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March 23, 2015

VIA ELECTRONIC FILING

Daniel P. Wolf
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, MN 55101-2147

Re: In the Matter of Minnesota Power's Renewable Resources Rider and 2015 Renewable Factor
Docket No. E015/M-14-962

Dear Mr. Wolf:

Minnesota Power hereby electronically submits its Reply Comments in the above-referenced Docket. An Affidavit of Service is included.

Please contact me at the number above if you have any questions about this filing.

Yours truly,

Susan Ludwig

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

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In the Matter of Minnesota Power's Renewable Resources Rider and 2015 Renewable Factor

Docket No. E015/M-14-962

****

I. INTRODUCTION

On November 10, 2014, Minnesota Power ("the Company") filed a Petition with the Minnesota Public Utilities Commission ("Commission") seeking approval to update cost recovery of incurred investments, expenditures and costs of renewable projects through the Company's Commission-approved Rider for Renewable Resources ("Renewable Resources Rider").

Minnesota Power provides these Reply Comments in response to the Department of Commerce – Division of Energy Resources ("Department") Comments in this Docket filed March 11, 2015.

The Department recommended that the Commission limit the Bison 4 costs included in the Company's Renewable Resource Rider to $337.7 million, require Minnesota Power to credit to revenue requirements all North Dakota Investment Tax Credits ("ND ITCs") used in ALLETE's consolidated North Dakota tax returns, require Minnesota Power to make a new Renewable Resources Rider filing with updated allocators and rates, and require Minnesota Power to file a new Renewable Resources Rider petition by the end of 2015 or demonstrate that the approved rates are still reasonable and will not result in an over recovery during 2016. Further, the Department stated that the Commission may wish to consider ways to mitigate the impact of rate increases on customer bills, possibly by stretching recovery of the tracker balance over a period of two years. The Department also requested that Minnesota Power provide additional information on the loss of a wholesale customer in 2014 and the adjusted allocation factors and proposed rates as requested in the Company's Boswell 4 Emission Reduction Rider (Docket No. E015/M-14-990).

II. DEPARTMENT RECOMMENDATIONS

Minnesota Power appreciates the Department's thorough review of the Renewable Resources Rider and the consensus reached on the cost recovery date for the Thomson hydro project effective January 1, 2015. The Company also appreciates the agreement of many other issues in this Docket. The following discussion addresses the Department's recommendations.

A. Bison 4 Wind Project Costs

The Department recommended that the Commission limit the Bison 4 costs to $337.7 million. As detailed in its September 16, 2014 Reply Comments in the 2014 Renewable Resources Docket,[1] the Company disagrees with the Department's interpretation of the cost cap being any number other than the total project cost as stated in the initial eligibility filing. For Bison 4, this number is $345 million. However, with the project in-service, the final project cost for Bison 4 is now projected to come in below the $337.7 million cap supported by the Department and so this issue will not impact customer rates in this Docket.

B. North Dakota Investment Tax Credits

The Department recommended that the Commission require Minnesota Power to credit to revenue requirements all North Dakota ITCs used in ALLETE's consolidated North Dakota tax returns, not just the credits consumed by Minnesota Power on a stand-alone basis. While Minnesota Power confirms that it will offset future Renewable Resources Rider revenue requirements with ND ITCs once they have been utilized, the Company disagrees that customers should be credited for ND ITCs used by Minnesota Power's affiliates via ALLETE's consolidated North Dakota tax return.

This issue has been extensively discussed in the 2014 Renewable Resources Rider Docket and there is clearly a disagreement between the Department and the Company on how the ND ITCs should be credited to customers. The Company believes it is appropriately following accounting standards and the Commission's decisions in Xcel Energy's Docket No. E002/GR-05-1428.

[1] Docket No. E015/M-14-349.

It is worth noting that neither Minnesota Power, nor any ALLETE subsidiary, utilized any ND ITCs in the period covered by this filing. Additionally, ALLETE is not expected to be able to utilize any ND ITCs until approximately 2018. Therefore, any decision made on the utilization of ND ITCs will have no impact on this current Docket. Since this issue has been extensively discussed in the 2014 Renewable Resources Rider Docket and there is clearly a disagreement between the Department and the Company as discussed below on how the ND ITCs should be credited to customers, Minnesota Power respectfully requests the issue to be resolved by the Commission at a hearing.

The following background may be helpful in examining this issue.

1. <u>ND ITCs Were Not a Driver to Build Wind</u>

From 2005 through 2014, North Dakota offered generous investment tax credits for wind production in order to attract diverse businesses to the state. Although the ND ITCs provided an incentive for wind production, the primary reason that wind was built in North Dakota was the higher wind capacity. As with Minnesota Power, most wind investors in North Dakota have experienced these credits to be far in excess of their North Dakota tax liability and are therefore generally not fully utilizing the credits. The vast majority of Minnesota Power's ITCs are expected to expire unutilized. It is important to note that ND ITC benefits were not a large driver of the cost-effective decision to build wind facilities in North Dakota. Furthermore, the net impact of utilizing ND ITCs for Minnesota Power customers will always be zero, since by definition, the credit is used to offset an income tax expense. The credit offers no benefit unless there is an offsetting income tax expense – an expense which would add to revenue requirements.

2. <u>Minnesota Power Adheres to Accounting Standards</u>

Minnesota Power, along with several other public utilities in Minnesota, files federal consolidated and state unitary income tax returns. The Company has adhered to affiliate interest rules and strives to maintain separation between Minnesota Power and affiliate operations. Minnesota Power follows the Federal Energy Regulatory Commission ("FERC") required tax treatment from AI93-5-000, Accounting for Income Taxes, which states "the FERC relies on the standalone method of allocating income taxes between members of a consolidated group."

3. Commission Precedent for Stand-Alone Accounting

Minnesota Power also follows the Commission's position in the Northern States Power Company's 2005 rate case.[2] In that Docket the Commission gave guidance regarding the inclusion of subsidiary revenues and guidance for computing income tax expense. The Commission stated "Any sharing of benefits is inevitably accompanied by the sharing of risks, which is why the Commission adopted and continues to enforce strict "stand-alone" allocation principles." The Commission stated the stand-alone method is intended to accurately reflect the cost of utility service because it matches the regulated income tax expense to the regulated revenues and expenses. The stand-alone method also supports the policy of maintaining financial separation between regulated and unregulated businesses so utility customers are responsible only for the costs of providing utility service.

When the historical separation between regulated and unregulated operations is breached, this fundamental principle of cost separation is violated. The Department's recommendation to use revenues from unregulated operations to utilize credits on behalf of regulated operations is a breach of this historical separation. Additionally, it is inconsistent rate-making policy to require that the deferred tax assets from NOLs included in rate base be the lower of stand-alone or consolidated while requiring that the stand-alone position be ignored for ND ITC usage. If the Commission decides to dispense with the stand-alone position, there could be unintended repercussions associated with dispensing of the stand-alone position for other purposes, and could open the door to multiple consequences not contemplated in this Docket.

4. Attempts Made to Monetize Credits

As detailed in Minnesota Power's response to the Commission Staff's Information Request Number 1, the Company has explored efforts to sell these state income tax credits to other North Dakota taxpayers on behalf of customers. While these attempts have so far been unsuccessful, Minnesota Power continues to monitor North Dakota legislative efforts with the intent of harnessing the value of the ND ITCs for customers if possible.

[2] Docket No. E002/GR-05-1428.

C. <u>Updated Allocation Factors</u>

The Department requested Minnesota Power make a new Renewable Resources Rider filing with updated allocators and rates and provide additional information on the loss of a wholesale customer in 2014 and the adjusted allocation factors and proposed rates as requested in the Company's Boswell 4 Emission Reductions Rider ("BEC4 Rider").[3] As submitted in the Company's March 16 Reply Comments in the BEC4 Rider, Minnesota Power has revised the jurisdictional and class allocation factors from the Company's last rate case to reflect the loss of a wholesale customer, Dahlberg Light & Power ("Dahlberg"). The allocators were revised as follows in the attached Exhibit B-5 on the pages indicted:

- The Dahlberg load, page 9, line 17, was subtracted from the system peak, page 8, column (a), to get the revised system peak, page 6, column (a);
- The Dahlberg load was zeroed out, page 7, line 17, to get the revised jurisdictional allocators, page 7, line 34;
- The revised jurisdictional allocators were then used to calculate the revised class allocation factors shown in rows 11 and 12 on page 4; and
- The revised allocators were normalized as shown on page 5.

The above adjustments due to the loss of Dahlberg as a wholesale customer will be incorporated into the revenue requirement calculations when the Company submits its Compliance Filing after the MPUC approves the 2015 RRR Factor Filing. The revised allocators will result in a relatively slight increase in Minnesota retail jurisdictional revenue requirements.

It should be noted that no adjustment has been made to the allocation factors for the planned idling of U.S. Steel's Keewatin Taconite ("Keetac") facility, one of Minnesota Power's Large Power taconite mining customers. U.S. Steel recently announced that it would indefinitely idle Keetac starting May 13 because of a global glut of iron ore, and lack of demand for U.S.-made steel. If the allocation factors were revised to include the idling of Keetac, the result would be a slight decrease in Minnesota jurisdictional revenue requirements.

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[3] Docket No. E015/M-14-990.

D. Mitigation of Rate Impacts

The Department is concerned that implementing the rates proposed in the 2014 Renewable Resources Rider and 2015 Renewable Resources Rider will result in significant increases to customers' monthly bills and suggested that the Commission may wish to consider ways to mitigate the proposed increases. One option suggested was to stretch recovery of the tracker balance over a period of two years. As stated in its Reply Comments in the 2014 Renewable Resources Rider filing on September 16, 2014, the Company is currently expending more capital on renewable and environmental retrofit projects than ever before in its history. The project planning for funding these investments was based on the expectation of timely current cost recovery. The large tracker balance in the Renewable Resources Rider indicates that there has already been a delay in receiving current cost recovery. Further delays in cost recovery could potentially prompt a downgrade in the Company's credit ratings, which would cause the cost of capital to rise and would increase costs of future projects for customers. The Department agrees that Minnesota Power could be seen to be financially harmed by a decision to stretch the recovery of its tracker balance, as the Company would incur additional financing charges. The Company requests that recovery of the tracker balance be allowed over the standard twelve month period. If the Commission should choose to consider an extended recovery of the tracker, Minnesota Power requests an appropriate rate of return on the tracker balance. The Company believes an appropriate rate to be the overall cost of capital approved in the last rate case, which is 8.18%.

E. Requirement for Next Renewable Resources Rider

The Department recommended that the Commission require Minnesota Power to file a new Renewable Resources Rider petition by the end of 2015, or make a compliance filing in this Docket demonstrating that the approved rates are still reasonable and will not result in an over recovery during 2016. Minnesota Power agrees with this recommendation.

III. CONCLUSION

Minnesota Power appreciates the Department's thorough review of the Renewable Resources Rider and has provided the requested information. As the issues identified in these Comments have already been established in record, the Company respectfully requests that this Docket be scheduled for a hearing as soon as possible.

Dated: March 23, 2015

Yours Truly,

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Minnesota Power
Renewable Resources Rider: 2012 / 2013 Factor Filing
Allocation Factors

Allocation factors used from 1/1/2010 until 3/31/11

	D-01		D-02	
	Rate Case	Normalized	Rate Case	Normalized
MN Jurisdiction	0.83057	1.0000	0.78623	1.0000
Residential	0.10527	0.12674	0.09965	0.12674
General Service	0.06914	0.08324	0.06545	0.08325
Large Light & Power	0.10909	0.13134	0.10326	0.13134
Large Power	0.53911	0.64908	0.51033	0.64908
Municipal Pumping	0.00568	0.00684	0.00538	0.00684
Lighting	0.00228	0.00275	0.00216	0.00275

The D-01 Power Supply Production - Demand allocator and D-02 Transmission - Demand allocator used in 2010 and until 3/31/2011 are from MP's 2008 MPUC rate case, Docket No. E-015/GR-08-415. Because the revenue tracker amounts are 100% MN Jurisdictional, the factor are normalized to obtain class allocations.

Allocation factors used beginning 4/1/2011

	D-01		D-02	
	Rate Case	Normalized	Rate Case	Normalized
MN Jurisdiction	0.82017	1.0000	0.77570	1.0000
Residential	0.11259	0.1373	0.10649	0.1373
General Service	0.06213	0.0758	0.05876	0.0758
Large Light & Power	0.12471	0.1521	0.11795	0.1521
Large Power	0.51269	0.6251	0.48489	0.6251
Municipal Pumping	0.00568	0.0069	0.00537	0.0069
Lighting	0.00237	0.0029	0.00224	0.0029

The D-01 and D-02 allocators from MP's 2009 MPUC rate case Docket No. E-015/GR-09-1151 were applied in 2011 Factor Filing begining April 2011.
Because the revenue tracker amounts are 100% MN Jurisdictional, the factor are normalized to obtain class allocations.

Minnesota Power
Docket No. E-015/GR-08-415
Demand Responsibility of Power Supply Cost Based on Peak & Average Methodology: D-01 & D-02
Test Year 7/08 - 6/09

		Total Retail	Residential	General Service	Large Light & Power	Large Power	Municipal Pumping	Lighting
1	Annual Energy (E-01 with losses)	9,126,513	1,077,380	706,210	1,151,501	6,103,175	66,306	21,941
2	Average Demand	1,041,839	122,989	80,618	131,450	696,709	7,569	2,505
3	Percent	100.000	11.805	7.738	12.617	66.873	0.727	0.240
4	Annual CP Demand (loss adjusted)	1,332,068	210,331	138,987	199,685	770,636	7,093	5,337
5	Percent	100.000	15.790	10.434	14.991	57.853	0.532	0.401
6	Annual Load Factor (Line 2 / Line 4)	0.78212						
7	1.0 - Load Factor	0.21788						
8	Average Factor (Line 3 x Line 6 total)	78.212	9.233	6.052	9.868	52.303	0.568	0.188
9	Peak Factor (Line 5 x Line 7 total)	21.788	3.441	2.273	3.266	12.605	0.116	0.087
10	Composite Factor - D-01 (Line 8 + Line 9)	100.000	12.674	8.325	13.134	64.908	0.684	0.275
11	Power Supply Production - D-01 Adjusted for Jurisditional Split (Line 10 x .83057)	83.057	10.527	6.914	10.909	53.911	0.568	0.228
12	Power Supply Transmission - D-02 Adjusted for Jurisditional Split (Line 10 x .78623)	78.623	9.965	6.545	10.326	51.033	0.538	0.216

Notes:
Residential, General Service, Large Light and Power and Municipal Pumping CP Demands from load research: CP demand per customer multiplied by budgeted number of customers and adjusted for losses. Large Power CP demand estimated based on actual measured 2007 CP adjusted for losses and ratio of 2007 to Test Year average demand. Lighting CP is average load based on Test Year budgeted total energy and 4,200 burning hours and adjusted for losses.

Minnesota Power
Docket No. E-015/GR-09-1151
Demand Responsibility of Power Supply Cost Based on Peak & Average Methodology: D-01 & D-02
Test Year 2010 Rebuttal Customer Budget
Revised from original work paper AF-3, page 14.

		Total Retail	Residential	General Service	Large Light & Power	Large Power	Municipal Pumping	Lighting
1	Annual Energy (E-01 with losses)	8,973,590	1,164,063	645,945	1,311,171	5,768,410	61,116	22,885
2	Average Demand	1,024,382	132,884	73,738	149,677	658,494	6,977	2,612
3	Percent	100.000	12.972	7.198	14.611	64.282	0.681	0.255
4	Annual CP Demand (loss adjusted)	1,267,035	214,342	116,138	224,399	697,256	9,334	5,567
5	Percent	100.000	16.917	9.166	17.711	55.031	0.737	0.439
6	Annual Load Factor (Line 2 / Line 4)	0.80849						
7	1.0 - Load Factor	0.19151						
8	Average Factor (Line 3 x Line 6 total)	80.849	10.488	5.820	11.813	51.971	0.551	0.206
9	Peak Factor (Line 5 x Line 7 total)	19.151	3.240	1.755	3.392	10.539	0.141	0.084
10	Composite Factor - D-01 (Line 8 + Line 9)	100.000	13.728	7.575	15.205	62.510	0.692	0.290
11	Power Supply Production - D-01 Adjusted for Jurisditional Split (Line 10 x .82017)	82.017	11.259	6.213	12.471	51.269	0.568	0.237
12	Power Supply Transmission - D-02 Adjusted for Jurisditional Split (Line 10 x .77570)	77.570	10.649	5.876	11.795	48.489	0.537	0.224

Notes:
Residential, General Service, Large Light and Power and Municipal Pumping CP demands per customer from load research multiplied by budgeted number of customers and adjusted for losses. Large Power CP demand based on 2008 CP adjusted for losses and ratio of 2008 to Test Year average demand. Large Light and Power and Large Power loads normalized to reflect three cusomters that moved from Large Power to Large Light and Power. Lighting CP is average load based on Test Year budgeted total energy and 4,200 burning hours and adjusted for losses.

Minnesota Power
Renewable Resources Rider
Revised Rate Case Alllocators

Demand Responsibility of Power Supply Cost Based on Peak & Average Methodology: D-01 & D-02
Revised to Reflect Loss of Dahlberg in 2014

		Total Retail	Residential	General Service	Large Light & Power	Large Power	Municipal Pumping	Lighting
1	Annual Energy (E-01 with losses)	8,973,590	1,164,063	645,945	1,311,171	5,768,410	61,116	22,885
2	Average Demand	1,024,382	132,884	73,738	149,677	658,494	6,977	2,612
3	Percent	100.000	12.972	7.198	14.611	64.282	0.681	0.255
4	Annual CP Demand (loss adjusted)	1,267,035	214,342	116,138	224,399	697,256	9,334	5,567
5	Percent	100.000	16.917	9.166	17.711	55.031	0.737	0.439
6	Annual Load Factor (Line 2 / Line 4)	0.80849						
7	1.0 - Load Factor	0.19151						
8	Average Factor (Line 3 x Line 6 total)	80.849	10.488	5.820	11.813	51.971	0.551	0.206
9	Peak Factor (Line 5 x Line 7 total)	19.151	3.240	1.755	3.392	10.539	0.141	0.084
10	Composite Factor - D-01 (Line 8 + Line 9)	100.000	13.728	7.575	15.205	62.510	0.692	0.290
11	Power Supply Production - D-01 Adjusted for Jurisditional Split (Line 10 x .83043)	83.043	11.400	6.291	12.627	51.910	0.575	0.240
12	Power Supply Transmission - D-02 Adjusted for Jurisditional Split (Line 10 x .78556	78.556	10.784	5.951	11.944	49.105	0.544	0.228

Notes:
Residential, General Service, Large Light and Power and Municipal Pumping CP demands per customer from load research multiplied by budgeted number of customers and adjusted for losses. Large Power CP demand based on 2008 CP adjusted for losses and ratio of 2008 to Test Year average demand. Large Light and Power and Large Power loads normalized to reflect three cusomters that moved from Large Power to Large Light and Power. Lighting CP is average load based on Test Year budgeted total energy and 4,200 burning hours and adjusted for losses.

Minnesota Power
RenewableResources Rider: 2015 Factor Filing
Revised Allocation Factors

	D-01 Revised /1	D-01 Normalized	D-02 Revised /1	D-02 Normalized
MN Jurisdiction	0.83043	1.0000	0.78556	1.0000
Residential	0.11400	0.1373	0.10784	0.1373
General Service	0.06291	0.0758	0.05951	0.0758
Large Light & Power	0.12627	0.1521	0.11944	0.1520
Large Power	0.51910	0.6251	0.49105	0.6251
Municipal Pumping	0.00575	0.0069	0.00544	0.0069
Lighting	0.00240	0.0029	0.00228	0.0029

1/ See Exhibit B-5, page 4, rows 11 and 12.
Because the revenue tracker amounts are 100% MN Jurisdictional, the factor are normalized to obtain class allocations.

Minnesota Power
Renewable Resources Rider

Adjusted System Net Load Peaks - Forecast & Normalized (MW)
Revised to Reflect Loss of Dahlberg in 2014

	Forecast	Normalized				Wheeling						
System Peak	Expected System Net Load Peak (a)	Dual Fuel (b)	Large Power Interruptible (c)	Production Peak (d)	Staples (e)	Wadena (f)	Subtotal (g)	Losses (h)	Silver Bay (i)	Total (j)	Transmission Peak (k)
Jan	1367.839	25.000	192.466	1,150.373	4.027	12.830	16.857	0.249	42.000	59.106	1,155.848
Feb	1355.239	24.772	193.174	1,137.293	3.935	12.022	15.957	0.236	41.000	57.193	1,141.465
Mar	1304.739	23.860	192.394	1,088.485	3.537	11.297	14.834	0.220	41.000	56.054	1,093.793
Apr	1384.507	25.301	192.910	1,166.296	3.185	10.185	13.370	0.198	41.000	54.568	1,166.490
May	1449.361	4.637	192.345	1,252.379	3.047	9.624	12.671	0.188	41.000	53.859	1,247.851
Jun	1541.085	4.927	192.623	1,343.535	3.875	11.190	15.065	0.223	41.000	56.288	1,337.187
Jul	1564.066	5.000	192.854	1,366.212	3.844	11.051	14.895	0.220	43.000	58.115	1,360.634
Aug	1552.582	4.964	192.597	1,355.021	3.852	11.039	14.891	0.220	43.000	58.111	1,349.961
Sep	1524.054	4.873	191.697	1,327.484	3.662	10.507	14.169	0.210	41.000	55.379	1,320.975
Oct	1533.982	4.905	191.703	1,337.374	3.032	8.607	11.639	0.172	41.000	52.811	1,327.836
Nov	1567.539	25.608	191.363	1,350.568	3.673	12.018	15.691	0.232	41.000	56.923	1,344.527
Dec	1559.473	28.462	191.636	1,339.375	3.793	11.052	14.845	0.220	42.000	57.065	1,333.997
Avg	1,475.372	15.192	192.314	1,267.866	3.622	10.952	14.574	0.216	41.500	56.289	1,265.047

Notes:
Production Peak (d) = (a) - (b) - (c).
Subtotal (g) = (e) + (f).
Losses (h) = (g) x Distribution Bulk Delivery loss.
Total (j) = (g) + (h) + (i).
Transmission Peak (k) = ((d) / (1 + transmission loss)) + (j).
Demand loss factors:

Secondary (%) @	
Line Transf (%) @	
Primary (%) @	
Distribution Subs (%) @	
Dist. Bulk Delivery (%) @	1.48
Transmission (%) @	4.89

Minnesota Power
Renewable Resources Rider

Demand Responsibility for Power Supply Costs Based on 12-Month Average CP Demands (MW)
Revised to Reflect Loss of Dahlberg in 2014

Line (No)		Lowest Level of Allocation (kV)	Demand at Meter (a)	Lowest Level of Allocation: Losses to Meter Point (b)	Lowest Level of Allocation: Demand at LLA (c)	Power Supply Transmission: Losses on Dist Bulk Del (d)	Power Supply Transmission: Demand at Trans (e)	Power Supply Production: Losses on Trans Sys (f)	Power Supply Production: Demand at Prod (g)
Group A - Full Requirement Customers									
1	Buhl	23	1.219	0.000	1.219	0.018	1.237	0.000	1.237
2	Gilbert	23	1.819	0.000	1.819	0.027	1.845	0.000	1.845
3	Keewatin	23	0.978	0.000	0.978	0.014	0.993	0.000	0.993
4	Mountain Iron	23	2.101	0.000	2.101	0.031	2.132	0.000	2.132
5	Nashwauk	23	2.305	0.000	2.305	0.034	2.340	0.000	2.340
6	Pierz	34	1.538	0.065	1.603	0.024	1.627	0.000	1.627
7	Randall	34	0.851	0.036	0.888	0.013	0.901	0.000	0.901
8	Biwabik	46	1.119	0.000	1.119	0.017	1.135	0.000	1.135
9	Ely	46	6.112	0.000	6.112	0.090	6.202	0.000	6.202
10	Aitkin	PST	5.872	0.000	5.872	0.000	5.872	0.000	5.872
11	Brainerd	PST	37.896	0.000	37.896	0.000	37.896	0.000	37.896
12	Grand Rapids	PST	25.729	0.000	25.729	0.000	25.729	0.000	25.729
13	Hibbing	PST	17.976	0.000	17.976	0.000	17.976	0.000	17.976
14	Proctor	PST	3.911	0.166	4.077	0.000	4.077	0.000	4.077
15	Two Harbors	PST	4.604	0.196	4.800	0.000	4.800	0.000	4.800
16	Virginia	PST	15.635	0.000	15.635	0.000	15.635	0.000	15.635
17	Dahlberg	PST	0.000	0.000	0.000	0.000	0.000	0.000	0.000
18	Group A - Total		129.664	0.463	130.128	0.269	130.396	0.000	130.396
19	- Demand Responsibility (%)						10.308		10.285
Group B - Private Utilities									
20	Superior Water, Light & Power Company	PST	84.588	0.000	84.588	0.000	84.588	0.000	84.588
21	Group B - Total		84.588	0.000	84.588	0.000	84.588	0.000	84.588
22	- Demand Responsibility (%)						6.687		6.672
Group C - Transmission and Distribution Wheeling Service									
23	Staples	34	3.622	0.000	3.622	0.054	3.675		
24	Wadena	34	10.952	0.000	10.952	0.162	11.114		
25	Group C - Total		14.574	0.000	14.574	0.216	14.789		
26	- Demand Responsibility (%)						1.169		
Group D - Wheeling Service									
27	Silver Bay Power Corp.	PST	41.500	0.000	41.500	0.000	41.500		
28	Group D - Total		41.500	0.000	41.500	0.000	41.500		
29	- Demand Responsibility (%)						3.281		
Group E - Distribution Wheeling Service									
30	Great River Energy	23, 34, 46	0	0	0	0	0		
31	Group E - Total		0	0	0	0	0		
32	- Demand Responsibility (%)						0.000		
Other									
33	Other - Total						993.773		1,052.881
34	- Demand Responsibility (%)						78.556		83.043
Total System									
35	System - Total						1,265.047		1,267.866
36	- Demand Responsibility (%)						100.000		100.000
							(D-02)		(D-01)
							DTRAN		DPROD

Notes:
Demand at LLA (c) = (a) + (b).
Demand at Trans (e) = (c) + (d).
Demand at Prod (g) = (e) + (f).
Demand loss factors:
Dist Bulk Delivery (%) @ 1.48
Transmission (%) @ 4.89
Transmission losses supplied through MISO and not allocated here.
Group A & B rebuttal demands estimated based on ratio of intital filing demands to energy and rebuttal energy.

System Net Load Peaks
Adjusted System Net Load Peaks - Forecast & Normalized (MW)
Test Year 2010 Rebuttal Customer Budget
Revised from original work paper, AF-3, page 2.
MP Exhibit (SJS) Rebuttal Schedule 3, page 2 of 15
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Forecast		Normalized			Wheeling						
System Peak	Expected System Net Load Peak (a)	Dual Fuel (b)	Large Power Interruptible (c)	Production Peak (d)	Staples (e)	Wadena (f)	Subtotal (g)	Losses (h)	Silver Bay (i)	Total (j)	Transmission Peak (k)
Jan	1383.700	25.000	192.466	1,166.234	4.027	12.830	16.857	0.249	42.000	59.106	1,170.970
Feb	1371.100	24.772	193.174	1,153.154	3.935	12.022	15.957	0.236	41.000	57.193	1,156.587
Mar	1320.600	23.860	192.394	1,104.346	3.537	11.297	14.834	0.220	41.000	56.054	1,108.915
Apr	1400.368	25.301	192.910	1,182.157	3.185	10.185	13.370	0.198	41.000	54.568	1,181.612
May	1465.222	4.637	192.345	1,268.240	3.047	9.624	12.671	0.188	41.000	53.859	1,262.973
Jun	1556.946	4.927	192.623	1,359.396	3.875	11.190	15.065	0.223	41.000	56.288	1,352.309
Jul	1579.927	5.000	192.854	1,382.073	3.844	11.051	14.895	0.220	43.000	58.115	1,375.756
Aug	1568.443	4.964	192.597	1,370.882	3.852	11.039	14.891	0.220	43.000	58.111	1,365.082
Sep	1539.915	4.873	191.697	1,343.345	3.662	10.507	14.169	0.210	41.000	55.379	1,336.097
Oct	1549.843	4.905	191.703	1,353.235	3.032	8.607	11.639	0.172	41.000	52.811	1,342.958
Nov	1583.400	25.608	191.363	1,366.429	3.673	12.018	15.691	0.232	41.000	56.923	1,359.649
Dec	1575.334	28.462	191.636	1,355.236	3.793	11.052	14.845	0.220	42.000	57.065	1,349.119
Avg	1,491.233	15.192	192.314	1,283.727	3.622	10.952	14.574	0.216	41.500	56.289	1,280.169

Notes:
Production Peak (d) = (a) - (b) - (c).
Subtotal (g) = (e) + (f).
Losses (h) = (g) x Distribution Bulk Delivery loss.
Total (j) = (g) + (h) + (i).
Transmission Peak (k) = ((d) / (1 + transmission loss)) + (j).
Demand loss factors:

Dist. Bulk Delivery (%) @	1.48
Transmission (%) @	4.89

Demand Responsibility for Power Supply Costs Based on 12-Month Average CP Demands (MW)
Test Year 2010 Rebuttal Customer Budget
Revised from original work paper, AF-3, page 3.
MP Exhibit (SJS) Rebuttal Schedule 3, page 3 of 15
Docket No. E-015/GR-09-1151

				Lowest Level of Allocation		Power Supply Transmission		Power Supply Production	
Line (No)		Lowest Level of Allocation (kV)	Demand at Meter (a)	Losses to Meter Point (b)	Demand at LLA (c)	Losses on Dist Bulk Del (d)	Demand at Trans (e)	Losses on Trans Sys (f)	Demand at Prod (g)
Group A - Full Requirement Customers									
1	Buhl	23	1.219	0.000	1.219	0.018	1.237	0.000	1.237
2	Gilbert	23	1.819	0.000	1.819	0.027	1.845	0.000	1.845
3	Keewatin	23	0.978	0.000	0.978	0.014	0.993	0.000	0.993
4	Mountain Iron	23	2.101	0.000	2.101	0.031	2.132	0.000	2.132
5	Nashwauk	23	2.305	0.000	2.305	0.034	2.340	0.000	2.340
6	Pierz	34	1.538	0.065	1.603	0.024	1.627	0.000	1.627
7	Randall	34	0.851	0.036	0.888	0.013	0.901	0.000	0.901
8	Biwabik	46	1.119	0.000	1.119	0.017	1.135	0.000	1.135
9	Ely	46	6.112	0.000	6.112	0.090	6.202	0.000	6.202
10	Aitkin	PST	5.872	0.000	5.872	0.000	5.872	0.000	5.872
11	Brainerd	PST	37.896	0.000	37.896	0.000	37.896	0.000	37.896
12	Grand Rapids	PST	25.729	0.000	25.729	0.000	25.729	0.000	25.729
13	Hibbing	PST	17.976	0.000	17.976	0.000	17.976	0.000	17.976
14	Proctor	PST	3.911	0.166	4.077	0.000	4.077	0.000	4.077
15	Two Harbors	PST	4.604	0.196	4.800	0.000	4.800	0.000	4.800
16	Virginia	PST	15.635	0.000	15.635	0.000	15.635	0.000	15.635
17	Dahlberg	PST	15.861	0.000	15.861	0.000	15.861	0.000	15.861
18	Group A - Total		145.526	0.463	145.989	0.269	146.258	0.000	146.258
19	- Demand Responsibility (%)						11.425		11.393
Group B - Private Utilities									
20	Superior Water, Light & Power Company	PST	84.588	0.000	84.588	0.000	84.588	0.000	84.588
21	Group B - Total		84.588	0.000	84.588	0.000	84.588	0.000	84.588
22	- Demand Responsibility (%)						6.608		6.589
Group C - Transmission and Distribution Wheeling Service									
23	Staples	34	3.622	0.000	3.622	0.054	3.675		
24	Wadena	34	10.952	0.000	10.952	0.162	11.114		
25	Group C - Total		14.574	0.000	14.574	0.216	14.789		
26	- Demand Responsibility (%)						1.155		
Group D - Wheeling Service									
27	Silver Bay Power Corp.	PST	41.500	0.000	41.500	0.000	41.500		
28	Group D - Total		41.500	0.000	41.500	0.000	41.500		
29	- Demand Responsibility (%)						3.242		
Group E - Distribution Wheeling Service									
30	Great River Energy	23, 34, 46	0	0	0	0	0		
31	Group E - Total		0	0	0	0	0		
32	- Demand Responsibility (%)						0.000		
Other									
33	Other - Total						993.033		1,052.881
34	- Demand Responsibility (%)						77.570		82.017
Total System									
35	System - Total						1,280.169		1,283.727
36	- Demand Responsibility (%)						100.000		100.000
							(D-02)		(D-01)
Notes:							DTRAN		DPROD

Demand at LLA (c) = (a) + (b).
Demand at Trans (e) = (c) + (d).
Demand at Prod (g) = (e) + (f).
Demand loss factors:
- Secondary (%) @ 0.68
- Line Transf (%) @ 1.69
- Primary (%) @ 3.93
- Distribution Subs (%) @ 0.33
- Dist Bulk Delivery (%) @ 1.48
- Transmission (%) @ 4.89

Transmission losses supplied through MISO and not allocated here.
Group A & B rebuttal demands estimated based on ratio of intital filing demands to energy and rebuttal energy.

STATE OF MINNESOTA	)	AFFIDAVIT OF SERVICE VIA
	) ss	E-FILING AND
COUNTY OF ST. LOUIS	)	

Dawn LaPointe, of the City of Duluth, County of St. Louis, State of Minnesota, says that on the 23rd day of March, 2015, she e-filed Minnesota Power's Reply Comments related to Renewable Resources Rider and 2015 Renewable Factor, Docket No. E015/M-14-962, on Burl Haar and Sharon Ferguson.

/s/ Dawn LaPointe
Dawn LaPointe

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