APPENDIX C – PART 1
COST IMPACTS

The intent of this section is to provide further details on the cost impacts of adding the Nobles 2 Wind Project to Minnesota Power's energy portfolio. To quantify the change in power supply cost when adding the Nobles 2 Project in 2020, the Strategist production cost model was utilized by simulating a power supply dispatch. There were ten Strategist futures with up to 30 sensitivities each for a total of 272 cases used to simulate the addition of the Nobles 2 Project. Included in all futures is the proposed 250 MW Nemadji Trail Energy Center Purchase and 10 MW Blanchard Solar purchase from the 2017 Energy*Forward* Resource Package. More detailed information about the assumptions included in each Future can be found in Section III of the Petition.

The ten futures were used to compare three different scenarios as shown in Table 1 below. Scenario 1 (Baseline) contains all Minnesota Power existing thermal and renewable energy resources included in the 2017 Energy*Forward* Resource Package, except for the Nobles 2 Project. Scenarios 2 and 3 vary the potential cost of the transmission system upgrades required to interconnect the Project to the transmission system between zero and the max cap per the PPA. Scenario 2 incrementally adds the proposed Nobles 2 Project and associated project costs to the Scenario 1 ("Baseline") scenario – without including additional costs for transmission system upgrades. Scenario 3 incrementally adds the maximum transmission system upgrade costs allowed to be passed on to Minnesota Power customers under the revised PPA terms to Futures developed for Scenario 2 – representing the maximum cost customers could pay for Nobles 2 energy.

- Scenario 1 – Energy*Forward* Resource Package without Nobles 2
- Scenario 2 – Energy*Forward* Resource Package with Nobles 2 base PPA pricing
- Scenario 3 – Energy*Forward* Resource Package with Nobles 2 and transmission adder at the cost cap set for transmission system upgrades

Table 1: Comparison of Key Assumptions by Future

Futures	Strategist Case Name	Resource Adequacy Season	CO_2 Regulation Penalty	Mid-Environmental Externality Values	Turn Energy Market Off	Excess Energy Sold Into Wholesale Market
Future 1	C1SR	Summer	No	No	No	Yes
Future 2	C2SR	Summer	No	No	No	No
Future 3	C3SR	Summer	Yes	No	No	Yes
Future 4	C4SR	Summer	Yes	No	No	No
Future 5	C1WR	Winter	No	No	No	Yes
Future 6	C2WR	Winter	No	No	No	No
Future 7	C3WR	Winter	Yes	No	No	Yes
Future 8	C4WR	Winter	Yes	No	No	No
Future 9	C5S	Summer	Yes	Yes	Yes	No
Future 10	C5W	Winter	Yes	Yes	Yes	No

For each of the 272 unique cases, the cost impacts of Scenario 1 and Scenario 2 were compared to determine which Scenario had the lowest overall power supply cost. In all cases, the addition of the Nobles 2 Wind Project lowered the overall power supply costs to Minnesota Power's Customers. When compared to Scenario 3, which includes the maximum transmission network upgrades, overall powr supply costs remain lower cost than Scenario 1 in all cases, demonstrating that the Nobles 2 Wind Project remains a benefit for customers if the cap on network upgrade cost is reached.

Tables 2 through 11 show the comparison of power supply costs for each Sensitvity in detail broken up by Future. In each table, the "gray" colored cell highlights the lower cost Scenario for each Sensitivity. The power supply costs presented are the net present value of the total power supply costs between 2017 and 2034.

Table 2: Scenario Comparative Analysis for Future 1 (C1SR)

		Power Supply Cost ($millions)		
Number	Sensitivity	SCENARIO 1: EFRP w/o NOBLES 2	SCENARIO 2: EFRP with NOBLES 2	SCENARIO 3: EFRP with NOBLES 2 & Transmission
0	BASE	$5,825	$5,734	$5,761
1	$9 CO2 2022	$6,207	$6,080	$6,107
2	$34 CO2 2022	$7,251	$7,002	$7,029
3	LOW COAL -30%	$5,419	$5,345	$5,372
4	HIGH COAL +30%	$6,200	$6,093	$6,120
5	LOWER GAS -50%	$5,644	$5,580	$5,607
6	LOW GAS -25%	$5,735	$5,661	$5,688
7	HIGH GAS +25%	$5,900	$5,797	$5,824
8	HIGHER GAS +50%	$5,967	$5,858	$5,885
9	HIGHEST GAS +100%	$6,109	$5,994	$6,021
10	LOW EXTERNALITY	$7,299	$7,010	$7,037
11	HIGH EXTERNALITY	$10,414	$9,955	$9,982
12	MID EXTERNALITY	$8,883	$8,507	$8,534
13	LOWER WHOLESALE MARKET	$5,568	$5,525	$5,552
14	LOW WHOLESALE MARKET	$5,725	$5,655	$5,682
15	HIGH WHOLESALE MARKET	$5,896	$5,791	$5,818
16	HIGHER WHOLESALE MARKET	$5,950	$5,829	$5,856
17	NO WHOLESALE MARKET	$6,324	$6,086	$6,113
18	50% TIE LIMIT	$5,901	$5,790	$5,817
19	NO MARKET TIERS OR SALES	$5,792	$5,720	$5,747
20	2017 PRICES	$5,674	$5,620	$5,648
21	-30% CAPITAL	$5,820	$5,729	$5,756
22	+30% CAPITAL	$5,829	$5,738	$5,765
23	-20% WIND CAPACITY	$5,827	$5,734	$5,762
24	AFR2017 HIGH	$6,075	$5,956	$5,983
25	AFR2017 LOW	$5,778	$5,694	$5,721
26	PRM +2%	$5,829	$5,735	$5,762
27	MISO COINCIDENT -2%	$5,821	$5,732	$5,759
28	MISO COINCIDENT +2%	$5,833	$5,738	$5,765
29	EE +15GW	$5,828	$5,739	$5,766
30	EE +30GW	$5,857	$5,772	$5,799
Least Cost Count		**0**	**31**	**0**

Table 3: Scenario Comparative Analysis for Future 2 (C2SR)

		Power Supply Cost ($millions)		
Number	Sensitivity	SCENARIO 1: EFRP w/o NOBLES 2	SCENARIO 2: EFRP with NOBLES 2	SCENARIO 3: EFRP with NOBLES 2 & Transmission
0	BASE	$5,834	$5,748	$5,775
1	$9 CO2 2022	$6,221	$6,098	$6,126
2	$34 CO2 2022	$7,265	$7,026	$7,053
3	LOW COAL -30%	$5,434	$5,367	$5,394
4	HIGH COAL +30%	$6,208	$6,107	$6,135
5	LOWER GAS -50%	$5,666	$5,609	$5,636
6	LOW GAS -25%	$5,753	$5,683	$5,710
7	HIGH GAS +25%	$5,904	$5,807	$5,834
8	HIGHER GAS +50%	$5,970	$5,865	$5,892
9	HIGHEST GAS +100%	$6,107	$5,992	$6,019
10	LOW EXTERNALITY	$7,299	$7,010	$7,037
11	HIGH EXTERNALITY	$10,414	$9,955	$9,982
12	MID EXTERNALITY	$8,883	$8,507	$8,534
13	LOWER WHOLESALE MARKET	$5,569	$5,527	$5,555
14	LOW WHOLESALE MARKET	$5,727	$5,660	$5,687
15	HIGH WHOLESALE MARKET	$5,922	$5,819	$5,846
16	HIGHER WHOLESALE MARKET	$5,994	$5,875	$5,902
17	NO WHOLESALE MARKET	$6,324	$6,086	$6,113
18	50% TIE LIMIT	$5,901	$5,790	$5,817
19	NO MARKET TIERS OR SALES	$5,792	$5,720	$5,747
20	2017 PRICES	$5,680	$5,632	$5,659
21	-30% CAPITAL	$5,830	$5,743	$5,771
22	+30% CAPITAL	$5,839	$5,753	$5,780
23	-20% WIND CAPACITY	$5,836	$5,749	$5,776
24	AFR2017 HIGH	$6,081	$5,965	$5,992
25	AFR2017 LOW	$5,789	$5,709	$5,736
26	PRM +2%	$5,839	$5,750	$5,777
27	MISO COINCIDENT -2%	$5,831	$5,747	$5,774
28	MISO COINCIDENT +2%	$5,842	$5,752	$5,779
29	EE +15GW	$5,838	$5,754	$5,781
30	EE +30GW	$5,867	$5,787	$5,814
Least Cost Count		**0**	**31**	**0**

Table 4: Scenario Comparative Analysis for Future 3 (C3SR)

		Power Supply Cost ($millions)		
Number	Sensitivity	SCENARIO 1: EFRP w/o NOBLES 2	SCENARIO 2: EFRP with NOBLES 2	SCENARIO 3: EFRP with NOBLES 2 & Transmission
0	BASE	$6,722	$6,532	$6,559
1	LOW COAL -30%	$6,341	$6,177	$6,204
2	HIGH COAL +30%	$7,080	$6,871	$6,898
3	LOWER GAS -50%	$6,520	$6,352	$6,379
4	LOW GAS -25%	$6,625	$6,445	$6,472
5	HIGH GAS +25%	$6,815	$6,619	$6,646
6	HIGHER GAS +50%	$6,908	$6,699	$6,726
7	HIGHEST GAS +100%	$7,047	$6,824	$6,851
8	LOW EXTERNALITY	$7,670	$7,340	$7,367
9	HIGH EXTERNALITY	$9,003	$8,634	$8,661
10	MID EXTERNALITY	$8,362	$8,011	$8,038
11	LOWER WHOLESALE MARKET	$6,327	$6,213	$6,240
12	LOW WHOLESALE MARKET	$6,564	$6,411	$6,438
13	HIGH WHOLESALE MARKET	$6,839	$6,625	$6,653
14	HIGHER WHOLESALE MARKET	$6,925	$6,689	$6,716
15	NO WHOLESALE MARKET	$7,186	$6,873	$6,900
16	50% TIE LIMIT	$6,797	$6,592	$6,619
17	NO MARKET TIERS OR SALES	$6,690	$6,524	$6,551
18	-30% CAPITAL	$6,717	$6,528	$6,555
19	+30% CAPITAL	$6,726	$6,537	$6,564
20	-20% WIND CAPACITY	$6,724	$6,533	$6,560
21	AFR2017 HIGH	$7,064	$6,845	$6,872
22	AFR2017 LOW	$6,652	$6,471	$6,498
23	PRM +2%	$6,726	$6,534	$6,561
24	MISO COINCIDENT -2%	$6,718	$6,531	$6,558
25	MISO COINCIDENT +2%	$6,730	$6,537	$6,564
26	EE +15GW	$6,722	$6,534	$6,561
27	EE +30GW	$6,734	$6,552	$6,579
	Least Cost Count	**0**	**28**	**0**

Table 5: Scenario Comparative Analysis for Future 4 (C4SR)

		Power Supply Cost ($millions)		
Number	Sensitivity	SCENARIO 1: EFRP w/o NOBLES 2	SCENARIO 2: EFRP with NOBLES 2	SCENARIO 3: EFRP with NOBLES 2 & Transmission
0	BASE	$6,735	$6,553	$6,581
1	LOW COAL -30%	$6,360	$6,202	$6,229
2	HIGH COAL +30%	$7,089	$6,889	$6,917
3	LOWER GAS -50%	$6,543	$6,384	$6,411
4	LOW GAS -25%	$6,644	$6,472	$6,500
5	HIGH GAS +25%	$6,823	$6,634	$6,661
6	HIGHER GAS +50%	$6,910	$6,705	$6,732
7	HIGHEST GAS +100%	$7,046	$6,827	$6,855
8	LOW EXTERNALITY	$7,670	$7,340	$7,367
9	HIGH EXTERNALITY	$9,003	$8,634	$8,661
10	MID EXTERNALITY	$8,362	$8,011	$8,038
11	LOWER WHOLESALE MARKET	$6,327	$6,216	$6,244
12	LOW WHOLESALE MARKET	$6,566	$6,419	$6,446
13	HIGH WHOLESALE MARKET	$6,871	$6,665	$6,692
14	HIGHER WHOLESALE MARKET	$6,979	$6,750	$6,777
15	NO WHOLESALE MARKET	$7,186	$6,873	$6,900
16	50% TIE LIMIT	$6,797	$6,592	$6,619
17	NO MARKET TIERS OR SALES	$6,690	$6,524	$6,551
18	-30% CAPITAL	$6,730	$6,549	$6,576
19	+30% CAPITAL	$6,739	$6,558	$6,585
20	-20% WIND CAPACITY	$6,737	$6,554	$6,581
21	AFR2017 HIGH	$7,071	$6,858	$6,885
22	AFR2017 LOW	$6,667	$6,494	$6,521
23	PRM +2%	$6,739	$6,555	$6,582
24	MISO COINCIDENT -2%	$6,731	$6,552	$6,579
25	MISO COINCIDENT +2%	$6,743	$6,558	$6,585
26	EE +15GW	$6,735	$6,555	$6,583
27	EE +30GW	$6,749	$6,575	$6,602
	Least Cost Count	**0**	**28**	**0**

Table 6: Scenario Comparative Analysis for Future 5 (C1WR)

Number	Sensitivity	Power Supply Cost ($millions) SCENARIO 1: EFRP w/o NOBLES 2	SCENARIO 2: EFRP with NOBLES 2	SCENARIO 3: EFRP with NOBLES 2 & Transmission
0	BASE	$5,827	$5,735	$5,763
1	$9 CO2 2022	$6,210	$6,082	$6,109
2	$34 CO2 2022	$7,253	$7,004	$7,031
3	LOW COAL -30%	$5,421	$5,347	$5,374
4	HIGH COAL +30%	$6,202	$6,095	$6,122
5	LOWER GAS -50%	$5,647	$5,582	$5,609
6	LOW GAS -25%	$5,737	$5,662	$5,690
7	HIGH GAS +25%	$5,902	$5,798	$5,825
8	HIGHER GAS +50%	$5,970	$5,860	$5,887
9	HIGHEST GAS +100%	$6,112	$5,996	$6,023
10	LOW EXTERNALITY	$7,301	$7,011	$7,038
11	HIGH EXTERNALITY	$10,416	$9,956	$9,983
12	MID EXTERNALITY	$8,885	$8,509	$8,536
13	LOWER WHOLESALE MARKET	$5,570	$5,527	$5,554
14	LOW WHOLESALE MARKET	$5,727	$5,657	$5,684
15	HIGH WHOLESALE MARKET	$5,899	$5,792	$5,820
16	HIGHER WHOLESALE MARKET	$5,952	$5,831	$5,858
17	NO WHOLESALE MARKET	$6,326	$6,088	$6,115
18	50% TIE LIMIT	$5,904	$5,792	$5,819
19	NO MARKET TIERS OR SALES	$5,794	$5,721	$5,748
20	2017 PRICES	$5,676	$5,622	$5,649
21	-30% CAPITAL	$5,822	$5,731	$5,758
22	+30% CAPITAL	$5,831	$5,740	$5,767
23	-20% WIND CAPACITY	$5,830	$5,737	$5,764
24	AFR2017 HIGH	$6,081	$5,961	$5,988
25	AFR2017 LOW	$5,780	$5,695	$5,722
26	PRM +2%	$5,833	$5,738	$5,765
27	MISO COINCIDENT -2%	$5,822	$5,732	$5,759
28	MISO COINCIDENT +2%	$5,837	$5,741	$5,768
29	EE +15GW	$5,831	$5,741	$5,768
30	EE +30GW	$5,858	$5,773	$5,800
Least Cost Count		**0**	**31**	**0**

Table 7: Scenario Comparative Analysis for Future 6 (C2WR)

Number	Sensitivity	Power Supply Cost ($millions) SCENARIO 1: EFRP w/o NOBLES 2	SCENARIO 2: EFRP with NOBLES 2	SCENARIO 3: EFRP with NOBLES 2 & Transmission
0	BASE	$5,837	$5,750	$5,777
1	$9 CO2 2022	$6,223	$6,100	$6,127
2	$34 CO2 2022	$7,267	$7,028	$7,055
3	LOW COAL -30%	$5,436	$5,368	$5,396
4	HIGH COAL +30%	$6,211	$6,109	$6,136
5	LOWER GAS -50%	$5,668	$5,610	$5,637
6	LOW GAS -25%	$5,756	$5,685	$5,712
7	HIGH GAS +25%	$5,907	$5,808	$5,836
8	HIGHER GAS +50%	$5,972	$5,866	$5,893
9	HIGHEST GAS +100%	$6,109	$5,993	$6,021
10	LOW EXTERNALITY	$7,301	$7,011	$7,038
11	HIGH EXTERNALITY	$10,416	$9,956	$9,983
12	MID EXTERNALITY	$8,885	$8,509	$8,536
13	LOWER WHOLESALE MARKET	$5,571	$5,529	$5,556
14	LOW WHOLESALE MARKET	$5,729	$5,662	$5,689
15	HIGH WHOLESALE MARKET	$5,924	$5,820	$5,848
16	HIGHER WHOLESALE MARKET	$5,997	$5,876	$5,904
17	NO WHOLESALE MARKET	$6,326	$6,088	$6,115
18	50% TIE LIMIT	$5,904	$5,792	$5,819
19	NO MARKET TIERS OR SALES	$5,794	$5,721	$5,748
20	2017 PRICES	$5,682	$5,634	$5,661
21	-30% CAPITAL	$5,832	$5,745	$5,772
22	+30% CAPITAL	$5,841	$5,754	$5,781
23	-20% WIND CAPACITY	$5,840	$5,751	$5,778
24	AFR2017 HIGH	$6,086	$5,970	$5,997
25	AFR2017 LOW	$5,791	$5,711	$5,738
26	PRM +2%	$5,843	$5,752	$5,780
27	MISO COINCIDENT -2%	$5,832	$5,747	$5,774
28	MISO COINCIDENT +2%	$5,846	$5,755	$5,782
29	EE +15GW	$5,841	$5,755	$5,782
30	EE +30GW	$5,869	$5,788	$5,815
	Least Cost Count	**0**	**31**	**0**

Table 8: Scenario Comparative Analysis for Future 7 (C3WR)

Number	Sensitivity	Power Supply Cost ($millions) SCENARIO 1: EFRP w/o NOBLES 2	SCENARIO 2: EFRP with NOBLES 2	SCENARIO 3: EFRP with NOBLES 2 & Transmission
0	BASE	$6,724	$6,534	$6,561
1	LOW COAL -30%	$6,343	$6,179	$6,206
2	HIGH COAL +30%	$7,082	$6,873	$6,900
3	LOWER GAS -50%	$6,523	$6,353	$6,381
4	LOW GAS -25%	$6,628	$6,447	$6,474
5	HIGH GAS +25%	$6,817	$6,621	$6,648
6	HIGHER GAS +50%	$6,910	$6,700	$6,728
7	HIGHEST GAS +100%	$7,049	$6,826	$6,853
8	LOW EXTERNALITY	$7,672	$7,342	$7,369
9	HIGH EXTERNALITY	$9,005	$8,635	$8,662
10	MID EXTERNALITY	$8,364	$8,013	$8,040
11	LOWER WHOLESALE MARKET	$6,329	$6,215	$6,242
12	LOW WHOLESALE MARKET	$6,566	$6,412	$6,440
13	HIGH WHOLESALE MARKET	$6,842	$6,627	$6,654
14	HIGHER WHOLESALE MARKET	$6,927	$6,691	$6,718
15	NO WHOLESALE MARKET	$7,188	$6,875	$6,902
16	50% TIE LIMIT	$6,800	$6,594	$6,621
17	NO MARKET TIERS OR SALES	$6,692	$6,526	$6,553
18	-30% CAPITAL	$6,719	$6,529	$6,557
19	+30% CAPITAL	$6,729	$6,538	$6,566
20	-20% WIND CAPACITY	$6,727	$6,535	$6,562
21	AFR2017 HIGH	$7,070	$6,849	$6,876
22	AFR2017 LOW	$6,654	$6,472	$6,499
23	PRM +2%	$6,730	$6,537	$6,564
24	MISO COINCIDENT -2%	$6,719	$6,531	$6,558
25	MISO COINCIDENT +2%	$6,734	$6,539	$6,567
26	EE +15GW	$6,724	$6,535	$6,563
27	EE +30GW	$6,736	$6,553	$6,580
	Least Cost Count	**0**	**28**	**0**

Table 9: Scenario Comparative Analysis for Future 8 (C4WR)

		Power Supply Cost ($millions)		
Number	Sensitivity	SCENARIO 1: EFRP w/o NOBLES 2	SCENARIO 2: EFRP with NOBLES 2	SCENARIO 3: EFRP with NOBLES 2 & Transmission
0	BASE	$6,737	$6,555	$6,582
1	LOW COAL -30%	$6,363	$6,203	$6,231
2	HIGH COAL +30%	$7,092	$6,891	$6,918
3	LOWER GAS -50%	$6,545	$6,385	$6,413
4	LOW GAS -25%	$6,646	$6,474	$6,501
5	HIGH GAS +25%	$6,825	$6,636	$6,663
6	HIGHER GAS +50%	$6,912	$6,707	$6,734
7	HIGHEST GAS +100%	$7,048	$6,829	$6,856
8	LOW EXTERNALITY	$7,672	$7,342	$7,369
9	HIGH EXTERNALITY	$9,005	$8,635	$8,662
10	MID EXTERNALITY	$8,364	$8,013	$8,040
11	LOWER WHOLESALE MARKET	$6,330	$6,218	$6,245
12	LOW WHOLESALE MARKET	$6,569	$6,420	$6,447
13	HIGH WHOLESALE MARKET	$6,873	$6,666	$6,693
14	HIGHER WHOLESALE MARKET	$6,981	$6,752	$6,779
15	NO WHOLESALE MARKET	$7,188	$6,875	$6,902
16	50% TIE LIMIT	$6,800	$6,594	$6,621
17	NO MARKET TIERS OR SALES	$6,692	$6,526	$6,553
18	-30% CAPITAL	$6,732	$6,550	$6,578
19	+30% CAPITAL	$6,741	$6,560	$6,587
20	-20% WIND CAPACITY	$6,740	$6,556	$6,583
21	AFR2017 HIGH	$7,077	$6,862	$6,889
22	AFR2017 LOW	$6,669	$6,495	$6,522
23	PRM +2%	$6,743	$6,558	$6,585
24	MISO COINCIDENT -2%	$6,732	$6,552	$6,579
25	MISO COINCIDENT +2%	$6,746	$6,560	$6,588
26	EE +15GW	$6,737	$6,557	$6,584
27	EE +30GW	$6,750	$6,576	$6,603
	Least Cost Count	**0**	**28**	**0**

Table 10: Scenario Comparative Analysis for Future 9 (C5S)

		Power Supply Cost ($millions)		
Number	Sensitivity	SCENARIO 1: EFRP w/o NOBLES 2	SCENARIO 2: EFRP with NOBLES 2	SCENARIO 3: EFRP with NOBLES 2 & Transmission
0	BASE	$8,362	$8,011	$8,038
1	LOW COAL -30%	$7,960	$7,635	$7,662
2	HIGH COAL +30%	$8,755	$8,381	$8,408
3	LOWER GAS -50%	$8,116	$7,795	$7,823
4	LOW GAS -25%	$8,244	$7,908	$7,935
5	HIGH GAS +25%	$8,474	$8,111	$8,138
6	HIGHER GAS +50%	$8,599	$8,218	$8,245
7	HIGHEST GAS +100%	$8,827	$8,403	$8,430
8	-30% CAPITAL	$8,357	$8,007	$8,034
9	+30% CAPITAL	$8,366	$8,016	$8,043
10	-20% WIND CAPACITY	$8,364	$8,012	$8,039
11	AFR2017 HIGH	$8,959	$8,506	$8,534
12	AFR2017 LOW	$8,255	$7,927	$7,954
13	PRM +2%	$8,366	$8,013	$8,040
14	MISO COINCIDENT -2%	$8,358	$8,010	$8,037
15	MISO COINCIDENT +2%	$8,370	$8,015	$8,042
16	EE +15GW	$8,353	$8,006	$8,034
17	EE +30GW	$8,334	$8,001	$8,029
Least Cost Count		**0**	**18**	**0**

Table 11: Scenario Comparative Analysis for Future 10 (C5W)

Number	Sensitivity	Power Supply Cost ($millions) SCENARIO 1: EFRP w/o NOBLES 2	SCENARIO 2: EFRP with NOBLES 2	SCENARIO 3: EFRP with NOBLES 2 & Transmission
0	BASE	$8,364	$8,013	$8,040
1	LOW COAL -30%	$7,963	$7,637	$7,664
2	HIGH COAL +30%	$8,758	$8,382	$8,409
3	LOWER GAS -50%	$8,119	$7,797	$7,824
4	LOW GAS -25%	$8,246	$7,909	$7,937
5	HIGH GAS +25%	$8,477	$8,112	$8,139
6	HIGHER GAS +50%	$8,601	$8,219	$8,247
7	HIGHEST GAS +100%	$8,829	$8,404	$8,431
8	-30% CAPITAL	$8,360	$8,008	$8,035
9	+30% CAPITAL	$8,369	$8,017	$8,044
10	-20% WIND CAPACITY	$8,367	$8,014	$8,041
11	AFR2017 HIGH	$8,965	$8,511	$8,538
12	AFR2017 LOW	$8,257	$7,928	$7,955
13	PRM +2%	$8,370	$8,015	$8,043
14	MISO COINCIDENT -2%	$8,359	$8,010	$8,037
15	MISO COINCIDENT +2%	$8,373	$8,018	$8,045
16	EE +15GW	$8,355	$8,008	$8,035
17	EE +30GW	$8,336	$8,002	$8,029
Least Cost Count		**0**	**18**	**0**

APPENDIX C – PART 2
ASSUMPTIONS AND OUTLOOKS

The following section provides a summary of the key economic modeling assumptions and bases that Minnesota Power (or the "Company") utilized in the Strategist Proview ("Strategist") analysis completed for the Nobles 2 Wind Project recommendation. This Appendix, detailing the assumptions and outlooks, is organized in the following format:

A) Base Case Economic Modeling Assumptions – a review of the base economic assumptions used in the analysis for the Nobles 2 Wind Project recommendation.

B) New Asset Resources Included – a description of the new resource alternatives included in the Nobles 2 Wind Project recommendation.

C) Assumptions Utilized in the Sensitivity Analysis.

D) Long-term Planning and Wholesale Market Interaction – discussion on utilizing the wholesale market in resource planning.

A. Base Case Economic Modeling Assumptions

Study Period

The timeline of the Nobles 2 Wind Project analysis is 2017 through 2031. The power supply costs shown in the analysis are the net present value of costs from 2017 through 2034 and are reported in 2016 dollars, unless noted otherwise. The reporting of power supply costs were extended past the required planning period to capture the costs of generation over a longer period of time.

The expansion planning analysis conducted with Strategist considered 15 years of end effects after 2034 when selecting the lowest cost plan.

Regulations, Pricing, and Wholesale Market

1. The Base Case forecasts utilized for natural gas prices, market energy prices, and market capacity prices over the study period:[1]

    a. The SO_2 allowance price for Cross-State Air Pollution Rule ("CSAPR") Group 2: \$3.52/ton in 2017 to \$0/ton in 2031.

    b. Natural gas forecast assumptions utilized in the base forecast.

        i. Natural Gas at Henry Hub: \$3.35/MMBtu in 2017 to \$5.29/MMBtu in 2031

        ii. Natural gas supply prices reflect the projected spot market at Henry Hub. In addition, a delivery charge was applied on a resource-specific basis.

[1] Values are in nominal dollars.

The delivery charges were escalated at approximately 2 percent annually, on average, after 2017. The delivery charges applied were as follows:

1. **[TRADE SECRET DATA EXCISED]** for the fuel supply of new generic combustion turbine and combined cycle gas generation alternatives
2. **[TRADE SECRET DATA EXCISED]** for the Nemadji Trail Energy Center ("NTEC") combined cycle facility
3. **[[TRADE SECRET DATA EXCISED]** for the Laskin Energy Center ("LEC")

iii. The firm delivery component of intermediate natural gas resources like the combined cycle was incorporated into the fixed cost revenue requirement for the asset.

c. Delivered coal price forecast assumptions utilized in the base forecast represent the attributes of each of Minnesota Power's facilities and include:

   i. **[TRADE SECRET DATA EXCISED]**

d. Delivered biomass price forecast assumptions utilized in the base forecast:

   i. **[TRADE SECRET DATA EXCISED]**

e. Wholesale Market Capacity (approximate): $1,277/MW-month in 2017 to $9,678/MW-month in 2031. Wholesale market capacity was made available up to a maximum of 50 MW for the model during all study years.

f. Wholesale Market Energy without carbon (approximate): $29/MWh in 2017 to $48/MWh in 2031.

g. Wholesale Market Energy with carbon (approximate): $29/MWh in 2017 to $66/MWh in 2031.

2. The Base Case energy market interaction structure for Minnesota Power's analysis assumed that the wholesale market was available throughout the study period. Further discussion regarding the Company's position related to the interaction with, and utilization of the wholesale energy market in long-term planning is discussed further in Part D of this Appendix. The wholesale energy market structure in the modeling represents the day-ahead interaction with the Midcontinent Independent System Operator ("MISO") regional market and helps utilities optimize power supply for customers. A sensitivity called 'Without Market' was developed that assumed the wholesale energy market was unavailable as a long-term power supply resource through the study period. This sensitivity was included to understand the impact to the planning analysis when the availability of the regional wholesale energy market is removed. A more detailed description of the structure of each market interaction is provided below.

   a. <u>With Wholesale Energy Market</u> ("With Market") – A conservative approach was taken when creating the wholesale energy market that would be made available as a power supply resource during the study period. While the regional market is a valuable and useful piece of a utility's power supply, it should not be considered an 'endless' resource. To help account for the increased risk and volatility that is present when purchasing incrementally larger amounts of energy from the short term market, an increasing price adder was included based on the level of energy purchased. As the volume of energy purchased from the market increased, so did the price adder. This is referred to as a 'Tiered Energy Market' and includes the following pricing assumptions:

i. 0 to 150 MW at base forecast price

ii. 151 to 300 MW at base forecast price plus $15/MWh premium adder

iii. 301 to 600 MW at base forecast price plus $40/MWh premium adder

iv. Greater than 600 MW at emergency energy price ($112/MWh in 2017 and escalating at the same rate as wholesale energy prices thereafter)

b. Without Wholesale Energy Market Sales ("No Market Sales") – For this scenario, the ability to sell surplus energy in the wholesale market was removed. All assumptions related to wholesale energy purchases (including emergency energy) remained the same as explained previously in section A.2.a. This scenario allows for the consideration of portfolios and their ability to supply only customer energy requirements and not an over-reliance on revenues generated through wholesale energy market sales.

3. The estimated decommissioning cost for Minnesota Power's small coal units which are retired at various points in the Nobles 2 Wind analysis are from a study completed by Burns & McDonnell called "Site Decommissioning Study 2015."[2] Decommissioning costs at each facility are assumed to be recovered and depreciated for 10 years past the shutdown date. Remaining plant balances at each facility are assumed to be recovered and depreciated according to their current schedule.

4. Carbon regulation penalty costs[3]

   Minnesota Power included a base outlook that included the base regulation penalty for carbon dioxide ("CO_2") for this planning evaluation. Minnesota Power continues to consider CO_2 regulation as unlikely to come into effect in the near term. Per Minnesota state requirements, it is including an evaluation of the mid-CO_2 regulation cost as listed below. The CO_2 regulation value for the mid-CO_2 regulation penalty are from the 2014 Order Establishing 2014 and 2015 Estimate of Future Carbon Dioxide Regulation Costs, pursuant to Minn. Stat. §216H.06, in Docket No. E999/CI-07-1199.

[2] Included in the 2015 Remaining Life Depreciation Petition (Docket No. E015/D-15-711).

[3] All carbon regulation penalty costs reflect dollars per ton.

a. Mid CO_2 regulation value ranging from $21.50/ton starting in 2022 to $26/ton in 2031.

Minnesota Power Resources and Bilateral Power Transactions

Another important component of a utility's power supply is the contracted purchases and sales conducted within the industry. These transactions optimize the power surpluses and deficits that occur due to industry load and supply changes. Also called bilateral transactions, these contracts allow the Company to work with other entities to procure energy and capacity.

A bilateral transaction is functionally different than the day-ahead regional energy and capacity markets represented by the MISO tariff construct. Bilateral transactions are typically forward, medium to longer-term contracts with defined pricing terms. Minnesota Power monitors the bilateral power markets to identify opportunities to contract with other entities when it is in the best interest of Minnesota Power's customers. For this analysis, the Company has the following bilateral transaction alternative made available based on its most recent industry and peer interactions:

5. An unidentified 50 MW bilateral purchase, referred to as a "bridge purchase" in the analysis write-up, was modeled in Strategist as a new resource alternative. The "bridge purchase" was made available in 2024 for one year in the summer and winter resource adequacy planning cases. The deferred bridge purchase energy pricing is based on the equivalent of purchasing energy from a natural gas combined cycle unit and was modeled as an intermediate type energy resource.

   In the scenarios where the Minnesota Public Utilities Commission's approved carbon regulation value is modeled, the bilateral purchase had a carbon penalty added to the energy price based on the emission rate for a combined cycle natural gas unit. **[TRADE SECRET DATA EXCISED].**

6. The emission rates for the thermal generation units included in Strategist are modeled as tons or pounds per MMBtu of fuel consumed for energy production. The level of effluents emitted per MWh generated will vary depending on the output level of a generation facility. As a generator is dispatched to a lower output level because of economic conditions, the effluents emitted per MWh will increase due to the generator operating at a less efficient level when compared to running at full output. The effluents modeled with emission rates in Strategist are:

   a. Carbon Monoxide (CO)
   b. Carbon Dioxide (CO_2)
   c. Lead (Pb)
   d. Mercury
   e. Nitrogen Oxide (NO_x)
   f. Particulate Matter 2.5 ($PM_{2.5}$)
   g. Sulfur Dioxide (SO_2)

There were two approaches taken to modeling emission rates for CO_2 in the Strategist model:

a. A CO_2 rate was set-up to calculate the cost of a CO_2 regulation penalty; this is referred to as "CO_2" in the Strategist model. These CO_2 rates were applied to the generation resources that would be subject to a CO_2 regulation penalty in a CO_2 constrained scenario.

b. A CO_2 rate was set up to calculate the externality cost of CO_2 and to measure the progress on meeting the State Green House Gas Goal (Minn. Stat. § 216H.02); this is referred to as "CO_2-E" in the Strategist model. This CO_2 rate was assigned to all power supply resources, including bilateral market purchases, generation and energy sales. The accompanying CO_2 with an energy sale is removed from the power supply. The "CO_2-E" rate modeled in Strategist was pounds per MWh. Note that the CO_2 emissions from MISO market energy purchases and sales were calculated outside of the Strategist model.

Minnesota Power Load and General Economic Assumptions

For the Nobles 2 Wind analysis, Minnesota Power considered portfolio development under both a summer and winter peak seasonal resource adequacy requirement. Minnesota Power's planning reserve margin requirement assumptions are driven by load forecast and MISO resource adequacy requirements.

7. Customer energy and demand requirements are based on the Moderate Growth Scenario (AFR Expected Case) in Minnesota Power's AFR2017, which includes an adjustment for change in the demand at Blandin. The energy and demand forecast is based on the AFR2017 econometric modeling results plus customer adjustments for increased energy sales to new customers and transmission losses.

   The transmission losses of 6 percent are added to the Annual Energies to capture the power supply requirements for serving Minnesota Power's customers.

8. Capacity accreditation values for Minnesota Power's existing fleet of generators are the unforced capacity ("UCAP") and are based on MISO's Planning Year 2017-2018 generation performance test results and historical XEFORd[4] per the Module E Resource Adequacy program.

9. Planning reserve margin is based on MISO's required reserve margin of 7.8 percent based on its Planning Year 2017-2018 Loss of Load Expectation Study and UCAP generating capability and projected energy demand in the MISO Region. These values are used in both the summer and winter season resource adequacy requirement planning models.

10. The utility discount rate is the weighted average cost of capital ("WACC") for Minnesota Power based on capital structure and allowed return on equity from the 2010 Rate Case. The utilized discount rate is 8.18 percent.

[4] Equivalent Forced Outage Rate Demand ("XEFORd") is a measure of the probability that a generating unit will not be available due to forced outages or forced de-ratings when there is demand on the unit to generate.

11. A general escalation rate of 2.0 percent was utilized, except for capital cost for new generation, which is escalated at 3.0 percent per year.

Minnesota Power Energy Efficiency Assumptions

Minnesota Power has evaluated past Conservation Improvement Program ("CIP") program performance, related success factors, and potential future opportunities to determine scenarios that would help meet the Company's resource planning goals, while continuing to comply with the State's CIP specific requirements related to the 1.5 percent energy-savings policy goal.

The Company's approach to developing scenarios for increased levels of planned energy efficiency included analysis and research, which provided insight into historical performance, future opportunities, and the changing energy efficiency environment in which the Company operates. Three scenarios of incremental energy and capacity savings were developed for modeling in the Strategist model: 11 GWh, 15 GWh or 30 GWh per year, resulting in aggregate capacity savings by 2025 of approximately 20 MW, 25 MW and 50 MW, respectively. These are the same three scenarios included in the 2015 Resource Plan (Docket No. E015/RP-15-690)

A high-level summary of the modeled scenarios is shown in Table 12, below. The "Scenarios" section titled "Plan" represents the additional GWh the associated plan includes in terms of first-year savings as compared to the existing plan which is included in the base energy forecast for the Nobles 2 Wind analysis. The remaining columns represent the costs and energy savings for the options. Note the energy and demand savings shown here are first-year savings and the associated costs are estimates for the plan year 2017.

Table 12: Summary of Alternative CIP Scenarios

Scenario	Annual Program Costs (million $)		*Annual Savings at the Generator	
Plan	*Total*	*Total Incremental Costs*	*Incremental Energy (GWh)*	*Summer Peak (GW)*
Existing	$7.1	$0.0	0	0.0071
+ 11 GWh	$9.7	$2.7	10.8	0.0087
+ 15 GWh	$11.1	$4.1	14.7	0.0093
+ 30 GWh	$17.6	$10.5	30	0.0116

B. New Asset Resources Included

The new resources that were included in the Nobles 2 Wind anlysis are detailed below. The capital costs were based on Minnesota Power's most current planning estimates for such resources and the results of Minnesota Power's most recent RFPs. The estimates for non-RFP resources are high level engineering projections and typically have a +/- 30 percent range of accuracy.

1. 228 MW (approximate) natural gas combustion turbine unit
    a. Estimated capital build costs in 2017 dollars is **[TRADE SECRET DATA EXCISED].**

The combined-cycle proposal that was evaluated as a possible new generation alternative is provided below. The costs are based on the proposals provided as a part of Minnesota Power's recent Request for Proposals ("RFP").

2. 250 MW partial ownership/share of 525 MW (approximate) natural gas 1x1 combined cycle facility (NTEC)
    a. Expected first year capacity payment in 2025 is **[TRADE SECRET DATA EXCISED]**.

The solar and wind proposals from the recent RFP that are included in the analysis and are part of the Energy*Forward* Resource Package are provided below. The costs are based on the prices defined in the contracts.

3. 10 MW (approximate) solar farm located in central Minnesota (Blanchard Solar)
    a. Expected energy cost is **[TRADE SECRET DATA EXCISED]**. The 10 MW RFP solar facility is expected to start operations by 2020.
4. 250 MW (approximate) wind farm provided through Tenaska's Nobles project located in southwestern Minnesota (Nobles 2 Wind).
    a. Expected energy cost is **[TRADE SECRET DATA EXCISED]** adjusted for transmission network upgrade costs at **[[TRADE SECRET DATA EXCISED].**This RFP wind product is expected to start operations in 2020.

C. Assumptions Utilized in the Sensitivity Analysis

The following variables were stressed low and high in the single variable sensitivity analysis.

1. Wholesale market energy without carbon
    a. A lower sensitivity representing a decrease of 50 percent from base: **[TRADE SECRET DATA EXCISED].**
    b. A low sensitivity representing a decrease of 25 percent from base: **[TRADE SECRET DATA EXCISED].**
    c. A high sensitivity representing an increase of 25 percent from base: **[TRADE SECRET DATA EXCISED].**

   d. A higher sensitivity representing an increase of 50 percent from base: **[TRADE SECRET DATA EXCISED].**

2. Wholesale market energy with carbon regulation penalty
   a. A lower sensitivity representing a decrease of 50 percent from base: **[TRADE SECRET DATA EXCISED].**
   b. A low sensitivity representing a decrease of 25 percent from base: **[TRADE SECRET DATA EXCISED].**
   c. A high sensitivity representing an increase of 25 percent from base: **[TRADE SECRET DATA EXCISED].**
   d. A higher sensitivity representing an increase of 50 percent from base: **[TRADE SECRET DATA EXCISED].**
3. Natural gas price forecast at Henry Hub
   a. A lower sensitivity representing a decrease of 50 percent from base: **[TRADE SECRET DATA EXCISED].**
   b. A low sensitivity representing a decrease of 25 percent from base: **[TRADE SECRET DATA EXCISED].**
   c. A high sensitivity representing an increase of 25 percent from base: **[TRADE SECRET DATA EXCISED].**
   d. A higher sensitivity representing an increase of 50 percent from base: **[TRADE SECRET DATA EXCISED].**
   e. The highest sensitivity representing an increase of 100 percent from base: **[TRADE SECRET DATA EXCISED].**
4. Carbon regulation penalty costs[5]

A base outlook was evaluated that included the base externality value for CO_2 in the base forecast. A base outlook that included the base regulation value for CO_2 was also evaluated for the Nobles 2 Wind analysis. Due to Minnesota state requirements, an evaluation of several levels of carbon regulation costs are included, and listed below.

The evaluation of several carbon regulation levels provides insight into what the customer impact of potential carbon regulation prices is likely to be. However, these costs should not directly impact long-term resource decisions until regulation has been defined and approved for implementation. The carbon regulation values for the sensitivities are from the 2014 Order Establishing 2014 and 2015 Estimate of Future Carbon Dioxide Regulation Costs, pursuant to Minn. Stat. §216H.06,in Docket No. E999/CI-07-1199. Minnesota Power delayed the start of the carbon regulation value to 2022 to align with the start of the EPA's now withdrawn Clean Power Plan.

[5] All carbon regulation penalty costs reflect dollars per ton.

a. A sensitivity based on the low carbon regulation value ranging from \$9/ton starting in 2022 to \$11/ton in 2031.

b. A sensitivity based on the high carbon regulation value ranging from \$34/ton starting in 2022 to \$41/ton in 2031.

5. Externality costs

The values for SO_2, $PM_{2.5}$, CO, NO_x, Pb, and CO_2 were stressed to low, mid-point, and high levels established for each effulent. The values used for CO and PB were the values indicated for the Metropolitan Fringe established in the State Externality Docket, Docket Nos. E999/CI-93-583 and E999/CI-00-1636. The values used for SO_2, $PM_{2.5}$, NO_x, and CO_2 were the most recent values established by the Commission in Docket 14-643.

a. The externality value for SO_2 in 2017 was \$4,757/ton in the low sensitivity case and \$11,849/ton in the high sensitivity case.

b. The externality value for $PM_{2.5}$ in 2017 was \$6,753/ton in the low sensitivity case and \$16,834/ton in the high sensitivity case.

c. The externality value for CO in 2017 was \$1/ton in the low sensitivity case and \$2/ton in the high sensitivity case.

d. The externality value for NO_x in 2017 was \$2,583/ton in the low sensitivity case and \$7,681/ton in the high sensitivity case.

e. The externality value for Pb in 2017 was \$2,523/lb in the low sensitivity case and \$3,047/lb in the high sensitivity case.

f. The externality value for CO_2 in 2017 was \$9/ton in the low sensitivity case and \$41/ton in the high sensitivity case.

6. Coal fuel prices

g. The low sensitivity reduced coal prices by approximately 30 percent from base.

h. The high sensitivity increased coal prices by approximately 30 percent from base.

7. Capital costs

a. The low sensitivity reduced base project costs by 30 percent from base.

b. The high sensitivity increased project costs by 30 percent from base.

8. Incremental energy efficiency

a. An increase of 15 GWh above base.

b. An increase of 30 GWh above base.

9. Wind Capacity Accreditation

   a. The capacity credit of existing wind farms was reduced by 20 percent from base.

10. Planning Reserve Margin ("PRM") requirement

    a. The PRM established by MISO in its 2017 Loss of Load Expectation ("LOLE") Report was increased by 2 percent from base.

11. MISO Coincidence Factor

    a. A low sensitivity to the MISO coincidence factor of 2 percent below base, which resulted in a MISO coincident peak demand higher than base.

    b. A high sensitivity to the MISO coincidence factor of 2 percent above base, which resulted in a MISO coincident peak demand lower than base.

12. Customer sales forecast

    a. The low sensitivity is based on a Potential Downside Scenario.

    b. The high sensitivity is based on a Potential Upside Scenario.

13. Sustained low market prices

    a. Wholesale energy market and natural gas prices kept constant from 2017 levels.

14. Purchases and sales tiers

    a. The lowered market sensitivity reduced interchange tie limits by 50 percent from base.

    b. The no wholesale market sensitivity removed the tiered energy market, allowing only purchases of emergency energy.

    c. The no market tiers or sales removed the tiered energy prices for market purchases and removed the capability to sell economic or surplus energy into the market.

D. Long-term Planning and Wholesale Market Interaction

This discussion is included to demonstrate why it is reasonable for the Company to assume a specific level or range of market purchases throughout the planning period within a resource plan or the Nobles 2 Wind analysis.

It should be noted that the term "market" consists of two segments, capacity and energy. Minnesota Power recognizes that exposure to either a capacity or energy market for a majority of power supply requirements is not in the best interest of customers. However, its utilization in moderation in long-term planning can, and does, bring benefits and efficiencies to its customers.

From a long-term planning perspective, the Company limits utilization of market capacity to no more than 50 MW through the planning period. The inclusion of a small amount of market capacity brings benefit to the customer by bridging short-term capacity needs. These purchases come at a lower cost than building a new resource, and bridge the Company's need until the capacity need grows to a large enough magnitude to justify a resource build. In the absence of market capacity, production cost models like Strategist would be forced to suggest that a utility build a new resource. A facility of up to hundreds of megawatt in size, depending on technology, would be recommended when a single megawatt purchase could satisfy the need. This is not prudent resource planning for capacity and can lead to an expedited overbuild of generation if the results of expansion planning models without market capacity were implemented as prescribed.

The availability of a small amount of market capacity must be present in the long-term. The foundation of resource planning, the regional reserve margin requirements, ensure that participating utilities are moving towards integrating new resources as demand rises on the power system. When demand is stagnant or falling, as the industry has seen recently, there can be generation surpluses on the system. Or as utilities build new resources that are in excess of their direct needs, due to the size of a particular generation technology, there can be temporary surpluses. The Company has utilized the bilateral market for decades to buy and sell capacity from existing generation sources on both a long and short-term basis. These transactions have benefited customers by keeping power supply additions paced with system load growth, and by allowing Minnesota Power to sell excess generation during load decline. The presence of a market capacity transaction in expansion planning outlooks shows that a utility can optimize the timing of its next resource by reaching out to the industry marketplace, and looking for a transaction to help bridge their customers to the next resource.

Similarly, the presence of an energy market in resource planning allows for the optimization of power supply needs on a more granular level. The onset of regional markets like MISO allows day to day energy needs to be pooled together such that each utility is continuously working for the larger energy needs of the region. It is prudent planning practice to include some wholesale market interaction in base planning assumptions, as utilities transition into new generating resources and power purchase transactions for customers. When considering the integration of intermittent generation into the supply portfolio, as many utilities have embarked on with the onset of the Minnesota Renewable Energy Standard and declining cost of solar and wind, it is appropriate to have a wholesale market available.

Energy market purchases are in the best interest of customers to plan and assist with the variability of intermittent resources. Wind, hydro, and solar all rely on the availability of other generation to "fill in the gaps" when the resource is not available. Not having the regional market available during long-term expansion planning to help with the intermittency of renewable generation would promote overbuilding of a single utility's system and not account for existing regional support. Excluding the presence of the market would not only result in increased customer cost, but also would minimize the value proposition of regional markets like MISO.

Minnesota Power has a long-term planning strategy of avoiding expansion plans that would rely on more than **[TRADE SECRET DATA EXCISED]** percent of energy supplied for load requirements to be solely supplied from the wholesale market. The Company will procure resources, either generation assets or bilateral power purchase transactions sourced from these assets to ensure its customers are not exposed to significant wholesale market fluctuations. Market energy purchases are limited through both a capacity limit and a tiered cost structure which increases as energy purchases increase (as described in item A.2). Both regional capacity and energy prices are projected through the independent scenario forecasts that Minnesota Power subscribes to, and are updated on a biannual basis. The uncertainty of market prices and level of capacity interaction is tested through sensitivity analyses. These sensitivities illustrate potential operational and cost risks for customers, and help identify if a different resource strategy is needed. Item C.1-2 above identifies the ranges utilized. The wholesale market is included in this analysis; the regional reserve margin and bilateral support of the region will continue to be part of the Company's power supply in the future.