

BEFORE THE OFFICE OF ADMINISTRATIVE HEARINGS
FOR THE MINNESOTA PUBLIC UTILITIES COMMISSION
STATE OF MINNESOTA

In the Matter of the Request by Minnesota Power
For a Certificate of Need for the
Great Northern Transmission Line

OAH Docket No. 65-2500-31196
MPUC Docket No. E-015/CN-12-1163

Exhibit _____

Rebuttal Testimony and Exhibits of

DAVID J. MCMILLAN

October 24, 2014

MR. DAVID J. MCMILLAN

OAH Docket No. 65-2500-31196

MPUC Docket No. E-015/CN-12-1163

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1 **I. INTRODUCTION**

2 **Q. Please state your name and business address.**

3 A. My name is David J. McMillan and my business address at Minnesota Power is
4 30 West Superior Street, Duluth, Minnesota 55802.

5 **Q. What are your current positions with Minnesota Power and ALLETE?**

6 A. I am the Executive Vice President – Minnesota Power and Senior Vice President –
7 External Affairs – ALLETE.

8 **Q. Have you previously filed testimony in this proceeding?**

9 A. Yes. I filed Direct Testimony providing an overview of Minnesota Power’s
10 Certificate of Need Application for the Great Northern Transmission Line (also
11 “Project”) and the Company’s overall approach to this Project, a discussion of the
12 Project ownership and Project participants, a discussion of the potential retail rate
13 impacts of the Project on Minnesota Power’s customers, and a summary of the key
14 factors supporting the issuance of a Certificate of Need for this Project.

15 **Q. What is the purpose of your Rebuttal Testimony?**

16 A. My Rebuttal Testimony addresses certain matters raised in the testimonies of the
17 two other parties filing Direct Testimony in this proceeding – the Department of
18 Commerce (“Department”) and the Large Power Intervenors (“LPI”). Residents
19 and Ratepayers Against Not-so-Great Northern Transmission (“RRANT”) did not
20 file any testimony. The Department filed testimony of Dr. Rakow and Mr. Shah.

1 After reviewing Mr. Shah’s testimony, Minnesota Power sees no need for
2 correction or other comment. Department witness Dr. Stephen Rakow and LPI
3 witness Lane Kollen do raise certain matters or provide recommendations that
4 require responses. Specifically, I will address the following matters raised by Dr.
5 Rakow:

- 6 • An update on the status of the Keeyask and Conawapa generating stations
7 in Manitoba, as well as an update on the Canadian portion of the new tie-
8 line that will meet the Project at the United States-Canadian border;
- 9 • The request for clarification on certain ownership and financial
10 responsibility issues;
- 11 • Further discussion of Minnesota Power’s intentions with respect to
12 recovery of its portion of the capital costs of the Project; and
- 13 • The request that the Minnesota Public Utilities Commission
14 (“Commission”) order Minnesota Power to use the Commission’s
15 externality values in all future Certificates of Need.

16 I will also address the following matters discussed in Mr. Kollen’s testimony:

- 17 • His recommendation that the Commission make the granting of a
18 Certificate of Need for the Project conditioned upon Commission approval
19 of the 133 MW Energy Sale Agreement and Energy Exchange Agreement

1 (collectively, the “133 MW Renewable Optimization Agreements”)
2 between Minnesota Power and Manitoba Hydro;

- 3 • The recommendation to put a “hard cap” on total costs of \$750 million in
4 “as spent” dollars and that the Commission “ensure” that ratepayers are
5 only obligated for 28.3% of the total costs of the Project;
- 6 • His recommendation that the Commission require allowance for funds used
7 during construction (“AFUDC”) treatment of construction costs during the
8 construction period;
- 9 • The recommendation to require rider recovery of the Project costs, rather
10 than recovery through base rates; and
- 11 • His recommendation that the Commission address inter-class subsidy issues
12 by allocating costs based on base revenues excluding fuel or other riders.

13 **Q. Do other Minnesota Power witnesses address any matters raised by other**
14 **witnesses?**

15 A. Yes. Minnesota Power witness Donahue will address certain other items
16 discussed by Dr. Rakow.

1 **II. RESPONSE TO DR. RAKOW**

2 **Q. Please provide an update regarding the status of activities in Manitoba**
3 **concerning new generating stations and the Canadian portion of the new tie-**
4 **line.**

5 A. As I discussed in my Direct Testimony, while Minnesota Power is developing the
6 Project, Manitoba Hydro is simultaneously developing the Canadian portion of
7 these major new transmission facilities, along with the construction of the
8 695 MW Keeyask Generating Station, being undertaken by the Keeyask
9 Hydropower Limited Partnership (“KHLP”) -- a partnership between the
10 Tataskweyak Cree Nation, War Lake First Nation, York Factory First Nation, Fox
11 Lake Cree Nation, and Manitoba Hydro to develop this facility in northern
12 Manitoba.

13 The Manitoba-Minnesota Transmission Line Project (“MMTP”) is the Canadian
14 portion of the new 500 kV transmission line that will interconnect with the Great
15 Northern Transmission Line. The MMTP is scheduled to be placed in service in
16 mid-2020. On July 2, 2014, the Province of Manitoba accepted the
17 recommendation from the Manitoba Public Utilities Board that Manitoba Hydro
18 should proceed with developing the MMTP, subject to further federal and
19 provincial regulatory approvals. Manitoba Hydro has completed two rounds of
20 public engagements and a preferred route has been selected that will be subject to

1 a final round of public engagement scheduled to commence in January 2015.
2 Feedback from the final round of public engagement along with environmental
3 assessment work will be utilized by Manitoba Hydro to finalize the route selection
4 and complete the regulatory submissions by the summer of 2015.

5 Regarding Keeyask, Manitoba Hydro is managing the construction of the project
6 and will be responsible for operating the generating station on behalf of the KHLP.
7 Manitoba Hydro and the KHLP continue to work towards meeting a 2019 in-
8 service date for the Keeyask Generating Station and in this regard a number of key
9 milestones have already been achieved, including:

- 10 • In March 2014, the general civil contract was awarded to a limited
11 partnership between Bechtel Canada Co., Barnard Construction of Canada
12 Ltd., and EllisDon Civil Ltd. The general civil contract includes rock
13 excavation, concrete for the powerhouse and spillway, earthen structures,
14 electrical and mechanical work and the construction and removal of
15 temporary cofferdams to manage river flows during construction.
- 16 • On July 2, 2014, the Province of Manitoba issued an environmental license
17 to the KHLP for the construction of the 695 MW Keeyask Generating
18 Station. The Province's decision was based on favorable recommendations
19 received from (i) a special panel of the Manitoba Public Utilities Board
20 responsible for reviewing Manitoba Hydro's development plans and (ii) the

1 Clean Environment Commission that was responsible for performing an
2 independent environmental review of the Keeyask project.

- 3 • On July 16, 2014, the KHLP officially commenced construction of the
4 Keeyask Generating Station as work started on the quarry cofferdam.
5 Materials from the quarry will be used to construct other cofferdams needed
6 to create dry working areas within the riverbed and used in the concrete
7 required for construction of the powerhouse and spillway.

8 Finally, both our Application and my Direct Testimony discussed the potential
9 development of the 1,485 MW Conawapa generating station, with an in-service
10 date of approximately 2026. As I noted in my Direct Testimony, Manitoba has not
11 determined to move forward with Conawapa at this time. On July 2, 2014, the
12 Province of Manitoba accepted the Public Utilities Board recommendation that
13 pre-construction expenditures planned for the Conawapa Generating Station will
14 be frozen until more export sales are confirmed and an updated business case is
15 brought back for independent review. The Province of Manitoba has asked
16 Manitoba Hydro to advance its efforts on firming up additional export power sales
17 and has confirmed that Conawapa remains vitally important to Manitoba's long-
18 term energy future.

1 **Q. At pages 30 – 36 of his Direct Testimony, Dr. Rakow discusses the intended**
2 **ownership and financial responsibilities associated with the Project. Has he**
3 **fairly described these matters?**

4 A. In general, yes. As Dr. Rakow notes, while Minnesota Power will have 51%
5 ownership of the Project, the Company will be responsible for financing just 46%
6 of the costs, due to a 5% Contribution in Aid of Construction (“CIAC”) to be paid
7 by Manitoba Hydro. Moreover, Manitoba Hydro will cover an additional 17.7%
8 of the financial responsibility for the construction costs of the Project through
9 payment of the Monthly Must Take Fee included in the 133 MW Renewable
10 Optimization Agreements discussed in my Direct Testimony, bringing Minnesota
11 Power and its ratepayers’ ultimate financial responsibility for the capital expenses
12 associated with the Project down to 28.3%. Dr. Rakow displays this revenue
13 responsibility, and the other components making up the full 100% revenue
14 requirements responsibility, in his Table 3 on page 36 of his Direct Testimony
15 (Mr. Donahue addresses this Table in his Rebuttal Testimony, including a
16 necessary clarification regarding operating and maintenance cost responsibility).
17 Dr. Rakow also requested confirmation or clarification of certain items in
18 Minnesota Power’s Rebuttal Testimony.

1 **Q. On what matters did Dr. Rakow seek confirmation or clarification?**

2 A. First, Dr. Rakow sought confirmation of the manner in which Minnesota Power
3 intends to handle the 17.7% share of the capital cost revenue requirement
4 responsibility to be covered by Manitoba Hydro through the scheduling fee
5 included in the 133 MW Renewable Optimization Agreements. At page 33 of his
6 testimony, Dr. Rakow accurately states that Minnesota Power intends to propose
7 that this 17.7% share of the capital costs be placed into rate base or into the
8 Transmission Cost Recovery Rider, with the Monthly Must Take Fee paid by
9 Manitoba Hydro applied as an offset.

10 Dr. Rakow also requested that Minnesota Power discuss how it envisions cost
11 recovery would work in the event Manitoba Hydro assigns its minority ownership
12 in the Project to another Minnesota Midcontinent Independent System Operator,
13 Inc. (“MISO”) transmission owner, that the Company confirm the revenue
14 requirements responsibility to be borne by Minnesota Power ratepayers, and that
15 the Company clarify certain operations and maintenance cost recovery matters.
16 Mr. Donahue addresses these issues in his Rebuttal Testimony.

17 Finally, Dr. Rakow requested that the Commission order Minnesota Power to use
18 the Commission’s externality values in all future Certificates of Need. Minnesota
19 Power will apply these values in future Certificates of Need. Minnesota Power

1 supports Dr. Rakow's conclusions that applying externality values to the Project
2 demonstrates additional benefits of the Project.

3 **III. RESPONSE TO MR. KOLLEN**

4 **Q. LPI witness Mr. Kollen does not challenge the need for the Project, but**
5 **recommends that Commission approval of the Certificate of Need be**
6 **“contingent” upon Commission approval of the 133 MW Renewable**
7 **Optimization Agreements between Minnesota Power and Manitoba Hydro**
8 **and Federal Energy Regulatory Commission (“FERC”) approval of the**
9 **Facilities Construction Agreement (“FCA”). How does Minnesota Power**
10 **respond?**

11 A. The 133 MW Renewable Optimization Agreements provide substantial benefits to
12 Minnesota Power and its ratepayers and are a central piece of the overall benefits
13 of the Project. These 133 MW Renewable Optimization Agreements will be filed
14 with the Commission in the very near future and Minnesota Power will submit its
15 petition for approval of the 133 MW Renewable Optimization Agreements to the
16 record of this docket once that filing occurs.

17 The FCA also provides substantial benefits to Minnesota Power and its ratepayers
18 in the form of the 5% CIAC discussed above. As Mr. Donahue discusses, the
19 FCA has now been filed with FERC.

1 Given the importance of both of these 133 MW Renewable Optimization
2 Agreements to the overall Project and the Project economics, Minnesota Power
3 has no objection to requiring their approval.

4 **Q. Mr. Kollen also recommends that the Commission establish a “hard cap” in**
5 **“as spent” dollars on the overall capital cost of the Project as estimated by**
6 **Mr. Kollen and that the Commission ensure that ratepayers are only**
7 **obligated to pay 28.3% of that amount. Is such a “hard cap” reasonable?**

8 A. No. A cost “cap” of the type suggested by Mr. Kollen is not appropriate as part of
9 a Certificate of Need approval and goes beyond any past Commission orders.

10 First, Minnesota Power has provided a range of capital costs as set forth in Mr.
11 Donahue’s testimony. This range is appropriate given that a final route and any
12 route permit conditions have not been decided for this Project. Second, the capital
13 cost caps recently imposed by the Commission for Minnesota Power’s Boswell 4
14 Project as well as for other transmission projects that require a Certificate of Need
15 are not “hard caps,” as recommended by Mr. Kollen but merely act to limit
16 Minnesota utilities’ ability to obtain current cost recovery outside of a general rate
17 case. For example, in the Commission’s November 4, 2013 order approving
18 Minnesota Power’s mercury plan to retrofit Boswell Unit 4 in Docket No. E-
19 015/M-12-920, the Commission stated: “To protect ratepayers from potential cost
20 overruns, the Commission will cap the total amount that Minnesota Power may

1 recover through the Boswell 4 rider at the amount stated in the Company’s
2 petition.” Order at 7. The Commission capped only the amount Minnesota Power
3 may recover through the rider; it did not impose a cap on total recovery, including
4 potential rate case recovery.

5 Second, to my knowledge, the Commission has not imposed a cost-cap as part of
6 the Certificate of Need approval and it is not reasonable to preemptively limit
7 future cost recovery as a part of this docket. The Commission will continue to
8 have the ability to assess the prudence of the costs incurred in developing the
9 Project and does not need to artificially “cap” the costs at this time

10 Third, while the Commission’s past practice of limiting current cost recovery does
11 provide incentives to manage the cost of the Project, Minnesota Power’s larger
12 obligations to limit impacts on customers has driven the development of this
13 Project. The Company’s efforts in this regard include assuring that all benefits
14 from the 133 MW Renewable Optimization Agreements (including environmental
15 benefits, as discussed in Mr. Rudeck’s Direct Testimony) flow through to
16 customers and allocating a significant portion of Project’s capital costs to
17 Manitoba Hydro lessening the impact of the Project on rates. These unique
18 contractual agreements with Manitoba Hydro already provide substantial ratepayer
19 benefit and protection.

1 Finally, Minnesota Power has included standard contingencies in its Project
2 estimates. Given the geography, long-lead time, and length and size of this
3 Project, those are reasonable contingencies and Minnesota Power should not be
4 penalized by a “hard cap” should some of these contingencies prove necessary.

5 **Q. Mr. Kollen further recommends that the Commission not allow a current**
6 **return on Construction Work in Progress (“CWIP”) but instead mandate**
7 **that the Company accrue allowance for funds used during construction**
8 **(“AFUDC”). Is this recommendation appropriate?**

9 **A.** No. Mr. Kollen’s recommendation has several flaws.

10 First, while Minnesota Power has worked to be transparent about cost recovery
11 matters, cost recovery treatment is not an issue that needs to be decided in the
12 Certificate of Need docket. Indeed, it would be premature and inappropriate to do
13 so at this time.

14 Second, under Minnesota Statutes Section 216B.16, subd. 7b, high voltage
15 transmission projects that receive a Certificate of Need are specifically eligible for
16 current cost recovery during construction. The Minnesota Legislature granted
17 utilities this authority to incentivize new transmission construction, such as the
18 Project, in lieu of the old paradigm that prohibited recovery of the costs of a new
19 asset until it was “used and useful” and placed into rate base.

1 Third, a current return on CWIP provides customers a lower overall capital cost.
2 As shown in Ex. ___ (DJM-R), Schedule 1, Minnesota Power estimates the overall
3 capital savings of CWIP treatment to be approximately \$55 million in nominal
4 dollars compared to recording AFUDC. Precluding a current return on CWIP
5 simply delays cost recovery until the Project is in-service. This delay will increase
6 total overall revenue requirements for Minnesota Power’s customers.

7 Fourth, Minnesota Power disagrees with Mr. Kollen’s statement that the Project
8 “has value only after it is constructed and placed in-service.” Given the
9 contractual requirements in the Power Purchase Agreements with Manitoba Hydro
10 and the certainty that those requirements are met, the long lead time it takes to
11 permit and construct a project and the significant capital cost outlay required to
12 construct a 500 kV line, Minnesota Power sees significant value to the Company
13 and its ratepayers prior to the date when the Project is placed in-service. Other
14 benefits from a return on CWIP include reduced rate shock for customers because
15 rate increases are gradually phased in during construction, and improved cash flow
16 for the utility which will in turn support stronger financial ratings and lower
17 capital costs for this Project and all other capital projects.

18 **Q. Does Minnesota Power support Mr. Kollen’s recommendation that the**
19 **Commission only allow rate recovery of Project costs through the**

1 **Transmission Cost Recovery Rider or some other rider, rather than through**
2 **base rates?**

3 A. No. Minnesota Power agrees that the Project will be eligible under Minnesota
4 Statute Section 216B.16, subd. 7b for the Transmission Cost Recovery Rider if the
5 Commission approves the Certificate of Need. Minnesota Power also agrees that
6 the benefits from the Monthly Must Take Fee and other revenues Minnesota
7 Power receives should be credited to ratepayers. However, once the Project is
8 built and in service, better ratemaking outcomes may well be achieved for
9 customers by addressing this major new asset addition through a traditional
10 general rate case. For example, a rate case would re-examine the issue of
11 wholesale/retail allocation and may provide benefits to retail customers. Further,
12 the transmission rider would use Minnesota Power's last approved return on
13 equity ("ROE") rather than re-examining and resetting the appropriate ROE going
14 forward. In addition, from the Company's perspective, under current Commission
15 precedent, utilities are not allowed to recover internal capital costs through rider
16 mechanisms. If the Project must stay in Minnesota Power's transmission rider,
17 there will not be an opportunity to recover these internal costs. Also, if the
18 Commission limits current cost recovery to a set capital range, then Minnesota
19 Power will not have the opportunity to recover any future capital costs.

1 **Q. Mr. Kollen requested the Company provide details of cost allocation, rate**
2 **design and rate impacts on customer classes. Did the Company prepare these**
3 **details?**

4 A. Yes. However, I must first note that the Company does not agree that cost
5 allocations or rate design matters belong in a Certificate of Need proceeding, as I
6 discuss further, below. Nonetheless, in order to be responsive to Mr. Kollen's
7 request, the Company provides information on two alternative examples of cost
8 allocation. For both examples the Company allocates the revenue requirements to
9 the Minnesota retail jurisdiction using the D-02 transmission demand allocation
10 factor from the Company's last rate case. In the first example, the jurisdictional
11 revenue requirements are allocated to the Large Power ("LP") Class and all other
12 Non-LP Classes using the D-02 transmission demand class allocation factors.
13 Under this approach, as Mr. Lane correctly states in his testimony, the greatest
14 percentage increase would fall on the LP Class. The allocation of revenue
15 requirements to jurisdiction and to customer classes under this approach is shown
16 in Ex. __ (DJM-R), Schedule 2, Table 1.

17 The second example was developed after clarifying the Company's understanding
18 of Mr. Kollen's recommendation on allocating revenue requirements. Under this
19 second approach, the jurisdictional revenue requirements are apportioned to
20 customer class on base revenue so that all customer classes have the same average

1 rate increase. The allocation of revenue requirements to jurisdiction and to
2 customer classes for this example is shown in Ex. __ (DJM-R), Schedule 2, Table
3 2.

4 **Q. Would you please explain the rate design for the first example?**

5 A. Yes. As shown in Table 1, the rate design for the LP Class incorporates demand
6 (\$/kW-month) and energy (¢/kWh) adders that recover costs in a manner that
7 preserves existing LP base rate design. Specifically, the LP revenue requirements
8 would be split between demand and energy based on LP's base rate demand and
9 energy revenue split of approximately 60% demand and 40% energy from
10 Minnesota Power's most recent retail rate case. The LP demand rate adder would
11 be calculated as 60% of the projected LP revenue requirement divided by the LP
12 Class Billing Demand (kW-month) from Minnesota Power's most recent budget.
13 The LP energy rate adder will be calculated as 40% of the projected LP revenue
14 requirement divided by the LP energy (kilowatt-hour) sales from Minnesota
15 Power's most recent budget. The rate design for the other Non-LP Classes is
16 calculated as a single average energy-based (¢/kWh) charge consisting of the
17 revenue requirements allocated to the other Non-LP Classes divided by the total
18 energy (kWh) sales of the other Non-LP Classes from Minnesota Power's most
19 recent budget.

1 **Q. Would you please explain the rate design for the second example?**

2 A. Yes. As shown in Table 2, the rate design for the LP Class is identical to the first
3 alternative. For all other Non-LP Classes, the rate design is separate average
4 energy-based ($\text{\$/kWh}$) charge for each class.

5 **Q. What are the estimated rate impacts of the two examples?**

6 A. The estimated rate impacts for all customer classes under the first and second
7 examples are shown for the years 2020, 2021 and 2022 in Ex. __ (DJM-R),
8 Schedule 2, Tables 3 and 4, respectively. Under the first alternative the Company
9 estimates the increase in years 2020, 2021 and 2022 will be 2.96%, 2.63%, and
10 2.53% for residential customers and 4.63%, 4.09%, and 3.94% for LP customers,
11 respectively. In the second alternative the Company estimates the increase for the
12 years 2020, 2021 and 2022 will be 3.98%, 3.54%, and 3.40% for all customer
13 classes.

14 **Q. Finally, does the Company agree with Mr. Kollen that the rate making issues
15 should be decided by the Commission in this case?**

16 A. No. Ratemaking involves both fact and policy decisions best left to future cost
17 recovery proceedings. Again, Mr. Kollen recommends that the Commission
18 essentially pre-determine items that can and will be addressed in subsequent
19 proceedings such as a rate case or a “factor” filing specific to Minnesota Power’s
20 Transmission Cost Recovery Rider. The purpose of this proceeding is to

1 determine whether Minnesota Power has demonstrated the need for the Project,
2 not to address other issues parties may have from past or future proceedings. As I
3 discussed in my Direct Testimony, the Company has met all the criteria necessary
4 for the granting of a Certificate of Need. Therefore, the Company continues to
5 respectfully request that the Commission grant it a Certificate of Need so that it
6 may proceed with the Great Northern Transmission Line Project.

7 **Q. Does this complete your Rebuttal Testimony?**

8 A. Yes.

9

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Exhibit _____ (DJM-R), Schedule 1, Page 1 of 1

Great Northern Transmission Line
Return on CWIP vs. AFUDC (nominal dollars)

Summary of Project Costs assuming a Return on CWIP

| <u>Total Project</u> | | | | |
|----------------------------------|----------------------|---|------------------------------|-----------------------------|
| Capital Expenditures | 749,737,208 | ➔ | Total Project = | 750,556,219 (CapEx + AFUDC) |
| Less MH CIAC | (37,527,811) | | MH CIAC = | 37,527,811 5.00% |
| Less Joint Owner Payments | (367,772,547) | | Joint Owner Responsibility = | <u>367,772,547</u> 49.00% |
| AFUDC | 819,011 | | MP Portion = | 345,255,861 46.00% |

Summary of Project Costs assuming AFUDC

| <u>Total Project</u> | | | | |
|----------------------------------|----------------------|---|------------------------------|-----------------------------|
| Capital Expenditures | 749,737,208 | ➔ | Total Project = | 805,723,778 (CapEx + AFUDC) |
| Less MH CIAC | (37,527,811) | | MH CIAC = | 37,527,811 4.66% |
| Less Joint Owner Payments | (367,772,547) | | Joint Owner Responsibility = | <u>367,772,547</u> 45.64% |
| AFUDC | 55,986,570 | | MP Portion = | 400,423,420 49.70% |

Notes:

- 1/ The Contribution In-Aid of Construction (CIAC) and Joint Owner Payments are made as construction progresses, so AFUDC under the second scenario would only accumulate on Minnesota Power's portion of the total project.
- 2/ Return on CWIP results in an estimated capital savings of \$55,167,559 (55,986,570 - 819,011) compared to recording AFUDC.

Minnesota Power
Great Northern Transmission Line CoN Support
Summary: Revenue Requirements, Cost Allocation and Rate Design
Alternative 1 Based on D-02 Allocator

| | <u>Allocations 1/</u> | <u>2020</u> | <u>2021</u> | <u>2022</u> |
|-------------------------------------|-----------------------|---------------|---------------|---------------|
| <u>Revenue Requirements (\$)</u> | | | | |
| Total Customer Revenue Requirements | 100.00% | 33,083,726 | 29,379,774 | 28,218,155 |
| MN Jurisdiction | 77.57% | 25,663,046 | 22,789,891 | 21,888,823 |
| Large Power | 48.49% | 16,041,968 | 14,245,959 | 13,682,701 |
| All Other Classes | 29.08% | 9,621,078 | 8,543,932 | 8,206,122 |
| <u>2015 Billing Units 2/</u> | | | | |
| Large Power | kW - month | 716,608 | 716,608 | 716,608 |
| | kWh | 6,037,136,000 | 6,037,136,000 | 6,037,136,000 |
| All Other Classes | kWh | 3,245,508,000 | 3,245,508,000 | 3,245,508,000 |
| <u>Billing Factors 3/</u> | | | | |
| Large Power | \$/kW - month | 1.12 | 0.99 | 0.95 |
| | ¢/kWh | 0.106 | 0.094 | 0.091 |
| All Other Classes | ¢/kWh | 0.296 | 0.263 | 0.253 |

Notes:

1/ The D-02 allocator is from MP's 2009 MPUC rate case Docket No. E-015/GR-09-1151.

2/ 2015 budget.

3/ For CoN rate impact using an average demand and energy rate for Large Power. In upcoming cost recovery filing, the LP rate design would be a demand rate adder (\$/kW-month) and an energy adder (¢/kWh). The LP allocated costs are to be split between demand and energy on the 2010 base rate demand and energy revenue split of approximately 60% demand and 40% energy per results of MP's most recent MPUC rate case (Docket No. E015/GR-09-1151). All other retail classes will have an energy adder (¢/kWh).

Minnesota Power
Great Northern Transmission Line CoN Support
Summary: Revenue Requirements, Cost Allocation and Rate Design
Alternative 2 Based on Revenue Allocator

| | 2015 Budgeted kWh /1 | Estimated Current Rate | Estimated Revenue | Percent of Revenue Allocator |
|---|-------------------------|---------------------------|----------------------|---------------------------------|
| Residential | 1,099,130,000 | 9.995 | 109,862,831 | 17.04% |
| General Service | 662,735,000 | 9.990 | 66,209,609 | 10.27% |
| Large Light & Power | 1,425,241,000 | 8.081 | 115,169,623 | 17.87% |
| Large Power | 6,037,136,000 | 5.740 | 346,507,468 | 53.76% |
| Municipal Pumping | 35,985,000 | 9.149 | 3,292,218 | 0.51% |
| Lighting | 22,417,000 | 15.657 | 3,509,779 | 0.54% |
| | | | 644,551,528 | 100.00% |
| | <u>Allocations 2/</u> | <u>2020</u> | <u>2021</u> | <u>2022</u> |
| <u>Revenue Requirements (\$)</u> | | | | |
| Total Customer Revenue Requirements | 100.00% | 33,083,726 | 29,379,774 | 28,218,155 |
| MN Jurisdiction | 77.57% | 25,663,046 | 22,789,891 | 21,888,823 |
| | <u>Allocations 3/</u> | | | |
| Residential | 17.04% | 4,374,227 | 3,884,502 | 3,730,917 |
| General Service | 10.27% | 2,636,159 | 2,341,023 | 2,248,463 |
| Large Light & Power | 17.87% | 4,585,519 | 4,072,139 | 3,911,134 |
| Large Power | 53.76% | 13,796,317 | 12,251,724 | 11,767,314 |
| Municipal Pumping | 0.51% | 131,081 | 116,405 | 111,803 |
| Lighting | 0.54% | 139,743 | 124,098 | 119,191 |
| | | 25,663,046 | 22,789,891 | 21,888,823 |
| <u>Billing Factors</u> | | | | |
| Residential | ¢/kWh | 0.398 | 0.353 | 0.339 |
| General Service | ¢/kWh | 0.398 | 0.353 | 0.339 |
| Large Light & Power | ¢/kWh | 0.322 | 0.286 | 0.274 |
| Large Power | ¢/kWh | 0.229 | 0.203 | 0.195 |
| Municipal Pumping | ¢/kWh | 0.364 | 0.323 | 0.311 |
| Lighting | ¢/kWh | 0.623 | 0.554 | 0.532 |
| <u>LP Factor Demand-Energy Split 4/</u> | | | | |
| | 2015 Budgeted | | | |
| <u>LP Billing Units</u> | | | | |
| | Billing Units /1 | | | |
| kW - month | 716,608 | | | |
| kWh | 6,037,136,000 | | | |
| <u>LP Factors</u> | | | | |
| | \$/kW - month | 0.96 | 0.85 | 0.82 |
| | ¢/kWh | 0.091 | 0.081 | 0.078 |

Notes:

1/ 2015 budget.

2/ The D-02 allocator is from MP's 2009 MPUC rate case Docket No. E-015/GR-09-1151.

3/ Percent of Revenue Allocator shown above, designed to give all classes an equal percentage increase.

4/ For CoN rate impact using an average demand and energy rate for Large Power. In upcoming cost recovery filing, the LP rate design would be a demand rate adder (\$/kW-month) and an energy adder (¢/kWh). The LP allocated costs are to be split between demand and energy on the 2010 base rate demand and energy revenue split of approximately 60% demand and 40% energy per results of MP's most recent MPUC rate case (Docket No. E015/GR-09-1151). All other retail classes will have an energy adder (¢/kWh).

MINNESOTA POWER
Great Northern Transmission Line
Estimated Average Rate Impacts
Alternative 1 Based on D-02 Allocator

| | <u>2020</u> | <u>2021</u> | <u>2022</u> |
|---|--------------|--------------|--------------|
| Minnesota Jurisdictional Revenue Requirement | \$25,663,046 | \$22,789,891 | \$21,888,823 |
| <u>Rate Class Impacts ¹</u> | | | |
| Residential (average current rate, cents/kWh) | 9.995 | 9.995 | 9.995 |
| Increase (cents/kWh) | 0.296 | 0.263 | 0.253 |
| Increase (%) | 2.96% | 2.63% | 2.53% |
| Average Impact (\$ / month) | \$2.40 | \$2.13 | \$2.05 |
| General Service (average current rate, cents/kWh) | 9.990 | 9.990 | 9.990 |
| Increase (cents/kWh) | 0.296 | 0.263 | 0.253 |
| Increase (%) | 2.96% | 2.63% | 2.53% |
| Average Impact (\$ / month) | \$8.24 | \$7.32 | \$7.04 |
| Large Light & Power (average current rate, cents/kWh) | 8.081 | 8.081 | 8.081 |
| Increase (cents/kWh) | 0.296 | 0.263 | 0.253 |
| Increase (%) | 3.66% | 3.25% | 3.13% |
| Average Impact (\$ / month) | \$674.78 | \$599.55 | \$576.75 |
| Large Power (average current rate, cents/kWh) | 5.740 | 5.740 | 5.740 |
| Increase (Demand & Energy Combined) (cents/kWh) | 0.266 | 0.235 | 0.226 |
| Increase (%) | 4.63% | 4.09% | 3.94% |
| Average Impact (\$ / month) | \$133,588 | \$118,235 | \$113,859 |
| Municipal Pumping (average current rate, cents/kWh) | 9.149 | 9.149 | 9.149 |
| Increase (cents/kWh) | 0.296 | 0.263 | 0.253 |
| Increase (%) | 3.24% | 2.87% | 2.77% |
| Average Impact (\$ / month) | \$31.93 | \$28.37 | \$27.29 |
| Lighting (average current rate, cents/kWh) | 15.657 | 15.657 | 15.657 |
| Increase (cents/kWh) | 0.296 | 0.263 | 0.253 |
| Increase (%) | 1.89% | 1.68% | 1.62% |
| Average Impact (\$ / month) | \$1.08 | \$0.96 | \$0.93 |

Notes:

1/ Average current rates are 2015 estimated rates based on Final 2010 TY General Rates in 2009 Rate Case (E-015/GR-09-1151) without riders adjusted to include current rider rates.

Current rider rates include Renewable Resources Rider rates, Transmission Cost Recovery Rider rates, Boswell 4 Emission Reduction Rider rates, current 2014 CPA rate and estimated 2015 FPE.

Average \$/month impact based on 2015 budgeted billing units.

MINNESOTA POWER
Great Northern Transmission Line
Estimated Average Rate Impacts
Alternative 2 Based on Revenue Allocator

| | <u>2020</u> | <u>2021</u> | <u>2022</u> |
|---|--------------|--------------|--------------|
| Minnesota Jurisdictional Revenue Requirement | \$25,663,046 | \$22,789,891 | \$21,888,823 |
| <u>Rate Class Impacts ¹</u> | | | |
| Residential (average current rate, cents/kWh) | 9.995 | 9.995 | 9.995 |
| Increase (cents/kWh) | 0.398 | 0.353 | 0.339 |
| Increase (%) | 3.98% | 3.54% | 3.40% |
| Average Impact (\$ / month) | \$3.22 | \$2.86 | \$2.75 |
| General Service (average current rate, cents/kWh) | 9.990 | 9.990 | 9.990 |
| Increase (cents/kWh) | 0.398 | 0.353 | 0.339 |
| Increase (%) | 3.98% | 3.54% | 3.40% |
| Average Impact (\$ / month) | \$11.07 | \$9.83 | \$9.44 |
| Large Light & Power (average current rate, cents/kWh) | 8.081 | 8.081 | 8.081 |
| Increase (cents/kWh) | 0.322 | 0.286 | 0.274 |
| Increase (%) | 3.98% | 3.54% | 3.40% |
| Average Impact (\$ / month) | \$733.45 | \$651.33 | \$625.58 |
| Large Power (average current rate, cents/kWh) | 5.740 | 5.740 | 5.740 |
| Increase (Demand & Energy Combined) (cents/kWh) | 0.229 | 0.203 | 0.195 |
| Increase (%) | 3.98% | 3.54% | 3.40% |
| Average Impact (\$ / month) | \$114,969 | \$102,098 | \$98,061 |
| Municipal Pumping (average current rate, cents/kWh) | 9.149 | 9.149 | 9.149 |
| Increase (cents/kWh) | 0.364 | 0.323 | 0.311 |
| Increase (%) | 3.98% | 3.54% | 3.40% |
| Average Impact (\$ / month) | \$39.29 | \$34.89 | \$33.51 |
| Lighting (average current rate, cents/kWh) | 15.657 | 15.657 | 15.657 |
| Increase (cents/kWh) | 0.623 | 0.554 | 0.532 |
| Increase (%) | 3.98% | 3.54% | 3.40% |
| Average Impact (\$ / month) | \$2.28 | \$2.03 | \$1.95 |

Notes:

1/ Average current rates are 2015 estimated rates based on Final 2010 TY General Rates in 2009 Rate Case (E-015/GR-09-1151) without riders adjusted to include current rider rates.

Current rider rates include Renewable Resources Rider rates, Transmission Cost Recovery Rider rates, Boswell 4 Emission Reduction Rider rates, current 2014 CPA rate and estimated 2015 FPE.

Average \$/month impact based on 2015 budgeted billing units.