Xcel Energy®

414 Nicollet Mall
Minneapolis, MN 55401

January 28, 2014

— VIA E-MAIL & FEDERAL EXPRESS —

RECEIVED
JAN 28 2014
NORTH DAKOTA
PUBLIC SERVICE COMMISSION

Darrell Nitschke
Executive Secretary
North Dakota Public Service Commission
State Capitol Building
600 East Boulevard, Dept. 408
Bismarck, ND 58505-0480

RE: NORTHERN STATES POWER COMPANY FOR
ELECTRIC RATE INCREASE APPLICATION
HEARING EXHIBIT R
CASE NOS. PU-12-813, PU-13-706, PU-13-707, PU-13-708, PU-13-742, PU-13-743, PU-13-194, PU-13-195

Dear Mr. Nitschke:

In follow-up to the Commission's January 23, 2014 hearing on the Comprehensive Settlement in the above referenced Cases, Northern States Power Company, submits Late Filed Exhibit R and and updated Exhibit List showing all NSP, NDPSC Staff and hearing exhibits.

During Mr. Sparby's testimony at the formal hearing, he discussed the Coordinating and Interchange Agreement from the 1980's by which the two NSP operating companies, NSPM and NSPW, share costs for the benefit of the entire system. Mr. Sparby also indicated recollection of a related Settlement Agreement to which multiple state regulatory commissions were signatories, resulting in a similar examination of demand allocation methodologies as is contemplated by the current Settlement Agreement in this case. At the request of Commission Advisory Counsel, these documents were requested to be submitted as Exhibit R. A brief description of each of the 3 documents comprising Exhibit R is included as the first page of the exhibit.

68 PU-13-194 Filed: 1/28/2014 Pages: 159
Late-filed Exhibit R and updated Exhibit List

74 PU-13-195 Filed: 1/28/2014 Pages: 159
Late-filed Exhibit R and updated Exhibit List

67 PU-13-743 Filed: 1/28/2014 Pages: 159
Late-filed Exhibit R and updated Exhibit List

67 PU-13-707 Filed: 1/28/2014 Pages: 159
Late-filed Exhibit R and updated Exhibit List

68 PU-13-742 Filed: 1/28/2014 Pages: 159
Late-filed Exhibit R and updated Exhibit List

67 PU-13-706 Filed: 1/28/2014 Pages: 159
Late-filed Exhibit R and updated Exhibit List

67 PU-13-708 Filed: 1/28/2014 Pages: 159
Late-filed Exhibit R and updated Exhibit List

182 PU-12-813 Filed: 1/28/2014 Pages: 159
Late-filed Exhibit R and updated Exhibit List

Please contact me if you have any questions regarding the information included in this submittal. I can be reached at debra.j.paulson@xcelenergy.com or 612-330-7571.

Sincerely,

DEBRA J. PAULSON
MANAGER, RATE CASES
NORTHERN STATES POWER COMPANY

cc: Via Electronic Mail Only:
Patrick Ward, Administrative Law Judge
Illona Jeffcoat-Sacco, NDPSC Advisory Staff Counsel
Mitch Armstrong, NDPSC Advisory Staff Counsel
Ryan Norrell, NDPSC Advocacy Staff Counsel
Kari Valley, NSP Counsel
Zeviel Simpser, Briggs & Morgan Outside Counsel for NSP
Mike Diller, NDPSC Advocacy Staff
Sara Cardwell, NDPSC Advocacy Staff
Pat Fahn, NDPSC Advisory Staff
Jerry Lein, NDPSC Advisory Staff

Northern States Power Company
2013 Electric Rate Increase
Application
Case No. PU-12-813

Formal Hearings 01/23/14
Exhibit List

Offered/Accepted	Exhibit	Document Description	Witness	Offering Party
NSP Exhibits: 08/27-13 – 8/29/13				
Stipulated	NSP-1	Cover Letter, Index, Rate Petition, Deficiency & Proposed Revenue Schedules, Interim Petition and Schedules	N/A	NSP
Stipulated	NSP-2	Interim Rate Tariffs (legislative & non-legislative)	N/A	NSP
Stipulated	NSP-3	Tariff Summary and Proposed Tariffs (legislative & non-legislative)	N/A	NSP
Stipulated	NSP-4	Revenue Analysis Workpapers	**Heuer, Anne**	NSP
Stipulated	NSP-5	Direct – Public	**McCarten**, Laura	NSP
Stipulated	NSP-6	Rebuttal – Public	**McCarten**, Laura	NSP
Stipulated	NSP-7	Direct – Public	**Foss,** Steven	NSP
Stipulated	NSP-8	Direct – Public	**O'Connor,** Timothy	NSP
Stipulated	NSP-9A	Rebuttal – Public	**O'Connor,** Timothy	NSP
Stipulated	NSP-9B	Rebuttal – Non-Public	**O'Connor,** Timothy	NSP
Stipulated	NSP-10A	Rebuttal – Public	**Koenig,** Sharon	NSP
Stipulated	NSP-10B	Rebuttal – Non-Public	**Koenig,** Sharon	NSP
Stipulated	NSP-11	Direct – Public	**Perkett,** Lisa	NSP
Stipulated	NSP-12	Rebuttal –Public	**Perkett,** Lisa	NSP
Stipulated	NSP-13	Rebuttal – Public	**Brockett, Scott**	NSP
Stipulated	NSP-14	Direct – Public	**Bulkley,**Ann	NSP
Stipulated	NSP-15	Rebuttal – Public	**Bulkley,** Ann	NSP
Stipulated	NSP-16A	Supplemental Direct – Public	**Wishart,** Steven	NSP
Stipulated	NSP-16B	Supplemental Direct – Non-Public	**Wishart,** Steven	NSP
Stipulated	NSP-17	Rebuttal – Public	**Wishart,** Steven	NSP
Stipulated	NSP-18	Direct - Public	**Heuer,** Anne	NSP
Stipulated	NSP-19	Rebuttal - Public	**Heuer,** Anne	NSP
Stipulated	NSP-20	Direct – Public	**Peppin,** Michael	NSP
Stipulated	NSP-21	Direct – Public	**Huso,** Steven	NSP
Stipulated	NSP-22	Rebuttal – Public	**Huso,** Steven	NSP

Northern States Power Company
2013 Electric Rate Increase
Application
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Formal Hearings 01/23/14
Exhibit List

Offered/Accepted	Exhibit	Document Description	Witness	Offering Party
	NSP-23	Opening Statement	McCarten	NSP
	NSP-24	Opening Statement	Foss	NSP
	NSP-25	Opening Statement	O'Connor	NSP
	NSP-26	Opening Statement	Koenig	NSP
	NSP-27	Opening Statement	Perkett	NSP
	NSP-28	Opening Statement	Brocket	NSP
	NSP-29	Opening Statement	Bulkley	NSP
	NSP-30	Opening Statement	Wishart	NSP
	NSP-31	Opening Statement	Heuer	NSP
	NSP-32	Opening Statement	Peppin	NSP
	NSP-33	Opening Statement	Huso	NSP
	NSP-34	NSP 10K (12-31-12)	Majoros Cross	NSP
	NSP-35	Yahoo Finance 1-yr look from Aug 2012- Aug 2013	King Cross	NSP
	NSP-36	Moody's (St. Louis fed, corp bond) Jan 2012-July 2013	King Cross	NSP
	NSP-37	DR1-004 Supplement		NSP
	NSP-38	Corrections to Filed Testimony		NSP
NSP Exhibits: 01/23/14				
Stipulated	NSP-39	Settlement Agreement dated December 13, 2013, including cover letter, agreement and Attachments A through G	Jointly by Advocacy Staff and NSP	
Stipulated	NSP-40	Supplemental Testimony Supporting Settlement - Public	Sparby	NSP
Stipulated	NSP-41	Supplemental Testimony Supporting Settlement - Public	Sederquist	NSP
Stipulated	NSP-42	Supplemental Testimony Supporting Settlement – Non-Public	Sederquist	NSP

Northern States Power Company
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Exhibit List

Offered/Accepted	Exhibit	Document Description	Witness	Offering Party
Stipulated	NSP-43	Settlement Workpapers – Non-Public		NSP
Stipulated	NSP-44	NSP Response to December 10, 2013 Notice (12/20/13)		NSP
PSC Advocacy Staff Exhibits: 08/27-13 – 8/29/13				
Stipulated	PSC-1	Direct Testimony & Exhibits	**Majoros**, Michael J.	PSC
Stipulated	PSC-2	Supplemental Testimony	**Majoros**, Michael J.	PSC
Stipulated	PSC-3	Direct Testimony & Exhibits	**King**, Charles W.	PSC
Stipulated	PSC-4	Revised Direct Testimony & Exhibits	**Mugrace**, Dante	PSC
Stipulated	PSC-5	Direct Testimony & Exhibits	**Pavlovic**, Karl Richard	PSC
Stipulated	PSC-6	Supplemental Testimony	**Pavlovic**, Karl Richard	PSC
Stipulated	PSC-7	Direct Testimony & Exhibits	**Cardwell**, Sara	PSC
	PSC-8	Table from 8-15-13 Cable Report (reporting required from last rate case)		PSC
	PSC-9	Attachment A to DR 10-003		PSC
	PSC-10	GND Chamber info (3 pgs)		PSC
	PSC-11	DR Response 8-68 Supplement		PSC
	PSC-12	Monthly Peaks 2005-2012 (Cardwell prepared graph from Brocket Schedule 2)		PSC

Northern States Power Company
2013 Electric Rate Increase
Application
Case No. PU-12-813

Formal Hearings 01/23/14
Exhibit List

Offered/Accepted	Exhibit	Document Description	Witness	Offering Party
	PSC-13	Empire Distribution Value Line Chart		PSC
	PSC-14	DR Response 5-14		PSC
	PSC-15	DR Response 5-65		PSC
	PSC-16	Opening Statement	Majoros	PSC
	PSC-17	Opening Statement	King	PSC
	PSC-18	Blue Chip Forecast/Actual Comparison	King	PSC
	PSC-19	Opening Statement	Pavlovic	PSC
	PSC-20	Opening Statement	Mugrace	PSC
	PSC-21	Opening Statement	Cardwell	PSC
	PSC-22	Correction to Testimony (To be filed)		PSC
PSC Advocacy Staff Exhibits: 01/23/14				
Stipulated	PSC-23	Direct Testimony of Advocacy Staff Supporting Settlement	Diller	PSC
Stipulated	PSC-24	Additional Direct Testimony of Advocacy Staff Supporting Settlement	Diller	PSC
Stipulated	PSC-25	NDPSC December 10, 2013 Notice of Intent to Consider Records in Case Nos.: PU-13-706, PU-13-707, PU-13-708, PU-13-194, PU-13-195, PU-13-742, PU-13-743, PU-09-61, PU-10-580, PU-07-790		PSC

Northern States Power Company
2013 Electric Rate Increase
Application
Case No. PU-12-813

Formal Hearings 01/23/14
Exhibit List

ALJ Directed Late-Filed Exhibits

Ex. A	Jurisdictional Demand Allocator - Order approving 12CP and identification of prior method used.
Ex. B	Pending ADP Cases for Which Cost Recovery is Not Requested in PU-12-813
Ex. B-1	Trade Secret version of Response to Data Request 2-8
Ex. C	Charitable & Economic Development Expenditures over part 20 Years
Ex. D	Opportunity for us of Intelliteam switched in Grand Forks, Minot or more in Fargo.
Ex. E	Demonstration of Cost Savings by Having Annual Incentive Plans
Ex. F	J.P. Morgan Report (August 20, 2013)
Ex. G	State of New York Orders demonstrating use of sustainable growth models
Ex. H	2012 End of Year ND Jurisdiction Utility Plant in Service
Ex. I	July 2013 Sales Forecast Update—ND Jurisdiction Total Sales for 2013 by Customer Class by Month
Ex. J	Updated Monthly Billed/Net Unbilled and Calendar Interim Rate Revenues (update data request response 5-65 for Apr-Jul 2013
Ex. K	Executive compensation assigned to ND Jurisdiction
Ex. L	Lobbing Cost -- Definition and Rate Case Treatment
Ex. M	Pension – Expected Returns and % Funding Levels, including explanation
Ex. N	Comparison of Staff and NSP Capital Structures
Ex. O	Comparison of Staff and NSP Revenue Requirements by Issue
Ex. P	Chronology of MN Legislative Mandates and Associated Regulatory Actions
Ex. Q	TCR Rider Information, Interaction with Base Rates and Workpapers
Ex. R	NSP Interchange Agreement History: 1984-1986

Northern States Power Company
North Dakota Electric Rate Case
NSP Interchange Agreement History: 1984-1986

Sept 17, 1984	Coordinating Agreement/Interchange Agreement between NSPM and NSPW. This is the agreement under which the NSP system companies coordinate their planning and operations and sell power and energy to each other. FERC Docket No. ER 84-690	PDF pages 2-71
May 31, 1985	Settlement Agreement related to the September 17, 1984 Interchange Agreement filing with FERC. This settlement identifies a demand allocation study is to be done by December 31, 1986. Four state commissions were signatories including North Dakota, Minnesota, South Dakota and Wisconsin. FERC Docket No. ER 84-690	PDF pages 72-93
Dec 1986	Report on the Examination of Demand Allocation Methodologies and Demand and Energy Measurement. This report was developed in satisfaction of Article 3.1 of the May 31, 1985 Settlement Agreement. A March 2, 1987 filing made in FERC Docket ER 87-279 indicated this study was shared with parties in early January 1987.	PDF pages 94-152

AGREEMENT TO COORDINATE PLANNING AND OPERATIONS AND INTERCHANGE POWER AND ENERGY

Among

NORTHERN STATES POWER COMPANY (Minnesota)

and

NORTHERN STATES POWER COMPANY (Wisconsin)

and

LAKE SUPERIOR DISTRICT POWER COMPANY

AGREEMENT TO COORDINATE PLANNING AND OPERATIONS AND INTERCHANGE POWER AND ENERGY Among NORTHERN STATES POWER COMPANY (Minnesota) and NORTHERN STATES POWER COMPANY (Wisconsin) and LAKE SUPERIOR DISTRICT POWER COMPANY

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AGREEMENT TO COORDINATE PLANNING AND OPERATIONS and INTERCHANGE POWER AND ENERGY

ARTICLE I
Recitals

1.1 THIS AGREEMENT, hereinafter referred to as the Interchange Agreement, is made this 17th day of September, 1984, by and among NORTHERN STATES POWER COMPANY, a Minnesota corporation, hereinafter referred to as "NSP (Minn)"; and NORTHERN STATES POWER COMPANY, a Wisconsin corporation, hereinafter referred to as "NSP (Wis)"; and LAKE SUPERIOR DISTRICT POWER COMPANY, a Wisconsin corporation, hereinafter referred to as "LSDP."

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

1.3 WHEREAS, NSP (Wis) and LSDP are subsidiaries of NSP (Minn); and

1.4 WHEREAS, the Parties for many years have coordinated the planning and operation of their power supply facilities under various coordinating agreements, the most recent of which was entitled "Coordinating Agreement Among Northern States Power Company (Minnesota) and Northern States Power Company (Wisconsin) and Lake Superior District Power Company" ("the 1982 Contract"); and

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
Exhibit	XI	-	Example of Development of Unit Rates for Power and Energy Sales

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

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

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

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

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

D. The pooling of reserves to reduce the magnitude of reserve capacity required by the respective

Parties in order to assure reliable service to their respective customers;

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

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

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

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

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

1.10 WHEREAS, the rates under which the sales of power and energy were made among the Parties under the 1982 Contract were formula rates stated in generalized terms; and

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

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

ARTICLE II
Objectives of Interchange Agreement

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

ARTICLE III
Definitions

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

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

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

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

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

ARTICLE IV
Coordinating Committee

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

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

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

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

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

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

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

ARTICLE V
Planning

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

ARTICLE VI
Interconnection of Systems

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

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

ARTICLE VII
Operation and Maintenance

7.1 Operation. The interconnected systems of the Parties shall be operated in continuous synchronism and in coordination with each other. If the synchronous operation of the systems becomes interrupted because of reasons beyond the control of any Party or because of scheduled

construction or maintenance, the Parties shall cooperate to remove the cause of the interruption as soon as practicable and restore the systems to normal operating condition.

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

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

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

7.4 Correction of Trouble. In the event that the interconnected operation of the systems herein contemplated results in trouble on any

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

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

ARTICLE VIII
Metering

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

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

8.3 Meter Tests, Accuracy, and Adjustments. Each meter shall be tested periodically and maintained in an accurate condition by the Party

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

ARTICLE IX
Sales

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

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

9.3 Continuity of Delivery. Power and energy sold hereunder shall be furnished continuously except for interruptions or curtailments in service caused by an uncontrollable force, or by operation of devices installed for system protection, or by the necessary installation, maintenance, repair, and replacement of facilities. Such interruptions or reductions in service shall not constitute a breach of this Interchange

Agreement, and no Party shall be liable to the others for damages resulting therefrom. Except in case of emergency, each Party shall give reasonable advance notice of temporary interruptions or curtailments in service necessary for such installations, maintenance, repair, and replacement of facilities, and shall attempt to schedule such interruptions or curtailments as convenient for all Parties.

ARTICLE X
Charges

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

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

10.3 True-up for Payments for Power. The unit rates for power developed pursuant to Exhibit III hereof shall initially be developed on the basis of estimated data for the calendar year. When actual cost data are available, the total annual costs shall be redetermined and the total

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

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

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

ARTICLE XI
General Provisions

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

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

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

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

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

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

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

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

11.9 Notices. Any notices, demands, or requests, required or authorized by this Interchange Agreement, shall be deemed properly given if mailed postage prepaid, to the President, NSP (Minn), Minneapolis, Minnesota, on behalf of NSP (Minn), and the President, NSP (Wis), Eau Claire, Wisconsin, on behalf of NSP (Wis) and the President, LSDP, Eau Claire, Wisconsin, on behalf of LSDP. The designation of the persons to be notified or the address of such person may be changed at any time by similar notice.

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

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

ARTICLE XII
Termination of Existing Agreements

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

A. Coordinating Agreement, dated April 23, 1982.

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

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

ARTICLE XIII
Term of Agreement

This Interchange Agreement shall become effective as of the date that it is permitted to become effective as a rate schedule under Section 205 of the Federal Power Act and shall continue in effect for a period of 10 years from that date. The contract may be terminated as of any date after the initial ten year period by any Party's giving the other Parties five years written notice. The Interchange Agreement may be terminated at any time by mutual agreement of the Parties. The applicable provisions of the Interchange Agreement shall continue in effect after termination to the extent necessary to provide for final billings and adjustment.

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

14.1 Automatically Adjusting Features. It is the intent of the Parties that Exhibits I, II, III, IV, V and VI of this Interchange Agreement establish formula-type procedures for developing the amounts of power and energy sales and the unit rates charged for such sales and that the amounts developed under the formula-type procedures set out in those exhibits will adjust automatically from time to time as provided in

the exhibits and that no filings will be made at the Federal Energy Regulatory Commission or any successor agency to reflect such automatic adjustments. It is the further intent of the Parties that any change in the formula-type procedures set out in the above specified exhibits shall be filed as a rate change under the Federal Power Act.

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

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

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

ATTEST

By _____
ASSISTANT SECRETARY

NORTHERN STATES POWER COMPANY
(MINNESOTA)

By _____
Executive Vice President

NORTHERN STATES POWER COMPANY
(WISCONSIN)

By _____
Secretary

By _____
President and Chief Executive Officer

LAKE SUPERIOR DISTRICT POWER
COMPANY

By _____
Secretary

By _____
President and Chief Executive Officer

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

Exhibit XI - Example of Development of Unit Rates for Power and Energy Sales

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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 Parties shall be determined as follows:

A - NSP (Minnesota) Power Sales to NSP (Wisconsin) and LSDP:

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

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

B - NSP (Wisconsin) Power Sales to NSP (Minnesota) and LSDP:

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

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

C - LSDP Power Sales to NSP (Minnesota) and NSP (Wisconsin):

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

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

Where:

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

"Demand" is each Party's demand in KW, based on a forecast of its average twelve monthly coincidental peak demands for the year of application.

"System Demand" is the NSP System demand in KW, based on a forecast of the total NSP System average twelve monthly peak demands for the year of application.

Exhibit VIII shows the development of the average twelve monthly coincidental peak demands for each Party and for the total NSP System as well as the forecast monthly peak load data.

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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 Parties shall be determined as follows:

A - NSP(Minnesota) Energy Sales to NSP(Wisconsin) and LSDP:

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

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

B - NSP(Wisconsin) Energy Sales to NSP(Minnesota) and LSDP:

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

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

C - LSDP Energy Sales to NSP(Minnesota) and NSP(Wisconsin):

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

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

Where:

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

"Energy Requirements" are each Party's energy requirements in kwh for the billing month.

"System Energy Requirements" is the total System energy requirements in kwh for the billing month.

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Exhibit III

FORMULA-TYPE PROCEDURES FOR DEVELOPMENT OF UNIT RATES FOR POWER SALES

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

A - NSP (Minnesota) Demand Rate for sales to NSP (Wisconsin) and LSDP:

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

B - NSP (Wisconsin) Demand Rate for sales to NSP (Minnesota) and LSDP:

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

C - LSDP Demand Rate for sales to NSP (Minnesota) and NSP (Wisconsin):

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

Where:

"DR" is the monthly unit demand rate (rate in dollars per KW) 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 demand, based on a forecast of its average twelve monthly coincidental peak demands for the year of application as shown in Exhibit VIII.

7 or 12

FORMULA-TYPE PROCEDURES FOR DEVELOPMENT OF UNIT RATES FOR ENERGY SALES

The monthly unit rates for the sales of kilowatt-hours of energy by each Party to the other Parties shall be determined as follows:

A - NSP(Minnesota) Energy Rates for sales to NSP(Wisconsin) and LSDP:

$$\text{ER to NSP(Wis)} = \frac{\text{NSP(Minn) Energy Costs}}{\text{NSP(Minn) Energy Requirements}} \times \text{NSP(Wis) Time of Use Ratio}$$

$$\text{ER to LSDP} = \frac{\text{NSP(Minn) Energy Costs}}{\text{NSP(Minn) Energy Requirements}} \times \text{LSDP Time of Use Ratio}$$

B - NSP(Wisconsin) Energy Rates for sales to NSP(Minnesota) and LSDP:

$$\text{ER to NSP(Minn)} = \frac{\text{NSP(Wis) Energy Costs}}{\text{NSP(Wis) Energy Requirements}} \times \text{NSP(Minn) Time of Use Ratio}$$

$$\text{ER to LSDP} = \frac{\text{NSP(Wis) Energy Costs}}{\text{NSP(Wis) Energy Requirements}} \times \text{LSDP Time of Use Ratio}$$

C - LSDP Energy Rates for sales to NSP(Minnesota) and NSP(Wisconsin):

$$\text{ER to NSP(Minn)} = \frac{\text{LSDP Energy Costs}}{\text{LSDP Energy Requirements}} \times \text{NSP(Minn) Time of Use Ratio}$$

$$\text{ER to NSP(Wis)} = \frac{\text{LSDP Energy Costs}}{\text{LSDP Energy Requirements}} \times \text{NSP(Wis) Time of Use Ratio}$$

Where:

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

"Energy Costs" are each Party's energy costs for the billing month.

"Energy Requirements" are each Party's energy requirements in kwh for the billing month.

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FORMULA-TYPE PROCEDURES FOR DEVELOPMENT OF UNIT RATES FOR ENERGY SALES

"Time of Use Ratio" is the ratio for each Party which reflects the Party's contribution to energy costs on a hourly rate basis compared to a monthly rate basis for the billing month. This ratio shall be determined as follows:

$$\text{NSP (Minn) Time of Use Ratio} = \frac{\dfrac{\sum_{\text{hrs.}} \left[\text{NSP(Minn) Energy Requirement} \times \text{System Energy Rate}\right]}{\sum_{\text{hrs.}} \left[\text{System Energy Costs}\right]}}{\dfrac{\text{NSP(Minn) Energy Requirements}}{\text{System Energy Requirements}}}$$

$$\text{NSP (Wis) Time of Use Ratio} = \frac{\dfrac{\sum_{\text{hrs.}} \left[\text{NSP(Wis) Energy Requirement} \times \text{System Energy Rate}\right]}{\sum_{\text{hrs.}} \left[\text{System Energy Costs}\right]}}{\dfrac{\text{NSP(Wis) Energy Requirements}}{\text{System Energy Requirements}}}$$

$$\text{LSDP Time of Use Ratio} = \frac{\dfrac{\sum_{\text{hrs.}} \left[\text{LSDP Energy Requirement} \times \text{System Energy Rate}\right]}{\sum_{\text{hrs.}} \left[\text{System Energy Costs}\right]}}{\dfrac{\text{LSDP Energy Requirements}}{\text{System Energy Requirements}}}$$

Where:

"System Energy Rate" is the hourly energy rate per kwh for the total NSP System.

"System Energy Costs" are the total NSP System energy costs for each hour in the billing month.

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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)	LSDP
1.	Electric Plant in Service (Sched. 1)			
2.	Accumulated Provision for Depreciation (Sched. 2)			
3.	Net Electric Plant in Service			
4.	Deduct: Accumulated Deferred Income Taxes (Sched. 3)			
5.	Add: Plant Held for Future Use (Sched. 4)			
6.	Fuel Stock Balances (Sched. 5)			
7.	Rate Base (Total lines 1 through 6)			
	COST OF SERVICE - DEMAND RELATED			
	A. Fixed Charges on Investment			
8.	Return on Rate Base at Specified Rate of Return (Sched. 6)			
9.	Income Taxes (Sched. 7)			
10.	Depreciation & Amortization Expense (Sched. 8)			
11.	Deferred Income Taxes (Sched. 9)			
12.	Property Taxes (Sched. 10)			
13.	Insurance (Sched. 11)			
14.	Total Fixed Charges (Total lines 8 through 13)			
	B. Fixed Power Production Expense			
15.	Fixed Operating and Maintenance Expense (Sched. 12)			
16.	Net Purchased Power Demand Costs (Sched. 13)			
17.	Production System Control & Load Dispatching (Sched. 14)			
18.	Total Fixed Power Production Expense (Total lines 15 through 17)			
	C. Fixed Transmission Expense			
19.	Operation and Maintenance Expense (Sched. 15)			
20.	Credits for Transmission Contracts (Sched. 16)			
21.	Credits for Transmission Wheeling (Sched. 17)			
22.	Total Fixed Transmission Expense (Total lines 19 through 21)			
23.	Total Month's Demand Related Costs (Total lines 14, 18 and 22)			

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Exhibit V
Schedule 1

ELECTRIC PLANT IN SERVICE

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

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

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

3. 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 purposes of this Agreement.

4. 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.

5. 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.

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Exhibit V
Schedule 2

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.

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

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Exhibit V
Schedule 3

ACCUMULATED DEFERRED INCOME TAXES

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

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Exhibit V
Schedule 4

PLANT HELD FOR FUTURE USE - LAND

Land Plant Held for Future Use is 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.

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Exhibit V
Schedule 5

FUEL STOCK BALANCES

Electric Production Fuel Stock balances recorded in FERC Accounts 151 and 152 shall be included at 100% of the average of the monthly balances in the accounts.

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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 determined according to this schedule and the rate of return on equity specified in Exhibit VII. The capital structure for NSP(Minn), NSP(Wis) and LSDP and the appropriate cost rates shall be determined for each calendar year in the following steps:

First, the debt and preferred stock of NSP Consolidated issued by NSP(Wis) and LSDP is directly assigned to each of the subsidiaries. The debt and preferred stock not assigned to these subsidiaries is attributed to NSP(Minn). The cost rates for these components of the capital structure are the actual cost rates of each company's debt and preferred stock. The retained earnings portion of the subsidiaries' common equity is also directly assigned to the respective subsidiaries. The return on equity provided for in Exhibit VII is used as the cost of each subsidiary's retained earnings.

Second, the subsidiary's total capitalization is apportioned in amounts such that the final capitalization ratios for each company is equal to the ratios of the consolidated capitalization. From these figures are subtracted the subsidiary's directly assigned capitalization amounts determined in Step 1. Each of the remaining amounts are assigned respective cost rates as if the funds were provided from NSP(Minn). The final capital structure and the cost rates for the subsidiaries are the addition of the amounts determined under Steps 1 and 2. The capitalization for NSP(Minn) is equal to the consolidated capital structure less the debt, preferred stock and retained earnings directly assigned to the subsidiaries under Step 1 and also less the amounts determined in Step 2.

Following completion of Steps 1 and 2, the capitalization ratios and cost rate for common equity for NSP(Minn), NSP(Wis) and LSDP will be equal to that of the consolidated company reflecting an assumption of common shared risk compatible with integrated system operations. The cost rates for debt and preferred stock will be distinct between companies based on their specific level and cost of financing.

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Exhibit V
Schedule 7
Page 1 of 3

COMPUTATION OF FEDERAL AND STATE INCOME TAXES

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

1.		Required Return on Rate Base (Schedule 6)
2.	Add:	Book Depreciation and Amortization (Schedule 8)
3.		Provision for Deferred Income Taxes (Schedule 9)
4.	Deduct:	Investment Tax Credit Flow Through (Schedule 7, Page 3 of 3)
5.		Income Tax Depreciation (Schedule 7, Page 3 of 3)
6.		Interest Expense (Schedule 7, Page 3 of 3)
7.		Preferred Dividend Credit (Schedule 7, Page 3 of 3)
8.		Income Tax Base
9.		Preliminary Income Taxes @ Income Tax Conversion Factor (1)
10.	Deduct:	Investment Tax Credit Flow Through (Line 4)
11.		Preferred Dividend Credit (Line 7)
12.		Federal and State Income Taxes

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

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

Agreement to Coordinate Planning and
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Exhibit V
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 and Federal Income Taxes:

W = _____ (N)
F = _____ (N)
W + F = _____ (N)

Lake Superior District Power Company

MI = _____ (N)
W = _____ (N)
F = _____ (N)
MI + W + F = _____ (N)

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

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

DEDUCTIONS FOR COMPUTATION OF FEDERAL AND STATE INCOME TAXES

Investment Tax Credit Flow Through

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

Income Tax Depreciation

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

Interest Expense

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

Preferred Dividend Credit

A Preferred Dividend Credit 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.

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Exhibit V
Schedule 8

DEPRECIATION AND AMORTIZATION EXPENSE

Depreciation expense is recorded in FERC Account 403 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. Schedule 8, Page 2 of 2, explains the current Tyrone Nuclear Plant amortization expense included for purposes of this Agreement.

NSP (Wis)'s demand related cost of service used in determining billings to NSP (Minn) for the period commencing January 1, 1985, shall include $7,500,000 per year for purposes of amortizing expenditures on the cancelled Tyrone nuclear generating plant. The inclusion of that amount shall continue until NSP (Wis) has recovered from NSP (Minn) its share of the entire actual Tyrone loss including amounts for funds used during construction accrued through February 28, 1979. In the last month of the amortization, an amount of less than one-twelfth of the $7,500,000 may be included in the fixed charges to achieve precise recovery of the loss.

NSP (Wis)'s demand related cost of service used in determining the billings to LSDP shall not include any amount for purposes of amortizing expenditures on the cancelled Tyrone nuclear generating plant since LSDP was a participant in that plant and, as such, bears its own cancellation losses.

LSDP's demand related cost of service used in determining the billings to NSP (Wis) and NSP (Minn) shall not include any amount for purposes of amortizing LSDP expenditures on the cancelled Tyrone nuclear generating plant.

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Exhibit V
Schedule 9

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.

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Exhibit V
Schedule 10

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.

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Exhibit V
Schedule 11

INSURANCE EXPENSE

The Insurance Expense is recorded in FERC Account 924. 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.

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Exhibit V
Schedule 12

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.

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Exhibit V
Schedule 13

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 non-associated utilities 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.

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Exhibit V
Schedule 14

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.

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Exhibit V
Schedule 15

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.

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Exhibit V
Schedule 16

CREDITS FOR TRANSMISSION CONTRACTS

Credit for Transmission Contracts is recorded in FERC Account 456 - Other Operating Revenue. Revenues from contractual arrangements for use of the transmission system by non-associated utilities is included as a credit to transmission expense to determine the transmission charges.

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Exhibit V
Schedule 17

CREDITS FOR TRANSMISSION WHEELING SERVICE

Revenue from Transmission Wheeling Service is recorded in FERC Account 456 - Transmission of Electricity for Others. These revenues are credited to transmission operating and maintenance expenses.

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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 4 of this exhibit.

	NSP(Minn)	NSP(Wis)	LSDP
1. Fuel Expenses (Schedule 1)			
2. Variable Production, Operating, and Maintenance Expense (Schedule 2)			
3. Net Purchased Power Energy Costs (Schedule 3)			
4. Total Energy Related Costs (Total lines 1 through 3)			

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Exhibit VI
Schedule 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.

Agreement to Coordinate Planning and
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Exhibit VI
Schedule 2

VARIABLE PRODUCTION OPERATION 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.

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Exhibit VI
Schedule 3

NET PURCHASED POWER ENERGY COSTS

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

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Exhibit VII

SPECIFICATION OF RATE OF RETURN ON COMMON EQUITY

The rate of return on common equity to determine the overall cost of capital as developed in accordance with Exhibit V, Schedule 6, is 15%.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit VIII

SPECIFICATION OF AVERAGE MONTHLY COINCIDENTAL PEAK DEMANDS
Calendar Year 1985

	Monthly Coincidental Peak Demands (KW)			
	NPS (Minn) Co.	NSP (Wis) Co.	LSDP Co.	Total System
January	3,861	710	133	4,704
February	3,614	630	137	4,381
March	3,418	588	124	4,130
April	3,391	558	111	4,060
May	3,423	574	114	4,111
June	3,985	627	124	4,736
July	4,814	734	115	5,663
August	4,618	650	118	5,386
September	4,214	649	124	4,987
October	3,428	612	121	4,161
November	3,704	622	128	4,454
December	3,726	719	126	4,571
Total	46,196	7,673	1,475	55,344
Average	3,850	639	123	4,612
Ratio	0.834707	0.138642	0.026651	1.000000

SPECIFICATION OF DEPRECIATION RATES

The following annual depreciation rates based upon the most recent depreciation studies and certified by the respective State Commissions are used to determine the annual depreciation expense accruals for purposes of this Agreement:

NSP (Minn)

FERC ACCOUNT		ANNUAL DEPRECIATION RATE PERCENT
PRODUCTION		
E311 STEAM	Structures and Improvements	3.88
E312 STEAM	Boiler Plant Equipment	3.61
E314 STEAM	Turbogenerator Units	3.06
E315 STEAM	Accessory Electric Equipment	3.11
E316 STEAM	Miscellaneous Power Plant Equipment	3.52
E321 NUCLEAR	Structures and Improvements	3.58
E322 NUCLEAR	Reactor Plant Equipment	3.67
E323 NUCLEAR	Turbogenerator Units	3.43
E324 NUCLEAR	Accessory Electric Equipment	3.50
E325 NUCLEAR	Miscellaneous Power Plant Equipment	4.17
E331 HYDRAULIC	Structures and Improvements	4.38
E332 HYDRAULIC	Reservoirs, Dams and Waterways	3.12
E333 HYDRAULIC	Water Wheels, Turbines & Generators	1.92
E334 HYDRAULIC	Accessory Electric Equipment	1.76
E335 HYDRAULIC	Miscellaneous Power Plant Equipment	3.85
E341 OTHER	Structures and Improvements	4.01
E342 OTHER	Fuel Holders, Producers & Accessories	4.41
E344 OTHER	Generators	4.22
E345 OTHER	Accessory Electric Equipment	5.02
E346 OTHER	Miscellaneous Power Plant Equipment	4.20
TRANSMISSION		
E352	Structures and Improvements	2.13
E353	Station Equipment	2.13
E354	Towers and Fixtures	2.17
E355	Poles and Fixtures	3.33
E356	Overhead Conductors & Devices	2.38
E357	Underground Conduit	1.82
E358	Underground Conductors & Devices	1.88
DISTRIBUTION		
E361	Structures and Improvements	2.44
E362	Station Equipment	2.50
GENERAL		
E397	Communication Equipment	7.50

SPECIFICATION OF DEPRECIATION RATES

NSP (Wis)

PRODUCTION

E311 STEAM	Structures and Improvements	3.14
E312 STEAM	Boiler Plant Equipment	5.00
E314 STEAM	Turbogenerator Units	2.86
E315 STEAM	Accessory Electric Equipment	3.33
E316 STEAM	Miscellaneous Power Plant Equipment	5.00
E331 HYDRAULIC	Structures and Improvements	2.00
E332 HYDRAULIC	Reservoirs, Dams and Waterways	2.09
E333 HYDRAULIC	Water Wheels, Turbines & Generators	1.91
E334 HYDRAULIC	Accessory Electric Equipment	2.63
E335 HYDRAULIC	Miscellaneous Power Plant Equipment	3.17
E341 OTHER	Structures and Improvements	5.25
E342 OTHER	Fuel Holders, Producers & Accessories	5.00
E343 OTHER	Prime Movers	5.00
E344 OTHER	Generators	5.00
E345 OTHER	Accessory Electric Equipment	5.00
E346 OTHER	Miscellaneous Power Plant Equipment	5.00

TRANSMISSION

E352	Structures and Improvements	2.63
E353	Station Equipment	2.43
E354	Towers and Fixtures	2.44
E355	Poles and Fixtures	2.63
E356	Overhead Conductors & Devices	2.00
E357	Underground Conduit	2.63
E358	Underground Conductors & Devices	1.88
E359	Roads and Trains	2.50

DISTRIBUTION

E361	Structures and Improvements	3.00
E362	Station Equipment	2.83

GENERAL

E397	Communication Equipment	6.67

SPECIFICATION OF DEPRECIATION RATES

LSDP

PRODUCTION

E311 STEAM	Structures and Improvements	3.18
E312 STEAM	Boiler Plant Equipment	3.75
E314 STEAM	Turbogenerator Units	2.56
E315 STEAM	Accessory Electric Equipment	2.78
E316 STEAM	Miscellaneous Power Plant Equipment	3.13
E331 HYDRAULIC	Structures and Improvements	1.67
E332 HYDRAULIC	Reservoirs, Dams and Waterways	1.93
E333 HYDRAULIC	Water Wheels, Turbines & Generators	1.41
E334 HYDRAULIC	Accessory Electric Equipment	2.71
E335 HYDRAULIC	Miscellaneous Power Plant Equipment	3.17
E341 OTHER	Structures and Improvements	4.55
E342 OTHER	Fuel Holders, Producers & Accessories	4.76
E343 OTHER	Prime Movers	4.76
E344 OTHER	Generators	5.26
E345 OTHER	Accessory Electric Equipment	4.35
E346 OTHER	Miscellaneous Power Plant Equipment	4.55

TRANSMISSION

E352	Structures and Improvements	2.33
E353	Station Equipment	2.38
E354	Towers and Fixtures	2.00
E355	Poles and Fixtures	3.83
E356	Overhead Conductors & Devices	2.63
E358	Underground Conductors & Devices	1.88
E359	Roads and Trains	2.00

DISTRIBUTION

E362	Station Equipment	2.25
E364	Poles, Towers and Fixtures	3.14

GENERAL

E397	Communication Equipment	6.67

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	
	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	

CLASSIFICATION OF PRODUCTION EXPENSES

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

EXAMPLE OF DEVELOPMENT OF UNIT RATES FOR POWER AND ENERGY SALES

The monthly amounts of sales of power by each Party to the other Parties for the month of June 1985 shall be determined as follows:

A - NSP (Minnesota) Power Sales to NSP (Wisconsin) and LSDP:

$$\text{PS to NSP(Wis)} = 3{,}850{,}000 \text{ KW} \times \frac{639{,}000 \text{ KW}}{4{,}612{,}000 \text{ KW}}$$

$$\text{PS to LSDP} = 3{,}850{,}000 \text{ KW} \times \frac{123{,}000 \text{ KW}}{4{,}612{,}000 \text{ KW}}$$

B - NSP (Wisconsin) Power Sales to NSP (Minnesota) and LSDP:

$$\text{PS to NSP(Minn)} = 639{,}000 \text{ KW} \times \frac{3{,}850{,}000 \text{ KW}}{4{,}612{,}000 \text{ KW}}$$

$$\text{PS to LSDP} = 639{,}000 \text{ KW} \times \frac{123{,}000 \text{ KW}}{4{,}612{,}000 \text{ KW}}$$

C - LSDP Power Sales to NSP (Minnesota) and NSP (Wisconsin):

$$\text{PS to NSP(Minn)} = 123{,}000 \text{ KW} \times \frac{3{,}850{,}000 \text{ KW}}{4{,}612{,}000 \text{ KW}}$$

$$\text{PS to NSP(Wis)} = 123{,}000 \text{ KW} \times \frac{639{,}000 \text{ KW}}{4{,}612{,}000 \text{ KW}}$$

Where:

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

"Demand" is each Party's demand in KW, based on a forecast of its average twelve monthly coincidental peak demands for the year of application.

"System Demand" is the NSP System demand in KW, based on a forecast of the total NSP System average twelve monthly peak demands for the year of application.

Exhibit VIII shows the development of the average twelve monthly coincidental peak demands for each Party and for the total NSP System as well as the forecast monthly peak load data.

EXAMPLE OF DEVELOPMENT OF UNIT RATES FOR POWER AND ENERGY SALES

The monthly amounts of sales of energy by each Party to the other Parties for the month of June 1985 shall be determined as follows:

A - NSP(Minnesota) Energy Sales to NSP(Wisconsin) and LSDP:

$$\text{ES to NSP(Wis)} = 1{,}818{,}198{,}000 \text{ kwh} \times \frac{299{,}568{,}000 \text{ kwh}}{2{,}180{,}593{,}000 \text{ kwh}}$$

$$\text{ES to LSDP} = 1{,}818{,}198{,}000 \text{ kwh} \times \frac{62{,}827{,}000 \text{ kwh}}{2{,}180{,}593{,}000 \text{ kwh}}$$

B - NSP(Wisconsin) Energy Sales to NSP(Minnesota) and LSDP:

$$\text{ES to NSP(Minn)} = 299{,}568{,}000 \text{ kwh} \times \frac{1{,}818{,}198{,}000 \text{ kwh}}{2{,}180{,}593{,}000 \text{ kwh}}$$

$$\text{ES to LSDP} = 299{,}568{,}000 \text{ kwh} \times \frac{62{,}827{,}000 \text{ kwh}}{2{,}180{,}593{,}000 \text{ kwh}}$$

C - LSDP Energy Sales to NSP(Minnesota) and NSP(Wisconsin):

$$\text{ES to NSP(Minn)} = 62{,}827{,}000 \text{ kwh} \times \frac{1{,}818{,}198{,}000 \text{ kwh}}{2{,}180{,}593{,}000 \text{ kwh}}$$

$$\text{ES to NSP(Wis)} = 62{,}827{,}000 \text{ kwh} \times \frac{299{,}568{,}000 \text{ kwh}}{2{,}180{,}593{,}000 \text{ kwh}}$$

Where:

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

"Energy Requirements" are each Party's energy requirements in kwh for the billing month.

"System Energy Requirements" is the total System energy requirements in kwh for the billing month.

EXAMPLE OF DEVELOPMENT OF UNIT RATES FOR POWER AND ENERGY SALES

The monthly unit rates for the sales of kilowatts of power by each Party to the other Parties for the month of June 1985 shall be determined as follows:

A - NSP (Minnesota) Demand Rate for sales to NSP (Wisconsin) and LSDP:

$$\text{DR to NSP(Wis) and LSDP} = \frac{\$43,723,000}{3,850,000\ \text{KW}}$$

B - NSP (Wisconsin) Demand Rate for sales to NSP (Minnesota) and LSDP:

$$\text{DR to NSP(Minn)} = \frac{\$3,504,000}{639,000\ \text{KW}}$$

$$\text{DR to LSDP} = \frac{\$2,809,000}{639,000\ \text{KW}}$$

C - LSDP Demand Rate for sales to NSP (Minnesota) and NSP (Wisconsin):

$$\text{DR to NSP(Minn) and NSP(Wis)} = \frac{\$807,000}{123,000\ \text{KW}}$$

Where:

"DR" is the monthly unit demand rate (rate in dollars per KW) 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 demand, based on a forecast of its average twelve monthly coincidental peak demands for the year of application as shown in Exhibit VIII.

EXAMPLE OF DEVELOPMENT OF UNIT RATES FOR POWER AND ENERGY SALES

The monthly unit rates for the sales of kilowatt-hours of energy by each Party to the other Parties for the month of June 1985 shall be determined as follows:

A - NSP(Minnesota) Energy Rates for sales to NSP(Wisconsin) and LSDP:

$$\text{ER to NSP(Wis)} = \frac{\$24,292,000}{1,818,198,000 \text{ kwh}} \times 1.00015$$

$$\text{ER to LSDP} = \frac{\$24,292,000}{1,818,198,000 \text{ kwh}} \times 0.99583$$

B - NSP(Wisconsin) Energy Rates for sales to NSP(Minnesota) and LSDP:

$$\text{ER to NSP(Minn)} = \frac{\$114,000}{299,568,000 \text{ kwh}} \times 1.00012$$

$$\text{ER to LSDP} = \frac{\$114,000}{299,568,000 \text{ kwh}} \times 0.99583$$

C - LSDP Energy Rates for sales to NSP(Minnesota) and NSP(Wisconsin):

$$\text{ER to NSP(Minn)} = \frac{\$105,000}{62,827,000 \text{ kwh}} \times 1.00012$$

$$\text{ER to NSP(Wis)} = \frac{\$105,000}{62,827,000 \text{ kwh}} \times 1.00015$$

Where:

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

"Energy Costs" are each Party's energy costs for the billing month.

"Energy Requirements" are each Party's energy requirements in kwh for the billing month.

EXAMPLE OF DEVELOPMENT OF UNIT RATES FOR POWER AND ENERGY SALES

"Time of Use Ratio" is the ratio for each Party which reflects the Party's contribution to energy costs on a hourly rate basis compared to a monthly rate basis for the billing month. This ratio for the month of June 1985 shall be determined as follows:

$$\text{NSP (Minn) Time of Use Ratio} = \frac{.83391}{.83381}$$

$$\text{NSP (Wis) Time of Use Ratio} = \frac{.13740}{.13738}$$

$$\text{LSDP Time of Use Ratio} = \frac{.02869}{.02881}$$

Where:

"System Energy Rate" is the hourly energy rate per kwh for the total NSP System.

"System Energy Costs" are the total NSP System energy costs for each hour in the billing month.

EXAMPLE OF DEVELOPMENT OF UNIT RATES FOR POWER AND ENERGY SALES

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

		June 1985 ($ 000's)		
	DEVELOPMENT OF RATE BASE	NSP(Minn)	NSP(Wis)	LSDP
1.	Electric Plant in Service	$2,543,959	$169,797	$55,410
2.	Accumulated Provision for Depreciation	1,079,116	61,867	28,725
3.	Net Electric Plant in Service	1,464,843	107,930	26,685
4.	Deduct: Accumulated Deferred Income Taxes	297,909	18,065	6,680
5.	Add: Plant Held for Future Use	0	0	0
6.	Fuel Stock Balances	64,897	1,218	379
7.	Rate Base (Total lines 1 through 6)	$1,231,831	$ 91,083	$20,384
	COST OF SERVICE - DEMAND RELATED			
	A. Fixed Charges on Investment			
8.	Return on Rate Base at Specified Rate of Return (ROR x one-twelfth)	$ 11,548	$ 863	$ 191
9.	Income Taxes	7,284	527	88
10.	Depreciation and Amortization Expense	7,290	420	141
11.	Deferred Income Taxes	1,146	96	30
12.	Property Taxes	4,559	114	35
13.	Insurance	799	5	2
14.	Total Fixed Charges (Total lines 8 through 13)	32,626	2,025*	487
	B. Fixed Power Production Expense			
15.	Fixed Operating and Maintenance Expense	9,405	581	235
16.	Net Purchased Power Demand Costs	772	0	0
17.	Production System Control & Load Dispatching	157	43	13
18.	Total Fixed Power Production Expense (Total lines 15 through 17)	10,334	624	248
	C. Fixed Transmission Expense			
19.	Operation and Maintenance Expense	1,065	173	72
20.	Credits for Transmission Contracts	(186)	(13)	0
21.	Credits for Transmission Wheeling	(116)	0	0
22.	Total Fixed Transmission Expense (Total lines 19 through 21)	763	160	72
23.	Total Month's Demand Related Costs (Total lines 14, 18 and 22)	$ 43,723	$ 2,809*	$ 807

*An increase of $695, changing lines 14 and 23 to $2,720 and $3,504, respectively, must be included in costs when billed to NSP (Minn) (and not to LSDP) to reflect the Tyrone amortization (see Exhibit III).

EXAMPLE OF DEVELOPMENT OF UNIT RATES FOR POWER AND ENERGY SALES

The energy-related costs used in Exhibit IV shall be those developed on line 4 of this exhibit.

Cost of Service - Energy Related	June 1985 ($ 000's) NSP(Minn)	NSP(Wis)	LSDP
1. Fuel Expenses	$18,657	$ 29	$ 61
2. Variable Production, Operating, and Maintenance Expense	3,560	85	44
3. Net Purchased Power Energy Costs	2,075	0	0
4. Total Energy Related Costs (Total lines 1 through 3)	$24,292	$114	$105

EXAMPLE OF DEVELOPMENT OF UNIT RATES FOR POWER AND ENERGY SALES

COMPUTATION OF FEDERAL AND STATE INCOME TAXES

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

$ 000's			June 1985 NSP(Minn)	NSP(Wis)	LSDP
1.	Required	Return on Rate Base	$11,548	$ 863	$ 19
2.	Add:	Book Depreciation and Amortization	13,244	420	14
3.		Provision for Deferred Income Taxes	1,146	96	
4.		Other as Appropriate	0	0	
5.	Deduct:	Investment Tax Credit Flow Through	812	19	
6.		Income Tax Depreciation	14,014	541	18
7.		Interest Expense	3,606	276	
8.		Preferred Dividend Credit	6	0	
9.		Other as Appropriate	0	3	
10.	Income Tax Base		$ 7,500	$ 540	$
11.	Preliminary Income Taxes @ Income Tax Conversion Factor (1)		$ 8,102	$ 546	$
12.	Deduct:	Investment Tax Credit Flow Through (Line 5)	812	19	
13.		Preferred Dividend Credit (Line 8)	6	0	
14.	Federal and State Income Taxes		$ 7,284	$ 527	$

(1)

$$\frac{\text{NSP (Minn) - Composite Tax Rate}}{1 - \text{Composite Tax Rate}} = \text{Income Tax Conversion Factor } \frac{.5193}{1 - .5193} = 1.0$$

$$\frac{\text{NSP (Wis) - Composite Tax Rate}}{1 - \text{Composite Tax Rate}} = \text{Income Tax Conversion Factor } \frac{.5027}{1 - .5027} = 1.0$$

$$\frac{\text{LSDP - Composite Tax Rate}}{1 - \text{Composite Tax Rate}} = \text{Income Tax Conversion Factor } \frac{.5007}{1 - .5007} = 1.0$$

EXAMPLE OF DEVELOPMENT OF UNIT RATES FOR POWER AND ENERGY SALES

Let: F = Federal Income Tax Rate = .46
M = Minnesota State Income Tax Rate = .12
D = North Dakota State Income Tax Rate = .105
S = South Dakota State Income Tax Rate = 0
W = Wisconsin State Income Tax Rate = .079
MI = Michigan State Single Business Tax Rate = .0235
N = Net Income After Net Deductions But Before Income Taxes

NSP Company (Minnesota)

Only Minnesota and Federal Income Taxes:
M = 1200 (N)
F = .4048 (N)
M + F = .5248 (N)

Only North Dakota and Federal Income Taxes:
F = .4326 (N)
D = .0596 (N)
F + D = .4922 (N)

Only South Dakota and Federal Income Taxes:
S + F = .46 (N)

NSP Company (Minnesota): Combined Minnesota, North Dakota, South Dakota
M + D + S + F = .5193 (N)

NSP Company (Wisconsin)

Wisconsin and Federal Income Taxes:
W = .079 (N)
F = .4237 (N)
W + F = .5027

Lake Superior District Power Company

MI = .0091 (N)
W = .0663 (N)
F = .4253 (N)
MI + W + F = .5007 (N)

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

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

EXAMPLE OF DEVELOPMENT OF UNIT RATES FOR POWER AND ENERGY SALES

CONSOLIDATED CAPITAL STRUCTURE AND DETERMINATION OF PARENT COMPANY CAPITALIZATION

Part I	NSP Capitalization ($ 000's)	NSP Capitalization %	Subsidiaries NSP(WISC) ($ 000's)	Subsidiaries LSDP ($ 000's)	Adjusted Parent ($ 000's)
Long Term Debt	1,047,142	43.11	49,195	14,800	983,147
Perferred Stock	217,549	8.96	-0-	3,000	214,549
			Retained Earnings Only		
Common Equity	1,164,084	47.93	76,846	13,299	1,073,939
Total	2,428,775	100.00	126,041	31,099	2,271,635

Part II	Adjusted Parent ($ 000's)	Paid in Capital NSP(WISC) ($ 000's)	Paid in Capital LSDP ($ 000's)	NSP(Minn) Parent Capitalization ($ 000's)	NSP(Minn) Parent Capitalization %
Long Term Debt	983,147	35,338	4,699	943,110	43.11
Preferred Stock	214,549	17,562	1,051	195,936	8.96
Common Equity	1,073,939	17,128	8,377	1,048,434	47.93
Total	2,271,635	70,028	14,127	2,187,480	100.00

NSP(MINN) PARENT CAPITAL STRUCTURE

Part III	Capital ($ 000's)	Ratio %	Cost %	Weighted Cost %
Long Term Debt	943,110	43.11	8.15	3.51
Preferred Stock	195,936	8.96	6.05	.54
Common Equity	1,048,434	47.93	15.00	7.19
Total	2,187,480	100.00		11.25

Agreement to Coordinate Planning and
Operations and Interchange Power and Energy

Exhibit XI
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EXAMPLE OF DEVELOPMENT OF UNIT RATES FOR POWER AND ENERGY SALES

DETERMINATION OF SUBSIDIARIES' CAPITALIZATION

LAKE SUPERIOR DISTRICT POWER

Part IV	From Part I ($ 000's)	From Part II ($ 000's)	Total ($ 000's)	Total %
Long Term Debt:				
Subsidiary Debt	14,800	-0-	14,800	32.72
Parent Debt	-0-	4,699	4,699	10.39
Preferred Stock:				
Subsidiary Stock	3,000	-0-	3,000	6.63
Parent Stock	-0-	1,051	1,051	2.32
Common Equity:				
Retained Earnings	13,299	-0-	13,299	29.41
Paid in Capital	-0-	8,377	8,377	18.52
Total	31,099	14,127	45,226	100.00

LSDP CAPITAL STRUCTURE

Part V	Capital ($ 000's)	Ratio %	Cost %	Weighted Cost %
Long Term Debt:				
Subsidiary Debt	14,800	32.72	8.29	2.71
Parent Debt	4,699	10.39	8.15	.85
Preferred Stock:				
Subsidiary Stock	3,000	6.63	5.02	.33
Parent Stock	1,051	2.32	6.05	.14
Common Equity:				
Subsidiary Retained Earnings	13,299	29.41	15.00	4.41
Parent Common Equity	8,377	18.52	15.00	2.78
Total	45,226	100.00		11.22

LSDP CAPITAL STRUCTURE (3) Classes)

Part VI				
Long Term Debt	19,499	43.11	8.26	3.56
Preferred Stock	4,051	8.96	5.29	.47
Common Equity	21,676	47.93	15.00	7.19
Total	45,226	100.00		11.22

Agreement to Coordinate Planning and
Operations and Interchange Power and Energy

Exhibit XI
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EXAMPLE OF DEVELOPMENT OF UNIT RATES FOR POWER AND ENERGY SALES

DETERMINATION OF SUBSIDIARIES' CAPITALIZATION

NSP(WISC)

Part IV	From Part I ($ 000's)	From Part II ($ 000's)	Total ($ 000's)	Total %
Long Term Debt:				
Subsidiary Debt	49,195	-0-	49,195	25.09
Parent Debt	-0-	35,338	35,338	18.02
Preferred Stock:				
Subsidiary Stock	-0-	-0-	-0-	-0-
Parent Stock	-0-	17,562	17,562	8.96
Common Equity:				
Retained Earnings	76,846	-0-	76,846	39.19
Paid in Capital	-0-	17,128	17,128	8.74
Total	126,041	70,028	196,069	100.00

NSP(WISC) CAPITAL STRUCTURE

Part V	Capital ($ 000's)	Ratio %	Cost %	Weighted Cost %
Long Term Debt:				
Subsidiary Debt	49,195	25.09	8.63	2.17
Parent Debt	35,338	18.02	8.15	1.47
Preferred Stock:				
Subsidiary Stock	-0-	-0-	-0-	-0-
Parent Stock	17,562	8.96	6.05	.54
Common Equity:				
Subsidiary Retained Earnings	76,846	39.19	15.00	5.88
Parent Common Equity	17,128	8.74	15.00	1.31
Total	196,069	100.00		11.37

NSP(WISC) CAPITAL STRUCTURE (3) Classes)

Part VI				
Long Term Debt	84,533	43.11	8.43	3.63
Preferred Stock	17,562	8.96	6.05	.54
Common Equity	93,974	47.93	15.00	7.19
Total	196,069	100.00		11.37

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Northern States Power Company (Minnesota)	)	
Northern States Power Company (Wisconsin)	)	Docket No. ER84-690-000
Lake Superior District Power Company	)	

SETTLEMENT AGREEMENT

This Settlement Agreement is made and entered into between, on the one hand, Northern States Power Company (Minnesota), Northern States Power Company (Wisconsin), and Lake Superior District Power Company (hereinafter collectively called the "NSP Companies") and, on the other, River Electric Association, City of Marshall, Minnesota, Cities and Villages of Bangor, Barron, Bloomer, Medford and Spooner, Wisconsin, Wisconsin Public Power Incorporated SYSTEM, Minnesota Public Utilities Commission, Minnesota Department of Public Service, North Dakota Public Service Commission, Public Utilities Commission of the State of South Dakota, and Public Service Commission of Wisconsin (hereinafter collectively called "the Intervenors").

On September 20, 1984 the NSP Companies jointly tendered for filing with the Federal Energy Regulatory Commission ("the Commission") an Interchange Agreement dated September 17, 1984. The Interchange Agreement revised and superseded the 1982 Coordinating Agreement among the NSP Companies. The stated purpose of the Interchange

Agreement was four-fold: (1) to define transmission facilities on a functional rather than a voltage basis; (2) to allocate demand costs on an average of the twelve monthly peak basis; (3) to introduce time differentiation into the development of the energy charges; and (4) to introduce greater specificity in the formula-type procedures for development of charges under the agreement.

The Commission on November 21, 1984 accepted the Interchange Agreement for filing, suspended it for one day, to become effective on January 1, 1985, subject to refund, and set hearing.

Subsequently, the NSP Companies and the Intervenors held two settlement conferences in Minneapolis. The first conference was held on January 18, 1985 and the second on February 27, 1985. At the second conference, the parties achieved a settlement in principle. This Settlement Agreement reduces the settlement in principle to writing for submission to the Commission.

As a result of the settlement discussions, but subject in every particular to the conditions set forth in this Settlement Agreement, including acceptance of this Settlement Agreement in its entirety and without change or condition by the Commission, and with the understanding that each term of the Settlement Agreement is in consideration and support of every other term, the NSP Companies and the Intervenors have agreed as follows:

ARTICLE I
Revisions in Interchange Agreement Exhibits

Article 1.1: The sheets contained in Appendix A hereto revise the exhibits to the Interchange Agreement to achieve three changes:

(a) New monthly coincident peak demands for 1985 are specified in Exhibit VIII. The new monthly coincident peak demands for 1985 are based on system load forecasts developed in December 1984 for calendar year 1985 and represent the NSP Companies' best estimate of its 1985 monthly coincident peak demands as of year-end 1984. The monthly coincident peak demands contained in Exhibit VIII as filed represented an earlier estimate available in September 1984 when the filing was made.

(b) Time differentiation in the development of the energy charges is eliminated. The impact of time differentiation on the charges among the NSP Companies would be minimal, and the burdens of administering the feature are deemed to outweigh any advantages.

(c) The cost of carrying fuel stocks is allocated on the basis of the energy allocator rather than the demand allocator. This treatment comports with Commission practice in wholesale ratemaking.

It is intended that the Commission, upon approval of this Settlement Agreement, accept for filing the sheets contained in Appendix A hereto as settlement rate schedules.

Article 1.2: The parties agree that the sheets contained in Appendix A hereto are to be effective as of January 1, 1985. In preparing the first monthly billing rendered under the Interchange Agreement after approval of this Settlement Agreement, the NSP Companies shall include in the billing such payments among themselves as may be required to adjust previous billings to reflect the revisions

contained in Appendix A. Such payments among the NSP Companies shall be with interest at the rates provided in the Commission's regulations.

ARTICLE II
Equity Return Reopener

Article 2.1: In November and December of any even numbered year, any firm requirements wholesale customer of any NSP Company or any state agency involved in regulation of public utilities or enforcement of state utility laws of any state in which an NSP Company renders electric service may give notice to the NSP Companies requesting that they make a filing of a new Exhibit VII specifying the rate of return on common equity under the Interchange Agreement. Such notice shall be given in writing in accordance with Article 11.9 of the Interchange Agreement.

Article 2.2: Within 60 days of receiving a notice under Article 2.1 hereof, the NSP Companies shall file under Section 205 of the Federal Power Act a new Exhibit VII of the Interchange Agreement. In making the filing, the NSP Companies shall request that (1) the new Exhibit VII be permitted to become effective 60 days after the filing date and (2) the new Exhibit VII be suspended for not more than one day. The NSP Companies shall have the sole discretion for determining the level of the rate of return on common equity in any new Exhibit VII. The level may be higher, lower or the same as the level specified in the Exhibit VII in effect at the time of the filing.

Article 2.3: If the rate of return on common equity specified in the new Exhibit VII is higher or lower than that specified in the existing Exhibit VII, the NSP Companies shall bear the burden of proof with respect to the change, but if the rate of return on common equity

specified in the new Exhibit VII is the same as that specified in the existing Exhibit VII, the burden of proof shall be on those parties challenging the rate of return.

Article 2.4: The NSP Companies agree that the Commission's determination of any rate of return on common equity made in a proceeding on a filing under Article 2.2 hereof shall be effective as to sales made on and after the date that the filing was permitted to become effective. After the Commission has issued a final order in such proceeding, 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 was permitted to become effective. Such payments among the NSP Companies shall be with interest at the rate provided in the Commission's regulations.

ARTICLE III
Future Studies

Article 3.1 The NSP Companies agree to conduct an examination of (1) the existing methodology for allocation of demand costs under the Interchange Agreement and selected alternative methodologies for use in the future and (2) the existing methods of measuring demand and energy requirements used for developing cost responsibilities under the Interchange Agreement for each NSP Company and selected revisions to those methods for use in the future. This examination shall be completed by December 31, 1986. The NSP Companies agree to make available to the Intervenors data and information that will allow the Intervenors to conduct their own examination of the two topics.

Article 3.2: On or before March 1, 1987, the NSP Companies shall make a filing with the Commission under Section 205 of the Federal Power Act which will deal with each of the two subjects identified in Article 3.1. The NSP Companies shall request that (1) the new filing be permitted to become effective 60 days after the filing date and (2) it be suspended for not more than one day. The filing may specify a treatment of the two subjects identified in Article 3.1 hereof that is either the same as or different from the treatment in effect under the Interchange Agreement at the time of the filing.

Article 3.3: The NSP Companies shall bear the burden of proof with respect to its filing under Article 3.2 hereof on the subject of demand allocation methodology, whether or not the filing proposes a change in the methodology from that in effect under the Interchange Agreement at the time of the filing. In the event that the NSP Companies and all other parties in any proceeding on the filing, including the Commission staff, were to fail to carry a prima facie burden of proof on the demand allocation issue, the demand allocation methodology in effect prior to the effective date of the Interchange Agreement shall be employed.

Article 3.4: The NSP Companies shall bear the burden of proof with respect to its filing under Article 3.2 hereof on the subject of methods of demand and energy measurement only if the filing proposes methods of measurement different from those in effect under the Interchange Agreement at the time of filing. If the methods are unchanged, the burden of proof shall be on those parties challenging the unchanged treatment.

Article 3.5: The NSP Companies agree that the Commission's determination in a proceeding on a filing made under Article 3.2 hereof

shall be effective as to sales made on and after the date that the filing was permitted to become effective. After the Commission has issued a final order in such proceeding, 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 was permitted to become effective. Such payments among the NSP Companies shall be with interest at the rate provided in the Commission's regulations.

ARTICLE IV
Relation to Retail and Wholesale Proceedings

Article 4.1: The parties agree that three categories of matters arising under the Interchange Agreement may be collaterally raised in retail proceedings of the NSP Companies or in wholesale proceedings of those companies involving sales to non-affiliates, subject, however, to removal of any matters so raised to the Commission for its exclusive determination in a proceeding under the Interchange Agreement. The three categories of matters are: (1) the prudence of the incurrence of any costs used to derive charges under the Interchange Agreement, (2) the details of the derivation of charges under the Interchange Agreement to the extent that the details of such derivation do not appear on the face of the Interchange Agreement and the exhibits thereto, and (3) the reasonableness of the estimated monthly coincident peak demands filed annually for the forthcoming year in Exhibit VIII of the Interchange Agreement. For purposes of Article IV, "the details of the derivation of charges under the Interchange Agreement" shall include, but not be limited to, all projections, estimates, accounting determinations and tax treatments made in deriving the charges, and the appropriateness of all

components of the charges for inclusion in the cost of providing service for ratemaking purposes for retail customers or non-affiliated wholesale customers. If a matter within any of the three categories specified above is raised in a retail or wholesale proceeding, the affected NSP Company shall not oppose its consideration in that proceeding on the basis that the matter has been filed or accepted in connection with the Interchange Agreement, but it may exercise rights of removal under Article 4.2 hereof.

Article 4.2: If a collateral challenge is brought in a retail or wholesale proceeding as contemplated in Article 4.1 hereof, any NSP Company or any other person having an interest in the matter may remove it from the retail or wholesale proceeding and place it before the Commission in a proceeding under the Interchange Agreement by making an appropriate filing with the Commission under the Federal Power Act (such filing might consist of, inter alia, a rate change filing, a complaint or a petition for a declaratory order). Such filing shall request that the determination of the Commission on the merits be made effective as of the date that the determination would have had an effect on the rates under consideration in the retail or wholesale proceeding if the issue had been left for determination in that proceeding (in the event of any uncertainty as to such date, the uncertainty shall be resolved by the forum from which the issue has been removed). Upon the making of a filing with the Commission to remove an issue to the Commission, the parties to this Settlement Agreement will take whatever action is necessary to terminate further consideration of the matter in the retail or wholesale proceeding and to allow the matter to be determined by the Commission in a proceeding under the Interchange Agreement.

Article 4.3: The parties acknowledge that any matter arising under the Interchange Agreement in a retail proceeding pursuant to Article 4.1 hereof would affect only the retail rates at issue in that proceeding, would not affect charges among the NSP Companies under the Interchange Agreement, and would not affect any retail proceeding in another jurisdiction or any wholesale proceeding.

Article 4.4: The parties agree that no matters arising under the Interchange Agreement other than those in the three categories identified in Article 4.1 shall be subject to being collaterally raised in retail proceedings of the NSP Companies or in wholesale proceedings of those Companies involving sales to non-affiliates.

ARTICLE V
Duration of Commitments Made in Articles II, III and IV

The commitments of the Company and the Intervenors made in Articles II, III and IV hereof shall endure until the Interchange Agreement (as distinct from the exhibits thereto) is cancelled, terminated or superseded.

ARTICLE VI
Reservation Regarding Exhibit XI Data for 1985

The estimated data for 1985 contained in Exhibit XI of the Interchange Agreement are included in the exhibit only for purposes of illustrating how charges are to be derived under the Interchange Agreement, and no party by signing this Settlement Agreement endorses the reasonableness of the estimated data or accepts the use of the data for any purpose other than the illustrative purpose of Exhibit XI.

ARTICLE VII
Reservation of Rights Under Sections 205 and 206 of the Federal Power Act

Nothing in this Settlement Agreement prevents the NSP Companies from making a unilateral filing at any time to change the Interchange Agreement or any exhibits thereto, including Exhibit VII, under Sections 205 or 206 of the Federal Power Act, and nothing prevents the Intervenors from unilaterally making, at any time, a complaint against the Interchange Agreement or any exhibit thereto under Section 206 of the Act.

ARTICLE VIII
Conditions

Article 8.1: The making of this Settlement Agreement shall not be deemed in any respect to constitute an admission by the NSP Companies or the Intervenors that any allegation or contention in this docket, or as to any of the foregoing matters, is true and valid.

Article 8.2: The making of this Settlement Agreement establishes no principles and shall not be deemed to foreclose the NSP Companies or the Intervenors from making any contention in any proceedings or investigation, except that no contentions shall be made in contradiction of the commitments in Articles I through VII hereof.

Article 8.3: The acceptance of this Settlement Agreement by the Commission shall not in any respect constitute a determination by the Commission as to the merits of any allegations or contentions made in this docket.

Article 8.4: This Settlement Agreement is expressly conditioned upon the Commission's acceptance of all the provisions thereof, without change or conditions, and upon the following further Commission actions:

(a) waiver of the requirements of Section 35.3 of its regulations under the Federal Power Act with respect to the rate schedule revisions provided for in Article 1.1 hereof, to the extent necessary to effectuate all of the provisions of this Settlement Agreement; and

(b) waiver by the Commission of the requirements of Section 35.13 of its regulations under the Federal Power Act with respect to said rate schedule revisions; and

(c) acceptance of said rate schedule revisions without suspension under Section 205 of the Federal Power Act, effective as of the date specified in Article 1.2 hereof.

Article 8.5: The discussions which have produced this Settlement Agreement have been conducted on the explicit understanding that all offers of settlement and discussions relating thereto are and shall be privileged, shall be without prejudice to the position of any party or participant presenting any such offer or participating in any such discussion, and are not to be used in any manner in connection with this proceeding or otherwise. The Settlement Agreement is submitted on the condition that, in the event the Commission does not by order accept it in its entirety, this Settlement Agreement shall be deemed withdrawn and shall not constitute any part of the record in this docket or be used for any other purposes.

This Settlement Agreement is entered into as of this _____ day of _____, 1985 by and between the NSP Companies and the Intervenors, by their respective attorneys who represent that they are fully authorized to do so on behalf of their principals.

NORTHERN STATES POWER COMPANY
(MINNESOTA)

By _____
Bruce A. Richard
President and Chief Operating Officer

NORTHERN STATES POWER COMPANY
(WISCONSIN)

By _____
Edwin M. Theisen
President and Chief Executive Officer

LAKE SUPERIOR DISTRICT POWER
COMPANY

By _____
Edwin M. Theisen
President and Chief Executive Officer

RIVER ELECTRIC ASSOCIATION
CITY OF MARSHALL, MINNESOTA

By _____
James D. Larson
Their Attorney

CITIES AND VILLAGES OF BANGOR, BARRON, BLOOMER, MEDFORD AND SPOONER, WISCONSIN
WISCONSIN PUBLIC POWER INCORPORATED SYSTEM

By _____
J. Leroy Thilly
Their Attorney

MINNESOTA PUBLIC UTILITIES COMMISSION
MINNESOTA DEPARTMENT OF PUBLIC SERVICE

By _____
Christopher K. Sandberg
Their Attorney

NORTH DAKOTA PUBLIC SERVICE COMMISSION

By _____
Ray H. Walton
Its Attorney

PUBLIC UTILITIES COMMISSION OF THE STATE OF SOUTH DAKOTA

By _____
Roberta Lovald
Its Executive Secretary

PUBLIC SERVICE COMMISSION OF
WISCONSIN

By Jon E. Kingstad
Jon E. Kingstad
Its Assistant Chief Counsel

FORMULA-TYPE PROCEDURES FOR DEVELOPMENT OF UNIT RATES FOR ENERGY SALES

The monthly unit rates for the sales of kilowatt-hours of energy by each Party to the other Parties shall be determined as follows:

A - NSP(Minnesota) Energy Rates for sales to NSP(Wisconsin) and LSDP:

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

B - NSP(Wisconsin) Energy Rates for sales to NSP(Minnesota) and LSDP:

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

C - LSDP Energy Rates for sales to NSP(Minnesota) and NSP(Wisconsin):

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

Where:

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

"Energy Costs" are each Party's energy costs for the billing month.

"Energy Requirements" are each Party's energy requirements in kwh for the billing month.

Agreement to Coordinate Planning and
Operations and Interchange Power and Energy

Exhibit V
Revised

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)	LSDP
1. Electric Plant in Service (Sched. 1)			
2. Accumulated Provision for Depreciation (Sched. 2)			
3. Net Electric Plant in Service			
4. Deduct: Accumulated Deferred Income Taxes (Sched. 3)			
5. Add: Plant Held for Future Use (Sched. 4)			
6. Fuel Stock Balances (Sched. 5) Note 1			
7. Rate Base (Total lines 1 through 6)			
COST OF SERVICE - DEMAND RELATED			
A. Fixed Charges on Investment			
8. Return on Rate Base at Specified Rate of Return (Sched. 6)			
9. Income Taxes (Sched. 7)			
10. Depreciation & Amortization Expense (Sched. 8)			
11. Deferred Income Taxes (Sched. 9)			
12. Property Taxes (Sched. 10)			
13. Insurance (Sched. 11)			
14. Total Fixed Charges (Total lines 8 through 13)			
B. Fixed Power Production Expense			
15. Fixed Operating and Maintenance Expense (Sched. 12)			
16. Net Purchased Power Demand Costs (Sched. 13)			
17. Production System Control & Load Dispatching (Sched. 14)			
18. Total Fixed Power Production Expense (Total lines 15 through 17)			
C. Fixed Transmission Expense			
19. Operation and Maintenance Expense (Sched. 15)			
20. Credits for Transmission Contracts (Sched. 16)			
21. Credits for Transmission Wheeling (Sched. 17)			
22. Total Fixed Transmission Expense (Total lines 19 through 21)			
23. Total Month's Demand Related Costs Note 1 (Total lines 14, 18 and 22)			

Note 1: Fuel Stock Balances included in the development of the rate base are assigned among the Companies on the basis of an energy allocator. The revenue requirements for fuel stock balances appear in the energy related costs in the determination of the energy unit cost.

Agreement to Coordinate Planning and
Operations and Interchange Power and Energy

Exhibit V
Schedule 5
Revised

FUEL STOCK BALANCES

Electric Production Fuel Stock balances recorded in FERC Accounts 151 and 152 shall be included at 100% of the average of the monthly balances in the accounts.

Note 1: Fuel Stock Balances included in the development of the rate base are assigned among the Companies on the basis of an energy allocator. The revenue requirements for fuel stock balances appear in the energy related costs in the determination of the energy unit cost.

Agreement to Coordinate Planning and
Operations and Interchange Power and Energy

Exhibit VIII
Revised

SPECIFICATION OF AVERAGE MONTHLY COINCIDENTAL PEAK DEMANDS
Calendar Year 1985

	Monthly Coincidental Peak Demands (KW)			
	NPS (Minn) Co.	NSP (Wis) Co.	LSDP Co.	Total System
January	3,864	735	137	4,736
February	3,884	690	143	4,717
March	3,574	640	129	4,343
April	3,308	578	98	3,984
May	3,320	544	106	3,970
June	3,944	597	128	4,669
July	4,931	649	116	5,696
August	4,662	662	116	5,440
September	4,227	610	126	4,963
October	3,329	572	111	4,012
November	3,591	606	120	4,317
December	3,814	702	139	4,655
Total	46,448	7,585	1,469	55,502
Average	3,871	632	122	4,625
Ratio	0.836871	0.136661	0.026468	1.000000

EXAMPLE OF DEVELOPMENT OF UNIT RATES FOR POWER AND ENERGY SALES

The monthly unit rates for the sales of kilowatt-hours of energy by each Party to the other Parties for the month of June 1985 shall be determined as follows:

A - NSP(Minnesota) Energy Rates for sales to NSP(Wisconsin) and LSDP:

$$\text{ER to NSP(Wis) and LSDP} = \frac{\$25,352,000}{1,818,198,000 \text{ kwh}}$$

B - NSP(Wisconsin) Energy Rates for sales to NSP(Minnesota) and LSDP:

$$\text{ER to NSP(Minn) and LSDP} = \frac{\$114,000}{299,568,000 \text{ kwh}}$$

C - LSDP Energy Rates for sales to NSP(Minnesota) and NSP(Wisconsin):

$$\text{ER to NSP(Minn) and NSP(Wis)} = \frac{\$105,000}{62,827,000 \text{ kwh}}$$

Where:

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

"Energy Costs" are each Party's energy costs for the billing month.

"Energy Requirements" are each Party's energy requirements in kwh for the billing month.

EXAMPLE OF DEVELOPMENT OF UNIT RATES FOR POWER AND ENERGY SALES

The monthly amounts of sales of power by each Party to the other Parties for the month of June 1985 shall be determined as follows:

A - NSP (Minnesota) Power Sales to NSP (Wisconsin) and LSDP:

$$\text{PS to NSP(Wis)} = 3{,}944{,}000 \text{ KW} \times \frac{597{,}000 \text{ KW}}{4{,}669{,}000 \text{ KW}}$$

$$\text{PS to LSDP} = 3{,}944{,}000 \text{ KW} \times \frac{128{,}000 \text{ KW}}{4{,}669{,}000 \text{ KW}}$$

B - NSP (Wisconsin) Power Sales to NSP (Minnesota) and LSDP:

$$\text{PS to NSP(Minn)} = 597{,}000 \text{ KW} \times \frac{3{,}944{,}000 \text{ KW}}{4{,}669{,}000 \text{ KW}}$$

$$\text{PS to LSDP} = 597{,}000 \text{ KW} \times \frac{128{,}000 \text{ KW}}{4{,}669{,}000 \text{ KW}}$$

C - LSDP Power Sales to NSP (Minnesota) and NSP (Wisconsin):

$$\text{PS to NSP(Minn)} = 128{,}000 \text{ KW} \times \frac{3{,}944{,}000 \text{ KW}}{4{,}669{,}000 \text{ KW}}$$

$$\text{PS to NSP(Wis)} = 128{,}000 \text{ KW} \times \frac{597{,}000 \text{ KW}}{4{,}669{,}000 \text{ KW}}$$

Where:

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

"Demand" is each Party's demand in KW, based on a forecast of its average twelve monthly coincidental peak demands for the year of application.

"System Demand" is the NSP System demand in KW, based on a forecast of the total NSP System average twelve monthly peak demands for the year of application.

Exhibit VIII shows the development of the average twelve monthly coincidental peak demands for each Party and for the total NSP System as well as the forecast monthly peak load data.

EXAMPLE OF DEVELOPMENT OF UNIT RATES FOR POWER AND ENERGY SALES

The monthly unit rates for the sales of kilowatts of power by each Party to the other Parties for the month of June 1985 shall be determined as follows:

A - NSP (Minnesota) Demand Rate for sales to NSP (Wisconsin) and LSDP:

$$\text{DR to NSP(Wis) and LSDP} = \frac{\$42,663,000}{3,944,000 \text{ KW}}$$

B - NSP (Wisconsin) Demand Rate for sales to NSP (Minnesota) and LSDP:

$$\text{DR to NSP(Minn)} = \frac{\$3,504,000}{597,000 \text{ KW}}$$

$$\text{DR to LSDP} = \frac{\$2,809,000}{597,000 \text{ KW}}$$

C - LSDP Demand Rate for sales to NSP (Minnesota) and NSP (Wisconsin):

$$\text{DR to NSP(Minn) and NSP(Wis)} = \frac{\$807,000}{128,000 \text{ KW}}$$

Where:

"DR" is the monthly unit demand rate (rate in dollars per KW) 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 demand, based on a forecast of its average twelve monthly coincidental peak demands for the year of application as shown in Exhibit VIII.

NORTHERN STATES POWER COMPANY

REPORT ON THE EXAMINATION OF DEMAND ALLOCATION METHODOLOGIES AND DEMAND AND ENERGY MEASUREMENT

UNDER THE
INTERCHANGE AGREEMENT
AMONG
NORTHERN STATES POWER COMPANY (MINNESOTA)
AND
NORTHERN STATES POWER COMPANY (WISCONSIN)
AND
LAKE SUPERIOR DISTRICT POWER COMPANY

DECEMBER 1986

Prepared by the
Allocation Methods Task Force

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Exhibit

A. Description of Standard Demand Allocation Methods
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I. INTRODUCTION

The Interchange Agreement among Northern States Power Company (Minnesota), Northern States Power Company (Wisconsin) and Lake Superior District Power Company is a formula rate specifying the price of power and energy which is bought and sold between the three Companies. A formula rate is a rate which adjusts the price of electricity periodically through the use of a formula and defined input parameters. The Federal Energy Regulatory Commission (FERC) has the authority to review and approve this formula. The formula itself does not change unless the Companies submit a filing to the FERC and obtain approval of the changed formula.

The Companies have found it necessary over the years to modify this formula rate. Most recently, on September 20, 1984, the Companies filed a revised formula rate with the FERC which incorporated several modified features. Intervening in that proceeding before the FERC were the Commissions of Minnesota, North Dakota, South Dakota and Wisconsin, the Minnesota Department of Public Service, and representatives of the Companies wholesale customers. Following considerable negotiation, a Settlement Agreement was reached between the parties on May 31, 1985, and was subsequently submitted to and approved by the FERC.

This report has been prepared pursuant to a provision of the Settlement Agreement which required the Companies to conduct two studies related to issues raised by intervenors in the Interchange Agreement negotiations. Article 3.1 of the Settlement Agreement states in part:

> The NSP Companies agree to conduct an examination of (1) the existing methodology for allocation of demand costs under the Interchange Agreement and selected alternative methodologies for use in the future and (2) the existing methods of measuring demand and energy requirements used for developing cost responsibilities under the Interchange Agreement for each NSP Company and selected revisions to those methods for use in the future.

In response to this Settlement Agreement provision, the Companies established the Allocation Methods Task Force to perform the studies required. Members of the Task Force represented the following areas of the Companies: Energy Forecasting, Load Research, Rate, System Operational Planning, and Transmission Planning.

This report summarizes the Companies conclusions and recommendations, explains the detailed analysis leading to those conclusions, and quantifies the impact on the three Companies which results from the recommendations made.

II. EXECUTIVE SUMMARY

On the basis of the analysis completed by the Allocation Methods Task Force, the Coordinating Committee of the Interchange Agreement adopted the recommendations presented by the Task Force. The following summarizes the Companies' positions on the studies required by the Interchange Agreement Settlement.

Examination of the Demand Allocation Methodology

NSP supports continued use of the Average of 12 Monthly Coincident Peaks (AMCP) method for purposes of allocating demand-related costs in the Interchange Agreement. It is proposed, however, that the data used to determine the AMCP allocation ratios be modified. Currently, the calculation of the AMCP is based on one year of forecasted monthly peaks. NSP proposes that three years of load data including 18 months of historical and 18 months of forecasted monthly peaks be used to calculate the AMCP. The actual data used in the calculation would be normalized to reflect known significant load changes.

This proposal is based on the following conclusions:

- The AMCP method is the conceptually appropriate method given the operational characteristics of the NSP system.
- The AMCP method is widely used in the electric utility industry and can be expected to have a high degree of acceptability by all the parties.
- The AMCP method produces manageable year-to-year changes in cost responsibility for the three Companies.
- The AMCP method tracks inter-company load responsibility trends and it also reflects actual system operation.
- The AMCP method is easily applied, explained, documented and reproduced.

Examination of Demand and Energy Measurement

After a complete review of the existing procedure, NSP has determined that it is appropriate to continue measuring the system demand and energy requirements of each Company following present procedures.

This conclusion is based on the following factors:

- Extensive effort has been and continues to be made to accurately record the monthly actual demand and energy requirements information for the NSP system.
- Metering equipment is located as close to the individual Companies boundaries as is practical.

While the source data used to identify each Companies requirements should not change, the use of such data in the Interchange Agreement is proposed to be modified with respect to assignment of transmission losses as discussed below.

Allocation of System Transmission Losses

NSP proposes that procedures be implemented to allocate (share) system transmission losses equally among the three Companies. Each Companies' peak demands and energy requirements as measured at the system level should be adjusted for transmission losses prior to the development of the cost allocation ratios. The result of these adjustments is that system transmission losses are shared by the three Companies in proportion to their contributions to requirements measured at the level between transmission and distribution voltages. The adjustments would be updated annually to coincide with the annual update of the cost allocation ratios.

This proposal is based on the following conclusions:

- The cost responsibility of system transmission losses in the Interchange Agreement is presently inconsistent with the manner in which investment and operation & maintenance expenses in production and transmission facilities are allocated between Companies.

- The detailed Company specific loss information necessary to implement allocating transmission losses is available from a recently completed NSP transmission and distribution loss study, performed to fulfill commitments in the Interchange Agreement Settlement as well as other regulatory needs.

- The implementation procedures are straightforward and easily incorporated into the Interchange Agreement cost responsibility formulas.

Impact of Proposals on Companies

The impact of the proposed change from the use of one year forecasted monthly peaks to 18 months of historical and 18 months of forecasted monthly peaks, in calculating the AMCP allocators, is as follows:

Impact of Proposed Demand Allocation Method

	Present Method	Proposed Method	Change
Demand Allocation Ratios:			
NSP(MN)	.839839	.839686	-0.02%
NSP(WI) & LSDP	.160161	.160314	0.10%
1986 Demand-Related Billings ($ Millions):			
NSP(MN)	$491.5	$491.4	-$0.1
NSP(WI) & LSDP	$93.7	$ 93.8	$0.1

The additional impact on the Companies resulting from the proposal to allocate transmission losses is as follows:

Impact of Proposal to Allocate Transmission Losses

	Losses Assigned As Measured	Losses Allocated	Change
Allocation Ratios			
Demand:			
NSP(MN)	.839686	.844313	0.6%
NSP(WI) & LSDP	.160314	.155687	-2.9%
Energy:			
NSP (MN)	.833716	.838344	.6%
NSP (WI) & LSDP	.166284	.161656	-2.8%
1986 Billings ($ Millions)			
Demand:			
NSP(MN)	$491.4	$494.1	$2.7
NSP(WI) & LSDP	$ 93.8	$ 91.1	-$2.7
Energy:			
NSP(MN)	$331.6	$333.4	$1.8
NSP(WI) & LSDP	$ 66.1	$ 64.3	-$1.8
Total:			
NSP(MN)	$823.0	$827.5	$4.5
NSP(WI) & LSDP	$159.9	$155.4	-$4.5

The overall impact on the Companies estimated for the year 1986 resulting from the two NSP proposals is to increase the billings to the MN Company by $4.4 million and to decrease the billings to the WI Company and LSDP by that same amount.

III. DEMAND ALLOCATION METHODOLOGY ANALYSIS

Study Objectives

The Allocation Methods Task Force established as a primary goal, the identification of a well-supported method for allocating demand-related costs in the Interchange Agreement. In order to meet this goal, the Task Force initially developed a set of criteria which represented the minimum standards required before a demand allocation method would be considered.

In order to assure that all reasonable methods were considered, a survey was conducted among members of the Rate Research Committee of the Edison Electric Institute. The survey requested information from each utility member concerning the methods used for allocating costs between subsidiaries, state jurisdictions, retail and wholesale jurisdictions and customer classes. In addition, previous studies performed by NSP which analyzed the various demand allocation methods were reviewed. A brief description of standard demand allocation methods is included in Exhibit A.

Various FERC cases were also reviewed to determine what tests FERC has relied on in the past to justify the reasonableness of demand cost allocation methods. The tests found appropriate involved analysis of method stability from year to year and system load characteristics. The latter tests focused on peak load patterns, scheduled maintenance, reserves and pronounced differences between monthly peaks. The Task Force subsequently incorporated several of these tests into its detailed analysis.

This initial study effort allowed the Task Force to meet its next objective, which was to select the allocation methods to be examined in greater detail. The present allocation method and three alternative methods were subsequently evaluated and ranked according to how well each met pre-established criteria.

The final objective was to select the most appropriate demand allocation method to be used in the Interchange Agreement. The conclusions and recommendations reached by the Task Force, based upon the detailed study effort, are discussed at the end of this section.

Evaluation Criteria

As part of the initial study effort, the Task Force developed a list of criteria for purposes of selecting and evaluating demand allocation methods. The criteria aided in identifying the allocation methods to be reviewed by the Task Force, and later, provided a means of ranking the reasonableness of each method.

The criteria developed by the Task Force is as follows:

Criteria to Evaluate Allocation Methods

1. The method has a sound conceptual basis which produces reasonable, fair and non-discriminatory results.

2. The method has a reasonable degree of acceptability by all parties.
3. The method can be performed at reasonable cost and within the time constraints required by the Interchange Agreement.
4. The method can be uniformly applied to all companies and jurisdictions.
5. The method produces reasonable year to year shifts in costs (degree of stability).
6. The method can be easily reproduced, replicated, explained and documented.
7. The method tracks any substantial load trends occurring in any jurisdiction.
8. The method adequately addresses managed load impacts.

Electric Utility Industry Survey

In order to assure that all reasonable and appropriate demand allocation methods were considered by the Task Force, a survey was conducted among members of the Rate Research Committee of the Edison Electric Institute. The survey requested information on how production and transmission costs are allocated to subsidiaries, state and federal jurisdictions and retail customer classes. Descriptions of the allocation methods and reasons for choosing the methods were also requested.

The survey results show that for utilities similar to NSP, with multiple state and federal jurisdictions, the most commonly used jurisdictional allocation method is the Average of 12 Monthly Coincident Peaks method. By far, the reason given most often for using this allocation method was the high degree of acceptability by the FERC and other parties. Allocation methods employing some variation of monthly or hourly coincident peaks accounted for 71% of the allocation methods used to allocate between subsidiaries, 89% of the methods used for retail and wholesale jurisdictional allocations, and 72% of the methods used for retail jurisdictional allocations. Of lesser use were methods employing probability of dispatch, average and excess demands, and several variations of non-coincident peaks.

A summary of the survey results is contained in Exhibit B. Brief descriptions of the most widely reported allocation methods are included in Exhibit A.

Other Considerations

Proceedings before the FERC indicate that system monthly load and generation capacity reserve characteristics are of paramount importance when choosing a well-supported demand allocation methodology. Consequently, the Task Force analyzed NSP actual system capacity reserves for the years 1982 through 1985 and forecast system capacity reserves for the years 1986 and 1987. Exhibit C contains graphs of the monthly system reserves for the 6 years analyzed and the detailed information used in this analysis.

System reserves including and excluding the capacity on scheduled maintenance were analyzed. The scheduling of maintenance was considered to be a significant factor in the evaluation of the operation of a generation system. In this examination, reserves were defined as follows:

Reserves = Net Available Dependable Capacity Minus Net Peak Load,

Percent Reserves = Reserves Divided by Net Peak Load Times 100,

Where: Net Available Dependable Capacity = Dependable Capacity Owned Less Dependable Capacity Sales Plus Dependable Capacity Purchases,

Net Peak Load = Firm Peak Load Less Firm Purchases Plus Firm Sales.

In calculating reserves including capacity on scheduled maintenance, net available dependable capacity included any capacity on scheduled maintenance. In calculating reserves excluding capacity on scheduled maintenance, net available dependable capacity was reduced by any capacity on scheduled maintenance.

Average monthly percent reserves vary from 29 to 85 percent for the period 1982 through 1987. When the 2 high reserve months of May and October are excluded from the analysis, the variance in average monthly percent reserves for the six years falls to 21 percentage points, from 29 to 50 percent. A similar analysis of reserves excluding capacity on scheduled maintenance shows a tighter range of average monthly percent reserves for the six years, and when the months of May and October are again removed, the monthly variation falls from 43 to 12 percentage points.

Overall, the variation from month to month in percent reserves is not significant when the shoulder months of May and October are excluded, indicating that for 10 months out of 12, the system load levels are important determinants of system generation requirements. The results of this analysis indicated, that realistically, all months should be considered as equally important.

Alternative Methods Reviewed

The preliminary study effort aided the Task Force in choosing the demand allocation methods to be selected for detailed review. The four methods selected were the following.

1. Average of 12 Monthly Coincident Peaks Method Based on One Forecast Year Data,

2. Average of 12 Monthly Coincident Peaks Method Based On a Combination of Historical and Forecast Years Data,

3. Average of Seasonal Coincident Peaks Method, and

4. Average of 12 Monthly Non-Coincident Peaks Method.

The first selected method is the method currently being used in the Interchange Agreement as a result of the settlement reached between the intervening parties on May 31, 1985. The second and fourth methods were selected in order to address concerns raised during settlement negotiations.

The third method was selected as an alternative to be reviewed as a result of the industry survey and the analysis of system reserves.

Analysis of Alternatives Reviewed

In order to analyze the selected allocation methods, the Task Force developed a procedure which could be used to rank each allocation method in relation to the pre-established criteria. The procedure involved weighting each of the eight criteria as to low, medium or high priority. Two of the criteria were also used as threshold screening tests. Any allocation method failing to meet the two screening criteria could be eliminated from the ranking. The two screening criteria were the following:

1. The method can be performed at reasonable cost and within the time constraints required by the Interchange Agreement, and

2. The method produces manageable year to year shifts in costs.

In addressing the first elimination criterion, the Task Force collected historical and forecasted data necessary to apply each of the four alternative allocation methods. The time and costs required to produce the required data and the dates the information becomes available were verified as meeting the needs for the Interchange Agreement.

The second elimination criterion, the degree of stability, was considered by the Task Force to also be of high priority. Dramatic year-to-year shifts in allocated costs between the three Companies would result in unreasonable impacts on the rate case planning process for all Companies in their retail and federal jurisdictions. The costs assigned through the Interchange Agreement affect a major portion of total revenue requirements.

In order to analyze the stability issue, the Task Force calculated allocation ratios for each Company from available historical and forecasted data. Annual shifts in costs resulting from each of the four allocation methods were determined by applying each Company's allocation ratio from year-to-year to fixed production and transmission costs which are shared through the Interchange Agreement. For 1986 these costs will be approximately $600 million. Exhibit D contains the results of the stability tests.

For the first allocation method, the Average of 12 Monthly Coincident Peaks based on one forecast year data, the company allocation ratios were calculated for the years 1984 through 1987. The results show that the largest annual dollar amount change for any one of the three Companies ranged from $640,000 to $2,070,000 for this method .

The second demand allocation method selected was also based on the Average of 12 Monthly Coincident Peaks. However, instead of basing the calculation on one forecast year, the calculation was based on a combination of historical and forecasted monthly coincident peaks. Several variations of this second method were analyzed for stability as follows:

1. 1 year actual (calendar) combined with 1 year forecast,
2. 2 years actual (calendar) combined with 1 year forecast,
3. 1 year actual (winter ending) combined with 1 year forecast,
4. 2 years actual (winter ending) combined with 1 year forecast, and
5. 3 consecutive years with 18 months actual and 18 months forecast.

The actual years considered in the first two variations were calendar years ending one year before the start of the forecast year. The actual years used in variations three and four were 12 and 24 months respectively ending with March of the year prior to the forecast calendar year. Company allocation ratios were calculated based on how the method would be applied for purposes of cost allocation for the years 1984, 1985, and 1986. The largest annual dollar amount change for any one of the three Companies for all the combinations ranged from $70,000 to $2,180,000.

The third demand allocation method analyzed was the Average of Seasonal Coincident Peaks. The year was separated into four seasons as follows:

Winter - December, January and February,
Spring - March, April and May,
Summer - June, July, August, and September,
Fall - October and November.

The system peak in each season was used to determine the coincident peaks for the Companies. Allocation ratios were calculated for the actual years 1982 through 1985. The largest annual dollar amount change for any one of the three Companies ranged from $1,250,000 to $7,870,000.

The final allocation method analyzed for stability was the Average of 12 Monthly Non-Coincident Peaks. Allocation ratios were calculated for the actual years 1981 through 1985. The largest annual dollar amount change for any one of the three Companies ranged from $910,000 to $2,330,000 for this fourth allocation method.

One of the additional criteria established by the Task Force was that the method should track reasonably well any substantial load trends occurring in any jurisdiction. This criterion is related to the stability criterion discussed earlier. A desirable method is one which is reasonably stable from year-to-year, but which is also capable of reflecting basic changes in load responsibility of the Companies as they change through time. An analysis of Company average monthly peak load growth rates indicated that the Minnesota Company is growing on average faster than WI Company and LSDP; therefore, the selected demand allocation method should produce a corresponding increase in the allocation ratio for MN Company. The average monthly peak load growth rates and accompanying data used in this analysis are also contained in Exhibit D.

The results of the stability and peak load growth examinations led the Task Force to the conclusion that the Average of Seasonal Coincident Peaks allocation method should be eliminated from further consideration because it resulted in shifts in costs which were more than triple those resulting from

any of the three remaining methods. An annual shift in costs of this magnitude was unacceptable and caused the method to be eliminated from further analysis and consideration.

The second criterion rated by the Task Force as high priority, in addition to the stability criterion, was that the method have a sound conceptual basis, and that it produce reasonable, fair and non-discriminatory results. Concerns expressed by intervening parties during settlement negotiations focused on the reasonableness of the Average 12 Monthly Coincident Peaks method in-so-far as it was calculated based on only one forecast year data. An analysis of how accurately various forecasts predicted actual Company monthly coincident peaks was conducted for the years 1984 and 1985. The data used in the analysis is included in Exhibit D.

The various forecasts analyzed differed from actual monthly peaks by -0.3% to 1.5% for MN Company, 3.1% to 3.2% for WI Company and -3.3% to -0.8% for LSDP. Although these percentages are relatively small, even small forecasting errors can have significant costing impacts on the two Wisconsin Companies. Averaging actual and forecast data from more than one year tends to moderate forecast uncertainty.

Finally, through consensus discussions among Task Force members and other NSP personnel, the three remaining allocation methods were ranked according to how well each method met the evaluation criteria. The results of the evaluations are included in Exhibit E. The rankings of the allocation methods, weighted by the importance of each of the criteria, are as follows from high to low: Average of 12 Monthly Coincident Peaks based on a Combination of Historical and Forecast Years (score = 45), Average of 12 Monthly Coincident Peaks based on One Forecast Year (score = 36), and Average of 12 Monthly Non-Coincident Peaks (score = 25).

Conclusions and Recommendations

Four demand allocation methods were selected by the Allocation Methods Task Force as meeting the minimum standards required for consideration. The four methods are the following:

1. Average of 12 Monthly Coincident Peaks Method Based on One Forecast Year Data (AMCP-Forecast),

2. Average of 12 Monthly Coincident Peaks Method Based on a Combination of Historical and Forecast Years Data (AMCP - Combination),

3. Average of Seasonal Coincident Peaks Method (ASCP), and

4. Average of 12 Monthly Non-Coincident Peaks Method (AMNCP).

These methods were evaluated based on the eight criteria established by the Task Force. The ASCP method was subsequently eliminated due to the high degree of instability in annual shifts of costs between the three Companies. The three remaining methods equally fulfilled two of the criteria, which were that they could be applied uniformly to all companies and jurisdictions, and they could be easily reproduced, replicated, explained and documented. The

AMCP-Combination allocation method ranked the highest for the two criteria considered to be the most important. This method has a sound conceptual basis reflecting the operational characteristics of the NSP system and generally exhibits appropriate stability in annual reallocated costs between the three Companies.

For the criteria rated as medium importance, the AMCP-Forecast method ranked highest for tracking substantial load trends and the AMNCP method ranked lowest in expected acceptability by all parties. The AMNCP method also ranked last in addressing managed load impacts on system requirements, a lower priority criterion. If the Companies managed their loads to control non-coincident peaks, the effect on the system coincident peak would be eroded. The method ranking last for the final lower priority criterion, reasonable costs and time constraints, was the AMCP-Combination method. This method requires two to three times the amount of data used by the other methods.

The results of the evaluation analysis indicated that the AMCP-Combination method ranked well above the other two methods; therefore, the AMCP-Combination method was selected as the most appropriate demand allocation method to be used in the Interchange Agreement.

The Allocation Methods Task Force recommends that NSP employ the Average of 12 Monthly Coincident Peaks method and that it be based on a combination of historical and forecast years data. The Task Force also recommends that the data combination incorporate 36 consecutive months, 18 months of actual monthly peaks and 18 months of forecasted monthly peaks. This combination allows the most current actual and forecast data to be used and weights actual and forecasted information equally.

Because this recommendation covers actual, as well as forecasted periods, the Task Force believes that special provision should be allowed to adjust the actual load data to reflect known significant load changes. An example of this would be a known loss or gain of a wholesale or large industrial customer. The actual data should be normalized to account for load variations of this type. Any deviation, however, should be of at least 10 MW.

Procedures currently in place in the Interchange Agreement for determining demand-related production and transmission costs and for annually updating cost allocation ratios should be continued.

IV. DEMAND AND ENERGY MEASUREMENT

Study Objectives

The second study required by the May 31, 1985, Settlement Agreement was an examination of the existing methods of measuring and determining the demand and energy requirements used for developing cost responsibilities for each NSP Company and examination of selected revisions to those methods for use in the future. In light of this goal, the Task Force initially reviewed the existing process by which demand and energy requirements are measured for use in the Interchange Agreement. Any possible changes or improvements could then be evaluated as to their cost/benefits. The assignment or responsibility for system transmission losses was also recognized as an integral part of the study effort. Factors influencing the transmission losses attributable to each Company were identified. A power flow modeling analysis was conducted to quantify the transmission losses for the Companies. The results of this study effort allowed the Task Force to recommend changes in the manner in which demand and energy requirements data are used in assigning cost responsibilities in the Interchange Agreement.

Review of Measurement Procedures

In an interconnected electric power system, the quantities of power and energy produced or purchased by the system must be equal to power and energy sales to retail customers and to other utilities, plus associated losses. NSP calculates its system power and energy requirements as the sum of power and energy generated, based on meter readings at generation sites, and net deliveries to the NSP system from other interconnected systems, based on meter readings at system boundary locations. This calculation is performed in the following three parts: (1) for the entire three Company NSP system, (2) for the WI Company and (3) for LSDP. Power and energy requirements for the MN Company are defined as the total system power and energy requirements less the power and energy requirements for the WI Company and LSDP. A detailed description of measurement procedures and sample calculations is contained in Exhibit F.

Power and energy generated by the NSP system is obtained from meter readings at 45 separate generating plants. The generation output for system use is the difference between metered output and the power and energy required for operating the generating plant.

The calculation of net deliveries to the NSP system based on system boundary meter readings involves several different procedures due to meter type and location. Meter readings at the boundaries of the control area, which is the area for which NSP has operational control responsibility, are reduced by meter readings measuring other utilities requirements within NSP's control area and for sales to other utilities or municipals located within NSP's control area. Other additions to net deliveries to the NSP system are meter readings measuring NSP's power and energy responsibilities in the control areas of other utilities and purchases under cogeneration type agreements.

In determining monthly net energy deliveries to the NSP system, the meter readings recorded reflect as close to the same time period as practically possible. Most meters are read at or adjusted to midnight on the last day of the calendar month where time series metering equipment is available. Other meters are read on the working day closest to the end of the calendar month. Meters located at interties with some utilities are read on a 20th to 20th of the month basis rather than on a calendar month basis. Over an annual period, variations in the time period have little impact on the validity of data collected.

Meter readings are obtained from nineteen meter locations which are used to determine power and energy requirements for the WI Company and LSDP. These meter readings do not affect the calculation of total system power and energy requirements. Eighteen meters measure interconnections between the MN and WI Companies. Of these, nine meters are at distribution voltage located virtually on the state border, six meters are at transmission voltage located a short distance from the border in Minnesota, and three meters are at transmission voltage located a short distance from the border in Wisconsin. Losses occurring between the meters in the MN Company and the state border are recorded as WI Company energy and losses occurring between the meters in the WI Company and the state border are recorded as MN Company energy. In order to quantify the overall impact of this metering situation, the Task Force estimated the annual energy and peak demand loss for each interconnection over a one year period. This analysis is contained in Exhibit G. The results indicate that about 3MW of transmission losses at time of system peak and 18,000 MWH of annual energy transmission losses assigned to the WI Company could be reassigned to the MN Company.

Conclusions and Recommendations

Extensive and detailed procedures are being performed by NSP to accurately record the demand and energy requirements of the NSP system. The central issue is not the measurement of requirements, but rather the proper method to assign responsibility for total demand and energy requirements between the Companies. Results of a detailed study effort indicate that any inequities of the present cost allocation method in the Interchange Agreement lie chiefly in the treatment of transmission losses. Making direct assignment of transmission losses, due to causal relationships, may be theoretically possible, but, it's a very elusive, time consuming, and expensive process, and doesn't reflect NSP's planning process. From a planning and operational perspective, NSP's production and transmission system is handled on an integrated basis. In other words, decisions are made with respect to new plant additions, or upgrades, on the basis of total system economics. Plant investment and operation and maintenance costs are allocated or shared on this basis among the Companies in the Interchange Agreement.

The comprehensive solution to the demand and energy measurement issues studied by the Task Force is to equally share all system transmission losses between the NSP Companies in a way consistant with the treatment of other production and transmission costs. The Task Force developed a set of procedures achieving this goal. The recommendations of the Task Force are more fully explained in the following section, TREATMENT OF SYSTEM TRANSMISSION LOSSES.

V. TREATMENT OF SYSTEM TRANSMISSION LOSSES

Interchange Agreement Objectives

The Interchange Agreement provides the contractual basis for the continued planning and operation of the power supply facilities of the Companies. In addition, the Agreement provides the basis for determining the amounts of power and energy needed to be sold among the Companies and the charges for such sales in order to equalize the unit costs of power supply for each Company. For this reason, production and transmission investment and associated operation and maintenance expenses for the NSP system are allocated between the three Companies based on relative demand requirements.

The transmission system losses associated with the operation of the system power supply facilities are currently paid by the Company in which they occur. This is a direct result of the existing demand and energy measurement process. This capturing of transmission losses by each Company results in these system level losses being assigned on a basis which is disproportionate to each Company's share of the total system level load requirements. The result is that the assignment of transmission system losses is inconsistent with the method used for determining the cost responsibilities of each Company. The objectives of the Interchange Agreement can best be achieved by adopting a procedure which effectively allocates transmission losses in a manner consistent with the other bulk power costs.

Allocation Methodology

In order to appropriately allocate system transmission losses, each Company's demand and energy requirements need to be determined such that the impact of transmission losses is excluded. The resultant demand and energy requirements values would then represent requirements at the boundary between the transmission and distribution systems. This is commonly referred to as the high side of the distribution system (HSDS). These values can then be used to calculate allocation ratios; that is, each Company's share of the total system demand and energy requirements at this HSDS level.

One method for arriving at requirements values at the HSDS level is to remove transmission losses from total Company demand and energy requirements through the use of transmission loss multipliers. These multipliers are determined from the NSP Transmission & Distribution Electric Loss Study December 1986. Over the last year, extensive effort has been expended to determine distribution and transmission losses for the NSP system and Companies. The results of that effort are published in the above mentioned report. The relevant summary schedules from that report are contained in Exhibit H for easy reference. The transmission loss multipliers used by the Task Force in the allocation of transmission losses are as follows:

Transmission Loss Multipliers

	Peak Demand	Annual Energy
MN Company	.965	.964
WI Company and LSDP	.932	.932
System Total	.959	.959

Conclusions and Recommendations

The objectives of the Interchange Agreement can best be achieved by adopting new procedures which allocate system transmission losses in a manner consistent with the method used to share other bulk power supply costs. The required procedures are easily implemented and incorporated into the Interchange Agreement cost responsibility formulas.

The Task Force recommends that the allocation of transmission losses be accomplished by applying transmission loss multipliers to the measured Company demand and energy requirements prior to the calculation of the Company cost allocation ratios. The transmission loss multipliers should be taken from the NSP Transmission & Distribution Electric Loss Study December 1986. As the Loss Study report recommends, the transmission loss multipliers would be updated annually, and would be reflected in the Interchange Agreement through the procedure now used to annually update the cost allocation ratios.

VI. IMPACT ON COMPANIES

In order to quantify the impact on the Companies due to the recommended proposals, the Allocation Methods Task Force analyzed changes in Company billings under the Interchange Agreement for the budget year 1986. The demand allocation ratios, currently based on one year of forecasted monthly coincident peaks, are used to allocate approximately $585.2 million. Energy-related costs total approximately $397.7 million and are allocated for the budget year 1986 based on forecasted energy requirements by Company. The present costs and allocation ratios by Company used in the impact analysis are as follows:

	System	MN Co.	WI Co.	LSDP
(1) Demand Allocation Ratios	1.000000	0.839839	0.138036	0.022125
(2) Demand-Related Costs ($ Millions)	$585.2	$491.5	$80.8	$12.9
(3) Energy Allocation Ratios	1.000000	0.833716	0.140481	0.025803
(4) Energy-Related Costs ($ Millions)	$397.7	$331.6	$55.9	$10.2

The first Task Force recommendation modifies the data used to determine the demand allocation ratios. The proposal incorporates three years of load data through the use of 18 months of historical and 18 months of forecasted monthly peaks. For the budget year 1986, actual coincident peaks were used for the months January 1984 through June 1985 and forecasted coincident peaks for the months July 1985 through December 1986. The resulting demand allocation ratios and changes in allocated costs are as follows:

	System	MN Co.	WI Co.	LSDP
(5) Recommended Demand Allocation Ratios	1.000000	0.839686	0.137427	0.022887
(6) Resulting Demand-Related Costs ($ Millions)	$585.2	$491.4	$80.4	$13.4
(7) Change in Demand-Related Costs from Line (2) ($ Millions)	$ 0.0	($0.1)	($0.4)	$0.5

The data and calculations used in this analysis are included in Exhibit I.

The second Task Force recommendation modifies the data used to determine both the demand and energy allocation ratios. This proposal involves adjusting the base data for transmission losses using transmission loss multipliers described in Section V. For purposes of quantifying this additional impact of

sharing transmission losses, the demand ratios obtained after adjusting for transmission losses were compared to the demand ratios resulting from the recommended demand allocation method. The results of this analysis, the details of which are also included in Exhibit I, are as follows:

	System	MN Co.	WI Co.	LSDP
(8) Resulting Demand Allocation Ratios	1.000000	0.844313	0.133457	.022230
(9) Resulting Demand-Related Costs ($ Millions)	$585.2	$494.1	$78.1	$13.0
(10) Change in Demand-Related Costs from Line (6) ($ Millions)	$0.0	$2.7	($2.3)	($0.4)
(11) Resulting Energy Allocation Ratios	1.000000	0.838344	0.136571	0.025085
(12) Resulting Energy-Related Costs ($ Millions)	$397.7	$333.4	$54.3	$10.0
(13) Change in Energy-Related Costs from Line (4) ($ Millions)	$0.0	$1.8	($1.6)	($0.2)
(14) Total Change in Costs Line (10) plus (13) ($ Millions)	$0.0	$4.5	($3.9)	($0.6)

The overall impact on Company billings estimated for the year 1986 from the two Task Force recommendations is approximately a $4.4 million increase for MN Company and a corresponding decrease in the billings for WI Company and LSDP.

DESCRIPTION OF STANDARD DEMAND ALLOCATION METHODS

Coincident Peak (CP) Method

Definition: Ratio of the demand of each group (Company, jurisdiction or class) at the time of the system peak to the system peak demand. The ratio can be based on peak demands averaged over any number of hours or months in a year.

Variations:

Annual CP(ACP) - Ratio of the demand of each group at the time of the annual system peak to the annual system peak demand. This method assumes that the capacity requirement of the system is determined by the annual peak demand. This method may be appropriate when the annual peak demand is considerably higher or growing substantially faster than other monthly peak demands.

Average of 12 Monthly CP (12 CP) - Ratio of the summation of the 12 monthly coincident peak demands of each group to the summation of the system monthly peak demands. This method reasonably reflects both magnitude and duration of peak demand and it reflects the fact that the production facilities being allocated are used over the entire year.

Non-Coincident Peak (NCP) Method:

Definition: Ratio of the maximum demand of each group to the summation of the maximum demands of all groups, irrespective of when each group's maximum demand occurs. The ratio is usually based on annual NCP's but could be based on any number of monthly averaged NCP's.

Variations:

Annual NCP - Ratio of the maximum demand of each group during a year to the summation of the maximum demands of all groups occurring anytime during that year. This method assumes that each group would, if served independently, require facilities to meet the group's maximum demand. The effect among groups is to apportion the diversity benefits without regard to the group's contribution to the system coincident peak load.

Average of 12 Monthly NCP - Ratio of the summation of the 12 monthly maximum demands of each group to the summation of the 12 monthly maximum demands of all groups.

Average and Excess Demand (AED) Method

Definition: Ratio of the average and excess demand of each group to the system peak demand. A group's average and excess demand is the sum of the group's average demand and the group's share of the system excess demand. Each group's average demand is the group's annual energy

divided by the hours in the year. The system excess demand is the difference between the system peak demand and the sum of all group average demands. The system excess demand is generally allocation to groups based on the non-coincident peak method.

This method recognizes both the magnitude of the system peak and annual energy requirements. The relationship between peak demand and energy requirements of the system is reflected in this method; that is, a system with a high load factor results in costs assigned mostly on energy requirements and a system with a low load factor results in few costs assigned on energy requirements.

NORTHERN STATES POWER COMPANY (MINNESOTA)
Survey of Demand Cost Allocation Methods
March 1986

Summary of Results on Production Plant Demand Cost Allocation Methods

	Allocation Between:					
	Subsidiaries		Retail & Wholesale		Retail Jurisdictions	
Allocation Method	Number of Responses	Percent	Number of Responses	Percent	Number of Responses	Percent
12 Monthly Coincident Peaks (CP)	2	29%	35	71%	12	41%
Other Variations of CP's:						
Annual CP	1		1		1	
NEPOOL (70% ACP + 30% 12CP)	2		1		1	
4 Summer Months CP's			4		2	
Sum., Win., Spring & Fall CP's			1			
Dec. & Jan CP's for 6 years			1		1	
4 Hours on Annual Peak Day			1			
4 Highest Month CP's					1	
3 Summer Month CP's					1	
8 Highest Month CP's					1	
4 Summer Month CP's Plus 8 Winter Month CP's					1	
Subtotal	3	42%	9	18%	9	31%
Variations of Non-Coincident Peaks (NCP):						
3 Highest NCP's in 24 Mo. Period	1					
Annual NCP	1					
Average & Excess Demands			3		6	
Sub-total	2	29%	3	6%	6	21%
Other Methods:						
Probability of Dispatch			1		2	
Hours Share of Each Unit Type			1			
Sub-total			2	4%	2	7%
Total Responses	7	100%	49	100%	29	100%

Exhibit C
Page 1 of 4

NSP SYSTEM PERCENT RESERVES*

For the Actual Years 1982 thru 1985
and the Forecast Years 1986 and 1987

	Page
Graph of NSP System Percent Reserves By Month Including Capacity Out For Scheduled Maintenance	2
Graph of NSP System Percent Reserves by Month Excluding Capacity Out For Scheduled Maintenance	3
Data Tables Used to Plot Graphs	4

* Percent Reserves are calculated as follows:

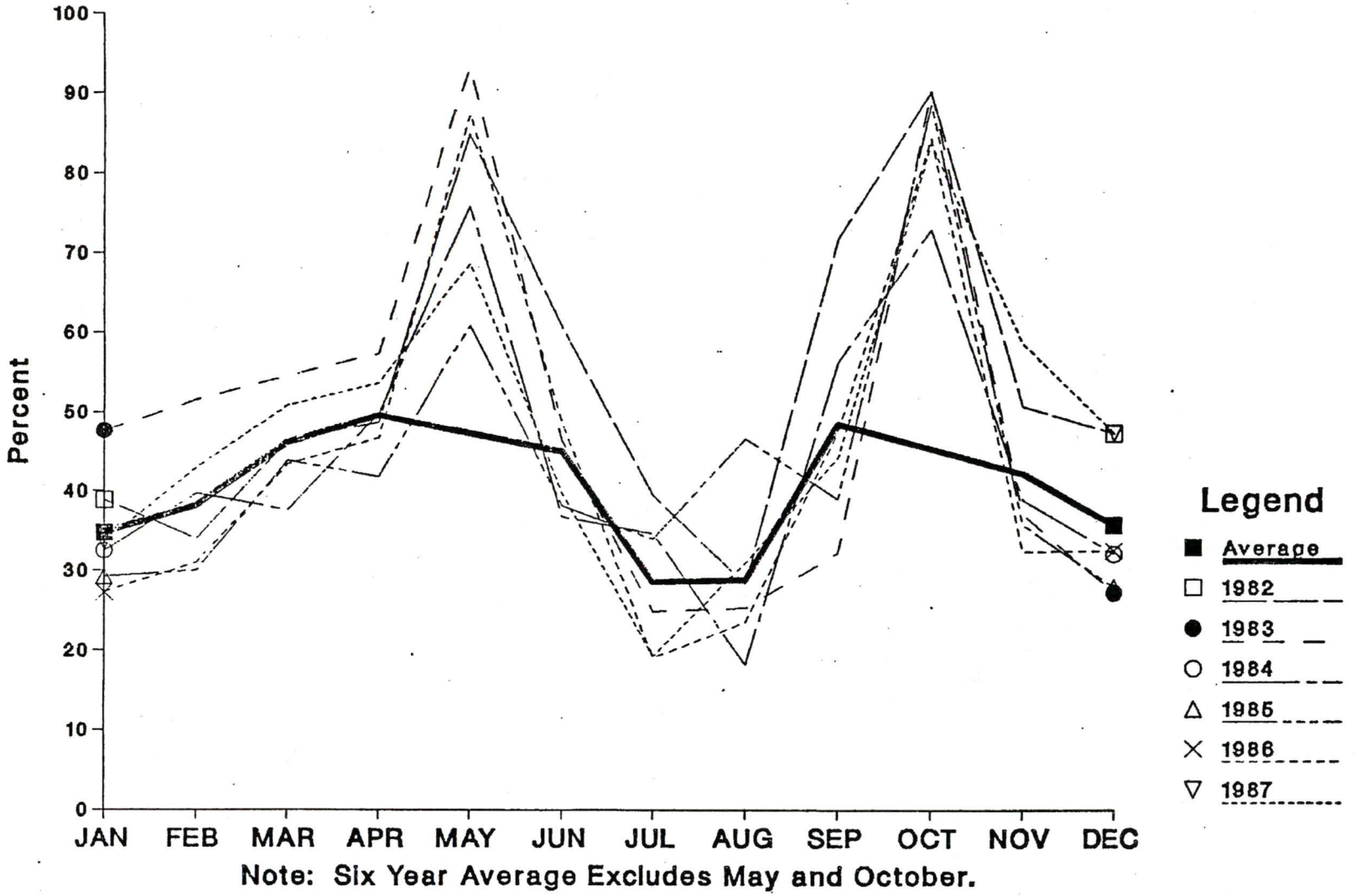
Percent Reserves = Reserves divided by net peak load times 100,

Where: Reserves = Net available dependable capacity minus net peak load,

Net Available Dependable Capacity = Dependable capacity owned less dependable capacity sales plus dependable capacity purchases, and

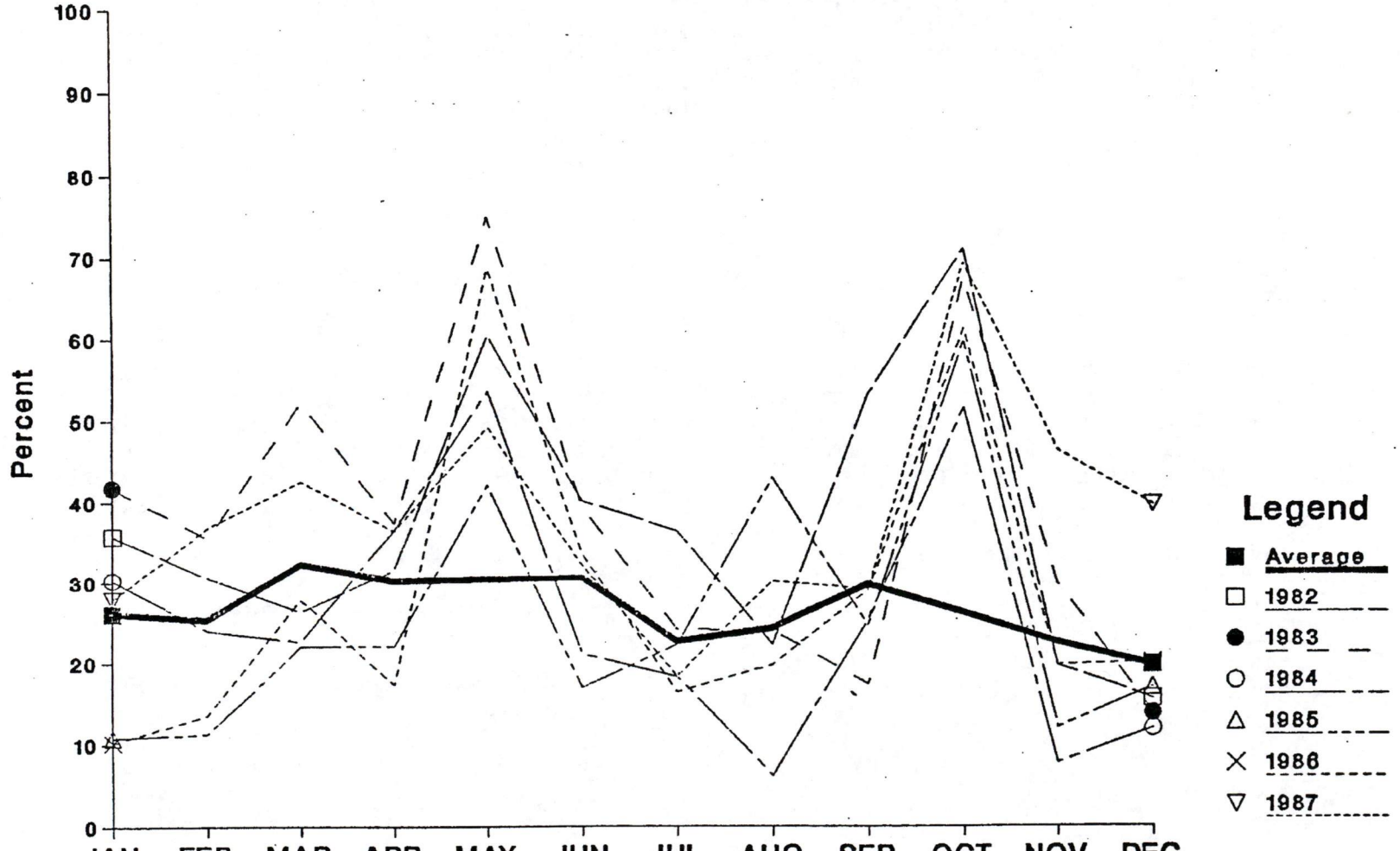
Net Peak Load = Firm peak load less firm purchases plus firm sales.

NSP System
Percent Reserves
Including Capacity on Scheduled Maintenance



Note: Six Year Average Excludes May and October.

NSP System
Percent Reserves
Excluding Capacity on Scheduled Maintenance



Note: Six Year Average Excludes May and October.

NSP (MN)
Electric Utility
Percent Reserves

Exhibit C
Page 4 of 4

Source: Energy Supply Planning Department

Including Capacity on Scheduled Maintenance

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	Average
1982	38.9	34.0	46.3	48.6	84.6	60.5	39.4	28.2	71.5	89.9	50.6	47.1	53.3
1983	47.6	51.5	54.5	57.1	93.2	46.2	24.8	25.2	32.1	90.3	37.0	27.1	48.9
1984	32.5	39.7	37.6	49.7	75.7	36.7	34.6	18.1	56.0	72.7	38.8	32.0	43.7
1985	29.2	30.0	43.8	41.7	60.7	38.1	33.9	46.5	38.9	88.3	35.7	27.8	42.9
1986	27.2	31.0	43.3	46.6	87.1	48.5	19.0	23.4	47.4	84.1	32.3	32.4	43.5
1987	33.6	42.9	50.8	53.5	68.5	39.7	19.2	30.9	44.1	83.5	58.4	47.2	47.7
Average	34.8	38.2	46.1	49.5	78.3	44.9	28.5	28.7	48.3	84.8	42.1	35.6	46.7

Excluding Capacity on Scheduled Maintenance

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	Average
1982	35.8	30.6	26.3	31.5	60.4	40.1	36.4	22.2	53.1	70.8	19.7	15.6	36.9
1983	41.8	35.5	52.1	37.3	74.9	39.4	24.1	24.0	17.3	67.2	29.8	13.8	38.1
1984	30.3	24.0	22.6	36.5	53.5	21.1	18.3	6.2	25.2	51.4	7.7	11.9	25.7
1985	10.8	11.3	22.0	22.0	42.1	17.0	22.2	42.9	24.5	59.7	12.0	17.0	25.3
1986	10.2	13.6	27.8	17.3	68.5	33.6	16.4	19.7	28.9	61.0	19.7	20.0	28.1
1987	27.9	36.8	42.5	36.4	49.1	32.2	18.3	30.1	29.1	69.1	46.2	39.6	38.1
Average	26.1	25.3	32.2	30.2	58.1	30.6	22.6	24.2	29.7	63.2	22.5	19.7	32.0

RESULTS OF TEST CONDUCTED ON SELECTED DEMAND ALLOCATION METHODS

	Page
Stability Test	2
Company Growth Rates	4
Predictability Test	5
Data Tables Used in Conducting Tests	6

TEST OF STABILITY

$ FIGURES ARE IN THOUSANDS

	MN RATIO	ANNUAL CHANGE	$ CHANGE	WS RATIO	ANNUAL CHANGE	$ CHANGE	LSDP RATIO	ANNUAL CHANGE	$ CHANGE
ACTUALS-CALENDAR YEAR									
1981	0.831165			0.141016			0.027819		
1982	0.835432	0.004268	$2,561	0.137607	-0.003409	-$2,045	0.026960	-0.000859	-$515
1983	0.835026	-0.000406	-$244	0.138070	0.000463	$278	0.026904	-0.000056	-$34
1984	0.837016	0.001990	$1,194	0.135619	-0.002450	-$1,470	0.027365	0.000461	$277
1985	0.840538	0.003522	$2,113	0.132804	-0.002815	-$1,689	0.026658	-0.000707	-$424
				Method 1 - 12 CP Forecast					
ONE YEAR FORECASTS									
1984-F83	0.836284			0.137736			0.025981		
1985-F84	0.836871	0.000587	$352	0.136662	-0.001074	-$644	0.026468	0.000487	$292
1986-F85	0.839839	0.002968	$1,781	0.134789	-0.001873	-$1,124	0.025372	-0.001095	-$657
1987-F85	0.843283	0.003444	$2,067	0.131829	-0.002960	-$1,776	0.024888	-0.000484	-$291
				Method 2 - 12 CP Combination					
COMBINATION-1 YR ACT (CALENDAR) & 1 YR FORECAST									
84 F-82	0.835873			0.137674			0.026453		
85 F-83	0.835973	0.000099	$60	0.137347	-0.000326	-$196	0.026680	0.000227	$136
86 F-84	0.838488	0.002515	$1,509	0.135186	-0.002161	-$1,297	0.026326	-0.000354	-$213
COMBINATION-1 YR ACT (WINTER END) & 1 YR FORECAST *									
84 F-82	0.835923			0.137475			0.026602		
85 F-83	0.835941	0.000018	$11	0.137354	-0.000121	-$73	0.026704	0.000103	$62
86 F-84	0.839040	0.003099	$1,859	0.134815	-0.002539	-$1,523	0.026145	-0.000560	-$336
COMBINATION-2 YR ACT (CALENDAR) & 1 YR FORECAST									
84F-81,82	0.834380			0.138734			0.026886		
85F-82,83	0.835801	0.001421	$853	0.137430	-0.001304	-$782	0.026769	-0.000117	-$70
86F-83,84	0.837374	0.001573	$944	0.136114	-0.001316	-$789	0.026512	-0.000257	-$154
COMBINATION-2 YR ACT (WINTER END) & 1 YR FORECAST *									
84F-81,82	0.834303			0.138796			0.026901		
85F-82,83	0.835813	0.001511	$906	0.137304	-0.001493	-$896	0.026883	-0.000018	-$11
86F-83,84	0.837721	0.001908	$1,145	0.135873	-0.001431	-$859	0.026406	-0.000477	-$286
COMBINATION-18 MO ACT & 18 MO FORECAST ***									
83/4F-82/3A	0.834785			0.138565			0.026651		
84/5F-83/4A	0.836060	0.001276	$765	0.137289	-0.001275	-$765	0.026651	-0.000000	-$0
85/6F-84/5A	0.839686	0.003625	$2,175	0.134122	-0.003167	-$1,900	0.026192	-0.000458	-$275

TEST OF STABILITY

$ FIGURES ARE IN THOUSANDS

	MN RATIO	ANNUAL CHANGE	$ CHANGE	WS RATIO	ANNUAL CHANGE	$ CHANGE	LSDP RATIO	ANNUAL CHANGE	$ CHANGE
				Method 3 - Seasonal CP					
ACTUAL SEASONAL PEAKS-WTR,SPR,SUM,FALL **									
1982	0.829813			0.142441			0.027746		
1983	0.832518	0.002705	$1,623	0.140980	-0.001461	-$876	0.026501	-0.001245	-$747
1984	0.830835	-0.001683	-$1,010	0.140586	-0.000395	-$237	0.028579	0.002078	$1,247
1985	0.843958	0.013123	$7,874	0.129848	-0.010738	-$6,443	0.026194	-0.002385	-$1,431
				Method 4 - NCP					
ACTUAL NON-COINCIDENT PEAKS - CALENDAR 12 MONTHS									
1981	0.825048			0.144878			0.030074		
1982	0.826674	0.001626	$976	0.144530	-0.000348	-$209	0.028796	-0.001279	-$767
1983	0.828221	0.001546	$928	0.143334	-0.001196	-$718	0.028446	-0.000350	-$210
1984	0.830898	0.002677	$1,606	0.139448	-0.003886	-$2,332	0.029654	0.001209	$725
1985	0.832413	0.001515	$909	0.139161	-0.000287	-$172	0.028425	-0.001229	-$737

* - WINTER ENDING YEAR-- APRIL THRU MARCH (EXAMPLE- 1983 IS APRIL 1983 THRU MARCH 1984)

** - SEASONS ARE: WINTER= DEC, JAN, FEB SPRING= MAR, APR, MAY SUMMER= JUN, JUL, AUG, SEP FALL= OCT, NOV

*** - 18 MO ACT/18 MO FC - EXAMPLE = FALL 85 WOULD CONSIST OF:
1984 ACTUAL - JAN THRU DEC
1985 ACTUAL - JAN THRU JUN
1985 FORECAST - JUL THRU DEC (FROM 2ND QRT 85 BUDGET)
1986 FORECAST - JAN THRU DEC (FROM FALL 85 BUDGET)

[ ] LARGEST CHANGE FOR ANY ONE OF THE THREE COMPANIES FOR THAT YEAR

ANNUAL GROWTH OF ACTUAL JURISDICTIONAL SYSTEM PEAKS
AVERAGE OF 12 MONTHLY DEMANDS

	MINN CO	GROWTH	WISC CO	GROWTH	LSDP CO	GROWTH
ACT COINC PEAKS						
1981	3354		569		112	
1982	3499	4.32%	576	1.23%	113	0.89%
1983	3665	4.74%	606	5.21%	118	4.42%
1984	3706	1.12%	601	-0.83%	121	2.54%
1985	3881	4.72%	613	2.00%	123	1.65%
ACT NCP						
1981	3354		589		122	
1982	3500	4.35%	612	3.90%	122	0.00%
1983	3681	5.17%	637	4.08%	126	3.28%
1984	3720	1.06%	624	-2.04%	133	5.56%
1985	3883	4.38%	649	4.01%	133	0.00%

PREDICTABILITY OF SYSTEM DEMAND RESPONSIBILITY
AVERAGE OF 12 MONTHLY DEMANDS

JURISIDICTION	1984 ACTUAL	1984 FC BASED ON FALL 83
MINN CO:		
MW	3706	3763
DIFF FROM ACTUAL		57
% OF ACTUAL		1.54%
WISC CO:		
MW	601	620
DIFF FROM ACTUAL		19
% OF ACTUAL		3.16%
LSDP CO:		
MW	121	117
DIFF FROM ACTUAL		-4
% OF ACTUAL		-3.31%

JURISIDICTION	1985 ACTUAL	1985 FC BASED ON FALL 84
MINN CO:		
MW	3881	3871
DIFF FROM ACTUAL		-10
% OF ACTUAL		-0.26%
WISC CO:		
MW	613	632
DIFF FROM ACTUAL		19
% OF ACTUAL		3.10%
LSDP CO:		
MW	123	122
DIFF FROM ACTUAL		-1
% OF ACTUAL		-0.81%

ANALYSIS OF JURISDICTIONAL SYSTEM PEAK MW DATA

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
ACT COIN PEAK MW													
1981:													
MINN CO	3309	3375	2979	2870	2969	3318	4146	3944	3666	3017	3234	3418	40245
WISC CO	592	648	582	566	508	529	565	573	541	562	538	624	6828
LSDP CO	128	120	119	111	107	102	114	116	97	106	111	116	1347
1982:													
MINN CO	3387	3476	3260	3143	3152	3724	4201	4462	3439	3009	3337	3398	41988
WISC CO	659	634	638	585	488	439	534	642	526	563	581	627	6916
LSDP CO	124	117	128	116	102	101	104	118	103	107	123	112	1355
1983:													
MINN CO	3378	3237	3183	3127	3058	3962	4614	4614	4440	3158	3444	3765	43980
WISC CO	630	649	577	533	542	621	662	597	609	527	613	712	7272
LSDP CO	124	130	120	100	102	121	113	113	123	110	121	140	1417
1984:													
MINN CO	3684	3458	3415	3222	3315	4097	4219	4748	3749	3380	3538	3649	44474
WISC CO	715	643	624	543	521	580	592	667	516	553	614	638	7206
LSDP CO	140	130	131	103	111	115	116	129	96	115	132	136	1454
1985:													
MINN CO	3784	3764	3395	3483	3767	4379	4525	4084	4369	3296	3744	3980	46570
WISC CO	685	697	611	545	558	537	562	603	647	567	629	717	7358
LSDP CO	132	130	129	116	111	109	118	115	118	125	130	144	1477
FORECAST COIN PEAKS MW													
1983-SPRING 83: (MM)													
MINN CO	0	0	0	0	0	0	4525	4525	3896	3092	3320	3539	22897
WISC CO	0	0	0	0	0	0	617	617	555	594	596	692	3671
LSDP CO	0	0	0	0	0	0	123	123	112	110	116	111	695
1984-SPRING 83: (MM)													
MINN CO	3658	3658	3342	3308	3613	4109	4658	4658	3994	3161	3374	3615	45148
WISC CO	695	695	669	565	559	566	635	635	569	620	612	720	7540
LSDP CO	126	126	123	120	109	115	129	129	115	113	120	114	1439
1984-FALL 83: (MM)													
MINN CO	3638	3578	3421	3306	3544	4092	4745	4330	4071	3258	3483	3695	45161
WISC CO	678	651	632	570	558	585	666	619	576	599	621	683	7438
LSDP CO	124	124	120	110	107	111	119	119	116	114	120	119	1403
1984-SPRING 84: (MM)													
MINN CO	0	0	0	0	0	0	4764	4508	4022	3336	3564	3648	23842
WISC CO	0	0	0	0	0	0	665	643	562	594	621	676	3761
LSDP CO	0	0	0	0	0	0	111	121	103	113	129	125	702

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
1985-SPRING 84: (MM)													
MINN CO	3857	3588	3374	3362	3445	4035	4870	4605	4279	3433	3679	3748	46275
WISC CO	706	657	628	581	555	587	680	657	598	612	641	695	7597
LSDP CO	141	136	128	118	111	114	113	124	110	117	134	128	1474
1985-FALL 84:													
MINN CO	3864	3884	3574	3308	3320	3944	4931	4662	4227	3329	3591	3814	46448
WISC CO	735	690	640	578	544	597	649	662	610	572	606	702	7585
LSDP CO	137	143	129	98	106	128	116	116	126	111	120	139	1469
1985-SPRING 85:													
MINN CO	0	0	0	0	0	0	5022	4681	4163	3550	3690	3736	24842
WISC CO	0	0	0	0	0	0	677	657	597	586	620	664	3801
LSDP CO	0	0	0	0	0	0	122	121	117	118	122	133	733
1986-FALL 85													
MINN CO	3977	3776	3539	3447	3521	4280	5125	5062	4300	3631	3983	3984	48625
WISC CO *	772	668	635	598	557	630	668	700	615	602	656	703	7804
LSDP CO *	140	131	126	102	106	121	119	128	115	117	128	136	1469
1987-FALL 85													
MINN CO	4092	3930	3666	3588	3662	4403	5307	5139	4427	3760	4105	4136	50215
WISC CO *	780	679	648	606	558	634	668	692	615	606	652	712	7850
LSDP CO *	142	134	128	104	107	123	119	126	116	117	128	138	1482

* LSDP HAS RESALE INCLUDED IN SYSTEM PEAKS FOR THIS ANALYSIS.

ACT NON-COIN PEAK MW

1981:													
MINN CO	3309	3375	2979	2870	2969	3318	4146	3944	3666	3017	3234	3418	40245
WISC CO	625	662	582	566	524	533	612	620	556	567	591	629	7067
LSDP CO	132	138	123	115	118	113	122	118	116	118	120	134	1467
1982:													
MINN CO	3431	3476	3260	3143	3152	3625	4201	4462	3439	3076	3337	3398	42000
WISC CO	659	682	648	594	553	558	613	662	559	577	604	634	7343
LSDP CO	129	129	126	115	111	115	121	126	123	118	125	125	1463
1983:													
MINN CO	3378	3237	3339	3127	3073	3962	4614	4632	4440	3158	3444	3765	44169
WISC CO	657	676	634	623	568	621	663	685	609	579	617	712	7644
LSDP CO	126	130	128	116	112	121	135	133	126	125	121	144	1517
1984:													
MINN CO	3684	3458	3415	3222	3318	4111	4219	4748	3757	3380	3538	3785	44635
WISC CO	718	675	644	572	541	587	662	667	582	553	614	676	7491
LSDP CO	143	136	136	114	125	135	137	134	128	128	135	142	1593
1985:													
MINN CO	3784	3764	3396	3488	3767	4379	4525	4084	4369	3311	3744	3980	46591
WISC CO	721	716	648	596	568	630	675	618	656	587	641	733	7789
LSDP CO	138	143	138	130	124	124	125	128	127	126	138	150	1591

CRITERIA RANKINGS OF SELECTED DEMAND ALLOCATION METHODS

		Page
Method 1:	Average of 12 Monthly Coincident Peaks Based on One Year Forecast Data	2
Method 2:	Average of 12 Monthly Coincident Peaks Based on a Combination of Historical and Forecast Years Data	3
Method 3:	Average of Seasonal Coincident Peaks	4
Method 4:	Average of 12 Monthly Non-Coincident Peaks	5

CRITERIA SELECTION OF ALLOCATION METHODS

METHOD: AVERAGE OF 12 MONTHS FORECAST COINCIDENT PEAKS

DESCRIPTION: PRESENT METHOD BEING USED - USES 1 FORECAST TEST YEAR

ELIMINATION RANKING:

	YES OR NO
1. CAN THIS METHOD BE PERFORMED WITHIN THE TIME CONSTRAINTS (ABOUT 2 MONTHS) OF THE INTERCHANGE AGREEMENT AND WITHOUT UNREASONABLE ADDITIONAL COSTS?	YES
2. DOES THIS METHOD PRODUCE REASONABLE YEAR-TO-YEAR SHIFTS IN COSTS --IS IT STABLE?	YES

(IF EITHER ANSWER ABOVE IS NO, DO NOT CONTINUE.)

CRITERIA RANKING: (ANSWER EACH QUESTION WITH 0-3 RANK WITH 3 BEING HIGHEST RANK)

	RANK 0 - 3	WTG FACTOR	WTD SCORE
1. HOW SOUND IS THE CONCEPTUAL BASIS OF THIS METHOD - IS IT REASONABLE, FAIR AND NON-DISCRIMINATORY - DOES IT MAKE SENSE?	2	4	8
2. HOW ACCEPTABLE IS THIS METHOD TO ALL THE PARTIES?	2	2	4
3. HOW REASONABLE ARE THE COSTS AND TIME CONSTRAINTS OF THIS METHOD?	3	1	3
4. CAN THE METHOD BE APPLIED UNIFORMLY TO ALL COMPANIES AND JURISDICTIONS?	3	2	6
5. HOW REASONABLE ARE THE YEAR -TO-YEAR SHIFTS IN COSTS - HOW STABLE ARE THE RESULTS?	0	4	0
6. IS THE METHOD EASILY REPRODUCED, REPLICATED, EXPLAINED AND DOCUMENTED?	3	2	6
7. HOW WELL DOES THE METHOD TRACK SUBSTANTIAL LOAD TRENDS OCCURRING IN ANY JURISDICTION?	3	2	6
8. HOW WELL DOES THE METHOD ADDRESS MANAGED LOAD IMPACTS?	3	1	3
TOTAL RAW SCORE:	19		
TOTAL WEIGHTED SCORE:			36

CRITERIA SELECTION OF ALLOCATION METHODS

METHOD: AVERAGE OF 12 MONTHS COMBINATION COINCIDENT PEAKS

DESCRIPTION: COMBINES HISTORIC AND FORECAST YEARS

ELIMINATION RANKING:	YES OR NO
1. CAN THIS METHOD BE PERFORMED WITHIN THE TIME CONSTRAINTS (ABOUT 2 MONTHS) OF THE INTERCHANGE AGREEMENT AND WITHOUT UNREASONABLE ADDITIONAL COSTS?	YES
2. DOES THIS METHOD PRODUCE REASONABLE YEAR-TO-YEAR SHIFTS IN COSTS --IS IT STABLE?	YES

(IF EITHER ANSWER ABOVE IS NO, DO NOT CONTINUE.)

CRITERIA RANKING: (ANSWER EACH QUESTION WITH 0-3 RANK WITH 3 BEING HIGHEST RANK)	RANK 0 - 3	WTG FACTOR	WTD SCORE
1. HOW SOUND IS THE CONCEPTUAL BASIS OF THIS METHOD - IS IT REASONABLE, FAIR AND NON-DISCRIMINATORY - DOES IT MAKE SENSE?	3	4	12
2. HOW ACCEPTABLE IS THIS METHOD TO ALL THE PARTIES?	2	2	4
3. HOW REASONABLE ARE THE COSTS AND TIME CONSTRAINTS OF THIS METHOD?	2	1	2
4. CAN THE METHOD BE APPLIED UNIFORMLY TO ALL COMPANIES AND JURISDICTIONS?	3	2	6
5. HOW REASONABLE ARE THE YEAR -TO-YEAR SHIFTS IN COSTS - HOW STABLE ARE THE RESULTS?	2	4	8
6. IS THE METHOD EASILY REPRODUCED, REPLICATED, EXPLAINED AND DOCUMENTED?	3	2	6
7. HOW WELL DOES THE METHOD TRACK SUBSTANTIAL LOAD TRENDS OCCURRING IN ANY JURISDICTION?	2	2	4
8. HOW WELL DOES THE METHOD ADDRESS MANAGED LOAD IMPACTS?	3	1	3
TOTAL RAW SCORE:	20		
TOTAL WEIGHTED SCORE:			45

CRITERIA SELECTION OF ALLOCATION METHODS

METHOD: AVERAGE OF 4 SEASONAL COINCIDENT PEAKS

DESCRIPTION: COULD ALSO BE AVERAGE OF 2 OR 3 SEASONAL COINCIDENT PEAKS - SUMMER & WINTER OR SUMMER, WINTER AND VALLEY.

ELIMINATION RANKING:	YES OR NO
1. CAN THIS METHOD BE PERFORMED WITHIN THE TIME CONSTRAINTS (ABOUT 2 MONTHS) OF THE INTERCHANGE AGREEMENT AND WITHOUT UNREASONABLE ADDITIONAL COSTS?	YES
2. DOES THIS METHOD PRODUCE REASONABLE YEAR-TO-YEAR SHIFTS IN COSTS --IS IT STABLE?	NO

(IF EITHER ANSWER ABOVE IS NO, DO NOT CONTINUE.)

CRITERIA RANKING: (ANSWER EACH QUESTION WITH 0-3 RANK WITH 3 BEING HIGHEST RANK)	RANK 0 - 3	WTG FACTOR	WTD SCORE
1. HOW SOUND IS THE CONCEPTUAL BASIS OF THIS METHOD - IS IT REASONABLE, FAIR AND NON-DISCRIMINATORY - DOES IT MAKE SENSE?	_____	4	_____
2. HOW ACCEPTABLE IS THIS METHOD TO ALL THE PARTIES?	_____	2	_____
3. HOW REASONABLE ARE THE COSTS AND TIME CONSTRAINTS OF THIS METHOD?	_____	1	_____
4. CAN THE METHOD BE APPLIED UNIFORMLY TO ALL COMPANIES AND JURISDICTIONS?	_____	2	_____
5. HOW REASONABLE ARE THE YEAR -TO-YEAR SHIFTS IN COSTS - HOW STABLE ARE THE RESULTS?	_____	4	_____
6. IS THE METHOD EASILY REPRODUCED, REPLICATED, EXPLAINED AND DOCUMENTED?	_____	2	_____
7. HOW WELL DOES THE METHOD TRACK SUBSTANTIAL LOAD TRENDS OCCURRING IN ANY JURISDICTION?	_____	2	_____
8. HOW WELL DOES THE METHOD ADDRESS MANAGED LOAD IMPACTS?	_____	1	_____
TOTAL RAW SCORE:	_____		
TOTAL WEIGHTED SCORE:			_____

CRITERIA SELECTION OF ALLOCATION METHODS

METHOD: AVERAGE OF 12 NON-COINCIDENT PEAKS (NCP)

DESCRIPTION: AVERAGE OF MINNESOTA, WISCONSIN, AND LSDP COMPANIES ABSOLUTE OR NON-COINCIDENT PEAKS.

ELIMINATION RANKING:	YES OR NO
1. CAN THIS METHOD BE PERFORMED WITHIN THE TIME CONSTRAINTS (ABOUT 2 MONTHS) OF THE INTERCHANGE AGREEMENT AND WITHOUT UNREASONABLE ADDITIONAL COSTS?	YES
2. DOES THIS METHOD PRODUCE REASONABLE YEAR-TO-YEAR SHIFTS IN COSTS --IS IT STABLE?	YES

(IF EITHER ANSWER ABOVE IS NO, DO NOT CONTINUE.)

CRITERIA RANKING: (ANSWER EACH QUESTION WITH 0-3 RANK WITH 3 BEING HIGHEST RANK)	RANK 0 - 3	WTG FACTOR	WTD SCORE
1. HOW SOUND IS THE CONCEPTUAL BASIS OF THIS METHOD - IS IT REASONABLE, FAIR AND NON-DISCRIMINATORY - DOES IT MAKE SENSE?	1	4	4
2. HOW ACCEPTABLE IS THIS METHOD TO ALL THE PARTIES?	1	2	2
3. HOW REASONABLE ARE THE COSTS AND TIME CONSTRAINTS OF THIS METHOD?	3	1	3
4. CAN THE METHOD BE APPLIED UNIFORMLY TO ALL COMPANIES AND JURISDICTIONS?	3	2	6
5. HOW REASONABLE ARE THE YEAR -TO-YEAR SHIFTS IN COSTS - HOW STABLE ARE THE RESULTS?	0	4	0
6. IS THE METHOD EASILY REPRODUCED, REPLICATED, EXPLAINED AND DOCUMENTED?	3	2	6
7. HOW WELL DOES THE METHOD TRACK SUBSTANTIAL LOAD TRENDS OCCURRING IN ANY JURISDICTION?	2	2	4
8. HOW WELL DOES THE METHOD ADDRESS MANAGED LOAD IMPACTS?	0	1	0
TOTAL RAW SCORE:	13		
TOTAL WEIGHTED SCORE:			25

DEMAND AND ENERGY MEASUREMENT

I. Introduction

II. Energy Measurement

A. Generation

B. Net Deliveries to the NSP System

1. Pool Ties
2. Non-Pool Ties With Other Utilities
3. Non-Pool Ties With Generating Municipals
4. North Dakota Service Territory
5. Miscellaneous Interconnections
6. Subsidiary Ties

C. Sample Calculation of Energy Requirements for the Three Companies

III. Demand Measurement

A. Generation

B. Net Deliveries to the NSP System

1. Pool Ties
2. Non-Pool Ties With Other Utilities
3. Non-Pool Ties With Generating Municipals
4. North Dakota Service Territory
5. Miscellaneous Interconnections
6. Subsidiary Ties

C. Sample Calculation of Demand Requirements for the Three Companies

I. INTRODUCTION

Peak month demands and monthly energy requirements are produced by NSP for many purposes, one of which is to determine cost responsibilities between NSP(MN), NSP(WI) and LSDP. The Interchange Agreement between the three Companies explains the process by which the Companies coordinate planning and operations of the NSP system and explains how the Companies share the costs associated with system bulk power supply and energy requirements. This report examines the method for measuring the demand and energy requirements of each of the three NSP Companies. The general procedures and sample calculations discussed herein are those currently used as of December 1986.

In an interconnected electric power system, the quantities of power and energy produced or purchased by the system must be equal to power and energy sales to retail customers and to other utilities, plus the associated losses. NSP calculates its system power and energy requirements as the sum of power and energy generated based on meter readings at generation sites, and net deliveries to the NSP system from other interconnected systems, based on meter readings at NSP system boundary locations. This calculation is performed in three parts: (1) for the entire three Company NSP system, (2) for the WI Company, and (3) for LSDP. Power and energy requirements for the MN Company are defined as the total system power and energy requirements less the power and energy requirements for the WI Company and LSDP.

II. ENERGY MEASUREMENT

Generation

Monthly energy generated is obtained from 45 separate generation locations. Data from 16 of the 45 plants are used to identify NSP(WI) generation and data from 11 of the 45 plants are used to identify LSDP generation. The kWh meters are read at approximately midnight on the last day of the calendar month. The generation output for system use is the difference between metered output and the energy required for operating the generating plant.

Net Deliveries to the NSP System

1. Pool Ties

   Meters at "pool tie" locations measure net energy flowing at the boundaries of the NSP "control area". The NSP control area is the geographic region for which NSP has responsibility to maintain power supply to match hourly loads plus losses. The NSP control area load encompasses both NSP and other utilities loads plus losses.

   There are approximately 70 pool tie metering points which interconnect NSP's control area with the following utilities:

   Dairyland Power Cooperative (DPC)
   Interstate Power Company (IPW)
   Manitoba Hydro-Electric Board (MHEB)
   Minnesota Power (MP)
   Northwestern Public Service (NWPS)
   Otter Tail Power Company (OTP)
   United Power Association (UPA)
   Western Area Power Administration (WAPA)
   Wisconsin Power and Light Co. (WPL)
   Wisconsin Public Service Corporation (WPS)

   The kWh meters are read on the working day closest to the last day of the calendar month. The meter readings are then adjusted by the System Operations Department to reflect readings as of midnight on the last day of the month. The adjustments are made by use of hourly digital readings available for these metering points.

2. Non-Pool Ties With Other Utilities

   Meters at "non-pool tie" locations measure the energy requirements of other utilities within NSP's control area, as well as NSP's energy requirements which are served by NSP's transmission system, but are in the control areas of other utilities.

For example, Dairyland Power Cooperative (DPC) has load responsibility in NSP's control area. The pool tie meter readings include this DPC power responsibility. The non-pool tie meter readings measuring this DPC energy requirement are then subtracted from NSP's kWh requirements. In addition, part of NSP's energy responsibility is within DPC's control area. The net meter readings from the non-pool tie meters which measure this responsibility are added to NSP's kWh requirements.

Over 300 non-pool tie meters measure the following utility load requirements:

Basic Electric Power Cooperative (BEPC)
Cooperative Power Association (CPA)
Dairyland Power Cooperative (DPC)
Heartland Consumers Power District (HCPD)
Interstate Power Company (IPW)
Minnesota Power (MP)
Missouri Basin Municipal Power Agency (MBMPA)
Northwestern Public Service (NWPS)
Otter Tail Power Company (OTP)
Southern Minnesota Municipal Power Agency (SMMPA)
United Power Association (UPA)
Western Area Power Administration (WAPA)

All non-pool tie meters are read on the working day closest to the end of the calendar month with two exceptions. Non-pool tie meter readings with DPC are read at midnight of the last day of the calendar month because magnetic tapes are available from these meters which contain the necessary hourly data. BEPC, CPA, HCPD, MBMPA and WAPA non-pool tie meter readings are made on a 20th to 20th of the month basis rather than on a calendar month basis.

Loss compensation as provided by FERC approved contracts is included in the energy requirements calculation. Transformation losses are also included in order to adjust meter readings to the point of delivery if specified by contract.

3. Non-Pool Ties With Generating Municipals

Meters at non-pool ties with 12 "generating municipals" measure the deliveries of energy sold to these municipals under Economy Service, Emergency Service, Short Term Power Service, etc. These municipals may or may not generate part of their own requirements. The services available to them are specified by contract. The kWh meter readings are made on a 20th to 20th of the month basis rather than on a calendar month basis.

4. North Dakota Service Territory

NSP's load responsibility in North Dakota is in the control areas of other utilities and is not served by NSP's interconnected transmission system. A number of the 26 meters measuring NSP's North Dakota energy requirements

have magnetic tapes, and therefore, the kWh requirements are recorded at midnight on the last day of the month. The remaining meter readings are made on a 20th to 20th of the month basis rather than on a calendar month basis.

5. Miscellaneous Interconnections

Meter readings are obtained from a number of locations to record deliveries to the system under cogeneration type agreements. There are presently 5 of these locations. The meter readings are read as close as possible to midnight on the last day of the month.

6. Subsidiary Ties

Additional meter readings are obtained from 19 meter locations which are used only for the purpose of determining NSP(WI) and LSDP kWh requirements, and therefore, are not included in the calculation of the total system kWh requirement. Eighteen tie meter locations exist between NSP(MN) and NSP(WI) and one tie meter location exists between NSP(WI) and LSDP. The kWh meter readings from these 19 locations are read as close as possible to midnight on the last day of the month.

Sample Calculation of Energy Requirements for the Three Companies

Table 1 summarizes the calculation of the energy requirements for the three Companies for the month of July 1986.

Table 1

Calculation of Energy Requirements
for the Month of July 1986

Energy in Megawatthours

	(1) NSP System	(2) NSP(WI)	(3) LSDP	(4=1-2-3) NSP(MN)
Generation:				
NSP(WI)	88,731	88,731		
LSDP	21,538		21,538	
Other	1,999,580			
Sub-total	2,109,849	88,731	21,538	
Pool Ties:				
DPC	4,152	112,805	(37,845)	
ISP	(247,597)			
MHEB	570,488			
MP	120,381		100,585	
NWPS	15,389			
OTP	20,657			
UPA	335,563			
WAPA	309,470			
WPL	(271,880)	(271,880)		
WPS	(9,520)	(9,520)		
Sub-total	847,103	(168,595)	62,740	
Non-Pool Ties With Other Utilities:				
DPC	17,426	26,397	(13,703)	
ISP	6,309			
MP	(3,621)		(3,621)	
OTP	(706)			
UPA	(5,078)			
SMMPA	(42,936)			
CPA	(152,685)			
MISC	(20,361)	7,323	(7,323)	
Sub-total	(201,652)	33,720	(24,647)	
Non-Pool Ties With Generating Municipals:	(40,181)			
North Dakota Service Territory:				
MPC	62,645			
MP	(70,063)			
UPA	92,911			
WAPA	41,610			
Sub-total	127,103			
Miscellaneous Interconnections:	5,710		6	
Subsidiary Ties:		407,023	7,857	
Total	2,847,932	360,879	67,494	2,419,559

III. DEMAND MEASUREMENT

The metering locations for calculating hourly demand requirements are exactly the same as the metering locations for calculating energy requirements. The demands used for determining cost responsibilities in the Interchange Agreement are the three Company loads at the time of the maximum integrated hourly demand occurring on the NSP system during each calendar month. The same process is followed each month in determining these demands, however, additional, more extensive procedures are followed twice a year, at the time of the summer and winter system peaks. These additional procedures are noted when applicable in the following discussion.

Generation

Hourly digital meter readings are available from all the major generation locations. Estimated hourly generation is obtained for mainly small generating plants, especially hydro facilities. As in the calculation of energy requirements, data from 16 of the 45 separable generation locations are used to determine NSP (WI) total generation and data from 11 of the 45 plants are used to identify LSDP total generation. The generation output for system use is the difference between metered output and the power required for operating the generating plant.

Net Deliveries to the NSP System

1. Pool Ties

   Hourly digital meter readings are available for the approximately 70 pool tie metering locations. These hourly readings record the power flowing into or out of the NSP control area.

2. Non-Pool Ties With Other Utilities

   Hourly digital meter readings are not available on a timely basis for the over 300 non-pool tie metering locations. For this reason, estimated hourly load patterns are used daily to forecast the power anticipated hourly at these locations. The daily load patterns are estimated based on historical monthly power flows, developed from a process incorporating the five previous years and the three previous months.

   Once the peak hour for the month has been determined using actual and estimated hourly readings for the NSP system, NSP (WI) and LSDP "pasturize" the estimated meter readings for that hour. Pasturization involves replacing the estimated readings with actual readings for metering locations equipped with magnetic tapes or similar hourly recording equipment. This information is not available until the following calendar month and is therefore not used in the initial peak demand determination for the NSP system.

At the conclusion of each summer and winter season, the NSP system peak demand for that season can be determined from the monthly peak demands. Estimated meter readings are pasturized for the entire NSP system for these two peak hours of the year. The actual peak hour demands are obtained for the non-pool tie meter locations from NSP magnetic tape recordings or from information provided by interconnected utilities.

Loss compensation as provided by contract is included in the demand requirements calculation similar to the calculation of energy requirements.

3. Non-Pool Ties with Generating Municipals

Deliveries of power to generating municipals are scheduled daily for the following day. These scheduled deliveries are used to estimate the daily hourly loads. When pasturized for the summer and winter peaks, actual hourly data is obtained from magnetic tape recordings.

4. North Dakota Service Territory

NSP's load responsibility in North Dakota is in the control areas of other utilities and is not served by NSP's interconnected transmission system.

Hourly digital readings are available for metering locations classified as pool ties. Estimated hourly load patterns are used to calculate anticipated demand requirements at the other metering locations. These estimates are pasturized at the time of the summer and winter peaks.

5. Miscellaneous Interconnections

As in the calculation of energy requirements, meter readings at these locations record net deliveries to the system under cogeneration type agreements. Power purchases are generally scheduled by hour on the proceeding day or are available before the end of each day.

6. Subsidiary Ties

Hourly digital readings are available for approximately half of these metering locations. Estimated hourly load patterns are used to calculate anticipated power flows at the remaining meter locations. These estimates are pasturized monthly by NSP(WI) and LSDP.

Sample Calculation of the Demand Requirements for the Three Companies

Table 2 summarizes the calculation of the coincident peak demands for the three Companies for the summer season peak during July 1986.

Table 2

Calculation of Demand Requirements for July 1986
Coincident With the NSP System Peak

NSP System Peak: July 18,1986, Hour Ending 1500
Demands in Kilowatts

	(1) NSP System	(2) NSP(WI)	(3) LSDP	(4=1-2-3) NSP(MN)
Generation:				
NSP(WI)	380,647	380,647		
LSDP	36,450		36,450	
Other	3,932,000			
Sub-total	4,349,097	380,647	36,450	
Pool Ties:				
DPC	100,000	229,000	(57,000)	
ISP	(141,000)			
MHEB	980,000			
MP	466,000		155,000	
NWPS	30,000			
OTP	45,000			
UPA	127,000			
WAPA	669,000			
WPL	(391,000)	(391,000)		
WPS	(12,000)	(12,000)		
Sub-total	1,873,000	(174,000)	98,000	
Non-Pool Ties With Other Utilities:				
DPC	52,075	62,164	(20,154)	
ISP	13,044			
MP	(6,132)		(6,132)	
OTP	(1,492)			
UPA	(9,555)			
SMMPA	(98,782)			
CPA	(315,476)			
MISC	(93,230)	14,705	(14,705)	
Sub-total	(459,548)	76,869	(40,991)	
Non-Pool Ties With Generating Municipals:	(4,785)			
North Dakota Service Territory:				
Pool Ties -				
MPC	133,000			
MP	(143,000)			
UPA	153,000			
WAPA	125,000			
Non-Pool Ties -				
MPC	4,106			
WAPA	(22,057)			
Sub-total	250,049			
Miscellaneous Interconnections:	4,000			
Subsidiary Ties:		437,355	12,000	
Total	6,011,813	720,871	105,459	5,185,483

Exhibit G

ANALYSIS OF MINNESOTA AND WISCONSIN COMPANY INTERCONNECTION METER LOCATIONS

Meter Designation	Voltage (Kv)	Miles from Border M-in MN Co. W-in WI Co.	Resistance Error (pu ohms)	Peak Demand (MW)	Estimated Peak Loss (MW)	Average Demand (MW)	Estimated Energy Loss (MWH)
Goodview 1&2 Tr	Dist.	0.00					
Shore Acres (LaCrescent)	Dist.	0.00					
Latch Island	Dist.	0.00					
Pettibone Island	Dist.	0.00					
St Croix Falls 23	Dist.	0.00					
St Croix Falls 24	Dist.	0.00					
Stillwater-Houlton	Dist.	0.00					
Winona 1&2 Tr	Dist.	0.00					
Hastings 160	69	3.00 M	.0500	10.0	0.050	9.2	373.8
King 5P8	115	0.90 M	.0008	86.0	0.059	63.9	286.6
King 8P5 & 8P6	345	19.30 M	.0011	434.0	2.072	378.4	13795.6
Oak Park 1 Tr	23	1.50 M	.1156	1.6	0.003	1.2	15.2
Oak Park 2 Tr	23	5.50 M	.8726	1.1	0.800	0.8	44.3
Red Rock 944	115	12.00 M	.0118	67.0	0.530	62.6	4059.7
St Croix Falls 4A37	69	0.05 M	.0003	0.5	0.000	5.6	1.0
Subtotal					3.514		18576.2
Nelson 511	69	1.80 W	.0077	12.2	0.011	5.2	18.5
Pepin 1 Tr	69	7.80 W	.0932	0.5	0.000	0.3	1.0
Red Wing 4H33	69	0.60 W	.0104	24.0	0.060	19.3	338.6
Subtotal					0.071		358.1
Net Total					3.443		18218.1

TRANSMISSION LOSS MULTIPLIERS

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NSP Transmission and Distribution Electric Loss Study

Exhibit 2

NSP Annual Energy Losses by Transmission Component 1982-1985

Transmission Component	Year	Mn Co	Wi Co	NSP Co
Bulk	1985	374,489,155	103,006,864	477,496,019
	1984	350,292,505	86,050,272	436,342,777
	1983	416,131,609	138,198,736	554,330,345
	1982	377,097,165	120,118,944	497,216,109
Transmission	1985	238,169,871	106,953,577	345,123,448
	1984	229,793,228	97,477,017	327,270,245
	1983	234,087,895	113,881,417	347,969,312
	1982	213,716,013	102,631,913	316,347,926
Subtransmission	1985	203,996,549	109,340,740	313,337,289
	1984	196,711,819	102,680,516	299,392,335
	1983	200,902,503	105,140,180	306,042,683
	1982	185,495,452	96,190,340	281,685,792
Four Year kWh Average of Total Transmission Losses		805,220,941	320,417,629	1,125,638,570
Four Year MWh Average of Total Transmission Supply		22,681,373	4,694,664	27,376,037
Average Annual Transmission Energy Loss Multiplier				4.1%

NSP Transmission and Distribution Electric Loss Study

Exhibit 3

Transmission Losses
MW Losses at Time of 12 Monthly Peaks

	Minnesota Company					Wisconsin Company					NSP Co
Month	1982	1983	1984	1985	Month Avg	1982	1983	1984	1985	Month Avg	Month Avg
January	100	125	142	138	126	41	74	55	52	56	182
February	123	116	137	141	129	72	63	51	54	60	189
March	113	120	134	142	127	60	71	47	58	59	186
April	103	115	126	153	124	49	65	41	73	57	181
May	128	125	106	151	128	61	42	26	53	46	173
June	125	133	141	139	135	55	38	44	41	45	179
July	153	138	171	156	155	44	37	64	51	49	204
August	173	140	157	119	147	37	39	50	30	39	186
September	115	121	105	140	120	51	29	26	40	37	157
October	103	113	129	116	115	63	28	41	32	41	156
November	115	116	141	139	128	30	60	55	51	49	177
December	112	113	148	145	130	24	51	62	58	49	178
Annual Avg of 12 Month Peaks	122	123	136	140	130	49	50	47	49	49	179
Four Year MW Average of 12 Monthly Peak Demand Losses					130					49	179
Four Year MW Average of 12 Monthly Peak Transmission Supply					3688					718	4,406
Average Annual Transmission Demand Loss Allocation Multiplier					3.5%					6.8%	4.1%

Northern States Power Company
Interchange Agreement
CALCULATION OF AVERAGE DEMAND TRANSMISSION LOSS MULTIPLIERS
Four Year Average (1982-1985)

	MN Co.			WI Co. & LSDP			Total System		
Yr/Mo	Peak Demand (MW)	Peak Loss (MW)	Percent Loss is of Demand	Peak Demand (MW)	Peak Loss (MW)	Percent Loss is of Demand	Peak Demand (MW)	Peak Loss (MW)	Percent Loss is of Demand
1982 Jan	3387	100	3.0	783	41	5.2	4170	141	3.4
Feb	3476	123	3.5	751	72	9.6	4227	195	4.6
Mar	3260	113	3.5	766	60	7.8	4026	173	4.3
Apr	3143	103	3.3	701	49	7.0	3844	152	4.0
May	3152	128	4.1	590	61	10.3	3742	189	5.1
Jun	3724	125	3.4	540	55	10.2	4264	180	4.2
Jul	4201	153	3.6	638	44	6.9	4839	197	4.1
Aug	4462	173	3.9	760	37	4.9	5222	210	4.0
Sep	3439	115	3.3	629	51	8.1	4068	166	4.1
Oct	3009	103	3.4	670	63	9.4	3679	166	4.5
Nov	3337	115	3.4	704	30	4.3	4041	145	3.6
Dec	3398	112	3.3	739	24	3.2	4137	136	3.3
Total	41988	1463	3.5	8271	587	7.1	50259	2050	4.1
1983 Jan	3378	125	3.7	754	74	9.8	4132	199	4.8
Feb	3237	116	3.6	779	63	8.1	4016	179	4.5
Mar	3183	120	3.8	697	71	10.2	3880	191	4.9
Apr	3127	115	3.7	633	65	10.3	3760	180	4.8
May	3058	125	4.1	644	42	6.5	3702	167	4.5
Jun	3962	133	3.4	742	38	5.1	4704	171	3.6
Jul	4614	138	3.0	775	37	4.8	5389	175	3.2
Aug	4614	140	3.0	710	39	5.5	5324	179	3.4
Sep	4440	121	2.7	732	29	4.0	5172	150	2.9
Oct	3158	113	3.6	637	28	4.4	3795	141	3.7
Nov	3444	116	3.4	734	60	8.2	4178	176	4.2
Dec	3765	113	3.0	852	51	6.0	4617	164	3.6
Total	43980	1475	3.4	8689	597	6.9	52669	2072	3.9
1984 Jan	3684	142	3.9	855	55	6.4	4539	197	4.3
Feb	3458	137	4.0	773	51	6.6	4231	188	4.4
Mar	3415	134	3.9	755	47	6.2	4170	181	4.3
Apr	3222	126	3.9	646	41	6.3	3868	167	4.3
May	3315	106	3.2	632	26	4.1	3947	132	3.3
Jun	4097	141	3.4	695	44	6.3	4792	185	3.9
Jul	4219	171	4.1	708	64	9.0	4927	235	4.8
Aug	4748	157	3.3	796	50	6.3	5544	207	3.7
Sep	3749	105	2.8	612	26	4.2	4361	131	3.0
Oct	3380	129	3.8	668	41	6.1	4048	170	4.2
Nov	3538	141	4.0	746	55	7.4	4284	196	4.6
Dec	3649	148	4.1	774	62	8.0	4423	210	4.7
Total	44474	1637	3.7	8660	562	6.5	53134	2199	4.1
1985 Jan	3784	138	3.6	817	52	6.4	4601	190	4.1
Feb	3764	141	3.7	827	54	6.5	4591	195	4.2
Mar	3395	142	4.2	740	58	7.8	4135	200	4.8
Apr	3483	153	4.4	661	73	11.0	4144	226	5.5
May	3767	151	4.0	669	53	7.9	4436	204	4.6
Jun	4379	139	3.2	646	41	6.3	5025	180	3.6
Jul	4525	156	3.4	680	51	7.5	5205	207	4.0
Aug	4084	119	2.9	718	30	4.2	4802	149	3.1
Sep	4369	140	3.2	765	40	5.2	5134	180	3.5
Oct	3296	116	3.5	692	32	4.6	3988	148	3.7
Nov	3744	139	3.7	759	51	6.7	4503	190	4.2
Dec	3980	145	3.6	861	58	6.7	4841	203	4.2
Total	46570	1679	3.6	8835	593	6.7	55405	2272	4.1

Northern States Power Company
Interchange Agreement
CALCULATION OF AVERAGE DEMAND TRANSMISSION LOSS MULTIPLIERS
Four Year Average (1982-1985)

	MN Co.			WI Co. & LSDP			Total System		
Yr/Mo	Peak Demand (MW)	Peak Loss (MW)	Percent Loss is of Demand	Peak Demand (MW)	Peak Loss (MW)	Percent Loss is of Demand	Peak Demand (MW)	Peak Loss (MW)	Percent Loss is of Demand
4 Yr Jan	3558	126	3.5	802	56	7.0	4360	182	4.2
Avg Feb	3484	129	3.7	783	60	7.7	4267	189	4.4
Mar	3313	127	3.8	740	59	8.0	4053	186	4.6
Apr	3244	124	3.8	660	57	8.6	3904	181	4.6
May	3323	128	3.9	634	46	7.3	3957	174	4.4
Jun	4041	135	3.3	656	45	6.9	4697	180	3.8
Jul	4390	155	3.5	700	49	7.0	5090	204	4.0
Aug	4477	147	3.3	746	39	5.2	5223	186	3.6
Sep	3999	120	3.0	685	37	5.4	4684	157	3.4
Oct	3211	115	3.6	667	41	6.1	3878	156	4.0
Nov	3516	128	3.6	736	49	6.7	4252	177	4.2
Dec	3698	130	3.5	807	49	6.1	4505	179	4.0
Total	44253	1564	3.5	8614	585	6.8	52867	2148	4.1
Loss Multiplier at Generation Level (1 - Percent Loss/100)			0.965			0.932			0.959
Loss Factor at Distribution Level (1 - (Peak Loss / Peak Demand-Peak Loss))			0.963			0.927			0.958

Northern States Power Company
Interchange Agreement
CALCULATION OF AVERAGE ENERGY TRANSMISSION LOSS MULTIPLIERS
Four Year Average (1982-1985)

	MN Co.			WI Co. & LSDP			Total System		
Year	Energy Requirement (MWH)	Energy Loss (MWH)	Percent Loss is of Requirement	Energy Requirement (MWH)	Energy Loss (MWH)	Percent Loss is of Requirement	Energy Requirement (MWH)	Energy Loss (MWH)	Percent Loss is of Requirement
1982	21233794	776309	3.7	4464316	318941	7.1	25698110	1095250	4.3
1983	22533946	851122	3.8	4712545	357220	7.6	27246491	1208342	4.4
1984	23249225	776798	3.3	4745865	286208	6.0	27995090	1063006	3.8
1985	23708528	816656	3.4	4855929	319301	6.6	28564457	1135957	4.0
4 Year Average	22681373	814859	3.6	4694664	320910	6.8	27376037	1125639	4.1
Loss Multiplier at Generation Level (1 - Percent Loss/100)			0.964			0.932			0.959
Loss Factor at Distribution Level (1 - (Peak Loss / Peak Demand-Peak Loss))			0.963			0.927			0.957

ANALYSIS OF TASK FORCE RECOMMENDATIONS ON COMPANY BILLINGS

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Northern States Power Company
Interchange Agreement
DEVELOPMENT OF RECOMMENDED DEMAND ALLOCATION RATIOS
Budget Year 1986

Year/Month A-Actual F-Forecast	MN Co. Peak Demand (MW)	MN Co. Transm. Loss Multiplier	MN Co. Distribution Level Demands (MW)	WI Co. Peak Demand (MW)*	WI Co. Transm. Loss Multiplier	WI Co. Distribution Level Demands (MW)	LSDP Peak Demand (MW)*	LSDP Transm. Loss Multiplier	LSDP Distribution Level Demands (MW)
1984 Jan A	3684	0.965	3555	732	0.932	682	123	0.932	115
Feb A	3458	0.965	3337	659	0.932	614	114	0.932	106
Mar A	3415	0.965	3295	642	0.932	598	113	0.932	105
Apr A	3222	0.965	3109	557	0.932	519	89	0.932	83
May A	3315	0.965	3199	535	0.932	499	97	0.932	90
Jun A	4097	0.965	3954	593	0.932	553	102	0.932	95
Jul A	4219	0.965	4071	606	0.932	565	102	0.932	95
Aug A	4748	0.965	4582	684	0.932	637	112	0.932	104
Sep A	3749	0.965	3618	530	0.932	494	82	0.932	76
Oct A	3380	0.965	3262	566	0.932	528	102	0.932	95
Nov A	3538	0.965	3414	630	0.932	587	116	0.932	108
Dec A	3649	0.965	3521	654	0.932	610	120	0.932	112
Total	44474		42917	7388		6886	1272		1184
1985 Jan A	3784	0.965	3652	701	0.932	653	116	0.932	108
Feb A	3764	0.965	3632	715	0.932	666	112	0.932	104
Mar A	3395	0.965	3276	628	0.932	585	112	0.932	104
Apr A	3483	0.965	3361	560	0.932	522	101	0.932	94
May A	3767	0.965	3635	572	0.932	533	97	0.932	90
Jun A	4379	0.965	4226	552	0.932	514	94	0.932	88
Jul F	5022	0.965	4846	692	0.932	645	107	0.932	100
Aug F	4681	0.965	4517	672	0.932	626	106	0.932	99
Sep F	4163	0.965	4017	612	0.932	570	102	0.932	95
Oct F	3550	0.965	3426	599	0.932	558	105	0.932	98
Nov F	3690	0.965	3561	634	0.932	591	108	0.932	101
Dec F	3736	0.965	3605	680	0.932	634	117	0.932	109
Total	47414		45754	7617		7097	1277		1190
1986 Jan F	3977	0.965	3838	788	0.932	734	124	0.932	116
Feb F	3776	0.965	3644	685	0.932	638	114	0.932	106
Mar F	3539	0.965	3415	652	0.932	608	109	0.932	102
Apr F	3447	0.965	3326	613	0.932	571	87	0.932	81
May F	3521	0.965	3398	571	0.932	532	92	0.932	86
Jun F	4280	0.965	4130	645	0.932	601	106	0.932	99
Jul F	5125	0.965	4946	684	0.932	637	103	0.932	96
Aug F	5062	0.965	4885	717	0.932	668	111	0.932	103
Sep F	4300	0.965	4150	630	0.932	587	100	0.932	93
Oct F	3631	0.965	3504	616	0.932	574	103	0.932	96
Nov F	3983	0.965	3844	671	0.932	625	113	0.932	105
Dec F	3984	0.965	3845	720	0.932	671	119	0.932	111
Total	48625		46925	7992		7446	1281		1194
3 Yr Total	140513	0.965	135595	22997	0.932	21433	3830	0.932	3570
Ratios As Measured:	0.839686			0.137427			0.022887		
Ratios at Dist. Level:			0.844313			0.133457			0.022230

* LSDP Resale demands are included in the WI Co.

Northern States Power Company
Interchange Agreement
IMPACT RESULTING FROM THE RECOMMENDED CHANGE
IN THE DEMAND ALLOCATION METHOD
For the Year 1986*
(Dollars in Thousands)

	System	MN Co.	WI Co.	LSDP
Present Method With Average of 12 Monthly CP Based on One Forecast Year				
Demand-Related Costs:				
Demand Requirements - MW	4,825	4,052	666	107
Allocation Ratios	1.000000	0.839839	0.138036	0.022125
Demand-Related Costs by Co.	$585,204	$491,477	$80,779	$12,948
Energy-Related Costs:				
Energy Requirements - MWH	29,530,706	24,620,227	4,148,493	761,986
Allocation Ratios	1.000000	0.833716	0.140481	0.025803
Energy-Related Costs by Co.	$397,723	$331,588	$55,873	$10,262
Total Allocated Costs	$982,927	$823,065	$136,652	$23,210
Composite Allocation	1.000000	0.837361	0.139026	0.023613
Recommended Method With Average of 12 Monthly CP Based on 18 Months Actual and 18 Months Forecast				
Demand-Related Costs:				
Demand Requirements - MW	4,648	3,903	639	106
Allocation Ratios	1.000000	0.839686	0.137427	0.022887
Demand-Related Costs by Co.	$585,204	$491,388	$80,423	$13,393
Energy-Related Costs:				
Energy Requirements - MWH	29,530,706	24,620,227	4,148,493	761,986
Allocation Ratios	1.000000	0.833716	0.140481	0.025803
Energy-Related Costs by Co.	$397,723	$331,588	$55,873	$10,262
Total Allocated Costs	$982,927	$822,976	$136,296	$23,655
Composite Allocation	1.000000	0.837271	0.138663	0.024066
Impact Resulting From Recommended Demand Allocation Method				
Total Allocated Costs		($89)	($356)	$445
Composite Allocation		(0.000090)	(0.000363)	0.000453

* Based on Second Quarter 1986 Forecast

Northern States Power Company
Interchange Agreement
ADDITIONAL IMPACT RESULTING FROM
ALLOCATING TRANSMISSION LOSSES
For the Year 1986*
(Dollars in Thousands)

	System	MN Co.	WI Co.	LSDP
Transmission Losses Assigned as Measured				
Demand-Related Costs:				
Demand Requirements				
Sum of 36 Monthly Peaks - MW	167,340	140,513	22,997	3,830
Average Monthly Peak - MW	4,648	3,903	639	106
Allocation Ratios	1.000000	0.839686	0.137427	0.022887
Demand-Related Costs by Co.	$585,204	$491,388	$80,423	$13,393
Energy-Related Costs:				
Energy Requirements - MWH	29,530,706	24,620,227	4,148,493	761,986
Allocation Ratios	1.000000	0.833716	0.140481	0.025803
Energy-Related Costs by Co.	$397,723	$331,588	$55,873	$10,262
Total Allocated Costs	$982,926	$822,976	$136,296	$23,655
Composite Allocation	1.000000	0.837271	0.138663	0.024065
Transmission Losses Allocated				
Demand-Related Costs:				
Demand Requirements				
Sum of 36 Monthly Peaks - MW	167,340	140,513	22,997	3,830
Average Monthly Peak - MW	4,648	3,903	639	106
Transmission Loss Multiplier		0.965	0.932	0.932
Distribution Level Demands				
Sum of 36 Monthly Peaks - MW	160,598	135,595	21,433	3,570
Average Monthly Peak - MW	4,461	3,767	595	99
Allocation Ratios	1.000000	0.844313	0.133457	0.022230
Demand-Related Costs by Co.	$585,204	$494,095	$78,100	$13,009
Energy-Related Costs:				
Energy Requirements - MWH	29,530,706	24,620,227	4,148,493	761,986
Transmission Loss Multiplier		0.964	0.932	0.932
Distribution Level Energy - MWH	28,310,465	23,733,899	3,866,395	710,171
Allocation Ratios	1.000000	0.838344	0.136571	0.025085
Energy-Related Costs by Co.	$397,723	$333,429	$54,317	$9,977
Total Allocated Costs	$982,927	$827,524	$132,417	$22,986
Composite Allocation	1.000000	0.841898	0.134717	0.023385
Impact Resulting From Allocating Losses				
Total Allocated Costs		$4,548	($3,879)	($669)
Composite Allocation		0.004627	(0.003946)	(0.000680)

* Based on Second Quarter 1986 Forecast