering		X
511	Structures	X	
512	Boiler plant		X
513	Electric plant		X
514	Miscellaneous steam plant	X	
	Nuclear Power Generation Operation		
517	Operation supervision and engineering	X	
518	Fuel		X
519	Coolants and water	X	
520	Steam expenses	X	
523	Electric expenses	X	
524	Miscellaneous nuclear power expenses	X	
525	Rents	X	
	Maintenance		
528	Supervision and engineering		X
529	Structures	X	
530	Reactor plant equipment		X
531	Electric plant		X
532	Miscellaneous nuclear plant	X	

SPECIFICATIONS OF DEMAND AND ENERGY
CLASSIFICATION OF PRODUCTION EXPENSES

Uniform System of Accounts Account No.	Description	Classification Demand	Energy
	Hydraulic Power Generation Operation		
535	Operation supervision and engineering	X	
536	Water for power	X	
537	Hydraulic expenses	X	
538	Electric expenses	X	
539	Miscellaneous hydraulic power expenses	X	
540	Rents	X	
	Maintenance		
541	Supervision and engineering	X	
542	Structures	X	
543	Reservoirs, dams and waterways	X	
544	Electric plant		X
545	Miscellaneous hydraulic plant	X	
	Other Power Generation Operation		
546	Operation Supervision and Engineering	X	
547	Fuel		X
548	Generation expenses	X	
549	Miscellaneous other power generation	X	
550	Rents	X	
	Maintenance		
551	Supervision and engineering	X	
552	Structures	X	
553	Generating and electric equipment	X	
554	Miscellaneous other power generation plant	X	
	Other Power Supply Expenses		
555	Purchased power		As Billed
556	System control and load dispatching	X	
557	Other expenses		As Billed

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, DC 20426

OFFICE OF ENERGY MARKET REGULATION

In Reply Refer To:
Northern States Power Company
(Minnesota)
Docket No. ER11-3234-000

May 19, 2011

Xcel Energy Services, Inc.
Attention: Mr. Scott M. Wilensky
Vice President, Regulatory and Resource Planning
414 Nicollet Mall
Minneapolis, MN 55401

Dear Mr. Wilensky:

On March 30, 2011, Xcel Energy Services Inc., submitted a revised Restated Agreement to Coordinate Planning and Operations and Interchange Power and Energy (Interchange Agreement) between Northern States Power Company (Minnesota) and Northern States Power Company (Wisconsin) (collectively, NSP Companies).[1] Pursuant to authority delegated to the Director, Division of Electric Power Regulation-Central, under 18 C.F.R. § 375.307, the submittal in the above referenced dockets is accepted for filing with an effective date of January 1, 2011, as requested.

Notices of the filings were published in the *Federal Register* with comments, protests, or interventions due on or before April 20, 2011. No adverse comments or protests were filed. Under 18 C.F.R. § 385.210, interventions are timely if made within the time prescribed by the Secretary. Under 18 C.F.R. § 385.214, the filing of a timely motion to intervene makes the movant a party to the proceeding, if no answer in opposition is filed within fifteen days. The filing of a timely notice of intervention makes a State Commission a party to the proceeding.

[1] The NSP Companies submitted the proposed revisions under the instant filing and Docket No. ER11-3235-000 because Northern States Power Company (Minnesota) is the designated filing party for the Interchange Agreement for the purposes of e-Tariff rules, and Northern States Power Company (Wisconsin) is submitting a concurrence record as required by Order No. 714.

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This action does not constitute approval of any service, rate, charge, classification, or any rule, regulation, contract, or practice affecting such rate or service provided for in the filed documents; nor shall such action be deemed as recognition of any claimed contractual right or obligation affecting or relating to such service or rate; and such action is without prejudice to any findings or orders which have been or may hereafter be made by the Commission in any proceeding now pending or hereafter instituted by or against any of the applicant(s).

This order constitutes final agency action. Requests for rehearing by the Commission may be filed within 30 days of the date of issuance of this order, pursuant to 18 C.F.R. § 385.713.

Sincerely,

Penny S. Murrell, Director
Division of Electric Power
Regulation – Central