

Direct Testimony and Schedules
Paul J. Lehman

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STATE OF NORTH DAKOTA
PUBLIC SERVICE COMMISSION BEFORE THE
NORTH DAKOTA PUBLIC SERVICE COMMISSION

NORTHERN STATES POWER COMPANY,
A MINNESOTA CORPORATION

CASE No. PU-_____

OTTER TAIL POWER COMPANY

CASE No. PU-_____

IN THE MATTER OF THE APPLICATION
FOR AN ADVANCE DETERMINATION OF
PRUDENCE FOR THE CAPX2020 GROUP
1 PROJECTS

TESTIMONY OF

Paul J Lehman
On Behalf of

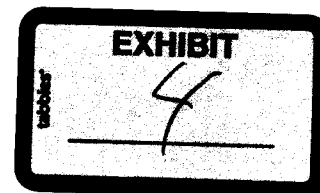
APPLICANTS

NORTHERN STATES POWER COMPANY, A MINNESOTA
CORPORATION,
AND
OTTER TAIL POWER COMPANY

September 17, 2009

Joint Exhibit C

- 53 PU-09-678 Filed 06/10/2010 Pages: 20
Exhibit 4
Emineth & Associates Court Reporters
- 54 PU-09-676 Filed 06/10/2010 Pages: 20
Exhibit 4
Emineth & Associates Court Reporters



1 I. INTRODUCTION AND QUALIFICATIONS

2

3 Q. PLEASE STATE YOUR NAME AND EMPLOYMENT ADDRESS.

4 A. My name is Paul J. Lehman and my business address is 414 Nicollet Mall,
5 Minneapolis, Minnesota, 55401.

6

7 Q. BY WHOM ARE YOU EMPLOYED AND WHAT IS YOUR POSITION?

8 A. I am employed by Xcel Energy Services Inc., the service company provider
9 for Northern States Power Company, a Minnesota corporation (“Xcel
10 Energy” or the “Company”) and my current position is Manager, Regulatory
11 Administration.

12

13 Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND EXPERIENCE.

14 A. I received a Bachelor of Science in Electrical Engineering from the University
15 of Minnesota in 1977. Thereafter I began my career at Northern States Power
16 Company as a Planning Engineer in its Power Supply Planning Department.
17 While in that area, I worked on planning the transmission system expansion
18 requirements for the Company.

19

20 In 1980, I became the Superintendent of Transmission Planning for Northern
21 States Power Company – Wisconsin, responsible for all power supply
22 planning efforts for the Company’s transmission needs in Wisconsin. This
23 included all regulatory reporting requirements for the Company Northern
24 States Power Company – Wisconsin.

25

26 In 1984, I moved to the Energy Supply Planning Department of Northern
27 States Power Company with various responsibilities and titles centered around

1 the planning activities associated with the Company's generating plants. This
2 included life extension efforts, alternative fuel supply evaluations, negotiating
3 contracts with non utility power suppliers under the Public Utilities Regulatory
4 Policies Act ("PURPA"), capacity supply acquisition activities within the Mid-
5 Continent Area Power Pool ("MAPP"), long term power supply planning and
6 acquisition and regulatory reporting requirements associated with these
7 various activities.

8
9 In 1990, I became the Manager of a new department within the Company,
10 Power Contracts, with responsibility for all of the contracting activities for the
11 power supply business needs of the Company.

12
13 In 1991, I became Manager, Electric Rate Design for Northern States Power
14 Company responsible for all the retail electric rate design activities and
15 requirements of the Company.

16
17 In 2000, I became an internal consultant providing services to other areas of
18 the Company on pricing and regulatory issues. During this time, I served as
19 the Company representative to the Federal Energy Regulatory Commission's
20 ("FERC") during its rulemaking activities for the interconnection of
21 generation to utility transmission systems including testifying on behalf of the
22 Edison Electric Institute ("EEI") before FERC on technical challenges and
23 issues associated with interconnection of wind to utility systems.

24
25 In 2008, I assumed my current position. My resume is attached as Schedule 1.
26

1 **Q. FOR WHOM ARE YOU TESTIFYING?**

2 A. I am providing testimony on behalf of Northern States Power Company, a
3 Minnesota corporation (“Xcel Energy”), Otter Tail Power Company (“Otter
4 Tail”), the joint Applicants in this proceeding.

5
6 **Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?**

7 A. The purpose of my testimony is to provide an overview of the cost recovery
8 and allocation methodologies for the Group 1 Projects.

9
10 **Q. WERE YOU INVOLVED IN THE PREPARATION OF THE APPLICATION FOR
11 ADVANCE DETERMINATION OF PRUDENCE IN THIS PROCEEDING?**

12 A. Yes. I provided information to the Applicants in their preparation of the
13 Application. The Application was prepared with my participation, using
14 information that I provided as well as the type of information that is regularly
15 relied upon by professionals in the ordinary course of business.

16
17

18 **II. COST RECOVERY AND ALLOCATIONS**

19

20 **Q. HOW WILL APPLICANTS RECOVER THE COST OF THEIR INVESTMENT IN
21 THE GROUP 1 PROJECTS?**

22 A. Applicants are both Transmission Owning Members of the Midwest
23 Independent Transmission System Operator, Inc. (“MISO”). As such,
24 Applicants’ transmission facilities above 100 kV are operated by MISO. As a
25 general matter, MISO calculates a revenue requirement for the recovery of
26 costs for the owners of the transmission facilities it operates and charges users
27 of the MISO Transmission System (those transmission facilities over which

1 MISO has functional control) in order to collect and remit to the MISO
2 transmission owners their cost recovery on their transmission assets.
3 Therefore, Applicants will, in general, recover their capital costs for their
4 ownership of the Group 1 Projects from users of the MISO Transmission
5 System.

6
7 **Q. IF APPLICANTS WILL RECOVER THEIR CAPITAL COSTS FROM MISO, HOW**
8 **ARE APPLICANTS' RATEPAYERS AFFECTED?**

9 A. As noted in my previous answer, in order to pay the utility owners of
10 transmission in the MISO footprint, MISO charges the utility users of the
11 transmission facilities in the MISO footprint for their use of those
12 transmission facilities to serve customers. Applicants, as users of transmission
13 facilities in the MISO footprint, on behalf of their ratepayers, will pay a
14 portion of those charges. It is these charges to use the transmission facilities
15 in the MISO footprint, including the Group 1 Projects, for which Applicants
16 will incur costs and which will be recovered from the ultimate benefactors of
17 this use, the Applicants' ratepayers.

18
19 **Q. HOW DOES MISO DETERMINE THE TRANSMISSION OWNER'S COST FOR**
20 **EACH TRANSMISSION FACILITY?**

21 A. Generally, the owner of a transmission facility will incorporate the costs of
22 that facility in its rate base as calculated pursuant to Attachment O of the
23 MISO Transmission, Energy Markets and Operating Reserves Tariff
24 ("Tariff"). The Attachment O rate base is then used to calculate the
25 Transmission Owner's revenue requirement and from that, a charge is
26 calculated for the use of the transmission facilities within the Transmission

1 Owner's pricing zone, which is roughly equivalent to that Transmission
2 Owner's transmission footprint.

3
4 However, some proposed transmission facilities are eligible for different cost
5 allocation methodology because MISO characterizes them as providing certain
6 regional and sub-regional benefits. For these projects, MISO attempts to
7 allocate the costs to those users of the MISO Transmission System who
8 benefit from these projects.

9
10 Therefore, Transmission Owning Members of MISO recover their costs of
11 investment in transmission facilities either by the MISO Attachment O
12 formula or through MISO's other cost allocation methodology.

13
14 **Q. YOU SAID THAT THE PAYMENT FOR CERTAIN TRANSMISSION FACILITIES IN**
15 **MISO ARE PAID FOR BY THOSE THAT BENEFIT FROM THE USE OF THE**
16 **FACILITIES. PLEASE EXPLAIN HOW MISO DETERMINES THIS.**

17 A. Yes. As a first step, MISO determines the resultant benefit of a proposed
18 transmission addition. To do this, MISO uses several broad categories. One
19 of these defines transmission facilities that provide an improvement in the
20 overall reliability of the entire MISO transmission system ("Regional Basis").
21 A second benefit category defines how proposed transmission facilities have a
22 more direct or local benefit to the transmission system ("Sub-Regional Basis").
23 A third benefit category is for the connection of generation to the MISO
24 system ("Generation Interconnection Projects"). Finally, the fourth benefit
25 category is for projects that have a high economic benefit to the MISO system
26 as compared to their costs ("Regionally Beneficial Projects"). In some cases,

1 proposed transmission projects may have benefits in more than one of these
2 benefit categories.

3
4 **Q. HOW DOES MISO ACCOUNT FOR EACH OF THESE BENEFIT CATEGORIES**
5 **WHEN DETERMINING ALLOCATION OF COST RESPONSIBILITY FOR**
6 **TRANSMISSION ADDITIONS?**

7 **A.** Each year, MISO reviews all of the transmission expansion plans proposed by
8 the MISO Transmission Owners and identifies those projects that are to be
9 included in what is know as “Appendix A” of the Midwest Transmission
10 Expansion Plan (“MTEP”). For projects included in Appendix A and
11 constructed?, MISO will collect the necessary funds to meet each of
12 Applicant’s revenue requirements through the cost allocation formula
13 approved in its Cost Allocation Policy (FERC Docket No. ER06-18). This
14 Policy allocates and recovers costs associated with new transmission projects
15 and system upgrades within the MISO Transmission System using provisions
16 developed by the Regional Expansion Criteria and Benefits (“RECB”) Task
17 Force. As expressed in the name of this task force, the provisions developed
18 set the criteria for how the benefits of proposed transmission expansion
19 facilities will be allocated to users of the MISO Transmission System.

20
21 As a first threshold, RECB criteria divides proposed transmission facilities
22 between those that are more local or direct in benefit from those that are
23 regional in benefit. Facilities that are regional in benefit are defined as
24 Baseline Reliability Projects (“BRP” or “BRPs”). I’ll address the more direct
25 or local projects later, but for those transmission projects with BRP
26 designations, MISO allocates some or all of their costs in one of two ways.

27

1 For transmission projects with voltages below 345 kV, MISO makes use of an
2 analysis known as the Line Outage Distribution Factor (“LODF”) method.
3 LODF is an engineering calculation of the change of flows on the
4 Transmission System created by the addition of a new transmission facility.
5 MISO uses computer software to measure and model the LODF of all
6 facilities within the MISO Transmission System for each new facility added to
7 the system. MISO then models the LODF for each pricing zone for each new
8 transmission facility. LODF is used because it is considered by MISO
9 planners as a way to determine the added benefit of a new transmission facility
10 to each of the pricing zones. Generally, pricing zones in close proximity to
11 the proposed transmission facility have the greatest LODF cost allocation and
12 those furthest away have little to no cost allocation from the LODF method,
13 thus this benefit assignment is defined as Sub-Regional.

14
15 For transmission projects of 345 kV or higher, the RECB criteria defines
16 some of the benefit of the proposed transmission facility as being for system
17 wide reliability. Therefore a portion of the costs of the proposed facility
18 (20 percent) is assigned to all pricing zones in MISO on what is known as a
19 “postage stamp” basis. Postage stamp cost allocation spreads cost
20 responsibility proportionally to the load in the pricing zones of MISO thus
21 this benefit assignment approach is defined as being Regional. The remaining
22 80 percent of the cost of the proposed transmission facility is then assigned
23 using the LODF method I just described.

24
25 One more factor that is included in the RECB criteria is if the proposed
26 transmission facilities have been designated (through MISO studies) as
27 necessary for interconnection of generation. If this is the case, then further

1 analysis is done to determine what portion of the transmission facilities are
2 solely for the purpose of Generation Interconnection and which portion may
3 have benefits from one of the other categories. The portion that is solely for
4 Generation Interconnection is assigned to the generation that requires the
5 facility for interconnection.

6
7 In the case of transmission facilities that have more purposes than just
8 interconnection of generation (“Network Upgrades”), MISO’s Generation
9 Interconnection cost allocation provides for up to 50 percent of the cost
10 responsibility to be passed back to the transmission owners and then
11 ultimately to the transmission users. This assignment of other purposes is
12 determined if the generation is either designated a “Network Resource” or is
13 being sold to a “Network Customer” for more than one year. In either of
14 these cases, the transmission facilities are serving a “network” purpose (in
15 addition to their generation interconnection purpose). MISO’s Tariff thus
16 treats the portion of the transmission cost responsibility passed back to the
17 transmission owner as BRP facility with cost allocation as described above.
18 The other 50 percent of costs would be assigned to the generator.

19
20 On July 9, 2009, MISO submitted proposed Tariff revisions to FERC that
21 would change the way costs for Generation Interconnection Projects are
22 allocated. MISO has proposed changing the 50/50 percent cost share for the
23 costs of Network Upgrades by allocating 100 percent of the costs of Network
24 Upgrades in a voltage class below 345 kV to the generators. MISO also
25 proposed allocating 90 percent of the costs of Network Upgrade facilities in a
26 voltage class of 345 kV or higher to the generators and 10 percent of the costs
27 to the users of the MISO Transmission System. The costs of the 10 percent

1 of the Network Upgrades allocated to users of the MISO Transmission
2 System would be allocated on a postage stamp basis to all MISO pricing
3 zones. MISO's proposed changes would apply to all generators, not just those
4 that interconnect using Network Resource Interconnection Service.
5

6 **Q. WHAT ABOUT THE LOCAL OR DIRECT BENEFIT TRANSMISSION FACILITIES**
7 **YOU MENTIONED? PLEASE EXPLAIN WHAT HAPPENS WITH THE COST**
8 **ASSIGNMENT OF THOSE FACILITIES.**

9 A. If the initial screening criteria of RECB determines that the benefit of a
10 proposed transmission facility is local in nature, then the assignment of costs
11 for that facility is left to the local pricing zone of the owner of the facility. For
12 example, a proposed transmission facility that serves a single customer on a
13 radial line would be directly assigned for the benefit of that customer.
14 Similarly, a proposed transmission facility that primarily benefits a local load
15 center or even a load center that is not part of the MISO system would be
16 assigned for the benefit of that local load center. This later consideration
17 becomes important when looking at two of the CapX2020 lines which I will
18 explain later.
19

20 **Q. WILL ANY OF THE GROUP 1 PROJECTS HAVE A BRP DESIGNATION UNDER**
21 **RECB?**

22 A. Yes. The Fargo Project and most of the Bemidji Project have been designated
23 as BRPs in the 2006 and 2008 MTEPs. The segment of the La Crosse Project
24 from North Rochester to La Crosse has also been designated as a BRP in the
25 2008 MTEP. The Hampton Corner to North Rochester 345 kV segment of
26 the La Crosse Project and both 161 kV circuits of the La Crosse Project were
27 screened as local facilities under the RECB criteria because the primary benefit

1 of these facilities are for the load of two non-MISO CapX2020 Utilities
2 (Dairyland Power Cooperative and Rochester Public Utilities). Similarly, a
3 non-MISO member (Minnkota Power Cooperative) has a 31.5 percent
4 ownership share of the Bemidji Project and thus that share is not treated as a
5 BRP by MISO.

6
7 Finally, the Brookings Project has been designated as a Generation
8 Interconnection Project (“GIP”) under RECB. This decision is currently
9 being discussed and analyzed and MISO has convened a public stakeholder
10 process to determine whether and how the MISO Tariff might be changed to
11 address stakeholder concerns over this designation.

12
13 In summary each of the Group 1 Projects have been designated for cost
14 responsibility as follows under the RECB criteria:

15
16 The Fargo Project – All of the cost responsibility assigned as a BRP with 20
17 percent through postage stamp to all MISO pricing zones and 80 percent
18 through the LODF method.

19
20 The Bemidji Project – 68.5 percent of the cost responsibility assigned as a
21 BRP through the LODF method (as applicable projects under 345 kV).

22
23 The La Crosse Project – All of the cost of the Hampton to North Rochester
24 portion of this project along with the 161 kV lines from North Rochester into
25 the Rochester area are assigned locally to the owners of this segment of the
26 line. Further, the cost of the project that non-MISO transmission owners
27 DPC and RPU will incur are not assigned to any MISO members. Finally, the

1 cost of the remaining portion of the project is assigned as a BRP with 20
2 percent through postage stamp to all MISO pricing zones and 80 percent
3 through the LODF method.

4
5 The Brookings Project – Initially, 100 percent of the line has been designated
6 as being the responsibility of the generators that require the project for their
7 interconnection (yet to be finalized). Under the existing MISO RECB
8 process, the ultimate cost responsibility for the project would leave 50 percent
9 assigned to the generators and potentially 50 percent assigned as a BRP with
10 20 percent of this half (10 percent of the total cost) through postage stamp to
11 all MISO pricing zones and 80 percent of this half (40 percent of total cost)
12 through the LODF method. I note, again, that this methodology is being
13 reviewed and MISO has convened a stakeholder process to assess more
14 appropriate ways to allocate the cost of the Brookings Project.

15
16 **Q. UP TO THIS POINT YOU HAVE DESCRIBED THE ALLOCATION OF COST TO**
17 **MISO PRICING ZONES. ONCE THOSE ALLOCATIONS HAVE BEEN MADE,**
18 **HOW ARE THE CHARGES THAT HAVE BEEN ALLOCATED TO PRICING ZONES**
19 **FURTHER ALLOCATED TO USERS OF THE MISO TRANSMISSION SYSTEM?**

20 A. Charges allocated to each pricing zone are then paid for by the utilities serving
21 load in each pricing zone (the users) in proportion to their load in that pricing
22 zone. For example, Xcel Energy serves over 80 percent of the load in its
23 pricing zone and therefore pays over 80 percent of the costs allocated to the
24 Xcel Energy pricing zone.

25
26 **Q. HAVE YOU CONDUCTED AN ANALYSIS THAT ACCOUNTS FOR ALL OF THE**
27 **ASSIGNMENT OF COST RESPONSIBILITY FOR THE GROUP 1 PROJECTS SUCH**

1 **THAT YOU CAN QUANTIFY THE COST RESPONSIBILITY THAT HAS BEEN**
2 **ASSIGNED TO THE APPLICANTS?**

3 A. Yes. The analysis is reflected in Appendix C, attached to the Application.

5 **Q. WOULD YOU PLEASE SUMMARIZE THE CONCLUSIONS OF THAT ANALYSIS?**

6 A. The expected costs assigned to each Applicants' respective North Dakota
7 jurisdiction will be equal to the revenue requirements for MISO charges
8 reflecting an investment of \$40-60 million for Xcel Energy and \$35-40 million
9 for Otter Tail in the Group 1 Projects. This ultimate cost responsibility will
10 generate a North Dakota jurisdictional annual levelized revenue requirement
11 of approximately \$9.5 million per year for Xcel Energy and \$7.5 million per
12 year for Otter Tail.

14 **Q. YOU MENTIONED THAT THE BROOKINGS PROJECT HAS BEEN**
15 **DESIGNATED AS A GENERATION INTERCONNECTION PROJECT UNDER**
16 **RECB AND THUS SUBJECT TO THE GENERATOR INTERCONNECTION**
17 **PROJECT COST ALLOCATION METHODOLOGY DISCUSSED ABOVE. IS THIS**
18 **SUBJECT TO CHANGE?**

19 A. As of the date of this filing, both Applicants, Xcel Energy and Otter Tail, are
20 transmission-owning members of MISO. However, Otter Tail and several
21 other transmission-owning members of MISO are currently in discussions
22 with MISO regarding modifications to the MISO GIP cost allocation
23 methodology. Because of the location of Otter Tail's pricing zone, there is a
24 large amount of generation in the MISO Queue that is seeking to interconnect
25 to the MISO Transmission System within Otter Tail's pricing zone. Based on
26 the GIP RECB cost allocation methodology currently in place, a substantial
27 proportion of the cost of the Generator Interconnection Projects' cost to

1 build transmission facilities will be disproportionately borne by Otter Tail
2 ratepayers. Otter Tail, Xcel Energy, and others are working with MISO to
3 develop a better allocation of the costs of these GIPs to address these
4 concerns.

5
6 As identified in the Application, as a result of this cost allocation issue, Otter
7 Tail has submitted notice to MISO reserving its right to withdraw from MISO
8 should the issue not be addressed to its satisfaction. The notice is a technical
9 requirement under the Tariff so that Otter Tail may preserve all its rights in
10 negotiations with MISO. Again, both Otter Tail and Xcel Energy are
11 proactively working with MISO to resolve the uncertainty in cost allocation
12 and reach a fair and reasonable solution among all stakeholders.

13 In an effort to address these concerns, MISO submitted to FERC the
14 proposed modifications to its GIP cost allocation methodology that I
15 described above. The outcome of this process may result in changes to the
16 way the costs for the Brookings Project will be allocated to Applicants and
17 other MISO members. Applicants will keep the Commission informed on
18 this process and of the impact any revised Tariff procedure may have on this
19 proceeding.

20
21 To that end, MISO's cost allocation methodology for Generation
22 Interconnection Projects may change prior to construction of the Group 1
23 Projects. Applicants will update the Commission regarding any such changes.

24
25 **Q. WHY IS MISO'S GENERATOR INTERCONNECTION PROJECT COST**
26 **ALLOCATION METHODOLOGY PROBLEMATIC FOR THE STAKEHOLDERS IN**
27 **THE BROOKINGS PROJECT?**

1 A. The Generator Interconnection Project cost allocation methodology is based
2 on the premise that interconnection facilities are built in response to approved
3 interconnection requests for which the generator has signed an
4 interconnection agreement and generation commitment. In the case of the
5 Brookings Project, MISO has identified a group of nineteen generators under
6 study for interconnection to the MISO Transmission System consisting of
7 1,300 MW of generating capacity. These studies have identified the Brookings
8 Project as a necessary Network Upgrade for the reliable interconnection of the
9 proposed generation projects. Therefore, MISO's starting position for
10 allocation of the generation portion of the costs of the Brookings Project
11 should be assigned to the generators making up the 1,300 MW of capacity
12 studied.

13
14 MISO's starting position creates a number of difficult complications in the
15 case of the Brookings Project. The nineteen generators identified by MISO
16 do not have signed interconnection agreements or power purchase
17 agreements. Therefore, the generators who will actually use the Brookings
18 Project are currently not under contract. This creates several problems with
19 the timing of the Brookings Project. First, the MISO Tariff requirement that
20 generation projects fund 100 percent of the upfront costs of the Brookings
21 Project is problematic since such generation projects do not yet exist and are
22 not available to provide such funding. Second, under the current project
23 schedule, we expect the Brookings Project to be completed prior to the
24 completion of all of the generation projects. Such timing is not contemplated
25 under the MISO Tariff. Last, because the 50/50 percent cost sharing
26 provisions apply only to generators who are interconnecting with Network
27 Resource Interconnection Service, the fact that the generators do not have

1 Interconnection Agreements makes it unclear how much of the potential 50
2 percent of the cost of the Brookings Project will actually be passed back to
3 CapX2020 Utilities' ratepayers in the form of MISO charges.

4

5 In light of all of these issues and cost allocation uncertainty, Applicants and
6 others have raised concerns with MISO on the need to address this situation
7 in some fashion in order to provide an allocation mechanism that is workable.

8

9 **Q. DOES THIS CONCLUDE YOUR TESTIMONY?**

10 A. Yes it does.

11

MR. PAUL J LEHMAN
Manager, Regulatory Administration
414 Nicollet Mall, Minneapolis, Minnesota

CURRENT RESPONSIBILITIES (August 2008 – Present)

Manage regulatory projects related to transmission facilities for Xcel Energy.

PREVIOUS EMPLOYMENT (Northern States Power Company)

Pricing Consultant	2000 - 2008
Manager, Electric Rate Design	1991 – 2000
Manager, Power Contracts	1990 – 1991
Various positions, Energy Supply Planning Including Superintendent, Power Systems Development And Superintendent, Bulk Power Planning	1984 – 1990
Superintendent, Transmission Planning	1980 – 1984
Planning Engineer, Power Supply Planning and Transmission Planning	1977 – 1980

PREVIOUS TESTIMONY

<u>Jurisdiction</u>	<u>Subject</u>	<u>Docket/Case No.</u>
Minnesota	Rate Design	E002/GR-05-1428
Colorado	Rate Design	04S-164E
Minnesota	Rate Design and Cost Allocation	E002/GR-92-1185
Minnesota	Legislative Committee Hearings on Wind Generation	NA
Minnesota	Power Purchase and Cogeneration Litigation	E002/GR-91-001
Minnesota	Joint Petition of Dakota County and Winona County	E002/CG-88-489
North Dakota	Rate Design and Cost Allocation	PU-400-92-399
North Dakota	Rules Governing Cogeneration and Small Power Production	PU-439-89-374
Wisconsin	Advance Plan 5	05-EP-5
Wisconsin	Advance Plan 4	05-EP-4
Wisconsin	Advance Plan 3	05-EP-3

EDUCATION

University of Minnesota – Institute of Technology Bachelor of Science in Electrical Engineering	1977
University of Minnesota – Continuing Education and Extension Pricing for Profits Strategies and Tactics	1992
University of Minnesota – Carlson School of Management Strategic Pricing Program	1997
Professional Pricing Society Fundamentals and Advanced Workshops of the Professional Pricing Skills Certificate Program	1999
University of Wisconsin, Madison – College of Engineering EEI Transmission Pricing School	2001

PROFESSIONAL REGISTRATIONS AND ASSOCIATIONS

Registered Professional Engineer in Minnesota and Wisconsin
Member, Institute of Electrical and Electronic Engineers

ARTICLES OR PAPERS PUBLISHED OR PRESENTED

Paul J. Lehman, et al, "MAPP Bulk Transmission Outage Data Collection and Analysis", IEEE Transactions on Power Apparatus and Systems, Volume PAS-103, Number 1, January 1984, p. 213-221.

Paul J. Lehman, et al, "Effects of Pooling Weather Associated MAPP Bulk Transmission Outage Data on Calculated Forced Outage Rates", IEEE Transactions on Power Apparatus and Systems, Volume PAS-103, Number 8, August 1984, p. 2345-2351.

Paul J. Lehman, et al, "Analysis of Pooling 345 kV Transmission Outage Data Between the Mid-Continent Area Power Pool and Northeast Utilities", IEEE Transactions on Power Apparatus and Systems, Volume PAS-104, Number 9, September 1985, p. 2427-2435.

Paul J. Lehman, et al, "The Procedure Used in the Probabilistic Transfer Capability Analysis of the MAPP Region Bulk Transmission System", IEEE Transactions on Power Apparatus and Systems, Volume PAS-104, Number 11, November 1985, p. 3013-3019.

Paul J. Lehman, et al, "The Effects of Terminal Complexity and Redundancy on the Frequency and Duration of Forced Outages", IEEE Transactions on Power Apparatus and Systems, Volume PWRS-2, Number 4, November 1987, p. 856-863.

**STATE OF NORTH DAKOTA
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VERIFICATION

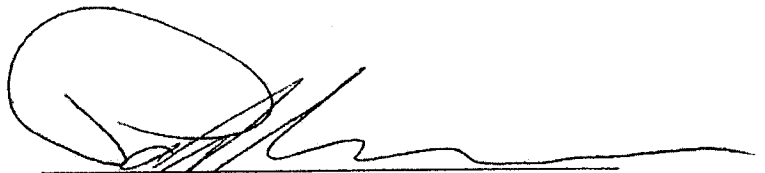
STATE OF MINNESOTA)
) ss.
COUNTY OF HENNEPIN)

PAUL J. LEHMAN, being first duly sworn on oath, deposes and says that he is Manager of Regulatory Administration for Xcel Energy Services Inc. on behalf of Applicant Northern States Power Company, a Minnesota corporation, in the above captioned matter, that the testimony and schedules submitted in the above captioned matter under his name were prepared under his direction, that he knows the contents thereof, and that the same is true and correct to the best of his knowledge and belief.

[SIGNATURE PAGE FOLLOWS]

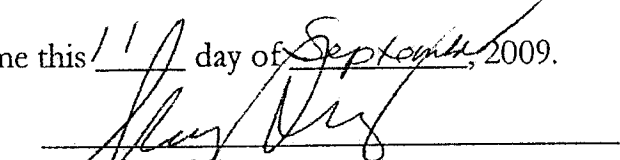
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Lehman Direct

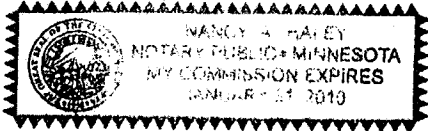


PAUL J. LEHMAN

Subscribed and sworn to before me this 11 day of September, 2009.



Notary Public
My Commission Expires: 1-31-2010



NDPSC Case Nos. PU-_____

Lehman Direct