MRO

2006 TEN-YEAR RELIABILITY ASSESSMENT

Compiled by

Midwest Reliability Organization

RELIABILITY ASSESSMENT COMMITTEE

October 2006

TABLE OF CONTENTS

INTRODUCTION

The Midwest Reliability Organization (MRO) replaced the Mid-Continent Area Power Pool (MAPP) as a reliability organization within North American Electric Reliability Council (NERC) in January 2005. MAPP continues to exist as a regional transmission group with a Regional Transmission Committee (RTC) and a Generation Reserve Sharing Pool (GRSP).   The MRO membership expanded its geography in 2005 with a new Canadian member. In January 2006, the MRO acquired additional members from the former Mid-America Interconnected Network, Inc. (MAIN) regional reliability council.

Compiled by the MRO Reliability Assessment Committee (RAC), this report is an assessment of the reliability of the MRO region for the 2006-2015 time period in order to comply with NERC Standards TPL-001 through TPL-004. While the RAC is responsible for the publication of this assessment, the committee relied on information from several sources including MAPP committees, Midwest ISO, and the American Transmission Company. During this information preparation process, the MAPP Reliability Studies, Design Review, and Transmission Operations Subcommittees also helped review MRO reliability from mid-term and long-term perspectives.

The assessment of reliability within the MRO region, which comprises the MRO-U.S. and MRO-Canada subregions, consists of three sections:

- Demand and energy,
- Resource adequacy assessment, and
- Transmission adequacy assessment

DEMAND AND ENERGY

DEMAND

The MRO-U.S. summer peak demand is expected to increase at an average rate of 1.9% per year during 2006–2015, a slight decrease from the 2.0% predicted last year for the 2005–2014 period. The MRO-U.S. 2015 noncoincident summer peak demand is projected to be 55,518 MW. For comparison purposes, the MAPP members project a 2015 noncoincident summer peak demand of 37,068 MW which represents a 4.1% increase compared to last year's 2014 projected demand level of 35,612 MW.

MRO members continue to forecast load based on normal weather conditions.

The MRO-Canada summer peak demand is expected to increase at an average rate of 0.84% per year during the 2006–2015 period, as compared to 1.17% predicted last year for the 2005–2014 period. The MRO-Canada 2015 noncoincident summer peak demand is projected to be 6,282 MW. This projection is 1.35% below the 2014 noncoincident summer peak demand predicted last year (6,367 MW).

The MRO-Canada winter peak demand is expected to increase at an average rate of 0.8% per year during the 2006–2015 period, as compared to 0.8% predicted last year for the 2005–2014 period. The MRO-Canada 2015 noncoincident winter peak demand is projected to be 7,641 MW. This projection is 1.6% above the 2014 noncoincident winter peak demand predicted last year (7,521 MW).

Long-term sales to other regions where the purchasing entities are known are expected to decrease from their current level of 446 MW in 2005 to about 144 MW in 2015. Long-term purchases from other regions where the selling entities are known are expected to decrease from their current level of 2,784 MW in 2005 to about 1,600 MW in 2015. Based on information from MRO members, there were no purchases or sales where the buyer or seller is unknown reported from 2006–2015.

Both the MAPP GRSP members and the former MAIN members utilize a load forecast uncertainty factor (LFU) within the determination of adequate generation reserve margin levels. The LFU considers both uncertainty attributable to weather conditions and economic conditions and is factored into the LOLE study used to determine adequate reserve margin levels.

ENERGY

The 2006 annual forecast energy consumption for MRO-Total (262,722 GWh) is 1.2% above the 2005 summer actual energy (259,525 GWh).

The MRO 2015 annual forecast energy is projected to be 305,891 GWh for the entire footprint. The MRO annual forecast energy is expected to increase at an average rate of 1.8% per year during the 2006–2015 period.

The 2006 annual forecast energy consumption for MRO-U.S. (220,006 GWh) is 1.6% above the 2005 annual actual energy (216,633 GWh).

The MRO-U.S. annual forecast energy is expected to increase at an average rate of 2.0% per year during the 2006–2015 period. The MRO-U.S. 2015 annual forecast energy is projected to be 259,074 GWh.

The 2006 annual energy consumption for MRO-Canada (42,716 GWh) is 0.4% below the 2005 annual actual energy (42,892 GWh).

The MRO-Canada annual forecast energy is expected to increase at an average rate of 1.1% per year during the 2006–2015 period, as compared to 1.3% predicted last year for the 2005–2014 period. The MRO-Canada 2015 annual forecast energy is projected to be 46,817 GWh.

RESOURCE ADEQUACY ASSESSMENT

OVERVIEW

A comparison of seasonal load and capability for the 2006-2015 for the MRO region is shown in Table 1. As seen from this table, the region's forecasted summer reserve margin varies from 23.3% in summer 2006 to 15.2% in summer 2012 and 8.2% in summer 2015. The forecasted winter reserve margin varies from 37.5% in winter 2006-2007 to 24.3% in winter 2015-2016.

Table 1

Midwest Reliability Organization

Forecasted Seasonal Load & Capability (MW)

		SUM 2006	WIN 2006	SUM 2007	WIN 2007	SUM 2008	WIN 2008	SUM 2009	WIN 2009	SUM 2010	*WIN 2010*
01	Internal Demand	47459	41335	48254	41953	49243	42914	50138	43585	51023	*44275*
02	Standby Demand	4	4	4	4	4	4	4	4	4	*4*
03	Total Internal Demand (01+02)	47464	41339	48258	41958	49247	42919	50142	43589	51027	*44279*
04	Direct Control Load Management	294	119	296	124	303	127	307	128	312	*129*
05	Interruptible Demand	1626	1044	1630	1043	1632	1047	1631	1047	1645	*1061*
06	Net Internal Demand (03-04-05)	45545	40175	46333	40789	47312	41745	48203	42416	49071	*43088*
07	Total Net Operable Capacity	51632	51022	52572	51817	53387	52585	54143	53385	54311	*53487*
07a	Uncommitted Capacity	45	45	45	45	45	45	45	45	45	*45*
07b1	Reliability Derating Unit Spec. Subtotal	0	0	0	0	0	0	0	0	0	*0*
07b2	Reliability Derating Group Subtotal	0	0	0	0	0	0	0	0	0	*0*
07c	Other Generation	0	0	0	0	0	0	0	0	0	*0*
07d	Subtotal Committed Capacity (7-7a-7b1-7b2-7c)	51587	50977	52527	51772	53342	52540	54098	53340	54266	*53442*
08	Generator Capacity, <1MW (8a+8b)	314	313	317	315	317	314	316	314	316	*314*
08a	Distributed Generator Capacity < 1 MW	256	255	259	257	259	256	258	256	258	*256*
08b	Other Capacity < 1 MW	58	58	58	58	58	58	58	58	58	*58*
09	Total Net Generator Capacity (7d+8)	51901	51290	52842	52087	53657	52854	54411	53654	54579	*53756*
9b	Distributed Generator Capacity >= 1 MW	116	114	116	114	116	114	116	114	116	*114*
10	Total Capacity Purchases	9013	8147	7752	7510	7494	7269	6972	7133	6428	*6832*
11	Total Firm Purchases	3304	3129	2926	2669	2757	2670	2758	2670	2584	*2494*
12	Total Participation Purchases	5709	5018	4826	4841	4738	4600	4215	4464	3845	*4339*
13	Total Capacity Sales	5071	4779	4360	4308	4133	4086	4455	4012	3766	*3524*
14	Total Firm Sales	2441	2485	2200	2182	2020	2010	2087	1934	1893	*1739*
15	Total Participation Sales	2630	2294	2160	2126	2113	2076	2368	2078	1873	*1785*
16	Net Capacity Resources (9+10-13)	55844	54655	56236	55286	57020	56035	56930	56775	57243	*57064*
17	Schedule L Purchases	50	251	51	245	52	246	53	268	54	*290*
18	Adjusted Net Capability (9+12-15)	54982	54014	55509	54802	56283	55377	56259	56041	56552	*56311*
19	Annual System Demand	46260	48133	47024	48925	47902	49884	48825	49168	49679	*50013*
20	Monthly Adjusted Net Demand (6-17-11+14)	44632	39284	45557	40059	46524	40842	47481	41415	48326	*42045*
21	Reserve Margin (18-20)	10350	14730	9952	14743	9759	14535	8778	14626	8226	*14266*
22	Reserve Margin Percent (21/20)	23.2%	37.5%	21.8%	36.8%	21.0%	35.6%	18.5%	35.3%	17.0%	*33.9%*

SUMMER: MAY 1 - OCT 31; WINTER: NOV 1 - APR 30

Table 1 (Continued)

Midwest Reliability Organization

Forecasted Seasonal Load & Capability (MW)

		SUM 2011	WIN 2011	SUM 2012	WIN 2012	SUM 2013	WIN 2013	SUM 2014	WIN 2014	SUM 2015	*WIN 2015*
01	Internal Demand	51940	44957	52833	45627	53670	46260	54598	46947	55514	*47636*
02	Standby Demand	4	4	4	4	4	4	4	4	4	*4*
03	Total Internal Demand (01+02)	51945	44962	52837	45632	53674	46264	54603	46951	55518	*47640*
04	Direct Control Load Management	315	130	321	132	324	134	328	136	332	*138*
05	Interruptible Demand	1645	1061	1645	1061	1645	1061	1646	1061	1646	*1058*
06	Net Internal Demand (03-04-05)	49985	43770	50873	44438	51706	45070	52630	45752	53541	*46444*
07	Total Net Operable Capacity	54608	53973	55373	54541	55403	54872	55703	54395	55462	*54632*
07a	Uncommitted Capacity	45	45	45	45	45	45	45	45	45	*45*
07b1	Reliability Derating Unit Spec. Subtotal	0	0	0	0	0	0	0	0	0	*0*
07b2	Reliability Derating Group Subtotal	0	0	0	0	0	0	0	0	0	*0*
07c	Other Generation	0	0	0	0	0	0	0	0	0	*0*
07d	Subtotal Committed Capacity (7-7a-7b1-7b2-7c)	54563	53928	55328	54496	55358	54827	55658	54350	55417	*54587*
08	Generator Capacity, <1MW (8a+8b)	316	314	316	314	316	314	316	313	316	*313*
08a	Distributed Generator Capacity < 1 MW	258	256	258	256	258	256	258	256	258	*256*
08b	Other Capacity < 1 MW	58	58	58	58	58	58	58	57	58	*57*
09	Total Net Generator Capacity (7d+8)	54876	54242	55640	54810	55670	55141	55970	54662	55730	*54899*
9b	Distributed Generator Capacity >= 1 MW	116	114	116	114	116	114	116	114	116	*114*
10	Total Capacity Purchases	6258	6790	6176	6219	5624	5325	5241	5219	4445	*4695*
11	Total Firm Purchases	2576	2494	2577	2495	2578	2495	2572	2489	2273	*2490*
12	Total Participation Purchases	3683	4297	3600	3725	3047	2831	2670	2731	2173	*2206*
13	Total Capacity Sales	3471	3216	3421	3186	3422	3067	3202	2967	2403	*2568*
14	Total Firm Sales	1698	1531	1678	1531	1679	1532	1679	1532	1380	*1633*
15	Total Participation Sales	1773	1685	1743	1655	1743	1535	1523	1435	1023	*935*
16	Net Capacity Resources (9+10-13)	57665	57815	58397	57842	57874	57398	58011	56913	57773	*57026*
17	Schedule L Purchases	55	312	56	335	57	359	58	382	59	*406*
18	Adjusted Net Capability (9+12-15)	56787	56854	57498	56880	56975	56437	57118	55958	56880	*56170*
19	Annual System Demand	50559	50875	51415	51723	52187	52490	53047	53409	53957	*54296*
20	Monthly Adjusted Net Demand (6-17-11+14)	49053	42499	49920	43142	50751	43750	51680	44416	52590	*45184*
21	Reserve Margin (18-20)	7734	14355	7578	13738	6224	12687	5438	11542	4290	*10986*
22	Reserve Margin Percent (21/20)	15.8%	33.8%	15.2%	31.8%	12.3%	29.0%	10.5%	26.0%	8.2%	*24.3%*

SUMMER: MAY 1 - OCT 31; WINTER: NOV 1 - APR 30

Currently, the MRO has not established resource adequacy standards or criteria for its members, although work is ongoing in this area. To maintain their system reliability, the MRO load serving entities are using different reserve margin targets:

- Members that belong to the MAPP Generation Reserve Sharing Pool (GRSP) are obligated to maintain a minimum reserve margin, or Reserve Capacity Obligation (RCO), of 15% for predominantly thermal systems and 10% for predominantly hydroelectric systems. There is one predominantly hydroelectric system in MRO-U.S. and one in MRO-Canada.
- The former MAIN members that joined MRO in 2006 continue to meet their former MAIN-recommended minimum reserve margin of 14%.
- The new Canadian member that joined MRO in 2005 does not belong to a GRSP. This member uses an expected unserved energy criteria which meets an approximate 13 – 15 % RCO.

Both predominantly hydroelectric systems in the MRO belong to the MAPP GRSP and are obligated to maintain a 10% RCO. All the new, non-MAPP GRSP members are considered predominantly thermal systems. For the purpose of this assessment, those systems within the MRO that are considered predominantly thermal (rather than hydro) systems are assessed based on a 15% reserve margin target. Although this is slightly above the reserve margin target of 14% for the former MAIN members and may result in a more pessimistic resource adequacy assessment of the MRO subregions than actually exists, a common reserve margin target for all of MRO provides for consistency and clarity in the assessment of MRO's resource adequacy.

MRO-U.S. is expected to continue to be a summer-peaking subregion. Current planned capacity reported in the MRO-U.S. region is below the MRO's targets for generation adequacy during the 2010–2015 period. The summer reserve margin for MRO-U.S. is forecast to decline from a high of 21.0% in 2006 to 14.2% in 2010 and 2.4% in 2015.

MRO-Canada is expected to continue to be a winter-peaking subregion. Adequate generating resources for MRO-Canada are forecasted over the next ten-year period. Reserve levels range from 29.5% in the summer of 2006 to 42.5% during the summer of 2015. Reserve levels vary slightly during the winter seasons from 25.4% in winter of 2005–2006 to 26.8% during the winter 2014–2015.

The following discussions provide the detailed resource adequacy assessments for the MRO-U.S. and MRO-Canada subregions. For each subregion, the expected reserve margins for its predominantly thermal systems, predominantly hydroelectric system, and combined generation systems are provided along with a subregional resource adequacy assessment.

MRO-U.S. ASSESSMENT

Expected Reserves for Predominantly Thermal Systems

Table 2 shows reserve margins for the 2006-2015 time period for the predominantly thermal systems of MRO-U.S. As seen in this table, the MRO-U.S. predominantly thermal system is forecast to maintain a 15% or higher summer reserve margin through 2008, beyond which time the reserve margins fall below 15%.

Table 2
MRO-U.S. Predominantly Thermal System Reserve Margins
(Percent of Non-Coincident Annual Demand Adjusted for Sales and Purchases)

	2006	2007	2008	2009	2010	2011	2012	2013	2014	*2015*
Summer	19.7%	18.1%	17.4%	14.9%	13.2%	11.6%	10.9%	7.5%	5.7%	1.2%
Winter	30.8%	30.1%	29.0%	30.2%	28.8%	42.5%	40.6%	37.9%	35.1%	33.4%

Expected Reserves for the Predominantly Hydroelectric System

Table 3 shows the forecast reserve margins for the 2005-2015 time period for the predominantly hydroelectric system of MRO-U.S. As seen in this table, the reserve margin for the MRO-U.S. predominantly hydroelectric system remains at, or above, 15% through 2015.

Table 3

MRO-U.S. Predominantly Hydroelectric System Reserve Margins

(Percent of Annual Demand Adjusted for Sales and Purchases)

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Summer	75.2%	75.2%	75.2%	58.5%	58.5%	59.1%	59.1%	59.1%	59.1%	59.1%
Winter	41.4%	41.4%	41.4%	41.5%	41.5%	41.5%	41.5%	41.5%	41.5%	41.5%

MRO-U.S. Resource Adequacy

Table 4 shows the reserve margins for the 2006-2015 time period for the combined predominantly thermal and hydroelectric systems of MRO-U.S. The subregion is expected to continue to be a summer-peaking subregion. Its summer reserve margin is forecast to decrease from 21.0% in 2006 summer to 2.4% in 2015 summer. The subregion's winter reserve margin varies from 31.1% in 2006 winter to 14.7% in 2015 winter. Because of the different levels of reserve targets for the predominantly thermal (15 percent) and hydroelectric (10 percent) systems, Table 4 does not show whether or not the resources available in MRO-U.S. would adequately meet the assumed reserve targets. This is assessed in Tables 5 and 6.

Table 4

MRO-U.S. Combined Generation Reserve Margins

(Percent of Annual Demand Adjusted for Sales and Purchases)

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Summer	21.0%	19.5%	18.7%	15.8%	14.2%	12.6%	11.9%	8.6%	6.8%	2.4%
Winter	31.1%	30.4%	29.4%	30.5%	29.1%	25.4%	23.4%	20.4%	17.4%	14.7%

Tables 5 shows the summer capacities in MW above the reserve targets for the MRO-U.S. subregion for the 2006-2015 time period. MRO-U.S. had a capacity surplus of 2,671 MW in 2006 summer. This capacity surplus is forecast to decrease to 630 MW in 2009 summer. A capacity deficit of 59 MW is shown as occurring in 2010 summer and reaching 5,625 MW in 2015 summer.

Table 5

MRO-U.S. Summer Capacity in MW above the Reserve Targets

	2006	2007	2008	2009	2010	2011	2012	2013	2014	*2015*
Available Reserve	8,261	7,782	7,633	6,601	6,024	5,451	5,236	3,856	3,088	1,103
Reserve above Reserve Targets	2,671	2,062	1,791	630	-59	-725	-1,061	-2,560	-3,458	-5,625

Table 6 shows the winter reserve capacities in MW above the reserve targets for the MRO-U.S. subregion for the 2006-2015 time period. MRO-U.S. had a capacity surplus of 6,902 MW in 2005-06 winter. This capacity surplus is forecast to decrease to 1,777 MW in 2015-16 winter. Thus, the subregion will have adequate winter generating capacity through 2015-16 winter.

Table 6

MRO-U.S. Winter Capacity in MW above the Reserve Targets

	2006-07	2007-08	2008-09	2009-10	2010-11	2011-12	2012-13	2013-14	2014-15	*2015-16*
Available Reserve	12,714	12,657	12,471	12,702	12,354	10,692	10,054	8,928	7,785	6,702
Reserve above Reserve Targets	6,902	6,707	6,419	6,800	6,356	6,209	5,467	4,251	2,992	1,777

MRO-CANADA ASSESSMENT

Expected Reserves for the Predominantly Thermal System

Table 7 shows the reserve margins for the 2006-2015 time period for the predominantly thermal system of MRO-Canada. As seen in this table, the summer reserve margin for the MRO-Canada predominantly thermal system decreases from 25.4% in 2006 summer to 14.1% in 2015 summer. The winter reserve margin varies from 19.1% in 2006 winter to 7.3% in 2015 winter.

Table 7

MRO-Canada Predominantly Thermal System Reserve Margins

(Percent of Annual Demand Adjusted for Sales and Purchases)

	2006	2007	2008	2009	2010	2011	2012	2013	2014	*2015*
Summer	25.4%	23.9%	22.8%	22.3%	20.4%	18.2%	16.5%	16.1%	14.9%	14.1%
Winter	19.1%	16.5%	16.5%	15.0%	13.2%	11.2%	9.5%	9.2%	8.1%	7.3%

Expected Reserves for the Predominantly Hydroelectric System

Table 8 shows the reserve margins for the 2006-2015 time period for the predominantly hydroelectric system of MRO-Canada. As seen in this table, the summer reserve margin for the MRO-Canada hydroelectric system is forecast to increase from 32.2% in 2006 summer to 63.4% in 2015 summer. The winter reserve margin varies and increase from 28.4% in 2006 winter to 54.6% in 2015 winter.

Table 8

MRO-Canada Predominantly Hydroelectric System Reserve Margins

(Percent of Annual Demand Adjusted for Sales and Purchases)

	2006	2007	2008	2009	2010	2011	2012	2013	2014	*2015*
Summer	32.2%	34.6%	33.7%	34.7%	36.1%	39.1%	41.7%	42.6%	43.1%	63.4%
Winter	28.4%	31.6%	30.6%	32.2%	33.7%	38.6%	39.9%	41.5%	41.8%	54.6%

MRO-Canada Resource Adequacy

MRO-Canada is expected to continue to be a winter-peaking subregion. Tables 9 and 10 show the summer and winter capacity for the 2006-2015 time period for the MRO-Canada combined predominantly thermal and hydroelectric systems. In these tables, the reserve targets are calculated by using an assumed 15% minimum reserve margin for the predominantly thermal system and a 10% RCO for the predominantly hydroelectric system.

As seen from Table 9, MRO-Canada is forecast to maintain a capacity surplus of 1,158 MW in 2006 summer and 2,217 MW in 2015 summer.

Table 9

MRO-Canada Summer Capacity in MW

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Total Generation	8950	8984	9022	9069	9107	9243	9312	9342	9356	9356
Net Internal Demand	5585	5702	5786	5862	5928	5984	6024	6030	6063	6026
Available Reserve	2040	2122	2076	2127	2149	2229	2288	2312	2293	3130
Reserve Targets	883	894	903	912	922	931	937	938	940	913
Reserve above Reserve Targets	1158	1228	1174	1215	1226	1299	1351	1375	1351	2217

As seen from Table 10, the subregion is also forecast to maintain a capacity surplus of 946 MW in 2006-07 winter and 1,665 MW in 2015-16 winter.

Table 10

MRO-Canada Winter Capacity in MW

	2005-06	2006-07	2007-08	2008-09	2009-10	2010-11	2011-12	2012-13	2013-14	2014-15	2015-16
Total Generation	9051	9078	9135	9163	9188	9388	9388	9433	9433	9433	9051
Net Internal Demand	6863	6970	7073	7152	7224	7284	7333	7366	7361	7385	7382
Available Reserve	1809	1771	1845	1823	1859	1874	2025	2022	2072	2048	2551
Reserve Targets	811	825	839	848	857	866	874	881	880	884	885
Reserve above Reserve Targets	997	946	1007	974	1002	1009	1151	1143	1191	1164	1665

TRANSMISSION ADEQUACY AND RELIABILITY ASSESSMENT

OVERVIEW

The existing transmission system within MRO-U.S. is comprised of 7,328 miles of 230 kV, 6,858 miles of 345 kV, and 343 miles of 500 kV transmission lines. MRO-U.S. members plan to add 1,043 miles of 345 kV and 245 miles of 230 kV transmission lines in the 2004-2013 time frame. The MRO-Canada existing transmission system is comprised of 4,578 miles of 230 kV and 130 miles of 500 kV transmission lines. MRO-Canada is planning for an additional 429 miles of 230 kV and an additional 539 miles of 500 kV HVDC transmission in the 2004-2013 time frame. MRO-U.S. and MRO-Canada have a total of 2030 miles of HVDC lines.

MRO members continue to plan for a reliable transmission system, consistent with the NERC reliability standards. Coordination of expansion plans in the region takes place through joint model development and study by the designated subcommittees of the MAPP Regional Transmission Committee and the MISO Expansion Planning Group. These committees include transmission owning members, transmission using members, power marketers, and state regulatory bodies. Together, these planning committees assess the adequacy of the transmission system within the MRO region.

In general, the MRO transmission system is judged to be adequate to meet firm obligations of the member systems, provided that the local facility improvements identified in both transmission plans are implemented. MRO continues to monitor the limiting flowgates within the region.

System stability operating guides involving the transmission facilities connecting Minneapolis-St. Paul to the Iowa and Wisconsin areas continue to manage congestion by limiting energy transfers from northern MRO to Iowa and Wisconsin. The Arrowhead-Weston 345-kV transmission line has been identified as a significant reinforcement to improve the overall performance of this interface. This line is expected to be in service in 2008. Information on the Arrowhead-Weston project can be found at: http://www.arrowhead-weston.com/.

The following discussions provide the detailed transmission adequacy and reliability assessments by area for the MRO footprint: Minnesota, Nebraska, Dakotas, Iowa, Wisconsin-Upper Michigan, and Canada. Except for the Wisconsin-Upper Michigan area, the transmission systems in most of these areas also belong to the MAPP Regional Transmission; and their assessments are based on transmission studies conducted by MAPP and Midwest ISO.

MINNESOTA AREA ASSESSMENT

The Minnesota Area assessment covers the state of Minnesota and the portion of western Wisconsin that is within the MAPP-MISO region. The traditional powerflow pattern in Minnesota is from the northwest to the southeast and central areas of the state. A major portion of the electric load in Minnesota is concentrated around the Twin Cities metropolitan area of Minneapolis-St. Paul, the principal load center of the Xcel Energy North Control Area.

Several bulk transmission system improvement projects in the Twin Cities area have recently been completed or are currently under way, and various additional facility additions and upgrades have been proposed for the study period. Future facility upgrades and capacitor addition in the Twin Cities area, along with selective reconductoring and new line additions, will eliminate currently identified limitations in this area.

Major planned transmission enhancements in the Twin Cities area during the next ten-year timeframe include upgrading the Westgate-Deephaven-Excelsior-Scott County 69 kV circuit to 115 kV (2009-2011)); upgrading Parkers Lake 345/115kV transformers to 672 MVA (2008-2010) and upgrading Eden Prairie 345/115kV transformers to 672MVA (2008-2010).

Committed projects in the Twin Cities area include rebuilding Red Rock-Rogers Lake115 kV line to double circuit (2004); adding a new 345/115kV transmission source at the Sherco substation; reconstructing Monticello-Salida Tap-St. Cloud 115kV to 310MVA summer rating (2006-2007); upgrading St. Louis Park-Aldrich 115kV to 310MVA summer rating (2006); and a new Air Lake-Vermillion-Empire 115kV line (2006-2007).

Shunt compensation at the Westgate (1x80MVAR), substation will address upcoming reactive deficiencies in the south metro area.

Numerous 115 kV substation equipments are schedule to be upgraded in the Twin Cities (Minneapolis/St. Paul) metro area throughout the study period to achieve higher capacity on the lines and ensure adequate load serving capability.

In addition to the improvements in the Twin Cities metro area, Xcel Energy is also pursuing development of transmission upgrades in the area of the Buffalo Ridge wind farms in southwestern Minnesota. The proposed facilities provide transmission outlet capacity for an additional 400 MW of wind generation (825 MW total). The proposed transmission system improvements include:

- A new 94-mile Split Rock (Sioux Falls, SD)-Lakefield Junction 345 kV line;
- An intermediate 345/115 kV station (Nobles Co);
- A 115kV line northward from Nobles Co into the Southwest Minnesota ("Buffalo Ridge") wind farm area;
- A 115 kV line from the Buffalo Ridge area northwestward to the existing White 345/115 kV substation in South Dakota;
- A second Lakefield Junction-Fox Lake 161 kV line;
- A $\pm$ 60 MVAR static VAR compensator at Lake Yankton;
- Several 69 kV, 115 kV, and 161 kV line upgrades;
- Replacement of several 230/115 kV and 115/69 kV transformers
- Additional 115 kV shunts capacitor banks.

These improvements also appear to be highly compatible with other transmission improvements which may be undertaken to further address local and regional load-serving needs, enhance power system transfer capability, or provide outlet capacity for additional generation developments in the Dakotas, Minnesota, and Iowa.

Dairyland Power Cooperative and Xcel Energy have proposed rebuilding the existing Chisago-St Croix Falls-Apple River 69 kV line to higher voltages to provide improved load serving capabilities to areas in east-central Minnesota and northwestern Wisconsin. The Chisago Electric

Reliability Project would consist of the following facilities: a Chisago-Lindstrom-Shafer-Lawrence Creek 115 kV line; a new Lawrence Creek substation located west of Taylors Falls, MN; a Lawrence Creek-St Croix Falls-Border 161 kV line; and a Border-Apple River 161/69 kV double circuit line. A Certificate of Need is expected to be filed for this project in the near future.

Great River Energy has proposed a new 115 kV line in the Baxter-Brainerd area of north central Minnesota. Great River Energy's present and projected loads have exceeded the capability of the existing 34.5 kV system. To improve the reliability of this area, Great River Energy has proposed to build a 115 kV line between Minnesota Power's Baxter and Brainerd substations. Great River Energy's 34.5 kV loads from the Baxter and Southdale areas will then be served from the new 115 kV line. This project is expected to be completed in phases with the load transfer to 115 kV in 2004 with the construction of a Brainerd-Southdale 115 kV line. The Southdale-Baxter 115 kV line portion, which will complete the loop, will be reevaluated for installation at a later time when route options have fully been reviewed.

Other projects proposed by Great River Energy in Minnesota are as follows:

- Hutchinson-Big Swan 69 kV line conversion to 115 kV which was completed in 2004
- Hubbard-Long Lake 115 kV line in 2005
- Elm Creek-Cedar Island-Parkers Lake 115 kV line in 2006
- Mud Lake-Wilson Lake 115 kV line in 2008
- West Cloud-Albany-Sauk Centre-Melrose-Alexandria 115 kV line in 2011
- Lakefield Junction –Watonwan Junction 115 kV in 2008
- New Salida 115/69 kV source on Sherco-Monticello 115 kV line in 2007
- New Linwood 230/69 kV source on Rush City-Blaine 230 kV line in 2007

Minnesota Power and Great River Energy are jointly reviewing the need for additional load serving capability in northern Minnesota. Currently the following lines are being reviewed for submittal to the permitting process:

- Badoura-Birch Lake-Pequot Lakes 115 kV line in 2007
- Badoura-Long Lake 115 kV line in 2008
- 34L Tap-Tower 115 kV line in 2009

Winter season power transfers from MAPP-US to MAPP-Canada are limited by various post-disturbance (loss of 500 or 345 kV transmission) loading and voltage stability concerns in the Red River Valley area of Eastern North Dakota and Northwestern Minnesota. The capability of the transmission system to supply peak loads in and surrounding the Red River Valley has also become limited by these same concerns. The addition of the Harvey – Glenboro 230 kV line, interconnecting Central North Dakota with Western Manitoba has provided short-term (3 – 5 years) relief for this problem; however, planning studies are continuing to determine the appropriate long-term solution.

Recent studies completed for the north central MN region have shown that low voltages are evident for loss of the 230 kV source into the Bemidji area. For this reason, Minnkota Power Cooperative is working together with Otter Tail Power Company to install a second 230/115 kV transformer at the existing Wilton substation. This second transformer will improve service to customers in the area in the event of the existing transformer being out-of-service. The transformer is expected to be in-service by June of 2005. Minnkota Power Cooperative is also planning to tap the Moranville-Shannon 230 kV line at Beaudette to improve load serving in the area.

Growing loads within northwestern Minnesota have driven the need for a larger load serving line between Audubon and Frazee. The existing 41.6 kV system can no longer support voltages during critical contingencies. Therefore, a project has been identified to upgrade the existing 41.6 kV line to 115 kV. The project will actually consist of three parts: the upgrade of the current Audubon – Detroit Lakes 41.6 kV line to 115 kV, continuing this upgrade from Detroit Lakes to Frazee, and upgrading the existing substations along this line to 115 kV. As part of this project, the 115 kV bus at the Audubon substation will also be rearranged. This project is intended to be an extension of the Inman – Rush Lake – Perham – Frazee 115 kV line. Project sponsors include Detroit Lakes Public Utilities, Otter Tail Power Company, Lake Region Electric Cooperative, Great River Energy, Western Minnesota Municipal Power Agency, and Missouri River Energy Services. This 115 kV line went in service in May of 2004.

Missouri River Energy Services has reconductored the 115 kV line from Grant County to Alexandria. This line section has been identified in recent transmission studies to exceed its thermal limit for many contingencies performed for the near-term planning horizon. Growing loads at Elbow Lake, Brandon and within the city of Alexandria within west central Minnesota has driven the need for more capacity along this 115 kV line. This project was completed in November of 2003.

Long-term transmission studies have identified low voltages during summer peak conditions at Elbow Lake, Brandon, and in the vicinity of Alexandria for loss of the 115 kV line section between the Grant County Substation and Elbow Lake. The Great River Energy Long Range Plan has identified this issue and will work with Otter Tail Power Company and Missouri River Energy Services to install a capacitor bank. The GRE plan recommended a 2 x 25 MVAr capacitor bank necessary in boosting the voltages to acceptable levels.

The Arrowhead-Weston transmission project is proceeding as a reinforcement for the bulk transmission system interconnecting Minnesota and Wisconsin. Currently, the Minnesota-WUMS (Wisconsin and Upper Michigan System) interface consists of a single 345 kV transmission line (King-Eau Claire-Arpin), one 115 kV line, one 161/138 kV transformer, and several 69 kV lines. The Arrowhead-Weston project will reinforce this interface by adding a new 345 kV transmission line from the Arrowhead Substation near Duluth, Minnesota to the new Gardner Park substation near Wausau, Wisconsin. A mid line 345/161 kV tap at Stone Lake is also being planned. Other identified planned project facilities at the Arrowhead substation include an 800 MVA 230/345 kV autotransformer, one 800 MVA 230 kV phase shifting transformer and 150 MVAr of 345 kV connected shunt reactive support. At Stone Lake, project facilities include a 300 MVA 345/161 kV autotransformer and 75 MVAr of 345 kV connected shunt reactive support. At the new Gardner Park substation, facilities include 150 MVAr of 115 kV connected shunt reactive support, and two 500 MVA 345/115 kV autotransformers. The Arrowhead - Weston project is scheduled for completion in mid 2008. Detailed technical studies to satisfy MAPP Design Review Subcommittee (DRS) requirements are currently underway to demonstrate overall impacts of this project on MAPP bulk system reliability.

A joint regional study for the Southeast Minnesota and Western Wisconsin area is currently underway by Rochester Public Utility, Xcel Energy North, Dairyland Power Cooperative, American Transmission Company, Alliant Energy, Great River Energy and Southern Minnesota Municipal Power Agency. This study will determine system upgrades needed to accommodate the transmission inadequacies in the following area:

- Rochester and La Crosse Area Load Serving
- Congestion on the Byron – Maple Leaf - Cascade Creek 161 kV line for a contingency on the Byron to Adams 345 line under high export.
- Increase of Minnesota Wisconsin Stability Interface (MWSI) levels.

In summary, the studies that were performed for this assessment show that the existing and planned transmission system in the Minnesota area can operate at all load levels respecting unscheduled contingencies, while meeting the relevant voltage and loading criteria without causing cascading, service interruptions, or instability to major portions of the MRO system.

NEBRASKA AREA ASSESSMENT

The Nebraska transmission network can be divided into two distinct regions for reliability: the eastern region and the western region. Presently, the electrical division between these two regions involves the transmission systems on either side of the Grand Island/Hastings area. Nebraska Public Power District (NPPD) and Omaha Public Power District (OPPD) currently post six constrained paths located within or adjacent to the NPPD and OPPD control areas.

The *Grand Island-Lincoln Interface* is a thermally constrained interface established to maintain reliable operation of the transmission network in this area during all critical first contingencies. High simultaneous north-to-south and west-to-east power flows are characteristic of the Grand Island-Lincoln Interface. The current limitation involves the first contingency outage of the Grand Island – McCool 345 kV line with subsequent overloads on the Grand Island – Aurora 115 kV line.

The *Western Nebraska-Western Kansas Interface* is defined as both a thermal and voltage constrained interface. Under heavy transfer and high load conditions, loss of the GGS-Red Willow and GGS-Sweetwater Ckt#2 345 kV double circuit results in post-contingent line loadings at or near overload limits as well as post-contingent voltages at or near low voltage emergency limits. An 18 MVAR voltage controlled capacitor bank is installed at the Enders 115 kV substation to alleviate the voltage limitations. The primary limiter on the Western Nebraska-Western Kansas Interface is thermal conductor limits on the underlying 115 kV systems.

The *Gerald Gentleman Station Stability Interface* is limited due to transient stability. To prevent the loss of major generating units in the western Nebraska region, NPPD has a Remedial Action Scheme (RAS) at GGS. The GGS RAS arming is dependent on certain critical prior outages and the amount of power flowing east and south of GGS. For combinations that would cause instability, a system of logic sends signals to fast valve GGS Unit #1 or trip GGS Unit #2. Stability limitations of the western Nebraska region have been and continue to be investigated in dynamic simulation studies.

The *Cooper South Interface* is defined to address the first-contingency operating limit on the north-south power transfer capability across this MAPP-Southwest Power Pool (SPP) boundary. The limit involves contingent loss of the Cooper-Fairport-St. Joe 345 kV line with subsequent overloads on the Cooper-St. Joe 345 kV line. Due to lower water levels in the Dakotas and Manitoba resulting in reduced generation levels during the past few years, Cooper South has not experienced the heavy north-to-south flows that it has in previous years.

The *Fort Calhoun South Interface* is defined to address first contingency operating limits on north-south power transfer capability through the OPPD system. The critical contingency for the Ft. Calhoun South interface is outage of the Ft. Calhoun-Sub 3459 and Ft. Calhoun-Sub 3454 345 kV double circuit. For this simultaneous outage, the limiting element is the OPPD Sub 1251-Sub 1297 161 kV line or the Sub 1226-Sub 1252 161 kV line.

The *Sub1226-Tekamah Interface* is a thermally constrained interface established to maintain reliable operation of the northern OPPD transmission network during heavy south-to-north transfers during winter load periods. The current limitation involves the first contingency outage of the Sub 3451-Raun 345 kV line with subsequent overloads on the Sub1226-Tekamah 161 kV line.

The far western Nebraska transmission system is sensitive to the variations in critical sources such as the Laramie River Station (LRS), the Stegall 345/230 kV transformer, and the Stegall and Sidney DC ties. Because of the weak system, contingency voltages may be anywhere from unacceptably low to excessively high. Single contingencies along the Chadron to Snake Creek to Big Spring 115 kV transmission path can result in high or low voltages depending on the loading condition and the location of the contingency. Separation of the 115 kV and 230 kV systems with loss of the Victory Hill or Wayside 230/115 kV transformers can also result in voltages at or near emergency voltage limits. The results of the N-1 contingency screening analysis are consistent with the results of previous assessments. Post-contingency switching of voltage control equipment including transformer LTC's, available capacitors, line reactors and tertiary reactors adequately returns voltages to within normal limits.

In the central Nebraska region, the Canaday 230/115 kV transformer overloads for an outage of the Crooked Creek-Riverdale 230 kV line when the Canaday Steam Plant is off-line. An operating procedure of opening the Canaday transformer eliminates the overloads in the area for this contingency.

In north-central Nebraska, the Ainsworth Wind Facility and associated transmission plans are under construction and should be completed prior to November 2005. This new 60 MW wind facility interconnects to NPPD's transmission system via a new 115/34.5 kV substation on the existing Ainsworth-Calamus-Thedford 115 kV line. The primary components of the transmission plan include a new 115/34.5 kV substation, a dynamic reactive power compensation system, transmission line refurbishment and various substation upgrades.

In eastern Nebraska, the Central City area is susceptible to voltage depression under single contingency events during summer peak loading conditions. To support the load growth in this area, the Central City 115 kV substation is being expanded to support the installation of an 18 MVAR 115 kV capacitor bank and a 115 kV PCB on the Grand Island-Central City 115 kV line. This project is scheduled to be complete prior to June 2005.

In southeastern Nebraska, NPPD completed the Beatrice Power Station addition and associated transmission facility plan in January 2005. The Beatrice Power Station (BPS) was developed as two nominal 80 MW combustion turbines and a nominal 90 MW steam turbine. The BPS generating units are tied into a new Beatrice Plant 115 kV substation, which tapped into the existing Beatrice – Sheldon and Beatrice – Clatonia – Sheldon 115 kV transmission lines. Transmission system upgrades associated with the addition of BPS also including substation related equipment upgrades, line refurbishment and line re-conductoring.

The Lincoln Electric System (LES) will be constructing a new 40th & Rokeby Substation to be supplied by a 1.0-mile double-circuit 115 kV line tapped into the existing 27th & Pine Lake to 56th & Pine Lake 115 kV line. The line and substation have an in-service date of 2006.

A new 3.5-mile radial 115 kV line will supply connect the NW12th & Arbor Substation from to the existing 19th & Alvo Substation. The line and substation have an in-service date of 2005. LES also plans to construct a 10.0-mile 115 kV line from the NW12th & Arbor Substation to the NW63rd & Holdrege Substation. The in-service date for this line is 2007.

LES plans to rebuild the existing 18.2-mile Sheldon – 20th & Pioneers 115 kV line because of deteriorating physical condition due to age; approximately 3.0-miles have already been rebuilt as the result of repairing storm damage. This 115 kV line will be rebuilt to a capacity of roughly 363 MVA. However, LES has not finalized a transmission plan, and the final plan may also incorporate rebuilding the 5.5-mile Rokeby – 20th & Pioneers 115 kV line to a higher capacity. The final transmission plan should be determined during the year 2005, but the project is not expected to begin prior to the year 2008.

LES will construct a 26-mile 345 kV line from the Wagener Substation to NW68th & Holdrege Substation, around the northern perimeter of Lincoln. This 345 kV line has an in-service date of 2008 that has been tentatively committed to by LES as part of the Nebraska City Unit 2 transmission plan.

LES plans to install a second 345/115 kV transformer at the NW68th & Holdrege Substation, with an in-service date currently projected for 2010. This transformer was not modeled for this assessment since its in-service date is currently being reviewed.

In January 2004, Lincoln Electric System's NW68th&Holdrege 345/115 kV 336 MVA transformer had an internal fault, which caused extensive damage. This transformer is a critical interconnection to the bulk transmission system through the NW68th&Holdrege-Moore 345 kV transmission line. Due to the criticality of this interconnection during heavy summer peak loading, a transmission plan was developed to re-configure the existing NW68th&Holdrege-Moore 345 kV as a 115 kV line, which would tap into the existing LES Sheldon-2nd&N 115 kV line. This three-terminal line option provides an additional transmission inlet source for serving the City of Lincoln during heavy summer peak loads and will remain configured until the NW68th & Holdrege transformer is replaced prior to Fall 2005.

The Omaha Public Power District (OPPD) is planning to construct a second coal-fired generating unit at the Nebraska City Power Station. Nebraska City Unit 2 (NC2) is expected to begin commercial operation in the spring of 2009 with an approximate nominal net output of 700 MW. The NC2 project consists of the NC2 generating unit and transmission expansion facilities, which include the construction of a new 345 kV substation (Southeast Lincoln), which will be tapped into the existing Wagener-Moore 345 kV line to accommodate a new 345 kV line from Sub 3458 (Nebraska City). Additional line upgrades as well as substation reconfigurations, additions and equipment upgrades are also planned with the NC2 project.

A new 161 kV line is being constructed from Substation 1206 to Substation 1217 with a new 161 kV load serving substation, Substation 1216, cut in the middle of this new line. The portion of the line from Substation 1206 to Substation 1216 is scheduled to be completed by summer of 2005, and the remaining portion of the line from Substation 1216 to Substation 1217 is scheduled to be completed in the Fall of 2005.

A second new 161 kV line is being constructed from MEC's 161 kV substation at the Council Bluffs Energy Center to Substation 1206 and is scheduled to be in service by the summer of 2005. This line is being constructed in conjunction with MEC's new CBEC4 power station. Substation 1206 will be expanded and upgraded due to the interconnection of this new 161 kV line.

In summary, the existing and planned transmission system in the Nebraska area can operate at all load levels respecting unscheduled contingencies while meeting the relevant voltage and loading criteria without causing cascading, service interruptions, or instability to major portions of the MRO system.

DAKOTAS AREA ASSESSMENT

Several projects under study for the Dakotas include wind generation facilities with combined output in the hundreds of megawatts during the next ten-year period. New coal-fired units are also under study. The Dakotas are a net exporter of energy.

A large dairy plant in northeastern South Dakota expanded its facility, which prompted Otter Tail Power Company to convert an existing 41.6 kV line to 115 kV out of the Toronto substation in South Dakota. This project was completed in January of 2004 and will insure adequate voltage levels to the customer during all system conditions.

A feasibility study is currently underway to determine system improvements needed to accommodate the interconnection of a new 600 MW coal-fired generation plant at the existing Big Stone plant. Two separate transmission alternatives are being evaluated during the feasibility study to determine the impacts of adding the new plant with each transmission alternative. Each alternative currently under review includes two new 230 kV lines going east of the plant into southwestern Minnesota. The study is currently assuming a 2011 in-service date for the new generating unit.

Stability simulations showed improvement in transient voltage performance for the future cases under similar conditions of high simultaneous NDEX/MHEX/MWSI exports. These improvements are due to planned improvements to the system such as various capacitor bank and transmission line additions that are shown in the out year models in adjacent regions such as Minnesota and Iowa. Export interface limits are defined under high simultaneous transfer conditions (NDEX/MWSI/MHEX), and are limited by various thermal, voltage, and stability limitations. North Dakota is dynamically limited by low voltage swings in the Wahpeton area and thermally limited by heavy line loading of the 115 kV and 230 kV lines in eastern South Dakota near Watertown/Groton for loss of the parallel 345 kV system. Lack of adequate base load generation to serve the Sioux Falls load center seems to aggravate this situation. A new 345 kV line from Lakefield to Sioux Falls is being planned to improve load-serving capability in the Sioux Falls region as well as provide necessary transmission to serve the expected growth in wind generation in that area.

In summary, the existing and planned transmission system in the Dakota region can operate at all load levels respecting unscheduled contingencies while meeting the relevant voltage and loading criteria without causing cascading, service interruptions, or instability to major portions of the MRO system.

IOWA AREA ASSESSMENT

Characteristics of System

The Iowa electric system is split between the Alliant, MidAmerican, and several cooperative / municipal electric systems and consists mainly of 345, 161, and 115 kV transmission facilities. The Alliant system is under Midwest Independent System Operator control (MISO), which assumed security responsibilities for its members in Iowa and southern Minnesota in December of 2001. Security analysis is being coordinated by MISO with existing control area operators. The MidAmerican system is under the Mid-Continent Area Power Pool control.

Applicable Planning Standards

The Iowa electric system is planned in accordance with the North American Electric Reliability Council (NERC), MISO, MAPP, and local system planning criteria as filed in by the individual utilities in FERC Form 715.

Overall System Reliability Assessment

The electric system has been evaluated for system normal, N-1, N-2, some breaker failure, and known multiple element contingencies. Any thermal, voltage, or dynamic violations have budgeted reinforcements and/or operating guides that are used to mitigate the violations. The Iowa electric system meets all the required thermal, voltage, and dynamic performance criteria.

Past powerflow studies have shown the following potential problem areas:

1. Marginal voltages in North Central Iowa for loss of the Webster 345/161 kV transformer and/or radial Lehigh – Webster 345kV line. An operating guide was developed that identified local area capacitor banks and generation that could be used to return voltages to acceptable levels. The addition of a large amount of wind generation on the 161 kV systems in northwest and north central Iowa should help this condition.
2. Marginal voltages and 115 kV transmission overloads for the Marshalltown area (Central Iowa) for outages on the 161 kV system. These problems should be diminished or eliminated by future planned upgrades for the Marshalltown area.

Constraints

Constrained interfaces were defined in Iowa due to heavy bulk power transfers from MAIN to MAPP and SPP. The Quad Cities West flowgate (6081) was defined in May of 2001, the Poweshiek – Reasnor flowgate (3704) was defined in July of 2001, and MidAmerican redefined the MAPP Montezuma West flowgate ATC in 2004. The Alliant Energy system also has a number of flowgates defined for transmission service and security analysis primarily in eastern Iowa with the major concerns being loss of the Quad Cities-Rock Creek 345 kV, loss of the Arnold-Hazleton 345 kV, and loss of Montezuma-Bondurant 345kV.

Alliant Energy has upgraded its 161 kV system in the Dubuque, IA area for increased capacity for issues caused by loss of the Wempleton-Paddock 345 kV line connecting Illinois and Wisconsin. Alliant Energy is also rebuilding the Poweshiek-Reasnor 161 kV line to mitigate overloading due to loss of the Montezuma-Bondurant 345 kV line. MidAmerican continues to monitor the Quad Cities West and the Montezuma - Bondurant flowgates for flows and potential upgrades.

The base MAPP-MISO models do not contain all of the underlying 69kV system in North Central Iowa by specific request. The MAPP-MISO models added these underlying 69kV facilities since many of the North Central Iowa voltage and thermal limitations shown in the base

MAPP-MISO models are diminished or eliminated with the addition of the underlying 69kV system.

Major Projects

Marshalltown Area Improvements:

1. ALT/CIPCO has been studying the Marshalltown area to identify possible solutions. The results from the studies include the upgrade of portions of the 34.5 kV system to 69 kV (expected in-service date of 6/1/07), the addition of 69 and 115 kV capacitors (expected in-service date of 12/31/06), and a proposed long-term plan to upgrade a portion of the 115 kV system to 161 kV.

These projects are needed to relieve potential thermal overloads and low voltages near the Marshalltown area.

Ankeny Area Improvements:

1. The MidAmerican Ankeny – NE Ankeny 161kV line has an expected in-service date of 3/1/05. MidAmerican plans to construct 6.5 miles of 161kV line from Ankeny to NE Ankeny.
2. The MidAmerican Ankeny – Sycamore 161kV line has an expected in-service date of 6/01/05. MidAmerican plans to construct 7.0 miles of 161kV line from Ankeny to Sycamore.

These projects are needed to serve load growth in the Des Moines and Ankeny areas.

Cedar Falls Utility Union Sub-MidAmerican Deere Engine Sub:

1. Cedar Falls Utilities (CFU) is proposing to build an 8.5 mile 161kV transmission line from CFU's Union Sub to MidAmerican's Deere Engine Sub with a new 161-12.47kV substation proposed in the southern part of the Cedar Falls Industrial Park. The project is expected to be in-service in the spring of 2005.

This project is needed to serve load growth in the Cedar Falls area.

Iowa Wind Generation Interconnections:

1. MidAmerican has received approval to expand its 310.5-megawatt wind project by 50 megawatts, for a total 360.5 megawatts. An additional 15 wind turbines will be constructed at MidAmerican's Intrepid Wind Project site in Sac and Buena Vista counties in northwest Iowa, and 35 additional turbines will be added to the Century Wind Project site in Wright and Hamilton counties in north central Iowa. The wind project is scheduled to be completed in 2005 with a total of 257 wind turbines.

MidAmerican Greater Des Moines Energy Center:

1. The MidAmerican Greater Des Moines Energy Center was placed in service in 2003. The remaining heat recovery steam turbine was placed in-service in early 2005.

Council Bluffs Energy Center Unit 4 and Associated Upgrades:

1. MidAmerican Energy Company is constructing a 790 MW, coal-fueled electric generating plant. The new plant will be developed on the current site of the existing Council Bluffs Energy Center (CBEC), located four miles south of Council Bluffs along Interstate 29. The plant will be operated by MidAmerican Energy Company but jointly owned. The site already contains three other units with a combined electrical generation capacity of more than 800 megawatts.
2. The CBEC – Grimes 345 kV line has an expected in-service date of 3/01/07. Plans include construction of a 140 mile Council Bluffs Energy Center (CBEC) – Grimes 345 kV line for Council Bluffs #4 outlet generation and construction of a new 345 kV Grimes substation near where the Sycamore-Lehigh 345 kV line leaves common right-of-way with the Booneville-Sycamore line, including a six terminal 345 kV ring bus, three terminal 161 kV ring bus and 345-161 kV 560 MVA auto-transformer.
3. The CBEC – Sub 1206 kV (Iowa – Nebraska tie) line has an expected in-service date of 5/01/05. Plans include the construction of a 9-mile 161 kV line from Council Bluffs Energy Center to OPPD Substation 1206 using T2-795 ACSR conductor or equivalent.
4. The CBEC – Avoca 161 kV rebuild has an expected in-service date of 12/31/06. Plans include the rebuild and re-conductor of 33 miles of the CBEC to Avoca 161 kV line using T2-556 ACSR or equivalent.
5. CBEC 345/161 kV 560 MVA Transformer Unit 2 – Expected in-service 5/01/05. Plans include the installation of a second 345-161 kV 560 MVA auto-transformer at Council Bluffs Energy Center to provide generation outlet capability.
6. The Grimes 345/161 kV 560 MVA transformer has an expected in-service date of 12/31/06. Plans include the installation of a 2nd 345-161 kV 560 MVA auto-transformer at the new Grimes substation.
7. A 17-mile Booneville - Norwalk 161 kV line has an expected in-service date of 9/01/06.

In summary, the existing and planned transmission system in the Iowa area can operate at all load levels respecting unscheduled contingencies while meeting voltage and loading criteria without causing cascading, service interruptions, or instability to the MRO system.

WISCONSIN-UPPER MICHIGAN SYSTEM (WUMS) ASSESSMENT

Characteristics of System

The WUMS electric transmission system encompasses the service territories of Alliant Energy – WP&L, We Energies, Wisconsin Public Service Corporation, Madison Gas & Electric Company, Upper Peninsula Power Company, and several cooperative and municipal electric systems consisting of 345-kV, 230-kV, 161-kV, 138-kV, 115-kV, and 69-kV transmission facilities. The WUMS electric transmission system is owned and operated by American Transmission Company, LLC (ATCLLC), which is an independent transmission company. ATCLLC's purpose is to provide a transmission system that reliably transfers power between producers and users. ATCLLC does not own or operate generation; its Balancing Authority customers are responsible for load and resource planning. The WUMS system is controlled by Midwest Independent System Operator (MISO), which assumed security responsibilities for its members in December of 2001.

Overall System Reliability Assessment

ATCLLC determined that its transmission system would meet the requirements in NERC Standards TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0 for the short term (2006 – 2010) and long term (beyond 2011) planning horizons, particularly at 100 kV and higher. To meet these requirements, ATCLLC needs to complete the projects (or their equivalents) that are listed in its 10-year construction schedule (Ref. 1). In some circumstances, interim remedial measures such as magnetic energy storage devices, special protection systems, and pre-contingency operating procedures are installed, or will be installed, until permanent system reinforcements can be placed in service.

This assessment is based primarily on the *ATCLLC 2005 10-Year Transmission System Assessment* (Ref. 1), ATCLLC Generator Interconnection Studies (Ref. 2), additional ATCLLC "in-house" planning studies (Ref. 3), and regional planning studies (Ref. 4, 5, 6, 7, 8, & 9). These studies were based primarily on analyses performed using MMWG 2004 series models (e.g. 2006 summer, 2010 summer, and 2014 summer) that included the latest ATC system details.

Thermal and Voltage Assessment

ATCLLC determined that its transmission system would meet the thermal and voltage requirements in NERC Standards TPL-001-0 through TPL-004-0 for the short term (2006 – 2010) and long term (beyond 2011) planning horizons, particularly at 100 kV and higher. The assessment of TPL-001-0 (normal) and TPL-002-0 (single element) requirements was based primarily on the 2005 10-Year Assessment Update (Ref. 1), ATCLLC generation interconnection studies (Ref. 2), and Addendum to MAIN 2014 Future System Voltage Study (Ref. 5).

An additional screening study, *Assessment of NERC Category C Compliance of the ATC Transmission System* (Ref. 3), other ATCLLC studies (Ref. 4), and *Addendum to MAIN 2014 Future System Voltage Study* (Ref. 5) were performed to address the TPL-003-0 (multiple elements) and TPL-004-0 (extreme events) requirements.

Transfer Capability

ATCLLC determined that the Wisconsin-Illinois, the Wisconsin-Michigan, and Wisconsin-Minnesota interfaces have some transfer capability issues for the short term (2006 – 2010) and long term (beyond 2011) planning horizons, particularly at 100 kV and higher. Historically, the transfer capability of each interface has been limited at various times for specific circumstances. The assessment of the Wisconsin-Illinois interface is partially based on the *Transmission System Impact Study, Evaluation of Proposed Wempletown-Paddock 345-kV Line* (Ref. 6). The assessment of the Wisconsin-Michigan interface is in part based on the *State of Michigan - Capacity Need Forum & Transmission Transfer Capability Study* (Ref. 7). The assessment of the Wisconsin-Minnesota interface is partially based on the *Southeastern Minnesota-Southwestern Wisconsin Reliability Enhancement Study* (Ref. 8), and the *2014 MAIN Summer Future System Study* (Ref.9).

Transient Stability Assessment

Transient Stability assessments performed by ATCLLC did not show any stability violations for the short term (2006 – 2010) and long term (beyond 2011) planning horizons, particularly at 100 kV and higher. In most cases, the fulfillment of TPL-001-0 (normal) and TPL-002-0 (single element) requirements was evaluated in ATCLLC Generation Interconnection studies (Ref. 2) or inferred from the adequacy results from TPL-003-0 (multiple element) and TPL-004-0 (extreme event) analyses.

The fulfillment of TPL-003-0 (multiple element) and TPL-004-0 (extreme event) requirements was primary evaluated in the *American Transmission Company (ATCLLC-NERC Category C) I.A.M3 Compliance Report* (Ref. 3) and the *MAIN Future Systems Studies Group (FSSG) Study of Selected NERC Category C and D Contingencies for 2009 and 2014 Summer Conditions* (Ref. 4). For both of these studies, ATCLLC investigated any results of concern and concluded that the concerns could be addressed or that potential cascading would not extend beyond the locally affected areas.

Small Signal Stability Assessment

The 2006 MRO small signal stability analysis is being performed for the WUMS system for the short term (2006 – 2010) and long term (beyond 2011) planning horizons, particularly at 100 kV and higher.

Major ATC System Projects for 2006 and beyond

A simple list of major planned, proposed, or provisional projects for the ATC system for the short term (2006 – 2010) and long term (beyond 2011) planning horizons is given below. A more extensive list and further details of major and minor ATCLLC projects can be found in the *2005 10-Year Transmission System Assessment Update* (Ref. 1).

- Add North Madison 345/138-kV transformer capacity (2006)
- Rebuild the Plains-Amberg-Stiles 138-kV double circuit line (2006)
- Convert the Columbia-North Madison 138-kV line to 345 kV (2006)
- Uprate the Fox River-Forest Junction 345-kV line (2006)
- Add a Gardner Park-Stone Lake 345-kV line (2006)

- Add a Stone Lake-Arrowhead 345-kV line (2008)
- Add Plains 345/138-kV transformer capacity (2008)
- Add a Morgan-Central Wisconsin-Werner West 345-kV line (2009)
- Add a Gardner Park-Central Wisconsin 345-kV line (2009)
- Upgrade Pleasant Prairie 345-kV breakers (2009)
- Add a Paddock-Rockdale 345-kV line (2010)
- Add a Salem-West Middleton 345-kV line (2013)
- Add a Rockdale-West Middleton 345-kV line (2011)
- Add Oak Creek-Brookdale 345-kV line (2013)
- Add Brookdale-Granville 345-kV line (2013)
- Upgrade the Oak Creek 345-kV bus (2013)
- Add a West Middleton-North Madison 345-kV line (2014)

ATC presently has 1116 miles of 345 kV and 88 miles of 230 kV transmission line circuits within the MRO. There are no 500 kV or 765 kV circuits within the MRO at this time. If the major ATC projects proposed for the next 10 years are built, then the ATC circuit miles would change to 1613 miles of 345 kV and 72 miles of 230 kV transmission line circuits.

Operational Issues

The ATCLLC transmission system is potentially susceptible to voltage instability during heavy MAPP to WUMS transfers (Ref. 10). The default interface limit is defined as an Interconnection Reliability Operating Limit (IROL) and is closely monitored and managed by MISO to no more than 790 MW. In addition the MISO conducts a daily P-V analysis and establishes lower transfer limits when necessary to help prevent voltage instability.

Construction outages are scheduled at the Upper Peninsula of Michigan and Wisconsin interface that will continue throughout the summer of 2006. The interface limit during construction outages is expected to be adequate.

Reactive power reserve deficiencies are emerging under high load conditions in the Madison area for an outage of one of the Columbia units and in the Milwaukee area for the simultaneous outage of Oak Creek Unit #8 and a local 345 kV line. These system situations can be addressed in the near term with generation redispatch. System improvement options to address these challenges are still under review.

Summary

Based on ATCLLC's latest assessments, the WUMS transmission system is expected to meet NERC Standards for the latest forecasts of expected loads, generation, and firm transactions in the short term (2006 – 2010) and long term (beyond 2011) planning horizons, particularly at 100 kV and higher.

Reference Documents

1. *ATCLLC - 2005 10-Year Transmission System Assessment Update, March 2006.* http://www.atc10yearplan.com
2. *ATCLLC Generator Interconnection Studies – MISO Generator Interconnection Studies*. http://www.midwestiso.org/plan_inter/documents/Public_Queue.htm
3. *American Transmission Company (ATCLLC-NERC Category C) I.A.M3 Compliance Report – December 15, 2004.*
4. *MAIN Future Systems Studies Group (FSSG) Study of Selected NERC Category C and D Contingencies for 2009 and 2014 Summer Conditions – March 2005.*
5. *Addendum to MAIN 2014 Future System Voltage Study – January 2006.*
6. *Transmission System Impact Study, Evaluation of Proposed Wempletown-Paddock 345 kV Line – November 24, 2003*
7. *State of Michigan - Capacity Need Forum & Transmission Transfer Capability- January 2006.* http://www.cis.state.mi.us/mpsc/electric/capacity/cnf
8. *Southeastern Minnesota-Southwestern Wisconsin Reliability Enhancement Study – July 20, 2005.*
9. *2014 MAIN Summer Future System Study- Including MAIN-ECAR-TVA, MAIN-MRO-SPP, and MAIN-SERC WEST Interregional Appraisals – November 2005.*
10. *MISO Summer 2005 Coordinated Seasonal Transmission Assessment – May 31, 2005.*

CANADIAN AREA ASSESSMENT

The Canadian area of MRO consists of the Manitoba Hydro (MH) and SaskPower (SPC) systems. The Manitoba Hydro system is synchronously interconnected to the SaskPower system to the west via three 230 kV and two 115 kV lines and to the Ontario Hydro Networks Company (OHNC) system to the east with two phase-shifted 230 kV lines. The SaskPower system also has a back-to-back HVdc link with the province of Alberta (WECC system) to the west. To the south, the Canadian area system is interconnected with the US part of the MRO system through a 500 kV line and three 230 kV lines in the MH system, a phase-shifted 230 kV line in SPC system, and a phase-shifted 115 kV line from the northwest OHNC system.

The Canadian area system reliability assessment is based on the results from steady state power flow and transient stability analysis for the summer peak and winter peak system conditions in the years 2004, 2009, and 2013. The analysis is conducted considering a set of NERC Table I disturbances that are associated with the system facilities in the MH and SPC systems and the interconnections of the Canadian area system with the USA, including Categories A, B and C.

Manitoba Hydro System

The MH system has approximately 5500 MW of total generation. The system is characterized by approximately 3600 MW of remote hydraulic generation located in northern Manitoba and connected to the concentration of load in southern Manitoba via two HVdc links specifically two 900 km HVdc transmission lines designated as Bipole 1 and Bipole 2. MH also has about 1450 MW of hydraulic generation and 480 MW thermal generation distributed throughout the Province. A NUG wind farm near St. Leon (southern Manitoba), capable of 99 MW, was connected to the Manitoba Hydro system in spring of 2005. The interconnection studies have been completed, but DRS review has not been completed to date. Manitoba Hydro plans to add a new hydraulic generating station in northern Manitoba in 2012 called Wuskwatim capable of 200 MW. The new generation and associated transmission facilities required to integrate the proposed generator into the Manitoba Hydro system will significantly improve the reliability of the northern AC system. The project has not yet been brought to the DRS for review.

The power flow base cases used for this assessment are derived from the 2003 series MAPP models. ACCC contingency analysis is performed for normal and disturbed system against the NERC transmission system performance criteria. System transient stability is tested by time domain simulation of various faults that result in loss of transmission elements.

For normal operations with all facilities in service, the Manitoba Hydro system demonstrates adequate performance in term of facility loading and voltages with various operating conditions for the 10-year period.

The ACCC results for single and double circuit contingency disturbances indicate some criteria violations in the Manitoba Hydro system. These violations and planned mitigations are briefly summarized as follows.

The 115 kV line HS5 from Harrow to Scotland may be overloaded upon loss of sources of supply to the Winnipeg Central system. This problem will be alleviated by adjusting the phase-shifting transformers at Scotland.

Loss of some MH double circuit lines cause slight overloading of parallel circuits. No cascade tripping of other lines occurs. The loss of the Dorsey – Ridgeway and Rosser – Ridgeway 230 kV double circuit tower lines causes the 230 kV line from Dorsey to St. Vital to be overloaded to 102 percent. A 110% 30-minute overload rating is permitted for double circuit tower line trips as pre-disturbance loading is well below line rating. Upgrading of the risers at St. Vital station will mitigate this problem. The loss of the two 230 kV lines from Dorsey to LaVerendyre stations that are on the same tower cause the remaining line from Dorsey to LaVerendrye to be slightly overloaded. A 115% 30-minute overload capability is allowed on this line for the loss of both circuits of a parallel double circuit line.

The MH hydraulic system generation is planned based on historical dependable river flows in drought conditions in order to meet firm winter peak load and firm export contracts. Consequently, during periods of normal or above normal river flows, large amounts of surplus energy are available for export on a short-term or seasonal basis. Conversely, MH may have to import power during extended periods of below normal river flows.

The interconnected system is expected to remain intact for an outage of one HVdc bipole for all the system conditions considered throughout this assessment period. A MH to US transfer capability (MHEX_S) of 2175 MW or higher is achievable over the 2004-13 assessment period. The MHEX_S limit can occur simultaneously with an NDEX of 1950 MW, an SP to US transfer of 165 MW, an OHNC to Minnesota Power (MP) transfer of 150 MW, and a Minnesota to Wisconsin stability interface (MWSI) at 1480 MW.

The MHEX is stability limited by transient performance criteria following severe faults in Manitoba, the Twin Cities area, and North Dakota. Stable operation at this transfer level is also contingent upon successful operation of the Dorsey-Forbes 500 kV line Special Protection System (SPS), which rapidly reduces the HVdc power level following contingencies which result in the outage of any portion of the line or associated facilities.

A US to MH firm transfer capability (MHEX_N) of 700 MW can be achieved in the winter peak conditions. This transfer level is determined with a US to SP transfer of 165 MW, and an MP to OHNC transfer of 100 MW. This simultaneous US to MH transfer is limited by transient stability and post-disturbance overload concerns.

The maximum MH-OHNC east and west total transfer capability of 288 MW is supported by the Manitoba – Ontario Operating Guide. These transfers are limited by voltage decline criteria and transmission system constraints in MH and OH.

The maximum MH-SP transfers of 475 MW east and 450 MW west are supported by the Manitoba – SaskPower Operating Guide. These transfer levels are limited by the post contingency voltage and overload criteria.

<u>SaskPower System</u>

The SPC system has approximately 3856 MW (gross) of installed generation, and 12,159 km of installed transmission and sub-transmission. The installed generation is composed of approximately 2830 MW (gross) of thermal generation, 855 MW of hydraulic generation, and 171 MW of wind generation distributed throughout the province of Saskatchewan. The transmission system is characterized by long transmission lines (230 kV and 138 kV) interconnecting dispersed load centers and bulk delivery supply points.

The SPC transmission system is adequate to meet firm obligations for the short, mid, and long-term planning horizons, provided that the local facility improvements identified in SaskPower's five-year Capital Budget and ten-year transmission plan are implemented. No major internal transmission constraints are expected that will impact reliability in Saskatchewan. No major external transmission constraints are expected that will impact reliability in Saskatchewan, as SaskPower does not rely on external resources.

The following major projects are currently budgeted for in order to maintain adequate BES reliability in the SPC system:

- Addition of a new 230 kV switching station in the Meadow Lake area including the installation of a 230-138 kV 200 MVA auto-transformer. Project provides reinforcement for the local area. Scheduled in-service date is early 2009.
- Addition of a 3rd 230-138 kV 250 MVA auto-transformer at the Regina switching station. Project mitigates post-contingency overloads on the existing transformers. Scheduled in-service date is early 2009.
- Addition of a 200 MVAr SVS at the Pasqua switching station. Project mitigates post-contingency voltage support issues in the Pasqua area. Scheduled in-service date is early 2009.
- Addition of a 184 km 230 kV transmission line from the Poplar River to Pasqua switching stations, and a 230-138 kV 333 MVA auto-transformer at the Pasqua switching station. Project mitigates post-contingency overloads and voltage support issues in the Regina and Pasqua area. Scheduled in service date is mid 2009.
- Various 230 kV and 138 kV transmission line up-rates and rebuilds.

Saskatchewan - Manitoba and Saskatchewan - North Dakota transfer capabilities are supported by the current versions of the SaskPower Operating Guides dealing with transfer capability. Transfer levels are limited by the post contingency voltage and overload criteria.

Summary

In summary, the existing and planned transmission system in the Canadian area can operate at all load levels and firm transfers respecting unscheduled contingencies while meeting the relevant voltage and loading criteria without causing cascading, firm service interruptions, or instability to major portions of the MRO system.