Northeast Power Coordinating Council
Reliability Assessment
For
Summer 2004

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

This report focuses on the assessment of reliability within NPCC for the summer of 2004. Portions of this report are based on work previously done for the NPCC Reliability Assessment for Summer 2003.

The NPCC Operations Planning Working Group (CO-12) 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 CO-12 Working Group have examined to determine the reliability and adequacy for NPCC for the summer of 2004 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 identifying NPCC and the associated Areas preparations to deal with possible uncertainties identified in this report.

Summary of Findings

The forecasted capacity outlook for NPCC during the peak week (week beginning July 04, 2004)\(^1\) indicates a forecasted margin of approximately 14,300 MW of operable spare capacity. During this week approximately 8,200 MW of the 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 this forecasted spare operable capacity. This limitation could reduce the overall capacity by approximately 3,900 MW. During high transfers from New Brunswick to New England, capacity located north of the Maine- New Hampshire interface may be bottled or locked in due to existing transmission constraints. This will reduce the overall spare capacity to NPCC by up to another 500 MW. As a result, the spare capacity available to the remainder of NPCC in the peak week is reduced to approximately 10,000 MW. This forecasted value of spare operable capacity available for the summer of 2004 represents a significant increase over the actual capacity margins observed during the summer of 2003.

- The week with the forecasted minimum margin occurs during the week beginning June 27, 2004 where the operable spare capacity available to NPCC after bottling is forecasted to be around 8,800 MW.

- Approximately 2,500 MW of new capacity (300 MW in New England and 755 MW in Ontario and 1,434 MW in NY) is still to be commissioned before summer.

\(^1\) Load and Capacity Forecast Summaries for NPCC, IMO, ISO-NE, NY-ISO, HQ and the Maritime’s are included in Appendix 1.
The sizeable spare operable Capacity Margins forecasted for this summer should counteract any negative impact delays to these capacity additions may have to the overall NPCC reliability assessment

- Even though NPCC as a whole shows adequate resources through the report period, there remains a load pocket within the New England Control Area, specifically in the southwestern portion of Connecticut that may be at greater risk of being capacity deficient. The concerns should see some relief this summer as 500 MW of new generation has or will be commissioned in this area since last summer.

- ISO-NE is addressing reliability concerns in southwest Connecticut, an area where demand may exceed supply plus total transmission import limits. A Request For Proposal (RFP) has been issued for up to 300 MW of quick-start capacity through the combination of generation resources, demand response resources, or peak-load reducing Conservation and Load Management (CL&M) projects.

- 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. Ontario had an Emergency Demand Response Program in place for the summers of 2002 and 2003. Work is in progress to extend the program through the summer of 2004.

- The shoulder months indicate that overall NPCC has significant margins of spare generating capacity.

- An analysis of historical periods of high Geomagnetically Induced Currents (GICs) was performed. While GIC’s experienced in late October 2003 were elevated (K9 Intensity) and caused some entities to take additional actions within their procedures, the results indicate that these procedures were adequate for managing the phenomenon.

- Area environmental constraints, specifically state, provincial and local emissions regulations may have some impact at various times through the summer 2004 period. The sizeable spare operable Capacity Margins forecasted for this summer, combined with the procedures in place should minimize any possible effects that may compromise the power system’s reliability.

- Since 2002, precipitation levels have restored most water reservoirs to near normal levels. Hydroelectric generation output may still be impacted in some isolated locations but is not expected to jeopardize the reliability of the system.

- Under specific conditions, Quebec and Ontario have identified difficulties controlling high or low voltages. As indicated in this report, these concerns should be manageable though effective management of outage programs.
• The CP-8 Working Group results indicate that all NPCC Areas demonstrated an annual Loss of Load Expectation (LOLE) of 0.1 days/year or less, under the Base Case assumptions. The potential use of operating procedures in response to a capacity shortage this summer is more likely to be required in southwest Connecticut, Boston, MA, New York City and Long Island, NY if reductions in anticipated resources and/or additional transmission limitations into NPCC materialize coincident with higher than expected loads.

• The Communication protocols in place are sufficient to ensure the timely and efficient communications in all regions to maximize reliance on the marketplace for emergency support.

• The CO-12 Working Group believes that NPCC and the associated Areas have adequate generation and transmission for the Summer Operating Period and have developed the necessary strategies and procedures to deal with operational problems and emergencies as they may develop. However, the Resource and Transmission Assessments in this report are mere snapshots in time and base case studies. Continued vigilance is required to monitor changes to any of the assumptions that can alter this report’s findings.
2. Introduction

The NPCC Task Force on Coordination of Operation established the Operations Planning Working Group (CO-12) to conduct overall assessments of the reliability of the generation and transmission system in the NPCC Region for the Summer Operating Period (defined as the months of May through September\(^2\)) and for other conditions as requested by the NPCC Task Force on Coordination of Operation.

For the operating period to be considered the CO-12 Working Group:

- Examined historical summer operational experiences and assessed their applicability for the period to be studied.

- Assessed the extent to which emergency operating procedures may be implemented by the NPCC Areas during the summer of interest.

- Reported potential sensitivities that may impact resource adequacy on an Area basis. These sensitivities included temperature variations, merchant plant delays, load forecast uncertainties, evolving load response measures, solar magnetic activity and system voltage and generator reactive capability limits.

- Reviewed the communications protocols with participants to ensure that timely and efficient communications will be in place in all regions to maximize reliance on the marketplace for emergency support.

- Reviewed the operational readiness of the NPCC and actions to mitigate potential problems.

- Assessed the implications of strategies adopted for the summer period on the adequacy of supply in the shoulder months.

- Coordinated data and modeling assumptions with NPCC Working Group CP-8, “Resource and Transmission Adequacy” and documented the methodology of each Area in its projection of load forecasts.

- Provided as appropriate, coordination with other parallel seasonal operational assessments including MAAC-ECAR-NPCC (MEN) and NERC RAS.

- Reviewed the actions that are being taken with respect to known recommendations that resulted from the August 14, 2003 Blackout.

\(^2\) For the purpose of this report, the Summer Operating Period is defined as the week beginning May 02, 2004 to the week beginning September 26, 2004 inclusive.
3. Demand Forecasts for 2004

The non-coincident forecasted peak demand for NPCC during the summer of 2004 is 106,642 MW (May-September period). This peak demand translates to a coincident peak demand of 104,520 MW which is expected during the week beginning July 04, 2004.

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 non coincident peak demand calculation is impacted by the fact that the Maritimes and Quebec experience late Spring demands that are influenced by heating loads that occur during the defined Summer Operating 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.

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 2004 demand forecast, a peak of 3,604 MW is predicted to occur for the summer period of June through August, during the week beginning June 6, 2004. This is a 2.3% increase over the Summer 2003 actual peak of 3,523 MW, which occurred on June 27, 2003. Since the Maritimes Area is a winter-peaking area, forecasted peaks for the shoulder months of May and September are normally higher than the summer period. For the week beginning May 2, 2004, the predicted peak is 3,922 MW; for the week beginning September 26, 2004, the predicted peak is 3,640 MW.
The load forecast for the Maritimes Area represents the expected load for the 2004 Summer Operating 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 Operator). 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 2004 peak demand is 25,735 MW. This is 615 MW (2.4%) higher than last year's forecast for 2003 of 25,120 MW. In order to arrive at the forecast for summer 2004, last year's forecast was first weather normalized to 25,170 MW and using this value, the forecast for 2004 is 565 MW (2.2%) higher.

In comparison to actual historical peak loads, the summer 2004 forecast is 1,050 MW (4.3%) higher than last year's actual peak electrical load of 24,685 MW. The all time electrical peak load for New England is 25,348 MW. This load was experienced on August 14, 2002.

The demand forecast for New England is based on weekly weather distributions. The weekly weather distributions were built using 30 years of Temperature Humidity Index (THI) data 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 temperature sensitive loads, a complete process of sampling and econometric models are used to project the overall
aggregate demand. A reasonable approximation for “normal weather” associated with this projection is 90 degrees Fahrenheit (32 degrees Celsius) and a dew point of 70 degrees Fahrenheit (21 degrees Celsius). At these forecasted load levels, a one-degree Fahrenheit increase in the THI (Fahrenheit) will result in approximately 800 MW of additional load. The amount of additional load depends on the total deviation from the “normal weather” approximation.

The reference case forecast of 25,735 MW has a 50% chance of being exceeded. New England also produces a load forecast of 27,305 MW that has only a 10% chance of being exceeded. This would be equivalent to an increase in the 50% load forecast of approximately 1,570 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 power system invoked load relief procedures (Operating Procedures) that may have been implemented at such times.

New York

The forecast peak for the New York Control Area is 31,800 MW, which is 370 MW higher than last year’s forecast of 31,430 MW. This forecast is 2.6 % 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 degrees Fahrenheit (27 degrees Celsius). At forecast load levels, a one-degree increase in the THI (Fahrenheit) will result in approximately 500 MW additional load. The extreme weather forecast peak is 33,390 MW.

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

![New York Summer 2004 Load Profiles](image)

Ontario

The forecasted weather normal, summer hourly peak demand for 2004 is 23,668 MW. This hourly peak is forecasted to occur during the week beginning July 04, 2004. The weather normal forecast is derived from an analysis of the average 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 (82 degrees Fahrenheit) and 65% relative humidity and represents the average weather that can be experienced during any given week during the assessment period.

The load model and resultant demands have been updated to reflect the latest median economic growth forecasts for Ontario. As was seen in 2001 and 2002, weather extremes can propel the demands significantly higher than the weather normal values. Since peak demands are highly weather sensitive the impacts of additional weather scenarios need to be understood as part of the assessment.
Load Forecast Uncertainty (LFU) is used to capture, in MW, the impact of these variations from normal weather. Therefore 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 about 5% 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. LFU equates to a potential increase in demand of about 1,200 MW over the weather normal for the peak week.

Lastly, the summer period can experience extreme weather driven demands where the system is likely to be under duress. For any given week, the IMO forecasts extreme weather demand by using the hottest day in the past thirty years as the reference point. Depending upon the week in this assessment period, the values that could be experienced under extreme weather conditions can be 8 – 17% higher than the normal weather prediction. This can equate to an increase of approximately 2,600 MW over the normal weather prediction on the peak week. During the shoulder months of May and September, the impact of extreme weather over normal weather forecasted demand can reach as high as approximately 3,200 MW.

The following graph indicates the range of possible demands that Ontario may experience over the assessment period.

Quebec
The forecasted summer peak for the Quebec Control Area in 2004 is 21,517 MW. This is 296 MW (1.3%) lower than last summer's peak of 21,813 MW which happened on an unseasonably cold day at the beginning of May, with temperatures around 5 degrees Celsius (41 degrees Fahrenheit). If we exclude this anomaly, the forecasted summer peak for 2004 is 966 MW (4.7%) above the peak of 20,551 MW reached on June 26th of last year, when temperatures reached 33 degrees Celsius (92 degrees Fahrenheit) with a Heat and Humidity Index of 42 degrees Celsius (108 degrees Fahrenheit) on the major load centers.

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 remainder 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 2004

The following assessment of resource adequacy indicates the week with the highest overall NPCC demand is July 04, 2004\(^3\).

With the addition of resources the overall net margin for NPCC has improved over the assessment for 2003. The majority of the resource increase is in Ontario and involves generation that has already returned to service. Therefore, if the expected additional resources do not materialize, the overall effect on the projected operable spare capacity for the 2004 Summer Period should be minimal.

During the peak week for NPCC the overall spare operable capacity is forecasted to be slightly greater than 14,300 MW. However, a portion of this spare operable capacity is in the Quebec and Maritimes Area. If conditions materialize as expected, transmission transfer capability between these Areas and the remainder of the NPCC Areas will limit the usage of all of these resources.

Additionally, under conditions of high transfers from New Brunswick to New England up to 500 MW of resources may become bottled north of the Maine / New Hampshire border due to possible transmission constraints.

The overall net margins for NPCC have been reduced by approximately 2,600 to 5,400 MW during the period of mid June to late August to account for this bottled capacity. After accounting for possible transmission constraints within NPCC, approximately 8,800 MW of spare operable capacity is forecasted for the week with the lowest net margin.

The following graph highlights the projection of NPCC Demands, a Projected Resources Scenario and an Existing Resource Scenario for the Summer Operating Period. The projection of NPCC Demand is a summation of each Areas projected demand on a weekly basis. The Projected Resources Scenario is a summation of each Areas; Projected Installed Capacity plus a projection of Interruptible Demands less Operating Reserve requirements, a projection of Known Outages, a projection of Unknown Outages, Bottled Resources and the Net of Firm Imports / Exports to NPCC. The Existing Resource Scenario uses the same elements as the Projected Resources Scenario but assumes that none of the resources that are currently undergoing commissioning or are forecast to be in service will be available at any time for the summer.

\(^3\) Detailed Load and Capacity Forecast Summaries specific to NPCC and each Area are included in Appendix I.
The 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 have an adverse impact on these capacity projections.

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 2004 assessment period. Net margins ranging from 4% to 37% are projected over the period May through September 2004.

**New England**

Operable capacity within New England is forecasted to be sufficient to meet load plus operating reserve requirements during the 2004 Summer Operating Period. The lowest projected operable capacity margin of 388 MW is expected to occur during the week beginning June 6, 2004 while the highest projected capacity margin of 8,038 MW is expected to occur during the week beginning May 2, 2004 if all assumed...
system conditions materialize. Available operable capacity is based on known outages, an allowance for unplanned outages\(^4\), anticipated generation additions and retirements, projected firm purchases and sales, and the impact of expected Demand Response Programs.

While ISO-NE expects to have adequate operable capacity margins for this summer, if operable capacity shortages occur due to higher than expected resource unavailability or higher than expected load conditions, ISO-NE may have to implement NEPOOL Operating Procedure No. 4 – Action During a Capacity Deficiency (OP-4). OP-4 is designed to provide additional generation and load relief needed to balance electric demand and supply while striving to maintain appropriate operating reserves.

Although it is projected that operable capacity is surplus for the ISO-NE Control Area, the southwestern Connecticut region may face reliability problems due to transmission constraints into and within that region. Pursuant to planning studies conducted for the 2003 and 2004 Regional Transmission Expansion Plans, ISO-NE has identified concerns regarding electric transmission reliability in the southwestern Connecticut sub-region. Under certain conditions, the electric load in the southwestern Connecticut region could exceed the combined ability of the electric generating resources in the region, and the available transmission capacity to import electric energy into the region. Under these conditions, the generation and transmission systems within the region may not be able to supply the electric load without overloading lines or causing low voltage. In order to address this reliability concern, ISO-NE has issued a Request For Proposal (RFP) for up to 300 MW of quick-start capacity through the combination of generation resources, demand response resources, or peak-load reducing Conservation and Load Management (CL&M) projects. This RFP defines a contract term of up to four years, covering 2004 – 2007, with an option for a one-year extension.

New York

NYISO forecasts available capacity of 38,518 MW for the peak week resulting in a capacity margin of 1,543 MW.

These resources represent all generation capability located physically within the New York Control Area and are able to participate in NYISO ICAP market. In addition to these generation resources within the NYCA, generation resources external to the NYCA can also participate in the NY ICAP market. Resources within the NYCA that provide firm capacity to an entity external to the NYCA are not qualified to participate in the ICAP market.

\(^4\) The allowance for unplanned outages is based on historical trends and is estimated to be between 2,100 MW and 3,400 MW during the summer.
NYISO conducts semi-annual and monthly Installed Capability (ICAP) auctions. Based on the forecast load for 2004, the ICAP requirement is 37,524 MW based on the 18% installed reserve margin requirement. When allowances are taken for unplanned outages (based on historical performance of 9.7% unavailable capacity), the net available resources will be 33,865 MW, which will be sufficient to meet the New York Control Area (NYCA) load and operating reserve requirement during the peak load hours, with a reserve margin of approximately 265 MW expected at peak conditions.

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 and Special Case Resources programs represents an additional 877 MW available through the market. NYISO Emergency Demand Response Program (EDRP) and Special Case Resources (SCR) are emergency procedures involving committed market resources but are not considered as interruptible load in the Load & Capacity table calculations of net margin.

New York Resource additions, totaling 1,434 MW are expected to be available for service prior to the summer peak. The Athens station represents 1073 MW of the total, and will connect to the 345 kV transmission system in upstate New York. The plant has completed testing and is expected to be commercial prior to the Summer peak period. Ravenswood 4 will have a real power output of 221 MW and will connect to the 138 kV system in New York City. These units are undergoing final testing and are expected to be commercial prior to the Summer peak period. Both Athens and Ravenswood 4 are natural gas fired combined cycle plants.

Two natural gas fired combustion turbines with a combined capability of 91 MW are being installed at Freeport in Long Island zone. Both are expected to be in service prior to July 1. Additionally, the Long Island Power Authority (LIPA) is installing two 48MW blocks of emergency generation at the Holtsville and Shoreham stations. These units are expected to be available for service June 1 through October 31, 2004.

As in previous years as part of the peak period capacity assessment, the NYISO determines the locational capacity requirements for the NYC and Long Island load zones in addition to the statewide capacity requirement. For the Summer 2004, based on the installed capacity as of February 2004, there was a projected deficiency of 270MW statewide, 109MW for the NYC load zone, and an 83MW surplus for the Long Island load zone. New capacity additions prior to the Summer will satisfy the statewide and locational requirements. The capacity additions on Long Island will further enhance the locational capacity margin in that zone.
The return to service of three nuclear units that were laid up in the late 1990's began in 2003. Bruce A units G4 and G3 and Pickering G4 unit began generating electricity in the later half of 2003. This represented a net capacity addition of 2,065 MW to Ontario.

The IMO is anticipating an additional 755 MW of gas fired operating capacity for the 2004 summer operating period. The generation addition at Imperial Oil is expected to complete commissioning by the Summer Operating Period adding 98 MW of capacity. The IMO also expects 625 MW of generation at Brighton Beach by June 30, 2004 and 32 MW at Northland Power - Kirkland Lake to be in commercial service by August 1, 2004.

With these additions, the IMO is anticipating positive spare operable capacity margin of 2,440 MW on the peak week based on the expected the weather normal load forecast. This forecast of spare operable capacity is based on the assumption that the new generating resources will meet their in service projections, known outages will proceed as planned, a projection of unknown outages, and a forecast of price responsive loads.

Known outages include the following; those resources that are scheduled to be on planned outages, transmission constrained resources and the difference between the installed capacity and the dependable capacity. 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, units on outage may not return to service as scheduled or there are delays to new and returning units. Of some concern for this summer are the number of units on outage that are expected to return to service before the end of June. While Ontario has a spare operable capacity margin of 1,200 MW or more
during this period, the IMO will monitor the capacity balance and take appropriate actions where necessary.

Quebec

TransEnergie 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 4,700 to 7,000 MW above load and firm sales projections are nevertheless expected.

Delays to In-service of New Generation Resources

Maritimes

The Maritimes Area has no new generation resources scheduled for commercial operation during the summer period May through September 2004.

New England

In the New England Control Area, from April 2001 through February 2003, approximately 7,200 MW (summer rating) of new capacity has been added to the system with an additional forecast of approximately 300 MW to be in service prior to June 1, 2004. Of the new generation assumed to be commercial this summer, approximately 250 MW will be located in southwestern Connecticut. This additional capacity will enhance the reliability of southwest Connecticut and assist in meeting the overall electricity demands during summer peak periods.

ISO New England closely monitors the construction and commissioning of new generators as well as transmission projects. However, any delay in the commissioning of the projected new generation within New England will decrease projected capacity margins.

New York

Construction at the Ravenswood and Athens sites is essentially complete, and the units have completed capability testing, these units are expected to be in commercial operation well in advance of the summer peak period.

The Ravenswood unit #4 became commercial on March 29 2004 and will satisfy the locational capacity deficiency noted in the NYC load zone. The balance of any statewide shortfall would be satisfied by Athens, new resources in the Long Island load zone or by external ICAP resources. The Long Island zone shows a surplus for the locational capacity assessment. Any delay in the operation of the planned units is
not expected to have a reliability impact. In addition, the installation of two 48MW blocks of emergency generation at the Shoreham and Holtsville sites will further enhance system reliability for the summer period.

Ontario

With the recent return to service of the three laid up nuclear units the impact of a delayed in service of new generation to the resource adequacy margin is not expected to be significant under normal weather conditions for the Summer Operating Period.

The IMO recognizes the risks associated with the timing of the in service of new generation facilities as well as the impact of weather on the demands. The IMO continuously monitors the in service date and the associated impact on the resource adequacy margins.

Quebec

The Sainte Marguerite-3 hydro plant (900 MW) was finally commissioned after a two year delay over the initial planning target. However, its total output continues to be restricted to 580 MW until a solution to problems with the turbines is found and implemented. This will not be done before the summer of 2004. 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™, Petroleum Coke, Hydro, Tidal, Municipal Waste, and Wood.

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

New England

In July of 2003, ISO New England formed the Fuel Diversity Working Group (FDWG) as a subcommittee reporting to the Transmission Expansion Advisory Committee (TEAC). The FDWG provides an arena for all stakeholders to discuss
and assess the reliability impacts resulting from the range of fuel mix and fuel delivery options available to electric generators serving New England.

Historically, traditional fuel supply and delivery options have been readily available to generators within New England during the summer months. For the summer of 2004, 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. The IMO does not anticipate any fuel supply inventory or delivery infrastructure concerns over the Summer Operating Period. While there are storage lakes associated with most hydroelectric facilities, the ability to predict hydroelectric energy is difficult as water flow conditions are primarily influenced by precipitation. To counter this, the hydroelectric installed capacity is reduced through portions of the study period to account for reductions in capacity when the available water historically falls below the dependable value. For the purposes of this assessment, 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 2004, 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 2004 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 2004 Multi-Area Probabilistic Reliability Assessment.

The study results indicate that all NPCC Areas demonstrated an annual loss of Load expectation (LOLE) of 0.1 days/year or less, under the Base Case assumptions for the expected load (the expected load is the weighted average of seven load levels, weighted by the probabilities assumed for each). Recent capacity added in New England, New York and Ontario, in addition to the capacity and Demand Response Programs planned to be available this year are contributing factors that tend to reduce the need for the use of operating procedures designed to mitigate resource shortages in 2004, as compared to last year’s analysis, under the identified expected conditions.

For the May - September 2004 period, Figure EX-1 shows the estimated potential range of use of the indicated operating procedures under Base Case assumptions. Figure EX-1 displays the results for the expected load and the extreme load (the extreme load level represents the second to highest load level).

![Figure EX-1](image)

**Figure EX-1**
Potential Range of Use of Indicated Operating Procedures for Summer 2004
Considering Base Case Assumptions (May – September)
(Expected and Extreme load levels)
However, the potential use of these operating procedures is more likely to be required in southwest Connecticut and Boston MA and New York City and Long Island, NY, if reductions in anticipated resources and/or additional transmission limitations into NPCC materialize coincident with higher than expected loads.
6. 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 the actual operating experience during the summer of 2003.

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 Commonwealth Edison as part of PJM’s energy market operations prior to this summer with AEP and Dominion Resources following later in 2004.

A tower on the B3N circuit between Ontario and Michigan (230 kV circuit Scott - Bunce Creek) was damaged in April of 2003. The options to return the circuit to service are still being explored. At the current time, it is estimated that the circuit will not return until after the summer operating period.

As a result, the ability to transfer energy into / out of Ontario on the Ontario-Michigan Interface will remain the same as last summer.

The B3N phase angle regulator (PAR) was forced from service in March 2003. The return to service of the PAR is not known at this time. Additionally, the final phase angle regulator installation on the Michigan-Ontario Interface (Lambton-St. Clair 345 kV circuit L4D) is not expected to be completed until the end of September. For the study period it has been assumed that the Michigan-Ontario Ties will remain free flowing.

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. 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.

Above this restrictive condition, high transfer conditions from New Brunswick to New England can bottle up to an additional 500 MW of operable spare capacity north of the Maine / New Hampshire border. This accounts for the adjustment to the Net NPCC Margins in the Resource Adequacy assessment (Section 4).

The installation of the PAR at Sandbar is part of the Northwest Vermont Reliability Project, and was expedited due the failure of the Plattsburgh PAR in April 2003. The new Sandbar PAR will be used to regulate the flow on the PV20 tie line between New York and Vermont. This new PAR will provide greater regulating range than the previous Plattsburgh PAR.

After August 14 the Long Island Power Authority obtained an emergency order from the US Department of Energy to operate the Cross-Sound Cable HVdc tie-line between New Haven Harbor (ISO-NE) and Shoreham (NYISO). Since that time the tie-line has been operated under this order, however, it is not yet considered commercially available and operation of it during the Summer Operating Period is not a certainty.

The following diagram indicates the assumed transfer capability used in the CP-8 Probabilistic studies. These same transfer capabilities were used in this report for the determination of Inter-Area / Inter-Region transmission adequacy and the calculation of bottled resources within NPCC.
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

During the summer of 2004 there are a few transmission upgrades that are expected to become in-service. These include the Sandbar Phase Angle Regulator (PAR) located in Vermont, the addition of a second Scobie Transformer in New Hampshire, and the Glenbrook STATCOM project that includes the tapping of the Darien-Southend 115 kV 1977 line located in CT.
As noted in the InterArea transmission adequacy review, the Sandbar PAR will be used to regulate the flow on the PV20 tie line between New York and Vermont.

The second Scobie autotransformer improves the regional reliability in the Manchester-Nashua area of New Hampshire. Due to area load growth, the existing autotransformer has recently experienced heavy loadings.

The Glenbrook STATCOM project and the tapping of the 1977 line into the Glenbrook Substation improve dynamic voltage and thermal response to contingencies in the Norwalk-Stamford area.

In November of 2003, the ISO-NE’s Board for Directors approved the 2003 Regional Transmission Expansion Plan (RTEP03). RTEP03 is a comprehensive electrical engineering assessment comprised of numerous studies and analyses of New England’s bulk electric power system.

RTEP03 concluded that the southwestern Connecticut (SWCT) region remains the first area of concern as it lacks the required transmission infrastructure needed to provide adequate reliability.

New York

There are no major transmission facility additions to the New York bulk power system expected for the 2004 Summer Operating Period.

After August 14 the Long Island Power Authority obtained an emergency order from the US Department of Energy to operate the Cross-Sound Cable HVdc tie-line between New Haven Harbor (ISO-NE) and Shoreham (NYISO). This line continues to operate under this condition, and is not considered commercially available for operation.

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 2003. Studies indicate that there will be sufficient transmission capability to meet the projected requirements under most conditions.

The installation of capacitor banks totaling 375 MVAr (250 MVAr scheduled for installation before summer and 125 MVAr installed late last summer), along with the reactive output of the new Brighton Beach Generation facility should ease voltage concerns previously identified in the Windsor, Burlington and Toronto areas. While the concerns may be eased, maintaining acceptable voltage profiles in these areas will
still require diligent assessment of outage plans, and dispatch/deployment of reactive resources.

Quebec

The Levis 315kV substation will see a major overhaul of its configuration this summer. This will permit, in the future, to diminish the impacts of outages on the transfer capability to New Brunswick. The work will run from April to November and some steps will have major impacts on the transfer capability to New Brunswick (during 4 days in August, the capability will be around 200 MW versus a maximum capability of 1050 MW). The transfer capability from New Brunswick to Quebec will not be affected for the outages planned during the Summer Operating Period.

An experimental 100 MW Variable Frequency Transformer (VFT) has been installed at the Langlois substation near the Les Cedres generating plant. It will still be in tests for the summer of 2004 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 for 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.

Apart from the preceding, 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.
7. Operational Readiness for 2004

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 2004 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. Major generating stations throughout New England have specified voltage schedules, which are maintained as closely as possible in system operations. In addition to voltage schedules, minimum and maximum voltage limits at several key generating or transmission stations have been established to promote system reliability during adverse voltage/reactive conditions. Also, a Tariff has been in place since August of 2001 that compensates New England generators for VAR support.
As part of the NERC transmittal entitled “Near-Term Actions to Assure Reliable Operations” as a result of the August 14 blackout, ISO-NE has surveyed the status of all generators in New England to ensure that Automatic Voltage Regulators (AVR) exist and are normally in-service for the resources as required by NEPOOL Operating Procedure No. 14 - Technical Requirements for Generation, Dispatchable and Interruptible Loads (OP-14).

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 been reviewing 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 was completed in February 2004. Analyses of the test results are underway to ensure that the demonstrated reactive capability is sufficient to meet system voltage support requirements. The results of the tests will be incorporated into the detailed capability studies for the summer.

Quebec

Being a winter peaking area, TransÉnergie does not expect to 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.

Short-term impacts on individual unit operation during 2004 summer are more influenced by the summer time regulations as opposed to 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 2004 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 past few summers was water level. Water levels have improved considerably and for 2004 Summer Operating Period this is not expected to be a significant concern. 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 2004 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, however it is the responsibility of the resource owners to monitor their compliance with state or federal standards. In order to mitigate the impact that these restrictions may have on the availability of generating units within New England, generator owners are encouraged to pursue temporary waivers to their environmental permits especially during periods of extreme capacity deficiencies.

In addition, ISO-NE includes discussions on the air emission impacts from the generating units within the 2003 RTEP report. Results of this analysis illustrate that air emissions by fossil-fueled generating units are highly dependent upon fuel prices.
(because of prices’ effect on dispatch of such units), but show less correlation with transmission improvements.

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 allowable dispatch 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.

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.

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, 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.

The CO-8 Operations Managers Working Group explored ways to obtain accurate and timely forecasts of solar magnetic disturbances and the resulting GICs for the NPCC Control Areas. As a result, NPCC contracted for GIC forecasting services from Solar Terrestrial Dispatch (STD) for a three-year period that began mid-2003. Forecast information is provided directly to the control centers in the NPCC Areas.

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. Even though we are on the declining side of the solar cycle there were a number of occasions during 2003 and early into 2004 in which STD provided alerts of solar activity that could reach K7 index of intensity or above. These alerts were provided for May 29, October 28-30, and November 4, 6,
18-20 of 2003 as well as January 19-20 of 2004. The most significant activity occurred on October 29, 2003 when intensity reached K9.

The following chart indicates the solar activity up to February 2004.

Monthly updates to this chart and further information can be found at www.sec.noaa.gov/.

With regard to expectations from STD of GIC activity during summer 2004 it is important to emphasize that it is not possible to predict several months in advance the extreme episodes of activity such as those that occurred during late October 2003.

While we are well on our way toward solar minimum in terms of sunspot counts, the geomagnetic activity cycle lags the sunspot cycle by several years. As a result, we are still very close to the maximum (perhaps just beginning to edge down off the maximum of the geomagnetic activity peak).

The biggest source of enhanced geomagnetic activity will continue to come from coronal hole-based sources over the next year. Although these sources of activity tend to be less of a concern, they are still quite capable of producing periods of GIC activity.

Minor to major geomagnetic storm intervals (K-indices of 5 to 6) will continue to be possible for several days each month during the summer months. Severe storm
intervals (K-indices of 7) will also be slightly possible for a few days during the summer months. Coronal hole-based disturbances rarely produce activity greater than K-indices of 7. Therefore, it is not expected that many events will exceed K-indices of 6 or 7, unless there is another burst of unexpected solar activity.

Overall, the summer should be fairly stable, with modestly elevated risks of GIC activity occurring for a few days approximately once (at most twice) each month during the summer months. GIC activity should remain confined to mostly weak levels when it occurs, but may infrequently (if at all, and then probably only briefly) reach moderate levels in some regions.

If the trend continues (and this is dependent upon whether new coronal holes form and/or old coronal holes maintain their structure), the last week and/or the first week of each month during the summer may see elevated levels of geomagnetic activity due to coronal hole disturbances.

In summary, there is no ability to forecast any significant solar activity in advance of this summer, it is very possible something could materialize.

The following is a summary of each Area’s experiences of GIC activity through the recent “high period” in October 2003. The resultant impact observed in the NPCC Control Areas indicates that the control actions that are in place appear to reasonably reduce the impact of GIC.

Maritimes

The Maritimes Area did not experience any significant disturbances in 2003 and no major problems are anticipated for 2004. The Maritimes Area did perform some limited control actions reducing exports on interconnections. On March 17, 2003 New England reduced imports from the Maritimes due to increased solar activity (K7). During the period October 29-30, 2003 exports to Hydro Quebec and, internally on the interconnection between New Brunswick and Nova Scotia were reduced according to procedures as a precaution due to the solar activity (K7).

The Maritimes Area Operating Procedures are consistent with NPCC Operating Procedures for GIC activity.

New England

In late October and early November of 2003, the New England Area experienced a significant amount of solar activity. Although these solar storms did not cause any major problems within the region, specific actions were taken as a result of the storms intensity in order to maintain the reliability of the system. Specifically, certain transmission maintenance outages were called back to service and energy transactions
with surrounding Control Areas were reduced during several observed Solar Magnetic Disturbances.

New York

The major solar storm that occurred in late October 2003 did not produce any perceptible impact on the New York system.

The NYISO System Operations Advisory Subcommittee is investigating the inclusion of an exclusive contingency set that would incorporate contingencies that have a higher probability of occurring during high levels of solar activity. The contingency list would be activated in the NYISO Security Constrained Dispatch program when a high level of GIC activity is present, and would help to mitigate the potential impact of these contingencies on the system.

Ontario

Throughout the period extending from 2001 into 2003, no actions beyond those required by the existing procedures were taken by the IMO. During the period of elevated GIC forecasts for the October 29 to 30 2003 solar storm period, the IMO undertook additional actions as indicated within procedures. These actions included the recall of certain planned transmission outages and the starting of additional units beyond normal requirements. While the IMO noted minor swings on the real and reactive power outputs at certain generating stations no specific operations can be attributed directly to the solar storm.

Quebec

During the summer of 2003, there were three occurrences of GICs. Alerts were called on May 29th, June 2nd and August 18th. The alerts predicted Kp levels of 7-8 and they actually reached a level of 8 in May and August, and only 6 in June. No adverse effects on the bulk system were recorded. Maximum voltage asymmetry recorded was 2 - 53% at the Châteauguay substation at 21h20 on May 29. Some transfer limitations on the bulk system were imposed but Interconnection capacities were not affected.

However, it is important to mention that at the end of October 2003, a massive storm hit the Quebec network as well as its neighbors with a maximum Kp level of 9 observed at 01h14 and at 12h15 on October 29. On the main grid, the 735kV network having all its lines series-compensated, the effects on the main grid were minor. The most severe impacts were felt on the Brisay to Tilly 315kV network in the north of James Bay (1,000 miles north of Montreal), which was not series-compensated. The maximum voltage asymmetry (7 - 15%) and quantity of even harmonics (9 - 8%) were both recorded at the Tilly substation where this 315kV subnetwork joins the
main grid. This brought the voltage to as low as 722kV at Tilly, which is only a minor violation of the low operating limit of 725kV. No equipment was lost during the storm that lasted 25 hours. During the two nights, imports from New England to Quebec on Phase-2 were limited to 200 MW by ISO-NE instead of the scheduled values between 500 and 600 MW.

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 the existing operations-related “B” and “C” documents by adding the requirement language from these documents to “A” documents. Over the past few years several Reference Documents had been developed, which have similar content to the “C” documents and have no requirement language. TFCO has now agreed to keep the “C” designation for the existing Procedures. These will be periodically reviewed and updated, as necessary. In addition, the Reference Documents will be reviewed and re-designated as new “C” documents. This will be a gradual process.

Since the Reliability Assessment for Summer 2003, the following revisions to NPCC documentation have occurred:

The C-9 “Monitoring Procedures for Operating Reserve Criteria” and C-12 “Procedures for Shared Activation of Ten Minute Reserve” Documents have been updated. Modifications had been made to the C-9 Document to make this document consistent with NERC DCS and with the NPCC A-06 Document (Operating Reserve Criteria). Modifications made to the C-12 Document addressed counterflows in the examples and included a number of editorial changes.

It should also be noted that the A-2 Document, “Basic Criteria for Design and Operation of Interconnected Power Systems” had gone through a review period of about one and a half years and recently received approval by the Reliability Coordinating Committee at a March 18, 2004 meeting. This document will still need to receive approval of the full NPCC membership before it is fully adopted.

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. Eighteen of these emergency preparedness conference calls were successfully conducted during 2003.

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

Since the implementation of the Standard Market Design (SMD) in March 2003, ISO-NE has placed a considerable amount of effort reviewing and revising as necessary, New England’s Market Rules and Operating Procedures. New England’s Operating Procedures are in compliance with the NPCC Operating Procedures and are supplemented with local procedures.

New York

The NYISO continues to review and refine operating and market processes based on experience gained through the sustained peak load periods of 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 Normal and Emergency Operating Procedures to improve the implementation and usefulness of that and other programs. There continue to be refinements to the NYISO Market operation based on the experience gained during peak load period operation, and new products and facilities are being added.
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.

As a result of the Blackout in August 2003, specific emphasis was placed on the review of Reactive Dispatch Procedures and Procedures for Loss of Telemetry.

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 to find additional generation in or out of the Control Area. After this step, Emergency Operating Procedures, compliant with NERC and NPCC are implemented.

Operating Procedures in Shoulder Months

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 2003 and no changes are anticipated for the summer of 2004.

New England

ISO-NE’s Outage Coordination staff has reviewed the proposed maintenance schedules for generators in the Control Area and, where appropriate, has 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 significant amount of capacity scheduled out-of-service in May. Since much of the generation on maintenance in May consists of large
generator outages, a delay in the return to service date of one or two generators could have a considerable impact on the operable capacity margin projected for June.

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 performs extensive reviews of reliability procedures on a regular basis. This includes the procedure for maintaining reserve margins and rectifying negative margins. These procedures are enforced during the shoulder months to ensure that the necessary control actions are taken in the appropriate time frame if needed to ensure that planning obligations are met.

Quebec

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; interrupting customers within Real-Time Demand and Profiled Response Program, purchasing emergency energy from the neighboring Control Areas, implementing voltage reductions, and public appeals for conservation. This emergency operating procedure provides load relief measures estimated to be between 3,000 to 4,000 MW\(^5\).

In addition to load relief measures from OP-4, Enrolling Participants or Demand Response Providers enrolled in the Real-Time Price Response Program have the option to voluntarily reduce energy consumption in real-time on the days ISO-NE activates the program and during the hours specified. ISO-NE typically activates the Real-Time Price Response Program when hourly Zonal Price are forecasted to be greater than or equal to $100/MWh.

New York

The NYISO introduced two load response programs for the New York Market in May 2001. The Emergency Demand Response Program (EDRP) 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 2003 period the NYISO did not experience peak conditions that required activation of the EDRP. However, load response programs were useful to maintain the balance between generation and load, during the system restoration period following the August 14, 2003 blackout.

The Emergency Demand Response Program is continuing for Summer 2004, and NYISO estimates potentially 900 MW of load relief, with 225 MW of that total being designated as “reliable.” This load relief will be available to support the New York State power system during capacity emergency periods. 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

\(^5\) This value is based on the NEPOOL OP-4 documents as of February 3, 2004 which can be found on the ISO-NE website.
response to the major emergency state (Section 3.2 NYISO Emergency Operations Manual).

Ontario

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 program involves 16 different customer sites with approximately 400 MW of load contracted in this ancillary service. When requested, the customers would reduce their demand on a voluntary basis. This demand response program would be implemented just prior to the interruption of firm load. The effectiveness of the program has been reviewed and approvals have been received to extend the program beyond the summer of 2004.

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 1713 MW of interruptible power available in winter, 1054 MW could be called on if needed during the summer.

Communications Systems with Operators and 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 stakeholders and 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 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 Control Areas as appropriate.

In addition, ISO-NE creates a seven-day forecast that is posted to the ISO-NE website. 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 issues 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 one and two.
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.

During the summer of 2004 the IMO will be introducing Multi Interval Optimization into the dispatch process. A benefit of this enhancement to the dispatch process is that Market Participants will now receive, in addition to actual dispatch instructions for the next interval, a dispatch advisory that will project out in time the potential dispatch requirements.

While the phone systems and associated infrastructure worked adequately during the blackout of 2003, the IMO recognized a number of areas of improvement. At the time of the blackout a Request for Proposal (RFP) was in place to replace the IMO phone system. This RFP was subsequently revised to include additional requirements, and the upgraded phone system will be in place prior to the summer operating period.

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. This process for communicating to the general public on resource issues proved to be an effective tool in 2003 for managing the resource shortfalls during the post blackout period. On April 1, 2004 the IMO corporate web site was revised with a number of enhancements. One of the enhancements will be placing an increased emphasis on resource adequacy issues by placing postings in a more prominent manner.

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 marketplace 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 Trans-Energie, has established procedures for the acquisition of emergency energy.

**New England**

When the NEPOOL Control Area experiences or is forecasted to experience a shortage of operating capacity, ISO-NE will request NEPOOL Participants to submit Emergency Energy Transactions (EETs) through the NEPOOL Market System. Through this bid based energy market, procedures are in place to determine the availability of the emergency assistance from its neighboring Control Areas when necessary.

**New York**

During 2002, the NYISO completed the process to review and update 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.

NPCC will be conducting a dispatcher and schedulers seminar in Toronto on May 5 and 6, 2004, for dispatchers and schedulers 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 operations staff. The keynote topic for the shift operations staff will be a through review of NPCC Inter-Control Area Restoration Coordination including a table top exercise. The seminar will also include the summer outlook for each Area, a summary of recent events within the industry and NPCC, developments coming from NERC, an update on NPCC policy and procedures, and a review of recent events in the industry. The schedulers in attendance will review the intricacies of their system and the impact of other areas on their system.

The agenda and seminar are developed by the NPCC CO-2 Working Group on Dispatcher Training, in conjunction with CO-8 System Operations Managers. The agenda for the scheduler's sessions is developed by an ad hoc group of Scheduling staff at the various areas also under the auspices of CO-8.

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

Throughout the year, ISO-NE Operators and satellite control center personnel participate in training session in preparation for both the summer and winter peak load periods. During the training sessions, applicable NPCC procedures and NEPOOL emergency operating procedures are reviewed in detail. The summer capacity assessment is also reviewed as well as area-specific voltage control issues
and intra-area communication procedures. The NERC certification program at ISO-NE is a NERC accredited training program.

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 2004. The training includes detailed review of the August 14, 2003 blackout, NERC and NPCC issues affected operations, full-scale system simulation emergency exercises, and acclimation to the upcoming hardware and software replacement of the NYISO EMS (SMD2).

NYISO Dispatcher Training staff will also present one week System Operator Training Seminars (SOTS) for a combined audience of the NYISO and New York Transmission Owner (TO) dispatcher crews. The topics addressed include an update on the NYISO EMS/Market tools replacement, back-up dispatch, restoration exercises, review of major emergencies, review of operating policies, update on the August 14, 2003 blackout and restoration, system protection, effects of GIC, regional issues, the summer outlook and a NYISO/industry update.

Single crews will participate in a statewide Restoration Drill and an Alternate Control Center Drill.

The combination of In-House Training, simulation and SOTS will meet the NERC Board of Trustees Blackout Recommendation #6 requirement for training prior to June 30, 2004.

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 capability assessment, review reactive dispatching techniques as well as, a review of the changes to emergency procedures.

Ontario will also adhere to the training recommendation set out in the NERC Board of Trustees Recommendations on the August 14, 2003 Blackout.

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 November 26, 2003 the IMO led the annual 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 2003 successfully met all objectives through a comprehensive simulated power system restoration of northern Ontario. The Exercise involved the shift operations from the IMO and 23 other organizations. These included nine major Distributors, two Transmitters, ten Connected Wholesale Customers operating from 15 different sites, the Ministry of Energy, Emergency Management Ontario, and seven Generators operating from 14 different sites.

Lastly, each shift at the IMO will 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.
8. Impact of NERC Blackout Recommendations

The Blackout of August 14, 2003 has had repercussion throughout the industry. The NPCC Area was hardest hit and, as a result, is particularly sensitive to ensure that actions are taken to prevent a reoccurrence.

To this end, NPCC has formed a Blackout Investigation Team (BIT). The NPCC-BIT provides oversight and monitoring of the activities of the NPCC Areas and the various Working Groups and Task Forces within NPCC to ensure that any near term operations related actions are completed prior to the summer of 2004. It is not intended for this report to provide a detailed account of the activities of this team. However, the CO-12 Working Group noted that there are three areas that deserve specific recognition in this report.

These are:

- Situational Awareness (By the Reliability Coordinator of events beyond the Reliability Coordinator Boundaries)
- Reactive Burden on the Power System
- Communication between Reliability Coordinators (RC) and Control Areas

Prior to the blackout, each RC in NPCC and PJM had access to power system data from beyond their boundaries. As a result of the blackout, New England, New York and Ontario are reviewing the interconnection data they receive, requesting additional telemetered data points from neighbouring interconnections and beyond, making this data readily accessible to the operations staff and providing the data in an easy to assimilate format. Each Area expects to have this work completed prior to the summer operating period.

During the month of April NERC-sponsored teams conducted reliability readiness audits of the IMO, NYISO, and ISO-NE. This included an on-site review of policies, procedures, facilities of each of these Control Area and Reliability Coordinator functions at each location. The teams also interviewed management, supervisory, and control center staff. Reports and findings are expected in May.

With respect to reactive burden to the power system, *NPCC Document B3 - Guidelines for Inter-AREA Voltage Control* provides general principles and guidance for effective inter-Area voltage control within NPCC. The procedure recognizes local control actions as the most effective method for voltage regulation, along with outlining steps to be taken when an area becomes deficient in reactive resources. While each Area is committed to reactive dispatching methodologies that will ensure compliance to this procedure, the TFCO at its March 4, 2004 meeting, took an action to review the procedure, and each Areas conformance prior to the Summer Operating Period.
Section 7 of this report outlines all Areas operational readiness to communicate with their customers quickly and take required actions needed to mitigate the need for emergency control actions. Communication between NPCC Areas benefited from the significant capacity deficiencies experienced by NPCC members in recent years by the development of well defined communication protocols to deal with emerging issues such as forecast and real-time energy and capacity deficiencies. These communication protocols have evolved and are now well defined and understood by all operations staff.

The PJM operations staff is in frequent communication with neighboring systems to the south and west and also has a close working relationship with NYISO.

These Inter-Region communication protocols have proven to be effective as was demonstrated during the restoration efforts of August 14, 2003 and the subsequent capacity deficiencies experienced by Ontario and NYISO in the following days.

The NERC Board of Trustees (BoT) approved a set of 14 recommendations to prevent and mitigate the impacts of future blackouts in February of 2004. Specific to the recommendations were remedial actions to be completed by June 30, 2004 along with associated readiness audits of PJM, MISO and First Energy.

The NERC BoT recommendations also outlined specific “reliability readiness” audits of Control Areas and Reliability Coordinators in the Eastern Interconnection to be performed to ensure these Reliability Coordinators and Control Areas can perform well, particularly under emergency conditions, and to strive for excellence in their assigned reliability functions and responsibilities.

The PJM, MISO and First Energy Audits were completed by the end of February and the results were presented at the NERC:OC meeting in March. NERC:OC accepted the Audit Reports for each of these entities, subject to completion of any outstanding actions identified. The Control Area Audits will be completed by the end of April with results known by late June.

PJM and MISO formulated remedial action plans to address BoT Blackout Recommendations specific to their Reliability Areas. The action plans were reviewed and approved at the March NERC:OC meeting with a requirement to have all tasks outlined in the plan verified as completed by June 30, 2004.

Synopses of the plans are as follows:

**PJM**

- Significant effort is being placed on improving communications with MISO. A Joint Operating Agreement (JOA) that is close to execution will detail a number

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6 ISO-NE, NYISO, IMO, AEP, MECS, Cinergy and LG&E
of processes where MISO and PJM will exchange data, respect limits in operation, and communicate status with each other to ensure that each organization is fully informed. Upon approval, the JOA will set a new standard in communications and coordination between RCs.

• Improve Operator and Reliability Coordinator Training - The recent NERC Audit found PJM’s Operator/RC training to be high quality. PJM’s use of realistic simulators as well as a comprehensive training program ensures that the PJM Operations team is capable of rapidly responding to any emergency.

• Evaluate Reactive Power and Voltage Control Practices - PJM’s On-line Reactive Transfer Monitoring continues to set the standard for advanced applications. With the expansion of the PJM EMS Model to now include AEP, DPL, and ComEd and beyond this wide area capability is further enhanced. PJM has started work on the joint development and monitoring of critical reactive interfaces near our various seams.

• Detailed protocols currently being drafted include - Outage Coordination, Emergency Operations, and Restoration - Ensure that emergency action plans and procedures are in place to safeguard the system under emergency conditions by defining actions operators may take to arrest disturbances and prevent cascading.

MISO

• The state estimator has been fully tested and was implemented on December 31, 2003. A new System Topology processor that will display each topology change by exception without any delay, and capable of running independent of the state estimator will be in service by June 30, 2004.

• Several wide area overviews of both the MISO footprint and beyond were implemented on December 31, 2003. The overviews allow the system operator to narrow the field of view and zero in on smaller segments of the system.

• Prior to June 30, 2004 all MISO operators will have completed the mandatory five days of system emergency training. The training will include regional / sub regional restoration drills, table-top drills with MISO and member company staff, and operations simulator training on a range of emergency conditions.

• Communication protocols have been reevaluated and improved along with associated procedures for emergency response and conservative operating. Neighbouring Reliability Coordinators (including the IMO) now receive a copy of MISO's Next-day and current day security analysis.

• A review of agreements with all entities that MISO performs Reliability Coordination Services for has been undertaken.
9. 2003 Post-Seasonal Assessment and Historical Review

The following summarizes some highlights of the review. Please refer to the NPCC Reliability Assessment for Summer 2003 for details on projections.

Maritimes

The peak load experienced by the Maritimes Area during the May – September period was 3,902 MW, which was approximately 88 MW (2.3%) higher than last year’s forecast of 3,813 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 2003. 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.

New England

The peak demand for the summer of 2003 was 24,685 MW and occurred hour ending 15:00 on August 22. This was 663 MW less than the all time summer peak demand of 25,348 MW that was experienced during the summer of 2002.

Overall, the weather during the 2003 summer was mild. Although it was a relatively humid summer, the ambient temperature only approached 90 degrees Fahrenheit (32 degrees Celsius) towards the end of June and again at the end of August. Because of the mild weather, no extreme peaks were experienced.

NEPOOL Operating Procedure No. 4 - Action During a Capacity Deficiency (OP-4) was called once during the summer of 2003. These actions were only required within the state of Connecticut in an effort to aid in the system restoration following the August 14 blackout.

All of the new generation projects that had been expected to become commercial during the summer 2003 were in-service and participating in New England’s energy market in time for the summer peak. Drought conditions did not have a significant effect on operations.
New York

The New York Control Area did not experience temperatures associated with design conditions during the summer of 2003, and therefore did not realize the forecast peak of 31,430 MW. The summer 2003 NYISO peak load of 30,333 MW occurred on June 26.

Ontario

The peak demand for the summer of 2003 was 24,753 MW and occurred on June 26, 2003. The date of the summer peak is reflective of the milder weather experienced in Ontario through most of July, compounded by the affects of the blackout that occurred on August 14, 2003. Had a request for conservation due to resource concerns not been issued, it is likely that the summer peak would have been set during the week following the blackout.

The following charts indicate the correlation of weather experienced during the summer on the resultant demands by displaying the average weekly temperature in Toronto for the summer of 2003 as compared to the historical average weekly temperature and the number of days the maximum daily temperature exceeded the historical average maximum.
The following chart shows the actual Ontario hourly peak demands for each week against the demand curves forecasted in the NPPC Reliability Assessment for Summer 2003. It can be noted that the lower demands in July are consistent with the temperatures experienced.
After excluding the events associated with August 14, the demands were met without use of any extraordinary control actions beyond the issuance of Energy Emergency Alerts (EEA). The IMO issued EEA 1 notifications on 8 days through the summer and proceeded to an EEA 2 on 1 day. Almost all notifications were attributed to a sudden loss of resources within the day and not an overall adequacy concern.

Quebec

The Quebec summer peak load was 20,551 MW on June 26 2003, which is about 200 MW below the expected peak. A late winter peak of 21,813 MW occurred on May 2 with temperatures at or near the freezing point all over the province. The summer of 2003 was quite uneventful with no significant things to report as far as forced outages, weather conditions, forest fires, etc…

Historical Review (Pre-2003)

The previous non-coincident peaks for each NPCC Area, the forecasted 2004 summer peak for each NPCC Area and the NPCC Coincident peak for 2004 are summarized in the table below.

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<th>Weather Normal</th>
<th>LFU</th>
<th>Weather Extreme</th>
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Table 1
Historical Peak Demands by Area Occurring May to September (MW)

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<th>Year</th>
<th>Ontario 7</th>
<th>Maritimes</th>
<th>New England</th>
<th>New York</th>
<th>Quebec</th>
<th>Total NPCC Demand</th>
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7 20 minute Peak Demand 1993 to 2001, peak hourly demand thereafter
8 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.
9 Forecast NPCC Coincident Peak Demand, not the sum of each individual Areas Forecasted Peak Demand.
10 Percent Change reflects the increase/decrease in projected peak for the 2004 Summer Operating Period over the actual peak for the 2003 summer.
11 Based on the extreme weather case, the IMO could experience a peak of 26,430, which represents an increase of 6.77% over the 2003 actual. This would translate into an NPCC Coincident Peak Demand of 107,282 MW for a 2.94 % increase over 2003.
10. 2004 Reliability Assessments of Neighboring Regions

East Central Area Reliability Coordination Agreement (ECAR)

Information from the ECAR 2004 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 2004 Summer Conditions” that is contained in ECAR’s 2003/2004 Winter Assessment of Load and Capacity.

The projected summer peak demand in ECAR for the summer of 2004 is 102,724 MW for Total Internal Demand. This 2004 summer peak is derived from demand forecasts received in January 2003 with any updates through August 2003. Therefore, actual operating experience from the last half of 2003 was not considered in developing this peak demand forecast.

Total capacity for the summer of 2004 is projected to be 127,115 MW. This assumes 1,420 MW of announced capacity additions within the ECAR region are in service by July 2004. Net scheduled interchange into the ECAR region at the time of the peak is anticipated to be 2,337 MW, making total Capacity Resources of 129,452 MW.

Capacity Margins for the summer of 2004 are forecast to be slightly higher than the margins forecast for the summer of 2003, 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 26,728 MW (20.6% of Net Capacity Resources). This assumes the announced capacity additions within the ECAR region are in service by July 2004.

Recent experience indicates that a minimal amount of capacity (1,197 MW) is expected to be scheduled out of service during the summer peak. This scheduled capacity outage along with a 4% operating reserve requirement (4,109 MW) means that the Margin for Contingencies is expected to be 21,422 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 14% 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 2004 Summer Assessment of Transmission System Performance, ECAR report 04-TSPP-3. This report will be published in mid-May 2004.

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 2004 summer forecast net peak demand is 56,201 MW. This forecast includes the effects of interruptible demand and load management capabilities, which are estimated to be 1,129 MW. The forecast peak assumes normal summer weather conditions. This forecast is 632 MW higher than the actual MAAC all-time summer peak of 55,569 MW that occurred on August 14, 2002.

Between June 1, 2003 and mid-July 2004, MAAC’s summer generating capacity is expected to increase by a net of 5,020 MW to 68,903 MW. 1,459 MW of the expected increase is already in service. All nuclear units should be in service and at full capacity (13,320 MW) at the time of the peak. MAAC also has 488 MW of external capacity resources under contract through the summer peak period. With the planned new generation, existing internal generation, and external capacity resources included, the MAAC capacity margin is forecasted to be 19.0% at the time of the forecasted peak.

The MAAC reserve margin is expected to be 23.5% at the time of the forecasted peak.

MAAC expects to have sufficient generating capacity to serve the 2004 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 1,979 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 1.4%.

PJM, the Regional Transmission Organization (RTO) for the MAAC region, is well prepared for operating emergencies should they occur. PJM's certified operating staff are trained and participate in regular emergency drills that include the criteria for declaring emergencies, prioritized action plans, staffing and responsibilities in preparation should there be an extremely hot summer.

The bulk transmission system is expected to perform adequately over various system conditions.
## Appendix I – 2004 Expected Load and Capacity Forecasts

### Table 1 - NPCC Summary

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<tr>
<th>Week</th>
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<th>Firm Purchases</th>
<th>Firm Sales</th>
<th>Total Capacity</th>
<th>Load Forecast</th>
<th>Interruptible Load</th>
<th>Known Maint./Derat.</th>
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Notes
1. Installed capacity includes capacity associated with IPPs.
2. Load forecast is expected weekly peak.

Please note that the information on this page is commercially sensitive, therefore confidential.
**Table 3—New England**

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<th>Week</th>
<th>Installed Capacity MW</th>
<th>Purchases MW</th>
<th>Sales MW</th>
<th>Total Capacity MW</th>
<th>Load Forecast MW</th>
<th>Interruptible Load MW</th>
<th>Known Maint./Derat. MW</th>
<th>Req. Operating Reserve MW</th>
<th>Unplanned Outages MW</th>
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**Notes**
- Installed capacity includes unit addition and retirement assumptions as outlined for the 04-05 OC and CP-8 MARS analysis.
- Purchases assumed are those noted in 2004 CELT report with minor adjustments made (NY) for consistency purposes.
- Load Forecast as determined for CELT 2004 and has a 50% chance of being exceeded.
- Interruptible Loads include 100% of the Day-Ahead Demand Response, Real-Time Demand Response, Real-Time Profiled Response; 50% of the Real-Time Price Response; and 200 MW assumed for SWCT RFP.
- Known Maintenance and Derating as April 5, 2004.
- Required operating reserve based on the first contingency (Generator at 1,160 MW) plus 1/2 the second contingency (Generator at 1,145MW).
- Unplanned outages includes: forced outages and maintenance outages scheduled less than 14 day in advance.
Table 4—New York

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<th>Available Capacity¹</th>
<th>Firm Purchases⁴</th>
<th>Firm Sales⁴</th>
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<th>Interruptible Load²</th>
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Important Notes
1 Includes all known generation, including new generation expected to be online in the New York Control Area
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 represented as per NYISO ICAP rules.

Please note that the information on this page is commercially sensitive, therefore confidential.
## Table 5—Ontario Summary

Updated - March 26, 2004

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<th>Total Capacity MW</th>
<th>Load Forecast MW</th>
<th>Interruptible Load MW</th>
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<th>Req. Operating Reserve MW</th>
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**Important notes**

1. Includes all generation registered in the market.
2. Load forecast is median growth, normal weather case, weekly 60-minute peaks.
3. 300 MW of price-responsive demand is assumed.
4. Includes known outages, deratings and allowances for hydroelectric capacity.

**Please note that the information on this page is commercially sensitive, therefore confidential.**
Table 6--Quebec Summary

2004 TransEnergie - Load and Capacity Forecast for Quebec

Revised April 23, 2004

<table>
<thead>
<tr>
<th>Week Beginning Sundays</th>
<th>Installed Capacity¹ MW</th>
<th>Firm Purchases MW</th>
<th>Firm Sales² MW</th>
<th>Net Capacity MW</th>
<th>Load Forecast³ MW</th>
<th>Interruptible Load MW</th>
<th>Known Maint./Derat. MW</th>
<th>Req. Operating Reserve MW</th>
<th>Unplanned Outages⁴ MW</th>
<th>Net Margin MW</th>
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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%.

Please note that the information on this page is commercially sensitive, therefore highly confidential.
### Table 7 - NPCC Bottled Capacity Calculations

#### CP-8 Assumed Transfer Capability

Revised April 19, 2004

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<td>TE to NY 1500</td>
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<td>TE to NE 1500</td>
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<td>NB to NE 700</td>
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<tr>
<td>Total Transfer Capability 5240</td>
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<td>4364 ATC - TE plus Maritimes to remainder of NPCC</td>
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<th>Week Beginning Sunday</th>
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<th>Maritimes Margin</th>
<th>Net Margin</th>
<th>Available Transfer Capability</th>
<th>Bottled NE resources</th>
<th>Bottled Resources</th>
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Peak Week
Appendix II - NPCC Operational Criteria and Procedures

A-2 Basic Criteria for Design and Operation of Interconnected Power Systems

Description: This Criteria establishes the basic principles and requirements for the design and the operation of the NPCC bulk power system.

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

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
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.npec.org/

TransEnergie

Drought Predictors
Canadian
Appendix IV - References

NPCC Summer 2004 Multi-Area Probabilistic Reliability Assessment – May 2004

NPCC Reliability Assessment for Summer 2003 - May 1, 2003

Draft 2004 Summer MEN Interregional Transmission System Reliability Assessment