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Public Service Commission of Wisconsin
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Xcel Energy

414 Nicollet Mall
Minneapolis, Minnesota 55401

March 15, 2023

Via eTariff

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 and
Northern States Power Company, a Wisconsin corporation
Docket No. ER23-____-000
Interchange Agreement – Annual Update
Revised Tariff Pages Effective January 1, 2023

Dear Ms. Bose:

Pursuant to Federal Power Act Section 205, 16 U.S.C. § 824d, and Section 35.13 of the Rules and Regulations of the Federal Energy Regulatory Commission ("Commission" or "FERC"), 18 C.F.R. § 35.13 (2022), Northern States Power Company, a Minnesota corporation ("NSPM") and Northern States Power Company, a Wisconsin corporation ("NSPW") (jointly the "NSP Companies"), submit revisions to 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 revisions to the Interchange Agreement are submitted in accordance with Order No. 714[1] and the Commission's eTariff filing requirements.

Although the NSP Companies are filing revisions to all of the Exhibits to the Interchange Agreement to comply with the Commission's eTariff processes (since the Interchange Agreement has not been filed in section format), only the following Interchange Agreement exhibits are being restated or revised:

Exhibit I
Exhibit II
Exhibit III
Exhibit IV
Exhibit V
Exhibit VI
Exhibit VII

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[1] *Electronic Tariff Filings,* Order No. 714, 124 FERC ¶ 61,270 (2008); *order on clarification*, Order No. 714-A, 147 FERC ¶ 61,115 (2014).

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Exhibit VIII
Exhibit IX

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 annual updates to Exhibits VII, VIII, and IX, the NSP Companies also propose modifications to Exhibits I, II, III, and IV to reflect new transmission loss multipliers based on a 2022 system loss study; modifications to Exhibits II, IV, V, and VI related to a proposed state retail tariff; and certain administrative tariff text modifications in Exhibits V and IX.

Marked versions of the complete Exhibit tariff pages showing the proposed revisions to the Interchange Agreement are included with this filing as an attachment in the XML package. The NSP Companies propose the revised tariff sheets be effective January 1, 2023, and respectfully request any waiver necessary for the tariff sheets to be effective on the date requested, so the NSP System cost allocations may be in effect for the full 2023 fiscal year.

A. Background

NSPM is an investor-owned Minnesota corporation engaged in, *inter alia*, 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 an investor-owned Wisconsin corporation engaged in, *inter alia*, 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"). The NSP Companies are transmission-owning members of the Midcontinent Independent System Operator, Inc. ("MISO"), and are market participants and use transmission services pursuant to the MISO Open Access Transmission, Energy and Operating Reserve Markets Tariff ("MISO Tariff") on file with and accepted by the Commission. Xcel Energy Services Inc. ("XES") is the centralized service company for the Xcel Energy holding company system and represents the Xcel Energy Operating Companies in proceedings before the Commission.[2]

The Interchange Agreement is a formula rate which provides for coordinated planning of the generation and transmission resources of the NSP Companies and the resulting 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 restate or update certain exhibits to the Interchange

[2] The other Xcel Energy Operating Companies are Public Service Company of Colorado and Southwestern Public Service Company.

Agreement.[3] The 2022 annual filing, which updated Exhibits I, II, III, IV, VII, VIII and IX and made certain other Exhibit revisions, was accepted effective January 1, 2022, by letter order dated May 3, 2022 in Docket No. ER22-1234-000.[4]

Neither of the NSP Companies serve any wholesale requirements production customers under rate schedules subject to Commission jurisdiction; rather, the NSP Companies serve only retail native load customers. As such, the Interchange Agreement solely affects the allocation of system costs between two affiliated and fully rate-regulated electric utilities for recovery in the retail rates of the NSP Companies.

B. Statement of Basis for Revised Tariff Sheets

As noted, 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.

Section C of this transmittal letter (below) discusses the proposed revisions to the Interchange Agreement tariff pages in more detail. Also attached as parts of this filing are appendices providing various supporting schedules and information.

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[3] *See* Article XIV of the Interchange Agreement. In the 2001 annual filing, the NSP Companies restated the Interchange Agreement in its entirety effective January 1, 2001. The 2011 annual update, filed in Docket Nos. ER11-3234-000 and ER11-3235-000, submitted the Interchange Agreement in eTariff format. The Interchange Agreement was restated in eTariff format in Docket No. ER16-1429-000 to reflect implementation of new eTariff software by XES and the Xcel Energy Operating Companies. *See Northern States Power Company, a Minnesota corporation*, Docket No. ER16-1415-000 *et al*. (June 2, 2016) (delegated letter order).

[4] *See Northern States Power Company, a Minnesota corporation*, Docket No. ER22-1234-000 (May 3, 2022) (delegated letter order).

C. Proposed Revised Tariff Sheets Effective January 1, 2023

1. Exhibits I, II, III and IV – Updated Transmission Loss Multipliers

In Docket No. ER22-1234-000, the NSP Companies filed an electrical loss analysis which updated the demand and energy transmission loss ratios ("transmission loss multipliers") used in the Interchange Agreement for allocation of demand and energy between the NSP Companies.[5] As discussed in the Affidavit of Mr. Mark J. Wehlage filed with the 2018 annual update to the Interchange Agreement in Docket No. ER18-1117-000, the NSP Companies anticipated updating the loss ratios periodically.[6] At this time, the NSP Companies propose to revise the loss factors effective January 1, 2023 using the same methodology described in Docket No. ER22-1234-000. The current and proposed transmission loss factors are as follows:

	Current		Proposed	
Loss Ratios	NSPM	NSPW	NSPM	NSPW
Demand	3.8%	4.7%	3.8%	4.4%
Energy	3.8%	5.0%	3.9%	5.2%

The demand and energy transmission loss multipliers stated in the Interchange Agreement Exhibits are calculated by subtracting 1 minus the applicable loss ratio. For example, the new NSPW demand loss multiplier equals 1.0 minus 0.044, or 0.956. The current and revised transmission loss multipliers are:

	Current		Proposed	
Loss Multipliers	NSPM	NSPW	NSPM	NSPW
Demand	0.962	0.953	0.962	0.956
Energy	0.962	0.950	0.961	0.948

The loss ratios were developed using four years (2018 – 2021) of actual information collected from the NSP System energy management system and state estimator system. The proposed transmission loss ratios affect only the allocation of NSP System demand and energy costs between the NSP Companies, and do not affect the loss ratios applied by MISO for transmission services under the MISO Tariff. The impact of the proposed transmission loss multipliers is shown in Appendix A and discussed further in Section C.3 below. Appendix B is a copy of the updated loss study in support of the proposed transmission loss ratio and transmission loss multipliers.

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[5] *See Northern States Power Company (Minnesota),* Interchange Agreement Annual Update, Docket No. ER22-1234-000, Transmittal Letter at 3-4 and App. B (filed Mar. 9, 2022).

[6] *See Northern States Power Company (Minnesota),* Interchange Agreement – Annual Update, Docket No. ER18-1117-000, Exhibit NSP-001 (filed Mar. 15, 2018).

2. Exhibits II, IV, V and VI

The NSP Companies propose modifications to Exhibits II, IV, V and VI to exclude the portion of costs related to production resources (either owned or a purchased power agreement) that are procured for a retail customer and direct assigned to participating customers under a state retail tariff. In addition, the NSP Companies propose administrative tariff updates to clarify the inclusion of Production Tax Credits in the computation of Federal and State Income Taxes. Each change is further described below.

a. Tariff Changes for New Dedicated Renewable Resource Program

In July 2022, NSPW submitted an application with the Public Service Commission of Wisconsin ("PSCW") seeking approval to offer a new voluntary renewable energy rider ("RER") tariff to certain retail customers. The program is targeted at retail commercial and industrial customers seeking dedicated renewable resources ("DRR") to meet their individual energy goals. NSPW expects to receive PSCW approval of the RER tariff by April 2023 and anticipates executing service agreements with customers beginning June 2023 with the first projects placed into service in 2024. NSPW's application with the PSCW proposed a 50-megawatt ("MW") capacity limit but as part of the approval process NSPW is seeking to increase the cap of the proposed program to 200 MW.

Eligible customers would have the option to purchase all or a portion of the energy generated from a DRR that is procured by NSPW. NSPW anticipates the procured DRR to be either an owned asset or a power purchase agreement. The NSP Companies propose tariff changes in this filing that will provide for the exclusion from the Interchange Agreement the costs associated with DRRs in support of the RER program.[7] While the NSPW program is the impetus for these tariff changes, the NSP Companies anticipate NSPM may consider a similar tariff to customers in the future. Accordingly, the NSP Companies have proposed tariff language that is not specific to NSPW. A complete listing of the proposed modifications is provided below.

1) Exhibit II – Formula Type Procedures for Development of Amounts of Energy Sales

The NSP Companies propose to add language to Exhibit II to remove energy requirements that are fulfilled by energy resources that are direct assigned to participating customers for ratemaking purposes under state retail tariffs.

[7] To illustrate, if 75 percent of a procured renewable resource is dedicated to the program, the NSP Companies intend to exclude 75 percent of the costs of that resource from the Interchange Agreement billings. The remaining 25 percent would be treated as a NSP System resource and included in the Interchange Agreement billings between the NSP Companies.

2) Exhibit IV – Formula Type Procedures for Development of Unit Rates for Energy Sales

   The NSP Companies propose to add language to Exhibit IV to remove energy requirements that are fulfilled by energy resources that are direct assigned to participating customers for ratemaking purposes under state retail tariffs.

3) Exhibit V – Formula Type Procedures for Development of Demand Related Costs
   - Exhibit V, Schedule 1– Electric Plant in Service;
   - Exhibit V, Schedule 2 – Accumulated Provision for Depreciation;
   - Exhibit V, Schedule 3 – Accumulated Deferred Income Taxes;
   - Exhibit V, Schedule 7, Page 3 – Deductions for Computation of Federal and State Income Taxes;
   - Exhibit V, Schedule 8 – Depreciation and Amortization Expense;
   - Exhibit V, Schedule 9 – Provision for Deferred Income Taxes;
   - Exhibit V, Schedule 10 – Property Taxes;
   - Exhibit V, Schedule 11 – Insurance Expense;
   - Exhibit V, Schedule 12 – Fixed Production Operating and Maintenance Expense

   The NSP Companies propose modifications to Exhibit V to add language to exclude amounts related to assets that are direct assigned to participating customers for ratemaking purposes under state retail tariffs in the calculation of demand related costs.

4) Exhibit VI – Formula Type Procedures for Development of Energy Related Costs
   - Exhibit VI, Schedule 2 – Variable Production Operating and Maintenance Expenses;
   - Exhibit VI, Schedule 3 – Net Purchased Power Energy Costs

   The NSP Companies propose modifications to Exhibit VI to add language to exclude amounts related to assets or purchased power energy costs that are direct assigned to participating customers for ratemaking purposes under state retail tariffs in the calculation of energy related costs.

b. Tariff Changes for Production Tax Credits

The NSP Companies are also proposing tariff revisions to clarify the inclusion of Production Tax Credits in the computation of Federal and State Income Taxes. NSPM has claimed a federal income tax credit based on the kilowatt-hours of electricity produced at its eligible wind energy facilities and has consistently included those credits in its computation of income taxes in the determination of fixed charges on the production investment. The changes to Exhibit V described below are intended to clarify the tariff language, consistent with the NSP Companies' practice.

1) Exhibit V, Schedule 7, Page 1 – Computation of Federal and State Income Taxes

   The NSP Companies propose to add two new lines (lines 4.1 and 10.1) to expressly include Production Tax Credits in the formula for the calculation of federal and state income taxes.

2) Exhibit V, Schedule 7, Page 2 – Determination of Federal and State Composite Income Tax Rates

   The NSP Companies propose to add language to Note 1 to clarify that Production Tax Credits are ignored in the computation of composite tax rates.

3) Exhibit V, Schedule 7, Page 3 – Deductions for Computation of Federal and State Income Taxes

   The NSP Companies propose to add language on Production Tax Credits similar to existing tariff language for the Investment Tax Credit Flow Through but noting the exclusion of amounts that are direct assigned to participating customers under the RER tariff as described above.

3. <u>Exhibit VIII – Specification of Average Monthly Peak Demands</u>

Exhibit VIII sets forth the specification of average monthly coincident peak demands for calendar year 2023 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. ER22-1234-000 and prior annual updates. Coincident peak demands are based upon three years of data consisting of 18 months of actual and 18 months of projected peak demands.

Enclosed with this filing as Appendix A, Page 1 is the calculation of the 2023 36-month coincident peak demand ratios for each of the NSP Companies using the proposed loss multipliers. These demand ratios are based on the average monthly coincident peak demands for calendar years 2021 – 2023 as set forth in Exhibit VIII. Appendix A, Page 2, is a statement of the financial impacts of these coincident peak demands on each of the NSP Companies, using the proposed loss multipliers. The table on the bottom of Appendix A, Page 2 quantifies the impact on the demand cost allocation of the proposed transmission loss multipliers compared to the current loss multipliers. While Appendix A 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.

4. Exhibit IX – Specification of Composite Depreciation Rates

Exhibit IX sets forth a specification of the composite depreciation rates currently approved for the NSP Companies by their respective state regulatory agencies. The modifications reflect, *inter alia*, changes in service lives, net salvage rates and mortality curves approved by the state regulatory bodies which have jurisdiction over NSPM and NSPW.[8] In addition to the updated rates on Exhibit IX, the NSP Companies propose an administrative tariff text modification to correct the spelling of "Transportation" on the NSPW schedule for FERC Account E392.

The Minnesota Public Utilities Commission ("MPUC"), the North Dakota Public Service Commission ("NDPSC") and the South Dakota Public Utilities Commission ("SDPUC") approved NSPM's currently effective depreciation rates in the following dockets:

- MPUC Docket No. E002/M-20-855, 2022-2024 Triennial Nucler Decommissioning Study & Assumptions, order dated August 24, 2022; MPUC Docket No. E,G002/D-19-723, 2020 Annual Review of Remaining Lives, order dated September 2, 2021; MPUC Docket No. E002/GR-15-826, Application for Authority to Increase Electric Rates in Minnesota, order dated June 12, 2017; MPUC Docket No. E002/M-19-688, Petition for Approval of True-up Mechanisms, order dated March 13, 2020; MPUC Docket No. E002/M-20-743, Petition for Approval of 2021 True-up Mechanisms, order dated April 2, 2021; MPUC Docket No. E,G002/D-17-581, Electric and Gas Five Year Transmission, Distribution and General Depreciation Study, order dated May 4, 2018; MPUC Docket No. E,G002/D-20-635, Annual Update of Remaining Lives and Depreciation Rates for Transmission, Distribution and General Accounts, order dated March 24, 2021; and MPUC Docket No. E002/M-17-828, 2019-2021 Triennial Nuclear Plant Decommissioning Accrual proceeding, first order dated January 7, 2019 and subsequent compliance order dated March 13, 2020;
- NDPSC Case No. PU-20-441, Application for Authority to Increase Rates for Electric Service in North Dakota, order dated August 18, 2021; and
- SDPUC Docket No. EL14-058, Application for Authority to Increase Electric Rates in South Dakota, settlement stipulation dated June 1, 2015, affirmed by the order dated June 16, 2015.

[8] The annual composite depreciation rates for production are calculated based on forecasted depreciation expense accruals and average plant balances. The forecasted depreciation expense is calculated based on approved remaining life depreciation lives and rates certified by the respective state Commissions for NSPM and NSPW. Rates for transmission, distribution, and general functions are the approved rates for each plant account. NSPM's rates are a blended calculation of the approved rates in Minnesota, North Dakota, and South Dakota. NSPW's approved rates are the same for both the Wisconsin and Michigan jurisdictions. Even though individual depreciation lives may not have changed from the previous year, the depreciation rates in Exhibit IX are composite rates and a change in plant balances can cause a change in the rate by FERC Account.

The PSCW and the Michigan Public Service Commission ("MPSC") approved NSPW's currently effective depreciation rates in the following dockets:

- PSCW Docket No. 4220-DU-111, Approval of Adjustments to its Proposed Remaining Lives Depreciation and Revised Depreciation Rates for Test Years 2022-2023, order dated August 6, 2021; and PSCW Docket No. 4220-UR-125, Application for Authority to Adjust Electric and Natural Gas Rates in Wisconsin, order dated December 20, 2021; and
- MPSC Docket No. U-21121, Application for Recognition of Revised Depreciation Rates, order dated October 13, 2021.

As detailed in Section G below, the new, relevant initial filings and state Commission orders establishing revised depreciation rates for each of the NSP Companies are attached as Appendices D and E. Prior state depreciation petitions and orders referenced above were submitted to the Commission in Docket Nos. ER16-1206-000, ER18-1117-000, ER19-1340-000, ER20-1249-000, ER21-1401-000, and ER22-1234-000. The NSP Companies respectfully request that the Commission waive any requirement to refile the state regulatory depreciation orders previously filed with the Commission and available in eLibrary or eTariff.

Appendix A, Page 3 provides a statement of the impacts of the changes to depreciation rates on each of the NSP Companies.

5. <u>Exhibit VII – Specification of Rate of Return on Common Equity</u>

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 2023 from the level accepted in Docket No. ER22-1234-000, so a statement of impact on each of the NSP Companies is not required.

D. Additional Information

The Commission in February 2018 approved an application in Docket No. EC17-166-000 under which Benson Power, LLC ("Benson Power") would sell and NSPM would acquire a 62.3 MW (nameplate) biomass-fired electric generation plant, terminate a multi-year Power Purchase Agreement between NSPM and Benson Power, and then shut down and dismantle the Benson Power Facility and remediate the plant site (all collectively the "Benson Transaction").[9] On June 14, 2018, as supplemented on July 2, 2018, the NSP Companies filed modifications to certain exhibits in the Interchange Agreement to allow NSPM to allocate to NSPW and recover a share

[9] *Northern States Power Company, a Minnesota corporation et al.*, 162 FERC ¶ 61,162 (2018).

of the costs incurred by NSPM for the Benson Transaction. These modifications were accepted effective June 29, 2018, by letter order dated August 10, 2018 in Docket No. ER18-1786-000.[10]

As discussed in the Direct Testimony of Ms. Karen L. Everson, Exhibit No. NSP-001 ("Everson Testimony") in Docket No. ER18-1786-000, the NSP Companies proposed to include in the annual Interchange Agreement filing an appendix setting forth the annual Benson Power revenue requirement based on current project cost estimates.[11] As shown in Appendix C-1, the NSP Companies estimate that NSPM will bill NSPW approximately $2.1 million in revenue requirements in 2023, reflecting amortization expense of approximately $1.6 million and a cost of capital of 6.86 percent.

Consistent with the Direct Testimony of Ms. Anne E. Heuer, Exhibit No. NSP-001 ("Heuer Testimony") in Docket No. ER15-698-000, the NSP Companies proposed to include in the annual Interchange Agreement filing an appendix calculating the current year annual revenue associated with the terminated Prairie Island Extended Power Uprate ("PI EPU") project.[12] As shown in Appendix C-2, the NSP Companies estimate that NSPM will bill NSPW approximately $0.6 million in revenue requirements in 2023.

Finally, in Docket No. ER20-1249-000 the NSP Companies filed modifications to certain exhibits in the Interchange Agreement to share plant acquisition adjustments between the two companies that are related to the production function. In that filing the NSP Companies proposed to include in the annual Interchange Agreement filing an appendix setting forth the acquisition adjustments that will be included in the formula. These modifications were accepted effective January 1, 2020, by letter order dated May 5, 2020 in Docket No. ER20-1249-000.[13] As shown in Appendix C-3, the NSP Companies anticipate inclusion of acquisition adjustments for three wind facilities in the billings from NSPM to NSPW in 2023.

E. <u>E-Tariff Compliance</u>

NSPM is submitting the proposed tariff changes on behalf of the NSP Companies. As described in further detail in Docket Nos. ER11-3234-000 and ER11-3235-000, the NSP

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[10] *See Northern States Power Co. (Minnesota), Northern States Power Co. (Wisconsin)*, Docket No. ER18-1786-000 (Aug. 10, 2018) (delegated letter order).

[11] *See Northern States Power Co. (Minnesota), Northern States Power Co. (Wisconsin),* Interchange Agreement - Recovery of Benson Power Plant Termination Costs, Docket No. ER18-1786-000, Everson Testimony at 21 (June 14, 2018).

[12] *See Northern States Power Co. (Minnesota), Northern States Power Co. (Wisconsin)*, Interchange Agreement – Prairie Island Extended Power Uprate Costs, Docket No. ER15-698-000, Exhibit No. NSP-001, Heuer Testimony at 19 (Dec. 22, 2014).

[13] *See Northern States Power Company, a Minnesota corporation*, Docket No. ER20-1249-000 (May 5, 2020) (delegated letter order).

Companies selected NSPM as the party to submit the annual updates to the Interchange Agreement. NSPW's Certificate of Concurrence was filed in Docket No. ER11-3235-000.

F. <u>Request for Acceptance for Filing, Requests for Waiver</u>

The NSP Companies request the Commission accept the revised tariff sheets for filing effective January 1, 2023. The NSP Companies request a waiver of the Commission's notice requirements pursuant to 18 C.F.R. § 35.11, 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.[14]

In *Central Hudson Gas & Electric Corporation,*[15] 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 fully rate-regulated electric utilities. In addition, neither of the NSP Companies serves any wholesale requirements customers whose rates would be affected by the changes proposed herein; and

(2) The Commission has regularly accepted the annual revisions to the Interchange Agreement effective January 1 of the filing year even though the revisions were not filed until sometime after January 1.

The NSP Companies also request that the Commission waive any requirement to refile depreciation supporting data, specifically state regulatory filings and orders affecting depreciation rates that have been previously filed with the Commission and are available in eLibrary. This information has already been filed with the Commission in Docket Nos. ER16-1206-000, ER18-1117-000, ER19-1340-000, ER20-1249-000, ER21-1401-000, and ER22-1234-000. The NSP Companies respectfully request that the Commission grant the waiver since the supporting information is available to staff and interested stakeholders through the Commission's eLibrary system.

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14 *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.

15 60 FERC ¶ 61,106 (1992), *reh'g denied* 61 FERC¶ 61,089 (1992).

G. <u>Contents of Filing; Notice; Service</u>

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

a. This transmittal letter;

b. The proposed revised Interchange Agreement Exhibits in clean format as an attachment in the XML package, with a January 1, 2023 effective date;

c. The proposed revised Interchange Agreement Exhibits in marked format, showing changes to the exhibits since they were accepted for filing in Docket No. ER22-1234-000; and

d. The following appendices:

   i. Appendix A, which sets forth the proposed 2023 36-month coincident peak demands, the financial impact of these proposed demands on each of the NSP Companies, and a statement of impact regarding depreciation rates on each of the NSP Companies;

   ii. Appendix B, a copy of the 2022 NSP System loss study supporting the proposed transmission loss ratios and the methodology used to calculate the proposed ratios;

   iii. Appendix C-1, which sets forth the 2023 Benson Power revenue requirement based on current project cost estimates, Appendix C-2, which sets forth the 2023 PI EPU revenue requirement, and Appendix C-3, which sets forth the production related acquisition adjustments based on current plant in-service dates;

   iv. Appendix D, NSPM's petition for approval of 2022-2024 Triennial Nuclear Decommissioning Study & Assumptions in MPUC Docket No. E002/M-20-855;

   v. Appendix E, the order issued August 24, 2022 in MPUC Docket No. E002/M-20-855 approving the 2022-2024 Triennial Nuclear Decommissioning Study & Assumptions; and

   vi. Appendix F, the Service List for this filing.

A copy or electronic notice of this filing will be sent by e-mail to all State Commissions with jurisdiction over the NSP Companies (see Appendix D). The NSP Companies will also provide a courtesy copy of this filing to the Director, Division of Electric Power Regulation – Central. A copy of this filing will be available for public inspection at the offices of NSPM at 414 Nicollet Mall – 401—7th , Minneapolis, Minnesota; and NSPW's office at 1414 W. Hamilton Avenue, Eau Claire, Wisconsin.

H. Correspondence and Communications

Please send all communications and correspondence in this docket to:

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I. Conclusion

The NSP Companies thus respectfully request the Commission accept the revised tariff sheets to the Interchange Agreement for filing effective January 1, 2023. Please direct any questions regarding this filing to the undersigned (715-737-2417) or Mr. David E. Pettit (303-294-2599).

Sincerely,

/s/ *Karen L. Everson*

Karen L. Everson
Director, Utility Accounting
Xcel Energy Services Inc., on behalf of
Northern States Power Company, a Minnesota corporation and
Northern States Power Company, a Wisconsin corporation

Enclosures

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:

0.962 for NSP(Minn)
0.~~953~~956 for NSP(Wis)

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

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

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

FORMULA TYPE PROCEDURES FOR DEVELOPMENT OF AMOUNTS OF ENERGY 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 current month, excluding energy requirements fulfilled by energy resources required by certain state energy policies ~~or~~ , statutes, or state retail tariffs that are direct assigned to participating customers for ratemaking purposes. [1/] The measured monthly energy requirements shall be adjusted by a Transmission Loss Multiplier.

"Transmission Loss Multipliers" are equal to:

0.~~962~~ 961 for NSP(Minn)
0.~~950~~ 948 for NSP(Wis)

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

[1/] Including, but not limited to, the NSP (Minn) Windsource® program.

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

FORMULA TYPE PROCEDURES FOR DEVELOPMENT OF UNIT RATES FOR 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:

0.962 for NSP(Minn)
0.~~953~~ 956 for NSP(Wis)

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

FORMULA TYPE PROCEDURES FOR DEVELOPMENT OF UNIT RATES FOR ENERGY 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 current month excluding energy requirements fulfilled by energy resources required by certain state energy policies ~~or~~, statutes, or state retail tariffs that are direct assigned to participating customers for ratemaking purposes.[1/] The measured monthly energy requirements shall be adjusted by a Transmission Loss Multiplier.

"Transmission Loss Multipliers" are equal to:

0.~~962~~961 for NSP(Minn)
0.~~950~~948 for NSP(Wis)

[1/] Including, but not limited to, the NSP (Minn) Windsource® program.

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

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)		
1.1	Pre-funded Allowance for Funds Used during Construction (Sched. 1.1)		
1.2	Electric Plant Acquisition Adjustments (Sched. 1.2)		
2.	Accumulated Provision for Depreciation (Sched. 2)		
2.1	Accumulated Provision for Amortization of Electric Plant Acquisition Adjustments (Sched. 2.1)		
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)		

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)
10.1 Theoretical Reserve Surplus Amortization Expense (Sched. 8.1)
10.2 Prairie Island Extended Power Uprate Amortization Revenue Requirement (Sched. 8.2)
10.3 Monticello Life Cycle Management / Extended Power Uprate Project Return on Rate Base Adjustment (Sched. 8.3)
10.4 Benson Power Termination Amortization Revenue Requirement (Sched. 8.4)
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)

FORMULA TYPE PROCEDURES FOR DEVELOPMENT OF DEMAND RELATED COSTS

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. Electric Plant in Service balances will exclude amounts related to assets that are direct assigned to participating customers for ratemaking purposes under state retail tariffs. The following FERC Accounts shall be included:

1. Intangible Plant Investment
   Water power and nuclear plant relicensing investment recorded in FERC Account 302. Intangible software directly related to the production and transmission functions recorded in FERC Account 303 and as agreed among the Parties.

2. Production Plant Investment
   Production plant investment recorded in FERC Accounts 310 through 348.

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 Midcontinent Independent System Operator, Inc.'s (MISO) 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.

ELECTRIC PLANT ACQUISITION ADJUSTMENTS

Electric Plant Acquisition Adjustments is recorded in FERC Account 114. The amounts included to determine the charges among the Parties shall include those amounts related to the production function and as agreed among the Parties.

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. Accumulated Provision for Depreciation balances will exclude amounts related to assets that are direct assigned to participating customers for ratemaking purposes under state retail tariffs.

These accounts are classified to the intangible, 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 PROVISION FOR AMORTIZATION OF ELECTRIC PLANT ACQUISITION ADJUSTMENTS

Accumulated Provision for Amortization of Electric Plant Acquisition Adjustments is recorded in FERC Account 115. The amounts included to determine the charges among the Parties shall include those amounts related to the production function and as agreed among the Parties.

ACCUMULATED DEFERRED INCOME TAXES

Accumulated Deferred Income Taxes included in FERC Accounts 190 and 281-283 are classified to the intangible, production, nuclear fuel, transmission, distribution and general plant functions in the same detail as the original cost of the plant in service. Accumulated Deferred Income Tax balances will exclude amounts related to assets that are direct assigned to participating customers for ratemaking purposes under state retail tariffs.

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 Midcontinent Independent 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 (MPUC Docket No. E002/GR-12-961, order dated September 3, 2013) to amortize the NSP (Minn) theoretical reserve surplus (as developed in the table below) beginning January 1, 2013 over a period other than the average remaining life. The NSP (Wis) portion of the theoretical reserve surplus is $26,674,271.

In the NSP (Minn) 2014 test year Minnesota retail electric rate case (MPUC Docket No. E002/GR-13-868, order dated May 8, 2015), the MPUC approved the balance of the remaining theoretical reserve surplus for transmission, distribution, intangible and general functions of plant to be amortized in a pattern of 50 percent for 2014, 30 percent for 2015, and 20 percent for 2016. The regulatory asset set-up was completed at the end of 2016 as detailed in the table below.

In the NSP (Minn) 2017 Annual Review of Remaining Lives (MPUC Docket No. E,G002/D-17-147, order dated February 8, 2018), the MPUC approved the amortization rates of the regulatory asset created through the amortization of the NSP (Minn) theoretical reserve surplus, effective January 1, 2017.

The accumulated amortization amounts are based on the schedule provided in Exhibit V, Schedule 8.1.

Balances as of 12/31/2016			
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.

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.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy | **Exhibit V Schedule 6**

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 6 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, or such date after January 1 determined by the Coordinating Committee, 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 such 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 of 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)
4.1 Production Tax Credit (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)
10.1 Production Tax Credit (Line 4.1)

11. Preferred Dividend Credit (Line 7)

12. Federal and State Income Taxes

(1) $\dfrac{\text{Composite Tax Rate (2)}}{\text{1 - Composite Tax Rate (2)}}$ = 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, Production 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.

Production Tax Credit

The Production Tax Credit is recorded in FERC Account 409.1. The amounts included for the calculation of income taxes are those amounts attributable to the plant investment related to the production function. Production Tax Credit will exclude amounts related to assets that are direct assigned to participating customers for ratemaking purposes under state retail tariffs.

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. Income Tax Depreciation will exclude amounts related to assets that are direct assigned to participating customers for ratemaking purposes under state retail tariffs.

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. Depreciation and amortization expense will exclude amounts related to assets that are direct assigned to participating customers for ratemaking purposes under state retail tariffs.

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 related to the theoretical reserve surplus. Theoretical Reserve Surplus Amortization Expense included in determining the charges among the Parties is recorded in FERC Account 407.4 (creation of Regulatory Asset) and FERC Account 407.3 (amortization of Regulatory Asset) by the plant functional classifications.

In the NSP (Minn) 2013 test year Minnesota retail electric rate case (MPUC Docket No. E002/GR-12-961, order dated September 3, 2013), the MPUC approved the amortization of the theoretical reserve surplus over a period other than the average remaining life. The NSP (Wis) portion of the theoretical reserve surplus is $26,674,271.

In the NSP (Minn) 2014 test year Minnesota retail electric rate case (MPUC Docket No. E002/GR-13-868, order dated May 8, 2015), the MPUC approved the accelerated amortization of the theoretical reserve surplus. Specifically, the MPUC approved the balance of the remaining theoretical reserve surplus for transmission, distribution, intangible and general functions of plant be amortized in a pattern of 50 percent for 2014, 30 percent for 2015, and 20 percent for 2016. Please refer to Exhibit V, Schedule 4.2. As of December 31, 2016, the theoretical reserve surplus was fully amortized.

In the NSP (Minn) 2017 Annual Review of Remaining Lives (MPUC Docket No. E,G002/D-17-147, order dated February 8, 2018), the MPUC approved the amortization rates to unwind the Regulatory Asset created through the amortization of the theoretical reserve surplus, effective January 1, 2017.

The table below shows the annual amortization expense amount beginning in 2013 and continuing through the remaining lives of the associated plant. Consistent with remaining life theory, NSP (Minn) will amortize the regulatory asset through an expense in FERC Account 407.3 and an offsetting credit to expense in FERC Account 403.

Theoretical Reserve Surplus Amortization Expense

Year	Transmission	Distribution	General	Total
2013	($3,330,665)	($2,256)	($1,362)	($3,334,283)
2014	($11,657,328)	($7,898)	($4,768)	($11,669,994)
2015	($6,994,397)	($4,738)	($2,861)	($7,001,996)
2016	($4,662,931)	($3,159)	($1,907)	($4,667,997)
2017	$630,625	$490	$1,857	$632,972
2018	$630,625	$490	$1,857	$632,972
2019	$630,625	$490	$1,857	$632,972
2020	$630,625	$490	$1,857	$632,972
2021	$630,625	$490	$1,857	$632,972
2022	$630,625	$490	$1,615	$632,730
2023	$630,625	$490	$0	$631,115

THEORETICAL RESERVE SURPLUS AMORTIZATION EXPENSE

Year	Transmission	Distribution	General	Total
2024	$630,625	$490	$0	$631,115
2025	$630,625	$490	$0	$631,115
2026	$630,625	$490	$0	$631,115
2027	$630,625	$490	$0	$631,115
2028	$630,625	$490	$0	$631,115
2029	$630,625	$490	$0	$631,115
2030	$630,625	$490	$0	$631,115
2031	$630,625	$490	$0	$631,115
2032	$630,625	$490	$0	$631,115
2033	$630,625	$490	$0	$631,115
2034	$630,625	$490	$0	$631,115
2035	$630,625	$490	$0	$631,115
2036	$630,625	$490	$0	$631,115
2037	$630,625	$490	$0	$631,115
2038	$630,625	$490	$0	$631,115
2039	$630,625	$490	$0	$631,115
2040	$630,625	$490	$0	$631,115
2041	$630,625	$490	$0	$631,115
2042	$630,625	$490	$0	$631,115
2043	$630,625	$490	$0	$631,115
2044	$630,625	$490	$0	$631,115
2045	$630,625	$490	$0	$631,115
2046	$630,625	$490	$0	$631,115
2047	$630,625	$490	$0	$631,115
2048	$630,625	$490	$0	$631,115
2049	$630,625	$490	$0	$631,115
2050	$630,625	$490	$0	$631,115
2051	$630,625	$490	$0	$631,115
2052	$630,625	$485	$0	$631,110
2053	$557,037	$408	$0	$557,445
2054	$525,623	$0	$0	$525,623
2055	$525,623	$0	$0	$525,623
2056	$445,622	$0	$0	$445,622
2057	$230,462	$0	$0	$230,462
2058	$225,990	$0	$0	$225,990
2059	$225,990	$0	$0	$225,990
2060	$225,990	$0	$0	$225,990
2061	$225,990	$0	$0	$225,990
2062	$225,990	$0	$0	$225,990
2063	$225,990	$0	$0	$225,990
2064	$153,398	$0	$0	$153,398
2065	$123,777	$0	$0	$123,777
2066	$17,670	$0	$0	$17,670
2067	$2,974	$0	$0	$2,974
2068	$2,974	$0	$0	$2,974
2069	$1,712	$0	$0	$1,712

PRAIRIE ISLAND EXTENDED POWER UPRATE AMORTIZATION REVENUE REQUIREMENT

This Schedule 8.2 explains the Prairie Island Nuclear Plant Extended Power Uprate (PI EPU) amortization expense revenue requirement calculation for purposes of this Agreement.

The PI EPU amortization revenue requirement is equal to the current year amortization and calculated return on rate base of NSP (Wis)'s portion ($11,996,581) of the total actual PI EPU cancelled project costs ($78,884,915) over the remaining life of the Prairie Island plant as determined by the Minnesota Public Utilities Commission (MPUC) in the NSP (Minn) 2014 test year rate case, Docket No. E002/GR-13-868.

NSP (Wis)'s portion of the total actual PI EPU cancelled project costs is based on the application of the coincident peak demand ratios accepted by the Commission for the Interchange Agreement in Docket No. ER14-1325-000. The annual amortization amount is calculated based on the 18.3-year remaining life of the Prairie Island Plant beginning on January 1, 2016. The annual amortization amount is calculated as follows:

	Total	NSP (Minn.)	NSP (Wis.)
Demand Allocation Between Parties	100.0000%	84.7923%	15.2077%
PI EPU Abandoned Plant Costs	$78,884,915	$66,888,334	$11,996,581
Annual Amortization Expense	$ 4,302,814	$ 3,648,455	$ 654,359

NSP (Minn)'s demand related cost of service used in determining billings to NSP (Wis) shall also include a return on the rate base associated with the unrecovered balance of PI EPU cancelled project costs including Allowance for Funds Used During Construction (AFUDC). The return on rate base shall be calculated as the 13 month average rate base of the PI EPU cancelled project costs, less accumulated amortization, less accumulated deferred income taxes multiplied by the NSP (Minn) weighted debt-only cost of capital. The cost of capital used to calculate the return on rate base shall include only the cost of debt at the current NSP (Minn) rate and capital structure percentage as determined under Exhibit V, Schedule 6.

NSP (Minn)'s demand related cost of service used in determining billings to NSP (Wis) for the period commencing January 1, 2016, shall include $654,359 per year for purposes of amortizing expenditures on the cancelled PI EPU project. The inclusion of that amount shall continue until NSP (Minn) has recovered from NSP (Wis) its share ($11,996,581) of the total actual PI EPU cancelled project costs including AFUDC. In the last month of the amortization, an amount of less than one-twelfth of the $654,359 may be included in the fixed charges to achieve precise recovery of the PI EPU cancelled project costs.

The PI EPU cancelled project costs included in determining the charges among the Parties are recorded by NSP (Minn) in Account 182.2 Unrecovered Plant and Regulatory Study Costs. PI EPU amortization expense is recorded by NSP (Minn) in Account 407 Amortization of Property Losses, Unrecovered Plant and Regulatory Study Costs.

This schedule will be effective beginning January 1, 2016.

MONTICELLO LIFE CYCLE MANAGEMENT / EXTENDED POWER UPRATE PROJECT RETURN ON RATE BASE ADJUSTMENT

Demand related costs will be reduced by the return on rate base for a portion of the Monticello Life Cycle Management/Extended Power Uprate (Monticello LCM/EPU) Project for purposes of this Agreement. The reduction incorporates into the Interchange Agreement billings from NSP (Minn.) to NSP (Wis.) the Minnesota Public Utilities Commission (MPUC) Orders in Docket No. E002/CI-13-754 (Investigation into Xcel Energy's Monticello LCM/EPU Project and Request for Recovery of Cost Overruns) and Docket No. E002/GR-13-868 (Application of Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota), (together the "Monticello LCM/EPU Orders").

The Monticello LCM/EPU Orders approved recovery of the total project cost, but limited recovery of the return on rate base to the original MPUC Certificate of Need application amounts, escalated, including AFUDC, to $415 million. The MPUC Order in Docket No. E002/GR-13-868 issued August 31, 2015, clarified that all (past, present and future) depreciation expense recorded in the accumulated depreciation reserve be allocated on a pro-rated basis between the total project cost that earns a return ($415 million) and the total project cost that does not earn a return (amounts in excess of $415 million).

The adjustment shall be calculated by determining the return on rate base and associated income taxes on the Monticello LCM/EPU Project prorated rate base not allowed a return and applying the NSP (Wis.) demand allocation percent. The Monticello LCM/EPU Project prorated rate base not allowed a return will be determined by applying the percentage of total Monticello LCM/EPU Project costs in excess of $415 million to total Monticello LCM/EPU Project costs to each component of the Total Monticello LCM/EPU Project rate base (plant in service, accumulated provision for depreciation, and accumulated deferred income taxes).

The reduced return on rate base shall continue until the Monticello LCM/EPU Project is fully depreciated, currently expected to be 2030.

BENSON POWER TERMINATION AMORTIZATION REVENUE REQUIREMENT

Demand related costs will be adjusted to include an amortization and return on the rate base of the costs incurred by NSP (Minn) to acquire the Benson Power, LLC ("Benson Power") biomass generating plant, terminate the power purchase agreement with Benson Power, and subsequently close and dismantle the Benson Power facility (collectively the "Total Actual Benson Power Termination Costs"). This adjustment incorporates into the Interchange Agreement billings from NSP (Minn.) to NSP (Wis.) the Minnesota Public Utilities Commission (MPUC) Order in Docket No. E002/M-17-530 (Petition to Terminate the PPA with Benson Power, LLC) and the FERC Order in Docket No. EC17-166-000 (approving the NSP (Minn) purchase of the Benson Power, LLC facility).

The Benson Power termination revenue requirement is equal to the current year amortization and calculated return on rate base of NSP (Wis)'s portion of the total actual costs incurred by NSP (Minn) to acquire the Benson Power generating plant, terminate the power purchase agreement with Benson Power, and close and dismantle the Benson Power facility and remediate the site of the Benson Power facility ("Benson Power Termination Costs").

The annual amortization charge to NSP (Wis) will be calculated as follows:

1.		Total Actual Benson Power Termination Costs
2.	Multiply	NSP (Wis)'s Share of the 2018 NSP System Budget Energy Ratio
3.	Equals	NSP (Wis)'s Portion of the Total Actual Benson Power Termination Costs
4.		NSP (Wis)'s Portion of the Total Actual Benson Power Termination Costs
5.	Divide	Period of Time between Termination Date and Contract Expiration (9/10/2028)
6.	Equals	Annual Amortization Charge to NSP (Wis)

A return on rate base will be calculated on the unrecovered balance of Benson Power Termination Costs. The return on rate base will be calculated as the 13 month average rate base of the actual incurred Benson Power Termination Costs, less accumulated amortization, less accumulated deferred income taxes multiplied by the NSP (Minn) cost of capital. The cost of capital shall be based on the NSP (Minn) currently authorized State of Minnesota retail electric return on equity and the cost of debt and capital structure percentage as determined under Exhibit V, Schedule 6, Return on Rate Base.

The Benson Power Termination Costs included in determining the charges among the Parties are recorded by NSP (Minn) in Account 182.2, Unrecovered Plant and Regulatory Study Costs, and Account 182.3, Other Regulatory Assets. The Benson Power Termination amortization expense is recorded by NSP (Minn) in Account 407, Amortization of Property Losses, Unrecovered Plant and Regulatory Study Costs, and Account 557, Other Expenses.

This schedule will be effective on the month and day NSPM acquires the Benson Power facility and terminates the power purchase agreement with Benson Power, and will continue through the contract expiration date of September 10, 2028.

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. Provision for Deferred Income Taxes will exclude amounts related to assets that are direct assigned to participating customers for ratemaking purposes under state retail tariffs.

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. The Property Tax expense or taxes in lieu of property taxes will exclude amounts related to assets that are direct assigned to participating customers for ratemaking purposes under state retail tariffs.

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. Insurance Expense will exclude amounts related to assets that are direct assigned to participating customers for ratemaking purposes under state retail tariffs.

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 Production Operating and Maintenance Expenses will exclude amounts related to assets that are direct assigned to participating customers for ratemaking purposes under state retail tariffs.

FIXED REGIONAL MARKET OPERATING AND MAINTENANCE EXPENSE

Regional Market 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, 456 - Other Electric Revenues, and 456.1 – Revenues From Transmission of Electricity of Others. These revenues are credited to transmission operating and maintenance expenses.

Provision for rate refunds recorded in FERC Account 449.1 include transmission related amounts being collected subject to refund which are estimated to be required to be refunded.

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

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 Production Operating and Maintenance Expenses will exclude amounts related to assets that are direct assigned to participating customers for ratemaking purposes under state retail tariffs.

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.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit VI
Schedule 3

NET PURCHASED POWER ENERGY COSTS

Purchased Power Energy Costs as billed are recorded in FERC Account 555 - Purchased Power and FERC Account 555.1 – Power Purchased for Energy Storage Operations. 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. Purchased Power Energy Costs shall be adjusted to exclude amounts related to energy requirements fulfilled by energy resources required by certain state energy policies ~~or~~ , statutes, or state retail tariffs that are direct assigned to participating customers for ratemaking purposes.[1/]

[1/] Including, but not limited to, the NSP (Minn) Windsource® program. For the community solar garden programs and other programs similar in nature, the actual cost of such energy shall be excluded from FERC Account 555 and substituted with the market cost of such generation. The market cost shall be calculated using the hourly day-ahead locational marginal price ("LMP") from the MISO energy market. Costs incurred for community solar garden generation power above the amount calculated using the hourly day-ahead LMP will be direct assigned to NSP (Minn) or NSP (Wis) and the applicable state jurisdiction approving the solar garden.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy **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 10.40%.

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

SPECIFICATION OF AVERAGE MONTHLY COINCIDENTAL PEAK DEMANDS

Calendar Year ~~2022~~2023 Contract Year
Monthly Coincidental Peak Demands (KW)

		NSP (Minn)	NSP (Wis)	Total System
~~2020~~2021	January	~~5,093~~4,838	~~1,077~~1,024	~~6,170~~5,862
	February	~~4,996~~5,126	~~1,094~~1,096	~~6,090~~6,222
	March	~~4,593~~4,576	~~949~~981	~~5,542~~5,557
	April	~~4,244~~4,465	~~852~~837	~~5,096~~5,302
	May	~~5,120~~5,862	~~986~~1,057	~~6,106~~6,919
	June	~~6,925~~7,507	~~1,191~~1,330	~~8,116~~8,837
	July	~~7,216~~7,546	~~1,356~~1,214	~~8,571~~8,760
	August	~~7,188~~7,216	~~1,217~~1,232	~~8,405~~8,448
	September	~~5,370~~6,008	~~980~~996	~~6,349~~7,004
	October	~~4,530~~5,119	~~953~~992	~~5,482~~6,111
	November	~~4,778~~4,643	~~947~~950	~~5,724~~5,593
	December	~~4,923~~5,108	~~1,034~~1,061	~~5,957~~6,169
	Total	~~64,975~~68,014	~~12,635~~12,770	~~77,610~~80,784
~~2021~~2022	January	~~4,838~~5,352	~~1,024~~1,071	~~5,862~~6,423
	February	~~5,126~~5,194	~~1,096~~1,016	~~6,222~~6,210
	March	~~4,576~~4,798	~~981~~965	~~5,557~~5,763
	April	~~4,465~~4,628	~~837~~938	~~5,302~~5,566
	May	~~5,862~~5,607	~~1,057~~1,125	~~6,919~~6,732
	June	~~7,507~~7,883	~~1,330~~1,362	~~8,837~~9,245
	July	~~6,963~~7,131	~~1,335~~1,319	~~8,299~~8,450
	August	~~7,004~~7,173	~~1,294~~1,277	~~8,298~~8,450
	September	~~6,199~~6,351	~~1,100~~1,126	~~7,299~~7,477
	October	~~4,558~~4,688	~~932~~978	~~5,490~~5,666
	November	~~4,657~~4,793	~~964~~991	~~5,621~~5,784
	December	~~5,085~~5,188	~~1,074~~1,109	~~6,159~~6,297
	Total	~~66,838~~68,786	~~13,027~~13,277	~~79,865~~82,063
~~2022~~2023	January	~~5,070~~5,207	~~1,115~~1,121	~~6,185~~6,328
	February	~~4,840~~4,980	~~1,067~~1,086	~~5,907~~6,066
	March	~~4,648~~4,741	~~1,038~~1,042	~~5,686~~5,783
	April	~~4,301~~4,379	~~902~~881	~~5,203~~5,260
	May	~~5,334~~5,449	~~1,054~~1,071	~~6,388~~6,520
	June	~~7,053~~7,105	~~1,290~~1,312	~~8,343~~8,417
	July	~~7,067~~7,142	~~1,362~~1,344	~~8,429~~8,486
	August	~~7,109~~7,189	~~1,320~~1,297	~~8,429~~8,486
	September	~~6,242~~6,304	~~1,122~~1,140	~~7,364~~7,444
	October	~~4,585~~4,619	~~945~~978	~~5,530~~5,597
	November	~~4,671~~4,710	~~982~~993	~~5,653~~5,703
	December	~~5,093~~5,134	~~1,091~~1,102	~~6,184~~6,236
	Total	~~66,011~~66,959	~~13,290~~13,367	~~79,301~~80,326

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

SPECIFICATION OF COMPOSITE DEPRECIATION RATES ~~2022~~2023 CONTRACT YEAR

The annual composite depreciation rates for production are calculated based on forecasted depreciation expense accruals and average plant balances. The forecasted depreciation expense is calculated based on approved remaining life depreciation lives and rates certified by the respective state Commissions for NSP (Minn) and NSP (Wis). Rates for transmission, distribution, and general functions are the approved rates for each plant account. NSP (Minn)'s rates are a blended calculation of the approved rates in Minnesota, North Dakota, and South Dakota. NSP (Wis)'s approved rates are the same for both the Wisconsin and Michigan jurisdictions. 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
PRODUCTION			
E311	STEAM	Structures and Improvements	~~4.58~~4.68%
E312	STEAM	Boiler Plant Equipment	~~4.75~~3.86%
E314	STEAM	Turbogenerator Units	~~4.97~~3.48%
E315	STEAM	Accessory Electric Equipment	~~3.89~~3.68%
E316	STEAM	Miscellaneous Power Plant Equipment	~~1.67~~4.23%
E302	NUCLEAR	Franchises & Consents	~~5.31~~5.45%
E321	NUCLEAR	Structures and Improvements	~~4.87~~4.98%
E322	NUCLEAR	Reactor Plant Equipment	~~4.19~~4.41%
E323	NUCLEAR	Turbogenerator Units	~~3.65~~3.85%
E324	NUCLEAR	Accessory Electric Equipment	~~4.23~~4.50%
E325	NUCLEAR	Miscellaneous Power Plant Equipment	~~4.87~~4.97%
E302	HYDRO	Franchises & Consents	~~3.74~~3.74%
E331	HYDRO	Structures and Improvements	~~7.26~~6.99%
E332	HYDRO	Reservoirs, Dams and Waterways	~~5.54~~5.54%
E333	HYDRO	Water Wheels, Turbines & Generators	~~5.64~~5.73%
E334	HYDRO	Accessory Electric Equipment	~~5.91~~5.96%
E335	HYDRO	Miscellaneous Power Plant Equipment	~~8.44~~5.45%
E336	HYDRO	Roads, Railroads and Bridges	~~0.89~~1.76%
E340.1	OTHER	Wind Rights	~~4.27~~2.61%
E341	OTHER	Structures and Improvements	~~3.99~~4.02%
E342	OTHER	Fuel Holders, Producers & Accessories	~~4.19~~4.71%
E343	OTHER	Prime Movers	~~3.39~~3.58%
E344	OTHER	Generators	~~4.25~~4.36%
E345	OTHER	Accessory Electric Equipment	~~4.06~~4.24%
E346	OTHER	Miscellaneous Power Plant Equipment	~~5.23~~5.19%
E348	OTHER	Energy Storage Equipment – Production	~~0.00~~0.00%

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

TRANSMISSION		
E351	Energy Storage Equipment – Transmission	0.00%
E352	Structures and Improvements	~~1.49~~1.50%
*E352	Structures and Improvements-Prod.	~~1.49~~1.50%
E353	Station Equipment	2.05%
*E353	Station Equipment-Prod.	2.05%
E354	Towers and Fixtures	1.77%
*E354	Towers and Fixtures-Prod.	1.77%
E355	Poles and Fixtures	~~2.41~~2.40%
*E355	Poles and Fixtures-Prod.	~~2.41~~2.40%
E356	Overhead Conductors & Devices	~~2.01~~2.03%
*E356	Overhead Conductors & Devices-Prod.	~~2.01~~2.03%
E357	Underground Conduit	1.36%
E358	Underground Conductors & Devices	~~2.06~~2.07%
DISTRIBUTION		
E361	Structures and Improvements	2.08%
*E361	Structures and Improvements-Prod.	2.09%
E362	Station Equipment	~~2.31~~2.32%
*E362	Station Equipment-Prod.	~~2.32~~2.34%
E363	Energy Storage Equipment – Distribution	0.00%
E364	Poles, Towers and Fixtures	~~4.60~~4.59%
E365	Overhead Conductors and Devices	~~3.17~~3.19%
E366	Underground Conduit	2.13%
E367	Underground Conductor and Devices	~~2.22~~2.21%
E368	Line Transformers	~~3.25~~3.26%
E368	Line Capacitors	~~3.96~~3.97%
E369	Overhead Services	~~4.32~~4.28%
E369	Underground Services	~~2.37~~2.36%
E370	Meters	~~6.53~~6.27%
E370.2	AGIS Meters	~~5.00~~5.02%
E370.3	Electric Vehicle Chargers	10.00%
E373	Street Lighting and Signal Systems	~~5.76~~5.65%

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

GENERAL - ELECTRIC

E302	Franchises & Consents	~~5.75~~4.97%
E303	Intangible Plant – 5 Year	~~19.90~~19.53%
E303	Intangible Plant – 10 Year	~~10.00~~10.31%
E390	Structures and Improvements	~~1.73~~1.88%
E391	Office Furniture and Equipment	~~4.80~~4.87%
E391	Network Equipment	~~16.80~~17.51%
E392	Transportation Equipment – Auto	9.75%
E392	Transportation Equipment – Light Truck	~~9.33~~9.81%
E392	Transportation Equipment – Trailers	~~6.18~~6.28%
E392	Transportation Equipment – Heavy Trucks	~~6.89~~7.13%
E393	Stores Equipment	4.55%
E394	Tools, Shop and Garage Equipment	~~6.52~~6.58%
E395	Laboratory Equipment	~~10.34~~10.62%
E396	Power Operated Equipment	~~5.47~~5.53%
E397	Communication Equipment – General	~~10.03~~10.45%
E397	Communication Equipment – Two Way	~~10.27~~10.38%
E397	Communication Equipment – AMR	~~6.29~~5.02%
*E397	Communication Equipment – EMS	~~6.28~~6.29%
E397	Communication Equipment – Smart Grid	~~10.03~~5.68%
E398	Miscellaneous Equipment	~~6.70~~6.80%

The Nuclear Decommissioning annual accrual is an approved amount which is recovered from customers to fund the decommissioning of the Monticello and Prairie Island nuclear generating facilities.

Jurisdiction	~~2022~~2023 Approved Accrual	Docket No./Case No.
Minnesota Retail	$~~27,418,421~~21,571,110	E-002/M-~~17-828~~20-855
North Dakota Retail	$2,250,002	PU-20-441
South Dakota Retail	$1,234,251	EL14-058
Wisconsin Retail	$~~10,204,776~~9,300,588	E-002/M-~~17-828~~20-855 4220-UR-125

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

SPECIFICATION OF COMPOSITE DEPRECIATION RATES ~~2022~~2023 CONTRACT YEAR

NSP (Wis)

FERC ACCOUNT		DESCRIPTION	ANNUAL DEPRECIATION RATE
PRODUCTION			
E311	STEAM	Structures and Improvements	~~5.36~~5.63%
E312	STEAM	Boiler Plant Equipment	~~4.29~~4.82%
E314	STEAM	Turbogenerator Units	~~4.12~~4.44%
E315	STEAM	Accessory Electric Equipment	~~5.50~~6.01%
E316	STEAM	Miscellaneous Power Plant Equipment	~~3.42~~3.78%
E302	HYDRO	Franchises & Consents	~~3.85~~1.48%
E331	HYDRO	Structures and Improvements	~~3.34~~3.43%
E332	HYDRO	Reservoirs, Dams and Waterways	~~4.05~~4.11%
E333	HYDRO	Water Wheels, Turbines & Generators	~~4.48~~4.57%
E334	HYDRO	Accessory Electric Equipment	~~5.47~~5.26%
E335	HYDRO	Miscellaneous Power Plant Equipment	~~4.70~~4.65%
E341	OTHER	Structures and Improvements	~~3.29~~3.77%
E342	OTHER	Fuel Holders, Producers & Accessories	~~3.68~~3.84%
E343	OTHER	Prime Movers	~~4.39~~4.38%
E344	OTHER	Generators	~~4.33~~4.53%
E345	OTHER	Accessory Electric Equipment	~~4.46~~4.65%
E346	OTHER	Miscellaneous Power Plant Equipment	~~2.23~~2.08%
E348	OTHER	Energy Storage Equipment – Production	0.00%
TRANSMISSION			
E351		Energy Storage Equipment – Transmission	0.00%
E352		Structures and Improvements	2.09%
*E352		Structures and Improvements-Prod.	2.09%
E353		Station Equipment	2.80%
*E353		Station Equipment-Prod.	2.80%
E354		Towers and Fixtures	1.80%
E355		Poles and Fixtures	3.28%
E356		Overhead Conductors & Devices	2.80%
E357		Underground Conduit	1.76%
E358		Underground Conductors & Devices	2.77%
E359		Roads and Trails	1.75%

DISTRIBUTION

E361	Structures and Improvements	2.03%
*E361	Structures and Improvements – Prod.	2.03%
E362	Station Equipment	2.51%
*362	Station Equipment – Prod.	2.51%
E363	Energy Storage Equipment – Distribution	~~0.00~~10.00%
E364	Poles, Towers and Fixtures	5.26%
E365	Overhead Conductors and Devices	3.51%
E366	Underground Conduit	1.62%
E367	Underground Conductor and Devices	2.24%
E368	Line Transformers	2.28%
E368	Line Capacitors	2.66%
E369	Overhead Services	3.61%
E369	Underground Services	2.73%
E370	Meters	4.54%
E370.1	Meters – Old	~~2.82~~0.00%
E370.2	Meters – AMR	4.84%
E371	Customer Installations	~~3.33~~0.00%
E371.4	Installations on Customer's Premises~~'s~~-EV	10.00%
E371.5	Customer Prem-REMS	3.33%
E373	Street Lighting and Signal Systems	5.72%

GENERAL ELECTRIC

E302	Franchises & Consents	5.00%
E303	Intangible Plant – 3 Year	33.33%
E303	Intangible Plant – 5 Year	25.98%
E303	Intangible Plant – 7 Year	14.29%
E303	Intangible Plant – 10 Year	10.00%
E303	Intangible Plant – 15 Year	6.67%
E390	Structures and Improvements	2.17%
E391	Office Furniture and Equipment	4.57%
E391	Network Equipment	18.83%
E392	~~Transporation~~Transportation Equipment – Auto	12.67%
E392	Transportation Equipment – Light Truck	12.38%
E392	Transportation Equipment – Trailers	5.62%
E392	Transportation Equipment – Heavy Truck	8.21%
E393	Stores Equipment	4.45%
E394	Tools, Shop and Garage Equipment	4.80%
E395	Laboratory Equipment	3.45%
E396	Power Operated Equipment	5.96%
E397	Communication Equipment – AES/AMR	6.11%
*E397	Communication Equipment – EMS	6.11%
E398	Miscellaneous Equipment	4.48%

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
	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	
548.1	Operation of energy storage equipment	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	
553.1	Maintenance of energy storage equipment	X	
554	Miscellaneous other power generation plant	X	
	Other Power Supply Expenses		
555	Purchased power		As Billed
555.1	Power purchased for storage operations		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:

0.962 for NSP(Minn)
0.956 for NSP(Wis)

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

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

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

FORMULA TYPE PROCEDURES FOR DEVELOPMENT OF AMOUNTS OF ENERGY 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 current month, excluding energy requirements fulfilled by energy resources required by certain state energy policies, statutes, or state retail tariffs that are direct assigned to participating customers for ratemaking purposes. [1/] The measured monthly energy requirements shall be adjusted by a Transmission Loss Multiplier.

"Transmission Loss Multipliers" are equal to:

0.961 for NSP(Minn)
0.948 for NSP(Wis)

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

[1/] Including, but not limited to, the NSP (Minn) Windsource® program.

FORMULA TYPE PROCEDURES FOR DEVELOPMENT OF UNIT RATES FOR 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:

0.962 for NSP(Minn)
0.956 for NSP(Wis)

FORMULA TYPE PROCEDURES FOR DEVELOPMENT OF UNIT RATES FOR ENERGY 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 current month excluding energy requirements fulfilled by energy resources required by certain state energy policies, statutes, or state retail tariffs that are direct assigned to participating customers for ratemaking purposes.[1/] The measured monthly energy requirements shall be adjusted by a Transmission Loss Multiplier.

"Transmission Loss Multipliers" are equal to:

0.961 for NSP(Minn)
0.948 for NSP(Wis)

[1/] Including, but not limited to, the NSP (Minn) Windsource® program.

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

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)		
1.1	Pre-funded Allowance for Funds Used during Construction (Sched. 1.1)		
1.2	Electric Plant Acquisition Adjustments (Sched. 1.2)		
2.	Accumulated Provision for Depreciation (Sched. 2)		
2.1	Accumulated Provision for Amortization of Electric Plant Acquisition Adjustments (Sched. 2.1)		
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)		

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)
10.1 Theoretical Reserve Surplus Amortization Expense (Sched. 8.1)
10.2 Prairie Island Extended Power Uprate Amortization Revenue Requirement (Sched. 8.2)
10.3 Monticello Life Cycle Management / Extended Power Uprate Project Return on Rate Base Adjustment (Sched. 8.3)
10.4 Benson Power Termination Amortization Revenue Requirement (Sched. 8.4)
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)

FORMULA TYPE PROCEDURES FOR DEVELOPMENT OF DEMAND RELATED COSTS

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. Electric Plant in Service balances will exclude amounts related to assets that are direct assigned to participating customers for ratemaking purposes under state retail tariffs. The following FERC Accounts shall be included:

1. Intangible Plant Investment
   Water power and nuclear plant relicensing investment recorded in FERC Account 302. Intangible software directly related to the production and transmission functions recorded in FERC Account 303 and as agreed among the Parties.

2. Production Plant Investment
   Production plant investment recorded in FERC Accounts 310 through 348.

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.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit V Schedule 1.1

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 Midcontinent Independent System Operator, Inc.'s (MISO) 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.

ELECTRIC PLANT ACQUISITION ADJUSTMENTS

Electric Plant Acquisition Adjustments is recorded in FERC Account 114. The amounts included to determine the charges among the Parties shall include those amounts related to the production function and as agreed among the Parties.

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. Accumulated Provision for Depreciation balances will exclude amounts related to assets that are direct assigned to participating customers for ratemaking purposes under state retail tariffs.

These accounts are classified to the intangible, 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 PROVISION FOR AMORTIZATION OF ELECTRIC PLANT ACQUISITION ADJUSTMENTS

Accumulated Provision for Amortization of Electric Plant Acquisition Adjustments is recorded in FERC Account 115. The amounts included to determine the charges among the Parties shall include those amounts related to the production function and as agreed among the Parties.

ACCUMULATED DEFERRED INCOME TAXES

Accumulated Deferred Income Taxes included in FERC Accounts 190 and 281-283 are classified to the intangible, production, nuclear fuel, transmission, distribution and general plant functions in the same detail as the original cost of the plant in service. Accumulated Deferred Income Tax balances will exclude amounts related to assets that are direct assigned to participating customers for ratemaking purposes under state retail tariffs.

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 Midcontinent Independent 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 (MPUC Docket No. E002/GR-12-961, order dated September 3, 2013) to amortize the NSP (Minn) theoretical reserve surplus (as developed in the table below) beginning January 1, 2013 over a period other than the average remaining life. The NSP (Wis) portion of the theoretical reserve surplus is $26,674,271.

In the NSP (Minn) 2014 test year Minnesota retail electric rate case (MPUC Docket No. E002/GR-13-868, order dated May 8, 2015), the MPUC approved the balance of the remaining theoretical reserve surplus for transmission, distribution, intangible and general functions of plant to be amortized in a pattern of 50 percent for 2014, 30 percent for 2015, and 20 percent for 2016. The regulatory asset set-up was completed at the end of 2016 as detailed in the table below.

In the NSP (Minn) 2017 Annual Review of Remaining Lives (MPUC Docket No. E,G002/D-17-147, order dated February 8, 2018), the MPUC approved the amortization rates of the regulatory asset created through the amortization of the NSP (Minn) theoretical reserve surplus, effective January 1, 2017.

The accumulated amortization amounts are based on the schedule provided in Exhibit V, Schedule 8.1.

Balances as of 12/31/2016			
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.

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 6 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, or such date after January 1 determined by the Coordinating Committee, 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 such 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 of 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)
4.1 Production Tax Credit (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)
10.1 Production Tax Credit (Line 4.1)
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, Production 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.

Production Tax Credit

The Production Tax Credit is recorded in FERC Account 409.1. The amounts included for the calculation of income taxes are those amounts attributable to the plant investment related to the production function. Production Tax Credit will exclude amounts related to assets that are direct assigned to participating customers for ratemaking purposes under state retail tariffs.

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. Income Tax Depreciation will exclude amounts related to assets that are direct assigned to participating customers for ratemaking purposes under state retail tariffs.

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. Depreciation and amortization expense will exclude amounts related to assets that are direct assigned to participating customers for ratemaking purposes under state retail tariffs.

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 related to the theoretical reserve surplus. Theoretical Reserve Surplus Amortization Expense included in determining the charges among the Parties is recorded in FERC Account 407.4 (creation of Regulatory Asset) and FERC Account 407.3 (amortization of Regulatory Asset) by the plant functional classifications.

In the NSP (Minn) 2013 test year Minnesota retail electric rate case (MPUC Docket No. E002/GR-12-961, order dated September 3, 2013), the MPUC approved the amortization of the theoretical reserve surplus over a period other than the average remaining life. The NSP (Wis) portion of the theoretical reserve surplus is $26,674,271.

In the NSP (Minn) 2014 test year Minnesota retail electric rate case (MPUC Docket No. E002/GR-13-868, order dated May 8, 2015), the MPUC approved the accelerated amortization of the theoretical reserve surplus. Specifically, the MPUC approved the balance of the remaining theoretical reserve surplus for transmission, distribution, intangible and general functions of plant be amortized in a pattern of 50 percent for 2014, 30 percent for 2015, and 20 percent for 2016. Please refer to Exhibit V, Schedule 4.2. As of December 31, 2016, the theoretical reserve surplus was fully amortized.

In the NSP (Minn) 2017 Annual Review of Remaining Lives (MPUC Docket No. E,G002/D-17-147, order dated February 8, 2018), the MPUC approved the amortization rates to unwind the Regulatory Asset created through the amortization of the theoretical reserve surplus, effective January 1, 2017.

The table below shows the annual amortization expense amount beginning in 2013 and continuing through the remaining lives of the associated plant. Consistent with remaining life theory, NSP (Minn) will amortize the regulatory asset through an expense in FERC Account 407.3 and an offsetting credit to expense in FERC Account 403.

Theoretical Reserve Surplus Amortization Expense

Year	Transmission	Distribution	General	Total
2013	($3,330,665)	($2,256)	($1,362)	($3,334,283)
2014	($11,657,328)	($7,898)	($4,768)	($11,669,994)
2015	($6,994,397)	($4,738)	($2,861)	($7,001,996)
2016	($4,662,931)	($3,159)	($1,907)	($4,667,997)
2017	$630,625	$490	$1,857	$632,972
2018	$630,625	$490	$1,857	$632,972
2019	$630,625	$490	$1,857	$632,972
2020	$630,625	$490	$1,857	$632,972
2021	$630,625	$490	$1,857	$632,972
2022	$630,625	$490	$1,615	$632,730
2023	$630,625	$490	$0	$631,115

THEORETICAL RESERVE SURPLUS AMORTIZATION EXPENSE

Year	Transmission	Distribution	General	Total
2024	$630,625	$490	$0	$631,115
2025	$630,625	$490	$0	$631,115
2026	$630,625	$490	$0	$631,115
2027	$630,625	$490	$0	$631,115
2028	$630,625	$490	$0	$631,115
2029	$630,625	$490	$0	$631,115
2030	$630,625	$490	$0	$631,115
2031	$630,625	$490	$0	$631,115
2032	$630,625	$490	$0	$631,115
2033	$630,625	$490	$0	$631,115
2034	$630,625	$490	$0	$631,115
2035	$630,625	$490	$0	$631,115
2036	$630,625	$490	$0	$631,115
2037	$630,625	$490	$0	$631,115
2038	$630,625	$490	$0	$631,115
2039	$630,625	$490	$0	$631,115
2040	$630,625	$490	$0	$631,115
2041	$630,625	$490	$0	$631,115
2042	$630,625	$490	$0	$631,115
2043	$630,625	$490	$0	$631,115
2044	$630,625	$490	$0	$631,115
2045	$630,625	$490	$0	$631,115
2046	$630,625	$490	$0	$631,115
2047	$630,625	$490	$0	$631,115
2048	$630,625	$490	$0	$631,115
2049	$630,625	$490	$0	$631,115
2050	$630,625	$490	$0	$631,115
2051	$630,625	$490	$0	$631,115
2052	$630,625	$485	$0	$631,110
2053	$557,037	$408	$0	$557,445
2054	$525,623	$0	$0	$525,623
2055	$525,623	$0	$0	$525,623
2056	$445,622	$0	$0	$445,622
2057	$230,462	$0	$0	$230,462
2058	$225,990	$0	$0	$225,990
2059	$225,990	$0	$0	$225,990
2060	$225,990	$0	$0	$225,990
2061	$225,990	$0	$0	$225,990
2062	$225,990	$0	$0	$225,990
2063	$225,990	$0	$0	$225,990
2064	$153,398	$0	$0	$153,398
2065	$123,777	$0	$0	$123,777
2066	$17,670	$0	$0	$17,670
2067	$2,974	$0	$0	$2,974
2068	$2,974	$0	$0	$2,974
2069	$1,712	$0	$0	$1,712

PRAIRIE ISLAND EXTENDED POWER UPRATE AMORTIZATION REVENUE REQUIREMENT

This Schedule 8.2 explains the Prairie Island Nuclear Plant Extended Power Uprate (PI EPU) amortization expense revenue requirement calculation for purposes of this Agreement.

The PI EPU amortization revenue requirement is equal to the current year amortization and calculated return on rate base of NSP (Wis)'s portion ($11,996,581) of the total actual PI EPU cancelled project costs ($78,884,915) over the remaining life of the Prairie Island plant as determined by the Minnesota Public Utilities Commission (MPUC) in the NSP (Minn) 2014 test year rate case, Docket No. E002/GR-13-868.

NSP (Wis)'s portion of the total actual PI EPU cancelled project costs is based on the application of the coincident peak demand ratios accepted by the Commission for the Interchange Agreement in Docket No. ER14-1325-000. The annual amortization amount is calculated based on the 18.3-year remaining life of the Prairie Island Plant beginning on January 1, 2016. The annual amortization amount is calculated as follows:

	Total	NSP (Minn.)	NSP (Wis.)
Demand Allocation Between Parties	100.0000%	84.7923%	15.2077%
PI EPU Abandoned Plant Costs	$78,884,915	$66,888,334	$11,996,581
Annual Amortization Expense	$ 4,302,814	$ 3,648,455	$ 654,359

NSP (Minn)'s demand related cost of service used in determining billings to NSP (Wis) shall also include a return on the rate base associated with the unrecovered balance of PI EPU cancelled project costs including Allowance for Funds Used During Construction (AFUDC). The return on rate base shall be calculated as the 13 month average rate base of the PI EPU cancelled project costs, less accumulated amortization, less accumulated deferred income taxes multiplied by the NSP (Minn) weighted debt-only cost of capital. The cost of capital used to calculate the return on rate base shall include only the cost of debt at the current NSP (Minn) rate and capital structure percentage as determined under Exhibit V, Schedule 6.

NSP (Minn)'s demand related cost of service used in determining billings to NSP (Wis) for the period commencing January 1, 2016, shall include $654,359 per year for purposes of amortizing expenditures on the cancelled PI EPU project. The inclusion of that amount shall continue until NSP (Minn) has recovered from NSP (Wis) its share ($11,996,581) of the total actual PI EPU cancelled project costs including AFUDC. In the last month of the amortization, an amount of less than one-twelfth of the $654,359 may be included in the fixed charges to achieve precise recovery of the PI EPU cancelled project costs.

The PI EPU cancelled project costs included in determining the charges among the Parties are recorded by NSP (Minn) in Account 182.2 Unrecovered Plant and Regulatory Study Costs. PI EPU amortization expense is recorded by NSP (Minn) in Account 407 Amortization of Property Losses, Unrecovered Plant and Regulatory Study Costs.

This schedule will be effective beginning January 1, 2016.

MONTICELLO LIFE CYCLE MANAGEMENT / EXTENDED POWER UPRATE PROJECT RETURN ON RATE BASE ADJUSTMENT

Demand related costs will be reduced by the return on rate base for a portion of the Monticello Life Cycle Management/Extended Power Uprate (Monticello LCM/EPU) Project for purposes of this Agreement. The reduction incorporates into the Interchange Agreement billings from NSP (Minn.) to NSP (Wis.) the Minnesota Public Utilities Commission (MPUC) Orders in Docket No. E002/CI-13-754 (Investigation into Xcel Energy's Monticello LCM/EPU Project and Request for Recovery of Cost Overruns) and Docket No. E002/GR-13-868 (Application of Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota), (together the "Monticello LCM/EPU Orders").

The Monticello LCM/EPU Orders approved recovery of the total project cost, but limited recovery of the return on rate base to the original MPUC Certificate of Need application amounts, escalated, including AFUDC, to $415 million. The MPUC Order in Docket No. E002/GR-13-868 issued August 31, 2015, clarified that all (past, present and future) depreciation expense recorded in the accumulated depreciation reserve be allocated on a pro-rated basis between the total project cost that earns a return ($415 million) and the total project cost that does not earn a return (amounts in excess of $415 million).

The adjustment shall be calculated by determining the return on rate base and associated income taxes on the Monticello LCM/EPU Project prorated rate base not allowed a return and applying the NSP (Wis.) demand allocation percent. The Monticello LCM/EPU Project prorated rate base not allowed a return will be determined by applying the percentage of total Monticello LCM/EPU Project costs in excess of $415 million to total Monticello LCM/EPU Project costs to each component of the Total Monticello LCM/EPU Project rate base (plant in service, accumulated provision for depreciation, and accumulated deferred income taxes).

The reduced return on rate base shall continue until the Monticello LCM/EPU Project is fully depreciated, currently expected to be 2030.

BENSON POWER TERMINATION AMORTIZATION REVENUE REQUIREMENT

Demand related costs will be adjusted to include an amortization and return on the rate base of the costs incurred by NSP (Minn) to acquire the Benson Power, LLC (“Benson Power”) biomass generating plant, terminate the power purchase agreement with Benson Power, and subsequently close and dismantle the Benson Power facility (collectively the “Total Actual Benson Power Termination Costs”). This adjustment incorporates into the Interchange Agreement billings from NSP (Minn.) to NSP (Wis.) the Minnesota Public Utilities Commission (MPUC) Order in Docket No. E002/M-17-530 (Petition to Terminate the PPA with Benson Power, LLC) and the FERC Order in Docket No. EC17-166-000 (approving the NSP (Minn) purchase of the Benson Power, LLC facility).

The Benson Power termination revenue requirement is equal to the current year amortization and calculated return on rate base of NSP (Wis)’s portion of the total actual costs incurred by NSP (Minn) to acquire the Benson Power generating plant, terminate the power purchase agreement with Benson Power, and close and dismantle the Benson Power facility and remediate the site of the Benson Power facility (“Benson Power Termination Costs”).

The annual amortization charge to NSP (Wis) will be calculated as follows:

1.		Total Actual Benson Power Termination Costs
2.	Multiply	NSP (Wis)’s Share of the 2018 NSP System Budget Energy Ratio
3.	Equals	NSP (Wis)’s Portion of the Total Actual Benson Power Termination Costs
4.		NSP (Wis)’s Portion of the Total Actual Benson Power Termination Costs
5.	Divide	Period of Time between Termination Date and Contract Expiration (9/10/2028)
6.	Equals	Annual Amortization Charge to NSP (Wis)

A return on rate base will be calculated on the unrecovered balance of Benson Power Termination Costs. The return on rate base will be calculated as the 13 month average rate base of the actual incurred Benson Power Termination Costs, less accumulated amortization, less accumulated deferred income taxes multiplied by the NSP (Minn) cost of capital. The cost of capital shall be based on the NSP (Minn) currently authorized State of Minnesota retail electric return on equity and the cost of debt and capital structure percentage as determined under Exhibit V, Schedule 6, Return on Rate Base.

The Benson Power Termination Costs included in determining the charges among the Parties are recorded by NSP (Minn) in Account 182.2, Unrecovered Plant and Regulatory Study Costs, and Account 182.3, Other Regulatory Assets. The Benson Power Termination amortization expense is recorded by NSP (Minn) in Account 407, Amortization of Property Losses, Unrecovered Plant and Regulatory Study Costs, and Account 557, Other Expenses.

This schedule will be effective on the month and day NSPM acquires the Benson Power facility and terminates the power purchase agreement with Benson Power, and will continue through the contract expiration date of September 10, 2028.

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. Provision for Deferred Income Taxes will exclude amounts related to assets that are direct assigned to participating customers for ratemaking purposes under state retail tariffs.

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. The Property Tax expense or taxes in lieu of property taxes will exclude amounts related to assets that are direct assigned to participating customers for ratemaking purposes under state retail tariffs.

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. Insurance Expense will exclude amounts related to assets that are direct assigned to participating customers for ratemaking purposes under state retail tariffs.

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 Production Operating and Maintenance Expenses will exclude amounts related to assets that are direct assigned to participating customers for ratemaking purposes under state retail tariffs.

FIXED REGIONAL MARKET OPERATING AND MAINTENANCE EXPENSE

Regional Market 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, 456 - Other Electric Revenues, and 456.1 – Revenues From Transmission of Electricity of Others. These revenues are credited to transmission operating and maintenance expenses.

Provision for rate refunds recorded in FERC Account 449.1 include transmission related amounts being collected subject to refund which are estimated to be required to be refunded.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy — **Exhibit VI**

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.

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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 Production Operating and Maintenance Expenses will exclude amounts related to assets that are direct assigned to participating customers for ratemaking purposes under state retail tariffs.

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 and FERC Account 555.1 – Power Purchased for Energy Storage Operations. 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. Purchased Power Energy Costs shall be adjusted to exclude amounts related to energy requirements fulfilled by energy resources required by certain state energy policies, statutes, or state retail tariffs that are direct assigned to participating customers for ratemaking purposes.[1/]

[1/] Including, but not limited to, the NSP (Minn) Windsource® program. For the community solar garden programs and other programs similar in nature, the actual cost of such energy shall be excluded from FERC Account 555 and substituted with the market cost of such generation. The market cost shall be calculated using the hourly day-ahead locational marginal price (“LMP”) from the MISO energy market. Costs incurred for community solar garden generation power above the amount calculated using the hourly day-ahead LMP will be direct assigned to NSP (Minn) or NSP (Wis) and the applicable state jurisdiction approving the solar garden.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy **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 10.40%.

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

SPECIFICATION OF AVERAGE MONTHLY COINCIDENTAL PEAK DEMANDS

Calendar Year 2023 Contract Year
Monthly Coincidental Peak Demands (KW)

		NSP (Minn)	NSP (Wis)	Total System
2021	January	4,838	1,024	5,862
	February	5,126	1,096	6,222
	March	4,576	981	5,557
	April	4,465	837	5,302
	May	5,862	1,057	6,919
	June	7,507	1,330	8,837
	July	7,546	1,214	8,760
	August	7,216	1,232	8,448
	September	6,008	996	7,004
	October	5,119	992	6,111
	November	4,643	950	5,593
	December	5,108	1,061	6,169
	Total	68,014	12,770	80,784
2022	January	5,352	1,071	6,423
	February	5,194	1,016	6,210
	March	4,798	965	5,763
	April	4,628	938	5,566
	May	5,607	1,125	6,732
	June	7,883	1,362	9,245
	July	7,131	1,319	8,450
	August	7,173	1,277	8,450
	September	6,351	1,126	7,477
	October	4,688	978	5,666
	November	4,793	991	5,784
	December	5,188	1,109	6,297
	Total	68,786	13,277	82,063
2023	January	5,207	1,121	6,328
	February	4,980	1,086	6,066
	March	4,741	1,042	5,783
	April	4,379	881	5,260
	May	5,449	1,071	6,520
	June	7,105	1,312	8,417
	July	7,142	1,344	8,486
	August	7,189	1,297	8,486
	September	6,304	1,140	7,444
	October	4,619	978	5,597
	November	4,710	993	5,703
	December	5,134	1,102	6,236
	Total	66,959	13,367	80,326

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

SPECIFICATION OF COMPOSITE DEPRECIATION RATES 2023 CONTRACT YEAR

The annual composite depreciation rates for production are calculated based on forecasted depreciation expense accruals and average plant balances. The forecasted depreciation expense is calculated based on approved remaining life depreciation lives and rates certified by the respective state Commissions for NSP (Minn) and NSP (Wis). Rates for transmission, distribution, and general functions are the approved rates for each plant account. NSP (Minn)'s rates are a blended calculation of the approved rates in Minnesota, North Dakota, and South Dakota. NSP (Wis)'s approved rates are the same for both the Wisconsin and Michigan jurisdictions. 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
PRODUCTION			
E311	STEAM	Structures and Improvements	4.68%
E312	STEAM	Boiler Plant Equipment	3.86%
E314	STEAM	Turbogenerator Units	3.48%
E315	STEAM	Accessory Electric Equipment	3.68%
E316	STEAM	Miscellaneous Power Plant Equipment	4.23%
E302	NUCLEAR	Franchises & Consents	5.45%
E321	NUCLEAR	Structures and Improvements	4.98%
E322	NUCLEAR	Reactor Plant Equipment	4.41%
E323	NUCLEAR	Turbogenerator Units	3.85%
E324	NUCLEAR	Accessory Electric Equipment	4.50%
E325	NUCLEAR	Miscellaneous Power Plant Equipment	4.97%
E302	HYDRO	Franchises & Consents	3.74%
E331	HYDRO	Structures and Improvements	6.99%
E332	HYDRO	Reservoirs, Dams and Waterways	5.54%
E333	HYDRO	Water Wheels, Turbines & Generators	5.73%
E334	HYDRO	Accessory Electric Equipment	5.96%
E335	HYDRO	Miscellaneous Power Plant Equipment	5.45%
E336	HYDRO	Roads, Railroads and Bridges	1.76%
E340.1	OTHER	Wind Rights	2.61%
E341	OTHER	Structures and Improvements	4.02%
E342	OTHER	Fuel Holders, Producers & Accessories	4.71%
E343	OTHER	Prime Movers	3.58%
E344	OTHER	Generators	4.36%
E345	OTHER	Accessory Electric Equipment	4.24%
E346	OTHER	Miscellaneous Power Plant Equipment	5.19%
E348	OTHER	Energy Storage Equipment – Production	0.00%

TRANSMISSION		
E351	Energy Storage Equipment – Transmission	0.00%
E352	Structures and Improvements	1.50%
*E352	Structures and Improvements-Prod.	1.50%
E353	Station Equipment	2.05%
*E353	Station Equipment-Prod.	2.05%
E354	Towers and Fixtures	1.77%
*E354	Towers and Fixtures-Prod.	1.77%
E355	Poles and Fixtures	2.40%
*E355	Poles and Fixtures-Prod.	2.40%
E356	Overhead Conductors & Devices	2.03%
*E356	Overhead Conductors & Devices-Prod.	2.03%
E357	Underground Conduit	1.36%
E358	Underground Conductors & Devices	2.07%
DISTRIBUTION		
E361	Structures and Improvements	2.08%
*E361	Structures and Improvements-Prod.	2.09%
E362	Station Equipment	2.32%
*E362	Station Equipment-Prod.	2.34%
E363	Energy Storage Equipment – Distribution	0.00%
E364	Poles, Towers and Fixtures	4.59%
E365	Overhead Conductors and Devices	3.19%
E366	Underground Conduit	2.13%
E367	Underground Conductor and Devices	2.21%
E368	Line Transformers	3.26%
E368	Line Capacitors	3.97%
E369	Overhead Services	4.28%
E369	Underground Services	2.36%
E370	Meters	6.27%
E370.2	AGIS Meters	5.02%
E370.3	Electric Vehicle Chargers	10.00%
E373	Street Lighting and Signal Systems	5.65%

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

GENERAL - ELECTRIC

E302	Franchises & Consents	4.97%
E303	Intangible Plant – 5 Year	19.53%
E303	Intangible Plant – 10 Year	10.31%
E390	Structures and Improvements	1.88%
E391	Office Furniture and Equipment	4.87%
E391	Network Equipment	17.51%
E392	Transportation Equipment – Auto	9.75%
E392	Transportation Equipment – Light Truck	9.81%
E392	Transportation Equipment – Trailers	6.28%
E392	Transportation Equipment – Heavy Trucks	7.13%
E393	Stores Equipment	4.55%
E394	Tools, Shop and Garage Equipment	6.58%
E395	Laboratory Equipment	10.62%
E396	Power Operated Equipment	5.53%
E397	Communication Equipment – General	10.45%
E397	Communication Equipment – Two Way	10.38%
E397	Communication Equipment – AMR	5.02%
*E397	Communication Equipment – EMS	6.29%
E397	Communication Equipment – Smart Grid	5.68%
E398	Miscellaneous Equipment	6.80%

The Nuclear Decommissioning annual accrual is an approved amount which is recovered from customers to fund the decommissioning of the Monticello and Prairie Island nuclear generating facilities.

Jurisdiction	2023 Approved Accrual	Docket No./Case No.
Minnesota Retail	$21,571,110	E002/M-20-855
North Dakota Retail	$2,250,002	PU-20-441
South Dakota Retail	$1,234,251	EL14-058
Wisconsin Retail	$9,300,588	E002/M-20-855 4220-UR-125

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

SPECIFICATION OF COMPOSITE DEPRECIATION RATES 2023 CONTRACT YEAR

NSP (Wis)

FERC ACCOUNT		DESCRIPTION	ANNUAL DEPRECIATION RATE
PRODUCTION			
E311	STEAM	Structures and Improvements	5.63%
E312	STEAM	Boiler Plant Equipment	4.82%
E314	STEAM	Turbogenerator Units	4.44%
E315	STEAM	Accessory Electric Equipment	6.01%
E316	STEAM	Miscellaneous Power Plant Equipment	3.78%
E302	HYDRO	Franchises & Consents	1.48%
E331	HYDRO	Structures and Improvements	3.43%
E332	HYDRO	Reservoirs, Dams and Waterways	4.11%
E333	HYDRO	Water Wheels, Turbines & Generators	4.57%
E334	HYDRO	Accessory Electric Equipment	5.26%
E335	HYDRO	Miscellaneous Power Plant Equipment	4.65%
E341	OTHER	Structures and Improvements	3.77%
E342	OTHER	Fuel Holders, Producers & Accessories	3.84%
E343	OTHER	Prime Movers	4.38%
E344	OTHER	Generators	4.53%
E345	OTHER	Accessory Electric Equipment	4.65%
E346	OTHER	Miscellaneous Power Plant Equipment	2.08%
E348	OTHER	Energy Storage Equipment – Production	0.00%
TRANSMISSION			
E351		Energy Storage Equipment – Transmission	0.00%
E352		Structures and Improvements	2.09%
*E352		Structures and Improvements-Prod.	2.09%
E353		Station Equipment	2.80%
*E353		Station Equipment-Prod.	2.80%
E354		Towers and Fixtures	1.80%
E355		Poles and Fixtures	3.28%
E356		Overhead Conductors & Devices	2.80%
E357		Underground Conduit	1.76%
E358		Underground Conductors & Devices	2.77%
E359		Roads and Trails	1.75%

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

DISTRIBUTION

E361	Structures and Improvements	2.03%
*E361	Structures and Improvements – Prod.	2.03%
E362	Station Equipment	2.51%
*362	Station Equipment – Prod.	2.51%
E363	Energy Storage Equipment – Distribution	10.00%
E364	Poles, Towers and Fixtures	5.26%
E365	Overhead Conductors and Devices	3.51%
E366	Underground Conduit	1.62%
E367	Underground Conductor and Devices	2.24%
E368	Line Transformers	2.28%
E368	Line Capacitors	2.66%
E369	Overhead Services	3.61%
E369	Underground Services	2.73%
E370	Meters	4.54%
E370.1	Meters – Old	0.00%
E370.2	Meters – AMR	4.84%
E371	Customer Installations	0.00%
E371.4	Installations on Customer's Premises-EV	10.00%
E371.5	Customer Prem-REMS	3.33%
E373	Street Lighting and Signal Systems	5.72%

GENERAL ELECTRIC

E302	Franchises & Consents	5.00%
E303	Intangible Plant – 3 Year	33.33%
E303	Intangible Plant – 5 Year	25.98%
E303	Intangible Plant – 7 Year	14.29%
E303	Intangible Plant – 10 Year	10.00%
E303	Intangible Plant – 15 Year	6.67%
E390	Structures and Improvements	2.17%
E391	Office Furniture and Equipment	4.57%
E391	Network Equipment	18.83%
E392	Transportation Equipment – Auto	12.67%
E392	Transportation Equipment – Light Truck	12.38%
E392	Transportation Equipment – Trailers	5.62%
E392	Transportation Equipment – Heavy Truck	8.21%
E393	Stores Equipment	4.45%
E394	Tools, Shop and Garage Equipment	4.80%
E395	Laboratory Equipment	3.45%
E396	Power Operated Equipment	5.96%
E397	Communication Equipment – AES/AMR	6.11%
*E397	Communication Equipment – EMS	6.11%
E398	Miscellaneous Equipment	4.48%

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
	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	
548.1	Operation of energy storage equipment	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	
553.1	Maintenance of energy storage equipment	X	
554	Miscellaneous other power generation plant	X	
	Other Power Supply Expenses		
555	Purchased power		As Billed
555.1	Power purchased for storage operations		As Billed
556	System control and load dispatching	X	
557	Other expenses		As Billed

File [04 Appendices A thru F.pdf] cannot be converted to PDF. (To download this file in its original format, please use the filename hyperlink from your search results. If you continue to experience difficulties, or to obtain a PDF generated version of files, please contact the helpdesk at ferconlinesupport@ferc.gov, or, call 866-208-3676 from 9AM to 5PM EST, weekdays. Please allow at least 48 hours for your helpdesk request to be processed.)

FERC rendition of the electronically filed tariff records in Docket No. ER23-01349-000
Filing Data:
CID: C000824
Filing Title: 2023 Interchange Agreement Annual Filing
Company Filing Identifier: 1125
Type of Filing Code: 10
Associated Filing Identifier:
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Tariff Record Data:
Record Content Description, Tariff Record Title, Record Version Number, Option Code:
Exhibits, Rate Schedules, 0.13.0, A
Record Narative Name:
Tariff Record ID: 200
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Proposed Date: 2023-01-01
Priority Order: 1000000000
Record Change Type: CHANGE
Record Content Type: 1
Associated Filing Identifier:

Exhibits

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

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:

0.962 for NSP(Minn)
0.956 for NSP(Wis)

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

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

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

FORMULA TYPE PROCEDURES FOR DEVELOPMENT OF AMOUNTS OF ENERGY 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 current month, excluding energy requirements fulfilled by energy resources required by certain state energy policies, statutes, or state retail tariffs that are direct assigned to participating customers for ratemaking purposes. [1/] The measured monthly energy requirements shall be adjusted by a Transmission Loss Multiplier.

"Transmission Loss Multipliers" are equal to:

0.961 for NSP(Minn)
0.948 for NSP(Wis)

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

[1/] Including, but not limited to, the NSP (Minn) Windsource® program.

FORMULA TYPE PROCEDURES FOR DEVELOPMENT OF UNIT RATES FOR 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:

0.962 for NSP(Minn)
0.956 for NSP(Wis)

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FORMULA TYPE PROCEDURES FOR DEVELOPMENT OF UNIT RATES FOR ENERGY 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 current month excluding energy requirements fulfilled by energy resources required by certain state energy policies, statutes, or state retail tariffs that are direct assigned to participating customers for ratemaking purposes.[1/] The measured monthly energy requirements shall be adjusted by a Transmission Loss Multiplier.

"Transmission Loss Multipliers" are equal to:

0.961 for NSP(Minn)
0.948 for NSP(Wis)

[1/] Including, but not limited to, the NSP (Minn) Windsource® program.

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

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)		
1.1	Pre-funded Allowance for Funds Used during Construction (Sched. 1.1)		
1.2	Electric Plant Acquisition Adjustments (Sched. 1.2)		
2.	Accumulated Provision for Depreciation (Sched. 2)		
2.1	Accumulated Provision for Amortization of Electric Plant Acquisition Adjustments (Sched. 2.1)		
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)		

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)
10.1 Theoretical Reserve Surplus Amortization Expense (Sched. 8.1)
10.2 Prairie Island Extended Power Uprate Amortization Revenue Requirement (Sched. 8.2)
10.3 Monticello Life Cycle Management / Extended Power Uprate Project Return on Rate Base Adjustment (Sched. 8.3)
10.4 Benson Power Termination Amortization Revenue Requirement (Sched. 8.4)
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)

FORMULA TYPE PROCEDURES FOR DEVELOPMENT OF DEMAND RELATED COSTS

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. Electric Plant in Service balances will exclude amounts related to assets that are direct assigned to participating customers for ratemaking purposes under state retail tariffs. The following FERC Accounts shall be included:

1. Intangible Plant Investment
   Water power and nuclear plant relicensing investment recorded in FERC Account 302. Intangible software directly related to the production and transmission functions recorded in FERC Account 303 and as agreed among the Parties.

2. Production Plant Investment
   Production plant investment recorded in FERC Accounts 310 through 348.

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 Midcontinent Independent System Operator, Inc.'s (MISO) 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.

ELECTRIC PLANT ACQUISITION ADJUSTMENTS

Electric Plant Acquisition Adjustments is recorded in FERC Account 114. The amounts included to determine the charges among the Parties shall include those amounts related to the production function and as agreed among the Parties.

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. Accumulated Provision for Depreciation balances will exclude amounts related to assets that are direct assigned to participating customers for ratemaking purposes under state retail tariffs.

These accounts are classified to the intangible, 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 PROVISION FOR AMORTIZATION OF ELECTRIC PLANT ACQUISITION ADJUSTMENTS

Accumulated Provision for Amortization of Electric Plant Acquisition Adjustments is recorded in FERC Account 115. The amounts included to determine the charges among the Parties shall include those amounts related to the production function and as agreed among the Parties.

ACCUMULATED DEFERRED INCOME TAXES

Accumulated Deferred Income Taxes included in FERC Accounts 190 and 281-283 are classified to the intangible, production, nuclear fuel, transmission, distribution and general plant functions in the same detail as the original cost of the plant in service. Accumulated Deferred Income Tax balances will exclude amounts related to assets that are direct assigned to participating customers for ratemaking purposes under state retail tariffs.

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 Midcontinent Independent 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 (MPUC Docket No. E002/GR-12-961, order dated September 3, 2013) to amortize the NSP (Minn) theoretical reserve surplus (as developed in the table below) beginning January 1, 2013 over a period other than the average remaining life. The NSP (Wis) portion of the theoretical reserve surplus is $26,674,271.

In the NSP (Minn) 2014 test year Minnesota retail electric rate case (MPUC Docket No. E002/GR-13-868, order dated May 8, 2015), the MPUC approved the balance of the remaining theoretical reserve surplus for transmission, distribution, intangible and general functions of plant to be amortized in a pattern of 50 percent for 2014, 30 percent for 2015, and 20 percent for 2016. The regulatory asset set-up was completed at the end of 2016 as detailed in the table below.

In the NSP (Minn) 2017 Annual Review of Remaining Lives (MPUC Docket No. E,G002/D-17-147, order dated February 8, 2018), the MPUC approved the amortization rates of the regulatory asset created through the amortization of the NSP (Minn) theoretical reserve surplus, effective January 1, 2017.

The accumulated amortization amounts are based on the schedule provided in Exhibit V, Schedule 8.1.

Balances as of 12/31/2016			
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.

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 6 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, or such date after January 1 determined by the Coordinating Committee, 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 such 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 of 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)
4.1 Production Tax Credit (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)
10.1 Production Tax Credit (Line 4.1)
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, Production 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.

Production Tax Credit

The Production Tax Credit is recorded in FERC Account 409.1. The amounts included for the calculation of income taxes are those amounts attributable to the plant investment related to the production function. Production Tax Credit will exclude amounts related to assets that are direct assigned to participating customers for ratemaking purposes under state retail tariffs.

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. Income Tax Depreciation will exclude amounts related to assets that are direct assigned to participating customers for ratemaking purposes under state retail tariffs.

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. Depreciation and amortization expense will exclude amounts related to assets that are direct assigned to participating customers for ratemaking purposes under state retail tariffs.

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 related to the theoretical reserve surplus. Theoretical Reserve Surplus Amortization Expense included in determining the charges among the Parties is recorded in FERC Account 407.4 (creation of Regulatory Asset) and FERC Account 407.3 (amortization of Regulatory Asset) by the plant functional classifications.

In the NSP (Minn) 2013 test year Minnesota retail electric rate case (MPUC Docket No. E002/GR-12-961, order dated September 3, 2013), the MPUC approved the amortization of the theoretical reserve surplus over a period other than the average remaining life. The NSP (Wis) portion of the theoretical reserve surplus is $26,674,271.

In the NSP (Minn) 2014 test year Minnesota retail electric rate case (MPUC Docket No. E002/GR-13-868, order dated May 8, 2015), the MPUC approved the accelerated amortization of the theoretical reserve surplus. Specifically, the MPUC approved the balance of the remaining theoretical reserve surplus for transmission, distribution, intangible and general functions of plant be amortized in a pattern of 50 percent for 2014, 30 percent for 2015, and 20 percent for 2016. Please refer to Exhibit V, Schedule 4.2. As of December 31, 2016, the theoretical reserve surplus was fully amortized.

In the NSP (Minn) 2017 Annual Review of Remaining Lives (MPUC Docket No. E,G002/D-17-147, order dated February 8, 2018), the MPUC approved the amortization rates to unwind the Regulatory Asset created through the amortization of the theoretical reserve surplus, effective January 1, 2017.

The table below shows the annual amortization expense amount beginning in 2013 and continuing through the remaining lives of the associated plant. Consistent with remaining life theory, NSP (Minn) will amortize the regulatory asset through an expense in FERC Account 407.3 and an offsetting credit to expense in FERC Account 403.

Theoretical Reserve Surplus Amortization Expense

Year	Transmission	Distribution	General	Total
2013	($3,330,665)	($2,256)	($1,362)	($3,334,283)
2014	($11,657,328)	($7,898)	($4,768)	($11,669,994)
2015	($6,994,397)	($4,738)	($2,861)	($7,001,996)
2016	($4,662,931)	($3,159)	($1,907)	($4,667,997)
2017	$630,625	$490	$1,857	$632,972
2018	$630,625	$490	$1,857	$632,972
2019	$630,625	$490	$1,857	$632,972
2020	$630,625	$490	$1,857	$632,972
2021	$630,625	$490	$1,857	$632,972
2022	$630,625	$490	$1,615	$632,730
2023	$630,625	$490	$0	$631,115

THEORETICAL RESERVE SURPLUS AMORTIZATION EXPENSE

Year	Transmission	Distribution	General	Total
2024	$630,625	$490	$0	$631,115
2025	$630,625	$490	$0	$631,115
2026	$630,625	$490	$0	$631,115
2027	$630,625	$490	$0	$631,115
2028	$630,625	$490	$0	$631,115
2029	$630,625	$490	$0	$631,115
2030	$630,625	$490	$0	$631,115
2031	$630,625	$490	$0	$631,115
2032	$630,625	$490	$0	$631,115
2033	$630,625	$490	$0	$631,115
2034	$630,625	$490	$0	$631,115
2035	$630,625	$490	$0	$631,115
2036	$630,625	$490	$0	$631,115
2037	$630,625	$490	$0	$631,115
2038	$630,625	$490	$0	$631,115
2039	$630,625	$490	$0	$631,115
2040	$630,625	$490	$0	$631,115
2041	$630,625	$490	$0	$631,115
2042	$630,625	$490	$0	$631,115
2043	$630,625	$490	$0	$631,115
2044	$630,625	$490	$0	$631,115
2045	$630,625	$490	$0	$631,115
2046	$630,625	$490	$0	$631,115
2047	$630,625	$490	$0	$631,115
2048	$630,625	$490	$0	$631,115
2049	$630,625	$490	$0	$631,115
2050	$630,625	$490	$0	$631,115
2051	$630,625	$490	$0	$631,115
2052	$630,625	$485	$0	$631,110
2053	$557,037	$408	$0	$557,445
2054	$525,623	$0	$0	$525,623
2055	$525,623	$0	$0	$525,623
2056	$445,622	$0	$0	$445,622
2057	$230,462	$0	$0	$230,462
2058	$225,990	$0	$0	$225,990
2059	$225,990	$0	$0	$225,990
2060	$225,990	$0	$0	$225,990
2061	$225,990	$0	$0	$225,990
2062	$225,990	$0	$0	$225,990
2063	$225,990	$0	$0	$225,990
2064	$153,398	$0	$0	$153,398
2065	$123,777	$0	$0	$123,777
2066	$17,670	$0	$0	$17,670
2067	$2,974	$0	$0	$2,974
2068	$2,974	$0	$0	$2,974
2069	$1,712	$0	$0	$1,712

PRAIRIE ISLAND EXTENDED POWER UPRATE AMORTIZATION REVENUE REQUIREMENT

This Schedule 8.2 explains the Prairie Island Nuclear Plant Extended Power Uprate (PI EPU) amortization expense revenue requirement calculation for purposes of this Agreement.

The PI EPU amortization revenue requirement is equal to the current year amortization and calculated return on rate base of NSP (Wis)'s portion ($11,996,581) of the total actual PI EPU cancelled project costs ($78,884,915) over the remaining life of the Prairie Island plant as determined by the Minnesota Public Utilities Commission (MPUC) in the NSP (Minn) 2014 test year rate case, Docket No. E002/GR-13-868.

NSP (Wis)'s portion of the total actual PI EPU cancelled project costs is based on the application of the coincident peak demand ratios accepted by the Commission for the Interchange Agreement in Docket No. ER14-1325-000. The annual amortization amount is calculated based on the 18.3-year remaining life of the Prairie Island Plant beginning on January 1, 2016. The annual amortization amount is calculated as follows:

	Total	NSP (Minn.)	NSP (Wis.)
Demand Allocation Between Parties	100.0000%	84.7923%	15.2077%
PI EPU Abandoned Plant Costs	$78,884,915	$66,888,334	$11,996,581
Annual Amortization Expense	$ 4,302,814	$ 3,648,455	$ 654,359

NSP (Minn)'s demand related cost of service used in determining billings to NSP (Wis) shall also include a return on the rate base associated with the unrecovered balance of PI EPU cancelled project costs including Allowance for Funds Used During Construction (AFUDC). The return on rate base shall be calculated as the 13 month average rate base of the PI EPU cancelled project costs, less accumulated amortization, less accumulated deferred income taxes multiplied by the NSP (Minn) weighted debt-only cost of capital. The cost of capital used to calculate the return on rate base shall include only the cost of debt at the current NSP (Minn) rate and capital structure percentage as determined under Exhibit V, Schedule 6.

NSP (Minn)'s demand related cost of service used in determining billings to NSP (Wis) for the period commencing January 1, 2016, shall include $654,359 per year for purposes of amortizing expenditures on the cancelled PI EPU project. The inclusion of that amount shall continue until NSP (Minn) has recovered from NSP (Wis) its share ($11,996,581) of the total actual PI EPU cancelled project costs including AFUDC. In the last month of the amortization, an amount of less than one-twelfth of the $654,359 may be included in the fixed charges to achieve precise recovery of the PI EPU cancelled project costs.

The PI EPU cancelled project costs included in determining the charges among the Parties are recorded by NSP (Minn) in Account 182.2 Unrecovered Plant and Regulatory Study Costs. PI EPU amortization expense is recorded by NSP (Minn) in Account 407 Amortization of Property Losses, Unrecovered Plant and Regulatory Study Costs.

This schedule will be effective beginning January 1, 2016.

MONTICELLO LIFE CYCLE MANAGEMENT / EXTENDED POWER UPRATE PROJECT RETURN ON RATE BASE ADJUSTMENT

Demand related costs will be reduced by the return on rate base for a portion of the Monticello Life Cycle Management/Extended Power Uprate (Monticello LCM/EPU) Project for purposes of this Agreement. The reduction incorporates into the Interchange Agreement billings from NSP (Minn.) to NSP (Wis.) the Minnesota Public Utilities Commission (MPUC) Orders in Docket No. E002/CI-13-754 (Investigation into Xcel Energy's Monticello LCM/EPU Project and Request for Recovery of Cost Overruns) and Docket No. E002/GR-13-868 (Application of Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota), (together the "Monticello LCM/EPU Orders").

The Monticello LCM/EPU Orders approved recovery of the total project cost, but limited recovery of the return on rate base to the original MPUC Certificate of Need application amounts, escalated, including AFUDC, to $415 million. The MPUC Order in Docket No. E002/GR-13-868 issued August 31, 2015, clarified that all (past, present and future) depreciation expense recorded in the accumulated depreciation reserve be allocated on a pro-rated basis between the total project cost that earns a return ($415 million) and the total project cost that does not earn a return (amounts in excess of $415 million).

The adjustment shall be calculated by determining the return on rate base and associated income taxes on the Monticello LCM/EPU Project prorated rate base not allowed a return and applying the NSP (Wis.) demand allocation percent. The Monticello LCM/EPU Project prorated rate base not allowed a return will be determined by applying the percentage of total Monticello LCM/EPU Project costs in excess of $415 million to total Monticello LCM/EPU Project costs to each component of the Total Monticello LCM/EPU Project rate base (plant in service, accumulated provision for depreciation, and accumulated deferred income taxes).

The reduced return on rate base shall continue until the Monticello LCM/EPU Project is fully depreciated, currently expected to be 2030.

BENSON POWER TERMINATION AMORTIZATION REVENUE REQUIREMENT

Demand related costs will be adjusted to include an amortization and return on the rate base of the costs incurred by NSP (Minn) to acquire the Benson Power, LLC ("Benson Power") biomass generating plant, terminate the power purchase agreement with Benson Power, and subsequently close and dismantle the Benson Power facility (collectively the "Total Actual Benson Power Termination Costs"). This adjustment incorporates into the Interchange Agreement billings from NSP (Minn.) to NSP (Wis.) the Minnesota Public Utilities Commission (MPUC) Order in Docket No. E002/M-17-530 (Petition to Terminate the PPA with Benson Power, LLC) and the FERC Order in Docket No. EC17-166-000 (approving the NSP (Minn) purchase of the Benson Power, LLC facility).

The Benson Power termination revenue requirement is equal to the current year amortization and calculated return on rate base of NSP (Wis)'s portion of the total actual costs incurred by NSP (Minn) to acquire the Benson Power generating plant, terminate the power purchase agreement with Benson Power, and close and dismantle the Benson Power facility and remediate the site of the Benson Power facility ("Benson Power Termination Costs").

The annual amortization charge to NSP (Wis) will be calculated as follows:

1.		Total Actual Benson Power Termination Costs
2.	Multiply	NSP (Wis)'s Share of the 2018 NSP System Budget Energy Ratio
3.	Equals	NSP (Wis)'s Portion of the Total Actual Benson Power Termination Costs
4.		NSP (Wis)'s Portion of the Total Actual Benson Power Termination Costs
5.	Divide	Period of Time between Termination Date and Contract Expiration (9/10/2028)
6.	Equals	Annual Amortization Charge to NSP (Wis)

A return on rate base will be calculated on the unrecovered balance of Benson Power Termination Costs. The return on rate base will be calculated as the 13 month average rate base of the actual incurred Benson Power Termination Costs, less accumulated amortization, less accumulated deferred income taxes multiplied by the NSP (Minn) cost of capital. The cost of capital shall be based on the NSP (Minn) currently authorized State of Minnesota retail electric return on equity and the cost of debt and capital structure percentage as determined under Exhibit V, Schedule 6, Return on Rate Base.

The Benson Power Termination Costs included in determining the charges among the Parties are recorded by NSP (Minn) in Account 182.2, Unrecovered Plant and Regulatory Study Costs, and Account 182.3, Other Regulatory Assets. The Benson Power Termination amortization expense is recorded by NSP (Minn) in Account 407, Amortization of Property Losses, Unrecovered Plant and Regulatory Study Costs, and Account 557, Other Expenses.

This schedule will be effective on the month and day NSPM acquires the Benson Power facility and terminates the power purchase agreement with Benson Power, and will continue through the contract expiration date of September 10, 2028.

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. Provision for Deferred Income Taxes will exclude amounts related to assets that are direct assigned to participating customers for ratemaking purposes under state retail tariffs.

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. The Property Tax expense or taxes in lieu of property taxes will exclude amounts related to assets that are direct assigned to participating customers for ratemaking purposes under state retail tariffs.

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. Insurance Expense will exclude amounts related to assets that are direct assigned to participating customers for ratemaking purposes under state retail tariffs.

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 Production Operating and Maintenance Expenses will exclude amounts related to assets that are direct assigned to participating customers for ratemaking purposes under state retail tariffs.

FIXED REGIONAL MARKET OPERATING AND MAINTENANCE EXPENSE

Regional Market 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, 456 - Other Electric Revenues, and 456.1 – Revenues From Transmission of Electricity of Others. These revenues are credited to transmission operating and maintenance expenses.

Provision for rate refunds recorded in FERC Account 449.1 include transmission related amounts being collected subject to refund which are estimated to be required to be refunded.

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 Production Operating and Maintenance Expenses will exclude amounts related to assets that are direct assigned to participating customers for ratemaking purposes under state retail tariffs.

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 and FERC Account 555.1 – Power Purchased for Energy Storage Operations. 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. Purchased Power Energy Costs shall be adjusted to exclude amounts related to energy requirements fulfilled by energy resources required by certain state energy policies, statutes, or state retail tariffs that are direct assigned to participating customers for ratemaking purposes.[1/]

[1/] Including, but not limited to, the NSP (Minn) Windsource® program. For the community solar garden programs and other programs similar in nature, the actual cost of such energy shall be excluded from FERC Account 555 and substituted with the market cost of such generation. The market cost shall be calculated using the hourly day-ahead locational marginal price ("LMP") from the MISO energy market. Costs incurred for community solar garden generation power above the amount calculated using the hourly day-ahead LMP will be direct assigned to NSP (Minn) or NSP (Wis) and the applicable state jurisdiction approving the solar garden.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy **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 10.40%.

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

SPECIFICATION OF AVERAGE MONTHLY COINCIDENTAL PEAK DEMANDS

Calendar Year 2023 Contract Year
Monthly Coincidental Peak Demands (KW)

		NSP (Minn)	NSP (Wis)	Total System
2021	January	4,838	1,024	5,862
	February	5,126	1,096	6,222
	March	4,576	981	5,557
	April	4,465	837	5,302
	May	5,862	1,057	6,919
	June	7,507	1,330	8,837
	July	7,546	1,214	8,760
	August	7,216	1,232	8,448
	September	6,008	996	7,004
	October	5,119	992	6,111
	November	4,643	950	5,593
	December	5,108	1,061	6,169
	Total	68,014	12,770	80,784
2022	January	5,352	1,071	6,423
	February	5,194	1,016	6,210
	March	4,798	965	5,763
	April	4,628	938	5,566
	May	5,607	1,125	6,732
	June	7,883	1,362	9,245
	July	7,131	1,319	8,450
	August	7,173	1,277	8,450
	September	6,351	1,126	7,477
	October	4,688	978	5,666
	November	4,793	991	5,784
	December	5,188	1,109	6,297
	Total	68,786	13,277	82,063
2023	January	5,207	1,121	6,328
	February	4,980	1,086	6,066
	March	4,741	1,042	5,783
	April	4,379	881	5,260
	May	5,449	1,071	6,520
	June	7,105	1,312	8,417
	July	7,142	1,344	8,486
	August	7,189	1,297	8,486
	September	6,304	1,140	7,444
	October	4,619	978	5,597
	November	4,710	993	5,703
	December	5,134	1,102	6,236
	Total	66,959	13,367	80,326

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

SPECIFICATION OF COMPOSITE DEPRECIATION RATES 2023 CONTRACT YEAR

The annual composite depreciation rates for production are calculated based on forecasted depreciation expense accruals and average plant balances. The forecasted depreciation expense is calculated based on approved remaining life depreciation lives and rates certified by the respective state Commissions for NSP (Minn) and NSP (Wis). Rates for transmission, distribution, and general functions are the approved rates for each plant account. NSP (Minn)'s rates are a blended calculation of the approved rates in Minnesota, North Dakota, and South Dakota. NSP (Wis)'s approved rates are the same for both the Wisconsin and Michigan jurisdictions. 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
PRODUCTION			
E311	STEAM	Structures and Improvements	4.68%
E312	STEAM	Boiler Plant Equipment	3.86%
E314	STEAM	Turbogenerator Units	3.48%
E315	STEAM	Accessory Electric Equipment	3.68%
E316	STEAM	Miscellaneous Power Plant Equipment	4.23%
E302	NUCLEAR	Franchises & Consents	5.45%
E321	NUCLEAR	Structures and Improvements	4.98%
E322	NUCLEAR	Reactor Plant Equipment	4.41%
E323	NUCLEAR	Turbogenerator Units	3.85%
E324	NUCLEAR	Accessory Electric Equipment	4.50%
E325	NUCLEAR	Miscellaneous Power Plant Equipment	4.97%
E302	HYDRO	Franchises & Consents	3.74%
E331	HYDRO	Structures and Improvements	6.99%
E332	HYDRO	Reservoirs, Dams and Waterways	5.54%
E333	HYDRO	Water Wheels, Turbines & Generators	5.73%
E334	HYDRO	Accessory Electric Equipment	5.96%
E335	HYDRO	Miscellaneous Power Plant Equipment	5.45%
E336	HYDRO	Roads, Railroads and Bridges	1.76%
E340.1	OTHER	Wind Rights	2.61%
E341	OTHER	Structures and Improvements	4.02%
E342	OTHER	Fuel Holders, Producers & Accessories	4.71%
E343	OTHER	Prime Movers	3.58%
E344	OTHER	Generators	4.36%
E345	OTHER	Accessory Electric Equipment	4.24%
E346	OTHER	Miscellaneous Power Plant Equipment	5.19%
E348	OTHER	Energy Storage Equipment – Production	0.00%

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TRANSMISSION		
E351	Energy Storage Equipment – Transmission	0.00%
E352	Structures and Improvements	1.50%
*E352	Structures and Improvements-Prod.	1.50%
E353	Station Equipment	2.05%
*E353	Station Equipment-Prod.	2.05%
E354	Towers and Fixtures	1.77%
*E354	Towers and Fixtures-Prod.	1.77%
E355	Poles and Fixtures	2.40%
*E355	Poles and Fixtures-Prod.	2.40%
E356	Overhead Conductors & Devices	2.03%
*E356	Overhead Conductors & Devices-Prod.	2.03%
E357	Underground Conduit	1.36%
E358	Underground Conductors & Devices	2.07%
DISTRIBUTION		
E361	Structures and Improvements	2.08%
*E361	Structures and Improvements-Prod.	2.09%
E362	Station Equipment	2.32%
*E362	Station Equipment-Prod.	2.34%
E363	Energy Storage Equipment – Distribution	0.00%
E364	Poles, Towers and Fixtures	4.59%
E365	Overhead Conductors and Devices	3.19%
E366	Underground Conduit	2.13%
E367	Underground Conductor and Devices	2.21%
E368	Line Transformers	3.26%
E368	Line Capacitors	3.97%
E369	Overhead Services	4.28%
E369	Underground Services	2.36%
E370	Meters	6.27%
E370.2	AGIS Meters	5.02%
E370.3	Electric Vehicle Chargers	10.00%
E373	Street Lighting and Signal Systems	5.65%

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<u>GENERAL - ELECTRIC</u>		
E302	Franchises & Consents	4.97%
E303	Intangible Plant – 5 Year	19.53%
E303	Intangible Plant – 10 Year	10.31%
E390	Structures and Improvements	1.88%
E391	Office Furniture and Equipment	4.87%
E391	Network Equipment	17.51%
E392	Transportation Equipment – Auto	9.75%
E392	Transportation Equipment – Light Truck	9.81%
E392	Transportation Equipment – Trailers	6.28%
E392	Transportation Equipment – Heavy Trucks	7.13%
E393	Stores Equipment	4.55%
E394	Tools, Shop and Garage Equipment	6.58%
E395	Laboratory Equipment	10.62%
E396	Power Operated Equipment	5.53%
E397	Communication Equipment – General	10.45%
E397	Communication Equipment – Two Way	10.38%
E397	Communication Equipment – AMR	5.02%
*E397	Communication Equipment – EMS	6.29%
E397	Communication Equipment – Smart Grid	5.68%
E398	Miscellaneous Equipment	6.80%

The Nuclear Decommissioning annual accrual is an approved amount which is recovered from customers to fund the decommissioning of the Monticello and Prairie Island nuclear generating facilities.

Jurisdiction	2023 Approved Accrual	Docket No./Case No.
Minnesota Retail	$21,571,110	E002/M-20-855
North Dakota Retail	$2,250,002	PU-20-441
South Dakota Retail	$1,234,251	EL14-058
Wisconsin Retail	$9,300,588	E002/M-20-855 4220-UR-125

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

SPECIFICATION OF COMPOSITE DEPRECIATION RATES 2023 CONTRACT YEAR

NSP (Wis)

FERC ACCOUNT		DESCRIPTION	ANNUAL DEPRECIATION RATE
PRODUCTION			
E311	STEAM	Structures and Improvements	5.63%
E312	STEAM	Boiler Plant Equipment	4.82%
E314	STEAM	Turbogenerator Units	4.44%
E315	STEAM	Accessory Electric Equipment	6.01%
E316	STEAM	Miscellaneous Power Plant Equipment	3.78%
E302	HYDRO	Franchises & Consents	1.48%
E331	HYDRO	Structures and Improvements	3.43%
E332	HYDRO	Reservoirs, Dams and Waterways	4.11%
E333	HYDRO	Water Wheels, Turbines & Generators	4.57%
E334	HYDRO	Accessory Electric Equipment	5.26%
E335	HYDRO	Miscellaneous Power Plant Equipment	4.65%
E341	OTHER	Structures and Improvements	3.77%
E342	OTHER	Fuel Holders, Producers & Accessories	3.84%
E343	OTHER	Prime Movers	4.38%
E344	OTHER	Generators	4.53%
E345	OTHER	Accessory Electric Equipment	4.65%
E346	OTHER	Miscellaneous Power Plant Equipment	2.08%
E348	OTHER	Energy Storage Equipment – Production	0.00%
TRANSMISSION			
E351		Energy Storage Equipment – Transmission	0.00%
E352		Structures and Improvements	2.09%
*E352		Structures and Improvements-Prod.	2.09%
E353		Station Equipment	2.80%
*E353		Station Equipment-Prod.	2.80%
E354		Towers and Fixtures	1.80%
E355		Poles and Fixtures	3.28%
E356		Overhead Conductors & Devices	2.80%
E357		Underground Conduit	1.76%
E358		Underground Conductors & Devices	2.77%
E359		Roads and Trails	1.75%

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Exhibit IX

DISTRIBUTION

E361	Structures and Improvements	2.03%
*E361	Structures and Improvements – Prod.	2.03%
E362	Station Equipment	2.51%
*362	Station Equipment – Prod.	2.51%
E363	Energy Storage Equipment – Distribution	10.00%
E364	Poles, Towers and Fixtures	5.26%
E365	Overhead Conductors and Devices	3.51%
E366	Underground Conduit	1.62%
E367	Underground Conductor and Devices	2.24%
E368	Line Transformers	2.28%
E368	Line Capacitors	2.66%
E369	Overhead Services	3.61%
E369	Underground Services	2.73%
E370	Meters	4.54%
E370.1	Meters – Old	0.00%
E370.2	Meters – AMR	4.84%
E371	Customer Installations	0.00%
E371.4	Installations on Customer's Premises-EV	10.00%
E371.5	Customer Prem-REMS	3.33%
E373	Street Lighting and Signal Systems	5.72%

GENERAL ELECTRIC

E302	Franchises & Consents	5.00%
E303	Intangible Plant – 3 Year	33.33%
E303	Intangible Plant – 5 Year	25.98%
E303	Intangible Plant – 7 Year	14.29%
E303	Intangible Plant – 10 Year	10.00%
E303	Intangible Plant – 15 Year	6.67%
E390	Structures and Improvements	2.17%
E391	Office Furniture and Equipment	4.57%
E391	Network Equipment	18.83%
E392	Transportation Equipment – Auto	12.67%
E392	Transportation Equipment – Light Truck	12.38%
E392	Transportation Equipment – Trailers	5.62%
E392	Transportation Equipment – Heavy Truck	8.21%
E393	Stores Equipment	4.45%
E394	Tools, Shop and Garage Equipment	4.80%
E395	Laboratory Equipment	3.45%
E396	Power Operated Equipment	5.96%
E397	Communication Equipment – AES/AMR	6.11%
*E397	Communication Equipment – EMS	6.11%
E398	Miscellaneous Equipment	4.48%

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	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	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	
548.1	Operation of energy storage equipment	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	
553.1	Maintenance of energy storage equipment	X	
554	Miscellaneous other power generation plant	X	
	Other Power Supply Expenses		
555	Purchased power		As Billed
555.1	Power purchased for storage operations		As Billed
556	System control and load dispatching	X	
557	Other expenses		As Billed

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