Northeast Power Coordinating Council
Reliability Assessment
For
Summer 2003

Approved by the Task Force on Coordination of Operation
May 2003
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1. Executive Summary

This report focuses on the assessment of reliability within NPCC for the summer of 2003. Portions of this report are built on work previously done for the NPCC Reliability Assessment for Summer 2002.

The Summer 2003 Operations Planning Working Group worked closely with the representatives of the NPCC CP-8 Working Group to ensure results are based on consistent data and modeling assumptions between the two studies.

Those aspects that the Summer Operations Planning Working Group have examined to determine the reliability and adequacy for NPCC for the summer of 2003 are discussed in detail in the specific report sections. The following Summary of Findings address the significant points of the report discussion. These findings are based on forecasted projections of: load requirements, resource configurations and transmission configurations. This report evaluates NPCC and the associated Area’s ability to deal with the differing resources and transmission configurations and recommends several actions to reasonably ensure that NPCC and the associated Areas are prepared to deal with possible uncertainties identified in this report.

Summary of Findings

- The following assessment of the forecasted capacity outlook was made for the week with the lowest overall NPCC margin (week beginning June 22, 2003)1. The lower NPCC net margin is influenced by lower net margins in New York and Ontario. These lower margins can primarily be attributed to slightly higher planned and/or unplanned generation outages than during the projected peak load week. The overall resource adequacy for the NPCC region during this week indicates that there will be approximately 8,100 MW of operable spare capacity. However, during this week over half of this spare capacity is in the Quebec and Maritimes Areas. The transfer capability between the Quebec and Maritimes Control Areas to the remainder of NPCC will not permit the usage of all the declared spare capacity. In addition, transmission constraints may limit the ability to transmit the New Brunswick and southeastern New England capacity to other NPCC Areas. Therefore, it is estimated that the net margins for NPCC are reduced by approximately 2,800 MW over this week (June 22, 2003) to account for this bottled capacity. As a result of this bottling, the spare capacity available to the remainder of NPCC is approximately 5,300 MW over this week. While New York and Ontario are projecting some relatively low margins during portions of the report period, after accounting for bottled resources, there should be sufficient resources to meet the forecasted load projections and operating reserve requirements within NPCC.

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1 Load and Capacity Forecast Summaries for NPCC, IMO, ISO-NE, NY-ISO, HQ and the Maritime’s are included in Appendix 1.
• The projected spare capacity available to the remainder of NPCC during the peak load week (week beginning July 6, 2003) is about 7,300 MW. This is projected to occur two weeks following the week with the lowest overall NPCC margin (week beginning June 22, 2003). By comparison the projected spare capacity, after accounting for bottled in capacity, for the 2002 Summer peak load week was about 3,400 MW.

• New England and New York have market-based demand response programs in place that are expected to provide load relief measures that are in addition to measures available under emergency conditions. In addition, to address reliability concerns in southwest Connecticut, an area of New England where demand may exceed supply plus total transmission import limits, a Request For Proposal (RFP) has been issued by Connecticut Light and Power Company in order to acquire new peaking generation and load relief within that area. Ontario had a pilot Emergency Demand Response Program in place for the summer of 2002. The pilot program was to end on April 30, 2003. Work is in progress to extend the program through the summer of 2003.

• NPCC generation capacity additions for the 2003 Summer are anticipated to total 7,144 MW, including 2,900 MW in New England, 1,179 MW in New York, 2,565 MW in Ontario, 450 MW in Quebec and 50 MW in the Maritimes. It should be noted that the Ontario addition includes the return to service of two Bruce units (770 MW each) and a Pickering unit (515 MW). Even though NPCC as a whole shows adequate resources through the report period, there remain load pockets within the New England control area, specifically southwest Connecticut that may be at greater risk of being capacity deficient.

• The Areas of New England, New York and Ontario will also have adequacy concerns under conditions of extreme weather-driven-demands or higher than projected generating unit outages without assistance from outside their respective Control Areas. The capability to assist adjoining NPCC Control Areas is exacerbated by the lack of load diversity between Control Areas.

• The shoulder months indicate that overall NPCC has significant margins of spare generating capacity. Furthermore, measures are being taken to ensure these margins are maintained to protect against maintenance over runs.

• Any delays to the in-service date of new capacity in New England, New York and Ontario will impact the overall capacity for these Areas. Similarly, removal of existing generation in critical areas, may adversely affect capacity margins.

• The working group has determined that each NPCC Area is reasonably prepared or is reviewing the necessary strategies and procedures to deal with operational problems and emergencies as they develop. However, the Resource and Transmission Assessments are mere snapshots in time and base case studies. Changes to the base case assumptions can alter this report’s findings.
• An analysis of historical periods of high Geomagnetically Induced Currents (GICs) was performed and the results indicate that present procedures for managing them are adequate. As we are now on the downward trend of the 11-year sunspot cycle, the probability of a major GIC event impacting generation or transmission coincident with the occurrence of peak load is decreasing.

• Area environmental constraints, specifically state, provincial and local emission regulations may have some impact at various times through the summer 2003 period.

• Since 2002, precipitation levels have restored most water reservoirs to near normal levels. Hydroelectric generation output may still be impacted in some isolated locations.

• Under specific conditions, some Control Areas have identified difficulties controlling high or low voltages.

2. Introduction

The NPCC Task Force on Coordination of Operation established the Operations Planning Working Group to review the projected 2003 summer\(^2\) conditions and assess the overall reliability of the generation and transmission system in NPCC. The objectives of the working group were to:

• Conduct a post-assessment review of 2002 Summer operating conditions.

• Examine historical summer operational experiences and assess their applicability for the summer 2003 period.

• Assess the extent to which emergency operating procedures may be implemented by the NPCC Areas during the summer of 2003.

• Study potential sensitivities that may impact resource adequacy, including temperature variations, merchant plant delays, load forecast uncertainties, evolving load response measures, solar magnetic activity and system voltage and generator reactive capability limits.

• Ensure that timely and efficient communications with participants in all regional markets will be in place in order to maximize reliance on the marketplace for emergency support.

• Review the operational readiness of the NPCC Areas and recommend actions to mitigate potential problems.

\(^2\) Summer 2003 is defined as the months of May to September inclusive.
• Assess the implications of strategies adopted for the summer period on the adequacy of supply in the shoulder months.

• Coordinate data and modeling assumptions with NPCC Working Group CP-8, “Resource and Transmission Adequacy.” Document the methodology of each Area in its projection of load forecasts; document the methodology of each Area in its projection of unit unavailability rates.

• Provide coordination with the seasonal assessments conducted for the summer of 2003 by the NERC Reliability Assessment Subcommittee and the MAAC-ECAR-NPCC (MEN) Study

3. Demand Forecasts for 2003

The non-coincident forecasted peak demand for NPCC during the summer of 2003 is 104,694 MW (May-September period). This peak demand translates to a coincident peak demand of 103,013 MW and is expected during the week beginning July 6, 2003.

Ambient weather conditions are the single most important variable impacting the demand forecasts during the summer months. As a result, each Area is aware that the summer peak demand could occur during any week of the summer period as a result of these weather variables. It should also be noted that the Maritimes and Quebec experience late Spring loads that are influenced by heating load and occur during the defined summer period.

The impact of extreme ambient weather conditions on load forecasts can be demonstrated by various means. The IMO, Maritimes and TransÉnergie (transmission operations division of Hydro-Quebec) represent the resulting load forecast uncertainty in their respective Areas as a percentage of the base load. NYISO and ISO-NE use a Temperature Humidity Index (THI) as a base and increase the load by a MW factor for each degree above the base value.

As demonstrated in Section 7, historically the peak loads and temperatures between New England and New York can have a high degree of correlation due to the relative locations of their respective load centers. Depending upon the extent of the weather system and duration, there is some potential for the Ontario peak demand to be coincident with New England and New York.

The method each Area uses to determine the peak forecast demand and the associated load forecast uncertainty relating to weather variables is described in greater detail in the Control Area Summary of Forecasts below.
Summary of Area Forecasts

Maritimes

Based on the Maritimes Area 2003 demand forecast, a peak of 3,474 MW is predicted to occur for the June through August period during the week beginning June 1, 2003. This is a less than a 1% increase over the Summer 2002 actual peak of 3,444 MW, which occurred on August 16, 2002. Since the Maritimes Area is a winter-peaking area, forecasted peaks for the months of May and September are normally higher than for the June through August period. For the week beginning April 27, 2003, the predicted peak is 3,813 MW; for the week beginning September 28, 2003, the predicted peak is 3,511 MW.

The load forecast for the Maritimes Area represents the expected load for the Summer 2003 assessment period. It should be noted that the Maritimes Area load is simply the mathematical sum of the forecasted weekly peak loads of the sub-areas (New Brunswick, Nova Scotia, Prince Edward Island, and the area served by the Northern Maine Independent System Administrator). As such, it does not take the effect of load coincidence within the week into account. If the total Maritimes Area load included a coincidence factor, the forecast load would be approximately 1-3% lower.

For New Brunswick Power, the load forecast is based on an End-use Model (sum of forecasted loads by use e.g. water heating, space heating, lighting etc.) for residential loads and an Econometric Model for general service and industrial loads, correlating forecasted economic growth and historical loads. Each of these models is weather adjusted using a 30-year historical average.

For Nova Scotia Power, the load forecast is based on a 30-year historical climate normal for the major load center, along with analyses of sales history, economic indicators, customer surveys, technological and demographic changes in the market, and the price and availability of other energy sources.

Maritimes Electric Company Ltd.’s (Prince Edward Island) load forecast uses average long-term weather for the peak period (typically December) and a time-based regression model to determine the forecasted annual peak. The remaining months are prorated on the previous year.

The Northern Maine Independent System Administrator performs a trend analysis on historic data in order to develop an estimate of future loads.

New England

The New England Control Area’s forecasted summer 2003 peak demand is 25,120 MW. This is 360 MW (1.5%) higher than last years forecast for 2003 of 24,760 MW. This reasoning for the increase in forecasted peak loads for 2003 can be summarized by the following:
• Using a seasonal regression, weather normalizing the forecasted 2002 summer peak of 24,200 MW to 24,390 MW
• The weather normalizing and forecasting methodology was revised to use a monthly regression, rather than a seasonal regression, for measuring the peak load response to temperature/humidity. The weather normalized peak for 2002 is calculated to be 24,590 MW using the new methodology. This is a 200 MW (0.8%) increase over the seasonal regression normalization of 24,390 MW.
• Using the latest economic and historical data, the forecasted peak growth into 2003 was revised to 2.2%. This 2.2% growth is applied to the 24,590 MW forecast to calculate the 2003 summer peak load forecast of 25,120 MW.

The actual summer peak experienced in 2002 was 25,348 MW. Using the temperature experienced at the time of peak, the forecast would be re-calculated to be 25,125 MW using the monthly regression methodology. This peak of 25,348 MW is the all time record of peak load for New England and surpassed the previous record of 24,967 MW by 381 MW.

The demand forecast for New England is based on weekly weather distributions. The weekly weather distributions were built using 30 years of data for the Temperature Humidity Index (THI) at the time of daily peaks (for non-holiday weekdays). The reference load forecast is based on a 50/50 probability of occurrence. While this temperature sampling is used to project the temperature sensitive loads, a complete process of sampling and econometric models are used to project the aggregate demand. A reasonable approximation for the “normal weather” associated with this projection is 90 degrees Fahrenheit and a dew point of 70 degrees. At these forecasted load levels, a one-degree increase in the THI will result in approximately 700 to 800 MW of additional load. The amount of additional load depends on the total deviation from the “normal weather” approximation.

As mentioned above, the reference case forecast of 25,120 MW has a 50% chance of being exceeded. New England also produces a load forecast that has a 10% chance of being exceeded that would be equivalent to an increase in the load forecast of approximately 1,630 MW.

The following graph illustrates the range of potential peak demands that ISO-NE may experience this summer and compares them to historical peaks. It should be noted that the historical peak values illustrated below are the peak loads reconstituted to reflect Operating Procedures that may have been implemented at that time.
New York

The forecast peak for the New York Control Area is 31,430 MW, which is 955 MW higher than last year’s forecast of 30,475 MW. This forecast is 1.4% higher than the all time peak of 30,983 MW that occurred on August 9, 2001. The forecast is based on the forecasts for the transmission districts by the Transmission Owners and municipal agencies. For peak load normalization, the NYISO uses a Temperature-Humidity Index (THI) value of 81.31 degrees. At forecast load levels, a one-degree increase in the THI will result in approximately 500 MW additional load.

The following illustration provides the range of potential peak demands that the New York Area may experience this summer.
Ontario

The forecasted weather normal, summer hourly peak demand for 2003 is 23,684 MW. This is forecasted to occur during the week beginning July 6, 2003. The forecast is derived from an analysis of demands using 30 years of historical weather based on a weekly resolution. The normal weather equates to an approximate average daily temperature of 28 degrees Celsius and 65% relative humidity.

As was seen in 2001 and again in 2002, weather extremes can drive the demands significantly higher than the weather normal values. The demand models used to create the 2003 load profiles have been updated to increase the sensitivities to hot weather as a result of experiences during the summer and fall of 2002.

Since peak demands are highly weather sensitive, Load Forecast Uncertainty (LFU) is used to capture, in MW, the impact of the variations from normal weather. Therefore the peak demands can be derived and given a probability of occurring based on the likelihood of observing the normal weather. For this forecast, there is a 50% chance the peak demand in any given week will exceed the weather normal base demands. LFU represents the impact on the peak demand of one standard deviation in the weather elements. The values of LFU associated with this analysis ranges from 4% to 9% of the predicted normal weather demands. The highest values of LFU for Ontario appear during those weeks just prior to and after the traditional summer vacation periods of July and August. For the peak week, LFU equates to a potential increase in demand of about 1,160 MW.
For the summer period the extreme weather demand for any given week is determined by using the hottest day in the past thirty years as the reference point. Depending upon the week in this study period, the values that could be experienced under extreme weather conditions can be 10 – 17% higher than the normal weather prediction. For the peak week, this can equate to an increase of approximately 2,600 MW over the normal weather prediction. During the shoulder months of May and September, the impact of extreme weather over normal weather forecasted demand can reach as high as 3,300 MW.

The following graph shows the forecast range of potential demands that the IMO may experience in each week.
Quebec

The forecasted summer peak for the Quebec Control Area in 2003 is 21,257 MW. This is 1,266 MW (5.6%) lower than last summer’s peak of 22,523 MW which happened on an unseasonably cold day at the beginning of May, with temperatures around the freezing point all over the province. If we exclude this anomaly, the forecasted summer peak for 2003 is 732 MW (3.5%) above the peak of 20,525 MW reached on September 9th of last year, when temperatures reached 33 degrees Celsius with a high Heat and Humidity Index on the major load centers in the south of the province while regions in the northeast had to resort to residential heating with temperatures around 5 degrees Celsius. The forecast is based on 35 years of historical weather with an offset of ±3 days for every date, which amounts to the equivalent of 245 years of sampling. Being exposed over the year to all kinds of extremes in weather, TransÉnergie uses three different load forecasting models (autumn, winter and spring). For the purpose of this assessment, the spring model is used up to the middle of August and the autumn model is used for the remaining of the period. The boundaries of the parameters of these models are regularly calibrated by comparing the results to the last two years of historical weather to reflect any new tendencies. Finally, TransÉnergie defines load forecast uncertainty (LFU) as a percentage calculated on a monthly resolution. The value for LFU is approximately 3% for the summer months, which represents from 600 to 700 MW. This value is accounted for in the Load and Capacity table provided in this assessment.

4. Resource Adequacy

NPCC Summary for 2003

The following assessment of resource adequacy was made for the week with the lowest overall NPCC margin (week beginning June 22, 2003)\(^3\). The lower net margin is influenced by lower net margins in New York and Ontario. These lower margins can primarily be attributed to slightly higher known and/or unplanned generation outages than during the projected peak load week. The overall resource adequacy for the NPCC region during this week indicates that there will be approximately 8,100 MW of operable spare capacity. However, during this week over half of this spare capacity is in the Quebec and Maritimes Area. The transfer capability between the Quebec and Maritimes Control Areas to the remainder of NPCC will not permit the usage of all the declared spare capacity. In addition, transmission constraints may limit the ability to transmit the New Brunswick and southeastern New England capacity to other NPCC Areas. Therefore it is estimated that the net margins for NPCC are reduced by approximately 2,800 MW over this week to account for this bottled capacity. As a result of this bottling, the spare capacity available to the remainder of NPCC is approximately 5,300 MW over this week.

\(^3\) Load and Capacity Forecast Summaries for NPCC, Ontario, New England, New York, Quebec and the Maritime’s are included in Appendix 1.
The projected spare capacity available to the remainder of NPCC during the peak load week (week beginning July 6, 2003) is about 7,300 MW. By comparison the projected spare capacity for the 2002 Summer peak load week was about 3,400 MW. While New York and Ontario are projecting some relatively low margins during portions of the report period, after accounting for bottled resources, there should be sufficient resources to meet the forecasted load projections and operating reserve requirements within NPCC.

The above assessment was performed on the basis of projected available capacity. Inadequate fuel supply, lower than normal water reservoirs, higher than anticipated forced outages or delays in anticipated new facilities can impact these capacity projections. Based on Control Area assessments there should be little impact to the overall capacity projections from these additional variables.

The following are the Area assessments supporting this overall resource adequacy assessment.

**Projected Load and Capacity Analysis by Area**

**Maritimes**

When allowances for unplanned outages (based on a discrete MW value representing a typical forced outage) are considered, the Maritimes Area is projecting more than adequate capacity margins for the Summer 2003 assessment period. Net margins ranging from 20% to 45% are projected over the period May through September 2003.

**New England**

Operable capacity within New England is forecasted to be sufficient to meet operating reserve requirements during all weeks of the summer peak load period. A positive capacity margin ranging from 1,600 MW to 5,700 MW is anticipated. Available capacity is based on known outages, an approximation of unknown outages, anticipated new generation additions, projected firm purchases, and capacity from Demand Response Programs.

While it is projected that operable capacity is expected to be surplus for the New England region, the southwest Connecticut region may face reliability problems due to transmission constraints into and within that region. To meet critical near-term electric system reliability needs in southwest Connecticut for the summer of 2003, Connecticut Light and Power Company has implemented an emergency plan for the period of June 1, 2003 through September 31, 2003 that includes:

- Issuing of a Request for Proposals (RFP) for the installation of up to 80 MW of temporary generation, seeking the preferred, clean-burning natural gas-
powered generation to address reliability needs and other power emergencies this summer;

- Installing voltage stabilization and performance equipment to maximize transmission import capabilities into southwest Connecticut; and

- Aggressively supporting and participating in ISO New England-administered Demand Side Management (DSM) programs that could potentially reduce this summer's peak load by up to 20 MW in southwest Connecticut.

Transmission constraints are also affecting import limits into the Boston Area and Northwest Vermont.

Maine, Southeast Massachusetts, and Rhode Island are areas within New England where supply exceeds native load but the existing transmission system limits the amount of excess energy that can be used to serve the demand in other areas.

In addition to known maintenance, an allowance for unplanned outages is also included. Unknown outages are based on historical trends and are estimated to be between 2,100 MW and 3,400 MW. However, if higher than expected resource unavailability or higher than expected load occurs in New England, then system operators may have to take load curtailment actions if sufficient assistance cannot be obtained from interconnecting areas. If necessary, New England would implement its Operating Procedures, which provide load and capacity relief to balance demand and supply and maintain adequate operating reserves.

New York

The NYISO conducts semi-annual and monthly Installed Capability (ICAP) auctions. Based on the forecast load for 2003, the ICAP requirement is 37,087 MW based on the 18% installed reserve margin requirement. When allowances are taken for unplanned outages (based on historical performance of 10.2% unavailable capacity), the net available resources will be 33,230 MW, which will be sufficient to meet the New York Control Area (NYCA) load and operating reserve requirement during the peak load hours; a capacity margin of zero MW is expected at peak conditions.

Generation resources which are external to the New York Control Area (NYCA) that provide ICAP to the NY market are included in the ICAP total of the NY Load and Capacity assessment. Resources within the NYCA that provide firm capacity to an entity external to the NYCA are not included in the ICAP total (i.e. this generation cannot participate in the ICAP market).

NYISO expects approximately 1,100 MW of load relief from emergency operating procedures that include internal load curtailment by the transmission owners, public appeals and 5% system wide voltage reductions. Participation in the Emergency Demand Response Program represents an additional 700 MW available through the market.
Ontario

The new TransAlta-Sarnia Cogeneration Project, which provides a net capacity increase of 510 MW, became fully dispatchable to the IMO controlled grid on March 27, 2003.

The return to service of three nuclear units that were laid up in the late 1990's is scheduled to begin in 2003. Bruce A units G4 and G3 are scheduled to be generating electricity April 29 and the end of June respectively. Each unit will provide a net capacity addition of 770 MW to the IMO-controlled grid. Pickering A G4 is scheduled to begin generating electricity by June 2003. This unit will provide a net capacity addition of 515 MW.

The IMO is anticipating positive capacity margins within Ontario to meet expected load and operating reserve requirements for peak hours of the report period based on weather normal demands.

This analysis is based on the assumption that the returning nuclear generation resources will meet their in service projections, a review of known outages, a projection of unknown outages, a forecast of price responsive loads, and the inclusion of known firm purchases that supplement the installed generating capability.

Known outages include those resources that are scheduled to be on planned outages, transmission constrained resources as well as the difference between the installed capacity and the dependable capacity associated with certain resources. For example hydroelectric capacity is reduced by varying amounts through portions of the study period to account for the energy available under median water conditions.

Unknown outages represent the average value of forced outages experienced in this same study period during previous years.

A value of 300 MW of price responsive load has been assumed to be available for this forecast based on past operational experience.

The net capacity margins, in table 5 of Appendix I, depict an estimate of the operable capacity margin that does not consider all the additional off-market control actions available to the IMO. For example, the IMO can institute a 3% or 5% voltage reduction. These control actions have the effect of reducing the demand by 1.7% to 2.5%, which, equates to approximately 390 MW to 500 MW on the peak week.

The risks associated with this analysis are that demands may be heavier than expected due to extreme weather, outages may not return to service as scheduled or delays to new and returning units. Of particular concern for this summer are the large number units on outage that are expected to return to service just prior to the summer period.
The adjustment of outage programs and securing of assistance (via market mechanisms or acquisition of emergency energy) from other control areas may be required during those periods that the margin of available capacity in Ontario is forecast to be insufficient to meet the expected Ontario demands plus operating reserve requirements.

The projected margins and controls actions available to the IMO are continuously assessed to determine the appropriate course of action.

Quebec

TransÉnergie is projecting more than adequate capacity margins for the Quebec Control Area during this period. Being a winter peaking region, the summer is the season during which maintenance work is performed, but margins in the range of 3,500 to 6,500 MW above load and firm sales projections are nevertheless expected.

**Delays to In-service of New Generation Resources**

Maritimes

The Maritimes Area has a 50 MW gas-fired combustion turbine scheduled for commercial operation on September 1, 2003. This unit was previously scheduled to be in service in October 2002.

New England

In the New England Control Area, from April 2001 through February 2003, approximately 4,300 MW (summer rating) of new capacity has been added with an additional forecast of 2,900 MW to be in service prior to June 1, 2003. Of the new generation assumed to be online this summer approximately 1,400 MW will be located in Boston. Past experience indicates that new projects with aggressive construction schedules, new designs or are large in magnitude, are frequently delayed due to unforeseen circumstances. ISO New England closely monitors the construction and commissioning progress of new generators. However, any delay in the commissioning of the new generation will decrease the projected capacity margins.

New York

Resource additions totaling 1,179 MW are expected to be available for service prior to the summer peak. Of this, 1080MW represents a new natural gas fired combined-cycle merchant plant located near Athens, NY, and the remaining 99 MW are simple-cycle combustion turbines in the Long Island zone. This resource assessment is based on the forecast of commercially available capacity at the start of the summer season so that any new capacity additions would serve to enhance the projected margin.
Ontario

Ontario will see the return to service of three laid-up nuclear units for the summer of 2003. The greatest concern to the summer capability period is the fact that no nuclear unit in Ontario has been returned to service from the laid-up state. Timing of the return to service of these units is critical to resource adequacy. The IMO recognizes the risks associated with the timing of the return to service and continuously monitors the resource adequacy margins.

Quebec

The commissioning of the Sainte Marguerite-3 hydro plant (900 MW) has been delayed again. It is likely that only one of its two 450 MW units shall be online for this summer. This assumption is used in this assessment. No other significant generation is expected.

Fuel Infrastructure by Area

The following is a self-assessment by each Area of the expected fuel supply infrastructure.

Maritimes

The fuel supply in the Maritimes Area is very diverse and includes Nuclear, Natural Gas, Coal, Oil (both light and residual), Orimulsion\textsuperscript{tm}, Petroleum Coke, Hydro, Tidal, Municipal Waste, and Wood.

The Maritimes Area does not anticipate any restrictions in capacity due fuel supply. Units that have been converted to the Orimulsion\textsuperscript{tm} fuel retain their full capability on oil. Moreover, the Area anticipates normal hydro conditions and the reservoirs are expected to be full.

New England

Historically, fuel supplies have been readily available to generators within New England during the summer months. For the summer of 2003, ISO New England does not foresee any fuel supply or delivery constraints.

New York

Traditionally, the New York Control Area generation mix has been dependent on fossil fuels for the largest portion of the installed capacity. Recent capacity additions or enhancements now available use natural gas as the primary fuel. While some existing units in southeastern New York have “dual-fuel” capability, use of residual or distillate oil as an alternate may be limited by environmental regulations.
Adequate supplies of all fuel types are expected to be available for the summer period.

Ontario

The majority of generation facilities operating on the IMO-controlled grid are represented by three basic types of fuel (Hydroelectric, Nuclear and Fossil). The fossil fueled facilities are predominately fired by coal. A portion of these fossil fired resources is fueled by natural gas or oil. A majority of the oil-fired capability is dual fueled by natural gas and oil. Adequate supplies of these fuels are expected to be available and there is no expectation of fuel delivery infrastructure problems for the summer period. Additionally, the hydroelectric installed capacity is reduced through portions of the study period to account for reductions in capacity when the available water falls below the dependable value. Dependable hydroelectric capacity is the capacity that is sustainable for a minimum of one hour per day, five days per week.

Quebec

Most of the generation resources in the Quebec Control Area are hydroelectric (95%) and hydraulic conditions are adequate. For the summer peak of 2003, TransÉnergie does not foresee any problems in meeting both its internal demand and full responsibility sales while still being able to assist neighboring Areas as needed.

5. Potential Usage of Operating Procedures

The NPCC CP-8 Working Group performed a probabilistic analysis to estimate the annual Loss of Load Expectation (LOLE) and projected use of Area Operating Procedures designed to mitigate resource shortages for the summer of 2003 under various conditions. This section is based on the CP-8 Study results.

The scenarios included expected and extreme load patterns. Detailed study results for each of these scenarios can be obtained from the NPCC CP-8 Working Group - Summer 2003 Multi-Area Probabilistic Reliability Assessment.

The study results indicate that all Areas demonstrated an annual LOLE of 0.1 days/year or less, under the Base Case and Severe Case assumptions for the expected load (the expected load is the weighted average of seven load levels, weighted by the probabilities assumed for each). They also indicate that New England and New York may experience conditions during the summer of 2003 that require the use of operating procedures designed to mitigate resource shortages. Use of these operating procedures is not anticipated for the Québec, Ontario, or the Maritimes Areas during the summer of 2003.

The potential use of these operating procedures in New England and New York is more likely to occur in Southwest Connecticut and New York City, respectively, if reductions in anticipated resources or increases in transmission constraints materialize coincident with higher than expected loads.
The actual number of times NPCC Area operating procedures were used to mitigate resource shortages for the summer of 2002 was within the range of last year’s estimate.

As compared to last year’s analysis, the identified additional resources, improved transmission transfer capability, and Demand Response Programs have reduced the estimated need for implementing operating procedures to maintain reliability within NPCC.

For the May - September 2003 period, Figure EX-1 shows the potential range of use of the indicated operating procedures under Base Case and Severe Case assumptions, expected and extreme load levels.

**Figure EX-1**

Potential Range of Use of Indicated Operating Procedures for Summer 2003
Considering Base and Severe Case assumptions (May – September)
(Expected and Extreme load levels)

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Transmission Adequacy

Many Inter-Regional and Intra-Area transmission studies are in the preliminary stages of assessment. Therefore, the transmission adequacy assessment for this report was made utilizing assumptions based on consultation with the staff in the appropriate area of expertise for Inter-Regional transfer capability, supplemented by Intra-Area Transmission assessments of each Control Area and a review of last year’s operating experience for equipment outage that occurred during the summer of 2002.
The following is a transmission adequacy assessment from the perspective of the ability to support energy transfers for the differing levels, Inter-Region, Inter-Area and Intra-Area.

**Inter-Regional Transmission Adequacy**

Evolution of the interconnected network is continuing in the northeastern U. S. Present plans are for the integration of the AEP and Dayton Power & Light systems as part of PJM’s energy market operations prior to this summer with Commonwealth Edison and Dominion Resources following later in 2003. However, there have been regulatory/political challenges to those plans, which has resulted in the deferral of the plans for AEP, Dayton Power & Light and has made the Dominion Resources plan uncertain.

The final phase angle regulator installation on the Michigan-Ontario Interface (345 kV circuit L4D) is not expected to be completed until the end of August. The B3N (230 kV circuit Scott - Bunce Creek) phase angle regulator was forced from service in March 2003. The return to service of the PAR is not known at this time. This has created additional uncertainty to the projection of having all Michigan-Ontario Interface phase angle regulators in service for any portion of the summer operating period. Therefore it is assumed that the Michigan-Ontario Ties will remain free flowing for a major portion of the study period.

In addition, a tower on the B3N circuit was damaged, which forced the circuit out of service. The tower must be replaced and the expected return date for the circuit is July 31, 2003. During this time the ability to import energy into Ontario on the Ontario-Michigan Interface will be reduced by approximately 150 MW from the normal level.

It is expected that the transmission system is adequate to support the anticipated Inter-Regional transfers.

**Inter Area Transmission Adequacy**

The transfer capability between the NPCC sub-Area containing the Quebec Control Area and the Maritimes Area with the remainder of NPCC is less than the surplus capacity in this sub-Area. This accounts for the adjustment to the Net NPCC Margins in the Resource Adequacy assessment (Section 6). The estimated transfer capabilities used in the CP-8 probabilistic assessment were used to calculate the remaining transfer capability after known transactions are taken into account. These estimated transfer capabilities are illustrated in Diagram 1 NPCC Transfer Limits CP-8 Base Case.
Diagram 1
Assumed Transfer Limits Between Areas

NPCC Transfer Limits - CP-8 Study - Base Case (Assumed Ratings)

Transmission Adequacy Assessment by Area

Maritimes

There have been no major additions to the Maritimes bulk transmission system. Interconnection capability remains unchanged and is expected to deliver up to 700 MW to New England and be capable of delivering up to 700 MW to Quebec.

New England

The following transmission upgrades are expected to be implemented during or prior to the summer of 2003:

- The installation of one 345/115 kV transformer at the Canal substation along with four additional circuit breakers to improve transmission reliability to the Cape Cod area;
• the addition of a 345/115 kV transformer at the West Rutland substation to improve reliability to the northwest Vermont region;
• Re-energizing the Coolidge to West Rutland line at 345kV will also improve the reliability to northwest Vermont;
• In order to improve reliability in the Boston area, the West Medway to Waltham 230 kV line is expected to be modified by increasing the sag limit.

For the summer of 2003, upgrades will be completed in the southwest Connecticut area that will provide some increases in the import capability. Specifically, two +/- 8 MVAR DVAR devices will be installed at the Stony Hill Bus as well as one at the Bates Rock Bus. Along with the DVAR devices, capacitor banks will be installed at the buses. The installation of these DVAR devices, along with the capacitor banks, will reduce the likelihood of load shedding in the southwest Connecticut area this summer.

Even with these scheduled improvements, there are still transmission constrained areas such as metropolitan Boston and southwest Connecticut. During periods of high demand, voltage and thermal limits may impact transfer capability into and within these transmission constrained load pockets.

New York

There are no major transmission facility additions to the New York bulk power system for the summer 2003 period.

Construction of the Cross Sound Cable, a 330 MW HVdc merchant transmission line and HVdc Converter Facilities between East Shore Substation in New Haven, CT, and the Shoreham, NY, has been completed. Commercial operation of the facility has been delayed due to regulatory issues. Parties involved in the operation of this facility are seeking an order from the FERC to allow emergency power transfer on this interconnection.

Phase II of the Marcy Flexible AC Transmission System (FACTS) Demonstration Project is scheduled for completion during the Spring 2003. The addition of static synchronous series compensator (SSSC) capability to FACTS Convertible Static Compensator (CSC) device will provide dynamic control of the transmission system power flows on either the Marcy – Coopers Corners or Marcy – New Scotland 345kV circuits. The new functionality and enhanced controls being installed in the 2nd quarter of 2003 will increase the number of operating configurations of the CSC to eleven modes.

Ontario

There are no new major transmission facilities scheduled to be placed in service prior to the summer operating period to change the overall transmission adequacy outlook from 2002. Studies indicate that there will be sufficient transmission capability to
meet the projected requirements under most conditions. However, there will continue to be limitations to the outage program during extreme weather driven demands in certain sub-areas of the province.

While several new small and one large capacitor bank installation that is expected to be available for the summer of 2003, the Windsor area and Toronto area will continue to experience low system voltages during extreme weather condition. As was experienced in 2002 maintaining acceptable voltage profiles will require diligent assessment of outage plans, and dispatch/deployment of reactive resources.

Quebec

No major maintenance outages are scheduled on the interconnections with neighboring Areas from May to September. Transfer capabilities will be at their maximum throughout the summer. Internal Transmission outage plans are assessed to meet load, firm sales, expected additional sales plus additional uncertainty margins.

An experimental 100 MW Variable Frequency Transformer (VFT) is currently being installed at the Langlois substation near the Les Cedres generating plant. It will begin testing in the summer of 2003 and could eventually increase the transfer capacity via lines CD1 and CD2 from Dennison (Niagara Mohawk, NYISO). The additional margin is not expected to be commercially available before 2004. This interconnection is currently being fed by islanding generation at the Les Cedres plant and this VFT will also increase switching flexibility by reducing the number of islanding operations.

6. Operational Readiness for 2003

The Resource and Transmission adequacy assessments are key elements in determining NPCC’s ability to meet the demands of the summer, but they are mere “snapshots in time” or simulations of conditions based on predictions of specific configurations. To mitigate the uncertainty surrounding load forecasts, forced outages and other conditions that cannot be controlled or predicted, the Control Areas of NPCC need to be prepared to deal with contingencies in real time.

The following is a synopsis of some of the most prevalent uncertainties affecting the ability to handle the projected demand and the mitigating actions NPCC Control Areas can take to diminish their impact during the summer 2003 period.

Reactive Capability of Generating Units

Heavy demand during the summer period requires that the transmission system voltages and the end-use reactive loads be supported by substantial reactive resources in relation to the real power requirements. While static VAR devices and shunt capacitors provide a known quantity of support based on design rating, the actual reactive capabilities of generators can vary significantly from the design capability.
The following is a discussion of each Areas methodology to monitor reactive capability.

Maritimes

The Maritimes Area, in addition to the reactive capability of the generating units, employs a number of capacitors and reactors in order to provide local area voltage control. The Area employs Static VAR Compensators and several synchronous condensers in key load centers to provide high-speed reactive power control. Further, the Maritimes Area is a winter peaking system and the loading of the transmission lines in summer is, in general, lower resulting in lower VAR consumption.

New England

ISO-NE and its satellite control centers continually monitor voltage and VAR conditions throughout the system to ensure reliability of the bulk power grid in New England. As transmission upgrades and new generators are added to the system, engineering analyses are conducted to determine appropriate voltage and VAR levels.

New York

Each generator providing voltage support service under the NYISO Tariff to the New York market is required to perform annual testing of reactive capability within 90% of its claimed operating capability. The NYISO staff reviews the test data and, if necessary, will perform appropriate voltage analysis to determine operating limits based on the reactive capability testing. In preparation for the summer peak period, the NYISO staff has reviewed the test data to ensure that all voltage support service providers are in compliance with the testing and reporting requirements for this ancillary service. The NYISO staff has also requested Transmission Owners and Generation Owners to identify local (in plant or station) issues that might limit a particular generator’s voltage support capability.

Ontario

The IMO has the authority to test the declared reactive capabilities of generating units. Testing of generating units, critical to the support of key portions of the IMO-controlled grid has been performed. Analysis of the test results are underway to ensure that the demonstrated reactive capability is sufficient to meet system voltage support requirements.

Quebec

Being a winter peaking area, TransÉnergie does not encounter voltage collapse problems during the summer. On the contrary, controlling overvoltages on the 735kV network during off-peak hours is the concern. This is accomplished mainly with ample provision of shunt reactors.
Environmental Impacts

The major Federal rules that apply to electric generating sources in the northeastern United States are the Acid Rain regulations, New Source Performance Standards (NSPS) and State Implementation Plans (SIPs). The Acid Rain regulations require power plants to reduce both SO₂ and NOₓ emissions on a year round basis. The NSPS regulations set regulations for new power plants and States develop SIPs to meet National Ambient Air Quality Standards (NAAQS). In the northeast U.S., the NAAQS of most concern is the ozone NAAQS. In order to meet the NAAQS, states in the northeast have developed a summer time NOₓ Budget Trading Program that has been in effect for the last three summers. Under this program, sources in participating States will be allocated around 212,838 allowances. Last summer these same sources emitted around 193,000 tons. In the three summers prior to 2002, a bank of 78,746 tons had been saved. However, according to the Clean Air Markets Division of the EPA there will be zero banked allowances carried forward into the 2003 ozone season because the NOₓ Budget Program is transitioning to the NOₓ State Implementation Plan (SIP) Call Program.

The environmental regulations affecting electric generating sources in Regions 1 and 2 (northeastern US) for the summer 2003 include both market based cap-and-trade programs and traditional command and control programs. EPA’s Acid Rain Program and the northeast’s NOₓ Budget Program are cap-and-trade programs that encourage sources to find the most cost effective means of meeting environmental goals while promoting energy efficiency. Other programs such as the New Source Performance Standards are command and control programs based on emission rates for given boiler types. Permitting issues related to new generation placement are a major portion of the command and control rules.

Short-term impacts on individual unit operation during 2003 summer are more influenced by the summer time regulations as opposed to the annual regulations because these regulations are more stringent. For the NOₓ Budget Program, sources may either install NOₓ control technologies or buy allowances from sources that have been overcontrolled. It is possible that fuel switching between oil and gas can be a problem. Quick start-up of mothballed units is also allowed under the rules.

Overall, it is not expected that EPA rules will have a major impact on electric system reliability through its environmental programs during 2003 summer. State, provincial and local environmental rules are expected to have more of an impact on electric system reliability that is described in more detail by Control Area.

Another environmental impact influencing generation during the summer is water level. This was a significant issue during the Summer 2002. With the exception of the Great Lakes, the above average precipitation during the latter half of 2002 and continuing into 2003 has allowed most reservoirs in the northeastern states to recover to normal condition. Snowpack depth in the watershed areas of the northeast is also near normal levels. Based on current forecast information, it is anticipated that hydro
generation and other generating facilities that use water for purposes of emission control or cooling are not likely to be impacted. Generators are encouraged to monitor water levels as the Summer peak season approaches.

The following are the Area assessments discussing environmental related issues.

Maritimes

The Maritimes Area closely monitors air emissions and other environmental discharges to ensure compliance with standards and limits set forth by Canadian Federal and Provincial environmental regulations. For the summer 2003 period, there may be occasions when some units are required to be de-rated in order to meet these regulations. However, these occasions are expected to be infrequent and of short duration.

New England

ISO-NE is mindful of environmental restrictions and constraints on New England’s generating capacity and usually conducts an annual pre-seasonal review. In preparation for the summer of 2003, a letter will be sent to all generating facilities within New England inquiring about the status of their environmental permits and potential impacts on operations due to environmental constraints. Generators are encouraged to pursue temporary waivers of their environmental permits during periods of extreme capacity deficiencies.

New York

There is a limited possibility that there may be a shortage of available capacity in the New York City metropolitan area due to environmental constraints. An extended period of high temperatures and high humidity leading to an unacceptable level of ozone in the region may limit the availability of generation to meet load. In 2001 the NYISO obtained a waiver from the New York State Department of Environmental Conservation (DEC) to address such an air quality emergency and is continuing to work with the DEC staff on this concern. Should such a situation arise, it is incumbent on the NYISO to maximize the availability of generation outside the effected area and insure that all other steps are taken in accordance with the capacity emergency procedures (NYISO Emergency Operations Manual). After this the DEC would allow operation outside of emission limits to avoid curtailment of firm load in New York.

During the second half of 2001 and continuing into 2002, precipitation over much of the Region was below average and was approaching drought conditions. As noted above, near average rainfall in the latter half of 2002, and precipitation levels and snowpack depth in the watershed areas of upstate NY are above normal approaching the end of Winter 2003. Should precipitation levels remain near average, water use
restrictions are not likely, and are not expected to effect generating availability or capacity.

Ontario

There are many environmental issues that specifically affect the operation of facilities in Ontario during the summer operating period. Compliance with these standards is strictly monitored by the facility owner.

Some facilities have annual energy limitations to observe permissible emission limits. These annual limits are not expected to impact the overall energy and capacity projections for the summer operating period.

It is also recognized that there is a potential to restrict generation to respect environmental regulations due to cooling water temperatures etc. The timing and the overall impact of any restrictions are unpredictable.

Currently it is the facility owner that would request the appropriate authority to permit a variance from these obligations to assist in a capacity deficiency. Experience gained in 2002 was utilized to revise procedures where the IMO requests the facility owner to obtain variances to environmental obligations under emergency procedures. These revised procedures should expedite any request to obtain an environmental variance if it is required.

Quebec

The bulk of generation in Quebec is hydroelectric based, therefore the environmental concerns, as they pertain to this report are not of concern.

Geomagnetically Induced Currents (GICs)

Past experiences have shown the serious effect that geomagnetic disturbances can have on the NPCC bulk power system. Quasi-DC currents induced in power lines flow to ground through transformer neutral connections. This can result in saturation of the transformer core leading to a variety of problems, including increased heating that has resulted in transformer failures. In addition, the harmonics generated in the transformer, as a result of the saturation, may produce unanticipated relay operations, such as sudden tripping of transmission lines or shunt capacitors.

GICs are produced by the magnetic field variations that occur when a mass of electrically charged particles from a solar coronal mass ejection impacts the earth’s magnetic field. Because of the low frequency compared to the AC frequency, the geomagnetically induced currents appear to a transformer as a slowly varying DC current.
GIC flowing through the transformer winding produces extra magnetization, during the half-cycles when the AC magnetization is in the same direction this effect can saturate the core of the transformer. This also results in severe distortion of the AC waveform with increased harmonic levels that can cause incorrect operation of relays and other equipment on the system and may lead to problems ranging from trip-outs of individual lines, transformers or shunt capacitors to collapse of the whole system.

GIC activity correlates to 11-year sunspot cycles. We are presently in Cycle 23 (twenty third cycle recorded runs approximately from 1996 through 2007), which began in 1996 and is predicted to end about January 2007. During the portion of the solar cycle that has greater sunspot activity, there is a higher probability of GICs occurring, which could impact the NPCC system. Observations of sunspot activity only provide insights as to the timing of the release of energy; it is the solar winds that ultimately determine the intensity and duration of a geomagnetic storm and those areas of the earth that will be ultimately affected. A satellite, positioned between the earth and the sun is capable of determining the intensity of the storm. The timing between when this satellite senses the magnitude of the storm and when the effects are noted on the earth is less than 1 hour.

Within NPCC the CO-8 Operations Managers Working Group has explored ways to obtain accurate and timely forecasts of solar magnetic disturbances and the resulting GICs for the NPCC Control Areas. NPCC has contracted for GIC forecasting services from Solar Terrestrial Dispatch (STD) for a three year period. Forecast information is provided directly to the control centers in the NPCC Areas.

Regarding recent GIC activity by the end of 2001 it was apparent sunspot activity had achieved a second peak late in the year. Activity is now on the declining side of solar cycle 23, and the minimum is predicted to occur in late 2006 or early January 2007. Significant GIC activity was observed in the months of April and October of 2002; however, no direct power system impact was identified. The following graph illustrates past geomagnetic disturbance levels and projections of future solar activity. Monthly updates, and further information can be found at www.sec.noaa.gov/. Based on historical experience, the affects of GICs to reliability should be manageable with our present procedures.
The following is a summary of each Area’s experiences of GIC activity through the recent “high period” as evidence of the potential impact to NPCC Control Areas as well as a summary of control actions in place to reduce the impact of GIC.

Maritimes

The Maritimes Area did not experience any significant disturbances in 2002 and no major problems are anticipated for 2003. The Maritimes Area Operating Procedures are consistent with NPCC Operating Procedures for GIC activity.

New England

On several occasions during 2002, New England received geomagnetic storm warnings. Proper notifications were made and applicable actions were taken in accordance with NPCC document C-15 entitled, “Procedures for Solar Magnetic Disturbances on Electrical Power Systems.” On May 23, 2002, several Level 1 GIC alarms were reported at the Chester Static VAR Compensator (SVC) in Maine. On that day, scheduled imports over the HQ HVDC Phase II facility and the tie with New Brunswick were temporarily reduced to ensure transmission reliability.
New York

During 2002, NYISO received notification of observed K-7 three times. There were no effects experienced that were comparable to the storms of March and November 2001, and there were no GIC power system effects observed.

Ontario

The IMO received numerous geomagnetic storm warnings throughout the period extending from 2001 into 2003. No actions beyond those required by the existing procedures were taken and no operating problems beyond elevated neutral currents were observed through this period.

Quebec

During the summer of 2002, there were two occurrences of GICs. Alerts were called on May 24, 2002 and on September 7, 2002. The alerts predicted Kp levels of 7-8 and they actually reached 7 on both occurrences and no adverse effects on the bulk system were recorded. Maximum voltage asymmetry recorded was 1.3%. Some transfer limitations on the bulk system were imposed but Interconnection capacities were not affected.

Operating Procedures

Detailed NPCC Operating Criteria, Procedures, Guides and Reference Documents provide the Areas with the necessary material to develop and maintain a concise set of operating procedures that are relevant to maintaining the security of the Control Area by observing local operating parameters. Listings and descriptions of the documents related to operational readiness for the summer months are summarized in Appendix II.

TFCO is systematically replacing operations-related “B” and “C” documents by adding the requirements language from these documents to “A” documents, creating Reference Documents with the non-requirements content.

Since the Reliability Assessment for Summer 2002, the following revisions to NPCC documentation have occurred:

The A-3 “Emergency Operation Criteria” and the A-6 “Operating Reserve Criteria” documents have been revised and approved by the NPCC membership. In addition, definitions required in the A-3 and A-6 documents have been added to the A-7 “Glossary of Terms” Document. New Reference Documents RD-04 “Operating Procedures for AEC Diversity Interchange” and RD-05 “Procedure for Operating Reserve Assistance” have been created. Also, draft versions of Reference Documents RD-06 “Monitoring Procedures for Operating Reserve Criteria” and RD-07
“Procedures for Shared Activation of Ten Minute Reserve” have been developed as revisions to the present C-9 and C-12 documents, respectively.

Major revisions to the A-3 Document include: inclusion of the requirements and specificity defined in former documents B-20, “Guidelines for Identifying Key Facilities and Their Critical Components for System Restoration,” and C-31, “Testing and Reporting Procedure for Key Facilities and Their Critical Components Required for System Restoration”. These requirements needed to be relocated into a criterion document. In addition, the monitoring of these requirements by the NPCC Compliance Monitoring and Assessment Subcommittee is specified.

Major revisions to the A-6 document include: the 30 minute restoration requirement for ten minute reserve deficiencies was changed to be consistent with the latest version of NERC Policy 1. This allows 90 minutes after the disturbance recovery period (15 minutes) for the contingency reserve to be restored – effectively 105 minutes from the start of the contingency and the synchronized reserve recovery requirement is extended from 10 to 15 minutes.

To be prepared to deal with the constantly changing conditions on the power system, NPCC routinely conducts weekly operational planning calls between Reliability Coordinators to coordinate short-term system operations. NPCC has also refined and expanded its emergency conference call mechanism to enable operational security entities in NPCC and neighboring regions to communicate current operating conditions and facilitate the procurement of assistance under emergency conditions. These calls may be initiated upon the request of any Reliability Coordinator and is coordinated by NPCC Staff. Due to the commercially sensitive real-time nature of the material discussed, only signatories to the NERC Confidentiality Agreement for Electric System Security Data may be party to these calls. The CO-8 Operations Managers Working Group has recently streamlined the emergency conference call procedure to be more focused on the situation causing the emergency and to limit discussion to the entities requesting emergency assistance and to those that could provide help. In addition, several security-related CO-8 conference calls have been held.

Each Area in NPCC is required under Document C-13, to review its coming twelve-week capacity margin projection on a weekly basis. This information is communicated to NPCC for review during the weekly conference operational calls held in accordance with C-13, “Operational Planning Coordination.” In addition to this review of twelve-week capacity margin projections, the weekly conference call discusses operations for the coming ten-day period as well as any information that may impact operations.

Each Control Area has complemented the NPCC Procedures and Guidelines with instructions as they apply to their local conditions. The following is a summary of activity that Areas have taken to ensure that instructions remain current.
Maritimes

The Maritimes Area Operating Procedures are in compliance with the NPCC Operating Procedures and are supplemented with local procedures.

New England

On March 1, 2003, ISO-NE implemented the Standard Market Design (SMD). This new market aims to identify Locational Marginal Prices (LMP), resolving seams issues with surrounding control areas, and introduces many new features to New England’s wholesale electricity markets. New features include: a Day Ahead Market (DAM), Real Time Market (RTM), Financial Transmission Rights (FTRs), LMP, Auction Revenue Rights (ARRs), and significant modifications to existing market rules and procedures.

In order to efficiently convert to the new markets, ISO-NE and NEPOOL Participants have been involved in a number of market trials. These market trials were designed to simulate the proposed markets under future conditions and provide training to all stakeholders. Market trials were completed by February 1, 2003 and any problems arising from them were managed by March 1, 2003.

In parallel with the implementation of SMD, a considerable amount of effort was focused on reviewing and revising New England’s Market Rules and Operating Procedures. New England’s Operating Procedures are in compliance with the NPCC Operating Procedures and NERC requirements.

New York

The NYISO continues to review and refine operating and market processes based on experience gained through the sustained peak load periods of the previous summers. The positive experience with the initial implementation of the Emergency Demand Response Program during that period means that program will continue and expand. Staff will continue the review of Operating Procedures to insure that these procedures remain consistent with NERC and NPCC requirements and with the interconnection agreements and coordinating procedures with the adjacent Areas.

Ontario

The IMO continuously reviews and revises all operating procedures to ensure that they are consistent with both NERC and NPCC requirements as well as with the Market Rules for Ontario.

Throughout the summer operating period, additional NERC Certified System Operators will be available to supplement Control Room Operations staff as conditions dictate.
Quebec

In the event of a capacity deficiency, TransEnergie would first ask Hydro-Quebec Marketing (HQM) to find additional generation in or out of the Control Area. After this step, Emergency Operating Procedures, compliant with NERC and NPCC are implemented.

Changes to Operating Procedures in Shoulder Months

As previously indicated in this report, the uncertainties associated with weather variability and maintenance overruns in the spring months can quickly lead to resource shortfalls. Past history has indicated that resource assessment procedures need special attention during this time frame. As a result of these capacity shortfalls, many of the Areas have taken actions to prevent a reoccurrence and are described below.

Maritimes

The Maritimes Area Operating Procedures for the shoulder and summer period are essentially the same as for the summer of 2002 and no changes are anticipated for the summer of 2003.

New England

ISO-NE’s Outage Coordination staff has reviewed the proposed maintenance schedules for generators in the Control Area and, where appropriate, have worked with the owners to adjust their outages in anticipation of load levels that may be experienced in the weeks prior to or following the summer peak load exposure period. However, there is a large amount of capacity scheduled out-of-service in May and if many of these units experience maintenance overruns, the operable capacity margins projected for June could be adversely degraded.

New York

NYISO Scheduling staff has reviewed the proposed maintenance outage schedules for generators in the Control Area and, where appropriate, have worked with the generator owners to adjust the outage schedules in anticipation of load levels that may be experienced in the weeks prior to or following the peak load exposure period.

Ontario

As stated above, the IMO has performed an extensive review of reliability procedures prior to incorporation into new market manuals. This includes the procedure for maintaining reserve margins and rectifying negative margins. These procedures will be enforced to ensure that the necessary control actions are taken in the appropriate time frame if needed to ensure that planning obligations are met.
The TransÉnergie Operating Procedures are updated on a continuous basis to reflect changes in the regulations, market rules and local procedures. There is not, however, any special Operating Procedures in the summer or shoulder months because TransÉnergie is a winter peaking system.

Load Response Programs

Each Area utilizes various methods of demand management associated with interruptible loads. In those Areas where market based structures have been implemented or are evolving there has been a shift in contractual obligations of the interruptible loads. The move is an attempt to manage load interruption, as a result of demand exceeding resources, by giving industrial and commercial customers the ability to respond to price signals in the wholesale electricity marketplace. Many of these programs are in varying degrees of development. The following is a summary of current interruptible load programs available or in development to be available for the summer period in each Area.

Maritimes

The Maritimes Area is a winter peaking area and does not have any Load Response Programs. Interruptible and Dispatchable loads are available for use when corrective action is required within the Control Area.

New England

During times of capacity deficiencies, ISO-NE declares NEPOOL Operating Procedure No. 4 (“Action During a Capacity Deficiency OP-4”) that includes; purchasing emergency energy from the neighboring control areas, interrupting dispatchable and interruptible load customers, implementing voltage reductions, and public appeals for conservation. This Emergency Operating Procedure (EOP) provides load relief measures estimated to be between 1,700 MW to 2,700 MW4.

In addition to OP-4, ISO-NE and NEPOOL Participants are continuing the Load Response Program (LRP) with the goal of temporarily reducing peak electricity demand by large power users. Through the LRP, NEPOOL Participants or Demand Response Providers enrolled directly with ISO-NE can enter into agreements with retail customers to encourage them to reduce their electricity consumption during periods of high prices or peak demand.

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4 This value is based on the NEPOOL OP-4 document as of November 20, 2002 which can be found at: www.iso-ne.com/cmsmss/Standard_Market_Design/Operating_Procedures/
Within the LRP, an asset can reside in one of four distinct programs:

1 – Day-Ahead Demand Response Program
2 – Real-Time Demand Response Program
3 – Real-Time Price Response Program
4 – Real-Time Profiled Response Program

Participants in the Day-Ahead Demand Response Program will offer an amount of energy into the Day-Ahead market and, if cleared, will be required to interrupt as offered. Those participants that do not clear in the Day-Ahead Demand Response Program have the option to participate in the Real-Time Price Response Program. Within this program, participants will have the option to voluntarily reduce energy consumption in real time when the Zonal Price produced by the Day-Ahead Energy Market is greater than or equal to $100/MWh.

Participants involved in the Real-Time Demand Response and Real-Time Profiled Response Programs will be activated during pre-determined actions of OP-4. Further details pertaining to the four programs can be found in the ISO-NE Load Response Manual.

New York

The NYISO introduced a new load response program for the New York Market in May 2001. The Emergency Demand Response Program is a program in which Customers would be paid to reduce their consumption by either interrupting load or switching to emergency standby generation when requested by the NYISO. During the Summer 2002 period, NYISO activated the EDRP on two occasions. NYISO received 663MW on July 30, and 636MW on August 14.

The Emergency Demand Response Program is continuing for Summer 2003, and NYISO estimates that approximately 700MW of load relief will be available to support the New York State power system during capacity emergency periods through this program. This program is in addition to the relief obtained through the emergency procedures for Operating Reserve Peak Forecast Shortage (Section 4.4.1 NYISO Emergency Operations Manual) or in response to the major emergency state (Section 3.2 NYISO Emergency Operations Manual).

Ontario

As mentioned in the resource adequacy assessment, under the IMO-Administered Market, there are about 300 MW of price responsive loads. A majority of these loads are treated as a resource that will be dispatched off the system by the IMO once the price of energy in the real time market has exceeded the bid (to Buy) price submitted by the load. The subject load must then reduce their demand according to the dispatch instructions or the load will face compliance proceedings.
In 2002, the IMO instituted an Emergency Demand Response Program to provide additional demand relief under emergency conditions. The pilot program, which runs until April 30, 2003, saw an additional 340 MW of customers involved in this contracted ancillary service. The customers would reduce their demand on a voluntary basis. This step was implemented just prior to the interruption of firm load. The effectiveness of the pilot program has been reviewed and work is underway to extend the program for the summer of 2003.

Quebec

The Quebec Area is a winter peaking system and does not usually need to resort to the load response programs during the summer, although, of the 1,356 MW of interruptible power available in winter, 667 MW could be called on if needed during the summer.

Emergency Communications Systems with Customers

There is nominally some time lag for control actions to take effect to rectify a resource deficiency. In the evolving market places there are now many players in Areas where at one time there were only a few. As a result, simultaneous communications need to be timely and efficient for multiple resources to respond to directions by the Reliability Coordinator to quickly mitigate the need for emergency control actions, including the shedding of load.

Below is a summary of the communication medium that each Area utilizes to communicate emergency situations with generators, transmitters and customers.

Maritimes

The individual Control Centers within the Maritimes Area provide timely and accurate information regarding the status of the power system to customers via websites, news releases, high volume Interactive Voice Response System and telephone contact through Public Affairs and Customer Services departments or Call Centers.

New England

In the event of a capacity deficiency, ISO-NE’s website provides real time information to the general public regarding the status of the power system and the amount of Emergency Energy Transactions requested during peak periods. In addition, Control Room Operations will convey the necessary information to ISO-NE’s Customer Service & Training and the Media and Corporate Communications Departments so that they can make the necessary communications to federal and state regulatory agencies and the media. Operations personnel convey the details of any capacity deficiency to the Satellite Control Centers and neighboring NPCC Areas as appropriate.
In addition, ISO-NE creates a seven-day forecast that is posted to the ISO web site. This posting includes a capacity analysis for the peak hour of each day, detailing the forecasted amount of surplus/deficient capacity for each future day to illustrate anticipated system conditions.

New York

The NYISO is continuing implementation of its Inter-Control Center Communications Protocol communications system (ICCP) allowing bi-directional data communication directly from the NYISO control center systems to the generating plants. In normal operation this facilitates the transmitting of schedules and base-points from the NYISO dispatch system to the generators, and improves the accuracy and timeliness of generator real and reactive power metering.

The NYISO website now displays information including actual control area load in addition to the real-time zonal pricing information and transmission outage schedules. Market Participants may also access a “dispatcher notes” page that provides information on current NYISO system operating conditions.

Ontario

On a daily and weekly basis the IMO will be issuing Security and Adequacy Assessments (SAA). These supply the Market Participants with detailed adequacy projections on an hourly resolution for a period of 14 days into the future and on a weekly resolution for the following two weeks.

The IMO also publishes to Market Participants a System Status Report (SSR) three times daily by Market Forecasts and Integration during the pre-dispatch period outlining deviations from the SAA published for days 1 and 2.

The SSR has capability to identify to Market Participants the following Advisories: Major Change Advisory, System Advisory and, System Emergency Advisory.

To address global adequacy concerns when there is insufficient energy or capacity available to the IMO-controlled grid or when there are insufficient offers in the real-time dispatch of the IMO-administered markets, the IMO shift staff can also issue a SSR. The SSR can be prepared on very short notice. A notice is sent to Market Participants via their dispatch workstations notifying them that a new SSR has been issued with the details of the SSR being published to the IMO Public Web site.

To address local area adequacy concerns, the IMO will direct Market Participants to submit offers, either via the Market Participant's dispatch workstation or telephone.

The IMO also recognizes the need to communicate with the general public at times when there might be supply shortfalls. To achieve this, the IMO created a public communications process to ensure that consumers and industries in the general public
were given all the information they need to make informed choices. The procedures proved to be an effective tool in 2002 for managing load during what proved to be the hottest summer in Ontario history.

Quebec

To satisfy demands in Quebec, TransÉnergie solicits additional capacity requirements it may need through Hydro Quebec Marketing (HQM). If HQM cannot secure the additional capacity required or there is not sufficient time to fulfill the need identified, TransÉnergie would take actions including the securing of emergency energy from neighboring systems, cutting of available interruptible loads and instituting voltage reductions. If these measures are deemed to be insufficient and there is adequate time a public appeal would be instituted through commercial media. The probability of resorting to these measures during the summer is very low.

Acquisition of Emergency Energy between Areas

In May of 2000, the NPCC Task Force on the Coordination of Operation adopted a Memorandum of Understanding for NPCC Area Emergency Assistance. This document outlines the steps to be taken when there is either a forecast or actual shortage of operating reserves. The objective of the process is to maximize the reliance on the marketplace to resolve resource inadequacies, minimizing the need for emergency transactions between Areas.

While all Areas are resolved to let the market place solve such inadequacies, there may be occasions where market forces cannot respond in the appropriate manner or time frame. The following is a summary of ability to transact emergency energy between adjacent Areas.

Maritimes

The Maritimes Area, through existing agreements with neighboring Control Areas, namely, ISO-NE and TransÉnergie, has established procedures for the acquisition of emergency energy.

New England

ISO-NE, through a bid based energy market, has procedures in place to determine the availability of emergency assistance from its neighboring control areas when necessary.

New York

During 2002, the NYISO completed updating of the emergency energy provisions in the interconnection agreements with the Control Areas neighboring New York.
Ontario

The IMO negotiated new operating agreements with the adjacent Reliability Authorities in 2002 as part of the steps to the new Market. These operating agreements contain provisions for the transaction of emergency energy into and out of Ontario and are only implemented in the event that market based solutions are ineffective.

Quebec

TransÉnergie has agreements with all the Control Areas neighboring Quebec that detail the conditions and procedures for acquiring emergency energy.

Training Programs

The Control Area operators routinely receive training as a regular part of their regime.

NERC is willing to offer the possibility to System Operators to replace their recertification requirement (every five years) by a proof of attendance to 16 hours per year of training coming from certified courses or programs. This would only be required for the last 2 years prior their recertification renewal (year 4 and 5) for a total of 32 hours for operators having been certified with the actual exam and, after having provided such a proof of attendance, every 2 years. These recognised hours of attendance would give operators CEH (Continuing Education Hours). Courses or programs providing those CEH would have to be certified by the NERC CERWG (Continuing Education Review Working Group). In April, a workshop will be offered in St. Louis for course and program providers to understand more the requirements that they will need to meet to be able to provide CEH. In summer, courses and programs certified to issue CEH could be offered by these providers and finally, in October or November the NERC Board of Trustees could approve this new process. More information is available on the NERC Web site.

The following is a summary of those activities planned prior to the summer operating period of 2003.

NPCC will be conducting a dispatcher seminar at ISO-New England on May 1 and 2, 2003, for dispatchers from each of the Control Areas in NPCC to share views and experiences. It is also a presentation vehicle for issues of concern to all NPCC Area operators. The keynote topic will be the New York-New England common market development. The seminar will also include the summer outlook for each Area, a summary of recent events within NPCC, developments coming from NERC, an update on NPCC policy and procedures, and a review of recent events in the industry. The agenda and seminar are developed by the NPCC CO-2 Working Group on Dispatcher Training, in conjunction with CO-8 System Operations Managers.
Maritimes

The Member companies that comprise the Maritimes Area routinely conduct their own operator training sessions and participate in NPCC Operators training seminars. Only the operators in the New Brunswick Power Control Center are required to be certified by NERC, although other operators have received certification. The Maritimes Area participates in the CO-2 Dispatcher Training Working Group.

New England

In late spring of 2003, ISO-NE Operators and satellite control center personnel will participate in training sessions in preparation for the summer peak load period. During these training sessions, applicable NPCC procedures and NEPOOL EOPs are reviewed in detail. The summer capacity assessment is also reviewed as well as area-specific voltage control issues and intra-area communication procedures. Training of ISO-NE Operations staff, including the Satellites, is continually on-going.

New York

NYISO Dispatcher Training staff will be conducting two weeks of in-house training for each crew of NYISO dispatchers prior to the summer of 2003. These sessions will address operations issues, updates on NERC activities (Policy 9, Infrastructure Protection Initiative, E-tag, etc.), NPCC policy changes, updates on NYISO market operations and market design, updates to NYISO applications and procedures.

NYISO Dispatcher Training staff also presented a series of one week System Operator Training Seminars for a combined audience of the NYISO dispatch staff and New York Transmission Owner (TO) system control operators. This program reviewed selected NYISO operating policies, recent system events, the system outlook for the Summer 2003, and issues of mutual concern to both TO and NYISO dispatchers. NYISO emergency operation procedures (Back-up Dispatch System, Alternate Control Center operation, and Restoration) were also reviewed in preparation for the spring drills.

Ontario

The IMO continuously operates a training program to ensure that the control room staff maintains awareness of current and new NERC, NPCC and local operating procedures.

In preparation for the summer operating period, the IMO has set aside time in the training program for Shift Operations staff to review results of the IMO summer assessment, review reactive dispatching techniques as well as, a review of the changes to emergency procedures.
Additionally, the IMO plans and participates in drills and exercises on a regular basis to hone emergency preparedness skills and test procedures by simulating real events.

On October 2, 2002 the IMO led an integrated power system restoration exercise to enhance and improve the response capabilities of the IMO, Market Participants and Emergency Response organization during emergency situations. Exercise 2002 successfully met all objectives through a comprehensive simulated power system restoration of southern Ontario excluding the portion east of Toronto. The Exercise involved the shift operations from the IMO and 23 other organizations. These included 11 major Distributors, 2 Transmitters, 5 Connected Wholesale Customers, the Ministry of Energy, Emergency Management Ontario, and 3 Generators.

The IMO will also perform a Rotational Load Shedding simulation exercise prior to the summer operating market commencement. This exercise will test procedures and training as well as verify communication methodologies and validate revised load shedding schedules.

Quebec

Aside from continually on-going training of the operations personnel, there are monthly and seasonal meetings where anticipated conditions are discussed and new procedures are explained.

7. 2002 Post-Seasonal Assessment and Historical Review

2002 Post-Seasonal Assessment

At the request of the Task Force on Coordination of Operation the Operations Planning Working Group conducted an assessment that reviewed 2002 summer actual operating conditions versus the 2002 Summer NPCC Reliability Assessment Report projections. The following summarizes some highlights of the review. Please refer to the 2002 Summer Report for details on projections.
Ontario

The 2002 summer was one of the warmest on Record. Hot humid conditions were experienced throughout the summer in Ontario. As a comparison, the actual weekly average temperature at Toronto exceeded the historical average temperature in every week of the report period except four. The chart below shows the average weekly temperature in 2002 plotted against the 30-year weekly average temperature as recorded at Toronto's Pearson Airport.

While the above graph shows the average temperatures for the summer exceeded the historical average, it is important to point out that there were 40 days where the maximum daily temperature exceeded 30 degrees Celsius (The historical average is normally only 12 to 13 days per summer). Additionally, there were 5 periods in the summer where this temperature extreme lasted 4 or more consecutive days with the longest lasting 8 days. Also of note were the above normal temperatures experienced though most of the month of September.
With the higher than expected temperatures came higher than expected demands. The following chart shows the actual Ontario hourly peak against the three curves illustrated in the 2002 TFCO Summer Operating Reliability assessment. The load exceeded 25,000 MW on 6 days through the report period for a total of 23 hours.

<table>
<thead>
<tr>
<th>Days Max Temperature above 20°C</th>
<th>May</th>
<th>June</th>
<th>July</th>
<th>August</th>
<th>September</th>
</tr>
</thead>
<tbody>
<tr>
<td>Historical</td>
<td>11.8</td>
<td>23.6</td>
<td>30.1</td>
<td>28.8</td>
<td>16.7</td>
</tr>
<tr>
<td>2002</td>
<td>9</td>
<td>21</td>
<td>31</td>
<td>30</td>
<td>26</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Days Max Temperature above 30°C</th>
<th>Historical</th>
<th>0.43</th>
<th>2.3</th>
<th>5.7</th>
<th>3.2</th>
<th>0.8</th>
</tr>
</thead>
<tbody>
<tr>
<td>2002</td>
<td>0</td>
<td>6</td>
<td>16</td>
<td>12</td>
<td>6</td>
<td></td>
</tr>
</tbody>
</table>

**Monthly Peak Hourly Demand for Ontario**

<table>
<thead>
<tr>
<th>Month</th>
<th>Day</th>
<th>HE</th>
<th>Hourly Demand</th>
</tr>
</thead>
<tbody>
<tr>
<td>May</td>
<td>30</td>
<td>16</td>
<td>20,068</td>
</tr>
<tr>
<td>June</td>
<td>26</td>
<td>16</td>
<td>23,578</td>
</tr>
<tr>
<td>July</td>
<td>3</td>
<td>16</td>
<td>25,330</td>
</tr>
<tr>
<td>August</td>
<td>13</td>
<td>14</td>
<td>25,414</td>
</tr>
<tr>
<td>September</td>
<td>8</td>
<td>17</td>
<td>25,062</td>
</tr>
</tbody>
</table>
With no new generation resources forecasted it was highlighted in the 2002 TFCO Summer Reliability Assessment that extreme weather impacts and/or higher than forecast outage rates would require the IMO control area to have a high reliance on imports. This was true throughout the summer operating period and into September. The maximum import attained was approximately 4200 MW, which is also close to the maximum simultaneous transfer capability into Ontario.

While the IMO relied upon market mechanisms to provide the required energy and operating reserve to the maximum extent possible, off market control actions, including the purchase of Emergency Energy from Neighbouring Reliability Coordinators were required on several occasions to supplement Energy and Operating Reserves. An emergency operating state was declared twice to maximize transmission capability. An EEA 3 alert and a 3% voltage reduction were implemented on one occasion. During an EEA 3 alert firm load interruption is imminent or in progress.

The IMO requested generators to seek environmental variances from outflow discharge temperatures limits at fossil facilities on two occasions. This request was made to ensure that the IMO had adequate energy in the event that the IMO suffered its single largest contingency. The approvals were granted, but the variances were not exercised.

The IMO effectively utilized the NPCC emergency conference calls 34 times and periodically joined the MISO Planning Conference call to ensure Neighbouring Reliability Coordinators in NPCC, PJM and MISO of the current or predicted operating state of the system.

The IMO maintained contact with Market Participants through System Status Reports (SSR) and System Adequacy Assessments (SAA) to identify the current and projected status of the IMO-administered market and the IMO-controlled grid.

Additionally, as resources became strained, the IMO issued public advisories and warnings to the general public through normal media facilities.

The transmission system performed well with minimum voltages being observed at all times, although marginally during certain periods.

The IMO completed a number of activities in preparation for the summer such as training, additional reliability studies under high demand conditions and the contracting for Emergency Demand Responsive loads. Utilization of the Emergency Demand Responsive loads was not required. These measures allowed the IMO staff to operate the system in a reliable manner through the period.
New England

During the summer of 2002, there were 12 days in which the temperature exceeded 90 °F in New England. The total New England Power Pool’s (NEPOOL) electrical load exceeded the reference peak load forecast of 24,200 MW (50% probability of forecast being exceeded) in 4 differing weeks. The summer 2002 New England peak load was 25,348 MW. Emergency Operating Procedures (EOPs) were implemented on six different days. Assistance from neighboring systems was utilized when necessary but overall, generation performed well and there were no major operating problems.

The load response program for the summer of 2002 included, at the time of the peak load, more than 250 customers providing a total of approximately 202 MW (including nearly 100MW in Southwest Connecticut). While the voluntary, price response program was implemented on twelve occasions during the summer of 2002, the mandatory demand response program was not activated during the summer.

About 3,800 MW of new generation had been projected to become commercial during the summer. Of this, only 350 MW actually went into service. Regional drought conditions did not have much impact on system operation.

Quebec

The Quebec summer peak load was 20,525 MW on September 9, 2002, which is about 1,000 MW above the expected peak. A late winter peak of 22,523 MW occurred on May 14 with temperatures at or below the freezing point all over the province. In July and August, major forest fires came near some major substations and the heavy smoke caused some insulator flashovers that resulted in a few lines tripping. Some transmission limitations were applied but did not affect the ability of TransÉnergie to provide outside assistance.

New York

NY experienced some unseasonably warm weather in the spring where the demands exceeded the winter peak demand. The summer of 2002 also saw several hot and humid days when demand exceeded 30,000 MW. The NYISO served demand greater than 30,000MW for a total of 25 hours and six separate days. The NY Control Area peak load was 30,664MW on July 29.

New capacity additions to the NYISO system during the summer totaled 435 MW, consisting of 10 natural gas fired combustion turbines on Long Island. The Long Island Power Authority also entered into a short-term lease for 10 truck-mounted combustion turbines for emergency energy supply during the summer peak load period. These units were used on several occasions during the peak load period.
A second Rock Tavern 345/115 kV transformer was placed in service. The Athens 345 kV substation was established on one of the existing Leeds – Pleasant Valley 345kV circuits as part of the preparation for the new Athens Generating Station expected to be operational during the Summer 2003. Construction of the HVdc Cross Sound Cable was completed between New Haven Harbor (ISO-NE) and Shoreham (NY) in August, and operational testing was conducted, but did not become available for commercial operation during the period.

Maritimes

The peak load experienced by the Maritimes Area during the May – September period was 3,731 MW, which was approximately 184 MW (5.2%) higher than last year’s forecast of 3,547 MW. This is due to the peak occurring in May while experiencing below normal temperatures. This resulted in a greater electric heating load than would normally be the case.

The Maritimes Area did not anticipate, nor did it experience, any capacity shortages during the summer of 2002. In fact, it was able to supply up to 700 MW (interconnection limit) to New England. However, transmission constraints due to excess generation in Northern New England sometimes reduced the power that could be transmitted.

Historical Review (Pre-2002)

As summarized in the table below, the forecasted 2003 summer peak is projected to be below the 2001 and 2002 actual peak for the NPCC Area. This is primarily due to slower economical growth and the fact that the previous years peak demand was the result of extreme weather conditions. If extreme weather conditions are experienced again this summer, it is likely that the forecast below will be exceeded.

<table>
<thead>
<tr>
<th>Year</th>
<th>Ontario⁶</th>
<th>Maritimes</th>
<th>New England</th>
<th>New York</th>
<th>Quebec</th>
<th>Total NPCC Demand</th>
</tr>
</thead>
<tbody>
<tr>
<td>1993</td>
<td>20,883</td>
<td>2,773</td>
<td>19,570</td>
<td>25,998</td>
<td>17,500</td>
<td>86,724</td>
</tr>
<tr>
<td>1994</td>
<td>20,918</td>
<td>2,797</td>
<td>20,519</td>
<td>27,062</td>
<td>17,562</td>
<td>88,858</td>
</tr>
<tr>
<td>1995</td>
<td>21,674</td>
<td>2,958</td>
<td>20,499</td>
<td>27,206</td>
<td>17,960</td>
<td>90,297</td>
</tr>
<tr>
<td>1996</td>
<td>21,378</td>
<td>2,937</td>
<td>19,507</td>
<td>25,587</td>
<td>18,193</td>
<td>87,602</td>
</tr>
<tr>
<td>1997</td>
<td>21,613</td>
<td>3,252</td>
<td>20,569</td>
<td>28,700</td>
<td>17,983</td>
<td>92,117</td>
</tr>
<tr>
<td>1998</td>
<td>22,443</td>
<td>3,314</td>
<td>21,406</td>
<td>28,166</td>
<td>18,463</td>
<td>93,792</td>
</tr>
</tbody>
</table>

⁵ Peak Demand in MW
⁶ 20 minute Peak Demand
### 8. 2003 Reliability Assessments of Neighboring Regions

**East Central Area Reliability Coordination Agreement (ECAR)**

Information from the ECAR 2003 Summer Assessment of Load and Capacity is not available for release at this time pending review and approval of the ECAR members. The following information is taken from the “Preview of 2003 Summer Conditions” that is contained in ECAR’s 2002/2003 Winter Assessment of Load and Capacity.

The projected summer peak demand in ECAR for the summer of 2003 is 101,800 MW for Total Internal Demand. This 2003 summer peak is derived from demand forecasts received in January 2002 with any updates through August 2002. Therefore, actual operating experience from the last half of 2002 was not considered in developing this peak demand forecast.

Total capacity for the summer of 2003 is projected to be 128,090 MW. This assumes 7,475 MW of announced capacity additions within the ECAR region are in service by July 2003. Net scheduled interchange into the ECAR region at the time of the peak is anticipated to be 2,590 MW, making total Capacity Resources of 130,680 MW.

Capacity Margins for the summer of 2003 are forecast to be higher than the margins forecast for the summer of 2002, based on the level of announced generation projects. The capacity margin based on Total Internal Demand (interruptible and direct control loads are served) and scheduled interchange is 28,880 MW (22.1% of Net Capacity Resources). This assumes the announced capacity additions within the ECAR region are in service by July 2003.

Recent experience indicates that a minimal amount of capacity (263 MW) is expected to be scheduled out of service during the summer peak. This scheduled capacity

---

<table>
<thead>
<tr>
<th>Year</th>
<th>Demand</th>
<th>Reserve</th>
<th>Total Capacity</th>
<th>Capacity Margins</th>
<th>Capacity Margin as % of Net Capacity Resources</th>
</tr>
</thead>
<tbody>
<tr>
<td>1999</td>
<td>23,435</td>
<td>3,249</td>
<td>22,544</td>
<td>30,311</td>
<td>18,965</td>
</tr>
<tr>
<td>2000</td>
<td>23,222</td>
<td>3,630</td>
<td>22,049</td>
<td>28,138</td>
<td>20,600</td>
</tr>
<tr>
<td>2001</td>
<td>25,269</td>
<td>3,640</td>
<td>24,967</td>
<td>30,983</td>
<td>20,052</td>
</tr>
<tr>
<td>2002</td>
<td>25,414</td>
<td>3,731</td>
<td>25,348</td>
<td>30,664</td>
<td>20,525</td>
</tr>
<tr>
<td>2003 Forecast</td>
<td>23,684</td>
<td>3,813</td>
<td>25,120</td>
<td>31,430</td>
<td>20,740</td>
</tr>
<tr>
<td>Percent Difference</td>
<td>-6.81%</td>
<td>+2.20%</td>
<td>-0.90%</td>
<td>+2.50%</td>
<td>+1.01%</td>
</tr>
</tbody>
</table>

7 This value is the weather normal demand used for the base case analysis. A graph in Section 4 represents the ranges of potential demands that the IMO could experience as a result of weather variables.

8 Percent Change reflects the increase/decrease in projected peak for the 2003 summer over the actual peak for the 2002 summer.
outage along with a 4% operating reserve requirement (4,072 MW) means that the Margin for Contingencies is expected to be 24,545 MW at the time of the ECAR peak. Recent random outage experience suggests that there is less than a 1% probability that random outages will exceed this Margin for Contingencies. This is the probability that the ECAR members will have to rely on supplemental capacity resources at the time of the peak. Supplemental capacity resources can include additional imports of power from outside the region, and/or the curtailment of contractually interruptible loads.

Under a severe condition scenario which assumes a combination of adverse conditions, (an additional 5% of load due to extreme hot weather, none of the projected capacity additions in service, and greater than 13% unavailable capacity), the ECAR Region will not have sufficient resources without supplemental power purchases. However, based on the import capability, there should be sufficient resources for this severe condition scenario.

Transmission assessment information is contained in the 2003 Summer Assessment of Transmission System Performance, ECAR report 02-TSPP-3. This report will be published in mid-May 2003.

The bulk transmission systems in ECAR are expected to perform reliably under a wide range of conditions. However, there will be a greater need for the Reliability Coordinators and Transmission Operators to communicate and coordinate their actions to preserve the continued reliability of the ECAR systems. It is anticipated that the ECAR transmission systems could become constrained as a result of unit unavailability and/or economic transactions that have historically resulted in large unanticipated power flows within and through the ECAR systems. If these conditions occur again this summer, local operating procedures, as well as the NERC Transmission Loading Relief procedure, will need to be invoked in order to maintain transmission system security. As long as transmission limitations are identified and available operating procedures are implemented when required, the ECAR bulk transmission systems are anticipated to perform reliably. During times of heavy regional and interregional transfers, it will be essential that Reliability Coordinators and Transmission Operators have timely and adequate information on the sources and sinks of scheduled transfers in order to identify appropriate corrective actions.

**Mid-Atlantic Area Council (MAAC)**

The MAAC 2003 summer forecast net peak demand is 53,591MW. This forecast includes the effects of interruptible demand and load management capabilities which are estimated to be 17,998 MW. The forecast peak assumes normal summer weather conditions. This forecast is 2,412 MW lower than the actual MAAC all-time summer peak of 56,003 MW that occurred on August 14, 2002.

Between June 1, 2002 and June 1, 2003, MAAC’s summer generating capacity is expected to increase by a net of 4,663 MW to 65,871 MW. 1,927 MW of the expected increase is already in service. All nuclear units should be in service and at
full capacity (13,030 MW) at the time of the peak. MAAC also has 488 MW of external capacity resources under contract through the summer peak period. Also, 11 MW of generating capacity is expected to be added between June 1st and the forecasted peak in July. With the planned new generation, existing internal generation, and external capacity resources included, the MAAC capacity margin is forecasted to be 19.2% at the time of the forecasted peak.

The MAAC reserve margin is expected to be 23.8% at the time of the forecasted peak. With the 11 MW of generating capacity that is expected to be added within the summer demand period of June through the end of September, the reserve margin will remain at 23.8%.

MAAC expects to have sufficient generating capacity to serve the 2003 forecast summer peak demand. When MAAC served its all-time summer peak on August 14, 2002 no emergency procedures were implemented.

MAAC has a net of 698 MW of long-term firm transmission service in place for energy sales out of MAAC through the summer peak period. Presently, these transactions are not capacity backed and therefore can be curtailed in the event of a PJM Capacity Emergency. Historically, approximately 1,200 MW of external capacity has been transferred out of MAAC on peak summer days and could therefore decrease the capacity margin by 1.5%.

PJM, the Regional Transmission Organization (RTO) in the MAAC region, is well prepared for operating emergencies should they occur. Regular drills have been conducted to exercise procedures in preparation should there be an extremely hot summer.

The bulk transmission system is expected to perform adequately over various system conditions.
### Table 1–NPCC Summary

**Revised May 1, 2003**

<table>
<thead>
<tr>
<th>Week Beginning</th>
<th>Installed Capacity</th>
<th>Firm Purchases</th>
<th>Firm Sales</th>
<th>Net Capacity</th>
<th>Load Forecast</th>
<th>Interruptible Load</th>
<th>Known Maint./Derat.</th>
<th>Req. Operating Reserve</th>
<th>Unplanned Outages</th>
<th>Net Margin</th>
<th>Bottled Resources</th>
<th>Revised Margin</th>
</tr>
</thead>
<tbody>
<tr>
<td>4/27/2003</td>
<td>141,690</td>
<td>1,202</td>
<td>2,360</td>
<td>140,532</td>
<td>82,750</td>
<td>1,767</td>
<td>25,505</td>
<td>7,108</td>
<td>8,808</td>
<td>18,128</td>
<td>4290</td>
<td>13,838</td>
</tr>
<tr>
<td>5/4/2003</td>
<td>142,154</td>
<td>1,202</td>
<td>2,360</td>
<td>140,996</td>
<td>82,191</td>
<td>1,805</td>
<td>25,110</td>
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<td>9,652</td>
<td>18,740</td>
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<td>14,095</td>
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<td>5/11/2003</td>
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<td>9,851</td>
<td>18,836</td>
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<td>5/18/2003</td>
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<td>85,901</td>
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<td>20,192</td>
<td>4858</td>
<td>15,334</td>
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<tr>
<td>6/1/2003</td>
<td>142,840</td>
<td>1,197</td>
<td>2,360</td>
<td>141,677</td>
<td>90,659</td>
<td>1,785</td>
<td>16,677</td>
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<td>9,460</td>
<td>19,557</td>
<td>3889</td>
<td>15,668</td>
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<td>6/8/2003</td>
<td>142,440</td>
<td>1,197</td>
<td>2,360</td>
<td>141,277</td>
<td>97,073</td>
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<td>10,023</td>
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<td>6/15/2003</td>
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<td>1,197</td>
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**Notes:**
1 Installed Capacity includes IPP.
2 Load Forecast is expected weekly peak.
Table 3--New England

Revised April 23, 2003

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Please note that the information in this spreadsheet is commercially sensitive, therefore highly confidential

1. Includes IPP and other known generation
2. Load forecast is expected weekly peak (Hourly)
3. Includes Interruptible and Dispatchable Loads used for 2003/2004 Objective Capability calculations + assumed RFP values
4. Firm purchases from NB, NY, and HQ obtained from CP-8 Representative
**Table 4--New York**

**Revised March 11, 2003**

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<th>Interruptible Load</th>
<th>Known Maint./Derat.</th>
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Please note that the information in this spreadsheet is commercially sensitive, therefore highly confidential.

1 NYISO Installed Capacity (ICAP) requirement.
2 Load forecast is expected weekly peak hourly (load+losses)
3 Type II and III DSM not reported. NYISO Emergency Demand Response Program (EDRP) and Special Case Resources (SCR) are emergency procedures involving committed market resources.
4 "Full Responsibility" Purchases/Sales are included as ICAP resources.
Table 5--Ontario

Revised March 18, 2003

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<th>Total Capacity MW</th>
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<th>Interruptible Load MW</th>
<th>Known Maint./Derat. MW</th>
<th>Req. Operating Reserve MW</th>
<th>Unplanned Outages MW</th>
<th>Net Margin MW</th>
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Notes
1 Includes all generation registered in the IMO Administered Market.
2 Load forecast is the weekly 60-minute peak demand, based on weather normal case and median growth.
3 Estimated 300 Mw of Price responsive loads.
4 Based on the historical average amount of generation experiencing outages during the period May to September, from 1998 to 2001.
## Table 6--Quebec

Revised  March 21, 2003

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<th>Net Capacity</th>
<th>Load Forecast</th>
<th>Interruptible Load</th>
<th>Known Maint./Derat.</th>
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Please note that the information in this spreadsheet is commercially sensitive, therefore highly confidential

1 Includes IPP and other known generation (Churchill Falls & Labrador Co.).
2 Includes transmission losses of 6%. Does not include firm sale of 45 MW to Cornwall Ontario - Load is supplied radially from Quebec Control Area
3 Load forecast is expected weekly peak (Hourly).
4 This value also includes a load forecast uncertainty (LFU) of 3%.
Appendix II - NPCC Operational Procedures

A-3 Emergency Operation Criteria

Description: Objectives, principles and requirements are presented to assist the NPCC Areas in formulating plans and procedures to be followed in an emergency or during conditions which could lead to an emergency.

A-6 Operating Reserve Criteria

Description: This Criteria establishes standard terminology and minimum requirements governing the amount, availability and distribution of operating reserve. Procedures are included for corrective action and mutual assistance in case of operating reserve shortages. The objective is to ensure a high level of reliability in the NPCC Region that is, as a minimum, consistent with the standards specified by the North American Electric Reliability Council (NERC).

B-3 Guidelines for Inter-Area Voltage Control

Description: This document establishes procedures and principles to be considered for occasions where a deficiency or an excess of reactive power can affect bulk power system voltage levels in a large portion of an Area or in two adjacent Areas.

B-12 Guidelines for On-Line Computer System Performance During Disturbances

Description: Establishes guidelines for the performance of NPCC Area on-line computer systems during a power system disturbance.

B-20 Guidelines for Identifying Key Facilities and Their Critical Components for System Restoration

Description: Establishes requirements and guidelines for the identification of Key Facilities and their Critical Components that are required for restoration of the power system following a partial or total system blackout.
C-4 Monitoring Procedures for Guidelines for Inter-Area Voltage Control

Description: This procedural document establishes TFCO's monitoring and reporting requirements for conformance with NPCC's Guidelines for Inter-AREA Voltage Control (Document B-3).

C-5 Monitoring Procedures for Emergency Operation Criteria

Description: This procedural document establishes TFCO's monitoring and reporting requirements for conformance with NPCC's Emergency Operation Criteria (Document A-3).

C-7 Monitoring Procedures for Guide for Rating Generating Capability

Description: This procedural document establishes the TFCO's monitoring and reporting requirements for conformance with the NPCC, Guide for Rating Generating Capability (Document B-9).

C-8 Monitoring Procedures for Control Performance Guide During Normal Conditions

Description: This procedural document establishes a performance measure for NPCC Areas and systems and outlines the reporting function for NPCC Control Performance Guide During Normal Conditions (Document B-2)

C-9 Monitoring Procedures for Operating Reserve Criteria (This Document has recently been revised and will have a new designation as Reference Document RD-06)

Description: This procedural document establishes the TFCO's monitoring and reporting requirements for conformance with the NPCC Operating Reserve Criteria (Document A-6)

C-11 Monitoring Procedures for Interconnected System Frequency Response (This Document has recently been revised and will have a new designation as Reference Document RD-10)

Description: This procedural document defines procedures for monitoring frequency responses to large generation losses.

C-12 Procedures for Shared Activation of Ten Minute Reserve (This Document has recently been revised and will have a new designation as Reference Document RD-07)
Description: This procedural document outlines procedures to share the activation of ten-minute reserve on an Area basis. The methods prescribed by the procedure are intended to ensure that lost generation or energy purchases are quickly replaced by several areas simultaneously loading generation in the few minutes immediately following a loss.

C-13 Operational Planning Coordination
Appendix D - NPCC Critical Facilities List

Description: This document coordinates the notification of planned facility outages among the Areas. It also establishes formal procedures for Area communications in advance of a period of likely capacity shortages as well as for weekly and emergency NPCC conference call among the Areas.

C-15 Procedures for Solar Magnetic Disturbances on Electrical Power Systems

Description: This procedural document clarifies the reporting channels and information available to the operator during solar alerts and suggests measures that may be taken to mitigate the impact of a solar magnetic disturbance.

C-19 Procedures During Shortages of Operating Reserve

Description: This procedure is intended to provide specific instructions for the redistribution of Operating Reserve among the Areas when one or more Area(s) are experiencing an Operating Reserve deficiency.

C-20 Procedures During Abnormal Operating Conditions

Description: This procedure is intended to complement the Emergency Operation Criteria (Document A-3) by providing specific instructions to the System Operator during such conditions in an NPCC Area or Areas.

RD-01 NPCC Emergency Preparedness Conference Call Procedures-NPCC Security Conference Call Procedures

RD-02 NPCC Inter-Control Area Power System Restoration Reference Document

RD-03 Procedures for Communications During Emergencies

RD-04 Operating Procedures for ACE diversity Interchange

RD-05 Procedure for Operating Reserve Assistance
Appendix III - Web Sites

ECAR
http://www.ecar.org/

Independent Electricity Market Operator
http://www.theimo.com/

ISO- New England
http://www.iso-ne.com

LEER Members
http://www.npcc.org/leer_members.htm

MAAC
http://www.maac-ca.com/

MAPP
http://www.mapp.org/

Maritimes
Maritimes Electric Company Ltd.
http://www.maritimeelectric.com

New Brunswick Power
http://www.nbpower.com/

Nova Scotia Power
http://www.nspower.ca/

Northern Maine Independent System Administrator
http://www.nmisa.com

New York ISO
http://www.nyiso.com/

North East Power Coordinating Council
http://www.npcc.org/

TransEnergie

Drought Predictors
Canadian
http://gfx.weatheroffice.ec.gc.ca/saisons/data/images/ccapcpn_06_s.gif
Appendix IV - References

NPCC Summer 2003 Multi-Area Probabilistic Reliability Assessment –May 2003

NPCC Reliability Assessment for Summer 2002 - May 1, 2002

Draft 2003 Summer MEN Interregional Transmission System Reliability Assessment