BEFORE THE MINNESOTA OFFICE OF ADMINISTRATIVE HEARINGS
600 North Robert Street
St. Paul, MN 55101

FOR THE MINNESOTA PUBLIC UTILITIES COMMISSION
121 Seventh Place East, Suite 350
St Paul, MN 55101-2147

IN THE MATTER OF THE PETITION OF NORTHERN STATES POWER COMPANY D/B/A XCEL ENERGY FOR APPROVAL OF COMPETITIVE RESOURCE ACQUISITION PROPOSAL AND CERTIFICATE OF NEED

PUC Docket No. E002/CN-12-1240
OAH Docket No. 8-2500-30760

REBUTTAL ATTACHMENTS OF DR. STEVE RAKOW

ON BEHALF OF

THE DIVISION OF ENERGY RESOURCES OF THE MINNESOTA DEPARTMENT OF COMMERCE

OCTOBER 18, 2013

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Contingency	PVSC ($, 000)							
	Bid Package GPV1	Bid Package BD617	Bid Package CCC1	Bid Package ICT1	Bid Package BD619 CCC1	Bid Package ICT1 CCC1	Bid Package ICT1 BD618	Bid Package BASE CASE
BASE CASE	$ 41,423,488	$ 41,326,470	$ 41,315,664	$ 41,381,884	$ 41,263,483	$ 41,322,652	$ 41,334,589	$ 41,396,524
CO2 Reduction	FAILED	FAILED	FAILED	FAILED	FAILED	FAILED	FAILED	FAILED
$34 CO2	$ 45,123,104	$ 45,049,946	$ 45,025,948	$ 45,106,472	$ 44,967,719	$ 45,045,544	$ 45,060,601	$ 45,115,540
$9 CO2	$ 37,878,588	$ 37,788,434	$ 37,776,260	$ 37,844,768	$ 37,730,115	$ 37,789,808	$ 37,796,333	$ 37,853,036
Low Externalities	$ 41,061,420	$ 40,964,034	$ 40,953,244	$ 41,019,588	$ 40,900,799	$ 40,960,140	$ 40,972,213	$ 41,034,260
High Market Price - 25%	$ 41,193,608	$ 41,104,754	$ 41,084,164	$ 41,161,572	$ 41,037,079	$ 41,096,980	$ 41,106,833	$ 41,165,008
Low Market Price + 25%	$ 41,304,536	$ 41,209,178	$ 41,238,564	$ 41,262,780	$ 41,189,875	$ 41,246,348	$ 41,219,029	$ 41,259,884
High Capital Cost + 10%	$ 41,751,736	$ 41,649,690	$ 41,621,188	$ 41,716,108	$ 41,555,763	$ 41,619,628	$ 41,645,065	$ 41,738,012
Low Capital Cost - 10%	$ 41,081,084	$ 40,998,754	$ 41,010,140	$ 41,045,788	$ 40,965,979	$ 41,025,664	$ 41,021,541	$ 41,047,264
High Coal + 20%	$ 42,591,108	$ 42,500,694	$ 42,478,064	$ 42,557,024	$ 42,427,467	$ 42,494,516	$ 42,512,905	$ 42,567,168
High Coal + 10%	$ 42,019,704	$ 41,925,010	$ 41,914,148	$ 41,981,588	$ 41,860,451	$ 41,922,224	$ 41,936,825	$ 41,994,872
Low Coal - 10%	$ 40,804,340	$ 40,708,466	$ 40,697,020	$ 40,761,344	$ 40,643,187	$ 40,702,224	$ 40,712,561	$ 40,775,576
Low Coal - 20%	$ 40,171,760	$ 40,075,046	$ 40,064,136	$ 40,128,440	$ 40,010,887	$ 40,069,988	$ 40,079,193	$ 40,141,884
Low Natural Gas - $1.50	$ 39,659,612	$ 39,571,578	$ 39,570,800	$ 39,620,376	$ 39,534,015	$ 39,594,588	$ 39,587,513	$ 39,615,308
Low Natural Gas - $1.00	$ 40,321,928	$ 40,234,154	$ 40,223,164	$ 40,286,852	$ 40,180,059	$ 40,238,648	$ 40,248,881	$ 40,281,532
Low Natural Gas - $0.50	$ 40,901,356	$ 40,812,210	$ 40,787,536	$ 40,864,376	$ 40,742,363	$ 40,804,116	$ 40,819,889	$ 40,867,692
High Natural Gas + $0.50	$ 41,912,376	$ 41,813,378	$ 41,765,388	$ 41,874,868	$ 41,707,155	$ 41,772,716	$ 41,818,881	$ 41,889,852
High Natural Gas + $1.00	$ 42,300,140	$ 42,213,266	$ 42,111,612	$ 42,281,856	$ 42,051,739	$ 42,116,772	$ 42,214,757	$ 42,298,652
High Natural Gas + $1.50	$ 42,650,168	$ 42,570,042	$ 42,422,196	$ 42,634,884	$ 42,355,883	$ 42,418,212	$ 42,562,517	$ 42,662,980
High Natural Gas + $2.00	$ 43,001,312	$ 42,913,682	$ 42,713,164	$ 42,977,468	$ 42,644,595	$ 42,708,464	$ 42,900,061	$ 43,009,304
High Natural Gas + $2.50	$ 43,322,752	$ 43,232,238	$ 42,995,328	$ 43,297,784	$ 42,926,251	$ 42,994,464	$ 43,219,169	$ 43,323,964
High Wind Credit + 25%	$ 41,380,468	$ 41,303,210	$ 41,262,884	$ 41,349,596	$ 41,223,167	$ 41,304,948	$ 41,301,345	$ 41,348,436
Low Wind Credit - 25%	$ 41,445,116	$ 41,358,910	$ 41,328,836	$ 41,438,448	$ 41,281,431	$ 41,364,776	$ 41,377,081	$ 41,427,900
High Forecast + 5%	$ 43,819,508	$ 43,749,034	$ 43,716,640	$ 43,826,200	$ 43,665,695	$ 43,705,424	$ 43,767,617	$ 43,817,048
Mid-High Forecast + 2.5%	$ 42,592,756	$ 42,545,058	$ 42,489,756	$ 42,596,164	$ 42,437,803	$ 42,481,332	$ 42,562,421	$ 42,601,828
Mid-Low Forecast - 2.5%	$ 40,249,608	$ 40,178,734	$ 40,197,444	$ 40,211,528	$ 40,151,467	$ 40,218,196	$ 40,196,845	$ 40,216,780
Low Forecast - 5%	$ 39,121,180	$ 39,075,954	$ 39,103,384	$ 39,107,792	$ 39,072,079	$ 39,125,080	$ 39,103,705	$ 39,084,848
Manitoba Hydro PPA Renew	$ 41,200,992	$ 41,107,218	$ 41,088,608	$ 41,172,936	$ 41,036,515	$ 41,109,904	$ 41,110,461	$ 41,168,476
Maximum	$ 45,123,104	$ 45,049,946	$ 45,025,948	$ 45,106,472	$ 44,967,719	$ 45,045,544	$ 45,060,601	$ 45,115,540
Average	$ 41,491,991	$ 41,406,635	$ 41,368,714	$ 41,463,277	$ 41,317,149	$ 41,379,754	$ 41,414,401	$ 41,470,505
Minimum	$ 37,878,588	$ 37,788,434	$ 37,776,260	$ 37,844,768	$ 37,730,115	$ 37,789,808	$ 37,796,333	$ 37,853,036

Contingency	PVSC Difference from Base Case, Same Contingency ($,000)							
	Bid Package GPV1	Bid Package BD617	Bid Package CCC1	Bid Package ICT1	Bid Package BD619 CCC1	Bid Package ICT1 CCC1	Bid Package ICT1 BD618	Bid Package BASE CASE
BASE CASE	$ 26,964	$ (70,054)	$ (80,860)	$ (14,640)	$ (133,041)	$ (73,872)	$ (61,935)	$ -
CO2 Reduction	FAILED	FAILED	FAILED	FAILED	FAILED	FAILED	FAILED	FAILED
$34 CO2	$ 7,564	$ (65,594)	$ (89,592)	$ (9,068)	$ (147,821)	$ (69,996)	$ (54,939)	$ -
$9 CO2	$ 25,552	$ (64,602)	$ (76,776)	$ (8,268)	$ (122,921)	$ (63,228)	$ (56,703)	$ -
Low Externalities	$ 27,160	$ (70,226)	$ (81,016)	$ (14,672)	$ (133,461)	$ (74,120)	$ (62,047)	$ -
High Market Price - 25%	$ 28,600	$ (60,254)	$ (80,844)	$ (3,436)	$ (127,929)	$ (68,028)	$ (58,175)	$ -
Low Market Price + 25%	$ 44,652	$ (50,706)	$ (21,320)	$ 2,896	$ (70,009)	$ (13,536)	$ (40,855)	$ -
High Capital Cost + 10%	$ 13,724	$ (88,322)	$ (116,824)	$ (21,904)	$ (182,249)	$ (118,384)	$ (92,947)	$ -
Low Capital Cost - 10%	$ 33,820	$ (48,510)	$ (37,124)	$ (1,476)	$ (81,285)	$ (21,600)	$ (25,723)	$ -
High Coal + 20%	$ 23,940	$ (66,474)	$ (89,104)	$ (10,144)	$ (139,701)	$ (72,652)	$ (54,263)	$ -
High Coal + 10%	$ 24,832	$ (69,862)	$ (80,724)	$ (13,284)	$ (134,421)	$ (72,648)	$ (58,047)	$ -
Low Coal - 10%	$ 28,764	$ (67,110)	$ (78,556)	$ (14,232)	$ (132,389)	$ (73,352)	$ (63,015)	$ -
Low Coal - 20%	$ 29,876	$ (66,838)	$ (77,748)	$ (13,444)	$ (130,997)	$ (71,896)	$ (62,691)	$ -
Low Natural Gas - $1.50	$ 44,304	$ (43,730)	$ (44,508)	$ 5,068	$ (81,293)	$ (20,720)	$ (27,795)	$ -
Low Natural Gas - $1.00	$ 40,396	$ (47,378)	$ (58,368)	$ 5,320	$ (101,473)	$ (42,884)	$ (32,651)	$ -
Low Natural Gas - $0.50	$ 33,664	$ (55,482)	$ (80,156)	$ (3,316)	$ (125,329)	$ (63,576)	$ (47,803)	$ -
High Natural Gas + $0.50	$ 22,524	$ (76,474)	$ (124,464)	$ (14,984)	$ (182,697)	$ (117,136)	$ (70,971)	$ -
High Natural Gas + $1.00	$ 1,488	$ (85,386)	$ (187,040)	$ (16,796)	$ (246,913)	$ (181,880)	$ (83,895)	$ -
High Natural Gas + $1.50	$ (12,812)	$ (92,938)	$ (240,784)	$ (28,096)	$ (307,097)	$ (244,768)	$ (100,463)	$ -
High Natural Gas + $2.00	$ (7,992)	$ (95,622)	$ (296,140)	$ (31,836)	$ (364,709)	$ (300,840)	$ (109,243)	$ -
High Natural Gas + $2.50	$ (1,212)	$ (91,726)	$ (328,636)	$ (26,180)	$ (397,713)	$ (329,500)	$ (104,795)	$ -
High Wind Credit + 25%	$ 32,032	$ (45,226)	$ (85,552)	$ 1,160	$ (125,269)	$ (43,488)	$ (47,091)	$ -
Low Wind Credit - 25%	$ 17,216	$ (68,990)	$ (99,064)	$ 10,548	$ (146,469)	$ (63,124)	$ (50,819)	$ -
High Forecast + 5%	$ 2,460	$ (68,014)	$ (100,408)	$ 9,152	$ (151,353)	$ (111,624)	$ (49,431)	$ -
Mid-High Forecast + 2.5%	$ (9,072)	$ (56,770)	$ (112,072)	$ (5,664)	$ (164,025)	$ (120,496)	$ (39,407)	$ -
Mid-Low Forecast - 2.5%	$ 32,828	$ (38,046)	$ (19,336)	$ (5,252)	$ (65,313)	$ 1,416	$ (19,935)	$ -
Low Forecast - 5%	$ 36,332	$ (8,894)	$ 18,536	$ 22,944	$ (12,769)	$ 40,232	$ 18,857	$ -
Manitoba Hydro PPA Renew	$ 32,516	$ (61,258)	$ (79,868)	$ 4,460	$ (131,961)	$ (58,572)	$ (58,015)	$ -
Maximum	$ 44,652	$ (8,894)	$ 18,536	$ 22,944	$ (12,769)	$ 40,232	$ 18,857	$ -
Average	$ 21,486	$ (63,870)	$ (101,791)	$ (7,228)	$ (153,356)	$ (90,751)	$ (56,104)	$ -
Minimum	$ (12,812)	$ (95,622)	$ (328,636)	$ (31,836)	$ (397,713)	$ (329,500)	$ (109,243)	$ -

Contingency	Rank							
	Bid Package GPV1	Bid Package BD617	Bid Package CCC1	Bid Package ICT1	Bid Package BD619 CCC1	Bid Package ICT1 CCC1	Bid Package ICT1 BD618	Bid Package BASE CASE
BASE CASE	8	4	2	6	1	3	5	7
CO2 Reduction	FAILED	FAILED	FAILED	FAILED	FAILED	FAILED	FAILED	FAILED
$34 CO2	8	4	2	6	1	3	5	7
$9 CO2	8	3	2	6	1	4	5	7
Low Externalities	8	4	2	6	1	3	5	7
High Market Price - 25%	8	4	2	6	1	3	5	7
Low Market Price + 25%	8	2	4	7	1	5	3	6
High Capital Cost + 10%	8	5	3	6	1	2	4	7
Low Capital Cost - 10%	8	2	3	6	1	5	4	7
High Coal + 20%	8	4	2	6	1	3	5	7
High Coal + 10%	8	4	2	6	1	3	5	7
Low Coal - 10%	8	4	2	6	1	3	5	7
Low Coal - 20%	8	4	2	6	1	3	5	7
Low Natural Gas - $1.50	8	3	2	7	1	5	4	6
Low Natural Gas - $1.00	8	3	2	7	1	4	5	6
Low Natural Gas - $0.50	8	4	2	6	1	3	5	7
High Natural Gas + $0.50	8	4	2	6	1	3	5	7
High Natural Gas + $1.00	8	4	2	6	1	3	5	7
High Natural Gas + $1.50	7	5	3	6	1	2	4	8
High Natural Gas + $2.00	7	5	3	6	1	2	4	8
High Natural Gas + $2.50	7	5	3	6	1	2	4	8
High Wind Credit + 25%	8	4	2	7	1	5	3	6
Low Wind Credit - 25%	8	3	2	7	1	4	5	6
High Forecast + 5%	7	4	3	8	1	2	5	6
Mid-High Forecast + 2.5%	6	4	3	7	1	2	5	8
Mid-Low Forecast - 2.5%	8	2	4	5	1	7	3	6
Low Forecast - 5%	7	2	4	6	1	8	5	3
Manitoba Hydro PPA Renew	8	3	2	7	1	4	5	6
Maximum	8.0	5.0	4.0	8.0	1.0	8.0	5.0	8.0
Average	7.7	3.7	2.5	6.3	1.0	3.6	4.6	6.7
Minimum	6.0	2.0	2.0	5.0	1.0	2.0	3.0	3.0

Contingency	Year 1st Generic Unit Added							
	Bid Package BASE CASE	Bid Package GPV1	Bid Package BD617	Bid Package CCC1	Bid Package ICT1	Bid Package BD619 CCC1	Bid Package ICT1 CCC1	Bid Package ICT1 BD618
Base Conditions	2017	2017	2019	2020	2018	2023	2023	2022
CO2 Reduction	FAILED	FAILED	FAILED	FAILED	FAILED	FAILED	FAILED	FAILED
$34 CO2	2017	2017	2019	2020	2018	2023	2023	2022
$9 CO2	2017	2017	2019	2020	2018	2023	2023	2022
Low Externalities	2017	2017	2019	2020	2018	2023	2023	2022
High Market Price - 25%	2017	2017	2019	2020	2018	2023	2023	2022
Low Market Price + 25%	2017	2017	2019	2020	2018	2023	2023	2022
High Capital Cost + 10%	2017	2017	2019	2020	2018	2023	2023	2022
Low Capital Cost - 10%	2017	2017	2019	2020	2018	2023	2023	2022
High Coal + 20%	2017	2017	2019	2020	2018	2023	2023	2022
High Coal + 10%	2017	2017	2019	2020	2018	2023	2023	2022
Low Coal - 10%	2017	2017	2019	2020	2018	2023	2023	2022
Low Coal - 20%	2017	2017	2019	2020	2018	2023	2023	2022
Low Natural Gas - $1.50	2017	2017	2019	2020	2018	2023	2023	2022
Low Natural Gas - $1.00	2017	2017	2019	2020	2018	2023	2023	2022
Low Natural Gas - $0.50	2017	2017	2019	2020	2018	2023	2023	2022
High Natural Gas + $0.50	2017	2017	2019	2020	2018	2023	2023	2022
High Natural Gas + $1.00	2017	2017	2019	2020	2018	2023	2023	2022
High Natural Gas + $1.50	2017	2017	2019	2020	2018	2023	2023	2022
High Natural Gas + $2.00	2017	2017	2019	2020	2018	2023	2023	2022
High Natural Gas + $2.50	2017	2017	2019	2020	2018	2023	2023	2022
High Wind Credit + 25%	2017	2018	2020	2022	2019	2024	2023	2023
Low Wind Credit - 25%	2017	2017	2018	2019	2018	2023	2022	2020
High Forecast + 5%	2017	2017	2017	2017	2017	2017	2017	2017
Mid-High Forecast + 2.5%	2017	2017	2017	2017	2017	2017	2018	2017
Mid-Low Forecast - 2.5%	2020	2020	2023	2024	2023	2025 & on	2025 & on	2025 & on
Low Forecast - 5%	2024	2025 & on	2025	2025 & on	2025 & on	2025 & on	2025 & on	2025 & on
Manitoba Hydro PPA Renew	2017	2017	2019	2020	2018	2023	2023	2022

Note: Low Wind Credit contingency has short term capacity added: 100 MW in 2015 and 2016.

Note: High Forecast contingency has short term capacity added: 400 MW in 2015 and 500 MW in 2016.

Note: Mid-High Forecast contingency has short term capacity added: 100 MW in 2015 and 250 MW in 2016.

Contingency	PVSC ($, 000, No CO2 Costs)							
	Bid Package GPV1	Bid Package BD617	Bid Package CCC1	Bid Package ICT1	Bid Package BD619 CCC1	Bid Package ICT1 CCC1	Bid Package ICT1 BD618	Bid Package BASE CASE
BASE CASE (No CO2)	$ 34,905,864	$ 34,813,138	$ 34,793,908	$ 34,859,700	$ 34,744,423	$ 34,807,540	$ 34,815,397	$ 34,876,344
CO2 Reduction	FAILED	FAILED	FAILED	FAILED	FAILED	FAILED	FAILED	FAILED
$34 CO2	$ 34,905,864	$ 34,813,138	$ 34,793,908	$ 34,859,700	$ 34,744,423	$ 34,807,540	$ 34,815,397	$ 34,876,344
$9 CO2	$ 34,905,864	$ 34,813,138	$ 34,793,908	$ 34,859,700	$ 34,744,423	$ 34,807,540	$ 34,815,397	$ 34,876,344
Low Externalities	$ 34,905,864	$ 34,813,138	$ 34,793,908	$ 34,859,700	$ 34,744,423	$ 34,807,540	$ 34,815,397	$ 34,876,344
High Market Price - 25%	$ 34,919,404	$ 34,823,266	$ 34,807,168	$ 34,874,404	$ 34,758,443	$ 34,820,796	$ 34,829,509	$ 34,887,436
Low Market Price + 25%	$ 34,542,928	$ 34,426,494	$ 34,454,668	$ 34,479,588	$ 34,403,835	$ 34,458,928	$ 34,433,397	$ 34,478,664
High Capital Cost + 10%	$ 35,230,980	$ 35,126,030	$ 35,091,536	$ 35,179,788	$ 35,026,975	$ 35,096,696	$ 35,118,937	$ 35,201,900
Low Capital Cost - 10%	$ 34,580,736	$ 34,493,318	$ 34,492,492	$ 34,539,612	$ 34,461,875	$ 34,515,340	$ 34,510,281	$ 34,536,788
High Coal + 20%	$ 36,141,084	$ 36,049,482	$ 36,030,344	$ 36,096,076	$ 35,980,763	$ 36,043,956	$ 36,051,717	$ 36,112,608
High Coal + 10%	$ 35,526,700	$ 35,434,550	$ 35,415,364	$ 35,480,992	$ 35,365,823	$ 35,428,836	$ 35,436,713	$ 35,497,724
Low Coal - 10%	$ 34,280,216	$ 34,186,894	$ 34,167,672	$ 34,233,500	$ 34,118,207	$ 34,181,332	$ 34,189,165	$ 34,250,160
Low Coal - 20%	$ 33,649,016	$ 33,555,128	$ 33,535,924	$ 33,601,696	$ 33,486,447	$ 33,549,518	$ 33,557,351	$ 33,618,460
Low Natural Gas - $1.50	$ 33,575,036	$ 33,485,866	$ 33,485,486	$ 33,525,154	$ 33,453,549	$ 33,509,540	$ 33,502,429	$ 33,530,790
Low Natural Gas - $1.00	$ 34,062,304	$ 33,972,542	$ 33,963,940	$ 34,014,600	$ 33,925,887	$ 33,985,600	$ 33,985,433	$ 34,023,304
Low Natural Gas - $0.50	$ 34,497,880	$ 34,407,450	$ 34,389,988	$ 34,451,248	$ 34,346,787	$ 34,408,872	$ 34,414,913	$ 34,464,256
High Natural Gas + $0.50	$ 35,292,916	$ 35,198,066	$ 35,144,560	$ 35,244,892	$ 35,089,659	$ 35,154,196	$ 35,193,373	$ 35,265,648
High Natural Gas + $1.00	$ 35,658,212	$ 35,550,190	$ 35,463,304	$ 35,608,204	$ 35,403,255	$ 35,469,500	$ 35,545,545	$ 35,629,024
High Natural Gas + $1.50	$ 35,991,300	$ 35,873,182	$ 35,752,856	$ 35,938,196	$ 35,689,667	$ 35,757,140	$ 35,864,841	$ 35,960,672
High Natural Gas + $2.00	$ 36,304,840	$ 36,178,358	$ 36,024,728	$ 36,247,312	$ 35,953,647	$ 36,021,224	$ 36,166,609	$ 36,272,600
High Natural Gas + $2.50	$ 36,600,856	$ 36,469,942	$ 36,281,100	$ 36,537,452	$ 36,205,147	$ 36,267,728	$ 36,454,321	$ 36,568,180
High Wind Credit + 25%	$ 34,884,544	$ 34,766,654	$ 34,753,032	$ 34,823,788	$ 34,709,555	$ 34,787,556	$ 34,769,925	$ 34,815,724
Low Wind Credit - 25%	$ 34,956,944	$ 34,838,614	$ 34,815,988	$ 34,916,752	$ 34,762,787	$ 34,854,928	$ 34,856,229	$ 34,904,824
High Forecast + 5%	$ 36,974,920	$ 36,864,794	$ 36,820,836	$ 36,907,840	$ 36,770,831	$ 36,834,828	$ 36,866,729	$ 36,935,184
Mid-High Forecast + 2.5%	$ 35,908,248	$ 35,827,546	$ 35,799,652	$ 35,894,472	$ 35,742,063	$ 35,804,436	$ 35,842,617	$ 35,876,116
Mid-Low Forecast - 2.5%	$ 33,938,268	$ 33,839,622	$ 33,829,272	$ 33,881,332	$ 33,807,139	$ 33,869,392	$ 33,858,973	$ 33,876,828
Low Forecast - 5%	$ 32,978,728	$ 32,901,038	$ 32,939,084	$ 32,960,780	$ 32,906,685	$ 32,970,100	$ 32,941,263	$ 32,925,974
Manitoba Hydro PPA Renew	$ 34,786,496	$ 34,674,246	$ 34,663,428	$ 34,731,708	$ 34,603,007	$ 34,676,504	$ 34,687,253	$ 34,744,064
Maximum	$ 36,974,920	$ 36,864,794	$ 36,820,836	$ 36,907,840	$ 36,770,831	$ 36,834,828	$ 36,866,729	$ 36,935,184
Average	$ 34,996,519	$ 34,896,142	$ 34,862,890	$ 34,948,451	$ 34,812,953	$ 34,877,670	$ 34,901,448	$ 34,958,604
Minimum	$ 32,978,728	$ 32,901,038	$ 32,939,084	$ 32,960,780	$ 32,906,685	$ 32,970,100	$ 32,941,263	$ 32,925,974

Contingency	PVSC Difference from Base Case, Same Contingency ($,000, No CO2 Costs)							
	Bid Package GPV1	Bid Package BD617	Bid Package CCC1	Bid Package ICT1	Bid Package BD619 CCC1	Bid Package ICT1 CCC1	Bid Package ICT1 BD618	Bid Package BASE CASE
BASE CASE	$ 29,520	$ (63,206)	$ (82,436)	$ (16,644)	$ (131,921)	$ (68,804)	$ (60,947)	$ -
CO2 Reduction	FAILED	FAILED	FAILED	FAILED	FAILED	FAILED	FAILED	FAILED
$34 CO2	$ 29,520	$ (63,206)	$ (82,436)	$ (16,644)	$ (131,921)	$ (68,804)	$ (60,947)	$ -
$9 CO2	$ 29,520	$ (63,206)	$ (82,436)	$ (16,644)	$ (131,921)	$ (68,804)	$ (60,947)	$ -
Low Externalities	$ 29,520	$ (63,206)	$ (82,436)	$ (16,644)	$ (131,921)	$ (68,804)	$ (60,947)	$ -
High Market Price - 25%	$ 31,968	$ (64,170)	$ (80,268)	$ (13,032)	$ (128,993)	$ (66,640)	$ (57,927)	$ -
Low Market Price + 25%	$ 64,264	$ (52,170)	$ (23,996)	$ 924	$ (74,829)	$ (19,736)	$ (45,267)	$ -
High Capital Cost + 10%	$ 29,080	$ (75,870)	$ (110,364)	$ (22,112)	$ (174,925)	$ (105,204)	$ (82,963)	$ -
Low Capital Cost - 10%	$ 43,948	$ (43,470)	$ (44,296)	$ 2,824	$ (74,913)	$ (21,448)	$ (26,507)	$ -
High Coal + 20%	$ 28,476	$ (63,126)	$ (82,264)	$ (16,532)	$ (131,845)	$ (68,652)	$ (60,891)	$ -
High Coal + 10%	$ 28,976	$ (63,174)	$ (82,360)	$ (16,732)	$ (131,901)	$ (68,888)	$ (61,011)	$ -
Low Coal - 10%	$ 30,056	$ (63,266)	$ (82,488)	$ (16,660)	$ (131,953)	$ (68,828)	$ (60,995)	$ -
Low Coal - 20%	$ 30,556	$ (63,332)	$ (82,536)	$ (16,764)	$ (132,013)	$ (68,942)	$ (61,109)	$ -
Low Natural Gas - $1.50	$ 44,246	$ (44,924)	$ (45,304)	$ (5,636)	$ (77,241)	$ (21,250)	$ (28,361)	$ -
Low Natural Gas - $1.00	$ 39,000	$ (50,762)	$ (59,364)	$ (8,704)	$ (97,417)	$ (37,704)	$ (37,871)	$ -
Low Natural Gas - $0.50	$ 33,624	$ (56,806)	$ (74,268)	$ (13,008)	$ (117,469)	$ (55,384)	$ (49,343)	$ -
High Natural Gas + $0.50	$ 27,268	$ (67,582)	$ (121,088)	$ (20,756)	$ (175,989)	$ (111,452)	$ (72,275)	$ -
High Natural Gas + $1.00	$ 29,188	$ (78,834)	$ (165,720)	$ (20,820)	$ (225,769)	$ (159,524)	$ (83,479)	$ -
High Natural Gas + $1.50	$ 30,628	$ (87,490)	$ (207,816)	$ (22,476)	$ (271,005)	$ (203,532)	$ (95,831)	$ -
High Natural Gas + $2.00	$ 32,240	$ (94,242)	$ (247,872)	$ (25,288)	$ (318,953)	$ (251,376)	$ (105,991)	$ -
High Natural Gas + $2.50	$ 32,676	$ (98,238)	$ (287,080)	$ (30,728)	$ (363,033)	$ (300,452)	$ (113,859)	$ -
High Wind Credit + 25%	$ 68,820	$ (49,070)	$ (62,692)	$ 8,064	$ (106,169)	$ (28,168)	$ (45,799)	$ -
Low Wind Credit - 25%	$ 52,120	$ (66,210)	$ (88,836)	$ 11,928	$ (142,037)	$ (49,896)	$ (48,595)	$ -
High Forecast + 5%	$ 39,736	$ (70,390)	$ (114,348)	$ (27,344)	$ (164,353)	$ (100,356)	$ (68,455)	$ -
Mid-High Forecast + 2.5%	$ 32,132	$ (48,570)	$ (76,464)	$ 18,356	$ (134,053)	$ (71,680)	$ (33,499)	$ -
Mid-Low Forecast - 2.5%	$ 61,440	$ (37,206)	$ (47,556)	$ 4,504	$ (69,689)	$ (7,436)	$ (17,855)	$ -
Low Forecast - 5%	$ 52,754	$ (24,936)	$ 13,110	$ 34,806	$ (19,289)	$ 44,126	$ 15,289	$ -
Manitoba Hydro PPA Renew	$ 42,432	$ (69,818)	$ (80,636)	$ (12,356)	$ (141,057)	$ (67,560)	$ (56,811)	$ -
Maximum	$ 68,820	$ (24,936)	$ 13,110	$ 34,806	$ (19,289)	$ 44,126	$ 15,289	$ -
Average	$ 37,915	$ (62,462)	$ (95,713)	$ (10,153)	$ (145,651)	$ (80,934)	$ (57,155)	$ -
Minimum	$ 27,268	$ (98,238)	$ (287,080)	$ (30,728)	$ (363,033)	$ (300,452)	$ (113,859)	$ -

Contingency	Rank (No CO2 Costs)							
	Bid Package GPV1	Bid Package BD617	Bid Package CCC1	Bid Package ICT1	Bid Package BD619 CCC1	Bid Package ICT1 CCC1	Bid Package ICT1 BD618	Bid Package BASE CASE
BASE CASE (No CO2)	8	4	2	6	1	3	5	7
CO2 Reduction	FAILED	FAILED	FAILED	FAILED	FAILED	FAILED	FAILED	FAILED
$34 CO2	8	4	2	6	1	3	5	7
$9 CO2	8	4	2	6	1	3	5	7
Low Externalities	8	4	2	6	1	3	5	7
High Market Price - 25%	8	4	2	6	1	3	5	7
Low Market Price + 25%	8	2	4	7	1	5	3	6
High Capital Cost + 10%	8	5	2	6	1	3	4	7
Low Capital Cost - 10%	8	3	2	7	1	5	4	6
High Coal + 20%	8	4	2	6	1	3	5	7
High Coal + 10%	8	4	2	6	1	3	5	7
Low Coal - 10%	8	4	2	6	1	3	5	7
Low Coal - 20%	8	4	2	6	1	3	5	7
Low Natural Gas - $1.50	8	3	2	6	1	5	4	7
Low Natural Gas - $1.00	8	3	2	6	1	5	4	7
Low Natural Gas - $0.50	8	3	2	6	1	4	5	7
High Natural Gas + $0.50	8	5	2	6	1	3	4	7
High Natural Gas + $1.00	8	5	2	6	1	3	4	7
High Natural Gas + $1.50	8	5	2	6	1	3	4	7
High Natural Gas + $2.00	8	5	3	6	1	2	4	7
High Natural Gas + $2.50	8	5	3	6	1	2	4	7
High Wind Credit + 25%	8	3	2	7	1	5	4	6
Low Wind Credit - 25%	8	3	2	7	1	4	5	6
High Forecast + 5%	8	4	2	6	1	3	5	7
Mid-High Forecast + 2.5%	8	4	2	7	1	3	5	6
Mid-Low Forecast - 2.5%	8	3	2	7	1	5	4	6
Low Forecast - 5%	8	1	4	6	2	7	5	3
Manitoba Hydro PPA Renew	8	3	2	6	1	4	5	7
Maximum	8.0	5.0	4.0	7.0	2.0	7.0	5.0	7.0
Average	8.0	3.7	2.2	6.2	1.0	3.6	4.5	6.6
Minimum	8.0	1.0	2.0	6.0	1.0	2.0	3.0	3.0

Contingency	Year 1st Generic Unit Added (No CO2 Costs) Bid Package BASE CASE	Bid Package GPV1	Bid Package BD617	Bid Package CCC1	Bid Package ICT1	Bid Package BD619 CCC1	Bid Package ICT1 CCC1	Bid Package ICT1 BD618
Base Conditions	2017	2017	2019	2020	2018	2023	2023	2022
CO2 Reduction	FAILED	FAILED	FAILED	FAILED	FAILED	FAILED	FAILED	FAILED
$34 CO2	2017	2017	2019	2020	2018	2023	2023	2022
$9 CO2	2017	2017	2019	2020	2018	2023	2023	2022
Low Externalities	2017	2017	2019	2020	2018	2023	2023	2022
High Market Price - 25%	2017	2017	2019	2020	2018	2023	2023	2022
Low Market Price + 25%	2017	2017	2019	2020	2018	2023	2023	2022
High Capital Cost + 10%	2017	2017	2019	2020	2018	2023	2023	2022
Low Capital Cost - 10%	2017	2017	2019	2020	2018	2023	2023	2022
High Coal + 20%	2017	2017	2019	2020	2018	2023	2023	2022
High Coal + 10%	2017	2017	2019	2020	2018	2023	2023	2022
Low Coal - 10%	2017	2017	2019	2020	2018	2023	2023	2022
Low Coal - 20%	2017	2017	2019	2020	2018	2023	2023	2022
Low Natural Gas - $1.50	2017	2017	2019	2020	2018	2023	2023	2022
Low Natural Gas - $1.00	2017	2017	2019	2020	2018	2023	2023	2022
Low Natural Gas - $0.50	2017	2017	2019	2020	2018	2023	2023	2022
High Natural Gas + $0.50	2017	2017	2019	2020	2018	2023	2023	2022
High Natural Gas + $1.00	2017	2017	2019	2020	2018	2023	2023	2022
High Natural Gas + $1.50	2017	2017	2019	2020	2018	2023	2023	2022
High Natural Gas + $2.00	2017	2017	2019	2020	2018	2023	2023	2022
High Natural Gas + $2.50	2017	2017	2019	2020	2018	2023	2023	2022
High Wind Credit + 25%	2017	2018	2020	2022	2019	2023	2023	2023
Low Wind Credit - 25%	2017	2017	2018	2019	2018	2023	2022	2020
High Forecast + 5%	2017	2017	2017	2017	2017	2017	2017	2017
Mid-High Forecast + 2.5%	2017	2017	2017	2017	2017	2017	2018	2017
Mid-Low Forecast - 2.5%	2020	2020	2023	2024	2023	2025 & on	2025 & on	2025 & on
Low Forecast - 5%	2024	2025 & on	2025	2025 & on	2025 & on	2025 & on	2025 & on	2025 & on
Manitoba Hydro PPA Renew	2017	2017	2019	2020	2018	2023	2023	2022

Note: Low Wind Credit has short term capacity added: 100 MW in 2015 and 2016.

Note: High Forecast has short term capacity added: 400 MW in 2015 and 500 MW in 2016.

Note: Mid-High Forecast has short term capacity added: 100 MW in 2015 and 250 MW in 2016.

State of Minnesota
DEPARTMENT OF COMMERCE
DIVISION OF ENERGY RESOURCES

Utility Information Request Response

Docket Number:	E002/CN-12-1240	Date Request Received:	October 3, 2013
Requested By:	Calpine Corporation	Date of Response:	October 15, 2013

Response submitted by: Steve Rakow
Title: Rates Analyst
Division/Unit: Division of Energy Resources
Telephone: 651-539-1833

Request No.	
2	Please refer to Dr. Steve Rakow's prepared direct testimony at page 7, lines 3-6 where Dr. Rakow states that "I added a deration pattern for the Calpine unit. This pattern was based upon Calpine's reported deration amount and the deration patterns used by Xcel for other recently-added units, including Blue Lake 7 and 8, Angus Anson 4, and Calpine's existing unit at the Mankato Energy Center." Please provide the source of "Calpine's reported deration amount" and the deration patterns used by Xcel for Blue Lake 7 and 8, Angus Anson 4, and Calpine's existing unit at the Mankato Energy Center.

DOC Response:

Regarding the request to "provide the source of 'Calpine's reported deration amount'" the statement quoted from Dr. Rakow's testimony is a reference to an email from Xcel pertaining to deration of the Calpine unit. A PDF of the email [filename: Microsoft Outlook - Memo Style.pdf] is included on a CD. The underlying Department calculations [filename: Calpine Deration Calc.xlsx] are also included.

Regarding the request to "provide … the deration patterns used by Xcel for Blue Lake 7 and 8, Angus Anson 4, and Calpine's existing unit at the Mankato Energy Center" the requested data is included on a CD [filename: Capacity Deration Values TRADE SECRET.xlsx]

NOTE: The file contains detailed generating unit level information and was drawn from a Strategist database that was labeled Trade Secret by Xcel. Thus, the Department understands that Xcel Energy maintains this information as trade secret. However, Calpine should feel free to check with Xcel to verify this understanding.

State of Minnesota
DEPARTMENT OF COMMERCE
DIVISION OF ENERGY RESOURCES

Utility Information Request Response

Docket Number:	E002/CN-12-1240	Date Request Received:	October 3, 2013
Requested By:	Calpine Corporation	Date of Response:	October 15, 2013

Response submitted by: Steve Rakow
Title: Rates Analyst
Division/Unit: Division of Energy Resources
Telephone: 651-539-1833

Request No.	
3	Please refer to Dr. Steve Rakow's Direct Testimony at page 38, lines 19-21 describing selected outputs from the second round of Strategist results. Please provide the Strategist results showing the capacity factor outputs for the Calpine, Invenergy and Xcel units proposed in this proceeding through the 2036 end date. **DOC Response:** Regarding "provide the Strategist results showing the capacity factor outputs for the Calpine, Invenergy and Xcel units proposed in this proceeding through the 2036 end date," the Department clarified with Calpine that the data was requested specifically for Scenarios 29 and 33. The requested data is included on a CD [filename: Bid Unit Capacity Factors.xlsx].

State of Minnesota
DEPARTMENT OF COMMERCE
DIVISION OF ENERGY RESOURCES

Utility Information Request Response

Docket Number: E002/CN-12-1240 Date Request Received: October 1, 2013

Requested By: Geronimo Energy Date of Response: October 11, 2013

Response submitted by: Steve Rakow

Request No.	
3	Reference: Rakow Direct, p. 12, ln 13-15: "This would allow the RFP to be issued after the Effective Load Carrying Capability (ELCC) study is completed, which would give better information regarding the production of solar power compared to Xcel's load." Question Does the Department have any knowledge that Xcel's completed ELCC study will be used by MISO to assign accredited capacity to solar projects? If so, please provide a reference or citation to any announcements from MISO indicating such a change will occur. **DOC Response:** No.

State of Minnesota

DEPARTMENT OF COMMERCE
DIVISION OF ENERGY RESOURCES

Utility Information Request Response

Docket Number:	E002/CN-12-1240	Date Request Received:	October 1, 2013
Requested By:	Geronimo Energy	Date of Response:	October 11, 2013
Response submitted by:	Steve Rakow		

Request No.	
4	Reference: Rakow Direct, p. 20, ln. 15-16: "The two different solar constructs relate to a 72 percent and a 50 percent solar accreditation by MISO." Question: Please provide a reference or the Department's reasoning for using a solar construct that assumes a 50 percent solar accreditation. **DOC Response:** See Attachment A for a reference. Specifically, the data on page 5 of 26 of Attachment A indicate that a 45 to 50 percent accreditation factor would be a reasonable lower bound.

State of Minnesota
DEPARTMENT OF COMMERCE
DIVISION OF ENERGY RESOURCES

Utility Information Request Response

Docket Number: E002/CN-12-1240 Date Request Received: October 1, 2013

Requested By: Geronimo Energy Date of Response: October 11, 2013

Response submitted by: Steve Rakow

Request No.	
5	Reference: Rakow Direct, SR-5B, p. 1-15: Question: Please define each Scenario listed in DOC Ex.__, SR-5B, p. 1-15 and provide a general description of what is represented in these tables. **DOC Response:** See Attachment B for the definitions.

State of Minnesota
DEPARTMENT OF COMMERCE
DIVISION OF ENERGY RESOURCES

Utility Information Request Response

Docket Number: E002/CN-12-1240 Date Request Received: October 1, 2013

Requested By: Geronimo Energy Date of Response: October 11, 2013

Response submitted by: Steve Rakow

Request No.	
6	Please provide a narrative description or table showing the total amount (MW), price, and in-service dates of solar energy added in the Department's modeled solar expansion plan. **DOC Response:** See Attachment C for a table showing the total MW and total cost of solar, by year.

State of Minnesota

DEPARTMENT OF COMMERCE
DIVISION OF ENERGY RESOURCES

Utility Information Request Response

Docket Number: E002/CN-12-1240 Date Request Received: October 1, 2013

Requested By: Geronimo Energy Date of Response: October 11, 2013

Response submitted by: Steve Rakow

Request No.	
7	Did the Department adjust the price of the generic solar units to account for the decrease in the solar ITC from 30% to 10% for projects in service after 2016?

DOC Response:

The Department did not make specific price adjustments to reflect future changes in tax laws or other factors that may affect various technologies over time; such adjustments would be too speculative (as has been seen in the past regarding various tax incentives for various generation technologies in various locations). Instead, the Department added capacity to solar units already existing on Xcel's system.

The results indicate that the price adjustments suggested by the question would have no effect on the overall modeling results. The same solar capacity/energy is required to be added in all scenarios and contingencies. Further, solar generation does not change with different system configurations. Therefore, the cost of solar would be the same in each of the Department's approximately 4,000 Strategist runs, meaning that adjustments in the cost data would have no effect on the results.

State of Minnesota

DEPARTMENT OF COMMERCE
DIVISION OF ENERGY RESOURCES

Utility Information Request Response

Docket Number: E002/CN-12-1240 Date Request Received: October 1, 2013

Requested By: Geronimo Energy Date of Response: October 11, 2013

Response submitted by: Steve Rakow

Request No.	
8	Did the Department adjust the price of the generic solar units to reflect that at least 10% of the solar energy required to meet the Solar Energy Standard must come from solar photovoltaic devices with a nameplate capacity of 20 kilowatts or less as required under Minn. Stat. § 216B.1691, subd. 2f(a)? If yes, please indicate the price and amount (MW) included for small solar in the Company's solar price. **DOC Response:** The Department did not adjust the price of the existing units; see the response to question seven for further explanation. Moreover, the price adjustment suggested by this question has another layer of speculation since it does not take into account the provision in Minnesota Statute §216B.1691 that the Solar Energy Standard could be delayed or modified if the impact of implementing the standard on customers' utility costs is too high.

State of Minnesota

DEPARTMENT OF COMMERCE
DIVISION OF ENERGY RESOURCES

Utility Information Request Response

Docket Number:	E002/CN-12-1240	Date Request Received:	October 1, 2013
Requested By:	Geronimo Energy	Date of Response:	October 11, 2013
Response submitted by:	Steve Rakow		

Request No.	
9	Please describe how the Department's Strategist modeling accounted for excess capacity in scenarios where the model selected combinations with more capacity than the identified need and provide all assumptions used in the model to address this excess capacity (e.g., price per kW- mo for capacity sold into the market). **DOC Response:** Strategist did nothing with the excess capacity—under the Department's structure, Strategist assigns no value to excess capacity on Xcel's system. The Department used this approach to reduce the potential that the model may prefer packages with greater capacity; not accounting for any value that excess capacity might have makes those larger packages less attractive.

State of Minnesota

DEPARTMENT OF COMMERCE
DIVISION OF ENERGY RESOURCES

Utility Information Request Response

Docket Number: E002/CN-12-1240 | Date Request Received: October 1, 2013

Requested By: Geronimo Energy | Date of Response: October 11, 2013

Response submitted by: Steve Rakow

Request No.	
10	For each of the Second Round bid package scenarios, please provide the excess capacity created by each resource combination in each year from 2016 to 2020. **DOC Response:** See Attachment D for the excess reserves created under each second round bid package.

State of Minnesota

DEPARTMENT OF COMMERCE
DIVISION OF ENERGY RESOURCES

Utility Information Request Response

Docket Number: E002/CN-12-1240 Date Request Received: October 1, 2013

Requested By: Geronimo Energy Date of Response: October 11, 2013

Response submitted by: Steve Rakow

Request No.	
11	Please provide the amount (MW) and cost assumptions used in the Department's Strategist modeling for the following inputs: a) generic CT units; b) generic CC units; c) generic market capacity; d) generic wind units; and e) generic solar units. **DOC Response:** The Department did not change Xcel's size and cost assumptions for the generic units. Note that, as configured here there are actually 3 different versions of CT expansion units and 2 different versions of CC expansion units present in Strategist as configured by the Department. However, one version of CC/CT expansion capacity is available each year. a) Generic CT units: 189 MW accredited capacity throughout the planning period. b) Generic CC units: 303 MW accredited capacity through 2025 and 707 MW accredited capacity thereafter. c) Generic market capacity: The Department did not allow market capacity to be available to Strategist. d) Generic wind units: 13 MW accredited capacity throughout the planning period. e) Not available. For the cost data, see Attachment E.

State of Minnesota

DEPARTMENT OF COMMERCE
DIVISION OF ENERGY RESOURCES

Utility Information Request Response

Docket Number: E002/CN-12-1240 Date Request Received: October 1, 2013

Requested By: Geronimo Energy Date of Response: October 11, 2013

Response submitted by: Steve Rakow

Request No.	
12	Please provide a citation, reference or the reasoning used to by the Department to assign accredited capacity to wind, CT or CC units within the Strategist model (e.g. MISO's Resource Adequacy BPM). **DOC Response:** Based upon past experience, the Department did not change Xcel's accreditation assumptions because Xcel's assumed accreditation of new units was reasonably close the accreditation of existing units on Xcel's system and in other Strategist databases reviewed by the Department. Xcel would be able to provide the underlying accreditation assumptions.

State of Minnesota
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DIVISION OF ENERGY RESOURCES

Utility Information Request Response

Docket Number: E002/CN-12-1240 Date Request Received: October 1, 2013

Requested By: Geronimo Energy Date of Response: October 11, 2013

Response submitted by: Steve Rakow

Request No.	
13	Please provide the full expansion plan for bid package GPV1. **DOC Response:** Please see the table on the next page.

MW of accredited capacity added

Year	M-13-603 Wind	RES Wind	CT	CC	GPV1
2012	-	-	-	-	-
2013	-	-	-	-	-
2014	-	-	-	-	-
2015	-	-	-	-	-
2016	-	-	-	-	-
2017	-	-	189	-	72
2018	-	-	189	-	72
2019	-	-	189	-	72
2020	-	-	379	-	72
2021	100	-	379	-	72
2022	100	-	379	-	72
2023	100	-	379	303	72
2024	100	-	379	303	72
2025	100	-	568	1,211	72
2026	100	-	568	1,211	72
2027	100	13	568	1,918	72
2028	100	13	758	1,918	72
2029	100	39	947	1,918	72
2030	100	39	1,136	1,918	72
2031	100	52	1,136	2,625	72
2032	100	77	1,515	2,625	72
2033	100	142	1,515	2,625	72
2034	100	155	1,515	3,332	72
2035	100	155	1,705	4,040	72
2036	47	194	2,083	4,040	72

State of Minnesota

Department of Commerce
Division of Energy Resources

Utility Information Request Response

Docket Number: E002/CN-12-1240 Date Request Received: October 1, 2013

Requested By: Geronimo Energy Date of Response: October 11, 2013

Response submitted by: Steve Rakow

Request No.	
14	Did the Department's Strategist modeling account for line loss savings attributable to Geronimo's 100 MW Solar Proposal? If so, please describe how the Department's Strategist modeling accounted for such line loss savings, and provide all assumptions used in the model to address line loss savings. **DOC Response:** The Department was not aware that Geronimo provided line loss savings data. Geronimo's bid did not identify what those savings might be or provide support for such a claim. Therefore, no line loss savings were assumed by the Department.

State of Minnesota
DEPARTMENT OF COMMERCE
DIVISION OF ENERGY RESOURCES

Utility Information Request Response

Docket Number:	E002/CN-12-1240	Date Request Received:	October 1, 2013
Requested By:	Geronimo Energy	Date of Response:	October 11, 2013

Response submitted by: Steve Rakow

Request No.	
15	Please provide a copy of DOC Ex.__ SR-4B referred to on p. 30, ln 6 of Dr. Rakow's Direct Testimony. **DOC Response:** See Attachment F for a copy of DOC Ex.__ SR-4B.

Xcel Energy®

414 Nicollet Mall
Minneapolis, MN 55401

May 1, 2013

—Via Electronic Filing—

Burl W. Haar
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, MN 55101

RE: SOLAR EFFECTIVE LOAD CARRYING CAPABILITY (ELCC) STUDY
DOCKET NO. E002/CI-13-315

Dear Dr. Haar:

Northern States Power Company, doing business as Xcel Energy, submits the attached preliminary Effective Load Carrying Capability (ELCC) study as proposed in our January 18, 2013 Reply Comments in Docket No. E002/GR-10-971 and ordered by the Minnesota Public Utilities Commission at their April 25, 2013 meeting.

Because all customers pay for the costs of power obtained from solar resources, it is important to closely align the price paid for solar power with the value provided by solar resources. The attached study analyzes the contribution of distributed solar electric generation to electric system reliability and the capacity value of solar on the NSP System. The Company also estimated accredited capacity for large solar systems using the methodology for intermittent resources prescribed by the Midwest Independent System Operator (MISO). We believe ELCC analysis and the MISO accreditation methodology are valuable tools to establish a sound basis for the value of solar that could be recognized in rates, regardless of the specific rate mechanism. For example, the analysis can be used to inform an appropriate solar capacity credit in the Standby Service Tariff or the buy rate under a Buy-all/Sell-all framework.

The Company will organize a meeting to review and discuss the preliminary study with interested parties, including the modeling assumptions and methodologies, and modify the analysis as necessary in response to parties' feedback. As ordered by the Commission, we will submit a solar rate proposal on October 1, 2013 that reflects the final analysis and any regulatory or policy changes that occur as part of the current legislative session. We will provide an update on July 1, 2013 that reports on our progress in working with stakeholders on the rate proposal.

We have electronically filed this document with the Minnesota Public Utilities Commission, and copies have been served on the parties on the attached service list.

Please contact me at amy.a.liberkowski@xcelenergy.com or 612-330-6613 if you have any questions regarding this filing.

Sincerely,

/s/

AMY LIBERKOWSKI
MANAGER
REGULATORY ANALYSIS

Enclosures
c: Service Lists

Effective Load Carrying Capability (ELCC) Study for Solar Generation Resources

Preliminary Results

Xcel Energy
Docket No. E002/CI-13-315

May 1, 2013

Table of Contents

I. Executive Summary

The goal of studying the value of solar resources in meeting peak electric demand is to develop a rate that appropriately reflects the value provided by solar resources, while protecting the interests of other customers who ultimately pay the costs of electricity purchased from these resources.

The analysis presented in this study expands on the work done in the Company's 2012 Solar Load Profile Study. Using a detailed simulation model, the Company calculated the effective load carrying capability (ELCC) of solar PV systems on the NSP System, which measures the contribution of solar to meeting peak electric demand. The Company also estimated accredited capacity using the methodology for intermittent resources prescribed in the Resource Adequacy Business Practices Manual developed by the Midwest Independent System Operator (MISO). The MISO methodology offers some advantages over the ELCC method, since it has received a thorough review process and can be easily replicated for individual projects.

The ELCC simulations used typical meteorological year (TMY) solar shapes that correlate well with the TMY load shapes used in the Company's simulation model. The MISO methodology was applied to the TMY data, as well as the actual data from three customer sites as presented in the 2012 Solar Load Profile Study. The analysis results show that, due to its variable nature, solar contributes less than its maximum rating to system reliability at peak periods.

ELCC & MISO Accreditation Summary Results*

Typical Meteorological Year	MISO Accreditation	ELCC	Average
TMY – Fixed Panel	45.4%	42.9%	44.2%
TMY – 1-Axis Tracking	52.3%	48.1%	50.2%

Customer Sites	MISO Accreditation
Customer Site 1 – Fixed Panel	60.7%
Customer Site 2 – Fixed Panel	58.6%
Customer Site 3 – 1-Axis Tracking	57.2%

* Percent of AC nameplate value

It is important to note that the data used in this analysis is limited. Currently, the NSP System has approximately 10 MW of solar resources in its entire footprint and MISO has yet to accredit any large solar installations.

II. Background

The Company currently has five customers with grid-connected solar PV systems that exceed the 60 kW_{AC} threshold requiring service under our Standby Service Tariff. The first system came online in April 2010. The most recent system came online in March 2013. Effective June 1, 2013, customers on the Standby Service Tariff will receive an interim solar capacity credit of $5.15 per kW per month.[1] This amount is halfway between the midpoint of the range identified by the Department and the Solar Rate Reform Group, $8.35, and the value suggested by the Company in its 2012 Solar Load Profile Study, $2.00. As ordered by the Commission, the Company will submit a new solar rate proposal on October 1, 2013 with a target implementation date of January 1, 2014.

The Company completed a solar load profile study in response to the Settlement Agreement in the Company's 2011 Test Year general electric rate case (Docket No. E002/GR-10-971). Specifically, the Settlement Agreement states:

> **F.2. Large Solar Facilities.** The Chamber proposed development of a new DG Solar rate that: a) would not have standby requirements; b) would not have demand charge penalties; and c) would reflect the Special MISO Mod E accrediting rating for solar installations. At this time, the Company lacks the information needed to determine the reasonableness of the Chamber's request. *The Company agrees to study the load profile of larger Solar facilities to determine the applicability of a solar facility's unique load characteristics to the standby and supplemental rate tariff and share those results with the Chamber by August 15, 2012.* (Italics added)

The Commission's May 14, 2012 FINDINGS OF FACT, CONCLUSIONS AND ORDER in the same docket required the study results to be filed with the Commission and shared with the Department of Commerce. The Company complied with the requirements, sharing the results with the Chamber on August 15, 2012 and filing public and non-public versions of the study on August 24, 2012. On September 14, 2012, the Company re-filed the study with the previously redacted information made public.

The 2012 Solar Load Profile Study provided an analysis of the production profiles of PV facilities greater than 60 kW_{AC} located at three customer sites using metering data. The customer-based analysis was also applied to solar data

[1] As ordered by the Commission at the April 25, 2013 hearing in Docket Nos. E002/GR-10-971 and E002/M-10-1278.

sets based on a typical meteorological year[2] (TMY) for locations at the Minneapolis-St. Paul International Airport (MSP) and the St. Cloud Regional Airport (StC). The results showed that the average solar generation during the summer peak demand hours of 1 p.m. to 7 p.m. ranged from 37% to 50% of maximum rated AC output.[3] Table 1 provides the availability factor results from the Solar Load Profile Study.

Table 1: Solar Facility Availability Factor Summary

	1 p.m. - 7 p.m. On-Peak						
	Customer Sites			**Modeled Sites**			
Tracking:	Fixed	Fixed	1-Axis	Fixed	Fixed	1-Axis	1-Axis
Site	1	2	3	MSP	StC	MSP	StC
Summer	47%	43%	46%	37%	37%	50%	50%
Winter	25%	27%	24%	23%	23%	28%	29%
Annual	32%	33%	30%	25%	25%	33%	32%

* Percent of AC nameplate value

The study concluded that solar contributes to meeting the Company's peak demand, but the contribution is highly variable by time of day, month, and customer load requirement. Due to the limited data available, the Company advised that further analysis would be needed to support decision-making. The ELCC study provides the preliminary results of this additional analysis.

III. Effective Load Carrying Capability (ELCC) of Solar

This preliminary analysis calculates the effective load carrying capability (ELCC) of solar PV systems on the NSP System, which measures the contribution of solar to meeting peak electric demand. The results should be regarded as generalizations, as the actual contribution of any one specific PV installation will depend on site location, panel orientation, and type of equipment used. As discussed below, the Company used a detailed simulation model of system reliability to calculate the ELCC based on TMY solar patterns for the Minneapolis airport location from the National Renewable Energy Laboratory's (NREL) PVWatts[4] database.

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[2] A typical meteorological year is an 8,760 hourly pattern that represents typical atmospheric conditions at a specific location.
[3] The summer peak demand period is defined as 1 p.m. to 7 p.m. during the months of June through September.
[4] http://www.nrel.gov/rredc/pvwatts/

A. Methodology

The calculation of ELCC incorporates the use of a measure of electric system reliability called loss of load expectation (LOLE). LOLE is calculated by taking the average of the hourly loss of load probabilities (LOLP) over an entire year. LOLPs are in turn calculated using computer models that simulate a utility's hourly loads, generation capacity, and forced outage rates. For this study, the Company set its reliability target as an LOLE of one day in 10 years (or 2.4 hours per year), which is an industry standard typically used when evaluating system reliability.

The ELCC attributed to solar generation can be calculated by analyzing two generation portfolios: one with incremental solar generation and another with an incremental, generic capacity resource such as a gas-fired combustion turbine. Once the system without either incremental solar generation profile or the incremental generic capacity resource has obtained the target LOLE of one day in 10 years, the incremental solar resource is added to the system and the resulting LOLE becomes the target for the incremental, generic capacity resource profile. The total capacity of the incremental, generic capacity resource portfolio is adjusted until the annual average of the portfolio's hourly LOLPs is equal to the target LOLE value obtained with the solar generation profile. Then, the ELCC of the solar generation is obtained by dividing the incremental generic capacity resource MW_{AC} by the incremental solar MW_{AC}. For example, an ELCC measure of 45% indicates that 45 MW of combustion turbine capacity would supply the same peak capacity requirements as 100 MW of installed solar capacity. It can be considered the percent of a PV system's maximum AC output that is available, on average, to meet system peak demand.

The Company conducted this ELCC analysis utilizing a ProSym[5] production cost simulation model. ProSym uses a TMY pattern to represent the hourly energy demand from our customers. As such, it was appropriate to use solar patterns that were also based on a TMY. If actual solar generation patterns from metered installations had been used, there would potentially have been a misalignment between solar generation and customer demand, which could have skewed the result of the LOLE calculation. Additionally, at this time, the number of actual customer sites and duration of metering data is insufficient to develop a representative sample.

[5] ProSym is a Ventyx product used in resource planning.

ProSym was run using two different TMY shapes from NREL's PVWatts[6] database. One was based on a fixed panel installation with a 45 degree tilt and a 180 degree azimuth (due south); the other was a single-axis tracking design with the same orientation that has the ability to track the sun as it moves across the sky. The orientations of these panels are typical for the Minnesota region, as they maximize the total annual capacity factor of solar arrays. As illustrated in Table 2, designing solar installations for maximum annual generation does not result in production at maximum capacity during the summer months when customer demand is highest. Instead, maximum output is achieved in February and March when the sun's position in the sky most closely matches the 45 degree tilt that was assumed in the TMY solar shapes.

Table 2: TMY Solar Shape Summary

	Fixed Panel		**1-Axis Tracking**	
	Average Capacity Factor	Maximum Generation	Average Capacity Factor	Maximum Generation
Jan	14%	96%	17%	95%
Feb	17%	100%	20%	100%
Mar	17%	100%	20%	100%
Apr	16%	89%	21%	91%
May	19%	88%	25%	89%
Jun	19%	78%	25%	78%
Jul	18%	76%	26%	78%
Aug	17%	76%	23%	78%
Sep	17%	81%	21%	81%
Oct	15%	84%	18%	84%
Nov	10%	79%	11%	79%
Dec	10%	86%	12%	86%
Annual	16%	100%	20%	100%

The specific procedure used in ProSym to calculate the ELCC of solar is as follows:

1) Set up ProSym model for reliability run analyses and convert all scheduled maintenance days to maintenance rates.
2) Adjust the firm generic resource capacity in ProSym until the system's LOLE is equal to one day in 10 years.
3) Add 100 MW_{AC} solar profile to the NSP System and run ProSym to record the resulting (lower) LOLE.
4) Remove the 100 MW_{AC} solar profile from ProSym and incrementally add small amounts of firm generic resource capacity (natural gas

[6] http://www.nrel.gov/rredc/pvwatts/

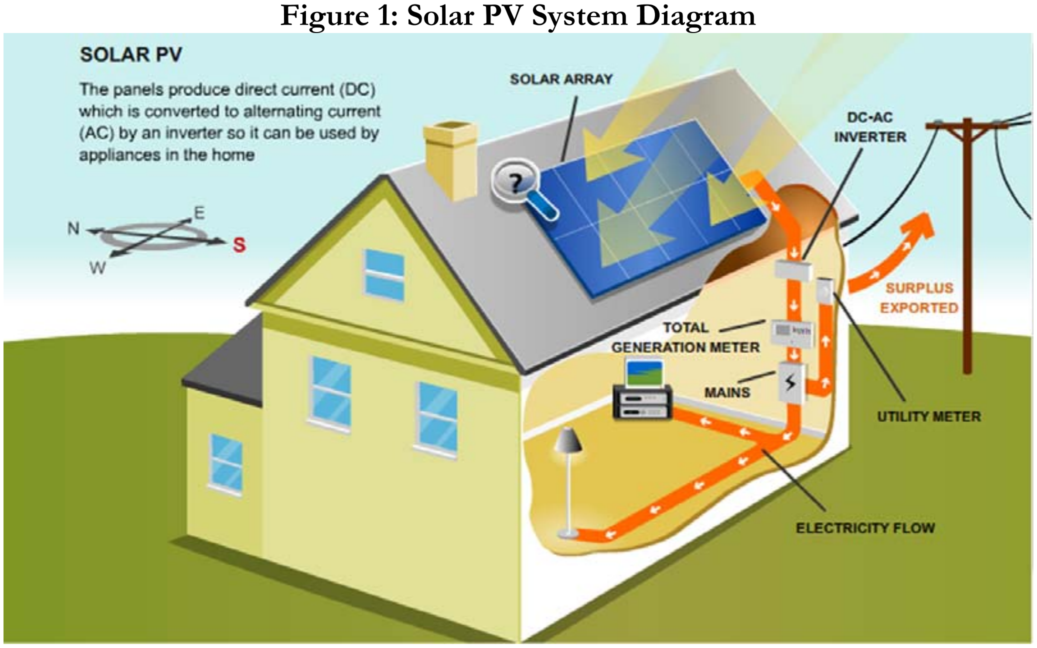
combustion turbine) until the LOLE returns to the lower LOLE observed in the previous step.

5) Calculate ELCC as (Firm Resource Capacity)/100 MW_{AC} Solar

The analysis used 100 MW increments of solar because, after testing, it was determined that the actual 10 MW level of solar on the NSP System was too small to produce reliable model results. Because the ELCC of solar is approximately 50% of the maximum rating, the amount of firm capacity in the ProSym model using the actual 10 MW on our system was only about 5 MW. In the context of the 10,000 MW NSP System, such a small increment of firm capacity was essentially "lost in the noise" of the rest of the model simulations. Testing with 100 MW provided much more stable results, allowing the ELCC values to be generalized to the smaller MW levels currently on the system.

We present the results as both a percent of AC capacity and DC capacity. As shown in Figure 1 below, solar panels create DC electricity that is passed through an inverter for conversion to AC electricity that can be used by end users or exported to the distribution grid. Some electricity is lost through the conversion process. This analysis assumed an inverter efficiency rating of 85%, which means that the maximum generation capacity of the PV system is 15% less than the DC nameplate capacity.

Figure 1: Solar PV System Diagram



Accompanying this study on compact disk is a comprehensive data package to assist in stakeholder review. The data is contained in two spreadsheets. The first spreadsheet titled "ELCC Data" contains the hourly inputs for load and solar profiles used in the analysis and the hourly LOLP results produced by ProSym. The second spreadsheet titled "MISO Method and Charts" provides the data and calculation for estimating the capacity credit values under the MISO methodology and the supporting data for the charts presented in the study. Attachment A provides an index to the data included in the spreadsheets.

B. Results

ProSym modeling results indicated that fixed panel installations have an ELCC of 42.9**%,** while single-axis tracking systems have an ELCC of 48.1**%**. That is, 42.9% of the maximum AC rating of a fixed panel PV installation and 48.1% of the maximum AC rating of a single-axis tracking system can be counted as firm capacity that contributes to total system reliability. Assuming an inverter efficiency rating of 85%, the corresponding DC ratings would be 36.5% and 40.9% for fixed panel and single-axis tracking, respectively. As previously noted, these results are based on TMY patterns with a 45% tilt and a 180 degree azimuth. The actual ELCC of any specific solar installation will vary year to year depending on the amount of solar insolation received and the orientation of the panel. Table 3 summarizes the ELCC values for fixed panel and single-axis tracking PV installations.

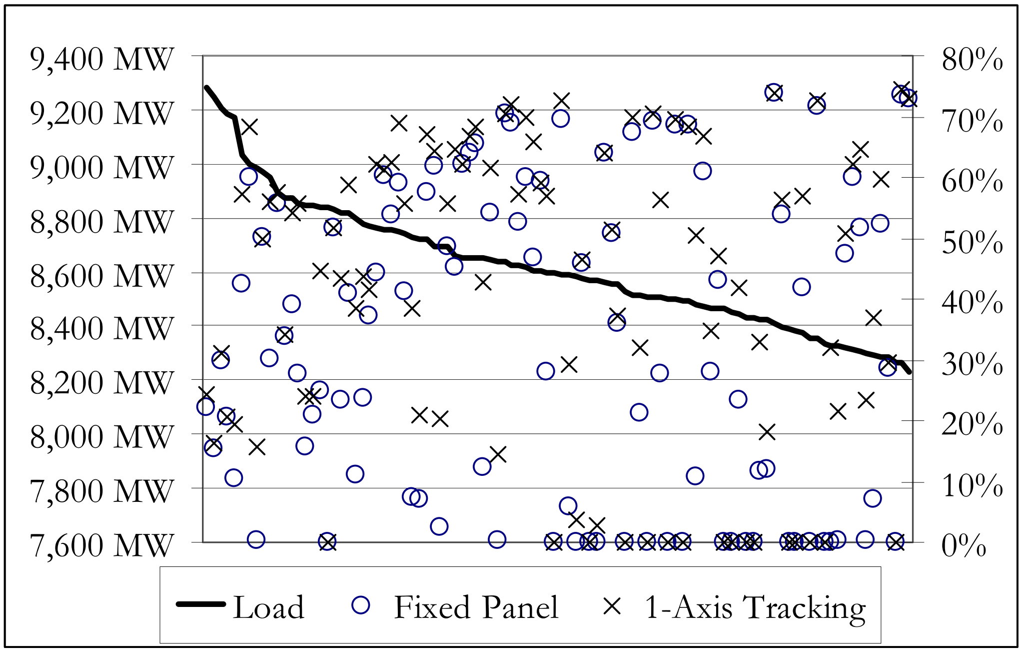
Table 3: ELCC Results

	ELCC Relative to Maximum AC Output	**ELCC Relative to Maximum DC Output***
Fixed Panel PV	42.9%	36.5%
1-Axis Tracking PV	48.1%	40.9%

* Assumes an inverter efficiency of 85%.

While calculation of solar's ELCC involves summing its contribution to system reliability in every hour of the year, the greatest contribution occurs during periods of the highest customer demands. Figure 2 illustrates the 100 highest customer demand hours, as modeled in ProSym, and the solar generation in each of those hours based on the PVWatts TMY. The secondary y-axis on the right measures the solar generation as a percent of maximum AC capacity. These results are specific to this ELCC study. Analysis of data from a specific year and specific site may produce different results, including greater (or lesser) correlation between peak demand and solar output.

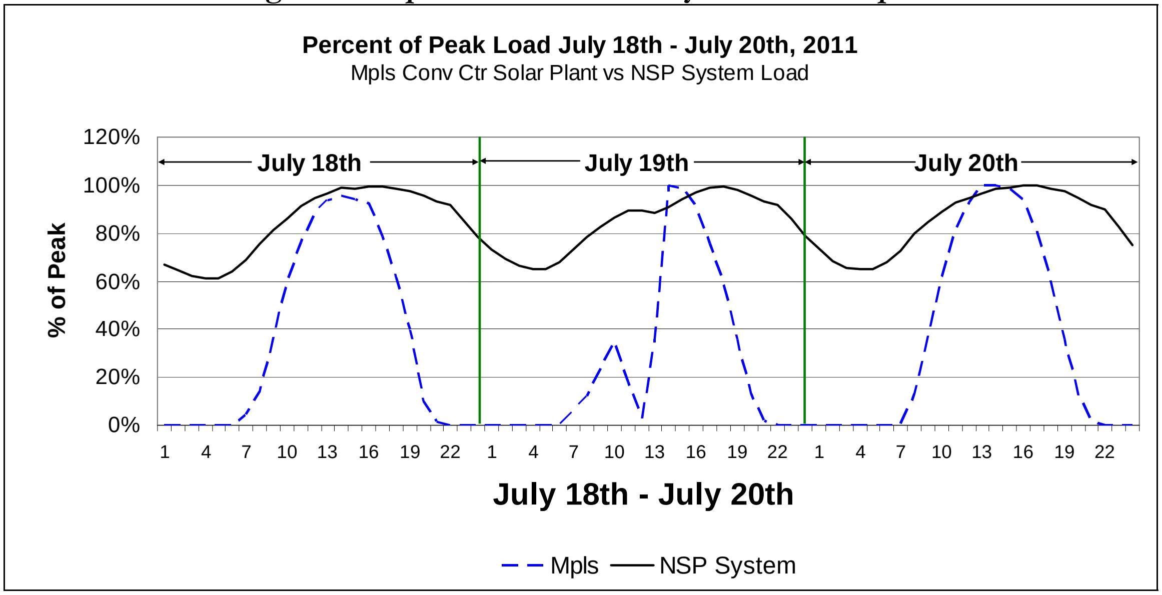
Figure 2: Solar Generation During Highest 100 Demand Hours



As shown above, during the 100 highest customer demand hours modeled in ProSym, fixed panel PV generates no energy in 18 hours, while single-axis tracking systems generate no energy in 14 hours. Inspection of the data reveals that these hours are between 6 p.m. and 10 p.m. in July and August. There are instances in the solar data where tracking systems generate power as late as 8 p.m. and fixed panel configurations generate as late as 7 p.m. However, these instances do not coincide with the highest customer demand hours.

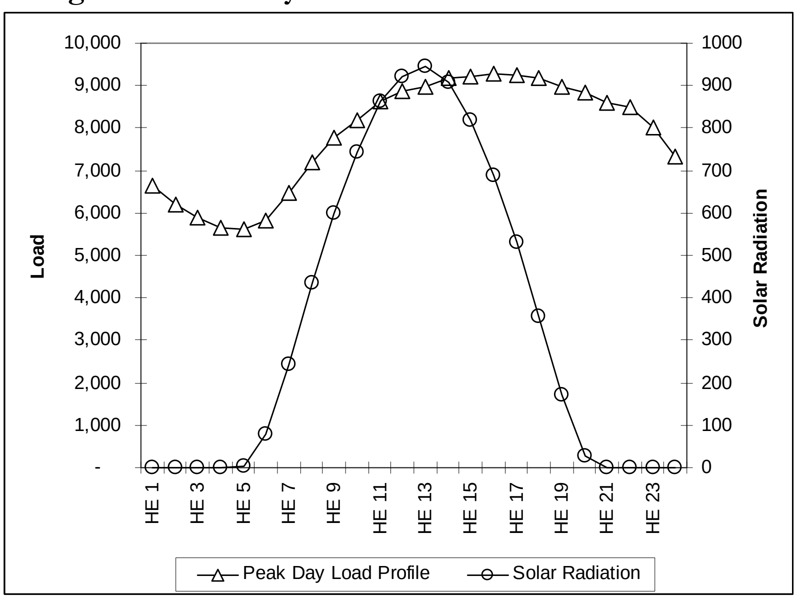
Figure 2 also highlights the variability of solar's contribution to meeting peak demand. There could be several reasons why solar output is not more closely correlated with periods of high demand. For example, it is possible that during periods of peak demand there may be atmospheric interferences (clouds or haze) that limit peak generation from solar panels. Figure 3 illustrates the impact of a storm's disturbance of solar output using actual solar output and system load data over a period of three days in July 2011. The solar output as a percentage of peak drops significantly on July 19 from 10 a.m. to 2 p.m. (hours 10-14), as the cloud interference related to a storm passes between the sun and the PV installation. Since the ELCC is measurement of reliability, the possibility of this type of weather event explains a portion of the difference between the ELCC finding and peak output of the PV system over a period of time.

Figure 3: Impact of Storm Activity on Solar Output



Additionally, peak load hours tend to occur later in the day when solar radiation is not at its peak. Figure 4 illustrates the typical hourly load pattern for a peak demand summer day on the NSP System and corresponding measured solar radiation. A similar pattern is present in Figure 3.

Figure 4: Peak Day Load Profile and Solar Radiation[7]



[7] Solar radiation source: National Solar Radiation Database - http://rredc.nrel.gov/solar/old_data/nsrdb/1991-2010/

C. Analysis Limitations

The Company believes it has produced a sound analysis of the ELCC for solar generation. As with any model, however, there are limitations to our analysis. For example, it was not possible to perfectly align the solar patterns with the load shape used in ProSym. While both solar and load patterns represent typical meteorological years, the vintages are different. The PVWatts database used years ranging from 1963 to 1990 to develop the TMY for solar. The load shape in ProSym is a TMY developed using data from the years 1990 to 1996. Thus, the weather patterns represented in the solar shape are not identical to the patterns in the load shape; both represent typical or average weather patterns, but they are not identical. Due to limited data, it does not seem possible to either fit actual solar data to ProSym's current load TMY, nor is it possible to find hourly load data from 1963 to 1990 that would fit the TMY that is used by PVWatts. One recommendation for future improvement in the assessment of solar's contribution to system reliability is to develop new TMY patterns for solar and load. The Company welcomes suggestions on how to improve the fit of the data.

IV. MISO Accreditation of Intermittent Resources

The Company also evaluated solar's contribution to peak demand using a methodology established by MISO. Any solar resource that connects directly to the transmission system and seeks to be accredited as a network resource must register with MISO and calculate a capacity credit. Currently, there are no large solar generation facilities that have received capacity credit in MISO.

The Resource Adequacy Business Practices Manual (BPM) specifies a methodology for establishing an accredited capacity value of non-wind intermittent generation. Section 4.2.2.3 of the BPM states:

> All other Intermittent Generation and Dispatchable Intermittent Resources will have their annual UCAP value determined based on the 3 year historical average output of the resource for hours 1500-1700 EST for the most recent Summer months (June, July, and August).[8]

For systems that are new, upgraded or returning from extended outages, where data does not exist for some or all of the previous 36 months, MISO instructs applicants to submit all operating data for June, July, or August with a

[8] https://www.midwestiso.org/Library/BusinessPracticesManuals/Pages/BusinessPracticesManuals.aspx

minimum of 30 consecutive days, in order to have their new or upgraded capacity registered with MISO.

The Company does not have three full years of hourly data that can be used to calculate the MISO UCAP value for solar. As a substitute, we applied the methodology to the single year of TMY data used in the ELCC analysis and the three sets of customer data presented in our 2012 Solar Load Profile Study. The results are summarized in Table 4.

Table 4: Solar Accreditation – MISO Methodology

	MISO Accreditation Relative to Maximum AC Output	MISO Accreditation Relative to Maximum DC Output*
TMY – Fixed Panel	45.4%	38.6%
TMY – 1-Axis Tracking	52.3%	44.5%
Customer Site 1 – Fixed Panel	60.7%	56.5%
Customer Site 2 – Fixed Panel	58.6%	49.8%
Customer Site 3 – 1-Axis Tracking	57.2%	51.0%

* TMY values assume 85% inverter efficiency

Using the MISO methodology, the accredited values for the customer sites is slightly higher than for the TMY data used in the ELCC analysis. It is possible that these sites have oriented their panels to capture more solar energy during peak periods, either by tilting panels to be flatter than the 45 degrees assumed in the TMY data or by pointing panels in a more westerly direction.

Figure 5 illustrates that the TMY shapes have more consistent year-round generation, while the generation at customer sites is more focused on the summer months.[9] Additionally, Attachment B provides charts of average generation by hour for June, July, and August for the customer sites and TMY shapes. These charts show that the generation in the TMY shapes is higher in the morning hours and lower in the afternoon in comparison to the customer data. This indicates that the azimuth of the customer sites might be oriented more towards the west than the due south orientation assumed by the TMY data. Without a larger sample of customer sites and a longer interval of metering data, it is not known if these customer site results are representative of the overall solar population or just particular to the three sample data set the Company was able to obtain.

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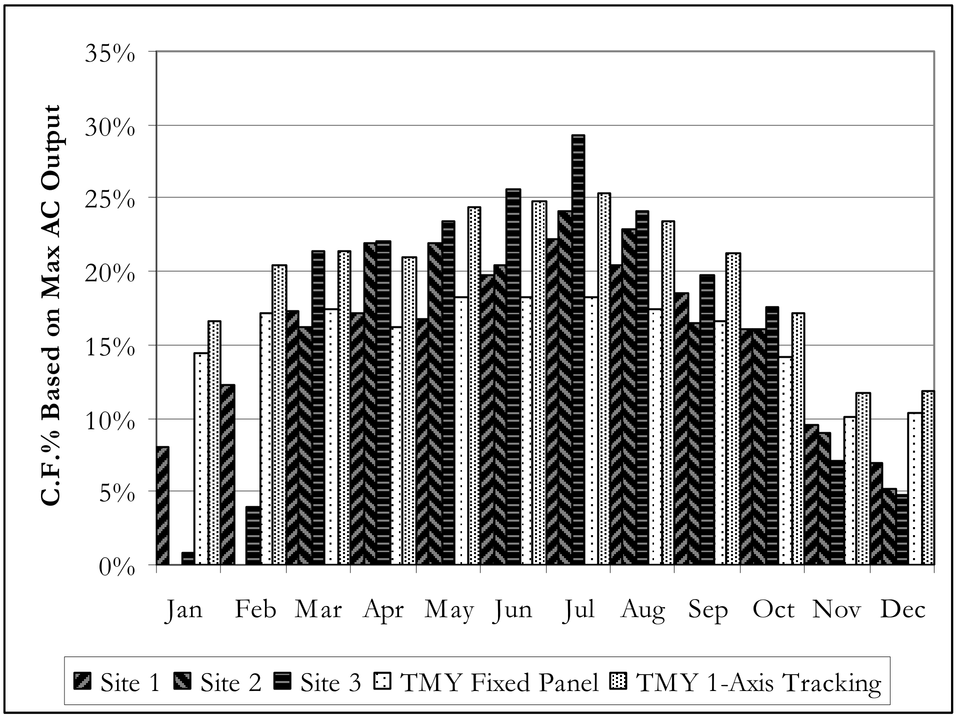
[9] The data for site 2 in January and February was unavailable.

Figure 5: Monthly Solar Capacity Factor Values



V. Rate Implications

A capacity credit should adequately reflect the contribution of solar to meeting peak demand, but not be excessive since all other customers pay for the credit. We used the results of the ELCC study and MISO methodology to estimate capacity credits by applying the solar capacity contribution percents to the generation ($4.99 per kW) and transmission ($2.52 per kW) cost components of the present average monthly demand charge. Although we have included transmission capacity cost credits in the table, transmission cost savings are not fully related to system peak loads and have not been clearly established. As shown in the table below, we estimate a generation capacity credit range of $2.14 per kW to $2.61 per kW, and if transmission capacity cost is included in the credit, the solar capacity credit range is $3.22 per kW to $3.93 per kW.

Table 5: Estimated Solar Capacity Credits

	Avg. Monthly Demand Charge	Fixed Panel		1-Axis	
		ELCC	MISO	ELCC	MISO
		42.9%	45.4%	48.1%	52.3%
Generation	$4.99	$2.14	$2.26	$2.40	$2.61
Gen. + Trans.	$7.51	$3.22	$3.41	$3.61	$3.93

The estimated solar capacity credits are derived from seasonal demand charges for firm service to maintain a consistent embedded cost basis for both rates and rate credits. The direct application of a solar capacity contribution percent to a current avoided cost could produce a credit that is inconsistent and out of proportion to the present rate that is credited.

VI. Conclusion

The analysis presented in this preliminary study confirms that solar generation contributes to system reliability, but at far less than its maximum rating. Based on the TMY analysis and the ELCC and MISO methodologies, fixed panel PV contributes, on average, 44% of its maximum rating to meeting system peak. The single-axis tracking systems average 50% of maximum rating. The results also show that the ELCC methodology for calculating accredited capacity results in lower but generally consistent values compared to the method prescribed by MISO.

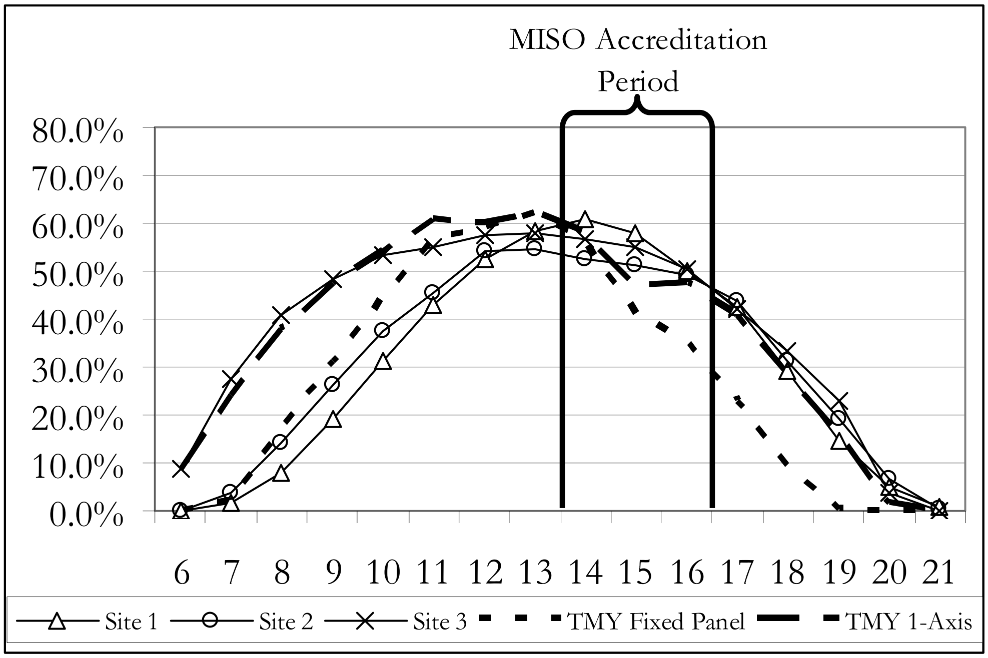
Index for Data Package

Attachment A.1 – ELCC Data.xls
- Tab 1 – Solar & Load Inputs
- Tab 2 – Hourly LOLP Results
- Tab 3 – Figure 2 Data (Solar Generation During Highest 100 Demand Hours)

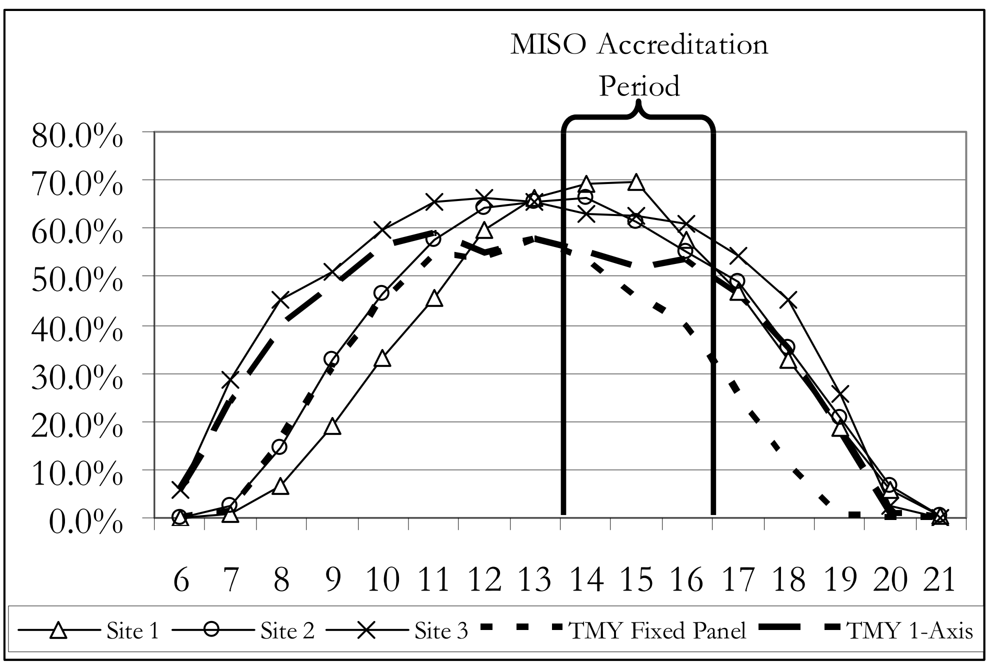
Attachment A.2 – MISO Method & Charts.xls
- Tab 1 – Figure 2 (Peak Day Load Profile and Solar Radiation)
- Tab 2 – Average Solar Shapes (as presented in Attachment A)
- Tab 3 – Figure 4 (Monthly Solar Capacity Factor Values)
- Tab 4 – Summary Data (Including MISO accreditation calculations)
- Tab 5 – Site Data (Hourly data and summary calculations)
- Tab 6 – TMY Data (Hourly data for TMY shapes)

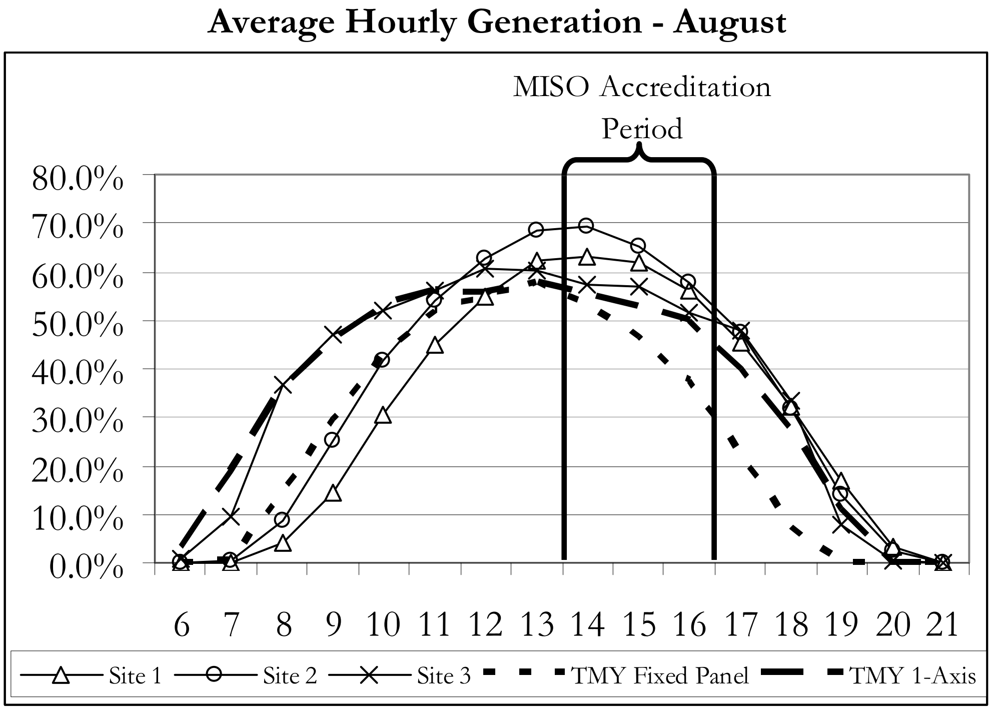
Average Generation by Hour for June, July, and August

Average Hourly Generation - June



Average Hourly Generation - July




Average Hourly Generation - August
MISO Accreditation Period
80.0%
70.0%
60.0%
50.0%
40.0%
30.0%
20.0%
10.0%
0.0%
6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21
Site 1
Site 2
Site 3
TMY Fixed Panel
TMY 1-Axis

CERTIFICATE OF SERVICE

I, SaGonna Thompson, hereby certify that I have this day served copies of the foregoing document on the attached list of persons.

xx by depositing a true and correct copy thereof, properly enveloped with postage paid in the United States mail at Minneapolis, Minnesota

xx electronic filing

Docket Nos. E002/GR-10-971 and E-002/M-10-1278

Dated this 1st day of May 2013

/s/

____

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James M.	Strommen	jstrommen@kennedy-graven.com	Kennedy & Graven, Chartered	470 U.S. Bank Plaza 200 South Sixth Street Minneapolis, MN 55402	Electronic Service	No	OFF_SL_10-971_Official
SaGonna	Thompson	Regulatory.Records@xcelenergy.com	Xcel Energy	414 Nicollet Mall FL 7 Minneapolis, MN 554011993	Electronic Service	No	OFF_SL_10-971_Official
Kari L	Valley	kari.l.valley@xcelenergy.com	Xcel Energy Service Inc.	414 Nicollet Mall FL 5 Minneapolis, MN 55401	Electronic Service	No	OFF_SL_10-971_Official
Scott M.	Wilensky	scott.wilensky@xcelenergy.com	Xcel Energy	7th Floor 414 Nicollet Mall Minneapolis, MN 554011993	Paper Service	No	OFF_SL_10-971_Official

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Michael	Allen	michael.allen@allenergysolar.com	All Energy Solar	721 W 26th st Suite 211 Minneapolis, Minnesota 55405	Electronic Service	No	OFF_SL_10-1278_Official
Julia	Anderson	Julia.Anderson@ag.state.mn.us	Office of the Attorney General-DOC	1800 BRM Tower 445 Minnesota St St. Paul, MN 551012134	Electronic Service	No	OFF_SL_10-1278_Official
John	Aune	johna@bluehorizonsolar.com	Blue Horizon Energy	7246 Washington Ave S Eden Prairie, MN 55344	Paper Service	No	OFF_SL_10-1278_Official
Joel	Cannon	jcannon@tenksolar.com	tenKsolar, Inc.	9549 Penn Avenue S Bloomington, MN 55431	Electronic Service	No	OFF_SL_10-1278_Official
John J.	Carroll	jcarroll@newportpartners.com	Newport Partners, LLC	9 Cushing, Suite 200 Irvine, California 92618	Electronic Service	No	OFF_SL_10-1278_Official
Sharon	Ferguson	sharon.ferguson@state.mn.us	Department of Commerce	85 7th Place E Ste 500 Saint Paul, MN 551012198	Electronic Service	No	OFF_SL_10-1278_Official
Nathan	Franzen	nathan.franzen@westwoodps.com	Westwood Professional Services	7699 Anagram Drive Eden Prairie, Minnestoa 55344	Paper Service	No	OFF_SL_10-1278_Official
Elizabeth	Goodpaster	bgoodpaster@mncenter.org	MN Center for Environmental Advocacy	Suite 206 26 East Exchange Street St. Paul, MN 551011667	Paper Service	No	OFF_SL_10-1278_Official
Burl W.	Haar	burl.haar@state.mn.us	Public Utilities Commission	Suite 350 121 7th Place East St. Paul, MN 551012147	Electronic Service	Yes	OFF_SL_10-1278_Official
Jan	Hubbard	Jan@AppliedEnergyInnovations.org	Applied Energy Innovations, LLC	4000 Minnehaha Avenue South Minneapolis, MN 55405	Paper Service	No	OFF_SL_10-1278_Official

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Jon	Kramer	jk2surf@aol.com	Sundial Solar	4708 york ave. S Minneapolis, MN 55410	Electronic Service	No	OFF_SL_10-1278_Official
John	Lindell	agorud.ecf@ag.state.mn.us	Office of the Attorney General-RUD	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012130	Electronic Service	No	OFF_SL_10-1278_Official
Rebecca	Lundberg	rebecca.lundberg@powerfullygreen.com	Powerfully Green	11451 Oregon Ave N Champlin, MN 55316	Electronic Service	No	OFF_SL_10-1278_Official
Martin	Morud	mmorud@trunorthsolar.com	Tru North Solar	5115 45th Ave S Minneapolis, MN 55417	Electronic Service	No	OFF_SL_10-1278_Official
Donna	Pickard	dpickard@aladdinsolar.com	Aladdin Solar	1215 Lilac Lane Excelsior, MN 55331	Electronic Service	No	OFF_SL_10-1278_Official
Gary	Shaver	N/A	Silicon Energy	3506 124th St NE Marysville, WA 98271	Paper Service	No	OFF_SL_10-1278_Official
SaGonna	Thompson	Regulatory.Records@xcelenergy.com	Xcel Energy	414 Nicollet Mall FL 7 Minneapolis, MN 554011993	Electronic Service	No	OFF_SL_10-1278_Official
Daniel	Williams	N/A	Powerfully Green	11451 Oregon Avenue N Champlin, MN 55316	Paper Service	No	OFF_SL_10-1278_Official

Item	Definition
BASE CASE	This is the base case.
CO2 Reduction	This implements Minn. Stat. 216H.02.
$34 CO2	This implements the Commisison's $34/ton CO2 value.
$9 CO2	This implements the Commisison's $9/ton CO2 value.
Low Externalities	This implements the Commisison's low externality values.
High Market Price - 25%	This increases market prices 25 percent
Low Market Price + 25%	This decreases market prices 25 percent
High Capital Cost + 10%	This increases capital cost of expansion units 10 percent.
Low Capital Cost - 10%	This decreases capital cost of expansion units 10 percent.
High Coal + 20%	This increases coal prices 20 percent.
High Coal + 10%	This increases coal prices 10 percent.
Low Coal - 10%	This decreases coal prices 10 percent.
Low Coal - 20%	This decreases coal prices 20 percent.
Low Natural Gas - $1.50	This decreases natural gas prices $1.50.
Low Natural Gas - $1.00	This decreases natural gas prices $1.00.
Low Natural Gas - $0.50	This decreases natural gas prices $0.50.
High Natural Gas + $0.50	This increases natural gas prices $0.50.
High Natural Gas + $1.00	This increases natural gas prices $1.00.
High Natural Gas + $1.50	This increases natural gas prices $1.50.
High Natural Gas + $2.00	This increases natural gas prices $2.00.
High Natural Gas + $2.50	This increases natural gas prices $2.50.
High Wind Credit + 25%	This increases wind capacity credit 25 percent.
Low Wind Credit - 25%	This decreases wind capacity credit 25 percent.
High Forecast + 5%	This increases the energy/demand forecast 5 percent.
Mid-High Forecast + 2.5%	This increases the energy/demand forecast 2.5 percent.
Mid-Low Forecast - 2.5%	This decreases the energy/demand forecast 2.5 percent.
Low Forecast - 5%	This decreases the energy/demand forecast 5 percent.
Manitoba Hydro PPA Renew	This removes the retirement dates for Xcel's PPA's with Manitoba Hydro.
Bid Package BASE CASE	This includes no bid proposals--all generic units.
Bid Package GPV1	This includes GPV1.
Bid Package BD617	This includes BD617.
Bid Package CCC1	This includes CCC1.
Bid Package ICT1	This includes ICT1.
Bid Package BD619 CCC1	This includes BD619 and CCC1.
Bid Package ICT1 CCC1	This includes ICT1 and CCC1.
Bid Package ICT1 BD618	This includes ICT1 and BD618.
PVSC ($000)	This shows the present value of societal costs in thousands of dollars.
PVSC Difference from Base Case, Same Contingency ($,000)	This shows the PVSC difference from the base case.
Rank	This is the rank in PVSC order.
Year 1st Generic Unit Added	This is the first year the scenario adds a generic expansion unit.

Year	Maximum Capacity (MW)		Total Cost ($000)
2012	6.39	$	4,991.9
2013	8.08	$	5,312.6
2014	9.77	$	5,312.2
2015	11.46	$	5,311.9
2016	13.15	$	5,312.6
2017	104.84	$	23,725.0
2018	196.53	$	41,669.4
2019	288.22	$	45,978.9
2020	289.91	$	45,305.0
2021	291.60	$	43,048.6
2022	293.29	$	43,517.3
2023	294.98	$	43,998.2
2024	296.67	$	44,596.4
2025	298.36	$	45,025.9
2026	300.05	$	45,559.0
2027	301.74	$	46,105.5
2028	303.43	$	46,762.3
2029	305.12	$	47,241.0
2030	305.35	$	33,264.2
2031	305.90	$	23,596.9
2032	305.90	$	23,505.9
2033	304.36	$	23,013.7
2034	304.35	$	23,013.7
2035	304.35	$	23,013.7
2036	304.35	$	23,056.2

Scenarios 39, 40 (Base Case)	2016	2017	2018	2019	2020
Peak Demand	9,524	9,613	9,708	9,799	9,881
Actual Reserve Margin	4.10	4.81	5.71	5.09	4.19
Required Reserve Margin	3.79	3.79	3.79	3.79	3.79
Excess Reserve Margin	0.31	1.02	1.92	1.30	0.40
Excess Reserves	29	98	187	128	40

Scenarios 25, 26 (GPV1)	2016	2017	2018	2019	2020
Peak Demand	9,524	9,613	9,708	9,799	9,881
Actual Reserve Margin	4.10	5.56	4.50	3.90	4.92
Required Reserve Margin	3.79	3.79	3.79	3.79	3.79
Excess Reserve Margin	0.31	1.77	0.71	0.11	1.13
Excess Reserves	29	170	69	10	112
Excess Rsrv, Diff from Base Case	-	72	(117)	(117)	72

Scenarios 27, 28 (BD617)	2016	2017	2018	2019	2020
Peak Demand	9,524	9,613	9,708	9,799	9,881
Actual Reserve Margin	4.10	5.00	3.96	5.29	4.38
Required Reserve Margin	3.79	3.79	3.79	3.79	3.79
Excess Reserve Margin	0.31	1.21	0.17	1.50	0.59
Excess Reserves	29	117	16	147	59
Excess Rsrv, Diff from Base Case	-	19	(171)	19	19

Scenarios 29, 30 (CCC1)	2016	2017	2018	2019	2020
Peak Demand	9,524	9,613	9,708	9,799	9,881
Actual Reserve Margin	4.10	5.82	4.76	4.15	5.17
Required Reserve Margin	3.79	3.79	3.79	3.79	3.79
Excess Reserve Margin	0.31	2.03	0.97	0.36	1.38
Excess Reserves	29	195	94	35	137
Excess Rsrv, Diff from Base Case	-	97	(93)	(93)	97

Scenarios 31, 32 (ICT1)	2016	2017	2018	2019	2020
Peak Demand	9,524	9,613	9,708	9,799	9,881
Actual Reserve Margin	5.72	4.44	5.35	4.74	3.84
Required Reserve Margin	3.79	3.79	3.79	3.79	3.79
Excess Reserve Margin	1.93	0.65	1.56	0.95	0.05
Excess Reserves	184	63	152	93	5
Excess Rsrv, Diff from Base Case	154	(35)	(35)	(35)	(35)

Scenarios 33, 34 (CCC1, BD619)	2016	2017	2018	2019	2020
Peak Demand	9,524	9,613	9,708	9,799	9,881
Actual Reserve Margin	4.10	5.82	4.76	6.28	5.37
Required Reserve Margin	3.79	3.79	3.79	3.79	3.79
Excess Reserve Margin	0.31	2.03	0.97	2.49	1.58
Excess Reserves	29	195	94	244	156
Excess Rsrv, Diff from Base Case	-	97	(93)	116	116

Scenarios 35, 36 (ICT1, CCC1)	2016	2017	2018	2019	2020
Peak Demand	9,524	9,613	9,708	9,799	9,881
Actual Reserve Margin	5.72	7.42	6.35	5.73	4.82
Required Reserve Margin	3.79	3.79	3.79	3.79	3.79
Excess Reserve Margin	1.93	3.63	2.56	1.94	1.03
Excess Reserves	184	349	249	190	102
Excess Rsrv, Diff from Base Case	154	251	62	62	62

Scenarios 37, 38 (ICT1, BD618)	2016	2017	2018	2019	2020
Peak Demand	9,524	9,613	9,708	9,799	9,881
Actual Reserve Margin	5.72	4.44	5.55	4.93	4.03
Required Reserve Margin	3.79	3.79	3.79	3.79	3.79
Excess Reserve Margin	1.93	0.65	1.76	1.14	0.24
Excess Reserves	184	63	171	112	24
Excess Rsrv, Diff from Base Case	154	(35)	(16)	(16)	(16)

CC PPA		
Item	**Amount**	**Notes**
Fixed Annual Capacity Rate	$ 80.75	$ / kW-year
Fixed Costs	$ 11,077	$,000 / year
Variable O & M Cost	$ 2.21	$ / MWh
First Year Available	2017	
Last Year Available	2026	

CC Defer		
Item	**Amount**	**Notes**
Fixed Annual Capacity Rate	$ 94.31	$ / kW-year
Variable O & M Cost	$ 2.21	$ / MWh
First Year Available	2027	
Last Year Available	2036	

225 CT		
Item	**Amount**	**Notes**
Construction Expenditures	$ 137,458	in $,000, if construction starts in 2011
Fixed Costs	$ 1,496	$,000 / year
Variable O & M Cost	$ 1.34	$ / MWh
First Year Available	2016	
Last Year Available	2019	

CT PPA		
Item	**Amount**	**Notes**
Fixed Annual Capacity Rate	$ 58.56	$ / kW-year
Fixed Costs	$ 1,496	$,000 / year
Variable O & M Cost	$ 9.82	$ / MWh
First Year Available	2020	
Last Year Available	2026	

CT Defer		
Item	**Amount**	**Notes**
Fixed Annual Capacity Rate	$ 65.27	$ / kW-year
Variable O & M Cost	$ 9.82	$ / MWh
First Year Available	2027	
Last Year Available	2036	

Wind		
Item	**Amount**	**Notes**
Transaction Option Fee	$ 2,000,000	the annual fee which is incurred whether or not the transaction is actually utilized
Transaction Energy Cost	$ 47.39	$ / MWh in 2011, escalated at about 2.36 percent annually

Master Scenario 1	Year CT/CC Added	Rank	Master Scenario 2	Year CT/CC Added	Rank	Master Scenario 3	Year CT/CC Added	Rank
CCC1	2020	30	CCC1	2020	26	CCC1	2020	43
GRE1 CCC1	2020	45	GRE1 CCC1	2020	44	GRE1 CCC1	2020	61
GRE2 CCC1	2020	70	GRE2 CCC1	2020	69	BD618 GPV1	2020	77
BD617 GPV1	2020	86	BD617 GPV1	2020	86	GRE2 CCC1	2020	81
GRE1 GPV1 BD618	2020	90	GRE1 GPV1 BD618	2020	90	ICT2	2020	84
ICT2	2020	98	ICT2	2020	98	GRE1 GPV1 BD619	2020	87
GRE2 GPV1 BD619	2020	99	GRE2 GPV1 BD619	2020	99	GRE1 GPV1 BD618	2020	96
GRE1 GPV1 BD617	2020	100	GRE1 GPV1 BD617	2020	101	BD617 GPV1	2020	97
GRE2 GPV1 BD618	2020	107	GRE2 GPV1 BD618	2020	107	GRE1 ICT2	2020	102
GRE1 ICT2	2020	113	GRE1 ICT2	2020	113	GRE2 GPV1 BD619	2020	107
GRE2 GPV1 BD617	2020	114	GRE2 GPV1 BD617	2020	114	GRE1 GPV1 BD617	2020	112
GRE2 ICT2	2020	123	GRE2 ICT2	2020	123	GRE2 GPV1 BD618	2020	116
						GRE2 ICT2	2020	120
						GRE2 GPV1 BD617	2020	124
						ICT1 GPV1	2020	140
						GRE1 GPV1 ICT1	2020	147
						GRE2 GPV1 ICT1	2020	150

Master Scenario 1	Year CT/CC Added	Rank	Master Scenario 2	Year CT/CC Added	Rank	Master Scenario 3	Year CT/CC Added	Rank
BD618 ICT1	2021	22	BD618 ICT1	2021	22			
GRE1 ICT1 BD619	2021	25	GRE1 ICT1 BD619	2021	25			
GRE1 ICT1 BD618	2021	37	GRE1 ICT1 BD618	2021	37			
BD617 ICT1	2021	39	BD617 ICT1	2021	39			
GRE2 ICT1 BD619	2021	48	GRE2 ICT1 BD619	2021	48			
GRE1 ICT1 BD617	2021	57	GRE1 ICT1 BD617	2021	57			
GRE2 ICT1 BD618	2021	62	GRE2 ICT1 BD618	2021	62			
CCC1 GPV1	2021	66	CCC1 GPV1	2021	66			
GRE2 ICT1 BD617	2021	78	GRE2 ICT1 BD617	2021	78			
GRE1 GPV1 CCC1	2021	83	GRE1 GPV1 CCC1	2021	81			
GRE2 GPV1 CCC1	2021	102	GRE2 GPV1 CCC1	2021	100			

Master Scenario 1	Year CT/CC Added	Rank	Master Scenario 2	Year CT/CC Added	Rank	Master Scenario 3	Year CT/CC Added	Rank
BD617 ND118	2022	49	BD617 ND118	2022	49	BD618 ICT1	2022	15
BD618 ND118 GRE1	2022	50	BD618 ND118 GRE1	2022	50	GRE1 ICT1 BD619	2022	19
GPV1 ICT1 BD619	2022	64	GPV1 ICT1 BD619	2022	64	BD617 ICT1	2022	26
BD617 ND118 GRE1	2022	67	BD617 ND118 GRE1	2022	68	GRE1 ICT1 BD618	2022	27
BD618 ND118 GRE2	2022	71	BD618 ND118 GRE2	2022	71	GRE2 ICT1 BD619	2022	40
GPV1 ICT1 BD618	2022	73	GPV1 ICT1 BD618	2022	73	GRE1 ICT1 BD617	2022	48
BD617 ND118 GRE2	2022	91	BD617 ND118 GRE2	2022	91	GRE2 ICT1 BD618	2022	51
GPV1 ICT1 BD617	2022	92	GPV1 ICT1 BD617	2022	92	GRE2 ICT1 BD617	2022	68
ND119 ND219 GRE2	2022	104	ND119 ND219 GRE2	2022	104	CCC1 GPV1	2022	72
ND118 ND218 GRE1	2022	109	ND118 ND218 GRE1	2022	109	GRE1 GPV1 CCC1	2022	91
ND118 ND218 GRE2	2022	120	ND118 ND218 GRE2	2022	120	GRE2 GPV1 CCC1	2022	111
ICT2 GPV1	2022	125	ICT2 GPV1	2022	125	ICT2 GPV1	2022	136
GRE1 GPV1 ICT2	2022	132	GRE1 GPV1 ICT2	2022	132	GRE1 GPV1 ICT2	2022	142
GRE2 GPV1 ICT2	2022	142	GRE2 GPV1 ICT2	2022	142	GRE2 GPV1 ICT2	2022	148

Master Scenario 4	Year CT/CC Added	Rank	Master Scenario 5	Year CT/CC Added	Rank	Master Scenario 6	Year CT/CC Added	Rank
BASE CASE	2020	113	CCC1	2020	26	BASE CASE	2020	114
GRE1	2020	123	GRE1 CCC1	2020	44	GRE1	2020	122
GRE2	2020	135	GRE2 CCC1	2020	69	GRE2	2020	133
			BD617 GPV1	2020	86			
			GRE1 GPV1 BD618	2020	90			
			ICT2	2020	98			
			GRE2 GPV1 BD619	2020	99			
			GRE1 GPV1 BD617	2020	101			
			GRE2 GPV1 BD618	2020	107			
			GRE1 ICT2	2020	113			
			GRE2 GPV1 BD617	2020	114			
			GRE2 ICT2	2020	123			

Master Scenario 4	Year CT/CC Added	Rank	Master Scenario 5	Year CT/CC Added	Rank	Master Scenario 6	Year CT/CC Added	Rank
GPV1 FVP	2021	114	BD618 ICT1	2021	22			
GPV1 FVP DGRD	2021	115	GRE1 ICT1 BD619	2021	25			
GPV1 DEGRADE	2021	125	GRE1 ICT1 BD618	2021	37			
GPV1	2021	129	BD617 ICT1	2021	39			
GRE1 GPV1	2021	138	GRE2 ICT1 BD619	2021	48			
GRE2 GPV1	2021	146	GRE1 ICT1 BD617	2021	57			
			GRE2 ICT1 BD618	2021	62			
			CCC1 GPV1	2021	66			
			GRE2 ICT1 BD617	2021	78			
			GRE1 GPV1 CCC1	2021	81			
			GRE2 GPV1 CCC1	2021	100			

Master Scenario 4	Year CT/CC Added	Rank	Master Scenario 5	Year CT/CC Added	Rank	Master Scenario 6	Year CT/CC Added	Rank
			BD617 ND118	2022	49	GPV1 FVP	2022	109
			BD618 ND118 GRE1	2022	50	GPV1 FVP DGRD	2022	112
			GPV1 ICT1 BD619	2022	64	GPV1 DEGRADE	2022	120
			BD617 ND118 GRE1	2022	68	GPV1	2022	124
			BD618 ND118 GRE2	2022	71	GRE1 GPV1	2022	132
			GPV1 ICT1 BD618	2022	73	GRE2 GPV1	2022	140
			BD617 ND118 GRE2	2022	91			
			GPV1 ICT1 BD617	2022	92			
			ND119 ND219 GRE2	2022	104			
			ND118 ND218 GRE1	2022	109			
			ND118 ND218 GRE2	2022	120			
			ICT2 GPV1	2022	125			
			GRE1 GPV1 ICT2	2022	132			
			GRE2 GPV1 ICT2	2022	142			

Master Scenario 7	Year CT/CC Added	Rank
CCC1	2020	26
GRE1 CCC1	2020	44
GRE2 CCC1	2020	69
BD617 GPV1	2020	86
GRE1 GPV1 BD618	2020	90
ICT2	2020	98
GRE2 GPV1 BD619	2020	99
GRE1 GPV1 BD617	2020	101
GRE2 GPV1 BD618	2020	107
GRE1 ICT2	2020	113
GRE2 GPV1 BD617	2020	114
GRE2 ICT2	2020	123

Master Scenario 8	Year CT/CC Added	Rank
BD618 ICT1	2020	29
GRE1 ICT1 BD619	2020	33
GRE1 ICT1 BD618	2020	42
BD617 ICT1	2020	43
GRE2 ICT1 BD619	2020	51
GRE1 ICT1 BD617	2020	60
GRE2 ICT1 BD618	2020	62
GRE2 ICT1 BD617	2020	83
CCC1 GPV1	2020	90
GRE1 GPV1 CCC1	2020	97
GRE2 GPV1 CCC1	2020	119
ICT2 GPV1	2020	132
GRE1 GPV1 ICT2	2020	140
GRE2 GPV1 ICT2	2020	151

Master Scenario 9	Year CT/CC Added	Rank
BD618 ICT1	2020	39
GRE1 ICT1 BD619	2020	49
GRE1 ICT1 BD618	2020	59
BD617 ICT1	2020	61
GRE2 ICT1 BD619	2020	73
GRE1 ICT1 BD617	2020	80
GRE2 ICT1 BD618	2020	81
ICT2	2020	91
GRE2 ICT1 BD617	2020	93
CCC1 GPV1	2020	95
GRE1 ICT2	2020	99
GRE1 GPV1 CCC1	2020	103
GRE2 ICT2	2020	114
GRE2 GPV1 CCC1	2020	119
ICT2 GPV1	2020	142
GRE1 GPV1 ICT2	2020	147
GRE2 GPV1 ICT2	2020	152

Master Scenario 7	Year CT/CC Added	Rank	Master Scenario 8	Year CT/CC Added	Rank	Master Scenario 9	Year CT/CC Added	Rank
BD618 ICT1	2021	22						
GRE1 ICT1 BD619	2021	25						
GRE1 ICT1 BD618	2021	37						
BD617 ICT1	2021	39						
GRE2 ICT1 BD619	2021	48						
GRE1 ICT1 BD617	2021	57						
GRE2 ICT1 BD618	2021	62						
CCC1 GPV1	2021	66						
GRE2 ICT1 BD617	2021	78						
GRE1 GPV1 CCC1	2021	81						
GRE2 GPV1 CCC1	2021	100						

Master Scenario 7	Year CT/CC Added	Rank
BD617 ND118	2022	49
BD618 ND118 GRE1	2022	50
GPV1 ICT1 BD619	2022	64
BD617 ND118 GRE1	2022	68
BD618 ND118 GRE2	2022	71
GPV1 ICT1 BD618	2022	73
BD617 ND118 GRE2	2022	91
GPV1 ICT1 BD617	2022	92
ND119 ND219 GRE2	2022	104
ND118 ND218 GRE1	2022	109
ND118 ND218 GRE2	2022	120
ICT2 GPV1	2022	125
GRE1 GPV1 ICT2	2022	132
GRE2 GPV1 ICT2	2022	142

Master Scenario 8	Year CT/CC Added	Rank
ICT1 CCC1	2022	22
GRE1 ICT1 CCC1	2022	31
BD617 ND118	2022	35
GRE2 ICT1 CCC1	2022	46
BD617 ND118 GRE1	2022	47
GPV1 ICT1 BD618	2022	52
BD618 ND118 GRE2	2022	53
ICT1 ICT2	2022	57
BD617 ND118 GRE2	2022	71
GPV1 ICT1 BD617	2022	72
GRE1 ICT2 ICT1	2022	74
GRE2 ICT2 ICT1	2022	92
BD617 ND118 GPV1	2022	99
GRE1 GPV1 BD618 ND118	2022	100
ND118 ND218 GRE2	2022	111
GRE1 GPV1 BD617 ND118	2022	116
GRE2 GPV1 BD618 ND118	2022	120
GRE2 GPV1 BD617 ND118	2022	127
GRE1 GPV1 ND118 ND219	2022	130
GRE2 ND119 ND219 GPV1	2022	131
GRE1 ND118 ND218 GPV1	2022	134
GRE2 GPV1 ND118 ND219	2022	138
GRE2 ND118 ND218 GPV1	2022	143

Master Scenario 9	Year CT/CC Added	Rank
ICT1 CCC1	2022	13
GRE1 ICT1 CCC1	2022	21
BD617 ND118	2022	31
BD618 ND118 GRE1	2022	32
GRE2 ICT1 CCC1	2022	44
BD617 ND118 GRE1	2022	51
BD618 ND118 GRE2	2022	56
GPV1 ICT1 BD618	2022	74
BD617 ND118 GRE2	2022	76
GPV1 ICT1 BD617	2022	86
ND118 ND218 GRE1	2022	94
ND118 ND218 GRE2	2022	105

Master Scenario 10	Year CT/CC Added	Rank	Master Scenario 11	Year CT/CC Added	Rank	Master Scenario 12	Year CT/CC Added	Rank
GPV1 FVP	2020	130	**GPV1 FVP**	2020	135	**GPV1 FVP**	2020	131
GPV1 FVP DGRD	2020	138	**GPV1 FVP DGRD**	2020	136	**GPV1 FVP DGRD**	2020	132
GPV1	2020	144	**GPV1 DEGRADE**	2020	144	**GPV1 DEGRADE**	2020	143
GPV1 DEGRADE	2020	146	**GPV1**	2020	147	**GPV1**	2020	146
GRE1 GPV1	2020	150	**GRE1 GPV1**	2020	151	**GRE1 GPV1**	2020	150
GRE2 GPV1	2020	153	**GRE2 GPV1**	2020	153	**GRE2 GPV1**	2020	153

Master Scenario 10	Year CT/CC Added	Rank	Master Scenario 11	Year CT/CC Added	Rank	Master Scenario 12	Year CT/CC Added	Rank

Master Scenario 10	Year CT/CC Added	Rank	Master Scenario 11	Year CT/CC Added	Rank	Master Scenario 12	Year CT/CC Added	Rank
BD619	2022	13	ICT1	2022	93	ICT1	2022	75
BD618	2022	18	GRE1 ICT1	2022	109	GRE1 ICT1	2022	90
BD619 GRE1	2022	22	GRE2 ICT1	2022	123	GRE2 ICT1	2022	107
BD617	2022	29						
BD618 GRE1	2022	31						
BD619 GRE2	2022	43						
BD617 GRE1	2022	46						
BD618 GRE2	2022	54						
BD617 GRE2	2022	68						
ICT1	2022	81						
GRE1 ICT1	2022	96						
GRE2 ICT1	2022	114						
ICT1 GPV1	2022	121						
GRE1 GPV1 ICT1	2022	135						
GRE2 GPV1 ICT1	2022	145						

Master Scenario 13	Year CT/CC Added	Rank
CCC1	2020	26
GRE1 CCC1	2020	44
GRE2 CCC1	2020	69
BD617 GPV1	2020	86
GRE1 GPV1 BD618	2020	90
ICT2	2020	98
GRE2 GPV1 BD619	2020	99
GRE1 GPV1 BD617	2020	101
GRE2 GPV1 BD618	2020	107
GRE1 ICT2	2020	113
GRE2 GPV1 BD617	2020	114
GRE2 ICT2	2020	123

Master Scenario 14	Year CT/CC Added	Rank
BD618 GRE1	2020	44
BD617	2020	46
BD619 GRE2	2020	56
BD617 GRE1	2020	66
BD618 GRE2	2020	71
BD617 GRE2	2020	91
ICT1 GPV1	2020	144
GRE1 GPV1 ICT1	2020	148
GRE2 GPV1 ICT1	2020	152

Master Scenario 15	Year CT/CC Added	Rank
CCC1	2020	30
GRE1 CCC1	2020	45
GRE2 CCC1	2020	70
BD617 GPV1	2020	86
GRE1 GPV1 BD618	2020	90
ICT2	2020	98
GRE2 GPV1 BD619	2020	99
GRE1 GPV1 BD617	2020	100
GRE2 GPV1 BD618	2020	107
GRE1 ICT2	2020	113
GRE2 GPV1 BD617	2020	114
GRE2 ICT2	2020	123
BD618 ICT1	2021	22
GRE1 ICT1 BD619	2021	25
GRE1 ICT1 BD618	2021	37
BD617 ICT1	2021	39
GRE2 ICT1 BD619	2021	48
GRE1 ICT1 BD617	2021	57
GRE2 ICT1 BD618	2021	62
CCC1 GPV1	2021	66
GRE2 ICT1 BD617	2021	78
GRE1 GPV1 CCC1	2021	83
GRE2 GPV1 CCC1	2021	102

Master Scenario 13	Year CT/CC Added	Rank	Master Scenario 14	Year CT/CC Added	Rank	Master Scenario 15	Year CT/CC Added	Rank
BD618 ICT1	2021	22						
GRE1 ICT1 BD619	2021	25						
GRE1 ICT1 BD618	2021	37						
BD617 ICT1	2021	39						
GRE2 ICT1 BD619	2021	48						
GRE1 ICT1 BD617	2021	57						
GRE2 ICT1 BD618	2021	62						
CCC1 GPV1	2021	66						
GRE2 ICT1 BD617	2021	78						
GRE1 GPV1 CCC1	2021	81						
GRE2 GPV1 CCC1	2021	100						

Master Scenario 13	Year CT/CC Added	Rank	Master Scenario 14	Year CT/CC Added	Rank	Master Scenario 15	Year CT/CC Added	Rank
BD617 ND118	2022	49	CCC1	2022	33	BD617 ND118	2022	49
BD618 ND118 GRE1	2022	50	ICT2	2022	52	BD618 ND118 GRE1	2022	50
GPV1 ICT1 BD619	2022	64	GRE1 CCC1	2022	54	GPV1 ICT1 BD619	2022	64
BD617 ND118 GRE1	2022	68	GRE1 ICT2	2022	75	BD617 ND118 GRE1	2022	67
BD618 ND118 GRE2	2022	71	GRE2 CCC1	2022	80	BD618 ND118 GRE2	2022	71
GPV1 ICT1 BD618	2022	73	BD618 GPV1	2022	81	GPV1 ICT1 BD618	2022	73
BD617 ND118 GRE2	2022	91	GRE1 GPV1 BD619	2022	90	BD617 ND118 GRE2	2022	91
GPV1 ICT1 BD617	2022	92	GRE2 ICT2	2022	96	GPV1 ICT1 BD617	2022	92
ND119 ND219 GRE2	2022	104	GRE1 GPV1 BD618	2022	102	ND119 ND219 GRE2	2022	104
ND118 ND218 GRE1	2022	109	BD617 GPV1	2022	104	ND118 ND218 GRE1	2022	109
ND118 ND218 GRE2	2022	120	GRE2 GPV1 BD619	2022	113	ND118 ND218 GRE2	2022	120
ICT2 GPV1	2022	125	GRE1 GPV1 BD617	2022	120	ICT2 GPV1	2022	125
GRE1 GPV1 ICT2	2022	132	GRE2 GPV1 BD618	2022	123	GRE1 GPV1 ICT2	2022	132
GRE2 GPV1 ICT2	2022	142	GRE2 GPV1 BD617	2022	134	GRE2 GPV1 ICT2	2022	142

Master Scenario 16	Year CT/CC Added	Rank	Master Scenario 17	Year CT/CC Added	Rank	Master Scenario 18	Year CT/CC Added	Rank

Master Scenario 16	Year CT/CC Added	Rank	Master Scenario 17	Year CT/CC Added	Rank	Master Scenario 18	Year CT/CC Added	Rank
BASE CASE	2021	79						
GRE1	2021	97						
GRE2	2021	116						

Master Scenario 16	Year CT/CC Added	Rank	Master Scenario 17	Year CT/CC Added	Rank	Master Scenario 18	Year CT/CC Added	Rank
GPV1 FVP	2022	112	**BASE CASE**	2022	51	**BASE CASE**	2022	46
GPV1 FVP DGRD	2022	113	**GRE1**	2022	71	**GRE1**	2022	64
GPV1 DEGRADE	2022	124	**GRE2**	2022	94	**GRE2**	2022	87
GPV1	2022	128						
GRE1 GPV1	2022	136						
GRE2 GPV1	2022	144						

Master Scenario 19	Year CT/CC Added	Rank	Master Scenario 20	Year CT/CC Added	Rank	Master Scenario 21	Year CT/CC Added	Rank
BD618 ICT1	2020	30	**CCC1**	2020	73	**CCC1**	2020	73
GRE1 ICT1 BD619	2020	37	**ICT2**	2020	84	**ICT2**	2020	84
GRE1 ICT1 BD618	2020	43	**GRE1 CCC1**	2020	87	**GRE1 CCC1**	2020	87
BD617 ICT1	2020	45	**GRE1 ICT2**	2020	94	**GRE1 ICT2**	2020	94
GRE2 ICT1 BD619	2020	54	**GRE2 CCC1**	2020	101	**GRE2 CCC1**	2020	101
GRE1 ICT1 BD617	2020	61	**GRE2 ICT2**	2020	109	**GRE2 ICT2**	2020	109
GRE2 ICT1 BD618	2020	67	**BD617 GPV1**	2020	116	**BD617 GPV1**	2020	116
CCC1 GPV1	2020	79	**GRE1 GPV1 BD618**	2020	117	**GRE1 GPV1 BD618**	2020	117
GRE2 ICT1 BD617	2020	86	**GRE2 GPV1 BD619**	2020	125	**GRE2 GPV1 BD619**	2020	125
GRE1 GPV1 CCC1	2020	93	**GRE1 GPV1 BD617**	2020	128	**GRE1 GPV1 BD617**	2020	128
GRE2 GPV1 CCC1	2020	108	**GRE2 GPV1 BD618**	2020	129	**GRE2 GPV1 BD618**	2020	129
ICT2 GPV1	2020	132	**GRE2 GPV1 BD617**	2020	137	**GRE2 GPV1 BD617**	2020	137
GRE1 GPV1 ICT2	2020	138						
GRE2 GPV1 ICT2	2020	148						

Master Scenario 19	Year CT/CC Added	Rank	Master Scenario 20	Year CT/CC Added	Rank	Master Scenario 21	Year CT/CC Added	Rank
BD617 ND118	2021	31						
BD617 ND118 GRE1	2021	44						
BD618 ND118 GRE2	2021	51						
GPV1 ICT1 BD618	2021	58						
BD617 ND118 GRE2	2021	69						
GPV1 ICT1 BD617	2021	82						
ND118 ND218 GRE2	2021	112						

Master Scenario 19	Year CT/CC Added	Rank	Master Scenario 20	Year CT/CC Added	Rank	Master Scenario 21	Year CT/CC Added	Rank
BD619 CCC1	2022	1	BD618 ICT1	2022	12	BD618 ICT1	2022	12
BD618 CCC1	2022	2	GRE1 ICT1 BD619	2022	14	GRE1 ICT1 BD619	2022	14
GRE1 CCC1 BD619	2022	3	BD617 ICT1	2022	21	BD617 ICT1	2022	21
BD617 CCC1	2022	4	GRE1 ICT1 BD618	2022	21	GRE1 ICT1 BD618	2022	21
GRE1 CCC1 BD618	2022	5	GRE2 ICT1 BD619	2022	31	GRE2 ICT1 BD619	2022	31
GRE2 CCC1 BD619	2022	6	GRE1 ICT1 BD617	2022	41	GRE1 ICT1 BD617	2022	41
GRE1 CCC1 BD617	2022	7	GRE2 ICT1 BD618	2022	44	GRE2 ICT1 BD618	2022	44
GRE2 CCC1 BD618	2022	8	GRE2 ICT1 BD617	2022	58	GRE2 ICT1 BD617	2022	58
GRE2 CCC1 BD617	2022	9	CCC1 GPV1	2022	95	CCC1 GPV1	2022	95
ICT1 CCC1	2022	10	GRE1 GPV1 CCC1	2022	106	GRE1 GPV1 CCC1	2022	106
GRE1 ICT1 CCC1	2022	15	ICT2 GPV1	2022	108	ICT2 GPV1	2022	108
GRE2 ICT1 CCC1	2022	23	GRE1 GPV1 ICT2	2022	121	GRE1 GPV1 ICT2	2022	121
ICT1 ICT2	2022	66	GRE2 GPV1 CCC1	2022	123	GRE2 GPV1 CCC1	2022	123
GPV1 ICT1 CCC1	2022	80	GRE2 GPV1 ICT2	2022	132	GRE2 GPV1 ICT2	2022	132
GRE1 ICT2 ICT1	2022	85						
GRE1 ICT1 GPV1 CCC1	2022	95						
GRE2 ICT2 ICT1	2022	98						
BD617 ND118 GPV1	2022	105						
GRE1 GPV1 BD618 ND118	2022	106						
GRE2 ICT1 GPV1 CCC1	2022	109						
GRE1 GPV1 BD617 ND118	2022	118						
GRE2 GPV1 BD618 ND118	2022	122						
GRE2 GPV1 BD617 ND118	2022	127						
GRE1 GPV1 ND118 ND219	2022	129						
GRE2 ND119 ND219 GPV1	2022	131						
GRE1 ND118 ND218 GPV1	2022	133						
GRE2 GPV1 ND118 ND219	2022	139						
GRE2 ND118 ND218 GPV1	2022	142						

Master Scenario 22	Year CT/CC Added	Rank	Master Scenario 23	Year CT/CC Added	Rank	Master Scenario 24	Year CT/CC Added	Rank
CCC1	2020	73	GPV1 FVP	2020	112	GPV1 FVP	2020	112
ICT2	2020	84	GPV1 FVP DGRD	2020	115	GPV1 FVP DGRD	2020	115
GRE1 CCC1	2020	87	BASE CASE	2020	116	BASE CASE	2020	116
GRE1 ICT2	2020	94	GPV1 DEGRADE	2020	127	GPV1 DEGRADE	2020	127
GRE2 CCC1	2020	101	GRE1	2020	128	GRE1	2020	128
GRE2 ICT2	2020	109	GPV1	2020	132	GPV1	2020	132
BD617 GPV1	2020	116	GRE2	2020	140	GRE2	2020	140
GRE1 GPV1 BD618	2020	117	GRE1 GPV1	2020	143	GRE1 GPV1	2020	143
GRE2 GPV1 BD619	2020	125	GRE2 GPV1	2020	150	GRE2 GPV1	2020	150
GRE1 GPV1 BD617	2020	128						
GRE2 GPV1 BD618	2020	129						
GRE2 GPV1 BD617	2020	137						

Master Scenario 22	Year CT/CC Added	Rank	Master Scenario 23	Year CT/CC Added	Rank	Master Scenario 24	Year CT/CC Added	Rank

Master Scenario 22	Year CT/CC Added	Rank	Master Scenario 23	Year CT/CC Added	Rank	Master Scenario 24	Year CT/CC Added	Rank
BD618 ICT1	2022	12						
GRE1 ICT1 BD619	2022	14						
GRE1 ICT1 BD618	2022	21						
BD617 ICT1	2022	21						
GRE2 ICT1 BD619	2022	31						
GRE1 ICT1 BD617	2022	41						
GRE2 ICT1 BD618	2022	44						
GRE2 ICT1 BD617	2022	58						
CCC1 GPV1	2022	95						
GRE1 GPV1 CCC1	2022	106						
ICT2 GPV1	2022	108						
GRE1 GPV1 ICT2	2022	121						
GRE2 GPV1 CCC1	2022	123						
GRE2 GPV1 ICT2	2022	132						

Round 1					
File		Solar Cap. Fact.	Wind RFP MW	Reliab.	Forecast
Scenario 1	Solar A, Wind 400, NCP, Base Fcast	72%	400	Non-Coinc	Fall 2011
Scenario 2	Solar A, Wind 600, NCP, Base Fcast	72%	600	Non-Coinc	Fall 2011
Scenario 3	Solar A, Wind 800, NCP, Base Fcast	72%	800	Non-Coinc	Fall 2011
Scenario 4	Solar A, Wind 400, CP, Base Fcast	72%	400	Coincident	Fall 2011
Scenario 5	Solar A, Wind 600, CP, Base Fcast	72%	600	Coincident	Fall 2011
Scenario 6	Solar A, Wind 800, CP, Base Fcast	72%	800	Coincident	Fall 2011
Scenario 7	Solar B, Wind 400, NCP, Base Fcast	50%	400	Non-Coinc	Fall 2011
Scenario 8	Solar B, Wind 600, NCP, Base Fcast	50%	600	Non-Coinc	Fall 2011
Scenario 9	Solar B, Wind 800, NCP, Base Fcast	50%	800	Non-Coinc	Fall 2011
Scenario 10	Solar B, Wind 400, CP, Base Fcast	50%	400	Coincident	Fall 2011
Scenario 11	Solar B, Wind 600, CP, Base Fcast	50%	600	Coincident	Fall 2011
Scenario 12	Solar B, Wind 800, CP, Base Fcast	50%	800	Coincident	Fall 2011
Scenario 13	Solar A, Wind 400, NCP, Spring'13 Fcast	72%	400	Non-Coinc	Spring 2013
Scenario 14	Solar A, Wind 600, NCP, Spring'13 Fcast	72%	600	Non-Coinc	Spring 2013
Scenario 15	Solar A, Wind 800, NCP, Spring'13 Fcast	72%	800	Non-Coinc	Spring 2013
Scenario 16	Solar A, Wind 400, CP, Spring'13 Fcast	72%	400	Coincident	Spring 2013
Scenario 17	Solar A, Wind 600, CP, Spring'13 Fcast	72%	600	Coincident	Spring 2013
Scenario 18	Solar A, Wind 800, CP, Spring'13 Fcast	72%	800	Coincident	Spring 2013
Scenario 19	Solar B, Wind 400, NCP, Spring'13 Fcast	50%	400	Non-Coinc	Spring 2013
Scenario 20	Solar B, Wind 600, NCP, Spring'13 Fcast	50%	600	Non-Coinc	Spring 2013
Scenario 21	Solar B, Wind 800, NCP, Spring'13 Fcast	50%	800	Non-Coinc	Spring 2013
Scenario 22	Solar B, Wind 400, CP, Spring'13 Fcast	50%	400	Coincident	Spring 2013
Scenario 23	Solar B, Wind 600, CP, Spring'13 Fcast	50%	600	Coincident	Spring 2013
Scenario 24	Solar B, Wind 800, CP, Spring'13 Fcast	50%	800	Coincident	Spring 2013
Scenario 25	Bid Package GPV1	GPV1			
Scenario 26	Bid Package GPV1 No CO2	GPV1			
Scenario 27	Bid Package BD617	BD617			
Scenario 28	Bid Package BD617 No CO2	BD617			
Scenario 29	Bid Package CCC1	CCC1			

Scenario 30	Bid Package CCC1 No CO2	CCC1
Scenario 31	Bid Package ICT1	ICT1
Scenario 32	Bid Package ICT1 No CO2	ICT1
Scenario 33	Bid Package BD619 CCC1	BD619 CCC1
Scenario 34	Bid Package BD619 CCC1 No CO2	BD619 CCC1
Scenario 35	Bid Package ICT1 CCC1	ICT1 CCC1
Scenario 36	Bid Package ICT1 CCC1 No CO2	ICT1 CCC1
Scenario 37	Bid Package ICT1 BD618	ICT1 BD619
Scenario 38	Bid Package ICT1 BD618 No CO2	ICT1 BD619
Scenario 39	Bid Package BASE CASE	
Scenario 40	Bid Package BASE CASE No CO2	

State of Minnesota

DEPARTMENT OF COMMERCE
DIVISION OF ENERGY RESOURCES

Utility Information Request Response

Docket Number:	E002/CN-12-1240	Date Request Received:	October 3, 2013
Requested By:	Geronimo Energy	Date of Response:	October 15, 2013

Response submitted by: Steve Rakow

Request No.	
16	References: Rakow Direct, p. 19, ln 8-10 and DOC Response to Geronimo IR#6 "This would allow the RFP to be issued after the Effective Load Carrying Capability (ELCC) study is completed, which would give better information regarding the production of solar power compared to Xcel's load." Question Please describe the existing solar units that were expanded to fill the solar need, including the current capacity of each project, the expanded size of the project and the price for each unit used in the model occur. **DOC Response**: Please see the file [Solar Capacity and Cost TRADE SECRET.xlsx] on a CD. NOTE: The file contains detailed generating unit level information and was drawn from a Strategist database that was labeled Trade Secret by Xcel. The Department confirmed with Xcel Energy that Xcel maintains this information as trade secret.

State of Minnesota

Department of Commerce
Division of Energy Resources

Utility Information Request Response

Docket Number:	E002/CN-12-1240	Date Request Received:	October 4, 2013
Requested By:	Geronimo Energy	Date of Response:	October 15, 2013

Response submitted by: Steve Rakow

Request No.	
17	References: Rakow Direct, p. 19, ln 10-13

"Turned on Xcel's construct for the wholesale energy market to be consistent with the Department's most recent IRP analysis (see Docket No. E015/RP-13-53); previously, the Strategist had been instructed not to consider (i.e., to turn off) the wholesale energy market."

DOC Response to Geronimo IR#9

"Strategist did nothing with the excess capacity—under the Department's structure, Strategist assigns no value to excess capacity on Xcel's system…"

Question

Please clarify how the Department's Strategist modeling accounted for the wholesale energy market, describing both how the model handled opportunities to buy from and sell into the wholesale energy market. Please include any assumptions the Department used related to amount (MW), price and environmental costs of modeled wholesale energy.

DOC Response:

Regarding how the model handled opportunities to buy from the wholesale energy market—there was an opportunity to buy from the wholesale energy market because the transmission link between the unit which can make wholesale sales to Xcel was now turned on. Previously this unit had been turned off.

Regarding how the model handled opportunities to sell into the wholesale energy market—there was no opportunity to sell into the wholesale energy market because the transmission link between the unit which can make wholesale purchases from Xcel remained off.

Regarding the assumptions for amount (MW), price and environmental costs, the Department did not alter the assumptions used by Xcel in the Strategist database.

State of Minnesota

DEPARTMENT OF COMMERCE
DIVISION OF ENERGY RESOURCES

Utility Information Request Response

Docket Number: E002/CN-12-1240 Date Request Received: October 3, 2013

Requested By: Invenergy Thermal Development LLC Date of Response: October 15, 2013

Response submitted by: Steve Rakow
Title: Rates Analyst
Division/Unit: Division of Energy Resources
Telephone: 651-539-1833

Request No.	
1.	Please provide in electronic format (with all formulas intact, if possible) Excel spread sheet backups of all tables related to Dr. Steve Rakow's direct testimony, including all of SR-2, SRR-4a, SRR-4b, SRR-5a, SRR-5b, and SRR-5c. In addition, please provide all relevant input and output files used in the analysis (similar to those provided by Xcel in its testimony), including Strategist input sheets and annual outputs.

DOC Response:

Regarding the request to provide "Excel spread sheet backups of all tables related to Dr. Steve Rakow's direct testimony, please see the CD enclosed with this response:

Requested Item	Status of Formulas	Filename
SR-2	available with formulas intact	Department Attachment 2.xlsx
SR-4a	not available with formulas intact	Department Attachment 4a.xlsx
SR-4b	not available with formulas intact	Department Attachment 4a.xlsx
SR-5a	not available with formulas intact	Department Attachment 5A.xlsx
SR-5b	not available with formulas intact	Department Attachment 5B.xlsx
SR-5c	not available with formulas intact	Department Attachment 5C.xlsx
Table 1	available with formulas intact	Table 1.xlsx

Note that most attachments were created by using Excel's "paste values" function in an attempt to avoid issues with updating formulas to externally linked data. The above files will be provided separately on a compact disk.

Regarding the request to, "provide all relevant input and output files used in the analysis," the Department clarified with Invenergy that the data was requested specifically for Scenario 15 and also that the request was for Strategist:

- inputs similar to those provided in Xcel Exhibit___(SWW-1), Schedule 2, starting on page 59 of the .pdf and
- outputs similar to those provided in Xcel Exhibit___(SWW-1), Schedule 3, starting on page 71 of the .pdf.

Note that Xcel Exhibit___(SWW-1), Schedule 2, at page 59 and Xcel Exhibit___(SWW-1), Schedule 3, at page 71 are not Strategist input or output files. Instead, they are the Company's summary of certain Strategist inputs and selected background assumptions that Xcel used to create the inputs. For the Department's Strategist inputs/outputs that are similar to the data presented by Xcel, please see the files provided on a CD.

State of Minnesota
DEPARTMENT OF COMMERCE
DIVISION OF ENERGY RESOURCES

Utility Information Request Response

Docket Number: E002/CN-12-1240 Date Request Received: October 3, 2013

Requested By: Minnesota Center for Environ. Advocacy Date of Response: October 15, 2013

Response submitted by: Steve Rakow
Title: Rates Analyst
Division/Unit: Division of Energy Resources
Telephone: 651-539-1833

Request No.	
1.	Rakow Direct, p. 3. Department witness Rakow states that a Certificate of Need is not required and the bidding process is "being used to select proposals that could meet the need identified in Xcel's last resource plan." Is it the Department's position that need has already been established in this matter and is not an issue to be address by the ALJ? If yes, provide the Department's explanation of the PUC's March 5, 2013 Order in which it said: "Finally, the Commission notes that it is approving Xcel's plan for planning purposes only. This approval does not relieve Xcel from the need to comply with any regulatory review required for any specific resource it might pursue in implementing this plan."
.	**DOC Response**: Yes. As explained in Dr. Rakow's Direct Testimony at page 3, > Minnesota Statutes § 216B.2422, subd. 5 (b) states in relevant part: "[I]f an electric power generating plant, as described in section 216B.2421, subdivision 2, clause (1), is selected in a bidding process approved or established by the Commission, a certificate of need proceeding under section 216B.243 is not required. Thus, while the Department agrees with the Minnesota Public Utilities Commission (Commission) that the Commission's resource planning order in Docket No. E002/RP-10-825 does not relieve Xcel from the need to comply with any regulatory review required, a certificate of need is not a required regulatory review.

State of Minnesota
DEPARTMENT OF COMMERCE
DIVISION OF ENERGY RESOURCES

Utility Information Request Response

Docket Number: E002/CN-12-1240 Date Request Received: October 3, 2013

Requested By: Minnesota Center for Environ. Advocacy Date of Response: October 15, 2013

Response submitted by: Steve Rakow
Title: Rates Analyst
Division/Unit: Division of Energy Resources
Telephone: 651-539-1833

Request No.	
2.	Does the Department believe Commission staff recommended to the Commission that need be evaluated in this contested case proceeding?

If your answer is no, please explain your interpretation of the following paragraph from the February 20, 2013 staff briefing papers.

"Therefore, staff believes it is appropriate that the RAP process be continued in the manner in which it was designed, a CN-like process for the need identified in the resource plan. Staff does not believe an explicit finding, as proposed by MCEA is necessary (that the Commission indicate in its Order that OAH resolve the issue of whether the projected need is justified, consistent with the Certificate of Need statute) however, if the Commission wishes to provide emphasis on this point to the ALJ, it would reasonable."

DOC Response:

No. Commission staff states "a CN-like process for the need identified in the resource plan." Thus, the proceeding is not a certificate of need. Rather, the phrase "CN-like process" is a description of the process so that those who wish to participate can have a model or outline ahead of time as to how the process will proceed. That is, parties should a process similar to this:

1. a petition from Xcel,
2. a completeness comment period,
3. a determination from the Commission regarding completeness;
4. a determination from the Commission regarding use of a contested case or a comment process, if a contested case:
    a. a pre-hearing conference with to determine a schedule;
    b. filing of testimony;
    c. public hearings;
    d. evidentiary hearings;
    e. briefs;
    f. administrative law judge report;
5. and so on.

State of Minnesota
DEPARTMENT OF COMMERCE
DIVISION OF ENERGY RESOURCES

Utility Information Request Response

Docket Number:	E002/CN-12-1240	Date Request Received:	October 3, 2013
Requested By:	Minnesota Center for Environ. Advocacy	Date of Response:	October 15, 2013

Response submitted by: Steve Rakow
Title: Rates Analyst
Division/Unit: Division of Energy Resources
Telephone: 651-539-1833

Request No.	
3.	In its June 21, 2013 Order the Commission said: "But when Xcel seeks to offer its own proposal into the competitive resource acquisition process, this process tracks the framework of the Certificate of Need process under Minn. Stat. § 216B.243." Is the Department's position that all of the criteria and requirements stated in Minn. Stat. § 216B.243 need to be proved in this matter? If you answer is no, state specifically which provisions, including subdivision and sub-paragraph, do not need to be proved in this matter. **<u>DOC Response</u>:** The Department agrees with the Commission Order that the process at hand tracks the framework of, or is modeled upon, that of a certificate need. However, it is also clear that under Minnesota Statutes no provisions of Minnesota Statutes § 216B.243 apply to this proceeding. See Dr. Rakow's Direct Testimony at page 3 for further details.

State of Minnesota
DEPARTMENT OF COMMERCE
DIVISION OF ENERGY RESOURCES

Utility Information Request Response

Docket Number:	E002/CN-12-1240	Date Request Received:	October 3, 2013
Requested By:	Minnesota Center for Environ. Advocacy	Date of Response:	October 15, 2013

Response submitted by: Steve Rakow
Title: Rates Analyst
Division/Unit: Division of Energy Resources
Telephone: 651-539-1833

Request No.	
4.	Provide, in electronic format, the workpapers used to create Figure 2 of Dr. Rakow's testimony. **DOC Response:** Please see the file [filename: FIGURE 2 NCP vs CP Xcel TRADE SECRET.xlsx] provided on a CD. NOTE: The file contains detailed generating unit level information and was drawn from a Strategist database that was labeled Trade Secret by Xcel. Thus, the Department understands that Xcel Energy maintains this information as trade secret. However, MCEA should feel free to check with Xcel to verify this understanding.

State of Minnesota
DEPARTMENT OF COMMERCE
DIVISION OF ENERGY RESOURCES

Utility Information Request Response

Docket Number:	E002/CN-12-1240	Date Request Received:	October 3, 2013
Requested By:	Minnesota Center for Environ. Advocacy	Date of Response:	October 15, 2013

Response submitted by: Steve Rakow
Title: Rates Analyst
Division/Unit: Division of Energy Resources
Telephone: 651-539-1833

Request No.	
5.	Provide, in electronic .REP format, the Strategist input and output files created by DOC for purposes of this testimony. **DOC Response:** Please see the approximately 200,000 files [*.REP] to be provided on several CDs. NOTE: The *.REP files are downloaded directly from a Strategist long-term modeling software. The database contains a detailed model of the NSP operating company that contains financial and technical information, including fuel price forecasts, transport costs, and generating unit level information, such as cost and performance data. Thus, the Department understands that Xcel Energy maintains this information as highly sensitive and/or trade secret. However, MCEA should feel free to check with Xcel to verify whether any one input is highly sensitive and/or trade secret or not.

State of Minnesota

DEPARTMENT OF COMMERCE
DIVISION OF ENERGY RESOURCES

Utility Information Request Response

Docket Number:	E002/CN-12-1240	Date Request Received:	October 4, 2013
Requested By:	Minnesota Center for Environ. Advocacy	Date of Response:	October 16, 2013

Response submitted by: Steve Rakow
Title: Rates Analyst
Division/Unit: Division of Energy Resources
Telephone: 651-539-1833

Request No.	
6. .	Provide, in electronic format, the workpapers used to create Table 1 of Dr. Rakow's testimony. **DOC Response:** Please see the file [filename: Table 1.xlsx] provided on a CD. NOTE: The file contains detailed generating unit level information and was drawn from a Strategist database that was labeled Trade Secret by Xcel. Thus, the Department understands that Xcel Energy maintains this information as trade secret. However, MCEA should feel free to check with Xcel to verify this understanding.

State of Minnesota
DEPARTMENT OF COMMERCE
DIVISION OF ENERGY RESOURCES

Utility Information Request Response

Docket Number: E002/CN-12-1240 Date Request Received: October 4, 2013

Requested By: Minnesota Center for Environ. Advocacy Date of Response: October 16, 2013

Response submitted by: Steve Rakow
Title: Rates Analyst
Division/Unit: Division of Energy Resources
Telephone: 651-539-1833

Request No.	
7.	Provide, in electronic format, the workpapers used to create the diversity factor Dr. Rakow applied to Xcel's non-coincident peak demand. Please include the response to MCC IR No.746 in Docket No. E002/GR-12-961. **DOC Response:** There are no workpapers beyond the table of data provided in Xcel's reply to MCC IR No. 746. For a public copy of the data in the response used by the Department, see Mr. Wishart's direct testimony at page 9. A file [filename: MCC746 Scan.pdf] containing a scan of the page used is included on a CD; the data on the scanned page was labeled Trade Secret by Xcel.

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Xcel Energy
Docket No.: E002/CN-12-1240
Response To: Department of Commerce Information Request No. 042
Requestor: Sachin Shah & Steve Rakow
Date Received: June 28, 2013 **SUPPLEMENT**

Question:

Subject: Information provided by Xcel Energy -- Northern States Power Company, A Minnesota Corporation (Xcel Energy, NSP or Company) in its *Petition to the Minnesota Public Utilities Commission Seeking Approval For A Competitive Resource Acquisition Proposal and For A Certificate of Need:*

Subject: Information provided by Invenergy Thermal Development LLC in the bids: *Cannon Falls Peaking Expansion: Goodhue County, Minnesota* and *Hampton Energy Center: Dakota County, Minnesota* (dated April 15, 2013 and May 9, 2013).

Subject: Information provided by Calpine Corporation and its affiliate Mankato Energy Center, LLC in the bid: *Calpine's Mankato Energy Center Expansion Proposal* (dated April 15, 2013 and May 8, 2013).

In Docket No. E002/CN-12-1240, the Company in its Certificate of Need (CN) filing, indicates the use of natural gas prices by existing generating units in its strategist base case.

On page 4 of the *Cannon Falls Peaking Expansion Bid* Invenergy in part states the following:

> … Invenergy proposes to develop the Cannon Falls Peaking Expansion and sell the capacity and energy to NSP with terms and conditions substantially similar to the existing Power Purchase Agreement between Cannon Falls and NSP dated April 1, 2005.

On page 4 of the *Hampton Energy Center Bid* Invenergy in part states the following:

> … Invenergy proposes to develop the Hampton Energy Center with a design and configuration that is very similar to Invenergy's existing Cannon Falls Facility this is located in Goodhue County. Furthermore, Invenergy proposes to sell the capacity and energy to NSP with terms and conditions substantially similar to the

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> existing Power Purchase Agreement between Cannon Falls and NSP dated April 1, 2005.

On page 4 of the *Calpine's Mankato Energy Center Expansion Proposal* Calpine in part states the following:

> Consistent with the Commission's directive that parties be held to the cost information provided in their bids,4 the specific pricing, terms and conditions of Calpine's Proposal represent a fixed-price indicative offer5 with long-term performance guaranties wherein Calpine will assume the construction, delivery date and long term operating risk of the Mankato Expansion.

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5. Subject to any material changes in project timing and/or scope required by the Commission or identified during final tolling agreement negotiations. Proposed pricing assumes a 2017 commercial operation date.

In Appendix A, on page 3 of the *Calpine's Mankato Energy Center Expansion Proposal* Calpine in part states the following:

> Calpine intends to follow the PPA structure used in the Purchased Power Agreement between MEC and Northern States Power Company executed on March 11, 2004 ("MEC PPA") for expediency, cost effectiveness and negotiating efficiency.

1. It is the Department's understanding, based on the above references, that Invenergy's *Bids* and Calpine's *Proposal* assume that Xcel would pay all of the fuel costs of purchasing and delivering natural gas to Cannon Falls facility's and Mankato Energy Center's points of delivery, respectively. Is this understanding correct?

2. If the answer to part (1) is in the affirmative, then please fully explain in detail if the natural gas fuel prices contained in Xcel's strategist base case for the existing Cannon Falls facility and the Mankato Energy Center would be appropriate to use in comparing the *Bids* and *Proposal* of Invenergy and Calpine, respectively, given the above references.

3. Please fully explain the type of natural gas being provided to the existing facilities at Cannon Falls and Mankato Energy Center (i.e., Firm, Interruptible, or a combination of Firm and Interruptible).

4. Please fully explain and identify the associated natural gas commodity costs in parts (2) and (3) above.

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5. Please fully explain and identify in detail the amount and type of interstate pipeline transportation and fixed reservation (demand) costs that are included in parts (2) and (3) above.

6. Please fully explain and identify the amount, if any, of local pipeline distribution service costs that are included in parts (2) and (3) above.

Where applicable for any and all parts above, please provide the requested data in a Microsoft Excel executable format with all links and formulae intact. If any of these links target an outside file, please provide all such additional files.

In addition, please provide your response in both a Microsoft Word and Adobe PDF format.

In addition, whenever acronyms are used in the data given in your response above, please provide an explanation of all acronyms used AND also provide a brief but complete explanation of the source of each data series that is provided.

If this information has already been provided in written testimony, filing, or in response to an earlier Department of Commerce (DOC) information request, please identify the specific testimony, and/or filing cite(s) or DOC information request number(s).

<u>Response</u>:

1. Yes, the bidders are proposing that Xcel be responsible for the costs of fuel purchasing and delivery for these projects and we are currently developing estimates of those costs. However, the bidder is responsible for installing and maintaining the incremental back-up fuel oil facilities.

2. No, it would not be appropriate to use the costs currently contained in Xcel's strategist base case to evaluate the *Bids* and *Proposal* of Invenergy and Calpine. The cost contained in the Strategist base case are natural gas commodity costs, plus the variable transport costs to deliver gas to the existing facilities based on the existing transport agreements. Although the natural gas commodity costs are likely to be representative of the supply cost, it is likely that the variable transport charges will be different. In addition, the Strategist base case does not include the annual fixed charges associated with fuel delivery at those sites.

   Both variable transport cost and annual fixed charges for fuel supply will be dependent on whether or not firm or interruptible fuel supply will be used at

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the facility. We are currently developing these estimates and propose to provide these costs in a supplemental response in approximately three weeks (Aug 9th). If the estimates are completed sooner than expected we will supply them as soon as they are available.

3. NSP uses a combination of firm and interruptible upstream transportation service to deliver firm gas supplies to Cannon Falls and Mankato, in addition to the back-up fuel oil. Gas supply is purchased at Ventura, Iowa on Northern Natural Gas (NNG) and then transported by NNG to the plants. Mankato is directly connected to NNG via a plant line. Cannon Falls is served from NNG via Greater Minnesota Gas (an intrastate pipeline).

4. Please see Attachment A for the associated natural gas commodity costs.

5. Attachment A also includes the volumetric transportation charges currently being used in Strategist for the two existing plants. The Strategist base case does not include the specific annual fixed charges (reservation / demand charge) associated with fuel delivery at those sites.

Please note that portions of Attachment A are marked "Non-Public" as it contains information the Company considers to be trade secret as defined by Minn. Stat. § 13.37(1)(b). This information has independent economic value from not being generally known to, and not being readily ascertainable by other parties, who could obtain economic value from its disclosure or use. Thus, Xcel Energy maintains this information as trade secret.

SUPPLEMENT:

5. Please see Attachment B for details regarding the estimated upstream pipeline transportation costs to provide fuel to the Mankato, Hampton, and Cannon Falls plants. All three plants would be sited in an area where the interstate natural gas pipeline is essentially fully subscribed, requiring construction of additional pipeline facilities to make the plants' fuel supply highly reliable. Mankato would be served by transportation service from Northern Natural Gas. Since Mankato is proposed as a combined cycle, intermediate load facility, it will require firm gas transportation on a year-round basis.

Hampton and Cannon Falls would be served by transportation from Northern Natural Gas and Greater Minnesota Transmission. Attachment B shows estimated costs to provide firm year-round transportation service to Hampton and Cannon Falls to make the plants' fuel supply highly reliable. In the alternative, if the

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Commission elects less reliable service for these two plants, Attachment B separately shows costs for interruptible transportation service to the plants. Using interruptible service, the Commission should expect the plants to have regular fuel supply in the summer months (April through October) except during periods of pipeline maintenance and emergency operations. However, in the winter months (November through March), the Commission should expect the plants to be unable to operate on most cold winter days due to interruption of gas transportation services on Northern Natural Gas. The interruptible service option is cheaper for low-load factor peaker plants; however, the plants will not be available on many winter days.

6. There are no local distribution charges for Mankato in NSP's Strategist base case; however, Cannon Falls and Hampton rely on Greater Minnesota Transmission as described in (3) above. The Greater Minnesota Transmission system, which is considered an intrastate facility, would also be used to serve the Hampton and Cannon Falls plants. Those costs are detailed in Attachment B to Response 5 above. There are no other distribution charges anticipated for these plants.

Preparer:	Curt Dallinger/Steve Wishart	
Title:	Director/Director	
Department:	Gas Planning/Resource Planning	
Telephone:	303-571-2784/612-330-6128	
Date:	July 23, 2013	**SUPPLEMENT: August 15, 2013**

Northern States Power Company

Gas Supply Costs for MN IPP Bids

Docket No. E002/CN-12-1240
Information Request DOC-042 Supplement
Attachment B, Page 1 of 1

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Firm Option

Plant	Connecting Pipeline	Capacity (MW)	Heat Rate (MMBtu/MWh)	Demand Volume (Dth/hour)	Demand Volume (Dth/day)	Minimum Delivery Pressure (psig)	Market Price	Annual Demand ($/year)	Total Variable Costs ($/Dth) (1)	Fuel 1/	Comments
								TRADE SECRET BEGINS:			**[TRADE SECRET BEGINS:**
Calpine Mankato	Firm NNG	345	7.25	2,501	40,020	550	**Ventura**		**$0.0377**	**.27 % 1.37%**	
Invenergy Hampton	Firm NNG	357	10.9	3,891	62,261	550	**Ventura**		**$0.0377**	**.27 & 1.37%**	
	GMT								**$0.0100**		
	Total								**$0.0477**		
Invenergy Cannon Falls	Firm NNG	179	10.9	1,951	31,218	550	**Ventura**		**$0.0377**	**.27 & 1.37%**	
	GMT								**$0.0100**		
	Total								**$0.0477**		
								TRADE SECRET ENDS]			**TRADE SECRET ENDS]**

Interruptible Option

Plant	Connecting Pipeline	Capacity (MW)	Heat Rate (MMBtu/MWh)	Demand Volume (Dth/hour)	Demand Volume (Dth/day)	Minimum Delivery Pressure (psig)	Market Price	Annual Demand ($/year)	Total Variable Costs ($/Dth) (1)	Fuel 1/	Comments
								[TRADE SECRET BEGINS:			
Invenergy Hampton	Int NNG	357	10.9	3,891	62,261	550	**Ventura**		**0.2675 & 0.6275**	**.27 & 1.37%**	**Plant subject to interruption (2)**
	GMT								**$0.0100**		
	Total								**$0.0100**		
Invenergy Cannon Falls	Int NNG	179	10.9	1,951	31,218	550	**Ventura**		**0.2675 & 0.6275**	**.27 & 1.37%**	**Plant subject to interruption (2)**
	GMT								**$0.0100**		
	Total								**$0.0100**		
								TRADE SECRET ENDS]			

(1) Rates are lower during the summer months of April - October and higher in the winter months of November - March.

(2) Using interruptible services only, plant may be without fuel occasionally in the summer due to pipeline maintenance and emergency operations. In the winter, service will be interrupted on many days due to firm customer demand.

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Xcel Energy
Docket No.: E002/CN-12-1240
Response To: Department of Commerce Information Request No. 067
Requestor: Steve Rakow, Sachin Shah
Date Received: October 2, 2013

Question:

For the years 2015 to 2022, either provide the following information (along with a detailed explanation of how each was calculated) or in the alternative, a statement that the data will be provided in the Company's rebuttal testimony:

a. Xcel's forecasted winter peak demand by month (November - March);
b. The MW of load management available to reduce the winter peak;
c. The accredited MW of supply units available to meet the winter peak;
d. The quantity and identity of natural gas units without back up fuel and using interruptible natural gas supplies that are considered as "available to meet the winter peak"; and
e. Please explain in detail what are the requirements of MISO accreditation for winter
f. Where applicable for any and all parts above, please provide the requested data in a Microsoft Excel executable format with all links and formulae intact. If any of these links target an outside file, please provide all such additional files.
g. In addition, whenever acronyms are used in the data given in your response above, please provide an explanation of all acronyms used AND also provide a brief but complete explanation of the source of each data series that is provided.
h. If this information has already been provided in written testimony, filing, or in response to an earlier Department of Commerce (DOC) information request, please identify the specific testimony, and/or filing cite(s) or DOC information request number(s).

Response:

a. Please see Attachment A to this response.

b. Please see Attachment A to this response.

c. Please reference Attachment B to this response. The data in Attachment B is based on our latest winter assessment and may not perfectly match data used in Strategist due to data vintage differences.

d. The following owned generation units operate with interruptible natural gas service, but without a back-up fuel supply. The Company does not report these units as "available to meet winter peak," and omits these units from long-term winter seasonal planning.

- Angus Anson Unit 4
- Blue Lake Unit 7
- Blue Lake Unit 8

e. MISO no longer maintains winter accreditation requirements. MISO's accreditation processes apply to the summer season.

f. Attachments A and B are in the requested format.

g. In Attachment A, the load forecast is based on our spring 2013 forecast, and the load management forecast is the same vintage, spring 2013. In Attachment B, the capacity values listed are based on our most recent loads and resources assessment. For purchased power contracts, the capacity values reflect the contracted value, while for owned units the capacity values reflect the most recent capacity testing under winter conditions.

h. NA.

Preparer:	Steve Wishart
Title:	Director – Resource Planning & Bidding
Department:	Resource Planning & Bidding
Telephone:	612-330-6128
Date:	October 16, 2013

NSP System Peak Demand Forecast
March 2013 Forecast

Monthly Base Peaks

	Winter Season							
Month	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21	2021-22	2022-23
November	6,213	6,253	6,305	6,357	6,416	6,484	6,546	6,613
December	6,602	6,643	6,696	6,749	6,810	6,878	6,941	7,006
January	6,486	6,532	6,588	6,640	6,703	6,770	6,830	6,893
February	6,295	6,347	6,399	6,451	6,517	6,579	6,640	6,701
March	5,940	5,993	6,046	6,099	6,165	6,229	6,292	6,352

Monthly Available Load Relief

	Winter Season							
Month	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21	2021-22	2022-23
November	365	365	365	365	365	365	365	365
December	366	366	366	366	366	366	366	366
January	365	365	365	365	365	365	365	365
February	365	365	365	365	365	365	365	365
March	366	366	366	366	366	366	366	366

NSP-MN and NSP-WI Resources Balance - Winter 2014

		2015	2016	2017	2018	2019	2020	2021	2022
Existing NSP Capacity									
Installed Net Dependable Capacity		**6,840 MW**	**6,916 MW**	**6,886 MW**	**6,871 MW**	**6,871 MW**	**6,839 MW**	**6,839 MW**	**6,839 MW**
A. Steam Turbines		2,361 MW	2,361 MW	2,361 MW	2,361 MW	2,361 MW	2,361 MW	2,361 MW	2,361 MW
B. Nuclear		1,710 MW	1,710 MW	1,710 MW	1,710 MW	1,710 MW	1,710 MW	1,710 MW	1,710 MW
C. Refuse Fired & Biomass		55 MW	55 MW	29 MW	29 MW	29 MW	29 MW	29 MW	29 MW
D. Combustion Turbine/Combined Cycle		2,171 MW	2,171 MW	2,171 MW	2,156 MW	2,156 MW	2,123 MW	2,123 MW	2,123 MW
E. Oil		394 MW	470 MW	470 MW	470 MW	470 MW	470 MW	470 MW	470 MW
F. Conventional Hydro		105 MW	105 MW	105 MW	105 MW	105 MW	105 MW	105 MW	105 MW
G. Diesels		4 MW	4 MW	0 MW	0 MW	0 MW	0 MW	0 MW	0 MW
H. Wind (owned) (MISO 13.3% accreditation)		40 MW	40 MW	40 MW	40 MW	40 MW	40 MW	40 MW	40 MW
Firm Purchased Capacity									
Manitoba Hydro Purchase		0 MW	0 MW	0 MW	0 MW	0 MW	0 MW	0 MW	0 MW
Manitoba Hydro Diversities		0 MW	0 MW	0 MW	0 MW	0 MW	0 MW	0 MW	0 MW
Manitoba Hydro Electric Board - 125 MW (year-round) system capacity and energy purchase		0 MW	0 MW	0 MW	0 MW	0 MW	0 MW	125 MW	125 MW
Manitoba Hydro Electric Board - 350 MW Diversity Sale Agreement		-350 MW	-350 MW	-350 MW	-350 MW	-350 MW	-350 MW	-350 MW	-350 MW
Manitoba Hydro Electric Board - 375/325 MW System Power Sale Agreement		375 MW	375 MW	375 MW	375 MW	375 MW	375 MW	375 MW	375 MW
Calpine Mankato (A)		298 MW	298 MW	298 MW	298 MW	298 MW	298 MW	298 MW	298 MW
Invenergy Cannon Falls		310 MW	310 MW	310 MW	310 MW	310 MW	310 MW	310 MW	310 MW
Minnkota (Coyote)									
LS Power		234 MW	234 MW	234 MW	234 MW	234 MW	234 MW	234 MW	234 MW
HERC		22 MW	22 MW						
Landfill Gas		5 MW	5 MW	5 MW	5 MW	5 MW	5 MW	5 MW	5 MW
Small Hydro		15 MW	15 MW	15 MW	15 MW	15 MW	15 MW	15 MW	15 MW
	Subtotal	**910 MW**	**910 MW**	**888 MW**	**888 MW**	**888 MW**	**888 MW**	**1,013 MW**	**1,013 MW**
Biomass Purchases									
St. Paul Cogen		15 MW	15 MW	15 MW	15 MW	15 MW	15 MW	15 MW	
Laurentian		32 MW	32 MW	32 MW	32 MW	32 MW	32 MW	32 MW	32 MW
Fibrominn		50 MW	50 MW	50 MW	50 MW	50 MW	50 MW	50 MW	50 MW
KODA Energy		10 MW	10 MW	10 MW					
	Subtotal	**108 MW**	**108 MW**	**108 MW**	**98 MW**	**98 MW**	**98 MW**	**98 MW**	**83 MW**
Wind PPAs									
Wind Nameplate Rating		1,361 MW	1,361 MW	1,359 MW	1,220 MW	1,220 MW	1,215 MW	1,215 MW	1,059 MW
Wind Accreditation Value - Overall		13.0%	13.0%	13.0%	13.5%	13.5%	13.5%	13.5%	13.3%
	Subtotal	**177 MW**	**177 MW**	**177 MW**	**165 MW**	**165 MW**	**164 MW**	**164 MW**	**141 MW**
Solar PPAs									
Slayton Solar Nameplate Rating		0 MW	0 MW	0 MW	0 MW	0 MW	0 MW	0 MW	0 MW
Solar Accreditation Value (C)		10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%
	Subtotal	**0 MW**	**0 MW**	**0 MW**	**0 MW**	**0 MW**	**0 MW**	**0 MW**	**0 MW**
Purchases and Sales Check		**1,195 MW**	**1,195 MW**	**1,173 MW**	**1,151 MW**	**1,151 MW**	**1,150 MW**	**1,275 MW**	**1,236 MW**
NSP Available Resources		**8,035 MW**	**8,111 MW**	**8,059 MW**	**8,022 MW**	**8,022 MW**	**7,988 MW**	**8,113 MW**	**8,075 MW**

Notes:

(A) Mankato Energy Center - If problems continue to exist (during Winter 2013/14) with MEC's back-up fuel supply, this resource will be removed from the available winter resources.

NSP System Peak Demand Forecast
March 2013 Forecast

Docket No. E002/CN-12-1240
Information Request No. DOC-67
Attachment A
Page 1 of 1

Monthly Base Peaks

	Winter Season							
Month	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21	2021-22	2022-23
November	6,213	6,253	6,305	6,357	6,416	6,484	6,546	6,613
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March	5,940	5,993	6,046	6,099	6,165	6,229	6,292	6,352

Monthly Available Load Relief

	Winter Season							
Month	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21	2021-22	2022-23
November	365	365	365	365	365	365	365	365
December	366	366	366	366	366	366	366	366
January	365	365	365	365	365	365	365	365
February	365	365	365	365	365	365	365	365
March	366	366	366	366	366	366	366	366

NSP-MN and NSP-WI Resources Balance - Winter 2014

	2015	2016	2017	2018	2019	2020	2021	2022
Existing NSP Capacity								
Installed Net Dependable Capacity	**6,840 MW**	**6,916 MW**	**6,886 MW**	**6,871 MW**	**6,871 MW**	**6,839 MW**	**6,839 MW**	**6,839 MW**
A. Steam Turbines	2,361 MW	2,361 MW	2,361 MW	2,361 MW	2,361 MW	2,361 MW	2,361 MW	2,361 MW
B. Nuclear	1,710 MW	1,710 MW	1,710 MW	1,710 MW	1,710 MW	1,710 MW	1,710 MW	1,710 MW
C. Refuse Fired & Biomass	55 MW	55 MW	29 MW	29 MW	29 MW	29 MW	29 MW	29 MW
D. Combustion Turbine/Combined Cycle	2,171 MW	2,171 MW	2,171 MW	2,156 MW	2,156 MW	2,123 MW	2,123 MW	2,123 MW
E. Oil	394 MW	470 MW	470 MW	470 MW	470 MW	470 MW	470 MW	470 MW
F. Conventional Hydro	105 MW	105 MW	105 MW	105 MW	105 MW	105 MW	105 MW	105 MW
G. Diesels	4 MW	4 MW	0 MW	0 MW	0 MW	0 MW	0 MW	0 MW
H. Wind (owned) (MISO 13.3% accreditation)	40 MW	40 MW	40 MW	40 MW	40 MW	40 MW	40 MW	40 MW
Firm Purchased Capacity								
Manitoba Hydro Purchase	0 MW	0 MW	0 MW	0 MW	0 MW	0 MW	0 MW	0 MW
Manitoba Hydro Diversities	0 MW	0 MW	0 MW	0 MW	0 MW	0 MW	0 MW	0 MW
Manitoba Hydro Electric Board - 125 MW (year-round) system capacity and energy purchase	0 MW	0 MW	0 MW	0 MW	0 MW	0 MW	125 MW	125 MW
Manitoba Hydro Electric Board - 350 MW Diversity Sale Agreement	-350 MW	-350 MW	-350 MW	-350 MW	-350 MW	-350 MW	-350 MW	-350 MW
Manitoba Hydro Electric Board - 375/325 MW System Power Sale Agreement	375 MW	375 MW	375 MW	375 MW	375 MW	375 MW	375 MW	375 MW
Calpine Mankato (A)	298 MW	298 MW	298 MW	298 MW	298 MW	298 MW	298 MW	298 MW
Invenergy Cannon Falls	310 MW	310 MW	310 MW	310 MW	310 MW	310 MW	310 MW	310 MW
Minnkota (Coyote)								
LS Power	234 MW	234 MW	234 MW	234 MW	234 MW	234 MW	234 MW	234 MW
HERC	22 MW	22 MW						
Landfill Gas	5 MW	5 MW	5 MW	5 MW	5 MW	5 MW	5 MW	5 MW
Small Hydro	15 MW	15 MW	15 MW	15 MW	15 MW	15 MW	15 MW	15 MW
Subtotal	**910 MW**	**910 MW**	**888 MW**	**888 MW**	**888 MW**	**888 MW**	**1,013 MW**	**1,013 MW**
Biomass Purchases								
St. Paul Cogen	15 MW	15 MW	15 MW	15 MW	15 MW	15 MW	15 MW	
Laurentian	32 MW	32 MW	32 MW	32 MW	32 MW	32 MW	32 MW	32 MW
Fibrominn	50 MW	50 MW	50 MW	50 MW	50 MW	50 MW	50 MW	50 MW
KODA Energy	10 MW	10 MW	10 MW					
Subtotal	**108 MW**	**108 MW**	**108 MW**	**98 MW**	**98 MW**	**98 MW**	**98 MW**	**83 MW**
Wind PPAs								
Wind Nameplate Rating	1,361 MW	1,361 MW	1,359 MW	1,220 MW	1,220 MW	1,215 MW	1,215 MW	1,059 MW
Wind Accreditation Value - Overall	13.0%	13.0%	13.0%	13.5%	13.5%	13.5%	13.5%	13.3%
Subtotal	**177 MW**	**177 MW**	**177 MW**	**165 MW**	**165 MW**	**164 MW**	**164 MW**	**141 MW**
Solar PPAs								
Slayton Solar Nameplate Rating	0 MW	0 MW	0 MW	0 MW	0 MW	0 MW	0 MW	0 MW
Solar Accreditation Value (C)	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%
Subtotal	**0 MW**	**0 MW**	**0 MW**	**0 MW**	**0 MW**	**0 MW**	**0 MW**	**0 MW**
Purchases and Sales Check	**1,195 MW**	**1,195 MW**	**1,173 MW**	**1,151 MW**	**1,151 MW**	**1,150 MW**	**1,275 MW**	**1,236 MW**
NSP Available Resources	**8,035 MW**	**8,111 MW**	**8,059 MW**	**8,022 MW**	**8,022 MW**	**7,988 MW**	**8,113 MW**	**8,075 MW**

Notes:

(A) Mankato Energy Center - If problems continue to exist (during Winter 2013/14) with MEC's back-up fuel supply, this resource will be removed from the available winter resources.

WINTHROP WEINSTINE

ATTORNEYS AND COUNSELORS AT LAW

September 25, 2013

Eric F. Swanson
Direct Dial: (612) 604-6511
Direct Fax: (612) 604-6811
eswanson@winthrop.com

VIA EMAIL

Timothy Edman
Xcel Energy
414 Nicollet Mall, 5th Floor
Minneapolis, MN 55401

RE: In the Matter of the Petition of Northern States Power Company d/b/a Xcel Energy for Approval of Competitive Resource Acquisition Proposal and Certificate of Need MPUC Docket No. E-002/CN-12-1240

Dear Mr. Edman:

Enclosed please find both a Public and Non-Public Version of Invenergy Thermal Development LLC ("Invenergy") Response to Information Request Number 29 from the Xcel Energy in the above-referenced docket.

Please note that the data set forth in the above-referenced Response to Information Request No. 29 includes highly sensitive pricing information, developed by Invenergy. Invenergy has taken all necessary and reasonable steps to maintain the confidentiality of this information and, if disclosed, Invenergy would suffer economic harm and its competitors in the energy markets would gain competitive and economic advantages. As such, this information includes data that: (1) was developed and supplied by Invenergy; (2) is the subject of reasonable efforts by Invenergy to maintain its secrecy; and (3) derives independent economic value, actual or potential, from not being generally known to or accessible by the public, including Invenergy's competitors in the energy marketplace.

Therefore, Invenergy has designated this document as a Non-Public Document pursuant to Minnesota Statutes § 13.37, subd. 1 (b) and Minnesota Rules 7829.0500. Invenergy denotes the documents containing non-public information with the header NON-PUBLIC DOCUMENT – CONTAINS TRADE SECRET INFORMATION. All such documents should be viewed only by those previously designated representatives of Xcel Energy ("Xcel") who have provided to Invenergy an executed "Exhibit A" to the ALJ's approved Protective Order.

Feel free to contact me with any questions or concerns.

Very truly yours,

WINTHROP & WEINSTINE, P.A.

Eric F. Swanson

Enclosures

Cc: Regulatory Records (via Email)

8349662v1

PUBLIC DOCUMENT:
TRADE SECRET INFORMATION EXCISED

☐ **Non Public Document – Contains Trade Secret Data**
☒ **Public Document – Trade Secret Data Excised**
☐ **Public Document**

Xcel Energy
Docket No.: E002/CN-12-1240
Request To: Invenergy Information Request No. 029
Requestor: Xcel Energy
Date Issued: September 12, 2013

<u>Question:</u>

Please refer to Section 4 of the Invenergy Hampton Energy Center and Goodhue County proposals in this matter, which each state in part:

[Begin Trade Secret:

End Trade Secret]

Please provide any price adjustments for each of Invenergy's proposals if there was an option in a signed Power Purchase Agreement to delay the commercial operation date to:

A.) June 1, 2018, and
B.) June 1, 2019.

Please note that portions of this request are marked "Non-Public" and should be treated as confidential. The marked area contains information which Invenergy considers to be trade secret data as defined by Minn. Stat. §13.37(1)(b).

Preparer: James R. Alders
Title: Strategy Consultant
Department: Regulatory Affairs
Telephone: 612-330-6732
Date: September 12, 2013

PUBLIC DOCUMENT:
TRADE SECRET INFORMATION EXCISED

Response:

In the event of revised Commercial Operation Dates Invenergy proposes the Capacity Prices set forth below.

Cannon Falls Expansion Capacity Price for the first year of commercial operation would be as follows:

[Begin Trade Secret:

Commercial Operation Date	Capacity Price
June 1, 2017	
June 1, 2018	
June 1, 2019	

All other pricing terms including proposed escalation rates are unchanged.

Hampton Energy Center Capacity Price for the first year of commercial operation would be as follows:

Commercial Operation Date	Capacity Price
June 1, 2017	
June 1, 2018	
June 1, 2019	

End Trade Secret]

All other pricing terms including proposed escalation rates are unchanged.

8349415v1

**PUBLIC DOCUMENT –
TRADE SECRET DATA REDACTED**

☐ **Non Public Document – Contains Trade Secret Data**
☒ **Public Document – Trade Secret Data Excised**
☐ **Public Document**

Xcel Energy			
Docket No.:	E002/CN-12-1240		
Request To:	Calpine Corporation	Information Request No.	016
Requestor:	Xcel Energy		
Date Issued:	September 12, 2013		

Question:

Please refer to Appendix B of the Calpine proposal in this matter, which states in part:

[Begin Trade Secret:

End Trade Secret]

Please provide any price adjustments if there was an option in a signed Power Purchase Agreement to delay the commercial operation date of Calpine's proposal to:

A.) June 1, 2018, and
B.) June 1, 2019.

Please note that portions of this request are marked "Non-Public" and should be treated as confidential. The marked area contains information which Calpine considers to be trade secret data as defined by Minn. Stat. §13.37(1)(b).

Response: (A) and (B): Calpine is willing to extend its bid to provide an option for a 2018 or 2019 commercial operation date (COD) based on the following:

[TRADE SECRET DATA BEGINS:

TRADE SECRET DATA ENDS]

***Please note that this response redacts information maintained by Calpine as Trade Secret Data pursuant to Minn. Stat. § 13.37, subd. 1(b). The trade secret information redacted is properly designated as trade secret because it: (1) was supplied by Calpine; (2) is the subject of reasonable efforts by Calpine to maintain its secrecy; and (3) derives independent economic value, actual or potential, from not being generally known to or accessible by the public.**

Response by:	Todd Thornton
Title:	Vice President of Commercial Development
Department:	NA
Telephone:	(713) 820-4037
Date:	September 23, 2013

Contingency	PVSC ($, 000; ICT1 Interruptible Gas)							
	Bid Package GPV1	Bid Package BD617	Bid Package CCC1	Bid Package ICT1	Bid Package BD619 CCC1	Bid Package ICT1 CCC1	Bid Package ICT1 BD618	Bid Package BASE CASE
BASE CASE	$ 41,423,488	$ 41,326,470	$ 41,315,664	$ 41,345,700	$ 41,263,483	$ 41,287,152	$ 41,299,021	$ 41,396,524
CO2 Reduction	FAILED	FAILED	FAILED	FAILED	FAILED	FAILED	FAILED	FAILED
$34 CO2	$ 45,123,104	$ 45,049,946	$ 45,025,948	$ 45,070,308	$ 44,967,719	$ 45,008,940	$ 45,024,601	$ 45,115,540
$9 CO2	$ 37,878,588	$ 37,788,434	$ 37,776,260	$ 37,809,104	$ 37,730,115	$ 37,753,868	$ 37,760,169	$ 37,853,036
Low Externalities	$ 41,061,420	$ 40,964,034	$ 40,953,244	$ 40,983,408	$ 40,900,799	$ 40,924,652	$ 40,936,641	$ 41,034,260
High Market Price - 25%	$ 41,193,608	$ 41,104,754	$ 41,084,164	$ 41,125,732	$ 41,037,079	$ 41,061,220	$ 41,070,953	$ 41,165,008
Low Market Price + 25%	$ 41,304,536	$ 41,209,178	$ 41,238,564	$ 41,225,952	$ 41,189,875	$ 41,209,780	$ 41,182,177	$ 41,259,884
High Capital Cost + 10%	$ 41,751,736	$ 41,649,690	$ 41,621,188	$ 41,680,620	$ 41,555,763	$ 41,584,128	$ 41,609,497	$ 41,738,012
Low Capital Cost - 10%	$ 41,081,084	$ 40,998,754	$ 41,010,140	$ 41,009,604	$ 40,965,979	$ 40,990,168	$ 40,985,449	$ 41,047,264
High Coal + 20%	$ 42,591,108	$ 42,500,694	$ 42,478,064	$ 42,520,920	$ 42,427,467	$ 42,459,120	$ 42,477,341	$ 42,567,168
High Coal + 10%	$ 42,019,704	$ 41,925,010	$ 41,914,148	$ 41,945,220	$ 41,860,451	$ 41,886,620	$ 41,901,165	$ 41,994,872
Low Coal - 10%	$ 40,804,340	$ 40,708,466	$ 40,697,020	$ 40,725,060	$ 40,643,187	$ 40,666,628	$ 40,677,149	$ 40,775,576
Low Coal - 20%	$ 40,171,760	$ 40,075,046	$ 40,064,136	$ 40,092,148	$ 40,010,887	$ 40,034,388	$ 40,043,761	$ 40,141,884
Low Natural Gas - $1.50	$ 39,659,612	$ 39,571,578	$ 39,570,800	$ 39,582,812	$ 39,534,015	$ 39,557,080	$ 39,550,049	$ 39,615,308
Low Natural Gas - $1.00	$ 40,321,928	$ 40,234,154	$ 40,223,164	$ 40,249,888	$ 40,180,059	$ 40,202,268	$ 40,212,225	$ 40,281,532
Low Natural Gas - $0.50	$ 40,901,356	$ 40,812,210	$ 40,787,536	$ 40,827,988	$ 40,742,363	$ 40,768,432	$ 40,784,153	$ 40,867,692
High Natural Gas + $0.50	$ 41,912,376	$ 41,813,378	$ 41,765,388	$ 41,839,620	$ 41,707,155	$ 41,737,564	$ 41,783,409	$ 41,889,852
High Natural Gas + $1.00	$ 42,300,140	$ 42,213,266	$ 42,111,612	$ 42,247,244	$ 42,051,739	$ 42,081,920	$ 42,179,761	$ 42,298,652
High Natural Gas + $1.50	$ 42,650,168	$ 42,570,042	$ 42,422,196	$ 42,601,444	$ 42,355,883	$ 42,383,588	$ 42,528,273	$ 42,662,980
High Natural Gas + $2.00	$ 43,001,312	$ 42,913,682	$ 42,713,164	$ 42,944,220	$ 42,644,595	$ 42,673,748	$ 42,865,849	$ 43,009,304
High Natural Gas + $2.50	$ 43,322,752	$ 43,232,238	$ 42,995,328	$ 43,263,660	$ 42,926,251	$ 42,959,316	$ 43,184,241	$ 43,323,964
High Wind Credit + 25%	$ 41,380,468	$ 41,303,210	$ 41,262,884	$ 41,313,432	$ 41,223,167	$ 41,269,116	$ 41,265,217	$ 41,348,436
Low Wind Credit - 25%	$ 41,445,116	$ 41,358,910	$ 41,328,836	$ 41,402,980	$ 41,281,431	$ 41,329,304	$ 41,341,513	$ 41,427,900
High Forecast + 5%	$ 43,819,508	$ 43,749,034	$ 43,716,640	$ 43,789,596	$ 43,665,695	$ 43,669,028	$ 43,730,945	$ 43,817,048
Mid-High Forecast + 2.5%	$ 42,592,756	$ 42,545,058	$ 42,489,756	$ 42,559,952	$ 42,437,803	$ 42,445,592	$ 42,525,917	$ 42,601,828
Mid-Low Forecast - 2.5%	$ 40,249,608	$ 40,178,734	$ 40,197,444	$ 40,175,872	$ 40,151,467	$ 40,182,260	$ 40,160,593	$ 40,216,780
Low Forecast - 5%	$ 39,121,180	$ 39,075,954	$ 39,103,384	$ 39,072,568	$ 39,072,079	$ 39,089,596	$ 39,067,529	$ 39,084,848
Manitoba Hydro PPA Renew	$ 41,200,992	$ 41,107,218	$ 41,088,608	$ 41,136,968	$ 41,036,515	$ 41,074,224	$ 41,074,297	$ 41,168,476
Maximum	$ 45,123,104	$ 45,049,946	$ 45,025,948	$ 45,070,308	$ 44,967,719	$ 45,008,940	$ 45,024,601	$ 45,115,540
Average	$ 41,491,991	$ 41,406,635	$ 41,368,714	$ 41,427,482	$ 41,317,149	$ 41,344,063	$ 41,378,589	$ 41,470,505
Minimum	$ 37,878,588	$ 37,788,434	$ 37,776,260	$ 37,809,104	$ 37,730,115	$ 37,753,868	$ 37,760,169	$ 37,853,036

Contingency	PVSC Difference from Base Case, Same Contingency ($,000; ICT1 Interruptible Gas)							
	Bid Package GPV1	Bid Package BD617	Bid Package CCC1	Bid Package ICT1	Bid Package BD619 CCC1	Bid Package ICT1 CCC1	Bid Package ICT1 BD618	Bid Package BASE CASE
BASE CASE	$ 26,964	$ (70,054)	$ (80,860)	$ (50,824)	$ (133,041)	$ (109,372)	$ (97,503)	$ -
CO2 Reduction	FAILED	FAILED	FAILED	FAILED	FAILED	FAILED	FAILED	FAILED
$34 CO2	$ 7,564	$ (65,594)	$ (89,592)	$ (45,232)	$ (147,821)	$ (106,600)	$ (90,939)	$ -
$9 CO2	$ 25,552	$ (64,602)	$ (76,776)	$ (43,932)	$ (122,921)	$ (99,168)	$ (92,867)	$ -
Low Externalities	$ 27,160	$ (70,226)	$ (81,016)	$ (50,852)	$ (133,461)	$ (109,608)	$ (97,619)	$ -
High Market Price - 25%	$ 28,600	$ (60,254)	$ (80,844)	$ (39,276)	$ (127,929)	$ (103,788)	$ (94,055)	$ -
Low Market Price + 25%	$ 44,652	$ (50,706)	$ (21,320)	$ (33,932)	$ (70,009)	$ (50,104)	$ (77,707)	$ -
High Capital Cost + 10%	$ 13,724	$ (88,322)	$ (116,824)	$ (57,392)	$ (182,249)	$ (153,884)	$ (128,515)	$ -
Low Capital Cost - 10%	$ 33,820	$ (48,510)	$ (37,124)	$ (37,660)	$ (81,285)	$ (57,096)	$ (61,815)	$ -
High Coal + 20%	$ 23,940	$ (66,474)	$ (89,104)	$ (46,248)	$ (139,701)	$ (108,048)	$ (89,827)	$ -
High Coal + 10%	$ 24,832	$ (69,862)	$ (80,724)	$ (49,652)	$ (134,421)	$ (108,252)	$ (93,707)	$ -
Low Coal - 10%	$ 28,764	$ (67,110)	$ (78,556)	$ (50,516)	$ (132,389)	$ (108,948)	$ (98,427)	$ -
Low Coal - 20%	$ 29,876	$ (66,838)	$ (77,748)	$ (49,736)	$ (130,997)	$ (107,496)	$ (98,123)	$ -
Low Natural Gas - $1.50	$ 44,304	$ (43,730)	$ (44,508)	$ (32,496)	$ (81,293)	$ (58,228)	$ (65,259)	$ -
Low Natural Gas - $1.00	$ 40,396	$ (47,378)	$ (58,368)	$ (31,644)	$ (101,473)	$ (79,264)	$ (69,307)	$ -
Low Natural Gas - $0.50	$ 33,664	$ (55,482)	$ (80,156)	$ (39,704)	$ (125,329)	$ (99,260)	$ (83,539)	$ -
High Natural Gas + $0.50	$ 22,524	$ (76,474)	$ (124,464)	$ (50,232)	$ (182,697)	$ (152,288)	$ (106,443)	$ -
High Natural Gas + $1.00	$ 1,488	$ (85,386)	$ (187,040)	$ (51,408)	$ (246,913)	$ (216,732)	$ (118,891)	$ -
High Natural Gas + $1.50	$ (12,812)	$ (92,938)	$ (240,784)	$ (61,536)	$ (307,097)	$ (279,392)	$ (134,707)	$ -
High Natural Gas + $2.00	$ (7,992)	$ (95,622)	$ (296,140)	$ (65,084)	$ (364,709)	$ (335,556)	$ (143,455)	$ -
High Natural Gas + $2.50	$ (1,212)	$ (91,726)	$ (328,636)	$ (60,304)	$ (397,713)	$ (364,648)	$ (139,723)	$ -
High Wind Credit + 25%	$ 32,032	$ (45,226)	$ (85,552)	$ (35,004)	$ (125,269)	$ (79,320)	$ (83,219)	$ -
Low Wind Credit - 25%	$ 17,216	$ (68,990)	$ (99,064)	$ (24,920)	$ (146,469)	$ (98,596)	$ (86,387)	$ -
High Forecast + 5%	$ 2,460	$ (68,014)	$ (100,408)	$ (27,452)	$ (151,353)	$ (148,020)	$ (86,103)	$ -
Mid-High Forecast + 2.5%	$ (9,072)	$ (56,770)	$ (112,072)	$ (41,876)	$ (164,025)	$ (156,236)	$ (75,911)	$ -
Mid-Low Forecast - 2.5%	$ 32,828	$ (38,046)	$ (19,336)	$ (40,908)	$ (65,313)	$ (34,520)	$ (56,187)	$ -
Low Forecast - 5%	$ 36,332	$ (8,894)	$ 18,536	$ (12,280)	$ (12,769)	$ 4,748	$ (17,319)	$ -
Manitoba Hydro PPA Renew	$ 32,516	$ (61,258)	$ (79,868)	$ (31,508)	$ (131,961)	$ (94,252)	$ (94,179)	$ -
Maximum	$ 44,652	$ (8,894)	$ 18,536	$ (12,280)	$ (12,769)	$ 4,748	$ (17,319)	$ -
Average	$ 21,486	$ (63,870)	$ (101,791)	$ (43,023)	$ (153,356)	$ (126,442)	$ (91,916)	$ -
Minimum	$ (12,812)	$ (95,622)	$ (328,636)	$ (65,084)	$ (397,713)	$ (364,648)	$ (143,455)	$ -

Contingency	Rank (ICT1 Interruptible Gas)							
	Bid Package GPV1	Bid Package BD617	Bid Package CCC1	Bid Package ICT1	Bid Package BD619 CCC1	Bid Package ICT1 CCC1	Bid Package ICT1 BD618	Bid Package BASE CASE
BASE CASE	8	5	4	6	1	2	3	7
CO2 Reduction	FAILED	FAILED	FAILED	FAILED	FAILED	FAILED	FAILED	FAILED
$34 CO2	8	5	4	6	1	2	3	7
$9 CO2	8	5	4	6	1	2	3	7
Low Externalities	8	5	4	6	1	2	3	7
High Market Price - 25%	8	5	4	6	1	2	3	7
Low Market Price + 25%	8	3	6	5	2	4	1	7
High Capital Cost + 10%	8	5	4	6	1	2	3	7
Low Capital Cost - 10%	8	4	6	5	1	3	2	7
High Coal + 20%	8	5	4	6	1	2	3	7
High Coal + 10%	8	5	4	6	1	2	3	7
Low Coal - 10%	8	5	4	6	1	2	3	7
Low Coal - 20%	8	5	4	6	1	2	3	7
Low Natural Gas - $1.50	8	5	4	6	1	3	2	7
Low Natural Gas - $1.00	8	5	4	6	1	2	3	7
Low Natural Gas - $0.50	8	5	4	6	1	2	3	7
High Natural Gas + $0.50	8	5	3	6	1	2	4	7
High Natural Gas + $1.00	8	5	3	6	1	2	4	7
High Natural Gas + $1.50	7	5	3	6	1	2	4	8
High Natural Gas + $2.00	7	5	3	6	1	2	4	8
High Natural Gas + $2.50	7	5	3	6	1	2	4	8
High Wind Credit + 25%	8	5	2	6	1	4	3	7
Low Wind Credit - 25%	8	5	2	6	1	3	4	7
High Forecast + 5%	8	5	3	6	1	2	4	7
Mid-High Forecast + 2.5%	7	5	3	6	1	2	4	8
Mid-Low Forecast - 2.5%	8	4	6	3	1	5	2	7
Low Forecast - 5%	8	4	7	3	2	6	1	5
Manitoba Hydro PPA Renew	8	5	4	6	1	2	3	7
Maximum	8.0	5.0	7.0	6.0	2.0	6.0	4.0	8.0
Average	7.9	4.8	3.9	5.7	1.1	2.5	3.0	7.1
Minimum	7.0	3.0	2.0	3.0	1.0	2.0	1.0	5.0

Contingency	Year 1st Generic Unit Added (ICT1 Interruptible Gas)							
	Bid Package BASE CASE	Bid Package GPV1	Bid Package BD617	Bid Package CCC1	Bid Package ICT1	Bid Package BD619 CCC1	Bid Package ICT1 CCC1	Bid Package ICT1 BD618
Base Conditions	2017	2017	2019	2020	2018	2023	2023	2022
CO2 Reduction	FAILED	FAILED	FAILED	FAILED	FAILED	FAILED	FAILED	FAILED
$34 CO2	2017	2017	2019	2020	2018	2023	2023	2022
$9 CO2	2017	2017	2019	2020	2018	2023	2023	2022
Low Externalities	2017	2017	2019	2020	2018	2023	2023	2022
High Market Price + 25%	2017	2017	2019	2020	2018	2023	2023	2022
Low Market Price - 25%	2017	2017	2019	2020	2018	2023	2023	2022
High Capital Cost + 10%	2017	2017	2019	2020	2018	2023	2023	2022
Low Capital Cost - 10%	2017	2017	2019	2020	2018	2023	2023	2022
High Coal + 20%	2017	2017	2019	2020	2018	2023	2023	2022
High Coal + 10%	2017	2017	2019	2020	2018	2023	2023	2022
Low Coal - 10%	2017	2017	2019	2020	2018	2023	2023	2022
Low Coal - 20%	2017	2017	2019	2020	2018	2023	2023	2022
Low Natural Gas - $1.50	2017	2017	2019	2020	2018	2023	2023	2022
Low Natural Gas - $1.00	2017	2017	2019	2020	2018	2023	2023	2022
Low Natural Gas - $0.50	2017	2017	2019	2020	2018	2023	2023	2022
High Natural Gas + $0.50	2017	2017	2019	2020	2018	2023	2023	2022
High Natural Gas + $1.00	2017	2017	2019	2020	2018	2023	2023	2022
High Natural Gas + $1.50	2017	2017	2019	2020	2018	2023	2023	2022
High Natural Gas + $2.00	2017	2017	2019	2020	2018	2023	2023	2022
High Natural Gas + $2.50	2017	2017	2019	2020	2018	2023	2023	2022
High Wind Credit + 25%	2017	2018	2020	2022	2019	2024	2023	2023
Low Wind Credit - 25%	2017	2017	2018	2019	2018	2023	2022	2020
High Forecast + 5%	2017	2017	2017	2017	2017	2017	2017	2017
Mid-High Forecast + 2.5%	2017	2017	2017	2017	2017	2017	2018	2017
Mid-Low Forecast - 2.5%	2020	2020	2023	2024	2023	2025 & on	2025 & on	2025 & on
Low Forecast - 5%	2024	2025 & on	2025	2025 & on	2025 & on	2025 & on	2025 & on	2025 & on
Manitoba Hydro PPA Renew	2017	2017	2019	2020	2018	2023	2023	2022

Note: Low Wind Credit contingency has short term capacity added: 100 MW in 2015 and 2016.

Note: High Forecast contingency has short term capacity added: 400 MW in 2015 and 500 MW in 2016.

Note: Mid-High Forecast contingency has short term capacity added: 100 MW in 2015 and 250 MW in 2016.

Contingency	PVSC ($, 000; No CO2 Costs; ICT1 Interruptible Gas)							
	Bid Package GPV1	Bid Package BD617	Bid Package CCC1	Bid Package ICT1	Bid Package BD619 CCC1	Bid Package ICT1 CCC1	Bid Package ICT1 BD618	Bid Package BASE CASE
BASE CASE	$ 34,905,864	$ 34,813,138	$ 34,793,908	$ 34,823,944	$ 34,744,423	$ 34,771,888	$ 34,779,561	$ 34,876,344
CO2 Reduction	FAILED	FAILED	FAILED	FAILED	FAILED	FAILED	FAILED	FAILED
$34 CO2	$ 34,905,864	$ 34,813,138	$ 34,793,908	$ 34,823,944	$ 34,744,423	$ 34,771,888	$ 34,779,561	$ 34,876,344
$9 CO2	$ 34,905,864	$ 34,813,138	$ 34,793,908	$ 34,823,944	$ 34,744,423	$ 34,771,888	$ 34,779,561	$ 34,876,344
Low Externalities	$ 34,905,864	$ 34,813,138	$ 34,793,908	$ 34,823,944	$ 34,744,423	$ 34,771,888	$ 34,779,561	$ 34,876,344
High Market Price - 25%	$ 34,919,404	$ 34,823,266	$ 34,807,168	$ 34,838,992	$ 34,758,443	$ 34,784,760	$ 34,793,277	$ 34,887,436
Low Market Price + 25%	$ 34,542,928	$ 34,426,494	$ 34,454,668	$ 34,442,968	$ 34,403,835	$ 34,422,484	$ 34,397,109	$ 34,478,664
High Capital Cost + 10%	$ 35,230,980	$ 35,126,030	$ 35,091,536	$ 35,144,032	$ 35,026,975	$ 35,061,068	$ 35,083,093	$ 35,201,900
Low Capital Cost - 10%	$ 34,580,736	$ 34,493,318	$ 34,492,492	$ 34,503,852	$ 34,461,875	$ 34,479,256	$ 34,474,005	$ 34,536,788
High Coal + 20%	$ 36,141,084	$ 36,049,482	$ 36,030,344	$ 36,060,320	$ 35,980,763	$ 36,008,308	$ 36,015,877	$ 36,112,608
High Coal + 10%	$ 35,526,700	$ 35,434,550	$ 35,415,364	$ 35,445,236	$ 35,365,823	$ 35,393,192	$ 35,400,873	$ 35,497,724
Low Coal - 10%	$ 34,280,216	$ 34,186,894	$ 34,167,672	$ 34,197,744	$ 34,118,207	$ 34,145,672	$ 34,153,321	$ 34,250,160
Low Coal - 20%	$ 33,649,016	$ 33,555,128	$ 33,535,924	$ 33,565,932	$ 33,486,447	$ 33,513,862	$ 33,521,505	$ 33,618,460
Low Natural Gas - $1.50	$ 33,575,036	$ 33,485,866	$ 33,485,486	$ 33,488,104	$ 33,453,549	$ 33,472,270	$ 33,465,091	$ 33,530,790
Low Natural Gas - $1.00	$ 34,062,304	$ 33,972,542	$ 33,963,940	$ 33,978,300	$ 33,925,887	$ 33,948,984	$ 33,949,113	$ 34,023,304
Low Natural Gas - $0.50	$ 34,497,880	$ 34,407,450	$ 34,389,988	$ 34,415,432	$ 34,346,787	$ 34,373,260	$ 34,379,017	$ 34,464,256
High Natural Gas + $0.50	$ 35,292,916	$ 35,198,066	$ 35,144,560	$ 35,210,004	$ 35,089,659	$ 35,118,776	$ 35,157,761	$ 35,265,648
High Natural Gas + $1.00	$ 35,658,212	$ 35,550,190	$ 35,463,304	$ 35,574,172	$ 35,403,255	$ 35,434,656	$ 35,510,849	$ 35,629,024
High Natural Gas + $1.50	$ 35,991,300	$ 35,873,182	$ 35,752,856	$ 35,904,368	$ 35,689,667	$ 35,722,212	$ 35,830,633	$ 35,960,672
High Natural Gas + $2.00	$ 36,304,840	$ 36,178,358	$ 36,024,728	$ 36,213,648	$ 35,953,647	$ 35,986,608	$ 36,132,253	$ 36,272,600
High Natural Gas + $2.50	$ 36,600,856	$ 36,469,942	$ 36,281,100	$ 36,503,544	$ 36,205,147	$ 36,233,116	$ 36,419,937	$ 36,568,180
High Wind Credit + 25%	$ 34,884,544	$ 34,766,654	$ 34,753,032	$ 34,787,944	$ 34,709,555	$ 34,751,900	$ 34,734,449	$ 34,815,724
Low Wind Credit - 25%	$ 34,956,944	$ 34,838,614	$ 34,815,988	$ 34,880,944	$ 34,762,787	$ 34,832,824	$ 34,820,421	$ 34,904,824
High Forecast + 5%	$ 36,974,920	$ 36,864,794	$ 36,820,836	$ 36,871,368	$ 36,770,831	$ 36,798,796	$ 36,830,221	$ 36,935,184
Mid-High Forecast + 2.5%	$ 35,908,248	$ 35,827,546	$ 35,799,652	$ 35,858,692	$ 35,742,063	$ 35,768,040	$ 35,806,301	$ 35,876,116
Mid-Low Forecast - 2.5%	$ 33,938,268	$ 33,839,622	$ 33,829,272	$ 33,845,908	$ 33,807,139	$ 33,833,760	$ 33,823,009	$ 33,876,828
Low Forecast - 5%	$ 32,978,728	$ 32,901,038	$ 32,939,084	$ 32,924,486	$ 32,906,685	$ 32,934,454	$ 32,905,019	$ 32,925,974
Manitoba Hydro PPA Renew	$ 34,786,496	$ 34,674,246	$ 34,663,428	$ 34,696,036	$ 34,603,007	$ 34,640,700	$ 34,651,533	$ 34,744,064
Maximum	$ 36,974,920	$ 36,864,794	$ 36,820,836	$ 36,871,368	$ 36,770,831	$ 36,798,796	$ 36,830,221	$ 36,935,184
Average	$ 34,996,519	$ 34,896,142	$ 34,862,890	$ 34,912,882	$ 34,812,953	$ 34,842,463	$ 34,865,663	$ 34,958,604
Minimum	$ 32,978,728	$ 32,901,038	$ 32,939,084	$ 32,924,486	$ 32,906,685	$ 32,934,454	$ 32,905,019	$ 32,925,974

Contingency	PVSC Difference from Base Case, Same Contingency ($,000; No CO2; ICT1 Interruptible Gas)							
	Bid Package GPV1	Bid Package BD617	Bid Package CCC1	Bid Package ICT1	Bid Package BD619 CCC1	Bid Package ICT1 CCC1	Bid Package ICT1 BD618	Bid Package BASE CASE
BASE CASE	$ 29,520	$ (63,206)	$ (82,436)	$ (52,400)	$ (131,921)	$ (104,456)	$ (96,783)	$ -
CO2 Reduction	FAILED	FAILED	FAILED	FAILED	FAILED	FAILED	FAILED	FAILED
$34 CO2	$ 29,520	$ (63,206)	$ (82,436)	$ (52,400)	$ (131,921)	$ (104,456)	$ (96,783)	$ -
$9 CO2	$ 29,520	$ (63,206)	$ (82,436)	$ (52,400)	$ (131,921)	$ (104,456)	$ (96,783)	$ -
Low Externalities	$ 29,520	$ (63,206)	$ (82,436)	$ (52,400)	$ (131,921)	$ (104,456)	$ (96,783)	$ -
High Market Price - 25%	$ 31,968	$ (64,170)	$ (80,268)	$ (48,444)	$ (128,993)	$ (102,676)	$ (94,159)	$ -
Low Market Price + 25%	$ 64,264	$ (52,170)	$ (23,996)	$ (35,696)	$ (74,829)	$ (56,180)	$ (81,555)	$ -
High Capital Cost + 10%	$ 29,080	$ (75,870)	$ (110,364)	$ (57,868)	$ (174,925)	$ (140,832)	$ (118,807)	$ -
Low Capital Cost - 10%	$ 43,948	$ (43,470)	$ (44,296)	$ (32,936)	$ (74,913)	$ (57,532)	$ (62,783)	$ -
High Coal + 20%	$ 28,476	$ (63,126)	$ (82,264)	$ (52,288)	$ (131,845)	$ (104,300)	$ (96,731)	$ -
High Coal + 10%	$ 28,976	$ (63,174)	$ (82,360)	$ (52,488)	$ (131,901)	$ (104,532)	$ (96,851)	$ -
Low Coal - 10%	$ 30,056	$ (63,266)	$ (82,488)	$ (52,416)	$ (131,953)	$ (104,488)	$ (96,839)	$ -
Low Coal - 20%	$ 30,556	$ (63,332)	$ (82,536)	$ (52,528)	$ (132,013)	$ (104,598)	$ (96,955)	$ -
Low Natural Gas - $1.50	$ 44,246	$ (44,924)	$ (45,304)	$ (42,686)	$ (77,241)	$ (58,520)	$ (65,699)	$ -
Low Natural Gas - $1.00	$ 39,000	$ (50,762)	$ (59,364)	$ (45,004)	$ (97,417)	$ (74,320)	$ (74,191)	$ -
Low Natural Gas - $0.50	$ 33,624	$ (56,806)	$ (74,268)	$ (48,824)	$ (117,469)	$ (90,996)	$ (85,239)	$ -
High Natural Gas + $0.50	$ 27,268	$ (67,582)	$ (121,088)	$ (55,644)	$ (175,989)	$ (146,872)	$ (107,887)	$ -
High Natural Gas + $1.00	$ 29,188	$ (78,834)	$ (165,720)	$ (54,852)	$ (225,769)	$ (194,368)	$ (118,175)	$ -
High Natural Gas + $1.50	$ 30,628	$ (87,490)	$ (207,816)	$ (56,304)	$ (271,005)	$ (238,460)	$ (130,039)	$ -
High Natural Gas + $2.00	$ 32,240	$ (94,242)	$ (247,872)	$ (58,952)	$ (318,953)	$ (285,992)	$ (140,347)	$ -
High Natural Gas + $2.50	$ 32,676	$ (98,238)	$ (287,080)	$ (64,636)	$ (363,033)	$ (335,064)	$ (148,243)	$ -
High Wind Credit + 25%	$ 68,820	$ (49,070)	$ (62,692)	$ (27,780)	$ (106,169)	$ (63,824)	$ (81,275)	$ -
Low Wind Credit - 25%	$ 52,120	$ (66,210)	$ (88,836)	$ (23,880)	$ (142,037)	$ (72,000)	$ (84,403)	$ -
High Forecast + 5%	$ 39,736	$ (70,390)	$ (114,348)	$ (63,816)	$ (164,353)	$ (136,388)	$ (104,963)	$ -
Mid-High Forecast + 2.5%	$ 32,132	$ (48,570)	$ (76,464)	$ (17,424)	$ (134,053)	$ (108,076)	$ (69,815)	$ -
Mid-Low Forecast - 2.5%	$ 61,440	$ (37,206)	$ (47,556)	$ (30,920)	$ (69,689)	$ (43,068)	$ (53,819)	$ -
Low Forecast - 5%	$ 52,754	$ (24,936)	$ 13,110	$ (1,488)	$ (19,289)	$ 8,480	$ (20,955)	$ -
Manitoba Hydro PPA Renew	$ 42,432	$ (69,818)	$ (80,636)	$ (48,028)	$ (141,057)	$ (103,364)	$ (92,531)	$ -
Maximum	$ 68,820	$ (24,936)	$ 13,110	$ (1,488)	$ (19,289)	$ 8,480	$ (20,955)	$ -
Average	$ 37,915	$ (62,462)	$ (95,713)	$ (45,722)	$ (145,651)	$ (116,141)	$ (92,941)	$ -
Minimum	$ 27,268	$ (98,238)	$ (287,080)	$ (64,636)	$ (363,033)	$ (335,064)	$ (148,243)	$ -

Contingency	Rank (No CO2, ICT1 Interruptible Gas)							
	Bid Package GPV1	Bid Package BD617	Bid Package CCC1	Bid Package ICT1	Bid Package BD619 CCC1	Bid Package ICT1 CCC1	Bid Package ICT1 BD618	Bid Package BASE CASE
BASE CASE	8	5	4	6	1	2	3	7
CO2 Reduction	FAILED	FAILED	FAILED	FAILED	FAILED	FAILED	FAILED	FAILED
$34 CO2	8	5	4	6	1	2	3	7
$9 CO2	8	5	4	6	1	2	3	7
Low Externalities	8	5	4	6	1	2	3	7
High Market Price - 25%	8	5	4	6	1	2	3	7
Low Market Price + 25%	8	4	6	5	2	3	1	7
High Capital Cost + 10%	8	5	4	6	1	2	3	7
Low Capital Cost - 10%	8	5	4	6	1	3	2	7
High Coal + 20%	8	5	4	6	1	2	3	7
High Coal + 10%	8	5	4	6	1	2	3	7
Low Coal - 10%	8	5	4	6	1	2	3	7
Low Coal - 20%	8	5	4	6	1	2	3	7
Low Natural Gas - $1.50	8	5	4	6	1	3	2	7
Low Natural Gas - $1.00	8	5	4	6	1	2	3	7
Low Natural Gas - $0.50	8	5	4	6	1	2	3	7
High Natural Gas + $0.50	8	5	3	6	1	2	4	7
High Natural Gas + $1.00	8	5	3	6	1	2	4	7
High Natural Gas + $1.50	8	5	3	6	1	2	4	7
High Natural Gas + $2.00	8	5	3	6	1	2	4	7
High Natural Gas + $2.50	8	5	3	6	1	2	4	7
High Wind Credit + 25%	8	5	4	6	1	3	2	7
Low Wind Credit - 25%	8	5	2	6	1	4	3	7
High Forecast + 5%	8	5	3	6	1	2	4	7
Mid-High Forecast + 2.5%	8	5	3	6	1	2	4	7
Mid-Low Forecast - 2.5%	8	5	3	6	1	4	2	7
Low Forecast - 5%	8	1	7	4	3	6	2	5
Manitoba Hydro PPA Renew	8	5	4	6	1	2	3	7
Maximum	8.0	5.0	7.0	6.0	3.0	6.0	4.0	7.0
Average	8.0	4.8	3.8	5.9	1.1	2.4	3.0	6.9
Minimum	8.0	1.0	2.0	4.0	1.0	2.0	1.0	5.0

Contingency	Year 1st Generic Unit Added (No CO2; ICT1 Interruptible Gas)							
	Bid Package BASE CASE	Bid Package GPV1	Bid Package BD617	Bid Package CCC1	Bid Package ICT1	Bid Package BD619 CCC1	Bid Package ICT1 CCC1	Bid Package ICT1 BD618
Base Conditions	2017	2017	2019	2020	2018	2023	2023	2022
CO2 Reduction	FAILED	FAILED	FAILED	FAILED	FAILED	FAILED	FAILED	FAILED
$34 CO2	2017	2017	2019	2020	2018	2023	2023	2022
$9 CO2	2017	2017	2019	2020	2018	2023	2023	2022
Low Externalities	2017	2017	2019	2020	2018	2023	2023	2022
High Market Price + 25%	2017	2017	2019	2020	2018	2023	2023	2022
Low Market Price - 25%	2017	2017	2019	2020	2018	2023	2023	2022
High Capital Cost + 10%	2017	2017	2019	2020	2018	2023	2023	2022
Low Capital Cost - 10%	2017	2017	2019	2020	2018	2023	2023	2022
High Coal + 20%	2017	2017	2019	2020	2018	2023	2023	2022
High Coal + 10%	2017	2017	2019	2020	2018	2023	2023	2022
Low Coal - 10%	2017	2017	2019	2020	2018	2023	2023	2022
Low Coal - 20%	2017	2017	2019	2020	2018	2023	2023	2022
Low Natural Gas - $1.50	2017	2017	2019	2020	2018	2023	2023	2022
Low Natural Gas - $1.00	2017	2017	2019	2020	2018	2023	2023	2022
Low Natural Gas - $0.50	2017	2017	2019	2020	2018	2023	2023	2022
High Natural Gas + $0.50	2017	2017	2019	2020	2018	2023	2023	2022
High Natural Gas + $1.00	2017	2017	2019	2020	2018	2023	2023	2022
High Natural Gas + $1.50	2017	2017	2019	2020	2018	2023	2023	2022
High Natural Gas + $2.00	2017	2017	2019	2020	2018	2023	2023	2022
High Natural Gas + $2.50	2017	2017	2019	2020	2018	2023	2023	2022
High Wind Credit + 25%	2017	2018	2020	2022	2019	2023	2023	2023
Low Wind Credit - 25%	2017	2017	2018	2019	2018	2023	2022	2020
High Forecast + 5%	2017	2017	2017	2017	2017	2017	2017	2017
Mid-High Forecast + 2.5%	2017	2017	2017	2017	2017	2017	2018	2017
Mid-Low Forecast - 2.5%	2020	2020	2023	2024	2023	2025 & on	2025 & on	2025 & on
Low Forecast - 5%	2024	2025 & on	2025	2025 & on	2025 & on	2025 & on	2025 & on	2025 & on
Manitoba Hydro PPA Renew	2017	2017	2019	2020	2018	2023	2023	2022

Note: Low Wind Credit has short term capacity added: 100 MW in 2015 and 2016.
Note: High Forecast has short term capacity added: 400 MW in 2015 and 500 MW in 2016.
Note: Mid-High Forecast has short term capacity added: 100 MW in 2015 and 250 MW in 2016.

Year	Scenario 25 (Total Accredited Capacity)						
	Wind RFP	Generic Wind	Generic CT	Generic CC	Generic Coal	GPV1	Total
2012	-	-	-	-	-	-	-
2013	-	-	-	-	-	-	-
2014	-	-	-	-	-	-	-
2015	-	-	-	-	-	-	-
2016	-	-	-	-	-	-	-
2017	-	-	189.4	-	-	72.0	261.4
2018	-	-	189.4	-	-	72.0	261.4
2019	-	-	189.4	-	-	72.0	261.4
2020	-	-	378.8	-	-	72.0	450.8
2021	99.8	-	378.8	-	-	72.0	550.6
2022	99.8	-	378.8	-	-	72.0	550.6
2023	99.8	-	378.8	302.7	-	72.0	853.3
2024	99.8	-	378.8	302.7	-	72.0	853.3
2025	99.8	-	568.2	1,210.8	-	72.0	1,950.8
2026	99.8	-	568.2	1,210.8	-	72.0	1,950.8
2027	99.8	12.9	568.2	1,918.0	-	72.0	2,670.9
2028	99.8	12.9	757.6	1,918.0	-	72.0	2,860.3
2029	99.8	38.7	947.0	1,918.0	-	72.0	3,075.5
2030	99.8	38.7	1,136.4	1,918.0	-	72.0	3,264.9
2031	99.8	51.6	1,136.4	2,625.2	-	72.0	3,985.0
2032	99.8	77.4	1,515.2	2,625.2	-	72.0	4,389.6
2033	99.8	141.9	1,515.2	2,625.2	-	72.0	4,454.1
2034	99.8	154.8	1,515.2	3,332.4	-	72.0	5,174.2
2035	99.8	154.8	1,704.6	4,039.6	-	72.0	6,070.8
2036	46.6	193.5	2,083.4	4,039.6	-	72.0	6,435.1

Year	Scenario 25 minus Scenario 39 (Total Accredited Capacity)						
	Wind RFP	Generic Wind	Generic CT	Generic CC	Generic Coal	GPV1	Total
2012	-	-	-	-	-	-	-
2013	-	-	-	-	-	-	-
2014	-	-	-	-	-	-	-
2015	-	-	-	-	-	-	-
2016	-	-	-	-	-	-	-
2017	-	-	-	-	-	72.0	72.0
2018	-	-	(189.4)	-	-	72.0	(117.4)
2019	-	-	(189.4)	-	-	72.0	(117.4)
2020	-	-	-	-	-	72.0	72.0
2021	-	-	-	-	-	72.0	72.0
2022	-	-	(189.4)	-	-	72.0	(117.4)
2023	-	-	(189.4)	302.7	-	72.0	185.3
2024	-	-	(189.4)	-	-	72.0	(117.4)
2025	-	-	(189.4)	-	-	72.0	(117.4)
2026	-	-	(189.4)	-	-	72.0	(117.4)
2027	-	-	(189.4)	-	-	72.0	(117.4)
2028	-	-	(189.4)	-	-	72.0	(117.4)
2029	-	-	-	-	-	72.0	72.0
2030	-	-	-	-	-	72.0	72.0
2031	-	-	(189.4)	-	-	72.0	(117.4)
2032	-	-	-	-	-	72.0	72.0
2033	-	-	(189.4)	-	-	72.0	(117.4)
2034	-	-	(189.4)	-	-	72.0	(117.4)
2035	-	-	-	-	-	72.0	72.0
2036	-	-	-	-	-	72.0	72.0

Year	Scenario 27 (Total Accredited Capacity)						
	Wind RFP	Generic Wind	Generic CT	Generic CC	Generic Coal	BD617	Total
2012	-	-	-	-	-	-	-
2013	-	-	-	-	-	-	-
2014	-	-	-	-	-	-	-
2015	-	-	-	-	-	-	-
2016	-	-	-	-	-	-	-
2017	-	-	-	-	-	208.4	208.4
2018	-	-	-	-	-	208.4	208.4
2019	-	-	189.4	-	-	208.4	397.8
2020	-	-	189.4	-	-	208.4	397.8
2021	99.8	-	189.4	-	-	208.4	497.6
2022	99.8	-	378.8	-	-	208.4	687.0
2023	99.8	-	378.8	-	-	208.4	687.0
2024	99.8	-	378.8	302.7	-	208.4	989.7
2025	99.8	-	378.8	1,210.8	-	208.4	1,897.8
2026	99.8	-	568.2	1,210.8	-	208.4	2,087.2
2027	99.8	12.9	568.2	1,918.0	-	208.4	2,807.3
2028	99.8	12.9	568.2	1,918.0	-	208.4	2,807.3
2029	99.8	38.7	757.6	1,918.0	-	208.4	3,022.5
2030	99.8	38.7	947.0	1,918.0	-	208.4	3,211.9
2031	99.8	51.6	1,136.4	2,625.2	-	208.4	4,121.4
2032	99.8	77.4	1,325.8	2,625.2	-	208.4	4,336.6
2033	99.8	141.9	1,325.8	2,625.2	-	208.4	4,401.1
2034	99.8	154.8	1,325.8	3,332.4	-	208.4	5,121.2
2035	99.8	154.8	1,515.2	4,039.6	-	208.4	6,017.8
2036	46.6	193.5	1,894.0	4,039.6	-	208.4	6,382.1

Year	Scenario 27 minus Scenario 39 (Total Accredited Capacity)						
	Wind RFP	Generic Wind	Generic CT	Generic CC	Generic Coal	BD617	Total
2012	-	-	-	-	-	-	-
2013	-	-	-	-	-	-	-
2014	-	-	-	-	-	-	-
2015	-	-	-	-	-	-	-
2016	-	-	-	-	-	-	-
2017	-	-	(189.4)	-	-	208.4	19.0
2018	-	-	(378.8)	-	-	208.4	(170.4)
2019	-	-	(189.4)	-	-	208.4	19.0
2020	-	-	(189.4)	-	-	208.4	19.0
2021	-	-	(189.4)	-	-	208.4	19.0
2022	-	-	(189.4)	-	-	208.4	19.0
2023	-	-	(189.4)	-	-	208.4	19.0
2024	-	-	(189.4)	-	-	208.4	19.0
2025	-	-	(378.8)	-	-	208.4	(170.4)
2026	-	-	(189.4)	-	-	208.4	19.0
2027	-	-	(189.4)	-	-	208.4	19.0
2028	-	-	(378.8)	-	-	208.4	(170.4)
2029	-	-	(189.4)	-	-	208.4	19.0
2030	-	-	(189.4)	-	-	208.4	19.0
2031	-	-	(189.4)	-	-	208.4	19.0
2032	-	-	(189.4)	-	-	208.4	19.0
2033	-	-	(378.8)	-	-	208.4	(170.4)
2034	-	-	(378.8)	-	-	208.4	(170.4)
2035	-	-	(189.4)	-	-	208.4	19.0
2036	-	-	(189.4)	-	-	208.4	19.0

Year	Scenario 29 (Total Accredited Capacity)						
	Wind RFP	Generic Wind	Generic CT	Generic CC	Generic Coal	CCC1	Total
2012	-	-	-	-	-	-	-
2013	-	-	-	-	-	-	-
2014	-	-	-	-	-	-	-
2015	-	-	-	-	-	-	-
2016	-	-	-	-	-	-	-
2017	-	-	-	-	-	286.4	286.4
2018	-	-	-	-	-	286.4	286.4
2019	-	-	-	-	-	286.4	286.4
2020	-	-	189.4	-	-	286.4	475.8
2021	99.8	-	189.4	-	-	286.4	575.6
2022	99.8	-	189.4	-	-	286.4	575.6
2023	99.8	-	378.8	-	-	286.4	765.0
2024	99.8	-	378.8	-	-	286.4	765.0
2025	99.8	-	947.0	605.4	-	286.4	1,938.6
2026	99.8	-	947.0	605.4	-	286.4	1,938.6
2027	99.8	12.9	947.0	1,312.6	-	286.4	2,658.7
2028	99.8	12.9	1,136.4	1,312.6	-	286.4	2,848.1
2029	99.8	38.7	1,325.8	1,312.6	-	286.4	3,063.3
2030	99.8	38.7	1,515.2	1,312.6	-	286.4	3,252.7
2031	99.8	51.6	1,515.2	2,019.8	-	286.4	3,972.8
2032	99.8	77.4	1,894.0	2,019.8	-	286.4	4,377.4
2033	99.8	141.9	1,894.0	2,019.8	-	286.4	4,441.9
2034	99.8	154.8	1,894.0	2,727.0	-	286.4	5,162.0
2035	99.8	154.8	2,083.4	3,434.2	-	286.4	6,058.6
2036	46.6	193.5	2,462.2	3,434.2	-	286.4	6,422.9

Year	Scenario 29 minus Scenario 39 (Total Accredited Capacity)						
	Wind RFP	Generic Wind	Generic CT	Generic CC	Generic Coal	CCC1	Total
2012	-	-	-	-	-	-	-
2013	-	-	-	-	-	-	-
2014	-	-	-	-	-	-	-
2015	-	-	-	-	-	-	-
2016	-	-	-	-	-	-	-
2017	-	-	(189.4)	-	-	286.4	97.0
2018	-	-	(378.8)	-	-	286.4	(92.4)
2019	-	-	(378.8)	-	-	286.4	(92.4)
2020	-	-	(189.4)	-	-	286.4	97.0
2021	-	-	(189.4)	-	-	286.4	97.0
2022	-	-	(378.8)	-	-	286.4	(92.4)
2023	-	-	(189.4)	-	-	286.4	97.0
2024	-	-	(189.4)	(302.7)	-	286.4	(205.7)
2025	-	-	189.4	(605.4)	-	286.4	(129.6)
2026	-	-	189.4	(605.4)	-	286.4	(129.6)
2027	-	-	189.4	(605.4)	-	286.4	(129.6)
2028	-	-	189.4	(605.4)	-	286.4	(129.6)
2029	-	-	378.8	(605.4)	-	286.4	59.8
2030	-	-	378.8	(605.4)	-	286.4	59.8
2031	-	-	189.4	(605.4)	-	286.4	(129.6)
2032	-	-	378.8	(605.4)	-	286.4	59.8
2033	-	-	189.4	(605.4)	-	286.4	(129.6)
2034	-	-	189.4	(605.4)	-	286.4	(129.6)
2035	-	-	378.8	(605.4)	-	286.4	59.8
2036	-	-	378.8	(605.4)	-	286.4	59.8

Year	Scenario 31a (Total Accredited Capacity)						
	Wind RFP	Generic Wind	Generic CT	Generic CC	Generic Coal	ICT1	Total
2012	-	-	-	-	-	-	-
2013	-	-	-	-	-	-	-
2014	-	-	-	-	-	-	-
2015	-	-	-	-	-	-	-
2016	-	-	-	-	-	154.5	154.5
2017	-	-	-	-	-	154.5	154.5
2018	-	-	189.4	-	-	154.5	343.9
2019	-	-	189.4	-	-	154.5	343.9
2020	-	-	189.4	-	-	154.5	343.9
2021	99.8	-	189.4	-	-	154.5	443.7
2022	99.8	-	378.8	-	-	154.5	633.1
2023	99.8	-	378.8	-	-	154.5	633.1
2024	99.8	-	378.8	302.7	-	154.5	935.8
2025	99.8	-	568.2	1,210.8	-	154.5	2,033.3
2026	99.8	-	568.2	1,210.8	-	154.5	2,033.3
2027	99.8	12.9	568.2	1,918.0	-	154.5	2,753.4
2028	99.8	12.9	757.6	1,918.0	-	154.5	2,942.8
2029	99.8	38.7	757.6	1,918.0	-	154.5	2,968.6
2030	99.8	38.7	947.0	1,918.0	-	154.5	3,158.0
2031	99.8	51.6	1,136.4	2,625.2	-	154.5	4,067.5
2032	99.8	77.4	1,325.8	2,625.2	-	154.5	4,282.7
2033	99.8	141.9	1,515.2	2,625.2	-	154.5	4,536.6
2034	99.8	154.8	1,515.2	3,332.4	-	154.5	5,256.7
2035	99.8	154.8	1,704.6	4,039.6	-	154.5	6,153.3
2036	46.6	193.5	2,083.4	4,039.6	-	-	6,363.1

Year	Scenario 31a minus Scenario 39 (Total Accredited Capacity)						
	Wind RFP	Generic Wind	Generic CT	Generic CC	Generic Coal	GPV1	Total
2012	-	-	-	-	-	-	-
2013	-	-	-	-	-	-	-
2014	-	-	-	-	-	-	-
2015	-	-	-	-	-	-	-
2016	-	-	-	-	-	154.5	154.5
2017	-	-	(189.4)	-	-	154.5	(34.9)
2018	-	-	(189.4)	-	-	154.5	(34.9)
2019	-	-	(189.4)	-	-	154.5	(34.9)
2020	-	-	(189.4)	-	-	154.5	(34.9)
2021	-	-	(189.4)	-	-	154.5	(34.9)
2022	-	-	(189.4)	-	-	154.5	(34.9)
2023	-	-	(189.4)	-	-	154.5	(34.9)
2024	-	-	(189.4)	-	-	154.5	(34.9)
2025	-	-	(189.4)	-	-	154.5	(34.9)
2026	-	-	(189.4)	-	-	154.5	(34.9)
2027	-	-	(189.4)	-	-	154.5	(34.9)
2028	-	-	(189.4)	-	-	154.5	(34.9)
2029	-	-	(189.4)	-	-	154.5	(34.9)
2030	-	-	(189.4)	-	-	154.5	(34.9)
2031	-	-	(189.4)	-	-	154.5	(34.9)
2032	-	-	(189.4)	-	-	154.5	(34.9)
2033	-	-	(189.4)	-	-	154.5	(34.9)
2034	-	-	(189.4)	-	-	154.5	(34.9)
2035	-	-	-	-	-	154.5	154.5
2036	-	-	-	-	-	-	-

Year	Scenario 33 (Total Accredited Capacity)						
	Wind RFP	Generic Wind	Generic CT	Generic CC	Generic Coal	BD619 & CCC1	Total
2012	-	-	-	-	-	-	-
2013	-	-	-	-	-	-	-
2014	-	-	-	-	-	-	-
2015	-	-	-	-	-	-	-
2016	-	-	-	-	-	-	-
2017	-	-	-	-	-	286.4	286.4
2018	-	-	-	-	-	286.4	286.4
2019	-	-	-	-	-	494.8	494.8
2020	-	-	-	-	-	494.8	494.8
2021	99.8	-	-	-	-	494.8	594.6
2022	99.8	-	-	-	-	494.8	594.6
2023	99.8	-	189.4	-	-	494.8	784.0
2024	99.8	-	189.4	-	-	494.8	784.0
2025	99.8	-	568.2	908.1	-	494.8	2,070.9
2026	99.8	-	568.2	908.1	-	494.8	2,070.9
2027	99.8	12.9	568.2	1,615.3	-	494.8	2,791.0
2028	99.8	12.9	757.6	1,615.3	-	494.8	2,980.4
2029	99.8	38.7	757.6	1,615.3	-	494.8	3,006.2
2030	99.8	38.7	947.0	1,615.3	-	494.8	3,195.6
2031	99.8	51.6	1,136.4	2,322.5	-	494.8	4,105.1
2032	99.8	77.4	1,325.8	2,322.5	-	494.8	4,320.3
2033	99.8	141.9	1,515.2	2,322.5	-	494.8	4,574.2
2034	99.8	154.8	1,515.2	3,029.7	-	494.8	5,294.3
2035	99.8	154.8	1,515.2	3,736.9	-	494.8	6,001.5
2036	46.6	193.5	1,894.0	3,736.9	-	494.8	6,365.8

Year	Scenario 33 minus Scenario 39 (Total Accredited Capacity)						
	Wind RFP	Generic Wind	Generic CT	Generic CC	Generic Coal	BD619 & CCC1	Total
2012	-	-	-	-	-	-	-
2013	-	-	-	-	-	-	-
2014	-	-	-	-	-	-	-
2015	-	-	-	-	-	-	-
2016	-	-	-	-	-	-	-
2017	-	-	(189.4)	-	-	286.4	97.0
2018	-	-	(378.8)	-	-	286.4	(92.4)
2019	-	-	(378.8)	-	-	494.8	116.0
2020	-	-	(378.8)	-	-	494.8	116.0
2021	-	-	(378.8)	-	-	494.8	116.0
2022	-	-	(568.2)	-	-	494.8	(73.4)
2023	-	-	(378.8)	-	-	494.8	116.0
2024	-	-	(378.8)	(302.7)	-	494.8	(186.7)
2025	-	-	(189.4)	(302.7)	-	494.8	2.7
2026	-	-	(189.4)	(302.7)	-	494.8	2.7
2027	-	-	(189.4)	(302.7)	-	494.8	2.7
2028	-	-	(189.4)	(302.7)	-	494.8	2.7
2029	-	-	(189.4)	(302.7)	-	494.8	2.7
2030	-	-	(189.4)	(302.7)	-	494.8	2.7
2031	-	-	(189.4)	(302.7)	-	494.8	2.7
2032	-	-	(189.4)	(302.7)	-	494.8	2.7
2033	-	-	(189.4)	(302.7)	-	494.8	2.7
2034	-	-	(189.4)	(302.7)	-	494.8	2.7
2035	-	-	(189.4)	(302.7)	-	494.8	2.7
2036	-	-	(189.4)	(302.7)	-	494.8	2.7

Year	Scenario 35a (Total Accredited Capacity)						
	Wind RFP	Generic Wind	Generic CT	Generic CC	Generic Coal	ICT1 CCC1	Total
2012	-	-	-	-	-	-	-
2013	-	-	-	-	-	-	-
2014	-	-	-	-	-	-	-
2015	-	-	-	-	-	-	-
2016	-	-	-	-	-	154.5	154.5
2017	-	-	-	-	-	440.9	440.9
2018	-	-	-	-	-	440.9	440.9
2019	-	-	-	-	-	440.9	440.9
2020	-	-	-	-	-	440.9	440.9
2021	99.8	-	-	-	-	440.9	540.7
2022	99.8	-	-	-	-	440.9	540.7
2023	99.8	-	189.4	-	-	440.9	730.1
2024	99.8	-	189.4	-	-	440.9	730.1
2025	99.8	-	757.6	605.4	-	440.9	1,903.7
2026	99.8	-	947.0	605.4	-	440.9	2,093.1
2027	99.8	12.9	947.0	1,312.6	-	440.9	2,813.2
2028	99.8	12.9	947.0	1,312.6	-	440.9	2,813.2
2029	99.8	38.7	1,136.4	1,312.6	-	440.9	3,028.4
2030	99.8	38.7	1,325.8	1,312.6	-	440.9	3,217.8
2031	99.8	51.6	1,515.2	2,019.8	-	440.9	4,127.3
2032	99.8	77.4	1,704.6	2,019.8	-	440.9	4,342.5
2033	99.8	141.9	1,704.6	2,019.8	-	440.9	4,407.0
2034	99.8	154.8	1,704.6	2,727.0	-	440.9	5,127.1
2035	99.8	154.8	1,894.0	3,434.2	-	440.9	6,023.7
2036	46.6	193.5	2,462.2	3,434.2	-	286.4	6,422.9

Year	Scenario 35a minus Scenario 39 (Total Accredited Capacity)						
	Wind RFP	Generic Wind	Generic CT	Generic CC	Generic Coal	GPV1	Total
2012	-	-	-	-	-	-	-
2013	-	-	-	-	-	-	-
2014	-	-	-	-	-	-	-
2015	-	-	-	-	-	-	-
2016	-	-	-	-	-	154.5	154.5
2017	-	-	(189.4)	-	-	440.9	251.5
2018	-	-	(378.8)	-	-	440.9	62.1
2019	-	-	(378.8)	-	-	440.9	62.1
2020	-	-	(378.8)	-	-	440.9	62.1
2021	-	-	(378.8)	-	-	440.9	62.1
2022	-	-	(568.2)	-	-	440.9	(127.3)
2023	-	-	(378.8)	-	-	440.9	62.1
2024	-	-	(378.8)	(302.7)	-	440.9	(240.6)
2025	-	-	-	(605.4)	-	440.9	(164.5)
2026	-	-	189.4	(605.4)	-	440.9	24.9
2027	-	-	189.4	(605.4)	-	440.9	24.9
2028	-	-	-	(605.4)	-	440.9	(164.5)
2029	-	-	189.4	(605.4)	-	440.9	24.9
2030	-	-	189.4	(605.4)	-	440.9	24.9
2031	-	-	189.4	(605.4)	-	440.9	24.9
2032	-	-	189.4	(605.4)	-	440.9	24.9
2033	-	-	-	(605.4)	-	440.9	(164.5)
2034	-	-	-	(605.4)	-	440.9	(164.5)
2035	-	-	189.4	(605.4)	-	440.9	24.9
2036	-	-	378.8	(605.4)	-	286.4	59.8

Year	Scenario 37a (Total Accredited Capacity)						
	Wind RFP	Generic Wind	Generic CT	Generic CC	Generic Coal	ICT1 BD618	Total
2012	-	-	-	-	-	-	-
2013	-	-	-	-	-	-	-
2014	-	-	-	-	-	-	-
2015	-	-	-	-	-	-	-
2016	-	-	-	-	-	154.5	154.5
2017	-	-	-	-	-	154.5	154.5
2018	-	-	-	-	-	362.9	362.9
2019	-	-	-	-	-	362.9	362.9
2020	-	-	-	-	-	362.9	362.9
2021	99.8	-	-	-	-	362.9	462.7
2022	99.8	-	189.4	-	-	362.9	652.1
2023	99.8	-	189.4	-	-	362.9	652.1
2024	99.8	-	378.8	-	-	362.9	841.5
2025	99.8	-	568.2	908.1	-	362.9	1,939.0
2026	99.8	-	568.2	908.1	-	362.9	1,939.0
2027	99.8	12.9	568.2	1,615.3	-	362.9	2,659.1
2028	99.8	12.9	757.6	1,615.3	-	362.9	2,848.5
2029	99.8	38.7	947.0	1,615.3	-	362.9	3,063.7
2030	99.8	38.7	1,136.4	1,615.3	-	362.9	3,253.1
2031	99.8	51.6	1,136.4	2,322.5	-	362.9	3,973.2
2032	99.8	77.4	1,515.2	2,322.5	-	362.9	4,377.8
2033	99.8	141.9	1,515.2	2,322.5	-	362.9	4,442.3
2034	99.8	154.8	1,515.2	3,029.7	-	362.9	5,162.4
2035	99.8	154.8	1,704.6	3,736.9	-	362.9	6,059.0
2036	46.6	193.5	2,272.8	3,736.9	-	208.4	6,458.2

Year	Scenario 37a minus Scenario 39 (Total Accredited Capacity)						
	Wind RFP	Generic Wind	Generic CT	Generic CC	Generic Coal	GPV1	Total
2012	-	-	-	-	-	-	-
2013	-	-	-	-	-	-	-
2014	-	-	-	-	-	-	-
2015	-	-	-	-	-	-	-
2016	-	-	-	-	-	154.5	154.5
2017	-	-	(189.4)	-	-	154.5	(34.9)
2018	-	-	(378.8)	-	-	362.9	(15.9)
2019	-	-	(378.8)	-	-	362.9	(15.9)
2020	-	-	(378.8)	-	-	362.9	(15.9)
2021	-	-	(378.8)	-	-	362.9	(15.9)
2022	-	-	(378.8)	-	-	362.9	(15.9)
2023	-	-	(378.8)	-	-	362.9	(15.9)
2024	-	-	(189.4)	(302.7)	-	362.9	(129.2)
2025	-	-	(189.4)	(302.7)	-	362.9	(129.2)
2026	-	-	(189.4)	(302.7)	-	362.9	(129.2)
2027	-	-	(189.4)	(302.7)	-	362.9	(129.2)
2028	-	-	(189.4)	(302.7)	-	362.9	(129.2)
2029	-	-	-	(302.7)	-	362.9	60.2
2030	-	-	-	(302.7)	-	362.9	60.2
2031	-	-	(189.4)	(302.7)	-	362.9	(129.2)
2032	-	-	-	(302.7)	-	362.9	60.2
2033	-	-	(189.4)	(302.7)	-	362.9	(129.2)
2034	-	-	(189.4)	(302.7)	-	362.9	(129.2)
2035	-	-	-	(302.7)	-	362.9	60.2
2036	-	-	189.4	(302.7)	-	208.4	95.1

Year	Scenario 39 (Total Accredited Capacity)						
	Wind RFP	Generic Wind	Generic CT	Generic CC	Generic Coal	Bid Package	Total
2012	-	-	-	-	-	-	-
2013	-	-	-	-	-	-	-
2014	-	-	-	-	-	-	-
2015	-	-	-	-	-	-	-
2016	-	-	-	-	-	-	-
2017	-	-	189.4	-	-	-	189.4
2018	-	-	378.8	-	-	-	378.8
2019	-	-	378.8	-	-	-	378.8
2020	-	-	378.8	-	-	-	378.8
2021	99.8	-	378.8	-	-	-	478.6
2022	99.8	-	568.2	-	-	-	668.0
2023	99.8	-	568.2	-	-	-	668.0
2024	99.8	-	568.2	302.7	-	-	970.7
2025	99.8	-	757.6	1,210.8	-	-	2,068.2
2026	99.8	-	757.6	1,210.8	-	-	2,068.2
2027	99.8	12.9	757.6	1,918.0	-	-	2,788.3
2028	99.8	12.9	947.0	1,918.0	-	-	2,977.7
2029	99.8	38.7	947.0	1,918.0	-	-	3,003.5
2030	99.8	38.7	1,136.4	1,918.0	-	-	3,192.9
2031	99.8	51.6	1,325.8	2,625.2	-	-	4,102.4
2032	99.8	77.4	1,515.2	2,625.2	-	-	4,317.6
2033	99.8	141.9	1,704.6	2,625.2	-	-	4,571.5
2034	99.8	154.8	1,704.6	3,332.4	-	-	5,291.6
2035	99.8	154.8	1,704.6	4,039.6	-	-	5,998.8
2036	46.6	193.5	2,083.4	4,039.6	-	-	6,363.1

Year	Scenario 26 (Total Accredited Capacity)						
	Wind RFP	Generic Wind	Generic CT	Generic CC	Generic Coal	GPV1	Total
2012	-	-	-	-	-	-	-
2013	-	-	-	-	-	-	-
2014	-	-	-	-	-	-	-
2015	-	-	-	-	-	-	-
2016	-	-	-	-	-	-	-
2017	-	-	189.4	-	-	72.0	261.4
2018	-	-	189.4	-	-	72.0	261.4
2019	-	-	189.4	-	-	72.0	261.4
2020	-	-	378.8	-	-	72.0	450.8
2021	99.8	-	378.8	-	-	72.0	550.6
2022	99.8	-	378.8	-	-	72.0	550.6
2023	99.8	-	568.2	-	-	72.0	740.0
2024	99.8	-	568.2	-	-	72.0	740.0
2025	99.8	-	1,136.4	605.4	-	72.0	1,913.6
2026	99.8	-	1,325.8	605.4	-	72.0	2,103.0
2027	99.8	12.9	1,325.8	1,312.6	-	72.0	2,823.1
2028	99.8	12.9	1,325.8	1,312.6	-	72.0	2,823.1
2029	99.8	38.7	1,515.2	1,312.6	-	72.0	3,038.3
2030	99.8	38.7	1,704.6	1,312.6	-	72.0	3,227.7
2031	99.8	51.6	1,704.6	2,019.8	-	72.0	3,947.8
2032	99.8	77.4	2,083.4	2,019.8	-	72.0	4,352.4
2033	99.8	141.9	2,083.4	2,019.8	-	72.0	4,416.9
2034	99.8	154.8	2,083.4	2,727.0	-	72.0	5,137.0
2035	99.8	154.8	2,272.8	3,434.2	-	72.0	6,033.6
2036	46.6	193.5	2,651.6	3,434.2	-	72.0	6,397.9

Year	Scenario 26 minus Scenario 40 (Total Accredited Capacity)						
	Wind RFP	Generic Wind	Generic CT	Generic CC	Generic Coal	GPV1	Total
2012	-	-	-	-	-	-	-
2013	-	-	-	-	-	-	-
2014	-	-	-	-	-	-	-
2015	-	-	-	-	-	-	-
2016	-	-	-	-	-	-	-
2017	-	-	-	-	-	72.0	72.0
2018	-	-	(189.4)	-	-	72.0	(117.4)
2019	-	-	(189.4)	-	-	72.0	(117.4)
2020	-	-	-	-	-	72.0	72.0
2021	-	-	-	-	-	72.0	72.0
2022	-	-	(189.4)	-	-	72.0	(117.4)
2023	-	-	-	-	-	72.0	72.0
2024	-	-	-	(302.7)	-	72.0	(230.7)
2025	-	-	378.8	(605.4)	-	72.0	(154.6)
2026	-	-	568.2	(605.4)	-	72.0	34.8
2027	-	-	-	101.8	-	72.0	34.8
2028	-	-	(189.4)	101.8	-	72.0	(154.6)
2029	-	-	(189.4)	101.8	-	72.0	34.8
2030	-	-	(189.4)	101.8	-	72.0	34.8
2031	-	-	(189.4)	101.8	-	72.0	(154.6)
2032	-	-	(189.4)	101.8	-	72.0	34.8
2033	-	-	(189.4)	101.8	-	72.0	(154.6)
2034	-	-	(189.4)	101.8	-	72.0	(154.6)
2035	-	-	(189.4)	101.8	-	72.0	34.8
2036	-	-	(189.4)	101.8	-	72.0	34.8

Year	Scenario 28 (Total Accredited Capacity)						
	Wind RFP	Generic Wind	Generic CT	Generic CC	Generic Coal	BD617	Total
2012	-	-	-	-	-	-	-
2013	-	-	-	-	-	-	-
2014	-	-	-	-	-	-	-
2015	-	-	-	-	-	-	-
2016	-	-	-	-	-	-	-
2017	-	-	-	-	-	208.4	208.4
2018	-	-	-	-	-	208.4	208.4
2019	-	-	189.4	-	-	208.4	397.8
2020	-	-	189.4	-	-	208.4	397.8
2021	99.8	-	189.4	-	-	208.4	497.6
2022	99.8	-	378.8	-	-	208.4	687.0
2023	99.8	-	378.8	-	-	208.4	687.0
2024	99.8	-	378.8	302.7	-	208.4	989.7
2025	99.8	-	378.8	1,210.8	-	208.4	1,897.8
2026	99.8	-	378.8	1,513.5	-	208.4	2,200.5
2027	99.8	12.9	757.6	1,513.5	-	208.4	2,592.2
2028	99.8	12.9	1,136.4	1,513.5	-	208.4	2,971.0
2029	99.8	38.7	1,136.4	1,513.5	-	208.4	2,996.8
2030	99.8	38.7	1,325.8	1,513.5	-	208.4	3,186.2
2031	99.8	51.6	1,515.2	2,220.7	-	208.4	4,095.7
2032	99.8	77.4	1,704.6	2,220.7	-	208.4	4,310.9
2033	99.8	141.9	1,894.0	2,220.7	-	208.4	4,564.8
2034	99.8	154.8	1,894.0	2,927.9	-	208.4	5,284.9
2035	99.8	154.8	1,894.0	3,635.1	-	208.4	5,992.1
2036	46.6	193.5	2,272.8	3,635.1	-	208.4	6,356.4

Year	Scenario 28 minus Scenario 40 (Total Accredited Capacity)						
	Wind RFP	Generic Wind	Generic CT	Generic CC	Generic Coal	BD617	Total
2012	-	-	-	-	-	-	-
2013	-	-	-	-	-	-	-
2014	-	-	-	-	-	-	-
2015	-	-	-	-	-	-	-
2016	-	-	-	-	-	-	-
2017	-	-	(189.4)	-	-	208.4	19.0
2018	-	-	(378.8)	-	-	208.4	(170.4)
2019	-	-	(189.4)	-	-	208.4	19.0
2020	-	-	(189.4)	-	-	208.4	19.0
2021	-	-	(189.4)	-	-	208.4	19.0
2022	-	-	(189.4)	-	-	208.4	19.0
2023	-	-	(189.4)	-	-	208.4	19.0
2024	-	-	(189.4)	-	-	208.4	19.0
2025	-	-	(378.8)	-	-	208.4	(170.4)
2026	-	-	(378.8)	302.7	-	208.4	132.3
2027	-	-	(568.2)	302.7	-	208.4	(196.1)
2028	-	-	(378.8)	302.7	-	208.4	(6.7)
2029	-	-	(568.2)	302.7	-	208.4	(6.7)
2030	-	-	(568.2)	302.7	-	208.4	(6.7)
2031	-	-	(378.8)	302.7	-	208.4	(6.7)
2032	-	-	(568.2)	302.7	-	208.4	(6.7)
2033	-	-	(378.8)	302.7	-	208.4	(6.7)
2034	-	-	(378.8)	302.7	-	208.4	(6.7)
2035	-	-	(568.2)	302.7	-	208.4	(6.7)
2036	-	-	(568.2)	302.7	-	208.4	(6.7)

Year	Scenario 30 (Total Accredited Capacity)						
	Wind RFP	Generic Wind	Generic CT	Generic CC	Generic Coal	CCC1	Total
2012	-	-	-	-	-	-	-
2013	-	-	-	-	-	-	-
2014	-	-	-	-	-	-	-
2015	-	-	-	-	-	-	-
2016	-	-	-	-	-	-	-
2017	-	-	-	-	-	286.4	286.4
2018	-	-	-	-	-	286.4	286.4
2019	-	-	-	-	-	286.4	286.4
2020	-	-	189.4	-	-	286.4	475.8
2021	99.8	-	189.4	-	-	286.4	575.6
2022	99.8	-	189.4	-	-	286.4	575.6
2023	99.8	-	378.8	-	-	286.4	765.0
2024	99.8	-	378.8	-	-	286.4	765.0
2025	99.8	-	757.6	908.1	-	286.4	2,051.9
2026	99.8	-	757.6	908.1	-	286.4	2,051.9
2027	99.8	12.9	1,325.8	908.1	-	286.4	2,633.0
2028	99.8	12.9	1,515.2	908.1	-	286.4	2,822.4
2029	99.8	38.7	1,704.6	908.1	-	286.4	3,037.6
2030	99.8	38.7	1,894.0	908.1	-	286.4	3,227.0
2031	99.8	51.6	1,894.0	1,615.3	-	286.4	3,947.1
2032	99.8	77.4	2,272.8	1,615.3	-	286.4	4,351.7
2033	99.8	141.9	2,272.8	1,615.3	-	286.4	4,416.2
2034	99.8	154.8	2,272.8	2,322.5	-	286.4	5,136.3
2035	99.8	154.8	2,462.2	3,029.7	-	286.4	6,032.9
2036	46.6	193.5	2,841.0	3,029.7	-	286.4	6,397.2

Year	Scenario 30 minus Scenario 40 (Total Accredited Capacity)						
	Wind RFP	Generic Wind	Generic CT	Generic CC	Generic Coal	CCC1	Total
2012	-	-	-	-	-	-	-
2013	-	-	-	-	-	-	-
2014	-	-	-	-	-	-	-
2015	-	-	-	-	-	-	-
2016	-	-	-	-	-	-	-
2017	-	-	(189.4)	-	-	286.4	97.0
2018	-	-	(378.8)	-	-	286.4	(92.4)
2019	-	-	(378.8)	-	-	286.4	(92.4)
2020	-	-	(189.4)	-	-	286.4	97.0
2021	-	-	(189.4)	-	-	286.4	97.0
2022	-	-	(378.8)	-	-	286.4	(92.4)
2023	-	-	(189.4)	-	-	286.4	97.0
2024	-	-	(189.4)	(302.7)	-	286.4	(205.7)
2025	-	-	-	(302.7)	-	286.4	(16.3)
2026	-	-	-	(302.7)	-	286.4	(16.3)
2027	-	-	-	(302.7)	-	286.4	(155.3)
2028	-	-	-	(302.7)	-	286.4	(155.3)
2029	-	-	-	(302.7)	-	286.4	34.1
2030	-	-	-	(302.7)	-	286.4	34.1
2031	-	-	-	(302.7)	-	286.4	(155.3)
2032	-	-	-	(302.7)	-	286.4	34.1
2033	-	-	-	(302.7)	-	286.4	(155.3)
2034	-	-	-	(302.7)	-	286.4	(155.3)
2035	-	-	-	(302.7)	-	286.4	34.1
2036	-	-	-	(302.7)	-	286.4	34.1

Year	Scenario 32a (Total Accredited Capacity)						
	Wind RFP	Generic Wind	Generic CT	Generic CC	Generic Coal	ICT1	Total
2012	-	-	-	-	-	-	-
2013	-	-	-	-	-	-	-
2014	-	-	-	-	-	-	-
2015	-	-	-	-	-	-	-
2016	-	-	-	-	-	154.5	154.5
2017	-	-	-	-	-	154.5	154.5
2018	-	-	189.4	-	-	154.5	343.9
2019	-	-	189.4	-	-	154.5	343.9
2020	-	-	189.4	-	-	154.5	343.9
2021	99.8	-	189.4	-	-	154.5	443.7
2022	99.8	-	378.8	-	-	154.5	633.1
2023	99.8	-	378.8	-	-	154.5	633.1
2024	99.8	-	568.2	-	-	154.5	822.5
2025	99.8	-	757.6	908.1	-	154.5	1,920.0
2026	99.8	-	757.6	1,210.8	-	154.5	2,222.7
2027	99.8	12.9	1,136.4	1,210.8	-	154.5	2,614.4
2028	99.8	12.9	1,325.8	1,210.8	-	154.5	2,803.8
2029	99.8	38.7	1,515.2	1,210.8	-	154.5	3,019.0
2030	99.8	38.7	1,704.6	1,210.8	-	154.5	3,208.4
2031	99.8	51.6	1,894.0	1,918.0	-	154.5	4,117.9
2032	99.8	77.4	2,083.4	1,918.0	-	154.5	4,333.1
2033	99.8	141.9	2,083.4	1,918.0	-	154.5	4,397.6
2034	99.8	154.8	2,083.4	2,625.2	-	154.5	5,117.7
2035	99.8	154.8	2,272.8	3,332.4	-	154.5	6,014.3
2036	46.6	193.5	2,841.0	3,332.4	-	-	6,413.5

Year	Scenario 32a minus Scenario 39 (Total Accredited Capacity)						
	Wind RFP	Generic Wind	Generic CT	Generic CC	Generic Coal	GPV1	Total
2012	-	-	-	-	-	-	-
2013	-	-	-	-	-	-	-
2014	-	-	-	-	-	-	-
2015	-	-	-	-	-	-	-
2016	-	-	-	-	-	154.5	154.5
2017	-	-	(189.4)	-	-	154.5	(34.9)
2018	-	-	(189.4)	-	-	154.5	(34.9)
2019	-	-	(189.4)	-	-	154.5	(34.9)
2020	-	-	(189.4)	-	-	154.5	(34.9)
2021	-	-	(189.4)	-	-	154.5	(34.9)
2022	-	-	(189.4)	-	-	154.5	(34.9)
2023	-	-	(189.4)	-	-	154.5	(34.9)
2024	-	-	-	(302.7)	-	154.5	(148.2)
2025	-	-	-	(302.7)	-	154.5	(148.2)
2026	-	-	-	-	-	154.5	154.5
2027	-	-	378.8	(707.2)	-	154.5	(173.9)
2028	-	-	378.8	(707.2)	-	154.5	(173.9)
2029	-	-	568.2	(707.2)	-	154.5	15.5
2030	-	-	568.2	(707.2)	-	154.5	15.5
2031	-	-	568.2	(707.2)	-	154.5	15.5
2032	-	-	568.2	(707.2)	-	154.5	15.5
2033	-	-	378.8	(707.2)	-	154.5	(173.9)
2034	-	-	378.8	(707.2)	-	154.5	(173.9)
2035	-	-	568.2	(707.2)	-	154.5	15.5
2036	-	-	757.6	(707.2)	-	-	50.4

Year	Scenario 34 (Total Accredited Capacity)						
	Wind RFP	Generic Wind	Generic CT	Generic CC	Generic Coal	BD619 CCC1	Total
2012	-	-	-	-	-	-	-
2013	-	-	-	-	-	-	-
2014	-	-	-	-	-	-	-
2015	-	-	-	-	-	-	-
2016	-	-	-	-	-	-	-
2017	-	-	-	-	-	286.4	286.4
2018	-	-	-	-	-	286.4	286.4
2019	-	-	-	-	-	494.8	494.8
2020	-	-	-	-	-	494.8	494.8
2021	99.8	-	-	-	-	494.8	594.6
2022	99.8	-	-	-	-	494.8	594.6
2023	99.8	-	189.4	-	-	494.8	784.0
2024	99.8	-	189.4	-	-	494.8	784.0
2025	99.8	-	568.2	908.1	-	494.8	2,070.9
2026	99.8	-	568.2	908.1	-	494.8	2,070.9
2027	99.8	12.9	1,136.4	908.1	-	494.8	2,652.0
2028	99.8	12.9	1,325.8	908.1	-	494.8	2,841.4
2029	99.8	38.7	1,515.2	908.1	-	494.8	3,056.6
2030	99.8	38.7	1,704.6	908.1	-	494.8	3,246.0
2031	99.8	51.6	1,704.6	1,615.3	-	494.8	3,966.1
2032	99.8	77.4	2,083.4	1,615.3	-	494.8	4,370.7
2033	99.8	141.9	2,083.4	1,615.3	-	494.8	4,435.2
2034	99.8	154.8	2,083.4	2,322.5	-	494.8	5,155.3
2035	99.8	154.8	2,272.8	3,029.7	-	494.8	6,051.9
2036	46.6	193.5	2,651.6	3,029.7	-	494.8	6,416.2

Year	Scenario 34 minus Scenario 40 (Total Accredited Capacity)						
	Wind RFP	Generic Wind	Generic CT	Generic CC	Generic Coal	BD619 CCC1	Total
2012	-	-	-	-	-	-	-
2013	-	-	-	-	-	-	-
2014	-	-	-	-	-	-	-
2015	-	-	-	-	-	-	-
2016	-	-	-	-	-	-	-
2017	-	-	(189.4)	-	-	286.4	97.0
2018	-	-	(378.8)	-	-	286.4	(92.4)
2019	-	-	(378.8)	-	-	494.8	116.0
2020	-	-	(378.8)	-	-	494.8	116.0
2021	-	-	(378.8)	-	-	494.8	116.0
2022	-	-	(568.2)	-	-	494.8	(73.4)
2023	-	-	(378.8)	-	-	494.8	116.0
2024	-	-	(378.8)	(302.7)	-	494.8	(186.7)
2025	-	-	(189.4)	(302.7)	-	494.8	2.7
2026	-	-	(189.4)	(302.7)	-	494.8	2.7
2027	-	-	(189.4)	(302.7)	-	494.8	2.7
2028	-	-	(189.4)	(302.7)	-	494.8	2.7
2029	-	-	(189.4)	(302.7)	-	494.8	2.7
2030	-	-	(189.4)	(302.7)	-	494.8	2.7
2031	-	-	(189.4)	(302.7)	-	494.8	2.7
2032	-	-	(189.4)	(302.7)	-	494.8	2.7
2033	-	-	(189.4)	(302.7)	-	494.8	2.7
2034	-	-	(189.4)	(302.7)	-	494.8	2.7
2035	-	-	(189.4)	(302.7)	-	494.8	2.7
2036	-	-	(189.4)	(302.7)	-	494.8	2.7

Year	Scenario 36a (Total Accredited Capacity)						
	Wind RFP	Generic Wind	Generic CT	Generic CC	Generic Coal	ICT1 CCC1	Total
2012	-	-	-	-	-	-	-
2013	-	-	-	-	-	-	-
2014	-	-	-	-	-	-	-
2015	-	-	-	-	-	-	-
2016	-	-	-	-	-	154.5	154.5
2017	-	-	-	-	-	440.9	440.9
2018	-	-	-	-	-	440.9	440.9
2019	-	-	-	-	-	440.9	440.9
2020	-	-	-	-	-	440.9	440.9
2021	99.8	-	-	-	-	440.9	540.7
2022	99.8	-	-	-	-	440.9	540.7
2023	99.8	-	189.4	-	-	440.9	730.1
2024	99.8	-	189.4	-	-	440.9	730.1
2025	99.8	-	568.2	908.1	-	440.9	2,017.0
2026	99.8	-	568.2	908.1	-	440.9	2,017.0
2027	99.8	12.9	1,136.4	908.1	-	440.9	2,598.1
2028	99.8	12.9	1,515.2	908.1	-	440.9	2,976.9
2029	99.8	38.7	1,515.2	908.1	-	440.9	3,002.7
2030	99.8	38.7	1,704.6	908.1	-	440.9	3,192.1
2031	99.8	51.6	1,894.0	1,615.3	-	440.9	4,101.6
2032	99.8	77.4	2,083.4	1,615.3	-	440.9	4,316.8
2033	99.8	141.9	2,272.8	1,615.3	-	440.9	4,570.7
2034	99.8	154.8	2,272.8	2,322.5	-	440.9	5,290.8
2035	99.8	154.8	2,272.8	3,029.7	-	440.9	5,998.0
2036	46.6	193.5	2,841.0	3,029.7	-	286.4	6,397.2

Year	Scenario 36a minus Scenario 39 (Total Accredited Capacity)						
	Wind RFP	Generic Wind	Generic CT	Generic CC	Generic Coal	GPV1	Total
2012	-	-	-	-	-	-	-
2013	-	-	-	-	-	-	-
2014	-	-	-	-	-	-	-
2015	-	-	-	-	-	-	-
2016	-	-	-	-	-	154.5	154.5
2017	-	-	(189.4)	-	-	440.9	251.5
2018	-	-	(378.8)	-	-	440.9	62.1
2019	-	-	(378.8)	-	-	440.9	62.1
2020	-	-	(378.8)	-	-	440.9	62.1
2021	-	-	(378.8)	-	-	440.9	62.1
2022	-	-	(568.2)	-	-	440.9	(127.3)
2023	-	-	(378.8)	-	-	440.9	62.1
2024	-	-	(378.8)	(302.7)	-	440.9	(240.6)
2025	-	-	(189.4)	(302.7)	-	440.9	(51.2)
2026	-	-	(189.4)	(302.7)	-	440.9	(51.2)
2027	-	-	378.8	(1,009.9)	-	440.9	(190.2)
2028	-	-	568.2	(1,009.9)	-	440.9	(0.8)
2029	-	-	568.2	(1,009.9)	-	440.9	(0.8)
2030	-	-	568.2	(1,009.9)	-	440.9	(0.8)
2031	-	-	568.2	(1,009.9)	-	440.9	(0.8)
2032	-	-	568.2	(1,009.9)	-	440.9	(0.8)
2033	-	-	568.2	(1,009.9)	-	440.9	(0.8)
2034	-	-	568.2	(1,009.9)	-	440.9	(0.8)
2035	-	-	568.2	(1,009.9)	-	440.9	(0.8)
2036	-	-	757.6	(1,009.9)	-	286.4	34.1

Year	Scenario 38a (Total Accredited Capacity)						
	Wind RFP	Generic Wind	Generic CT	Generic CC	Generic Coal	ICT1 BD618	Total
2012	-	-	-	-	-	-	-
2013	-	-	-	-	-	-	-
2014	-	-	-	-	-	-	-
2015	-	-	-	-	-	-	-
2016	-	-	-	-	-	154.5	154.5
2017	-	-	-	-	-	154.5	154.5
2018	-	-	-	-	-	362.9	362.9
2019	-	-	-	-	-	362.9	362.9
2020	-	-	-	-	-	362.9	362.9
2021	99.8	-	-	-	-	362.9	462.7
2022	99.8	-	189.4	-	-	362.9	652.1
2023	99.8	-	189.4	-	-	362.9	652.1
2024	99.8	-	492.1	-	-	362.9	954.8
2025	99.8	-	681.5	908.1	-	362.9	2,052.3
2026	99.8	-	681.5	908.1	-	362.9	2,052.3
2027	99.8	12.9	1,249.7	908.1	-	362.9	2,633.4
2028	99.8	12.9	1,439.1	908.1	-	362.9	2,822.8
2029	99.8	38.7	1,628.5	908.1	-	362.9	3,038.0
2030	99.8	38.7	1,817.9	908.1	-	362.9	3,227.4
2031	99.8	51.6	1,817.9	1,615.3	-	362.9	3,947.5
2032	99.8	77.4	2,196.7	1,615.3	-	362.9	4,352.1
2033	99.8	141.9	2,196.7	1,615.3	-	362.9	4,416.6
2034	99.8	154.8	2,196.7	2,322.5	-	362.9	5,136.7
2035	99.8	154.8	2,386.1	3,029.7	-	362.9	6,033.3
2036	46.6	193.5	2,954.3	3,029.7	-	208.4	6,432.5

Year	Scenario 38a minus Scenario 39 (Total Accredited Capacity)						
	Wind RFP	Generic Wind	Generic CT	Generic CC	Generic Coal	GPV1	Total
2012	-	-	-	-	-	-	-
2013	-	-	-	-	-	-	-
2014	-	-	-	-	-	-	-
2015	-	-	-	-	-	-	-
2016	-	-	-	-	-	154.5	154.5
2017	-	-	(189.4)	-	-	154.5	(34.9)
2018	-	-	(378.8)	-	-	362.9	(15.9)
2019	-	-	(378.8)	-	-	362.9	(15.9)
2020	-	-	(378.8)	-	-	362.9	(15.9)
2021	-	-	(378.8)	-	-	362.9	(15.9)
2022	-	-	(378.8)	-	-	362.9	(15.9)
2023	-	-	(378.8)	-	-	362.9	(15.9)
2024	-	-	(76.1)	(302.7)	-	362.9	(15.9)
2025	-	-	(76.1)	(302.7)	-	362.9	(15.9)
2026	-	-	(76.1)	(302.7)	-	362.9	(15.9)
2027	-	-	492.1	(1,009.9)	-	362.9	(154.9)
2028	-	-	492.1	(1,009.9)	-	362.9	(154.9)
2029	-	-	681.5	(1,009.9)	-	362.9	34.5
2030	-	-	681.5	(1,009.9)	-	362.9	34.5
2031	-	-	492.1	(1,009.9)	-	362.9	(154.9)
2032	-	-	681.5	(1,009.9)	-	362.9	34.5
2033	-	-	492.1	(1,009.9)	-	362.9	(154.9)
2034	-	-	492.1	(1,009.9)	-	362.9	(154.9)
2035	-	-	681.5	(1,009.9)	-	362.9	34.5
2036	-	-	870.9	(1,009.9)	-	208.4	69.4

Year	Scenario 40 (Total Accredited Capacity)						
	Wind RFP	Generic Wind	Generic CT	Generic CC	Generic Coal	Bid Package	Total
2012	-	-	-	-	-	-	-
2013	-	-	-	-	-	-	-
2014	-	-	-	-	-	-	-
2015	-	-	-	-	-	-	-
2016	-	-	-	-	-	-	-
2017	-	-	189.4	-	-	-	189.4
2018	-	-	378.8	-	-	-	378.8
2019	-	-	378.8	-	-	-	378.8
2020	-	-	378.8	-	-	-	378.8
2021	99.8	-	378.8	-	-	-	478.6
2022	99.8	-	568.2	-	-	-	668.0
2023	99.8	-	568.2	-	-	-	668.0
2024	99.8	-	568.2	302.7	-	-	970.7
2025	99.8	-	757.6	1,210.8	-	-	2,068.2
2026	99.8	-	757.6	1,210.8	-	-	2,068.2
2027	99.8	12.9	1,325.8	1,210.8	-	-	2,649.3
2028	99.8	12.9	1,515.2	1,210.8	-	-	2,838.7
2029	99.8	38.7	1,704.6	1,210.8	-	-	3,053.9
2030	99.8	38.7	1,894.0	1,210.8	-	-	3,243.3
2031	99.8	51.6	1,894.0	1,918.0	-	-	3,963.4
2032	99.8	77.4	2,272.8	1,918.0	-	-	4,368.0
2033	99.8	141.9	2,272.8	1,918.0	-	-	4,432.5
2034	99.8	154.8	2,272.8	2,625.2	-	-	5,152.6
2035	99.8	154.8	2,462.2	3,332.4	-	-	6,049.2
2036	46.6	193.5	2,841.0	3,332.4	-	-	6,413.5

Contingency	PVSC ($, 000; ICT1 Interruptible Gas) Bid Package BD617 CCC1a	Bid Package BD617 ICT1a	Bid Package ICT1 CCC1a	Bid Package CCC1 ICT1a	Bid Package BASE CASE
BASE CASE	$ 41,258,564	$ 41,280,804	$ 41,310,372	$ 41,270,568	$ 41,396,524
CO2 Reduction	FAILED	FAILED	FAILED	FAILED	FAILED
$34 CO2	$ 44,970,000	$ 45,010,328	$ 45,043,556	$ 44,985,680	$ 45,115,540
$9 CO2	$ 37,722,140	$ 37,738,556	$ 37,777,884	$ 37,730,640	$ 37,853,036
Low Externalities	$ 40,895,864	$ 40,918,492	$ 40,947,832	$ 40,908,164	$ 41,034,260
High Market Price - 25%	$ 41,031,376	$ 41,049,724	$ 41,086,296	$ 41,038,584	$ 41,165,008
Low Market Price + 25%	$ 41,181,984	$ 41,157,812	$ 41,235,592	$ 41,184,060	$ 41,259,884
High Capital Cost + 10%	$ 41,551,332	$ 41,586,632	$ 41,612,076	$ 41,562,904	$ 41,738,012
Low Capital Cost - 10%	$ 40,961,064	$ 40,974,984	$ 41,008,672	$ 40,978,240	$ 41,047,264
High Coal + 20%	$ 42,427,904	$ 42,454,852	$ 42,486,804	$ 42,433,084	$ 42,567,168
High Coal + 10%	$ 41,855,368	$ 41,884,328	$ 41,911,856	$ 41,866,188	$ 41,994,872
Low Coal - 10%	$ 40,638,160	$ 40,660,692	$ 40,689,384	$ 40,650,744	$ 40,775,576
Low Coal - 20%	$ 40,005,496	$ 40,027,248	$ 40,056,744	$ 40,018,116	$ 40,141,884
Low Natural Gas - $1.50	$ 39,524,288	$ 39,529,000	$ 39,573,740	$ 39,533,416	$ 39,615,308
Low Natural Gas - $1.00	$ 40,172,180	$ 40,189,532	$ 40,221,108	$ 40,183,012	$ 40,281,532
Low Natural Gas - $0.50	$ 40,735,960	$ 40,766,968	$ 40,790,252	$ 40,745,584	$ 40,867,692
High Natural Gas + $0.50	$ 41,707,196	$ 41,763,416	$ 41,767,776	$ 41,714,260	$ 41,889,852
High Natural Gas + $1.00	$ 42,057,052	$ 42,158,600	$ 42,120,748	$ 42,058,996	$ 42,298,652
High Natural Gas + $1.50	$ 42,365,868	$ 42,504,624	$ 42,435,440	$ 42,364,804	$ 42,662,980
High Natural Gas + $2.00	$ 42,661,856	$ 42,842,016	$ 42,733,376	$ 42,653,332	$ 43,009,304
High Natural Gas + $2.50	$ 42,949,896	$ 43,160,336	$ 43,022,412	$ 42,935,624	$ 43,323,964
High Wind Credit + 25%	$ 41,218,560	$ 41,247,704	$ 41,268,964	$ 41,248,264	$ 41,348,436
Low Wind Credit - 25%	$ 41,301,780	$ 41,327,328	$ 41,345,576	$ 41,323,712	$ 41,427,900
High Forecast + 5%	$ 43,674,304	$ 43,721,648	$ 43,699,496	$ 43,661,976	$ 43,817,048
Mid-High Forecast + 2.5%	$ 42,465,584	$ 42,497,984	$ 42,485,616	$ 42,434,528	$ 42,601,828
Mid-Low Forecast - 2.5%	$ 40,145,956	$ 40,164,740	$ 40,179,328	$ 40,157,360	$ 40,216,780
Low Forecast - 5%	$ 39,064,212	$ 39,047,572	$ 39,084,200	$ 39,089,008	$ 39,084,848
Manitoba Hydro PPA Renew	$ 41,032,916	$ 41,059,052	$ 41,099,672	$ 41,061,220	$ 41,168,476
Maximum	$ 44,970,000	$ 45,010,328	$ 45,043,556	$ 44,985,680	$ 45,115,540
Average	$ 41,317,661	$ 41,360,184	$ 41,370,177	$ 41,325,632	$ 41,470,505
Minimum	$ 37,722,140	$ 37,738,556	$ 37,777,884	$ 37,730,640	$ 37,853,036

Contingency	PVSC Difference from Base Case, Same Contingency ($,000) Bid Package BD617 CCC1a	Bid Package BD617 ICT1a	Bid Package ICT1 CCC1a	Bid Package CCC1 ICT1a	Bid Package BASE CASE
BASE CASE	$ (137,960)	$ (115,720)	$ (86,152)	$ (125,956)	$ -
CO2 Reduction	FAILED	FAILED	FAILED	FAILED	FAILED
$34 CO2	$ (145,540)	$ (105,212)	$ (71,984)	$ (129,860)	$ -
$9 CO2	$ (130,896)	$ (114,480)	$ (75,152)	$ (122,396)	$ -
Low Externalities	$ (138,396)	$ (115,768)	$ (86,428)	$ (126,096)	$ -
High Market Price - 25%	$ (133,632)	$ (115,284)	$ (78,712)	$ (126,424)	$ -
Low Market Price + 25%	$ (77,900)	$ (102,072)	$ (24,292)	$ (75,824)	$ -
High Capital Cost + 10%	$ (186,680)	$ (151,380)	$ (125,936)	$ (175,108)	$ -
Low Capital Cost - 10%	$ (86,200)	$ (72,280)	$ (38,592)	$ (69,024)	$ -
High Coal + 20%	$ (139,264)	$ (112,316)	$ (80,364)	$ (134,084)	$ -
High Coal + 10%	$ (139,504)	$ (110,544)	$ (83,016)	$ (128,684)	$ -
Low Coal - 10%	$ (137,416)	$ (114,884)	$ (86,192)	$ (124,832)	$ -
Low Coal - 20%	$ (136,388)	$ (114,636)	$ (85,140)	$ (123,768)	$ -
Low Natural Gas - $1.50	$ (91,020)	$ (86,308)	$ (41,568)	$ (81,892)	$ -
Low Natural Gas - $1.00	$ (109,352)	$ (92,000)	$ (60,424)	$ (98,520)	$ -
Low Natural Gas - $0.50	$ (131,732)	$ (100,724)	$ (77,440)	$ (122,108)	$ -
High Natural Gas + $0.50	$ (182,656)	$ (126,436)	$ (122,076)	$ (175,592)	$ -
High Natural Gas + $1.00	$ (241,600)	$ (140,052)	$ (177,904)	$ (239,656)	$ -
High Natural Gas + $1.50	$ (297,112)	$ (158,356)	$ (227,540)	$ (298,176)	$ -
High Natural Gas + $2.00	$ (347,448)	$ (167,288)	$ (275,928)	$ (355,972)	$ -
High Natural Gas + $2.50	$ (374,068)	$ (163,628)	$ (301,552)	$ (388,340)	$ -
High Wind Credit + 25%	$ (129,876)	$ (100,732)	$ (79,472)	$ (100,172)	$ -
Low Wind Credit - 25%	$ (126,120)	$ (100,572)	$ (82,324)	$ (104,188)	$ -
High Forecast + 5%	$ (142,744)	$ (95,400)	$ (117,552)	$ (155,072)	$ -
Mid-High Forecast + 2.5%	$ (136,244)	$ (103,844)	$ (116,212)	$ (167,300)	$ -
Mid-Low Forecast - 2.5%	$ (70,824)	$ (52,040)	$ (37,452)	$ (59,420)	$ -
Low Forecast - 5%	$ (20,636)	$ (37,276)	$ (648)	$ 4,160	$ -
Manitoba Hydro PPA Renew	$ (135,560)	$ (109,424)	$ (68,804)	$ (107,256)	$ -
Maximum	$ (20,636)	$ (37,276)	$ (648)	$ 4,160	$ -
Average	$ (152,843)	$ (110,321)	$ (100,328)	$ (144,873)	$ -
Minimum	$ (374,068)	$ (167,288)	$ (301,552)	$ (388,340)	$ -

Contingency	PVSC Difference from Round 2, Same Contingency ($,000)			
	BD617 CCC1a MINUS BD619 CCC1	BD617 ICT1a MINUS ICT1 BD618	ICT1 CCC1a MINUS ICT1 CCC1	CCC1 ICT1a MINUS ICT1 CCC1
BASE CASE	$ (4,919)	$ (53,785)	$ (12,280)	$ (52,084)
CO2 Reduction	FAILED	FAILED	FAILED	FAILED
$34 CO2	$ 2,281	$ (50,273)	$ (1,988)	$ (59,864)
$9 CO2	$ (7,975)	$ (57,777)	$ (11,924)	$ (59,168)
Low Externalities	$ (4,935)	$ (53,721)	$ (12,308)	$ (51,976)
High Market Price + 25%	$ (5,703)	$ (57,109)	$ (10,684)	$ (58,396)
Low Market Price - 25%	$ (7,891)	$ (61,217)	$ (10,756)	$ (62,288)
High Capital Cost + 10%	$ (4,431)	$ (58,433)	$ (7,552)	$ (56,724)
Low Capital Cost - 10%	$ (4,915)	$ (46,557)	$ (16,992)	$ (47,424)
High Coal + 20%	$ 437	$ (58,053)	$ (7,712)	$ (61,432)
High Coal + 10%	$ (5,083)	$ (52,497)	$ (10,368)	$ (56,036)
Low Coal - 10%	$ (5,027)	$ (51,869)	$ (12,840)	$ (51,480)
Low Coal - 20%	$ (5,391)	$ (51,945)	$ (13,244)	$ (51,872)
Low Natural Gas - $1.50	$ (9,727)	$ (58,513)	$ (20,848)	$ (61,172)
Low Natural Gas - $1.00	$ (7,879)	$ (59,349)	$ (17,540)	$ (55,636)
Low Natural Gas - $0.50	$ (6,403)	$ (52,921)	$ (13,864)	$ (58,532)
High Natural Gas + $0.50	$ 41	$ (55,465)	$ (4,940)	$ (58,456)
High Natural Gas + $1.00	$ 5,313	$ (56,157)	$ 3,976	$ (57,776)
High Natural Gas + $1.50	$ 9,985	$ (57,893)	$ 17,228	$ (53,408)
High Natural Gas + $2.00	$ 17,261	$ (58,045)	$ 24,912	$ (55,132)
High Natural Gas + $2.50	$ 23,645	$ (58,833)	$ 27,948	$ (58,840)
High Wind Credit + 25%	$ (4,607)	$ (53,641)	$ (35,984)	$ (56,684)
Low Wind Credit - 25%	$ 20,349	$ (49,753)	$ (19,200)	$ (41,064)
High Forecast + 5%	$ 8,609	$ (45,969)	$ (5,928)	$ (43,448)
Mid-High Forecast + 2.5%	$ 27,781	$ (64,437)	$ 4,284	$ (46,804)
Mid-Low Forecast - 2.5%	$ (5,511)	$ (32,105)	$ (38,868)	$ (60,836)
Low Forecast - 5%	$ (7,867)	$ (56,133)	$ (40,880)	$ (36,072)
Manitoba Hydro PPA Renew	$ (3,599)	$ (51,409)	$ (10,232)	$ (48,684)
Maximum	$ 27,781	$ (32,105)	$ 27,948	$ (36,072)
Average	$ 513	$ (54,217)	$ (9,577)	$ (54,121)
Minimum	$ (9,727)	$ (64,437)	$ (40,880)	$ (62,288)

Contingency	Rank			
	Bid Package BD617 CCC1a	Bid Package BD617 ICT1a	Bid Package ICT1 CCC1a	Bid Package CCC1 ICT1a
BASE CASE	1	3	4	2
CO2 Reduction	FAILED	FAILED	FAILED	FAILED
$34 CO2	1	3	4	2
$9 CO2	1	3	4	2
Low Externalities	1	3	4	2
High Market Price + 25%	1	3	4	2
Low Market Price - 25%	2	1	4	3
High Capital Cost + 10%	1	3	4	2
Low Capital Cost - 10%	1	2	4	3
High Coal + 20%	1	3	4	2
High Coal + 10%	1	3	4	2
Low Coal - 10%	1	3	4	2
Low Coal - 20%	1	3	4	2
Low Natural Gas - $1.50	1	2	4	3
Low Natural Gas - $1.00	1	3	4	2
Low Natural Gas - $0.50	1	3	4	2
High Natural Gas + $0.50	1	3	4	2
High Natural Gas + $1.00	1	4	3	2
High Natural Gas + $1.50	2	4	3	1
High Natural Gas + $2.00	2	4	3	1
High Natural Gas + $2.50	2	4	3	1
High Wind Credit + 25%	1	2	4	3
Low Wind Credit - 25%	1	3	4	2
High Forecast + 5%	2	4	3	1
Mid-High Forecast + 2.5%	2	4	3	1
Mid-Low Forecast - 2.5%	1	3	4	2
Low Forecast - 5%	2	1	3	5
Manitoba Hydro PPA Renew	1	2	4	3

Contingency	Year 1st Generic Unit Added Bid Package BD617 CCC1a	Bid Package BD617 ICT1a	Bid Package ICT1 CCC1a	Bid Package CCC1 ICT1a
Base Conditions	2024 & on	2022	2018	2024 & on
CO2 Reduction	FAILED	FAILED	FAILED	FAILED
$34 CO2	2023	2022	2018	2023
$9 CO2	2023	2022	2018	2023
Low Externalities	2023	2022	2018	2023
High Market Price + 25%	2023	2022	2018	2023
Low Market Price - 25%	2023	2022	2018	2023
High Capital Cost + 10%	2023	2022	2018	2023
Low Capital Cost - 10%	2023	2022	2018	2023
High Coal + 20%	2023	2022	2018	2023
High Coal + 10%	2023	2022	2018	2023
Low Coal - 10%	2023	2022	2018	2023
Low Coal - 20%	2023	2022	2018	2023
Low Natural Gas - $1.50	2023	2022	2018	2023
Low Natural Gas - $1.00	2023	2022	2018	2023
Low Natural Gas - $0.50	2023	2022	2018	2023
High Natural Gas + $0.50	2023	2022	2018	2023
High Natural Gas + $1.00	2023	2022	2018	2023
High Natural Gas + $1.50	2023	2022	2018	2023
High Natural Gas + $2.00	2023	2022	2018	2023
High Natural Gas + $2.50	2023	2022	2018	2023
High Wind Credit + 25%	2024	2023	2023	2023
Low Wind Credit - 25%	2018	2018	2018	2022
High Forecast + 5%	2017	2017	2017	2017
Mid-High Forecast + 2.5%	2017	2017	2017	2017
Mid-Low Forecast - 2.5%	2025 & on	2025 & on	2025 & on	2025 & on
Low Forecast - 5%	2025 & on	2025 & on	2025 & on	2025 & on
Manitoba Hydro PPA Renew	2023	2022	2018	2023

Contingency	PVSC ($, 000; No CO2; ICT1 Interruptible Gas) Bid Package BD617 CCC1a	Bid Package BD617 ICT1a	Bid Package ICT1 CCC1a	Bid Package CCC1 ICT1a	Bid Package BASE CASE
BASE CASE	$ 34,735,780	$ 34,757,428	$ 34,794,096	$ 34,746,984	$ 34,876,344
CO2 Reduction	FAILED	FAILED	FAILED	FAILED	FAILED
$34 CO2	$ 34,735,780	$ 34,757,428	$ 34,794,096	$ 34,746,984	$ 34,876,344
$9 CO2	$ 34,735,780	$ 34,757,428	$ 34,794,096	$ 34,746,984	$ 34,876,344
Low Externalities	$ 34,735,780	$ 34,757,428	$ 34,794,096	$ 34,746,984	$ 34,876,344
High Market Price - 25%	$ 34,750,196	$ 34,771,196	$ 34,807,356	$ 34,761,192	$ 34,887,436
Low Market Price + 25%	$ 34,393,808	$ 34,373,288	$ 34,447,660	$ 34,397,332	$ 34,478,664
High Capital Cost + 10%	$ 35,018,336	$ 35,056,316	$ 35,087,920	$ 35,031,516	$ 35,201,900
Low Capital Cost - 10%	$ 34,453,224	$ 34,456,000	$ 34,499,416	$ 34,459,652	$ 34,536,788
High Coal + 20%	$ 35,972,108	$ 35,993,688	$ 36,030,488	$ 35,983,404	$ 36,112,608
High Coal + 10%	$ 35,357,180	$ 35,378,812	$ 35,415,380	$ 35,368,416	$ 35,497,724
Low Coal - 10%	$ 34,109,572	$ 34,131,232	$ 34,167,896	$ 34,120,724	$ 34,250,160
Low Coal - 20%	$ 33,477,818	$ 33,499,480	$ 33,536,088	$ 33,488,936	$ 33,618,460
Low Natural Gas - $1.50	$ 33,441,424	$ 33,442,272	$ 33,489,486	$ 33,447,750	$ 33,530,790
Low Natural Gas - $1.00	$ 33,914,764	$ 33,927,124	$ 33,966,532	$ 33,924,960	$ 34,023,304
Low Natural Gas - $0.50	$ 34,336,824	$ 34,357,660	$ 34,391,852	$ 34,348,612	$ 34,464,256
High Natural Gas + $0.50	$ 35,084,236	$ 35,136,040	$ 35,145,852	$ 35,094,064	$ 35,265,648
High Natural Gas + $1.00	$ 35,402,192	$ 35,487,080	$ 35,467,812	$ 35,409,356	$ 35,629,024
High Natural Gas + $1.50	$ 35,693,296	$ 35,809,748	$ 35,761,980	$ 35,695,708	$ 35,960,672
High Natural Gas + $2.00	$ 35,961,660	$ 36,110,800	$ 36,031,080	$ 35,961,244	$ 36,272,600
High Natural Gas + $2.50	$ 36,216,576	$ 36,396,532	$ 36,283,152	$ 36,209,036	$ 36,568,180
High Wind Credit + 25%	$ 34,700,192	$ 34,721,048	$ 34,747,416	$ 34,726,996	$ 34,815,724
Low Wind Credit - 25%	$ 34,781,820	$ 34,813,776	$ 34,831,980	$ 34,796,632	$ 34,904,824
High Forecast + 5%	$ 36,773,460	$ 36,807,604	$ 36,821,360	$ 36,811,832	$ 36,935,184
Mid-High Forecast + 2.5%	$ 35,761,132	$ 35,776,956	$ 35,806,780	$ 35,754,108	$ 35,876,116
Mid-Low Forecast - 2.5%	$ 33,797,260	$ 33,800,460	$ 33,826,904	$ 33,808,832	$ 33,876,828
Low Forecast - 5%	$ 32,895,788	$ 32,901,010	$ 32,925,536	$ 32,908,972	$ 32,925,974
Manitoba Hydro PPA Renew	$ 34,594,388	$ 34,638,588	$ 34,663,820	$ 34,622,180	$ 34,744,064
Maximum	$ 36,773,460	$ 36,807,604	$ 36,821,360	$ 36,811,832	$ 36,935,184
Average	$ 34,808,532	$ 34,845,053	$ 34,864,079	$ 34,819,237	$ 34,958,604
Minimum	$ 32,895,788	$ 32,901,010	$ 32,925,536	$ 32,908,972	$ 32,925,974

Contingency	PVSC Difference from Base Case, Same Contingency ($,000) Bid Package BD617 CCC1a	Bid Package BD617 ICT1a	Bid Package ICT1 CCC1a	Bid Package CCC1 ICT1a	Bid Package BASE CASE
BASE CASE	$ (140,564)	$ (118,916)	$ (82,248)	$ (129,360)	$ -
CO2 Reduction	FAILED	FAILED	FAILED	FAILED	FAILED
$34 CO2	$ (140,564)	$ (118,916)	$ (82,248)	$ (129,360)	$ -
$9 CO2	$ (140,564)	$ (118,916)	$ (82,248)	$ (129,360)	$ -
Low Externalities	$ (140,564)	$ (118,916)	$ (82,248)	$ (129,360)	$ -
High Market Price - 25%	$ (137,240)	$ (116,240)	$ (80,080)	$ (126,244)	$ -
Low Market Price + 25%	$ (84,856)	$ (105,376)	$ (31,004)	$ (81,332)	$ -
High Capital Cost + 10%	$ (183,564)	$ (145,584)	$ (113,980)	$ (170,384)	$ -
Low Capital Cost - 10%	$ (83,564)	$ (80,788)	$ (37,372)	$ (77,136)	$ -
High Coal + 20%	$ (140,500)	$ (118,920)	$ (82,120)	$ (129,204)	$ -
High Coal + 10%	$ (140,544)	$ (118,912)	$ (82,344)	$ (129,308)	$ -
Low Coal - 10%	$ (140,588)	$ (118,928)	$ (82,264)	$ (129,436)	$ -
Low Coal - 20%	$ (140,642)	$ (118,980)	$ (82,372)	$ (129,524)	$ -
Low Natural Gas - $1.50	$ (89,366)	$ (88,518)	$ (41,304)	$ (83,040)	$ -
Low Natural Gas - $1.00	$ (108,540)	$ (96,180)	$ (56,772)	$ (98,344)	$ -
Low Natural Gas - $0.50	$ (127,432)	$ (106,596)	$ (72,404)	$ (115,644)	$ -
High Natural Gas + $0.50	$ (181,412)	$ (129,608)	$ (119,796)	$ (171,584)	$ -
High Natural Gas + $1.00	$ (226,832)	$ (141,944)	$ (161,212)	$ (219,668)	$ -
High Natural Gas + $1.50	$ (267,376)	$ (150,924)	$ (198,692)	$ (264,964)	$ -
High Natural Gas + $2.00	$ (310,940)	$ (161,800)	$ (241,520)	$ (311,356)	$ -
High Natural Gas + $2.50	$ (351,604)	$ (171,648)	$ (285,028)	$ (359,144)	$ -
High Wind Credit + 25%	$ (115,532)	$ (94,676)	$ (68,308)	$ (88,728)	$ -
Low Wind Credit - 25%	$ (123,004)	$ (91,048)	$ (72,844)	$ (108,192)	$ -
High Forecast + 5%	$ (161,724)	$ (127,580)	$ (113,824)	$ (123,352)	$ -
Mid-High Forecast + 2.5%	$ (114,984)	$ (99,160)	$ (69,336)	$ (122,008)	$ -
Mid-Low Forecast - 2.5%	$ (79,568)	$ (76,368)	$ (49,924)	$ (67,996)	$ -
Low Forecast - 5%	$ (30,186)	$ (24,964)	$ (438)	$ (17,002)	$ -
Manitoba Hydro PPA Renew	$ (149,676)	$ (105,476)	$ (80,244)	$ (121,884)	$ -
Maximum	$ (30,186)	$ (24,964)	$ (438)	$ (17,002)	$ -
Average	$ (150,071)	$ (113,551)	$ (94,525)	$ (139,367)	$ -
Minimum	$ (351,604)	$ (171,648)	$ (285,028)	$ (359,144)	$ -

Contingency	PVSC Difference from Round 2, Same Contingency ($,000)			
	BD617 CCC1a MINUS BD619 CCC1	BD617 ICT1a MINUS ICT1 BD618	ICT1 CCC1a MINUS ICT1 CCC1	CCC1 ICT1a MINUS ICT1 CCC1
BASE CASE	$ (8,643)	$ (57,969)	$ (13,444)	$ (60,556)
CO2 Reduction	FAILED	FAILED	FAILED	FAILED
$34 CO2	$ 13,005	$ (57,969)	$ (13,444)	$ (60,556)
$9 CO2	$ 13,005	$ (57,969)	$ (13,444)	$ (60,556)
Low Externalities	$ 13,005	$ (57,969)	$ (13,444)	$ (60,556)
High Market Price + 25%	$ 12,753	$ (58,313)	$ (13,440)	$ (59,604)
Low Market Price - 25%	$ (30,547)	$ (60,109)	$ (11,268)	$ (61,596)
High Capital Cost + 10%	$ 29,341	$ (62,621)	$ (8,776)	$ (65,180)
Low Capital Cost - 10%	$ (5,875)	$ (54,281)	$ (15,924)	$ (55,688)
High Coal + 20%	$ 12,925	$ (58,029)	$ (13,468)	$ (60,552)
High Coal + 10%	$ 12,989	$ (57,901)	$ (13,456)	$ (60,420)
Low Coal - 10%	$ 13,025	$ (57,933)	$ (13,436)	$ (60,608)
Low Coal - 20%	$ 13,033	$ (57,871)	$ (13,430)	$ (60,582)
Low Natural Gas - $1.50	$ (11,277)	$ (60,157)	$ (20,054)	$ (61,790)
Low Natural Gas - $1.00	$ 1,237	$ (58,309)	$ (19,068)	$ (60,640)
Low Natural Gas - $0.50	$ 10,873	$ (57,253)	$ (17,020)	$ (60,260)
High Natural Gas + $0.50	$ 46,381	$ (57,333)	$ (8,344)	$ (60,132)
High Natural Gas + $1.00	$ 83,825	$ (58,465)	$ (1,688)	$ (60,144)
High Natural Gas + $1.50	$ 120,081	$ (55,093)	$ 4,840	$ (61,432)
High Natural Gas + $2.00	$ 157,153	$ (55,809)	$ 9,856	$ (59,980)
High Natural Gas + $2.50	$ 191,385	$ (57,789)	$ 15,424	$ (58,692)
High Wind Credit + 25%	$ 11,493	$ (48,877)	$ (40,140)	$ (60,560)
Low Wind Credit - 25%	$ 50,989	$ (42,453)	$ (22,948)	$ (58,296)
High Forecast + 5%	$ 36,773	$ (59,125)	$ (13,468)	$ (22,996)
Mid-High Forecast + 2.5%	$ 34,893	$ (65,661)	$ 2,344	$ (50,328)
Mid-Low Forecast - 2.5%	$ (6,679)	$ (58,513)	$ (42,488)	$ (60,560)
Low Forecast - 5%	$ (5,675)	$ (40,253)	$ (44,564)	$ (61,128)
Manitoba Hydro PPA Renew	$ 35,581	$ (48,665)	$ (12,684)	$ (54,324)
Maximum	$ 191,385	$ (40,253)	$ 15,424	$ (22,996)
Average	$ 31,298	$ (56,396)	$ (13,591)	$ (58,434)
Minimum	$ (30,547)	$ (65,661)	$ (44,564)	$ (65,180)

Contingency	Rank			
	Bid Package BD617 CCC1a	Bid Package BD617 ICT1a	Bid Package ICT1 CCC1a	Bid Package CCC1 ICT1a
BASE CASE	1	3	4	2
CO2 Reduction	FAILED	FAILED	FAILED	FAILED
$34 CO2	1	3	4	2
$9 CO2	1	3	4	2
Low Externalities	1	3	4	2
High Market Price + 25%	1	3	4	2
Low Market Price - 25%	2	1	4	3
High Capital Cost + 10%	1	3	4	2
Low Capital Cost - 10%	1	2	4	3
High Coal + 20%	1	3	4	2
High Coal + 10%	1	3	4	2
Low Coal - 10%	1	3	4	2
Low Coal - 20%	1	3	4	2
Low Natural Gas - $1.50	1	2	4	3
Low Natural Gas - $1.00	1	3	4	2
Low Natural Gas - $0.50	1	3	4	2
High Natural Gas + $0.50	1	3	4	2
High Natural Gas + $1.00	1	4	3	2
High Natural Gas + $1.50	1	4	3	2
High Natural Gas + $2.00	2	4	3	1
High Natural Gas + $2.50	2	4	3	1
High Wind Credit + 25%	1	2	4	3
Low Wind Credit - 25%	1	3	4	2
High Forecast + 5%	1	2	4	3
Mid-High Forecast + 2.5%	2	3	4	1
Mid-Low Forecast - 2.5%	1	2	4	3
Low Forecast - 5%	1	2	4	3
Manitoba Hydro PPA Renew	1	3	4	2

Contingency	Year 1st Generic Unit Added Bid Package BD617 CCC1a	Bid Package BD617 ICT1a	Bid Package ICT1 CCC1a	Bid Package CCC1 ICT1a
Base Conditions	2023	2022	2018	2023
CO2 Reduction	FAILED	FAILED	FAILED	FAILED
$34 CO2	2023	2022	2018	2023
$9 CO2	2023	2022	2018	2023
Low Externalities	2023	2022	2018	2023
High Market Price + 25%	2023	2022	2018	2023
Low Market Price - 25%	2023	2022	2018	2023
High Capital Cost + 10%	2023	2022	2018	2023
Low Capital Cost - 10%	2023	2022	2018	2023
High Coal + 20%	2023	2022	2018	2023
High Coal + 10%	2023	2022	2018	2023
Low Coal - 10%	2023	2022	2018	2023
Low Coal - 20%	2023	2022	2018	2023
Low Natural Gas - $1.50	2023	2022	2018	2023
Low Natural Gas - $1.00	2023	2022	2018	2023
Low Natural Gas - $0.50	2023	2022	2018	2023
High Natural Gas + $0.50	2023	2022	2018	2023
High Natural Gas + $1.00	2023	2022	2018	2023
High Natural Gas + $1.50	2023	2022	2018	2023
High Natural Gas + $2.00	2023	2022	2018	2023
High Natural Gas + $2.50	2023	2022	2018	2023
High Wind Credit + 25%	2024	2023	2023	2023
Low Wind Credit - 25%	2018	2018	2018	2022
High Forecast + 5%	2017	2017	2017	2017
Mid-High Forecast + 2.5%	2017	2017	2017	2017
Mid-Low Forecast - 2.5%	2025 & on	2025 & on	2025 & on	2025 & on
Low Forecast - 5%	2025 & on	2025 & on	2025 & on	2025 & on
Manitoba Hydro PPA Renew	2023	2022	2018	2023

Year	Scenario 41 (Total Accredited Capacity)						
	Wind RFP	Generic Wind	Generic CT	Generic CC	Generic Coal	BD617 CCC1a	Total
2012	-	-	-	-	-	-	-
2013	-	-	-	-	-	-	-
2014	-	-	-	-	-	-	-
2015	-	-	-	-	-	-	-
2016	-	-	-	-	-	-	-
2017	-	-	-	-	-	208.4	208.4
2018	-	-	-	-	-	208.4	208.4
2019	-	-	-	-	-	494.8	494.8
2020	-	-	-	-	-	494.8	494.8
2021	99.8	-	-	-	-	494.8	594.6
2022	99.8	-	-	-	-	494.8	594.6
2023	99.8	-	189.4	-	-	494.8	784.0
2024	99.8	-	189.4	-	-	494.8	784.0
2025	99.8	-	568.2	908.1	-	494.8	2,070.9
2026	99.8	-	568.2	908.1	-	494.8	2,070.9
2027	99.8	12.9	568.2	1,615.3	-	494.8	2,791.0
2028	99.8	12.9	757.6	1,615.3	-	494.8	2,980.4
2029	99.8	38.7	757.6	1,615.3	-	494.8	3,006.2
2030	99.8	38.7	947.0	1,615.3	-	494.8	3,195.6
2031	99.8	51.6	1,136.4	2,322.5	-	494.8	4,105.1
2032	99.8	77.4	1,325.8	2,322.5	-	494.8	4,320.3
2033	99.8	141.9	1,515.2	2,322.5	-	494.8	4,574.2
2034	99.8	154.8	1,515.2	3,029.7	-	494.8	5,294.3
2035	99.8	154.8	1,515.2	3,736.9	-	494.8	6,001.5
2036	46.6	193.5	1,894.0	3,736.9	-	494.8	6,365.8

Year	Scenario 41 minus Scenario 39 (Total Accredited Capacity)						
	Wind RFP	Generic Wind	Generic CT	Generic CC	Generic Coal	BD617 CCC1a	Total
2012	-	-	-	-	-	-	-
2013	-	-	-	-	-	-	-
2014	-	-	-	-	-	-	-
2015	-	-	-	-	-	-	-
2016	-	-	-	-	-	-	-
2017	-	-	(189.4)	-	-	208.4	19.0
2018	-	-	(378.8)	-	-	208.4	(170.4)
2019	-	-	(378.8)	-	-	494.8	116.0
2020	-	-	(378.8)	-	-	494.8	116.0
2021	-	-	(378.8)	-	-	494.8	116.0
2022	-	-	(568.2)	-	-	494.8	(73.4)
2023	-	-	(378.8)	-	-	494.8	116.0
2024	-	-	(378.8)	(302.7)	-	494.8	(186.7)
2025	-	-	(189.4)	(302.7)	-	494.8	2.7
2026	-	-	(189.4)	(302.7)	-	494.8	2.7
2027	-	-	(189.4)	(302.7)	-	494.8	2.7
2028	-	-	(189.4)	(302.7)	-	494.8	2.7
2029	-	-	(189.4)	(302.7)	-	494.8	2.7
2030	-	-	(189.4)	(302.7)	-	494.8	2.7
2031	-	-	(189.4)	(302.7)	-	494.8	2.7
2032	-	-	(189.4)	(302.7)	-	494.8	2.7
2033	-	-	(189.4)	(302.7)	-	494.8	2.7
2034	-	-	(189.4)	(302.7)	-	494.8	2.7
2035	-	-	(189.4)	(302.7)	-	494.8	2.7
2036	-	-	(189.4)	(302.7)	-	494.8	2.7

Year	Scenario 43 (Total Accredited Capacity)						
	Wind RFP	Generic Wind	Generic CT	Generic CC	Generic Coal	BD617 ICT1a	Total
2012	-	-	-	-	-	-	-
2013	-	-	-	-	-	-	-
2014	-	-	-	-	-	-	-
2015	-	-	-	-	-	-	-
2016	-	-	-	-	-	-	-
2017	-	-	-	-	-	208.4	208.4
2018	-	-	-	-	-	208.4	208.4
2019	-	-	-	-	-	362.9	362.9
2020	-	-	-	-	-	362.9	362.9
2021	99.8	-	-	-	-	362.9	462.7
2022	99.8	-	189.4	-	-	362.9	652.1
2023	99.8	-	189.4	-	-	362.9	652.1
2024	99.8	-	378.8	-	-	362.9	841.5
2025	99.8	-	568.2	908.1	-	362.9	1,939.0
2026	99.8	-	568.2	908.1	-	362.9	1,939.0
2027	99.8	12.9	568.2	1,615.3	-	362.9	2,659.1
2028	99.8	12.9	757.6	1,615.3	-	362.9	2,848.5
2029	99.8	38.7	947.0	1,615.3	-	362.9	3,063.7
2030	99.8	38.7	1,136.4	1,615.3	-	362.9	3,253.1
2031	99.8	51.6	1,136.4	2,322.5	-	362.9	3,973.2
2032	99.8	77.4	1,515.2	2,322.5	-	362.9	4,377.8
2033	99.8	141.9	1,515.2	2,322.5	-	362.9	4,442.3
2034	99.8	154.8	1,515.2	3,029.7	-	362.9	5,162.4
2035	99.8	154.8	1,704.6	3,736.9	-	362.9	6,059.0
2036	46.6	193.5	2,083.4	3,736.9	-	362.9	6,423.3

Year	Scenario 43 minus Scenario 39 (Total Accredited Capacity)						
	Wind RFP	Generic Wind	Generic CT	Generic CC	Generic Coal	BD617 ICT1a	Total
2012	-	-	-	-	-	-	-
2013	-	-	-	-	-	-	-
2014	-	-	-	-	-	-	-
2015	-	-	-	-	-	-	-
2016	-	-	-	-	-	-	-
2017	-	-	-	-	-	208.4	208.4
2018	-	-	-	-	-	208.4	208.4
2019	-	-	-	-	-	362.9	362.9
2020	-	-	-	-	-	362.9	362.9
2021	99.8	-	-	-	-	362.9	462.7
2022	99.8	-	189.4	-	-	362.9	652.1
2023	99.8	-	189.4	-	-	362.9	652.1
2024	99.8	-	378.8	-	-	362.9	841.5
2025	99.8	-	568.2	908.1	-	362.9	1,939.0
2026	99.8	-	568.2	908.1	-	362.9	1,939.0
2027	99.8	12.9	568.2	1,615.3	-	362.9	2,659.1
2028	99.8	12.9	757.6	1,615.3	-	362.9	2,848.5
2029	99.8	38.7	947.0	1,615.3	-	362.9	3,063.7
2030	99.8	38.7	1,136.4	1,615.3	-	362.9	3,253.1
2031	99.8	51.6	1,136.4	2,322.5	-	362.9	3,973.2
2032	99.8	77.4	1,515.2	2,322.5	-	362.9	4,377.8
2033	99.8	141.9	1,515.2	2,322.5	-	362.9	4,442.3
2034	99.8	154.8	1,515.2	3,029.7	-	362.9	5,162.4
2035	99.8	154.8	1,704.6	3,736.9	-	362.9	6,059.0
2036	46.6	193.5	2,083.4	3,736.9	-	362.9	6,423.3

	Scenario 45 (Total Accredited Capacity)						
Year	Wind RFP	Generic Wind	Generic CT	Generic CC	Generic Coal	ICT1 CCC1a	Total
2012	-	-	-	-	-	-	-
2013	-	-	-	-	-	-	-
2014	-	-	-	-	-	-	-
2015	-	-	-	-	-	-	-
2016	-	-	-	-	-	154.5	154.5
2017	-	-	-	-	-	154.5	154.5
2018	-	-	189.4	-	-	154.5	343.9
2019	-	-	189.4	-	-	440.9	630.3
2020	-	-	189.4	-	-	440.9	630.3
2021	-	99.8	189.4	-	-	440.9	730.1
2022	-	99.8	189.4	-	-	440.9	730.1
2023	-	99.8	189.4	-	-	440.9	730.1
2024	-	99.8	189.4	-	-	440.9	730.1
2025	-	99.8	757.6	605.4	-	440.9	1,903.7
2026	-	99.8	947.0	605.4	-	440.9	2,093.1
2027	12.9	99.8	947.0	1,312.6	-	440.9	2,813.2
2028	12.9	99.8	947.0	1,312.6	-	440.9	2,813.2
2029	38.7	99.8	1,136.4	1,312.6	-	440.9	3,028.4
2030	38.7	99.8	1,325.8	1,312.6	-	440.9	3,217.8
2031	51.6	99.8	1,515.2	2,019.8	-	440.9	4,127.3
2032	77.4	99.8	1,704.6	2,019.8	-	440.9	4,342.5
2033	141.9	99.8	1,704.6	2,019.8	-	440.9	4,407.0
2034	154.8	99.8	1,704.6	2,727.0	-	440.9	5,127.1
2035	154.8	99.8	1,894.0	3,434.2	-	440.9	6,023.7
2036	193.5	46.6	2,462.2	3,434.2	-	286.4	6,422.9

Year	Scenario 45 minus Scenario 39 (Total Accredited Capacity)						
	Wind RFP	Generic Wind	Generic CT	Generic CC	Generic Coal	ICT1 CCC1a	Total
2012	-	-	-	-	-	-	-
2013	-	-	-	-	-	-	-
2014	-	-	-	-	-	-	-
2015	-	-	-	-	-	-	-
2016	-	-	-	-	-	154.5	154.5
2017	-	-	-	-	-	154.5	154.5
2018	-	-	189.4	-	-	154.5	343.9
2019	-	-	189.4	-	-	440.9	630.3
2020	-	-	189.4	-	-	440.9	630.3
2021	-	99.8	189.4	-	-	440.9	730.1
2022	-	99.8	189.4	-	-	440.9	730.1
2023	-	99.8	189.4	-	-	440.9	730.1
2024	-	99.8	189.4	-	-	440.9	730.1
2025	-	99.8	757.6	605.4	-	440.9	1,903.7
2026	-	99.8	947.0	605.4	-	440.9	2,093.1
2027	12.9	99.8	947.0	1,312.6	-	440.9	2,813.2
2028	12.9	99.8	947.0	1,312.6	-	440.9	2,813.2
2029	38.7	99.8	1,136.4	1,312.6	-	440.9	3,028.4
2030	38.7	99.8	1,325.8	1,312.6	-	440.9	3,217.8
2031	51.6	99.8	1,515.2	2,019.8	-	440.9	4,127.3
2032	77.4	99.8	1,704.6	2,019.8	-	440.9	4,342.5
2033	141.9	99.8	1,704.6	2,019.8	-	440.9	4,407.0
2034	154.8	99.8	1,704.6	2,727.0	-	440.9	5,127.1
2035	154.8	99.8	1,894.0	3,434.2	-	440.9	6,023.7
2036	193.5	46.6	2,462.2	3,434.2	-	286.4	6,422.9

Year	Scenario 47 (Total Accredited Capacity)						
	Wind RFP	Generic Wind	Generic CT	Generic CC	Generic Coal	CCC1 ICT1a	Total
2012	-	-	-	-	-	-	-
2013	-	-	-	-	-	-	-
2014	-	-	-	-	-	-	-
2015	-	-	-	-	-	-	-
2016	-	-	-	-	-	-	-
2017	-	-	-	-	-	286.4	286.4
2018	-	-	-	-	-	286.4	286.4
2019	-	-	-	-	-	440.9	440.9
2020	-	-	-	-	-	440.9	440.9
2021	99.8	-	-	-	-	440.9	540.7
2022	99.8	-	-	-	-	440.9	540.7
2023	99.8	-	189.4	-	-	440.9	730.1
2024	99.8	-	189.4	-	-	440.9	730.1
2025	99.8	-	757.6	605.4	-	440.9	1,903.7
2026	99.8	-	947.0	605.4	-	440.9	2,093.1
2027	99.8	12.9	947.0	1,312.6	-	440.9	2,813.2
2028	99.8	12.9	947.0	1,312.6	-	440.9	2,813.2
2029	99.8	38.7	1,136.4	1,312.6	-	440.9	3,028.4
2030	99.8	38.7	1,325.8	1,312.6	-	440.9	3,217.8
2031	99.8	51.6	1,515.2	2,019.8	-	440.9	4,127.3
2032	99.8	77.4	1,704.6	2,019.8	-	440.9	4,342.5
2033	99.8	141.9	1,704.6	2,019.8	-	440.9	4,407.0
2034	99.8	154.8	1,704.6	2,727.0	-	440.9	5,127.1
2035	99.8	154.8	1,894.0	3,434.2	-	440.9	6,023.7
2036	46.6	193.5	2,272.8	3,434.2	-	440.9	6,388.0

Year	Scenario 47 minus Scenario 39 (Total Accredited Capacity)						
	Wind RFP	Generic Wind	Generic CT	Generic CC	Generic Coal	CCC1 ICT1a	Total
2012	-	-	-	-	-	-	-
2013	-	-	-	-	-	-	-
2014	-	-	-	-	-	-	-
2015	-	-	-	-	-	-	-
2016	-	-	-	-	-	-	-
2017	-	-	-	-	-	286.4	286.4
2018	-	-	-	-	-	286.4	286.4
2019	-	-	-	-	-	440.9	440.9
2020	-	-	-	-	-	440.9	440.9
2021	99.8	-	-	-	-	440.9	540.7
2022	99.8	-	-	-	-	440.9	540.7
2023	99.8	-	189.4	-	-	440.9	730.1
2024	99.8	-	189.4	-	-	440.9	730.1
2025	99.8	-	757.6	605.4	-	440.9	1,903.7
2026	99.8	-	947.0	605.4	-	440.9	2,093.1
2027	99.8	12.9	947.0	1,312.6	-	440.9	2,813.2
2028	99.8	12.9	947.0	1,312.6	-	440.9	2,813.2
2029	99.8	38.7	1,136.4	1,312.6	-	440.9	3,028.4
2030	99.8	38.7	1,325.8	1,312.6	-	440.9	3,217.8
2031	99.8	51.6	1,515.2	2,019.8	-	440.9	4,127.3
2032	99.8	77.4	1,704.6	2,019.8	-	440.9	4,342.5
2033	99.8	141.9	1,704.6	2,019.8	-	440.9	4,407.0
2034	99.8	154.8	1,704.6	2,727.0	-	440.9	5,127.1
2035	99.8	154.8	1,894.0	3,434.2	-	440.9	6,023.7
2036	46.6	193.5	2,272.8	3,434.2	-	440.9	6,388.0

Year	Scenario 39 (Total Accredited Capacity)						
	Wind RFP	Generic Wind	Generic CT	Generic CC	Generic Coal	Bid Package	Total
2012	-	-	-	-	-	-	-
2013	-	-	-	-	-	-	-
2014	-	-	-	-	-	-	-
2015	-	-	-	-	-	-	-
2016	-	-	-	-	-	-	-
2017	-	-	189.4	-	-	-	189.4
2018	-	-	378.8	-	-	-	378.8
2019	-	-	378.8	-	-	-	378.8
2020	-	-	378.8	-	-	-	378.8
2021	99.8	-	378.8	-	-	-	478.6
2022	99.8	-	568.2	-	-	-	668.0
2023	99.8	-	568.2	-	-	-	668.0
2024	99.8	-	568.2	302.7	-	-	970.7
2025	99.8	-	757.6	1,210.8	-	-	2,068.2
2026	99.8	-	757.6	1,210.8	-	-	2,068.2
2027	99.8	12.9	757.6	1,918.0	-	-	2,788.3
2028	99.8	12.9	947.0	1,918.0	-	-	2,977.7
2029	99.8	38.7	947.0	1,918.0	-	-	3,003.5
2030	99.8	38.7	1,136.4	1,918.0	-	-	3,192.9
2031	99.8	51.6	1,325.8	2,625.2	-	-	4,102.4
2032	99.8	77.4	1,515.2	2,625.2	-	-	4,317.6
2033	99.8	141.9	1,704.6	2,625.2	-	-	4,571.5
2034	99.8	154.8	1,704.6	3,332.4	-	-	5,291.6
2035	99.8	154.8	1,704.6	4,039.6	-	-	5,998.8
2036	46.6	193.5	2,083.4	4,039.6	-	-	6,363.1

Year	Scenario 42 (Total Accredited Capacity)						
	Wind RFP	Generic Wind	Generic CT	Generic CC	Generic Coal	BD617 CCC1a	Total
2012	-	-	-	-	-	-	-
2013	-	-	-	-	-	-	-
2014	-	-	-	-	-	-	-
2015	-	-	-	-	-	-	-
2016	-	-	-	-	-	-	-
2017	-	-	-	-	-	208.4	208.4
2018	-	-	-	-	-	208.4	208.4
2019	-	-	-	-	-	494.8	494.8
2020	-	-	-	-	-	494.8	494.8
2021	99.8	-	-	-	-	494.8	594.6
2022	99.8	-	-	-	-	494.8	594.6
2023	99.8	-	189.4	-	-	494.8	784.0
2024	99.8	-	189.4	-	-	494.8	784.0
2025	99.8	-	568.2	908.1	-	494.8	2,070.9
2026	99.8	-	568.2	908.1	-	494.8	2,070.9
2027	99.8	12.9	1,136.4	908.1	-	494.8	2,652.0
2028	99.8	12.9	1,325.8	908.1	-	494.8	2,841.4
2029	99.8	38.7	1,515.2	908.1	-	494.8	3,056.6
2030	99.8	38.7	1,704.6	908.1	-	494.8	3,246.0
2031	99.8	51.6	1,704.6	1,615.3	-	494.8	3,966.1
2032	99.8	77.4	2,083.4	1,615.3	-	494.8	4,370.7
2033	99.8	141.9	2,083.4	1,615.3	-	494.8	4,435.2
2034	99.8	154.8	2,083.4	2,322.5	-	494.8	5,155.3
2035	99.8	154.8	2,272.8	3,029.7	-	494.8	6,051.9
2036	46.6	193.5	2,651.6	3,029.7	-	494.8	6,416.2

Year	Scenario 42 minus Scenario 40 (Total Accredited Capacity)						
	Wind RFP	Generic Wind	Generic CT	Generic CC	Generic Coal	BD617 CCC1a	Total
2012	-	-	-	-	-	-	-
2013	-	-	-	-	-	-	-
2014	-	-	-	-	-	-	-
2015	-	-	-	-	-	-	-
2016	-	-	-	-	-	-	-
2017	-	-	(189.4)	-	-	208.4	19.0
2018	-	-	(378.8)	-	-	208.4	(170.4)
2019	-	-	(378.8)	-	-	494.8	116.0
2020	-	-	(378.8)	-	-	494.8	116.0
2021	-	-	(378.8)	-	-	494.8	116.0
2022	-	-	(568.2)	-	-	494.8	(73.4)
2023	-	-	(378.8)	-	-	494.8	116.0
2024	-	-	(378.8)	(302.7)	-	494.8	(186.7)
2025	-	-	(189.4)	(302.7)	-	494.8	2.7
2026	-	-	(189.4)	(302.7)	-	494.8	2.7
2027	-	-	(189.4)	(302.7)	-	494.8	2.7
2028	-	-	(189.4)	(302.7)	-	494.8	2.7
2029	-	-	(189.4)	(302.7)	-	494.8	2.7
2030	-	-	(189.4)	(302.7)	-	494.8	2.7
2031	-	-	(189.4)	(302.7)	-	494.8	2.7
2032	-	-	(189.4)	(302.7)	-	494.8	2.7
2033	-	-	(189.4)	(302.7)	-	494.8	2.7
2034	-	-	(189.4)	(302.7)	-	494.8	2.7
2035	-	-	(189.4)	(302.7)	-	494.8	2.7
2036	-	-	(189.4)	(302.7)	-	494.8	2.7

Year	Scenario 44 (Total Accredited Capacity)						
	Wind RFP	Generic Wind	Generic CT	Generic CC	Generic Coal	BD617 ICT1a	Total
2012	-	-	-	-	-	-	-
2013	-	-	-	-	-	-	-
2014	-	-	-	-	-	-	-
2015	-	-	-	-	-	-	-
2016	-	-	-	-	-	-	-
2017	-	-	-	-	-	208.4	208.4
2018	-	-	-	-	-	208.4	208.4
2019	-	-	-	-	-	362.9	362.9
2020	-	-	-	-	-	362.9	362.9
2021	99.8	-	-	-	-	362.9	462.7
2022	99.8	-	189.4	-	-	362.9	652.1
2023	99.8	-	189.4	-	-	362.9	652.1
2024	99.8	-	492.1	-	-	362.9	954.8
2025	99.8	-	681.5	908.1	-	362.9	2,052.3
2026	99.8	-	681.5	908.1	-	362.9	2,052.3
2027	99.8	12.9	1,249.7	908.1	-	362.9	2,633.4
2028	99.8	12.9	1,439.1	908.1	-	362.9	2,822.8
2029	99.8	38.7	1,628.5	908.1	-	362.9	3,038.0
2030	99.8	38.7	1,817.9	908.1	-	362.9	3,227.4
2031	99.8	51.6	1,817.9	1,615.3	-	362.9	3,947.5
2032	99.8	77.4	2,196.7	1,615.3	-	362.9	4,352.1
2033	99.8	141.9	2,196.7	1,615.3	-	362.9	4,416.6
2034	99.8	154.8	2,196.7	2,322.5	-	362.9	5,136.7
2035	99.8	154.8	2,386.1	3,029.7	-	362.9	6,033.3
2036	46.6	193.5	2,764.9	3,029.7	-	362.9	6,397.6

Year	Scenario 44 minus Scenario 40 (Total Accredited Capacity)						
	Wind RFP	Generic Wind	Generic CT	Generic CC	Generic Coal	BD617 ICT1a	Total
2012	-	-	-	-	-	-	-
2013	-	-	-	-	-	-	-
2014	-	-	-	-	-	-	-
2015	-	-	-	-	-	-	-
2016	-	-	-	-	-	-	-
2017	-	-	-	-	-	208.4	208.4
2018	-	-	-	-	-	208.4	208.4
2019	-	-	-	-	-	362.9	362.9
2020	-	-	-	-	-	362.9	362.9
2021	99.8	-	-	-	-	362.9	462.7
2022	99.8	-	189.4	-	-	362.9	652.1
2023	99.8	-	189.4	-	-	362.9	652.1
2024	99.8	-	492.1	-	-	362.9	954.8
2025	99.8	-	681.5	908.1	-	362.9	2,052.3
2026	99.8	-	681.5	908.1	-	362.9	2,052.3
2027	99.8	12.9	1,249.7	908.1	-	362.9	2,633.4
2028	99.8	12.9	1,439.1	908.1	-	362.9	2,822.8
2029	99.8	38.7	1,628.5	908.1	-	362.9	3,038.0
2030	99.8	38.7	1,817.9	908.1	-	362.9	3,227.4
2031	99.8	51.6	1,817.9	1,615.3	-	362.9	3,947.5
2032	99.8	77.4	2,196.7	1,615.3	-	362.9	4,352.1
2033	99.8	141.9	2,196.7	1,615.3	-	362.9	4,416.6
2034	99.8	154.8	2,196.7	2,322.5	-	362.9	5,136.7
2035	99.8	154.8	2,386.1	3,029.7	-	362.9	6,033.3
2036	46.6	193.5	2,764.9	3,029.7	-	362.9	6,397.6

Year	Scenario 46 (Total Accredited Capacity)						
	Wind RFP	Generic Wind	Generic CT	Generic CC	Generic Coal	ICT1 CCC1a	Total
2012	-	-	-	-	-	-	-
2013	-	-	-	-	-	-	-
2014	-	-	-	-	-	-	-
2015	-	-	-	-	-	-	-
2016	-	-	-	-	-	154.5	154.5
2017	-	-	-	-	-	154.5	154.5
2018	-	-	189.4	-	-	154.5	343.9
2019	-	-	189.4	-	-	440.9	630.3
2020	-	-	189.4	-	-	440.9	630.3
2021	99.8	-	189.4	-	-	440.9	730.1
2022	99.8	-	189.4	-	-	440.9	730.1
2023	99.8	-	189.4	-	-	440.9	730.1
2024	99.8	-	189.4	-	-	440.9	730.1
2025	99.8	-	568.2	908.1	-	440.9	2,017.0
2026	99.8	-	568.2	908.1	-	440.9	2,017.0
2027	99.8	12.9	1,136.4	908.1	-	440.9	2,598.1
2028	99.8	12.9	1,515.2	908.1	-	440.9	2,976.9
2029	99.8	38.7	1,515.2	908.1	-	440.9	3,002.7
2030	99.8	38.7	1,704.6	908.1	-	440.9	3,192.1
2031	99.8	51.6	1,894.0	1,615.3	-	440.9	4,101.6
2032	99.8	77.4	2,083.4	1,615.3	-	440.9	4,316.8
2033	99.8	141.9	2,272.8	1,615.3	-	440.9	4,570.7
2034	99.8	154.8	2,272.8	2,322.5	-	440.9	5,290.8
2035	99.8	154.8	2,272.8	3,029.7	-	440.9	5,998.0
2036	46.6	193.5	2,841.0	3,029.7	-	286.4	6,397.2

Year	Scenario 46 minus Scenario 40 (Total Accredited Capacity)						
	Wind RFP	Generic Wind	Generic CT	Generic CC	Generic Coal	ICT1 CCC1a	Total
2012	-	-	-	-	-	-	-
2013	-	-	-	-	-	-	-
2014	-	-	-	-	-	-	-
2015	-	-	-	-	-	-	-
2016	-	-	-	-	-	154.5	154.5
2017	-	-	-	-	-	154.5	154.5
2018	-	-	189.4	-	-	154.5	343.9
2019	-	-	189.4	-	-	440.9	630.3
2020	-	-	189.4	-	-	440.9	630.3
2021	99.8	-	189.4	-	-	440.9	730.1
2022	99.8	-	189.4	-	-	440.9	730.1
2023	99.8	-	189.4	-	-	440.9	730.1
2024	99.8	-	189.4	-	-	440.9	730.1
2025	99.8	-	568.2	908.1	-	440.9	2,017.0
2026	99.8	-	568.2	908.1	-	440.9	2,017.0
2027	99.8	12.9	1,136.4	908.1	-	440.9	2,598.1
2028	99.8	12.9	1,515.2	908.1	-	440.9	2,976.9
2029	99.8	38.7	1,515.2	908.1	-	440.9	3,002.7
2030	99.8	38.7	1,704.6	908.1	-	440.9	3,192.1
2031	99.8	51.6	1,894.0	1,615.3	-	440.9	4,101.6
2032	99.8	77.4	2,083.4	1,615.3	-	440.9	4,316.8
2033	99.8	141.9	2,272.8	1,615.3	-	440.9	4,570.7
2034	99.8	154.8	2,272.8	2,322.5	-	440.9	5,290.8
2035	99.8	154.8	2,272.8	3,029.7	-	440.9	5,998.0
2036	46.6	193.5	2,841.0	3,029.7	-	286.4	6,397.2

Year	Scenario 48 (Total Accredited Capacity)						
	Wind RFP	Generic Wind	Generic CT	Generic CC	Generic Coal	CCC1 ICT1a	Total
2012	-	-	-	-	-	-	-
2013	-	-	-	-	-	-	-
2014	-	-	-	-	-	-	-
2015	-	-	-	-	-	-	-
2016	-	-	-	-	-	-	-
2017	-	-	-	-	-	286.4	286.4
2018	-	-	-	-	-	286.4	286.4
2019	-	-	-	-	-	440.9	440.9
2020	-	-	-	-	-	440.9	440.9
2021	99.8	-	-	-	-	440.9	540.7
2022	99.8	-	-	-	-	440.9	540.7
2023	99.8	-	189.4	-	-	440.9	730.1
2024	99.8	-	189.4	-	-	440.9	730.1
2025	99.8	-	568.2	908.1	-	440.9	2,017.0
2026	99.8	-	568.2	908.1	-	440.9	2,017.0
2027	99.8	12.9	1,136.4	908.1	-	440.9	2,598.1
2028	99.8	12.9	1,515.2	908.1	-	440.9	2,976.9
2029	99.8	38.7	1,515.2	908.1	-	440.9	3,002.7
2030	99.8	38.7	1,704.6	908.1	-	440.9	3,192.1
2031	99.8	51.6	1,894.0	1,615.3	-	440.9	4,101.6
2032	99.8	77.4	2,083.4	1,615.3	-	440.9	4,316.8
2033	99.8	141.9	2,272.8	1,615.3	-	440.9	4,570.7
2034	99.8	154.8	2,272.8	2,322.5	-	440.9	5,290.8
2035	99.8	154.8	2,272.8	3,029.7	-	440.9	5,998.0
2036	46.6	193.5	2,651.6	3,029.7	-	440.9	6,362.3

Year	Scenario 48 minus Scenario 40 (Total Accredited Capacity)						
	Wind RFP	Generic Wind	Generic CT	Generic CC	Generic Coal	CCC1 ICT1a	Total
2012	-	-	-	-	-	-	-
2013	-	-	-	-	-	-	-
2014	-	-	-	-	-	-	-
2015	-	-	-	-	-	-	-
2016	-	-	-	-	-	-	-
2017	-	-	-	-	-	286.4	286.4
2018	-	-	-	-	-	286.4	286.4
2019	-	-	-	-	-	440.9	440.9
2020	-	-	-	-	-	440.9	440.9
2021	99.8	-	-	-	-	440.9	540.7
2022	99.8	-	-	-	-	440.9	540.7
2023	99.8	-	189.4	-	-	440.9	730.1
2024	99.8	-	189.4	-	-	440.9	730.1
2025	99.8	-	568.2	908.1	-	440.9	2,017.0
2026	99.8	-	568.2	908.1	-	440.9	2,017.0
2027	99.8	12.9	1,136.4	908.1	-	440.9	2,598.1
2028	99.8	12.9	1,515.2	908.1	-	440.9	2,976.9
2029	99.8	38.7	1,515.2	908.1	-	440.9	3,002.7
2030	99.8	38.7	1,704.6	908.1	-	440.9	3,192.1
2031	99.8	51.6	1,894.0	1,615.3	-	440.9	4,101.6
2032	99.8	77.4	2,083.4	1,615.3	-	440.9	4,316.8
2033	99.8	141.9	2,272.8	1,615.3	-	440.9	4,570.7
2034	99.8	154.8	2,272.8	2,322.5	-	440.9	5,290.8
2035	99.8	154.8	2,272.8	3,029.7	-	440.9	5,998.0
2036	46.6	193.5	2,651.6	3,029.7	-	440.9	6,362.3

Year	Scenario 40 (Total Accredited Capacity)						
	Wind RFP	Generic Wind	Generic CT	Generic CC	Generic Coal	Bid Package	Total
2012	-	-	-	-	-	-	-
2013	-	-	-	-	-	-	-
2014	-	-	-	-	-	-	-
2015	-	-	-	-	-	-	-
2016	-	-	-	-	-	-	-
2017	-	-	189.4	-	-	-	189.4
2018	-	-	378.8	-	-	-	378.8
2019	-	-	378.8	-	-	-	378.8
2020	-	-	378.8	-	-	-	378.8
2021	99.8	-	378.8	-	-	-	478.6
2022	99.8	-	568.2	-	-	-	668.0
2023	99.8	-	568.2	-	-	-	668.0
2024	99.8	-	568.2	302.7	-	-	970.7
2025	99.8	-	757.6	1,210.8	-	-	2,068.2
2026	99.8	-	757.6	1,210.8	-	-	2,068.2
2027	99.8	12.9	1,325.8	1,210.8	-	-	2,649.3
2028	99.8	12.9	1,515.2	1,210.8	-	-	2,838.7
2029	99.8	38.7	1,704.6	1,210.8	-	-	3,053.9
2030	99.8	38.7	1,894.0	1,210.8	-	-	3,243.3
2031	99.8	51.6	1,894.0	1,918.0	-	-	3,963.4
2032	99.8	77.4	2,272.8	1,918.0	-	-	4,368.0
2033	99.8	141.9	2,272.8	1,918.0	-	-	4,432.5
2034	99.8	154.8	2,272.8	2,625.2	-	-	5,152.6
2035	99.8	154.8	2,462.2	3,332.4	-	-	6,049.2
2036	46.6	193.5	2,841.0	3,332.4	-	-	6,413.5

Contingency	PVSC ($, 000) Bid Package BD617 CCC1a	Bid Package BD617 ICT1a	Bid Package ICT1 CCC1a	Bid Package CCC1 ICT1a	Bid Package BASE CASE
BASE CASE	$ 41,263,124	$ 41,289,976	$ 41,321,276	$ 41,280,400	$ 41,404,044
CO2 Reduction	FAILED	FAILED	FAILED	FAILED	FAILED
$34 CO2	$ 45,016,044	$ 45,062,316	$ 45,081,124	$ 45,024,364	$ 45,164,172
$9 CO2	$ 37,689,156	$ 37,706,384	$ 37,748,852	$ 37,702,860	$ 37,825,868
Low Externalities	$ 40,899,028	$ 40,926,284	$ 40,957,328	$ 40,916,592	$ 41,040,404
High Market Price - 25%	$ 41,029,372	$ 41,052,320	$ 41,089,644	$ 41,042,728	$ 41,169,168
Low Market Price + 25%	$ 41,177,036	$ 41,196,832	$ 41,239,316	$ 41,186,452	$ 41,268,712
High Capital Cost + 10%	$ 41,558,196	$ 41,595,800	$ 41,623,732	$ 41,573,484	$ 41,749,088
Low Capital Cost - 10%	$ 40,965,624	$ 40,982,040	$ 41,018,828	$ 40,987,312	$ 41,054,792
High Coal + 20%	$ 42,439,032	$ 42,469,932	$ 42,501,416	$ 42,448,372	$ 42,582,836
High Coal + 10%	$ 41,863,372	$ 41,895,544	$ 41,926,976	$ 41,879,564	$ 42,006,940
Low Coal - 10%	$ 40,639,492	$ 40,664,752	$ 40,696,708	$ 40,657,184	$ 40,781,600
Low Coal - 20%	$ 40,002,876	$ 40,027,100	$ 40,059,728	$ 40,020,364	$ 40,144,376
Low Natural Gas - $1.50	$ 39,493,248	$ 39,500,392	$ 39,546,600	$ 39,509,888	$ 39,587,936
Low Natural Gas - $1.00	$ 40,152,424	$ 40,173,860	$ 40,210,576	$ 40,171,180	$ 40,268,120
Low Natural Gas - $0.50	$ 40,727,512	$ 40,761,468	$ 40,787,772	$ 40,743,644	$ 40,866,536
High Natural Gas + $0.50	$ 41,724,848	$ 41,782,728	$ 41,789,912	$ 41,737,636	$ 41,912,752
High Natural Gas + $1.00	$ 42,082,592	$ 42,187,416	$ 42,153,920	$ 42,089,392	$ 42,332,600
High Natural Gas + $1.50	$ 42,402,164	$ 42,547,404	$ 42,471,152	$ 42,404,692	$ 42,707,012
High Natural Gas + $2.00	$ 42,706,112	$ 42,901,216	$ 42,778,452	$ 42,703,492	$ 43,066,112
High Natural Gas + $2.50	$ 43,004,096	$ 43,246,524	$ 43,081,732	$ 42,993,732	$ 43,394,024
High Wind Credit + 25%	$ 41,228,224	$ 41,268,068	$ 41,271,252	$ 41,252,632	$ 41,360,988
Low Wind Credit - 25%	$ 41,311,676	$ 41,347,084	$ 41,349,708	$ 41,324,880	$ 41,450,624
High Forecast + 5%	$ 43,698,420	$ 43,742,636	$ 43,711,724	$ 43,675,384	$ 43,850,296
Mid-High Forecast + 2.5%	$ 42,473,236	$ 42,510,640	$ 42,508,392	$ 42,455,896	$ 42,618,132
Mid-Low Forecast - 2.5%	$ 40,141,112	$ 40,162,948	$ 40,177,852	$ 40,163,364	$ 40,221,052
Low Forecast - 5%	$ 39,050,180	$ 39,065,292	$ 39,098,592	$ 39,079,048	$ 39,081,776
Manitoba Hydro PPA Renew	$ 41,039,120	$ 41,069,908	$ 41,112,156	$ 41,072,020	$ 41,180,340
Maximum	$ 45,016,044	$ 45,062,316	$ 45,081,124	$ 45,024,364	$ 45,164,172
Average	$ 41,325,086	$ 41,375,439	$ 41,382,027	$ 41,336,909	$ 41,484,826
Minimum	$ 37,689,156	$ 37,706,384	$ 37,748,852	$ 37,702,860	$ 37,825,868

	PVSC Difference from Base Case, Same Contingency ($,000)

Contingency	Bid Package BD617 CCC1a	Bid Package BD617 ICT1a	Bid Package ICT1 CCC1a	Bid Package CCC1 ICT1a	Bid Package BASE CASE
BASE CASE	$ (140,920)	$ (114,068)	$ (82,768)	$ (123,644)	$ -
CO2 Reduction	FAILED	FAILED	FAILED	FAILED	FAILED
$34 CO2	$ (148,128)	$ (101,856)	$ (83,048)	$ (139,808)	$ -
$9 CO2	$ (136,712)	$ (119,484)	$ (77,016)	$ (123,008)	$ -
Low Externalities	$ (141,376)	$ (114,120)	$ (83,076)	$ (123,812)	$ -
High Market Price - 25%	$ (139,796)	$ (116,848)	$ (79,524)	$ (126,440)	$ -
Low Market Price + 25%	$ (91,676)	$ (71,880)	$ (29,396)	$ (82,260)	$ -
High Capital Cost + 10%	$ (190,892)	$ (153,288)	$ (125,356)	$ (175,604)	$ -
Low Capital Cost - 10%	$ (89,168)	$ (72,752)	$ (35,964)	$ (67,480)	$ -
High Coal + 20%	$ (143,804)	$ (112,904)	$ (81,420)	$ (134,464)	$ -
High Coal + 10%	$ (143,568)	$ (111,396)	$ (79,964)	$ (127,376)	$ -
Low Coal - 10%	$ (142,108)	$ (116,848)	$ (84,892)	$ (124,416)	$ -
Low Coal - 20%	$ (141,500)	$ (117,276)	$ (84,648)	$ (124,012)	$ -
Low Natural Gas - $1.50	$ (94,688)	$ (87,544)	$ (41,336)	$ (78,048)	$ -
Low Natural Gas - $1.00	$ (115,696)	$ (94,260)	$ (57,544)	$ (96,940)	$ -
Low Natural Gas - $0.50	$ (139,024)	$ (105,068)	$ (78,764)	$ (122,892)	$ -
High Natural Gas + $0.50	$ (187,904)	$ (130,024)	$ (122,840)	$ (175,116)	$ -
High Natural Gas + $1.00	$ (250,008)	$ (145,184)	$ (178,680)	$ (243,208)	$ -
High Natural Gas + $1.50	$ (304,848)	$ (159,608)	$ (235,860)	$ (302,320)	$ -
High Natural Gas + $2.00	$ (360,000)	$ (164,896)	$ (287,660)	$ (362,620)	$ -
High Natural Gas + $2.50	$ (389,928)	$ (147,500)	$ (312,292)	$ (400,292)	$ -
High Wind Credit + 25%	$ (132,764)	$ (92,920)	$ (89,736)	$ (108,356)	$ -
Low Wind Credit - 25%	$ (138,948)	$ (103,540)	$ (100,916)	$ (125,744)	$ -
High Forecast + 5%	$ (151,876)	$ (107,660)	$ (138,572)	$ (174,912)	$ -
Mid-High Forecast + 2.5%	$ (144,896)	$ (107,492)	$ (109,740)	$ (162,236)	$ -
Mid-Low Forecast - 2.5%	$ (79,940)	$ (58,104)	$ (43,200)	$ (57,688)	$ -
Low Forecast - 5%	$ (31,596)	$ (16,484)	$ 16,816	$ (2,728)	$ -
Manitoba Hydro PPA Renew	$ (141,220)	$ (110,432)	$ (68,184)	$ (108,320)	$ -
Maximum	$ (31,596)	$ (16,484)	$ 16,816	$ (2,728)	$ -
Average	$ (159,740)	$ (109,387)	$ (102,799)	$ (147,916)	$ -
Minimum	$ (389,928)	$ (164,896)	$ (312,292)	$ (400,292)	$ -

	Rank

Contingency	Bid Package BD617 CCC1a	Bid Package BD617 ICT1a	Bid Package ICT1 CCC1a	Bid Package CCC1 ICT1a	Bid Package BASE CASE
BASE CASE	1	3	4	2	5
CO2 Reduction	FAILED	FAILED	FAILED	FAILED	FAILED
$34 CO2	1	3	4	2	5
$9 CO2	1	3	4	2	5
Low Externalities	1	3	4	2	5
High Market Price + 25%	1	3	4	2	5
Low Market Price - 25%	1	3	4	2	5
High Capital Cost + 10%	1	3	4	2	5
Low Capital Cost - 10%	1	2	4	3	5
High Coal + 20%	1	3	4	2	5
High Coal + 10%	1	3	4	2	5
Low Coal - 10%	1	3	4	2	5
Low Coal - 20%	1	3	4	2	5
Low Natural Gas - $1.50	1	2	4	3	5
Low Natural Gas - $1.00	1	3	4	2	5
Low Natural Gas - $0.50	1	3	4	2	5
High Natural Gas + $0.50	1	3	4	2	5
High Natural Gas + $1.00	1	4	3	2	5
High Natural Gas + $1.50	1	4	3	2	5
High Natural Gas + $2.00	2	4	3	1	5
High Natural Gas + $2.50	2	4	3	1	5
High Wind Credit + 25%	1	3	4	2	5
Low Wind Credit - 25%	1	3	4	2	5
High Forecast + 5%	2	4	3	1	5
Mid-High Forecast + 2.5%	2	4	3	1	5
Mid-Low Forecast - 2.5%	1	2	4	3	5
Low Forecast - 5%	1	2	5	3	4
Manitoba Hydro PPA Renew	1	2	4	3	5

	Year 1st Generic Unit Added

Contingency	Bid Package BD617 CCC1a	Bid Package BD617 ICT1a	Bid Package ICT1 CCC1a	Bid Package CCC1 ICT1a	Bid Package BASE CASE
Base Conditions	2024 & on	2022	2018	2023	2024 & on
CO2 Reduction	FAILED	FAILED	FAILED	FAILED	FAILED
$34 CO2	2023	2022	2018	2023	2017
$9 CO2	2023	2022	2018	2023	2017
Low Externalities	2023	2022	2018	2023	2017
High Market Price + 25%	2023	2022	2018	2023	2017
Low Market Price - 25%	2023	2022	2018	2023	2017
High Capital Cost + 10%	2023	2022	2018	2023	2017
Low Capital Cost - 10%	2023	2022	2018	2023	2017
High Coal + 20%	2023	2022	2018	2023	2017
High Coal + 10%	2023	2022	2018	2023	2017
Low Coal - 10%	2023	2022	2018	2023	2017
Low Coal - 20%	2023	2022	2018	2023	2017
Low Natural Gas - $1.50	2023	2022	2018	2023	2017
Low Natural Gas - $1.00	2023	2022	2018	2023	2017
Low Natural Gas - $0.50	2023	2022	2018	2023	2017
High Natural Gas + $0.50	2023	2022	2018	2023	2017
High Natural Gas + $1.00	2023	2022	2018	2023	2017
High Natural Gas + $1.50	2023	2022	2018	2023	2017
High Natural Gas + $2.00	2023	2022	2018	2023	2017
High Natural Gas + $2.50	2023	2022	2018	2023	2017
High Wind Credit + 25%	2024	2022	2023	2023	2017
Low Wind Credit - 25%	2018	2018	2018	2022	2017
High Forecast + 5%	2017	2017	2017	2017	2017
Mid-High Forecast + 2.5%	2017	2017	2017	2017	2017
Mid-Low Forecast - 2.5%	2025 & on	2025 & on	2025 & on	2025 & on	2020
Low Forecast - 5%	2025 & on	2025 & on	2025 & on	2025 & on	2024
Manitoba Hydro PPA Renew	2023	2022	2018	2023	2017

Contingency	PVSC ($, 000; No CO2) Bid Package BD617 CCC1a	Bid Package BD617 ICT1a	Bid Package ICT1 CCC1a	Bid Package CCC1 ICT1a	Bid Package BASE CASE
BASE CASE	$ 34,680,352	$ 34,703,784	$ 34,743,016	$ 34,698,448	$ 34,824,620
CO2 Reduction	FAILED	FAILED	FAILED	FAILED	FAILED
$34 CO2	$ 34,680,352	$ 34,703,784	$ 34,743,016	$ 34,698,448	$ 34,824,620
$9 CO2	$ 34,680,352	$ 34,703,784	$ 34,743,016	$ 34,698,448	$ 34,824,620
Low Externalities	$ 34,680,352	$ 34,703,784	$ 34,743,016	$ 34,698,448	$ 34,824,620
High Market Price - 25%	$ 34,693,448	$ 34,712,488	$ 34,754,444	$ 34,706,652	$ 34,833,192
Low Market Price + 25%	$ 34,335,712	$ 34,332,416	$ 34,391,440	$ 34,340,104	$ 34,428,520
High Capital Cost + 10%	$ 34,962,900	$ 35,003,004	$ 35,037,616	$ 34,983,740	$ 35,156,172
Low Capital Cost - 10%	$ 34,395,504	$ 34,397,956	$ 34,443,816	$ 34,405,504	$ 34,483,552
High Coal + 20%	$ 35,922,384	$ 35,945,776	$ 35,985,208	$ 35,940,528	$ 36,066,660
High Coal + 10%	$ 35,304,676	$ 35,328,092	$ 35,367,312	$ 35,322,804	$ 35,448,952
Low Coal - 10%	$ 34,051,112	$ 34,074,560	$ 34,113,764	$ 34,069,176	$ 34,195,372
Low Coal - 20%	$ 33,416,312	$ 33,439,752	$ 33,478,872	$ 33,434,314	$ 33,560,572
Low Natural Gas - $1.50	$ 33,354,738	$ 33,355,142	$ 33,407,380	$ 33,366,214	$ 33,449,082
Low Natural Gas - $1.00	$ 33,840,036	$ 33,850,324	$ 33,895,552	$ 33,853,416	$ 33,952,112
Low Natural Gas - $0.50	$ 34,272,168	$ 34,291,628	$ 34,331,924	$ 34,287,508	$ 34,402,288
High Natural Gas + $0.50	$ 35,037,000	$ 35,091,024	$ 35,103,336	$ 35,053,912	$ 35,224,524
High Natural Gas + $1.00	$ 35,362,728	$ 35,461,388	$ 35,432,788	$ 35,376,908	$ 35,597,932
High Natural Gas + $1.50	$ 35,660,496	$ 35,801,948	$ 35,733,868	$ 35,669,764	$ 35,942,364
High Natural Gas + $2.00	$ 35,937,084	$ 36,122,176	$ 36,012,372	$ 35,941,964	$ 36,266,536
High Natural Gas + $2.50	$ 36,198,096	$ 36,411,576	$ 36,271,460	$ 36,195,432	$ 36,568,448
High Wind Credit + 25%	$ 34,643,404	$ 34,676,500	$ 34,691,460	$ 34,672,200	$ 34,777,764
Low Wind Credit - 25%	$ 34,730,432	$ 34,763,376	$ 34,775,504	$ 34,746,560	$ 34,865,520
High Forecast + 5%	$ 36,732,508	$ 36,762,380	$ 36,773,592	$ 36,763,028	$ 36,905,992
Mid-High Forecast + 2.5%	$ 35,715,568	$ 35,725,432	$ 35,751,404	$ 35,710,656	$ 35,830,520
Mid-Low Forecast - 2.5%	$ 33,735,512	$ 33,739,464	$ 33,765,620	$ 33,747,460	$ 33,823,616
Low Forecast - 5%	$ 32,826,046	$ 32,832,608	$ 32,857,666	$ 32,840,932	$ 32,860,714
Manitoba Hydro PPA Renew	$ 34,547,368	$ 34,590,032	$ 34,617,952	$ 34,572,392	$ 34,704,588
Maximum	$ 36,732,508	$ 36,762,380	$ 36,773,592	$ 36,763,028	$ 36,905,992
Average	$ 34,755,431	$ 34,797,192	$ 34,813,571	$ 34,770,184	$ 34,912,721
Minimum	$ 32,826,046	$ 32,832,608	$ 32,857,666	$ 32,840,932	$ 32,860,714

	PVSC Difference from Base Case, Same Contingency ($,000; No CO2)

Contingency	Bid Package BD617 CCC1a	Bid Package BD617 ICT1a	Bid Package ICT1 CCC1a	Bid Package CCC1 ICT1a	Bid Package BASE CASE
BASE CASE	$ (144,268)	$ (120,836)	$ (81,604)	$ (126,172)	$ -
CO2 Reduction	FAILED	FAILED	FAILED	FAILED	FAILED
$34 CO2	$ (144,268)	$ (120,836)	$ (81,604)	$ (126,172)	$ -
$9 CO2	$ (144,268)	$ (120,836)	$ (81,604)	$ (126,172)	$ -
Low Externalities	$ (144,268)	$ (120,836)	$ (81,604)	$ (126,172)	$ -
High Market Price - 25%	$ (139,744)	$ (120,704)	$ (78,748)	$ (126,540)	$ -
Low Market Price + 25%	$ (92,808)	$ (96,104)	$ (37,080)	$ (88,416)	$ -
High Capital Cost + 10%	$ (193,272)	$ (153,168)	$ (118,556)	$ (172,432)	$ -
Low Capital Cost - 10%	$ (88,048)	$ (85,596)	$ (39,736)	$ (78,048)	$ -
High Coal + 20%	$ (144,276)	$ (120,884)	$ (81,452)	$ (126,132)	$ -
High Coal + 10%	$ (144,276)	$ (120,860)	$ (81,640)	$ (126,148)	$ -
Low Coal - 10%	$ (144,260)	$ (120,812)	$ (81,608)	$ (126,196)	$ -
Low Coal - 20%	$ (144,260)	$ (120,820)	$ (81,700)	$ (126,258)	$ -
Low Natural Gas - $1.50	$ (94,344)	$ (93,940)	$ (41,702)	$ (82,868)	$ -
Low Natural Gas - $1.00	$ (112,076)	$ (101,788)	$ (56,560)	$ (98,696)	$ -
Low Natural Gas - $0.50	$ (130,120)	$ (110,660)	$ (70,364)	$ (114,780)	$ -
High Natural Gas + $0.50	$ (187,524)	$ (133,500)	$ (121,188)	$ (170,612)	$ -
High Natural Gas + $1.00	$ (235,204)	$ (136,544)	$ (165,144)	$ (221,024)	$ -
High Natural Gas + $1.50	$ (281,868)	$ (140,416)	$ (208,496)	$ (272,600)	$ -
High Natural Gas + $2.00	$ (329,452)	$ (144,360)	$ (254,164)	$ (324,572)	$ -
High Natural Gas + $2.50	$ (370,352)	$ (156,872)	$ (296,988)	$ (373,016)	$ -
High Wind Credit + 25%	$ (134,360)	$ (101,264)	$ (86,304)	$ (105,564)	$ -
Low Wind Credit - 25%	$ (135,088)	$ (102,144)	$ (90,016)	$ (118,960)	$ -
High Forecast + 5%	$ (173,484)	$ (143,612)	$ (132,400)	$ (142,964)	$ -
Mid-High Forecast + 2.5%	$ (114,952)	$ (105,088)	$ (79,116)	$ (119,864)	$ -
Mid-Low Forecast - 2.5%	$ (88,104)	$ (84,152)	$ (57,996)	$ (76,156)	$ -
Low Forecast - 5%	$ (34,668)	$ (28,106)	$ (3,048)	$ (19,782)	$ -
Manitoba Hydro PPA Renew	$ (157,220)	$ (114,556)	$ (86,636)	$ (132,196)	$ -
Maximum	$ (34,668)	$ (28,106)	$ (3,048)	$ (19,782)	$ -
Average	$ (157,290)	$ (115,529)	$ (99,150)	$ (142,537)	$ -
Minimum	$ (370,352)	$ (156,872)	$ (296,988)	$ (373,016)	$ -

	Rank (No CO2)

Contingency	Bid Package BD617 CCC1a	Bid Package BD617 ICT1a	Bid Package ICT1 CCC1a	Bid Package CCC1 ICT1a	Bid Package BASE CASE
BASE CASE	1	3	4	2	5
CO2 Reduction	FAILED	FAILED	FAILED	FAILED	FAILED
$34 CO2	1	3	4	2	5
$9 CO2	1	3	4	2	5
Low Externalities	1	3	4	2	5
High Market Price + 25%	1	3	4	2	5
Low Market Price - 25%	2	1	4	3	5
High Capital Cost + 10%	1	3	4	2	5
Low Capital Cost - 10%	1	2	4	3	5
High Coal + 20%	1	3	4	2	5
High Coal + 10%	1	3	4	2	5
Low Coal - 10%	1	3	4	2	5
Low Coal - 20%	1	3	4	2	5
Low Natural Gas - $1.50	1	2	4	3	5
Low Natural Gas - $1.00	1	2	4	3	5
Low Natural Gas - $0.50	1	3	4	2	5
High Natural Gas + $0.50	1	3	4	2	5
High Natural Gas + $1.00	1	4	3	2	5
High Natural Gas + $1.50	1	4	3	2	5
High Natural Gas + $2.00	1	4	3	2	5
High Natural Gas + $2.50	2	4	3	1	5
High Wind Credit + 25%	1	3	4	2	5
Low Wind Credit - 25%	1	3	4	2	5
High Forecast + 5%	1	2	4	3	5
Mid-High Forecast + 2.5%	2	3	4	1	5
Mid-Low Forecast - 2.5%	1	2	4	3	5
Low Forecast - 5%	1	2	4	3	5
Manitoba Hydro PPA Renew	1	3	4	2	5

	Year 1st Generic Unit Added (No CO2)

Contingency	Bid Package BD617 CCC1a	Bid Package BD617 ICT1a	Bid Package ICT1 CCC1a	Bid Package CCC1 ICT1a	Bid Package BASE CASE
Base Conditions	2023	2022	2018	2023	2017
CO2 Reduction	FAILED	FAILED	FAILED	FAILED	FAILED
$34 CO2	2023	2022	2018	2023	2017
$9 CO2	2023	2022	2018	2023	2017
Low Externalities	2023	2022	2018	2023	2017
High Market Price + 25%	2023	2022	2018	2023	2017
Low Market Price - 25%	2023	2022	2018	2023	2017
High Capital Cost + 10%	2023	2022	2018	2023	2017
Low Capital Cost - 10%	2023	2022	2018	2023	2017
High Coal + 20%	2023	2022	2018	2023	2017
High Coal + 10%	2023	2022	2018	2023	2017
Low Coal - 10%	2023	2022	2018	2023	2017
Low Coal - 20%	2023	2022	2018	2023	2017
Low Natural Gas - $1.50	2023	2022	2018	2023	2017
Low Natural Gas - $1.00	2023	2022	2018	2023	2017
Low Natural Gas - $0.50	2023	2022	2018	2023	2017
High Natural Gas + $0.50	2023	2022	2018	2023	2017
High Natural Gas + $1.00	2023	2022	2018	2023	2017
High Natural Gas + $1.50	2023	2022	2018	2023	2017
High Natural Gas + $2.00	2023	2022	2018	2023	2017
High Natural Gas + $2.50	2023	2022	2018	2023	2017
High Wind Credit + 25%	2024	2022	2023	2023	2017
Low Wind Credit - 25%	2018	2018	2018	2022	2017
High Forecast + 5%	2017	2017	2017	2017	2017
Mid-High Forecast + 2.5%	2017	2017	2017	2017	2017
Mid-Low Forecast - 2.5%	2025 & on	2025 & on	2025 & on	2025 & on	2020
Low Forecast - 5%	2025 & on	2025 & on	2025 & on	2025 & on	2024
Manitoba Hydro PPA Renew	2023	2022	2018	2023	2017

Round 1						
File		Solar Cap. Fact.	Wind RFP MW	Reliab.	Forecast	Natural Gas
Scenario 1	Solar A, Wind 400, NCP, Base Fcast	72%	400	Non-Coinc	Fall 2011	Firm
Scenario 2	Solar A, Wind 600, NCP, Base Fcast	72%	600	Non-Coinc	Fall 2011	Firm
Scenario 3	Solar A, Wind 800, NCP, Base Fcast	72%	800	Non-Coinc	Fall 2011	Firm
Scenario 4	Solar A, Wind 400, CP, Base Fcast	72%	400	Coincident	Fall 2011	Firm
Scenario 5	Solar A, Wind 600, CP, Base Fcast	72%	600	Coincident	Fall 2011	Firm
Scenario 6	Solar A, Wind 800, CP, Base Fcast	72%	800	Coincident	Fall 2011	Firm
Scenario 7	Solar B, Wind 400, NCP, Base Fcast	50%	400	Non-Coinc	Fall 2011	Firm
Scenario 8	Solar B, Wind 600, NCP, Base Fcast	50%	600	Non-Coinc	Fall 2011	Firm
Scenario 9	Solar B, Wind 800, NCP, Base Fcast	50%	800	Non-Coinc	Fall 2011	Firm
Scenario 10	Solar B, Wind 400, CP, Base Fcast	50%	400	Coincident	Fall 2011	Firm
Scenario 11	Solar B, Wind 600, CP, Base Fcast	50%	600	Coincident	Fall 2011	Firm
Scenario 12	Solar B, Wind 800, CP, Base Fcast	50%	800	Coincident	Fall 2011	Firm
Scenario 13	Solar A, Wind 400, NCP, Spring'13 Fcast	72%	400	Non-Coinc	Spring 2013	Firm
Scenario 14	Solar A, Wind 600, NCP, Spring'13 Fcast	72%	600	Non-Coinc	Spring 2013	Firm
Scenario 15	Solar A, Wind 800, NCP, Spring'13 Fcast	72%	800	Non-Coinc	Spring 2013	Firm
Scenario 16	Solar A, Wind 400, CP, Spring'13 Fcast	72%	400	Coincident	Spring 2013	Firm
Scenario 17	Solar A, Wind 600, CP, Spring'13 Fcast	72%	600	Coincident	Spring 2013	Firm
Scenario 18	Solar A, Wind 800, CP, Spring'13 Fcast	72%	800	Coincident	Spring 2013	Firm
Scenario 19	Solar B, Wind 400, NCP, Spring'13 Fcast	50%	400	Non-Coinc	Spring 2013	Firm
Scenario 20	Solar B, Wind 600, NCP, Spring'13 Fcast	50%	600	Non-Coinc	Spring 2013	Firm
Scenario 21	Solar B, Wind 800, NCP, Spring'13 Fcast	50%	800	Non-Coinc	Spring 2013	Firm
Scenario 22	Solar B, Wind 400, CP, Spring'13 Fcast	50%	400	Coincident	Spring 2013	Firm
Scenario 23	Solar B, Wind 600, CP, Spring'13 Fcast	50%	600	Coincident	Spring 2013	Firm
Scenario 24	Solar B, Wind 800, CP, Spring'13 Fcast	50%	800	Coincident	Spring 2013	Firm

Round 2						
File		Solar Cap. Fact.	Wind RFP MW	Reliab.	Forecast	Natural Gas
Scenario 25	Bid Package GPV1	72%	750	Non-Coinc	Fall 2011	Firm
Scenario 26	Bid Package GPV1 No CO2	72%	750	Non-Coinc	Fall 2011	Firm
Scenario 27	Bid Package BD617	72%	750	Non-Coinc	Fall 2011	Firm
Scenario 28	Bid Package BD617 No CO2	72%	750	Non-Coinc	Fall 2011	Firm
Scenario 29	Bid Package CCC1	72%	750	Non-Coinc	Fall 2011	Firm
Scenario 30	Bid Package CCC1 No CO2	72%	750	Non-Coinc	Fall 2011	Firm
Scenario 31	Bid Package ICT1	72%	750	Non-Coinc	Fall 2011	Firm
Scenario 32	Bid Package ICT1 No CO2	72%	750	Non-Coinc	Fall 2011	Firm
Scenario 33	Bid Package BD619 CCC1	72%	750	Non-Coinc	Fall 2011	Firm
Scenario 34	Bid Package BD619 CCC1 No CO2	72%	750	Non-Coinc	Fall 2011	Firm
Scenario 35	Bid Package ICT1 CCC1	72%	750	Non-Coinc	Fall 2011	Firm
Scenario 36	Bid Package ICT1 CCC1 No CO2	72%	750	Non-Coinc	Fall 2011	Firm
Scenario 37	Bid Package ICT1 BD618	72%	750	Non-Coinc	Fall 2011	Firm
Scenario 38	Bid Package ICT1 BD618 No CO2	72%	750	Non-Coinc	Fall 2011	Firm
Scenario 39	Bid Package BASE CASE	72%	750	Non-Coinc	Fall 2011	Firm
Scenario 40	Bid Package BASE CASE No CO2	72%	750	Non-Coinc	Fall 2011	Firm

Round 3, Part 1							
File		Solar Cap. Fact.	Wind RFP MW	Reliab.	Forecast	Natural Gas
Scenario 31a	Bid Package ICT1	72%	750	Non-Coinc	Fall 2011	ICT1 Interrupt
Scenario 32a	Bid Package ICT1 No CO2	72%	750	Non-Coinc	Fall 2011	ICT1 Interrupt
Scenario 35a	Bid Package ICT1 CCC1	72%	750	Non-Coinc	Fall 2011	ICT1 Interrupt
Scenario 36a	Bid Package ICT1 CCC1 No CO2	72%	750	Non-Coinc	Fall 2011	ICT1 Interrupt
Scenario 37a	Bid Package ICT1 BD618	72%	750	Non-Coinc	Fall 2011	ICT1 Interrupt
Scenario 38a	Bid Package ICT1 BD618 No CO2	72%	750	Non-Coinc	Fall 2011	ICT1 Interrupt

Round 3, Part 2						
File		Solar Cap. Fact.	Wind RFP MW	Reliab.	Forecast	Natural Gas
Scenario 41	Bid Package BD617 CCC1a	72%	750	Non-Coinc	Fall 2011	ICT1 Interrupt
Scenario 42	Bid Package BD617 CCC1a No CO2	72%	750	Non-Coinc	Fall 2011	ICT1 Interrupt
Scenario 43	Bid Package BD617 ICT1a	72%	750	Non-Coinc	Fall 2011	ICT1 Interrupt
Scenario 44	Bid Package BD617 ICT1a No CO2	72%	750	Non-Coinc	Fall 2011	ICT1 Interrupt
Scenario 45	Bid Package ICT1 CCC1a	72%	750	Non-Coinc	Fall 2011	ICT1 Interrupt
Scenario 46	Bid Package ICT1 CCC1a No CO2	72%	750	Non-Coinc	Fall 2011	ICT1 Interrupt
Scenario 47	Bid Package CCC1 ICT1a	72%	750	Non-Coinc	Fall 2011	ICT1 Interrupt
Scenario 48	Bid Package CCC1 ICT1a No CO2	72%	750	Non-Coinc	Fall 2011	ICT1 Interrupt

Round 3, Part 3						
File		Solar Cap. Fact.	Wind RFP MW	Reliab.	Forecast	Natural Gas
Scenario 51	Bid Package BD617 CCC1a	72%	600	Non-Coinc	Fall 2011	ICT1 Interrupt
Scenario 52	Bid Package BD617 CCC1a No CO2	72%	600	Non-Coinc	Fall 2011	ICT1 Interrupt
Scenario 53	Bid Package BD617 ICT1a	72%	600	Non-Coinc	Fall 2011	ICT1 Interrupt
Scenario 54	Bid Package BD617 ICT1a No CO2	72%	600	Non-Coinc	Fall 2011	ICT1 Interrupt
Scenario 55	Bid Package ICT1 CCC1a	72%	600	Non-Coinc	Fall 2011	ICT1 Interrupt
Scenario 56	Bid Package ICT1 CCC1a No CO2	72%	600	Non-Coinc	Fall 2011	ICT1 Interrupt
Scenario 57	Bid Package CCC1 ICT1a	72%	600	Non-Coinc	Fall 2011	ICT1 Interrupt
Scenario 58	Bid Package CCC1 ICT1a No CO2	72%	600	Non-Coinc	Fall 2011	ICT1 Interrupt
Scenario 59	Bid Package BASE CASE	72%	600	Non-Coinc	Fall 2011	ICT1 Interrupt
Scenario 60	Bid Package BASE CASE No CO2	72%	600	Non-Coinc	Fall 2011	ICT1 Interrupt