NEW ENGLAND
2002 TRIENNIAL REVIEW
OF
RESOURCE ADEQUACY

Prepared by ISO New England Inc.

APPROVED BY

THE NPCC RCC ON NOVEMBER 14, 2002

1.0 EXECUTIVE SUMMARY

1.1 Major Findings

This report was prepared to satisfy the requirements for a Triennial Review of New England Control Area's Resource Adequacy as established by the Northeast Power Coordinating Council (NPCC). The guidelines for the review are specified in the NPCC Document B-8 entitled, "*Guidelines for Area Review of Resource Adequacy"* (Revised: June 28, 2001).

For the first time, this review used a multi-area reliability model, General Electric's Multi-Area Reliability Simulation (GE MARS) program, to assess resource adequacy of the New England Power Pool (NEPOOL) bulk power generation system. The NEPOOL system was modeled as 13 interconnected sub-areas. The transmission interface transfer capabilities between these sub-areas have been determined based on the reliability criteria established by both NEPOOL and the Northeast Power Coordinating Council (NPCC). The representation of the NEPOOL system into sub-areas is consistent with New England's Regional Transmission Expansion Plan (RTEP).

This review shows that NEPOOL will meet the NPCC Resource Adequacy Criterion for the period 2003 through 2007, inclusive, for both the reference and high load forecasts.

A sensitivity scenario with the deactivation of Devon Power LLC's Units 7, 8 and 10[1] were also investigated. These results show that NEPOOL still has adequate resources to meet its reliability criterion for the period 2003 through 2007, inclusive, under both the reference and high load forecasts.

[1] The NEPOOL Reliability Committee has voted to recommend approval of the deactivation application for the units effective October 1, 2002.

1.2 Summary of Major Assumptions and Results

Table1 shows the major assumptions used in this review.

Table 1 - Major Assumptions

Assumptions	Description
Reliability Criterion	NPCC Criterion: LOLE of 1 day in 10 years
Load Model	8760 hourly loads with forecast uncertainty factors
Reliability Model	GE MARS
Unit Availability	Historic Averages: 5 year EFOR (1997 to 2001)
Tie Benefits	Assumed 1,800 MW. Tie Benefits assumption encompasses entire study period 2003 – 2007, inclusive.
Emergency Operating Procedures (Load Relief, Voltage Reduction)	Modeled
New Generating Capacity Additions	Year 2003 – 5,984 MW (Summer Rating)
Generating Capacity Retirements	Year 2003 – 354 MW (Summer Rating)
Generation Capacity Deactivations[2]	Year 2003 – 231 MW (Summer Rating)
Reflecting Internal Transmission Constraints	Based on Various Transmission Studies

The 2001 and 2002 ISO New England Regional Transmission Expansion Plans have identified that there are severe reliability problems in southwestern Connecticut (defined as the Southwest Connecticut and Norwalk sub-areas in the RTEP01 and RTEP02). This is primarily a local problem due to the inadequate transmission capability to import power into the southwestern Connecticut area and the lack of local transmission capability to move power around within that area. This Triennial Review, along with the MARS reliability analyses conducted in the RTEP studies; do not reflect internal transmission constraints that exist within southwestern Connecticut. This analysis also does not reflect the possibility that ISO New England and NEPOOL could acquire additional resources for the southwestern Connection region through the implementation of short term mitigating plans prior to permanent transmission upgrades are complete, such as the Southwest Connecticut Emergency Capability Supplement implemented for the summer 2002. In actual system operations, ISO New England could (and has in the past) develop load-shedding schemes to shed a predetermined amount of load in southwestern Connecticut to protect the reliability of the entire NEPOOL system. These schemes are not assumed in this Triennial Review.

Tables 2 and 3 below show the results of the study. The Base Case is based on all the major assumptions listed in Table 1 with the exception of the generation capacity deactivation assumption. The Sensitivity Case includes the generation capacity deactivation assumption. The Loss of Load Expectation (LOLE) values in these tables are expressed in days per year. An LOLE lower than 0.1 days per year is better than criterion.

[2] Only modeled in the sensitivity case.

Table 2 - Loss of Load Expectation Results for the Base Case

Year	LOLE Based On Reference Load Forecast (Days per Year)	LOLE Based On High Load Forecast (Days per Year)
2003	0.006	0.021
2004	0.000	0.004
2005	0.000	0.007
2006	0.000	0.015
2007	0.003	0.033

Table 3 - Loss of Load Expectation Results for the Sensitivity Case

Year	LOLE Based On Reference Load Forecast (Days per Year)	LOLE Based On High Load Forecast (Days per Year)
2003	0.029	0.084
2004	0.002	0.014
2005	0.002	0.016
2006	0.003	0.041
2007	0.006	0.082

The results of the review as presented in Tables 2 and 3 show that NEPOOL has enough existing and planned generating resources to meet the NPCC resource adequacy criterion.

2.0 Table of Contents

List of Tables

List Of Figures

3.0 Introduction

The purpose of this report is to review the resource adequacy of NEPOOL as required by NPCC. As part of its Reliability Assessment Program, NPCC conducts resource adequacy reviews of its members' areas to ascertain whether or not each area will have enough resources to meet the NPCC Resource Reliability Criterion. These resource adequacy reviews are currently done on a triennial basis.

The past resource adequacy reviews for NEPOOL were conducted using a single bus model, under the assumption that there are no transmission constraints within the New England Bulk Power System. This assumption was appropriate at that time due to the full integration requirement for new generation resources. Under today's deregulated environment, a less stringent interconnection requirement (Minimum Interconnection Standard) was adopted to interconnect a generating unit to the New England grid which has promoted the installation of merchant generation and resulted in the addition of many such units to the New England system. Most of these merchant plants are located near interstate natural gas pipelines, which can be in regions where the existing power transmission facilities are inadequate to handle the additional supply capability. Under such circumstances, it is necessary to model the transmission constraints so that the reliability of bulk power generation system is correctly evaluated from a deliverability point of view. In this review, and consistent with New England's Regional Transmission Expansion Plan (RTEP), the NEPOOL system was modeled as 13 interconnected sub-areas and the transmission interface transfer capabilities between these sub-areas have been determined based on the reliability criteria established by both NEPOOL and Northeast Power Coordinated Council (NPCC). The General Electric Multi-Area Reliability Simulation Model (GE MARS) was used for conducting this review of resource adequacy.

This report compares current and previous resource plans and analyzes the adequacy of NEPOOL's planned resources based on the reference and high peak load forecasts for the period 2003 to 2007.

3.1 Previous Triennial Review of NEPOOL's Resource Adequacy

The NPCC Reliability Coordinating Committee approved the previous NEPOOL Triennial Review of Resource Adequacy in March 2000. The findings of that review showed that NEPOOL had adequate resources to meet the NPCC Reliability Criterion for the period 2000 through 2009 for the reference load forecast. Under a high load forecast, the review showed that NEPOOL had adequate resources to meet its reliability criterion through 2005. A contingency plan was developed should the high load forecast materialize.

3.2 Comparison of Current and Previous Resource Plans

The previous Triennial Review of NEPOOL's Resource Adequacy was based on the 1999 NEPOOL Load Forecast, which projected a summer peak load with a compound annual load growth rate of 1.94% for the period 2000 to 2009. The 2002 NEPOOL Load Forecast projects a summer peak load[3] compound annual load growth rate of 1.38% for the period 2003 - 2007. The comparison of these two forecasts is shown in Figure 1.

[3] Peak Load is adjusted to account for the impacts of Demand Side Management (DSM) Programs and the NEPOOL Participant recognized non-utility capacity, which is netted from the load forecast. The reference load forecast used is found within the "2002 *Capacity, Energy, Loads and Transmission Report*", dated April 1, 2002 (CELT). The high peak load forecast used is characterized as having 10 percent chance of being exceeded. A description of the DSM components is given in Appendix A.1.5.

Figure 1 - Summer Reference Peak Load Forecasts (1999 vs. 2002 Triennial Review)

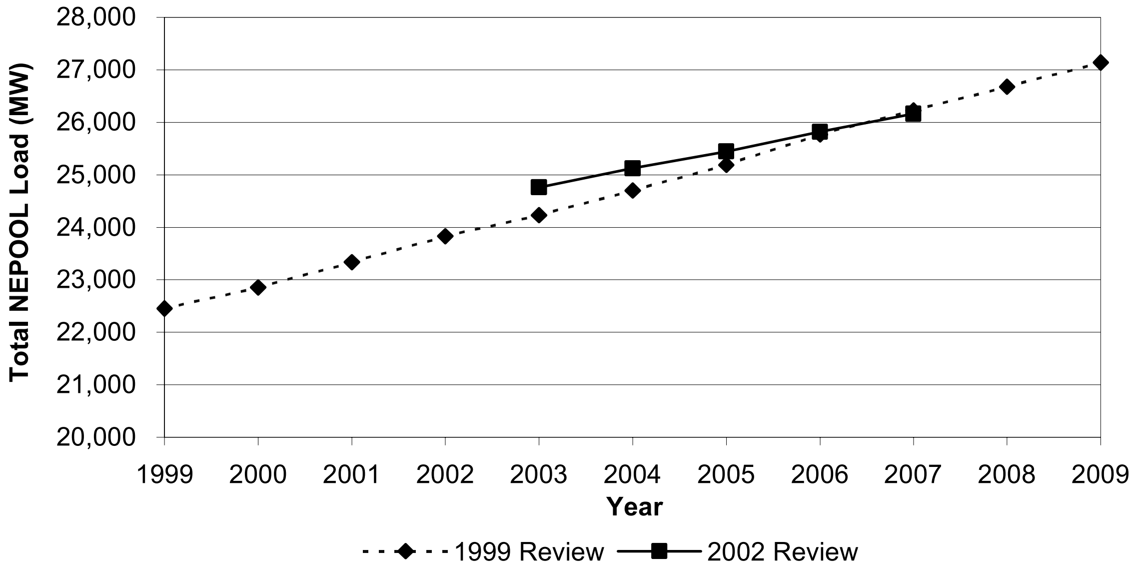
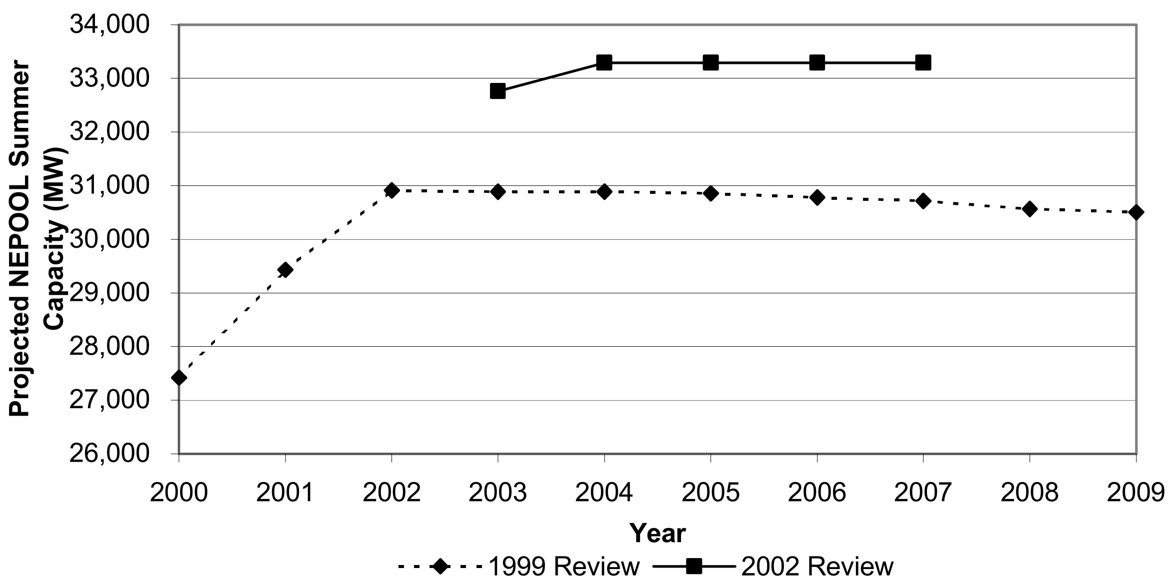


Figure 2 compares the projected installed capacity (summer rating) for the 1999 and 2002 Triennial Reviews.

Figure 2 - Projected Summer Capacity[4] (1999 vs. 2002 Triennial Review)



[4] Capacity is the sum of NEPOOL Internal Installed Capacity (including projected additions, retirements, and rerating) + Firm Purchases from other control areas. For the 1999 review, it also includes the net interconnection credit of 1500 MW associated with the Hydro-Québec Phase II Firm Energy Contract (Up to August 2001, inclusive).

Tables 4 and 5 below summarize the capacity addition and attrition assumptions for the 1999 and 2002 reviews. Capacity deactivation for the 2002 Review is modeled only in the sensitivity case.

Table 4 - Assumed New Capacity Additions (Summer Ratings)

	1999 Review	2002 Review
Assumed Cumulative New Capacity Additions by Year 2003 (MW)	6,817	5,984

Table 5 - Assumed Capacity Attrition (Retirement or Deactivation) (Summer Ratings)

	1999 Review	2002 Review
Assumed Capacity Retirement by Year 2003 (MW)	160	354
Assumed Capacity Deactivation[5] by Year 2003 (MW)	319	231
Cumulative Capacity Attrition by Year 2003 (MW)	479	585

In this 2002 New England Triennial Review, 354 MW of capacity attrition was assumed for the base cases. Unlike information regarding unit additions, which is abundantly available, information regarding unit attrition is almost non-existent. Many New England generating owners have noted that they do not know the impact of the Standard Market Design on generating resources and therefore, they are not able to determine the fate of their generating units even though some of these units are non-economically competitive today. It is expected that any future unit deactivation or retirement that could impact the reliability of the NEPOOL power system, NEPOOL would take appropriate action to mitigate any possible reliability problem through its formal approval process under the Restated NEPOOL Agreement Section 18.4. Such future unit attrition would be captured in the annual review of New England resource adequacy.

[5] Capacity deactivation includes Devon Power LLC's Units 7, 8 and 10, which was only modeled in the sensitivity case.

4.0 Resource Adequacy Criterion

4.1 Statement of NEPOOL Resource Adequacy Criterion

The NEPOOL Resource Adequacy Criterion complies with the NPCC criterion and reads:

> "Resources will be planned and installed in such a manner that, after due allowance for the factors enumerated below, the probability of disconnecting non-interruptible customers due to resource deficiency, on the average, will be no more than once in ten years."

a. The possibility that load forecasts may be exceeded as a result of weather variations.
b. Immature and mature equivalent forced outage rates appropriate for generating units of various sizes and types, recognizing partial and full outages.
c. Seasonal adjustment of resource capability.
d. Proper maintenance requirements.
e. Available operating procedures.
f. The reliability benefits of interconnections with systems that are not NEPOOL participants.
g. Such other factors as may from time-to-time be appropriate.

4.2 Application of NEPOOL Resource Adequacy Criterion

The NEPOOL Resource Adequacy Criterion is used to determine the amount of resources needed to reliably supply the system.In calculating the amount of resources needed, NEPOOL also takes into account the tie benefits that are available from neighboring systems. The tie benefits are modeled as available capacity on a seasonal basis. The Hydro-Québec, New York and New Brunswick interconnections have been modeled.

To properly capture the intended operation of the system, the emergency operating procedures that are implemented during periods of capacity deficiencies are also modeled in the form of the amount of load relief that is obtainable. It is assumed that the system operators will always maintain at least some minimum level of operating reserve to ensure control over transmission loadings and maintain a minimum reliability level.

The amount of additional generation and load relief, which may be obtained during a capacity deficiency, are shown in Table 6. This table provides the different actions and their priority when implementing NEPOOL Operating Procedure No.4 (OP4) – "*Action During A Capacity Deficiency*". In actual practice, these actions may be implemented in a different order to reflect the current situation and the magnitude of the expected deficiency faced at the time. OP4 Actions 14 to 16 were not modeled as load relief in the reliability assessment and are therefore listed as contingency resources. Actions 1 to 13 were modeled in this review. The amount of OP4 load relief modeled in this Review is described in Appendix A.1.7. The amount of load relief obtainable through OP4 Action 6 is modeled as tie reliability benefits and the assumed benefits are shown in Appendix A.1.3.

Load relief from OP4 actions is assumed to be constant through the study period except for the load relief obtainable through voltage reduction, which is assumed to be 1.33 percent of the load.

Table 6 - NEPOOL Operating Procedure No. 4 - Action During a Capacity Deficiency Based on a 24,200 MW System Load

Action #	Description	MW
1	Implement Power Caution and advise generators to prepare to provide emergency energy	0
2	Order on generation<5MW requiring special ISO treatment	0
3	Curtail Type 2 NEPOOL Interruptible Loads – Block E	12
4	Curtail Type 2 NEPOOL Interruptible Loads – Block D	0
5	Curtail Type 2 NEPOOL Interruptible Loads – Block C	39
6	Purchase Emergency Capacity and Energy	Variable, depending on system conditions (Could be between 0 and 1,000 MW)
7	Curtail Type 2 NEPOOL Interruptible Loads – Block B	8
8	Curtail Type 2 NEPOOL Interruptible Loads – Block A	64
9	Voluntary Load Curtailment of NEPOOL Participants' Facilities. Implement Power Watch.	40
10	Customer Generation Contractually Available to NEPOOL Participants During a Capacity Deficiency. Curtail Type 5 NEPOOL Interruptible Loads Total Action 10	5 0 5
11	Allow 30 Minute Reserve to go to Zero (0)	About 575 MW, depending on NE's 2nd contingency
12	Implementation of 5%Voltage Reduction (VR) requiring more than 10 minutes. *In later actions of OP4 the New England ten-minute reserve may be allowed to diminish to maintain an absolute minimum required level*.	5 *About 1,000 MW depending on system conditions and circumstances and on NE's largest contingency*.
13	Implementation of 5% VR requiring 10 minutes or less.	315
14	Customer Generation not contractually available to NEPOOL Participants Voluntary Load Curtailment by Large Industrial and Commercial Customers Total Action 14	5 200[6] 200-205
15	Radio and TV Appeals for Voluntary Load Curtailment. Implement Power Warning.	200
16	Request State Governors to Reinforce Appeals for Voluntary Load Curtailment and Declaration of Power Warning.	100
	Grand Total	**2,563 - 3,568**

[6] The actual load relief obtained is highly dependent on circumstances surrounding the appeals, including timing and the amount of advanced notice that can be given.

4.3 Statement of Required Resources

NEPOOL does not have a required reserve margin criterion. Required resources are planned based on meeting the annual reliability criterion of no more than one day in ten years disconnection of non-interruptible customers.

4.4 Comparison of NEPOOL and NPCC Resource Reliability Criterion

The NEPOOL's resource adequacy criterion as defined in Section 4.1 complies with the criterion established by the NPCC.

4.5 Resource Adequacy Studies Conducted Since the 1999 Triennial Review

As part of the Regional Transmission Expansion Plan, 2001 (RTEP01), ISO New England conducted various sub-area resource adequacy studies using GE MARS. These studies are detailed in the report entitled "2001 Regional Transmission Expansion Plan (RTEP01)", dated October 19, 2001. ISO New England has also conducted further sub-area resource adequacy studies as part of the Regional Transmission Expansion Plan, 2002 (RTEP02) effort. These sub-area resource adequacy studies are detailed in the Draft RTEP02 report. The Final RTEP02 report will be published by the fourth quarter of the year.

5.0 Resource Adequacy Assessment

5.1 Proposed Resources Based On Reference Load Forecast[7]

5.1.1 Base Case For The Reference Load Forecast

The Base Case is based on all the major assumptions listed in Table 1 with the exception of the generation capacity deactivation assumption. Table 7 shows that NEPOOL will have adequate installed capability to meet its reliability criterion through 2007.

Table 7 - Base Case Results Based on Summer Reference Peak Load Forecast

Year	Summer Reference Peak Load (MW)	Installed Capability[8] (MW)	LOLE (Days/Year)
2003	24,760	32,763	0.006
2004	25,123	33,292	0.000
2005	25,443	33,292	0.000
2006	25,817	33,292	0.000
2007	26,159	33,292	0.003

5.1.2 Sensitivity Case For The Reference Load Forecast

Devon Power LLC. (Devon) had submitted its Generation 18.4 applications for the deactivation of Devon Units 7, 8 and 10 on August 1, 2002. These units are located within southwestern Connecticut area and they have a combined summer capacity rating of 231 MW. Because southwestern Connecticut has traditionally had a constant need to import significant amounts of power into the region due to generation deficiencies, combined with severe transmission constraints into and within the region, ISO New England has conducted a study[9] to investigate the reliability impacts of the deactivation of these Devon units. Based on the study results, ISO New England concludes that these Devon units can not be deactivated until October 1, 2002. In this review, a Sensitivity Case was developed to model the deactivation of these Devon units starting on October 1, 2002.

The results in Table 8 show that NEPOOL still meets the reliability criterion through 2007, if the Devon Units 7, 8 and 10 are deactivated on October 1, 2002.

[7] The reference peak load forecast is characterized as having a "50/50" percent probability of occurring.

[8] Installed Capability is the sum of NEPOOL Internal Installed Capacity (including projected additions, and retirements) + Firm Purchases from other control areas

[9] "Report on Studies Evaluating Reliability Impacts of Deactivation of Devon Units 7, 8, and 10 by ISO New England Inc," dated July 9, 2002. The results of this study is also detailed in the RTEP02 Report.

Table 8 - Sensitivity Case Results Based on Reference Summer Peak Load Forecast

Year	Summer Reference Peak Load (MW)	Installed Capability (MW)	LOLE (Days/Year)
2003	24,760	32,532	0.029
2004	25,123	33,067	0.002
2005	25,443	33,067	0.002
2006	25,817	33,067	0.003
2007	26,159	33,067	0.006

5.2 Proposed Resources Based On High Load Forecast

5.2.1 Base Case For The High Load Forecast

Recognizing the impact of load uncertainty on resource capacity requirements, ISO-NE develops a high load forecast that is characterized as having a 10 percent chance of being exceeded. Table 9 below shows the results of the resource adequacy review based on the high load forecast and the assumed new capacity additions.

Table 9 - Base Case Results Based on Summer High Peak Load Forecast

Year	Summer High Peak Load (MW)	Installed Capability (MW)	LOLE (Days/Year)
2003	25,872	32,763	0.021
2004	26,507	33,292	0.004
2005	27,054	33,292	0.007
2006	27,629	33,292	0.015
2007	28,152	33,292	0.033

The results of the review based on the high load forecast show that NEPOOL has adequate resources to meet its reliability criterion through 2007.

5.2.2 Sensitivity Case For The High Load Forecast

Table 10 shows that even with the deactivation of Devon Units 7, 8 and 10 units on October 1, 2002, NEPOOL will still have adequate installed capability to meet its reliability criterion through 2007 under the high load forecast.

Table 10 - Sensitivity Case Results Based on High Peak Load Forecast

Year	Summer High Peak Load (MW)	Installed Capability (MW)	LOLE (Days/Year)
2003	25,872	32,532	0.084
2004	26,507	33,067	0.014
2005	27,054	33,067	0.016
2006	27,629	33,067	0.041
2007	28,152	33,067	0.082

6.0 Planned Resource Capacity Mix

Figure 3 - NEPOOL's Resource Capacity Mix By Fuel Type

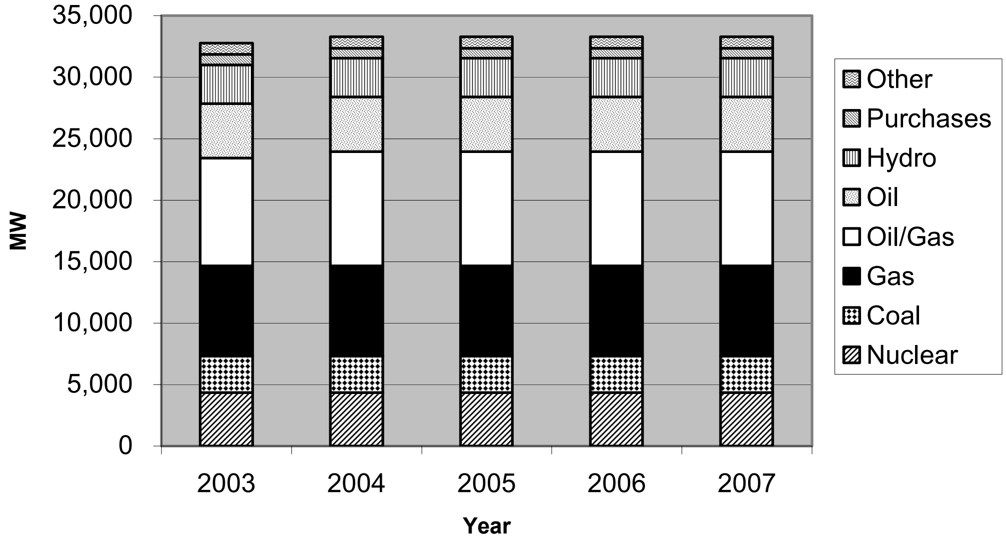


Figure 3 shows the projected NEPOOL's resource capacity mix by fuel type. Most of the future units are fueled primarily by natural gas with approximately half having oil as a backup fuel.

Table 11 shows the projected NEPOOL's resource capacity mix by fuel type in percentage terms.

Table 11 - NEPOOL's Resource Capacity Mix By Fuel Type in Percentage of Total Installed Capacity

Fuel Type	Year 2003	Year 2004	Year 2005	Year 2006	Year 2007
Nuclear	13.25	13.03	13.03	13.03	13.03
Coal	9.11	8.96	8.96	8.96	8.96
Gas	22.36	22.00	22.00	22.00	22.00
Oil/Gas	26.75	27.94	27.94	27.94	27.94
Oil	13.58	13.37	13.37	13.37	13.37
Hydro	9.61	9.46	9.46	9.46	9.46
Purchases	2.55	2.49	2.49	2.49	2.49
Others	2.79	2.75	2.75	2.75	2.75

APPENDIX

A.1 Description of Resource Reliability Model

The General Electric Multi-Area Reliability Simulation (GE MARS) model was used for conducting this analysis. GE MARS can model a bulk power system comprised of several control areas and each control area can be modeled as having different sub-areas. The transmission constraints within a system are modeled as transfer limits on the interfaces or interface groups between the interconnected sub-areas. The model uses hourly chronological load profiles and can calculate the reliability indices for up to ten load levels.

GE MARS uses a sequential Monte Carlo simulation to compute the reliability of a system comprised of a number of interconnected areas containing generation and load. This Monte Carlo process simulates the year repeatedly (multiple replications) in order to evaluate the impacts of a wide range of possible random generation outage combinations. The transmission system is modeled in terms of transfer limits on the interfaces between interconnected areas. Chronological system histories are developed by combining randomly generated operating histories of the generating units and inter-area transfer limits with the hourly chronological loads. For each hour, the program computes the isolated area margins based on the available capacity and load demand in each area. GE MARS then uses a transportation algorithm to determine the extent to which areas with negative margin can be assisted by areas having positive margin, subject to the available transfer capacity between the areas. The program collects the statistics for computing the reliability indices and proceeds to the next hour. After simulating all of the hours in the year, the program computes the annual indices and tests for convergence. If the simulation has not converged to an acceptable level, it proceeds to another replication of the study year; otherwise, it moves on to the next study year.

A.1.1 Load Model

A.1.1.1 Hourly Loads

The 2003 through 2007 hourly loads for the NEPOOL system are based on: NEPOOL hourly loads starting in 1977; operating company hourly loads starting in 1989; real time interface and external tie hourly flows starting in July 1999; hourly generator output starting in 1989; and, hourly substation loads from the EMS State Estimator starting in September 2001. A detailed description of the hourly load forecast is presented in the RTEP02 report.

A.1.1.2 Load Forecast Uncertainty

Monthly load forecast uncertainty multipliers were determined based on the monthly peak load distribution patterns. A normal distribution was assumed and a seven load level approximation was used to represent the distribution of the load forecast uncertainty, that is the mean, three deviations above and three deviations below the mean.

A.2 Resource Unit Representation

A.2.1 Unit Ratings

A.2.1.1 Definition

Existing capacity data was based on the Seasonal Claimed Capability (SCC) reported in the April 2002 CELT[10] report. Only the units in ISO-NE's Energy Management System (EMS) are modeled. Seasonal Claimed Capability (SCC) represents the Summer (SCC-S) and Winter (SCC-W) Claimed Capability of a generating unit submitted by NEPOOL Participants. The summer ratings period runs from June 1 through September 30, and the winter ratings period runs from October 1 through May 31. Claimed capability is the demonstrated maximum dependable load carrying capability, in megawatts, of such unit, excluding capacity required for station service use.

NEPOOL CELT reports are published on ISO-NE's website:
http://www.iso-ne.com/Historical_Data/CELT_Report/2002_CELT_Report/

A.2.1.2 Procedure for verifying ratings

ISO-NE has the right to initiate audits of all standard generating units to verify their Seasonal Claimed Capability. Audits are initiated by ISO-NE by ordering the generator output to be increased from its current operating level (if that level is below SCC) to its SCC. The required duration for a claimed capability audit is at least two hours and no more than eight hours, depending on the Capability Period and type of unit. In order to pass a claimed capability audit, a unit must demonstrate it can achieve average output greater than or equal to Claimed Capability. Full details of the audit process can be found in the NEPOOL Market Rules and Procedures, Appendix 11D (Rating and Auditing NEPOOL Resources): *http://www.iso-ne.com/mrp/main.html*.

A.2.1.3 Unit Unavailability Factors Represented

A.2.1.3.1 Each unit was modeled with its five year (1997 and 2001) average Equivalent Forced Outage Rate (EFOR).

A.2.1.3.2 The unit outage data was based on actual history.

A.2.1.3.3 Unit maturity was considered in this review. For new units, unit immaturity was assumed for the first 3 years of operation. After this period, unit Target Unit Availability (TUA) was used. Reference Table 12.

A.2.1.3.4 Table 13 shows the average EFOR for each unit type used in the review.

Table 12 - Assumed EFOR For The New Units To Reflect Maturity

Year of Operation	EFOR(%)
1st Year	14.46
2nd Year	7.92
3rd Year	4.78
4th Year	4.49 (TUA)

[10] The *Capacity, Energy, Loads and Transmission Report* (CELT) is a source of assumptions for use in planning and reliability studies, and fulfills in part the reporting requirements of DOE, NERC Reliability Assessment Subcommittee, NPCC, EEI, EFSB(MA) and NEPOOL. The CELT forecast assumptions do not constitute a "plan".

Table 13 - NEPOOL Average EFORs By Unit Type

Unit Type	EFOR(%)
FOSSIL	8.28
CC	5.19
DIESEL	4.21
JET	3.25
NUCLEAR	5.90
HYDRO	0.83

A.2.1.4 Purchases and Sales Representation

The external contracts that NEPOOL market participants have with neighboring systems were modeled. The following capacity purchases in MW were included in the model.

Table 14 - Purchases and Sales[11]

Summer (MW)

	Year 2003	Year 2004	Year 2005	Year 2006	Year 2007
New Brunswick	400	400	400	400	400
Hydro-Québec	310	310	310	310	310
New York	127	120	120	120	120

Winter (MW)

	Year 2003	Year 2004	Year 2005	Year 2006	Year 2007
New Brunswick	400	400	400	400	400
Hydro-Québec	310	310	310	310	310
New York	127	120	120	120	120

A.2.1.5 Retirements

In this review, Sithe's New Boston Unit 1 was reflected as retiring on July 1, 2002. As a sensitivity case, Devon Power LLC's Units 7, 8 and 10 were deactivated on October 1, 2002.

A.3 Representation Of Interconnected Systems

Tie benefits from Hydro-Québec, New York and New Brunswick were modeled. A total of 1,800 MW of tie benefits was assumed for the summer period throughout the study period 2003 - 2007. This 1,800 MW amount is higher than the zero to 1,000 MW range of emergency assistance assumed obtainable in Table 6, which details NEPOOL's Operating Procedure No. 4 - "*Action During a Capacity Deficiency*". Table 6 assumed a lower amount of emergency purchases because it reflects possible short-term capacity purchases over the interconnections that are not modeled in this review.

Table 15 shows the breakdown of the assumed tie benefits from the external control areas.

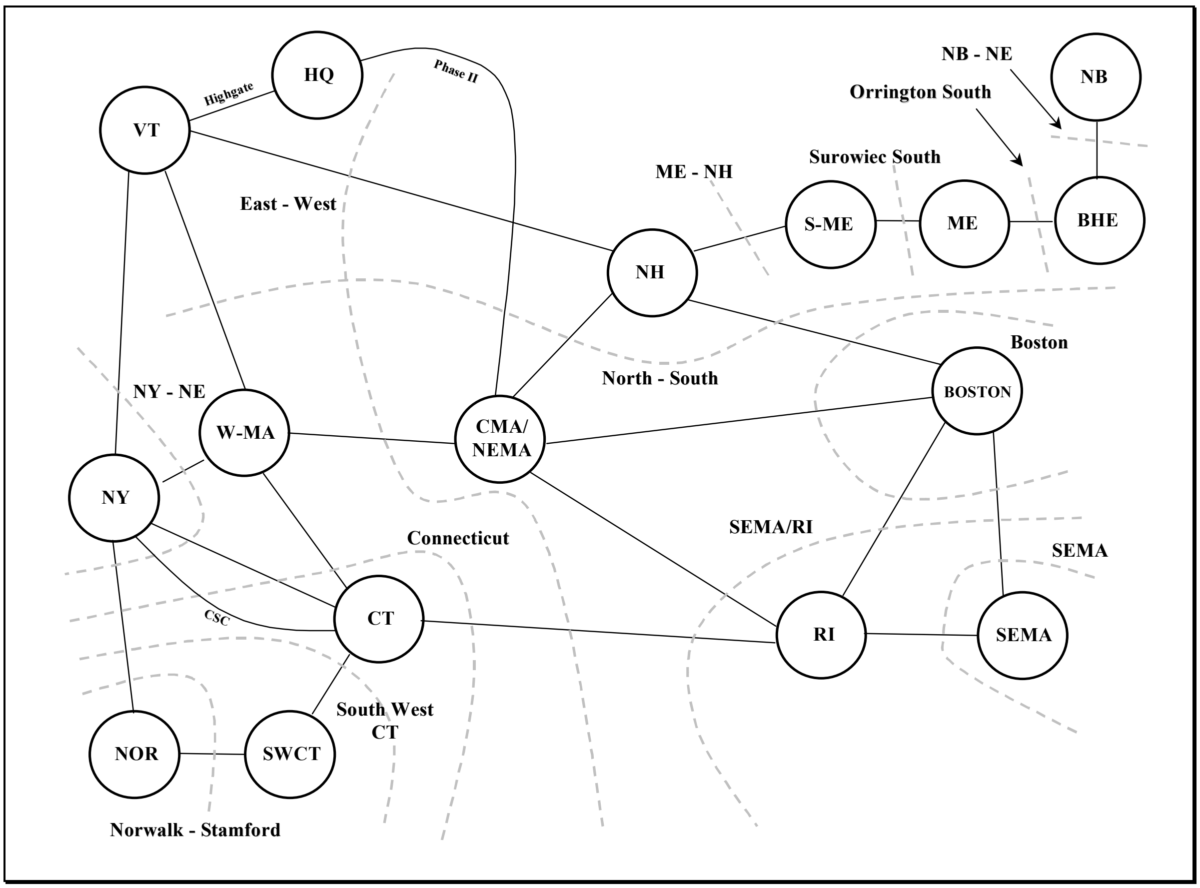
[11] The number in this table is the net of firm purchases and sales. Positive values represent net purchases.

Table 15 - Assumed Tie Benefits From External Control Areas

External Control Area	Assumed Tie Benefits (MW)
Hydro-Québec	1,200
New Brunswick	250
New York	350
Total	**1,800**

Figure 4 shows the NEPOOL Sub-Area representation.

Figure 4 - NEPOOL Sub-Area Representation



See next page for definitions.

A.3.1 Sub-areas

BHE	-	Bangor Hydro Electric
ME	-	Maine
S-ME	-	Southern Maine
NH	-	New Hampshire
VT	-	Vermont / Southwest New Hampshire
BOSTON	-	Boston Import
CMA-NEMA	-	Central Massachusetts / Northeastern Massachusetts
W-MA	-	Western Massachusetts
SEMA	-	Southeastern Massachusetts
RI	-	Rhode Island
CT	-	Connecticut
SWCT	-	Southwestern Connecticut
NOR	-	Norwalk / Stamford

NB, HQ and NY represent the New Brunswick, Hydro-Québec and New York external control areas respectively.

A.3.2 Interface Limits (MW)

Interface or Interface Group	Interface Limit (MW)
New Brunswick to NE	700
Orrington South	1,050
Surowiec South	1,150
Maine – NH	1,400
North to South	2,700
Boston Import	3,500
	3,600 (Jan 1 2006)
SEMA Export	1,450
SEMA / RI Export	2,200
East to West	2,100
Connecticut Import	2,500
Southwestern CT Import	1,850
	2,150 (May 1 2004)
Norwalk / Stamford Import	1,100
New York / New England (Summer)	1,400
New York / New England (Winter)	1,700
HQII Import	1,500
Highgate Import	225

Please note that the power flow on the proposed +/- 330 MW Cross Sound Cable (CSC), a DC interconnection between New England and New York, is assumed to be zero during the study period.

A.4 Modeling of Limited Energy Sources

NEPOOL's pumped storage and hydro units were considered available to meet daily and monthly peak loads except when they are on planned maintenance or forced outages.

A.5 Modeling of Demand Side Management (DSM)

ISO New England models DSM as a load adjustment to forecasted monthly NEPOOL peak loads as shown in the 2002 CELT Report. The values associated with the annual peak loads used in this review are shown in Table 16 below.

Table 16 - NEPOOL's DSM Load Adjustment to Summer Peak

Year	2003	2004	2005	2006	2007
Total DSM (MW)	1,553	1,586	1,645	1,700	1,740

The total DSM value is made up of the following categories:

Non-OP4 Interruptible Contracts:
This is the amount of customer load that is under contract with a utility that can be controlled at the time of system peak in response to a signal by a dispatcher and generally achieved within 10 to 30 minutes.

Peak Load Management:
This is the amount of customer load reduced from or shifted off system peak with only a minimum or no change in energy consumption.

Conservation on Peak:
This is the amount of customer load reduction at the time of system peak due to utility programs, which reduce customer load during many hours of the year.

Loss Adjustment:
This is the estimated reduction in transmission and distribution losses due to the implementation of DSM programs.

A.6 Modeling of Resources

Modeling of resources is as described in the above sections.

A.7 Other Assumptions

Although ISO-NE and NEPOOL has an active demand response resources program with a target of several hundred MW of participation, ISO-NE has not modeled the impact of such demand response resources in this Triennial Review. For this Triennial Review, the assumed demand response resources are the dispatchable and interruptible loads associated with the implementation of modeling OP 4 actions. In addition, the amount of load relief obtainable from the implementation of a 5% voltage reduction, one of the OP 4 actions, is also modeled. The following describes the amount of load relief associated with the calling of the interruption of dispatchable and interruptible loads and the implementation of voltage reduction in OP 4:

Dispatchable and Interruptible Loads	228 MW
5% Voltage Reduction	1.33% of Hourly Load

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