5. SYSTEM CAPACITY

5.1 Introduction

Minn. Rules pt. 7849.0280 requires information about GRE's capability of meeting the forecast demand with existing transmission and generation facilities and the extent to which that capability will be enhanced by the proposed new transmission line.

Many of the informational requirements of 7849.0280 relate to generation facilities and, because increased generation is not necessary to meet the forecasted demand in the WHCEA system, GRE requested an exemption from several portions of 7849.0280. The Commission, in its July 2, 2002 Order, agreed and limited the information required under the rule to that specified in subparts A and H. Subpart A requires a general discussion of the planning process used by GRE and subpart H requires a graph depicting the levels of demand and capacity anticipated before and after completion of the proposed line. The information below therefore focuses on the planning programs and agencies utilized by GRE in determining the best means of meeting the forecast demand for the WHCEA Plymouth-Maple Grove load center.

5.2 Transmission Planning Programs – Standards and Criteria

GRE plans, designs and operates its generation and transmission facilities in accordance with industry standards, criteria and processes. Principal among those are the standards and criteria established by the North American Electric Reliability Council (NERC), the National Electric Safety Code, and the MAPP implementation processes.

5.2.1 North American Electric Reliability Council

Reliability standards for electric transmission planning are established by NERC. Since its formation in 1968, NERC has operated primarily as a voluntary organization based on reciprocity and mutual self-interest. Its main purpose is to maintain electric system reliability in North America. As currently constituted, NERC is a not-for-profit corporation made up of ten Regional Councils throughout the country. Regional Council members come from all segments of the industry and account for virtually all the electricity supplied in the United States and Canada. MAPP serves as one of the NERC's Regional Councils.

Compliance with NERC's standards is mandatory for market participants, but, as a private entity, NERC lacks independent legal authority to enforce these standards. The growth of competition and the structural changes taking place in the industry are causing participants to re-examine the current system of voluntary compliance. NERC is presently working to incorporate a contract-based enforcement mechanism among the ten Regional Councils. NERC is also undergoing a transformation into the “North American Electric Reliability Organization” (NAERO). Like NERC, NAERO's principal focus will be on the development and implementation of reliability standards throughout North America. Proposed federal legislation provides NAERO with statutory, as opposed to contractual, authority to enforce reliability standards among all market participants.

The NERC planning standards apply primarily to the "bulk" electric system, meaning the electric generation resources, transmission lines, and interconnections generally operated above 100 kV. These systems must be capable of performing under a wide variety of expected system conditions, and must be planned to withstand probable forced maintenance outages and other service interruptions known as "contingencies." The standards are designed to keep the interconnected system planned, designed, and operating to withstand a number of contingencies caused by the loss of a generation unit, transmission line, or other system failures. The standards require companies to continually keep the system in a secure state (able to withstand the next contingency, even after one or more contingencies have already occurred).

NERC's reliability standards can be found on its website, http://www.nerc.com/standards.

5.2.2 National Electric Safety Code

The National Electric Safety Code (NESC) provides a second set of planning criteria. The NESC governs the design, construction and operation of electric utility transmission facilities to ensure public and employee safety.

The NESC was initially defined in the 1920s and is currently revised every five years following extensive research and review. A complete discussion of NESC standards can be found at http://standards.ieee.org/nesc/newssites.html.

The NESC specifies the physical clearances and the mechanical strength of structures and equipment required to ensure safe operation of high-voltage electrical facilities such as transmission lines and substations. Consideration of the Code's line-ground and line-line clearances, coupled with the Code's mechanical strength requirements, determines whether existing transmission lines can be reconductored or converted to higher voltages. The Code's provisions also establish the minimum clearances required from adjacent structures, such as buildings.

5.3 Regional Planning Under MAPP

National reliability standards and criteria are implemented in the Upper Midwest through MAPP, the Mid-Continent Area Power Pool. Organized in 1972, MAPP is a voluntary association of electric utilities and other electric industry participants operating under contract to facilitate the pooling of generation and transmission services. MAPP's goals are to ensure that the regional interconnected electric system is operated securely and efficiently, and that the economic benefits of power pooling are equitably shared through coordination, consistent standards and enforcement.

MAPP has approximately 107 members, including investor-owned utilities, electric cooperatives (including GRE), municipal utilities and public power districts, a federal power-marketing agency, private power marketers, regulatory agencies, and independent power producers. It currently performs the following three core functions:

- It serves as one of the ten regional councils within NERC, and as such is responsible for the safety and reliability of the bulk electric system;

- It is a regional transmission group, responsible for facilitating open access of the transmission system as required by the Federal Energy Regulatory Commission (FERC); and

- It provides a power and energy market where MAPP members and non-members engage in the buying and selling of electric energy, capacity, and ancillary services at wholesale.

The process by which regional transmission planning and analysis occurs begins with each MAPP member that owns and/or operates transmission facilities. Pursuant to MAPP’s Restated Agreement, these members are required to prepare and maintain comprehensive plans for their transmission facilities that conform to reliability and transmission assessment standards established by NERC and implemented on a regional basis by MAPP. At a minimum, these plans assess the following:

- the member’s current and expected transmission requirements to serve its retail and wholesale customers,

- its present and future network and firm transmission service (i.e. wheeling service) obligations,

- its coordination with neighboring utilities’ plans, and

- any other contractual or regulatory obligations that in any way affect its transmission facilities.

Once completed, these plans are submitted to the Sub-regional Planning Groups (SPGs).

MAPP has established five SPGs to facilitate regional planning. The SPGs provide a forum to coordinate the individual member plans and to incorporate the planning expertise of the members' planning staff. The SPGs also facilitate the coordination of plans between SPGs and neighboring non-member utility systems.

Each SPG assesses the adequacy of proposed member plans to best meet the needs of the sub-region. It then develops a coordinated sub-regional transmission plan for the ensuing ten years, including alternatives for all transmission facilities in the sub-region at a capacity of 115 kV or greater. Sub-regional plans are designated to:

- Identify load serving problems;
- Identify transfer capability limitations within the sub-region and with neighboring sub-regions and regions;
- Identify transmission needs for new generation based on requests of generation owners;
- Propose and study transmission expansion alternatives;
- Recommend preferred alternatives;
- Address sub-regional deficiencies identified by MAPP's regional transmission plan (Regional Plan) (discussed below); and
- Provide assessment of impacts of MAPP's Regional Plan on the sub-region.

The completed sub-regional plans are then submitted to MAPP's Transmission Planning Sub-committee (TPSC), a sub-committee of the Regional Transmission Council (RTC), biennially on or before June 1.

Using both the individual and sub-regional plans as a basis, TPSC develops a Regional Plan for all transmission facilities 115 kV and higher in the MAPP region. The Regional Plan is based on a ten-year rolling forecast and is intended to enable the transmission needs of MAPP members and the region generally to be met on a consistent, reliable, environmentally responsible and economical basis. In addition, the TPSC ensures that projects proposed in one sub-region are consistent with and do not undermine or duplicate projects proposed in another sub-region. The TPSC also studies and quantifies transfer capability across the MAPP region, identifying flow gates that act to limit the transfer of power for either exports or imports. These studies are then used as a basis to assess future regional projects.

The Regional Plan compares projects against alternative projects based on costs, reliability concerns and benefits, contractual and other obligations of the affected utilities, permitting concerns, and other factors. Once adopted by the RTC as a necessary and prudent plan, MAPP typically relies on the most affected utility or utilities to use their best efforts to support and implement the projects.

The most current Regional Plan approved by MAPP is the Regional Plan, 2000 through 2009 (as revised on March 21, 2001), available on MAPP's website at **http://www.mapp.org.Library/RegionPlan.htm**. This plan recommends the construction of certain transmission facilities and GRE's proposed 115 kV line for the Plymouth – Maple Grove load center is specifically included in the plan.

5.4 Modeling

Primary responsibility for building and maintaining the models used to analyze the reliability of the electrical system in Minnesota and throughout the MAPP region falls with MAPP's Modeling Building Working Group (MBWG). The MBWG maintains what is essentially a power flow, base case transmission model library. The library includes a series of power system models that simulate the behavior of the bulk electric system. The models are designed to accurately represent all major generation, load, and transmission facilities in MAPP.

The MBWG maintains the following base case models. For each model, the generation, transfers, and load demand reflect expected operating conditions during the defined period.

- **Summer Peak Load.** This model replicates the expected summer peak demand in MAPP, including load reductions caused by demand side management and other conservation programs.

- **Winter Peak Load.** This model replicates expected winter peak demand, including load reductions caused by demand side management and other conservation programs.

- **Spring Light Load.** This model replicates the energy load on a typical early morning in April.

- **Summer Off-Peak Load.** This model replicates 85% of the summer peak load conditions in the operating model (the model that looks only at next year's conditions) and 70% of summer peak load conditions in the planning, summer off-peak models (those models that look at conditions in the two-year to ten-year planning horizon).

- **Winter Off-Peak Load.** This model replicates 90% of the winter peak load conditions in the operating model. There are no winter off-peak models associated with the planning models.

Computer software is used to simulate the response of the transmission network models under the various systems intact or outage conditions. Equipment current carrying capability, system voltages, transient stability, small signal stability, and voltage stability can all be analyzed in these simulations. The output from the computer programs is compared against the appropriate criteria (NERC, MAPP, and local utility). Among other things, the analysis is designed to locate system inadequacies. Alternatives are then developed that attempt to address the inadequacies. The alternatives are then placed into the models and the computer analysis is rerun to determine the effectiveness of each of the alternatives. Review of these simulations and consideration of other factors will generally result in a recommended transmission alternative. The results are incorporated into a study report where they are then evaluated by MAPP and its various planning committees. GRE's proposed Plymouth – Maple Grove 115 kV line was subjected to the above-described analysis as part of the process that resulted in its inclusion in the MAPP Regional Plan.

The Plymouth-Maple Grove area was studied using the Summer Peak Model. The yearly electrical peak for this area occurs during the summer peak. The proposed project along with the alternatives were designed to satisfy the system needs during the summer peaks for the years 2005 through 2026.

5.5 GRE's Independent Application of Programs, Criteria and Modeling

As noted above, MAPP has included GRE's proposed 115 kV line in its most current Regional Plan. MAPP's conclusion is based on its independent review of the needs of the greater regional transmission system. Independent of MAPP, GRE's own planning and modeling analysis also concluded that a 115 kV line was the best long-term solution to the needs of the WHCEA Plymouth – Maple Grove distribution system.

GRE's internal analysis of its present 69 kV system and the future system, under Options 1, 2, 3, 4 and 5, was conducted using the Power Technology Inc. PSS/E (Rev. 26) load flow program, applying the standards of NERC. These applications identified the prospective line overloads and substation deficiencies to be anticipated, and when they would occur, based upon the forecast levels of demand. Remedies (line rebuilding or upgrading, substation modifications, etc.) were identified and are shown in the Project Component lists included in Section 3 for each of Options 1, 2, 3, 4 and 5. A further review of the options, with considerations of cost, reliability, environmental and other issues, resulted in GRE's conclusion that the 115 kV line (Option 1) is the preferred choice.

The GRE Transmission Planning Criteria utilized for the study of this area apply sound engineering judgment to determine the need for future facilities. The criteria, as shown below in Tables 5-1 to 5-3, include acceptable thermal loadings and voltage limits permitted. These planning criteria are consistent with NERC and MAPP and are approved by MAPP.

Table 5-1 Steady-State Loadings for Maximum Thermal Loading

Facility	< 100 kV	> 100 kV	
		System Intact	Single Contingency
Transmission Line	100%	100%	110%
Transformer	100%	100%	125%

Table 5-2 Steady-State Load Serving Substation Voltage Limits

Criteria	Allowable Voltage tolerance (% of nominal)	
	System Intact	Single Contingency
Maximum Voltage	105%	105%
Minimum Voltage	95%	92%

Table 5-3 Maximum Voltage Change for Switched Capacitor Banks

Allowable Voltage change for Switched Shunts (%)	
System Intact	Single Contingency
3%	5%

5.6 Ability of Present System to Meet Demand

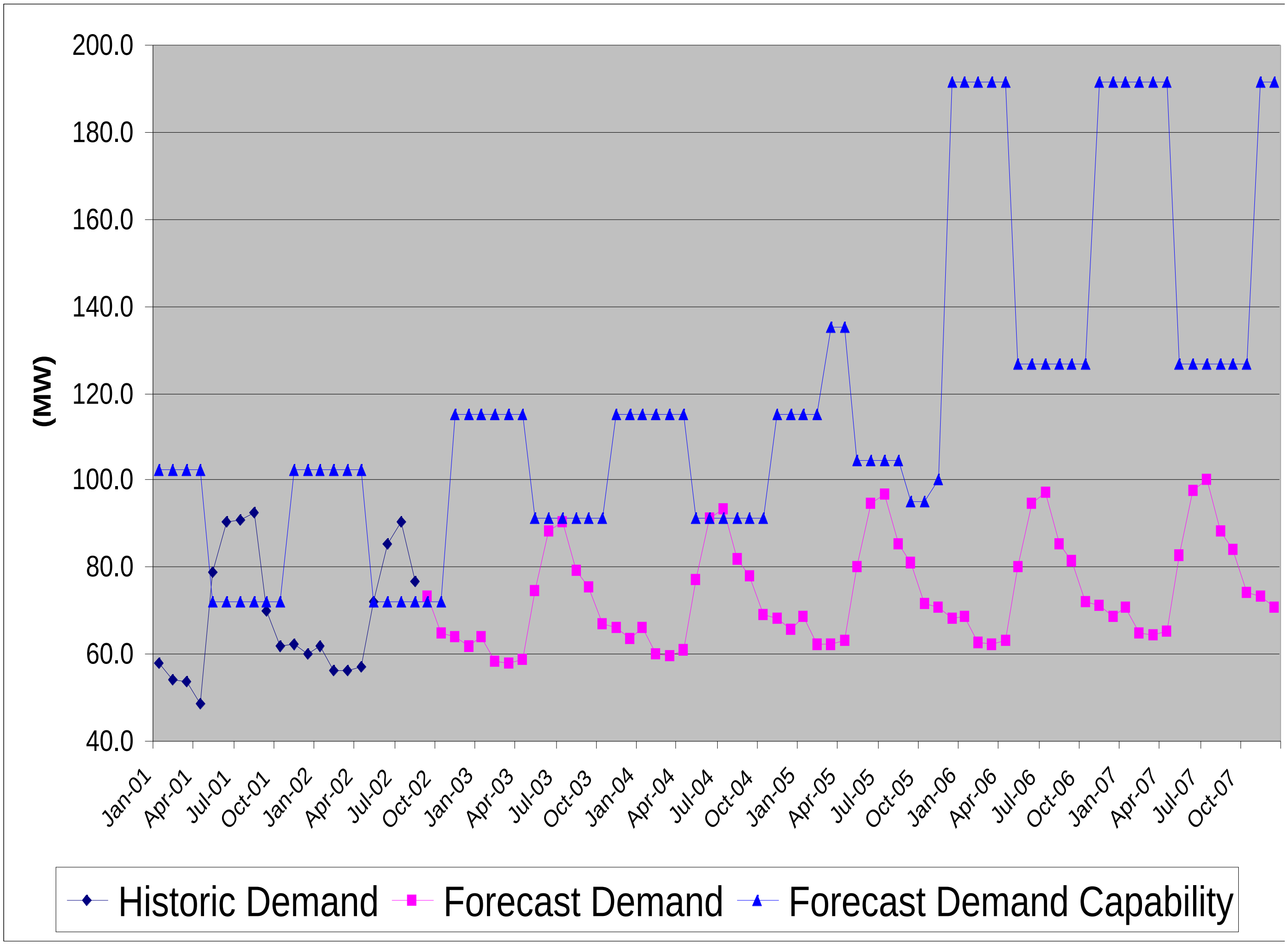
The existing 69 kV system simply cannot meet the forecast demand. The application of the above-discussed planning programs has identified the transmission lines and substation facilities that would eventually fall into noncompliance with the reliability standards and criteria subscribed to by GRE and discussed more fully above. The specific problems and potential remedies are set out in detail in Section 3.

The inability of the present system to meet the forecast demand and the impact of potential maintenance outages on the existing facilities and construction outages for the new facilities are depicted numerically in Table 5-4 and graphically in Figure 5-1.

Table 5-4 Monthly Adjusted Net Demand/Capability

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2001												
Adjusted Net Demand	58	54	53	49	79	90	91	92	70	62	62	60
Adjusted Net Capability	102	102	102	102	72	72	72	72	72	72	102	102
2002												
Adjusted Net Demand	62	56	56	57	72	85	90	77	73	65	64	62
Adjusted Net Capability	102	102	102	102	72	72	72	72	72	72	115	115
2003												
Adjusted Net Demand	64	58	58	59	74	88	90	79	75	67	66	64
Adjusted Net Capability	115	115	115	115	91	91	91	91	91	91	115	115
2004												
Adjusted Net Demand	66	60	60	61	77	91	93	82	78	69	68	66
Adjusted Net Capability	115	115	115	115	91	91	91	91	91	91	115	115
2005												
Adjusted Net Demand	68	62	62	63	80	94	97	85	81	72	71	68
Adjusted Net Capability	115	115	135	135	104	104	104	104	95	95	100	191
2006												
Adjusted Net Demand	69	63	62	63	80	95	97	85	81	72	71	68
Adjusted Net Capability	191	191	191	191	127	127	127	127	127	127	191	191
2007												
Adjusted Net Demand	71	65	64	65	83	98	100	88	84	74	73	71
Adjusted Net Capability	191	191	191	191	127	127	127	127	127	127	191	191

Figure 5-1 Monthly Adjusted Net Demand/Capability



5.7 System Capacity with Proposed 115 kV Line Project

The proposed 115 kV line project will increase the capacity available to the seven substations to a total of 184 MW. Total forecast demand ranges from 160 MW (lower limit of forecast demand) to 184 MW (upper limit of forecast demand) in the year 2026. Therefore, the proposed 115 kV line is adequate to meet the long-range forecasted demand for the Plymouth – Maple Grove load center.