

Exhibits

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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.

	<u>DEVELOPMENT OF RATE BASE</u>	<u>NSP(Minn)</u>	<u>NSP(Wis)</u>
1.	Electric Plant in Service (Sched. 1)		
1.1	Pre-funded Allowance for Funds Used during Construction (Sched. 1.1)		
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.	<u>Add: Electric Construction Work in Progress (Sched. 4.1)</u>		
<u>6.1</u>	<u>Add: Accumulated Amortization of Theoretical Reserve Surplus (Sched. 4.2)</u>		
7.	Rate Base (Total lines 1 through <u>6.1</u>)		
 <u>COST OF SERVICE - DEMAND RELATED</u>			
A. <u>Fixed Charges on Investment</u>			
8.	Return on Rate Base at Specified Rate of Return (Sched. 6)		
9.	Income Taxes (Sched. 7)		
10.	Depreciation & Amortization Expense (Sched. 8)		
<u>10.1</u>	<u>Theoretical Reserve Surplus Amortization Expense (Sched. 8.1)</u>		
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. <u>Fixed Power Production and Regional Market Expense</u>			
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. <u>Fixed Transmission Expense</u>			
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.

PRE-FUNDED ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION

Pre-funded Allowance for Funds Used during Construction (AFUDC) is an offsetting AFUDC calculation incorporating the effect of specific regulation whereby customers of a particular jurisdiction are paying for the financing costs during the construction phase of a project. Pre-funded AFUDC is accumulated in FERC Account 253. The amounts included to determine the charges among the Parties shall include those FERC jurisdictional amounts related to the transmission function whereby a current return is earned through the Midwest Independent Transmission System Operator, Inc.'s application of FERC Order 679 under Attachment O-NSP and Attachment GG and MM of the MISO Open Access Transmission, Energy and Operating Reserve Markets Tariff.

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.

ELECTRIC CONSTRUCTION WORK IN PROGRESS

Electric Construction Work in Progress is recorded in FERC Account 107. Electric Construction Work in Progress included for the determination of charges among the Parties shall include the average monthly construction expenditure balance limited to the net FERC jurisdictional portion of transmission projects that earn a current return through the Midwest Independent Transmission System Operator Inc.'s (MISO) application of FERC Order 679 under Attachment O-NSP and Attachments GG and MM of the MISO Open Access Transmission, Energy and Operating Reserve Markets Tariff (Tariff) and excluding AFUDC incurred post project eligibility as approved by FERC under the MISO Tariff.

ACCUMULATED AMORTIZATION OF THEORETICAL RESERVE SURPLUS

Accumulated Amortization of Theoretical Reserve Surplus is recorded in FERC Account 182.3; in accordance with the Minnesota Public Utilities Commission (MPUC) decision to amortize the NSP (Minn) theoretical reserve surplus (as developed in Table 1 below) over a period other than the average remaining life. In the 2013 test year Minnesota retail electric rate case (MPUC Docket No. E002/GR-12-961, order dated September 3, 2013), the MPUC ordered NSP (Minn) to amortize the theoretical reserve surplus for transmission, distribution, intangible and general assets over an eight-year period, commencing January 1, 2013. The NSP (Wis) portion of the reserve is \$26,674,271. The accumulated amortization amounts are based on the schedule provided in Exhibit V, Schedule 8.1.

This account is classified to the transmission, distribution, intangible and general functions of plant.

<u>Functional Class</u>	<u>Total NSP (Minn) Actual to Theoretical Reserve Difference</u>	<u>NSP (Minn) State of Minnesota Actual to Theoretical Reserve Difference</u>	<u>NSP (Wis) Actual to Theoretical Reserve Difference</u>
<u>Intangible 1/</u>	<u>\$417,044</u>	<u>\$365,054</u>	<u>\$0</u>
<u>Transmission</u>	<u>200,466,880</u>	<u>149,597,398</u>	<u>26,645,321</u>
<u>Distribution 2/</u>	<u>109,362,353</u>	<u>109,362,353</u>	<u>18,051</u>
<u>General</u>	<u>6,727,378</u>	<u>5,888,716</u>	<u>10,899</u>
<u>Total Electric Utility</u>	<u>\$316,973,655</u>	<u>\$265,213,520</u>	<u>\$26,674,271</u>

Notes:

1/ No Intangible reserve to NSP (Wis).

2/ Distribution reserve difference included under “NSP (Wis) Actual to Theoretical Reserve Difference” relates to Distribution serving system generation.

**Agreement to Coordinate Planning and
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**Exhibit V
Schedule 5**

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.

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**Exhibit V
Schedule 6**

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

(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:

$$\begin{aligned} M &= \text{_____} (N) \\ F &= \text{_____} (N) \\ M + F &= \text{_____} (N) \end{aligned}$$

Only North Dakota and Federal Income Taxes:

$$\begin{aligned} F &= \text{_____} (N) \\ D &= \text{_____} (N) \\ F + D &= \text{_____} (N) \end{aligned}$$

Only South Dakota and Federal Income Taxes:

$$S + F = \text{_____} (N)$$

NSP Company (Minnesota): Combined Minnesota, North Dakota, South Dakota

$$M + D + S + F = \text{_____} (N)$$

NSP Company (Wisconsin):

Wisconsin, Michigan and Federal Income Taxes

$$\begin{aligned} W &= \text{_____} (N) \\ MI &= \text{_____} (N) \\ F &= \text{_____} (N) \\ W + MI + F &= \text{_____} (N) \end{aligned}$$

- 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.

THEORETICAL RESERVE SURPLUS AMORTIZATION EXPENSE

NSP (Minn)'s demand related cost of service used in determining billings to NSP (Wis) shall include the following annual amounts for purposes of amortizing the NSP (Wis) portion (\$26,674,271) of the NSP (Minn) theoretical reserve surplus amortization, as calculated on Exhibit V, Schedule 4.2. These amounts are in accordance with the Minnesota Public Utilities Commission (MPUC) decisions listed in Exhibit V, Schedule 4.2. The September 3, 2013 MPUC order (Docket No. E002/GR-12-961) included an 8 year amortization period beginning January 1, 2013.

Theoretical Reserve Surplus Amortization Expense

<u>Year</u>	<u>Transmission</u>	<u>Distribution</u>	<u>General</u>	<u>Total</u>
<u>2013</u>	<u>(\$3,330,665)</u>	<u>(\$2,256)</u>	<u>(\$1,362)</u>	<u>(\$3,334,283)</u>

Theoretical Reserve Surplus Amortization Expense represents the current year amortization of the total theoretical depreciation reserve surplus over the amortization period determined by the MPUC.

Theoretical Reserve Surplus Amortization Expense included in determining the charges among the Parties is recorded in FERC Account 407.4 (creation of Regulatory Asset)¹, by the plant functional classifications.

¹ When the amortization is completed, NSP (Minn) and NSP (Wis) will make a section 205 filing with the Commission to add FERC Account 407.3 (reduction of Regulatory Asset), or other appropriate account, to this Schedule 8.1, to amortize the Theoretical Reserve Surplus regulatory asset over the average remaining lives of the functional classes of assets.

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.

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Exhibit VII

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
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Exhibit VIII

SPECIFICATION OF AVERAGE MONTHLY COINCIDENTAL PEAK DEMANDS

Calendar Year 2013 Contract Year

Monthly Coincidental Peak Demands (KW)

		<u>NSP (Minn)</u>	<u>NSP (Wis)</u>	<u>Total System</u>
2011	January	5582	1017	6599
	February	5488	1021	6509
	March	5205	943	6147
	April	4794	887	5682
	May	5239	998	6237
	June	7696	1283	8979
	July	8083	1348	9431
	August	7157	1078	8235
	September	7367	1231	8598
	October	5469	886	6355
	November	5170	928	6098
	December	<u>5389</u>	<u>1013</u>	<u>6403</u>
	Total	72,638	12,634	85,272
2012	January	5385	1031	6415
	February	5017	966	5983
	March	5055	921	5975
	April	4730	879	5608
	May	6089	947	7036
	June	7413	1148	8561
	July	7355	1317	8672
	August	7398	1274	8672
	September	6810	1243	8053
	October	5260	945	6206
	November	5244	997	6241
	December	<u>5557</u>	<u>1097</u>	<u>6653</u>
	Total	71,312	12,764	84,076
2013	January	5496	1062	6558
	February	5351	1039	6390
	March	5075	916	5991
	April	4757	949	5706
	May	6041	1077	7118
	June	7183	1299	8482
	July	7184	1298	8482
	August	7199	1282	8481
	September	6834	1253	8087
	October	5283	957	6240
	November	5256	1009	6265
	December	<u>5571</u>	<u>1107</u>	<u>6678</u>
	Total	71,229	13,249	84,478

SPECIFICATION OF COMPOSITE DEPRECIATION RATES 2013 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)

<u>FERC ACCOUNT</u>	<u>DESCRIPTION</u>	<u>ANNUAL DEPRECIATION RATE PERCENT</u>
<u>PRODUCTION</u>		
E311	STEAM Structures and Improvements	3.1506%
E312	STEAM Boiler Plant Equipment	3.4226%
E314	STEAM Turbogenerator Units	3.5238%
E315	STEAM Accessory Electric Equipment	3.00299%
E316	STEAM Miscellaneous Power Plant Equipment	2.8475%
E302	NUCLEAR Franchises & Consents	4.9130%
E321	NUCLEAR Structures and Improvements	2.4207%
E322	NUCLEAR Reactor Plant Equipment	2.6009%
E323	NUCLEAR Turbogenerator Units	3.40220%
E324	NUCLEAR Accessory Electric Equipment	2.55181%
E325	NUCLEAR Miscellaneous Power Plant Equipment	2.24190%
E325	NUCLEAR Decommissioning Minnesota Jurisdiction	0.00%
E325	NUCLEAR Decommissioning South Dakota Jurisdiction	0.59000%
E325	NUCLEAR Decommissioning FERC Wisconsin Jurisdiction	0.00%
E325	NUCLEAR Decommissioning North Dakota Jurisdiction	0.00%
E325	NUCLEAR Decommissioning Wisconsin Jurisdiction	0.71000%
E302	HYDRO Franchises & Consents	3.74%
E331	HYDRO Structures and Improvements	0.92378%
E332	HYDRO Reservoirs, Dams and Water	2.91309%
E333	HYDRO Water Wheels, Turbines & Generators	4.6596%
E334	HYDRO Accessory Electric Equipment	4.6445%
E335	HYDRO Miscellaneous Power Plant Equipment	1.09361%
E340.1	OTHER Wind Rights	3.14401%
E341	OTHER Structures and Improvements	3.0820%
E342	OTHER Fuel Holders, Producers & Accessories	2.91340%
E344	OTHER Generators	3.6374%
E345	OTHER Accessory Electric Equipment	3.3250%
E346	OTHER Miscellaneous Power Plant Equipment	3.5214%

**Agreement to Coordinate Planning and
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Exhibit IX

TRANSMISSION

E352	Structures and Improvements	<u>1.542.49%</u>
*E352	Structures and Improvements-Prod.	<u>1.542.36%</u>
E353	Station Equipment	<u>2.0360%</u>
*E353	Station Equipment-Prod.	<u>2.0358%</u>
E354	Towers and Fixtures	<u>1.882.15%</u>
*E354	Towers and Fixtures-Prod.	<u>1.922.57%</u>
E355	Poles and Fixtures	<u>2.151.93%</u>
*E355	Poles and Fixtures-Prod.	<u>2.1957%</u>
E356	Overhead Conductors & Devices	<u>2.1031%</u>
*E356	Overhead Conductors & Devices-Prod.	<u>2.1472%</u>
E357	Underground Conduit	<u>1.372.00%</u>
E358	Underground Conductors & Devices	<u>1.842.12%</u>

DISTRIBUTION

E361	Structures and Improvements	<u>2.2879%</u>
*E361	Structures and Improvements-Prod.	<u>2.1889%</u>
E362	Station Equipment	<u>2.1987%</u>
*E362	Station Equipment-Prod.	<u>2.1889%</u>
E364	Poles, Towers and Fixtures	<u>4.640.96%</u>
E365	Overhead Conductors and Devices	<u>2.7946%</u>
E366	Underground Conduit	<u>2.1003%</u>
E367	Underground Conductor and Devices	<u>2.0712%</u>
E368	Line Transformers	<u>3.072.59%</u>
E368	Line Capacitors	<u>4.532.91%</u>
E369	Overhead Services	<u>4.502.75%</u>
E369	Underground Services	<u>3.122.78%</u>
E370	Meters	<u>5.753.58%</u>
E370.1	Meters-Old	<u>0.002.62%</u>
E373	Street Lighting and Signal Systems	<u>4.5976%</u>

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Exhibit IX

GENERAL - ELECTRIC

E303	Intangible Plant – 5 Year	20.00%
E390	Structures and Improvements	2.2 92 %
E391	Office Furniture and Equipment	5.2 56 %
E391	Network Equipment	25.00%
E392	Transportation Equipment – Auto	16.4 08.00 %
E392	Transportation Equipment – Light Truck	9.1 500 %
E392	Transportation Equipment – Trailers	8.3 89.00 %
E392	Transportation Equipment – Heavy Trucks	7.6 292 %
E393	Stores Equipment	5.3 400 %
E394	Tools, Shop and Garage Equipment	6.4 467 %
E394	Hand Held Meter Readers	<u>0.00</u> 20.00 %
E395	Laboratory Equipment	<u>8.39</u> 10.00 %
E396	Power Operated Equipment	8.3 09.00 %
E397	Communication Equipment	<u>10.50</u> 11.11 %
E397	Communication Equipment-AMR	6.7 067 %
E398	Miscellaneous Equipment	<u>7.32</u> 6.67 %

SPECIFICATION OF COMPOSITE DEPRECIATION RATES

NSP(Wis):

<u>FERC ACCOUNT</u>	<u>DESCRIPTION</u>	<u>ANNUAL DEPRECIATION RATE PERCENT</u>
<u>PRODUCTION</u>		
E311	STEAM Structures and Improvements	3.28%
E312	STEAM Boiler Plant Equipment	3.47%
E314	STEAM Turbogenerator Units	3.56%
E315	STEAM Accessory Electric Equipment	3.65%
E316	STEAM Miscellaneous Power Plant Equipment	3.82%
E302	HYDRO Franchises & Consents	3.53%
E331	HYDRO Structures and Improvements	2.98%
E332	HYDRO Reservoirs, Dams & Water	2.79%
E333	HYDRO Water Wheels, Turbines & Generators	3.49%
E334	HYDRO Accessory Electric Equipment	3.10%
E335	HYDRO Miscellaneous Power Plant Equipment	2.91%
E341	OTHER Structures and Improvements	1.12%
E342	OTHER Fuel Holders, Producers & Accessories	1.14%
E343	OTHER Prime Movers	1.10%
E344	OTHER Generators	1.24%
E345	OTHER Accessory Electric Equipment	1.62%
E346	OTHER Miscellaneous Power Plant Equipment	1.64%
<u>TRANSMISSION</u>		
E352	Structures and Improvements	3.09%
*E352	Structures and Improvements-Prod.	3.10%
E353	Station Equipment	3.25%
*E353	Station Equipment-Prod.	3.26%
E354	Towers and Fixtures	2.77%
E355	Poles and Fixtures	2.97%
E356	Overhead Conductors & Devices	2.96%
E357	Underground Conduit	2.39%
E358	Underground Conductors & Devices	1.45%
E359	Roads and Trails	2.24%

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Exhibit IX

DISTRIBUTION

E361	Structures and Improvements	3.00%
*E361	Structures and Improvements-Prod.	2.99%
E362	Station Equipment	3.10%
*E362	Station Equipment-Prod.	3.12%
E364	Poles, Towers and Fixtures	3.64%
E365	Overhead Conductors and Devices	3.43%
E366	Underground Conduit	3.22%
E367	Underground Conductor and Devices	3.21%
E368	Line Transformers	3.61%
E368	Line Transformers/Other	3.61%
E368	Line Capacitors	3.66%
E369	Overhead Services	3.93%
E369	Underground Services	3.93%
E370	Meters	4.00%
E370.1	Meters-Old	4.17%
E370.2	Meters-AMR	4.50%
E371	Customer Installations	2.84%
E373	Street Lighting	6.38%

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%

**Agreement to Coordinate Planning and
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Exhibit X

SPECIFICATIONS OF DEMAND AND ENERGY
CLASSIFICATION OF PRODUCTION EXPENSES

Uniform System
of Accounts
Account No.

Description

Classification
Demand 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	

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Exhibit 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

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.

	<u>DEVELOPMENT OF RATE BASE</u>	<u>NSP(Minn)</u>	<u>NSP(Wis)</u>
1.	Electric Plant in Service (Sched. 1)		
1.1	Pre-funded Allowance for Funds Used during Construction (Sched. 1.1)		
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.	Add: Electric Construction Work in Progress (Sched. 4.1)		
6.1	Add: Accumulated Amortization of Theoretical Reserve Surplus (Sched. 4.2)		
7.	Rate Base (Total lines 1 through 6.1)		
 <u>COST OF SERVICE - DEMAND RELATED</u>			
A. <u>Fixed Charges on Investment</u>			
8.	Return on Rate Base at Specified Rate of Return (Sched. 6)		
9.	Income Taxes (Sched. 7)		
10.	Depreciation & Amortization Expense (Sched. 8)		
10.1	Theoretical Reserve Surplus Amortization Expense (Sched. 8.1)		
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. <u>Fixed Power Production and Regional Market Expense</u>			
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. <u>Fixed Transmission Expense</u>			
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.

PRE-FUNDED ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION

Pre-funded Allowance for Funds Used during Construction (AFUDC) is an offsetting AFUDC calculation incorporating the effect of specific regulation whereby customers of a particular jurisdiction are paying for the financing costs during the construction phase of a project. Pre-funded AFUDC is accumulated in FERC Account 253. The amounts included to determine the charges among the Parties shall include those FERC jurisdictional amounts related to the transmission function whereby a current return is earned through the Midwest Independent Transmission System Operator, Inc.'s application of FERC Order 679 under Attachment O-NSP and Attachment GG and MM of the MISO Open Access Transmission, Energy and Operating Reserve Markets Tariff.

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.

ELECTRIC CONSTRUCTION WORK IN PROGRESS

Electric Construction Work in Progress is recorded in FERC Account 107. Electric Construction Work in Progress included for the determination of charges among the Parties shall include the average monthly construction expenditure balance limited to the net FERC jurisdictional portion of transmission projects that earn a current return through the Midwest Independent Transmission System Operator Inc.'s (MISO) application of FERC Order 679 under Attachment O-NSP and Attachments GG and MM of the MISO Open Access Transmission, Energy and Operating Reserve Markets Tariff (Tariff) and excluding AFUDC incurred post project eligibility as approved by FERC under the MISO Tariff.

ACCUMULATED AMORTIZATION OF THEORETICAL RESERVE SURPLUS

Accumulated Amortization of Theoretical Reserve Surplus is recorded in FERC Account 182.3 in accordance with the Minnesota Public Utilities Commission (MPUC) decision to amortize the NSP (Minn) theoretical reserve surplus (as developed in Table 1 below) over a period other than the average remaining life. In the 2013 test year Minnesota retail electric rate case (MPUC Docket No. E002/GR-12-961, order dated September 3, 2013), the MPUC ordered NSP (Minn) to amortize the theoretical reserve surplus for transmission, distribution, intangible and general assets over an eight-year period, commencing January 1, 2013. The NSP (Wis) portion of the reserve is \$26,674,271. The accumulated amortization amounts are based on the schedule provided in Exhibit V, Schedule 8.1.

This account is classified to the transmission, distribution, intangible and general functions of plant.

Functional Class	Total NSP (Minn) Actual to Theoretical Reserve Difference	NSP (Minn) State of Minnesota Actual to Theoretical Reserve Difference	NSP (Wis) Actual to Theoretical Reserve Difference
Intangible 1/	\$417,044	\$365,054	\$0
Transmission	200,466,880	149,597,398	26,645,321
Distribution 2/	109,362,353	109,362,353	18,051
General	6,727,378	5,888,716	10,899
Total Electric Utility	\$316,973,655	\$265,213,520	\$26,674,271

Notes:

1/ No Intangible reserve to NSP (Wis).

2/ Distribution reserve difference included under “NSP (Wis) Actual to Theoretical Reserve Difference” relates to Distribution serving system generation.

**Agreement to Coordinate Planning and
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**Exhibit V
Schedule 5**

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.

**Agreement to Coordinate Planning and
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**Exhibit V
Schedule 6**

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

(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:

$$\begin{aligned} M &= \text{_____} (N) \\ F &= \text{_____} (N) \\ M + F &= \text{_____} (N) \end{aligned}$$

Only North Dakota and Federal Income Taxes:

$$\begin{aligned} F &= \text{_____} (N) \\ D &= \text{_____} (N) \\ F + D &= \text{_____} (N) \end{aligned}$$

Only South Dakota and Federal Income Taxes:

$$S + F = \text{_____} (N)$$

NSP Company (Minnesota): Combined Minnesota, North Dakota, South Dakota

$$M + D + S + F = \text{_____} (N)$$

NSP Company (Wisconsin):

Wisconsin, Michigan and Federal Income Taxes

$$\begin{aligned} W &= \text{_____} (N) \\ MI &= \text{_____} (N) \\ F &= \text{_____} (N) \\ W + MI + F &= \text{_____} (N) \end{aligned}$$

- 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.

THEORETICAL RESERVE SURPLUS AMORTIZATION EXPENSE

NSP (Minn)'s demand related cost of service used in determining billings to NSP (Wis) shall include the following annual amounts for purposes of amortizing the NSP (Wis) portion (\$26,674,271) of the NSP (Minn) theoretical reserve surplus amortization, as calculated on Exhibit V, Schedule 4.2. These amounts are in accordance with the Minnesota Public Utilities Commission (MPUC) decisions listed in Exhibit V, Schedule 4.2. The September 3, 2013 MPUC order (Docket No. E002/GR-12-961) included an 8 year amortization period beginning January 1, 2013.

	<u>Theoretical Reserve Surplus Amortization Expense</u>			
<u>Year</u>	<u>Transmission</u>	<u>Distribution</u>	<u>General</u>	<u>Total</u>
2013	(\$3,330,665)	(\$2,256)	(\$1,362)	(\$3,334,283)

Theoretical Reserve Surplus Amortization Expense represents the current year amortization of the total theoretical depreciation reserve surplus over the amortization period determined by the MPUC.

Theoretical Reserve Surplus Amortization Expense included in determining the charges among the Parties is recorded in FERC Account 407.4 (creation of Regulatory Asset)¹, by the plant functional classifications.

¹. When the amortization is completed, NSP (Minn) and NSP (Wis) will make a section 205 filing with the Commission to add FERC Account 407.3 (reduction of Regulatory Asset), or other appropriate account, to this Schedule 8.1, to amortize the Theoretical Reserve Surplus regulatory asset over the average remaining lives of the functional classes of assets.

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%.

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Exhibit VIII

SPECIFICATION OF AVERAGE MONTHLY COINCIDENTAL PEAK DEMANDS

Calendar Year 2013 Contract Year

Monthly Coincidental Peak Demands (KW)

		<u>NSP (Minn)</u>	<u>NSP (Wis)</u>	<u>Total System</u>
2011	January	5582	1017	6599
	February	5488	1021	6509
	March	5205	943	6147
	April	4794	887	5682
	May	5239	998	6237
	June	7696	1283	8979
	July	8083	1348	9431
	August	7157	1078	8235
	September	7367	1231	8598
	October	5469	886	6355
	November	5170	928	6098
	December	<u>5389</u>	<u>1013</u>	<u>6403</u>
	Total	72,638	12,634	85,272
2012	January	5385	1031	6415
	February	5017	966	5983
	March	5055	921	5975
	April	4730	879	5608
	May	6089	947	7036
	June	7413	1148	8561
	July	7355	1317	8672
	August	7398	1274	8672
	September	6810	1243	8053
	October	5260	945	6206
	November	5244	997	6241
	December	<u>5557</u>	<u>1097</u>	<u>6653</u>
	Total	71,312	12,764	84,076
2013	January	5496	1062	6558
	February	5351	1039	6390
	March	5075	916	5991
	April	4757	949	5706
	May	6041	1077	7118
	June	7183	1299	8482
	July	7184	1298	8482
	August	7199	1282	8481
	September	6834	1253	8087
	October	5283	957	6240
	November	5256	1009	6265
	December	<u>5571</u>	<u>1107</u>	<u>6678</u>
	Total	71,229	13,249	84,478

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Exhibit IX

SPECIFICATION OF COMPOSITE DEPRECIATION RATES 2013 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)

<u>FERC ACCOUNT</u>	<u>DESCRIPTION</u>	<u>ANNUAL DEPRECIATION RATE PERCENT</u>
<u>PRODUCTION</u>		
E311	STEAM Structures and Improvements	3.15%
E312	STEAM Boiler Plant Equipment	3.42%
E314	STEAM Turbogenerator Units	3.52%
E315	STEAM Accessory Electric Equipment	3.00%
E316	STEAM Miscellaneous Power Plant Equipment	2.84%
E302	NUCLEAR Franchises & Consents	4.91%
E321	NUCLEAR Structures and Improvements	2.42%
E322	NUCLEAR Reactor Plant Equipment	2.60%
E323	NUCLEAR Turbogenerator Units	3.40%
E324	NUCLEAR Accessory Electric Equipment	2.55%
E325	NUCLEAR Miscellaneous Power Plant Equipment	2.24%
E325	NUCLEAR Decommissioning Minnesota Jurisdiction	0.00%
E325	NUCLEAR Decommissioning South Dakota Jurisdiction	0.59%
E325	NUCLEAR Decommissioning FERC Wisconsin Jurisdiction	0.00%
E325	NUCLEAR Decommissioning North Dakota Jurisdiction	0.00%
E325	NUCLEAR Decommissioning Wisconsin Jurisdiction	0.71%
E302	HYDRO Franchises & Consents	3.74%
E331	HYDRO Structures and Improvements	0.92%
E332	HYDRO Reservoirs, Dams and Water	2.91%
E333	HYDRO Water Wheels, Turbines & Generators	4.65%
E334	HYDRO Accessory Electric Equipment	4.64%
E335	HYDRO Miscellaneous Power Plant Equipment	1.09%
E340.1	OTHER Wind Rights	3.14%
E341	OTHER Structures and Improvements	3.08%
E342	OTHER Fuel Holders, Producers & Accessories	2.91%
E344	OTHER Generators	3.63%
E345	OTHER Accessory Electric Equipment	3.32%
E346	OTHER Miscellaneous Power Plant Equipment	3.52%

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Exhibit IX

TRANSMISSION

E352	Structures and Improvements	1.54%
*E352	Structures and Improvements-Prod.	1.54%
E353	Station Equipment	2.03%
*E353	Station Equipment-Prod.	2.03%
E354	Towers and Fixtures	1.88%
*E354	Towers and Fixtures-Prod.	1.92%
E355	Poles and Fixtures	2.15%
*E355	Poles and Fixtures-Prod.	2.19%
E356	Overhead Conductors & Devices	2.10%
*E356	Overhead Conductors & Devices-Prod.	2.14%
E357	Underground Conduit	1.37%
E358	Underground Conductors & Devices	1.84%

DISTRIBUTION

E361	Structures and Improvements	2.28%
*E361	Structures and Improvements-Prod.	2.18%
E362	Station Equipment	2.19%
*E362	Station Equipment-Prod.	2.18%
E364	Poles, Towers and Fixtures	4.64%
E365	Overhead Conductors and Devices	2.79%
E366	Underground Conduit	2.10%
E367	Underground Conductor and Devices	2.07%
E368	Line Transformers	3.07%
E368	Line Capacitors	4.53%
E369	Overhead Services	4.50%
E369	Underground Services	3.12%
E370	Meters	5.75%
E370.1	Meters-Old	0.00%
E373	Street Lighting and Signal Systems	4.59%

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Exhibit IX

GENERAL - ELECTRIC

E303	Intangible Plant – 5 Year	20.00%
E390	Structures and Improvements	2.29%
E391	Office Furniture and Equipment	5.22%
E391	Network Equipment	25.00%
E392	Transportation Equipment – Auto	16.40%
E392	Transportation Equipment – Light Truck	9.15%
E392	Transportation Equipment – Trailers	8.38%
E392	Transportation Equipment – Heavy Trucks	7.62%
E393	Stores Equipment	5.34%
E394	Tools, Shop and Garage Equipment	6.44%
E394	Hand Held Meter Readers	0.00%
E395	Laboratory Equipment	8.39%
E396	Power Operated Equipment	8.30%
E397	Communication Equipment	10.50%
E397	Communication Equipment-AMR	6.70%
E398	Miscellaneous Equipment	7.32%

SPECIFICATION OF COMPOSITE DEPRECIATION RATES

NSP(Wis):

<u>FERC ACCOUNT</u>	<u>DESCRIPTION</u>	<u>ANNUAL DEPRECIATION RATE PERCENT</u>
<u>PRODUCTION</u>		
E311	STEAM Structures and Improvements	3.28%
E312	STEAM Boiler Plant Equipment	3.47%
E314	STEAM Turbogenerator Units	3.56%
E315	STEAM Accessory Electric Equipment	3.65%
E316	STEAM Miscellaneous Power Plant Equipment	3.82%
E302	HYDRO Franchises & Consents	3.53%
E331	HYDRO Structures and Improvements	2.98%
E332	HYDRO Reservoirs, Dams & Water	2.79%
E333	HYDRO Water Wheels, Turbines & Generators	3.49%
E334	HYDRO Accessory Electric Equipment	3.10%
E335	HYDRO Miscellaneous Power Plant Equipment	2.91%
E341	OTHER Structures and Improvements	1.12%
E342	OTHER Fuel Holders, Producers & Accessories	1.14%
E343	OTHER Prime Movers	1.10%
E344	OTHER Generators	1.24%
E345	OTHER Accessory Electric Equipment	1.62%
E346	OTHER Miscellaneous Power Plant Equipment	1.64%
<u>TRANSMISSION</u>		
E352	Structures and Improvements	3.09%
*E352	Structures and Improvements-Prod.	3.10%
E353	Station Equipment	3.25%
*E353	Station Equipment-Prod.	3.26%
E354	Towers and Fixtures	2.77%
E355	Poles and Fixtures	2.97%
E356	Overhead Conductors & Devices	2.96%
E357	Underground Conduit	2.39%
E358	Underground Conductors & Devices	1.45%
E359	Roads and Trails	2.24%

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Exhibit IX

DISTRIBUTION

E361	Structures and Improvements	3.00%
*E361	Structures and Improvements-Prod.	2.99%
E362	Station Equipment	3.10%
*E362	Station Equipment-Prod.	3.12%
E364	Poles, Towers and Fixtures	3.64%
E365	Overhead Conductors and Devices	3.43%
E366	Underground Conduit	3.22%
E367	Underground Conductor and Devices	3.21%
E368	Line Transformers	3.61%
E368	Line Transformers/Other	3.61%
E368	Line Capacitors	3.66%
E369	Overhead Services	3.93%
E369	Underground Services	3.93%
E370	Meters	4.00%
E370.1	Meters-Old	4.17%
E370.2	Meters-AMR	4.50%
E371	Customer Installations	2.84%
E373	Street Lighting	6.38%

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%

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Exhibit X

SPECIFICATIONS OF DEMAND AND ENERGY
CLASSIFICATION OF PRODUCTION EXPENSES

Uniform System
of Accounts
Account No.

Description

Classification
Demand 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	

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Exhibit 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