

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

In the Matter of the Application of Northern States Power Company,
A Minnesota Corporation
For Authority to Increase Rates for
Electric Service in North Dakota
Case No. PU-12-813

**DIRECT TESTIMONY OF
KARL RICHARD PAVLOVIC
July 2013**

**On Behalf of the Advocacy Staff of the
North Dakota Public Service Commission**

July 17, 2013

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3 **DIRECT TESTIMONY OF**
4 **KARL R. PAVLOVIC**

5 **QUALIFICATIONS**

6 **Q. PLEASE STATE YOUR NAME, POSITION AND BUSINESS ADDRESS.**

7 A. My name is Karl Richard Pavlovic. My business address is 8100 Professional Place,
8 Suite 306, Hyattsville, MD 20785. I am a Senior Consultant with Snavely King Majoros
9 & Associates, Inc. (“Snavely King”).

10 **Q. PLEASE DESCRIBE SNAVELY KING.**

11 A. Snavely King was founded by Charles W. King and the late Carl M. Snavely in 1970 to
12 conduct research on a consulting basis into the rates, revenues, costs and economic
13 performance of regulated firms and industries. The firm has a professional staff of 10
14 economists, accountants, engineers and cost analysts. Most of its work involves the
15 development, preparation and presentation of expert witness testimony before federal and
16 state regulatory agencies. Over the course of its 42-year history, members of the firm
17 have participated in over 1000 proceedings before almost all of the state commissions
18 and all Federal commissions that regulate utilities or transportation industries.

19 **Q. HAVE YOU PREPARED A SUMMARY OF YOUR QUALIFICATIONS AND**
20 **EXPERIENCE?**

21 A. Yes. Attachments A and B to my testimony summarize my qualifications and
22 experience.

23 **Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY IN REGULATORY**
24 **PROCEEDINGS?**

25 A. Yes. Attachment B is a list of my engagements as an expert and/or expert witness before
26 state and federal regulatory agencies.

27 **Q. HAVE YOU PREVIOUSLY APPEARED BEFORE THIS COMMISSION?**

1 A. No.

2 **Q. BEFORE WHICH AGENCIES HAVE YOU PREVIOUSLY TESTIFIED IN**
3 **REGULATORY PROCEEDINGS?**

4 A. I have submitted testimony to the Federal Communications Commission, the Federal
5 Energy Regulatory Commission, the Alaska Public Utilities Commission, the
6 Corporation Commission of the State of Kansas, the Delaware Public Service
7 Commission, the Maryland Public Service Commission, and the Public Service
8 Commission of the District of Columbia.

9 **Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS?**

10 A. I received undergraduate and graduate degrees in Philosophy from Yale College and
11 Purdue University. By education and professional experience I have expertise in formal
12 and mathematical logic, statistics, economics, financial analysis, econometrics, and
13 computer modeling. In the course of my professional career I have gained knowledge in
14 the areas of commercial and industrial operations in the energy, transportation, and
15 telecommunications industries and am familiar with a wide range of experimental and
16 investigative methods in science and engineering. For over 25 years I have served as a
17 consultant on the economics of regulated industries to clients in the public and private
18 sectors. In that capacity I have been responsible for the design and execution of
19 statistical, economic and financial analyses of discrete commercial operations, individual
20 firms, and industry sectors for use by management and counsel in formulating and
21 implementing commercial and litigation strategy. In a number of cases, these analyses
22 have been the basis for testimony by me or others in regulatory and court proceedings.
23 My consulting assignments in the energy field have included analyses of crude oil and

1 petroleum product markets, the operations and costs of petroleum pipelines,
2 investigations of operating and plant investment costs and least cost planning of electric
3 and natural gas utilities, and all aspects of the restructuring of electric markets.

4 **Q. PLEASE SUMMARIZE YOUR ELECTRIC REGULATORY EXPERIENCE.**

5 Until recently my electric regulatory experience has been primarily before the Public
6 Service Commission of the District of Columbia with regard to the Potomac Electric
7 Power Company (Pepco). I have testified in numerous cases regarding (a) planning
8 reserve margin, (b) “lost revenues” attributable to Demand-Side Management (“DSM”)
9 programs, (c) weather emergency response, (d) operational and financial issues with
10 regard to Pepco’s divestiture of its generating assets and the subsequent unbundling of its
11 retail rates, (e) performance of renewable and energy efficiency programs, (f) the
12 performance of Pepco’s transmission and distribution facilities, (g) the cost and benefits
13 of the Pepco-Conectiv merger, (h) the procurement of Standard Offer Service (“SOS”)
14 electric supply and retail SOS rates, (i) the need for new transmission lines to serve load,
15 and (j) issues of cost allocation, revenue requirement distribution, and rate design. I also
16 served for a number of years as the technical representative of the Office of the People’s
17 Counsel of the District of Columbia to Pepco’s Productivity Improvement Working
18 Group and on various member working groups within PJM. Most recently I have
19 testified in Maryland and Delaware regarding Baltimore Gas and Electric’s and Delmarva
20 Power and Light’s electric costs of service, rate designs and reliability investment
21 recovery mechanisms.

22 **Q. WHAT IS THE OBJECTIVE OF YOUR TESTIMONY?**

1 A. I have been asked by the Advocacy Staff of the North Dakota Public Service Commission
2 (Staff) to examine the assertions and proposals in this proceeding by Northern States Power
3 (NSP) regarding its North Dakota jurisdictional and class costs of service, rate design, and
4 proposed Transmission Cost Recovery (TCR) tracker.

5 **Q. HAVE YOU PREPARED ANY EXHIBITS IN SUPPORT OF YOUR**
6 **RECOMMENDATIONS?**

7 A. Yes. I have included eight exhibits.

8 Exhibit KRP-1: NSP Jurisdictional Allocators by FERC Account

9 Exhibit KRP-2: 2007 to 2013 NSP System Peak Demand

10 Exhibit KRP-3: Jurisdictional Rate Base Adjustment Factors

11 Exhibit KRP-4: Jurisdictional O&M Expense Adjustment Factors

12 Exhibit KRP-5: Class Cost of Service Cost Classifications and Allocators

13 Exhibit KRP-6: Rate Structure Matrix

14 Exhibit KRP-7: Class Rate Component Matrix

15 Exhibit KRP-8: "How Should Regulators View Cost Trackers"

16

17 **Q. HOW IS YOUR TESTIMONY ORGANIZED?**

18 A. My testimony is organized into four sections. In the first section I address NSP's
19 jurisdictional allocation of costs to North Dakota. In the second section I address NSP's
20 allocation of North Dakota jurisdictional costs to North Dakota customer classes. In the
21 third section I address NSP's rate design proposals. In the fourth section I address NSP's
22 proposed Transmission Cost Recovery tracker.

23 **I. SUMMARY OF TESTIMONY AND CONCLUSIONS**

1 **Q. PLEASE SUMMARIZE YOUR TESTIMONY.**

2 A. As explained in my testimony below, NSP's jurisdictional cost assignment methods and
3 procedures are, with the exception of the use of a 12 coincident peak demand allocator,
4 appropriate and in accordance with the principles enunciated in the NARUC Cost Allocation
5 Manual. The 12 coincident peak demand over-allocates system costs to the North Dakota
6 jurisdiction. NSP's class cost assignment methods and procedures are appropriate and
7 consistent with the NARUC cost allocation principles. NSP's proposed customer class
8 revenue distribution is cost based and reasonable. The class cost study does not, however,
9 directly support the current rate structure. NSP's proposed modifications to the rate
10 components, moving customer and demand charges towards full cost recovery, are
11 appropriate and reasonable. NSP's rate structure, however, is overly complex and the tariff
12 is virtually incomprehensible. NSP's application for a Transmission Cost Recovery (TRC)
13 rider does not comport with the statutory requirements for Commission consideration and
14 lacks a demonstration that the costs proposed for the tracker meet the criteria for inclusion in
15 a tracker.

16 My recommendations are:

- 17 • The Commission should direct NSP to use a single coincident peak demand
18 allocator for purposes of assigning system costs to the North Dakota
19 jurisdiction.
- 20 • The Commission should adopt NSP's class cost study for the purposes of
21 class revenue requirement distribution.
- 22 • The Commission should direct NSP to eliminate the rate classes for which it
23 has no North Dakota customers, eliminate the Residential Time of Day rate

1 classes, and eliminate the customer charge distinction between standard,
2 underground and space heating customers.

3 • The Commission should also direct NSP to further simplify its rate structure,
4 reducing the number of rate classes and aligning its class cost study so as to
5 directly support the simplified rate structure.

6 • The Commission should direct NSP to overhaul its tariff substituting plain
7 language for technical terms wherever possible, include a section defining
8 in plain language the technical terms that are used in the tariff, and place
9 specific tariff sheet references wherever rate schedules and riders make
10 reference to other riders or rate schedules.

11 • The Commission should direct NSP to remove its Account Service Charge
12 as it is in violation of Administrative Rules: 69-09-02-02.1

13 • The Commission should defer consideration of NSP's TRC proposal until
14 such time as NSP submits an application that comports with the statutory
15 requirements and demonstrates that the tracker costs meet the criteria for
16 inclusion in a tracker.

17 **II. DISCUSSION**

18 **NSP'S NORTH DAKOTA JURISDICTIONAL ALLOCATION**

19 **Q. HAVE YOU EXAMINED NSP'S METHODS AND PROCEDURES UNDERLYING**
20 **ITS ASSIGNMENT OF COSTS TO THE NORTH DAKOTA JURISDICTION?**

21 A. Yes. NSP's North Dakota costs are summarized in Schedule 8 of Exhibit ___ (AEH-1), the
22 Direct Testimony of Anne E. Heuer. NSP's jurisdictional methods and procedures are set
23 forth in Schedule 12 of Exhibit ___ (AEH-1). I have also examined the electronic files

1 which calculate the North Dakota costs assignments and allocations that are summarized in
2 Schedule 8 and the workpapers to those files.¹

3 **Q. PLEASE BRIEFLY SUMMARIZE NSP'S JURISDICTIONAL METHODS AND**
4 **PROCEDURES?**

5 A. The NSP electric system comprises assets and operations in Minnesota, North Dakota and
6 South Dakota. Those assets and operations produce, transmit and deliver electricity to retail
7 and wholesale customers. NSP first functionalizes its facilities investment and operating
8 expenses as distribution, transmission, production, fuel and purchased energy, customer
9 accounts, customer sales, property taxes, and administrative & general based on the Federal
10 Energy Regulatory Commission (FERC) system of accounts. The functionalized system
11 costs are then either directly assigned based on NSP location coding or allocated by FERC
12 account to the North Dakota jurisdiction. For the allocation of costs NSP uses three
13 allocation methods: (1) 12 coincident peak demand, (2) energy delivered, and (3) number of
14 customers. The allocation method selected for each FERC account is based on cost-
15 causation. Exhibit KRP-1 lists by FERC account the allocators used by NSP.

16 **Q. WHAT IS YOUR ASSESSMENT OF NSP'S JURISDICTIONAL METHODS AND**
17 **PROCEDURES?**

18 A. NSP's jurisdictional methods and procedures are, with one exception, appropriate and
19 conceptually in accordance with the principles enunciated in the NARUC Electric Utility
20 Cost Allocation Manual, particularly the principle of cost-causation. The exception is
21 NSP's use of 12 coincident peak demand to allocate production capacity costs and
22 transmission costs, which is inappropriate given NSP's system operation and performance.

¹ Responses to NDPS 6-001 – 6-007, 10-007 – 10-010, and 11-001 – 11-004.

1 **Q. WHY IS THE 12 COINCIDENT PEAK DEMAND METHOD INAPPROPRIATE**
2 **FOR NSP’S SYSTEM?**

3 A. There are several different methods of calculating coincident peak demand,² each of which
4 is appropriate to the specific peaking pattern experienced by a system. The 12 coincident
5 peak method calculates system and jurisdictional coincident peak demands as the average of
6 the system’s monthly coincident peak demands and is appropriate for a transmission system
7 where “significant variations in monthly peak demands are not present”³ or generation
8 systems where “monthly peaks lie within a narrow range.”⁴ NSP’s system, however,
9 experiences significant variation in its monthly peak demand – NSP is a strongly summer
10 peaking system as can be seen on page 1 of Exhibit KRP-2 where I have graphed NSP’s
11 historical monthly peak demands for the years 2007 through 2012 and NSP’s forecast
12 monthly peak demands for 2013.

13 **Q. WHAT IS THE APPROPRIATE METHOD FOR NSP’S SYSTEM?**

14 A. For a strongly summer peaking system like NSP’s the appropriate method for calculating
15 coincident peak demand is the single system coincident peak method⁵ which calculates
16 system and jurisdictional peak demands as the highest monthly system peak demand. As
17 the NARUC Manual states,

18 “[t]he single highest peak demand is the overriding consideration that drives power
19 supply cost decisions. Customer contribution to this single annual system peak is
20 used to measure customer responsibility. The result is that those customers which
21 most heavily contribute to the single monthly peak will pay proportionally large
22 amounts of the cost ...”
23

² NARUC Manual at 44-48 and 77 – 79.

³ NARUC Manual at 79 (emphasis added)..

⁴ NARUC Manual at 46.

⁵ NARUC Manual at 77.

1 **Q. HAVE YOU QUANTIFIED AND COMPARED THE IMPACT ON THE NORTH**
2 **DAKOTA ALLOCATION OF THE SINGLE COINCIDENT PEAK AND 12**
3 **COINCIDENT PEAK METHODS?**

4 A. Yes. On page 2 of Exhibit KRP-2 I have calculated NSP’s jurisdictional allocation factors
5 using both methods for the historical years 2007 – 2012 and the forecast year 2013. For all
6 these years the single coincident peak allocation to the North Dakota jurisdiction is
7 significantly less than the 12 coincident peak allocation. For forecast 2013, the test year in
8 this proceeding, the single coincident peak produces a North Dakota allocation factor of
9 5.4942% compared to NSP’s 12 coincident peak allocation factor of 6.0227%.

10 **Q. DO YOU RECOMMEND THAT THE TEST YEAR NORTH DAKOTA**
11 **JURISDICTIONAL COSTS BE ADJUSTED TO REFLECT A COINCIDENT PEAK**
12 **DEMAND ALLOCATION FACTOR OF 5.4924%?**

13 A. No. For consistency with the adjustments that Staff proposes that are based three-year
14 financial averages, I recommend that the test year North Dakota jurisdictional costs be
15 adjusted to reflect a single coincident peak allocation factor of 5.0864%, which is the
16 average single coincident peak allocation factor for the years 2010 through 2012. The
17 calculation of this allocation factor is shown on page 2 of Exhibit KRP-2. In Exhibit KRP-3
18 and Exhibit KRP-4, I have calculated adjustment factors for, respectively, rate base items
19 and production and transmission O&M expense items. Table 1, below, summarizes these
20 adjustment factors.

21 **TABLE 1 – Rate Base and O&M Adjustment Factors**

Plant in Service Adjustment Factor	87.1%
Reserve Adjustment Factor	87.2%

CWIP Adjustment Factor	84.8%
Accumulated Deferred Taxes Adjustment Factor	87.1%
Production O&M Adjustment Factor	83.3%
Transmission O&M Adjustment Factor	84.5%

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2 **Q. DO YOU HAVE ANY OTHER RECOMMENDATIONS REGARDING NSP'S**
3 **ALLOCATIONS TO THE NORTH DAKOTA JURISDICTION?**

4 A. Yes. The costs of NSP's Wind2Battery Project and high cost Purchased Power Agreements
5 (PPAs) should be excluded from the North Dakota jurisdictional costs.

6 **Q. WHY SHOULD THE WIND2BATTERY PROJECT BE EXCLUDED FROM**
7 **NORTH DAKOTA JURISDICTIONAL COSTS?**

8 A. This project is not cost effective. While part of the project was paid for with MN
9 renewable development funds, there is no reason to allocate any of these costs to the
10 North Dakota jurisdiction. While Advocacy Staff has ignored some of the high priced
11 projects that NSP is involved in, it can no longer recommend that the Commission accept
12 such projects into NSP's North Dakota jurisdictional costs. The Commission should send
13 in this proceeding a strong signal to both NSP and the Minnesota Commission that North
14 Dakota will no longer tolerate projects that are uneconomical and, therefore, not in the
15 best interests of North Dakota customers.

16 **Q. WHAT HIGH COST PPAS DO YOU RECOMMEND BE EXCLUDED FROM**
17 **THE NORTH DAKOTA JURISDICTIONAL COSTS?**

1 A. Best Power, Outland Solar, FibroMinn, Laurentian Energy Authority I, St. Paul
2 Cogeneration, KODA Energy LLC, Adams, Danielson Wind Farm, Grant County Wind,
3 LLC, North Community Turbines, North Wind Turbines, Ridgewood Power Partners
4 LLC, Uilk Wind Farm, Valley View Transmission, Winona County Wind, Community
5 Wind South, and Moraine Wind II.

6 **Q. WHY DO YOU RECOMMEND THAT NORTH DAKOTA CUSTOMERS NO**
7 **LONGER PAY THE COSTS OF THESE PPAs?**

8 A. With the exception of the Community Wind South and Moraine Wind II projects, all of
9 the other projects are priced over \$60 per MWH. A number of these high priced projects
10 are MN CBED projects. North Dakota customers shouldn't have to pay for high priced
11 Minnesota contracts that are designed to benefit local Minnesota communities. There are
12 also solar projects in this mix. Solar has not been shown to be cost effective in most
13 states and NSP's current solar PPAs are not an exception to this. There are also projects
14 in this mix that have Minnesota legislative mandated prices which again, should not be
15 the responsibility of North Dakota customers. In looking at the Community Wind South
16 and Moraine Wind II projects, while these are below the \$60 per MWH cut off, the PPAs
17 were approved at a time when the costs were considered above market. The Minnesota
18 Commission reluctantly approve both of these contracts because of prior commitments
19 which should not be the responsibility of ND customers.

20 **Q. ARE THERE ANY SILVER LININGS IN THE ADVOCACY STAFF'S**
21 **POSITIONS ON PPAs?**

22 A. Yes. The Commission has not yet allowed recovery for the Prairie Rose PPA in the fuel
23 clause. While the Company claims that it filed an ADP and recovery should be allowed,

1 the Company didn't file the ADP until early 2012 in spite of signing the contract in mid-
2 2011 and obtaining Minnesota Commission approval a few months later. While the
3 Company claims that it did nothing wrong, Advocacy Staff notes that the Company later
4 promised to file ADPs within 30 days of making filings in Minnesota. Advocacy Staff
5 reminds the Company that in a February 5, 2013 letter to the Minnesota Commission they
6 stated that they have enough RECs through 2020 to comply in all states. And because the
7 North Dakota objective is only 10 percent, the Company will be in compliance for many
8 years beyond 2020 without needing new renewable resources.

9 Advocacy Staff also notes that the Prairie Rose project uses a net zero interconnection
10 with the Anson plant. Prairie Rose is 240 MW and Angus Anson is a 405 MW
11 generating station. It is not clear that there is any need for this wind project and that
12 money could not be saved by operating the Angus Anson Plant?

13 In spite of these concerns and the fact that customers are currently receiving benefits by
14 not including this contract currently in the fuel clause, Staff believes over the long run the
15 project will be acceptably priced and reasonable. Staff recommends its recovery in the
16 fuel clause going forward once final rates are approved in this case. The Company
17 should not, however, be allowed recovery for the costs prior to the conclusion of this case
18 considering that the ADP was not timely and the project is more expensive than current
19 prices.

20 **NSP'S CLASS COST OF SERVICE**

21 **Q. HAVE YOU EXAMINED NSP'S METHODS AND PROCEDURES UNDERLYING**
22 **ITS ASSIGNMENT OF COSTS TO THE NORTH DAKOTA RATE CLASSES?**

1 A. Yes. NSP’s assignment of the North Dakota jurisdictional costs to its North Dakota rate
2 classes is presented and summarized in Schedules 3-5 of Exhibit___(MAP-1), the Direct
3 Testimony of Michael A. Peppin. NSP’s class cost of service methods and procedures are
4 set forth in Schedule 2 of Exhibit ___(MAP-1). I have also examined the electronic files
5 which calculate the class costs assignments and allocations that are presented and
6 summarized in Schedule 3, the workpapers to those files, and NSP system planning
7 documents.⁶

8 **Q. PLEASE BRIEFLY SUMMARIZE NSP’S CLASS COST OF SERVICE METHODS**
9 **AND PROCEDURES.**

10 A. NSP takes the standard three-step approach to class cost assignment of functionalizing,
11 classifying, and then directly assigning or allocating costs , as appropriate, the North Dakota
12 jurisdictional costs to its customer classes. NSP begins by assigning individual cost items to
13 operational functions, i.e., generation, transmission, distribution, or customer. Within each
14 function individual cost items are then classified as to cost drivers, i.e., capacity required,
15 energy delivered, or customers served. NSP classifies generation plant costs as capacity-
16 driven or energy-driven using ratios based on current replacement costs for each type of
17 generation. In addition, the capacity-driven plant costs are further separated into summer
18 and winter components using an average and excess analysis. Transmission costs and
19 distribution substation and transformer costs are classified as capacity-driven. Distribution
20 primary line, secondary facilities, and services costs are classified into capacity and
21 customer components using the Minimum Distribution System (MDS) method.
22 Distribution metering and customer service costs are classified as customer-driven. Finally,
23 specific customer-dedicated cost items are directly assigned, while the remainder of the

⁶ Responses to NDPSC 6-013 – 6-016 and 1-019.

1 classified cost items are allocated to the customer classes using allocations factors that
2 reflect the classes' cost-causative characteristics, i.e., class kW demand for costs classified
3 as capacity-driven, class kWh delivered for costs classified as energy-driven, and number of
4 customers for costs classified as customer-driven. Exhibit KRP-5 reproduces pages from
5 Schedule 2 that show NSP's cost classification matrix, list and describe the allocators used,
6 and list the customer classes used.

7 **Q. WHAT IS YOUR ASSESSMENT OF NSP'S CLASS COST OF SERVICE**
8 **METHODS AND PROCEDURES?**

9 A. NSP's class cost of service methods and procedures are conceptually in accordance with the
10 principles enunciated in the NARUC Electric Utility Cost Allocation Manual. There are
11 theoretical issues regarding the determination of capacity and energy components of
12 generation plant costs and the determination of capacity/customer components of
13 distribution plant costs. Most of these issues are a matter of whether class contributions to
14 system diversity are accurately reflected in NSP's capacity/demand allocators. Resolution
15 of these issues, however, would require detailed studies and analyses of NSP's system that I
16 have not undertaken. I found no overt indications of problems in NSP's class cost of service
17 results.

18 **RATE DESIGN**

19 **Q. HAVE YOU EXAMINED NSP'S PROPOSED RATE DESIGN?**

20 A. Yes. NSP's rate design for the North Dakota jurisdiction is presented and summarized in
21 pages 3-16 and Schedules 2-8 of Exhibit___(SVH-1), the Direct Testimony of Steven V.

1 Huso and the proposed tariff sheets provided in NSP’s application. I have also examined
2 the electronic files which calculate NSP’s proposed rates and the workpapers to those files.⁷

3 **Q. PLEASE BRIEFLY SUMMARIZE NSP’S CLASS COST OF SERVICE METHODS**
4 **AND PROCEDURES.**

5 A. NSP proposes to distribute revenue responsibility to the Residential and C&I classes based
6 on full cost of service. For the Lighting classes, NSP proposes what it characterizes as “a
7 modest movement to cost,” which results from its proposed reduction in the range of cost
8 differentials for the Lighting classes.⁸ As regards rate structure, NSP proposes no changes
9 to its current rate schedules,⁹ but does propose changes to the level of the individual
10 components. Specifically, NSP proposes to move the customer charges closer to cost and a
11 relative reduction in the energy charges for the Residential and Non-Demand C&I schedules
12 and to increase demand charges relative to energy and fuel costs charges for the C&I
13 Demand schedules. For the Lighting schedules NSP proposes a significant increase in the
14 Full Service schedule charges, a very slight increase in the Energy schedule charges, and no
15 increase in the Protective schedule charges.

16 **Q. WHAT IS YOUR ASSESSMENT OF NSP’S PROPOSED REVENUE**
17 **RESPONSIBILITY DISTRIBUTION?**

18 A. The cost of service study results demonstrate that the Residential and C&I classes under the
19 current rates are very close to full cost recovery, while the Lighting classes fall significantly
20 short of full recovery.¹⁰ Bringing the lighting classes to full recovery would, as Mr. Huso

⁷ Responses to NDPSC 7-001 – 7-009.

⁸ Page 5, lines 9-15 of Exhibit____(SVH-1).

⁹ Page 6, lines 15-169-15 of Exhibit____(SVH-1).

¹⁰ Exhibit____(MAP-1), Schedule 3.

notes, result in significant rate shock to the Full Service subclass.¹¹ My recommendation is that NSP’s proposed revenue responsibility distribution be adopted by the Commission and that the revenue requirement approved in this proceeding be distributed to the classes in proportion to the revenue responsibility proposed in Table 2 of Mr. Huso’s testimony.¹²

TABLE 2 - REVENUE RESPONSIBILITY DISTRIBUTION

Class	NSP 2013 Proposed Revenue (000) /1	Percent Distribution
Residential	\$76,777	38.5%
Non-Demand	12,537	6.3%
C&I Demand	108,334	54.3%
Lighting	1,948	0.9%
Total	\$199,597	100.0%

/1: Source – Table 2, page 6 of Exhibit__ (SVH-1)

Q. WHAT IS YOUR ASSESSMENT OF NSP’S PROPOSED RATE STRUCTURE AND PROPOSED RATE COMPONENT MODIFICATIONS?

A. Conceptually, the proposed modifications, all of which move customer and demand rate components towards full cost recovery, are appropriate and wholly consistent with the goal of having rate components in fact reflect full cost of service and thereby send proper price signals to customers. NSP’s current rate structure, however, is overly complex, produces component rate distinctions not clearly based on cost and, as presented in NSP’s tariff, virtually incomprehensible.

Q. PLEASE GIVE SOME EXAMPLES OF HOW THE RATE STRUCTURE IS OVERLY COMPLEX.

¹¹ Page 14, lines 14-27, Exhibit__ (SVH-1).

¹² Responses to NDPSC 7-001 – 7-009.

1 A. In Exhibit KRP-6 I have constructed a matrix of NSP's North Dakota rate classes versus rate
2 structure components and rider applications as presented in NSP's Tariff No. 2. What this
3 matrix reveals is that NSP has effectively 30 rate classes that are distinguished from each
4 other by rate structure and/or, in the case of classes with the same structure, different rates.
5 Examples of the latter are the Residential classes which have different customer charges
6 depending on whether the customer is served by underground or overhead facilities. In
7 Exhibit KRP-7 I have constructed a matrix showing the charges for the various rate
8 components of the rate classes shown in Exhibit KRP-7. Of these 30 rate classes, four have
9 no customers (D19, D 34, D62, and D63). Of the four Residential Time of Use rate classes,
10 two have, respectively 1 and 2 customers (D02Res and D02 Rsh) and two have,
11 respectively, 9 and 15 customers (D04Res and D04Rsh). The two D02 rate classes,
12 standard and space heating, are distinguished by (1) energy charges, which is consistent with
13 cost causation and (2) customer charge, which is not consistent with cost causation.
14 Similarly, the two D04 rate classes, standard and space heating, are distinguished by (1)
15 energy charges, which is consistent with cost causation and (2) customer charge, which is
16 not consistent with cost causation. Given the number of customers that have selected the
17 Residential Time of Use rate classes over the regular Residential rate schedules, I question
18 whether even the time of day energy charges reflect the actual cost of service. The
19 customer charge situation is similar with regard to the four regular Residential rate
20 schedules, where the customer charges differ between standard, underground and space
21 heating and also the customer charges for the Residential Time of Day rate classes. On the
22 basis of which I question whether any of Residential rate class customer charges can be said
23 to be cost based, given that the class cost study develops costs for a single Residential

1 customer class without regard of the rate structure underlying the eight residential rate
2 classes. A similar situation arises with regard to the twelve commercial rate classes are
3 elaborated upon just three customer classes in the class cost of service study.

4 **Q. PLEASE GIVE SOME EXAMPLES OF THE INCOMPRESIBILITY OF THE**
5 **TARIFF.**

6 A. “Commercial” and “non-residential”, which are equivalent terms, are used indiscriminately
7 to no discernible purpose in the tariff. Similarly “Oct-May” and “Other Months”, which are
8 equivalent terms, are used indiscriminately to no discernible purpose in the tariff. There is
9 no clear indication in the tariff that the Energy Controlled Service Rider applies to rate
10 schedule D21. The rider tariff sheets lack specific tariff sheet references to the applicable
11 rate schedule tariff sheets and the rate schedule tariff sheets lack specific tariff sheet
12 references to the rider tariff sheets. There are a large number of technical terms used in the
13 tariff sheets that are nowhere defined (e.g., Tier 1, Tier 2, secondary, primary, transmission,
14 transmission transformed, disconnecting means, control period, single phase, three phase,
15 etc). There is an apparently arbitrary mixture of rate component charges that are stated in
16 either dollars or cents. All of this turns reading the tariff into a task akin to biblical exegesis.

17 **Q. WHAT ARE YOUR RECOMMENDATIONS REGARDING RATE STRUCTURE**
18 **AND TARIFF NDPSC NO. 2?**

19 A. NSP should overhaul its rate structure, reducing the number of rate classes and redesign its
20 class cost study so as to directly support the simplified rate structure and improve the
21 comprehensibility of the tariff in the ways discussed above. As a practical matter, it is not
22 possible to affect such an overhaul within this proceeding. As a consequence my
23 recommendation to the Commission is that it direct NSP to eliminate the rate classes for

1 which it has no North Dakota customers, eliminate the Residential Time of Day rate classes,
2 and eliminate the customer charge distinction between standard, underground and space
3 heating customer charges purposes of this proceeding. I also recommend that the
4 Commission direct NSP to undertake at the conclusion of this proceeding to simplify its rate
5 structure and align its class cost study with the simplified rate structure. As regards the
6 tariff, I recommend that the Commission direct NSP to substitute plain language for
7 technical terms wherever possible in the tariff, include a section defining in plain language
8 the technical terms that are used, and place specific tariff sheet references where ever rate
9 schedules and riders make reference to other riders of rate schedules.

10
11 The Commission should also direct NSP to remove its Account History Charge from its
12 tariff as it doesn't conform to the Commission Administrative Rules: 69-09-02-02.1.

13 **TRANSMISSION COST RECOVERY (TRC) TRACKER**

14 **Q. PLEASE DESCRIBE NSP'S TRANSMISSION COST RECOVERY TRACKER.**

15 A. NSP witnesses McCarten and Heuer present NSP's proposed Transmission Cost Recovery
16 (TRC) tracker.¹³ The TRC is a hybrid cost tracker designed to recover both (1) transmission
17 investment and operating expenses associated with new or modified electric transmission
18 facilities that are not included in rate base in this proceeding and (2) federally regulated
19 transmission costs for MISO facilities that increase regional transmission capacity or
20 reliability. On pages 1 and 2 of Schedule 22 of Exhibit ___(AEH-1), Ms Heuer presents an
21 example of the calculation of the tracker revenue requirement. The revenue requirement for
22 each transmission project is forecasted on a total company basis and a portion then allocated
23 to NSP's North Dakota jurisdiction. The revenue requirement includes calculation of

¹³ McCarten Direct at 3; Heuer Direct at 84-94; Exhibit ___(AEH-1) Schedule 22.

1 separate debt and equity return components to which are added various income statement
2 items. The jurisdictional revenue requirements for individual projects are then summed and
3 netted against forecast revenues received under MISO 26 and 26A tariffs.

4 **Q. PLEASE DESCRIBE THE SURCHARGE THROUGH WHICH NSP PROPOSES**
5 **TO RECOVER TRANSMISSION COSTS.**

6 A. Ms Heuer presents an example calculation of the surcharge on page 3 of Schedule 22 of
7 Exhibit ___(AEH-1) and NSP witness Huso presents the rider tariff page. The surcharge is
8 a single per kWh charge applicable to all customer classes that is calculated by dividing the
9 forecast net revenue requirement by the forecast jurisdictional sales kWh. The tariff page
10 presented by witness Huso reflects a single \$0.000000 per-kWh charge applicable to all
11 classes. NSP intends separately to file later this year for approval of a non-zero surcharge
12 covering unspecified transmission investments to be effective January 1, 2014.¹⁴

13 **Q. CAN YOU BRIEFLY DESCRIBE THE REGULATORY STATUS OF COST**
14 **RECOVERY TRACKERS?**

15 A. While trackers depart from the standard regulatory model in very important ways that result
16 in a reduction of the utility's risk, they are not new to the world of regulated utilities. A
17 succinct summary of the regulatory pros and cons of trackers can be found in a 2009
18 whitepaper from the National Regulatory Research Institute¹⁵, which I have included as
19 Exhibit KRP-8 to my testimony. In the past trackers have been instituted only under
20 extraordinary circumstances which Commissions have noted in justifying departures from
21 the traditional regulatory model. There are two types of tracker. The first and older type of
22 tracker is an expense tracker. Examples of extraordinary cost circumstances justifying a

¹⁴ Huso Direct at 15.

¹⁵ "How Should Regulators View Cost Trackers," National Regulatory Research Institute, September 2009.

1 departure from the traditional model have been costs that: (1) are outside the control of a
2 utility; (2) are unpredictable and volatile; or (3) are substantial and recurring. In the electric
3 industry the classic examples of this kind of tracker are the ubiquitous fuel adjustment
4 clauses. These clauses recognize that the electric generation fuel (gas, petroleum, and coal)
5 commodity costs are substantial, unpredictable, volatile, and beyond the control of utility
6 management. The other and more recent type is an investment or capital expenditure
7 tracker. Recently, capital expenditure trackers have been accepted in a number of
8 jurisdictions for recovery of “infrastructure investments.” However, Commissions have
9 generally approved investment trackers only after a showing that: (1) the tracker targets
10 incremental investment; (2) the tracker is needed; (3) the tracker will address the identified
11 need; and (4) the tracker represents a quantifiable benefit to ratepayers.

12 **Q. ARE THERE STATUTORY PROVISIONS IN NORTH DAKOTA THAT ARE**
13 **RELEVANT TO THE PROPOSED TRC TRACKER?**

14 A. Yes. Section 49-05-04.3 of the North Dakota Century Code provides that “[t]he
15 commission may approve, reject, or modify a tariff filed under section 49-05-06 which
16 provides for an adjustment of rates to recover jurisdictional capital and operating costs
17 incurred by a public utility for new or modified electric transmission facilities.”¹⁶ The tariff
18 must:

- 19 a. Allow the public utility to recover on a timely basis its investment and
20 associated costs for new or modified electric transmission facilities not reflected
21 in the utility's general rate schedule;
22
23 b. Allow a return on the public utility's investment made for new or modified
24 electric transmission facilities at the level approved in the utility's most recent
25 general rate case;
26
27 c. Provide a current return on construction work in progress for new or modified

¹⁶ N.D.C.C. 49-05-04.3, sub. 1.

1 electric transmission facilities, provided the cost recovery from retail customers of
2 the allowance for funds used during construction is not sought through any other
3 means; and

4
5 d. Terminate cost recovery after the public utility's costs for new or modified
6 electric transmission facilities have been recovered fully or have been reflected in
7 the utility's general rate tariffs.
8

9 The rate adjustment, i.e., surcharge, under the tariff must be accompanied by:

10 a. A description and quantification of the costs incurred by the public utility for
11 new or modified electric transmission facilities which are subject to recovery;

12
13 b. A schedule for implementation of the applicable transmission facility projects;

14
15 c. Calculations to establish that the rate adjustment is consistent with the terms of
16 the tariff;

17 **Q. WHAT IS YOUR ASSESSMENT OF NSP'S TRC TRACKER PROPOSAL?**

18 A. Based on my review of the materials presented by Ms. Heuer and Mr. Huso and received in
19 discovery,¹⁷ NPSM's proposal is premature because it is incomplete. The Section 49-05
20 statutory authority cited by NSP clearly requires that the tracker application to the
21 Commission be documented by quantification of the costs proposed for inclusion, a
22 schedule for implementation the costs, and calculation of the rate adjustment that would
23 result from those costs. NSP states it intends to make a filing later this year that will
24 presumably include these items, but has not provided them here.

25 **Q. BASED ON THE INFORMATION NSP DID SUBMIT IN THIS PROCEEDING**
26 **WHAT IS YOUR ASSESSMENT OF THE PROPOSED TRACKER?**

27 A. As regards to the operating expense portion of the TRC, the transmission operating expenses
28 NSP proposes to include in the TRC do not meet three of the four the criteria for inclusion in
29 a tracker. Transmission operating expenses are not unpredictable, not volatile, and not
30 beyond the control of management. While it is not possible at this point to determine

¹⁷ NSP responses to NDPSC 6-010, 6-011, and 6-012.

1 whether the operating expenses would be substantial, because NSP has not provided a
2 quantification of those expenses, measured against NSP's total transmission operating
3 expenses, the operating expenses are not likely to be substantial. As regards the investment
4 portion of the TRC, the type of transmission investment NSP proposes to include in the
5 TRC is appropriate for treatment in tracker providing it is shown that the investment is (1)
6 incremental, (2) needed, (3) will meet the identified need, and (4) that tracker recovery will
7 provide a benefit to ratepayers over revenue requirement recovery.

8 **Q. WHAT ARE YOUR RECOMMENDATIONS REGARDING THE TRC**
9 **PROPOSAL?**

10 A. I recommend that the Commission defer any consideration of the TRC in this proceeding.
11 On the assumption that NSP will file an application at some later time that does comport
12 with the statutory authority and in the interest of the Commission's most efficient
13 consideration of such an application, I also recommend that the Commission direct NSP to
14 file with any such application analyses demonstrating that the investment costs and
15 operating expenses proposed meet the criteria for inclusion in a tracker.

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

17 A. Yes.