APPENDIX I: RENEWABLE ENERGY STANDARD AND SOLAR ENERGY STANDARD COST IMPACT REPORT

Appendix I serves as Minnesota Power's Renewable Energy Cost Impact Report ("Report") to the Minnesota Public Utilities Commission ("Commission") in compliance with Minn. Stat. § 216B.1691, subd. 2e (Docket No. E999/CI-11-852). The statute is intended to provide a mechanism for determining and communicating to legislators and constituents what utility rates would be if the 2007 Minnesota Next Generation Energy Act ("NGEA") had never been implemented. This Report is intended to be in full compliance with the Commission's January 6, 2015 Order Establishing Uniform Reporting System for Estimating Rate Impact of Minn. Stat § 216B.1691 ("Order"), as well as the language and objective of the statute.

The NGEA helped to create a framework for utilities to implement expanded renewable energy portfolios. The NGEA requires Minnesota electric utilities to obtain increasing amounts of energy from eligible renewable resources according to a specified timeline. The amounts are calculated in terms of a percentage of each utility's total retail sales. During the 2011 legislative session, legislation was passed which requires utilities to report the impacts of the NGEA on customers. In 2013, the Minnesota Legislature directed the Commission to develop a uniform system for utilities to use when estimating how electric rates have been influenced by Minn. Stat. § 216B.1691. The Commission issued two notices, November 6, 2013, and April 18, 2014, respectively, seeking comments on Commission Staff's proposed general guiding principles and format for a uniform reporting system. The Commission approved the general guiding principles and format to be used by reporting utilities, including Minnesota Power, at a hearing on October 2, 2014, which was reflected in the January 6, 2015 Order.

The Order is comprehensive, but also provides some flexibility to reporting utilities due to the vast differences in demographics, structure and load. Utilities estimating the rate impact of Minn. Stat. § 216B.1691 are required to do the following:

- Report data for the period 2005 until the last reported year. (Order Point 1A.1 & 1A.2).
- Analyze costs from the year following the last reported year, and for the following 15 years. (Order Point 2A.1 & 2A.2).
- Include all facilities used to comply with the Renewable Energy Standard ("RES") and the Solar Energy Standard ("SES"), regardless of when the facilities were constructed. (Order Point 2B).
- Calculate direct costs to include payments under power purchase agreements and revenue requirements associated with utility-owned renewable energy projects. (Order Point 2C).
- Provide a narrative discussion about the impact that adding generators powered by renewable sources may have had on the utility's indirect costs, such as the cost for ancillary services and base load cycling. (Order Point 2D).
- Include transmission costs for transmission improvements created exclusively for the purpose of gaining access to electricity from renewable resources, as well as the percentage directly attributable to compliance with the RES and SES. Additionally, for multi-purpose transmission providing access to renewable resources include a narrative estimating the costs and portion the utility would allocate to the cost of gaining access to renewable resources. (Order Point 2E.1 & 2E.2).

- Calculate savings arising from avoiding energy and capacity costs that the utility would have incurred directly in the absence of the RES and SES. (Order Point 2F.1 & 2F.2).
- Calculate savings arising from avoiding costs (past and future) that the utility would have incurred indirectly in the absence of the RES and SES to include costs of sulfur dioxides (“SO_2”) and oxides of nitrogen (“NO_x”) permits required under Title IV of the Federal Clean Air Act, and expected future emission compliance costs, including costs of SO_2 and NOx permits, as well as the range of compliance cost values for carbon dioxide (“CO_2”) set by the Commission under Minn. Stat. § 216H.06. (Order Point 2G.1 & 2G.2).
- Report estimated annualized and estimated levelized costs. (Order Point 2H).
- Calculate separately the rate impacts of complying with the RES and the SES. (Order Point 2I.1 & 2I.2).
- Calculate the ultimate rate impact of Minn. Stat. § 216H.1691 to reflect the fact that renewable energy comprises only a fraction of a utility’s total energy costs, and consequently most of a utility’s energy costs are unaffected by the RES and SES. (Order Point 2J.1).
- Calculate additional modifications as are agreed upon by the Department of Commerce – Division of Energy Resources and the commenters. (Order Point 2J.2).

Minnesota Power provides historical and future rate impact information for the RES and SES as required under Minn. Stat. § 216B.1691, subd. 2e. The analysis shows that the investments the Company has made on behalf of its customers to meet the RES have been reasonable and resulted in estimated rates impacts that are competitive with alternative power supply resource options.

Methodology

For the purpose of this study, the Company calculated separate rate impacts for the RES and the SES. RES rate impact calculations were performed for two different time frames: Historic Years 2005-2020, and Future Years 2021-2035. Recognizing that the SES was adopted in 2013, the start of the rate impact calculations aligned with the timing of the first solar project. SES rate impact calculations were performed for two different time frames: Historic Years 2005-2020, and Future Years 2021-2035.

Included in the historic and future RES rate impact calculations are estimates of transmission costs directly attributable to renewable resources. Specifically, the transmission costs are for transmission assets required to access and transmit the renewable energy produced by the four large wind projects: Bison 1, Bison 2, Bison 3 and Bison 4 which comprise the Bison Wind Energy Center. The Bison Wind Energy Center is located in west central North Dakota, near the city of New Salem, in Oliver County. The calculation of the direct cost of renewables includes 100 percent of the revenue requirements associated with these transmission projects (see Row C in Tables 1 thru 9).

Historic Cost Impact for the RES (2005 – 2020)

Historic rate impacts were determined by comparing the actual direct costs associated with the Company’s renewable generation each year with an estimate of the direct costs that would have been incurred had Minnesota Power acquired the same accredited generation capacity (MW) and energy (MWh) from non-renewable resources. The cost of building a new natural gas

1x1 combined cycle ("CC") unit and associated fixed operations and maintenance ("O&M") expenses were used to estimate avoided capacity costs. The energy cost from a 1x1 CC and associated variable O&M expenses were used to estimate the avoided energy cost.[1] The construction costs and generation characteristics represents a 1x1 CC typically built around 2010.

Minnesota Power's last Renewable Energy Cost Impact Report was submitted as part of Appendix I: Renewable Energy Standard and Solar Energy Standard Cost Impact in its 2015 integrated resource plan.[2] The same methodology used for the 2015 report was applied to the historic RES rate impact shown in the current report.

Table 1: Historic RES Rate Impact (2005 - 2012)

		Historic (2005 - 2012)							
	RES Generation	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**
A	Total RES Generation (PPA + Owned; GWh)	502	370	643	888	893	1,008	1,037	1,020
	Costs Associated with RES Generation (Revenue Requirements)								
B	Purchased Power + Owned Generation (millions)	$ 11.3	$ 12.6	$ 18.4	$ 28.3	$ 35.2	$ 49.1	$ 60.5	$ 79.8
C	RES Attributable Transmission (millions)	$ -	$ -	$ -	$ -	$ -	$ 1.3	$ 2.8	$ 3.6
D = B+C	Total Cost for RES Generation (millions)	$ 11.3	$ 12.6	$ 18.4	$ 28.3	$ 35.2	$ 50.5	$ 63.3	$ 83.3
E = D/A	Total Cost for RES Generation ($/MWh)	$ 22.6	$ 34.0	$ 28.5	$ 31.8	$ 39.5	$ 50.1	$ 61.1	$ 81.7
	Avoided Costs due to RES								
F	Avoided Energy Costs PPAs & Owned Generation (millions)	$ 30.5	$ 18.4	$ 32.2	$ 55.3	$ 28.2	$ 35.6	$ 33.6	$ 24.2
G	Avoided Capacity Cost PPAs & Owned Generation (millions)	$ 39.8	$ 40.0	$ 43.9	$ 45.3	$ 47.5	$ 32.6	$ 40.9	$ 47.3
H	Avoided Transmission Cost (millions)	$ 0.1	$ 0.1	$ 0.1	$ 0.1	$ 0.1	$ 0.1	$ 0.1	$ 0.1
I	Avoided Emissions Cost PPAs & Owned Generation (millions)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
J = F+G+H+I	Total Avoided Costs PPAs & Owned Generation (millions)	$ 70.3	$ 58.5	$ 76.2	$ 100.8	$ 75.8	$ 68.3	$ 74.6	$ 71.6
K = J/A	Total Avoided Costs PPAs & Owned Generation ($/MWh)	$ 140.23	$ 158.25	$ 118.49	$ 113.55	$ 84.90	$ 67.70	$ 71.95	$ 70.21
L = D-J	Total RES Premium/Discount (millions)	$ (59.0)	$ (45.9)	$ (57.9)	$ (72.5)	$ (40.6)	$ (17.8)	$ (11.3)	$ 11.7
M = E-K	Total RES Premium/Discount ($/MWh)	$ (117.66)	$ (124.27)	$ (89.95)	$ (81.71)	$ (45.44)	$ (17.64)	$ (10.87)	$ 11.47
	Annualized RES Rate Impacts								
N	Minnesota Power Sales (Retail & Wholesale; GWh)	10,345	10,444	10,671	10,826	8,062	10,417	10,988	11,107
O = L/N	Rate Impact ($/MWh)	$ (5.70)	$ (4.40)	$ (5.42)	$ (6.70)	$ (5.03)	$ (1.71)	$ (1.03)	$ 1.05
P = O/10	Rate Impact (¢/kWh)	(0.57)	(0.44)	(0.54)	(0.67)	(0.50)	(0.17)	(0.10)	0.11

Table 2: Historic RES Rate Impact (2013 - 2020)

		Historic (2013 - 2020)							
	RES Generation	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
A	Total RES Generation (PPA + Owned; GWh)	1,396	1,694	2,397	2,894	2,968	2,477	2,594	3,005
	Costs Associated with RES Generation (Revenue Requirements)								
B	Purchased Power + Owned Generation (millions)	$ 85.0	$ 107.8	$ 109.8	$ 114.6	$ 93.3	$ 113.9	$ 102.6	$ 109.5
C	RES Attributable Transmission (millions)	$ 4.0	$ 6.4	$ 6.6	$ 6.6	$ 5.6	$ 4.0	$ 3.9	$ 3.7
D = B+C	Total Cost for RES Generation (millions)	$ 89.0	$ 114.2	$ 116.4	$ 121.2	$ 99.0	$ 117.9	$ 106.5	$ 113.2
E = D/A	Total Cost for RES Generation ($/MWh)	$ 63.8	$ 67.4	$ 48.6	$ 41.9	$ 33.3	$ 47.6	$ 41.0	$ 37.7
	Avoided Costs due to RES								
F	Avoided Energy Costs PPAs & Owned Generation (millions)	$ 43.3	$ 80.1	$ 58.4	$ 65.1	$ 80.4	$ 66.0	$ 58.7	$ 57.8
G	Avoided Capacity Cost PPAs & Owned Generation (millions)	$ 49.0	$ 35.2	$ 52.6	$ 66.2	$ 67.3	$ 66.2	$ 68.3	$ 63.2
H	Avoided Transmission Cost (millions)	$ 0.1	$ 0.1	$ 0.1	$ 0.2	$ 0.2	$ 0.2	$ 0.2	$ 0.2
I	Avoided Emissions Cost PPAs & Owned Generation (millions)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
J = F+G+H+I	Total Avoided Costs PPAs & Owned Generation (millions)	$ 92.5	$ 115.4	$ 111.1	$ 131.5	$ 147.8	$ 132.4	$ 127.2	$ 121.2
K = J/A	Total Avoided Costs PPAs & Owned Generation ($/MWh)	$ 66.26	$ 68.12	$ 46.36	$ 45.44	$ 49.80	$ 53.46	$ 49.04	$ 40.33
L = D-J	Total RES Premium/Discount (millions)	$ (3.5)	$ (1.2)	$ 5.3	$ (10.3)	$ (48.8)	$ (14.5)	$ (20.7)	$ (8.0)
M = E-K	Total RES Premium/Discount ($/MWh)	$ (2.49)	$ (0.70)	$ 2.21	$ (3.56)	$ (16.46)	$ (5.84)	$ (7.99)	$ (2.66)
	Annualized RES Rate Impacts								
N	Minnesota Power Sales (Retail & Wholesale; GWh)	10,986	11,039	10,059	9,831	10,654	10,639	10,483	9,230
O = L/N	Rate Impact ($/MWh)	$ (0.32)	$ (0.11)	$ 0.53	$ (1.05)	$ (4.58)	$ (1.36)	$ (1.98)	$ (0.87)
P = O/10	Rate Impact (¢/kWh)	(0.03)	(0.01)	0.05	(0.10)	(0.46)	(0.14)	(0.20)	(0.09)

[1] The energy cost is based on historical natural gas prices at Ventura multiplied by the heat rate of the 1x1 CC plus variable O&M costs. The assumed heat rate for the 1x1 CC was 7,000 Btu/kWh.

[2] See Docket No. E015/RP-15-690.

Future RES Rate Impact (2021-2035)

Future RES rate impacts were calculated by comparing Minnesota Power's power supply cost projections within the EnCompass software tool for two different futures: 1) a "RES" compliant future that reflects the 2021 Plan recommended in the 2021 integrated resource plan ("2021 Plan"): and 2) a "No RES" future in which all renewable generation capacity and energy contained in the "RES" future used to meet the RES are removed and replaced with non-renewable generation. The type and timing of replacement energy and capacity was based on an expansion plan using EnCompass. Note that this is the same approach Minnesota Power used in the 2015 Integrated Resource Plan.

The "RES" future is the 2021 Plan discussed in Section V. Details of the power supply assumptions in the 2021 Plan are also discussed in Section V and Appendix K. Per the Order, the RES rate impact analysis includes the required calculation of saving from avoided costs, which contains the Commission-approved CO_2 regulation penalty for the Reference Case of $15/ton starting in 2025 and escalates annually at the inflation rate.

By comparing the difference between the annual power supply costs of the "RES" and "No RES" futures, one can project the cost impact of the actions the Company has taken to comply with the RES. Note that these future rate impacts reflect the cost of all the actions taken to comply with the RES and not the individual renewable projects that were built in response to the RES or already existed prior to the RES. The rate impacts will be different when calculated for incremental renewable resources.

Table 3 and Table 4 show the projected future rate impacts attributed to meeting the RES by year for 2021 - 2028 and 2029 - 2035, respectively. Table 5 shows the levelized costs and rate impacts associated with meeting the RES for the historic period (2005 – 2020) and future period (2021 - 2035).

Table 3: Future RES Rate Impact (2021 - 2028)[3]

		Future (2021 - 2028)							
	RES Generation	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
A	Total RES Generation (PPA + Owned; GWh)	3,688	3,679	3,684	3,698	3,689	3,672	3,672	3,696
	Costs Associated with RES Generation (Revenue Requirements)								
B	Purchased Power + Owned Generation (millions)	$ 128.3	$ 132.4	$ 151.4	$ 151.8	$ 180.9	$ 178.0	$ 175.1	$ 173.1
C	RES Attributable Transmission (millions)	$ 3.5	$ 3.3	$ 3.2	$ 3.0	$ 2.9	$ 2.8	$ 2.7	$ 2.6
D = B+C	Total Cost for RES Generation (millions)	$ 131.8	$ 135.7	$ 154.5	$ 154.8	$ 183.8	$ 180.8	$ 177.7	$ 175.6
E = D/A	Total Cost for RES Generation ($/MWh)	$ 35.7	$ 36.9	$ 42.0	$ 41.9	$ 49.8	$ 49.3	$ 48.4	$ 47.5
	Avoided Costs due to RES								
F	Avoided Energy Costs PPAs & Owned Generation (millions)	$ 85.4	$ 74.7	$ 65.9	$ 75.9	$ 75.1	$ 79.6	$ 81.0	$ 93.0
G	Avoided Capacity Cost PPAs & Owned Generation (millions)	$ 85.1	$ 82.9	$ 80.6	$ 78.3	$ 76.1	$ 74.0	$ 71.9	$ 69.9
H	Avoided Transmission Cost (millions)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
I	Avoided Emissions Cost PPAs & Owned Generation (millions)	$ -	$ -	$ -	$ -	$ 14.1	$ 12.0	$ 10.1	$ 12.3
J = F+G+H+I	Total Avoided Costs PPAs & Owned Generation (millions)	$ 170.5	$ 157.6	$ 146.5	$ 154.2	$ 165.3	$ 165.6	$ 163.0	$ 175.1
K = J/A	Total Avoided Costs PPAs & Owned Generation ($/MWh)	$ 46.23	$ 42.84	$ 39.76	$ 41.71	$ 44.81	$ 45.10	$ 44.38	$ 47.37
L = D-J	Total RES Premium/Discount (millions)	$ (38.7)	$ (21.9)	$ 8.1	$ 0.6	$ 18.5	$ 15.2	$ 14.8	$ 0.5
M = E-K	Total RES Premium/Discount ($/MWh)	$ (10.50)	$ (5.96)	$ 2.19	$ 0.15	$ 5.03	$ 4.15	$ 4.03	$ 0.15
	Annualized RES Rate Impacts								
N	Minnesota Power Sales (Retail & Wholesale; GWh)	9,485	9,570	9,568	9,603	9,794	9,962	9,982	10,023
O = L/N	Rate Impact ($/MWh)	$ (4.08)	$ (2.29)	$ 0.84	$ 0.06	$ 1.89	$ 1.53	$ 1.48	$ 0.05
P = O/10	Rate Impact (¢/kWh)	(0.41)	(0.23)	0.08	0.01	0.19	0.15	0.15	0.01

[3] In preparing the RES rate impact analysis Minnesota Power discovered errors in the revenue requirements in EnCompass for Bison 1-4, run of river hydro, and Hibbard. In the RES rate impact analysis the errant revenue requirements were corrected. Note that the correction to these revenue requirements has no impact to the IRP analysis given these error were consistent across all scenarios evaluated and did not impact new alternatives and generators considered for retirement.

Table 4: Future RES Rate Impact (2029 - 2035)

		Future (2029 - 2035)						
	RES Generation	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
A	Total RES Generation (PPA + Owned; GWh)	3,696	3,680	3,683	3,686	3,686	3,678	3,681
	Costs Associated with RES Generation (Revenue Requirements)							
B	Purchased Power + Owned Generation (millions)	$ 173.1	$ 170.4	$ 171.1	$ 175.7	$ 173.0	$ 167.3	$ 164.6
C	RES Attributable Transmission (millions)	$ 2.6	$ 2.5	$ 2.4	$ 2.2	$ 2.1	$ 2.0	$ 2.0
D = B+C	Total Cost for RES Generation (millions)	$ 175.6	$ 172.8	$ 173.4	$ 177.9	$ 175.2	$ 169.4	$ 166.5
E = D/A	Total Cost for RES Generation ($/MWh)	$ 47.5	$ 47.0	$ 47.1	$ 48.3	$ 47.5	$ 46.0	$ 45.2
	Avoided Costs due to RES							
F	Avoided Energy Costs PPAs & Owned Generation (millions)	$ 93.0	$ 97.7	$ 100.0	$ 108.4	$ 108.6	$ 108.6	$ 119.4
G	Avoided Capacity Cost PPAs & Owned Generation (millions)	$ 69.9	$ 67.9	$ 65.0	$ 62.9	$ 61.3	$ 59.8	$ 58.0
H	Avoided Transmission Cost (millions)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
I	Avoided Emissions Cost PPAs & Owned Generation (millions)	$ 12.3	$ 13.3	$ 17.0	$ 15.3	$ 13.5	$ 17.1	$ 16.6
J = F+G+H+I	Total Avoided Costs PPAs & Owned Generation (millions)	$ 175.1	$ 178.8	$ 181.9	$ 186.6	$ 183.3	$ 185.5	$ 194.0
K = J/A	Total Avoided Costs PPAs & Owned Generation ($/MWh)	$ 47.37	$ 48.60	$ 49.41	$ 50.63	$ 49.74	$ 50.44	$ 52.70
L = D-J	Total RES Premium/Discount (millions)	$ 0.5	$ (6.0)	$ (8.5)	$ (8.7)	$ (8.2)	$ (16.1)	$ (27.5)
M = E-K	Total RES Premium/Discount ($/MWh)	$ 0.15	$ (1.64)	$ (2.31)	$ (2.37)	$ (2.21)	$ (4.39)	$ (7.46)
	Annualized RES Rate Impacts							
N	Minnesota Power Sales (Retail & Wholesale; GWh)	10,023	10,009	10,018	10,020	10,021	9,959	9,921
O = L/N	Rate Impact ($/MWh)	$ 0.05	$ (0.60)	$ (0.85)	$ (0.87)	$ (0.81)	$ (1.62)	$ (2.77)
P = O/10	Rate Impact (¢/kWh)	0.01	(0.06)	(0.08)	(0.09)	(0.08)	(0.16)	(0.28)

Table 5: Levelized RES Costs and Rate Impact

		Discount Rate 7.0639%	
	Levelized RES Generation	**Historic Period (2005-2020)**	**Future Period (2021-2035)**
A	Total RES Generation (PPA + Owned; GWh)	1,346	3,684
	Levelized Costs Associated with RES Generation (Revenue Requirements)		
B	Purchased Power + Owned Generation (millions)	$ 59.3	$ 160.7
C	RES Attributable Transmission (millions)	$ 2.4	$ 2.7
D = B+C	Total Cost for RES Generation (millions)	$ 61.7	$ 163.5
E = D/A	Total Cost for RES Generation ($/MWh)	$ 45.9	$ 44.4
	Levelized Avoided Costs due to RES		
F	Avoided Energy Costs PPAs & Owned Generation (millions)	$ 43.6	$ 88.7
G	Avoided Capacity Cost PPAs & Owned Generation (millions)	$ 47.6	$ 72.6
H	Avoided Transmission Cost (millions)	$ 0.1	$ -
I	Avoided Emissions Cost PPAs & Owned Generation (millions)	$ -	$ 8.9
J = F+G+H+I	Total Avoided Costs PPAs & Owned Generation (millions)	$ 91.4	$ 170.2
K = J/A	Total Avoided Costs PPAs & Owned Generation ($/MWh)	$ 67.88	$ 46.19
L = D-J	Total RES Premium/Discount (millions)	$ (29.6)	$ (6.7)
M = E-K	Total RES Premium/Discount ($/MWh)	$ (22.01)	$ (1.81)
	Levelized RES Rate Impacts		
N	Minnesota Power Sales (Retail & Wholesale; GWh)	10,370	9,810
O = L/N	Rate Impact ($/MWh)	$ (2.86)	$ (0.68)
P = O/10	Rate Impact (¢/kWh)	(0.29)	(0.07)

Historic Cost Impact for the SES (2016 – 2020)

Historic rate impacts were determined by comparing the actual direct costs associated with the Company's solar generation each year with an estimate of the direct costs that would have been incurred had Minnesota Power acquired the same accredited generation capacity (MW) and energy (MWh) from non-renewable resources. The cost of building a new framed combustion turbine ("CT") unit and associated fixed operations and maintenance ("O&M") expenses were used to estimate avoided capacity costs. The energy cost from a CT and associated variable O&M expenses were used to estimate the avoided energy cost.[4] The construction costs and generation characteristics represents a CT typically built around 2020.

Table 6: Historic SES Rate Impact (2016 - 2020)

		Historic (2016 - 2020)				
	SES Generation	**2016**	**2017**	**2018**	**2019**	**2020**
A	Total SES Generation (PPA + Owned; MWh)	1,720	17,134	18,577	15,743	18,141
	Costs (Revenue Requirements) associated with SES Generation					
B	Purchased Power + Owned Generation (thousands)	$ 358.4	$ 1,782.5	$ 1,731.3	$ 1,917.4	$ 1,806.8
C	SES Attributable Transmission (thousands)	$ -	$ -	$ -	$ -	$ -
D = B+C	Total Cost for SES Generation (thousands)	$ 358.4	$ 1,782.5	$ 1,731.3	$ 1,917.4	$ 1,806.8
E = D/A	Total Cost for SES Generation ($/MWh)	$ 208.4	$ 104.0	$ 93.2	$ 121.8	$ 99.6
	Avoided Costs due to SES					
F	Avoided Energy Costs PPAs & Owned Generation (thousands)	$ 45.6	$ 554.5	$ 588.4	$ 414.6	$ 395.0
G	Avoided Capacity Cost PPAs & Owned Generation (thousands)	$ -	$ 489.9	$ 672.5	$ 692.0	$ 364.9
H	Avoided Transmission Cost (thousands)	$ -	$ -	$ -	$ -	$ -
I	Avoided Emissions Cost PPAs & Owned Generation (thousands)	$ -	$ -	$ -	$ -	$ -
J = F+G+H+I	Total Avoided Costs PPAs & Owned Generation (thousands)	$ 45.6	$ 1,044.4	$ 1,261.0	$ 1,106.6	$ 759.9
K = J/A	Total Avoided Costs PPAs & Owned Generation ($/MWh)	$ 26.53	$ 60.95	$ 67 88	$ 70.29	$ 41.89
L = D-J	Total SES Premium/Discount (thousands)	$ 312.8	$ 738.1	$ 470.4	$ 810.8	$ 1,046.9
M = E-K	Total SES Premium/Discount ($/MWh)	$ 181.87	$ 43.08	$ 25 32	$ 51.50	$ 57.71
	Annualized SES Rate Impacts					
N	Minnesota Power Retail Sales (non-SES exempt; MWh)	3,037,096	3,023,548	3,033,136	3,024,576	2,890,666
O = L/N	Retail Rate Impact ($/MWh)	$ 0.10	$ 0.24	$ 0.16	$ 0.27	$ 0.36
P = O/10	Retail Rate Impact (¢/kWh)	0.01	0.02	0 02	0.03	0.04

Future SES Rate Impact (2021 - 2035)

Future SES rate impacts were derived using a similar methodology described above for future RES rate impacts in that the comparisons of power supply cost were made for two different futures using the EnCompass software tool: 1) a "SES" compliant future that reflects the 2021 Plan recommended in Section V, and 2) a "No SES" future in which all solar generation capacity and energy contained in the "SES" future used to meet the SES are removed and replaced with non-renewable generation. The type and timing of the replacement energy and capacity was based on an expansion plan using EnCompass. The difference in annual power supply cost between the two futures represents the project cost impact associated with the Company's expected actions to comply with the SES. The "SES" future is the 2021 Plan discussed in Section V.

It is important to note that unlike the RES, the SES applies to only a portion of Minnesota Power's customers, and will have rate impacts only for non-exempt retail customers. Wholesale

[4] The energy cost is based on historical natural gas prices at Ventura multiplied by the heat rate of the CT plus variable O&M costs. The assumed heat rate for the CT was 9,120 Btu/kWh.

customers are excluded entirely. Consequently, the values presented for the SES rate impacts represent the impacts to non-exempt retail customers only.

Table 7 and Table 8 show the estimated future rate impacts attributed to meeting the SES by year for 2021 - 2028 and 2029 - 2035, respectively. Table 9 shows the levelized costs and rate impacts associated with meeting the SES for the historic period (2016 – 2020) and future period (2021 - 2035).

Table 7: Future SES Rate Impact (2021 - 2028)[5]

		Future (2021 - 2028)							
	SES Generation	2021	2022	2023	2024	2025	2026	2027	2028
A	Total SES Generation (PPA + Owned; MWh)	17,906	61,369	61,274	61,262	61,058	60,912	60,798	60,795
	Costs (Revenue Requirements) associated with SES Generation								
B	Purchased Power + Owned Generation (thousands)	$ 2,191.2	$ 4,809.2	$ 4,877.0	$ 4,950.6	$ 5,017.5	$ 5,090.3	$ 4,381.5	$ 4,424.1
C	SES Attributable Transmission (thousands)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
D = B+C	Total Cost for SES Generation (thousands)	$ 2,191.2	$ 4,809.2	$ 4,877.0	$ 4,950.6	$ 5,017.5	$ 5,090.3	$ 4,381.5	$ 4,424.1
E = D/A	Total Cost for SES Generation ($/MWh)	$ 122.4	$ 78.4	$ 79.6	$ 80.8	$ 82.2	$ 83.6	$ 72.1	$ 72.8
	Avoided Costs due to SES								
F	Avoided Energy Costs PPAs & Owned Generation (thousands)	$ 448.8	$ 1,847.0	$ 851.6	$ 4,087.8	$ 1,280.7	$ 872.7	$ 1,841.9	$ 1,907.4
G	Avoided Capacity Cost PPAs & Owned Generation (thousands)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
H	Avoided Transmission Cost (thousands)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
I	Avoided Emissions Cost PPAs & Owned Generation (thousands)	$ -	$ -	$ -	$ -	$ 879.1	$ 957.1	$ (653.0)	$ 696.5
J = F+G+H+I	Total Avoided Costs PPAs & Owned Generation (thousands)	$ 448.8	$ 1,847.0	$ 851.6	$ 4,087.8	$ 2,159.8	$ 1,829.8	$ 1,188.9	$ 2,603.9
K = J/A	Total Avoided Costs PPAs & Owned Generation ($/MWh)	$ 25.07	$ 30.10	$ 13.90	$ 66.73	$ 35.37	$ 30.04	$ 19.55	$ 42.83
L = D-J	Total SES Premium/Discount (thousands)	$ 1,742.4	$ 2,962.2	$ 4,025.4	$ 862.8	$ 2,857.7	$ 3,260.4	$ 3,192.6	$ 1,820.2
M = E-K	Total SES Premium/Discount ($/MWh)	$ 97.31	$ 48.27	$ 65.70	$ 14.08	$ 46.80	$ 53.53	$ 52.51	$ 29.94
	Annualized SES Rate Impacts								
N	Minnesota Power Retail Sales (non-SES exempt; MWh)	3,027,112	3,185,868	3,331,174	3,338,945	3,329,914	3,336,209	3,341,023	3,354,433
O = L/N	Retail Rate Impact ($/MWh)	$ 0.58	$ 0.93	$ 1.21	$ 0.26	$ 0.86	$ 0.98	$ 0.96	$ 0.54
P = O/10	Retail Rate Impact (¢/kWh)	0.06	0.09	0.12	0.03	0.09	0.10	0.10	0.05

Table 8: Future SES Rate Impact (2029 - 2035)

		Future (2029 - 2035)						
	SES Generation	2029	2030	2031	2032	2033	2034	2035
A	Total SES Generation (PPA + Owned; MWh)	60,592	60,508	60,402	60,339	60,149	60,076	59,954
	Costs (Revenue Requirements) associated with SES Generation							
B	Purchased Power + Owned Generation (thousands)	$ 4,426.6	$ 5,066.5	$ 4,506.1	$ 4,563.8	$ 5,292.0	$ 4,711.8	$ 4,792.5
C	SES Attributable Transmission (thousands)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
D = B+C	Total Cost for SES Generation (thousands)	$ 4,426.6	$ 5,066.5	$ 4,506.1	$ 4,563.8	$ 5,292.0	$ 4,711.8	$ 4,792.5
E = D/A	Total Cost for SES Generation ($/MWh)	$ 73.1	$ 83.7	$ 74.6	$ 75.6	$ 88.0	$ 78.4	$ 79.9
	Avoided Costs due to SES							
F	Avoided Energy Costs PPAs & Owned Generation (thousands)	$ 1,449.4	$ 2,317.1	$ 2,650.0	$ 1,210.3	$ 1,660.4	$ 1,910.1	$ 3,892.7
G	Avoided Capacity Cost PPAs & Owned Generation (thousands)	$ -	$ 464.2	$ 512.3	$ 537.7	$ 541.5	$ 134.1	$ 313.2
H	Avoided Transmission Cost (thousands)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
I	Avoided Emissions Cost PPAs & Owned Generation (thousands)	$ 790.4	$ 266.3	$ 460.2	$ 991.2	$ 918.6	$ 299.4	$ 539.8
J = F+G+H+I	Total Avoided Costs PPAs & Owned Generation (thousands)	$ 2,239.9	$ 3,047.6	$ 3,622.4	$ 2,739.3	$ 3,120.5	$ 2,343.5	$ 4,745.8
K = J/A	Total Avoided Costs PPAs & Owned Generation ($/MWh)	$ 36.97	$ 50.37	$ 59.97	$ 45.40	$ 51.88	$ 39.01	$ 79.16
L = D-J	Total SES Premium/Discount (thousands)	$ 2,186.8	$ 2,018.9	$ 883.7	$ 1,824.5	$ 2,171.5	$ 2,368.2	$ 46.7
M = E-K	Total SES Premium/Discount ($/MWh)	$ 36.09	$ 33.37	$ 14.63	$ 30.24	$ 36.10	$ 39.42	$ 0.78
	Annualized SES Rate Impacts							
N	Minnesota Power Retail Sales (non-SES exempt; MWh)	3,346,655	3,349,806	3,355,435	3,371,030	3,366,899	3,370,103	3,373,311
O = L/N	Retail Rate Impact ($/MWh)	$ 0.65	$ 0.60	$ 0.26	$ 0.54	$ 0.64	$ 0.70	$ 0.01
P = O/10	Retail Rate Impact (¢/kWh)	0.07	0.06	0.03	0.05	0.06	0.07	0.00

[5] For the proposed 20 MW utility-scale solar projects in Northern Minnesota (Docket No. E015/M-20-828) Minnesota Power used in the IRP EnCompass model an estimated PPA price based on the best available information at that time. For the SES Rate Impact analysis the PPA price was updated with the pricing shown in the 20 MW utility-scale solar projects petition.

Table 9: Levelized SES Costs and Rate Impact

		Discount Rate 7.0639%	
	Levelized SES Generation	Historic Period (2005-2020)	Future Period (2021-2035)
A	Total SES Generation (PPA + Owned; MWh)	13,820	56,235
	Levelized Costs (Revenue Requirements) associated with SES Generation		
B	Purchased Power + Owned Generation (thousands)	$ 1,476.7	$ 4,510.4
C	SES Attributable Transmission (thousands)	$ -	$ -
D = B+C	Total Cost for SES Generation (thousands)	$ 1,476.7	$ 4,510.4
E = D/A	Total Cost for SES Generation ($/MWh)	$ 106.85	$ 80.21
	Levelized Avoided Costs due to SES		
F	Avoided Energy Costs PPAs & Owned Generation (thousands)	$ 391.4	$ 1,690.8
G	Avoided Capacity Cost PPAs & Owned Generation (thousands)	$ 430.3	$ 113.4
H	Avoided Transmission Cost (thousands)	$ -	$ -
I	Avoided Emissions Cost PPAs & Owned Generation (thousands)	$ -	$ 340.8
J = F+G+H+I	Total Avoided Costs PPAs & Owned Generation (thousands)	$ 821.8	$ 2,144.9
K = J/A	Total Avoided Costs PPAs & Owned Generation ($/MWh)	$ 59.46	$ 38.14
L = D-J	Total SES Premium/Discount (thousands)	$ 654.9	$ 2,365.5
M = E-K	Total SES Premium/Discount ($/MWh)	$ 47.39	$ 42.07
	Levelized SES Rate Impacts		
N	Minnesota Power Retail Sales (non-SES exempt; MWh)	3,006	3,296
O = L/N	Retail Rate Impact ($/MWh)	$ 0.22	$ 0.72
P = O/10	Retail Rate Impact (¢/kWh)	0.02	0.07

Indirect Cost Impact – Ancillary Service and Base Load Cycling (2005 – 2035)

Minnesota Power operates its thermal and renewable fleet in the Midcontinent Independent System Operator ("MISO") regional market on a daily basis. Each unit is offered into the Day-Ahead Energy and Operating Reserve Market for the energy and ancillary services products available. MISO's region-wide optimization identifies which units will and will not be utilized for the next day's market.

Wind energy is the largest component of renewable energy in Minnesota Power's portfolio, providing over 3 million MWh each year for customers. The onset of additional wind in the Midwest has created a new operational environment for MISO to manage on a dispatch basis. The Company is monitoring trends and adapting its operational strategy for generating units with the additional wind in its portfolio. To adapt to the growing renewables in Minnesota Power's power supply and regionally the Company has made significant operational change to its thermal fleet.

Many variables impact the regional marketplace including both supply and demand-side factors. The regional market has seen a decline in market pricing; this trend can be attributable in part to both a surplus of energy from new generation (renewable and other forms), lower natural gas pricing, and a decline in customer demand. Although, the Company has observed what appears to be more volatile energy prices in recent months during periods of tight demand. The recent polar vortex event in February 2021 resulted in the highest monthly LMP observed over the last 10 years. Typically, a lower priced regional energy market creates more dispatch changes to the thermal unit fleet across the Midwest. The generating units that are higher in cost are the first to be impacted (have reductions in energy production), and the more efficient generating facilities see less change. In recent years the lower prices are now impacting operations at Minnesota Power's most efficient thermal units resulting in the need to transition to more flexible operations.

Since the 2015 IRP, Minnesota Power has seen reduced generation output due to lower market pricing in the region. The lower pricing is exacerbated during times when the wind production is high in MISO and demand is low, such as during the overnight hours. Minnesota Power has taken action at several of its smaller coal plants in response to the lower energy prices, including converting the mission for Laskin Energy Center from a coal baseload operations to a natural gas fired peaking operation, along with retirement of five coal generation facilities. Minnesota Power's remaining two thermal generating units at Boswell Energy Center have seen less generation output recently due to lower market pricing due to the competitive production costs at the facility. To adapt to periods of lower market prices BEC Unit 3 is transitioning to economic dispatch in July 2021. Also, Minnesota Power is in discussion with WPPI, co-owner of BEC Unit 4, on an economic dispatch transmission and with MISO on transmission reliability concerns.

The Ancillary Services Market identifies trends in a region's ability to meet its reliability requirements through the pricing and procurement of services such as regulation (balancing the system), along with spin and supplemental reserves (protecting against unexpected increases and decreases of load and generation). Typically an increase in the need for ancillary services is indicative of additional fluctuations on the power system which need to be managed. MISO identifies the requirements for ancillary services on a daily basis to ensure reliability for each local balancing area. The MISO ancillary program started in January 2009

At this time Minnesota Power has not been able to definitively pinpoint the onset of renewables and its resulting impact to ancillary product requirements for its customers, although trends over the last five years give an indication that the value for near term flexibility could be increasing. Since 2015, the price paid for Regulation services has increased nearly 25%, although, the level of regulation procured by MISO is unchanged. A generator is compensated for providing Regulation by being capable to increase or decrease generation in 5 minute intervals as directed by MISO. Currently, Boswell units 3 and 4 provide Regulation service to the MISO market, although this can only be provided when the units are online. Prices for other ancillary services, Spin and Supplemental, have decreased since 2015. Minnesota Power's conclusion based on Ancillary Services Market trend is near-term flexibility is increasing in value within the MISO market, which could be caused by less generation resources available that can provide this regulation.

In summary, Minnesota Power has seen lower energy market prices when the wind is strong in the MISO footprint in comparison to when there is less wind available. Lower pricing will pressure generating units to reduce operating levels and require more flexible baseload operations as pricing declines and to ensure a reliable power supply for customers. To date, Minnesota Power has made significant operational change to its thermal generation due to lower pricing, including retirement, idling, refueling, and transition to economic dispatch operations for baseload generation. The Company has not identified any direct impacts to its ancillary services requirements that are due to renewable implementation as part of the RES or SES requirements.

Avoided Environmental Permitting and Emission Compliance Cost Impact

When determining the cost of a new natural gas 1x1 CC resource and the CT, the avoided costs for future emission compliance, including cost of SO_2 and NO_x permits are factored into its value. Therefore, the avoided permitting and emission related costs are accounted for in the capital cost for the new natural gas CC and CT resources. Minnesota Power also applied the Commission-approved \$21.50/ton CO_2 regulation penalty[6] beginning in 2019.

Transmission Cost Impact (2005-2035)

Minnesota Power's renewable portfolio is comprised primarily of a combination of long-standing hydro resources, an expanding wind portfolio, and regional solar. Transmission costs for renewable resource assets in service prior to 2005 and the RES being established were not included in the cost impact calculation. Transmission improvements associated with renewable resources added in recent years that qualify under the RES are included in the estimated costs.

<u>Multipurpose High Voltage Direct Current Line ("DC Line")</u>

In early 2010, Minnesota Power finalized its purchase of the 465 mile, +/- 250 kV DC Line that connects Center, N.D., and Hermantown, Minn. The DC Line was built in the 1970s to bring electricity from Milton R. Young 2 ("Young 2") lignite coal generating station in Center, N.D., to Minnesota Power's customers. The Company's purchase of the DC Line cleared the way for the DC Line to be repurposed to facilitate the delivery of wind power generated in North Dakota to Minnesota Power's customers. Between 2010 and 2013, the Company completed a series of upgrades that increased the capacity of the DC Line to 550 MW.[7]

[6] Minn. Stat. § 216H.06.

[7] The 50 MW upgrade to the DC Line was completed in November 2013.

Figure 1: Minnesota Power's DC Line Map

The purchase of the DC Line and the phase-out of Minnesota Power's long-term contract to buy coal-fired generation from Young 2 were approved by the Commission in December 2009. Up until June 2014, Minnkota Power Cooperative ("Minnkota") and Minnesota Power were each receiving 227.5 MW (50 percent shares) of electric generation from Young 2 that was delivered to customers via the DC Line. As described in Appendix C of the 2021 Plan, the Company is gradually reducing its 227.5 MW share of coal-fired generation from Young 2 and, by 2026, will no longer take any of the Young 2 output for its customers. Additionally, Minnkota began utilizing its newly constructed Center to Grand Forks 345 kV transmission line in August 2014 to transfer its share of Young 2 output.[8] These actions result in an increasing amount of capacity being available on the DC Line for the transfer of wind energy, with the full 550 MW of capacity available in 2026. Figure 2 illustrates the proportion of coal-fired generation versus wind energy being transferred via the DC Line.

[8] Minnkota's share of Young 2 will gradually increase to 455 MW during the period of 2014 - 2026 due to purchasing Minnesota Power's 227.5 share of Young 2 generation.

Figure 2: Proportion of Coal to Wind Energy on the DC Line (2010 - 2029)

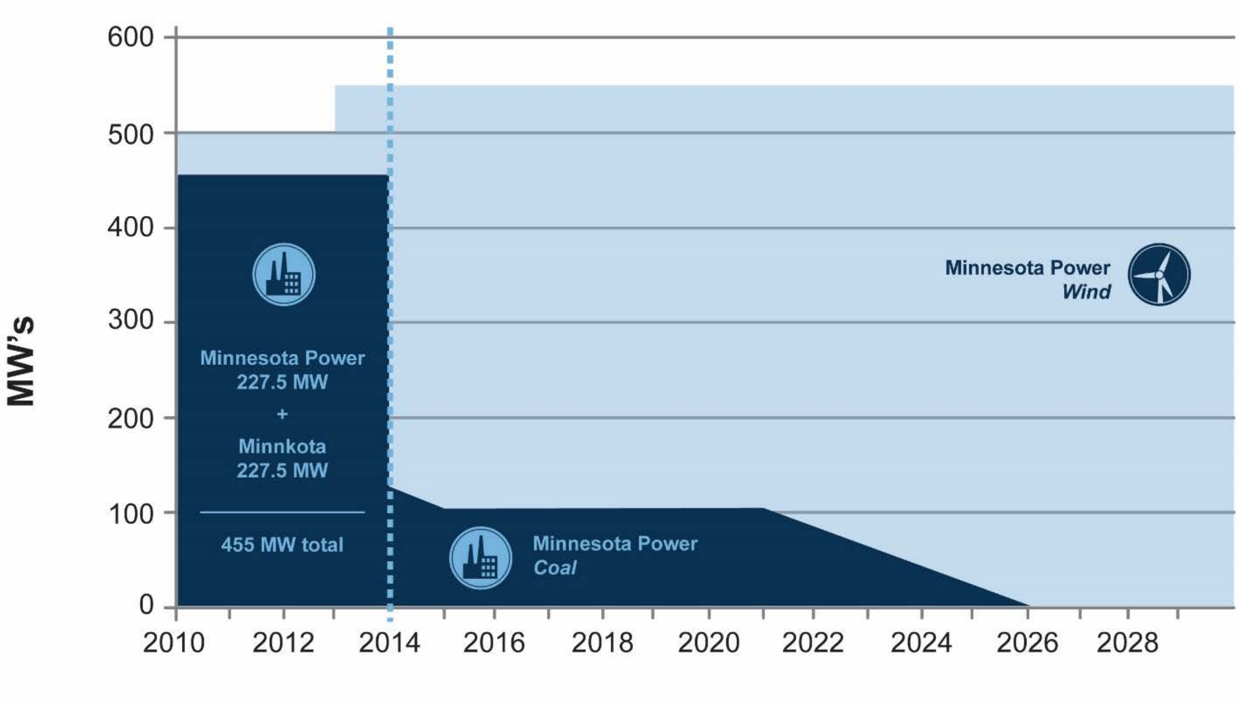

Table 10 contains the estimated DC Line cost for transferring wind power from the Bison Wind Center and Oliver County I and II to Minnesota Power customers via the DC Line over the planning period. The estimated costs are based on the amount of capacity available on the DC Line to transmit wind energy multiplied the revenue requirements for the HVDC. The HVDC revenue requirements for the historic period and future period is based on a transmission revenue requirement model that incorporates capital and O&M.[9] The ability to transfer an increasing amount of wind power via the DC Line over the planning period is reflected in Row D of Table 10.

[9] Minnesota Power has been evaluating the need for modernization and potential capacity upgrades to extend the life and expand the usefulness of the HVDC line. The projected revenue requirements shown in Table 10 assumes the modernization project is complete by end of 2027 and there are no capacity upgrades.

Table 10: DC Line Estimate of Costs for Renewable Energy Transfer

[TRADE SECRET DATE BEGINS

[redacted]

TRADE SECRET DATA ENDS]

Minnesota Power leveraged the existing transmission assets installed for the Bison 1 Project (Docket No. E-015/M-09-285) in 2010 and 2011 to transmit the power from the subsequent constructed Bison 2, 3 and 4 projects to the point of interconnection. The costs shown in Tables 1, 2, 3 and 4 reflect the following transmission assets:

- A new 230 kV alternating current ("AC") transmission line, initially about 22 miles in length which was later extended 11 miles to accommodate the Bison 4 Wind project. The line is required to transmit wind generation from the substation to the point of interconnection.
- Two new substations, the Bison Substation and Tri-County Substation, that each include a 34.5 kV/230 kV transformer to enable connecting the power output to the high voltage electrical transmission network
- Modification to the existing 230 kV Square Butte Substation
- Increase in capacity of the DC Line from 500 MW to 550 MW

No new transmission assets were needed for Taconite Ridge Wind Center due to its proximity to existing transmission infrastructure; therefore, no transmission related costs for the facility were included in the calculation. The 34.5 kV collector system required to deliver the power generated by the ten turbines to the existing substation is considered a distribution asset of Taconite Ridge Wind Center. Additionally, the Company did not include transmission costs for its existing hydroelectric stations which were constructed and placed in service well before 2005 and establishment of the RES or for wind Power Purchase Agreements given transmission cost are included in the energy price.

Ultimate Rate Impact

It was assumed for purposes of this Report that because Minnesota Power plans and constructs resources for its system as a whole, historic and future cost/rate impacts to wholesale customers are similar in magnitude to those for retail customers. With the exception of the SES (due to customer exemptions), it was assumed that wholesale and retail rate impacts due to renewables will closely track one another. As a result, the values presented for the RES rate impacts in this Report approximately represent all customer rate impacts (both retail and wholesale). The historic and future annualized RES rate impacts are shown in Rows O and P in Tables 1, 2 3, and 4, and the historic and future levelized rate impacts are shown in Rows O and P in Table 5. The historic and future annualized SES rate impacts are shown in Rows O and P in Tables 6, 7 and 8, and the historic and future levelized rate impacts are shown in Rows O and P in Table 9. For non-exempt retail customers, the total RES and SES rate impact is the combination of the rate impact described in this Report.

In summary, the analysis shows that the investments Minnesota Power has made on behalf of its customers to meet the RES have been reasonable and resulted in estimated rates impacts that are competitive with alternative power supply resource options. Historically, costs associated with facilities to meet the RES have provided a net benefit to customers' rates compared with the cost of building a natural gas CC unit to replace the energy from qualifying renewable sources. This trend is expected to continue in future years. Both historic and projected costs to meet the SES show increases to non-solar exempt customer rates ranging from $0.22/MWh (historic levelized) to $0.72/MWh (projected levelized). The Company will continue to closely monitor developments in renewable resource technology and trends in order to ensure Minnesota Power complies with existing and future renewable energy related standards and to meet the Company's own sustainability goals in the most cost-effective manner on behalf of its customers.