Appendix B

Studies

Appendix B.1

Plymouth Area Load Serving Study
(November 2010)

Plymouth Area Load Serving Study

Xcel Energy Services; Distribution Planning

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1.0 ABSTRACT

In recent years, the Distribution Planning Department ("Distribution Planning") of Northern States Power Company, a Minnesota corporation ("Xcel Energy"), observed an increasing frequency and length of overload conditions on the electric distribution delivery system in the Plymouth area during its review of distribution system load. In response, Distribution Planning conducted detailed analyses of the 13 feeder circuits in the area that is experiencing the most significant overload conditions ("Focused Study Area") and determined that based on historical peak load levels from 2006, there is an existing deficit of 37 megawatts ("MW"). Transformer capacity is also limited. The three substation transformers in the Focused Study Area have only 1 MW of N-1 capacity available based on the historical peak load levels . Distribution Planning concluded that these deficit will only increase based on the growth trends seen in this area over the last decade.

Distribution Planning then conducted detailed analyses of facilities surrounding the Plymouth area, called the Greater Study Area, encompassing a total of 7 substation transformers and 27 feeder circuits, including the original 13 feeder circuits, to evaluate whether there was existing capacity that could be used to address the identified capacity deficit in the Focused Study Area. Distribution Planning determined that the distribution system in the Greater Study Area was already at or beyond capacity. For the 7 distribution transformers there is a 34 MW deficit of N-1 capacity. The existing area substations could not be expanded any further to accommodate the electrical equipment required to provide the needed additional capacity.

Distribution Planning further determined that common distribution system improvements, including adding new feeder circuits, extending existing feeder circuits and reconfiguring feeder circuits, are not sufficient enough to provide the necessary system support. Distribution Planning concluded that a new distribution source would be needed to provide the additional required capacity.

Distribution Planning evaluated three alternative new sources and concluded that the best performing option with respect to system performance, operability, future growth, cost, and electrical losses, consisted of converting the existing 34.5 kilovolt ("kV") Hollydale substation, located near the intersection of MN Highway 55 and County Road 101 in Plymouth, to a 115 kV substation. Hollydale substation would tap a 115 kV transmission line (rebuilt from 69 kV) connecting Medina substation to Hollydale Substation to a new transmission substation in Plymouth near Interstate 494 ("Pomerleau Lake substation"). The proposed configuration is estimated to cost $12.8 million for distribution facilities. The plan will provide 34 MW of additional load serving support with the initial installation of a single transformer with 34 MW and an additional 16 MW when a second transformer is added at the Hollydale substation in the Plymouth area. This additional capacity will meet the immediate distribution system needs and provide additional support for further demand growth in the Focused Study Area.

This document is a compilation of these various study efforts undertaken by Distribution Planning.

2.0 PRINCIPLES OF DISTRIBUTION PLANNING

2.1 DISTRIBUTION SYSTEM OVERVIEW

Distribution feeder circuits for standard service to customers are designed as radial circuits. Therefore, the failure of any single critical element of the feeder circuit causes a customer outage, which is an allowed outcome for a distribution system. Feeders are designed to facilitate restoration of mainline capacity and restoration of service to most customers with simple manual field switching with some exceptions. The distribution system is planned to generally facilitate single-contingency switching to restore outages within approximately one hour.

2.1.1 DISTRIBUTION SUBSTATIONS

Xcel Energy plans and constructs distribution substations with a physical footprint sized for the ultimate substation design. The maximum ultimate design capacity established in Xcel Energy planning criteria is three transformers at the same distribution voltage.[1] This maximum size balances substation and feeder circuit costs with customer service considerations including limitations of feeder circuit routes emanating from substations, circuit exposure of long feeder circuits, ease of operation, cost of operation, customer outage restoration, and the electrical losses. Over time, transformers and feeder circuits are incrementally added within the established footprint until the substation is built to ultimate design capacity.

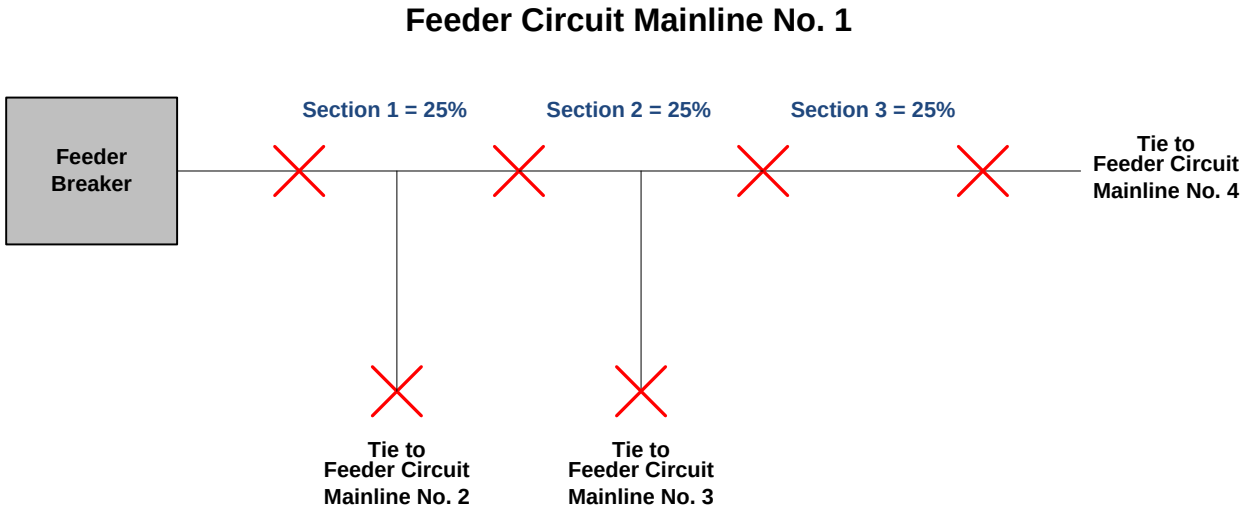
2.1.2 DISTRIBUTION FEEDER CIRCUITS SYSTEM INTACT AND FIRST CONTINGENCY PLANNING

Normal operation (also called system intact or N-0 operation) is the condition under which all-electric infrastructure equipment is fully functional. First contingency operation (also called N-1 or contingency operation) is the condition under which a single element (feeder circuit or distribution substation transformer) is out of service. Each distribution main feeder is generally composed of three equal sections. A feeder circuit should be loaded to no more than 75% of capacity during N-0 conditions. For example, a 12 MVA feeder circuit is designed to be loaded to 9 MVA during normal operating conditions. To achieve this goal, a main feeder is generally designed so that each section is loaded to approximately 25% of the total capacity for the main feeder. This loading level provides reserve capacity that can be used to carry the load of adjacent feeders during first contingency N-1 conditions.

Figure 2.1 depicts a main feeder circuit, including the breaker and the three sections. The Xs in the diagram represent switches that can be activated to isolate or connect sections of a feeder lines.

[1] There is one exception to this criteria. In downtown Minneapolis, the Fifth Street Substation houses four transformers to serve the significant load.

Figure 2.1: Typical Distribution Feeder Circuit Mainline with Three Sections Capable of System Intact N-0 and First Contingency N-1 Operations



2.2 DISTRIBUTION SYSTEM DESIGN AND OPERATION

Distribution system load is planned, measured, and forecasted with the goal to serve all customer electric load under system intact and first contingency conditions. A distribution delivery system that has adequate N-1 capacity is one in which all customer load can be restored through distribution system reconfiguration by means of electrical switching in the event of the outage of any single element.

Adequate N-1 substation transformer capacity, no feeder normal (N-0) overloads, and adequate field tie capability for feeder first contingency (N-1) distribution restoration are key design and operation objectives. To achieve these objectives, Xcel Energy uses distribution planning criteria to achieve uniform development of Xcel Energy's distribution systems. Distribution Planning considers these criteria when identifying deficiencies with existing distribution systems and identifying improvements to address the identified deficiencies.

2.2.1 PLANNING CRITERIA, DISTRIBUTION FEEDER CIRCUITS

While the distribution guidelines vary depending on the specific distribution system, there are several basic design guidelines that apply to all areas of Xcel Energy's distribution system. They are as follows:

- Voltage at the customer meter will be maintained within 5% of nominal voltage, which is typically 120 volts.
- Voltage imbalance goals on the feeder circuits are less than or equal to 3%. Feeder circuits deliver three-phase load from a distribution substation transformer to customers. Three-phase electrical motors and other equipment are designed to operate

best when the voltage on all of the three phases is the same or balanced.

- The currents on each of the three phases of a feeder circuit are balanced to the greatest extent possible to minimize the total neutral current at the feeder breaker. When phase currents are balanced, more power can be delivered through the feeders.
- Under system intact, N-0 operating conditions, typical feeder circuits should be loaded to less than 75% of capacity. Xcel Energy developed this standard to help ensure that service to customers can be maintained in an N-1 condition or contingency. If feeder circuits were loaded to their maximum capacity and there were an outage, the remaining system components would not be able to make up for the loss because adding load to the remaining feeder circuits would cause them to overload. By targeting a 75% loading level, there is generally sufficient remaining capacity on the system to cover an outage of an adjacent feeder with minimal service interruptions. A typical feeder circuit capable of delivering 12 MVA, for example, is normally loaded to 9 MVA and loaded up to 12 MVA under N-1 conditions.

2.2.2 LIMITATIONS TO INSTALLING FEEDER CIRCUITS

Spatial and thermal limits restrict the number of feeder circuits that may be installed between a distribution substation transformer and customer load. Consequently, this limits substation size. Normal overhead construction is one feeder circuit on a pole line; high density overhead construction is two feeder circuits on a single pole line (double deck construction). When overhead feeder circuit routes are full, the next cost effective installation is to bury the cable in an established utility easement. Thermal limits require certain minimum spacing between multiple feeder circuit main line cables. Thermal limits for primary distribution lines are defined in Electric Distribution Bulletins ("EDB"): UND6 and CAL2 for underground and the Construction & Design Manual C-26 for overhead.

When new feeder circuits are added to a mature distribution system, minimum spacing between feeder circuit main line cables sometimes cannot be achieved because of right-of-way limitations or a high concentration of feeder cables. Adding express feeders to serve distant high-load concentrations requires cable installation across distribution service areas where they do not serve any customer load. Cable spacing limitations and/or feeder cable concentrations frequently occur where many feeder cables must be installed in the same corridor near distribution substations or when crossing natural or manmade barriers.

When feeder cables are concentrated, they are most often installed underground in groups (banks) of pipes encased in concrete that are commonly called "duct banks". When feeder circuits are concentrated in duct banks, those cables encounter more severe thermal limits than multiple buried underground feeder circuits. Planning Engineers use CYMCAP software for determining maximum N-0 and N-1 feeder circuit cable capacities for circuits installed in duct banks.

When underground feeders fill existing duct lines to the rated thermal capacity, and there is no more room in utility easement or street right-of-way routes for additional duct lines from a substation to the distribution load, feeder circuit routing options are exhausted.

2.2.3 PLANNING CRITERIA, DISTRIBUTION SUBSTATION TRANSFORMERS

Transformers have nameplate ratings that identify capacity limits. Xcel Energy's Transformer Loading Guide provides the recommended limits for loading substation transformers adjusted for altitude, average ambient temperature, winding taps-in-use, etc. The Transformer Loading Guide is based upon the American National Standards Institute/Institute of Electrical and Electronic Engineers ("ANSI/IEEE") standard for transformer loading, ANSI/IEEE C57.92.

The Xcel Energy Transformer Loading Guide consists of a set of hottest-spot and top-oil temperatures and a generalized interpretation of the loading level equivalents of those temperatures. The top-oil and hottest-spot temperatures in the Xcel Energy Transformer Loading Guide are the criteria used by Substation Maintenance engineers to determine Normal and Single-Cycle transformer loading limits that Capacity Planning Engineers use for transformer loading analysis. When internal transformer temperatures exceed pre-determined design maximum load limits, the transformer sustains irreparable damage, which is commonly referred to as equipment "loss-of-life". Loss-of-life refers to the shortening of the equipment design life that leads to premature transformer degradation and failure.

Transformer design life is determined by the longevity of all of the transformer components. At a basic level most substation transformers have a high voltage coil of conductor and a low voltage coil electrically insulated from each other and submerged in a tank of oil. Transformer operation generates heat; the more load transformed from one voltage to the other, the more heat; too much heat damages the insulation and connections inside the transformer. Hottest-spot temperatures refer to the places inside the transformer that have the greatest heat, and top-oil temperature limits refer to the maximum design limits of the material and components inside the transformer.

To ensure maximum life and the ability to reliably serve customers, Xcel Energy's loading objective for transformers is 75% of normal rating or lower under system intact conditions. Substation transformer utilization rates below 75% are indicative of a robust distribution system that has multiple restoration options in the event of a substation transformer becoming unavailable because of an equipment failure or required maintenance and construction. The higher the transformer utilization, the higher the risk that service will be interrupted in the event of a transformer outage.

2.2.4 ONGOING DISTRIBUTION SYSTEM RELIABILITY ASSESSMENT

Distribution Planning regularly evaluates loads to determine overloads. Mitigations (projects) are developed to address the overloads. In general, infrastructure additions that address overloaded distribution system elements is an ongoing process.

Distribution Planning annually compares feeder circuit historical and forecast peak load demands to distribution feeder circuit maximum loading limits to identify feeder circuits overloaded under system intact (N-0) conditions and feeder circuits overloaded under single contingency (N-1) conditions during peak loading.

Distribution Planning also annually compares substation transformer historical and forecasted peak load demands on substation transformers to capacity load limits under system intact (N-0) and single contingency (N-1) conditions. Distribution Planning provides distribution substation transformer loads to the Transmission Planning Department ("Transmission Planning"). Distribution and transmission planners routinely coordinate to identify distribution load impacts to the transmission system.

Distribution Planning then quantifies the amount of overload and the duration of peak loading for feeder circuit and substation transformer overloads under system intact (N-0) and single contingency (N-1 conditions), determines the approximate cost of mitigating the overloads, and identifies the most critical distribution system needs.

When Distribution Planning determines that a distribution system requires additional capacity from a new distribution source, it makes a formal request to Transmission Planning to interconnect to the transmission system. Transmission Planning takes the request and Distribution Planning and Transmission Planning coordinate to develop several options that will address the distribution system deficiencies. Transmission Planning performs analyses to determine the impact of the selected options on the transmission system.

3.0 PLYMOUTH STUDY AREAS

Distribution Planning conducted this detailed distribution area planning study of the Plymouth area distribution delivery system because the area was experiencing more frequent feeder circuit overloads due to an increase in the demand for power. To better isolate the problem, Distribution Planning developed two study areas. They are generally described as follows:

Focused Study Area: First, Distribution Planning examined an area of Plymouth, clearly defined by geographic boundaries, that is served electrically by 13 specific distribution feeder circuits and is experiencing the most severe overload conditions. Distribution Planning analyzed the loading levels on these 13 distribution feeder circuits.

Greater Study Area: Second, Distribution Planning examined a larger area of Plymouth, defined not by geographic boundaries but by the location of three distribution substations, which house an aggregate total of 7 distribution substation transformers, and the 27 distribution feeder circuits emanating from those three substations. Distribution Planning analyzed the loading levels of these 7 distribution substation transformers.

More detailed descriptions of the study areas are provided below.

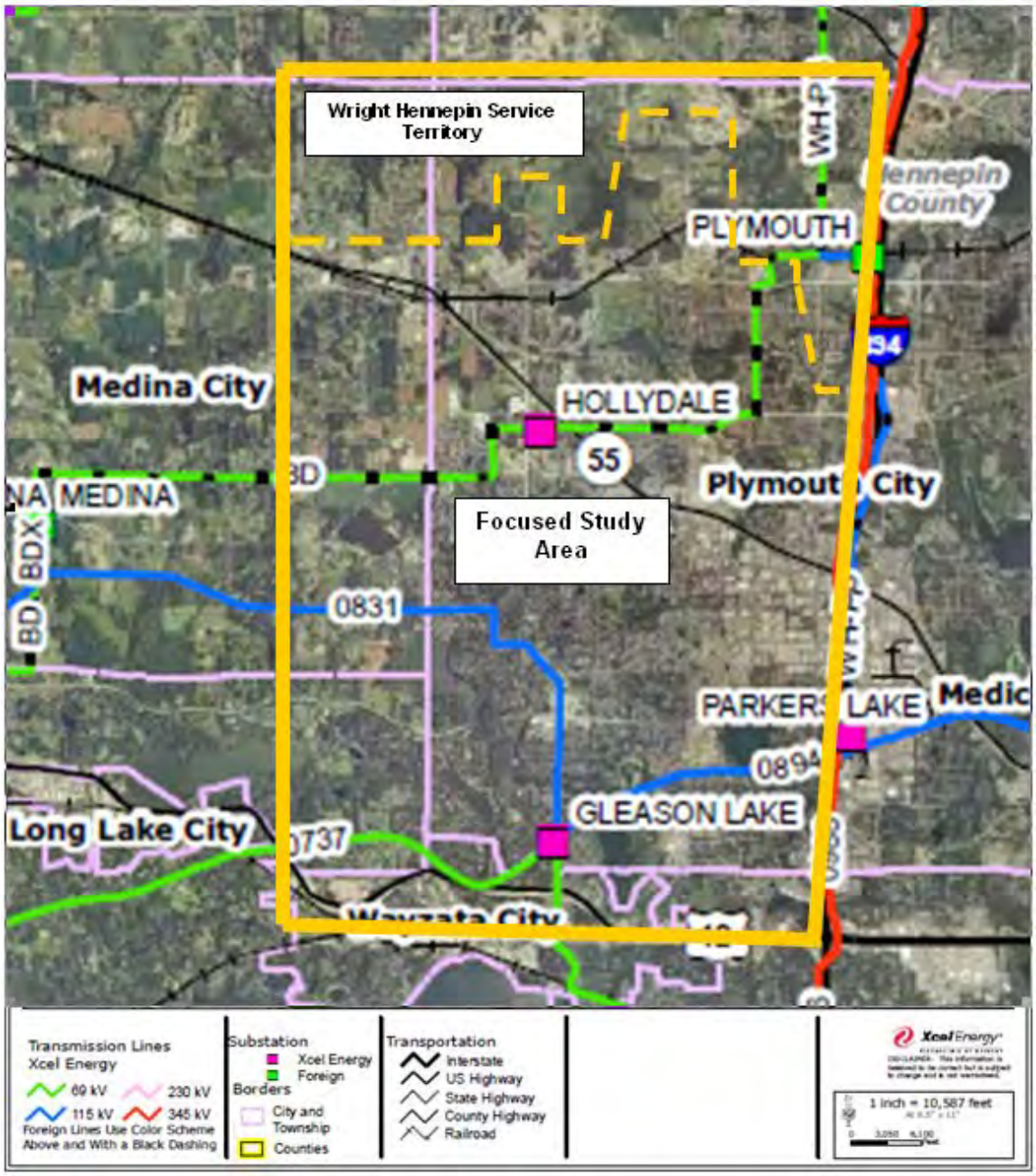
3.1 DESCRIPTION OF FOCUSED STUDY AREA

The Focused Study Area is an approximate 24-square mile area in Plymouth with the following geographic boundaries:

> North Boundary: The Xcel Energy service territory border which is approximately an east to west line along County Road 47 from County Road 116 on the west to Interstate 494 on the east;
>
> East Boundary: Interstate 494 from Country Road 47 on the north to US Highway 12 (Interstate 394) on the south;
>
> South Boundary: US Highway 12 (Interstate 394) from Interstate 494 on the Xcel Energy service territory border on the west; and
>
> West Boundary: The Xcel Energy service territory border which is approximately a north to south line along County Road 116 from the Xcel Energy service territory border on the north to US Highway 12 on the south.

The Focused Study Area is illustrated in Figure 3.1.

Figure 3.1: Focused Study Area



The Focused Study Area distribution load is primarily fed from three 115 kV transmission lines: Medina – Gleason Lake, Gleason Lake – Parkers Lake and Parkers Lake – Medicine Lake, which make up part of the looped 115 kV transmission system that extends from the western metro area, east towards Minneapolis. Thirteen feeder circuits emanating from three substations serve the Focused Study Area. The three substations are Gleason Lake substation, Hollydale substation, and Parkers Lake substation. The 13 feeder circuits, eleven at a distribution voltage of 13.8 kV and two at a distribution voltage of 34.5 kV, provide power to the Focused Study Area.

There are two substations within the Focused Study Area. The Gleason Lake Substation, which is located in the southern portion of the Focused Study Area at the intersection of County Road 101 and the Luce Line Trail, has nine feeder circuits, seven at a voltage of 13.8 kV and two at a voltage of 34.5 kV. Hollydale substation is located within the Focused Study Area as well and is located near the intersection of County Road 101 and MN Highway 55. Hollydale substation differs from a standard substation in that the substation transformer is fed from a 34.5 kV Gleason Lake distribution feeder as opposed to a 69 kV (or higher voltage) transmission line. There is a 69 kV Great River Energy transmission line that does currently serve as an emergency backup to Hollydale substation. This line is used only as emergency backup because using the 69 kV transmission line as the normal load serving source at Hollydale substation would cost Xcel Energy approximately $600,000 a year in O&M since Great River Energy owns this line. Even if this source were available at no cost, Great River Energy plans to remove the 115/69 kV transformer at Medina that feeds the 69 kV Medina-Hollydale transmission line, which means this source will not be available in the near future. Parkers Lake substation, which is located outside of the perimeter of the Focused Study Area, serves the remaining Focused Study Area load. Figure 3.2 summarizes the amount of 2009 load that the three primary electric distribution substations and the associated 13 feeder circuits served in the Focused Study Area.

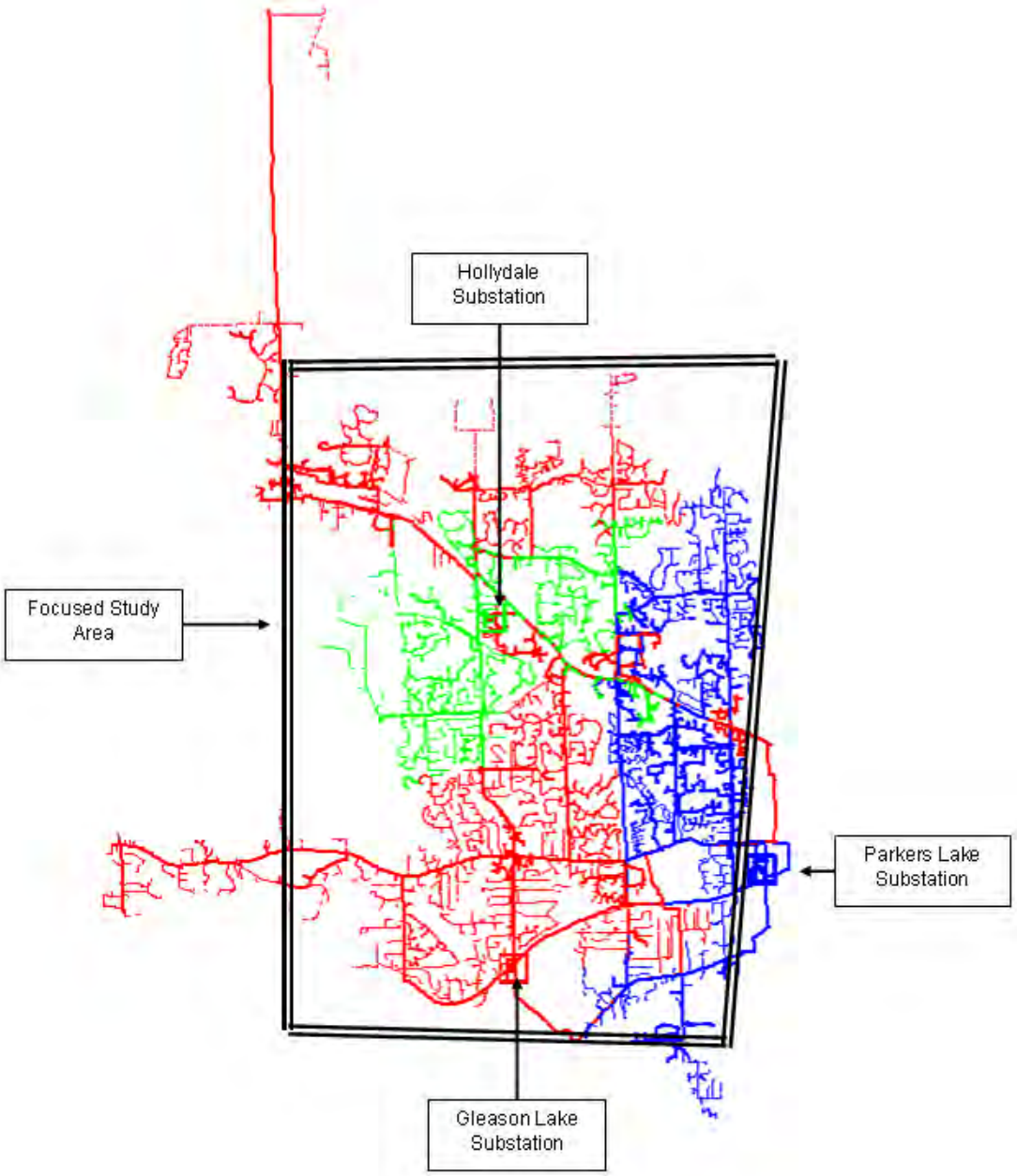
Figure 3.2: Electric Distribution Substations and Associated Feeder Circuits Serving 2009 Load in Focused Study Area

Substations	No. of Feeder Circuits	Amount of Load (kW) Served by Substation	Percentage of Load Served by Substation
Within Focused Study Area			
Gleason Lake	5	45,766	40%
Hollydale*	2	15,680	14%
Bordering Focused Study Area			
Parkers Lake	6	53,358	46%
Total	**13**	114,804	100.0%

*All Hollydale substation load is served by a 34.5kV Gleason Lake feeder circuit. The Hollydale load has been split out from the total Gleason Lake substation load.

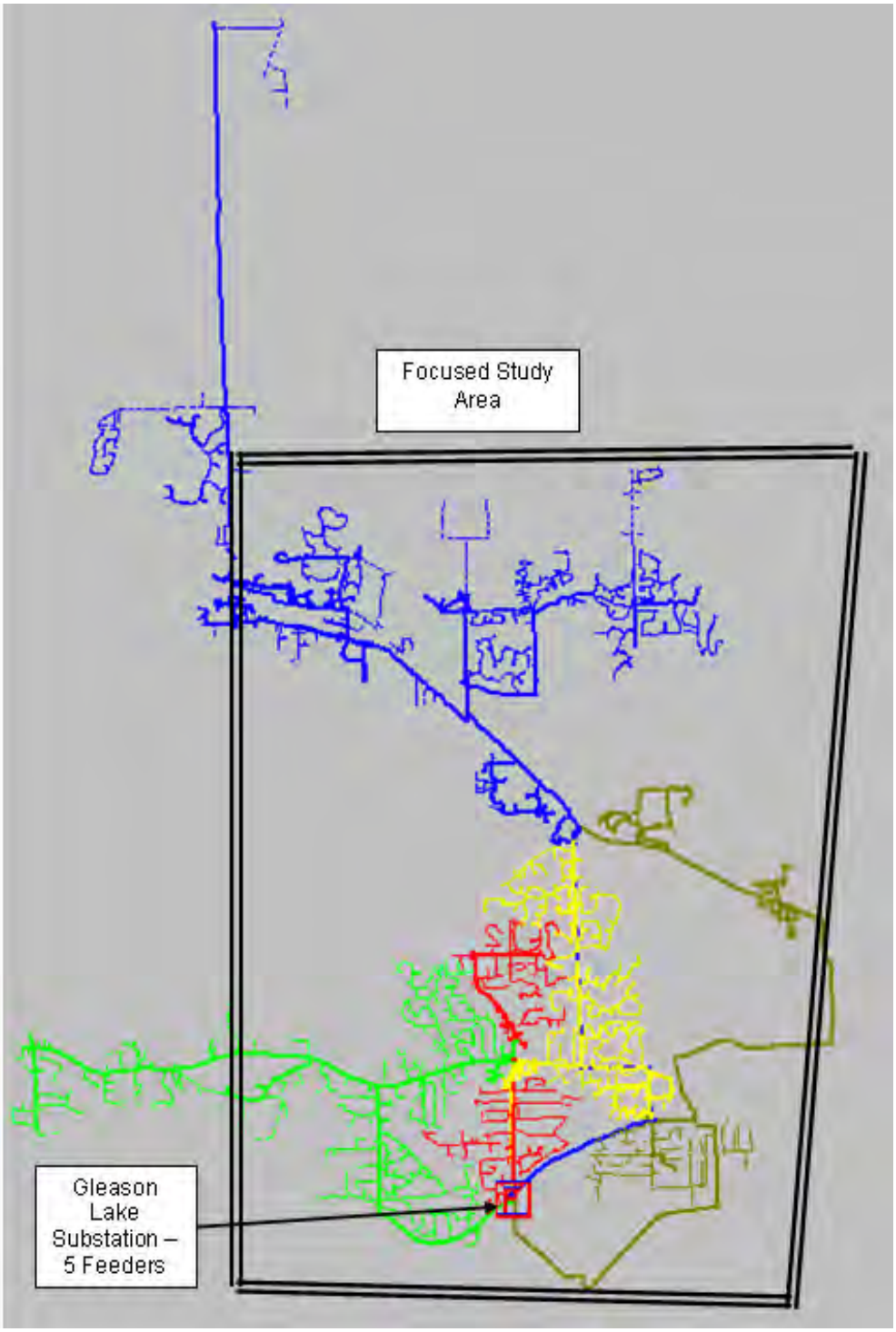
Each of these substations and its respective number of feeder circuits that serve the Focused Study Area load are depicted in Figure 3.3, Figure 3.4, Figure 3.5 and Figure 3.6

Figure 3.3: Primary Electric Distribution Substations and Associated Feeder Circuits Serving Focused Study Area Load



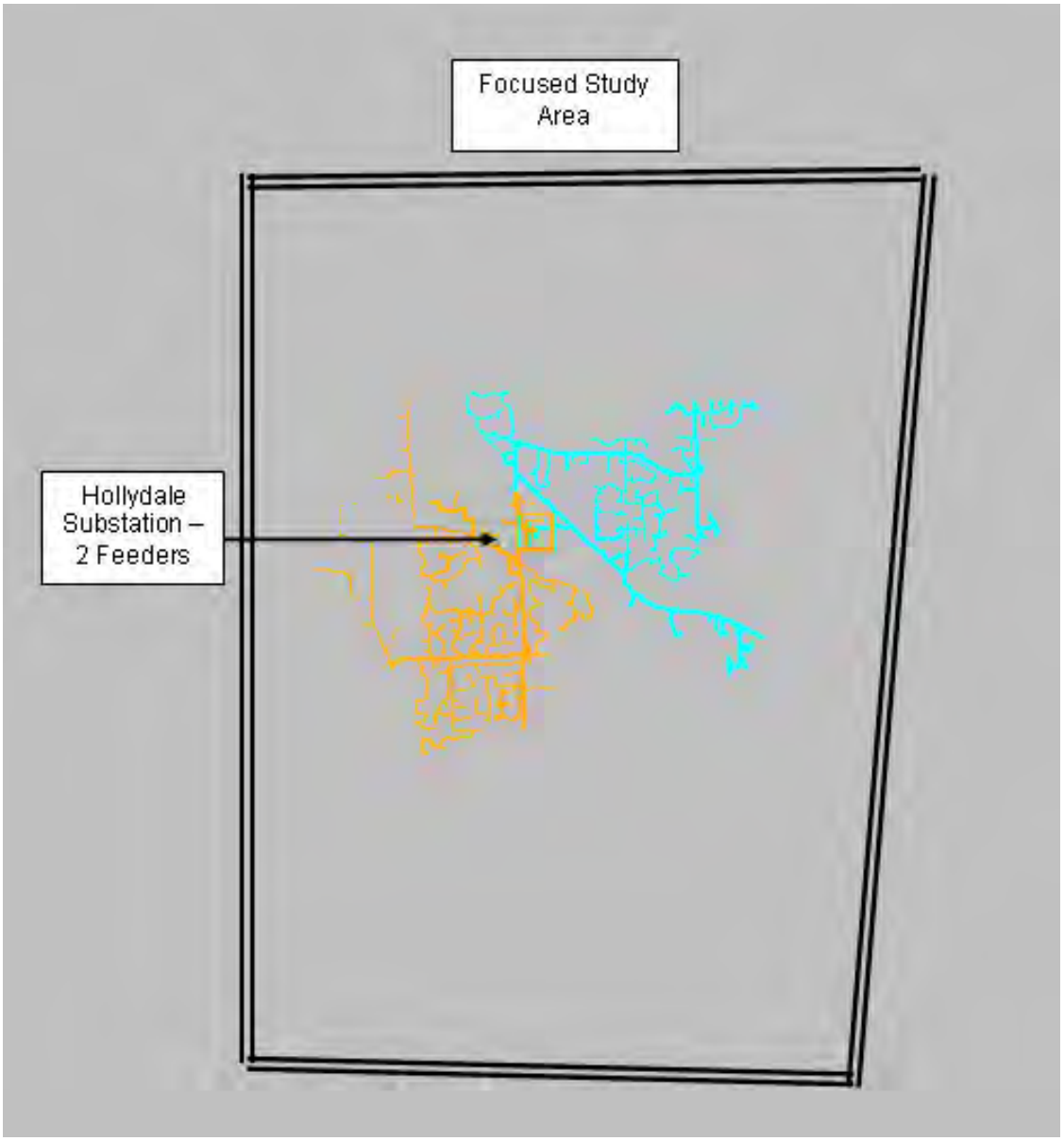
The above Figure 3.3shows each of the distribution substations and their associated feeder circuits that serve Focused Study Area load. Red feeder circuits are served by Gleason Lake Substation. Blue feeder circuits are served by Parkers Lake substation. Green feeder circuits are served by Hollydale substation.

Figure 3.4: Gleason Lake Substation and Associated Five Feeder Circuits Serving Focused Study Area Load



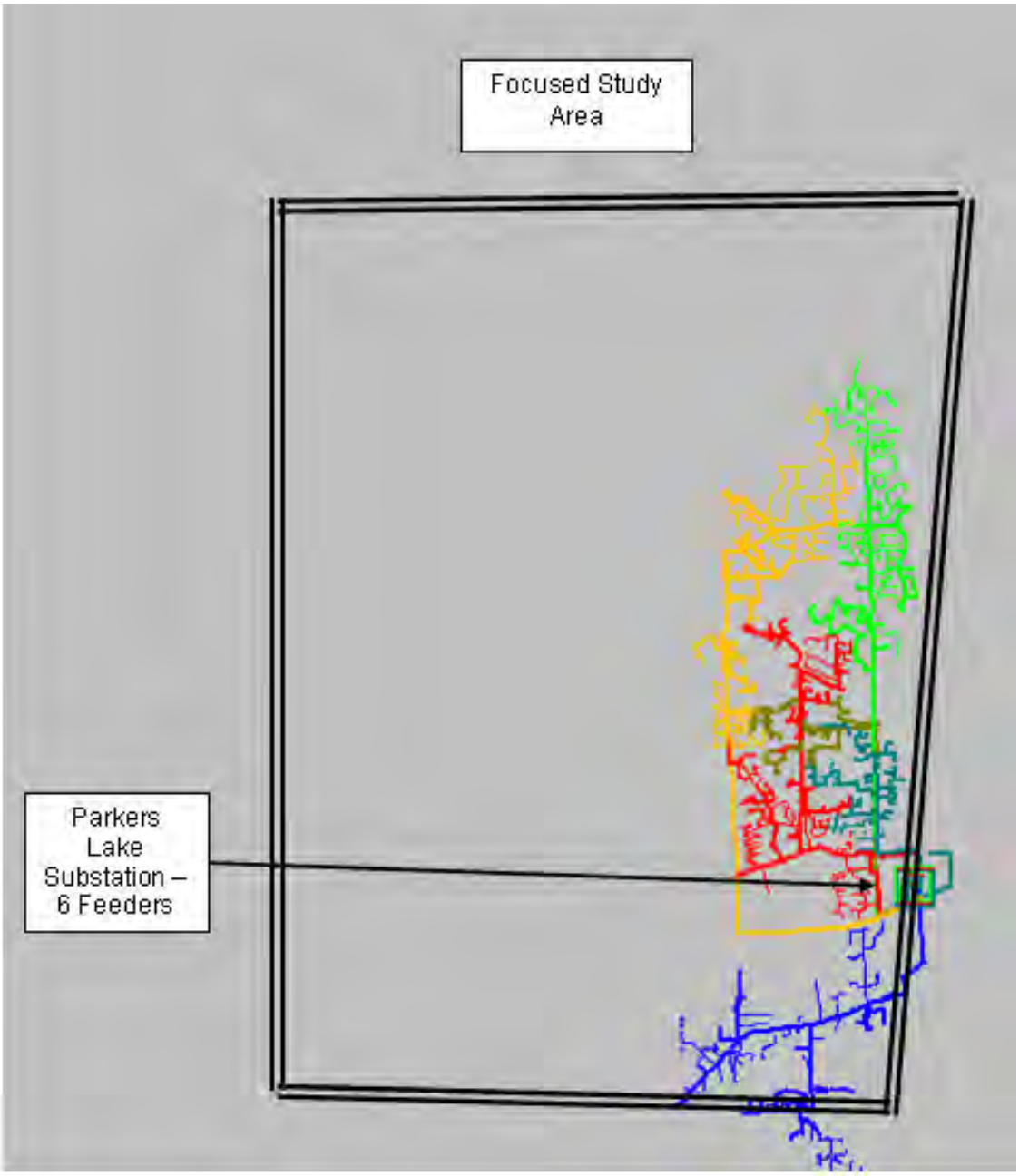
The above Figure 3.4 shows the Gleason Lake Substation and the five feeder circuits, each highlighted in a different color, that emanate from that substation and serve Focused Study Area load.

Figure 3.5: Hollydale Substation and Associated Two Feeder Circuits Serving Focused Study Area Load



The above Figure 3.5 shows the Hollydale Substation and the two feeder circuits, each highlighted in a different color, that emanate from that substation and serve Focused Study Area load.

Figure 3.6: Parkers Lake Substation and Associated Six Feeder Circuits Serving Focused Study Area Load

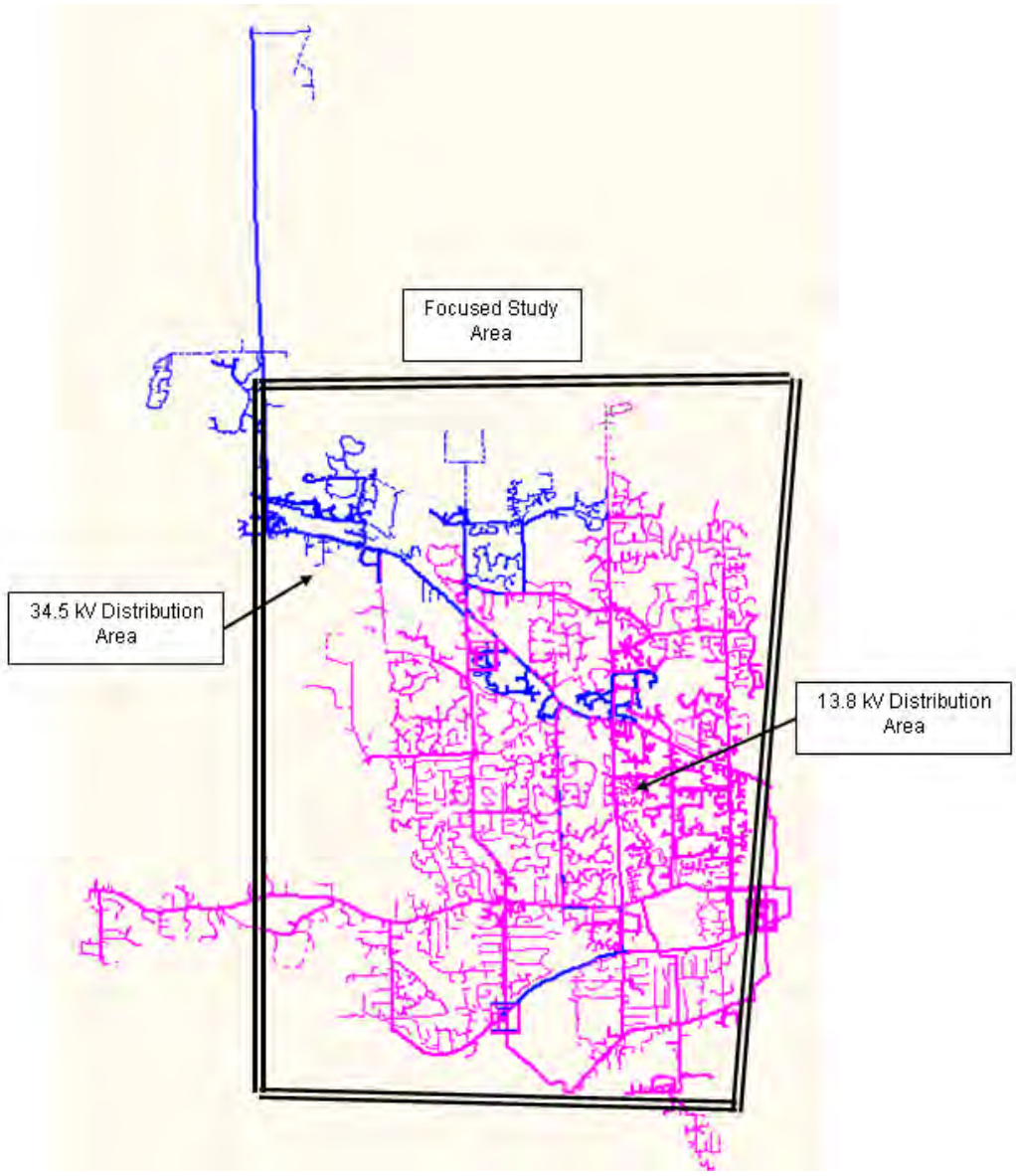


The above Figure 3.6 shows the Parkers Lake Substation and the six feeder circuits that emanate from that substation and serves Focused Study Area load.

As stated previously, there are two different primary distribution voltage levels within the Focused Study Area, 34.5 kV and 13.8 kV. In order to develop a long range plan for this area and properly analyze the distribution system, a distinction needed to be made between which areas will ultimately be served by 13.8 kV distribution feeders and which areas will ultimately be served by 34.5 kV distribution feeders. Figure 3.7 identifies which areas have been designated at which voltage. The

blue identifies the areas designated as 34.5 kV distribution areas and the pink identifies the areas designated as 13.8 kV distribution areas.

Figure 3.7: Ultimate Distribution Voltages within the Focused Study Area



Planning decisions have already been made outside the scope of this study that have scaled back the expansion of the 34.5 kV distribution system in this area and the plan laid out in the Figure 3.7 above only continues that strategy. At this point, it is not beneficial from operational, planning and financial perspectives to add any 34.5 kV capacity to the area. This plan relieves the 34.5 kV distribution system such that no additional 34.5 kV capacity needs to be installed to sustain the 34.5 kV distribution system.

Figure 3.8 summarizes the amount of 2009 load served in the two distribution voltage areas.

Figure 3.8: Ultimate Distribution Voltages Serving 2009 Load in the Focused Study Area

Distribution Voltage	Amount of Load (kW)	Percentage of Load
34.5 kV Distribution Voltage	16,668	15%
13.8 kV Distribution Voltage	98,136	85%
Total	114,804	100.0%

3.2 BACKGROUND OF THE PLYMOUTH FOCUSED STUDY AREA

In 1993 Hollydale substation was constructed as a 69/13.8 kV distribution substation that tapped a Great River Energy 69 kV transmission line running from Medina substation to Plymouth substation. The Hollydale substation was positioned such that it added capacity to an area of the Focused Study Area that Parkers Lake and Gleason Lake 13.8 kV feeder circuits could not reasonably reach. By 1998 the 13.8 kV feeder circuit and substation transformer capacity within the Focused Study Area had been used up and there was once again a need for additional substation transformers and feeder circuits. Additionally, Great River Energy transmission planners identified an overload on the 69 kV transmission line serving Hollydale substation. Both of these issues drove the decision to introduce the 34.5 kV distribution voltage to the Focused Study Area. At the 34.5 kV voltage level, new feeder circuits were able to not only serve more load but also serve load further from the substation in which they were housed. Subsequently, a 70 MW 115/34.5 kV substation transformer was added at Gleason Lake substation. The new 34.5 kV feeder circuits out of Gleason Lake substation were able to relieve existing overloads on the 13.8 kV system. Additionally, to mitigate the overload on the 69 kV transmission line, the Hollydale load was moved from the 69/13.8 kV transformer to a 34.5/13.8 kV transformer which used one of the Gleason Lake 34.5 kV feeder circuits as its "transmission" source

Since the installation of the 34.5 kV distribution system, customer electricity usage has grown in Plymouth. There has been a great deal of development in the Focused Study Area, especially concentrated along MN Highway 55, Interstate 494, and Interstate 394, specifically the Plymouth City Center, but also including residential areas located away from these corridors. Recent development projects in the area include Lowes, Plymouth Cinema, Cub Foods and Lifetime Fitness at Hwy 55 and Vicksburg, a commercial development at Hwy 55 and Rockford Road, Providence Academy at Schmidt and Lake Road and housing by Wayzata High School on Peony Lane. Additional residential developments are also planned for the area including Woodcrest, Spring Meadow, and Taylor Creek at Vicksburg and Schmidt Lake Road, Enclave on Hunters Drive and Elm Creek Highlands on Peony Lane.

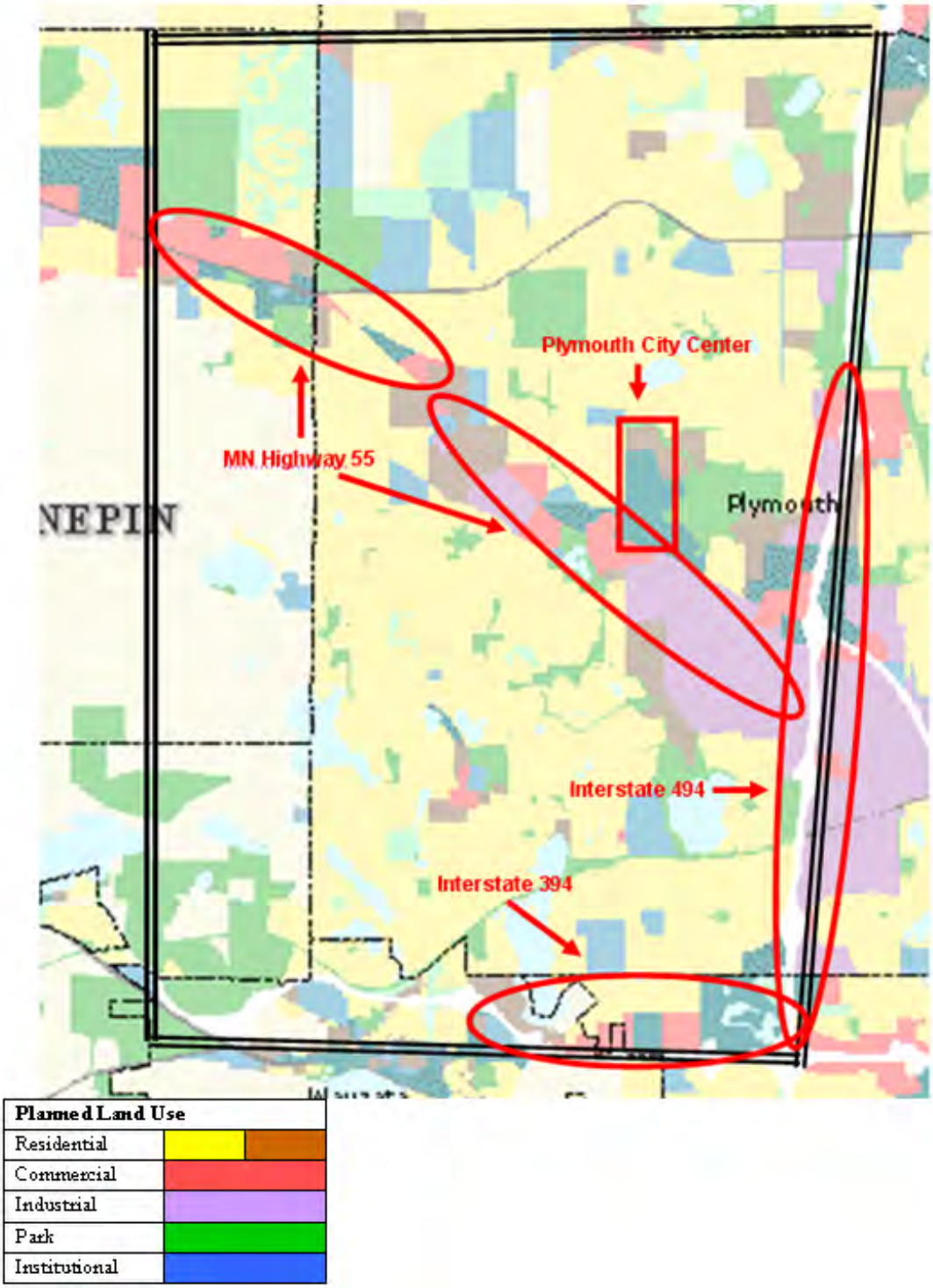
Average residential usage has also grown substantially. The average residential home now uses more than twice the amount of power than it did 50 years ago. Information from the Minnesota Department of Commerce in a report titled "Energy Policy and Conservation Report 2004" shows that weather normalized electric consumption among Minnesota residential customers increased from just over 4.0 annual megawatt hours in 1965 to just under 9.0 annual megawatt hours in 2000. This report is available on the Minnesota Department of Commerce website at the following location:
http://www.state.mn.us/mn/externalDocs/Commerce/Quadrennial_Report__2004_071404102049_2004-QuadReport.pdf. This increase in annual usage is also partly due to the number of consumer

electronics that are available and commonly in use in homes. In addition, air conditioning is commonly used in private residences and any growth in residential load will include this weather dependent component.

The loads in Plymouth are expected to continue to grow. Planning reports issued by the City of Plymouth planning department describe City plans to facilitate continued development and redevelopment in the Plymouth area over the next few years. Current and future redevelopment is concentrated along the MN Highway 55 corridor and in areas adjacent to that corridor (*e.g.*, Plymouth City Center). The Plymouth Plan (Apr. 14, 2009; available at www2.ci.plymouth.mn.us/) designate planned land use along this major growth corridor to include higher density housing, commercial, office, public/institutional, transportation/communications/utilities, and other land use types. The Plymouth planning reports also provides that the City intends to continue to promote business retention and expansion and residential growth within the City. The City plans to do this by developing and maintaining the City's infrastructure to help serve the needs of businesses and residents and to increase its supply of housing. These planned developments and improvements will increase load demand in the Focused Study Area.

Figure 3.9 delineates the existing major growth corridors in the Focused Study Area.

Figure 3.9: Existing Major Growth Corridors in Focused Study Area



Zoning Data Source: Metropolitan Council - http://gis.metc.state.mn.us/index.asp

The 13.8 kV and 34.5 kV distribution delivery systems in Plymouth have struggled to keep up with the increasing customer demand for electricity. Since the Gleason Lake substation is the only remaining distribution substation source in the Focused Study Area, the feeders in that area are serving increasingly larger loads farther from the nearest substation source, resulting in higher electrical line losses and reduced customer reliability. In response to this load growth Xcel Energy has taken numerous steps to maintain reliable service in the Focused Study Area, including reinforcing existing feeder circuits, adding new feeder circuits, replacing equipment damaged by overloads, and rearranging feeder circuits to maintain service during overloads.

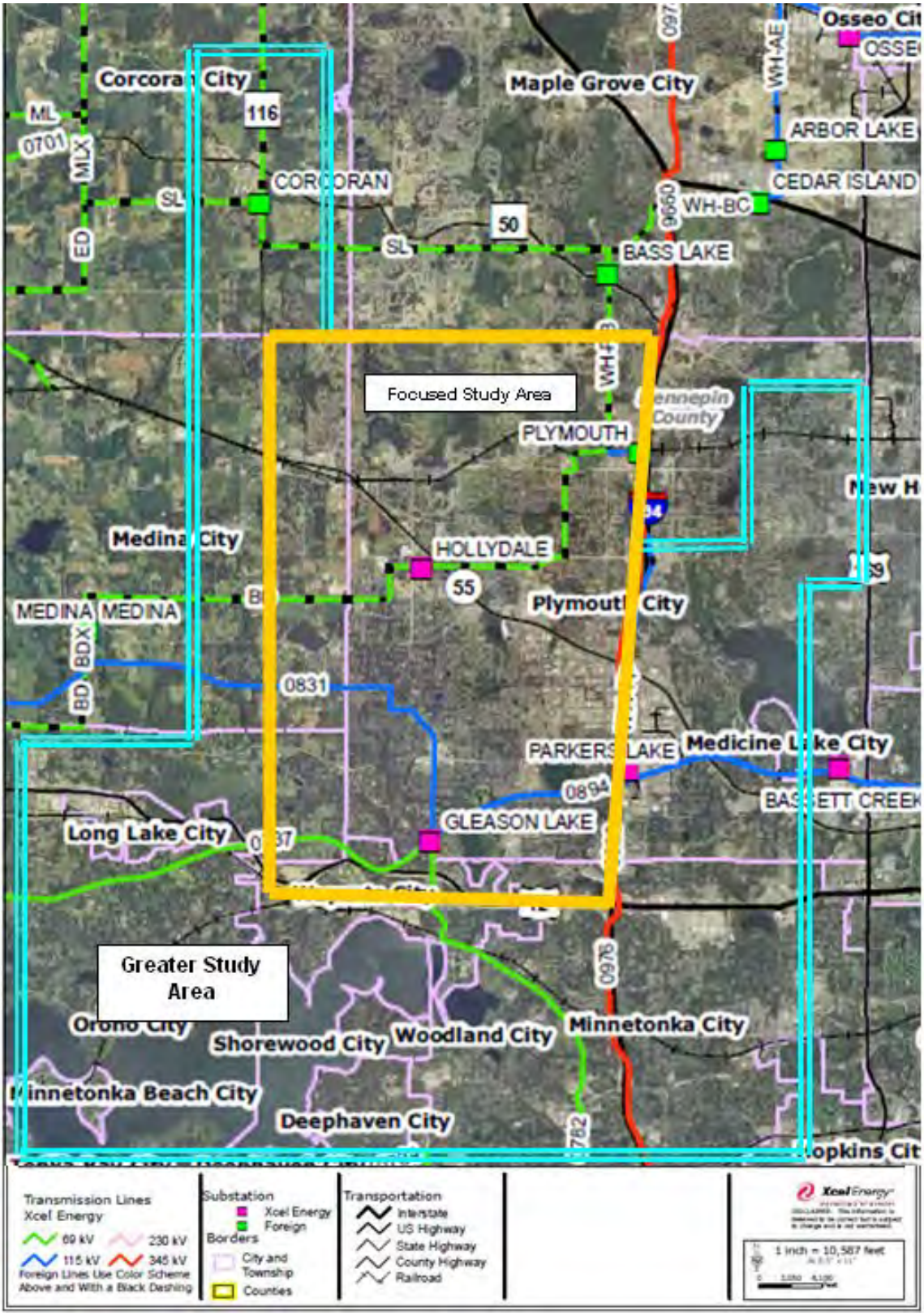
In 2005 and 2006, the Plymouth distribution delivery system experienced historical peak loads. It became apparent that the distribution delivery system in the area was becoming increasingly vulnerable to more and longer overloads. As a result, Distribution Planning Engineers in 2008 intensified their analysis of the Plymouth distribution delivery system, concentrating in particular on the Focused Study Area to develop a more robust, longer-term solution to address the continued growth in power demand.

3.3 DESCRIPTION OF THE GREATER STUDY AREA

Distribution Planning also examined the Plymouth electricity distribution delivery system within the Greater Study Area, in part, to assess the availability of existing capacity, if any, on distribution transformers near the Focused Study Area.

The Greater Study Area consists of the geographic area served by three substations, including Gleason Lake, Hollydale, and Parkers Lake substations, and their associated substation transformers and circuit feeders. The Greater Study Area, which covers an approximate 50 square-mile area, is illustrated in Figure 3.10.

Figure 3.10: Greater Study Area



The Greater Study Area distribution load is served by 27 feeder circuits, two at a distribution voltage of 34.5 kV and 25 at a distribution voltage of 13.8 kV. These feeder circuits are served from seven distribution substation transformers that are housed at a total of three substations: Gleason Lake, Hollydale and Parkers Lake The three substations, in turn, are served from 115 kV transmission lines that loop the Greater Study Area, with the exception of Hollydale substation as discussed earlier.

Figure 3.11 summarizes the amount of 2009 load that the electric distribution substations served in the Greater Study Area.

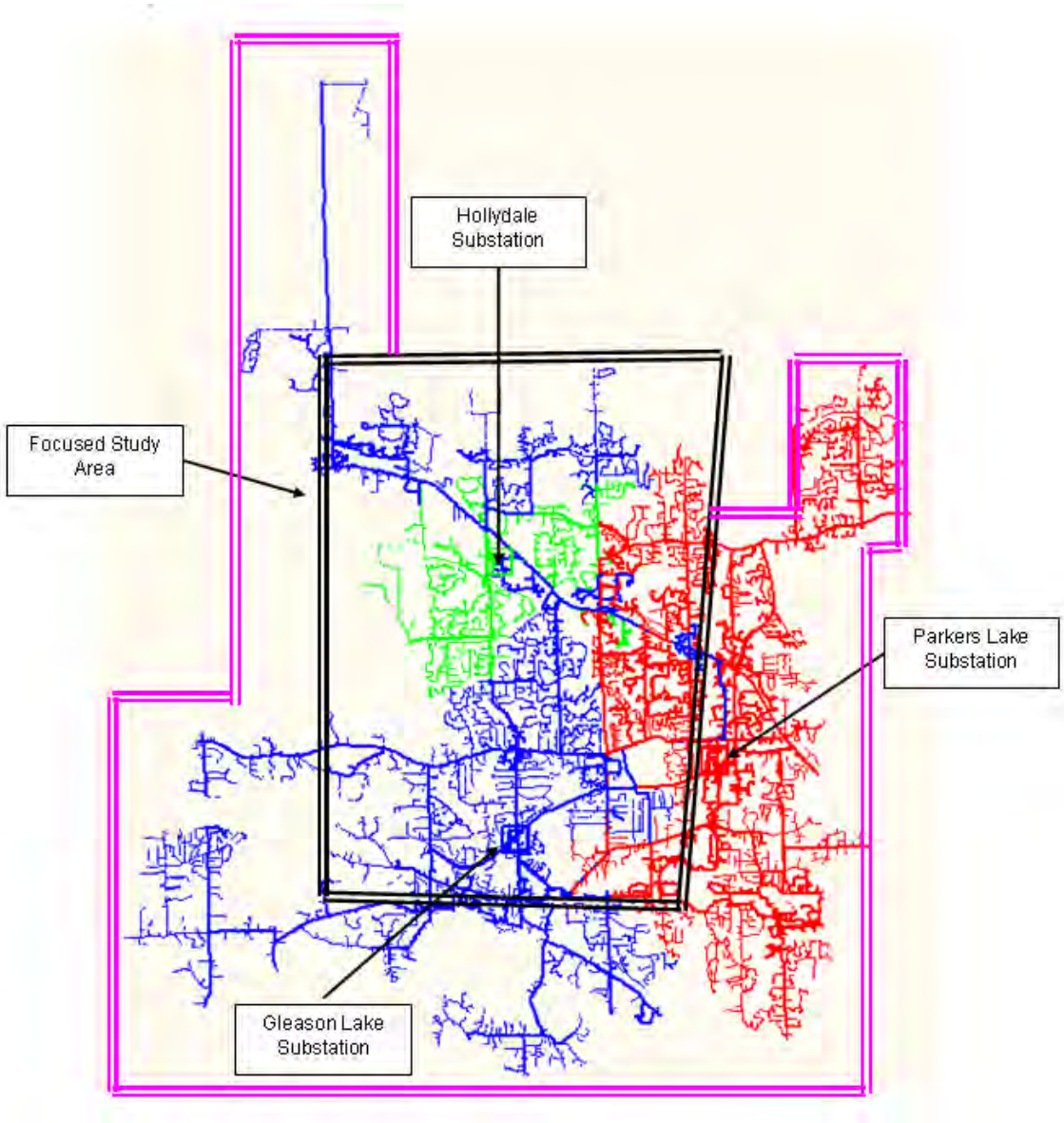
Figure 3.11: 2009 Non-Coincident Substation Transformer Load in Greater Study Area

Substations	No. of Feeder Circuits	Load (in kW) Served by Substation	% of Load Served by Substation
Gleason Lake	9	64,180	33.2%
Hollydale*	2	13,120	6.8%
Parkers Lake	16	115,840	60.0%
Total	**27**	193,140	100.0%

*All Hollydale substation load is served by a 34.5kV Gleason Lake feeder circuit. The Hollydale load has been split out from the total Gleason Lake substation load.

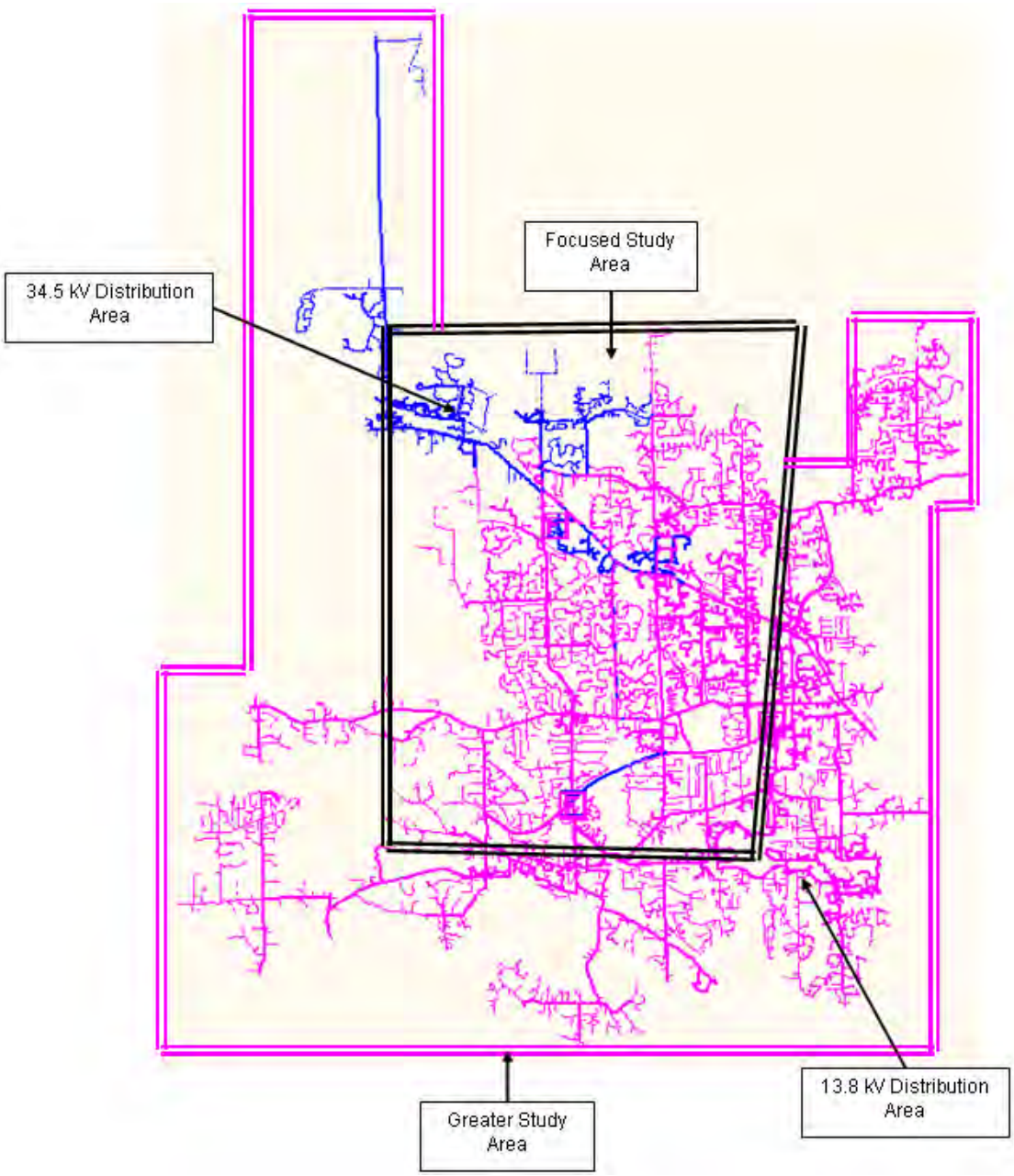
Each of the substations and its respective number of feeder circuits that serve Greater Study Area load are depicted in Figure 3.12.

Figure 3.12: Substations and Associated Feeder Circuits Serving Greater Study Area Load



As discussed in the description of the Focused Study Area, there are two different distribution voltages in the Greater Study Area, 13.8 kV and 34.5 kV and a distinction was made between which areas will be served by either distribution voltage. The areas previously identified as ultimately being served by 34.5 kV distribution feeders within the Focused Study Area are the same within the Greater Study Area. The remaining load will ultimately be served by 13.8 kV feeders. Figure 3.13 identifies the 13.8 kV designated areas and the 34.5 kV areas. The blue identifies the areas designated as 34.5 kV distribution areas and the pink identifies the areas designated as 13.8 kV distribution areas.

Figure 3.13: Ultimate Distribution Voltages within the Greater Study Area



4.0 ANALYSIS OF THE PLY ELECTRIC DISTRIBUTION DELIVERY SYSTEM IN THE FOCUSED STUDY AREA

4.1 FEEDER CIRCUITS

Distribution Planning assessed the electric distribution delivery system's ability to serve existing and future electricity loads in the Focused Study Area by evaluating the historical and forecasted load levels and utilization rates of the 13 feeder circuits (11-13.8kV and 2-34.5kV) that serve the Focused Study Area over a period of 20 years (*i.e.*, target year of 2030). The Planning Engineers then identified existing and anticipated capacity deficiencies resulting in overloads during N–0 (system-intact) and N–1 (single contingency) operating conditions.

In conducting this Study, Planning Engineers relied on the following resources:

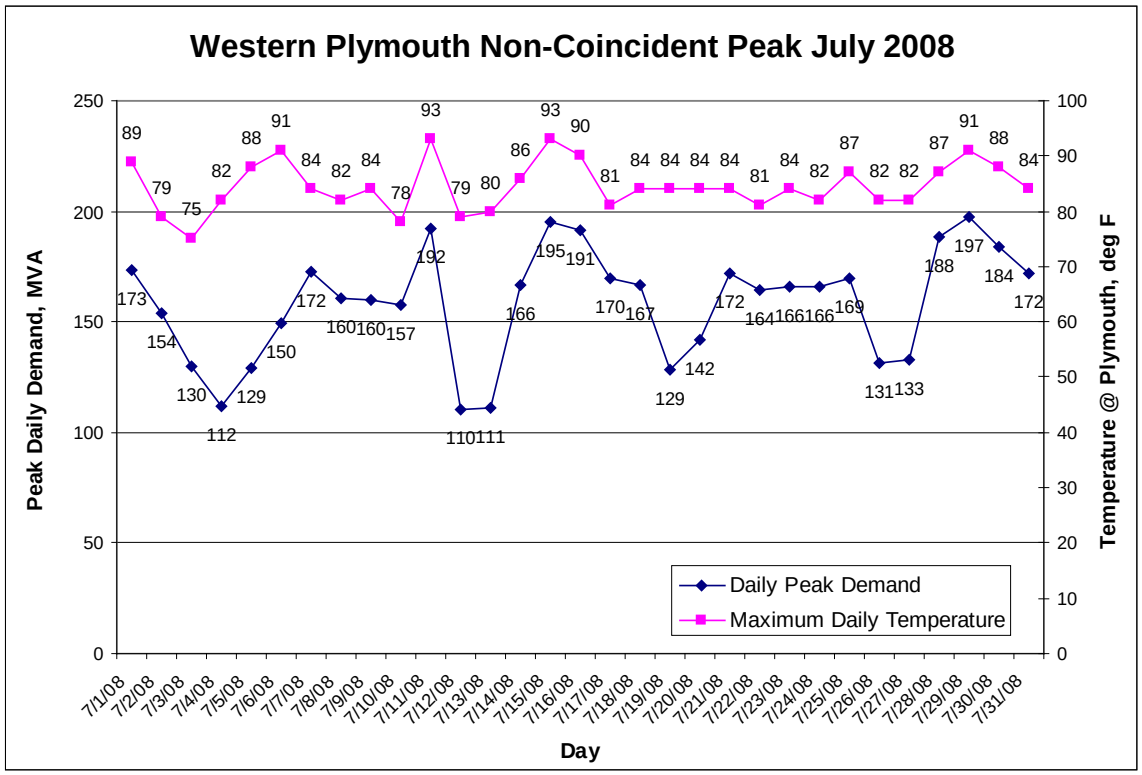
- SynerGEE Electric software package. SynerGEE is a software tool that can be used to explore and analyze feeder circuit reconfigurations. When historical peak load data is added from the Distribution Asset Analysis ("DAA") software package, SynerGEE is capable of providing load flow and voltage regulation analysis. SynerGEE is a tool that can generate geographically correct pictures of tabular feeder circuit loading data. This functionality has been achieved through the implementation of a Geographical Information System ("GIS") extraction process. Through this process, each piece of equipment on a feeder, including conductor sections, service transformers, switches, fuses, capacitor banks, etc., is extracted from the GIS and tied to an individual record that contains information about its size, phasing, and location along the feeder. All distribution feeders that are part of the Focused Study Area were extracted from the GIS software and imported into SynerGEE.
- Xcel Energy Distribution Planning Load Forecast for N-0 feeder circuit and substation transformer analysis. Planning Engineers used DAA to record historical non-coincident peak loads on distribution feeder circuits and distribution substation transformers. Distribution Planning Engineers annually examine each distribution feeder circuit and distribution substation transformer for peak loading. They use specific knowledge of distribution equipment, local government plans and customer loads to forecast future electrical load growth. Planning Engineers consider many types of information for the best possible future load forecasts including: historical load growth, customer planned load additions, circuit and other distribution equipment additions, circuit reconfigurations, and local government sponsored development or redevelopment.
- Xcel Energy Feeder Status Sheets for feeder circuit N-1 load allocation and N-1 analysis. Planning Engineers used Feeder Status Sheet software ("FSS") to allocate measured peak loads to main line feeder sections. Engineers validate and record feeder main line additions and reconfigurations using this tool. They analyze the N-1, first contingency breakdown of each distribution feeder circuit for the forecasted years.
- Xcel Energy Substation One Line Drawings. Planning Engineers used Xcel Energy Computer Aided Design software ("CAD") to develop CAD drawings modified by substation engineers as needed to reflect present substation configurations.
- Xcel Energy Distribution Feeder Maps. Planning Engineers used Xcel Energy CAD software to develop CAD drawings to reflect present feeder circuit mainline and tap configuration.

- Plymouth Maps. Planning Engineers used Internet live search maps to make an ad hoc map of the area, GIS software and SynerGEE software tool to make geographic based pictures of the feeder circuit configuration and to illustrate feeder circuit loading levels.

4.1.1 FEEDER CIRCUIT HISTORICAL LOAD

Feeder circuit peak loading in the Plymouth area is measured during the summer. Both feeder circuit and substation transformer load correlates to summer temperatures. This is illustrated in Figure 4.1, which compares the Greater Study Area Substation transformer measured peak load and outside temperature during July 2008.

Figure 4.1: July 2008 Greater Study Area Substation Peak Load and Outside Temperatures

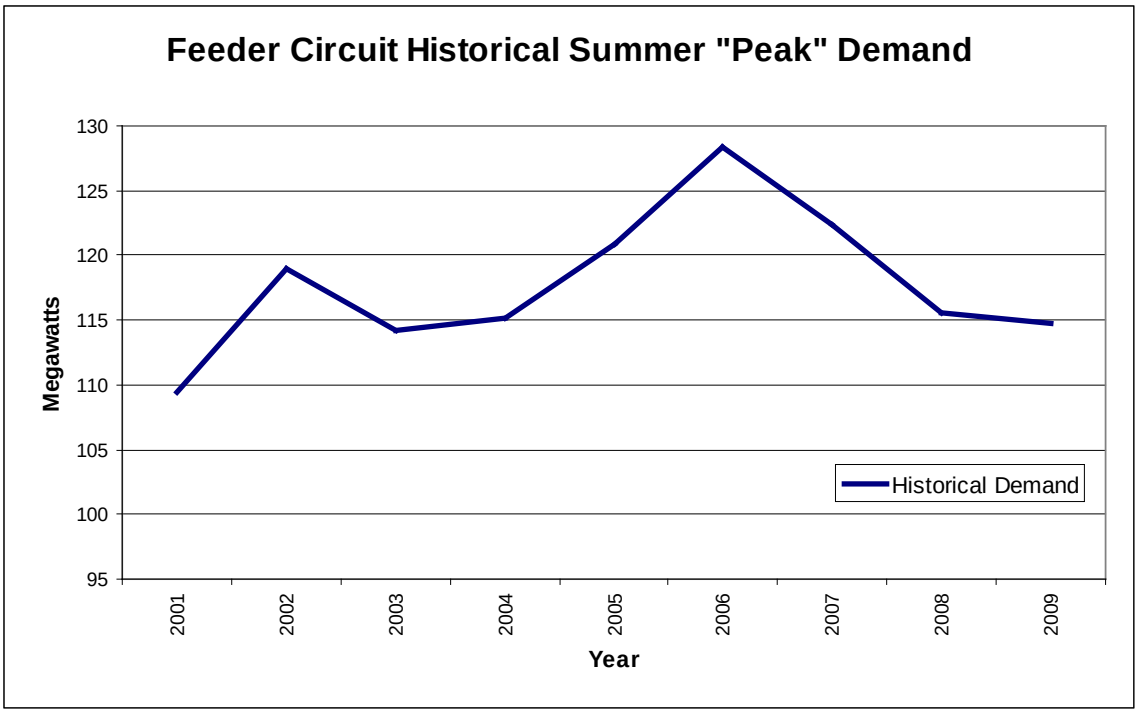


Each distribution feeder in the Plymouth area has three phase meters located in the substation, which are read monthly and the data recorded in Passport, a record-keeping software. These meters record the monthly peak for the feeder. The distribution feeders in the Focused Study Area also have a SCADA system that monitors the real time average or three phase amps on the feeder. This system feeds a SCADA data warehouse and the DAA warehouse where hourly data is stored so the feeder load history can be viewed by Electric Capacity Planning and Field Operations. When three phase load data is available, the highest recorded phase measurement is used in the distribution forecast. Each feeder circuit non-coincident peak history from 2001 through 2009 is used to forecast 2010 through 2030 peak loads.

Measured peak loads fluctuate from year to year due to the impacts of duration and intensity of hot weather and customer air conditioning usage. In the Focused Study Area, feeder circuit load fluctuates in a bandwidth of 5 MW to 14 MW from historic peaks occurring in 2002 and 2006 and

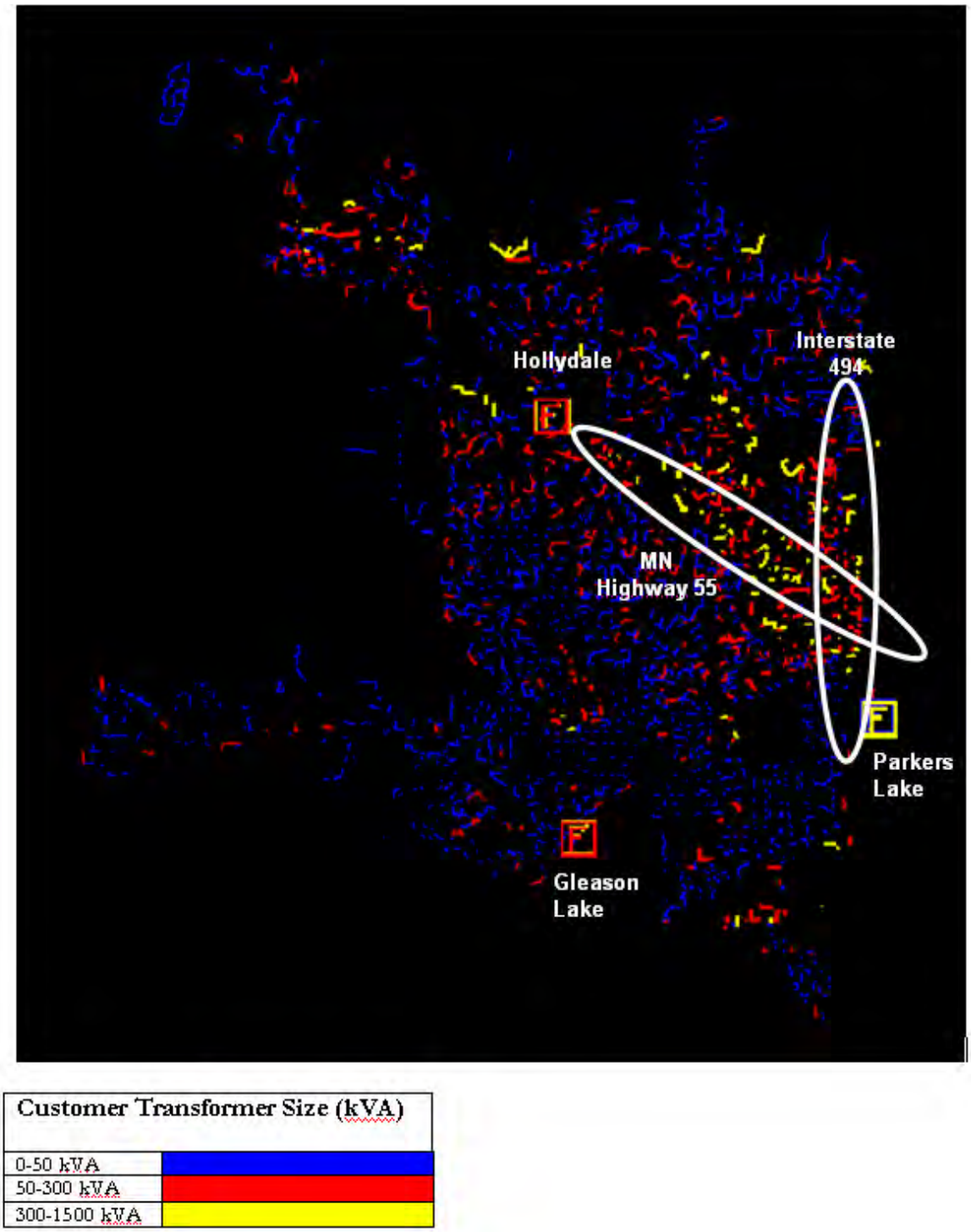
successive cooler years. Even though the measured peak load decreases, the historic peak represents latent load levels that will recur in years that have higher temperatures than in 2009. The measured peak load for feeders increased an average of 0.7% per year in the eight years between 2001 and 2009. Note 2008 and 2009 are cooler years with lower peaks. Using the growth between the peak years of 2002 and 2006 the average is 2.0%. The historical loads for the feeder circuits serving the Focused Study Area from 2001 through 2009 are shown below in Figure 4.2 and are also detailed in Appendix A.

Figure 4.2: Historical Summer "Peak" Demand for the Focused Study Area



In addition to peak loads, Planning Engineers researched existing customer load density. Individual distribution transformers serve a single customer or multiple customers. As customer load grows in developed areas such as the Focused Study Area, distribution transformers are changed to higher capacity equipment when customer demand exceeds the capacity of the original transformer. Distribution transformers are an excellent indicator of customer electrical loading and peak electrical demand. Figure 4.3 is a graphic, developed using SynerGEE software, illustrating distribution transformer installation by size (which indicates present customer load density) in the Focused Study Area.

Figure 4.3: Distribution Transformer Sizes (Which Is Indicative of Customer Load Density) in Focused Study Area (2009)



The customer load serving transformers shown in Figure 4.3 are colored based on the size of the transformer. The largest commercial customers in Plymouth are shown in yellow. Customers in large multi-residence buildings (more than 100 units), large multi-use buildings, large retail stores, or

corporate data centers typically have one or more transformers depicted as yellow dots. Customers in small and mid-sized commercial buildings, including retail stores and restaurants are served by smaller transformers that are shown as red. Residential customers and other lowest usage customers are shown in blue. Red and yellow show high density load corridors along MN Highway 55 and Interstate 494.

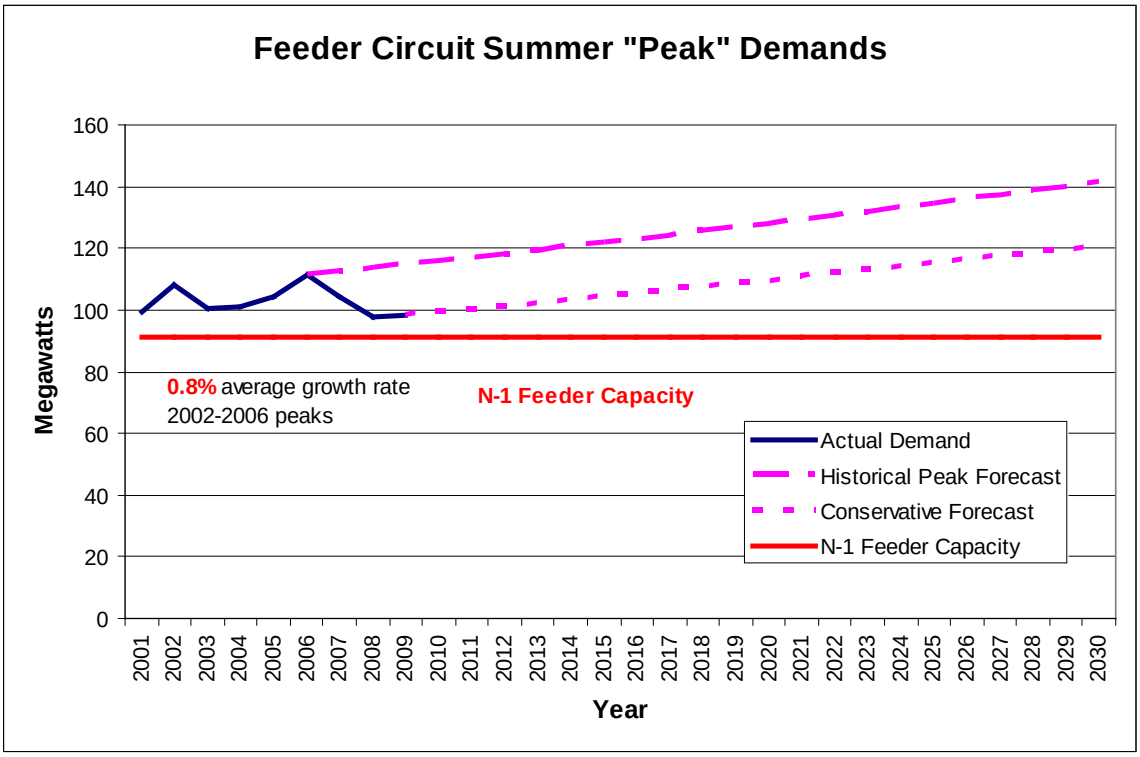
4.1.2 FEEDER CIRCUIT LOAD FORECASTS

The feeder circuit load is forecasted for each feeder circuit. Feeder circuit load forecast evaluation, trending method, considers a combination of historical growth, customer reported load additions, local government and developer projects or plans, and any additional information that impacts the circuit load growth. The table entries were calculated using the individual feeder circuit forecasts provided in Appendix B.

The historical data analysis of Focused Study area in the previous paragraph combined the 13.8 kV areas and 34.5 kV areas in order to gain an accurate representation of historical load growth within the Focused Study area from 2001-2009. The historical load data indicated that the load has been growing within the Focused Study Area over the last decade. To analyze the distribution system for the future and identify the capacity needs, the 13.8 kV and 34.5 kV areas as identified in Section 3.1 of this Study, need to be analyzed separately. Approximately 9 MVA of 34.5 kV load was assumed transferred to the 13.8 kV system for this analysis. The 34.5 kV feeder analysis includes the imbedded Hollydale 13.8 kV feeder load to reflect the impact of the 34.5kV source at Hollydale.

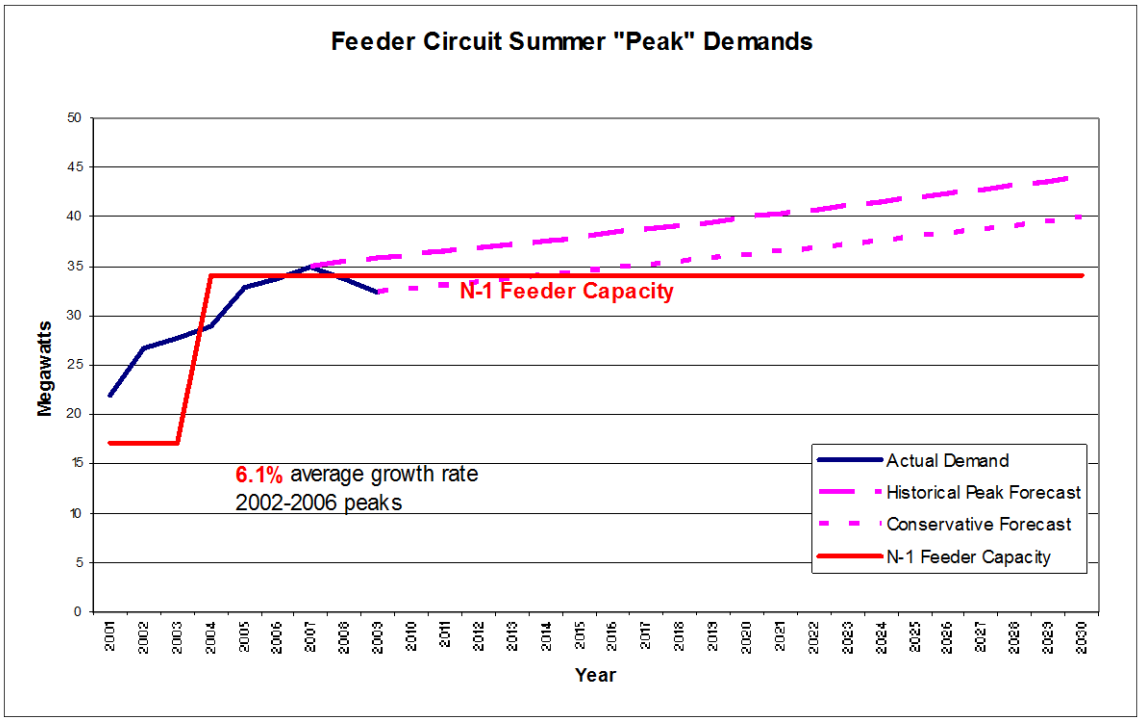
When forecasting future load, Distribution Planning applied a 1.0 % growth rate based on historic loading, anticipated customer conservation and a soft economy. Distribution Planning analyzed eleven 13.8 kV feeders and two 34.5 kV feeders for the next 20 years. Two forecasts were then developed. One is based on the historical peak from 2006 ("Historic Peak Forecast") which represents growth in demand of approximately 29 MW on the 13.8 kV feeders and approximately 8 MW on the 34.5 kV feeders by 2020. The second, "Conservative Forecast", is based on the cooler year peak loads from 2009 which represents growth in demand of approximately 11 MW on the 13.8 kV feeders and approximately 4 MW on the 34.5 kV feeders by 2020. Actual peak loads will likely fall between the conservative forecast demand and the historic peak levels. Figure 4.4 and Figure 4.5 are linear depictions of the load growth on the eleven 13.8 kV feeder circuits and the two 34.5 kV feeder circuits in the Focused Study Area from 2001 through 2030.

Figure 4.4: Historical and Forecasted Load Growth on Eleven 13.8 kV Feeder Circuits in Focused Study Area



Over time, demand on the distribution system generally trends upward, with some dips due to weather or economic downturns. The historic downturns have been followed by increases in demand that reach levels equal to or greater than the prior peak. For example, from the year 2002 to the year 2004, demand declined by approximately 7 MW. Then, from the year 2004 to the year 2006, demand increased again by approximately 10 MW, reaching a new peak of 111 MW. From year 2006 to 2009, there has been a similar decline in demand from the historical 2006 peak by approximately 13 MW. It can be reasonably expected that 2006 summer peak load levels will recur within the next several years once temperatures approach the same levels that occurred in the 2006 summer season.

Figure 4.5: Historical and Forecasted Load Growth on Two 34.5 kV Feeder Circuits in Focused Study Area



Just as the 13.8 kV feeders in Figure 4.4, Figure 4.5 shows that demand on the 34.5 kV system generally trends upward. Unlike the 13.8 kV feeders, there are no significant dips due to weather or economic downturns, indicating that the 34.5 kV system has experienced significant growth over the last decade. The only drop in demand on the 34.5 kV feeders is from 2007 to 2009 and that drop can be attributed to cooler weather. It can be expected that the decision to no longer expand the 34.5 kV system in this area will slow the growth. However, steady growth on the existing load should be expected and future years should look much more like the linear depiction of the historical 13.8 kV loads. It should also be noted that the spike in N-1 capacity from 2003 to 2004 is due to the addition of the second 34.5 kV feeder circuit out of Gleason Lake substation.

4.1.3 FEEDER CIRCUIT OVERLOADS AND UTILIZATION PERCENTAGES

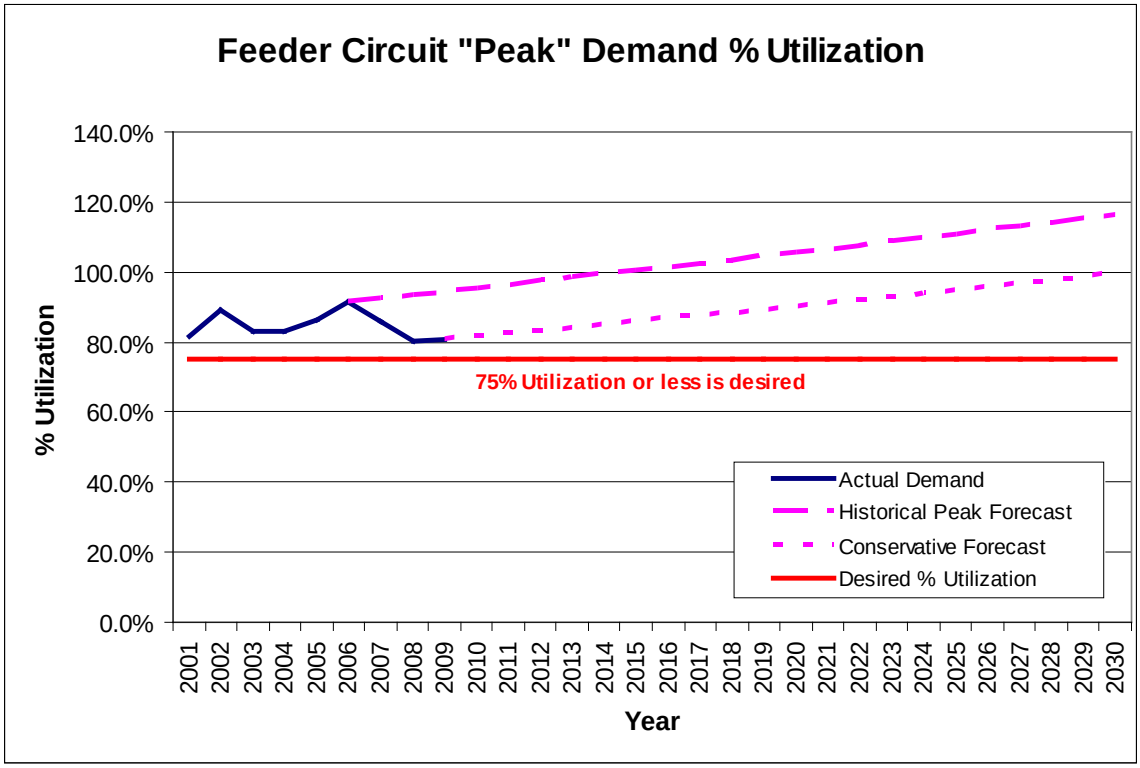
As discussed in Section 2.0, Distribution Planning aims to maintain utilization rates at or below 75% on distribution feeder circuits to help ensure a robust distribution system capable of providing electrical service under first contingency N-1 conditions. This desired loading level of 75% only applies to the 13.8 kV feeder circuits, the 34.5 kV feeder circuits have a unique configuration and therefore have a different desired loading level. There are only two 34.5 kV feeder circuits in this geographical area and therefore the feeder circuits only have one tie for backup during a contingency situation, while the 13.8 kV feeders generally have 3 ties, as described in Section 2.0. Since the 34.5 kV feeder circuits only have one tie as opposed to three, their desired loading level is 50%. At 50% utilization, each feeder circuit can fully back the other one up during N-1 conditions.

To assess the robustness of the system in the Focused Study Area over time, Planning Engineers analyzed the historical utilization rates and projected utilization rates of the 13.8 kV and 34.5 kV

feeder circuits based on forecast demand. Planning Engineers examined the historical loading and utilization of the eleven 13.8 kV feeder circuits and two 34.5 kV feeder circuits that serve Focused Study Area load. Figure 4.6 and Figure 4.7 show the conservative forecast linear growth ("Conservative Forecast") of feeder circuit utilization for the eleven 13.8 kV and two 34.5 kV feeder circuits between 2001 and 2030 as well as the upper-limit peak load forecast ("Historic Peak Forecast") based on historic peak load levels.

The feeder circuit load history shown is actual average non-coincident peak loading of the eleven 13.8 kV feeder circuits and the two 34.5 kV feeder circuits measured at the beginning of the feeder circuit in the substation. The sum of the individual feeder circuit peak loads is compared to the sum of the individual feeder circuit capacities to calculate feeder circuit utilization each year. Average load growth for the time period is calculated by comparing total non-coincident feeder circuit loads from the beginning to the end of the comparison period.

Figure 4.6: Focused Study Area – Eleven 13.8 kV Feeder Circuits, Utilization Percentage



The above analysis demonstrates a capacity need on the 13.8 kV distribution system within the Focused Study Area. Utilization rates of the 13.8 kV feeder circuits have exceeded the desired 75% utilization level since 2001. Even using the more conservative forecast based on the cooler summer peaks of 2009, average utilization rates on the 13.8 kV feeder circuits will exceed 90% by approximately 2020 unless system improvements are made. A peak load forecast starting from the historic peak 2006 level provides an upper forecast limit in 2009 of more than 13% above the conservative forecast utilization levels in Figure 4.6.

Figure 4.7: Focused Study Area – Two 34.5 kV Feeder Circuits, Utilization Percentage

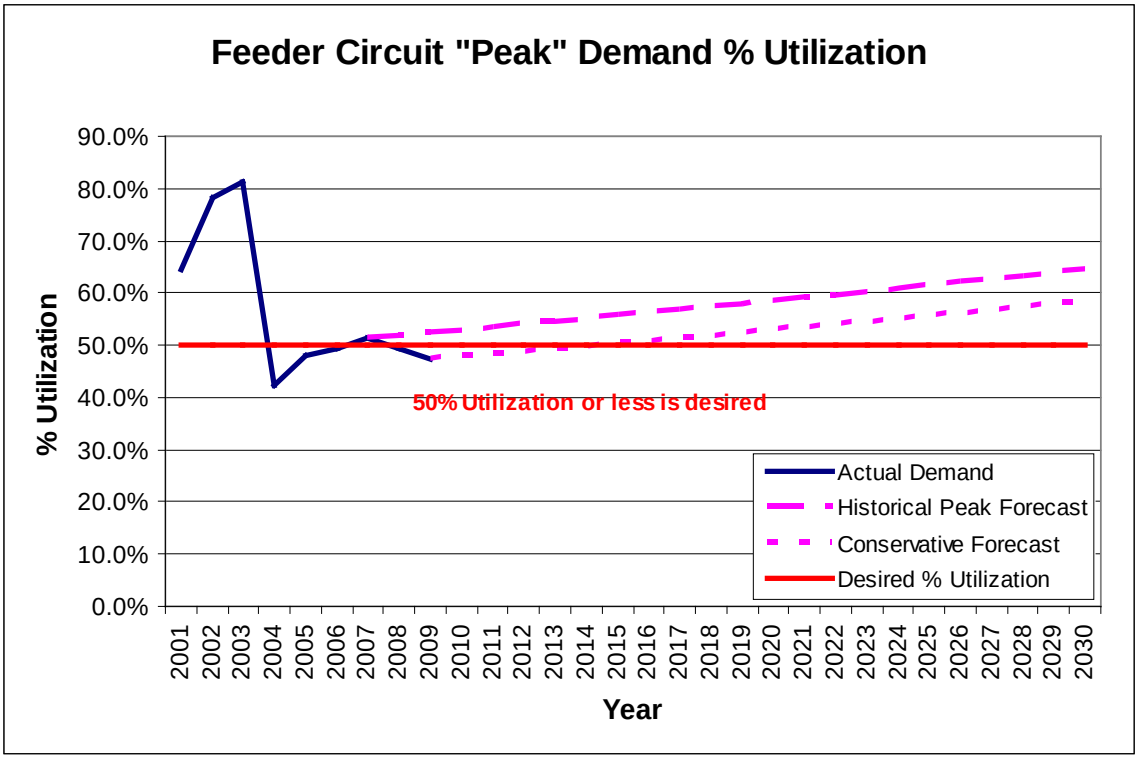


Figure 4.7 shows the same analysis of the 34.5 kV feeder circuits as depicted in Figure 4.6 for the 13.8 kV feeder circuits. This analysis also demonstrates a capacity need on the 34.5 kV distribution system within the Focused Study Area. The change in utilization from 2003 to 2004, is due to the addition of the second 34.5 kV feeder circuit in the Focused Study Area. Even with this capacity addition, peak load levels still continued to exceed the desired 50% loading level. Just as on the 13.8 kV distribution system within the Focused Study Area, these utilization levels are only projected to increase unless system improvements are made.

Figure 4.8 and Figure 4.9 provide additional detail on the historical and anticipated utilization percentages and overloads for the eleven 13.8 kV feeder circuits and two 34.5 kV feeder circuits in the Focused Study Area for various years between 2001 and 2030.

Figure 4.8: Summary of Feeder Circuit Utilization and Overloads for the Eleven 13.8 kV Feeder Circuits in the Focused Study Area

Historical Feeder Circuit Utilization and Overloads And Forecast Using Conservative Trending									
	2001	2004	2006	2009	2010	2015	2020	2025	2030
# of Circuits	11	11	11	11	11	11	11	11	11
MW Capacity	121	121	121	121	121	121	121	121	121
Feeder Actual	2001-2009 Average								
% Growth	0.8								

% Utilization	82%	83%	92%	81%					
Forecast					2010-2020 Average			2020-2030 Average	
% Growth					1.0%			1.0%	
% Utilization					82%	86%	90%	95%	100%
N-0 Overloads									
# Severe >115%	1	2	2	1	1	1	2	2	2
# of Circuits > 100%	2	2	4	3	3	3	3	4	6
MW > 100%	3.7	5.5	10.7	4.3	4.7	6.5	8.3	10.7	14.0
N-1 Conditions									
# of Circuits > 75%	8	7	8	7	7	7	7	8	8
MW > 75%	16.9	14.9	24.1	15.3	16.0	19.6	23.5	27.5	32.2

Figure 4.9: Summary of Feeder Circuit Utilization and Overloads for the Two 34.5 kV Feeder Circuits in the Focused Study Area

Historical Feeder Circuit Utilization and Overloads And Forecast Using Conservative Trending									
	2001	**2004**	**2006**	**2009**	**2010**	**2015**	**2020**	**2025**	**2030**
# of Circuits	1	2	2	2	2	2	2	2	2
MW Capacity	34	68	68	68	68	68	68	68	68
Feeder Actual	2001-2009 Average								
% Growth	6.1%								
% Utilization	64%	42%	49%	47%					
Forecast					2010-2020 Average			2020-2030 Average	
% Growth					1.0%			1.0%	
% Utilization					48%	50%	53%	56%	58%
N-0 Overloads									
# Severe >115%	0	0	0	0	0	0	0	0	0
# of Circuits >100%	0	0	0	0	0	0	0	0	1
MW > 100%	0	0	0	0	0	0	0	0	0.8
N-1 Conditions									

# of Circuits > 50%	1	1	1	1	1	1	1	1	1
MW > 50%	4.9	10.5	12.6	11.3	11.5	13.0	14.5	16.1	17.8

The information in Figure 4.8 and Figure 4.9, which was extracted from the detailed feeder circuit forecast data in Appendix B, shows that the Focused Study Area distribution system experienced steady peak growth in the decade leading up to 2009 loads that increasingly exceeded circuit capacities with increasing numbers of circuits overloaded in both system intact N-0 and first contingency N-1 conditions. Even when the number of circuits overloaded does not increase, the quantity of overloads increases. Figure 4.10 summarizes the additional feeder circuit capacity (in MW) needed to mitigate the overloads detailed in Figure 4.8. The assumption was made that all new feeders would be 13.8 kV due to the decision to no longer expand the 34.5 kV distribution system in the area. A single new 13.8 kV feeder circuit will have 13.5 MW of capacity and will serve 10 MW of load at 75% utilization.

Figure 4.10: Summary of Feeder Circuit Capacity Required to Mitigate the Feeder Circuit Overloads

Minimum Number of Feeders Required to Correct N-0 and N-1 Overloads									
	2001	**2004**	**2006**	**2009**	**2010**	**2015**	**2020**	**2025**	**2030**
N-0 Deficiency (MW)	3.7	5.5	10.7	4.3	4.7	6.4	8.3	10.7	14.8
Minimum # of New Feeders Needed	1	1	2	1	1	1	1	2	2
N-1 Deficiency (MW)	21.8	25.4	36.7	26.6	27.5	32.6	38.0	43.6	50.0
Minimum # of New Feeders Needed	3	3	4	3	3	4	4	5	6

Note: Minimum number of feeders assumes 13.5MW feeder circuits loaded to 75% or less.

This analysis shows that there is currently a deficit of approximately 37 MW in the Focused Study Area based on the 2006 peak loading and the system capacity under N-1 conditions. 2006 loading levels represent established overloads for connected load that exists on the electrical system and peak loading that has been previously reached under the most recent hottest weather conditions. Using conservative forecasting methods, which use the cooler summer peaks of 2009 as a starting point; by 2020, the deficit will be 38 MW, essentially returning to the 2006 level.

Areas like Plymouth that experience strong and steady growth and redevelopment go through several stages of overload operating conditions, starting with isolated feeder circuit overloads and progressing to widespread overloads that exceed substation transformer capacity limits.

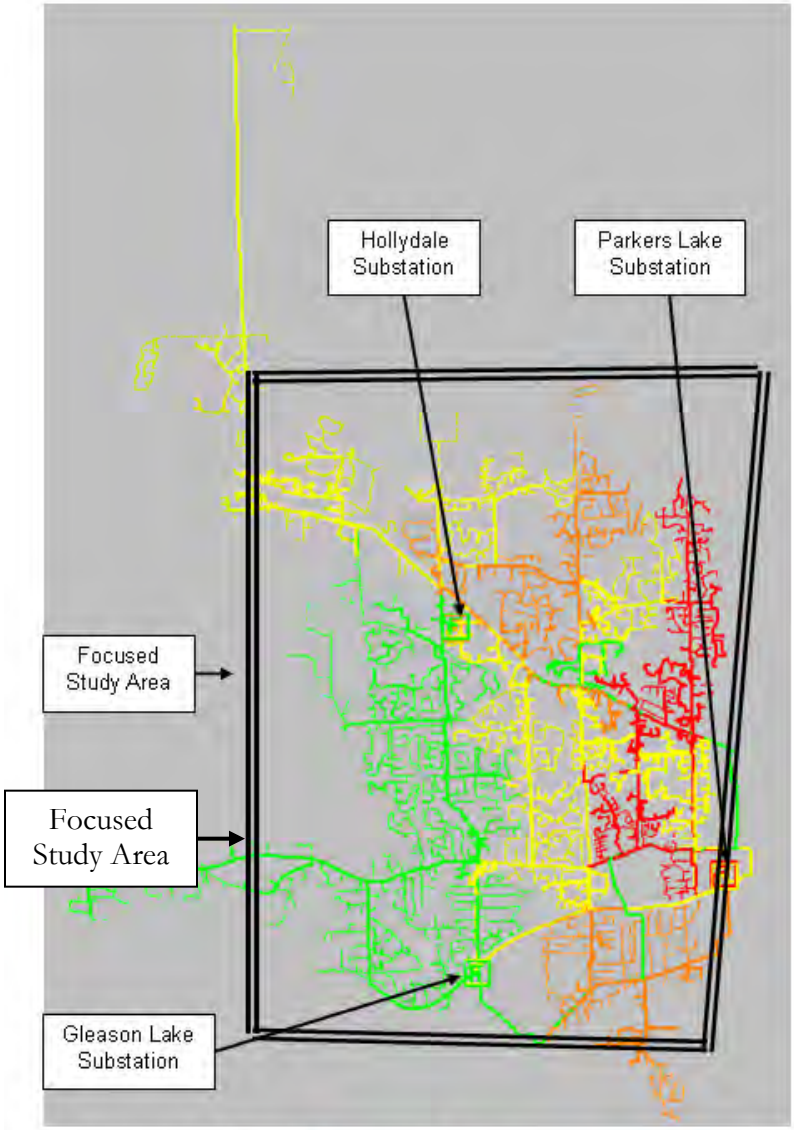
Isolated feeder overloads, which can be characterized by average feeder utilization percentage less than 75% (50% on the 34.5 kV distribution system), typically occur when there is redevelopment that increases load demand within a small part of the distribution system. While the average utilization percentage generally indicates the loading level of the entire Focused Study Area, feeders that are located geographically distant from each other can have either satisfactory capacity to serve customer load or alternately measure severe overloads. This variant is often caused by customer load mobility that can be characterized by new load or area redevelopment and revitalization.

Widespread feeder overloads, which can be characterized by average feeder utilization percentage of more than 75% (50% on the 34.5 kV distribution system), typically occur in distribution areas due to a combination of customer addition of spot loads and focused redevelopment by existing customers, developers or City initiatives. Distribution systems that start out with adequate N-1 and N-0 capacity, can quickly progress beyond isolated overloads when a large part of the distribution system is redeveloped or focused redevelopment is targeted in an area or along a corridor.

To better illustrate the number, concentration and location of the historical and forecasted overloads, Planning Engineers developed distribution system maps depicting the overloaded feeder circuits in N-0 system intact and N-1 first contingency operating conditions for 2006 and future forecast year 2020. These distribution system maps are depicted in Figure 4.11 and Figure 4.12. The color codes in the distribution system maps represent rows in Figure 4.8 for the labeled years as follows:

> <u># Severe > 115%, N-0 Overloads</u>: The quantity of feeder circuits that are severely overloaded under system intact conditions are identified as shown in red.
>
> <u># of Circuits >100%, N-0 Overloads</u>: The quantity of feeder circuits that are overloaded under system intact conditions are identified as shown in orange and red depending on the severity of the overload with red feeder circuits having the most severe overloads.
>
> <u>MW > 100%, N-0 Overloads</u>: The sum of the system intact overloads, in MW for the number of circuits that are identified as overloaded and shown in orange and red.
>
> <u># Circuits > 75%, N-1 Conditions</u>: The quantity of feeder circuits that are loaded above 75% capacity indicating first contingency overload conditions are identified as shown in yellow, orange, and red. Yellow circuits are feeder circuits with first contingency overloads.
>
> <u>MW > 75%, N-1 Conditions</u>: The sum of the first contingency overloads, in MW for the number of circuits that are identified as overloaded and shown in yellow, orange, and red.

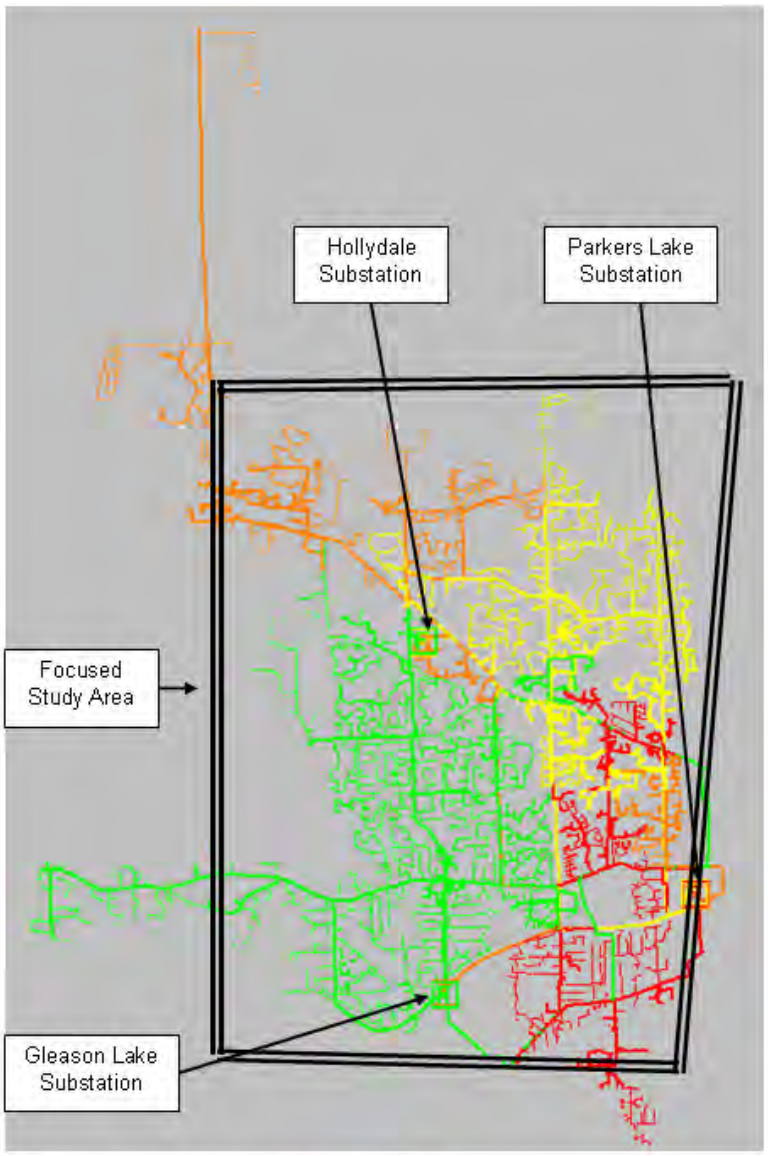
Figure 4.11: Focused Study Area 2006 N-0 Feeder Circuit Risks – System Intact (Using historical feeder peak year)



Feeder Circuits Colored by N-0 Circuit Loading:		
4 Circuits	<75%	
5 Circuits	75%-100%	
2 Circuits	100%-115%	
2 Circuits	>115%	

Above Figure 4.11 shows that of the thirteen feeder circuits in the Focused Study Area, in the historical feeder peak year of 2006, under system intact N-0 conditions, 4 feeders were utilized at less than 75%, 5 feeders were utilized between 75%-100%, 2 feeders were utilized between 100%-115%, and 2 circuits were utilized at greater than 115%. Note that many of the most severe overloads occur along previously identified areas of more concentrated load and faster load growth.

Figure 4.12: Focused Study Area 2020 N-0 Feeder Circuit Risks – System Intact (Using conservative forecast)

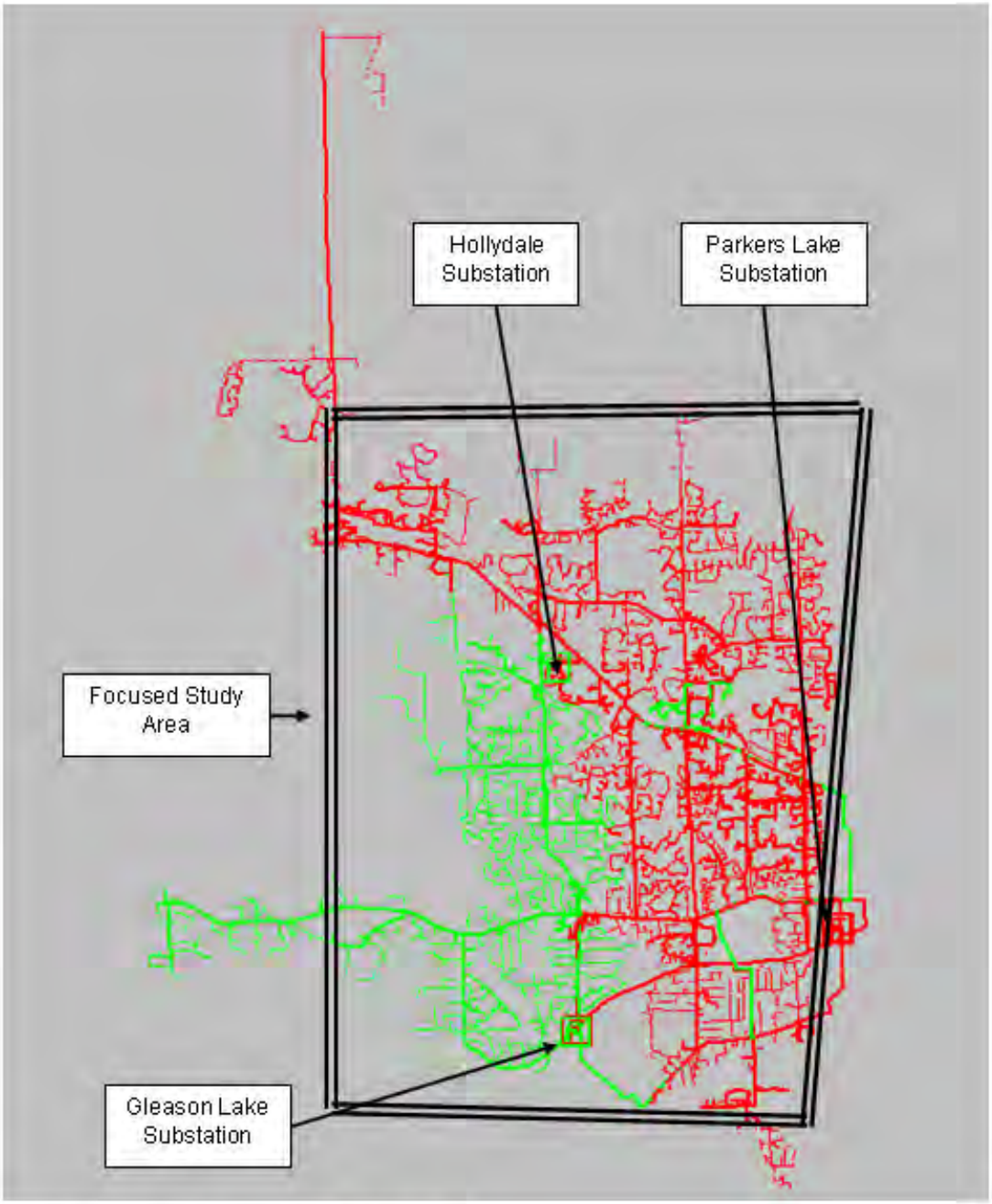


Feeder Circuits Colored by N-0 Circuit Loading:		
5 Circuits	<75%	
4 Circuits	75%-100%	
2 Circuits	100%-115%	
2 Circuits	>115%	

Above Figure 4.12 shows that of the thirteen feeder circuits in the Focused Study Area, based on 2020 forecasted load under system intact N-0 conditions, 8 feeders will be overloaded. Note this is using the more conservative forecast. The 8 overloaded feeders consist of 4 feeders utilized between 75%-100%, 2 feeders utilized between 100%-115%, and 2 circuits utilized at greater than 115%.

Overloads are even more widespread across the feeder circuits in the Focused Study Area under N-1 loading conditions. Figure 4.13 and Figure 4.14 color codes represent first contingency overloads existing for 2006 and forecasted for 2020. A comparison of Figure 4.13 and Figure 4.14 shows that forecasted load levels, which are conservatively based on the cooler loads of 2009 and take into consideration possible customer conservation and the impacts of a slow economy, reach 2006 historic peak load levels again in 2020, resulting in similar N-1 overload conditions. When a typical single feeder circuit fails during peak loading conditions, the main-line of the failed circuit is switched into three sections (the whole feeder is switched on a 34.5 kV feeder) and each one of the three sections is transferred to a separate adjacent feeder circuit. Adjacent feeders must not be already encumbered by the load of a prior feeder circuit failure or scheduled switching event. The N-1 data provided in this section of the Study for the feeder circuits serving the Focused Study Area are based on the loss of a single mainline feeder circuit. The circuits that will experience an overload under first contingency conditions are shown in red. Feeder circuits shown in red demonstrate the cumulative effect on the feeder circuits of switching the load from any single feeder circuit failure during peak loading conditions.

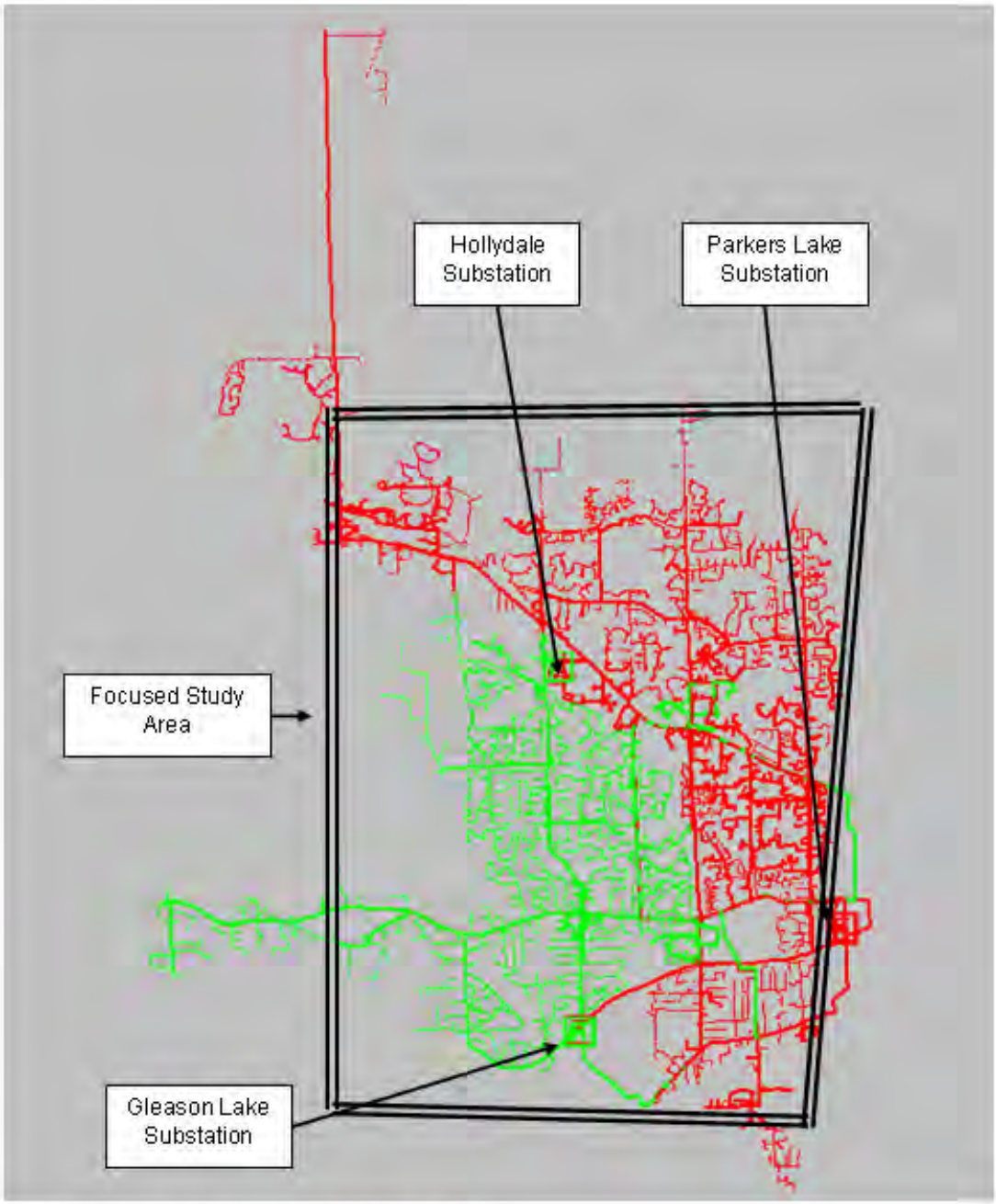
Figure 4.13: Focused Study Area 2006 N-1 Feeder Circuit Risks – Single Contingency



Feeder Circuits Colored by N-1 Circuit Loading:		
4 Circuits	No N-1 Risk	
9 Circuits	N-1 Risk	

Above Figure 4.13 shows that of the 13 feeder circuits in the Focused Study Area, in 2006 under single contingency N-1 conditions, 9 feeders would be at risk for experiencing overload conditions.

Figure 4.14: Focused Study Area 2020 N-1 Feeder Circuit Risks – Single Contingency



Feeder Circuits Colored by N-1 Circuit Loading:		
5 Circuits	No N-1 Risk	
8 Circuits	N-1 Risk	

Above Figure 4.14 shows that of the thirteen feeder circuits in the Focused Study Area, under 2020 forecasted load under single contingency N-1 conditions, 8 feeders would be at risk for experiencing overload conditions.

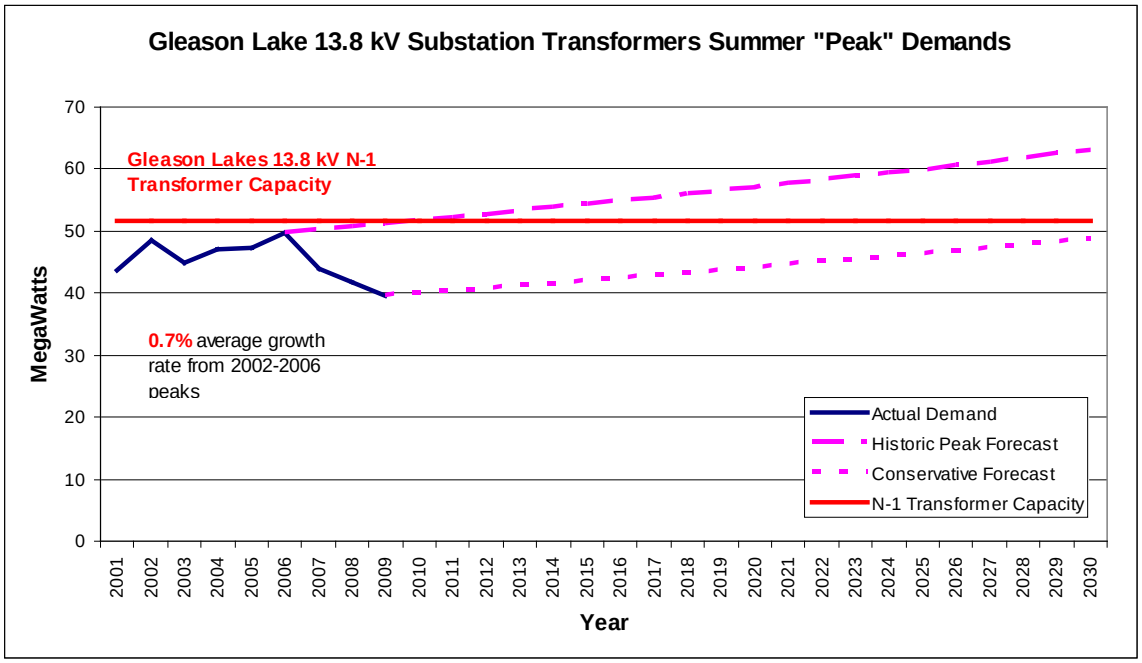
The data demonstrates that the Focused Study Area has been experiencing higher than optimal utilization rates on its feeders for the past decade. Without additional capacity additions in the area, these high utilization rates will increase the number and duration of overloads on feeders. Based on this analysis, Distribution Planning concluded that to ensure continued reliable service in the area, additional improvements are required.

4.2 GLEASON LAKE SUBSTATION TRANSFORMERS

After examining feeder circuit peak demands, Distribution Planning Engineers looked at the loading levels for the two 13.8 kV transformers and the one 34.5 kV transformer housed at the Gleason Lake Substation. Gleason Lake Substation is the only substation served by transmission that is in the Focused Study Area. Hollydale substation also lies within the Focused Study Area however, as discussed earlier, its ability to provide additional capacity is dependent on the available 34.5 kV capacity at Gleason Lake substation.

The historical and forecasted loads for the two 13.8 kV and one 34.5 kV Gleason Lake Substation transformers serving the Focused Study Area from 2001 through 2030 are included in Appendix A and B. Figure 4.15 shows the Conservative Forecast and the Historical Peak Forecast applied to the two 13.8 kV substation transformers at the Gleason Lake Substation from 2001 through 2030.

Figure 4.15: Historical and Forecasted Load Growth on Two 13.8 kV Substation Transformers at Gleason Lake Substation in the Focused Study Area (Non-Coincident)



Gleason Lake Substation transformer loads fluctuate in a bandwidth of 4 to 6 MW between historic peak load years in 2002 and 2006 and lower peak load levels of succeeding years. Actual peak load levels will likely fall between the conservative forecast demand used in this Study and the historic peak forecast load levels illustrated in Figure 4.15 above.

Above Figure 4.15 indicates that historically the 13.8 kV load levels at Gleason Lake substation have approached the N-1 substation limit, but have not exceeded the limit. Using the historical peak forecast demand load projections, there is roughly only 1 MW of additional load serving capacity on the 13.8 kV Gleason Lake distribution system. Using the conservative forecast demand load projections, there is roughly 12 MW of additional load serving capacity on the 13.8 kV Gleason Lake distribution system. Earlier analysis in Figure 4.10 demonstrates that even with this 12 MW of additional load serving capacity, the capacity deficiencies on the 13.8 kV distribution system within the Focused Study Area cannot be fully solved.

Figure 4.16 shows the same analysis done on the 34.5 kV substation transformer at Gleason Lake substation.

Figure 4.16: Historical and Forecasted Load Growth on One 34.5 kV Substation Transformers at Gleason Lake Substation in the Focused Study Area

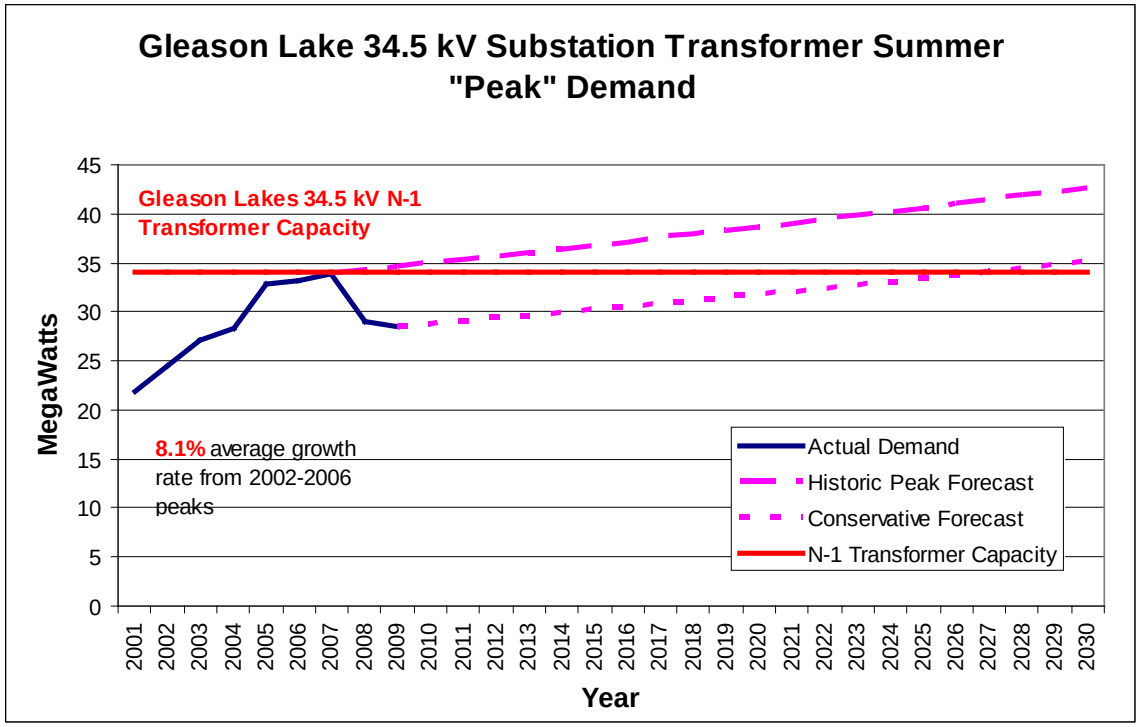


Figure 4.16 shows that the 34.5 kV substation transformer at Gleason Lake substation has experienced loading similar to the 13.8 kV substation transformers. The load on the 34.5 kV substation transformer has slightly exceeded the N-1 limit. Using the historic peak forecast demand projections, there is 0 MW of additional load serving capacity on the 34.5 kV Gleason Lake distribution system. Using the conservative forecast demand projections, there is roughly 6 MW of additional load serving capacity on the 34.5 kV Gleason Lake distribution system. As previously stated, this alone is not enough capacity to solve the deficiencies on the distribution system in the Focused Study Area. Combining the 6 MW of load serving capacity available on the 34.5 kV substation transformer with the 12 MW on the 13.8 kV substation transformers, the deficiencies can still not be fully solved.

The Gleason Lake substation is presently at its maximum design capacity based on transformer capacity ratings and available space. Based on these restrictions, and the analysis above, Distribution Planning concluded that Gleason Lake substation transformers do not have the required capacity to solve the capacity issues within the Focused Study Area.

5.0 ANALYSIS OF THE GREATER PLYMOUTH AREA ELECTRIC DISTRIBUTION DELIVERY SYSTEM

5.1 SUMMARY OF TRANSFORMER LOADING.

After determining that the Plymouth electric distribution delivery system in the Focused Study Area has an existing feeder circuit capacity deficit of 37 MW and that this deficit is only expected to increase in future years, Distribution Planning examined the Gleason Lake Substation transformer capacity.

In 2006 the Gleason Lake 13.8 kV substation transformers were within 2 MW of the substation's N-1 capacity limit. In the cooler years following 2006 the load has not been as high on the substation transformers. However, even using a forecast based off the cooler year's peak loading, there isn't sufficient capacity to relieve the overloads in the Focused Study Area.

The Gleason Lake 34.5 kV substation transformer's load level was essentially at the substation's N-1 capacity limit in 2007. In the subsequent cooler summers the load still remained within about 4 MW of the substation's N-1 limit. Consequently, the Gleason Lake 34.5 kV substation transformer is not capable of relieving the overloads on the Focused Study Area feeder circuits.

Based on all of the above analysis and the fact that the Gleason Lake substation is already at its ultimate design capacity, Planning Engineers broadened the scope of their analysis to include the Greater Study Area in order to determine, in part, the availability of additional capacity near the Focused Study Area.

5.2 HISTORICAL LOAD AND LOAD FORECASTS

Historic substation transformer demands (2001 through 2009) were used as a basis to forecast each of the 7 substation transformer loads in the Greater Study Area. Distribution Planning Engineers used DAA, which supports multi-year analyses, to forecast distribution substation transformer loads from 2010 to 2030, using historical growth rates and knowledge of anticipated future load levels.

The Greater Study Area includes the 7 substation transformers comprising the three (3) Metro West substations that ring the Focused Study Area (Gleason Lake, Hollydale, and Parkers Lake). Six of these seven substation transformers are at a voltage of 13.8 kV and one is at a voltage of 34.5 kV. Similar to feeder circuit peak loads in the Focused Study Area, transformer peak loads in the Greater Study Area occurred in 2002 and again in the 2006 timeframe.

For analysis purposes, the 13.8 kV substation transformers and the 34.5 kV substation transformers should be considered separately, just as in Chapter 4. The only 34.5 kV substation transformer in the Greater Study Area is the one housed at Gleason Lake substation. Thus, the 34.5 kV distribution system within the Focused Study Area is the same as the 34.5 kV distribution system within the Greater Study Area. Chapter 4 already contains all of the analysis required for the 34.5 kV distribution system and therefore Chapter 5 will only contain analysis of the six 13.8 kV substation transformers within the Greater Study Area.

Each distribution substation in the Greater Study Area has a demand meter for each transformer located in the substation, which is read monthly, and the data is recorded in Passport. These meters record the monthly peak for the substation transformer. All affected distribution substation

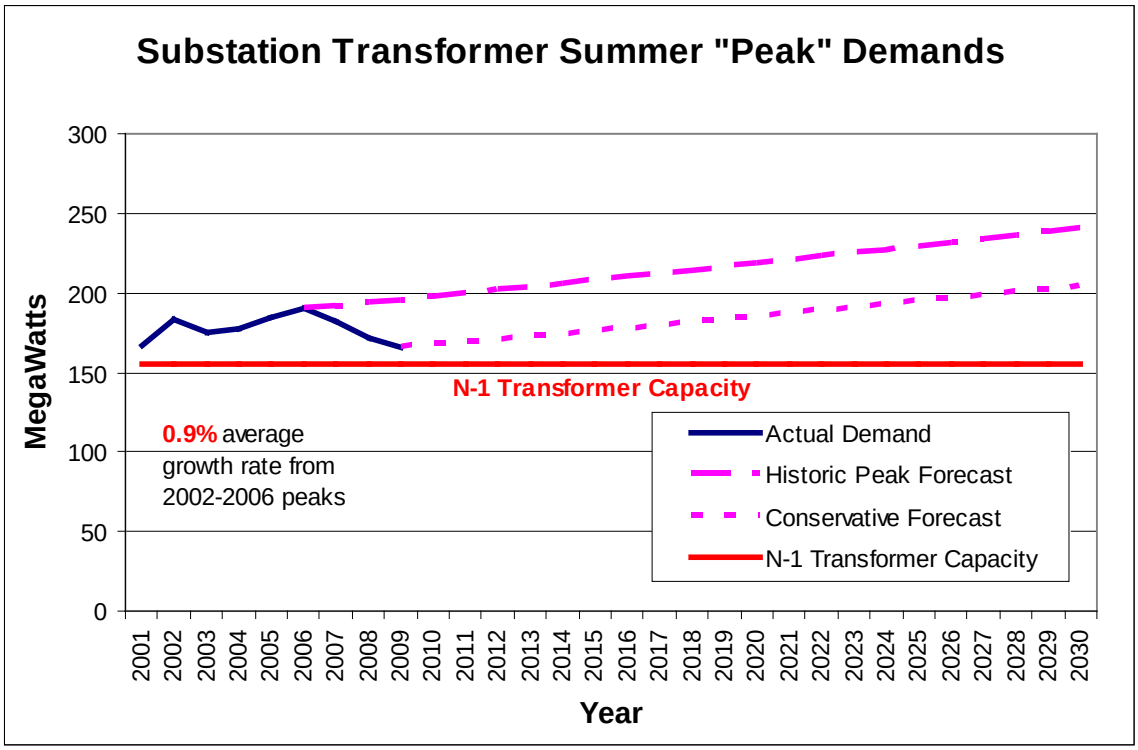
transformers also have a SCADA system connection that monitors the real time load on the transformer. Similar to the distribution feeders, this system feeds a SCADA data warehouse and the DAA warehouse where hourly data is stored so Electric Capacity Planning and Field Operations can view the substation transformer's load history. Each transformer's peak in a multi-transformer substation is non coincident.

Each of the six 13.8 kV distribution substation transformers in the three substations serve multiple feeder circuits. Substation transformer peak load is proportional but not equal to the sum of the feeder circuit peak loads served from that substation transformer. The detail of substation transformer loading is a larger granularity than feeder circuit loads with a corresponding greater impact on customer service.

Each distribution substation transformer in the Greater Study Area serves the aggregate load of the connected down-line feeder circuits of that transformer. While each of the feeder circuits has a non-coincident peak load that the feeder circuit must be capable of serving, the combination of multiple feeders serves the diversified load of the aggregated feeders. Since the substation transformers serve diversified feeder load, the non-coincident transformer load is less than the sum of the feeder peak loads.

The historical and forecasted loads for the six 13.8 kV substation transformers serving the Greater Study Area from 2001 through 2030 are provided in Appendix C of this Study. Figure 5.1 is a linear depiction of the load growth on the six 13.8 kV substation transformers in the Greater Study Area from 2001 through 2030.

Figure 5.1: Greater Study Area – Historical and Forecasted Loads



The lower dashed line shows the forecast peak load levels from 2009 peak loads that are also in Appendix C, while the upper dashed line shows loads forecast based on 2006 historic peak load levels. The sum of the historic peaks increased an average of 0.9% annually.

Comparison of transformer load levels for the Greater Study Area to the Focused Study Area transformer load levels, provided in Section 4.0 for the Gleason Lake Substation, shows a similar load growth pattern from 2001 through 2009 with increasing peaks in 2002, and 2006. The Gleason Lake Substation load growth, at an average of 0.7% growth per year, is similar to the six 13.8 kV distribution substation transformer 0.9% per year growth. Load diversity results in a transformer peak load that is slightly less than the sum of all of the feeder circuit peak loads fed from the substation transformer due to the feeder circuits reaching their individual peaks at different times.

Substation transformer contingency overloads typically occur in distribution areas where many and continued distribution fixes to widespread overloads use up existing feeder circuits and consume distribution substation transformer capacity. Distribution systems that experience feeder circuit N-1 and N-0 overloads soon measure substation transformer N-1 overloads of increasing amounts for longer durations.

Figure 5.2 summarizes the anticipated overloads for the six 13.8 kV substation transformers in the Greater Study Area for various years between 2001 and 2030 and compares the historical peak and conservative forecasts.

Figure 5.2: Summary of Substation Overloads of the Three Substations Serving Greater Study Area Load

Greater Study Area – Six (6) 13.8 kV Substation Transformers Overload Summary									
	2001	**2004**	**2006**	**2009**	**2010**	**2015**	**2020**	**2025**	**2030**
# of Transformers	6	6	6	6	6	6	6	6	6
MW Normal Capacity	264.4	264.4	264.4	264.4	264.4	264.4	264.4	264.4	264.4
Actual Loads			**Peak Year**						
% Growth	0.9% Average Annual Growth Rate 2002 to 2006 peaks								
# of Transformers with N-1 Overloads	4	4	4	4					
N-1 MW Overload	11.8	22.6	34.5	14.7					
Historic Peak Trend Forecast Overloads									
% Growth					1.0% Average Annual Forecast Growth Rate 2010 to 2030				
# Transformers N-1					4	6	6	6	6
N-1 MW Overload					42.2	52.3	62.9	74.0	85.7
Conservative Trend Forecast Overloads			**Peak Year**						
# Transformers N-1					4	4	4	4	6
N-1 MW Overload					14.7	25.2	34.4	44.0	54.2

Planning Engineers generated graphics that illustrate the transformer overloads tabulated above and that provide a geographic based perspective of the present and forecast substation transformer overloads under single contingency (N-1) scenarios. These figures illustrate the geographic placement and loading level by color of substation transformers described in the table of Figure 5.2 in the Greater Study Area. Colors are used to represent substation transformer loading levels and identify overloads under N-1 first contingency operating conditions for load capacity limits in 2006 and future forecast year 2020.

Substation transformer N-1 loading levels for all distribution transformers of the same distribution voltage (13.8 kV) are addressed together because the means to transfer large amounts of load between substation transformers is built into the substation design. Substation transformer loading levels for a substation are planned for N-1 conditions resulting from the worst case possibility of one transformer (the largest transformer if the transformers are different capacities) out of service during peak loading. The maximum amount of transformer capacity that can be served from all transformers grouped together in a substation under N-1 conditions is also known as substation firm capacity. The N-1 data provided in this section of the Study for substation transformers in the Greater Study Area are based on the loss of a single transformer in a substation.

Two of the transformer overload graphics are depicted in Figure 5.3 and Figure 5.4, respectively. The color codes in the graphics depict varying amounts of load described in the chart at Figure 5.1 and the table at the Figure 5.2 for the labeled years as follows:

> Not Overloaded - The feeder circuits emanating from the substation transformers that are not overloaded during N-1 conditions are shown in green. The quantity of substation transformers that are not overloaded is listed.
>
> < 10 MW Overloads in Yellow - The feeder circuits that are overloaded by 10 MW or less under N-1 conditions are yellow. The number of substation transformers that are overloaded by less than 10 MW are listed. 10 MW is the maximum amount of load that can be transferred by utilizing field switching in about 2 hours.
>
> 10 to 25 MW Overloads in Orange - The feeder circuits that are overloaded by less than 25 MW but more than 10 MW are orange. The quantity of substation transformers that are overloaded by 10 to 25 MW is listed. 25 MW is the typical amount of load that can be served by a mobile transformer installation. A mobile transformer can sometimes be installed as quickly as 24 hours under emergency conditions.
>
> Severe Overloads > 25 MW in Red - The feeder circuits that are overloaded by more than 25 MW are red. The quantity of substation transformers that are overloaded by more than 25 MW is listed. Typically, more than 25 MW of load cannot be restored in less than 24 hours if a large substation transformer fails and could result in extended customer outages.

Figure 5.3 shows first contingency N-1 substation transformer loading from 2006. Gleason Lake substation transformers do not reflect first contingency overload. The Hollydale substation transformer has an N-1 overload of less than 10 MW. The Parkers Lake substation transformers have N-1 overloads of more than 25 MW.

Figure 5.3: Greater Study Area 2006 N-1 13.8 kV Substation Transformer Risks – Single Contingency

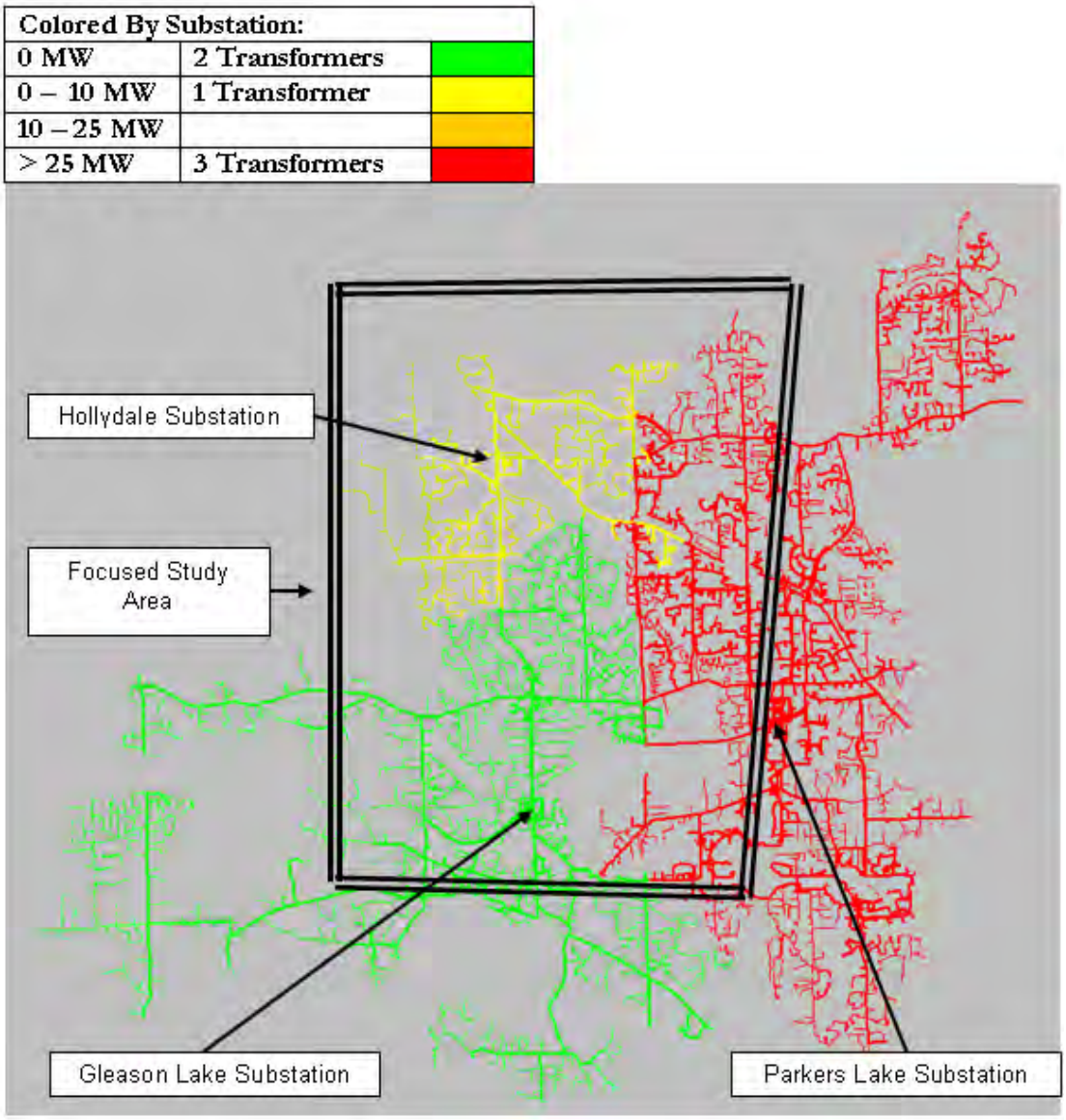


Figure 5.4 shows first contingency N-1 substation transformer loading from 2020. Gleason Lake substation transformers do not reflect first contingency overload. The Hollydale substation transformer has an N-1 overload in the range of 10 MW to 20 MW. The Parkers Lake substation transformers still have N-1 overloads of more than 25 MW.

Figure 5.4: Greater Study Area 2020 N-1 Substation Transformer Risks – Single Contingency

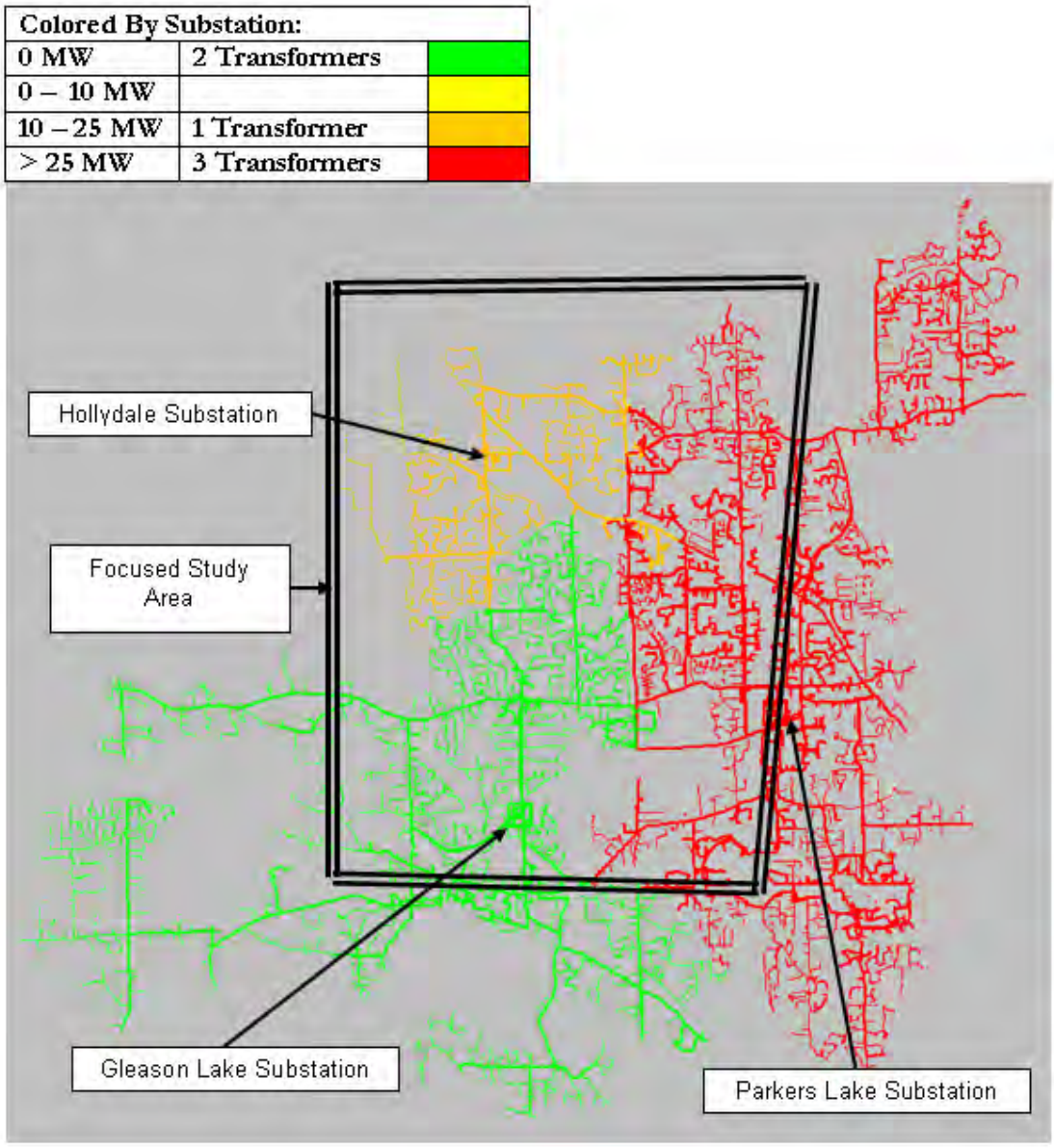


Figure 5.5 summarizes the additional substation transformer capacity (in MW) needed to mitigate the overloads detailed in Figure 5.2. A single new 50 MVA substation transformer will serve 36.75 MW of load at 75% utilization.

Figure 5.5: Summary of Substation Transformer Capacity Required to Mitigate Overloads

Minimum Number of Substation Transformers Required to Correct Greater Study Area Transformer N-1 Overloads Based on Conservative Trend Forecast									
	2001	**2004**	**2006**	**2009**	**2010**	**2015**	**2020**	**2025**	**2030**
N-1 Deficiency (MW)	11.8	22.6	34.5	14.7	16.4	25.2	34.4	44.1	54.2
Minimum # of New Transformers* Needed	1	1	1	1	1	1	1	2	2

*Assumes 50 MVA transformers with 75% or less utilization.

Figure 5.5 shows that there has been an existing need for one new 13.8 kV substation transformers in the Greater Study Area since 2006. Even though conservative load forecasts are lower than 2006 levels, 2006 historic peak load levels remain as latent load that is likely to recur, and even exceed 2006 levels due to additional customer load, when future years reach temperature levels of the summer of 2006. As load grows, it is anticipated that additional transformers will be needed in future years. Figure 5.5 is based on conservative forecasted peak load, and the timing of the need for additional transformers in the future is subject to change based on actual future load growth data. The historic peak trend forecast would indicate a second transformer is needed as early as 2009 versus 2025. Any substation constructed to house the one currently needed transformers, however, should be designed to accommodate the likely future inclusion of additional transformers.

6.0 ANALYSIS OF ALTERNATIVES

The analysis of Sections 4.0 and 5.0 identified needs for both feeder circuit capacity and substation transformer capacity within the Focused and Greater Study Areas. Planning Engineers first laid out the criteria each alternative for distribution capacity addition must meet. After defining the criteria to evaluate distribution system improvements, Planning Engineers identified potential solutions to provide necessary additional capacity to the Focused Study Area.

6.1 CRITERIA USED TO DEVELOP AND COMPARE ALTERNATIVES

Distribution Planning Engineers evaluated and compared the effectiveness of each of the alternatives to address the identified system deficiencies according to the following objective criteria: System Performance, Operability, Future Growth, Cost, and Electrical Losses, which are described in more detail below.

To facilitate a comparison of the alternatives, each alternative must be developed to equally fix N-0 and N-1 overloaded feeder circuits and N-1 substation transformer overloads in the Focused Study Area. Additionally, each alternative must add equivalent capacity to the distribution system over the scope of the Study period.

6.1.1 SYSTEM PERFORMANCE

System performance is how the physical infrastructure addition of an alternative impacts energy delivery to distribution customers. Frequency of outages has been found to correlate to circuit length with longer feeders experiencing more outages than shorter feeders. Each unit of length of a feeder circuit generally has comparable exposure due to common outage causes, including underground circuit outages caused by public damage (*e.g.*, customer dig-ins to cable), equipment failure; and overhead circuit outages caused by acts of nature (*e.g.*, lightning).

SynerGEE system models of 13.8 kV feeder circuits indicate that fully loaded 12,000 kW circuits more than approximately four miles long with the load at the end of the feeder cannot maintain nominal voltage within required +/-5% limits.

Accordingly, for purposes of this Study, performance is based on the equipment and control systems required to maintain customer nominal voltage, and customer exposure to outages as differentiated by the length of the feeder circuit from the substation transformer to the customer.

6.1.2 OPERABILITY

Operability is how the alternative impacts Xcel Energy distribution equipment, operating crews and construction crews operating the distribution system during normal and contingency operations. Operability is evaluated based on system planning criteria that represent the robust capability of the distribution response as described by feeder circuit and substation transformer N-0 and N-1 percent utilization and ease of operation as impacted by integration with the installed distribution delivery system. Integration of non-standard equipment using new and untested technology in the first several generations of implementation are often complicated to operate, or have unanticipated difficulties that require additional engineering to solve problems, additional expenditures, additional equipment, new operating techniques and crew training. New technologies often require several

generations of changes to reach simplicity of operation required to maintain present levels of customer service and reliability.

6.1.3 FUTURE GROWTH

Future growth is how the alternative facilitates and enables future infrastructure additions required to serve future customer demand. Possibility for future growth is enhanced by an alternative that addresses future customer demand with the least cost amount of additional distribution infrastructure.

For example, when considering a standard solution, an alternative that locates a substation nearest the load center and has room to add feeder circuits and substation transformers has better future growth possibilities than an alternative that requires adding another substation with an additional transmission line into the Focused Study Area.

6.1.4 COST

Cost is the total cost of the proposed alternative based on indicative estimates and may change with estimate refinement. Cost is the present value of all anticipated expenditures required for an alternative to serve the forecast customer loads through 2030.

6.1.5 ELECTRICAL LOSSES

Electrical losses are most often discussed in reference to the additional amount of generation required to make up for the incremental line losses. Increased efficiency in the electrical delivery system reduces the amount of generation needed to serve load. Electrical losses also impact the amount of distribution system equipment by requiring incrementally increased amounts of electrical feeder circuits and substation transformers to make up for electrical energy lost by transporting electrical energy at distribution voltages when compared to using transmission line voltages.

6.2 COMPARISON OF ALTERNATIVES

Each alternative consists of incremental installation plans from initial installation through the alternative's planned design capacity through 2030. Identified final improvements for each alternative in 2020 are expected to provide the necessary capacity to the year 2030. The three alternatives being compared are as follows:

- Alternative-1 ("A1"): Hollydale 115/13.8 kV distribution substation and two 115 kV transmission lines
- Alternative -2 ("A2"): Perimeter 115/13.8 kV distribution substation
- Alternative – 3 ("A3"): Upgrade of the Gleason Lake and Parkers Lake 115/13.8 kV distribution substations

A1 is considered standard installation. A2 and A3 are considered non-standard installation because they involve using distribution voltage express feeder circuits at 13.8 kV to move power from a

distant substation transformer location instead of using a 115 kV transmission line to transmit power.

6.2.1 STANDARD ALTERNATIVES

The existing 69 kV system is no longer adequate to reliably serve load in the Focused Study Area. Consequently, engineers looked to establish a 115 kV source. The Hollydale substation is centrally located within the Focused Study Area and was built with the potential of conversion to 115 kV and is the optimum location to serve load growth. Therefore, the Hollydale substation source was the only standard alternative considered.

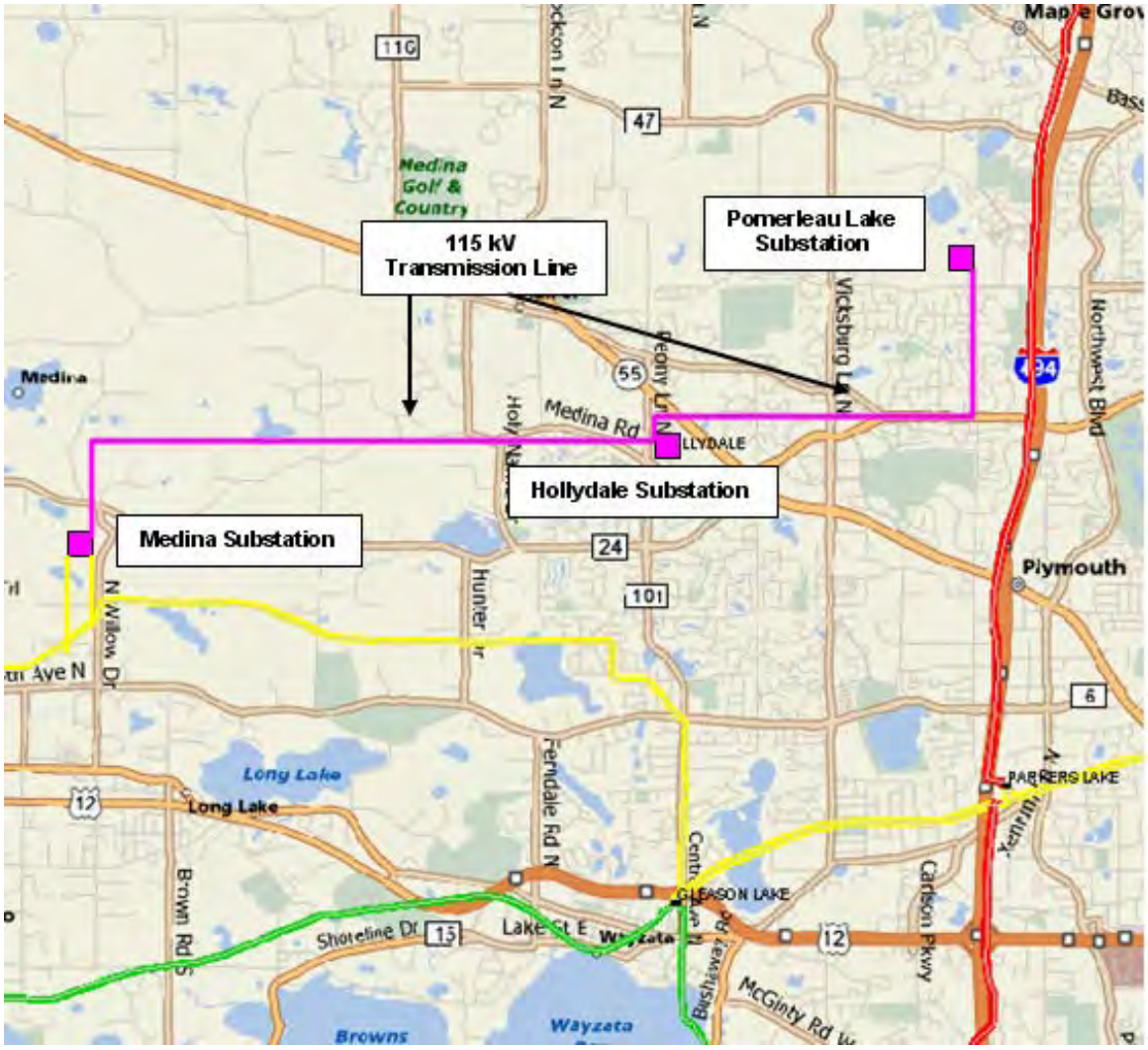
6.2.1.1 A1: Hollydale 115/13.8 kV distribution substation and two 115 kV transmission lines

This option initially includes a standard installation with an ultimate design capacity of two (2) 115/13.8 kV distribution substation transformers with a total of six (6) 13.8 kV feeder circuits at the existing Hollydale substation including the two (2) existing circuits. A new 115 kV transmission line would be constructed from Medina substation to Hollydale substation to Pomerleau Lake substation. There is currently a 69 kV Great River Energy transmission line running along this corridor however, Xcel Energy would purchase this line, remove it, and construct a new 115 kV transmission line. This line would feed the Hollydale substation transformers and the existing 34.5 kV sub-transmission source would be used only as a contingency back up. Future feeders and a second bank would be installed at Hollydale. Additional feeders in the area may be installed at Gleason Lake or Parkers Lake.

The initial installation includes a single substation transformer, and two new feeder circuits installed at the Hollydale substation in 2013. The second transformer and three feeders could be installed in approximately 2016 followed by another feeder in 2025.

Figure 6.1 illustrates the A1 configuration.

Figure 6.1: A1 - Hollydale 115/13.8 kV distribution substation and two 115 kV transmission lines



A1 best satisfies the Planning Engineers' criteria. With respect to System Performance, A1 installs additional substation transformer capacity at one new substation nearest to the identified load center in the Focused Study Area. As a result, A1 requires shorter feeder circuits to serve load. Shorter feeder circuits consist of less equipment, have fewer elements that can fail, and have less exposure to external factors that increase the chance of feeder outages. A1 is capable of maintaining adequate voltage on feeder circuits. A1 also has the best operability over the other alternatives. A1 is an extension of the existing simple distribution system and provides for a large number of standard options that could be quickly implemented under contingency conditions. With respect to Future Growth, A1 provides the most possibilities of all the alternatives for future capacity additions. The Gleason Lake and Parkers Lake substation transformers could be replaced with larger units, the Gleason Lake 115/34.5 kV 70 MVA substation transformer could be removed to allow for an addition 115/13.8 kV substation transformer, and the new 115 kV transmission line would have the ability to source additional new substations.

A1, at ultimate design capacity, will provide 50 MW of capacity and is estimated to cost approximately $12.8 million and is the least cost alternative. Staging costs include the following:

2013
Hollydale 115 kV substation - $4,340,000
Distribution 2 feeder circuits - $1,600,000
Total Costs - $5,940,000

2016
2nd substation transformer added at Hollydale - $3,000,000
Distribution 3 feeder circuits - $2,400,000
Total Costs - $5,400,000

2025
Distribution 1 feeder circuits - $1,500,000
Total Costs - $1,500,000

Cost information for A1 is provided in Appendix D.

With respect to electrical losses, A1 has the lowest line losses because it utilizes 115 kV transmission lines to transmit power to the load center. A1 is the lowest loss alternative while alternatives A2 and A3 have higher losses.

6.2.2 NON-STANDARD ALTERNATIVES – USE DISTRIBUTION VOLTAGES INSTEAD OF TRANSMISSION VOLTAGES TO TRANSMIT POWER TO THE FOCUSED STUDY AREA

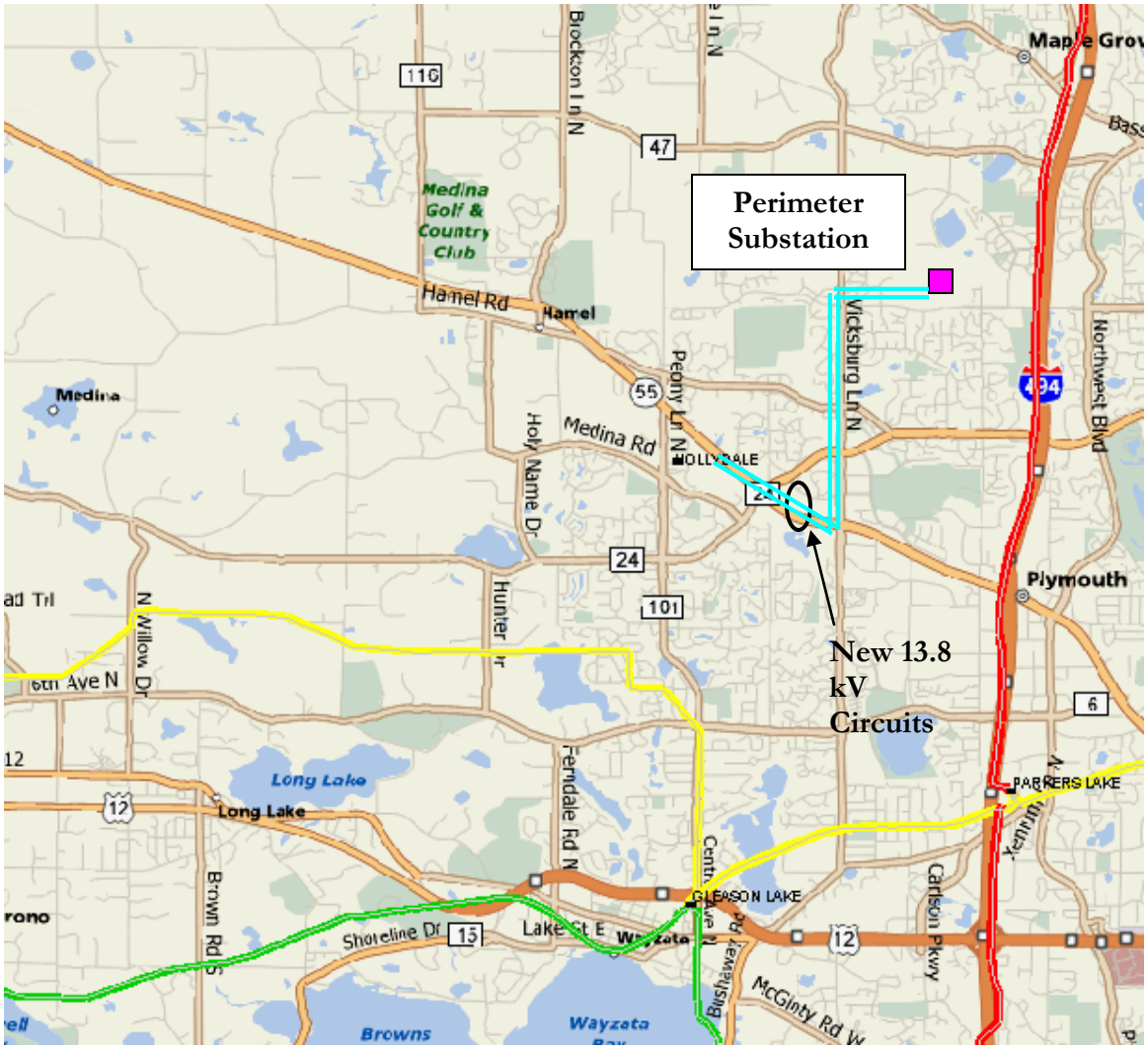
6.2.2.1 A2: Perimeter 115/13.8 kV distribution substation

This option initially includes an installation with an ultimate design capacity of two (2) 115/13.8 kV distribution substation transformers with a total of six (6) 13.8 kV feeder circuits at a new substation somewhere on the perimeter 115 kV lines, surrounding the study area. One location for the new Perimeter substation could be just south of Pomerleau Lake in Plymouth. This new substation would be fed from Great River Energy's existing 115 kV Parkers Lake - Plymouth transmission line. One thing to note is that because Great River Energy's transmission line serves this substation, Xcel Energy would have to pay Great River Energy $47,000/MW annually in facility charges for approximately 50 MW. This would amount to approximately $2.35 Million annually.

The initial installation includes a single substation transformer and four associated feeder circuits installed at a Perimeter substation. This would replace the existing two feeders at Hollydale. The second transformer and three feeders could be installed in approximately 2016 followed by another feeder in 2025.

Figure 6.2 illustrates the A2 configuration.

Figure 6.2: A2 - Perimeter 115/13.8 kV distribution substation



A2 meets the various criteria by which Planning Engineers compared each alternative. With respect to System Performance, A2 installs additional substation transformer capacity at one new location which is a greater distance than the substation under A1 from the identified load center in the Focused Study Area. As a result, A2 requires longer feeder circuits than A1 to serve load, and therefore, is subject to greater exposure to conditions that could lead to line failures. With respect to Operability, similar to A1, A2 is an extension of the existing distribution system and provides for a large number of standard options that could be quickly implemented under contingency conditions. With respect to Future Growth, A2 does not provide as many possibilities as A1.

A2 is estimated to cost approximately $26.3 million and is the highest cost alternative. Staging costs include the following:

2013
Perimeter 115 kV substation - $9,245,000 (plus $2,100,000 for land)
Distribution duct and 4 feeder circuits - $6,000,000
Total Costs - $17,345,000

2016
2nd substation transformer added at Perimeter sub - $3,000,000
Distribution duct and 2 feeder circuits - $4,500,000
Total Costs - $7,500,000
2025
Distribution 1 feeder circuits - $1,500,000
Total Costs - $1,500,000
Facility charges
O&M Costs - $2,350,000 annually

Cost information for A2 is provided in Appendix D.

With respect to electrical losses, A2 results in more electrical losses than A1 and slightly lower than A3 because it utilizes 13.8 kV feeder circuits instead of 115 kV transmission lines to transmit power from the substation to the load center.

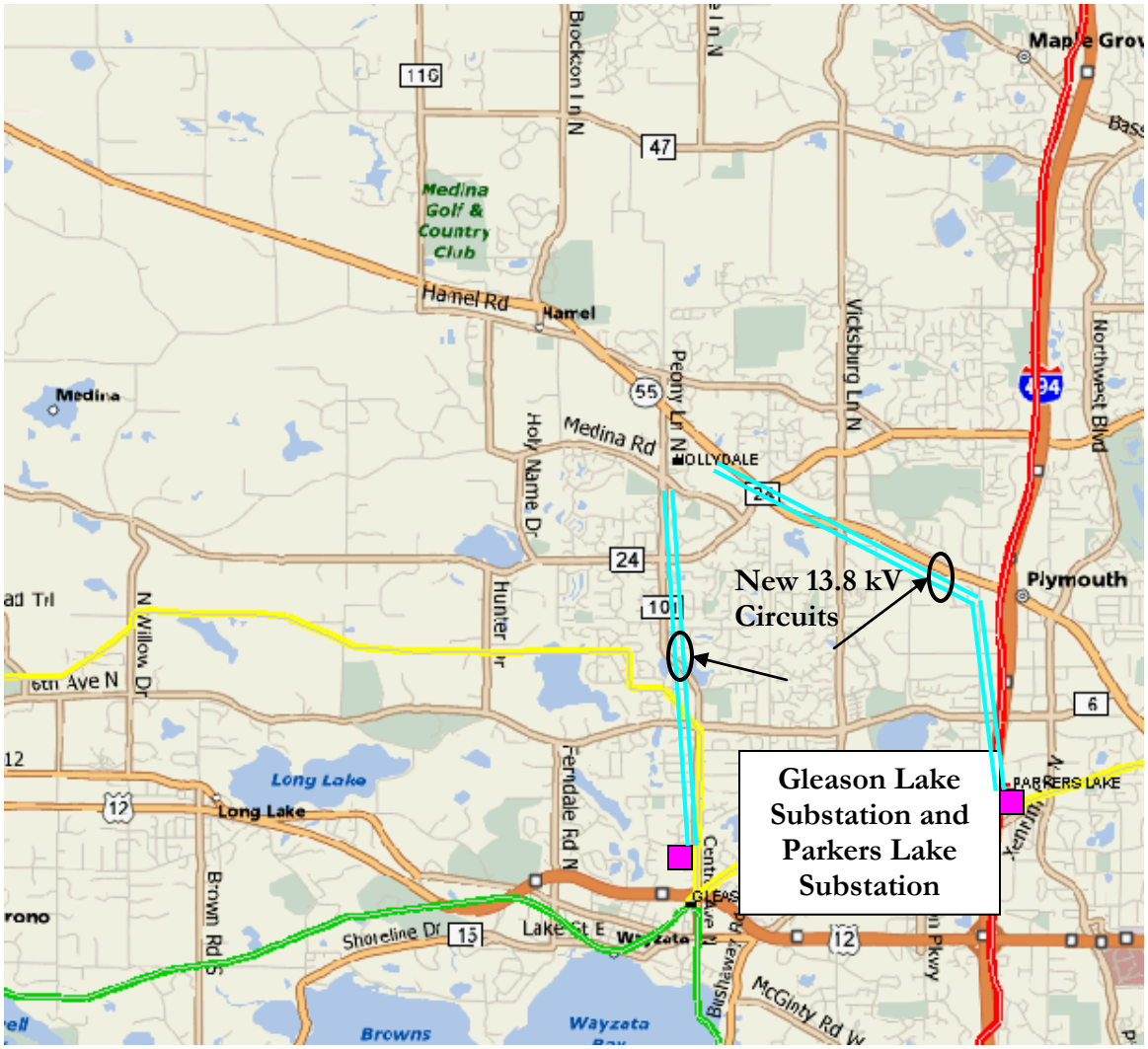
6.2.2.2 A3: Upgrade of the Gleason Lake and Parkers Lake 115/13.8 kV distribution substations

This option includes upgrading the existing two (2) 47 MVA transformers (one will be replaced with a 70 MVA in 2011 due to a failure) at Gleason Lake substation to 70 MVA units and three (3) existing 47 MVA transformers at Parkers Lake substation to 70 MVA units.

The initial installation includes upgrading one substation transformer at Gleason Lake substation to a 70 MVA unit, and installing two new feeder circuits. The three existing transformers at Parkers Lake substation could be replaced with 70 MVA units, and three feeders could be installed in approximately 2016 followed by another feeder in 2025.

Figure 6.3 illustrates the A3 configuration.

Figure 6.3: A3 – Upgrade of the Parkers Lake 115/13.8 kV distribution substation



A3 has the longest feeder circuits of the three alternatives. Longer feeder circuits consist of more equipment, have more elements that can fail, and have more exposure to external factors that increase the chance of feeder outages. A3 is the worst alternative with respect to System Performance.

With respect to Operability, A3 uses standard distribution delivery components in a non-standard way by extending feeders from outside the Focused Study Area into the area. This results in longer feeder lines which makes A3 more vulnerable during overload and outage conditions. A3 also uses long express feeder circuits that require many more components to keep in running order and fully operational during all possible conditions.

With respect to Future Growth, A3 provides very little possibility for future capacity additions. This option exhausts all capacity addition options at Parkers Lake substation.

A3 is estimated to cost approximately $21.5 million and is the middle cost alternative. Staging costs include the following:

2013
Upgrade of Parkers Lake substation transformer - $2,500,000
Distribution duct and feeder circuits - $4,000,000
Total Costs - $6,500,000
2016
Upgrade of three Parkers Lake substation transformers - $7,500,000
Distribution duct and feeder circuits - $6,000,000
Total Costs - $13,500,000
2025
Distribution feeder circuits - $1,500,000
Total Costs - $1,500,000

Cost information for A3 is provided in Appendix D.

With respect to electrical losses, A3 results in more electrical losses than A1 and slightly higher than A2 because it utilizes longer 13.8 kV feeder circuits instead of 115 kV transmission lines to transmit power from Parkers Lake substation to the load center.

6.2.3 GENERATION AS AN ALTERNATIVE

Engineers also studied the availability of traditional peaking generation sources (e.g., diesel generation) to meet the load serving need and determined that generation would not satisfy the existing or expected future demand for electricity in the study area. The identified need is one of distribution load-serving capacity only; no additional generation capacity is needed to serve the study area. Generation would not correct the geographically diverse distribution feeder circuit overloads because the more than 27 feeder circuits including 13 in the Focused Study Area operate as radial circuits. This means that generation would need to be sized specifically to each feeder and need to be flexible enough to allow reconfiguration of feeders due to load growth or operational issues. In addition, generation would not eliminate the need for new facilities. If only generation were installed, the generators would have to connect to each substation because each substation is a standalone facility. This would require expansion of the substation, installation of a step up transformer and lines to connect to the substation.

6.2.4 PREFERRED NEW DISTRIBUTION SOURCE ALTERNATIVE

Distribution Planning compared each alternative relative to all alternatives with respect to each evaluation criteria. The results of the comparison are summarized in the decision matrix in Figure 6.4. Note that A1 has the highest total score using all the criteria and is the preferred alternative.

Figure 6.4: Alternatives Comparison Matrix

ALTERNATIVES COMPARISON CRITERIA	Alternative 1 Hollydale 115/ 13.8 kV sub	Alternative 2- Perimeter 115/13.8 kV sub	Alternative 3- Upgrade of Gleason lake and Parkers Lake 115/13.8 kV sub
1 - Distribution System Performance	4	2	0
2 – Operability	3	3	2
3 - Future Growth	4	3	1
4 – Cost	4	1	2
5 - Electrical Losses	4	2	2
TOTAL			

Note: Higher number ranking is a better alternative (*i.e.*, 4 is best). A zero score indicates the alternative is not feasible due to not meeting minimum required standards.

Based on the above analysis, Planning Engineers determined that A1 is the preferred new source alternative because it best satisfies the five established distribution planning criteria. A1 locates a new distribution substation closest to the greatest amount of customer load. A1 has the shortest feeder circuits, resulting in the least amount of customer exposure to outages and the best system performance. It uses the smallest addition of proven reliable elements to relieve existing overloads, resulting in the highest operability of the alternatives considered. The substation location proposed in A1 is closest to planned future load growth, so it has the best potential to adapt to future growth. A1 is the least expensive to construct and has the lowest electrical losses, making it the most cost effective and efficient option of the three alternatives that are capable of meeting the area customer load requirements.

7.0 RECOMMENDATION

Distribution Planning recommends A1 to meet the identified capacity needs on the Plymouth electrical distribution delivery system in the Focused Study Area. To confirm that A1 will mitigate the feeder overloads in the Focused Study Area, Distribution Planning Engineers analyzed how the distribution system would function after construction of the first phase of A1.

Figure 7.1 displays the area of load served by each substation in 2013 within the context of the Focused Study Area. The distribution infrastructure to be installed in 2013 would include one new 115/13.8 kV substation transformer at Hollydale substation, and two new 13.8 kV feeder circuits out of Hollydale substation.

Figure 7.1: Post-Proposed Initial Installation – Focused Study Area

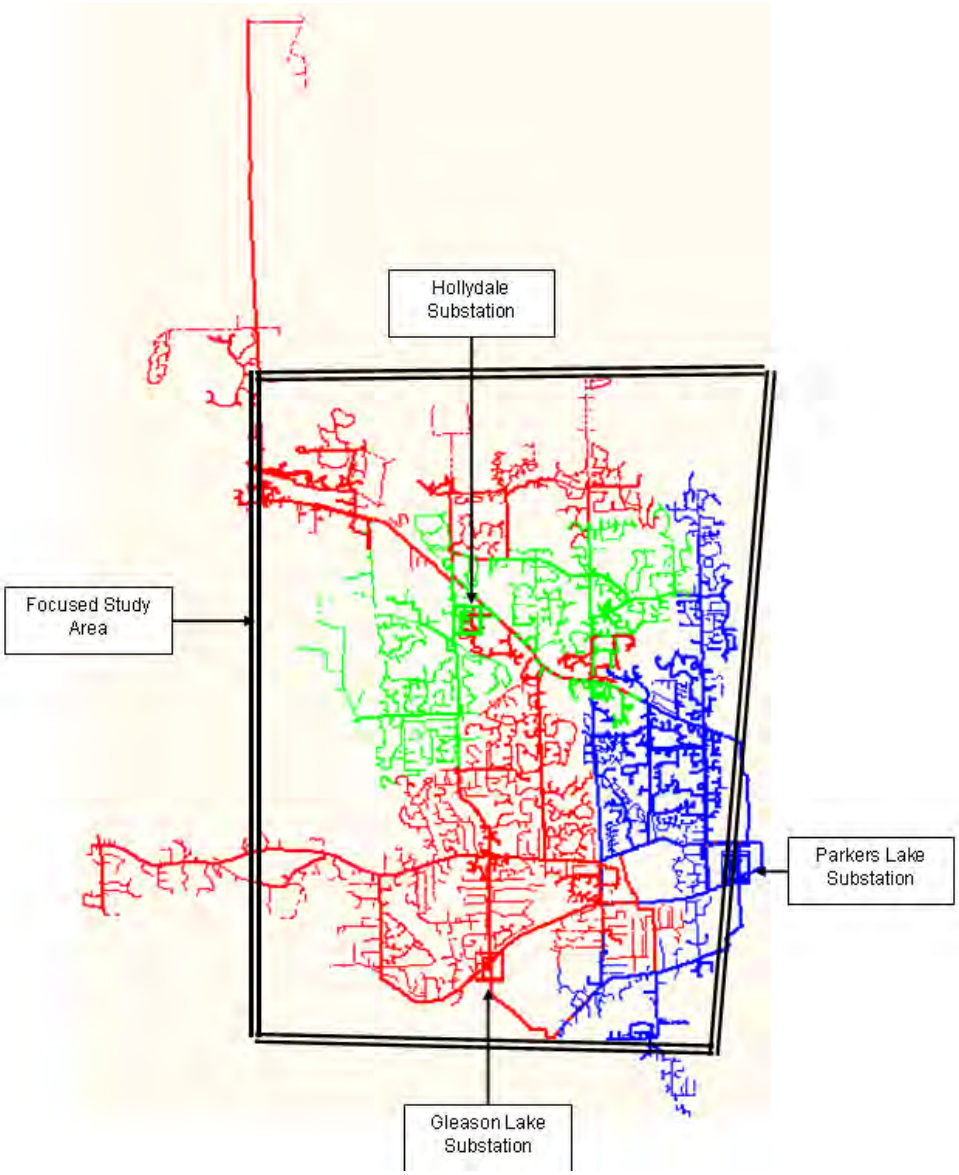
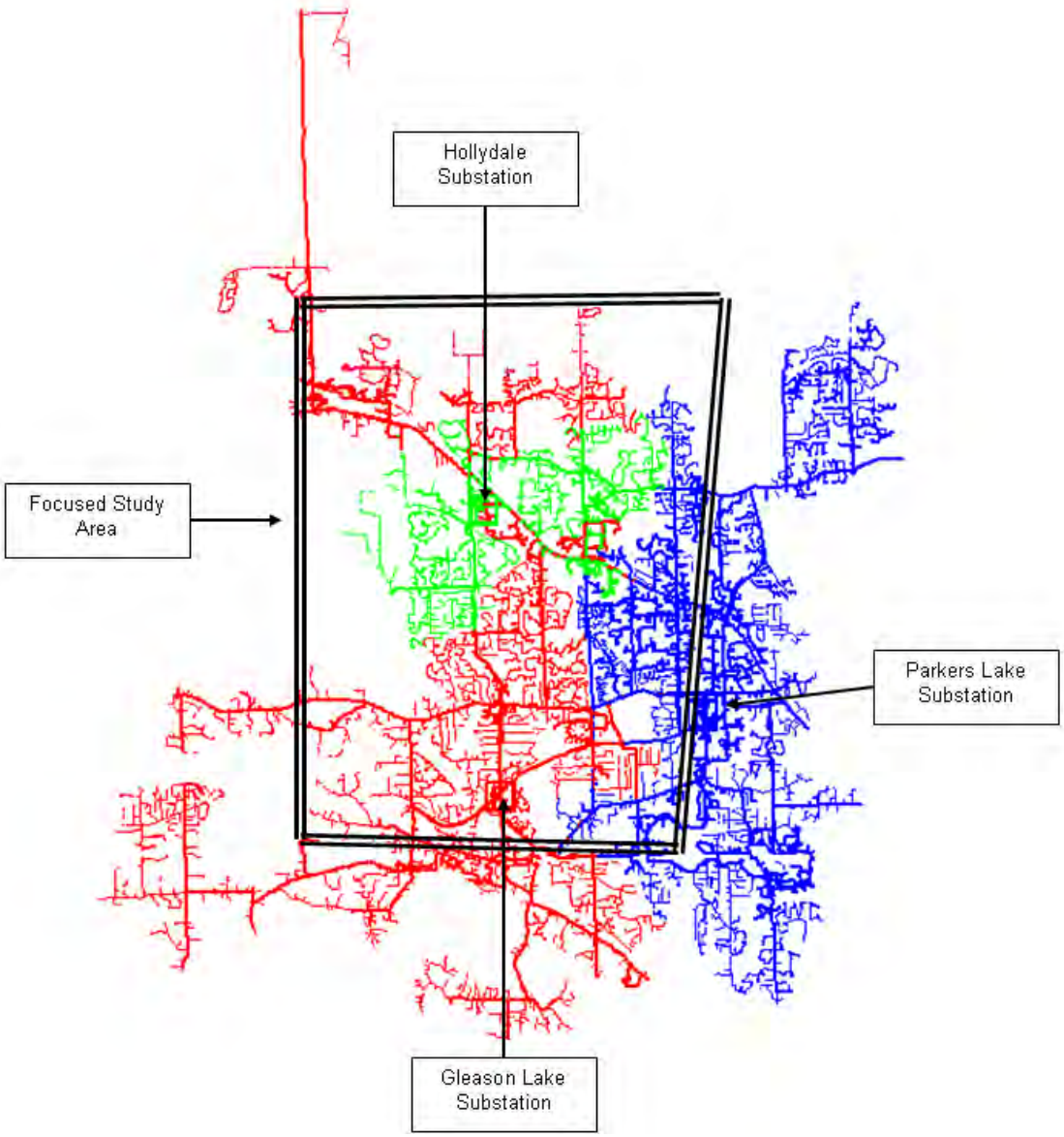


Figure 7.2 displays the area of load served by each substation transformer following the installation of the infrastructure associated with alternative A1 in the context of the Greater Study Area.

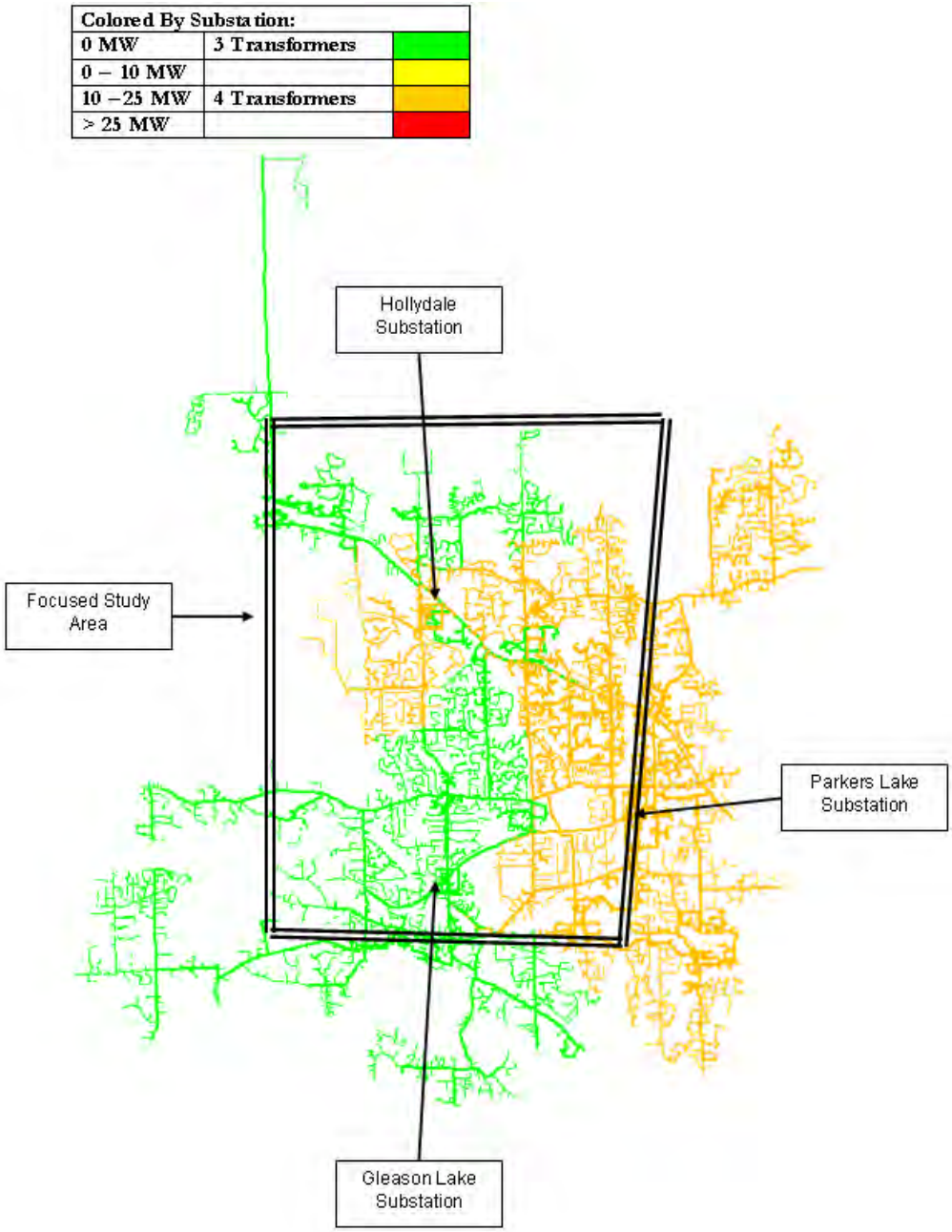
Figure 7.2: Post-Proposed Initial Installation – Greater Study Area



Through the end of the Study period, the additional infrastructure to be installed would consist of one more 115/13.8 kV substation transformer at Hollydale substation and four more 13.8 kV feeders out of the substations within the Greater Study Area. Hollydale substation will relieve some Parkers Lake and Gleason Lake feeder circuits while the Parkers Lake and Gleason Lake circuits will be reconfigured as needed.

Figure 7.3 displays the overloaded transformers in the Greater Study Area after installation of the infrastructure associated with alternative A1.

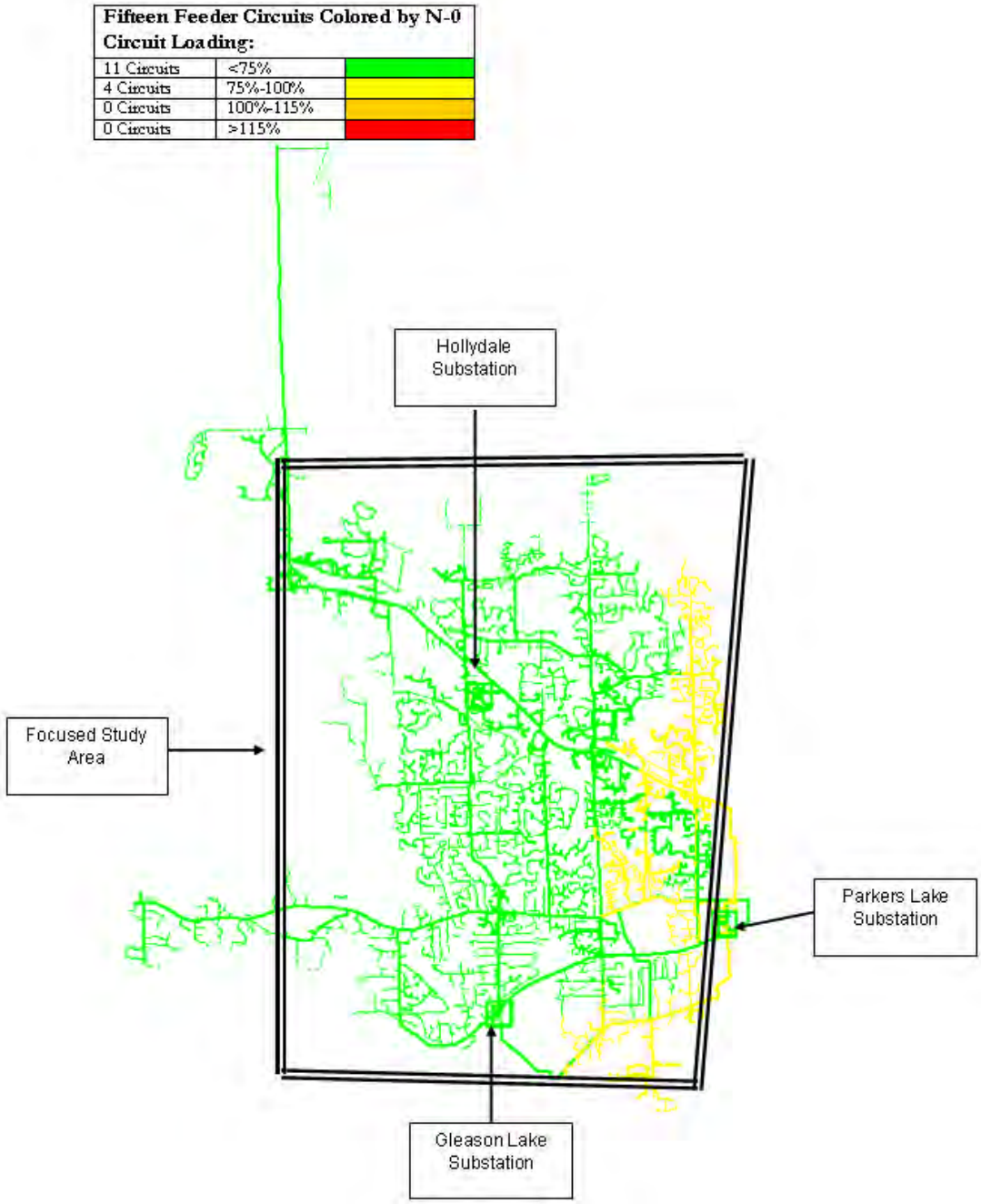
Figure 7.3: Post-Proposed Project Installation: 2013 N-1 Contingency Substation Transformer Risks



In 2013, the capacity additions will eliminate the N-1 risk on the Gleason Lake 34.5 kV substation transformer and reduce the N-1 substation transformer overloads on the Hollydale and Parkers Lake transformers but it will not eliminate them. The proposed capacity additions in the following years will eliminate the Hollydale N-1 substation transformer overloads and still further reduce the Parkers Lake N-1 substation transformer overloads. Proposed capacity additions outside of the scope of this study will fully eliminate the Parkers Lake N-1 substation transformer overloads.

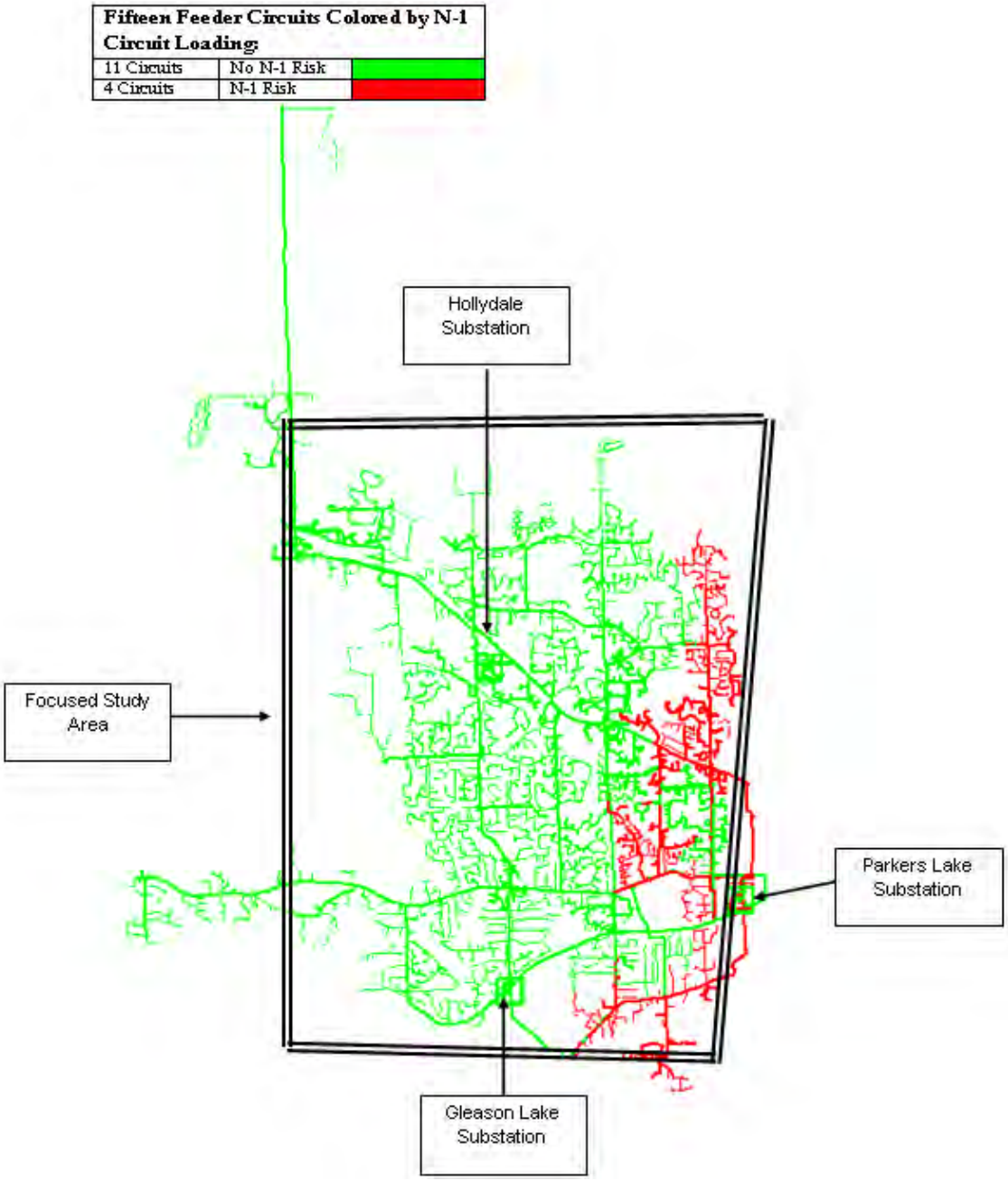
All N-0 system intact overloads in the Focused Study Area can be solved by the capacity additions in 2013. Figure 7.4 shows the N-0 feeder circuit overloads solved by the new feeder circuits of the recommended alternative in 2013.

Figure 7.4: Post-Proposed Project Installation: 2013 N-0 Feeder Circuit Risks



The majority of the N-1 first contingency overloads can be solved by the capacity additions of the new feeder circuits in 2013. Figure 7.5 shows the N-1 first contingency feeder circuit overloads solved by the new feeder circuits of the recommended alternative in 2013.

Figure 7.5: Post-Proposed Project Installation: 2013 N-1 Feeder Circuit Risks



Roughly all N-0 and N-1 feeder circuit overloads will be eliminated by the proposed capacity additions in the years following 2013.

Distribution Planning recommends that the first phase of A1 be constructed to be in-service by 2013.

Appendix A

Hollydale - Focused Study Area - Historical
Feeders

MW									
Feeder	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**
HOL061	2.553	5.994	5.880	5.586	6.115	6.174	8.036	7.546	7.350
HOL062	9.404	10.037	8.330	9.085	10.330	10.388	8.795	8.137	8.330
PKL062	11.285	11.358	8.585	8.281	8.330	6.364	6.076	6.724	6.579
PKL074	12.740	13.230	12.668	12.181	12.430	14.257	12.812	10.873	11.767
PKL075	7.523	9.506	9.261	7.553	8.327	9.713	9.362	8.771	8.256
PKL081	9.444	10.476	9.989	11.693	11.218	11.557	11.230	9.517	8.637
PKL083	9.604	10.719	9.501	8.771	8.589	9.530	8.553	8.612	8.862
PKL084	9.501	9.800	9.258	9.258	10.135	10.290	9.980	9.996	9.258
GSL061	9.800	8.527	8.040	7.796	8.283	8.404	6.370	5.782	5.684
GSL076	8.634	9.310	8.820	8.693	9.453	9.800	8.330	7.479	7.448
GSL079	7.350	7.699	8.722	8.771	8.040	8.673	8.232	6.773	7.154
GSL341	23.520	28.383	29.400	29.194	30.027	31.360	32.340	31.360	29.890
GSL342	0.000	0.000	0.000	2.940	6.091	8.466	9.137	9.745	11.270
TOTALS	109.401	119.008	114.244	115.131	120.923	128.414	122.422	115.632	114.804

KVA										
Feeder	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	
HOL061	2605	6116	6000	5700	6240	6300	8200	7700	7500	Included with GSL341 feeder load
HOL062	9596	10242	8500	9270	10541	10600	8974	8303	8500	Included with GSL341 feeder load
PKL062	11515	11590	8760	8450	8500	6494	6200	6861	6713	
PKL074	13000	13500	12927	12430	12684	14548	13073	11095	12007	
PKL075	7677	9700	9450	7707	8497	9911	9553	8950	8424	
PKL081	9637	10690	10193	11932	11447	11793	11459	9711	8813	
PKL083	9800	10938	9695	8950	8764	9724	8728	8788	9043	
PKL084	9695	10000	9447	9447	10342	10500	10184	10200	9447	
GSL061	10000	8701	8204	7955	8452	8576	6500	5900	5800	
GSL076	8810	9500	9000	8870	9646	10000	8500	7632	7600	
GSL079	7500	7856	8900	8950	8204	8850	8400	6911	7300	
GSL341	24000	28962	30000	29790	30640	32000	33000	32000	30500	without load transfers to 13.8 kV used in study analysis
GSL342	0	0	0	3000	6215	8639	9323	9944	11500	without load transfers to 13.8 kV used in study analysis
TOTALS	111634	121437	116576	117481	123391	131035	124920	117992	117147	

Hollydale - Focused Study Area - Historical
Banks

MW											
Bank	Capacity (N-0)	Capacity (N-1)	2001	2002	2003	2004	2005	2006	2007	2008	2009
GSL TR7	46.850		20.090	21.511	20.835	21.413	20.159	21.678	19.600	18.620	17.640
GSL TR8	46.850		23.520	26.950	24.108	25.666	27.048	27.969	24.284	23.108	21.942
TOTAL	93.700	51.750	43.610	48.461	44.943	47.079	47.207	49.647	43.884	41.728	39.582
KVA											
Bank	Capacity (N-0)	Capacity (N-1)	2001	2002	2003	2004	2005	2006	2007	2008	2009
GSL TR7	47806		20500	21950	21260	21850	20570	22120	20000	19000	18000
GSL TR8	47806		24000	27500	24600	26190	27600	28540	24780	23580	22390
TOTAL	95612	52806	44500	49450	45860	48040	48170	50660	44780	42580	40390

MW											
Bank	Capacity (N-0)	Capacity (N-1)	2001	2002	2003	2004	2005	2006	2007	2008	2009
GSL TR4	74.996	34.019	21.952	24.446	27.103	28.290	32.811	33.181	33.916	28.986	28.428
KVA											
Bank	Capacity (N-0)	Capacity (N-1)	2001	2002	2003	2004	2005	2006	2007	2008	2009
GSL TR4	76527	34713	22400	24944.5	27655.939	28867.10826	33481	33858.11659	34608.25083	29577.43658	29007.74476 NOTE: includes decrease due to transfers to 13.8kV used for study analysis
			24000	28500	29310	32080	37200	40000	41000	36000	36910 NOTE: original without transfers to 13.8kV used for study analysis

Appendix B

Hollydale - Focused Study Area - Forecast
35kV feeders

All forecasts have a 1.0% growth rate
values in MW

Historical Peak Forecast	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
GSL341	30.656	30.963	31.273	31.586	31.901	32.220	32.542	32.868	33.196	33.528	33.864	34.202	34.544	34.890	35.239	35.591	35.947	36.306	36.670	37.036	37.407	37.781	38.158	38.540
GSL342	4.354	4.398	4.442	4.486	4.531	4.576	4.622	4.668	4.715	4.762	4.810	4.858	4.906	4.955	5.005	5.055	5.105	5.156	5.208	5.260	5.313	5.366	5.419	5.474
TOTALS	35.010	35.360	35.714	36.071	36.432	36.796	37.164	37.536	37.911	38.290	38.673	39.060	39.451	39.845	40.244	40.646	41.052	41.463	41.878	42.296	42.719	43.146	43.578	44.014

Conservative Forecast	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
GSL341			28.296	28.580	28.866	29.155	29.446	29.741	30.038	30.339	30.642	30.949	31.258	31.571	31.886	32.205	32.527	32.853	33.181	33.513	33.848	34.186	34.528	34.874
GSL342			4.050	4.091	4.131	4.173	4.214	4.257	4.299	4.342	4.386	4.429	4.474	4.518	4.564	4.609	4.655	4.702	4.749	4.796	4.844	4.893	4.942	4.991
TOTALS			32.348	32.671	32.998	33.328	33.661	33.998	34.338	34.681	35.028	35.378	35.732	36.089	36.450	36.814	37.183	37.554	37.930	38.309	38.692	39.079	39.470	39.865

already includes transfers to 13.8kV used for study analysis

Hollydale - Focused Study Area - Forecast
13.8kV feeders

All forecasts have a 1% growth rate
values in MW

Historical Peak Forecast	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
HOL061	6.174	6.236	6.298	6.361	6.425	6.489	6.554	6.619	6.686	6.752	6.820	6.888	6.957	7.027	7.097	7.168	7.240	7.312	7.385	7.459	7.533	7.609	7.685	7.762	7.839
HOL062	10.388	10.492	10.597	10.703	10.810	10.918	11.027	11.137	11.249	11.361	11.475	11.590	11.705	11.823	11.941	12.060	12.181	12.303	12.426	12.550	12.675	12.802	12.930	13.059	13.190
PKL062	6.364	6.428	6.492	6.557	6.623	6.689	6.756	6.823	6.891	6.960	7.030	7.100	7.171	7.243	7.315	7.389	7.462	7.537	7.612	7.689	7.765	7.843	7.922	8.001	8.081
PKL074	14.257	14.400	14.544	14.689	14.836	14.984	15.134	15.285	15.438	15.593	15.749	15.906	16.085	16.226	16.388	16.552	16.718	16.885	17.054	17.224	17.396	17.570	17.746	17.923	18.103
PKL075	9.713	9.810	9.908	10.007	10.107	10.208	10.310	10.413	10.518	10.623	10.729	10.836	10.945	11.054	11.165	11.276	11.389	11.503	11.618	11.734	11.851	11.970	12.090	12.211	12.333
PKL081	11.557	11.673	11.789	11.907	12.026	12.147	12.268	12.391	12.515	12.640	12.766	12.894	13.023	13.153	13.285	13.417	13.552	13.687	13.824	13.962	14.102	14.243	14.385	14.529	14.675
PKL083	9.530	9.625	9.721	9.818	9.916	10.016	10.116	10.217	10.319	10.422	10.527	10.632	10.738	10.845	10.954	11.063	11.174	11.286	11.399	11.513	11.628	11.744	11.862	11.980	12.100
PKL084	10.290	10.393	10.497	10.602	10.708	10.815	10.923	11.032	11.143	11.254	11.367	11.480	11.595	11.711	11.828	11.946	12.065	12.186	12.308	12.431	12.556	12.681	12.808	12.936	13.066
GSL061	8.404	8.489	8.573	8.659	8.746	8.833	8.922	9.011	9.101	9.192	9.284	9.377	9.470	9.565	9.661	9.757	9.855	9.953	10.053	10.154	10.255	10.358	10.461	10.566	10.671
GSL076	9.800	9.898	9.997	10.097	10.198	10.300	10.403	10.507	10.612	10.718	10.825	10.934	11.043	11.153	11.265	11.377	11.491	11.606	11.722	11.839	11.958	12.077	12.198	12.320	12.443
GSL079	8.673	8.760	8.847	8.936	9.025	9.115	9.207	9.299	9.392	9.486	9.580	9.676	9.773	9.871	9.969	10.069	10.170	10.271	10.374	10.478	10.583	10.689	10.795	10.903	11.012
From GSL341	1.684	1.700	1.717	1.735	1.752	1.770	1.787	1.805	1.823	1.841	1.860	1.878	1.897	1.916	1.935	1.955	1.974	1.994	2.014	2.034	2.054	2.075	2.096	2.117	2.138
From GSL342	4.432	4.476	4.521	4.566	4.611	4.658	4.704	4.751	4.799	4.847	4.895	4.944	4.994	5.044	5.094	5.145	5.196	5.248	5.301	5.354	5.407	5.461	5.516	5.571	5.627
TOTALS	111.265	112.378	113.502	114.637	115.783	116.941	118.110	119.291	120.484	121.699	122.906	124.135	125.377	126.630	127.897	129.176	130.467	131.772	133.090	134.421	135.765	137.122	138.494	139.879	141.277

Conservative Forecast	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
HOL061				7.350	7.424	7.498	7.573	7.648	7.725	7.802	7.880	7.959	8.039	8.119	8.200	8.282	8.365	8.449	8.533	8.618	8.705	8.792	8.880	8.968	9.058
HOL062				8.330	8.413	8.497	8.582	8.668	8.755	8.842	8.931	9.020	9.110	9.202	9.294	9.386	9.480	9.575	9.671	9.768	9.865	9.964	10.064	10.164	10.266
PKL062				6.579	6.645	6.711	6.778	6.846	6.914	6.983	7.053	7.124	7.195	7.267	7.340	7.413	7.487	7.562	7.638	7.714	7.791	7.869	7.948	8.027	8.108
PKL074				11.767	11.885	12.003	12.123	12.245	12.367	12.491	12.616	12.742	12.869	12.998	13.128	13.259	13.392	13.526	13.661	13.798	13.936	14.075	14.216	14.358	14.501
PKL075				8.256	8.338	8.421	8.506	8.591	8.677	8.763	8.851	8.940	9.029	9.119	9.210	9.303	9.396	9.490	9.584	9.680	9.777	9.875	9.974	10.073	10.174
PKL081				8.637	8.723	8.810	8.898	8.987	9.077	9.168	9.260	9.352	9.446	9.540	9.636	9.732	9.829	9.928	10.027	10.127	10.229	10.331	10.434	10.538	10.644
PKL083				8.862	8.951	9.040	9.131	9.222	9.314	9.407	9.501	9.596	9.692	9.789	9.887	9.986	10.086	10.187	10.289	10.392	10.495	10.600	10.706	10.813	10.922
PKL084				9.258	9.351	9.444	9.539	9.634	9.730	9.828	9.926	10.025	10.125	10.227	10.329	10.432	10.537	10.642	10.748	10.856	10.964	11.074	11.185	11.297	11.410
GSL061				5.684	5.741	5.798	5.856	5.915	5.974	6.034	6.094	6.155	6.217	6.279	6.341	6.405	6.469	6.534	6.599	6.665	6.732	6.799	6.867	6.936	7.005
GSL076				7.448	7.522	7.598	7.674	7.750	7.828	7.906	7.985	8.065	8.146	8.227	8.309	8.393	8.477	8.561	8.647	8.733	8.821	8.909	8.998	9.088	9.179
GSL079				7.154	7.226	7.298	7.371	7.444	7.519	7.594	7.670	7.747	7.824	7.902	7.981	8.061	8.142	8.223	8.306	8.389	8.473	8.557	8.643	8.729	8.817
From GSL341				1.593	1.608	1.625	1.641	1.657	1.674	1.690	1.707	1.724	1.742	1.759	1.777	1.794	1.812	1.831	1.849	1.867	1.886	1.905	1.924	1.943	1.963
From GSL342				7.220	7.292	7.365	7.438	7.513	7.588	7.664	7.740	7.818	7.896	7.975	8.055	8.135	8.217	8.299	8.382	8.466	8.550	8.636	8.722	8.809	8.897
TOTALS				98.136	99.118	100.109	101.110	102.121	103.142	104.174	105.215	106.267	107.330	108.403	109.487	110.582	111.688	112.805	113.933	115.072	116.223	117.385	118.559	119.745	120.942

Hollydale - Focused Study Area - Forecast
34.5kv Banks

All forecasts have a 1.0% growth rate
values in MW

Historic Peak Forecast	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
GSL TR4	33.714	34.051	34.392	34.736	35.083	35.434	35.788	36.146	36.507	36.873	37.241	37.614	37.990	38.370	38.753	39.141	39.532	39.928	40.327	40.730	41.137	41.548	41.964	42.384

Conservative Forecast	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
GSL TR4			30.083	30.384	30.688	30.995	31.304	31.618	31.934	32.253	32.576	32.901	33.230	33.563	33.898	34.237	34.580	34.925	35.275	35.627	35.984	36.344	36.707	37.074

already includes transfers to 13.8kV used for study anaylsis

Hollydale - Focused Study Area - Forecast
13.8kV Banks

All forecasts have a 1.0% growth rate
values in MW

Historic Peak Forecast	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
GSL TR7	21.678	21.894	22.113	22.334	22.558	22.783	23.011	23.241	23.474	23.708	23.946	24.185	24.427	24.671	24.918	25.167	25.419	25.673	25.930	26.189	26.451	26.715	26.982	27.252	27.525
GSL TR8	27.969	28.249	28.531	28.817	29.105	29.396	29.690	29.987	30.287	30.590	30.895	31.204	31.516	31.832	32.150	32.471	32.796	33.124	33.455	33.790	34.128	34.469	34.814	35.162	35.513
TOTAL	49.647	50.143	50.645	51.151	51.663	52.179	52.701	53.228	53.760	54.298	54.841	55.389	55.943	56.503	57.068	57.638	58.215	58.797	59.385	59.979	60.579	61.184	61.796	62.414	63.038

Conservative Forecast	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
GSL TR7				17.640	17.816	17.995	18.175	18.356	18.540	18.725	18.912	19.102	19.293	19.486	19.680	19.877	20.076	20.277	20.479	20.684	20.891	21.100	21.311	21.524	21.739
GSL TR8				21.942	22.162	22.383	22.607	22.833	23.061	23.292	23.525	23.760	23.998	24.238	24.480	24.725	24.972	25.222	25.474	25.729	25.986	26.246	26.509	26.774	27.041
TOTAL				39.582	39.978	40.378	40.782	41.189	41.601	42.017	42.437	42.862	43.290	43.723	44.161	44.602	45.048	45.499	45.954	46.413	46.877	47.346	47.820	48.298	48.781

Appendix C

Hollydale Great Study Area
Historical

MW											
Bank	**N-0 Capacity**	**N-1 Capacity**	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**
HOL TR2	28.110	4.900	8.820	11.966	12.015	11.897	12.838	13.720	14.700	13.230	12.858
PKL TR1	46.850	98.600	41.160	45.433	42.493	43.336	45.668	42.267	44.737	40.337	39.739
PKL TR2	46.850		39.200	42.346	39.661	40.454	41.042	45.080	43.198	38.730	38.465
PKL TR3	48.886		34.300	35.535	35.407	35.074	37.240	39.053	35.094	37.181	35.319
GSL TR7	46.850	51.750	20.090	21.511	20.835	21.413	20.159	21.678	19.600	18.620	17.640
GSL TR8	46.850		23.520	26.950	24.108	25.666	27.048	27.969	24.373	23.108	21.942
TOTALS	264.396	155.250	167.090	183.740	174.518	177.841	183.995	189.767	181.702	171.206	165.963

KVA											
Bank	**N-0 Capacity**	**N-1 Capacity**	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**
HOL TR2	28684	5000	9000	12210	12260	12140	13100	14000	15000	13500	13120
PKL TR1	47806	100612	42000	46360	43360	44220	46600	43130	45650	41160	40550
PKL TR2	47806		40000	43210	40470	41280	41880	46000	44080	39520	39250
PKL TR3	49884		35000	36260	36130	35790	38000	39850	35810	37940	36040
GSL TR7	47806	52806	20500	21950	21260	21850	20570	22120	20000	19000	18000
GSL TR8	47806		24000	27500	24600	26190	27600	28540	24870	23580	22390
TOTALS	269792	158418	170500	187490	178080	181470	187750	193640	185410	174700	169350

Totals in MW										
Gleason Lake	43.610	48.461	44.943	47.079	47.207	49.647	43.973	41.728	39.582
Parkers Lake	114.660	123.313	117.561	118.864	123.950	126.400	123.029	116.248	113.523

Hollydale Greater Study Area
Forecasts

All forecasts have a 1.0% growth rate
Values in MW

Historic Peak Forecast	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
HDL TR2	13.720	13.857	13.996	14.136	14.277	14.420	14.564	14.710	14.857	15.005	15.155	15.307	15.460	15.615	15.771	15.928	16.088	16.249	16.411	16.575	16.741	16.908	17.078	17.248	17.421
PKL TR1	42.267	42.690	43.117	43.548	43.984	44.423	44.868	45.318	45.770	46.227	46.690	47.156	47.628	48.104	48.585	49.071	49.562	50.057	50.558	51.064	51.574	52.090	52.611	53.137	53.668
PKL TR2	45.080	45.531	45.986	46.446	46.910	47.380	47.853	48.332	48.815	49.303	49.796	50.294	50.797	51.305	51.818	52.336	52.860	53.388	53.922	54.462	55.006	55.556	56.112	56.673	57.240
PKL TR3	39.053	39.444	39.838	40.236	40.639	41.045	41.456	41.870	42.289	42.712	43.139	43.570	44.006	44.446	44.890	45.339	45.793	46.251	46.713	47.180	47.652	48.129	48.610	49.096	49.587
GSL TR7	21.078	21.894	22.113	22.334	22.558	22.783	23.011	23.241	23.474	23.709	23.946	24.185	24.427	24.671	24.918	25.167	25.419	25.673	25.930	26.189	26.451	26.715	26.982	27.252	27.525
GSL TR8	27.989	28.249	28.531	28.817	29.105	29.396	29.690	29.987	30.287	30.590	30.895	31.204	31.516	31.832	32.150	32.471	32.796	33.124	33.455	33.790	34.128	34.469	34.814	35.162	35.513
TOTALS	189.767	191.665	193.582	195.517	197.473	199.447	201.442	203.456	205.491	207.546	209.621	211.717	213.834	215.973	218.133	220.314	222.517	224.742	226.990	229.259	231.552	233.868	236.206	238.568	240.954

Conservative Forecast	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
HDL TR2				12.858	12.986176	13.11603776	13.24719814	13.37967012	13.51346682	13.64860149	13.7850875	13.92293838	14.06216776	14.20278944	14.34481733	14.48826551	14.63314816	14.77947964	14.92727444	15.07654718	15.22731266	15.37958578	15.53338164	15.68871546	15.84560261
PKL TR1				39.739	40.13639	40.53775939	40.94313144	41.35256275	41.76608838	42.18374926	42.60558676	43.03164262	43.46195905	43.89657864	44.33554443	44.77889987	45.22668887	45.67895576	46.13574532	46.59710277	47.0630738	47.53370454	48.00904158	48.489132	48.97402332
PKL TR2				38.465	38.84965	39.2381465	39.63052797	40.02683324	40.42710158	40.83137259	41.23968632	41.65208318	42.06860401	42.48929005	42.91415295	43.34332478	43.77675803	44.21452561	44.65667087	45.10323758	45.55426995	46.00981265	46.46991078	46.93460969	47.40395599
PKL TR3				35.319	35.672392	36.02911592	36.38940708	36.75330115	37.12083416	37.4920425	37.86696299	38.24563256	38.62808888	39.01436977	39.40451347	39.7985586	40.19654419	40.59850963	41.00449473	41.41453968	41.82868507	42.24697192	42.66944164	43.09613606	43.52709742
GSL TR7				17.640	17.8164	17.994564	18.17450964	18.35625474	18.53981728	18.72521546	18.91246761	19.10159228	19.29260821	19.48553429	19.68038964	19.87719353	20.07596547	20.27672512	20.47949237	20.68428673	20.89113017	21.10004147	21.31104189	21.5241523	21.73939383
GSL TR8				21.942	22.161632	22.38323832	22.6070706	22.83314131	23.06147272	23.29008745	23.52900833	23.76825841	24.00788099	24.2378396	24.480218	24.72502018	24.97227038	25.22199308	25.47421201	25.72895514	25.98624469	26.24610714	26.50856821	26.77365389	27.04139043
TOTALS				185.963	187.623	189.299	190.992	192.702	194.429	196.173	197.935	199.714	201.511	203.326	205.160	207.011	208.881	210.770	212.678	214.605	216.551	218.516	220.501	222.508	224.531

Parkers Lake					131.533					138.242					145.294					152.705					160.495
Gleason Lake					51.663					54.298					57.089					59.979					63.038
Parkers Lake					114.658432					120.5071644					126.6542409					133.11488					139.9050767
Gleason Lake					39.978022					42.01780291					44.18060763					46.41324244					48.78076428

Appendix D

Alternative-1 ("A1"): Hollydale 115/13.8 kV distribution substation and two 115 kV transmission lines

Facility	equipment	Cost			
Phase 1				**TAM**	**DCP**
Hollydale TR1	1-50 MVA transformer	$	1,770,000		$ 1,770,000
Hollydale TR1	TAM portion of sub	$	2,570,000	$ 2,570,000	
feeders	2 - 13.8 kV feeders	$	1,600,000		$ 1,600,000
TOTAL		$	5,940,000	$ 2,570,000	$ 3,370,000
Phase 2					
Hollydale TR2	1-50 MVA transformer	$	3,000,000		
feeders	3 - 13.8 kV feeders	$	2,400,000		
TOTAL		$	5,400,000		
Phase 3					
feeders	1 - 13.8 kV feeder	$	1,500,000		
TOTAL		$	1,500,000		
Grand Total		$	12,840,000		

Alternative -2 ("A2"): Perimeter 115/13.8 kV distribution substation

Facility	equipment	Cost			
Phase 1				**TAM**	**DCP**
Perimeter sub TR1	1-50 MVA transformer	$	5,705,000		$ 5,705,000
Perimeter sub TR1	TAM portion of sub	$	3,540,000	$ 3,540,000	
Perimeter sub land	Sub site	$	2,100,000		
feeders	4 - 13.8 kV feeders	$	6,000,000		
TOTAL		$	17,345,000		
Phase 2					
Perimeter sub TR2	1-50 MVA transformer	$	3,000,000		
feeders	3 - 13.8 kV feeders	$	4,500,000		
TOTAL		$	7,500,000		
Phase 3					
feeders	1 - 13.8 kV feeder	$	1,500,000		
TOTAL		$	1,500,000		
Grand Total		$	26,345,000		

Alternative – 3 ("A3"): Upgrade of the Gleason Lake and Parkers Lake 115/13.8 kV distribution substations

Facility	equipment	Cost		TAM		DCP	
Phase 1							
Gleason Lake TR2	1-70 MVA transformer	$	2,500,000	$	-	$	2,500,000
feeders	2 - 13.8 kV feeders	$	4,000,000	$	-	$	4,000,000
TOTAL		$	6,500,000	$	-	$	6,500,000
Phase 2							
Parkers Lake TR1, 2, 3	3-70 MVA transformer	$	7,500,000				
feeders	3 - 13.8 kV feeders	$	6,000,000				
TOTAL		$	13,500,000				
Phase 3							
feeders	1 - 13.8 kV feeder	$	1,500,000				
TOTAL		$	1,500,000				
Grand Total		$	21,500,000				

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Appendix B.2

Hollydale/Meadow Lake Load Serving Study
(June 2011)

Hollydale/Meadow Lake Load Serving Study

Xcel Energy Services; Transmission System Planning and Reliability Assessment.

Justin Michlig

June 2011

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1.0: Background & Scope of Study

Northern States Power Company, a Minnesota corporation ("Xcel Energy") is a Minnesota corporation headquartered in Minneapolis, Minnesota. Xcel Energy provides electricity services to approximately 1.2 million customers and natural gas services to 425,000 residential, commercial and industrial customers in the State. The purpose of this study is to evaluate two requests from Xcel Energy's Capacity Planning Department (Capacity Planning) for 115 kV transmission sources in the western Minneapolis area to meet the growing customer demand for power in the area. The overall study area extends from Medina to North Minneapolis east to west and Osseo to Highway 394 north to south and includes the cities of Plymouth and Medina (Study Area). Substation additions and transmission connections are needed to support the distribution system.

The first Capacity Planning request is for 115 kV transmission connections at the Hollydale Substation in Plymouth to support the distribution system serving primarily the immediate area west of Interstate 494 (I-494). Distribution Planning has identified a need for this connection by mid 2013. The second request is for a new "Meadow Lake" substation near Schmidt Lake Road and Highway 169 to support the distribution system serving primarily the immediate area east of I-494 including New Hope. Distribution Planning has identified a need for this connection in 2015.

2.0: Conclusions & Recommended Plan

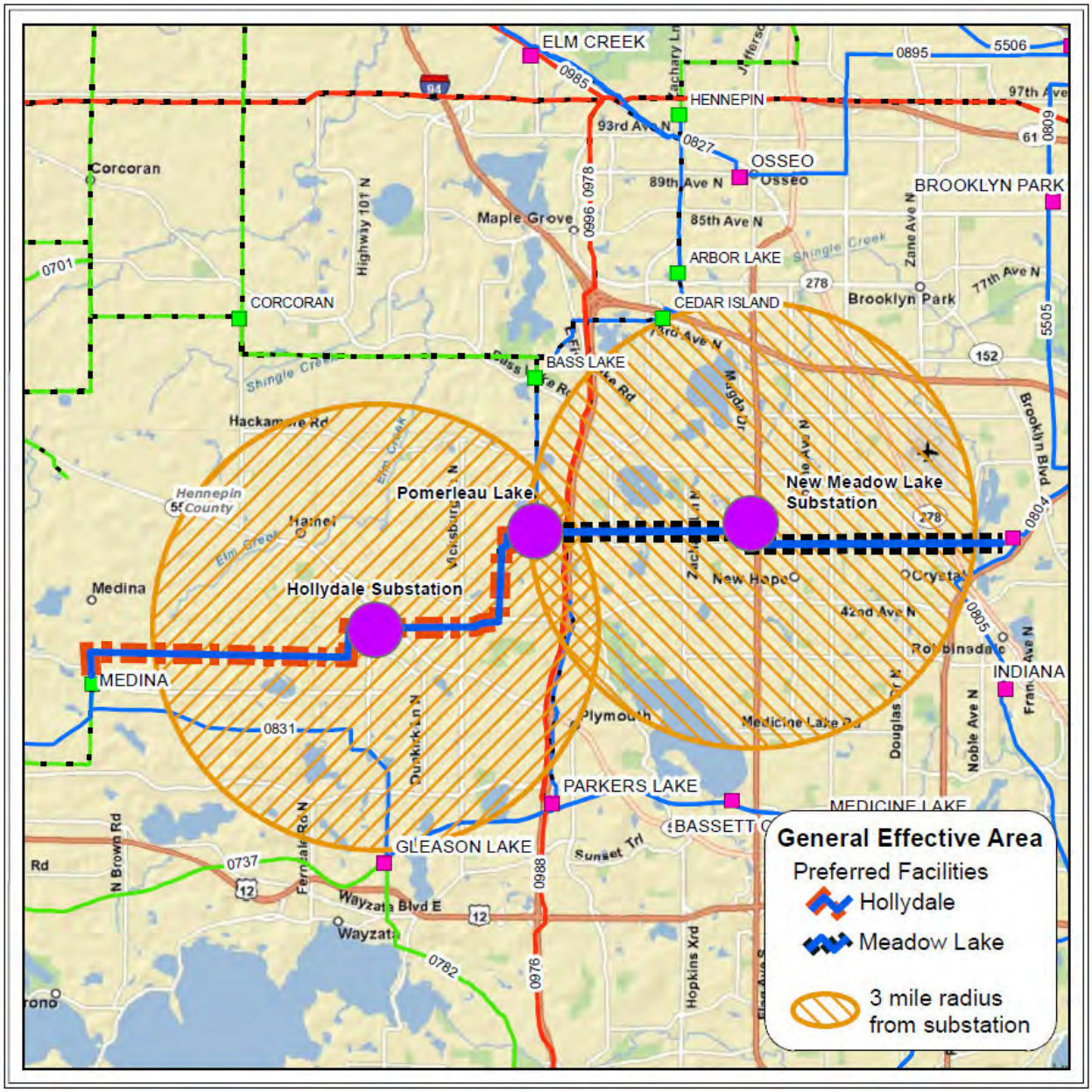
To provide support for a Hollydale Substation, the recommended plan is to construct a new 115 kV transmission line connecting the Medina Substation, the Hollydale Substation and a new Pomerleau Lake switching substation (Pomerleau Lake Substation). This alternative was the best performing alternative because it provides voltage support outside of the 345 kV loop for a 115 kV double circuit loss between Gleason Lake Substation and Parkers Lake Substation.

To provide transmission sources at a new Meadow Lake Substation, the recommended plan is to construct a new Pomerleau Lake—Meadow Lake–Twin Lakes 115 kV transmission line. This alternative provides reduced loading on the two lines between Parkers Lake Substation and downtown Minneapolis.

Combined, the two recommended plans provide the least cost alternative for meeting both distribution needs. It also is the most robust transmission solution.

A diagram of the recommended plans and the effective distribution coverage area of each is shown in Figure 1.

Figure 1. Study Area Distribution Coverage



3.0: Study History & Participants

Xcel Energy has worked with both Great River Energy and Wright Hennepin Electric Co-Op in preparing this study. A special thanks is extended to Yewlsew Atnafu, Dave Kempf, Lance Hovland, and Wayne Bauernschmitt for their participation and review of the study.

4.0: Analysis

4.1: NERC Criteria

For this analysis, the North American Electric Reliability Corporation ("NERC") Category A-C contingencies were viewed. Table 1 is a re-creation of the NERC table of TPL definitions available at www.nerc.com.

Table 1. NERC TPL Definitions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault	 Yes Yes Yes Yes	 No [b] No [b] No [b] No [b]	 No No No No
	Single Pole Block, Normal Clearing [e]: 4. Single Pole (dc) Line	 Yes	 No [b]	 No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing[e]: 1. Bus Section 2. Breaker (failure or internal Fault)	 Yes Yes	 Planned/ Controlled[c] Planned/ Controlled[c]	 No No
	SLG or 3Ø Fault, with Normal Clearing[e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing[e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	 Yes	 Planned/ Controlled[c]	 No
	Bipolar Block, with Normal Clearinge: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearinge: 5. Any two circuits of a multiple circuit towerline[f]	 Yes Yes	 Planned/ Controlled[c] Planned/ Controlled[c]	 No No
	SLG Fault, with Delayed Clearinge (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	 Yes Yes Yes Yes	 Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c]	 No No No No

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.
b) Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.
c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (nonrecallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.
d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.
e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.
f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

4.2: Models Employed

4.2.1: Steady State Models

For this study, Midwest Reliability Organization (MRO) 2009 series Pass four models were used. Summer Peak models were chosen because summer is the most severe operating season for the Study Area and the greater Twin Cities. The 2015 and 2020 models were isolated for testing and modified as stated below.

4.2.2: Modeling Changes

Load Assumptions

The load values in this study were unchanged from the 2009 series models, except for the greater Twin Cities area. The Twin Cities was scaled up based off of the 2007 summer peak. The 2007 summer peak was selected because it was a warm summer, but not extremely hot. The 2007 Xcel Energy loads were scaled up at about two percent. Great River Energy supplied loads for their co-op substations in the Twin Cities.

The Xcel Energy Study Area load forecast was supplied by Capacity Planning. Loads were supplied for two scenarios. The first scenario represented the northwestern metro load if Meadow Lake Substation were not constructed. The second scenario represents the western load if Meadow Lake Substation were built. Table 2 and Table 3 below show the reported demand used in the study.

Table 2. Northwest Metro Load Without Meadow Lake Substation

Northwest Metro Substation Loading Summary (KW)		
Without new Meadow Lake		
Substation	**2015**	**2020**
Basset Creek	51641	53740
Brooklyn Park	41962	43668
Elm Creek	78658	81855
Gleason Lake	82068	85403
Hollydale	24590	25589
Indiana	43580	45352
Medicine Lake	162395	168996
Orono	17047	17740
Osseo	83211	86594
Parkers Lake	103814	108034
Twin Lakes	176254	183418
West Coon Rapids (34.5kV)	93537	97338

Table 3. Northwest Metro Load with Meadow Lake Substation

Northwest Metro Substation Loading Summary (KW's)		
Transmission Alternative		
Substation	**2015**	**2020**
Basset Creek	51641	53740
Brooklyn Park	41962	43668
Elm Creek	78658	81855
Gleason Lake	82068	85403
Hollydale	24590	25589
Indiana	43580	45352
Meadow Lake	39647	61499
Medicine Lake	153958	152595
Orono	17047	17740
Osseo	80636	83914
Parkers Lake	99253	103288
Twin Lakes	158082	151887
West Coon Rapids (34.5kV)	87635	91197

Generation Assumptions

- Great River Energy's pseudo generators removed from service.
- 217 MWs of generation reduced in 2015 model and 282 MWs in the 2020 model to meet Great River Energy's reported peak.
- 179 MWs of generation added in 2015 and 321 MWs added in 2020 to meet the expected load. The load in the 2009 series model for Xcel Energy is the peak system wide. The study area will have a higher peak than the MRO model indicates due to the coincidence in a local area peak.

Topology Changes

- Xcel Energy's Twin Cities transformers converted to three winding representations
- Edina – St. Louis Park line rating corrected to 198 MVA Summer Normal, 218 MVA Summer Emergency
- Opened voltage bandwidth on Chisago 500/345 kV tertiary capacitors
- Locked Heron Lake LTC
- Fixed voltage mismatches on Buffalo Ridge
- Opened voltage bandwidth on Tracy cap

- Altered voltage set point on Woodstock
- Took Litchfield capacitor out of service
- Removed SPG cap from bus 698127
- Altered G255 shunt
- Altered voltage set point at Litchfield

4.3: Conditions Studied

4.3.1: Steady State Contingencies Modeled

All NERC categories A through C conditions were analyzed in the western Twin Cities metro area. Contingency files (PSS/E *.con) were built to automate the contingencies. All Category B, and Category C contingencies that were not captured by PSS/E's single line outage function were written into this file. In addition to single branch outages, double branch outages were taken in the study for 100 kV and above lines. The double branch of PSS/E was used to simulate Category C3 contingencies. Appendix B includes the files used.

4.4: Selection of Termini and Intermediate Connection Points

The selection of termini (connecting substations) were made with knowledge of the area electrical system. Points in the system that are capable of accepting a connection and have enough electrical strength to support the proposed loading were chosen. Line routes in the study were assumed to follow existing transmission routes and major transportation corridors. Assumptions on routing were made for planning purposes and may differ from those selected by during route proceedings. Also, additional routes and connection points may be available outside the study area, but would require connections to the substation locations requested by Capacity Planning.

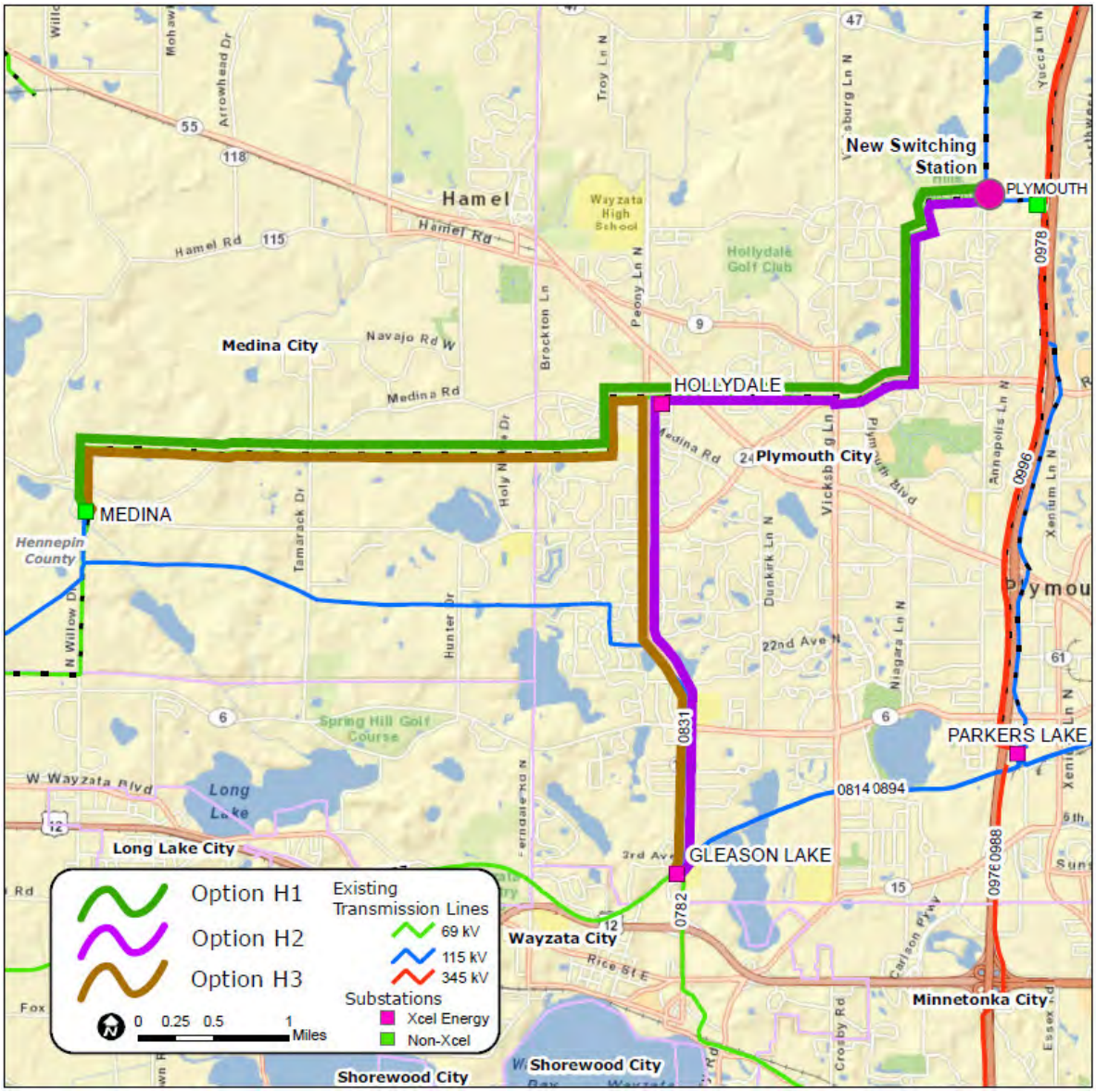
4.4.1: Hollydale Termini

The current Hollydale Substation is located near Highway 55 and County Road 101 in Plymouth. Distribution Planning has requested the electrical capacity of the substation be expanded meet reliability needs. The substation will be supplied at 115 kV to meet Distribution Planning's proposal of an ultimate design of two transformers rated at 50 MVA.

The potential 115 kV sources analyzed to provide additional capacity were limited to the two substations that are geographically close to Hollydale Substation, GRE's Medina Substation and Xcel Energy's Gleason Lake Substation. These substations are shown in Figure 2 and Figure 3 below.

Figure 2. Hollydale Substation Location

Figure 3. Hollydale Substation Connection Options



Option H1

This connection option brings a new 115 kV line from GRE's Medina Substation to a new 115 kV switching substation, near GRE's Plymouth Substation. The 115 kV line would replace the existing 69 kV line in the corridor. The switching substation would be located on the GRE 115 kV line (WH-PB) between GRE's Plymouth and Bass Lake substations. The new switching substation to be located near GRE's Plymouth distribution substation is needed because there is not enough room in the Plymouth Substation or land around it to expand it to add new transmission lines. A proposed name for this substation is Pomerleau Lake.

Approx Miles of 115 kV: 8 Miles

Option H2

Like Option H1, this path terminates into a new switching substation near GRE's Plymouth Substation. The western termination would be Gleason Lake. The line could follow the 69 kV corridor between Hollydale Substation and the new switching substation and the 34.5 kV distribution corridor south to Gleason Lake Substation from Hollydale Substation.

Approx Miles of 115 kV: 8.5 Miles

Option H3

The third possible connection is Medina-Hollydale-Gleason Lake. Similar to option H1, this connection could use the 69 kV corridor between Medina and Hollydale substations. The line could then head south on the 34.5 kV corridor to Gleason Lake Substation.

Approx Miles of 115 kV: 8.5 Miles

4.4.2: Meadow Lake Terminus

Meadow Lake Substation has been proposed by Distribution Planning near the intersection of Highway 169 and Schmidt Lake Road. The ultimate build out of this site will have three 50 or 70 MVA 115/13.8 kV banks owned by Xcel Energy and one 28 MVA bank owned by Wright Hennepin Electric Co-Op. Figure 4 shows the anticipated siting area for the new substation. Figure 5 shows the alternatives evaluated in this study.

Figure 4. Meadow Lake Substation Anticipated Siting Area

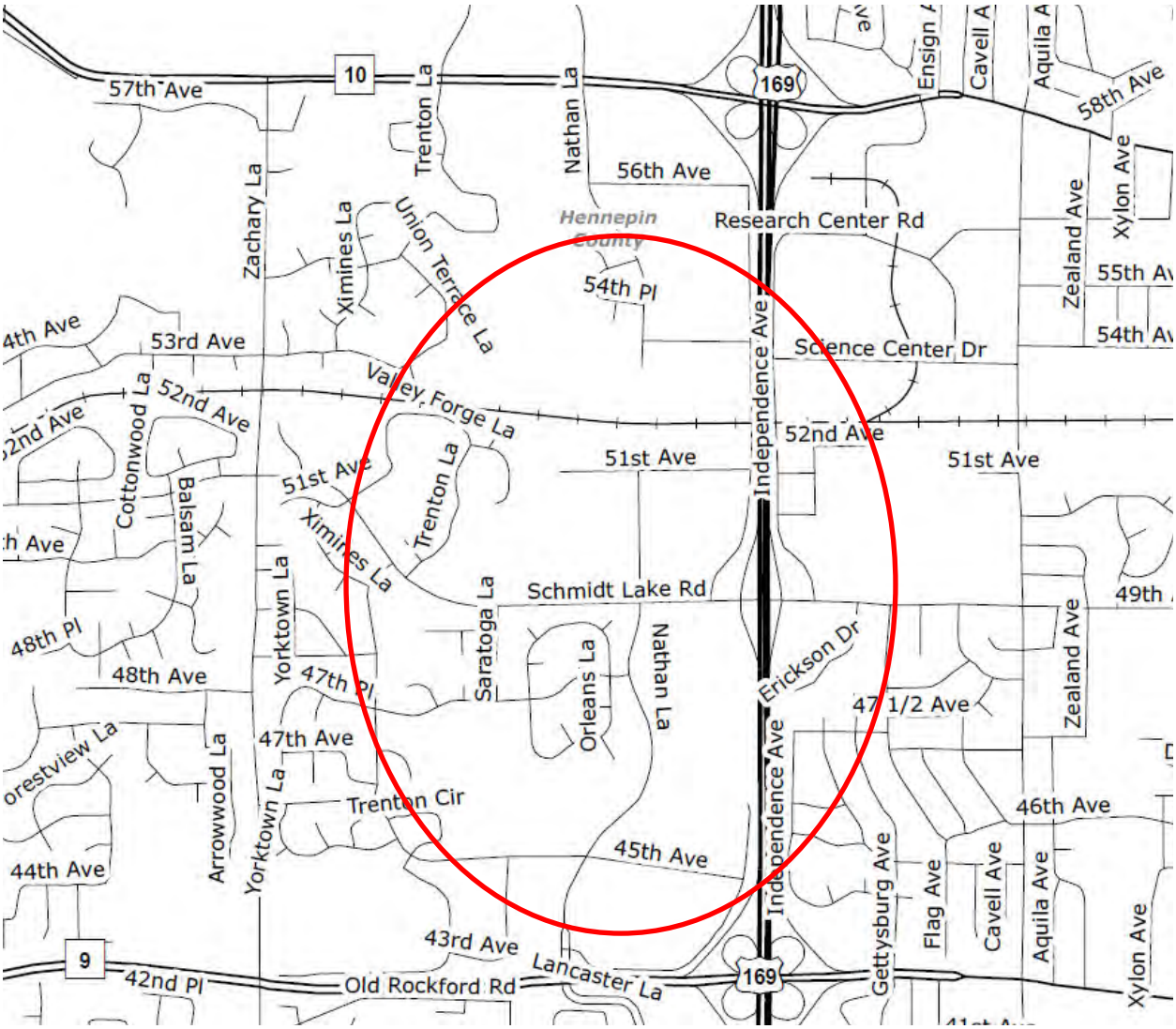
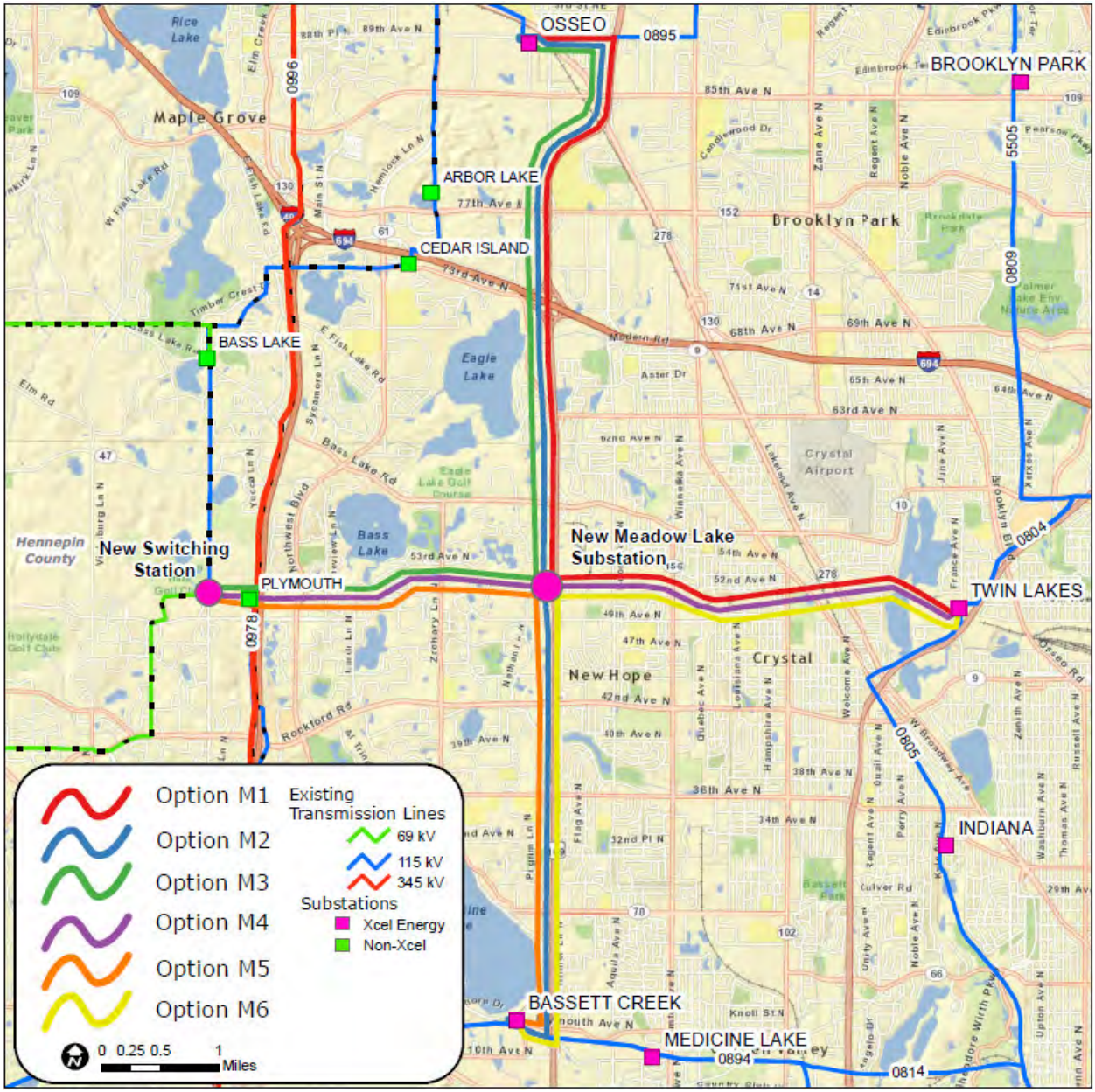


Figure 5. Meadow Lake Substation Connection Options



All Meadow Lake Substation connections tested use major transportation corridors for routing assumptions because there is a lack of existing transmission corridors. The main corridors are Highway 169 and the CP rail corridor between Old Rockford Road and Bass Lake Road. All of the alternatives include connections to two substations. The line will be built and operated with a nominal line to line voltage of 115 kV.

Option M1

The first connection has terminations at Osseo Substation and Twin Lake Substation. From the Osseo Substation to Meadow Lake the connection is assumed to follow

Highway 169. The line would then turn east along the CP railroad line to the Twin Lakes Substation.

Approx Miles of 115 kV: 8.8

Option M2

This connection is between Osseo Substation and Basset Creek Substation. The route for this option was assumed to run north and south along Highway 169.

Approx Miles of 115 kV: 7.8

Option M3

This connection is between Plymouth Substation and Osseo Substation. The CP railroad corridor was the assumed route to connect a new switching substation in Plymouth to Meadow Lake. The route would follow the Highway 169 kV corridor north to Osseo Substation.

Approx Miles of 115 kV: 7

Option M4

This connection is between a new switching substation by Plymouth Substation and the Twin Lakes Substation. The assumed route is centered on the CP railroad line the majority of the way from a new switching substation in Plymouth (Pomerleau Lake Switching Substation) and Twin Lakes. Meadow Lake Substation is assumed to be located along the line near this corridor.

Approx Miles of 115 kV: 6.6 Miles

Option M5

This connection is between Plymouth Substation and Basset Creek Substation. Between the new switching substation in Plymouth (Pomerleau Lake Switching Substation) and Meadow Lake Substation, the line is assumed to run parallel to the CP railroad line. Highway 169 is used to get south to the Basset Creek Substation.

Approx Miles of 115 kV: 7

Option M6

This connection is between the Basset Creek and Twin Lakes substations. The initial section follows Highway 169 between Meadow Lake and Basset Creek substations. The CP railroad line right of way is assumed for the portion between Twin Lakes and Meadow Lake substations.

Approx Miles of 115 kV: 8

4.5: Evaluation of Options

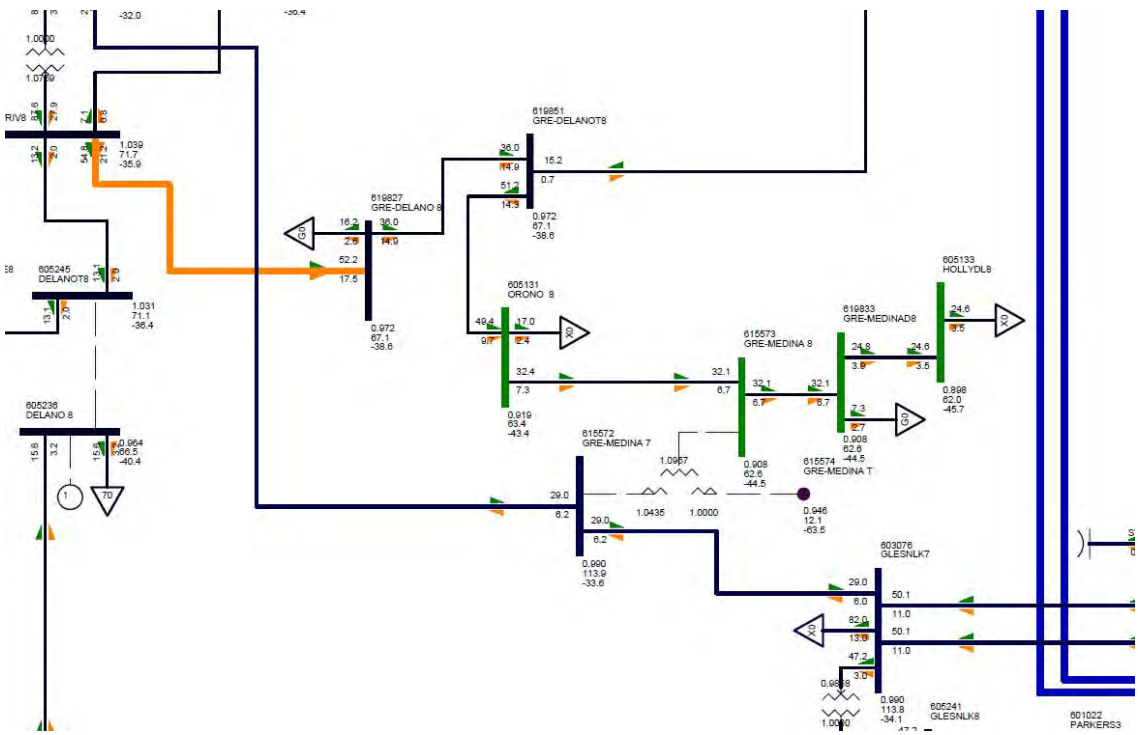
4.5.1: Hollydale Options.

Current System with Load Increase

The current system serves the Hollydale Substation with a 34.5 kV feeder supplied at Gleason Lake Substation. There is an emergency feed from the GRE 69 kV line tying back to the Medina Substation. The 34.5 kV and 69 kV systems are not strong enough to support the growing load in the area as forecast by Distribution Planning.

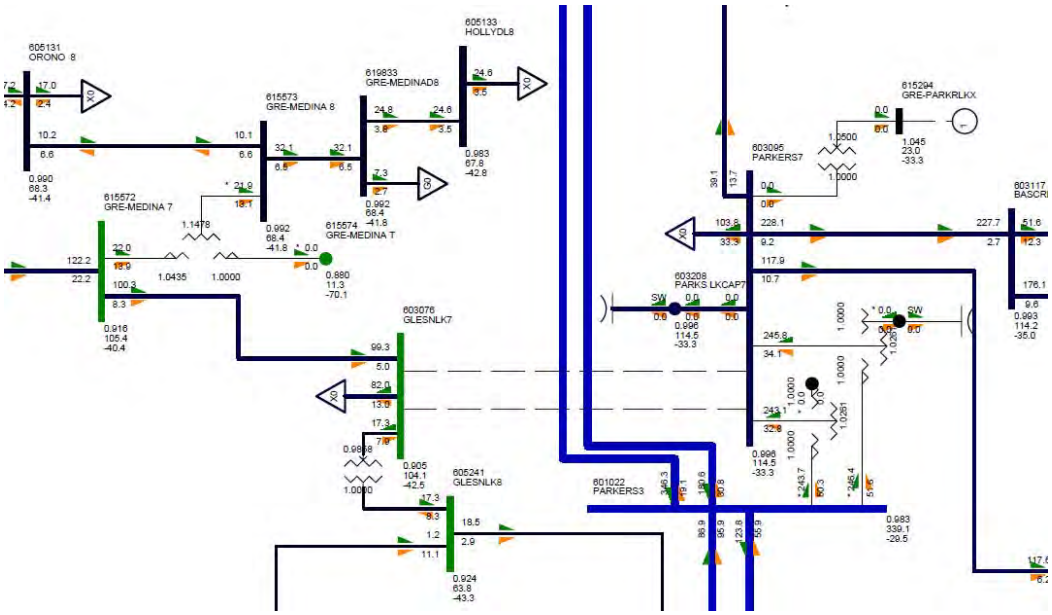
In general there are two issues: First, The 69 kV system is not able to support the connection for loss of the Medina Substation transformer. Second, general load growth in the western Metro Area outside the I-494 loop has brought the transmission system near its load serving ability. Facilities constructed to address the interconnection have the ability to help the general transmission system functionality. Figure 6 is a simulation of Medina transformer outage in 2015 which shows low voltages near Hollydale and overloads stemming from the Crow River Substation on the 69 kV system.

Figure 6. Medina Transformer Outage in 2015



Capacity Planning is planning on moving load from Parkers Lake Substation to Hollydale Substation. This will reduce the voltage for a double circuit outage of Gleason Lake – Parkers Lake. The voltage is .905 in 2015 and will be below the .90 criteria by 2020. Figure 7 below shows this outage.

Figure 7. Gleason Lake – Parkers Lake Double Circuit Outage in 2015



Options H1 & H2

Options H1 and H2 provide nearly identical results because they connect the Parkers Lake – Crow River line to another point in the western Metro Area 115 kV system. During the loss of the double circuit from Gleason Lake to Parkers Lake, voltage is maintained at Gleason Lake and on the 69 kV system to the south. Figure 8 shows the line from Hollydale to Medina and a double circuit outage of Parkers Lake to Gleason Lake. Figure 9 shows a connection between Hollydale to Gleason Lake with the same double circuit outage.

There is better voltage for the connection to Gleason Lake, but both are within the criteria of .90 PU voltage. Gleason Lake has one position left at 115 kV which has been designed for a conversion of the 69 kV corridor south to Westgate (Eden Prairie). At this time it would be preferred to terminate the line at Medina to reserve the position at Gleason Lake when the need arises. Gleason Lake is an acceptable electrical option to terminate the line, but routing may be difficult.

Figure 8. Hollydale Substation at 115 kV Double Circuit Outage

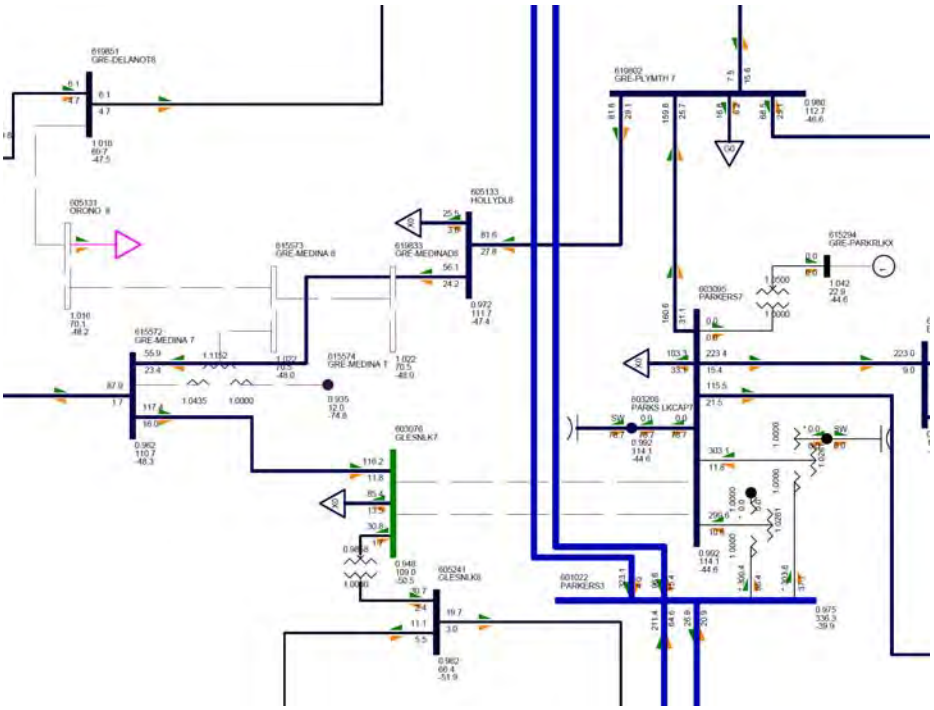
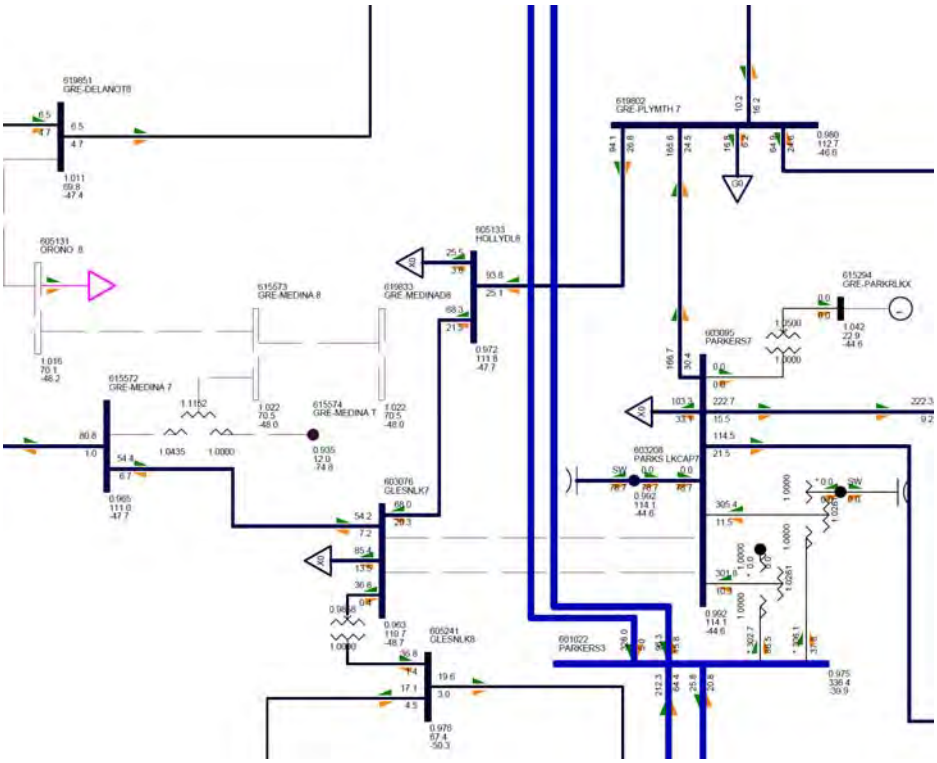


Figure 9. Hollydale – Gleason Lake Double Circuit Outage



Option H3

Option H3 is not developed for further analysis. The option is a detriment to the current system and is not recommended. The option will provide similar voltages and concerns seen in Figure 7. The option will not improve voltages during the Gleason Lake – Parkers Lake outage. It moves outside the 345 kV Twin Cities ring electrically and does not add a connection to the stronger 115 kV system inside the Twin Cities loop. The Crow River end of the 115 kV line is not strong enough to support this configuration. In the long term, the conductor towards the northwest will overload due to load growth.

4.5.2: Meadow Lake Options

There are no existing transmission facilities in the area of Highway 169 and Schmidt Lake Rd. As a result, it is assumed that connections to the Meadow Lake Substation will be on new right of way. To provide the necessary redundant transmission to this load, two connections to different substations are proposed. This section explores the alternative connections analyzed (see Figure 5, Meadow Lake Substation Connections). All options for connecting Meadow Lake into the transmission system were done independent of the Hollydale Project plans.

Option M1

Connecting to Osseo Substation to Twin Lakes Substation will put added pressure on the line between Osseo Substation and GRE's Hennepin Substation. There are approximately 1.5 miles of 795 ACSR that will be overloaded. The change from base case in 2020 is 10% in loading. It moves to 103% of the lines 30 minute emergency limit. There are no voltage violations associated with this chosen termination. It neither improves nor degrades the system assuming an upgrade of this conductor. Due to the extra scope of work and cost considering the Hollydale Project which has been submitted for permitting, this option is not recommended.

Option M2

Connecting Osseo to Basset Creek does not pose any NERC Category B concerns with all system components intact. NERC has issued an interpretation to the Midwest Independent Transmission System Operator (MISO) that maintenance outages are not contingencies. The transmission system under a maintenance outage is subject to all TPL requirements at the projected load. The NERC order can be found in Appendix A. This means that Xcel Energy needs to plan for additional outages in addition to those needed for maintenance and construction.

During a maintenance outage of either Basset Creek – Parkers Lake or Meadow Lake – Osseo, loss of the other line will cause high flows on the line between Aldrich and Medicine Lake substations. This flow will overload the line between Aldrich and Medicine Lake substations by 2020 on peak. Because the design for the future Meadow Lake Substation calls for an additional two transformers, this loading will most likely go up. It will become increasingly difficult to impossible to perform maintenance

on these lines for the Option M2 alternative as load grows. For this reason, Option M2 is not recommended.

Option M3

Similar to Option M2, there are no problems with any NERC TPL Category B contingencies without maintenance outages. However, a maintenance outage of either Parkers Lake – Plymouth or Elm Creek – Arbor Lakes is a concern. A Category B contingency with this outage will cause overload on the line from Elm Creek – Osseo and low voltages for the GRE loads served between Elm Creek and Parkers Lake substations. This option is not recommended because of system flexibility concerns, but could be feasible with the construction of the Hollydale interconnection (Opt H1 or H2). The Pomerleau Lake connection would give an additional source to the GRE line between Parkers Lake and Elm Creek.

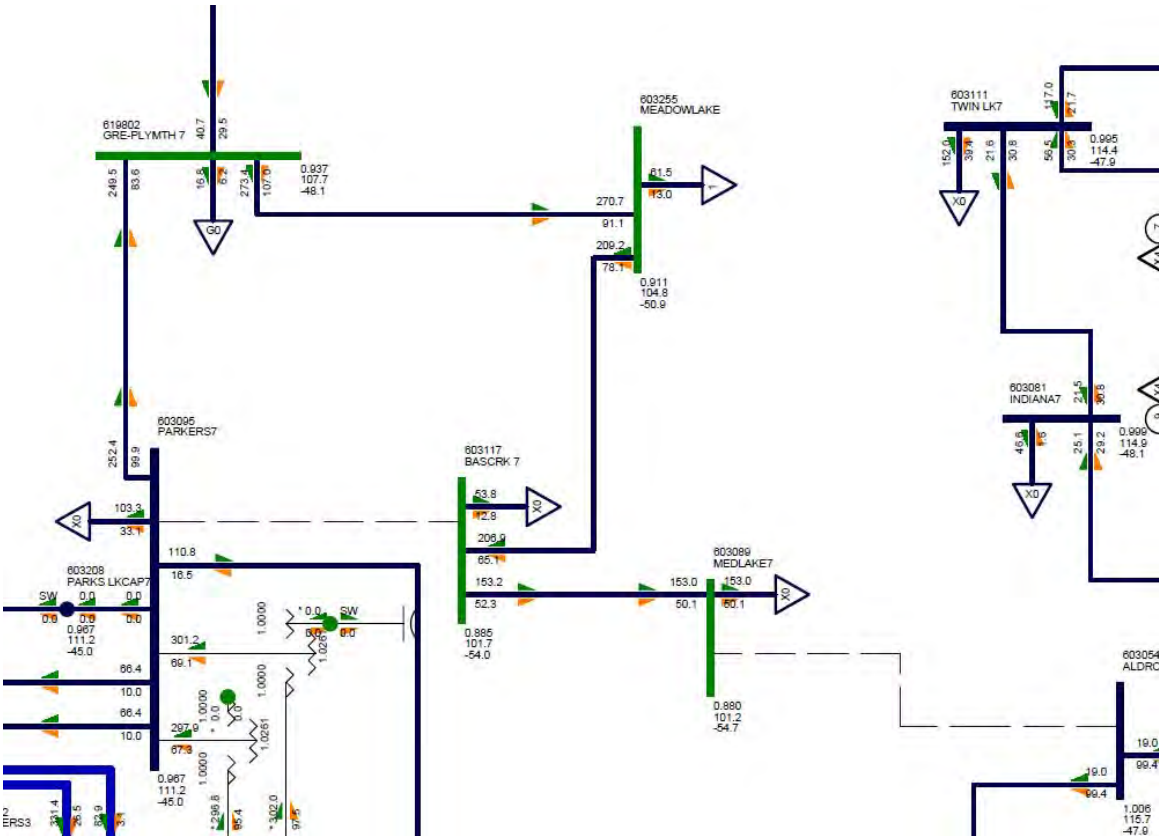
Option M4

A connection between a future new Pomerleau Lake switching substation and Twin Lakes Substation is preferred to serve the future new Meadow Lake Substation. This connection provides a redundant path to the 115 kV double circuit line between the western portion of the 345 kV loop and Minneapolis. This alternative matches or improves contingent loading and voltage under steady state conditions for all flagged contingencies. This option does not require construction of any the Hollydale option to provide these benefits. Xcel Energy recommends that this option be constructed.

Option M5

Using a Plymouth to Basset Creek connection provides similar performance to Option M2. There are two sets of contingencies that will limit maintenance outages of the following four lines. The outage of the lines between Aldrich – Medicine Lake substations and Basset Creek – Parkers Lake substations create low voltage along the Basset Creek and Medicine Lake lines. Figure 10 is a simulation of the outage on a 2020 summer peak model. The Meadow Lake, Plymouth and Basset Creek substations are not at their final build out size, so with load growth these substations will have more restrictive maintenance outages. As a result, Parkers Lake – Basset Creek and Meadow Lake – Plymouth will overload Aldrich to Medicine Lake.

Figure 10. BCR- PKL & MED – ALD outage



Option M6

The connection between Basset Creek and Twin Lakes substations is possible electrically, but it provides no improvement to the transmission system. Improvements will need to take place in the Gleason Lake area to mitigate low voltages upon loss of the Parkers Lake – Gleason Lake double circuit lines. The double circuit loss is a NERC Category C contingency.

4.6: Performance Evaluation Methods

PSS/E is a power flow simulation program developed by Siemens Power Technologies International. PSS/E ver. 30.3.2 was used to analyze options provided in the study. The AC Contingency Analysis (ACCC) function of PSS/E is utilized to speed up contingency analysis. The program used the contingencies specified for this study to report violations of Voltage and Thermal limits. The contingencies studied represented NERC Category B and C conditions.

5.0: Results of Detailed Analyses

5.1: Powerflow (System Intact & Contingency)

There were more than 5000 contingencies analyzed through PSS/E's ACCC program. These contingencies were run on each connection for the Meadow Lake Substation. The Hollydale Substation connections are located in a more focused area so the solutions were done by hand with a final automated contingency run done to ensure the recommended Hollydale and Meadow Lake substation connections will function reliably.

There are no overload or voltage conditions with system intact operation of any of the connections analyzed. Contingencies are analyzed under Section 4.5 Options Evaluated. All issues are addressed and noted.

5.2: Losses: Technical Evaluation

The analysis of system loss changes was undertaken at the transmission level. Loss values are represented in changes from the transmission system base case. As can be seen from Table 4 and Table 5, there is little difference for losses between any of the transmission connection choices for either project. No economic comparison was done for the loss savings because of the minimal impact it would have.

Table 4. Hollydale Loss Analysis

Hollydale Loss Analysis

Connection	MED-PLY	GSL-PLY	MED-GSL
2015	0.6	0.6	
2020	0.7	0.7	

Table 5. Meadow Lake Loss Analysis

Meadow Lake Loss Analysis

Connection	1 (OSS-TWL)	2 (BSK - OSS)	3 (PLY - OSS)	4 (PLY - TWL)	5 (PLY - BSK)	6 (BSK - TWL)
2015	0	0	-0.1	0	0	0
2020	-0.3	-0.4	-0.2	-0.2	-0.3	-0.3

6.0: Economic Analysis

6.1: Installed Cost

Cost information is provided in Table 6-10 below. All Costs are given in U.S. Dollars and rounded to the nearest 100k value.

Table 6. Substation Indicative Costs

Substation Indicative Costs	
Conversion of Hollydale	$4,340
3 Position Pomerleau Switching Substation	$7,200
4th Pomerleau Position	$680
Total Meadow Lake Cost	$12,245
Twin Lakes Termination	$2,755
Gleason Lake, Medina or Osseo Termination costs	$1,500
Basset Creek additional termination	$2,000

Table 7. Transmission Line Indicative Costs Used Per Mile

Transmission Line Indicative Costs Used Per Mile	
Hollydale to Plymouth, Medina, or Pomerleau (Single 795 ACSS)	$922
Meadow Lake – Osseo or Basset Creek (2-795 ACSS)	$1,380
Twin Lakes – Meadow Lake (2-795 ACSS)	$1,213
Meadow Lake – Plymouth (2-795 ACSS)	$1,646
Removal of Plymouth – Medina 69 kV (total)	$525

Table 8. Hollydale Options

Hollydale			
	Option H1	Option H2	Option H3
Line	$7,380	$7,841	$7,841
Sub	$13,040	$13,040	$7,340
Total	$20,420	$20,881	$15,181

Table 9. Meadow Lake Options

Meadow Lake Options						
	Option M1	Option M2	Option M3	Option M4	Option M5	Option M6
	Osseo - Twin Lakes	Osseo - Basset Creek	Plymouth - Osseo	Plymouth - Twin Lakes	Plymouth - Basset Creek	Basset Creek - Twin Lakes
Line	$11,511	$12,767	$11,511	$9,220	$10,476	$10,476
Sub	$16,500	$15,745	$20,945	$22,200	$21,445	$17,000
Total	$28,011	$28,512	$32,456	$31,420	$31,921	$27,476

Table 10. Meadow Lake Options Including Recommended Hollydale Option H1

Meadow Lake Options Including Recommended Hollydale Option H1						
	Option M1	Option M2	Option M3	Option M4	Option M5	Option M6
	Osseo - Twin Lakes	Osseo - Basset Creek	Plymouth - Osseo	Plymouth - Twin Lakes	Plymouth - Basset Creek	Basset Creek - Twin Lakes
Line	$18,891	$20,147	$18,891	$16,600	$17,856	$17,856
Sub	$29,540	$28,785	$27,465	$28,720	$27965	$30,040
Total	$48,431	$48,932	$46,356	$45,320	$45,821	$47,896

7.0: Relevant Concerns

7.1: Load-Serving Issues

7.2: Constructability & Schedule Considerations

The Hollydale and Meadow Lake interconnections will have very few constructability issues from a system outage perspective. The construction of Hollydale will require construction from east to west. This will allow Medina to be supported as the 115/69 kV Medina transformer is removed. It will be important to move the Orono Substation to the 115 kV line between Medina and Crow River due to the removal of the Medina 115/69 kV transformer. With the east to west construction pattern outages should be relatively easy to grant from transmission operations.

Similarly, the Meadow Lake construction sequence will not have any outage concerns for line construction. There may be outage concerns when the Twin Lakes Substation is re-configured. Further detailed engineering will be required to assess and address these concerns.

7.3: Double-Circuit Line Considerations

Hollydale is currently connected to a 69 kV line that is passing by the substation. Once the 115 kV connections is constructed there will be no need for the 69 kV line. Due to the location of Meadow Lake, a double circuit of an existing line is not possible. There are no existing transmission lines near the proposed Meadow Lake site.

A single circuit configuration for both proposals is adequate to provide capacity for anticipated needs. Accordingly, neither proposal is recommended to be constructed as double circuit.

7.3: Future Use of Facilities

Within the 345 kV ring around the Twin Cities, capacity on the 345/115 kV transformers is running out due to load growth. The transformers that are currently installed are very large. Some have the capability of being upgraded to a larger size, but more

transformers will be required. Due to space constraints at existing substations, new locations will most likely be needed to house transformers.

The location of the Pomerleau Lake Substation makes it a prime candidate to house 345/115 kV transformers. It will be physically near the 345 kV ring and multiple 115 kV lines. For this possible purpose, it is recommended to acquire enough property for this purpose.

Appendix A: NERC Interpretation

Guidance was issued by NERC and requires that the system be designed to handle contingencies during maintenance and construction outages.

The following revised interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 was developed by the NERC Planning Committee on March 13, 2008:

This provision was not previously interpreted by NERC since its approval by FERC and other regulatory authorities. TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are performed is required. For studies that include planned outages, compliance with the contingency assessment for TPL-002-0 and TPL-003-0 as outlined in Table 1 would include any necessary system adjustments which might be required to accommodate planned outages since a planned outage is not a “contingency” as defined in the NERC *Glossary of Terms Used in Standards*.

Appendix B: Powerflow Contingency Files

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COM 'CATEGORY B'

COM '5M35 BKR fail Crooked Lake or Cat B Between Elm
Crk-West Coon RPDS-Crooked Lake'
COM 'Disconnect Champlin BUS 603049'
COM 'Disconnect Champlin Tap BUS 603050'
cONTINGENCY 'B2.CHM,WCR,CRL,ECK'
DISCONNECT BUS 603049
DISCONNECT BUS 603050
END

COM '5M272 BKR FAIL CROOKED LAKE OR CAT B CRL-
PAR'
COM '603070-615396 CRKEDLK7-GRE-VILGTEN8'
COM '615396-615397-615398 PARKWOODS TR1 3
WINDING'
CONTINGENCY 'B2.CRL,PAR'
TRIP BRANCH FROM BUS 603070 TO BUS 615396 CKT 1
TRIP BRANCH FROM BUS 615396 TO BUS 615397 TO
BUS 615398 CKT 1
END

COM 'ELM CREEK - WEST COON RAPIDS FAULT AS'
COM 'DISCONNECT HENNEPIN BUS 616302'
COM 'DISCONNECT OSSEO BUS 603094'
CONTINGENCY 'B2.ECK,WCR AS'
DISCONNECT BUS 616302
DISCONNECT BUS 603094
END

COM 'ELM CREEK TR 9 FAILURE AS'
COM 'DICONNECT ELM CREEK BUS 601005
CONTINGENCY 'B3.ECK TR9 AS'
DISCONNECT BUS 601005
END


COM
'_____________________________________________________
_____________________,
COM 'CATEGORY C'
COM 'CATEGORY C'
COM 'CATEGORY C'

COM 'DOUBLE CIRCUIT'
COM 'DOUBLE CIRCUIT'

COM 'DBL CKT ECK-HSN & ECK-CHM 115 kV'
COM '603006-603126 ELMCRK 7-HASSAN 7'
COM 'DISCONNECT CHAMPLIN BUS 603049'
COM 'DISCONNECT CHAMPLIN TAP BUS 603050'
CONTINGENCY 'C5.ECK-HSN,ECK-CHM'
TRIP LINE FROM BUS 603006 TO BUS 603126 CKT 1
DISCONNECT BUS 603049
DISCONNECT BUS 603050
END

COM 'DBL CKT TWL-CNC & TWL-RIV 115 kV'
COM '603111-603068 TWIN LK7-COON CK7'
COM '603111-603099 TWIN LK7-RIVRSID7'
CONTINGENCY 'C5.TWL-CNC,TWL-RIV'
TRIP LINE FROM BUS 603111 TO BUS 603068 CKT 1
TRIP LINE FROM BUS 603111 TO BUS 603099 CKT 1
END

COM 'DBL CKT TWL-CNC & BRP-CNC 115 kV'
COM '603111-603068 TWIN LK7-COON CK7'
COM '603125-603068 BRKLNPK7-CCON CK7'
CONTINGENCY 'C5.TWL-CNC,BRP-CNC'
TRIP LINE FROM BUS 603111 TO BUS 603068 CKT 1
TRIP LINE FROM BUS 603125 TO BUS 603068 CKT 1
END

COM 'DBL CKT TWL-CNC & BRP-CNC 115 kV'
COM '603111-603068 TWIN LK7-COON CK7'
COM '603125-603099 BRKLNPK7-RIVRSID7'
CONTINGENCY 'C5.TWL-CNC,BRP-RIV'
TRIP LINE FROM BUS 603111 TO BUS 603068 CKT 1
TRIP LINE FROM BUS 603125 TO BUS 603099 CKT 1
END

COM 'DBL CKT TWL-CNC & BRP-CNC 115 kV'
COM '603111-603099 TWIN LK7-RIVRSID7'
COM '603125-603099 BRKLNPK7-RIVRSID7'
CONTINGENCY 'C5.TWL-RIV,BRP-RIV'
TRIP LINE FROM BUS 603111 TO BUS 603099 CKT 1
TRIP LINE FROM BUS 603125 TO BUS 603099 CKT 1
END

COM 'DBL CKT MEL-ALD & TWL-ALD 115 kV PRE-AS'
COM '603089-603054 MEDLAKE7-ALDRCH27'
COM '603081-603053 INDIANA7-ALDRICH7'
CONTINGENCY 'C5.MEL-ALD,TWL-ALD PRE-AS'
TRIP LINE FROM BUS 603089 TO BUS 603054 CKT 1
TRIP LINE FROM BUS 603081 TO BUS 603053 CKT 1
END

COM 'DBL CKT MEL-ALD & TWL-ALD 115 kV POST-AS'
COM '603089-603054 MEDLAKE7-ALDRCH27'
COM 'DISCONNECT INDIANA BUS 603081'
CONTINGENCY 'C5.MEL-ALD,TWL-ALD POST-AS'
TRIP LINE FROM BUS 603089 TO BUS 603054 CKT 1
DISCONNECT BUS 603081
END


COM 'DBL CKT ECK-MNN & SHC-CNC 345 kV'
COM '601005-601010 ELM CRK3-MNTCELO3'
COM 'LOSS OF COON CREEK XFMR #9'
COM 'SHERBURN CO. TO COON CREEK GRE&XCEL
LINE DISCONNECT BUS 601027'
CONTINGENCY 'C5.ECK-MNN,SHC-CNC#1'
TRIP BRANCH FROM BUS 601005 TO BUS 601010 CKT 1
TRIP BRANCH FROM BUS 601019 TO BUS 603068 TO
BUS 605018 CKT 9
DISCONNECT BUS 601027
END

COM 'DBL CKT ECK-PKL & SHC-CNC 345 kV'
COM '601005-601022 ELM CRK3-PARKERS3'
COM 'LOSS OF COON CREEK XFMR #9'
COM 'SHERBURN CO. TO COON CREEK GRE&XCEL
LINE DISCONNECT BUS 601027'
CONTINGENCY 'C5.ECK-PKL,SHC-CNC#1'
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TRIP LINE FROM BUS 601005 TO BUS 601022 CKT 1
TRIP BRANCH FROM BUS 601019 TO BUS 603068 TO
BUS 605018 CKT 9
DISCONNECT BUS 601027
END

COM 'DBL CKT ECK-PKL & DKN-PKL 345 kV'
COM '601005-601022 ELM CRK3-PARKERS3'
COM 'DICKINSON TO PARKERS LAKE GRE&XCEL LINE
DISCONNECT BUS 601026'
CONTINGENCY 'C5.ECK-PKL,DKN-PKL#1'
TRIP LINE FROM BUS 601005 TO BUS 601022 CKT 1
DISCONNECT BUS 601026
END

COM 'DBL CKT DKN-CNC & DKN-PKL 345 kV'
COM '615353-601019 GRE-DICKNSN3-COON CK3'
COM 'DICKINSON TO PARKERS LAKE GRE&XCEL LINE
DISCONNECT BUS 601026'
CONTINGENCY 'C5.DKN-PKL,DKN-PKL'
TRIP LINE FROM BUS 615353 TO BUS 601019 CKT 1
DISCONNECT BUS 601026
SET BUS 615353 LOAD TO 1060 MW
END

COM 'DBL CKT CNC-KOL & CNC-TER 345 kV'
COM '601019-601021 COON CK3-KOLMNLK3'
COM 'DISCONNECT KOHLMAN LAKE TR#9
COM '601019-601024 COON CK3-TERMINL3'
COM 'DISCONNECT TERMINAL XFMR #10'
CONTINGENCY 'C5.CNC-KOL,CNC-TER'
TRIP LINE FROM BUS 601019 TO BUS 601021 CKT 1
TRIP LINE FROM BUS 603084 TO BUS 601021 TO BUS
605702 CKT 9
TRIP LINE FROM BUS 601019 TO BUS 601024 CKT 1
TRIP BRANCH FROM BUS 601024 TO BUS 603110 TO
BUS 605516 CKT 10
END

COM 'DBL CKT CNC-SHC & CNC-BUL-SHC 345 kV'
COM '601019-601011 COON CK3-SHERCO 3'
COM 'DISCONNECT BUNKER LAKE 345 Kv BUS 615327'
COM 'DISCONNECT BUNKER LAKE 3 WINDING XFMR'
CONTINGENCY 'C5.CHC-SHC,CNC-BUL-SHC'
TRIP LINE FROM BUS 601019 TO BUS 601011 CKT 1
DISCONNECT BUS 615327
TRIP BRANCH FROM BUS 615327 TO BUS 615330 TO
BUS 615328 CKT 1
END



COM 'STUCK BREAKER'
COM 'STUCK BREAKER'


COM 'NSP STK 5M143 BKR'
COM '603111-603068 TWIN LK7-COON CK7'
COM '603111-603099 TWIN LK7-RIVRSID7'
CONTINGENCY 'NSP STK 5M143 BKR TWIN LAKES'
TRIP LINE FROM BUS 603111 TO BUS 603068 CKT 1
TRIP LINE FROM BUS 603111 TO BUS 603099 CKT 1
END

COM 'NSP STK 5M145 BKR'
COM '603111-603068 TWIN LK7-COON CK7'
COM '603111-603081 TWIN LK7-INDIANA7'
COM '603081-603053 INDIANA7-ADTRICH7'
CONTINGENCY 'NSP STK 5M145 BKR TWIN LAKES'
TRIP LINE FROM BUS 603111 TO BUS 603068 CKT 1
TRIP LINE FROM BUS 603111 TO BUS 603081 CKT 1
TRIP LINE FROM BUS 603081 TO BUS 603053 CKT 1
END

COM 'NSP STK 5m242 BKR'
COM '603006-603049 ELMCRK7 -CHAMPLN7'
COM '603049-603050 CHAMPLN7-CHAMP T7'
COM '603050-603070 CHAMP T7-CRKEDLK7'
COM '603050-603112 CHAMP T7-WCNRAPD7'
COM '603006-603126 ELMCRK7 -HASSAN 7'
CONTINGENCY 'C2.5m242 BKR ELM CREEK'
TRIP LINE FROM BUS 603006 TO BUS 603049 CKT 1
TRIP LINE FROM BUS 603049 TO BUS 603050 CKT 1
TRIP LINE FROM BUS 603050 TO BUS 603070 CKT 1
TRIP LINE FROM BUS 603050 TO BUS 603112 CKT 1
TRIP LINE FROM BUS 603112 TO BUS 603068 CKT 1
END

COM 'NSP STK 5M243 BKR'
COM '603006-603049 ELMCRK7 -CHAMPLN7'
COM '603049-603050 CHAMPLN7-CHAMP T7'
COM '603050-603070 CHAMP T7-CRKEDLK7'
COM '603050-603112 CHAMP T7-WCNRAPD7'
COM '603211 SHUNT REMOVED'
CONTINGENCY 'C2.5M243 BKR ELM CREEK'
TRIP LINE FROM BUS 603006 TO BUS 603049 CKT 1
TRIP LINE FROM BUS 603049 TO BUS 603050 CKT 1
TRIP LINE FROM BUS 603050 TO BUS 603070 CKT 1
TRIP LINE FROM BUS 603050 TO BUS 603112 CKT 1
DISCONNECT BUS 603211
END

COM 'NSP STK 5M277 BKR ELM CREEK AS'
COM '601005-601010 ELM CRK3-MNTCELO3'
COM '601005-601022 ELM CRK3-PARKERS3'
COM '601005-603006 ELM CRK3-ELMCRK 7'
COM '603006-616302 ELMCRK 7-OSSEO  7'
COM '603094-603112 OSSEO  7-WCNRAPD7'
CONTINGENCY 'NSP STK 5M277 BKR ELM CLREEK AS'
DISCONNECT BUS 601005
DISCONNECT BUS 603094
DISCONNECT BUS 616302
END

COM 'NSP STK 5M278 BKR AS'
COM '603006-616302 ELMCRK 7-OSSEO  7'
COM '603094-603112 OSSEO  7-WCNRAPD7'
COM '603211 SHUNT REMOVED'
CONTINGENCY 'NSP STK 5M278 BKR ELM CLREEK AS'
DISCONNECT BUS 603094
DISCONNECT BUS 616302
DISCONNECT BUS 603211
END

COM 'NSP STK 5M276 8M47 8M49 BKR, TRANSFORMER
FAILURE, OR BUS FAULT ON 115 OR 345 AS'
COM '601005-601010 ELM CRK3-MNTCELO3'
COM '601005-601022 ELM CRK3-PARKERS3'
COM '601005-603006 ELM CRK3-ELMCRK 7'
CONTINGENCY 'NSP STK 5M276 8M47 8M49 BKR ELM
CLREEK AS'
DISCONNECT BUS 601005
END

COM 'NSP STK 5M281 BKR ELM CREEK'
COM 'DISCONNECT CAP @ ELM CREEK BUS 603211'
COM 'DISCONNECT ARBOR LAKES BUS 619803'
CONTINGENCY 'C2.5M281 ECK'
DISCONNECT BUS 603211
DISCONNECT BUS 616302
END
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COM 'NSP STK 5M28 BKR WEST COON RAPIDS AS'
COM 'DISCONNECT CHAMPLIN BUS 603049'
COM 'DISCONNECT CHAMPLIN TAP BUS 603050'
COM 'DISCONNECT HENNEPIN BUS 616302'
COM 'DISCONNECT OSSEO BUS 603094'
CONTINGENCY 'C2.5M28 BKR WCR AS'
DISCONNECT BUS 603049
DISCONNECT BUS 603050
DISCONNECT BUS 616302
DISCONNECT BUS 603094
END

COM 'NSP STK 5M29 BKR'
COM '603006-603049 ELMCRK7 -CHAMPLN7'
COM '603049-603050 CHAMPLN7-CHAMP T7'
COM '603050-603070 CHAMP T7-CRKEDLK7'
COM '603050-603112 CHAMP T7-WCNRAPD7'
COM '603112-603068 WCNRAPD7-COON CK7'
CONTINGENCY 'C2.5M29 BKR WST COON RPDS'
TRIP LINE FROM BUS 603006 TO BUS 603049 CKT 1
TRIP LINE FROM BUS 603049 TO BUS 603050 CKT 1
TRIP LINE FROM BUS 603050 TO BUS 603070 CKT 1
TRIP LINE FROM BUS 603050 TO BUS 603112 CKT 1
TRIP LINE FROM BUS 603112 TO BUS 603068 CKT 1
END

COM 'NSP STK 5M117 BKR'
COM '603068-603112 COON CK7-WCNRAPD7'
COM '603068-603091 COON CK7-MOORELK7'
CONTINGENCY 'NSP STK 5M117 BKR COON CREEK'
TRIP LINE FROM BUS 603068 TO BUS 603112 CKT 1
TRIP LINE FROM BUS 603068 TO BUS 603091 CKT 1
END

COM 'NSP STK 5M118 BKR'
COM '603068-615396 COON CK7-GRE-PRKWOOD7'
COM '603068-603091 COON CK7-MOORELK7'
CONTINGENCY 'NSP STK 5M118 BKR COON CREEK'
TRIP LINE FROM BUS 603068 TO BUS 615396 CKT 1
TRIP LINE FROM BUS 603068 TO BUS 603091 CKT 1
END

COM 'NSP STK 5M114 BKR COON CREEK AS'
COM '601019-603068 COON CK3-COON CK7 CKT9'
COM '603068-603125 COON CK7-BRKLNPK7'
COM 'DISCONNECT COON CREEK - OWNER CHANGE -
SHERCO'
COM '-----------------------------------------------------'
CONTINGENCY 'NSP STK 5M114 BKR COON CREEK AS'
TRIP BRANCH FROM BUS 601019 TO BUS 603068 TO
BUS 605018 CKT 9
TRIP LINE FROM BUS 603068 TO BUS 603125 CKT 1
DISCONNECT BUS 601027
END

COM 'NSP STK 5M115 BKR COON CREEK'
COM '603068-615396 COON CK7-PRKWOOD7'
COM '603068-603125 COON CK7-BRKLNPK7'
COM 'PARKWOOD XFMR 2 REMOVE'
COM '-----------------------------------------------------'
CONTINGENCY 'NSP STK 5M115 BKR COON CREEK'
TRIP LINE FROM BUS 603068 TO BUS 615396 CKT 1
TRIP LINE FROM BUS 603068 TO BUS 603125 CKT 1
TRIP LINE FROM BUS 615396 TO BUS 615397 TO BUS
615399 CKT 2
END

COM 'NSP STK 5M124 BKR COON CREEK'
COM 'COON CRK XFMR CKT 10'
COM '603068-615396 COON CK7-PRKWOOD7'
COM 'PARKWOOD XFMR 2 REMOVE'
COM '-----------------------------------------------------'
CONTINGENCY 'NSP STK 5M124 BKR COON CREEK'
TRIP BRANCH FROM BUS 601019 TO BUS 603068 TO
BUS 605017 CKT 10
TRIP LINE FROM BUS 603068 TO BUS 615396 CKT 1
TRIP LINE FROM BUS 615396 TO BUS 615397 TO BUS
615399 CKT 2
END

COM 'NSP STK 5M123 BKR COON CREEK'
COM 'COON CRK XFMR CKT 10'
COM '603068-603111 COON CK7-TWIN LK7'
COM '-----------------------------------------------------'
CONTINGENCY 'NSP STK 5M123 BKR COON CREEK'
TRIP BRANCH FROM BUS 601019 TO BUS 603068 TO
BUS 605017 CKT 10
TRIP LINE FROM BUS 603068 TO BUS 603111 CKT 1
END

COM 'NSP STK 8M24 BKR COON CREEK'
COM 'COON CRK XFMR CKT 10'
COM '601019-615353 COON CK3-DICKNSN3'
COM '601019-601011 COON CK3-SHERCO 3'
COM '-----------------------------------------------------'
CONTINGENCY 'NSP STK 8M24 BKR COON CREEK'
TRIP BRANCH FROM BUS 601019 TO BUS 603068 TO
BUS 605017 CKT 10
TRIP LINE FROM BUS 601019 TO BUS 615353 CKT 1
TRIP LINE FROM BUS 601019 TO BUS 601011 CKT 1
END

COM 'NSP STK 8M23 BKR COON CREEK'
COM 'COON CRK XFMR CKT 9'
COM '601019-615353 COON CK3-DICKNSN3'
COM 'dISCONNECT SHERCO - OWNER CHANGE -
COON CREEK'
COM '-----------------------------------------------------'
CONTINGENCY 'NSP STK 8M23 BKR COON CREEK'
TRIP BRANCH FROM BUS 601019 TO BUS 603068 TO
BUS 605018 CKT 9
TRIP LINE FROM BUS 601019 TO BUS 615353 CKT 1
DISCONNECT BUS 601027
END

COM 'NSP STK 8M36 BKR COON CREEK'
COM 'COON CRK XFMR CKT 10'
COM '601019-601024 COON CK3-TERMINL3'
COM '601019-601011 COON CK3-SHERCO 3'
COM 'TERMINAL XFMR CKT 10'
COM '-----------------------------------------------------'
CONTINGENCY 'NSP STK 8M36 BKR COON CREEK'
TRIP BRANCH FROM BUS 601019 TO BUS 603068 TO
BUS 605017 CKT 10
TRIP LINE FROM BUS 601019 TO BUS 601024 CKT 1
TRIP LINE FROM BUS 601019 TO BUS 601011 CKT 1
TRIP BRANCH FROM BUS 601024 TO BUS 603110 TO
BUS 605516 CKT 10
END

COM 'NSP STK 8M35 BKR COON CREEK'
COM 'COON CRK XFMR CKT 9'
COM '601019-601024 COON CK3-TERMINL3'
COM 'dISCONNECT SHERCO - OWNER CHANGE -
COON CREEK'
COM 'DISCONNECT TERMINAL XFMR 10'
COM '-----------------------------------------------------'
CONTINGENCY 'NSP STK 8M35 BKR COON CREEK'
TRIP BRANCH FROM BUS 601019 TO BUS 603068 TO
BUS 605018 CKT 9
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TRIP LINE FROM BUS 601019 TO BUS 601024 CKT 1
DISCONNECT BUS 601027
TRIP BRANCH FROM BUS 601024 TO BUS 603110 TO
BUS 605516 CKT 10
END

COM 'NSP STK 8M38 BKR COON CREEK'
COM 'COON CRK XFMR CKT 9'
COM '601019-601021 COON CK3-KOLMNLK3'
COM 'dISCONNECT SHERCO - OWNER CHANGE -
COON CREEK'
COM ' DISCONNECT KOHLMAN LAKE XFMR 9'
COM '-------------------------------------------------------'
CONTINGENCY 'NSP STK 8M38 BKR COON CREEK'
TRIP BRANCH FROM BUS 601019 TO BUS 603068 TO
BUS 605018 CKT 9
TRIP LINE FROM BUS 601019 TO BUS 601021 CKT 1
DISCONNECT BUS 601027
TRIP BRANCH FROM BUS 603084 TO BUS 601021 TO
BUS 605702 CKT 9
END

COM 'NSP STK 8M39 BKR COON CREEK'
COM '601019-601021 COON CK3-KOLMNLK3'
COM 'dISCONNECT COON CREEK-BUNKER-SHERCO'
COM ' DISCONNECT KOHLMAN LAKE XFMR 9'
COM 'TRIP BUNKER LAKE 3 WINDING XFMR CKT 1'
COM '-------------------------------------------------------'
CONTINGENCY 'NSP STK 8M39 BKR COON CREEK'
TRIP LINE FROM BUS 601019 TO BUS 601021 CKT 1
DISCONNECT BUS 615327
TRIP LINE FROM BUS 603084 TO BUS 601021 TO BUS
605702 CKT 9
TRIP BRANCH FROM BUS 615327 TO BUS 615330 TO
BUS 615328 CKT 1
END

COM 'NSP STK 8M40 BKR COON CREEK'
COM '601019-601011 COON CK3-SHERCO 3'
COM 'DISCONNECT COON CREEK-BUNKER-SHERCO'
COM 'TRIP BUNKER LAKE 3 WINDING XFMR CKT 1'
COM 'DISCONNECT COON CRK CKT 10 XFMR'
COM '-------------------------------------------------------'
CONTINGENCY 'NSP STK 8M40 BKR COON CREEK'
TRIP LINE FROM BUS 601019 TO BUS 601011 CKT 1
DISCONNECT BUS 615327
TRIP BRANCH FROM BUS 615327 TO BUS 615330 TO
BUS 615328 CKT 1
TRIP BRANCH FROM BUS 601019 TO BUS 603068 TO
BUS 605017 CKT 10
END

COM 'CATEGORY B'

COM 'Fault PKL-BCR-MEL'
COM 'Disconnect BASSETT CREEK BUS 603117'
cONTINGENCY 'B2.PKL-BCR-MEL'
DISCONNECT BUS 603117
END


COM
'_____________________________________________________
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COM 'CATEGORY C'
COM 'CATEGORY C'
COM 'CATEGORY C'

COM 'DOUBLE CIRCUIT'
COM 'DOUBLE CIRCUIT'

COM 'DBL CKT PKL-MEL & PKL-CEL 115 kV'
COM 'DISCONNECT BASSETT CREEK BUS 603117'
COM '603095-603173 PARKERS7-CEDARLK7'
CONTINGENCY 'C5.PKL-MEL,PKL-CEL PRE-AS'
DISCONNECT BUS 603117
TRIP LINE FROM BUS 603095 TO BUS 603173 CKT 1
END
CONTINGENCY 'C5.PKL-MEL,PKL-CEL POST-AS-1'
TRIP LINE FROM BUS 603095 TO BUS 603117 CKT 1
TRIP LINE FROM BUS 603095 TO BUS 603173 CKT 1
END
CONTINGENCY 'C5.PKL-MEL,PKL-CEL POST-AS-2'
TRIP LINE FROM BUS 603089 TO BUS 603117 CKT 1
TRIP LINE FROM BUS 603095 TO BUS 603173 CKT 1
END

COM 'DBL CKT PKL-GSL & PKL-GSL 115 kV'
COM '603095-603076 PARKERS7-GLESNLK7 #1'
COM '603095-603076 PARKERS7-GLESNLK7 #2'
CONTINGENCY 'C5.PKL-GSL 1&2'
TRIP LINE FROM BUS 603095 TO BUS 603076 CKT 1
TRIP LINE FROM BUS 603095 TO BUS 603076 CKT 2
END

COM 'DBL CKT CEL-SLP & ALD-SLP 115 kV'
COM '603173-603108 CEDARLK7-STLSPRK7'
COM '603054-603108 ALDRCH27-STLSPRK7'
CONTINGENCY 'C5.CEL-SLP,ALD-SLP'
TRIP LINE FROM BUS 603173 TO BUS 603108 CKT 1
TRIP LINE FROM BUS 603054 TO BUS 603108 CKT 1
END

COM 'DBL CKT PKL-EDP & PKL-BLL'
COM '601022-601025 PARKERS3-EDEN PR3'
COM '601022-601015 PARKERS3-BLUE LK3'
COM 'EDEN PRAIRIE TR #10 3 WINDING'
CONTINGENCY 'C5.PKL-EDP,PKL-BLL'
TRIP LINE FROM BUS 601022 TO BUS 601025 CKT 1
TRIP LINE FROM BUS 601022 TO BUS 601015 CKT 1
TRIP LINE FROM BUS 601025 TO BUS 603120 TO BUS
605706 CKT 10
END


COM 'STUCK BREAKER'
COM 'STUCK BREAKER'

COM 'STK 5M48 BKR PARKERS LAKE BS'
COM '603095-603076 PARKERS7-GLESNLK7 CKT 2'
COM 'LOSS OF 180 MVAR OF SWITCHED SHUNT'
CONTINGENCY 'NSP STK 5M48 BKR PARKERS LAKE
BS'
TRIP LINE FROM BUS 603095 TO BUS 603076 CKT 2
DISCONNECT BUS 603208
END


COM 'STK 5M49 BKR PARKERS LAKE AS'
COM '603095-603117 PARKERS7-BASCRK 7'
COM '603095-603076 PARKERS7-GLESNLK7 CKT 2'
COM '603117-603089 BASCRK 7-MEDLAKE7'
CONTINGENCY 'NSP STK 5M49 BKR PARKERS LAKE
AS'
TRIP LINE FROM BUS 603095 TO BUS 603117 CKT 1
TRIP LINE FROM BUS 603095 TO BUS 603076 CKT 2
TRIP LINE FROM BUS 603117 TO BUS 603089 CKT 1
END
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COM 'STK 5M51 BKR PARKERS LAKE'
COM '603095-603076 PARKERS7-GLESNLK7 CKT 1'
COM 'LOSS OF 180 MVAR OF SWITCHED SHUNT'
CONTINGENCY 'NSP STK 5M51 BKR PARKERS LAKE'
TRIP LINE FROM BUS 603095 TO BUS 603076 CKT 1
DISCONNECT BUS 603208
END

COM 'STK 5M52 BKR PARKERS LAKE'
COM '603095-603173 PARKERS7-CEADRLK7'
COM '603095-603076 PARKERS7-GLESNLK7 CKT 1'
CONTINGENCY 'NSP STK 5M52 BKR PARKERS LAKE'
TRIP LINE FROM BUS 603095 TO BUS 603173 CKT 1
TRIP LINE FROM BUS 603095 TO BUS 603076 CKT 1
END

COM 'STK 5M55 BKR PARKERS LAKE'
COM 'Disconnect GRE PLYMOUTH BUS 619802'
COM 'DISCONNECT GRE BASS LK BUS 619800'
COM 'LOSS OF 180 MVAR OF SWITCHED SHUNT'
CONTINGENCY 'NSP STK 5M55 BKR PARKERS LAKE'
DISCONNECT BUS 619802
DISCONNECT BUS 619800
DISCONNECT BUS 603208
END

COM 'STK 5M57 BKR PARKERS LAKE'
COM 'LOSS OF THREE WINDING TRANSFORMER #10'
COM 'LOSS OF 180 MVAR OF SWITCHED SHUNT'
CONTINGENCY 'NSP STK 5M57 BKR PARKERS LAKE'
TRIP BRANCH FROM BUS 601022 TO BUS 603095 TO
BUS 605021 CKT 10
DISCONNECT BUS 603208
END

COM 'STK 5M60 BKR PARKERS LAKE'
COM 'LOSS OF THREE WINDING TRANSFORMER #9
WITH REACTORS'
COM 'LOSS OF 180 MVAR OF SWITCHED SHUNT'
CONTINGENCY 'NSP STK 5M60 BKR PARKERS LAKE'
TRIP BRANCH FROM BUS 601022 TO BUS 603095 TO
BUS 605022 CKT 9
DISCONNECT BUS 603208
END

COM 'STK 8M11 BKR PARKERS LAKE'
COM 'LOSE PARKERS LAKE 3 WINDING XFMR CKT 9
AND REACTORS'
COM '601022-601026 PARKERS3-MPLEGV13'
COM '601026-615353 DICKNSN3-MPLEGV13'
CONTINGENCY 'NSP STK 8M11 BKR PARKERS LAKE'
TRIP BRANCH FROM BUS 601022 TO BUS 603095 TO
BUS 605022 CKT 9
TRIP LINE FROM BUS 615353 TO BUS 601026 CKT 1
TRIP LINE FROM BUS 601022 TO BUS 601026 CKT 1
END

COM 'STK 8M12 BKR PARKERS LAKE'
COM '601022-601015 PARKERS3-BLUE LK3'
COM '601022-601026 PARKERS3-MPLEGV13'
COM '601026-615353 DICKNSN3-MPLEGV13'
CONTINGENCY 'NSP STK 8M12 BKR PARKERS LAKE'
TRIP LINE FROM BUS 601022 TO BUS 601015 CKT 1
TRIP LINE FROM BUS 615353 TO BUS 601026 CKT 1
TRIP LINE FROM BUS 601022 TO BUS 601026 CKT 1
END

COM 'STK 8M13 BKR PARKERS LAKE'
COM 'LOSS OF THREE WINDING TRANSFORMER #10'
COM '601022-601015 PARKERS3-BLUE LK3'
CONTINGENCY 'NSP STK 8M13 BKR PARKERS LAKE'
TRIP BRANCH FROM BUS 601022 TO BUS 603095 TO
BUS 605021 CKT 10
TRIP LINE FROM BUS 601022 TO BUS 601015 CKT 1
END

COM 'STK 8M14 BKR PARKERS LAKE'
COM 'LOSE PARKERS LAKE 3 WINDING XFMR CKT 9'
COM '601022-601005 PARKERS3-ELM CRK3'
CONTINGENCY 'NSP STK 8M14 BKR PARKERS LAKE'
TRIP BRANCH FROM BUS 601022 TO BUS 603095 TO
BUS 605022 CKT 9
TRIP LINE FROM BUS 601022 TO BUS 601005 CKT 1
END

COM 'STK 8M15 BKR PARKERS LAKE'
COM '601022-601005 PARKERS3-ELM CRK3'
COM '601022-601025 PARKERS3-EDEN PR3'
COM '601025-603120 EDEN PR3-EDEN PR7 CKT #10'
CONTINGENCY 'NSP STK 8M15 BKR PARKERS LAKE'
TRIP LINE FROM BUS 601022 TO BUS 601005 CKT 1
TRIP LINE FROM BUS 601022 TO BUS 601025 CKT 1
TRIP LINE FROM BUS 601025 TO BUS 603120 TO BUS
605706 CKT 10
END

COM 'STK 8M16 BKR PARKERS LAKE'
COM 'LOSS OF THREE WINDING TRANSFORMER #10'
COM '601022-601025 PARKERS3-EDEN PR3'
COM '601025-603120 EDEN PR3-EDEN PR7 CKT #10'
CONTINGENCY 'NSP STK 8M16 BKR PARKERS LAKE'
TRIP BRANCH FROM BUS 601022 TO BUS 603095 TO
BUS 605021 CKT 10
TRIP LINE FROM BUS 601022 TO BUS 601025 CKT 1
TRIP LINE FROM BUS 601025 TO BUS 603120 TO BUS
605706 CKT 10
END

COM 'STK 5M347 BKR GLEASON LAKE'
COM '603076-603095 GLESNLK7-PARKERS7 CKT 1'
COM '603076-615572 GLESNLK7-MEDINA 7'
CONTINGENCY 'C2.5M347 BKR GLEASON LAKE'
TRIP LINE FROM BUS 603076 TO BUS 603095 CKT 1
TRIP LINE FROM BUS 603076 TO BUS 615572 CKT 1
END

COM 'STK 5M84 BKR GLEASON LAKE'
COM '603076-615572 GLESNLK7-MEDINA 7'
COM '603076-605241 GLESNLK7-GLESNLK8'
CONTINGENCY 'NSP STK 5M84 BKR GLEASON LAKE'
TRIP LINE FROM BUS 603076 TO BUS 615572 CKT 1
TRIP LINE FROM BUS 603076 TO BUS 605241 CKT 1
END

COM 'STK 115/69 Kv XFMR BKR GLEASON LAKE'
COM '603076-605241 GLESNLK7-GLESNLK8'
COM '605241-605239 GLESNLK8-MOUND  8'
COM '605241-605002 GLESNLK8-GLENLK18'
COM '605239-615060 MOUND  8-ST BONI8'
COM 'CLOSE 605002-605000 GLENLK18-GLENLK28'
CONTINGENCY 'NSP STK 115/69 Kv XFMR BKR GLK
NOT NERC'
TRIP LINE FROM BUS 605241 TO BUS 605239 CKT 1
TRIP LINE FROM BUS 603076 TO BUS 605241 CKT 1
TRIP LINE FROM BUS 605241 TO BUS 605002 CKT 1
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TRIP LINE FROM BUS 605239 TO BUS 615060 CKT 1
CLOSE LINE FROM BUS 605002 TO BUS 605000 CKT 1
END

COM 'CATEGORY B'

COM 'FAULT AHI-APA-TER MTL 115 KV'
COM 'DISCONNECT APACHE TAP BUS 603056'
COM '603057-605258-605711 ARDNHLS7-ARDNHL28'
CONTINGENCY 'B2.APA-TER-AHI'
DISCONNECT BUS 603056
TRIP BRANCH FROM BUS 603057 TO BUS 605258 TO
BUS 605711 CKT 2
END

COM 'FAULT MAIN ST - ELLIOT PARK 115 KV'
COM '603074-603088 ELLOTPK7-MAIN ST7'
COM 'DISCONNECT ELLIOT PARK CAP'
CONTINGENCY 'B2.ELP-MST'
TRIP LINE FROM BUS 603074 TO BUS 603088 CKT 1
DISCONNECT BUS 603209
END

COM 'Fault CNC-TER 345 KV'
COM '601024-601019 TERMINL3-COON CK3'
COM 'DISCONNECT TERMINAL TR 10 3 WINDING'
cONTINGENCY 'B2.CNC-TER'
TRIP LINE FROM BUS 601024 TO BUS 601019 CKT 1
TRIP BRANCH FROM BUS 601024 TO BUS 603110 TO
BUS 605516 CKT 10
END

COM 'Fault KOL-KOL 345 KV'
COM '601024-601021 TERMINL3-KOLMNLK3'
COM 'DISCONNECT TERMINAL TR 9 3 WINDING'
cONTINGENCY 'B2.TER-KOL'
TRIP LINE FROM BUS 601024 TO BUS 601021 CKT 1
TRIP BRANCH FROM BUS 601024 TO BUS 603110 TO
BUS 605517 CKT 9
END


COM
'_____________________________________________________
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COM 'CATEGORY C'
COM 'CATEGORY C'
COM 'CATEGORY C'

COM 'DOUBLE CIRCUIT'
COM 'DOUBLE CIRCUIT'


COM 'DBL CKT RIVERSIDE - WEST RIVER ROAD 115 KV'
COM '603099-603176 RIVRSID7-WRIV RD7 #1'
COM '603099-603176 RIVRSID7-WRIV RD7 #2'
CONTINGENCY 'C5.WRR-RIV'
TRIP LINE FROM BUS 603099 TO BUS 603176 CKT 1
TRIP LINE FROM BUS 603099 TO BUS 603176 CKT 2
END

COM 'MULTI CKT RIV-FST,RIV-ELP 115 KV'
COM '603099-603075 RIVRSID7-FIFTHST7'
COM '603099-603074 RIVRSID7-ELLOTPK7'
CONTINGENCY 'C5.RIV-FST,RIV-ELP'
TRIP LINE FROM BUS 603099 TO BUS 603075 CKT 1
TRIP LINE FROM BUS 603099 TO BUS 603074 CKT 1
END

COM 'MULTI CKT RIV-FST,RIV-MST 115 KV'
COM '603099-603075 RIVRSID7-FIFTHST7'
COM '603099-603088 RIVRSID7-MAIN ST7'
CONTINGENCY 'C5.RIV-FST,RIV-MST'
TRIP LINE FROM BUS 603099 TO BUS 603075 CKT 1
TRIP LINE FROM BUS 603099 TO BUS 603088 CKT 1
END

COM 'MULTI CKT RIV-MST,RIV-ELP 115 KV'
COM '603099-603088 RIVRSID7-MAIN ST7'
COM '603099-603074 RIVRSID7-ELLOTPK7'
CONTINGENCY 'C5.RIV-MST,RIV-ELP'
TRIP LINE FROM BUS 603099 TO BUS 603088 CKT 1
TRIP LINE FROM BUS 603099 TO BUS 603074 CKT 1
END

COM 'DOUBLE CKT APA-AHI-TER,TER-RPL 115 KV'
COM 'DISCONNECT APACHE TAP BUS 603056'
COM '603110-603100 TERMINL7-ROSE PL7'
COM '603057-605258-605711 ARDNHLS7-ARDNHL28'
CONTINGENCY 'C5.APA-AHI-TER,TER-RPL'
DISCONNECT BUS 603056
TRIP LINE FROM BUS 603110 TO BUS 603100 CKT 1
TRIP BRANCH FROM BUS 603057 TO BUS 605258 TO
BUS 605711 CKT 2
END

COM 'DBL CKT TERMINAL SPUR 345 KV'
COM 'DISCONNECT 345 KV TERMINAL BUS 601024'
CONTINGENCY 'C5.TER-KOL,TER-CNC'
DISCONNECT BUS 601024
TRIP BRANCH FROM BUS 601024 TO BUS 603110 TO
BUS 605517 CKT 9
END


COM 'STUCK BREAKER'
COM 'STUCK BREAKER'


COM 'NSP STK 5M293 BKR WEST RIVER ROAD 115 KV'
COM '603176-603053 WRIV RD7-ALDRICH7 CKT2'
COM '603176-603099 WRIV RD7-RIVRSID7 CKT2'
CONTINGENCY 'C2.5M293 BKR WEST RIVER ROAD'
TRIP LINE FROM BUS 603176 TO BUS 603053 CKT 2
TRIP LINE FROM BUS 603176 TO BUS 603099 CKT 2
END

COM 'NSP STK 5M296 BKR WEST RIVER ROAD 115 KV'
COM '603176-603053 WRIV RD7-ALDRICH7 CKT2'
COM '603176-603099 WRIV RD7-RIVRSID7 CKT1'
CONTINGENCY 'C2.5M296 BKR WEST RIVER ROAD'
TRIP LINE FROM BUS 603176 TO BUS 603053 CKT 2
TRIP LINE FROM BUS 603176 TO BUS 603099 CKT 1
END

COM 'NSP STK 5M308 BKR RIVERSIDE 115 KV'
COM '603099-603091 RIVRSID7-MOORELK7'
COM 'DISCONNECT UNIT NO. 10 BUS 600071'
CONTINGENCY 'C2.5M308 BKR RIVERSIDE'
TRIP LINE FROM BUS 603099 TO BUS 603091 CKT 1
DISCONNECT BUS 600071
END


COM 'NSP STK 5M311 BKR RIVERSIDE 115 KV'
COM '603099-603055 RIVRSID7-APACHE 7'
COM 'DISCONNECT UNIT NO. 7 BUS 600007'
CONTINGENCY 'C2.5M311 BKR RIVERSIDE'
TRIP LINE FROM BUS 603099 TO BUS 603055 CKT 1
DISCONNECT BUS 600007
END
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COM 'NSP STK 5M319 BKR RIVERSIDE 115 KV'
COM '603099-603176 RIVERSID7-WRIV RD7 CKT 2'
COM 'GEN UNIT NO. 9'
CONTINGENCY 'C2.5M319 BKR RIVERSIDE'
TRIP LINE FROM BUS 603099 TO BUS 603176 CKT 2
DISCONNECT BUS 600070
END

COM 'NSP STK 5M330 BKR RIVERSIDE 115 KV'
COM '603099-603088 RIVRSID7-MAIN ST7'
COM '603099-603055 RIVRSID7-APACHE 7'
CONTINGENCY 'C2.5M330 BKR RIVERSIDE'
TRIP LINE FROM BUS 603099 TO BUS 603088 CKT 1
TRIP LINE FROM BUS 603099 TO BUS 603055 CKT 1
END

COM 'NSP STK 5M333 BKR RIVERSIDE 115 KV'
COM '603099-603125 RIVRSID7-BRKLNPK7'
COM '603099-603075 RIVRSID7-FIFTHST7'
CONTINGENCY 'C2.5M333 BKR RIVERSIDE'
TRIP LINE FROM BUS 603099 TO BUS 603125 CKT 1
TRIP LINE FROM BUS 603099 TO BUS 603075 CKT 1
END

COM 'NSP STK 5M180 BKR APACHE 115 KV'
COM 'DISCONNECT APACHE BUS 603055'
COM 'DISCONNECT APACHE TAP BUS 603056'
CONTINGENCY 'C2.5M180 BKR RIVERSIDE'
DISCONNECT BUS 603055
DISCONNECT BUS 603066
END

COM
'+++++++++++++++++++++++++++++++++++++++++++++++
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COM 'DUE TO LIMITATIONS OF PSSE CONTINGENCY
FILES THE BREAKER FAILURES AT'
COM 'ALDRICH WILL RESULT IN REMOVAL OF ALL 240
MVAR'S OF CAPACITORS.
COM 'IF THIS BECOMES A PROBLEM 120 MVAR OF CAP
BANKS CAN BE TURNED BACK ON'
COM 'DURING MOST OUTAGES TO HELP SUPPORT
VOLTAGES.'

COM 'STK 5M403 BKR ALDRICH 115 KV'
COM 'LOSS OF HERC GENERATOR'
COM 'LOSS OF 120 MVAR OF SWITCHED SHUNT'
CONTINGENCY 'NSP STK 5M403 BKR ALDRICH'
DISCONNECT BUS 603044
DISCONNECT BUS 603210
END

COM 'STK 5M406 BKR ALDRICH 115 KV'
COM '603053-603176 ALDRICH7-WRIV RD7'
COM 'LOSS OF 120 MVAR OF SWITCHED SHUNT'
CONTINGENCY 'NSP STK 5M406 BKR ALDRICH'
TRIP LINE FROM BUS 603053 TO BUS 603176 CKT 2
DISCONNECT BUS 603210
END

COM 'STK 5M409 BKR ALDRICH 115 KV'
COM '603053-603176 ALDRICH7-WRIV RD7'
COM 'LOSS OF 120 MVAR OF SWITCHED SHUNT'
CONTINGENCY 'NSP STK 5M409 BKR ALDRICH'
TRIP LINE FROM BUS 603053 TO BUS 603176 CKT 1
DISCONNECT BUS 603210
END

COM 'STK 5M410 BKR ALDRICH 115 KV'
COM '603053-603176 ALDRICH7-WRIV RD7'
COM '603053-603075 ALDRICH7-FIFTHST7'
CONTINGENCY 'NSP STK 5M410 BKR ALDRICH'
TRIP LINE FROM BUS 603053 TO BUS 603081 CKT 1
TRIP LINE FROM BUS 603081 TO BUS 603111 CKT 1
END

COM 'STK 5M411 BKR ALDRICH 115 KV'
COM '603053-603075 ALDRICH7-FIFTHST7'
COM 'LOSS OF 120 MVAR OF SWITCHED SHUNT'
CONTINGENCY 'NSP STK 5M411 BKR ALDRICH'
TRIP LINE FROM BUS 603053 TO BUS 603075 CKT 1
DISCONNECT BUS 603210
END

COM 'STK 5M412 BKR ALDRICH 115 KV'
COM '603054-603089 ALDRICH7-MEDLAKE7'
COM 'LOSS OF 120 MVAR OF SWITCHED SHUNT'
CONTINGENCY 'NSP STK 5M412 BKR ALDRICH'
TRIP LINE FROM BUS 603054 TO BUS 603089 CKT 1
DISCONNECT BUS 603210
END

COM 'STK 5M413 BKR ALDRICH 115 KV'
COM 'DISCONNECT ALDRICH 2 BUS 603054'
CONTINGENCY 'NSP STK 5M413 BKR ALDRICH'
DISCONNECT BUS 603054
END

COM 'STK 5M414 BKR ALDRICH 115 KV'
COM '603054-603108 ALDRICH7-STLSPRK7'
COM 'LOSS OF 120 MVAR OF SWITCHED SHUNT'
CONTINGENCY 'NSP STK 5M414 BKR ALDRICH'
TRIP LINE FROM BUS 603054 TO BUS 603108 CKT 1
DISCONNECT BUS 603210
END

COM 'STK 5M415 BKR ALDRICH 115 KV'
COM '603053-603081 ALDRICH7-INDIANA7'
COM '603081-603111 INDIANA7-TWIN LK7'
COM 'LOSS OF 120 MVAR OF SWITCHED SHUNT'
CONTINGENCY 'NSP STK 5M415 BKR ALDRICH'
TRIP LINE FROM BUS 603053 TO BUS 603081 CKT 1
TRIP LINE FROM BUS 603081 TO BUS 603111 CKT 1
DISCONNECT BUS 603210
END

COM 'END OF ALDRICH BREAKER FAILURES'
COM
'+++++++++++++++++++++++++++++++++++++++++++++++
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COM 'FIFTH STREET BUS FAULT'
COM 'DISCONNECT FIFTH STREET BUS 603075'
CONTINGENCY 'C1.FST'
DISCONNECT BUS 603075
END

COM 'NSP STK 5M64 BKR'
COM '603075-603088 FIFTHST7-MAIN ST7'
COM '603088-603078 MAIN ST7-GOPHER 7'
CONTINGENCY 'STK 5M64 BKR MAIN ST'
TRIP LINE FROM BUS 603075 TO BUS 603088 CKT 1
TRIP LINE FROM BUS 603088 TO BUS 603078 CKT 1
END

COM 'NSP STK 5M66 BKR'
COM '603099-603088 RIVRSID7-MAIN ST7'
COM '603088-603074 MAIN ST7-ELLOTPK7'
CONTINGENCY 'STK 5M66 BKR MAIN ST'
TRIP LINE FROM BUS 603099 TO BUS 603088 CKT 1
TRIP LINE FROM BUS 603088 TO BUS 603074 CKT 1
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DISCONNECT BUS 603209
END

COM 'NSP STK 5M68 BKR'
COM '603075-603088 FIFTHST7-MAIN ST7'
COM '603088-603074 MAIN ST7-ELLOTPK7'
CONTINGENCY 'STK 5M68 BKR MAIN ST'
TRIP LINE FROM BUS 603099 TO BUS 603088 CKT 1
TRIP LINE FROM BUS 603088 TO BUS 603074 CKT 1
DISCONNECT BUS 603209
END

COM 'NSP STK 5M70 BKR'
COM '603099-603088 RIVRSID7-MAIN ST7'
COM '603088-603078 MAIN ST7-GOPHER 7'
CONTINGENCY 'STK 5M70 BKR MAIN ST'
TRIP LINE FROM BUS 603099 TO BUS 603088 CKT 1
TRIP LINE FROM BUS 603088 TO BUS 603078 CKT 1
END

COM 'NSP STK 5M182 BKR ELLIOT PARK 115 KV'
COM '603074-603099 ELLOTPK7-RIVRSID7'
COM '603074-603088 ELLOTPK7-MAIN ST7'
COM 'LOSE ELLIOT PARK SHUNT'
COM '-----------------------------------------------------'
CONTINGENCY 'C2.5m182 BKR ELLIOT PARK'
TRIP LINE FROM BUS 603074 TO BUS 603099 CKT 1
TRIP LINE FROM BUS 603074 TO BUS 603088 CKT 1
DISCONNECT BUS 603209
END

COM 'NSP STK 5M184 BKR ELLIOT PARK 115 KV'
COM '603074-603099 ELLOTPK7-RIVRSID7'
COM '603074-603105 ELLOTPK7-SO TOWN7'
COM 'LOSE ELLIOT PARK SHUNT'
COM '-----------------------------------------------------'
CONTINGENCY 'C2.5m184 ELLIOT PARK'
TRIP LINE FROM BUS 603074 TO BUS 603099 CKT 1
TRIP LINE FROM BUS 603074 TO BUS 603105 CKT 1
DISCONNECT BUS 603209
END

COM 'NSP STK 5M186 BKR ELLIOT PARK 115 KV'
COM '603074-603105 ELLOTPK7-SO TOWN7'
COM '603074-603088 ELLOTPK7-MAIN ST7'
COM 'LOSE ELLIOT PARK SHUNT'
COM '-----------------------------------------------------'
CONTINGENCY 'C2.5m186 ELLIOT PARK'
TRIP LINE FROM BUS 603074 TO BUS 603105 CKT 1
TRIP LINE FROM BUS 603074 TO BUS 603088 CKT 1
DISCONNECT BUS 603209
END

COM 'STK 5M12 BKR TERMINAL 115 KV'
COM '603110-603100 TERMINL7-ROSE PL7'
COM '603110-603114 TERMINL7-WESTERN7'
CONTINGENCY 'STK 5P12 BKR TERMINAL'
TRIP LINE FROM BUS 603110 TO BUS 603100 CKT 1
TRIP LINE FROM BUS 603110 TO BUS 603113 CKT 1
END

COM 'STK 5M15 BKR TERMINAL 115 KV'
COM '603110-603130 TERMINL7-PRIOR  7'
COM 'DISCONNECT APACHE TAP BUS 603056'
CONTINGENCY 'STK 5P15 BKR TERMINAL'
TRIP LINE FROM BUS 603110 TO BUS 603130 CKT 1
DISCONNECT BUS 603056
END

COM 'STK 8P18 BKR TERMINAL 115 KV AS'
COM 'TRIP TERMINAL THREE WINDING TRANSFORMER
CKT 9'
COM '601024-601021 TERMINL3-KOLMNLK3'
COM '603110-603078 TERMINL7-GOPHER 7'
CONTINGENCY 'STK 5P18 BKR TERMINAL AS'
TRIP BRANCH FROM BUS 601024 TO BUS 603110 TO
BUS 605517 CKT 9
TRIP LINE FROM BUS 601024 TO BUS 601021 CKT 1
TRIP LINE FROM BUS 603078 TO BUS 603110 CKT 1
END


COM
'_____________________________________________________
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COM 'CATEGORY D'
COM 'CATEGORY D'
COM 'CATEGORY D'

COM 'TRIPLE CKT RIV-ELK,MST,FST 115 KV'
COM '603099-603088 RIVRSID7-MAIN ST7'
COM '603099-603074 RIVRSID7-ELLOTPK7'
COM '603099-603075 RIVRSID7-FIFTHST7'
CONTINGENCY 'D6.RIV-MST,RIV-ELP,RIV-FST'
TRIP LINE FROM BUS 603099 TO BUS 603088 CKT 1
TRIP LINE FROM BUS 603099 TO BUS 603074 CKT 1
TRIP LINE FROM BUS 603099 TO BUS 603075 CKT 1
END

COM 'CATEGORY B'

COM 'FAULT CAR-SCO-GND MTL 115 KV'
COM 'DISCONNECT SCOTT CO. TAP BUS 603102'
COM '603063-605275 CARVRCO7-CARVRCO8 #2'
COM 'GLENDALE TR1 THREE WINDING'
CONTINGENCY 'B2.CAR-SCO-GND'
DISCONNECT BUS 603102
TRIP BRANCH FROM BUS 603063 TO BUS 605275 CKT 2
TRIP BRANCH FROM BUS 615541 TO BUS 615542 TO
BUS 615543 CKT 1
END


COM
'_____________________________________________________
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COM 'CATEGORY C'
COM 'CATEGORY C'
COM 'CATEGORY C'

COM 'BUS FAULT'
COM 'BUS FAULT'

COM 'WEST WACONIA BUS FAULT 115 KV'
COM 'DISCONNECT WEST WACONIA BUS 603132'
COM 'DISCONNECT ST. BONI BUS 615548'
CONTINGENCY 'C1.WWK AS'
DISCONNECT BUS 603132
DISCONNECT BUS 615548
END
CONTINGENCY 'C1.WWK POST AS'
DISCONNECT BUS 603132
END

COM 'CARVER COUNTY BUS 2 FAULT 115 KV'
COM '603063-605275 CARVRCO7-CARVRCO8 #1'
COM '603063-603132 CARVRCO7-STBONI 7'
CONTINGENCY 'C1.CAR 1'
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TRIP BRANCH FROM BUS 603063 TO BUS 605275 CKT 1
TRIP LINE FROM BUS 603063 TO BUS 603132 CKT 1
END

COM 'CARVER COUNTY BUS 1 FAULT 115 KV'
COM '603063-605275 CARVRCO7-CARVRCO8 #2'
COM 'DISCONNECT SCOTT CO TAP BUS 603102'
COM 'GLENDALE TR1 THREE WINDING'
CONTINGENCY 'C1.CAR 2'
TRIP BRANCH FROM BUS 603063 TO BUS 605275 CKT 2
DISCONNECT BUS 603102
TRIP BRANCH FROM BUS 615541 TO BUS 615542 TO
BUS 615543 CKT 1
END

COM 'DOUBLE CIRCUIT'
COM 'DOUBLE CIRCUIT'

COM 'SCOTT CO - BLACK DOG, CARVER CO - SCOTT
CO - GLENDALE'
COM 'GLENDALE TR1 THREE WINDING'
COM 'DISCONNECT SCOTT CO TAP BUS 603102'
COM '603063-605275 CARVRCO7-CARVRCO8 #2'
COM 'DISCONNECT SOUTH SHAKOPEE BUS 603060'
COM 'DISCONNECT EAGLE CREEK BUS 618701'
COM 'DISCONNECT SAVAGE BUS 603101'
CONTINGENCY 'C5.SCO-BDS,CAR-SCO-GDN'
TRIP BRANCH FROM BUS 615541 TO BUS 615542 TO
BUS 615543 CKT 1
DISCONNECT BUS 603102
TRIP BRANCH FROM BUS 603063 TO BUS 605275 CKT 2
DISCONNECT BUS 603060
DISCONNECT BUS 618701
DISCONNECT BUS 603101
END


COM 'STUCK BREAKER'
COM 'STUCK BREAKER'

COM 'NSP STK 5M102 BKR CARVER COUNTY 115 KV
BS'
COM 'DISCONNECT CARVER CO 115 KV BUS 603063'
CONTINGENCY 'C2.5M102 BKR CAR BS'
DISCONNECT BUS 603063
END

COM 'NSP STK 5M108 BKR SCOTT CO 115 KV BS'
COM '603103-603181 SCOTTCO7-MNRIVER7'
COM 'DISCONNECT SCOTT CO TAP BUS 603102'
COM '603063-605275 CARVRCO7-CARVRCO8 #1'
CONTINGENCY 'C2.5M108 BKR SCO BS'
TRIP LINE FROM BUS 603103 TO BUS 603181 CKT 1
DISCONNECT BUS 603102
TRIP BRANCH FROM BUS 603063 TO BUS 605275 CKT 1
END

COM 'NSP STK 5M219 BKR SCOTT CO 115 KV BS'
COM 'DISCONNECT DEAN LAKE BUS 603119'
COM 'DISCONNECT HYLAND LAKE BUS 603080'
COM 'DISCONNECT SOUTH SHAKOPEE BUS 603060'
COM 'DISCONNECT EAGLE CREEK BUS 618701'
COM 'DISCONNECT SAVAGE BUS 603101'
COM '603103-605244 SCOTTCO7-SCOTTCO8 #1'
CONTINGENCY 'C2.5M219 BKR SCO BS'
TRIP LINE FROM BUS 603103 TO BUS 603181 CKT 1
DISCONNECT BUS 603119
DISCONNECT BUS 603080
DISCONNECT BUS 603060
DISCONNECT BUS 618701
DISCONNECT BUS 603101
TRIP BRANCH FROM BUS 603103 TO BUS 605244 CKT 1
END

COM 'NSP STK 5M220 BKR SCOTT CO 115 KV'
COM 'DISCONNECT DEAN LAKE BUS 603119'
COM 'DISCONNECT HYLAND LAKE BUS 603080'
COM 'DISCONNECT SOUTH SHAKOPEE BUS 603060'
COM 'DISCONNECT EAGLE CREEK BUS 618701'
COM 'DISCONNECT SAVAGE BUS 603101'
COM '603103-605244 SCOTTCO7-SCOTTCO8 #2'
COM 'DISCONNECT SCOTT CO CAPS'
CONTINGENCY 'C2.5M220 SCO'
DISCONNECT BUS 603119
DISCONNECT BUS 603080
DISCONNECT BUS 603060
DISCONNECT BUS 618701
DISCONNECT BUS 603101
TRIP BRANCH FROM BUS 603103 TO BUS 605244 CKT 2
DISCONNECT BUS 603230
END

COM 'NSP STK 5M221 BKR SCOTT CO 115 KV BS'
COM '603103-603181 SCOTTCO7-MNRIVER7'
COM '603103-605244 SCOTTCO7-SCOTTCO8 #1'
CONTINGENCY 'C2.5M221 BKR SCO BS'
TRIP LINE FROM BUS 603103 TO BUS 603181 CKT 1
TRIP BRANCH FROM BUS 603103 TO BUS 605244 CKT 1
END

COM 'NSP STK 5M222 BKR SCOTT CO 115 KV'
COM '603103-605244 SCOTTCO7-SCOTTCO8 #2'
COM 'DISCONNECT SCOTT CO TAP BUS 603102'
COM '603063-605275 CARVRCO7-CARVRCO8 #1'
COM 'DISCONNECT SCOT CO CAPS BUS 603230'
CONTINGENCY 'C2.5M108 BKR SCO'
TRIP BRANCH FROM BUS 603103 TO BUS 605244 CKT 2
DISCONNECT BUS 603102
TRIP BRANCH FROM BUS 603063 TO BUS 605275 CKT 1
DISCONNECT BUS 603230
END


COM
'_____,_____
_____'
COM 'CATEGORY D'
COM 'CATEGORY D'
COM 'CATEGORY D'


COM 'CATEGORY B'

COM 'BLUE LAKE GEN 1-4 115 KV'
COM 'DISCONNECT BLUE LAKE TR 6 STAR BUS 605572'
COM 'DISCONNECT BLUE LAKE TR 5 STAR BUS 605571'
CONTINGENCY 'B2.BLL GEN 1-4'
DISCONNECT BUS 605572
DISCONNECT BUS 605571
END

COM 'BLUE LAKE GEN 7-8 115 KV'
COM 'DISCONNECT BLUE LAKE TR 8 BUS 600044'
COM 'DISCONNECT BLUE LAKE TR 7 STAR BUS 600043'
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CONTINGENCY 'B2.BLL GEN 7-8'
DISCONNECT BUS 600044
DISCONNECT BUS 600043
END

COM 'DEAN LAKE - HYLAND LAKE 115 KV AS'
COM 'DISCONNECT DEAN LAKE BUS 603119'
COM 'DISCONNECT HYLAND LAKE BUS 603080'
CONTINGENCY 'B2.BLL-SCO AS'
DISCONNECT BUS 603119
DISCONNECT BUS 603080
END

COM 'WESTGATE - SCOTT CO 115 KV AS'
COM 'DISCONNECT BLUFF CREEK BUS 603115'
COM 'DISCONNECT CHANHASSEN BUS 618700'
CONTINGENCY 'B2.WSG-SCO AS'
DISCONNECT BUS 603115
DISCONNECT BUS 618700
END

COM 'EDEN PRAIRIE - BLUE LAKE 345 KV'
COM '601025-601015 EDEN PR3-BLUE LK3'
COM 'EDEN PRAIRIE 3 WINDING TR 9'
CONTINGENCY 'B2.EDP-BLL'
TRIP LINE FROM BUS 601025 TO BUS 601015 CKT 1
TRIP BRANCH FROM BUS 601025 TO BUS 603120 TO
BUS 605705 CKT 9
END


COM
'_____________________________________________________
_____________________'
COM 'CATEGORY C'
COM 'CATEGORY C'
COM 'CATEGORY C'


COM 'DOUBLE CIRCUIT'
COM 'DOUBLE CIRCUIT'

COM 'EDEN PRAIRIE - WESGTAGE DBL CKT 115 KV'
COM '603120-603114 EDEN PR7-WSTGATE7 CKT 1'
COM '603120-603114 EDEN PR7-WSTGATE7 CKT 2'
CONTINGENCY 'C5.EDP-WSG'
TRIP LINE FROM BUS 603120 TO BUS 603114 CKT 1
TRIP LINE FROM BUS 603120 TO BUS 603114 CKT 2
END

COM 'EDEN PRAIRIE - BLUE LAKE, BLUE LAKE -
PARKERS LAKE 345 KV'
COM '601025-601015 EDEN PR3-BLUE LK3'
COM 'EDEN PRAIRIE 3 WINDING TR 9'
COM '601015-601022 BLUE LK3-PARKRS3'
CONTINGENCY 'C5.EDP-BLL,BLL-PKL'
TRIP LINE FROM BUS 601025 TO BUS 601015 CKT 1
TRIP BRANCH FROM BUS 601025 TO BUS 603120 TO
BUS 605705 CKT 9
TRIP LINE FROM BUS 601015 TO BUS 601022 CKT 1
END


COM 'BLUE LAKE - WILMARTH, BLUE LAKE - SCOTT CO
345/115 KV AS'
COM 'DISCONNECT HYLAND LAKE BUS 603080'
COM 'DISCONNECT DEAN LAKE BUS 603119'
COM '601015-601004 BLUE LK3-WILMART3'
CONTINGENCY 'C5.BLL-WLM,BLL-SCO AS'
DISCONNECT BUS 603080
DISCONNECT BUS 603119
TRIP LINE FROM BUS 601015 TO BUS 601004 CKT 1
END

COM 'STUCK BREAKER'
COM 'STUCK BREAKER'


COM 'NSP STK 5m3 BKR WESTGATE'
COM '603120-603114 EDEN PR7-WSTGATE7 CKT 2'
COM 'LOSE WESTGATE SHUNT'
CONTINGENCY 'C2.5M3 BKR WEST GATE'
TRIP LINE FROM BUS 603120 TO BUS 603114 CKT 2
DISCONNECT BUS 603222
END

COM 'NSP STK 5M7 BKR WESTGATE'
COM '603114-603115 WSTGATE7-BLUFFCK7'
COM '603115-618700 BLUFFCK7-CHANHAS7'
COM '618700-603181 CHANHAS7-MNRIVER7'
COM 'LOSE WESTGATE SHUNT'
CONTINGENCY 'NSP STK 5M7 BKR WEST GATE'
TRIP LINE FROM BUS 603114 TO BUS 603115 CKT 1
TRIP LINE FROM BUS 618700 TO BUS 603115 CKT 1
TRIP LINE FROM BUS 618700 TO BUS 603181 CKT 1
DISCONNECT BUS 603222
END

COM 'NSP STK 8m45 BKR EDEN PRARIE B.S. (breaker
sectionalizing)'
COM '601025-601015 EDEN PR3-BLUE LK3'
COM '601025-601022 EDEN PR3-PARKERS3'
COM '601025-603120-605705 EDEN PR3-EDEN PR7 CKT
9'
COM '601025-603120-605706 EDEN PR3-EDEN PR7 CKT
10'
COM '603120-603073 EDEN PR7-EDINA  7;'
COM '-----------------------------------------------------'
CONTINGENCY 'NSP STK 8M45 BKR EDEN PRARIE B.S.'
TRIP LINE FROM BUS 601025 TO BUS 601015 CKT 1
TRIP LINE FROM BUS 601025 TO BUS 601022 CKT 1
TRIP LINE FROM BUS 601025 TO BUS 603120 TO BUS
605705 CKT 9
TRIP LINE FROM BUS 601025 TO BUS 603120 TO BUS
605706 CKT 10
TRIP LINE FROM BUS 603120 TO BUS 603073 CKT 1
END

COM 'NSP STK 8m210 BKR EDEN PRARIE'
COM '601025-601015 EDEN PR3-BLUE LK3'
COM '601025-603120-605705 EDEN PR3-EDEN PR7 CKT
9'
COM '603120-603073 EDEN PR7-EDINA  7;'
COM '-----------------------------------------------------'
CONTINGENCY 'C2.8M210 BKR EDEN PRARIE'
TRIP LINE FROM BUS 601025 TO BUS 601015 CKT 1
TRIP LINE FROM BUS 601025 TO BUS 603120 TO BUS
605705 CKT 9
TRIP LINE FROM BUS 603120 TO BUS 603073 CKT 1
END

COM 'NSP STK 8m213 BKR EDEN PRARIE'
COM '601025-601022 EDEN PR3-PARKERS3'
COM '601025-603120-605706 EDEN PR3-EDEN PR7 CKT
10'
COM '603120-603073 EDEN PR7-EDINA  7;'
COM '-----------------------------------------------------'
CONTINGENCY 'C2.8M213 BKR EDEN PRARIE'
TRIP LINE FROM BUS 601025 TO BUS 601022 CKT 1
TRIP LINE FROM BUS 601025 TO BUS 603120 TO BUS
605706 CKT 10
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TRIP LINE FROM BUS 603120 TO BUS 603073 CKT 1
END

COM 'NSP STK 8m211 BKR EDEN PRARIE'
COM '601025-601022 EDEN PR3-PARKERS3'
COM '601025-603120-605706 EDEN PR3-EDEN PR7 CKT
10'
COM '603120-603114 EDEN PR7-WSTGATE7 CKT 1;'
COM '-----------------------------------------------------'
CONTINGENCY 'C2.8M211 BKR EDEN PRARIE'
TRIP LINE FROM BUS 601025 TO BUS 601022 CKT 1
TRIP LINE FROM BUS 601025 TO BUS 603120 TO BUS
605706 CKT 10
TRIP LINE FROM BUS 603120 TO BUS 603114 CKT 1
END

COM 'NSP STK 8m214 BKR EDEN PRARIE'
COM '601025-601015 EDEN PR3-BLUE LK3'
COM '601025-603120-605705 EDEN PR3-EDEN PR7 CKT
9'
COM '603120-603114 EDEN PR7-WSTGATE7 CKT 2'
COM '-----------------------------------------------------'
CONTINGENCY 'C2.8M214 BKR EDEN PRARIE'
TRIP LINE FROM BUS 601025 TO BUS 601015 CKT 1
TRIP LINE FROM BUS 601025 TO BUS 603120 TO BUS
605705 CKT 9
TRIP LINE FROM BUS 603120 TO BUS 603114 CKT 2
END

COM 'NSP STK 5M154 BKR BLUE LAKE'
COM 'DISCONNECT GENERATORS 1,2,3 AND 4'
COM '603062-603061 BLUE LK7-BLK DOG7'
COM '-----------------------------------------------------'
CONTINGENCY 'NSP STK 5m154 BKR BLUE LAKE'
TRIP LINE FROM BUS 603074 TO BUS 603099 CKT 1
DISCONNECT BUS 600024
DISCONNECT BUS 605572
DISCONNECT BUS 600025
DISCONNECT BUS 605571
DISCONNECT BUS 600023
DISCONNECT BUS 600022
END

COM 'NSP STK 5M157 BKR BLUE LAKE'
COM 'DISCONNECT GENERATORS 7 AND 8'
COM 'LOSE BLUE LAKE 7 - HYLAND LAKE - DEAN LAKE -
SCOTT CO'
COM '-----------------------------------------------------'
CONTINGENCY 'NSP STK 5m157 BKR BLUE LAKE'
DISCONNECT BUS 600044
DISCONNECT BUS 603080
DISCONNECT BUS 603119
DISCONNECT BUS 600043
END

COM 'NSP STK 5M151 BKR BLUE LAKE'
COM '601015-603062-605704 BLUE LK3-BLUE LK7 CKT 9'
COM '603062-602014 BLUE LK7-BLUE LK4'
COM '-----------------------------------------------------'
CONTINGENCY 'NSP STK 5m151 BKR BLUE LAKE'
TRIP LINE FROM BUS 601015 TO BUS 603062 TO BUS
605704 CKT 9
TRIP LINE FROM BUS 603062 TO BUS 602014 CKT 1
END

COM 'NSP STK 8m26 BKR BLUE LAKE'
COM '601015-603062-605704 BLUE LK3-BLUE LK7 CKT 9'
COM '601015-601022 BLUE LK3-PARKERS3'
COM '-----------------------------------------------------'
CONTINGENCY 'NSP STK 8M26 BKR BLUE LAKE'
TRIP LINE FROM BUS 601015 TO BUS 603062 TO BUS
605704 CKT 9
TRIP LINE FROM BUS 601015 TO BUS 601022 CKT 1
END

COM 'NSP STK 8M33 BKR BLUE LAKE'
COM '601015-601004 BLUE LK3-WILMART3'
COM '601015-601022 BLUE LK3-PARKERS3'
COM '-----------------------------------------------------'
CONTINGENCY 'NSP STK 8M33 BKR BLUE LAKE'
TRIP LINE FROM BUS 601015 TO BUS 601004 CKT 1
TRIP LINE FROM BUS 601015 TO BUS 601022 CKT 1
END

COM 'NSP STK 8M32 BKR BLUE LAKE'
COM '601015-603062-605704 BLUE LK3-BLUE LK7 CKT 9'
COM '601015-601004 BLUE LK3-WILMART3'
COM '-----------------------------------------------------'
CONTINGENCY 'NSP STK 8M32 BKR BLUE LAKE'
TRIP LINE FROM BUS 601015 TO BUS 603062 TO BUS
605704 CKT 9
TRIP LINE FROM BUS 601015 TO BUS 601004 CKT 1
END

COM 'NSP STK 8m27 BKR BLUE LAKE'
COM 'DISCONNECT INVER HILLS'
COM '601015-601022 BLUE LK3-PARKERS3'
COM '-----------------------------------------------------'
CONTINGENCY 'NSP STK 8M27 BKR BLUE LAKE'
DISCONNECT BUS 601020
TRIP LINE FROM BUS 601015 TO BUS 601022 CKT 1
END

COM 'NSP STK 8m28 BKR BLUE LAKE'
COM 'DISCONNECT INVER HILLS'
COM '601015-601003 BLUE LK3-PR ISLD3'
COM '-----------------------------------------------------'
CONTINGENCY 'NSP STK 8M28 BKR BLUE LAKE'
DISCONNECT BUS 601020
TRIP LINE FROM BUS 601015 TO BUS 601003 CKT 1
END

COM 'NSP STK 8m34 BKR BLUE LAKE'
COM '601025-603120-605705 EDEN PR3-EDEN PR7 CKT
9'
COM '601025-601015 EDEN PR3-BLUE LK3'
COM '601015-601022 BLUE LK3-PR ISLD3'
COM '-----------------------------------------------------'
CONTINGENCY 'NSP STK 8M34 BKR BLUE LAKE'
TRIP LINE FROM BUS 601025 TO BUS 603120 TO BUS
605705 CKT 9
TRIP LINE FROM BUS 601015 TO BUS 601025 CKT 1
TRIP LINE FROM BUS 601015 TO BUS 601003 CKT 1
END

COM 'CATEGORY B'

COM 'WILSON-BLACK DOG-NINE MILE CREEK MTL 115
KV'
COM 'DISCONNECT WILSON TAP BUS 603204'
CONTINGENCY 'B2.WIL-BDS-NMC'
DISCONNECT BUS 603204
END
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COM
'_____________________________________________________
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COM 'CATEGORY C'
COM 'CATEGORY C'
COM 'CATEGORY C'


COM 'DOUBLE CIRCUIT'
COM 'DOUBLE CIRCUIT'

COM 'DBL CKT SOUTHTOWN - CEDERVALE,
SOUTHTOWN - SHEPARD 115 KV'
COM '603105-603104 SO TOWN7-SHEPARD7 CKT 1'
COM '603105-603064 SO TOWN7-CDRVALE7 CKT 1'
CONTINGENCY 'C5.SOU-SHP,SOU-CDV'
TRIP LINE FROM BUS 603105 TO BUS 603104 CKT 1
TRIP LINE FROM BUS 603105 TO BUS 603064 CKT 1
END

COM 'DOUBLE CIRCUIT EDINA - EDEN PRAIRIE, EDINA -
NINE MILE CREEK 115 KV'
COM '603073-603120 EDINA 7-EDEN PR7'
COM '603073-603135 EDINA 7-NINE MI7'
CONTINGENCY 'C5.EDA-EDP,EDA-NMC'
TRIP LINE FROM BUS 603073 TO BUS 603120 CKT 1
TRIP LINE FROM BUS 603073 TO BUS 603135 CKT 1
END


COM 'STUCK BREAKER'
COM 'STUCK BREAKER'



COM 'NSP STK 5M167 BKR WILSON 115 KV'
COM '603116-603118 WILSON 7-E BLOOM7'
COM '603116-603204 WILSON 7-WILSON TAP7'
COM 'REMOVE SHUNT AT WILSON'
COM '-----------------------------------------------------'
CONTINGENCY 'NSP STK 5M167 BKR WILSON'
TRIP LINE FROM BUS 603116 TO BUS 603118 CKT 1
TRIP LINE FROM BUS 603116 TO BUS 603204 CKT 1
DISCONNECT BUS 603221
END

COM 'NSP STK 5M173 BKR WILSON 115 KV BS'
COM '603116-603118 WILSON 7-E BLOOM7'
COM '603116-603204 WILSON 7-WILSON TAP7'
COM '603204-603135 WILSON TAP7-MINE MI7'
COM '603204-603061 WILSON TAP7-BLK DOG7'
COM 'REMOVE SHUNT AT WILSON'
COM '-----------------------------------------------------'
CONTINGENCY 'C2.5M173 BKR WILSON BS'
TRIP LINE FROM BUS 603116 TO BUS 603118 CKT 1
DISCONNECT BUS 603204
DISCONNECT BUS 603221
DISCONNECT BUS 603116
END

COM 'NSP STK 5M171 BKR WILSON 115 KV'
COM '603116-603066 WILSON 7-BLK DG27 CKT 2'
COM '603116-603204 WILSON 7-WILSON TAP7'
COM 'REMOVE SHUNT AT WILSON'
COM '-----------------------------------------------------'
CONTINGENCY 'C2.5M171 BKR WIL'
TRIP LINE FROM BUS 603116 TO BUS 603066 CKT 2
TRIP LINE FROM BUS 603116 TO BUS 603204 CKT 1
DISCONNECT BUS 603221
END

COM 'NSP STK 5M169 BKR WILSON 115 KV'
COM '603116-603061 WILSON 7-BLK DOG7 CKT 1'
COM '603116-603204 WILSON 7-WILSON TAP7'
COM 'REMOVE SHUNT AT WILSON'
COM '-----------------------------------------------------'
CONTINGENCY 'NSP STK 5M169 BKR WILSON'
TRIP LINE FROM BUS 603116 TO BUS 603061 CKT 1
TRIP LINE FROM BUS 603116 TO BUS 603204 CKT 1
DISCONNECT BUS 603221
END

COM 'NSP STK 5M261 BKR Black Dog 115 KV'
COM 'Disconnect 603061 and all attached generation'
COM '603101-618701 SAVAGE 7-EAGLECK7'
COM '618701-603060 EAGLECK7-SHAKOPE7'
COM 'DISOCNNECT SCOTT CO TAP BUS 603102'
COM '603063-605275 CARVRCO7-CARVRCO8 #2'
CONTINGENCY 'NSP STK 5M261 BKR BLACK DOG'
DISCONNECT BUS 603061
DISCONNECT BUS 600011
DISCONNECT BUS 600012
TRIP LINE FROM BUS 603101 TO BUS 618701 CKT 1
TRIP LINE FROM BUS 618701 TO BUS 603060 CKT 1
DISCONNECT BUS 603102
TRIP BRANCH FROM BUS 603063 TO BUS 605275 CKT 2
END

COM 'NSP STK 5M253, 5M258, AND GEN BKR BLACK
DOG 115 KV'
COM '603116-603061 WILSON 7-BLK DOG7 CKT 1'
COM '603061-603101 BLK DOG7-SAVAGE 7'
COM '603101-618701 SAVAGE 7-EAGLECK7'
COM '618701-603060 EAGLECK7-SHAKOPE7'
COM 'DISOCNNECT SCOTT CO TAP BUS 603102'
COM '603063-605275 CARVRCO7-CARVRCO8 #2'
COM 'DISCONNECT GENERATOR 5'
CONTINGENCY 'NSP STK 5m258,253 AND GEN BKR
BLACK DOG'
TRIP LINE FROM BUS 603116 TO BUS 603061 CKT 1
TRIP LINE FROM BUS 603061 TO BUS 603101 CKT 1
TRIP LINE FROM BUS 603101 TO BUS 618701 CKT 1
TRIP LINE FROM BUS 618701 TO BUS 603060 CKT 1
DISCONNECT BUS 603102
TRIP BRANCH FROM BUS 603063 TO BUS 605275 CKT 2
DISCONNECT BUS 600011
END

COM 'NSP STK 5M255, 5M256, AND GEN BKR BLACK
DOG 115 KV'
COM '603061-603062 BLK DOG7-BLUE LK7'
COM '603116-603061 WILSON 7-BLK DOG7 CKT 3'
COM '603116-603135 WILSON 7-NINE MI7'
COM 'DISCONNECT GENERATOR 5 BUS 600012'
CONTINGENCY 'NSP C2.5m255,256 & GEN 2 BKR BLACK
DOG'
TRIP LINE FROM BUS 603061 TO BUS 603062 CKT 1
DISCONNECT BUS 603204
DISCONNECT BUS 600012
END

COM 'NSP STK 5M264 BKR BLACK DOG 115 KV'
COM 'DISCONNECT BLACK DOG 603066'
COM 'DISCONNECT BLACK DOG GEN 3 AND 4'
COM '603059-615433 RIVERWD7-BURNVIL7'
COM 'GLENDALE TR2 3 WINDING'
CONTINGENCY 'NSP STK 5M264 BKR BLACK DOG'
DISCONNECT BUS 603066
DISCONNECT BUS 600013
DISCONNECT BUS 600014
TRIP LINE FROM BUS 603059 TO BUS 615433 CKT 1
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TRIP BRANCH FROM BUS 615541 TO BUS 615542 TO
BUS 615544 CKT 2
END

COM 'NSP STK 5M254, 5M257, 5M259 AND 4GEN BKR
BLACK DOG 115 KV'
COM '603066-603064 BLK DG27-CDRVALE7'
COM '603066-615541 BLK DG27-GLNDALE7'
COM '603059-615433 RIVERWD7-BURNVIL7'
COM '603066-615446 BLK DG27-PILOTKBT'
COM 'DISCONNECT GENERATOR 4'
COM 'GLENDALE TR2 3 WINDING'
CONTINGENCY 'NSP STK 5m254,257,259,4GEN BKR
BLACK DOG 115 KV'
TRIP LINE FROM BUS 603066 TO BUS 603064 CKT 1
TRIP LINE FROM BUS 603066 TO BUS 615541 CKT 1
TRIP LINE FROM BUS 603066 TO BUS 615446 CKT 1
DISCONNECT BUS 600014
TRIP BRANCH FROM BUS 615541 TO BUS 615542 TO
BUS 615544 CKT 2
END

COM 'NSP STK 5M251, 5M252, AND 3GEN BKR BLACK
DOG 115 KV'
COM '603066-603064 BLK DG27-CDRVALE7'
COM '603066-603059 BLK DG27-RIVERWD7'
COM '603059-615433 RIVERWD7-BURNVIL7'
COM '603066-615446 BLK DG27-PILOTKBT'
COM 'DISCONNECT GENERATOR 3'
CONTINGENCY 'NSP STK 5m251,252,3GEN BKR BLACK
DOG'
TRIP LINE FROM BUS 603066 TO BUS 603064 CKT 1
TRIP LINE FROM BUS 603066 TO BUS 603059 CKT 1
TRIP LINE FROM BUS 603059 TO BUS 615433 CKT 1
TRIP LINE FROM BUS 603066 TO BUS 615446 CKT 1
DISCONNECT BUS 600013
END

COM 'NSP STK 5M160 BKR EDINA BS'
COM '603073-603135 EDINA 7-NINE MI7'
COM '603073-603120 EDINA 7-EDEN PR7'
COM '-------------------------------------------------------'
CONTINGENCY 'NSP STK 5M160 BKR EDINA BS'
TRIP LINE FROM BUS 603073 TO BUS 603135 CKT 1
TRIP LINE FROM BUS 603073 TO BUS 603120 CKT 1
END

COM 'NSP STK 5M159 BKR EDINA BS'
COM '603073-603108 EDINA 7-STLSPRK7'
COM '603073-603120 EDINA 7-EDEN PR7'
COM '-------------------------------------------------------'
CONTINGENCY 'NSP STK 5M159 BKR EDINA BS'
TRIP LINE FROM BUS 603073 TO BUS 603108 CKT 1
TRIP LINE FROM BUS 603073 TO BUS 603120 CKT 1
END

COM 'NSP STK 5P136,138,140 BKR SOUTHTOWN'
COM 'DISCONNECT SOUTHTOWN BECAUSE OF
STRAIGHT BUS'
COM '-------------------------------------------------------'
CONTINGENCY 'NSP STK 5P136,138,140 BKR
SOUTHTOWN'
DISCONNECT BUS 603105
END


COM 'CATEGORY B'

COM 'FAULT MONTI 345/230 KV XFMR AS'
COM 'DISCONNECT MONTICELLO 230 KV BUS 602010'
CONTINGENCY 'B3.MNN 345/230 AS'
DISCONNECT BUS 602010
END


COM
'_____________________________________________________
_____________________'
COM 'CATEGORY C'
COM 'CATEGORY C'
COM 'CATEGORY C'


COM 'DOUBLE CIRCUIT'
COM 'DOUBLE CIRCUIT'


COM 'STUCK BREAKER'
COM 'STUCK BREAKER'


COM
'_____________________________________________________
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COM 'CATEGORY D'
COM 'CATEGORY D'
COM 'CATEGORY D'

COM 'SHERCO CORRIDOR OUTAGE 345 KV'
COM 'DISCONNECT SHERCO UNITS 1-3'
COM '601011-601019 SHERCO 3-COON CK3'
COM '601011-601010 SHERCO 3-MNTCELO3'
COM 'DISCONNECT BUNKER LAKE BUS 615327'
COM 'DISCONNECT MAPLE GROVE OWNER SPLIT BUS
601027'
COM 'TRIP TR 9 COON CREEK 3 WINDING'
CONTINGENCY 'SHERCO CORRIDOR'
DISCONNECT BUS 600002
DISCONNECT BUS 600000
DISCONNECT BUS 600001
TRIP LINE FROM BUS 601011 TO BUS 601019 CKT 1
TRIP LINE FROM BUS 601011 TO BUS 601010 CKT 1
DISCONNECT BUS 615372
DISCONNECT BUS 615330
DISCONNECT BUS 601027
TRIP BRANCH FROM BUS 601019 TO BUS 603068 TO
BUS 605018 CKT 9
END


COM 'CATEGORY B'

COM
'_____________________________________________________
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COM 'CATEGORY C'
COM 'CATEGORY C'
COM 'CATEGORY C'


COM 'DOUBLE CIRCUIT'
COM 'DOUBLE CIRCUIT'

COM 'DBL CKT CHISAGO-KING, CHISAGO - KOHLMAN
LAKE 345 KV'
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COM ‘601018-601021 CHIS CO3-SHEPARD7 CKT 1’
COM ‘601018-601014 CHIS CO3-CDRVALE7 CKT 1’
COM ‘KOHLMAN LAKE TR 10 3 WINDING’
CONTINGENCY ‘C5.CHI-ASL,CHI-KOL’
TRIP LINE FROM BUS 601018 TO BUS 601021 CKT 1
TRIP LINE FROM BUS 601018 TO BUS 601014 CKT 1
TRIP BRANCH FROM BUS 601021 TO BUS 603084 TO
BUS 605703 CKT 10
END



COM ‘STUCK BREAKER’
COM ‘STUCK BREAKER’

COM ‘NSP 7P2 STK BKR ROCK CREEK 230 KV’
COM ‘DISCONNECT ROCK CREEK BUS 602037’
COM ‘DISCONNECT RUSH CITY BUS 615460’
CONTINGENCY ‘C2.7P2 RCR’
DISCONNECT BUS 602037
DISCONNECT BUS 615460
END

COM ‘CATEGORY B’

COM
‘_____,_____
_____’
COM ‘CATEGORY C’
COM ‘CATEGORY C’
COM ‘CATEGORY C’


COM ‘DOUBLE CIRCUIT’
COM ‘DOUBLE CIRCUIT’



COM ‘STUCK BREAKER’
COM ‘STUCK BREAKER’

COM ‘STK 5P45 BKR’
COM ‘603055-603056 APACHE 7-APACHET7’
COM ‘603056-603057 APACHE 7-ARDNHLS7’
COM ‘603057-603087 ARDNHLS7-LXNGTON7’
COM ‘603056-603110 APACHET7-TERMINL7’
COM ‘AUTO TRANSFER CLOSE 605268-605219 TCAAP
8-TCAAPTP8’
CONTINGENCY ‘STK 5P45 BKR ARDEN HILLS’
DISCONNECT BUS 603056
DISCONNECT BUS 603057
DISCONNECT BUS 605711
CLOSE BRANCH FROM BUS 605268 TO BUS 605219 CKT
1
END

COM ‘CATEGORY B’

COM ‘FAULT LONG LAKE - KING 115 KV’
COM ‘DISCONNECT BAYTOWN BUS 603048’
COM ‘603086-603084 LONG LK7-KOLMNLK7’
CONTINGENCY ‘B2.LLK-ASK’
DISCONNECT BUS 603048
TRIP LINE FROM BUS 603086 TO BUS 603084
END

COM ‘FAULT KOHLMAN LAKE - GOOSE LAKE 115 KV’
COM ‘603084-603077 KOLMNLK7-GOOSELK7’
COM ‘603077

COM ‘FAULT KOHLMAN LAKE - CHISAGO CO 345 KV’
COM ‘601018-601021 CHIS CO3-KOLMNLK7 CKT 1’
COM ‘KOHLMAN LAKE TR 10 3 WINDING’
CONTINGENCY ‘B2.KOL-CHI’
TRIP LINE FROM BUS 601018 TO BUS 601021 CKT 1
TRIP BRANCH FROM BUS 601021 TO BUS 603084 TO
BUS 605703 CKT 10
END

COM ‘FAULT KOHLMAN -COON CREEK 345 KV’
COM ‘601021-601019 KOLMNLK3- COON CK3’
COM ‘KOHLMAN LAKE TR 9 3 WINDING’
CONTINGENCY ‘B2.KOL-CNC’
TRIP LINE FROM BUS 601021 TO BUS 601019 CKT 1
TRIP BRANCH FROM BUS 601021 TO BUS 603084 TO
BUS 605702 CKT 9
END


COM
‘_____,_____
_____’
COM ‘CATEGORY C’
COM ‘CATEGORY C’
COM ‘CATEGORY C’


COM ‘DOUBLE CIRCUIT’
COM ‘DOUBLE CIRCUIT’

COM ‘DBL CKT KOHLMAN LAKE - TERMINAL, KOHLMAN
LAKE - COON CREEK 345 KV’
COM ‘601021-601019 KOLMNLK3- COON CK3’
COM ‘601021-601024 KOLMNLK3- TERMINL3’
COM ‘TERMINAL TR 9 3 WINDING’
COM ‘KOHLMAN LAKE TR 9 3 WINDING’
CONTINGENCY ‘C5.KOL-CNC,KOL-TER’
TRIP LINE FROM BUS 601021 TO BUS 601019 CKT 1
TRIP LINE FROM BUS 601021 TO BUS 601024 CKT 1
TRIP BRANCH FROM BUS 601024 TO BUS 603110 TO
BUS 605517 CKT 9
TRIP BRANCH FROM BUS 601021 TO BUS 603084 TO
BUS 605702 CKT 9
END

COM ‘DBL CKT KOHLMAN LAKE - CHISAGO, KOHLMAN
LAKE - KING 345 KV
COM ‘601021-601014 KOLMNLK3-AS KING3’
COM ‘601021-601018 KOLMNLK3-CHIS CO3’
COM ‘KOHLMAN LAKE TR 10 3 WINDING’
CONTINGENCY ‘C5.KOL-ASK,KOL-CHI’
TRIP LINE FROM BUS 601021 TO BUS 601014 CKT 1
TRIP LINE FROM BUS 601021 TO BUS 601018 CKT 1
TRIP BRANCH FROM BUS 601021 TO BUS 603084 TO
BUS 605703 CKT 10
END

COM ‘DBL CKT KING - KOHLMAN LAKE, KING - CHISAGO
345 KV’
COM ‘601014-601021 AS KING3-KOLMNLK3’
COM ‘601014-601018 AS KING3-CHIS CO3’
CONTINGENCY ‘C5.ASK-KOL,ASK-CHI’
TRIP LINE FROM BUS 601014 TO BUS 601021 CKT 1
TRIP LINE FROM BUS 601014 TO BUS 601018 CKT 1
END

COM ‘KING - EAU CLAIRE, KING - RED ROCK 345 KV’
COM ‘601014-601028 AS KING3-EAU CL 3’
COM ‘601014-601023 AS KING3-REDROCK3’
CONTINGENCY ‘C5.ASK-EAU,ASK-RRK’
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TRIP LINE FROM BUS 601014 TO BUS 601028 CKT 1
TRIP LINE FROM BUS 601014 TO BUS 601023 CKT 1
END



COM 'STUCK BREAKER'
COM 'STUCK BREAKER'



COM 'STK 8P30 BKR KOHLMAN LAKE 345 KV'
COM '601021-603084 KOLMNLK3-KOLMNLK7 CKT 9'
COM '601021-601019 KOLMNLK3-COON CK3'
COM '601021-601014 KOLMNLK3-AS KING3'
CONTINGENCY 'STK 8P30 BKR KOLHMAN LAKE'
TRIP BRANCH FROM BUS 601021 TO BUS 603084 TO
BUS 605702 CKT 9
TRIP LINE FROM BUS 601021 TO BUS 601019 CKT 1
TRIP LINE FROM BUS 601021 TO BUS 601014 CKT 1
END

COM 'STK 8P32 BKR KOHLMAN LAKE 345 KV'
COM '601021-603084 KOLMNLK3-KOLMNLK7 CKT 10'
COM '601021-601018 KOLMNLK3-CHIS CO3'
COM '601021-601014 KOLMNLK3-AS KING3'
CONTINGENCY 'NSP STK 8P32 BKR KOLHMAN LAKE'
TRIP BRANCH FROM BUS 601021 TO BUS 603084 TO
BUS 605703 CKT 10
TRIP LINE FROM BUS 601021 TO BUS 601018 CKT 1
TRIP LINE FROM BUS 601021 TO BUS 601014 CKT 1
END

COM 'STK 8P33 BKR KOHLMAN LAKE 345 KV'
COM '601021-603084 KOLMNLK3-KOLMNLK7 CKT 9'
COM '601021-601024 KOLMNLK3-TERMINL3'
COM '601021-601019 KOLMNLK3-COON CK3'
CONTINGENCY 'STK 8P33 BKR KOLHMAN LAKE'
TRIP BRANCH FROM BUS 601021 TO BUS 603084 TO
BUS 605702 CKT 9
TRIP LINE FROM BUS 601021 TO BUS 601024 CKT 1
TRIP LINE FROM BUS 601021 TO BUS 601019 CKT 1
END


COM 'STK 8P34 BKR KOHLMAN LAKE 345 KV'
COM '601021-603084 KOLMNLK3-KOLMNLK7 CKT 10'
COM '601021-601024 KOLMNLK3-TERMINL3'
COM '601021-601018 KOLMNLK3-CHIS CO3'
CONTINGENCY 'STK 8P34 BKR KOLHMAN LAKE'
TRIP BRANCH FROM BUS 601021 TO BUS 603084 TO
BUS 605703 CKT 10
TRIP LINE FROM BUS 601021 TO BUS 601024 CKT 1
TRIP LINE FROM BUS 601021 TO BUS 601018 CKT 1
END

COM 'STK 5P106 BKR KOHLMAN LAKE 115 KV'
COM '601021-603084 KOLMNLK3-KOLMNLK7 CKT 9'
COM '601021-601019 KOLMNLK3-COON CK3'
COM '603084-603086 KOLMNLK7-LONG LK7'
CONTINGENCY 'STK 5P106 BKR KOLHMAN LAKE'
TRIP BRANCH FROM BUS 601021 TO BUS 603084 TO
BUS 605702 CKT 9
TRIP LINE FROM BUS 601021 TO BUS 601019 CKT 1
TRIP LINE FROM BUS 603084 TO BUS 603086 CKT 1
END

COM 'NSP STK 5P51 BKR LONG LAKE 115 KV'
COM '603084-603086 KOLMNLK7-LONG LK7'
COM '603086-603048 LONG LK7-BAYTOWN7'
COM '603048-603058 BAYTOWN7-AS KING7'
COM 'LONG LAKE LOAD NOW SUPPORTED FROM
OAKDALE'
CONTINGENCY 'STK 5P51 BKR NEAR LONG LAKE'
DISCONNECT BUS 603048
TRIP LINE FROM BUS 603084 TO BUS 603086 CKT 1
END

COM 'NSP STK 5P2 BKR KING'
COM '601014-603058 AS KING3-AS KING7'
COM '603058-603093 AS KING7-OAKPARK7'
COM '-----------------------------------------------------'
CONTINGENCY 'NSP STK 5P2 BKR KING'
TRIP LINE FROM BUS 601014 TO BUS 603058 TO BUS
605709 CKT 1
TRIP LINE FROM BUS 603058 TO BUS 603093 CKT 1
END

COM 'NSP STK 8P4 BKR KING'
COM '601014-601021 AS KING3-KOLMNLK3'
COM '601014-603058 AS KING3-AS KING7'
COM '-----------------------------------------------------'
CONTINGENCY 'NSP STK 8P4 BKR KING'
TRIP LINE FROM BUS 601014 TO BUS 601021 CKT 1
TRIP LINE FROM BUS 601014 TO BUS 603058 TO BUS
605709 CKT 1
END

COM 'NSP STK 8P1 BKR KING 345 KV'
COM 'DISCONNECT KING GENERATOR'
COM '601014-603058 AS KING3-AS KING7'
COM 'REMOVE KINGS REACTORS'
COM '-----------------------------------------------------'
CONTINGENCY 'NSP STK 8P1 BKR KING'
DISCONNECT BUS 600006
TRIP LINE FROM BUS 601014 TO BUS 603058 TO BUS
605709 CKT 1
END

COM 'NSP STK 8P2 BKR KING'
COM 'DISCONNECT KING GENERATOR'
COM '601014-601023 AS KING3-REDROCK3'
COM '-----------------------------------------------------'
CONTINGENCY 'NSP STK 8P2 BKR KING'
DISCONNECT BUS 600006
TRIP LINE FROM BUS 601014 TO BUS 601023 CKT 1
END

COM 'NSP STK 8P3 BKR KING'
COM '601014-601018 AS KING3-CHIS CO3'
COM '601014-601023 AS KING3-REDROCK3'
COM '-----------------------------------------------------'
CONTINGENCY 'NSP STK 8P3 BKR KING'
TRIP LINE FROM BUS 601014 TO BUS 601018 CKT 1
TRIP LINE FROM BUS 601014 TO BUS 601023 CKT 1
END

COM 'NSP STK 8P6 BKR KING'
COM '601014-601018 AS KING3-CHIS CO3'
COM '601014-601028 AS KING3-EAU CL 3'
COM '-----------------------------------------------------'
CONTINGENCY 'NSP STK 8P6 BKR KING'
TRIP LINE FROM BUS 601014 TO BUS 601018 CKT 1
TRIP LINE FROM BUS 601014 TO BUS 601028 CKT 1
END

COM 'NSP STK 8P5 BKR KING'
COM '601014-601021 AS KING3-KOLMNLK3'
COM '601014-601028 AS KING3-EAU CL 3'
COM '-----------------------------------------------------'
CONTINGENCY 'NSP STK 8P5 BKR KING'
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TRIP LINE FROM BUS 601014 TO BUS 601021 CKT 1
TRIP LINE FROM BUS 601014 TO BUS 601028 CKT 1
END

COM 'CATEGORY B'


COM
'_____________________________________________________
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COM 'CATEGORY C'
COM 'CATEGORY C'
COM 'CATEGORY C'


COM 'DOUBLE CIRCUIT'
COM 'DOUBLE CIRCUIT'



COM 'DBL CKT ROGERS LAKE - RED ROCK, ROGERS
LAKE - STOCK YARDS'
COM '603098-603097 ROGRSLK7-REDROCK7'
COM '603098-603107 ROGRSLK7-STCKYDS7'
CONTINGENCY 'C5.RLK-RRK,RLK-STY'
TRIP LINE FROM BUS 603098 TO BUS 603097 CKT 1
TRIP LINE FROM BUS 603098 TO BUS 603107 CKT 1
END



COM 'STUCK BREAKER'
COM 'STUCK BREAKER'

COM 'NSP STK 5P62 BKR ROGERS LAKE'
COM '603098-603097 ROGRSLK7-REDROCK7'
COM 'SWITCH OUT ROGERS LAKE 115 Kv CAPS'
COM '-----------------------------------------------------'
CONTINGENCY 'NSP STK 5P62 BKR ROGERS LAKE'
TRIP LINE FROM BUS 603098 TO BUS 603097 CKT 1
DISCONNECT BUS 603212
END

COM 'NSP STK 5P60 BKR ROGERS LAKE'
COM '603098-603161 ROGRSLK7-LONE OA7'
COM '603098-603052 ROGRSLK7-AIRPRT 7'
COM '-----------------------------------------------------'
CONTINGENCY 'NSP STK 5P60 BKR ROGERS LAKE'
TRIP LINE FROM BUS 603098 TO BUS 603161 CKT 1
TRIP LINE FROM BUS 603098 TO BUS 603052 CKT 1
END


COM 'NSP STK 5P191 BKR ROGERS LAKE'
COM '603098-603107 ROGRSLK7-STCKYDS7'
COM 'SWITCH OUT ROGERS LAKE 115 Kv CAPS'
COM '-----------------------------------------------------'
CONTINGENCY 'NSP STK 5P191 BKR ROGERS LAKE'
TRIP LINE FROM BUS 603098 TO BUS 603107 CKT 1
DISCONNECT BUS 603212
END

COM 'NSP STK 5P229 BKR ROGERS LAKE'
COM '603098-603079 ROGRSLK7-HIBRDGE7'
COM 'SWITCH OUT ROGERS LAKE 115 Kv CAPS'
COM '-----------------------------------------------------'
CONTINGENCY 'NSP STK 5P229 BKR ROGERS LAKE'
TRIP LINE FROM BUS 603098 TO BUS 603079 CKT 1
DISCONNECT BUS 603212
END

COM 'NSP STK 5P190 BKR ROGERS LAKE 115 KV'
COM '603098-603107 ROGRSLK7-STCKYDS7'
COM '603098-603133 ROGRSLK7-LONEOK27'
COM '603133-603161 LONEOK27-LONE OA7'
COM '-----------------------------------------------------'
CONTINGENCY 'NSP STK 5P190 BKR ROGERS LAKE'
TRIP LINE FROM BUS 603098 TO BUS 603107 CKT 1
TRIP LINE FROM BUS 603098 TO BUS 603133 CKT 2
CLOSE LINE FROM BUS 603133 TO BUS 603161 CKT 1
END

COM 'NSP STK 5P467 BKR HIGH BRIDGE 115 KV'
COM 'LOSS UNIT 8'
COM '603079-603072 HIBRDGE7-DYTNBLF7'
CONTINGENCY 'C2.5P467 HBR'
DISCONNECT BUS 600066
TRIP LINE FROM BUS 603079 TO BUS 603072 CKT 1
END

COM 'NSP STK 5P464 BKR HIGH BRIDGE 115 KV'
COM 'LOSS UNIT 7'
COM '603079-603090 HIBRDGE7-MERIMPK7'
CONTINGENCY 'C2.5P464 HBR'
DISCONNECT BUS 600065
TRIP LINE FROM BUS 603079 TO BUS 603090 CKT 1
END

COM 'NSP STK 5P470 BKR HIGH BRIDGE 115 KV'
COM 'LOSS UNIT 9'
COM 'DISCONNECT ST. PAUL CO GEN'
CONTINGENCY 'C2.5P470 HBR'
DISCONNECT BUS 600067
DISCONNECT BUS 600040
END

COM 'CATEGORY B'


COM
'_____________________________________________________
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COM 'CATEGORY C'
COM 'CATEGORY C'
COM 'CATEGORY C'


COM 'DOUBLE CIRCUIT'
COM 'DOUBLE CIRCUIT'



COM 'DBL CKT RED ROCK - BATTLE CREEK, RED ROCK
- NORTH STAR STEEL 115 KV'
COM 'DISCONNECT BATTLE CREEK BUS 603123'
COM 'DISCONNECT NORTH STAR STEEL JCT BUS
603163'
CONTINGENCY 'C5.RRK-BCK,RRK-NSS'
DISCONNECT BUS 603123
DISCONNECT BUS 603163
END

COM 'DBL CKT RED ROCK - WOODBURY, RED ROCK -
AFTON 115 KV'
COM '603097-603171 REDROCK7-WOODBUR7'
COM '603097-603051 REDROCK7-AFTON  7'
CONTINGENCY 'C5.RRK-WDY,RRK-AFT'
TRIP LINE FROM BUS 603097 TO BUS 603171 CKT 1
TRIP LINE FROM BUS 603097 TO BUS 603051 CKT 1
END
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COM 'DBL CKT RED ROCK - COTTAGE GROVE, RED
ROCK - KING 115/345 KV'
COM '603097-603069 REDROCK7-COTTAGE7'
COM '601023-601014 REDROCK3-AS KING7'
CONTINGENCY 'C5.RRK-CGR,RRK-ASK'
TRIP LINE FROM BUS 603097 TO BUS 603069 CKT 1
TRIP LINE FROM BUS 601023 TO BUS 601014 CKT 1
END

COM 'DBL CKT RED ROCK - PRAIRIE ISLAND 1&2'
COM '601023-601003 REDROCK3-PR ISLD3 #1'
COM '601023-601003 REDROCK3-PR ISLD3 #2'
CONTINGENCY 'C5.PRI-RRK 1&2'
TRIP LINE FROM BUS 601023 TO BUS 601003 CKT 1
TRIP LINE FROM BUS 601023 TO BUS 601003 CKT 2
END

COM 'DBL CKT RED ROCK - PRAIRIE ISLAND #2,
PRAIRIE ISLAND - BYRON 345 KV'
COM '601023-601003 REDROCK3-PR ISLD3 #2'
COM '601003-613060 PR ISD3-BYRON 3'
CONTINGENCY 'C5.RRK-PRI#2,PRI-BYR'
TRIP LINE FROM BUS 601023 TO BUS 601003 CKT 2
TRIP LINE FROM BUS 601003 TO BUS 613060 CKT 1
END


COM 'STUCK BREAKER'
COM 'STUCK BREAKER'



COM 'NSP STK 8P24 BKR RED ROCK'
COM '601023-601020 REDROCK3-INVRHLS3 CKT 1'
COM '601023-601003 REDROCK3-PR ISLD3 CKT 1'
COM '-----------------------------------------------------'
CONTINGENCY 'NSP STK 8P24 BKR RED ROCK'
TRIP LINE FROM BUS 601023 TO BUS 601020 CKT 1
TRIP LINE FROM BUS 601023 TO BUS 601003 CKT 1
END

COM 'NSP STK 8P22 BKR RED ROCK'
COM 'TRIP RRK TR10 3 WINDING'
COM '601023-601014 REDROCK3-AS KING3'
COM '-----------------------------------------------------'
CONTINGENCY 'NSP STK 8P22 BKR RED ROCK'
TRIP LINE FROM BUS 601023 TO BUS 603097 TO BUS
605701 CKT 10
TRIP LINE FROM BUS 601023 TO BUS 601014 CKT 1
END

COM 'NSP STK 8P25 BKR RED ROCK'
COM 'TRIP RRK TR10 3 WINDING'
COM '601023-601003 REDROCK3-PR ISLD3 CKT 1'
COM '-----------------------------------------------------'
CONTINGENCY 'NSP STK 8P25 BKR RED ROCK'
TRIP LINE FROM BUS 601023 TO BUS 603097 TO BUS
605701 CKT 10
TRIP LINE FROM BUS 601023 TO BUS 601003 CKT 1
END

COM 'NSP STK 8P28 BKR RED ROCK'
COM 'TRIP RRK TR10 3 WINDING'
COM '601023-601003 REDROCK3-PR ISLD3 CKT 2'
COM '-----------------------------------------------------'
CONTINGENCY 'NSP STK 8P28 BKR RED ROCK'
TRIP LINE FROM BUS 601023 TO BUS 603097 TO BUS
605701 CKT 10
TRIP LINE FROM BUS 601023 TO BUS 601003 CKT 2
END

COM 'NSP STK 8P27 BKR RED ROCK'
COM 'RED ROCK TR9 3 WINDING'
COM '601023-601003 REDROCK3-PR ISLD3 CKT 2'
COM '-----------------------------------------------------'
CONTINGENCY 'NSP STK 8P27 BKR RED ROCK'
TRIP LINE FROM BUS 601023 TO BUS 603097 TO BUS
605700 CKT 9
TRIP LINE FROM BUS 601023 TO BUS 601003 CKT 2
END

COM 'NSP STK 8P23 BKR RED ROCK'
COM '601023-603097 REDROCK3-REDROCK7 CKT 9'
COM '601023-601020 REDROCK3-INVRHLS3 CKT 1'
COM '-----------------------------------------------------'
CONTINGENCY 'NSP STK 8P23 BKR RED ROCK'
TRIP LINE FROM BUS 601023 TO BUS 603097 TO BUS
605700 CKT 9
TRIP LINE FROM BUS 601023 TO BUS 601020 CKT 1
END

COM 'NSP STK 5P82 BKR RED ROCK'
COM '603097-603069 REDROCK7-COTTAGE7'
COM 'RED ROCK TR9 3 WINDING'
COM '-----------------------------------------------------'
CONTINGENCY 'NSP STK 5P82 BKR RED ROCK'
TRIP LINE FROM BUS 603097 TO BUS 603069 CKT 1
TRIP LINE FROM BUS 601023 TO BUS 603097 TO BUS
605700 CKT 9
END

COM 'NSP STK 5P83 BKR RED ROCK'
COM 'SWITCH OUT RED ROCK 115 Kv CAPS'
COM 'RED ROCK TR9 3 WINDING'
COM '-----------------------------------------------------'
CONTINGENCY 'NSP STK 5P83 BKR RED ROCK'
DISCONNECT BUS 603219
TRIP LINE FROM BUS 601023 TO BUS 603097 TO BUS
605700 CKT 9
END

COM 'NSP STK K4 BKR RED ROCK'
COM '603097-603107 REDROCK7-STCKYDS7'
COM 'DISCONNECT REDROCK-RIVERFALLS-
CRYSTALCAVE'
COM '-----------------------------------------------------'
CONTINGENCY 'NSP STK K4 BKR RED ROCK'
TRIP LINE FROM BUS 603097 TO BUS 603107 CKT 1
DISCONNECT BUS 680265
DISCONNECT BUS 603157
DISCONNECT BUS 603158
DISCONNECT BUS 603199
DISCONNECT BUS 603159
END

COM 'NSP STK 944 BKR RED ROCK'
COM 'REMOVE SHUNTS FROM REDROCK 115 Kv'
COM 'DISCONNECT REDROCK-RIVERFALLS-
CRYSTALCAVE'
COM '-----------------------------------------------------'
CONTINGENCY 'NSP STK 944 BKR RED ROCK'
DISCONNECT BUS 603219
DISCONNECT BUS 680265
DISCONNECT BUS 603157
DISCONNECT BUS 603158
DISCONNECT BUS 603199
DISCONNECT BUS 603159
END

COM 'NSP STK K5 BKR RED ROCK'
COM 'TRIP RRK TR10 3 WINDING'
COM '603097-603098 REDROCK7-ROGRSLK7'
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COM '-----------------------------------------------------'
CONTINGENCY 'NSP STK K5 BKR RED ROCK'
TRIP LINE FROM BUS 601023 TO BUS 603097 TO BUS
605701 CKT 10
TRIP LINE FROM BUS 603098 TO BUS 603097 CKT 1
END

COM 'NSP STK 943 BKR RED ROCK'
COM 'SWITCH OUT RED ROCK 115 Kv CAPS AND
REACTORS'
COM 'TRIP RRK TR10 3 WINDING'
COM '-----------------------------------------------------'
CONTINGENCY 'NSP STK 943 BKR RED ROCK'
DISCONNECT BUS 603219
TRIP LINE FROM BUS 601023 TO BUS 603097 TO BUS
605701 CKT 10
END

COM 'NSP STK K3 BKR RED ROCK'
COM '603097-603051 REDROCK7-AFTON  7'
COM '603097-603123 REDROCK7-BATTCRK7 CKT 2'
COM '603123-603124 BATTCRK7-BATCRKT7 CLOSE'
COM '-----------------------------------------------------'
CONTINGENCY 'NSP STK K3 BKR RED ROCK'
TRIP LINE FROM BUS 603097 TO BUS 603123 CKT 2
TRIP LINE FROM BUS 603097 TO BUS 603051 CKT 1
CLOSE LINE FROM BUS 603123 TO BUS 603124 CKT 1
END

COM 'NSP STK 966 BKR RED ROCK'
COM '603097-603051 REDROCK7-AFTON  7'
COM 'SWITCH OUT RED ROCK 115 Kv CAPS'
COM '-----------------------------------------------------'
CONTINGENCY 'NSP STK 966 BKR RED ROCK'
TRIP LINE FROM BUS 603097 TO BUS 603051 CKT 1
DISCONNECT BUS 603219
END

COM 'NSP STK K2 BKR RED ROCK'
COM '603097-603171 REDROCK7-WOODBUR7'
COM 'DISCONNECT REDROCK-MAXWELL'
COM '603123-603124 BATTCRK7-BATCRKT7 CLOSE'
COM '-----------------------------------------------------'
CONTINGENCY 'NSP STK K2 BKR RED ROCK'
TRIP LINE FROM BUS 603097 TO BUS 603171 CKT 1
CLOSE LINE FROM BUS 603123 TO BUS 603124 CKT 1
DISCONNECT BUS 603163
DISCONNECT BUS 603164
DISCONNECT BUS 603165
DISCONNECT BUS 603162
END

COM 'NSP STK 946 BKR RED ROCK'
COM '603097-603171 REDROCK7-WOODBUR7'
COM 'SWITCH OUT RED ROCK 115 Kv CAPS'
COM '-----------------------------------------------------'
CONTINGENCY 'NSP STK 946 BKR RED ROCK'
TRIP LINE FROM BUS 603097 TO BUS 603171 CKT 1
DISCONNECT BUS 603219
END

COM 'CATEGORY B'
COM 'CATEGORY B'

COM 'INVER HILLS - CHEMOLITE'
COM 'DISCONNECT RICH VALLEY BUS 603127'
COM 'DISCONNECT LINDE TAP 603106'
CONTINGENCY 'B2.IVH-CHE'
DISCONNECT BUS 603127
DISCONNECT BUS 603106
END

COM
'_____________________________________________________
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COM 'CATEGORY C'
COM 'CATEGORY C'
COM 'CATEGORY C'

COM 'DOUBLE CIRCUIT'
COM 'DOUBLE CIRCUIT'

COM 'DBL CKT BLUE LAKE - INVER HILLS - RED ROCK,
BLUE LAKE - PRAIRIE ISLAND 345 KV'
COM 'DISCONNECT INVER HILLS BUS 601020'
COM '601015-601003 BLUELK3-PR ISLD3'
CONTINGENCY 'C5.BLL-IVH-RRK,RRK-PRI'
DISCONNECT BUS 601020
TRIP LINE FROM BUS 601015 TO BUS 601003 CKT 1
END

COM 'DBL CKT BLUE LAKE - INVER HILLS - RED ROCK,
BLUE LAKE - PRAIRIE ISLAND 345 KV'
COM '601023-601003 REDROCK3-PR ISLD3 '
COM '601015-601003 BLUELK 3-PR ISLD3'
CONTINGENCY 'C5.BLL-PRI,RRK-PRI'
TRIP LINE FROM BUS 601023 TO BUS 601003 CKT 1
TRIP LINE FROM BUS 601015 TO BUS 601003 CKT 1
END

COM 'STUCK BREAKER'
COM 'STUCK BREAKER'

COM 'NSP STK 5P141 BKR INVER HILLS'
COM '603082-603085 INVRHLS7-KOCHREF7'
COM 'DISCONNECT ALL INVER HILLS GENERATION'
COM '-----------------------------------------------------'
CONTINGENCY 'NSP STK 5P141 BKR INVER HILLS'
TRIP LINE FROM BUS 603082 TO BUS 603085 CKT 1
DISCONNECT BUS 600029
DISCONNECT BUS 605574
DISCONNECT BUS 605574
DISCONNECT BUS 605575
DISCONNECT BUS 600031
DISCONNECT BUS 600030
DISCONNECT BUS 605573
DISCONNECT BUS 600027
DISCONNECT BUS 600026
END

COM 'NSP STK 5P144 BKR INVER HILLS'
COM '603082-603083 INVRHLS7-INVRGRV7'
COM '603083-605263 INVRGRV7-INVERGR8'
COM 'DISCONNECT ALL INVER HILLS GENERATION'
COM '-----------------------------------------------------'
CONTINGENCY 'NSP STK 5P144 BKR INVER HILLS'
TRIP LINE FROM BUS 603082 TO BUS 603083 CKT 1
TRIP LINE FROM BUS 603083 TO BUS 605263 CKT 2
DISCONNECT BUS 600029
DISCONNECT BUS 605574
DISCONNECT BUS 605574
DISCONNECT BUS 605575
DISCONNECT BUS 600031
DISCONNECT BUS 600030
DISCONNECT BUS 605573
DISCONNECT BUS 600027
DISCONNECT BUS 600026
END
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COM 'NSP STK 5P147 BKR INVER HILLS AS'
COM 'DISCONNECT REDRCK-INVERHILLS-BLUELAKE'
COM 'DISCONNECT ALL INVER HILLS GENERATION'
COM '-----------------------------------------------------'
CONTINGENCY 'NSP STK 5P147 BKR INVER HILLS AS'
DISCONNECT BUS 601020
DISCONNECT BUS 600029
DISCONNECT BUS 605574
DISCONNECT BUS 605574
DISCONNECT BUS 605575
DISCONNECT BUS 600031
DISCONNECT BUS 600030
DISCONNECT BUS 605573
DISCONNECT BUS 600027
DISCONNECT BUS 600026
END

COM 'NSP STK 5P148 BKR INVER HILLS AS'
COM 'DISCONNECT REDRCK-INVERHILLS-BLUELAKE'
COM 'DISCONNECT INVER HILLS TO cHEMOLITE'
COM '-----------------------------------------------------'
CONTINGENCY 'NSP STK 5P148 BKR INVER HILLS AS'
DISCONNECT BUS 601020
DISCONNECT BUS 603127
DISCONNECT BUS 603129
DISCONNECT BUS 603106
DISCONNECT BUS 603128
END

COM 'NSP STK 5P145 BKR INVER HILLS'
COM '603082-603083 INVRHLS7-INVRGRV7'
COM '603083-605263 INVRGRV7-INVERGR8'
COM 'DISCONNECT INVER HILLS TO cHEMOLITE'
COM '-----------------------------------------------------'
CONTINGENCY 'NSP STK 5P145 BKR INVER HILLS'
TRIP LINE FROM BUS 603082 TO BUS 603083 CKT 1
TRIP LINE FROM BUS 603083 TO BUS 605263 CKT 2
DISCONNECT BUS 603127
DISCONNECT BUS 603129
DISCONNECT BUS 603106
DISCONNECT BUS 603128
END

COM 'NSP STK 5P142 BKR INVER HILLS'
COM '603082-603085 INVRHLS7-KOCHREF7'
COM 'DISCONNECT INVER HILLS TO cHEMOLITE'
COM '-----------------------------------------------------'
CONTINGENCY 'NSP STK 5P142 BKR INVER HILLS'
TRIP LINE FROM BUS 603082 TO BUS 603085 CKT 1
DISCONNECT BUS 603127
DISCONNECT BUS 603129
DISCONNECT BUS 603106
DISCONNECT BUS 603128
END

COM 'NSP STK 5P215 BKR ROSEMOUNT'
COM 'DISCONNECT BUSES BETWEEN CHEMOLITE AND
ROSEMOUNT'
COM '603168-603085 ROSEMON7-KOCHREF7'
COM '-----------------------------------------------------'
CONTINGENCY 'NSP STK 5P215 BKR ROSEMOUNT'
DISCONNECT BUS 603169
DISCONNECT BUS 616966
TRIP LINE FROM BUS 603168 TO BUS 603085 CKT 1
END

COM 'NSP STK 5P214 BKR ROSEMOUNT'
COM '603168-601022 ROSEMON7-EMPIRE 7'
COM '603168-603085 ROSEMON7-KOCHREF7'
COM '-----------------------------------------------------'
CONTINGENCY 'NSP STK 5P214 BKR ROSEMOUNT'
TRIP LINE FROM BUS 603168 TO BUS 616927 CKT 1
TRIP LINE FROM BUS 603168 TO BUS 603085 CKT 1
END

COM 'NSP STK 5P15 BKR INVER GROVE'
COM 'DISCONNECT INVER GROVE BUS'
COM '603098-603133 ROGRSLK7-LONEOK27'
COM '603133-603161 LONEOK27-LONE OA7'
COM '-----------------------------------------------------'
CONTINGENCY 'NSP STK 5P15 BKR RED ROCK'
DISCONNECT BUS 603083
TRIP LINE FROM BUS 615446 TO BUS 615447 TO BUS
615448 CKT 1
END

COM 'NSP STK 5p30 BKR CHEMOLITE BS'
COM '603067-603169 CHEMOLT7-WHAST  7'
COM '603067-603106 CHOMOLT7-LINDE  7'
CONTINGENCY 'NSP STK 5p30 BKR CHEMOLITE BS'
TRIP LINE FROM BUS 603067 TO BUS 603169 CKT 1
TRIP LINE FROM BUS 603067 TO BUS 603106 CKT 1
END

COM 'NSP STK 5P135 BKR CHEMOLITE'
COM 'DISCONNECT GENERATION 600018 & 600017'
COM '603067-603069 CHEMOLT7-COTTAGE7'
COM '-----------------------------------------------------'
CONTINGENCY 'NSP STK 5P135 BKR CHEMOLITE'
DISCONNECT BUS 600018
DISCONNECT BUS 600017
TRIP LINE FROM BUS 603067 TO BUS 603069 CKT 1
END

COM 'NSP STK 5P133 BKR CHEMOLITE'
COM 'DISCONNECT GENERATION 600018 & 600017'
COM 'DISCONNECT BUSES FROM CHEMOLITE-
INVERHILLS'
COM ''
COM '-----------------------------------------------------'
CONTINGENCY 'NSP STK 5P133 BKR CHEMOLITE'
DISCONNECT BUS 600018
DISCONNECT BUS 600017
DISCONNECT BUS 603106
DISCONNECT BUS 603128
DISCONNECT BUS 603127
DISCONNECT BUS 603129
END

COM 'NSP STK 5P130 BKR CHEMOLITE'
COM 'DISCONNECT BUSES BETWEEN CHEMOLITE AND
ROSEMOUNT'
COM 'DISCONNECT BUSES FROM CHEMOLITE-
INVERHILLS'
COM '
COM '-----------------------------------------------------'
CONTINGENCY 'NSP STK 5P130 BKR CHEMOLITE'
DISCONNECT BUS 603106
DISCONNECT BUS 603128
DISCONNECT BUS 603127
DISCONNECT BUS 603129
DISCONNECT BUS 603169
DISCONNECT BUS 616966
END

COM 'NSP STK 5P132 BKR CHEMOLITE BS'
COM 'DISCONNECT BUSES BETWEEN CHEMOLITE AND
ROSEMOUNT'
COM 'DISCONNECT BUSES FROM CHEMOLITE-
INVERHILLS'
COM '603067-603069 CHEMOLT7-COTTAGE7'
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COM '-------------------------------------------------------'
CONTINGENCY 'NSP STK 5P132 BKR CHEMOLITE BS'
DISCONNECT BUS 603169
DISCONNECT BUS 616966
TRIP LINE FROM BUS 603067 TO BUS 603069 CKT 1
END

COM 'CATEGORY B'
COM 'CATEGORY B'

COM 'LAKE MARION - AIRLAKE, AIR LAKE - VERMILLION
RIVER'
COM '603131-603190 AIRLAKE7-VRMLRVR7'
COM '603131-615440 AIRLAKE7-GRE-LKMARN 7'
CONTINGENCY 'B2.LKM-ALK-VMR'
TRIP LINE FROM BUS 603131 TO BUS 603190 CKT 1
TRIP LINE FROM BUS 603131 TO BUS 615440 CKT 1
DISCONNECT BUS 603106
END


COM
'_____________________________________________________
____________________'
COM 'CATEGORY C'
COM 'CATEGORY C'
COM 'CATEGORY C'


COM 'DOUBLE CIRCUIT'
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COM 'DOUBLE CIRCUIT'



COM 'STUCK BREAKER'
COM 'STUCK BREAKER'

COM 'NSP STK 5P232 BKR EMPIRE'
COM '616927-603168 EMPIRE 7-ROSEMON7'
COM '616927-603196 EMPIRE 7-CANNFLS7'
COM '-------------------------------------------------------'
CONTINGENCY 'NSP STK 5P232 BKR EMPIRE'
TRIP LINE FROM BUS 616927 TO BUS 603168 CKT 1
TRIP LINE FROM BUS 616927 TO BUS 603196 CKT 1
END

COM 'NSP STK 5P233 BKR EMPIRE'
COM '616927-603190 EMPIRE 7-VRMLRVR7'
COM '616927-603196 EMPIRE 7-CANNFLS7'
COM '-------------------------------------------------------'
CONTINGENCY 'NSP STK 5P233 BKR EMPIRE'
TRIP LINE FROM BUS 616927 TO BUS 603190 CKT 1
TRIP LINE FROM BUS 616927 TO BUS 603196 CKT 1
END


SINGLE BRANCH IN SYSTEM TWINCITIES
DOUBLE BRANCH IN SYSTEM MEADOW_HOLLY

END
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Appendix B.3

Addendum to Plymouth Area Load Serving Study (May 9, 2012)

Hollydale - Focusted Study Area - Historical
Feeders
Revised May 9, 2012

MW

Feeder	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
HOL061	2.553	5.994	5.880	5.586	6.115	6.174	8.036	7.546	7.350	6.748	8.089
HOL062	9.404	10.037	8.330	9.085	10.330	10.388	8.795	8.137	8.330	8.234	8.795
PKL062	11.285	11.358	8.585	8.281	8.330	6.364	6.076	6.724	6.579	6.971	6.483
PKL074	12.740	13.230	12.668	12.181	12.430	14.257	12.812	10.873	11.767	11.348	13.692
PKL075	7.523	9.506	9.261	7.553	8.327	9.713	9.362	8.771	8.256	9.219	9.707
PKL081	9.444	10.476	9.989	11.693	11.218	11.557	11.230	9.517	8.637	9.600	10.445
PKL083	9.604	10.719	9.501	8.771	8.589	9.530	8.553	8.612	8.862	9.279	7.771
PKL084	9.501	9.800	9.258	9.258	10.135	10.290	9.980	9.996	9.258	8.248	7.792
GSL061	9.800	8.527	8.040	7.796	8.283	8.404	6.370	5.782	5.684	3.773	4.851
GSL076	8.634	9.310	8.820	8.693	9.453	9.800	8.330	7.479	7.448	7.232	7.703
GSL079	7.350	7.699	8.722	8.771	8.040	8.673	8.232	6.773	7.154	6.399	7.340
GSL341	23.520	28.383	29.400	29.194	30.027	31.360	32.340	31.360	29.890	31.634	16.415
GSL342	0.000	0.000	0.000	2.940	6.091	8.466	9.137	9.745	11.270	11.721	29.400
TOTALS	109.401	119.008	114.244	115.131	120.923	128.414	122.422	115.632	114.804	115.424	121.598

KVA

Feeder	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	
HOL061	2605	6116	6000	5700	6240	6300	8200	7700	7500	6886	8254	Included with GSL341 feeder load
HOL062	9596	10242	8500	9270	10541	10600	8974	8303	8500	8402	8974	Included with GSL341 feeder load
PKL062	11515	11590	8760	8450	8500	6494	6200	6861	6713	7113	6615	
PKL074	13000	13500	12927	12430	12684	14548	13073	11095	12007	11580	13971	
PKL075	7677	9700	9450	7707	8497	9911	9553	8950	8424	9407	9905	
PKL081	9637	10690	10193	11932	11447	11793	11459	9711	8813	9796	10658	
PKL083	9800	10938	9695	8950	8764	9724	8728	8788	9043	9468	7930	
PKL084	9695	10000	9447	9447	10342	10500	10184	10200	9447	8416	7951	
GSL061	10000	8701	8204	7955	8452	8576	6500	5900	5800	3850	4950	
GSL076	8810	9500	9000	8870	9646	10000	8500	7632	7600	7380	7860	
GSL079	7500	7856	8900	8950	8204	8850	8400	6911	7300	6530	7490	
GSL341	24000	28962	30000	29790	30640	32000	33000	32000	30500	32280	16750	without load transfers to 13.8 kV used in study analysis
GSL342	0	0	0	3000	6215	8639	9323	9944	11500	11960	30000	without load transfers to 13.8 kV used in study analysis
TOTALS	111634	121437	116576	117481	123391	131035	124920	117992	117147	117780	124080	

Hollydale-Focused Study Area-Historical Banks

Revised June 29, 2012

MW													
Bank	**Capacity (N-0)**	**Capacity (N-1)**	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**
GSL TR7	46.850		20.090	21.511	20.835	21.413	20.159	21.678	19.600	18.620	17.640	17.738	22.109
GSL TR8	46.850		23.520	26.950	24.108	25.666	27.048	27.969	24.284	23.108	21.942	24.324	26.700
TOTAL	93.700	51.750	43.610	48.461	44.943	47.079	47.207	49.647	43.884	41.728	39.582	42.062	48.809
KVA													
Bank	**Capacity (N-0)**	**Capacity (N-1)**	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**
GSL TR7	47806		20500	21950	21260	21850	20570	22120	20000	19000	18000	18100	22560
GSL TR8	47806		24000	27500	24600	26190	27600	28540	24780	23580	22390	24820	27245
TOTAL	95612	52806	44500	49450	45860	48040	48170	50660	44780	42580	40390	42920	49805

MW														
Bank	**Capacity (N-0)**	**Capacity (N-1)**	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	
GSL TR4	74.996	34.019	21.952	24.446	27.103	28.290	32.811	33.181	33.916	28.986	28.428	32.70848	36.496	
KVA														
Bank	**Capacity (N-0)**	**Capacity (N-1)**	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	
GSL TR4	76527	34713	22400	24944.5135	27655.939	28867.10826	33481	33858.11659	34608.25083	29577.43658	29007.74476	33376	37241	NOTE: includes decrease due to transfers to 13.8kV used for study analysis
			24000	26500	29310	32080	37200	40000	41000	36000	36910	41890	46110	NOTE: original without transfers to 13.8kV used for study analysis

Appendix A-2

Hollydale Greater Study Area
Historical
Revised May 9, 2012

MW

Bank	N-0 Capacity	N-1 Capacity	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
HOL TR2	28.110	4.900	8.820	11.966	12.015	11.897	12.838	13.720	14.700	13.230	12.858	13.122	15.112
PKL TR1	46.850	98.600	41.160	45.433	42.493	43.336	45.668	42.267	44.737	40.337	39.739	40.895	47.942
PKL TR2	46.850		39.200	42.346	39.661	40.454	41.042	45.080	43.198	38.730	38.465	39.396	44.659
PKL TR3	48.886		34.300	35.535	35.407	35.074	37.240	39.053	35.094	37.181	35.319	35.662	34.751
GSL TR7	46.850	51.750	20.090	21.511	20.835	21.413	20.159	21.678	19.600	18.620	17.640	17.738	22.109
GSL TR8	46.850		23.520	26.950	24.108	25.666	27.048	27.969	24.373	23.108	21.942	24.324	26.700
TOTALS	264.396	155.250	167.090	183.740	174.518	177.841	183.995	189.767	181.702	171.206	165.963	171.137	191.272

KVA

Bank	N-0 Capacity	N-1 Capacity	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
HOL TR2	28684	5000	9000	12210	12260	12140	13100	14000	15000	13500	13120	13390	15420
PKL TR1	47806	100612	42000	46360	43360	44220	46600	43130	45650	41160	40550	41730	48920
PKL TR2	47806		40000	43210	40470	41280	41880	46000	44080	39520	39250	40200	45570
PKL TR3	49884		35000	36260	36130	35790	38000	39850	35810	37940	36040	36390	35460
GSL TR7	47806	52806	20500	21950	21260	21850	20570	22120	20000	19000	18000	18100	22560
GSL TR8	47806		24000	27500	24600	26190	27600	28540	24870	23580	22390	24820	27245
TOTALS	269792	158418	170500	187490	178080	181470	187750	193640	185410	174700	169350	174630	195175

Totals in MW

Gleason Lake	43.610	48.461	44.943	47.079	47.207	49.647	43.973	41.728	39.582	42.062	48.809
Parkers Lake	114.660	123.313	117.561	118.864	123.950	126.400	123.029	116.248	113.523	115.954	127.351

Hollydale Greater Study Area
Forecasts
Revised May 9, 2012

All forecasts have a 1.0% growth rate
Values in MW

Historic Peak Forecast	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
HOL TR2	13.720	13.857	13.996	14.136	14.277	14.420	14.564	14.710	14.857	15.005	15.155	15.307	15.460	15.615	15.771	15.928	16.088	16.249	16.411	16.575	16.741	16.908	17.078	17.248	17.421
PKL TR1	42.267	42.690	43.117	43.548	43.984	44.423	44.868	45.316	45.770	46.227	46.690	47.156	47.628	48.104	48.585	49.071	49.562	50.057	50.558	51.064	51.574	52.090	52.611	53.137	53.668
PKL TR2	45.080	45.531	45.986	46.446	46.910	47.380	47.853	48.332	48.815	49.303	49.796	50.294	50.797	51.305	51.818	52.336	52.860	53.388	53.922	54.462	55.006	55.556	56.112	56.673	57.240
PKL TR3	39.053	39.444	39.838	40.236	40.639	41.045	41.456	41.870	42.289	42.712	43.139	43.570	44.006	44.446	44.890	45.339	45.793	46.251	46.713	47.180	47.652	48.129	48.610	49.096	49.587
GSL TR7	21.678	21.894	22.113	22.334	22.558	22.783	23.011	23.241	23.474	23.708	23.946	24.185	24.427	24.671	24.918	25.167	25.419	25.673	25.930	26.189	26.451	26.715	26.982	27.252	27.525
GSL TR8	27.969	28.249	28.531	28.817	29.105	29.396	29.690	29.987	30.287	30.590	30.895	31.204	31.516	31.832	32.150	32.471	32.796	33.124	33.455	33.790	34.128	34.469	34.814	35.162	35.513
TOTALS	189.767	191.665	193.582	195.517	197.473	199.447	201.442	203.456	205.491	207.546	209.621	211.717	213.834	215.973	218.133	220.314	222.517	224.742	226.990	229.259	231.552	233.868	236.206	238.568	240.954

Conservative Forecast	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
HOL TR2				12.858	12.986	13.116	13.247	13.38	13.513	13.649	13.785	13.923	14.062	14.203	14.345	14.488	14.633	14.779	14.927	15.077	15.227	15.38	15.533	15.689	15.846
PKL TR1				39.739	40.136	40.538	40.943	41.353	41.766	42.184	42.606	43.032	43.462	43.897	44.336	44.779	45.227	45.679	46.136	46.597	47.063	47.534	48.009	48.489	48.974
PKL TR2				38.465	38.85	39.238	39.631	40.027	40.427	40.831	41.24	41.652	42.069	42.489	42.914	43.343	43.777	44.215	44.657	45.103	45.554	46.01	46.47	46.935	47.404
PKL TR3				35.319	35.672	36.029	36.389	36.753	37.121	37.492	37.867	38.246	38.628	39.014	39.405	39.799	40.197	40.599	41.004	41.415	41.829	42.247	42.669	43.096	43.527
GSL TR7				17.640	17.816	17.995	18.175	18.356	18.54	18.725	18.912	19.102	19.293	19.486	19.68	19.877	20.076	20.277	20.479	20.684	20.891	21.1	21.311	21.524	21.739
GSL TR8				21.942	22.162	22.383	22.607	22.833	23.061	23.292	23.525	23.76	23.998	24.238	24.48	24.725	24.972	25.222	25.474	25.729	25.986	26.246	26.509	26.774	27.041
TOTALS				165.963	167.623	169.299	170.992	172.702	174.429	176.173	177.935	179.714	181.511	183.326	185.160	187.011	188.881	190.770	192.678	194.605	196.551	198.516	200.501	202.506	204.531

Parkers Lake	131.533	138.242	145.294	152.705	160.495
Gleason Lake	51.663	54.298	57.068	59.979	63.038
Parkers Lake	114.66	120.51	126.65	133.11	139.91
Gleason Lake	39.978	42.017	44.161	46.413	48.781