INITIAL DRAFT REPORT
For Discussion Purposes Only

New York Independent System Operator

Initial Planning Process Report

Prepared by the
NYISO Planning Staff

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Table of Contents

1 Introduction

In general, electricity deregulation has led to the unbundling of generation and transmission development. Largely gone are the days of planning in which generation and transmission plans were highly coordinated. In today's world, the reliability of the power system is ensured by a combination of resources provided by market forces and regulated wires companies. The purpose of this electric system expansion plan is to determine whether the electric system resources provided by a combination of market forces and regulated entities is providing sufficient resources to ensure the reliability of the New York State bulk power system is maintained throughout the ten year planning horizon. In addition, scenario analysis will be conducted to identify any opportunities or risk that should be monitored by the NYISO upcoming Comprehensive Planning Process.

At the advent of electricity market deregulation, generation development surged while transmission development lagged. Transmission expansion is primarily driven by three factors: 1) to interconnect new generation to the grid; 2) to maintain system reliability; and 3) to facilitate the economic transfer of power. Today, transmission expansion is being driven by the first two with the third a by product to some extent of the first two. Transmission expansion to facilitate economic transfers (i.e., reduce transmission congestion) is almost nonexistent. This report will not make any assessment as to whether the lack of transmission development to facilitate economic transfers is adversely impacting the efficiency of the wholesale electricity market. However, it will present an assessment of historical congestion costs for use by market participants in making their own assessments regarding transmission expansion to support economic transfers.

This report is the first electric system planning report prepared by the New York Independent System Operator. This initial planning document represents the first in a series of annual electric systems plans designed to ensure that the reliability of the New York State bulk power system is maintained. Just as important as the electric system plan is the planning process itself. Electric system planning is an ongoing process of evaluating, monitoring and updating as conditions warrant. It is hoped that this initial planning report is the first in a series that provides informative and valuable information to the NY wholesale electricity marketplace.

This report begins with a summary of the major findings and conclusion and then presents the results of the analysis that led to those findings.

2 Summary of Findings and Conclusions

Below is a summary of major findings and conclusions that were developed from the work conducted for the initial planning process. The summary is organized into two sections. The first summarizes the findings of the initial planning study and the second summaries the findings of the work that was conducted in reporting the historical congestion for 2003.

Initial Planning Study

1. The NYCA peak load is expected to increase from 31,410 MW in 2003 to 35,350 MW in 2013. This represents a statewide compound annual growth rate of 1.2%. The compound growth rate for the last ten years (1993-2003) has been just slightly over 1.5%.

2. Upstate New York (NYCA Zones A-F) growth was flat to slightly negative depending whether you measure against weather adjusted or actual load and energy. Southeast New York (NYCA and Zones G-K) accounted for all the load growth in the NYCA over the last ten years. Load growth in this part of the state was approximately 2.5% over the ten-year period. The forecast growth rate for Southeast New York through 2013 is 1.73% and for Upstate it is 0.8%.

3. For the baseline system, with all Class Year 2001, 2002, and 2003 projects totaling over 10,000 MW included, the NY power system meets all applicable reliability criteria.

4. Southeast's share of NYCA load has increased from approximately 57.9% to 63.5% while Upstate's share has declined. The opposite is true for generating capacity. Including generator addition through early 2004, Southeasts share of NYCA generating capacity has declined from slightly over 53% to slightly less than 52% since 1993.

5. The location quotient which is defined as the generating capability within the zone plus transmission import capability into the zone divided by the zonal weather normalized peak load for the two critical NY load pockets has declined from 1993 to 2003. A ratio below 2 is an indication that a zone should be evaluated for locational capacity requirements. The New York City ratio has declined from approximately 1.50 in 1993 to 1.28 in 2003. The Long Island ratio has declined from approximately 1.8 to 1.44 over the same period.

6. The conclusion to be drawn from findings four and five above is that the NYCA has become more dependent on the transmission system to meet resource adequacy and energy requirements. While there have been several proposed HVDC merchant transmission projects, there are no major transmission enhancements planned over the ten year planning horizon for the NY bulk power

AC transmission system that would be designed primarily to increase transfer capability between upstate and downstate and/or neighboring control areas.

7. In the expansion scenario in which only units under construction are included, the NY power system will not be able to meet its resource adequacy requirements beyond 2007 or as early as 2006 depending on load growth and capacity additions on Long Island.

8. Capacity beyond that currently under construction needs to be committed to the NY market and construction started within approximately a one-year time frame. This is especially critical in the New York City and Long Island load pockets.

9. Resource Adequacy analysis conducted as part of this initial planning study and also in support of the NYSRC IRM study indicates that resource adequacy criteria can be met with lower installed statewide capacity requirements by increasing the locational requirements above the current levels. Likewise, increasing transfer capability into the load pockets can have an equal affect. This analysis needs to be developed further.

10. As a result of increasing load and power transfer levels and the lack of any new generation connecting to the 115 kV system upstate over the study period, the analysis indicates increasing voltage violations on the upstate 115 kV system. These issues need to be studied further as part of the comprehensive planning process.

11. The reactive power demands from both load growth and losses from increased flows on the New York Transmission System are growing at a faster pace than the installation of reactive power sources in many zones in the NYCA. In addition, there is a growing flow of real and reactive power from the Bulk Power System to the 115 kV and 138 kV systems through load growth and unit retirements on the non Bulk Power System. The reactive reserves and Bulk Power Transformer flows need to be studied in greater detail in the comprehensive planning process.

12. There are over 1,600 MW of announced generating capacity retirements in the NYCA through 2008. Many factors, such as more restrictive emission requirements which results in the economic obsolescence of a facility, could result in additional retirements. The reliability impacts of retirements need to be evaluated, at a minimum, from voltage and locational capacity considerations NY should consider developing and implementing procedures that would require any facility proposed for retirement to be evaluated for any adverse reliability impacts and mitigation plans developed as necessary, similar to what New England currently has in place and as FERC directed PJM as part of its reliability must run decision.

13. New York's power supply has benefited from a diverse fuel supply and, in particular, a large percentage of dual fueled fired generating capability.

Generating capability being added to the NYCA is primarily gas fired combined cycle plants. Although the New York City units under construction are dual fired, the environmental permits allow for only 720 hours of operation per year on the alternate fuel which is distillate. In addition, there are technical considerations that potentially limit operating time on the alternate fuel to no more than a total 360 hours annually and no more than 240 hours continuously. This issue needs to be explored further in the comprehensive planning process.

14. There was no wind power scenario included in the initial planning study pending completion of the GE reliability study regarding wind generation.

Reporting of Historical Congestion:

15. The primary definition adopted for reporting of historical congestion was the change in mitigated bid production cost or the "societal cost savings" resulting from the elimination of congestion. It is defined as the difference between the mitigated bid production cost for the constrained as found system and the simulated unconstrained system. The total savings calculated in this manner for 2003 were $68.4 million. .

16. The key assumption in calculating the impacts of congestion on LBMP payments are the changes that results from the difference between the "as found" network and a totally unconstrained system. While it is a useful benchmark to put these reporting statistics on a common basis, the achievement of a totally unconstrained transmission network is both economically and practically infeasible. This must be taken into account in any interpretation imputed to the numbers reported in this report.

17. The congestion component of the Transmission Usage Charge (the "accounting cost") totaled $959.5 million in 2003. These payments were offset by the payout to holders of Transmission Congestion Contracts (TCC) and/or congestion payments forgiven because of grandfathered rights of $683 million. Assuming all TCCs are hedges for loads, which is not necessarily the case, the net result is a simulated total unhedged congestion payments of $276 million.

    However, holders of TCCs spent $190 million in procuring their TCCs and there was a simulated collection shortfall for TCC payouts of $156.3 million which the Transmission Owners are obligated to cover but can recover through the Transmission Service Charge (TSC). The net affect of the shortfall and the revenue from the purchase of TCC contracts which gets credited to the TSC would be to reduce the TSC by over 30 million dollars. In conclusion, aggregate congestion dollar payment and flows can be calculated but determining the economic impact on any individual market participant is uncertain at present any may, in fact, be unknowable.

18. The primary observations from the analysis conducted to develop 2003 historical congestion report are: 1) the flow of funds resulting from power system congestion is complex; 2) an invaluable tool for analyzing congestion in the aggregate and by limiting transmission facility has been developed; and 3) while our understanding of the impact of congestion has been greatly enhanced, unwinding the cost and benefits of transmission upgrades from the perspective of congestion economics will be difficult and complex.

19. The top ten limiting facilities accounted for 95% of the congestion payments and 97% of the unhedged congestion payments as defined in this report. Seven were located downstate while three were located upstate. The primary driver of congestion payments downstate were the result of transmission limitations from the cable interface (Sprain brook and Dunwoodie) into New York City and out to Long Island. The primary driver of congestion payments upstate was the Central East voltage limit.

20. In the comprehensive process, this analytical capability that has been developed in the initial planning process will be used to test the impact on congestion costs of relieving specific limiting facilities or constraints or unusual circumstances. This type of analysis is planned, on a selective basis, beginning with the January 2004 data. As noted above, the majority of the congestion impact in New York in 2003 was caused by a relatively few facilities. This does NOT mean that congestion impacts can be easily relieved with investments to upgrade only these facilities. Relief of one constraint almost always shifts the congestion to another facility, which may result in only a small net benefit to the region as a whole.

3 Background

Article 18.03 of the New York Independent System Operator Agreement states the following:

“18.03 Compilation of a New York State Transmission Plan.

(a) The ISO will compile a consolidated New York State Transmission Plan (the “Plan”) as described in the ISO OATT, which will be comprised of all transmission projects proposed by Transmission Owners, as well as projects proposed by other Market Participants, that are found to meet all applicable criteria and include appropriate Transfer Capability mitigation measures, and that have pending applications for construction permits or approvals.

(b) The Plan shall be compiled in coordination with the transmission systems of neighboring ISOs, Control Areas, and Canadian systems.

(c) The Plan shall conform with applicable NYSRC standards, in accordance with ISO Procedures detailed in ISO manuals.

(d) The Plan will be compiled by the ISO staff, with Transmission Owner support and other participation, for Operating Committee review and approval.”

The NYISO OATT defines the New York Transmission Plan as follows:

“A plan developed by the NYISO staff with Transmission Owner’s support that is a compilation of transmission projects proposed by the Transmission Owners and others, that are found to meet all applicable criteria”

To implement these requirements and recognizing the planning process needs to encompass more than just the transmission system, the Operating Committee approved the formation of the Electric Systems Planning Working Group (ESPWG) to work in conjunction with the Transmission Planning Advisory Subcommittee (TPAS) to develop the initial electric systems planning process as well as the comprehensive planning process. This effort began in the spring of 2003. The initial planning process scope was approved by the Operating Committee on September 10, 2003.

The scope of the Initial Planning Process is set forth in Appendix A and consist of the following primary elements:

- Identifies reliability needs only
- Expanded 10-year planning horizon

- Includes base case and scenario analysis

- Reports on historic congestion

The development of the initial planning process is only the first step in the development of a comprehensive planning process. The development of the comprehensive process is needed to bring the NYISO into compliance with the Federal Energy Regulatory Commissions' Order 2000 planning requirement. Order 2000 requires that all ISOs/RTOs have a fully functional comprehensive planning process. The comprehensive process builds upon the initial process. It moves beyond identifying reliability needs to addressing reliability and economic needs inclusive of cost allocation and recovery. The development of the comprehensive process is proceeding in two steps. Step I addresses reliability needs while step II will address economic needs. The goal is to file a comprehensive process addressing reliability needs with FERC by the fall of 2004 with completion of step II by year end.

4 The NY Power Grid In Context

On December 1, 1999, the NYISO assumed responsibility for the operation of New York State's bulk power system and of the newly established electric energy markets. New York's wholesale energy markets were established coincident with the establishment of the NYISO. Prior to December 1, operation of the bulk power system was the responsibility of the New York Power Pool. The NYISO is charged with two overriding responsibilities: First, maintain the safe and reliable operation of New York's bulk power system; and second, operate fair, non-discriminatory and effective wholesale electric markets.

Geographically, the New York Control Area (NYCA) is situated in the center of the Northeastern North America electrical grid which includes the Mid-Atlantic and New England States in the US and the Canadian Provinces of Ontario, Quebec, and Maritimes. In fact, NY has been described as the "Hub of the Northeast". Figure I display the major electricity markets operating in the region along with summary statistics. This area includes a customer load greater than the entire Western Interconnection and provides electric service to the capital cities of two members of the G-7 as well as the financial capital of the world. Figure 1 also displays the nominal transfer capabilities between the major markets in the Northeast. *The key point is that the total nominal transfer capability between the control areas in the Northeast is only on the order of 5% of the total peak load of the region. The transfer capability as percent of the regional load was about 6% ten years ago and over the next ten years will decline to approximately 4% absent any new tie capability.*

Figure 1

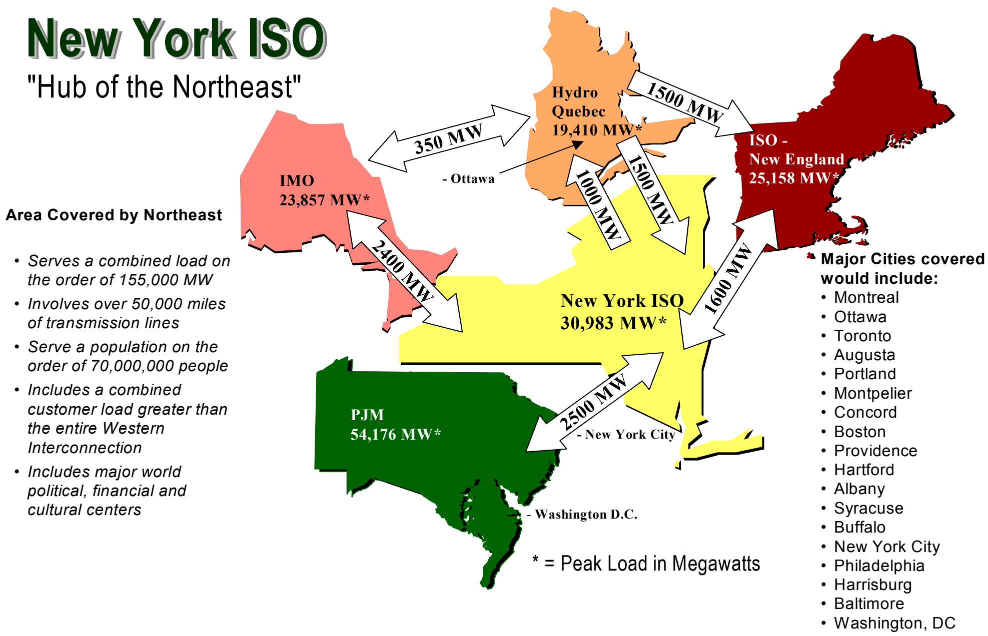


Figure 2

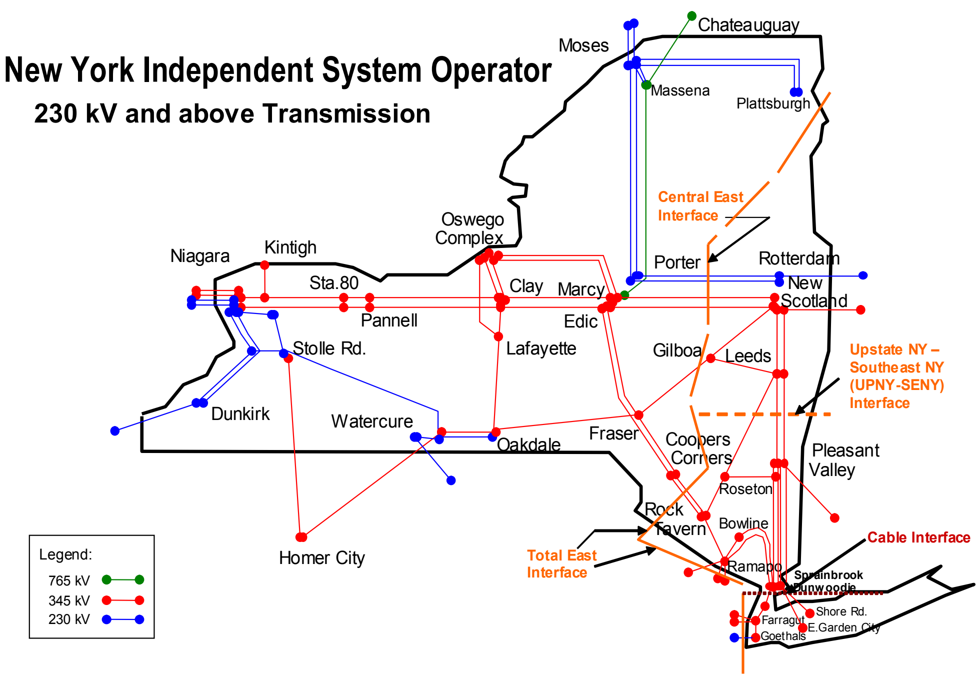
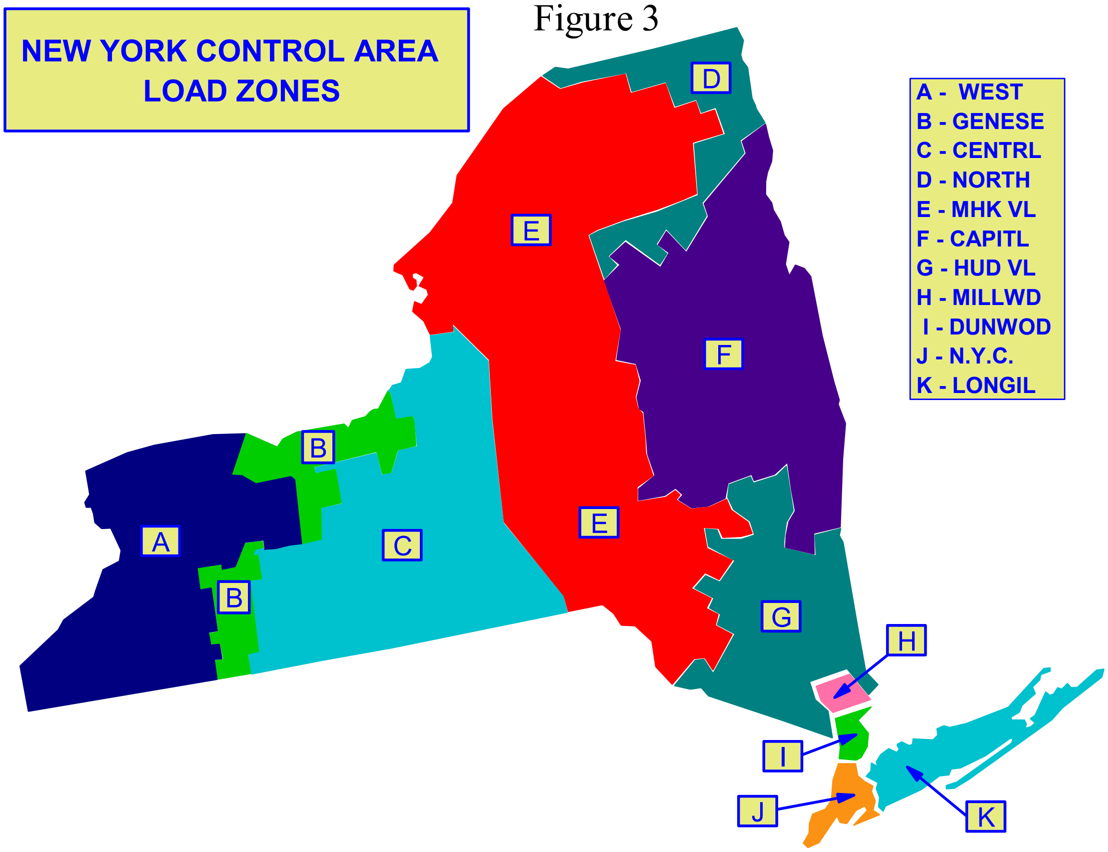


Figure 2 displays the bulk power transmission system for the NYCA. It shows facilities operating at 230 thousand volts (kV) and above. This represents more that 4,000 miles of high voltage transmission lines. If the underlying 138 and 115 kV transmission lines are included, the mileage exceeds 10,000 miles. Figure 2 also displays key NYCA transmission interfaces. Transmission interfaces are groupings of transmission lines which measure the transfer capability between regions such as the transfer capability between the Northeastern control areas presented in Figure 1.

The New York wholesale electricity market is divided into eleven pricing or load zones. Figure 3 presents the geographical boundaries for these pricing zones.

Figure 3



The development of these load zones was driven primarily by the topology or configuration of the transmission system and secondarily by the franchise areas of the investor owned utilities. These load areas were initially developed by the New York Power Pool after the 1965 Northeast blackout as part of a process of identifying critical bulk power system transmission interfaces. Subsequently, these load zones were utilized to define pricing zones for the wholesale electricity market.

On a pricing basis, zones A-E have relatively homogeneous prices and can be defined as one super zone called West NY, while the balance of the zones can be defined as East NY. Pricing is not homogeneous within the eastern zones. Zones F – I are defined as the Hudson Valley which leaves Zone J (New York City) and Zone K (Long Island) as two additional areas defined in east NY. The boundary between West NY and East NY including the boundary between PJM and the East zones defines the Total East transmission interface. This interface is represented by the orange line on Figure 2. The upper half of the Total East interface is defined as the Central East interface while the lower half including the dotted part of the orange line is known as the interface between Upstate NY and Southeast NY or the UPNY – SENY interface. The dotted part of the line effectively divides the Hudson Valley into a lower and upper part electrically. Below the UPNY – SENY interface you have the *cable interface* which includes the red dotted line on the transmission map and also the lower end of the total east interface. This interface contains all the major underground and/or submarine cables supplying New York City and Long Island.

Table I presents the approximate non-coincident peak loads and capacity contained in the super zones defined above for summer 2004. Table II below presents the nominal transfer capability across the major transmission interfaces defined above. The transmission facilities that make up the interfaces are the facilities that tie the zones together electrically.

Table I

Approximate Summer Peak Load/Capacity

Zone	Peak Load (MW)	Capacity (MW)
WEST (A-E)	9,700	14,600
Hudson Valley (F-I)	6,700	9,080
New York City (J)	11,150	8,810
Long Island (K)	5,050	5,090

Note: Numbers are approximate and based on projections for the summer of 2004

Table II

Nominal Transfer Capability

Transmission Interface	Transfer Capability (MW)
TOTAL EAST	6100
Central East	2850
UPNY – SENY	5100
Cable Interface	
• New York City	4700
• Long Island	1270

As a result of the distribution of load and capacity on the NYCA power system, power flows are primarily west to east and then southeast or predominantly from the northwest to the southeast into the highly congested urban zones of New York City and Long Island. All power flows from the west including the transmission ties to the neighboring control areas of Ontario, Hydro Quebec and PJM must cross the Total East Interface with large portions flowing across the Central East portion of the interface and then across the UPNY – SENY interface to reach the cable interface.

In addition to being highly dependent on the transmission system, the New York City and Long Island zones' electricity generating infrastructure has the highest average age of generating units in the state and, recent peaking plant additions notwithstanding, is still highly dependent on an aging fleet of combustion and gas turbine capacity. Also, the generation mix in Western NY has much larger proportions of hydro, nuclear and coal. This creates a high potential for economic transfer from West NY to New York City and Long Island. (Economic transfer is the transmission of power from a lower cost region to a higher cost region.)

5 Historical Trends

This initial electric systems expansion plan is a ten year look ahead to 2013. Therefore, to provide background and context, this section presents the historical trends and overview regarding load growth, generating capability and transmission system additions, and fuel diversity for the New York Control Area (NYCA) for the last ten years.

Load Growth: The NYCA peak load has grown from approximately 27,000 MW in 1993 on a weather adjusted basis to 31,410 MW in 2003, which totals approximately 4,410 MW. This represents a ten year compound growth rate of approximately 1.52%. However, a regional analysis presents a much different picture on growth rate basis. Load growth in West NY and Upper Hudson Valley (Zone F) has been flat to slightly negative. The Lower Hudson Valley (Zones G-H-I) has grown at a rate of slightly in excess of 2% annually and represents almost 18% of the ten year growth of 4,400 MW. New York City has also grown in excess of 2% annually and accounts for almost 50% of the MW growth in the NYCA over the last ten years. Long Island has grown in excess of 3% annually and accounts for almost one-third of the NYCA load growth over the last ten years.

Generating Capability: Table III below presents generating capability for the NYCA to the nearest 10 MW and the regions as defined above for the years 1993, 2000 and 2003. These numbers are based on summer ratings and were derived from the annual "Load and Capacity Data Report" which represents generating capability as January 1 of the reporting year. This capacity has been adjusted for capacity sold out of State such as the NYPA hydro allotment and non-qualifying capacity such as the Indian Point gas turbines. These adjustments total approximately 400 MW.

Table III
New York Installed Generating Capability (MW)
For Select Years

Region	1993	2000	2003
West NY	13,950	14,480	14,780
Upper Hudson Valley	1,840	2,440	2,550
Lower Hudson Valley	5,500	5,530	5,480
New York City	8,270	7,870	8,820
Long Island	4,300	4,370	5,060
Total	33,860	34,690	36,690

The purpose of the above table is to present information on trends in NYCA capacity and an approximate estimate of the amount of capacity that would be available to meet installed capacity requirements. The first observation that can be made is that the 4,400 MW of load growth over the ten year period has been offset by just short of 3,000 MW of additional generating capacity, not including demand response. In fact, in excess of two thirds of the capacity additions that have been installed over the last ten years have been realized since the NYISO began operations of the NYCA wholesale electricity market on December 1, 1999.

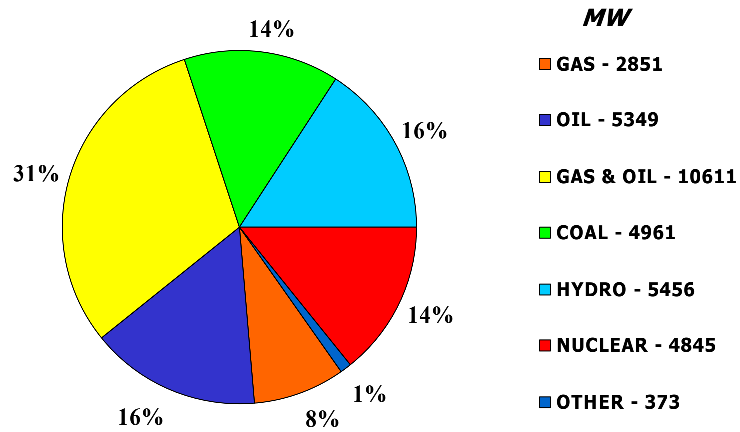
If the summer of 2004 is included, the load growth is expected to increase by 400 MW to a total 31,800 MW but the capacity additions will increase by over 1300 MW. Including demand response, this means the 4,800 MW of load growth that would have occurred between 1993 and the summer of 2004 will have been offset by a combination of demand response and capacity additions. The amount of system resources both capacity and demand response that been added to the NYCA since the wholesale electricity market opened total just short of 4000 MW. This represents slightly over 80% of the resources that have been added between 1993 and 2004.

However, just as the load growth story over the last ten years embodies regional overtones, the expansion of NYCA generating capability also embodies regional overtones. While essentially all the load growth has occurred in Southeast NY (SENY) - i.e., Lower Hudson Valley, New York City and Long Island, the generation expansion has been more uniformly distributed between SENY and Upstate NY (UPNY) – West NY and Capital or Zone F. The peak load share for UPNY of the NYCA peak load has declined from 42.1% to 36.5% while SENY's share has increased from 57.9% to 63.5%. At the same time, UPNY's share of NYCA installed capacity has increased slightly from 46.6% to 47.2% while SENY's share has declined slightly from 53.4% to 52.8%. If the capacity additions that have occurred in 2003 and early 2004, UPNY's share increases to over 48% while SENY's share declines to less than 52%. The conclusion that can be drawn from these trends is that is that the NYCA has become more dependent on the transmission system in meeting its resource adequacy and energy requirements.

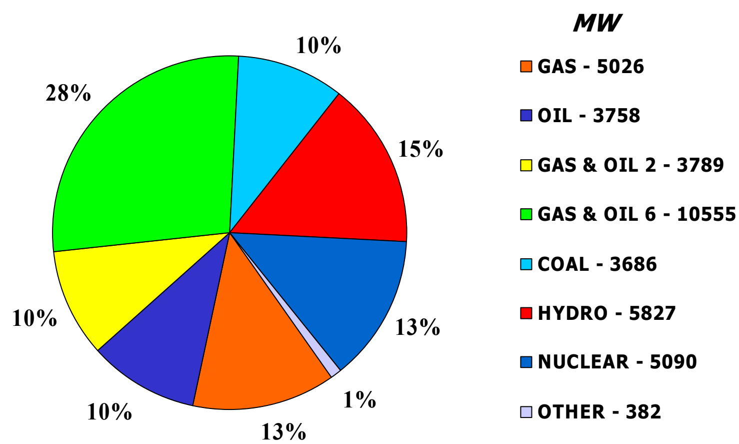
Transmission System: While the NYCA has becoming more dependent on the transmission system, expansion of the transmission system has been has minimal. The "1993 Load and Capacity Data" book reported approximately 10,750 miles of transmission lines in service operating at 115 kV or higher while the "2004 Load and Capacity Data" book reported approximately 10,625 miles of transmission lines in service operating at 115 kV or higher. These numbers should not be interpreted to mean that the NYCA transmission system has contracted. The transmission and sub-transmission (i.e., 69 kV and 34.5 kV) system has been expanded to accommodate local load growth requirements. The primary explanation for the reduction in the reported mileage between the 1993 book and 2004 book was the transfer of Orange and Rockland Utilities, Inc operation in Northern New Jersey from the NYCA to the PJM control area.

<u>Fuel Diversity:</u> Fuel diversity is not only important from economic perspective but also from a reliability perspective. Fuel diversity, in particular dual fuel capability, provides operational flexibility and a hedge against the disruption of anyone particular fuel source. The first chart below presents the fuel mix of NYCA generating capability as of 1993, while the second presents the fuel mix as it existed as of January 1, 2004 (year end 2003).

1993
NYCA CAPACITY BY FUEL TYPE



2004
NYCA CAPACITY BY FUEL TYPE



As the charts above shows, NY has an excellent fuel mix which has changed minimally over the last ten years. In 1993, dual fuel capability (gas and oil) accounted for 31% of generating capability while by year end 2003 it accounted for 38% fuel mix. Also, note that that the amount generating capability that burns natural gas as a sole source of fuel has increased from 8% of generating capability to 13%. Another point to note is that the 2004 chart splits natural gas and oil between units that burn #2 oil or distillate as opposed to #6 oil as an alternate fuel. Since new combined cycle generating units burn natural gas as their primary fuel and burn #2 oil or distillate as an alternate fuel on a limited basis. This will be an important reliability consideration on a going forward basis.

The excellent fuel mix that NY enjoys today is the result of the actions taken by NY investor owned utilities as a result of the oil embargo and fuel price shocks of the mid and late 1970's. New coal and nuclear capacity was constructed and existing capacity was either converted back to coal or dual fuel capability (the ability to burn natural gas as well as #6 oil). The real challenge on a going forward basis will be to maintain the benefits that fuel diversity, in particular dual fuel capability, provide today.

6 NYCA Load and Energy Forecast: 2004 - 2013

6.1 Introduction

This document describes the demand forecast for the ten year period beginning with 2004 and extending through 2013. It begins with this summary, continues with an overview of historic electricity and economic trends in New York State, and concludes with the ten year forecast of summer and winter peak demands and annual energy requirements.

The NYISO has initiated the Electric System Planning Process (ESPP) to assess the adequacy of New York's electricity infrastructure for meeting reliability needs over the 2004 – 2013 horizon. As part of this assessment, a ten year forecast of summer and winter peak demands and annual energy requirements was performed.

The electricity forecast is based on projections of New York's economy performed by Economy.com in the autumn of 2003. The Economy.com forecast includes detailed projections of employment, output, income and other factors for twenty three regions in New York State.

A summary of the electricity forecast and the key economic variables that drive it follows:

	Average Annual Rates of Change	
	84 - 03	**03 - 13**
Employment	0.53%	0.83%
Households	0.51%	0.38%
Total Income	2.26%	1.66%
Health&Ed Employment Share	2.28%	1.29%
Manufacturing Employment Share	-3.56%	-0.92%
Average Electric Price	1.26%	-0.09%
Summer Peak	1.74%	1.54%
Winter Peak	1.17%	0.76%
Annual Energy Requirements	1.26%	1.38%

The NYCA summer peak is projected to grow from the weather normalized peak load of 31,410 MW in 2003 to 35,330 MW in 2013. This represents a total load growth over the next ten years of 3940 MW. This compares to a growth of 4,400 MW over the previous ten years. Again, SENY will be the fastest growing part of the state but West NY should experience positive growth over the next ten years.

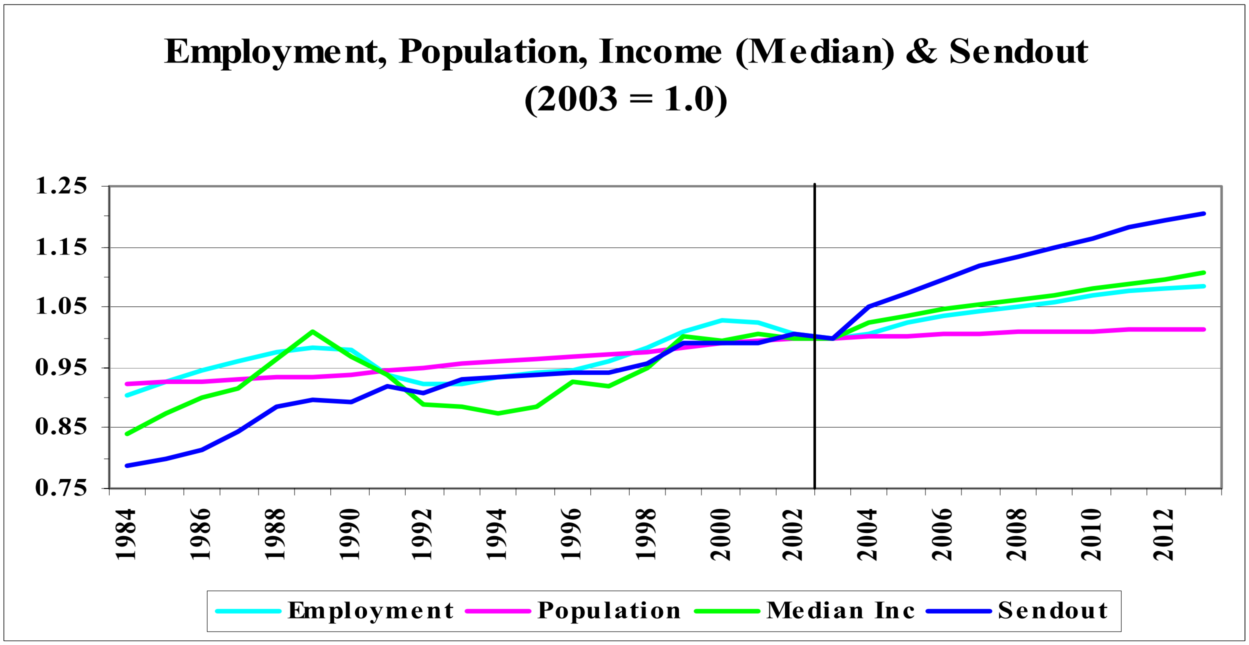
6.2 Historical Overview

Table 1 shows the New York Control Area's (NYCA) historic peak and energy growth for the last twenty years.

20 Year Historic Peak and Energy Data and Growth Rates

Calendar	Annual Energy		Summer Peak			Winter Peak	
Year	(GWH)	Growth (%)	(MW)	Growth (%)	Winter	(MW)	Growth (%)
1984	124,637		21,870		84 - 85	20,291	
1985	126,290	1.33%	22,926	4.83%	85 - 86	20,664	1.84%
1986	128,748	1.95%	22,942	0.07%	86 - 87	20,247	-2.02%
1987	133,531	3.71%	24,427	6.47%	87 - 88	22,593	11.59%
1988	140,048	4.88%	25,720	5.29%	88 - 89	23,227	2.81%
1989	141,883	1.31%	25,390	-1.28%	89 - 90	23,003	-0.96%
1990	140,919	-0.68%	24,985	-1.60%	90 - 91	22,579	-1.84%
1991	145,019	2.91%	26,839	7.42%	91 - 92	22,981	1.78%
1992	143,421	-1.10%	24,951	-7.03%	92 - 93	22,806	-0.76%
1993	146,915	2.44%	27,139	8.77%	93 - 94	23,809	4.40%
1994	147,777	0.59%	27,065	-0.27%	94 - 95	23,345	-1.95%
1995	148,429	0.44%	27,206	0.52%	95 - 96	23,394	0.21%
1996	148,527	0.07%	25,585	-5.96%	96 - 97	22,728	-2.85%
1997	148,896	0.25%	28,699	12.17%	97 - 98	22,445	-1.25%
1998	151,377	1.67%	28,161	-1.87%	98 - 99	23,878	6.38%
1999	156,356	3.29%	30,311	7.63%	99 - 00	24,041	0.68%
2000	156,636	0.18%	28,138	-7.17%	00 - 01	23,774	-1.11%
2001	156,787	0.10%	30,982	10.11%	01 - 02	23,713	-0.26%
2002	158,745	1.25%	30,664	-1.03%	02 - 03	24,454	3.12%
2003	158,014	-0.46%	30,333	-1.08%	03 - 04	25,262	3.30%
Annual Average Growth Rates		1.26%		1.74%			1.16%

Summer peak has grown faster than sendout and winter peak has grown the slowest. This period started with New York's economy rebounding from the 1981 – 1982 recession. Until interrupted by the next recession, sendout growth averaged 2.1% and employment, 1.3%. The 1990 – 1991 recession was particularly hard on New York and it was not until 1998 that total employment recovered to its pre-recession level. During this period (1990 – 1998), sendout grew only 0.8% per year. However, after bottoming in 1992, the New York economy did grow (slowly, at fist) until the last recession which started in March, 2001. Even though the recession ended in November of that year, jobs are still being lost in New York. Sendout grew 1.1% annually from 1998 – 2000 and only 0.2 % per year since then.



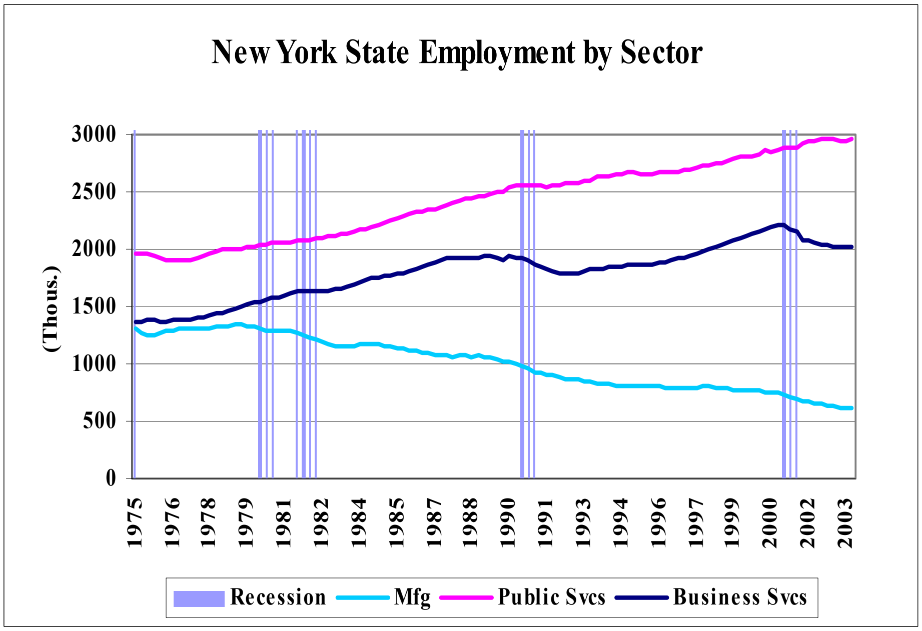
Historically and in the forecast, sendout has grown faster than measures of New York's economy. This is due to many factors including increased air conditioning, the advent and spread of computers and other information technologies, and a general preference for more convenience as incomes have increased.

6.3 New York's Changing Economy

A factor which has had considerable impact on the nature of electricity use is the changing structure of New York's economy. These changes have been pronounced over the last twenty year, and longer. The most significant are changes in industry composition and in the relative economic fortunes of the Upstate and Downstate economies.

6.3.1 Industry Composition

Chart 2 shows how employment in major industrial sectors has fared in New York since 1975.



Public services include government, education and health care. Business services include finance, professional, managerial and administrative services.

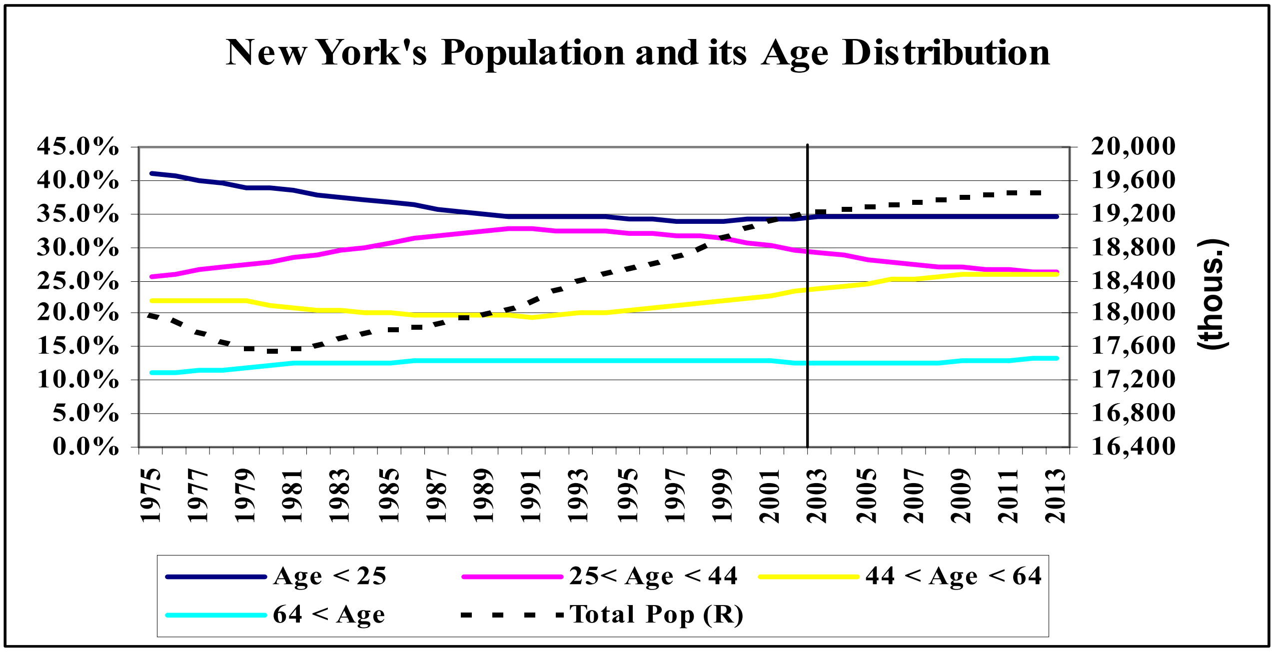
Manufacturing employment has declined almost without interruption since 1979. Business service employment, which was comparable to manufacturing in 1975, is now three times as great. Public service employment was about 60% greater than manufacturing in 1975. It is now five times as great, and greater than manufacturing and business services combined. Of the approximately 1.5 million jobs added in New York since 1975, 1.0 million, or two thirds, have been in public services. Even during the economic expansion of the 1990's, less than half the employment gains in New York have been in the private sector.

The change in composition of the State's economy has implications for its electricity use. Factories tend to be high load factor electricity consumers. Public and business services, located primarily in office buildings, are lower load factor consumers. Their use also responds more to weather since much of it is for heating and, particularly, air conditioning. Electricity use has also become less responsive to economic cycles since manufacturing, the most cyclically sensitive component of the economy, has diminished in importance, both relatively and absolutely.

6.3.2 Demographic Trends

While these economic shifts were taking place, New York's population was undergoing pronounced changes as well. Chart 3 illustrates:

Chart 3



Total population was about 18 million in 1975 and bottomed at 17.6 million in 1980. From 1980 through 2003, population grew by approximately 72 thousand annually. Growth is expected to continue at about 23 thousand per year through 2013.

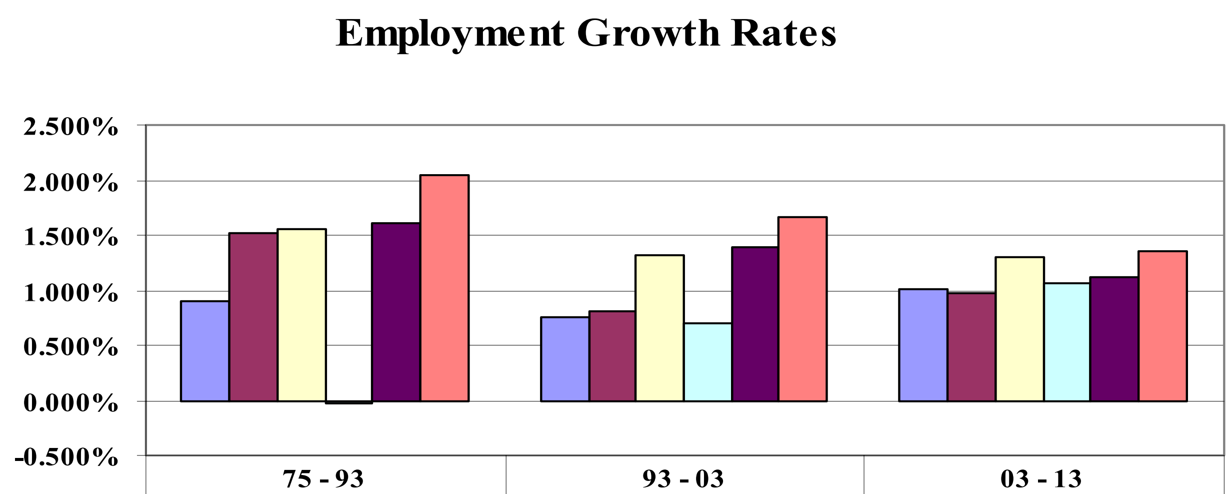
Like the rest of the US, the age of New York's population has shifted towards the older end of the distribution. The younger cohorts have declined from 40% to 35% of the total. The over 64 cohort has increased from 10% to 12%. The cohorts that contribute most to the labor force have in aggregate have increased from 44% to 52% of the population. However, their paths over the last 28 years have been dramatically different. The 25 – 44 age group increased from 25% to almost 35% of the population from 1975 – 1990 while the 44 – 64 old cohort stayed close to 20%. Since 1990, the younger group's share has decreased to 30% while the older ones has increased to almost 25%. By 2013, these two cohorts are predicted to be of approximately equal size.

Slower population growth and an age distribution shift towards the older cohorts means that household formation will be slower than in forecast period than it was historically.

6.3.3 Relative Economic Fortunes

Economic growth in New York has been uneven. New York City, its suburbs, and Long Island have grown at rates approaching the nation. Other regions in the State have lagged. To illustrate this, economic zones have been developed that correspond to groupings of the eleven electrical zones of the New York Control Area. West corresponds to NYCA zones A – E. Upper Hudson Valley is F, Lower Hudson Valley is G – I, New York City is J and Long Island is K.

Chart 4 shows the average employment growth rates for two historical periods and the ten year forecast for the four economic zones described above and the US.

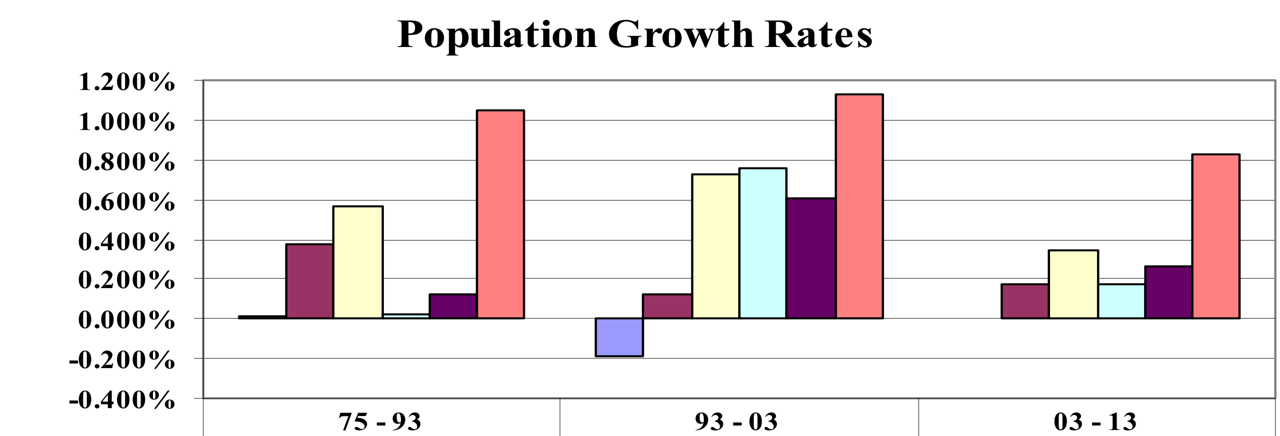


	75 - 93	93 - 03	03 - 13
West	0.897%	0.760%	1.001%
Up Hud Val	1.522%	0.806%	0.972%
Low Hud Val	1.550%	1.327%	1.308%
NYC	-0.029%	0.700%	1.070%
LI	1.616%	1.398%	1.114%
US	2.041%	1.671%	1.356%

West Up Hud Val Low Hud Val NYC LI US

Lower Hudson Valley and Long Island have had the best employment growth since 1993. New York City's was strong until the World Trade Center attack of September 11, 2001. Together, these regions have far outperformed the upstate regions and have fared almost as well as the US.

Population growth follows similar trends. Chart 5:



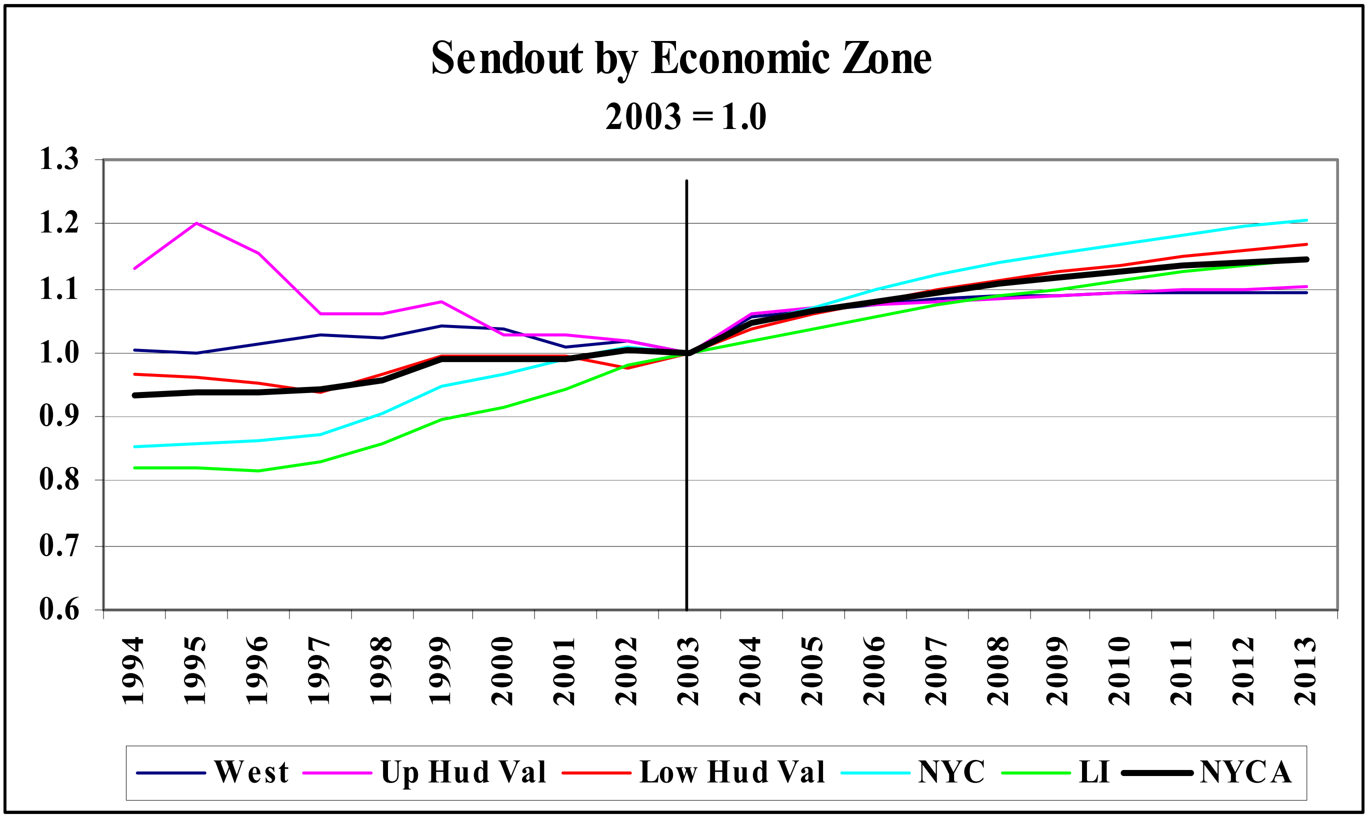
	75 - 93	93 - 03	03 - 13
West	0.014%	-0.188%	-0.002%
Up Hud Val	0.375%	0.121%	0.174%
Low Hud Val	0.562%	0.723%	0.348%
NYC	0.020%	0.761%	0.171%
LI	0.123%	0.608%	0.263%
US	1.049%	1.129%	0.832%

West Up Hud Val Low Hud Val NYC LI US

The Lower Hudson Valley has had the most rapid population growth and is expected to have it in the forecast. This is due to the expansion of New York City's northern suburbs. Growth in other downstate areas is expected to slow from the last ten years' pace. Growth in the Upper Hudson valley is expected to increase modestly.

Western New York, which essentially includes all of the State west of Schenectady, has seen it population decline relative to 1975 levels. Continued modest decline is predicted. This is an effect of the decline of manufacturing jobs, upon which this region was more dependent than the others.

These economic and demographic trends are reflected in sendout growth across the regions of the State, as shown in Chart 6.



The West and Upper Hudson Valley regions experienced net declines in sendout from 1993 through 2003 while the other regions has experienced growing sendout. Long Island (18% growth) and New York City (15%) have led the State. 1993 – 2003 sendout in the State excluding these two zones actually declined.

In the forecast, these trends are expected to attenuate. The fastest growing zone is predicted to be the Lower Hudson Valley. The West and Upper Hudson Valley, while again lagging the rest of the state are expected to see positive growth.

Below is a table that presents the base, high, and low NYCA forecast summary for the period 2004 – 2013 for energy, summer and winter peak loads. The ten year growth rate of 1.19% for summer peak load base case represents a reduction when compared to the previous ten years based on weather adjusted numbers of 1.52%.

6.4 Load Forecast Table

NYISO Long Term Forecast - 2004 to 2013

Energy - GWh

Year	Low	Base	High
2003		158,014	
2004	164,510	165,210	165,950
2005	166,470	168,000	169,550
2006	168,230	170,640	173,040
2007	169,810	173,100	176,440
2008	170,770	174,950	179,270
2009	171,130	176,120	181,350
2010	172,000	177,830	184,060
2011	172,610	179,290	186,550
2012	172,720	180,120	188,320
2013	173,120	181,260	190,420

Summer Peak - MW

Year	Low	Base	High
2003		30,333	
2004	31,700	**31,800**	31,900
2005	32,110	32,320	32,530
2006	32,430	32,770	33,100
2007	32,770	33,220	33,680
2008	33,050	33,630	34,230
2009	33,270	33,990	34,720
2010	33,550	34,410	35,310
2011	33,790	34,800	35,860
2012	33,890	35,050	36,280
2013	34,020	35,340	36,770

Winter Peak - MW

Year	Low	Base	High
2003-04		25,262	
2004	25,430	25,620	25,810
2005	25,620	25,920	26,210
2006	25,790	26,200	26,600
2007	25,890	26,400	26,920
2008	25,910	26,520	27,150
2009	26,000	26,700	27,450
2010	26,050	26,860	27,730
2011	26,040	26,930	27,910
2012	26,060	27,050	28,150
2013	26,160	27,140	28,250

Annual Avg Growth Rates (Energy - Low)		Annual Avg Growth Rates (Summer - Low)		Annual Avg Growth Rates (Winter - Low)	
93-03 (Actual)	0.83%	93-03 (Actual)	1.12%	93-03 (Actual)	0.59%
03-13 (Actual)	0.92%	03-13 (Actual)	1.15%	03-13 (Actual)	0.35%
03-13 (Normal)	0.57%	03-13 (Normal)	0.80%	03-13 (Normal)	0.51%

Annual Avg Growth Rates (Energy - Base)		Annual Avg Growth Rates (Summer - Base)		Annual Avg Growth Rates (Winter - Base)	
93-03 (Actual)	0.83%	93-03 (Actual)	1.12%	93-03 (Actual)	0.59%
03-13 (Actual)	1.38%	03-13 (Actual)	1.54%	03-13 (Actual)	0.76%
03-13 (Normal)	1.03%	03-13 (Normal)	1.19%	03-13 (Normal)	0.92%

Annual Avg Growth Rates (Energy - High)		Annual Avg Growth Rates (Summer - High)		Annual Avg Growth Rates (Winter - High)	
93-03 (Actual)	0.83%	93-03 (Actual)	1.12%	93-03 (Actual)	0.59%
03-13 (Actual)	1.88%	03-13 (Actual)	1.94%	03-13 (Actual)	1.21%
03-13 (Normal)	1.53%	03-13 (Normal)	1.59%	03-13 (Normal)	1.37%

Load Factor (Summer)		Load Factor (Winter)	
93-03 (Actual)	60.5%	93-03 (Actual)	73.1%
03-13 (Actual)	59.1%	03-13 (Actual)	75.7%

* 2004 Peak demand corresponds to 2004 ICAP results, based on normal weather, & summed over TO projections.
2003 Weather-normalized Summer Peak is 31,410 MW; normalized Winter peak is 24,900 MW; normalized annual usage is 163,624 GWh.
Growth rates are shown based on both 2003 actual & 2003 normal loads. (Winter peaks run from Nov of previous year through Apr of current.)

7 Description of Baseline System

The Base Case assumptions are fully defined by existing processes, study reports, and existing documents. No additional analytical work is required.

The following information contains the Base Case assumptions. The information is from the "NYISO 2003 Load & Capacity Report."

7.1 Capacity (by type) and Load by Year for NYCA

Table 7.1. Load and Capacity Table

	Installed Capacity											
Category	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Steam Turbine (Oil)	1747	1747	1747	1747	1747	1747	1747	1747	1747	1747	1747	1747
Steam Turbine (Oil & Gas)	10534	10534	10367	9999	9999	9467	9467	9467	9467	9467	9467	9467
Steam Turbine (Gas)	233	233	233	233	233	233	233	233	233	233	233	233
Steam Turbine (Coal)	3783	3783	3783	3783	3783	3783	3783	3783	3783	3783	3783	3783
Steam Turbine (Wood)	38	38	38	38	38	38	38	38	38	38	38	38
Steam Turbine (Refuse)	256	256	256	256	256	256	256	256	256	256	256	256
Steam (PWR Nuclear)	2473	2473	2473	2473	2473	2473	2473	2473	1975	1975	1975	1975
Steam (BWR Nuclear)	2606	2606	2606	2606	2606	2606	2606	1987	1987	1987	1987	1987
Pumped Storage Hydro	1291	1291	1291	1291	1291	1291	1291	1291	1291	1291	1291	1291
Internal Combustion	129	129	129	129	129	129	129	129	129	129	129	129
Conventional Hydro	4533	4583	4633	4683	4733	4783	4783	4783	4783	4783	4783	4783
Combined Cycle	4706	5786	7144	11154	12444	13524	13524	13524	13524	13524	13524	13524
Jet Engine (Oil)	531	531	531	531	531	531	531	531	531	531	531	531
Jet Engine (Gas & Oil)	171	171	171	171	171	171	171	171	171	171	171	171
Combustion Turbine (Oil)	1398	1398	1398	1398	1398	1398	1398	1398	1398	1398	1398	1398
Combustion Turbine (Oil & Gas)	1418	1418	1418	1418	1418	1418	1418	1418	1418	1418	1418	1418
Combustion Turbine (Gas)	1200	1379	1963	1963	1963	1963	1963	1963	1963	1963	1963	1963
Wind	45	45	45	45	45	45	45	45	45	45	45	45
Other	1	1	1	1	1	1	1	1	1	1	1	1
Import Capability												
Capacity Import	2755	2755	2755	2755	2755	2755	2755	2755	2755	2755	2755	2755
Demand Response Programs	500	500	500	500	500	500	500	500	500	500	500	500
NYCA Demand	31590	32010	32420	32790	33170	33570	33930	34320	34710	35110	35480	35860
Required Capability	36686	37182	37666	38102	38551	39023	39447	39908	40368	40840	41276	41725
Total NYCA Capability	39849	41157	42983	46675	48015	48613	48613	47995	47496	47496	47496	47496
Reserve Margin	28%	31%	35%	45%	47%	47%	45%	42%	39%	37%	36%	34%

*Capacity based on Summer Capability

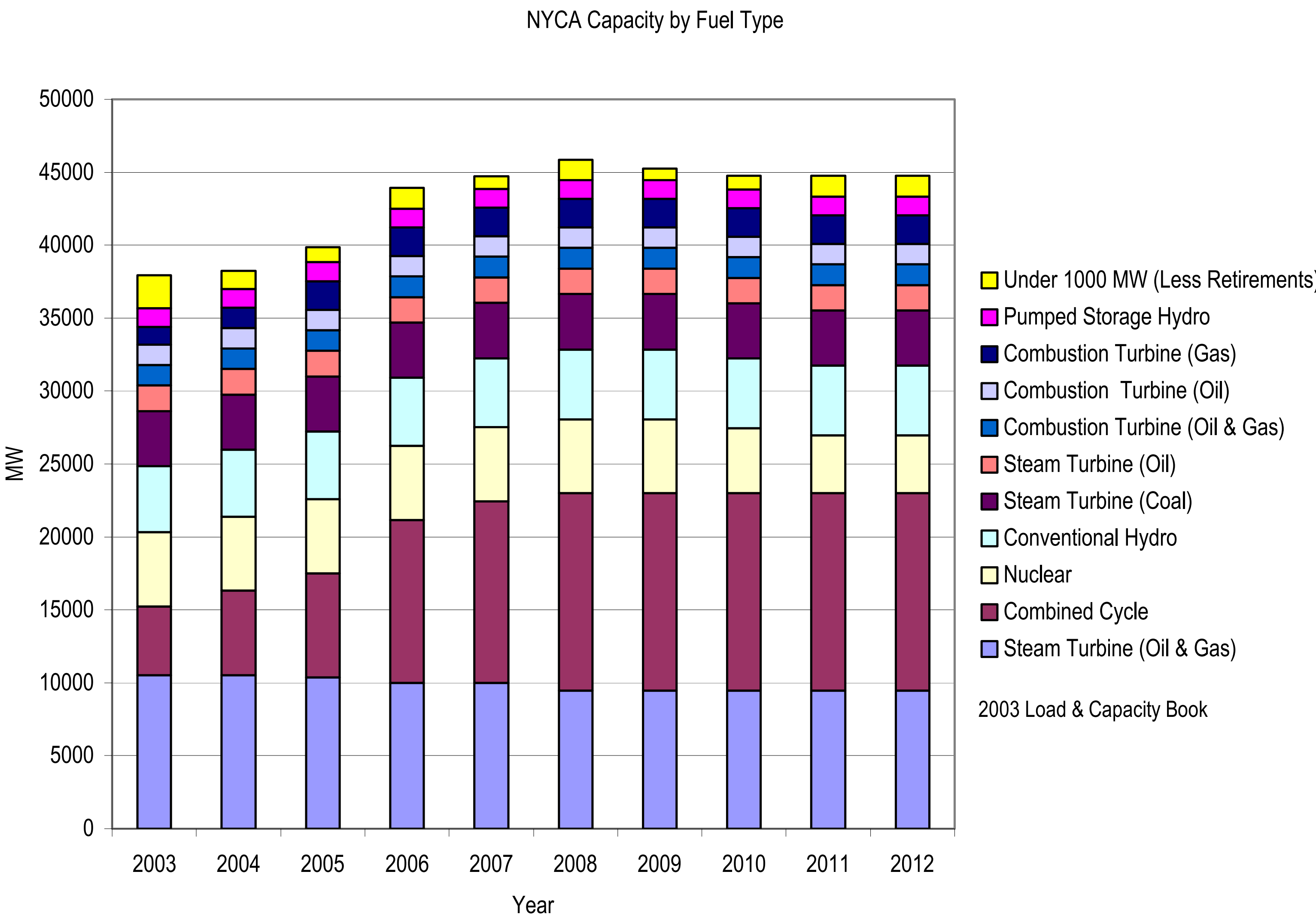
7.2 Generation by Zone, by Type

Capability By Zone and Type

As of January 1, 2003

Generator Type	ZONE A	ZONE B	ZONE C	ZONE D	ZONE E	ZONE F	ZONE G	ZONE H	ZONE I	ZONE J	ZONE K	*TOTAL*
	Summer Capability Period (KW)						*Summer Capability Period (KW)*					
Steam Turbine (Oil)	0	0	1680800	0	0	0	0	0	0	66000	0	**1746800**
Steam Turbine (Oil & Gas)	0	0	0	0	0	368400	2558500	0	0	5189800	2417500	**10534200**
Steam Turbine (Gas)	690	0	0	0	0	0	0	0	0	0	232500	**233190**
Steam Turbine (Coal)	2087400	247000	673600	0	51600	0	723200	0	0	0	0	**3782800**
Steam Turbine (Wood)	0	0	0	18100	19700	500	0	0	0	0	0	**38300**
Steam Turbine (Refuse)	37300	0	33826	0	0	11700	8700	50500	0	0	114300	**256326**
Steam (PWR Nuclear)	0	498100	0	0	0	0	0	1974700	0	0	0	**2472800**
Steam (BWR Nuclear)	0	0	2605600	0	0	0	0	0	0	0	0	**2605600**
Pumped Storage Hydro	240000	0	0	0	0	1051400	0	0	0	0	0	**1291400**
Internal Combustion	8600	2000	22168	1700	0	5064	13500	0	0	2000	74240	**129272**
Conventional Hydro	2451538	29831	121986	936794	464885	426162	99700	0	2600	0	0	**4533496**
Combined Cycle	458400	115400	1385900	320500	331600	705200	0	0	0	1147400	241200	**4705600**
Jet Engine (Oil)	0	0	0	0	0	0	0	0	0	0	531300	**531300**
Jet Engine (Gas & Oil)	0	0	0	0	0	0	0	0	0	0	170500	**170500**
Combustion Turbine (Oil)	0	14000	0	0	0	0	17800	46500	0	744300	575300	**1397900**
Combustion Turbine (Oil & Gas)	0	0	0	0	0	0	102100	0	0	1177100	139200	**1418400**
Combustion Turbine (Gas)	40060	14000	84500	0	0	0	0	0	0	497500	563600	**1199660**
Wind	26	6700	30026	0	8565	20	10	0	0	0	0	**45347**
Other	0	0	0	0	0	0	0	0	680	0	0	**680**
Totals	**5324014**	**927031**	**6638406**	**1277094**	**876350**	**2568446**	**3523510**	**2071700**	**3280**	**8824100**	**5059640**	**37093571**

7.3 Generation Capacity Mix Charts



7.4 Generation Additions

TABLE EX-1

PROPOSED PROJECTS INCLUDED IN THE 2003 NEW YORK AREA TRANSMISSION REVIEW

PROJECTS MODELED IN THE 2002 ATR DEVELOPER / PROJECT	Size (MW)	Proposed In-Service Date	Interconnection points	NYISO Queue No.
PG&E Athens	1080	Any day—Testing complete	Leeds-Pl. Val. 91 line	2
PSEG Bethlehem	350	2005/S	Albany 115	3
LIPA/TE CT-LI DC Tie-line	330	In Service	Shoreham, Long Island	4
ANP/Ramapo*	1100	*	*	*
NYPA Poletti Project	500	2005/01	Astoria West	18
ConEd East River Repowering	288	2004/09	E13th, ER69	25
SCS Astoria Energy	1000	2006/12	Astoria E	31
Mirant Bowline Point 3	750	2008	Ladentown	29
KeySpan Ravenswood	270	2004/02	Vernon East	17
NYC Energy Kent Ave	79.9	2004/12	Vernon-Greenwood	19
Calpine Wawayanda	500	2006	Coopers C-Rock Tav	22
ANP Brookhaven	580	2007	Holbrook-Brookhaven line	32
LMA Lockport II	79.9	2003/Q4	Harrison Radiator	65
Reliant Repowering Phases 1 & 2	546	2007	Astoria E & W	24, 70
AE Neptune PJM-NYC DC Line	600	2004/Q4	West 49th St.	89A
Fortistar VP	79.9	2005/03	Fresh Kills	90
Fortistar VAN	79.9	2005/03	Fresh Kills	91
PSEG Cross Hudson Project	550	2005/03	West 49th St.	93
Calpine JFK Expansion	45	2004	JFK	96
NEW PROJECTS FOR THE 2003 ATR DEVELOPER / PROJECT				
KeySpan Spagnoli Road CC Unit	250	2006/02	Spagnoli Road, Long Island	20
Glenville Energy Park	540	2006/S	Rotterdam	33
PP&L Global Kings Park	300	2006/02	Pilgrim	43
Besicorp Empire State Newsprint	660	2006/02	Reynolds Road 345	69
CHG&E Rock Tavern Transformer	N/A	I/S	Rock Tavern 345	
Liberty Radial Interconnection to NYC	400	2006	Goethals 230	110

- Project withdrawn—Not modeled in this review

7.5 Transmission Additions and Upgrades

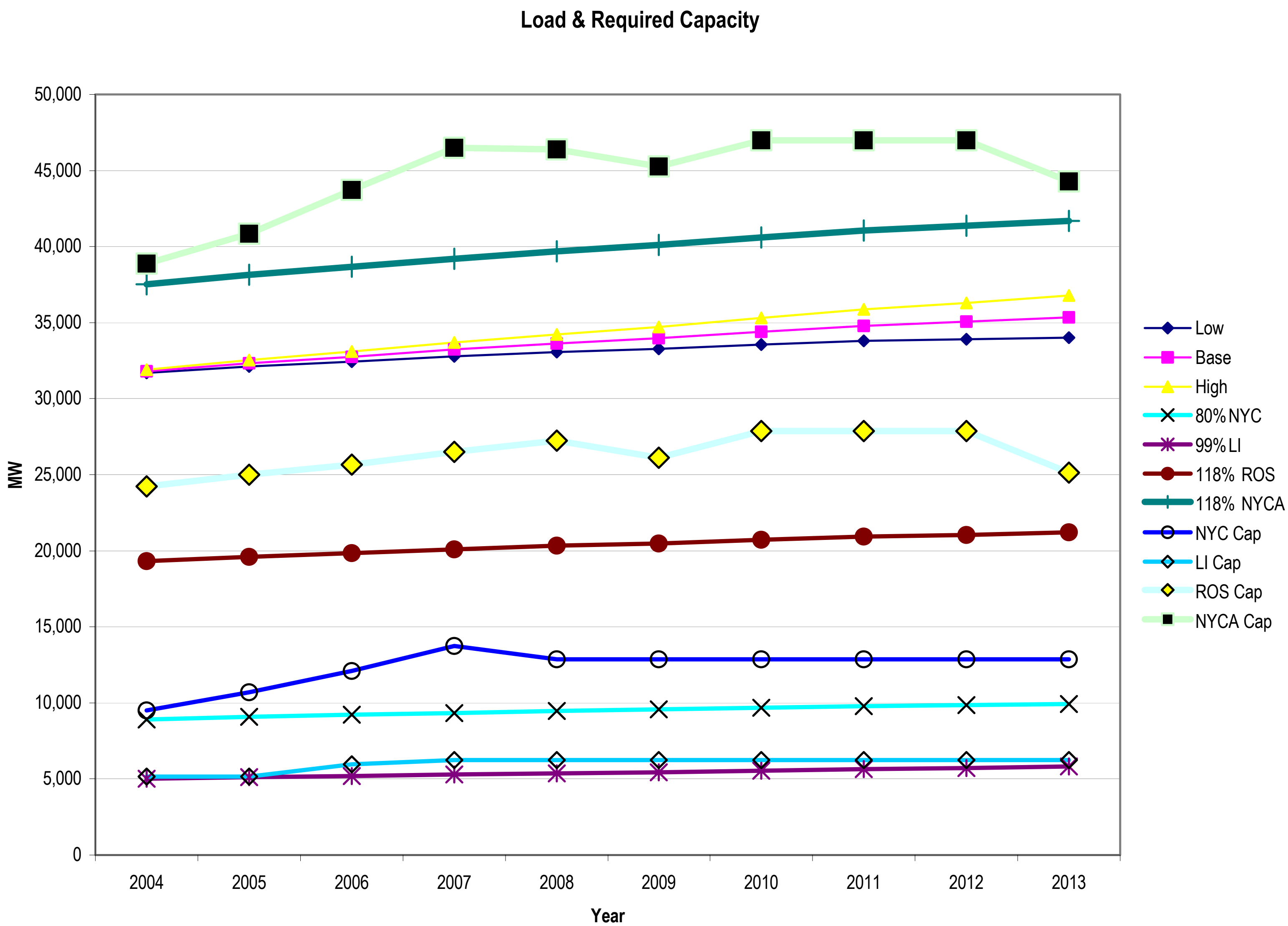
The Base Case transmission system is as defined in ATR2003. The following table lists new planned bulk power transmission projects. All, except the last three items, were included in the Base Case.

Table 7.2. Planned ATR2003 Transmission Projects

	Last Intermediate Review: 2002 Forecast for Summer 2007	This Intermediate Review: 2003 Forecast for Summer 2008	
Bulk Transmission:	**Planned I/S Date**	**Status / I/S Date**	**Included**
Cross Sound DC Cable	2002 W	In Service	Y
Sills Rd 138 kV Substation	2003 S	2007	Y
Neptune NJ-NYC DC Cable	2003 S	2004 W	Y
PSEG Cross Hudson Cable	2004 S	2005 S	Y
ANP Ramapo Substation	2003 S	Cancelled	N
Spagnoli Rd Substation 1 mile long 138 kV 320 MVA Cable connecting Spagnoli Rd and Ruland Rd Substations		2006 S	Y
Kings Park Substation 4 mile long 138 kV Cable connecting Kings Park and Pilgrim Substations		2006 S	Y
New Substation for Besicorp Empire State Newsprint Plant 9 mile long 345 kV Overhead Transmission line connecting the new substation with Reynolds Road 345 kV substation		2006 S	Y
Goethals Substation upgrades to interconnect 400 MW Liberty Project 0.6 miles long 230 kV cable connecting new Liberty Substation to Goethals Substation		2006	Y

7.6 Load and Capacity Projections

The Baseline System is as defined in ATR2003. The following table shows that that the Baseline System meets the current reserve requirements for NYCA, NYC, and Long Island.



8 Analysis Methodology

The Initial Planning Process was performed in three stages, an Input Stage, an Analysis Stage, and a Review Stage. During the Input Stage, information was gathered from various Stakeholder Groups, Neighboring Control Areas, existing reliability assessments, and existing NYISO publications and reports. Results from the Input Stage regarding methodology, identification of scenario drivers, and initial identification of scenarios was presented to ESPWG and TPAS. The findings from the Input Stage are summarized in the next three sections, which follow the same outline as the initial presentation of the Input Stage. This is to reflect that based on intermediate results in the Analysis Stage, modifications to the Input Stage were done as appropriate.

As part of Initial Planning Process analysis, screening for 2008 and 2013 are deemed adequate. The 2008 assessments were completed as part of the NYISO's 2003 Area Transmission Review. The 2013 screening is an attempt to establish system adequacy for a 5-year projection beyond 2008.

For the Baseline System, for a five-year out case(2008), and a ten-year out case (2013), reliability simulations were performed. Load and generation projections were determined from NYISO 2003 Load & Capacity Report. Reliability simulation used the MARS set-up from the latest IRM study. Transfer limits in the IRM were used for years 1 through 4 and impacts derived from the ATR 2003 were used for years 5 through 10. It was not necessary to repeat this analysis with changing transfer limits as the transmission screening analysis did not reveal any significant impacts.

The transmission screening analysis for 2008 was completed as part of ATR 2003 and was not repeated. Transmission screening is required for 2013.

Short circuit analysis was performed to ensure that potential increases in future fault currents will not exceed available circuit breaker interruption capabilities.

8.1 Resource Adequacy Analysis

Introduction

This task focused on evaluating the adequacy of the NYCA transmission system as it impacts the generation system reliability and the determination of the state-wide installed reserve requirements. NYSRC Reliability Rule AR-1 states that the state-wide reserve requirements will be such that: "Adequate resource capacity shall exist in the NYCA such that, after due allowance for scheduled outages and deratings, forced outages and deratings, assistance from neighboring systems, NYS Transmission System transfer capability, uncertainty of load forecasts, and capacity and/or load relief from available operating procedures, the probability of disconnecting firm load due to a resource deficiency will be, on the average, no more than once in ten years." (NYSRC Reliability Rules Manual (www.nysrc.org/documents.html)). This requirement is often stated in terms of maintaining a daily loss-off-load expectation (LOLE) of 0.1 days per year.

MARS

The primary tool used for the performance of the reliability analysis was GE's Multi-Area Reliability Simulation program (MARS). MARS uses a Monte Carlo simulation to compute the reliability of a generation system comprised of any number of interconnected areas or zones. MARS is able to reflect in its reliability calculations each of the factors listed in NYSRC Reliability Rule AR-1, including the impacts of the transfer capability of the transmission system.

Data

A Baseline System Case was developed that included the existing system in combination with the generation and transmission system additions and upgrades that are projected to occur throughout the study period. Because emergency assistance from neighboring systems contributes to the reliability of the NYCA system, the load and generation of the neighboring systems was modeled. The source for the data on the existing system was the MARS database maintained by NYISO staff for use in determining the annual installed reserve requirements. The load and generation was updated through the study period based on data from the latest Load & Capacity Data report issued by NYISO. Similar reports for the neighboring systems were referenced for updating the data in those regions.

Methodology

The first step in the analysis was to calculate the NYCA LOLE for the Reference Case assuming no transmission system transfer limitations within the NYCA system. This will indicate whether the installed generation is sufficient to satisfy the load demand. The system did not fail to meet the LOLE criterion of 0.1 days per year, therefore generation did not have to be added proportionately throughout the state to improve the system to 0.1 days per year.

The NYCA LOLE was then computed including the effects of the internal transfer limitations. This will indicate whether the NYCA transmission system is adequate to deliver the generation to the load. The NYCA LOLE did not exceed 0.1 days per year, therefore additional MARS simulations were not run in which the transfer limits of the interfaces that are most severely impacting generation system reliability will be increased until the reliability criterion is met.

8.2 Transmission System Screening Analysis

A comprehensive transmission reliability analysis would include steady-state voltage, thermal, and transfer limit analysis, as well as first-swing stability and short circuit analyses at a minimum. It could also include steady-state or dynamic voltage stability analysis, three-phase cycle-by-cycle electro-magnetic transients (EMT) analysis to investigate power quality, control and/or machine torsional interactions, as well as longer time-frame analyses of second-to-second voltage and frequency regulation. Many of these analyses (e.g., fundamental frequency steady-state, dynamic and short circuit analyses) may be performed annually to ensure a reliable transmission system. Others (e.g., sub-synchronous resonance analysis) may only be performed for specific situations (e.g., addition of significant series compensation to a radial transmission line connecting a large thermal plant to the rest of the power system).

Similarly, some analyses are more likely to uncover significant transmission constraints than others. For instance, a steady-state thermal or transfer limit analysis could identify the need for additional transmission lines between different regions of the state, while a first-swing stability analysis could identify the need for faster relaying on an existing transmission line. In general, additional transmission lines are capital intensive, require a long construction time, and cross multiple administrative districts with each requiring appropriate permits. By contrast, a relay upgrade is frequently located at a single existing substation and can be installed relatively quickly and inexpensively. Therefore, any evaluation of the transmission reliability of an uncertain future system (e.g., 2013) should focus on those analyses most likely to uncover significant problems.

Such a screening level evaluation should focus first on steady-state thermal and voltage analyses. Stability and short circuit analyses can be deferred until the future system configuration is more certain. Specialty EMT and other analysis can be ignored until required of individual developers or manufacturers for particular projects. A detailed description of this type of screening level analysis is described in the following sections.

Objective

The objective of the screening analysis was to identify the regions or corridors requiring significant transmission system upgrades, if any, to meet system reliability criteria in 2013. In particular, the goal was to determine which transmission reinforcement areas could provide the most system performance benefit, over the broadest rage of possible system future conditions. Multiple scenarios representing different possible 2013 system conditions (e.g., generation, load, transmission variations) were evaluated. The performance of these systems will be compared to that of NYISO's power flow representing 2008 system conditions as studied in the 2003 Area Transmisssion Review.

Power flow analysis alone was performed, focusing on the voltage and thermal performance of the bulk power transmission system as well as limited transfer analysis of selected NY power system interfaces. No evaluation of potential transmission system upgrades were included.

Study Approach

The Initial Planning Process used a relative approach to determine the performance of the 2013 power system. First, 2008 system performance was determined in order to establish the benchmark. Then, system performance under various 2013 scenarios was determined and compared to the benchmark. This relative approach removes any ambiguities as to the actual impact of the various scenarios since existing criteria violations, if any, will be identified.

Task 1. 2013 Reference Database Development

The 2008 power flow was modified to represent the Baseline System assumptions for transmission system upgrades, generation additions and/or retirements, and load levels. The resulting power flow case was reviewed to identify any pre-contingency thermal, voltage and/or interface transfer violations. Additional modifications were made to eliminate or mitigate these criteria violations. Any remaining pre-contingency violations were flagged as potential components of a required transmission system upgrade to a particular region or corridor.

Task 2. 2013 Scenario Database Development

The 2013 Baseline System power flowwas modified to represent the scenario case assumptions for transmission system upgrades, generation additions and/or retirements, and load levels. The resulting power flows were reviewed to identify any pre-contingency thermal, voltage and/or interface transfer violations. Additional modifications were made to eliminate or mitigate these criteria violations. Any remaining pre-contingency violations were flagged as potential components of a required transmission system upgrade to a particular region or corridor.

Task 3. Contingency Analysis

The objective of this work is to determine whether any of the 2013 cases will be constrained by either voltage or thermal limitations under steady-state post-contingency conditions. The four 2013 system conditions described in Tasks 1 and 2, as well as the 2008 benchmark power flow, will be analyzed.

Approximately 100 contingencies will be evaluated covering all relevant line, transformer, generator and multiple element outages in the study area. The analysis will compare voltage and loading performance against appropriate criteria, as defined under the study assumptions. Criteria violations will be flagged and summarized. Specifically, the incremental impact due to a 2013 case will be identified by any voltage or thermal violations that did not occur in the benchmark 2008 system or under pre-contingency 2013 system conditions.

Task 4. Transfer Limit Analysis

Power transfer limits were determined for the 2008 benchmark system and the 2013 study systems. The following significant interfaces will be evaluated. All interface evaluations were performed on a relative basis, showing the change in maximum power transfer from the benchmark system to the study system.

The interfaces initially identified to be evaluated are as follows:

- New York City Cable system
- UPNY-Con Edison
- UPNY-SENY
- Total East
- Central East

The following interfaces were added/substituted during the Analysis Stage:

- Dunwoodie South Closed
- LIPA Import

In order to determine transfer limits, it was necessary to vary the power flow across the interface(s) under study by adjusting generation at one or more locations on one side of the interface, and adjusting generation by a like amount at one or more locations on the other side of the interface. The assumed locations for adjusting generation for evaluating transfer limits of the various interfaces were similar to the study assumptions for the 2003 ATR.

Task 5. Development of Relative shift Factor Tables

A table of relative shift factors of existing large generators and the proposed projects was developed.

Task 6. Evaluation of Analytical Results

The results of the analysis described in Tasks 3 and 4 was evaluated to identify the regions or corridors requiring transmission system upgrades, if any, to meet system reliability criteria in 2013. Some upgrades may be required under the wide variety of potential 2013 system conditions. Others may be primarily dependent upon one or more assumptions in the reference and/or scenario cases.

8.3 Short Circuit Analysis

A fault duty study was performed using ASPEN to determine the impact of the 2013 maximum generation scenario on local circuit breakers. Additional analyses of other generation scenarios was not necessary to be performed as excessive short circuit currents were only anlyzed for the maximum generation scenario. The NYISO methodology was used.

Three-phase, single-phase and line-line-ground short-circuit currents were determined for the same substations as in the 2002 ATRA. These bus level currents were compared to the breaker ratings. Any bus fault current that exceeded the breaker fault interrupting capability was noted, and an individual breaker assessment was performed to identify if a reliability need existed. The individual breaker analyses was performed to determine whether the fault current seen by a specific breaker exceeded that breaker's rating.

9 Issues Driving Future Scenarios

9.1 Introduction

There are multiple drivers that can cause deviations to the NYISO Base Case over the 10-year study period. These drivers could have positive or negative impacts on the existing NY transmission system. Below is a description of the drivers that NYISO has identified as potential causes of deviations to Base Case. This identification was used to initially identify scenarios for analysis. The actual scenarios studied were modified based on intermediate analysis results.

Review of other RTO/ISO planning studies did not reveal additional set of issues.

9.2 Issues

HVDC Transmission Expansion

There are various HVDC projects proposed in New York State, such as the Empire Connection Project. This project entails building 2000 MW HVDC lines that would allow less expensive generation to flow from Upstate NY into NY City. The completion of this project could potentially lead to cancellations or delays for some of the approximately 4000 MWs of proposed NYC generation due to economic competition form NY upstate. In general, HVDC Transmission line Expansion projects such as the Empire Connection would help to increase transmission capability in New York State.

Wind/Renewable Additions

New NY state mandates and targets could cause significant wind and renewable generation additions. The uncertainty associated with the fuel sources for renewable generation such as wind, makes it difficult to associate a pattern to the impact of transmission loading. There is currently a study in progress, sponsored by the NYISO and NYSERDA, to determine the probable impacts that the new renewable generation additions will have on the transmission system in New York.

Generation Expansion

There is currently approximately 9500 MW of proposed new generation in New York state. The current economic climate across the country has caused a significant number of projects to be canceled or delayed. The same phenomena could very likely occur in New York State. Cancellations or delays in load pockets, such as New York City, would require generation from other areas to help meet demand. This would cause heavier loading on the existing transmission system interfaces to NYC

Retirement of Existing Generation

Revenue shortfalls for steam oil and gas plants, caused by the expiration of existing Power Purchase Agreements and competition from new, more efficient combined cycle plants could lead to potential retirements. The loss of generation due to retirements in transmission-constrained areas would cause more loading on the existing transmission system as it tries to meet demand requirements in those areas.

Regulatory issues could also lead to potential retirements. For example, the Indian Point nuclear plant's proximity to population centers has created pressure for the plant to be shut down for safety reasons. Re-licensing of this plant may not occur due to this pressure. This plant helps New York City to meet load obligations. Upstate generation would be needed to help fill this potential void and cause more loading on the existing transmission system.

Transmission Owner Plans

Transmission owners in NY State could possibly build new interconnections with neighboring systems. This would increase the import capability into New York State and allow more power to flow and hence increase loading on the existing transmission system within NY.

Existing Transmission Infrastructure Aging

As the current transmission infrastructure ages, the amount of power that can flow on the transmission lines will steadily decrease. This could potentially cause trouble for load pockets that depend on imports to meet load.

Environmental Compliance

It is likely that environmental regulations in NY State can become more stringent. The existing steam oil/gas and steam coal plants will need to curtail operation or install emission control technology to meet these new regulations. The potential high cost of compliance with the environmental regulations could cause some of these existing units to retire.

There is also a proposal to require Indian Point nuclear unit to build cooling towers to avoid using water from the Hudson River. This would be a high expense and could potentially force Indian Point to retire. As mentioned elsewhere in the report, retiring Indian Point and/or retiring NYC steam oil/gas units will increase transmission loading on the interfaces connecting upstate and downstate NY.

Fuel Availability/Diversity

There is a potential for a natural gas shortage in the New York State. This could cause natural gas fired units to burn other fuels or curtail operation. If unit operation curtailment due to fuel unavailability occurs in load pockets, generation from other areas would need to help meet demand, causing heavier loading on the existing transmission system. Many of the dual fired units are larger older units that if retired would have impacts other than fuel mix.

Impact of New Technologies

Many new technologies that are applicable to electricity generation and transmission are under research and development. Some examples are Carbon Filament Transmission Lines, Distributed generation and New Energy Management Systems. The carbon filament lines will allow transmission lines to operate with higher voltages thus, increasing their loading capacity, distributed generation will allow electricity generation at the location of the load and the new energy management system can reduce on-peak demand. New technologies such as these will help to alleviate loading on the existing transmission system.

Load Forecast Uncertainty

There is considerable uncertainty associated with any load forecast. Many events can cause actual loads to deviate from forecasted values. The existing transmission system may or may not benefit from a load forecast swing. Lower than forecasted load would cause less loading on the transmission lines vice versa.

Neighboring System Plans

Neighboring systems could possibly upgrade current transmission interconnections or build new interconnections into New York. These changes would cause more power to flow into New York. This additional power flow from neighboring regions would increase loading on the existing transmission system within NY.

The implementation of a demand response program would help to reduce on-peak demand. An example of this would be having a factory shut down during a peak time to help reduce the load on the system. This type of program could help transmission-constrained areas to decrease loading on the transmission system.

9.3 Quantifying the Effect

The following tables show the changes that appropriately characterize the potential effect of each issue in terms of generation and demand.

HVDC Transmission Expansion

- Empire Project is completed increasing transfer capability from Upstate NY to Zone J by 2000 MW
- New generation proposed for Zone J, after January 1, 2005, is delayed
- Projects are assumed to be delayed 2X of current proposed installation date

Table 9.1. HVDC Transmission Expansion

HVDC Transmission Expansion	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Zone J	0	-660	-1660	-2740	-2740	-2740	-2080	-2080	-1080	-1080	0

Wind/Renewable Additions

- Approximately 3000 MW of new wind generation is proposed to be installed during the study period
- Potential sites are in Zones A, B, C, D, E, & K

Table 9.2. Wind/Renewable Additions

Wind/Renewable Additions	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Zone A	0	+100	+200	+300	+400	+500	+500	+500	+500	+500	+500
Zone B	0	+100	+200	+300	+400	+500	+500	+500	+500	+500	+500
Zone C	0	+100	+200	+300	+400	+500	+500	+500	+500	+500	+500
Zone D	0	+100	+200	+300	+400	+500	+500	+500	+500	+500	+500
Zone E	0	+100	+200	+300	+400	+500	+500	+500	+500	+500	+500
Zone K	0	0	0	0	0	0	+500	+500	+500	+500	+500

Generation Expansion

- New generation proposed for Zones J & K, after January 1, 2005, are delayed due to the current economic climate
- Projects are assumed to be delayed 2X of current proposed installation date

Table 9.3. Generation Expansion

Generation Expansion	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Zone J	0	-660	-1660	-2740	-2740	-2740	-2080	-2080	-1080	-1080	0
Zone K	0	0	-250	-810	-810	-810	-810	-810	-560	-560	0

Retirement of Existing Generation

- Assumptions for retiring a unit were based on following criteria:
  - Selecting the largest plant in each Zone
  - Not allowing Reserve Margins to drop below the 18 % requirement during the study period
- Transmission Owner Plans
- Assumed not to deviate from the Base Case over the Study Period

Table 9.4. Retirement of Existing Generation

Retirement of Existing Generation	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Zone A											
Coal	0	0	0	-722	-722	-722	-722	-722	-722	-722	-722
Zone B											
Coal	0	0	0	-247	-247	-247	-247	-247	-247	-247	-247
Zone C											
Oil	0	0	0	-1681	-1681	-1681	-1681	-1681	-1681	-1681	-1681
Zone G											
Oil	0	0	0	-1170	-1170	-1170	-1170	-1170	-1170	-1170	-1170
Zone H											
Nuclear	0	0	0	-1975	-1975	-1975	-1975	-1975	-1975	-1975	-1975
Oil	0	0	0	-47	-47	-47	-47	-47	-47	-47	-47

Existing Transmission Infrastructure Aging

- Assumed not to cause any deviation from the Base Case over the Study Period

Environmental Compliance

- Coal Plants in NY State without Emission Control Technology would retire due to more stringent environmental rules proposed for 2007
- Hudson River cooling water units would need to build cooling towers and retire due to the additional economic burden

Table 9.5. Environmental Compliance

Environmental Compliance	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Zone C											
Coal	0	0	0	-159	-159	-159	-159	-159	-159	-159	-159
Zone G											
Coal	0	0	0	-494	-494	-494	-494	-494	-494	-494	-494
Zone H											
Nuclear	0	0	0	-1975	-1975	-1975	-1975	-1975	-1975	-1975	-1975

Fuel Availability/Diversity

- Proposed Natural Gas pipelines to built into Zone K during the study period are delayed
- New natural gas fueled generation proposed for Zones J & K after January 1, 2005 are delayed due to natural gas shortages
- Projects are assumed to be delayed 2X of current proposed installation date
- Dual fired units retire, further worsening the fuel mix towards an overeliance on natural gas. While winter gas interruptions presently do not pose a great threat to the NYCA, this could worsen.
- Many of the existing dual fired units are large older units outside of Zone J and K.

Table 9.6. Fuel Availability/Diversity

Fuel Availability/ Diversity	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Zone J	0	-660	-1660	-2740	-2740	-2740	-2080	-2080	-1080	-1080	0
Zone K	0	0	-250	-810	-810	-810	-810	-810	-560	-560	0

Impact of New Technologies

- Due to the uncertainty of new technologies becoming available during the study period, they are assumed to not to cause any deviation form the Base Case

Load Forecast Uncertainty

- The current projected load growth is assumed to increase from 1.1% to 2% for the study period

Table 9.7. Load Forecast Uncertainty

Load Forecast Uncertainty	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
NYCA Demand	0	+230	+513	+799	+1078	+1411	+1728	+2059	+2394	+2774	+3160

Neighboring System Plans

- Assumed not to deviate from the Base Case over the Study Period. Plans are incorporated in normal update procedures.

Demand Response Programs

- Additional demand response programs are initiated, raising current levels 2X

Table 9.8. Demand Response Programs

Demand Response Programs	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Demand Response Programs	0	+500	+500	+500	+500	+500	+500	+500	+500	+500	+500

10 Scenario Definition

Following analysis of the Base Case, test cases which combine variations in installed generation, load forecasts, transmission system transfer capabilities, and available assistance from neighboring systems will be simulated to determine their impact on the reliability of the NYCA system and hence the adequacy of the transmission system.

Suggested potential scenarios for consideration include:

1. DC Transmission Expansion
   a. As described in impact 2.2.
   b. Only identified scenario that primarily involves transmission change. Will not be done if high load forecast is reliable.
2. Upstate generation reduction
   a. As described in impact 2.5
   b. Fully covers environmental compliance impact 2.7
3. Downstate generation reduction
   a. As described in impact 2.4
   b. Fully covers fuel availability/diversity impact 2.8
4. Load Forecast Uncertainty
   a. As described in impact 2.10, or using the high load forecast from the LFWG
   b. Load growth distributed as an equal percentage increase in all regions

Issues not specifically covered by the above scenarios include:

1. Wind/Renewable Additions (issue 2.3) – being covered in a separate study sponsored by NYSERDA and NYISO.
2. Infrastructure Aging – assumed to have no effect over the study period
3. New Technologies – insufficiently defined to include as any different identifiable impact
4. Neighboring System Plans – not assumed to change, but may merit additional investigation if dependence on external support is shown to increase significantly under any of the scenarios.
5. Demand response systems – effectively decreases load. Will likely be accompanied by some form of generation reduction that drives the need. Thus, this could be viewed as a minor variation on either upstate or downstate, generation reduction scenarios.

11 Baseline Reliability Needs Assessment

11.1 First Five Year Period – Existing Reliability Assessments

Existing Reliability Assessments form the basis for the first five year period. Ordinarily the information from the NYISO Annual Transmission Reliability Assessment (ATRA) would be one of the existing assessments used for the Initial Planning Process. However, for 2003, the ATRA has been delayed for an indefinite period. Therefore, it will be necessary for this study to include separate Resource Adequacy and Short Circuit assessments, whose databases will be consistent with that of the 2003 NPCC New York Area Transmission Review.

11.1.1.1 The 2004 NYSRC Installed Reserve Margin (IRM) Study

The "NEW YORK CONTROL AREA INSTALLED CAPACITY REQUIREMENTS FOR THE PERIOD MAY 2004 THROUGH APRIL 2005" study report dated December 11, 2003 presents the results of the resource adequacy study to determine the minimum Installed Reserve Margin (IRM). The database developed for this study also served as the starting point for the 2008 and and 2013 analysis. Below are excerpts from the study.

Using Base Case assumptions, this NYSRC technical study resulted in a statewide IRM requirement of **17.1%**[1]. This study also presents results from various scenarios to assess the sensitivity of Base Case assumptions on the IRM. When taken together, the Base Case, sensitivity case results and other relevant factors provide the basis for the NYSRC determination of the statewide IRM requirement for Year 2004.

In addition to calculating a base case IRM requirement, the Year 2004 IRM study calculated the sensitivity of the required IRM to changes in several key study assumptions. These results are depicted in Table 1.

Table 1

COMPARISON WITH 2003 STUDY*- NYCA

Parameter	IRM Change	IRM %
Previous Study IRM (2003 Study)		**17.5**
Updated Load Shape Model	-0.5	
Updated Load Forecast Uncertainty Model	-0.4	
Updated Zonal Load & Capacity Distributions	+1.4	
New Generating Units	-0.5	
Updated Gas Turbine Derate Model	-0.3	
Updated Generating Unit & Cable System EFORs	-1.5	
Updated EOPs (including SCRs & EDRP)	+1.0	
Updated Transmission Model	+0.2	
New Version of MARS	+0.2	
Net Change from 2003 Study	-0.4	
New Study IRM (2004 Study) Results		**17.1**

[1] There is a 99.7 % probability that the base case result is within the range of 16.8% to 17.4%. See Appendix A.

*See report titled "New York Control Area Installed Capacity Requirements for the period May 2003 through April 2004", dated January 10, 2003, for 2003 study model description and assumptions.

The acceptable LOLE reliability level used for establishing NYCA IRM requirements is dictated by the NYSRC Reliability Rules, wherein Rule A-R1 (*Statewide Installed Reserve Margin Requirements)* states:

> *Adequate resource capacity shall exist in the NYCA such that, after due allowance for scheduled outages and deratings, forced outages and deratings, assistance from neighboring systems, NYS Transmission System transfer capability, uncertainty of load forecasts, and capacity and/or load relief from available operating procedures, the probability of disconnecting firm load due to a resource deficiency will be, on the average, no more than once in ten (10) years.*

This NYSRC Reliability Rule is consistent with the NPCC Resource Adequacy Standard in NPCC Document A-2.

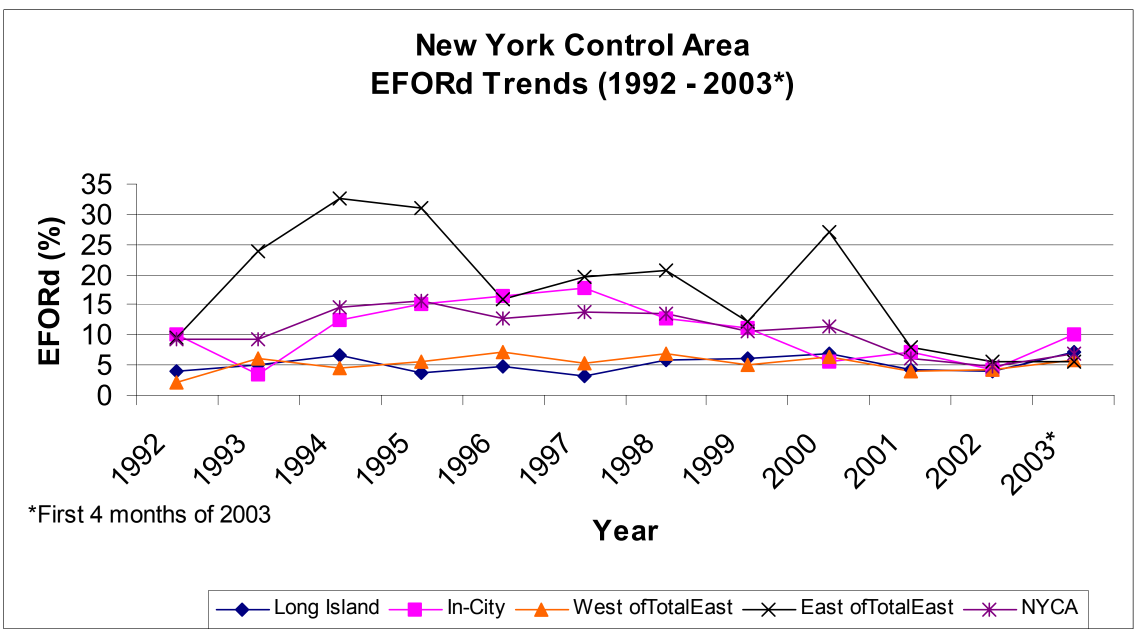


Figure 1

From the period of 1999 through 2003, these studies have resulted in the NYSRC adopting an 18% reserve margin. This 18% Reserve Margin Requirements were used as target numbers for the scenario development and as a screening method to identify potential reliability needs. A reliability need was only identified if the LOLE exceeded the once in ten years criteria from a MARS analysis.

NYISO IMPLEMENTATION OF THE NYCA IRM REQUIREMENT

NYISO Translation of NYCA Capacity Requirements to Unforced Capacity:

The NYISO values capacity sold and purchased in the market in a manner that considers the forced outage ratings of individual units — Unforced Capacity or “UCAP”. To maintain consistency between the rating of a unit (UCAP) and the statewide ICR, the ICR must also be translated to an unforced capacity basis. In the NYCA, this translation occurs twice during the course of each capability year, prior to the start of the Summer and Winter Capability Seasons.

Additionally, any Locational Capacity Requirements in place are also translated to equivalent UCAP values during these periods. The conversion to UCAP essentially translates from one index to another — and is not a reduction of actual installed resources. Therefore, no degradation in reliability is expected. The NYISO employs a translation methodology that converts UCAP requirements to ICAP in a manner that assures compliance with NYSRC Resource Adequacy Rule A-R1. The conversion to UCAP provides financial incentives to decrease the forced outage rates while improving reliability.

11.1.1.2 The 2004 NYISO Locational Requirements Study

At the beginning of this study, the Locational Requirements set annually by the NYISO were 80% for NYC and 95% for Long Island. For this study, these Locational Requirements were used in the same screening manner as the 18% Installed Reserve Margin. Locational requirements can change annually and have been updated in the following study, “Locational Installed Capacity Requirements Study, COVERING THE NEW YORK CONTROL AREA For the 2004 – 2005 Capability Year”, to 80% for NYC and 99% for Long Island. This study is excerpted below. The subject of Locational Requirements is under intense review in the Installed Capacity Subcommittee.

The NYISO locational ICAP requirements study used, as its starting point, the statewide Installed Reserve Margin (IRM) study conducted by the NYSRC[2]. This study is available on the NYSRC web site at www.nysrc.org.

As can be seen in Table 1, the two zones that have “low capacity plus import capability to expected load” (column 6) ratios are zones J (New York City) and K (Long Island). These zones have the potential to impact the NYCA LOLE most significantly. Thus, in order to maintain compliance with the NYSRC/NPCC LOLE criteria without increasing NYCA IRM requirements, these two zones must maintain a minimum level of locational ICAP.

2 IBID

Year 2004 Table-1

Installed Capacities, Loads, and Transfer Capability in the MARS model

(1) 11.1.1. 11.1.1.	(2) Capacity*	(3) Load	(4) Import Capability	(5) (2)/(3)	(6) (2+4)/(3)
A	5174	2863	4000	1.81	3.20
B	927	1899	3900	0.49	2.54
C	6638	2848	4870	2.33	4.04
D	1249	884	3500	1.41	5.37
E	876	1550	10770	0.57	7.51
F	3528	2223	5750	1.59	4.17
G	3524	2083	8920	1.69	5.97
H	2072	905	7600	2.29	10.69
I	3	1501	10980	0.00	7.32
J	9074	11150	5120	0.81	1.27
K	5246	5059	2136	1.04	1.46

*This is the “2002 Load & Capacity Data” Report’s (Gold Book) Summer Capacity of 37,094 less 303 MW of firm sales plus 1,521 MW of additional (those that had been added since the Gold Book plus the IRM proposed units) resources identified in the NYSRC IRM Study.

Under a base case statewide installed reserve margin, the locational ICAP requirement for Long Island should be increased to 99% of the forecast Long Island peak load. For New York City, a minimum of 80% of the forecast New York City peak load is required to meet the NYSRC/NPCC LOLE criteria. The increase in the Long Island requirement is due to updated assumptions that occurred during the IRM study. These factors include; the hourly load shape change from 1995 to 2002 data, a wider distribution in the Long Island zonal load forecast uncertainty data, and increased equivalent forced outage rates (EFOR) on the interfaces surrounding Long Island.

11.1.1.5 NPCC New York Resource Adequacy Review (RAR)

Another existing assessment, the New York Independent System Operator's (NYISO) "Interim Review of Resource Adequacy Covering the New York Control Area For the Years 2003-2006". This assessment is conducted to comply with the Reliability Assessment Program established by the Northeast Power Coordinating Council (NPCC). This assessment follows the resource adequacy review guidelines as outlined in the NPCC B-8 Document "Guidelines for Area Review of Resource Adequacy. "

Results of this interim assessment show that the New York Control Area (NYCA) will comply with the NPCC resource adequacy reliability criterion under the Base and High Load Forecasts.

Table 3 summarizes the NYCA system Loss of Load Expectation (LOLE) results for various scenarios. It indicates that the NYCA is in compliance with the NPCC criterion under both the Base and High Load Forecast cases.

Table 3. LOLE under Base and High Load Forecasts

Year	Base Case Load Forecast		High Load Forecast	
	2002 Triennial (Days/Year)	2003 Interim (Days/Year)	2002 Triennial (Days/Year)	2003 Interim (Days/Year)
2002		N/A		N/A
2003	0.004	0.019	0.009	0.095
2004	0.003	0.010	0.010	0.050
2005	0.008	0.005	0.021	0.019
2006	0.017	0.008	0.043	0.031

11.1.2 Transmission Adequacy Assessments(ATR)

The 2003 ATR studied the Year 2008 and serves as the basis for the transmission assessment for the baseline system for the first five years. Below is a summary of the findings.

In the first assessment, load flow and stability analysis was conducted to evaluate the thermal, voltage and stability performance of the New York State Bulk Power System for normal (or design) contingencies as defined in the NPCC and NYSRC reliability criteria and rules. This assessment demonstrated that there are no adverse impacts that would be detrimental to the reliability of the New York State Bulk Power System. Voltage analysis for this review indicated greater voltage drops for major contingencies, and consequently lower transfer limits on the affected interfaces as compared to last year's review. This is not a major problem since the controlling transfer limits are still the thermal limits although the margin is becoming narrower. NYISO staff recommends to update the voltage studies, particularly on the southeastern New York interfaces, to review the voltage related operating limits in that area.

The main conclusion of this review is that the New York State Bulk Power Transmission System, as planned through the year 2008, is in conformance with the NPCC "Basic Criteria for Design and Operation of Interconnected Power Systems" and the reliability criteria described in the NYSRC Reliability Rules.

NYS BULK POWER SYSTEM TRANSFER LIMITS IN THE YEAR 2008

Interface		Normal Transfer Limit (MW)	Type	Emergency Transfer Limit (MW)	Type
Dysinger East	- Closed	3700**	V	3800**	V
	- Open	2400**	V	2475**	V
West Central	- Closed	2400**	V	2525**	V
	- Open	1100**	V	1175**	V
Volney East	- Closed	5050**	V	5175**	VX
	- Open	4325**	V	4400**	VX
Moses South	- Closed	1450**	T	1875**	T
	- Open	1300**	T	1700**	T
Total East		5150	T	5800	T
Central East		2625	T	2800	S
UPNY-SENY	- Closed	5025	T	5675	T
	- Open	4475	T	5125	T
UPNY-CONED	- Closed	6875	T	7775	T
	- Open	4850	T	5750	T
Millwood South	- Closed	8025**	T	11150**	T
Dunwoodie South	- Closed	6500	T	6500	T
	- Open	4475	T	4475	T
Long Island Import		1375	T	1375	T

Notes:
1) Transfer Limits expressed in MW, and rounded down to nearest 25 MW point.
2) Thermal and Voltage Limits Apply under Summer Peak Load Conditions.
3) Emergency Limits account for more restrictive voltage collapse limit.
4) Transfer Limits for All-Lines-In Condition.
5) Transfer Limits assume 600 MW base schedule on the Ramapo PAR.

Type Codes: T – Thermal; V - Voltage Post; VX - Voltage 95%; S – Stability

** From 2000 Comprehensive review report—Not evaluated in this review

11.1.3 Resource Adequacy Assessment

As noted previously a separate resource adequacy assessment was done for this Initial Planning Process since it was not completed in the 2003 Annual Transmission Reliability Assessment. As can be seen in the following table, the Baseline System has installed capacity well above the 18% IRM and the Locational Requirements of 80% percent In City and the initial 95% for Long Island. The updated 99% requirement will not change the results of this screening analysis. As a result of the high reserve margins shown below, the LOLE was so low as to be indeterminable for 2008, even under the High Load Scenario.

Baseline System Case

	2008		
	Low Load	**Base Load**	**High Load**
Demand (MW)	33,052	33,635	34,228
Base Capacity (MW)	45,841	45,841	45,841
Reserve Margin (%)	38.69	36.29	**33.93**
Demand (J)			12,242
Capacity (J)			13,621
Cap/Load Ratio (J)			**111.27**
Demand (K)			5,387
Capacity (K)			6,591
Cap/Load Ratio (K)			**122.35**
LOLE (d/y)			
NYCA			
Zone J			
Zone K			

11.1.4 Short Circuit Assessment

As noted previously a separate short circuit assessment was done for this Initial Planning Process. The analysis resulted in the identification of fifteen substations with bus fault levels exceeding the lowest rating of the breakers at those substations. The methodology employed was the that described in the “NYSIO Guideline for Fault Current Assessment”, contained in Appendix 2. The ratings and bus monitored list was the same as that used for the 2002 ATRA fault current assessment. The base case included all Class Year 2001, 2002, and 2003 Projects. The NYPA Poletti expansion was represented fully on the Astoria West Station.

Study assumptions and methodology:

Base case used:

The "NYISO_SC_2008-Rev2.olr" received on May 4, 2004; the Short Circuit case includes Athens, Bethlehem, and all Class Year 01, 02 and 03 projects.

The following units have been retired and taken out of service in this case:

Old Poletti project is not retired in this case.

SCS Astoria project representation is consistent with Class 01 and Class 02 SC representations. Four units are on Astoria East-E bus and two units on Astoria East-W bus.

NYPA Poletti project interconnection corresponds with the latest known configuration: I.e.: interconnected at Astoria West bus.

Latest data from the neighboring systems (IMO, PJM and ISO-NE) received as of 4/1/04, has been added in the case in place of the old data.

HQ tie has been left as is (no new data).

PJM provided what was used specifically for their latest RTEP.

The distribution system data supplied by NYSEG, NIMO and CHG&E has been added.

Also, the transmission changes planned by 2008 and reported by each TO during the input stage and timely with this case creation process, were incorporated, except:

Mott Haven substation which has been removed from the case and the original Dunwoodie-Rainey lines have been restored.

The distribution system data supplied by NYSEG, NIMO and CHG&E has been added.

Methodology:

The "NYISO Guideline for Fault Current Assessment" was used. The same set of monitoring buses developed for ATRA2002 was used.

The same set of Lowest Breaker Ratings as for ATRA2002 was used to identify the overdutied substations.

3LG, 2LG and 1LG faults were applied.

The results were compared against the lowest breaker rating: if the bus fault value is greater or equal to the lowest breaker rating, it is identified and tabulated.

Some of these substations will not be overdutied after an Individual Breaker Analysis(IBA) is performed. Since the Initial Planning Process defines reliability needs in terms of quantities and not necessarily in terms of specific facilities, the fifteen substations identified above were screened to determine if it was probable that at least one breaker would be overdutied on an IBA basis. Those substations were then grouped by zone, and a reliability need for additional fault current mitigation was identified. The results are indicated in the table below for the fifteen substations. After an IBA assessment, there is a reliability need for some form of fault current mitigation in Zones A, F, J, and K.

Table 11.1.1 NYCA Substations Identified as Potentially Overdutied

NrCrt	Bus Name	NOM. KV	Lowest Bkr Rating (kA)	3LG(kA)	2LG(kA)	1LG(kA)
1	**BUCHAN S**	345	40	**40.55**	39.43	35.81
2	**RAMAPO**	345	40	**46.52**	**45.55**	39.18
3	**VOLNEY**	345	37	36.86	**37.50**	32.55
4	**PACKARD**	230	37.7	**41.42**	**40.86**	36.38
5	**AST-WEST**	138	45	44.23	**49.26**	**51.45**
6	**BARRETT**	138	38.7	**45.70**	**46.08**	**45.71**
7	**CORONA NORTH**	138	45	41.27	**46.88**	41.45
8	**FR KILLS**	138	40	39.28	**40.73**	**40.47**
9	**HUDSON E**	138	40	**40.68**	**40.28**	37.26
10	**JAMAICA**	138	40	**48.65**	**50.16**	**45.36**
11	**NRTHPRT1**	138	56.2	**61.99**	**64.03**	**64.89**
12	**PILGRIM**	138	55.8	**63.37**	**65.33**	**59.01**
13	**QUEENSBG**	138	45	42.97	**49.26**	**47.40**
14	**ROTT99G**	115	40	**43.46**	**46.11**	**47.50**
15	**E RIVER**	69	50	46.44	**50.61**	**52.88**

11.2 Second Five Year Period Assessment

11.2.1 Resource Adequacy Assessment

As noted previously, the resource adequacy assessment for the baseline system was done for 2008 and 2013 for the Initial Planning Process.

The Base Case for this study was developed from the MARS database used by NYISO in performing the statewide Installed Reserve Margin (IRM) study for the New York State Reliability Council (NYSRC). The table below lists the new unit additions that were assumed to be installed in the Base Case through 2008. This list includes two interconnection projects in which a unit installed outside of NYCA is directly connected to the NYCA system. More detail on the unit modeling can be found in Appendix 4.

TABLE - BASE CASE NEW UNIT ADDITIONS

Project	Capacity (MW)	Zone	Projected In-Service Date
PG&E Athens	1,080	F	In Service
PSEG Bethlehem	763	F	2005/S
LIPA/TE CT-LI DC Tie-line	330	K	In Service
NYPA Poletti Project	500	J	2005/01
ConEd East River Repowering	288	J	2004/09
SCS Astoria Energy	1,000	J	2006/12
Mirant Bowline Point 3	750	G	2008
KeySpan Ravenswood	270	J	2004/02
NYC Energy Kent Ave	79.9	J	2004/12
Calpine Wawayanda	500	G	2006
ANP Brookhaven	580	K	2007
LMA Lockport II	79.9	A	2003/Q4
Reliant Repowering Phases 1 & 2	546	J	2007
AE Neptune PJM-NYC DC Line	600	J	2004/Q4
Fortistar VP	79.9	J	2005/03
Fortistar VAN	79.9	J	2005/03
PSEG Cross Hudson Project	550	J	2005/03
Calpine JFK Expansion	45	J	2004
KeySpan Spagnoli Road CC Unit	250	K	2006/02
Glenville Energy Park	540	F	2006/S
PP&L Global Kings Park	300	K	2006/02
Besicorp Empire State Newsprint	660	F	2006/02
Liberty Radial Interconnection to NYC	400	J	2006

The load and capacity for 20008 and 2013 for the Base Case assumptions are shown in the table below for NYCA and for Zones J and K. The LOLE is for 2013 under High Load assumptions was found to be 0.002 days/year, well within the NYCA criterion. Consequently, it was not necessary to run the simulations for the other loads assumptions or year.

Base Case

	2008			2013		
	Low Load	**Base Load**	**High Load**	**Low Load**	**Base Load**	**High Load**
Demand (MW)	33,052	33,635	34,228	34,016	35,342	36,768
Base Capacity (MW)	45,841	45,841	45,841	45,841	45,841	45,841
Reserve Margin (%)	38.69	36.29	**33.93**	34.76	29.71	**24.67**
Demand (J)			12,242			13,150
Capacity (J)			13,621			13,621
Cap/Load Ratio (J)			**111.27**			**103.58**
Demand (K)			5,387			5,787
Capacity (K)			6,591			6,591
Cap/Load Ratio (K)			**122.35**			**113.90**
LOLE (d/y)						
NYCA						**0.002**
Zone J						0.000
Zone K						0.002

11.2.2 Transmission Adequacy Assessment

The power flow analyses, including both conventional thermal and voltage contingency analysis as well as thermal transfer limit analysis, performed in this study are described in the following subsections. A description of the study approach, system conditions, analytical tools, and contingency lists is provided.

11.2.2.1 Power System Databases

The 2008 summer peak power flow database from the 2003 ATR representing the desired baseline study assumptions, as well as a 2014 summer peak database, were provided by NYISO. They were converted from PSS/e to GE's PSLF format, solved and reviewed. The 2014 database was modified to better represent the desired 2013 reference study scenario by reducing NY load by 1%, per NYISO recommendation. To compensate for the load reduction, several generators were also removed for a total of approximately 352MW. The removed generators were 75963 GRNIDG 3 (57MW), 79289 INDECK-C (91.5MW), 74736 YORK G3 (70MW), 74301 ER G6 #2 (62MW), 74920 WADNGRV3 (71MW). A brief summary of all three summer peak cases, including total NY load, generation, and significant interface flows, is shown in *Table 0-1*. The definition of each interface is shown in *Appendix A*.

Table 0-1. Summer Peak Power Flow Summary.

	2008		**2014**		**2013**	
Quantity	**P (MW)**	**Q (MVAr)**	**P (MW)**	**Q (MVAr)**	**P (MW)**	**Q (MVAr)**
NY Load	32,889	13,596	35,518	14,867	35,177	14,052
NY Generation	32,525	8,394	35,119	11,635	34,767	10,211
Interfaces:						
ConEd Cable	2227	-368	2117	-129	2130	12
LIPA Import	1292	-598	1366	-392	1379	-318
Central East	2013	-14	2003	-24	2047	-27
NE-NY	114	104	215	374	216	360
ON-NY	35	118	-34	-14	-2	-15
West Central Open	470	-138	324	-130	385	-125
Total East	3873	-39	3913	-390	3961	-488
UPNY-ConEd Closed	6072	-57	6133	621	6131	105
UPNY-SENY Closed	5039	311	5117	137	5088	-80
PJM-NY	347	-61	471	-348	445	-431
Dunwoodie-South Closed	5136	-900	5214	-289	5234	-142

11.2.2.2 Contingency Analysis

A variety of power flow base cases were developed for evaluation under 2008 benchmark conditions, as well as various 2013 scenario conditions. A list of outages, power flow solution parameters, monitoring assumptions, and performance criteria, as described in the following subsections, were developed for this analysis.

11.2.2.3 Contingency Lists

The analysis was performed using a subset of the contingency lists used for the 2003 ATR. These lists included single element transmission line outages, transformer outages, generating unit outages as well as multiple generating unit (i.e., generating station) outages. The selected transmission lines and transformers were at 230kV and above, including autotransformers with at least one side at that voltage level. All generating units with a rating of at least 100MVA were included in the outage list as well. The generating station outages were based upon the single unit outage list but also included any units with a rating of less than 100MVA.

NYISO provided lists of the most severe stuck breaker contingencies for several of the interfaces under evaluation; Total East, Central East, UPNY-SENY, UPNY-ConEd, and Dunwoodie South. All 2008 and 2013 contingency lists are shown in *Appendix B*.

11.2.2.4 Performance Criteria

The pre- and post-contingency voltage criteria are shown in *Table 0-2*. Individual bus voltage criteria was employed when more stringent than any given area criteria.

Under normal conditions, thermal branch loading was required to be below 1.00pu of the element's continuous rating. Under post-contingency conditions, the branch loading was required to be below 1.00pu of the element's long term emergency rating. Several branches that represent cables were allowed loadings up to 1.00pu of the short term emergency rating under post-contingency conditions. These branches are shown in *Table 0-3*, as well as their long term emergency (LTE – rate 2) and short term emergency (STE – rate 3) MVA ratings.

All NY bus voltages, line and transformer flows at 115kV and above were monitored for criteria violations. The areas monitored were 1 (WEST), 2 (GENESSEE), 3 (CENTRAL), 4 (NORTH), 5 (MOHAWK), 6 (CAPITAL), 7 (HUDSON), 8 (MILLWOOD), 9 (DUNWOODI), 10 (NYC), 11 (L ISLAND).

Table 0-2. Voltage Criteria.

	All Lines In		Contingency	
Area/Bus	**Vmin**	**Vmax**	**Vmin**	**Vmax**
Areas 1-11	0.95	1.05	0.90	1.05
74310	1.000	1.050	0.950	1.050
74311	1.000	1.050	0.950	1.050
74313	1.003	1.050	0.950	1.100
77400	1.000	1.050	0.950	1.050
75400	0.980	1.050	0.950	1.100
74316	1.003	1.050	0.950	1.100
78450	1.006	1.050	0.950	1.050
74327	0.980	1.050	0.950	1.100
75403	0.980	1.050	0.950	1.100

Table 2-2 (continued). Voltage Criteria.

	All Lines In		Contingency	
Area/Bus	Vmin	Vmax	Vmin	Vmax
79581	1.009	1.050	0.950	1.050
74333	0.980	1.050	0.950	1.100
74336	0.980	1.050	0.950	1.100
74340	1.003	1.050	0.950	1.100
78701	1.000	1.050	0.950	1.078
79583	1.009	1.050	0.950	1.100
74341	0.997	1.050	0.950	1.100
78702	1.009	1.050	0.950	1.050
78703	1.009	1.050	0.950	1.050
79584	0.980	1.050	0.950	1.050
75405	0.971	1.050	0.928	1.100
79801	1.003	1.041	0.950	1.050
74344	0.994	1.050	0.950	1.100
74345	0.980	1.050	0.950	1.100
74347	1.003	1.050	0.950	1.100
74001	1.009	1.050	0.950	1.050
74002	1.000	1.050	0.950	1.050
75404	0.980	1.050	0.950	1.100
74348	1.003	1.050	0.950	1.100
79800	1.003	1.041	0.950	1.050
74331	0.950	1.050	0.950	1.050
74000	0.950	1.050	0.950	1.050
75000	0.950	1.050	0.950	1.050
77406	0.950	1.050	0.950	1.050
75407	0.950	1.050	0.950	1.050
84819	0.950	1.050	0.950	1.050
79577	0.950	1.050	0.950	1.050
79578	0.950	1.050	0.950	1.050
74300	1.000	1.100	1.000	1.150
79591	0.978	1.050	0.950	1.050
79592	0.978	1.050	0.950	1.050
76663	0.943	1.050	0.900	1.050
76500	0.950	1.050	0.950	1.050
75414	0.950	1.050	0.950	1.050
75415	0.950	1.050	0.950	1.050
78980	0.950	1.050	0.950	1.050
79590	0.978	1.050	0.950	1.050
75418	0.935	1.050	0.900	1.050
75051	0.978	1.050	0.950	1.050
85219	0.950	1.050	0.950	1.050
85119	0.950	1.050	0.950	1.050
78733	0.950	1.050	0.950	1.050

Table 2-2 (continued). Voltage Criteria.

	All Lines In		Contingency	
Area/Bus	**Vmin**	**Vmax**	**Vmin**	**Vmax**
75424	0.950	1.050	0.950	1.050
75426	0.950	1.050	0.950	1.050
77431	0.950	1.050	0.950	1.050
75444	0.950	1.050	0.950	1.050
75446	0.950	1.050	0.950	1.050
76527	0.950	1.050	0.950	1.050
75457	0.950	1.050	0.950	1.050
75476	0.950	1.050	0.950	1.050
79599	0.950	1.050	0.950	1.050
79600	0.950	1.050	0.950	1.050
79601	0.950	1.050	0.950	1.050
75486	0.950	1.050	0.950	1.050
75488	0.950	1.050	0.950	1.050
79602	0.950	1.050	0.950	1.050
74043	0.950	1.050	0.950	1.050
78485	0.950	1.050	0.950	1.050
74046	0.950	1.050	0.950	1.050
78782	0.950	1.050	0.950	1.050
74048	0.950	1.050	0.950	1.050
79811	0.950	1.050	0.950	1.050

Table 0-3. Branches (i.e, Cables) with Short Term Emergency Criteria.

Branch Identification	LTE (MVA)	STE (MVA)
Dunwoodie-Rainey "3" 345kV	817	1081
Dunwoodie-Rainey "4" 345kV	817	1081
Sprainbrook-W. 49th St. "1" 345kV	866	1291
Sprainbrook-W. 49th St. "2" 345kV	866	1291
Sprainbrook-Tremont "1" 345kV	729	758
Farragut-Rainey "1" 345kV	758	1081
Farragut-Rainey "2" 345kV	791	1097
Farragut-Rainey "3" 345kV	758	1081
E. 15th St. 45-Farragut "1" 345kV	882	1258
E. 15th St. 45-W. 49th St. "1" 345kV	866	1291
E. 15th St. 46-Farragut "1" 345kV	882	1258
E. 15th St. 46-W. 49th St. "1" 345kV	866	1291
E. 15th St. 47-Farragut "1" 345kV	683	1124
E. 15th St. 47-Astoria "1" 345kV	621	1476
E. 15th St. 48-Farragut "1" 345kV	683	1124
E. 15th St. 48-Astoria "1" 345kV	621	1476
Farragut-Gowanus N. "1" 345kV	807	1183
Farragut-Gowanus S. "1" 345kV	807	1183
Goethals N.-Gowanus N. "1" 345kV	683	1022
Goethals S.-Gowanus S. "1" 345kV	683	1022

The base cases were solved with all phase shifting transformers (PARs), load tap changing (LTC) transformers and voltage switched shunts (SVDs) acting. Contingencies were solved with PARs, LTCs and SVDs fixed at their pre-outage state. For generator outages, a system redispatch was performed with approximately 30% of the tripped generation picked up in NY at NYISO selected generators. The remaining 70% was picked up at the swing machine, TVA's Browns Ferry Unit 3.

11.2.2.5 Transfer Limit Analysis

Linear transfer limit analysis was used to determine the maximum loading levels of selected interfaces, based on thermal loadings of lines and transformers in the study area. The transfer limit analysis was performed for all contingencies and criteria as described in *Section 11.2.2.2*.

The analysis was performed by first running all N-1 contingencies on a base transfer condition. All N-1 contingencies are then run on a case with an increase in transfers (e.g. a 200MW transaction from western NY to NYC). Linear extrapolation/interpolation, from these full AC power flow results, was used to calculate the incremental transfer level at which normal and post-contingency overloads began to occur. From that, maximum interface flows were determined.

While the limiting element may be located anywhere in NY, additional screening was performed to ensure that interfaces were limited by relatively local lines or transformers.

Branches with low distribution factors (less than 0.01) were ignored. In addition, the focus was on limiting elements at 230kV and above.

11.2.2.6 Generation Shift Procedure

Six interfaces were selected for evaluation: UPNY-SENY Closed, UPNY-ConEd Closed, Dunwoodie-South Closed, Central East, Total East, and LIPA Import. As noted above, these interfaces are defined in *Appendix A*. Different generation shift procedures were implemented to stress the different interfaces, as shown in *Table 0-4*.

The generation shifts shown in this table are slightly different from the generation shifts employed in the 2003 ATR. These shift patterns were modified to account for the differences in computational methodologies between PTI's PSS/E and MUST programs and GE's PSLF programs.

Specifically, the shifts from the 2003 ATR specified that a portion of the generation shift be performed at 78963 BETHGT3 (-0.075pu), 78706 ATHENSC1 (-0.245pu), and 78707 ATHENSS1 (-0.125pu). However, those units were out of service in the 2008 summer peak case. Therefore, the 78962 BETHGT2, 78708 ATHENSC2, and 78709 ATHENSS2 units were substituted.

Similarly, the NYISO information specified that a portion of the LIPA Import generation shift be performed at 74708 RAV 2 (0.16pu), 79546 POLETTI (0.15pu), 74942 NYPA (-0.10pu). However, those units were out of service or non-existent (74942 NYPA) in the 2008 summer peak case. Therefore, the 74707 RAV 1 unit was substituted in NYC and the 74912 PTJEFG3 unit was substituted on Long Island.

Once the generation shift was implemented, the power flow was solved allowing no PAR, LTC or SVC action.

Table 0-4. Generation Shift Procedure for Transfer Limit Analysis.

	200MW Increase		**200MW Decrease**	
Interface	**Generator**	**pu**	**Generator**	**pu**
UPNY-ConEd Closed, UPNY-SENY Closed, Dunwoodie-South Closed	76640 DUNKGEN3	0.05	74906 N.PORT	0.13
	77051 HNTLY68G	0.05	74301 E RIVER	0.035
	77951 9M PT 1G	0.50	74302 E RIVER	0.035
	79515 MOS19-20	0.10	74707 RAV 1	0.20
	81765 NANTICG6	0.15	74706 AST 5	0.20
	80900 LAKEVWG5	0.15	74705 AST 4	0.20
			74703 AK 2	0.20
Total East, Central East	76640 DUNKGEN3	0.05	74906 N.PORT	0.05
	77051 HNTLY68G	0.05	74301 E RIVER	0.05
	77951 9M PT 1G	0.50	74302 E RIVER	0.05
	79515 MOS19-20	0.10	74702 RAV 3	0.19
	81765 NANTICG6	0.15	74190 ROSE GN1	0.18
	80900 LAKEVWG5	0.15	78955 ALBY STM	0.035
			78961 BETHGT1	0.015
			78962 BETHGT2	0.075
			78964 BETH STM	0.02
			78708 ATHENSC2	0.245
			78709 ATHENSS2	0.125
LIPA Import	74190 ROSTON	0.17	74906 NRTPTG1	0.18
	74301 E RIVER	0.025	74908 NRTPTG3	0.18
	74302 E RIVER	0.025	74909 NRTPTG4	0.18
	74702 RAV 3	0.25	74913 PTJEFG4	0.36
	79538 POLETGT	0.135	74912 PTJEFG3	0.10
	79390 BOWLINE	0.085		
	74707 RAV 1	0.31		
West Central	81765 NANTICG6	0.50	75523 KINTIG24	0.10
	80900 LAKEVWG5	0.50	79940 GINNA 19	0.10
			77951 9M PT 1G	0.10
			79513 MOS17-18	0.10
			78007 N.O-BRG	0.10
			79529 GILBOA#3	0.10
			74190 ROSE GN1	0.10
			74701 IND PT 2	0.10
			74702 RAV 3	0.10
			74906 NRTPTG1	0.10

11.2.3 2008 System Evaluation

The benchmark evaluation of the 2008 summer peak system is described in this section. The results of the conventional thermal and voltage contingency analysis are described in *Section 11.2.3.1* and the results of the transfer limit analysis are described in *Section 11.2.3.4*.

11.2.3.1 Contingency Analysis

The contingency analysis was performed in accordance with the study approach described above. A detailed discussion of the results is provided in the following subsections.

11.2.3.2 Pre-Contingency Results

Pre-contingency bus voltage violations are shown in *Table 0-5*. The first five columns identify the bus by number, name, voltage level (kV), area, and zone. The final column shows the bus voltage violation under 2008 summer peak conditions.

Similarly, pre-contingency branch loading violations are shown in *Table 0-6*. The first six columns identify the branch by from bus number and name, to bus number and name, voltage level (kV), and circuit number. Two values in the voltage level column indicate the overload branch was a transformer. The seventh column shows the branch rating in MVA. Transformer loadings were calculated on the basis of MVA flow, line loadings were calculated on the basis of current flow. For simplicity, however, both transformer and line ratings are shown in MVA. The final column shows the loading violation under 2008 summer peak conditions.

All 2008 summer peak pre-contingency bus voltage and branch loading criteria violations will be treated in the same manner for the 2008 and 2013 evaluation.

Table 0-5. Pre-Contingency Bus Voltage Violations.

Bus #	Bus Name	kV	Area	Zone	2008 Summer Peak (pu)
78055	STARK	115	5	3	1.051
79326	W.NYACK	138	7	11	0.949
79593	PLAT T#1	230	4	14	1.055
79599	MOS 115	115	4	14	1.054

Table 0-6. Pre-Contingency Branch Loading Violations.

From #	From Name	To #	To Name	kV	ID	MVA	2008 Summer Peak (pu)
74333	GOTHLS N	74336	GOWANUSN	345	1	460	1.06
74335	GOTHLS S	74337	GOWANUSS	345	1	460	1.013
74336	GOWANUSN	74477	GOWNUS1T	345/138	1	226	1.06
74384	ASTE-ERG	74413	CORONA-S	138	1	154	1.022
74384	ASTE-ERG	74413	CORONA-S	138	3	154	1.02
74402	ASTE-WRG	74465	CORONA-N	138	2	154	1.06
74402	ASTE-WRG	74465	CORONA-N	138	4	154	1.025
74402	ASTE-WRG	74492	HG 1	138	1	161	1.021
74403	ASTORIAW	74496	HG 5	138	1	177	1.042
74476	GOWNUS1R	74484	GRENWOOD	138	1	226	1.031
74477	GOWNUS1T	74476	GOWNUS1R	138	1	226	1.04
76665	PACKARD2	76710	PACK(N)E	230/115	1	141	1.05
79800	ROCH 345	79819	S80 1TR	345/115	1	200	1.07

11.2.3.3 Post-Contingency Results

Complete post-contingency results for the 2008 benchmark case are shown in the linked Excel file, 08only.xls, which is included in Appendix 5. All outages solved for the 2008 benchmark case.

One 345kV bus minimum voltage violation was observed on the Stolle Rd 345kV (0.89pu) in response to the loss of the Homer City-Stolle Rd 345kV line. Another 345kV bus voltage violation was observed on the SHOEMTAP bus in response to either a Coopers Corners (0.88pu) or Rock Tavern (0.88pu) stuck breaker outage. Low voltages were also observed on the SHOEMTAP 345kV bus for the 32 and 42E, as well as 32 and 42W, tower outages.

Several 230kV buses (76660 ELM-70, 76661 ELM-71, 76662 ELM-72, 76666 SENCA-71, 76667 SENCA-72) exhibited low voltages (0.86pu to 0.87pu) in response to local outages. Low voltages were also observed on a number of 138kV buses in area 10 (NYC) in response to the loss of FARRABUT-FGT/HAT7 345/148kV transformer #1, a Rainey 345/138kV transformer (2E, 7E, 7W, 3W), or a W 49th St 345/138kV transformer (1, 4, 5).

Finally, a number of 115kV and 138kV buses exhibited low voltages (0.88pu to 0.90pu) for the loss of the Ginna unit #1, Milliken units #1 and #2, Fishkill 345/115kV transformer #1, or various stuck breaker outages.

Overloads on Rochester 345/115 transformers #1 and #3 (1.09pu to 1.14pu) were observed in response to the loss of Ginna unit #1, or any of the Rochester transformers #1, #2 or #3. The Reynolds 345/115kV transformer was overloaded (1.08pu) for the loss of the Alps-Reynolds 345kV line. Overloads on the Waldwick-S Mahwah 345kV lines (1.066pu to 1.188pu) were observed for several local outages. The 345kV overload was observed on the Bowline 345/138kV transformer #1 in response to the loss of Ladentown-Bowline 345kV line #3.

Several 230kV line overloads (1.087pu to 1.182pu) were observed near the Sawyer substation in response to local 230kV outages.

All 2008 summer peak post-contingency bus voltage and branch loading criteria violations will be considered pre-existing conditions, and therefore ignored in the 2013 evaluation.

11.2.3.4 Transfer Limit Analysis

The transfer limit analysis was used to determine maximum flow levels of selected interfaces, based upon thermal loadings of lines and transformers in the study area. The analysis was performed in accordance with the study approach as described above.

A summary of the interface limits under 2008 summer peak load conditions is shown in *Table 0-7*. The first column identifies the interface by name. The second columns shows the maximum interface power transfer to ensure acceptable system performance under the most limiting N-0, N-1, stuck breaker or other outage condition. The final three columns show the limiting element, its rating in MVA, and the limiting outage. While the limiting element may be located anywhere in NY, additional screening was performed to ensure that interfaces were limited by relatively local lines or transformers. Thus, the Total East interface was limited by the Rock Tavern-Calpine 345kV line rather than by a NYC 345kV cable.

Table 0-7. Interface Transfer Limits under 2008 Summer Peak Conditions.

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Interface	MW Limit	Limiting Element	Rated MVA	Limiting Outage
UPNY-ConEd Closed	7045	Rock Tavern-Ramapo 345kV Line	1890	Roseton-Fishkill 345kV Line
UPNY-SENY Closed	5248	Pleasant Valley-Leeds 345kV Line	1538	Pleasant Valley-Athens 345kV Line
Dunwoodie-South Closed	6053	Dunwoodie-Shore Rd 345kV Line	962	Northport generating units #1-#4
Total East	6825	Rock Tavern-Calpine 345kV Line	1793	COOPC345-SHOEMTAP 345kV Line
Central East	3240	Rock Tavern-Calpine 345kV Line	1793	COOPC345-SHOEMTAP 345kV Line
LIPA Import	1348	Northport-Norwalk 138kV Line	352	TWR: W89 & W90 (Dunwoodie-Plville 345kV #1 & #2)
West Central	807	Pleasant Valley-Leeds 345kV Line	1538	Pleasant Valley-Athens 345kV Line

The above transfer limits are close to those computed for the 2003 ATR, thus benchmarking the GE PSLF analysis setup.

11.2.4 2013 System Evaluation

The steady-state evaluation of the 2013 summer peak system is described in this section. The 2013 study scenarios are described in *Section 11.2.4.1*. The results of the conventional thermal and voltage contingency analysis are described in *Section 0* and the results of the transfer limit analysis are described in *Section 11.2.4.6*. The 2013 power flow baseline representation was derived from the 2008 ATR power flow case by updating the network model with the databank updates received through March 2004 and updating the load model with the 2013 load representaion.

11.2.4.1 Scenario Description

The 2013 reference case was developed from the 2014 database provided by NYISO, as described in *Section 11.2.2.1*. Four additional 2013 cases representing different transmission, generation, and load scenarios were also evaluated. A brief description of each scenario, including an indication of the differences between it and the reference case, follows.

Scenario 1 represented a 2013 system condition with higher than expected load levels. The 2013 reference system load level in NY was 35,177MW. For Scenario 1, the NY load was increased by approximately 4% (1521MW) to 36,698MW. To compensate for the added load, additional power was generated at selected units. As much as possible, the load increase in a particular area was met with a corresponding generation increase in that same area. The change in status and/or power output at the selected units is shown in *Table 0-8.*

Table 0-8. Generating Units Redispatched to Meet Higher Load Levels in Scenario 1.

				Reference		Scenario 1		
#	**Name**	**kV**	**ID**	**ST**	**Power (MW)**	**ST**	**Power (MW)**	**Increase (MW)**
74190	ROSE GN1	24	1	1	414	1	610	196
74700	AK 3	22	1	1	175	1	491	316
74702	RAV 3	22	1	1	355	1	420	65
74702	RAV 3	22	2	1	449	1	540	91
74707	RAV 1	20	1	1	80	1	180	100
74708	RAV 2	20	1	1	80	1	180	100
78706	ATHENSC1	16	1	1	150	1	250	100
78707	ATHENSS1	14	1	1	100	1	110	10
78708	ATHENSC2	16	1	1	150	1	250	100
78709	ATHENSS2	14	1	1	100	1	110	10
78710	ATHENSC3	16	1	1	150	1	250	100
78711	ATHENSS3	14	1	1	100	1	110	10
74924	SPAGNOLI	14	1	0	0	1	130	130
74924	SPAGNOLI	14	2	0	0	1	100	100
78963	BETHGT3	18	1	0	0	1	155	155
	Total							**1543**

Scenario 2 represented a 2013 system with significant amounts of retired generation. The retired units, as well as the units chosen to replace them, are shown in *Table 0-9*. The generation decrease in a particular area was met with a corresponding generation increase in that same area as much as possible.

Table 0-9. Retired Units, as well as Redispatched Units, in Scenario 2.

				Reference		Scenario 2		
#	**Name**	**kV**	**ID**	**ST**	**Power (MW)**	**ST**	**Power (MW)**	**Difference (MW)**
Retirement:								
77050	HNTLY67G	14	1	1	96	0	0	-96
77050	HNTLY67G	14	2	1	96	0	0	-96
77051	HNTLY68G	14	1	1	95	0	0	-95
77051	HNTLY68G	14	2	1	95	0	0	-95
77052	HUNT115G	14	1	1	85	0	0	-85
77052	HUNT115G	14	2	1	85	0	0	-85
77052	HUNT115G	14	3	1	85	0	0	-85
77052	HUNT115G	14	4	1	85	0	0	-85
77952	OSWGO 5G	22	5	1	681	0	0	-681
79390	BOW2	20	2	1	592	0	0	-592
79391	BOW1	20	1	1	592	0	0	-592
	Total							**-2587**
Redispatch:								
74190	ROSE GN1	24	1	1	414	1	610	196
74193	DANSK G4	16	3	0	0	1	241	241
75963	GRNIDG 3	14	3	0	0	1	57	57
77450	GERES LK	115	3	0	0	1	80	80
78706	ATHENSC1	16	1	1	150	1	250	100
78707	ATHENSS1	14	1	1	100	1	110	10
78708	ATHENSC2	16	1	1	150	1	250	100
78709	ATHENSS2	14	1	1	100	1	110	10
78710	ATHENSC3	16	1	1	150	1	250	100
78711	ATHENSS3	14	1	1	100	1	110	10
78951	JMCGT13	14	1	0	0	1	95	95
78952	JMC2ST13	14	1	0	0	1	121	121
78953	JMCGT213	14	1	0	0	1	95	95
78962	BETHGT2	18	1	1	110	1	155	45
78963	BETHGT3	18	1	0	0	1	155	155
78964	BETH STM	18	1	1	200	1	325	125
79548	IP#3 GEN	22	1	0	0	1	1011	1011
	Total							**2551**

Scenario 3 represented a 2013 system condition with a redistribution of generation from the bulk power system (230kV and above) to the lower level transmission system (138kV and below). This redistribution was performed only in Areas 1 through 9, and therefore, excluded NYC and Long Island. In addition, only units with a maximum power output of at least 10MW were included. The largest of the redispatched units are shown in *Table 0-10*. Any unit with a change in output of greater than 20 MW is shown, the remainder are represented by an aggregate value. The total redistribution from generators connected at 230kV and above to generators connected at 138kV and below was approximately

2500MW. The sub-transmission level generation increase in a particular area was met with a corresponding bulk system generation decrease in that same area as much as possible.

Table 0-10. Redispatch of Units from Bulk System to Sub-Transmission in Scenario 3.

#	Name	kV	ID	Reference ST	Reference Power (MW)	Scenario 3 ST	Scenario 3 Power (MW)	Difference (MW)
Bulk System Units (230kV and above):								
74190	ROSE GN1	24	1	1	414	0	0	-414
76641	DUNKGEN4	14	1	1	96	0	0	-96
76641	DUNKGEN4	14	2	1	96	0	0	-96
77051	HNTLY68G	14	2	1	95	0	0	-95
77969	SITH-S5	18	5	1	160	0	0	-160
77970	SITH-S6	18	6	1	160	0	0	-160
78708	ATHENSC2	16	1	1	150	0	0	-150
78709	ATHENSS2	14	1	1	100	0	0	-100
78710	ATHENSC3	16	1	1	150	0	0	-150
78711	ATHENSS3	14	1	1	100	0	0	-100
79307	CALPST1	18	1	1	170	0	0	-170
79397	BOWLNCT3	18	1	1	166	0	0	-166
79520	MOS23-24	14	1	1	57	0	0	-57
79520	MOS23-24	14	2	1	57	0	0	-57
79527	GILBOA#1	17	1	1	250	0	0	-250
79529	GILBOA#3	17	3	1	250	0	0	-250
	Total							**-2471**
Sub-Transmission System Units (138kV and below):								
74193	DANSK G4	16	4	0	0	1	241	241
74194	DANSK G3	16	3	0	0	1	138	138
74195	DANSK G2	14	2	0	0	1	61	61
74196	DANSK G1	14	1	0	0	1	54	54
75527	CLR 1	1	1	0	0	1	75	75
75753	BINCO13$	14	1	0	0	1	59	59
75963	GRNIDG 3	14	3	0	0	1	57	57
76807	AM BRASS	115	1	0	0	1	62	62
77450	GERES LK	115	3	0	0	1	80	80
78000	ALCOA-NM	115	1	0	0	1	79	79
78039	N GOUVNR	115	1	0	0	1	38	38
78073	KAMINEGT	14	1	0	0	1	65	65
78074	KAMINEST	14	1	0	0	1	43	43
78877	NORT+NSH	35	1	0	0	1	25	25
78951	JMCGT13	14	1	0	0	1	95	95
78952	JMC2ST13	14	1	0	0	1	148	148
78953	JMCGT213	14	1	0	0	1	95	95
78959	LGE-GT	14	1	0	0	1	50	50
78960	LGE-ST	14	1	0	0	1	40	40
78963	BETHGT3	18	1	0	0	1	155	155
79137	IP CORIN	115	1	0	0	1	32	32
79137	IP CORIN	115	2	0	0	1	32	32
79289	INDECK-C	14	1	0	0	1	93	93
79354	SHOEM69	69	1	0	0	1	27	27
79657	JAMESTWN	13	1	0	0	1	75	75
78962	BETHGT2	18	1	1	110	1	155	45
78964	BETH STM	18	1	1	200	1	325	125
79242	M+S+EV+D	35	1	1	13	1	36	24
Miscellaneous Small Units								353
	Total							**2465**

Scenario 4 was developed from Scenario 3 and represented a 2013 system condition with fewer new power plants in service. The unbuilt units, as well as the units chosen to replace them, are shown in *the following table*.

Table 0-11. Unbuilt Units, as well as Redispatched Units, in Scenario 4.

				Scenario 3		Scenario 4		
#	**Name**	**kV**	**ID**	**ST**	**Power (MW)**	**ST**	**Power (MW)**	**Difference (MW)**
Not Built:								
78713	GLENVIL1	18	1	1	172	0	0	-172
78714	GLENVIL2	18	1	1	172	0	0	-172
78715	GLENVIL3	18	1	1	200	0	0	-200
78809	BESI20G1	20	1	1	161	0	0	-161
78810	BESI20G2	20	1	1	161	0	0	-161
78811	BESI20G3	20	1	1	297	0	0	-297
79305	CALPGT1	18	1	1	165	0	0	-165
79306	CALPGT2	18	1	1	165	0	0	-165
79307	CALPST1	18	1	0	0	0	0	0
79395	BOWLNCT1	18	1	1	166	0	0	-166
79396	BOWLNCT2	18	1	1	166	0	0	-166
79397	BOWLNCT3	18	1	0	0	0	0	0
79398	BOWLNST	18	1	1	308	0	0	-308
	Total							**-2133**
Redispatch:								
77952	OSWGO 5G	22	5	1	681	1	781	100
77953	OSWGO 6G	22	6	0	0	1	781	781
78706	ATHENSC1	16	1	1	150	1	250	100
78707	ATHENSS1	14	1	1	100	1	110	10
78708	ATHENSC2	16	1	0	0	1	250	250
78709	ATHENSS2	14	1	0	0	1	110	110
78710	ATHENSC3	16	1	0	0	1	250	250
78711	ATHENSS3	14	1	0	0	1	110	110
79527	GILBOA#1	17	1	0	0	1	250	250
79528	GILBOA#2	17	2	0	0	1	250	250
	Total							**2211**

A summary of the MVAr losses for all 2008 and 2013 study scenarios is shown in *Table 0-12*. The losses under all 2013 conditions were greater than the losses in 2008 (3484MVAr). The highest losses, 7266MVAr, were observed for Scenario 1 with higher than expected load. The lowest MVAr losses in 2013, 4210MVAr, were observed for Scenario 2 with unit retirements. The difference in losses between Scenario 2 and the 2013 reference case (5575MVAr) was primarily in the 345kV system. Most of the retired units were connected to the 230kV and 345kV system, while the units dispatched as replacements were connected to both the 345kV system and the 115kV system. The losses for Scenario 3, with more units on the 138kV and below system, were 5351MVAr – less than the reference. The losses for Scenario 4, same as Scenario 3 with fewer new units in service, were 6981MVAr. The difference in losses between Scenarios 3 and 4 were once again primarily in the 345kV system. The new plants removed from Scenario

3 to create Scenario 4 were connected to both the 115kV and 345kV systems, while the replacement units were all connected to the 345kV system.

A summary of the real and reactive power flow in selected transformers is shown in the linked Excel spreadsheet, transformerflow.xls, in Appendix 5. The selected transformers are primarily 345/115kV, 345kV/138kV or 230kV/115kV. No NYC, area 10, transformers are included.

In 2008, reactive power flow exceeds 100MVAr from the high side to the low side on fourteen transformers, for a total reactive flow of about 1850MVAr. The results are similar in the 2013 reference and Scenario 4 with fewer new units in service. The 2013 reference had about 1800MVAr flowing from the transmission system (230kV and above) to the sub-transmission system (138kV and below) on the transformers with at least 100MVAr of flow. The flow was also approximately 1800MVAr for Scenario 4. Higher levels of reactive flow, approximately 2050MVAr, were observed for Scenario 1 with higher than expected load levels. Somewhat smaller flows, about 1550MVAr, were observed for Scenarios 2 (unit retirement) and 3 (redispatch generation from 230kV and above to 138kV and below).

Lower levels of both MVAr losses and reactive flow from the transmission system to the sub-transmission system were observed in the cases with higher levels of generation in service on the sub-transmission system (138kV and below).

A zonal summary of the reactive reserves in New York for 2004, 2008 and 2013 is shown in the linked Excel spreadsheet, reservesummary.xls. Four columns of information are shown for each of the study cases. The first column shows the reactive power reserve (Q) for all units, both in service and out of service. The second column shows the reactive power reserve for in service units only. For in service units the reactive reserve is equal to the maximum reactive output less the actual reactive output. For out of service units the reactive reserve is equal to the maximum reactive output. The third column shows the shunt capacitive (B) reserve for all voltage controlled shunt devices.

The total unit reactive reserve increased significantly between 2004 and 2008 due to the addition of new generating facilities (Calpine, Bowline, Besicorp, Bethlehem, Glenville, SUN, ANP-SRG, Astoria Orion, Astoria SCS, Linden, Bergen, Poletti, Spagnoli). The capacitive reserve on the shunt devices also increased with the addition of voltage controlled devices as well as the above units.

Both the unit reactive reserve and shunt device capacitive reserve decreased from 2008 to the 2013 reference, due to the increase in system load combined with few unit or shunt device additions.

The unit reactive reserve and shunt device capacitive reserve also decreased from the 2013 reference to 2013 Scenario 4 (more units on the lower voltage system and fewer new power plants in service). About half of the decrease occured in areas 5 (Mohawk) and 6 (Capital). Between the reference and Scenario 4, there was a significant difference in the generation dispatch of these two areas. The Glenville, Besicorp and Calpine projects were in service in the reference case, but were replaced by smaller units with less reactive capability in Scenario 4.

Table 0-12. Summary of MVAr Losses for All 2013 Scenarios.

		2008							2013 Reference						
#	Name	Other	115kV	138kV	230kV	345kV	765kV	Total	Other	115kV	138kV	230kV	345kV	765kV	Total
1	WEST	549	271		-36	-76		709	571	250		0	23		844
2	GENESSEE	184	159			-113		230	251	297			-112		436
3	CENTRAL	391	207		17	273		888	411	208		42	406		1067
4	NORTH	114	42		-45		-227	-117	112	114		-43		-218	-35
5	MOHAWK	37	14		-7	701	-499	246	37	30		17	692	-491	284
6	CAPITAL	221	136		1	238		596	260	259		16	217		753
7	HUDSON	327	136	159		284		909	366	159	182		225		935
8	MILLWOOD	37	9	5		292		343	36	6	10		282		334
9	DUNWOODIE	197		-5		-1582		-1390	176		2		-1569		-1391
10	NYC	2138		661	135	-1409		1525	2626		1218	143	-1297		2690
11	LI	317		-295	-477			-454	377		-266		-454		-343
	NY SUM	4512	973	526	-412	-1391	-726	3484	5223	1323	1146	175	-1587	-710	5575

		2013 Scenario 1 - Increased Load							2013 Scenario 2 - Unit Retirements						
#	Name	Other	115kV	138kV	230kV	345kV	765kV	Total	Other	115kV	138kV	230kV	345kV	765kV	Total
1	WEST	592	263		10	18		883	546	246		-41	-105		646
2	GENESSEE	280	337			-108		508	243	239			-107		375
3	CENTRAL	423	238		37	350		1048	349	176		-7	24		542
4	NORTH	113	126		-42		-215	-18	112	130		-41		-215	-14
5	MOHAWK	39	40		0	545	-497	128	37	32		-50	276	-488	-192
6	CAPITAL	287	287		15	240		829	273	256		2	205		735
7	HUDSON	433	178	194		296		1105	210	102	184		233		733
8	MILLWOOD	41	8	15		343		407	186	7	9		240		442
9	DUNWOODIE	194		63		-1423		-1166	176		-1		-1519		-1344
10	NYC	3072		1703	144	-1130		3789	2624		1217	138	-1344		2635
11	LI	433		-241		-439		-247	377		-267		-457		-347
	NY SUM	5908	1475	1734	164	-1309	-712	7266	5133	1188	1140	0	-2553	-703	4210

		2013 Scenario 3 - Redistribution to <=138kV							2013 Scenario 4 - S3 + Fewer New Plants						
#	Name	Other	115kV	138kV	230kV	345kV	765kV	Total	Other	115kV	138kV	230kV	345kV	765kV	Total
1	WEST	573	258		-3	17		845	576	267		18	3		864
2	GENESSEE	231	268			-112		387	234	268			-111		392
3	CENTRAL	432	197		32	300		961	523	241		43	775		1581
4	NORTH	99	118		-40		-218	-41	99	129		-39		-217	-29
5	MOHAWK	61	49		-29	789	-473	396	62	55		91	1278	-480	1007
6	CAPITAL	281	228		-5	278		782	219	204		35	233		692
7	HUDSON	372	72	169		152		771	385	73	178		447		1086
8	MILLWOOD	36	9	10		251		306	37	10	10		275		332
9	DUNWOODIE	176		-4		-1563		-1391	177		1		-1572		-1393
10	NYC	2624		1221	143	-1297		2691	2640		1236	152	-1239		2790
11	LI	376		-270		-462		-356	378		-263		-455		-340
	NY SUM	5262	1199	1126	98	-1648	-691	5351	5330	1247	1162	300	-364	-697	6981

11.2.4.2 Contingency Analysis

The 2013 contingency analysis was performed in accordance with the study approach described above. Complete post-contingency results for the 2013 cases compared to the 2008 benchmark case are shown in the linked Excel file, 08-13all2.xls, in Appendix 5. Tab "*Pre-C Voltages*" shows the absolute voltage violations under pre-contingency conditions. Tabs "*Post-C V by Bus*" and "*Post-C V by Outage*" show the absolute voltage violations under post-contingency conditions sorted by bus number and outage description, respectively. Tab "*Pre-C OLs*" shows the branch overloads under pre-contingency conditions. Tabs "*Post-C OLs by Branch*" and "*Post-C OLs by Outage*" show the branch overloads under post-contingency conditions sorted by branch and outage description, respectively. All results are sorted by outage, and then by bus number. Tab "*No Solve*" shows the contingencies that did not solve.

The "*Pre-C Voltages*", "*Post-C V by Bus*" and "*Post-C V by Outage*" tabs identify each bus by number, name, voltage level (kV), area and zone in the first five columns. The next column shows the short identifier for the outage. The following six columns show the bus voltage for each of the 2008 and 2013 study scenarios. The final column includes a brief description of the outage. A zero indicates an acceptable voltage was observed but not recorded in the output files. A 9 indicates that the contingency did not solve. Voltage violations are highlighted in red.

The "*Pre-C OLs*", "*Post-C OLs by Branch*" and "*Post-C OLs by Outage*" tabs identify the overloaded element by from bus number, name, and voltage level, to bus number, name, and voltage level, as well as circuit number, from bus area, to bus area, and branch type (line or transformer). The next two columns show the element rating in MVA and the short identifier for the outage. The following six columns show the element loading in per unit on the current rating for lines and MVA rating for transformers for each of the 2008 and 2013 study scenarios. The final column includes a brief description of the outage. A zero indicates an acceptable branch loading was observed but not recorded in the output files. Unsolved contingencies are indicated by a 9. Long term emergency (rate 2) overloads are highlighted in red.

The ""*No Solve*" tab shows the outage's short identifier in the first column. The next five columns indicate whether ("solved") or not ("error") the contingency solved for each of the 2008 and 2013 study scenarios. The final column includes a brief description of the outage. Unsolved cases are highlighted in red.

A detailed discussion of the results is provided in the following subsections.

11.2.4.3 Pre-Contingency Results

As described in *Section 11.2.3,* only one pre-contingency low voltage violation was observed in 2008 on the W Nyack 138kV bus. In 2013, no low voltages were observed on 138kV, 230kV or 345kV buses under reference conditions or Scenarios 1, 2 and 3. One low voltage (0.92pu) was observed on the Rotterdam 230kV bus under Scenario 4 conditions with fewer new plants in service. However, approximately forty 115kV bus voltage violations were observed for the 2013 reference as well as Scenarios 1 (higher load) and 2 (unit retirement). In contrast, about ten 115kV voltage violations were observed in Scenarios 3 and 4, which both had more units on the 138kV and below system. The severity of the voltage violations was also much higher for the 2013 reference, Scenario1 (higher load), and Scenario 2 (unit retirement) compared to Scenarios 3 and 4. The worst case voltage, 0.83pu, was observed on the BARTN115 115kV bus under Scenario 1 (higher load) conditions. Under Scenario 3 conditions with high levels of 138kV and below units in service, the voltage at this bus was 0.91pu, approximately 0.08pu higher.

The largest difference between 2008 and 2013 with respect to pre-contingency branch loading on the 230kV and 345kV system was observed on the GOTHLS S-GOWANUS S 345kV line. The pre-contingency loading was 1.01pu in 2008, 1.21pu for the 2013 reference condition, and as high as 1.39pu for 2013 Scenario 1. This may indicate the need for additional adjustment of the NYC PAR settings for future 2013 system analysis.

Both the number of overloads and severity of overloads on the 115kV and 138kV system increased between 2008 and 2013. Among the 2013 cases, more overloads were observed for the high load Scenario 1 than any other. The best performance, or least overloads, was observed with Scenarios 3 (more 138kV and below units in service) and 4 (fewer new plants in service). The largest overload, 2.01pu, was observed on the ASTORIAW-HG 5 138kV line under the high load Scenario 1. The loading on this branch was 1.67pu under Scenario 4 conditions, and 1.04pu under 2008 system conditions.

11.2.4.4 Unsolved Contingencies

All outages solved for the 2008 benchmark case. Sixteen to twenty five contingencies, both single element and stuck breaker outages, did not solve for 2013 reference, Scenario 2 (unit retirement), Scenario 3 (high level of 138kV and below units in service), and Scenario 4 (fewer new plants in service). About 70 contingencies did not solve for 2013 Scenario 1 with higher than anticipated system load. The additional unsolved contingencies were primarily stuck breaker, multiple generating unit, and NYC transmission line or transformer outages. Note that there were some differences between the 2008 and 2013 contingency lists due to changes in transmission system topology and the addition of new generating facilities. A brief review of the contingencies indicated that the solution problems were not primarily numerical. However, no effort was made to manually solve the contingencies. As noted before, a complete description of each contingency is shown in *Appendix 5*. The unsolved contingencies were mostly a function of reactive deficiencies.

11.2.4.5 Post-Contingency Results

Post-contingency voltage performance for the 2013 cases was generally worse than observed in the 2008 benchmark case. Several 345kV voltage violations were observed.

One violation was on the Stolle Rd bus for both 2008 (0.89pu) and 2013 (0.88pu) in response to the loss of the Homer City-Stolle Rd 345kV line.

Voltage violations were also observed on the Tremont 345kV bus (0.87pu to 0.92pu) for the loss of the Sprainbrook-Tremont 345kV line in 2013, but not in 2008. Similarly, low voltages were observed on this bus (0.86pu to 0.91pu) for several Sprainbrook stuck breaker outages in 2013.

The low voltages on the SHOEMTAP 345kV bus observed in 2008 (0.88pu) were still lower in 2013 (0.83pu to 0.87pu) in 2013 for a Cooper's Corner or Rock Tavern stuck breaker outage. Similarly, the low voltages observed in 2008 in response to the 34 and 42E (0.87pu), as well as 34 and 42W (0.88pu), tower outages were lower in 2013 (0.81pu to 0.86pu).

Several 230kV buses (76660 ELM-70, 76661 ELM-71, 76662 ELM-72, 76666 SENCA-71, 76667 SENCA-72) also exhibited low voltages in response to local outages for both 2008 and 2013. No significant difference was observed.

Under 2013 Scenario 4 conditions (fewer new plants in service), the voltage on the Rotterdam 230kV bus was 0.88pu to 0.89pu in response to several severe contingencies (loss of all Bethlehem units, the Marcy-Massena 765kV line, towers 40 and 41, or towers 41 and 33). As noted above, the pre-contingency voltage on this bus was 0.92pu under this study condition.

Low voltages were also observed on a number of 138kV buses in area 10 (NYC) in response to the loss of various 345/138kV transformers as well as several Sprainbrook stuck breaker outages. Finally, a number of 115kV buses exhibited low voltages for the loss of the various generating units as well as several tower outages.

The lowest voltages were always observed for 2013 Scenario 1 (higher than expected load). The best voltage performance was observed for 2013 Scenario 3, which had more 138kV and below generating units in service.

Significantly more branch overloads at 115kV, 138kV and 345kV were observed under all 2013 conditions compared to the 2008 benchmark. Again the highest overloads were always observed for 2013 Scenario 1 with higher than expected load. The best performance was observed for 2013 Scenarios 3, which had more 138kV and below generating units in service, and 4, which had fewer new units in service.

11.2.4.6 Transfer Limit Analysis

The transfer limit analysis was used to determine maximum flow levels of selected interfaces, based upon thermal loadings of lines and transformers in the study area. The analysis was performed in accordance with the study approach as described above.

A summary of the interface limits under 2013 reference summer peak load conditions is shown in *the following table*. The first column identifies the interface by name. The second columns shows the maximum interface power transfer to ensure acceptable system performance under the most limiting N-0, N-1, stuck breaker or other outage condition. The final three columns show the limiting element, its rating in MVA, and the limiting outage. While the limiting element may be located anywhere in NY, additional screening was performed to ensure that interfaces were limited by relatively local lines or transformers. In addition, elements with pre-contingency overloads were ignored for this analysis, and the next most limiting element selected.

Interface limits, for the most limiting of all N-0, N-1, stuck breaker, tower and bus contingencies, are summarized in *Appendix 5* for both the 2008 and 2013 study conditions. The difference in the UPNY-ConEd and LIPA Import interface flows was less than 2% between the 2008 and 2013 reference cases.

The UPNY-SENY interface flow increased between 2008 and 2013 by approximately 400MW. This occurred because the initial flow on the limiting Pleasant Valley-Leeds 3454kV line was higher in 2008 (1050MW or 0.79pu) than in 2013 (1010MW or 0.75pu). In addition, the post-contingency distribution factor for this line was higher in 2008 (18.4%) than in 2013 (17.2%). The combination of these two factors resulted in a lower 2008 interface limit than was observed in 2013.

The Dunwoodie South interface flow decreased between 2008 and 2013 by approximately 900MW. This occurred because the post-contingency distribution factor for this line was higher in 2013 (9%) than in 2008 (4%). The relatively large difference in distribution factor was primarily because the limiting outage changed. Thus, a lower 2013 interface limit was observed, compared to 2008.

The Total East and Central East interface flow limits decreased by about 350MW (5%) and 200MW (6%), respectively, between 2008 and 2013. This occurred because the normal and LTE ratings on the limiting Rock Tavern-Calpine 345kV line changed from 1793MVA and 1793MVA, respectively, in 2008 to 1554MVA and 1733MVA, respectively, in 2013. Therefore, a lower interface limit was observed in 2013 than in 2008.

Table 0-13. Interface Transfer Limits under 2013 Reference Conditions.

Interface	MW LIMIT	ting Element	MVA	Limiting Outage
UPNY-ConEd Closed	7172	Pleasant Valley-Athens 345kV Line	1538	Towers 34 & 42E (Rck Tav-Calp 345kV + Rck Tav-Cpr Crns 345kV)
UPNY-SENY Closed	5642	Pleasant Valley-Leeds 345kV Line	1538	Pleasant Valley-Athens 345kV Line
Dunwoodie-South Closed	5125	Dunwoodie-Shore Rd 345kV Line	962	HMP HRBR-EGC DUM 345kV Line
Total East	6458	Rock Tavern-Calpine 345kV Line	1733	COOPC345-N.M. TAP 345kV Line
Central East	3035	Rock Tavern-Calpine 345kV Line	1733	COOPC345-N.M. TAP 345kV Line
LIPA Import	1323	HMP HRBR-EGC DUM 345kV Line	948	Dunwoodie-Shore Rd 345kV Line

Table 0-14. Interface Transfer Limits under 2008 and 2013 Study Conditions.

Interface	2008	2013 Reference
UPNY-ConEd Closed	7045 MW	7172 MW
UPNY-SENY Closed	5248 MW	5642 MW
Dunwoodie-South Closed	6053 MW	5125 MW
Total East	6825 MW	6458 MW
Central East	3240 MW	3035 MW
LIPA Import	1348 MW	1323 MW

11.2.4.7 Conclusions

NYISO performed an initial long range planning study to evaluate system performance in the year 2013 under a variety of possible future scenarios. System performance in the year 2008 was used as a benchmark for comparison. Steady-state analyses were performed, both conventional thermal and voltage contingency analysis as well as thermal transfer limit analysis.

In addition to the reference 2013 system condition, four different 2013 scenarios were evaluated. Scenario 1 represented a 2013 system condition with higher than expected load levels. The 2013 reference system load level in NY was 35,177MW. For Scenario 1, the NY load was increased by approximately 4% (1521MW) to 36,698MW. Scenario 2 represented a 2013 system with significant amounts of retired generation. The Huntley, Oswego and Bowline units were retired for a total of approximately 2,600MW. Scenario 3 represented a 2013 system condition with a redistribution of generation from the bulk power system (230kV and above) to the lower level transmission system (138kV and below). This redistribution was performed only in Areas 1 through 9, and therefore, excluded NYC and Long Island. The total redistribution from generators connected at 230kV and above to generators connected at 138kV and below was approximately 2500MW. Scenario 4 was developed from Scenario 3 and represented a 2013 system condition with fewer new power plants in service. In particular, the Glenville, Besicorp, Bowline, and Calpine projects were out of service in Scenario 4.

Lower levels of both MVAr losses and reactive flow from the transmission system to the sub-transmission system were observed in the 2013 cases with higher levels of generation in service on the sub-transmission system (138kV and below).

In 2008, only one pre-contingency low voltage violation was observed. However, approximately forty pre-contingency bus voltage violations were observed for the 2013 reference as well as for Scenarios 1 (higher than expected load) and 2 (unit retirement). In contrast, ten pre-contingency voltage violations were observed in Scenario 3, which represented a case with more units on the 138kV and below system, and twelve pre-contingency voltage violations were observed in Scenario 4, which had fewer new plants in service. The severity of the voltage violations was also much higher for the 2013 reference, Scenario 1 (higher load), and Scenario 2 (unit retirement) compared to Scenarios 3 and 4.

The largest difference between 2008 and 2013 with respect to pre-contingency branch loading on the 230kV and 345kV system was observed on the GOTHLS S-GOWANUS S 345kV line. This may indicate the need for additional adjustment of the NYC PAR settings for future 2013 system analysis. Both the number of overloads and severity of overloads on the 115kV and 138kV system increased between 2008 and 2013. Among the 2013 cases, more overloads were observed for the high load Scenario 1 than any other. The best performance, or least overloads, was observed with Scenarios 3 (more 138kV and below units in service) and 4 (fewer new plants in service).

All outages solved for the 2008 benchmark case. Sixteen to twenty five contingencies, both single element and stuck breaker outages, did not solve for 2013 reference, Scenario 2 (unit retirement), Scenario 3 (high level of 138kV and below units in service), and

Scenario 4 (fewer new plants in service). About 70 contingencies did not solve for 2013 Scenario 1 with higher than anticipated system load. The additional unsolved contingencies were primarily stuck breaker, multiple generating unit, and NYC transmission line or transformer outages. No effort was made to manually solve these contingencies.

Post-contingency voltage performance for the 2013 cases was generally worse than observed in the 2008 benchmark case. The lowest voltages were always observed for 2013 Scenario 1 (higher than expected load). The best voltage performance was observed for 2013 Scenarios 3, which had more 138kV and below generating units in service, and 4, which had fewer new plants in service.

Significantly more post-contingency branch overloads at 115kV, 138kV and 345kV were observed under all 2013 conditions compared to the 2008 benchmark. Again the highest overloads were always observed for 2013 Scenario 1 (higher than expected load). And again, the best performance was observed for 2013 Scenarios 3 and 4.

Finally, a transfer limit analysis was used to determine maximum flow levels of selected interfaces, based upon thermal loadings of lines and transformers in the study area. The selected interfaces were UPNY-ConEd, UPNY-SENY, Dunwoodie South, West Central, Central East, Total East, and LIPA Import.

The difference in the UPNY-ConEd and LIPA Import interface flows was less than 2% between the 2008 and 2013 reference cases.

The UPNY-SENY interface flow increased between 2008 and 2013 by approximately 400MW. This occurred because the initial flow on the limiting Pleasant Valley-Leeds 3454kV line was higher in 2008 than in 2013, and the post-contingency distribution factor for this line was higher in 2008 than in 2013.

The Dunwoodie South interface flow decreased between 2008 and 2013 by approximately 900MW. This occurred because the post-contingency distribution factor for this line was higher in 2013 than in 2008, primarily because the limiting outage changed.

The Total East and Central East interface flow limits decreased by about 350MW and 200MW, respectively, between 2008 and 2013. This occurred because the normal and LTE ratings on the limiting Rock Tavern-Calpine 345kV line changed from 1793MVA and 1793MVA, respectively, in 2008 to 1554MVA and 1733MVA, respectively, in 2013.

In general, this screening analysis showed similar performance between the 2008 benchmark and all of the 2013 scenarios. The largest adverse impact on system performance in 2013 was due to a higher than expected load level in Scenario 1. The largest beneficial impact on system performance in 2013 was due to a redistribution of generation from the bulk power system (230kV and above) to the lower level transmission system (138kV and below) in Scenario 3.

12 Scenario Adequacy Analysis

12.1 Stakeholder and Neighboring Control Area Input

The Initial Planning Process included supplemental input from Neighboring Control Areas and the various Stakeholder Groups. This was accomplished through the various ESPWG meetings as well as direct solicitation. The information gathered from this input stage proved valuable to the process, especially for the scenario analysis.

12.2 Resource Adequacy Assessment

MARS analysis was performed for years 2008 and 2013 for each scenario replicating the Base Case analysis, as described in Section 3.

The following table describes the different scenarios that were simulated and summarizes the results. A more detailed discussion of each of the scenarios is found in the following section.

Since no new generating capacity was assumed between 2008 and 2013, it was not necessary to run 2008 if the results from the 2013 simulations indicated that NYCA was able to meet its LOLE criterion. Similarly, if the system was adequate assuming the High Load forecast, the simulations were not run for the lower forecast assumptions.

Table 12.1 Summary of Base Case and Scenarios

Case	Description	Year	Load Forecast	NYCA LOLE (days/yr)
Base Case	Reference case developed from data for NYISO Installed Reserve Margin (IRM) study. 8,449 MW installed between 2004 and 2008.	2013	High	0.002
Base Case V-1	Base Case with a 10% EFOR for all new units.	2013	High	0.004
Conservative Base Case	Base Case with only 2,744 MW of new capacity installed between 2004 and 2008.	2008	High	0.087
		2013	High	1.056
Scenario A	No new generation after 2005. 5,126 MW from Base Case not installed.	2008	High	0.042
		2013	High	0.353
		2013	Base	0.101
	With 550 MW increase in transfer limits into Zone K.	2013	High	0.100
Scenario A-1	No new generation in Zone J (NYC) after 2005.	2013	High	0.052
Scenario A-2	No new generation in Zone J (NYC) after 2005; Neptune and Liberty interconnections not in service.	2008	High	0.023
		2010	High	0.042
		2012	High	0.161
		2013	High	0.251
Scenario A-2-B	Combine Scenarios A-2 and B.	2013	High	9.141
Scenario C	No assistance from neighboring Areas.	2013	High	0.007
Scenario E	Retire total of 3,867 MW of generation in zones with high reserves.	2013	High	0.017
Scenario E-1	Scenario E with Poletti also removed.	2013	High	0.024
Scenario A-1-C-0	Scenario A-1 with no assistance from neighboring Areas.	2013	High	0.102
Scenario A-1-C-1000	Scenario A-1 with assistance from neighboring areas limited to 1,000 MW.	2013	High	0.052

12.2.1 Base Case V-1

This case is the same case as the Base Case above, except that the EFOR (effective forced outage rates) of new units are assumed to be 10%. In the Base Case, the weighted average EFOR of the new units was 6.3%.

As shown in the table below, increasing the forced outage rated had little impact on the NYCA reliability, increasing the LOLE slightly to 0.004 days/year.

Base Case V-1	(10% EFOR for new units)					
	Low Load	Base Load	High Load	Low Load	Base Load	High Load
Demand	33,052	33,635	34,228	34,016	35,342	36,768
Base Capacity	45,841	45,841	45,841	45,841	45,841	45,841
Reserve Margin	38.69	36.29	**33.93**	34.76	29.71	**24.67**
LOLE (d/y)						
NYCA						**0.004**
Zone J						0.000
Zone K						0.004

12.2.2 Conservative Base Case

This case assumes that only a handful of new units will come on line as planned. The total new capacity that will be installed between 2004 and 2008 is only 2,744 MW of capacity.

The LOLE for 2008 is found to be **0.087** with internal constraints in NYCA, which posed no reliability issue, while that for 2013 is **1.056,** which doesn't meet the reliability criteria.

Conservative Base Case	Low Load	Base Load	High Load	Low Load	Base Load	High Load
Demand	33,052	33,635	34,228	34,016	35,342	36,768
Base Capacity	40,588	40,588	40,588	40,588	40,588	40,588
Reserve Margin	22.80	20.67	**18.58**	19.32	14.84	**10.39**
LOLE (d/y)						
NYCA			**0.087**			**1.056**
Zone J			0.051			0.829
Zone K			0.047			0.766

12.2.3 Scenario-A - No New Generation Beyond 2005

The assumption of this case is that no new generation will come on line in New York State after 2005, based on various uncertainties associated with these new units. These are proposed projects included in the 2003 New York Area Transmission Review, which are slated to come on line beyond 2005. The total capacity of these potential generators is 5,126 MW. These units are listed below:

TABLE - BASE CASE UNITS NOT INCLUDED IN SCENARIO A

Project	Capacity (MW)	Zone	Projected In-Service Date
SCS Astoria Energy	1,000	J	2006/12
Mirant Bowline Point 3	750	G	2008
Calpine Wawayanda	500	G	2006
ANP Brookhaven	580	K	2007
Reliant Repowering Phases 1 & 2	546	J	2007
KeySpan Spagnoli Road CC Unit	250	K	2006/02
Glenville Energy Park	540	F	2006/S
PP&L Global Kings Park	300	K	2006/02
Besicorp Empire State Newsprint	660	F	2006/02

As shown in the table below, the NYCA LOLE in this case was 0.042 days/year with the High Load forecast for 2008, and 0.353 days/years for 2013 (High Load). The 2013 was then rerun with the internal NYCA constraints removed, which resulted in an LOLE of 0.045 days/year, which indicated that there was sufficient installed generation, but that it could not be delivered to the load.

A comparison of the LOLE for the zones indicated that most of the problem was in Zone K, due to the fact that the transfer capability to Zone-K (Long Island area) from Zone-I (Dunwoodie area) and Zone -J (ConEd area) were limiting. Thus, we incrementally increased the transfer capability of these two interfaces. The original transfer limit of Zone -I to Zone -K was 1,270 MW and that of ConEd to Zone -K was 250 MW. In the first sensitivity case, we increased these transfer limits by 50 MW each, for a total tranfer capability into Zone-K of 1,620 MW. This reduced the NYCA LOLE to 0.261 days/year. As shown in the table below, a total increase of 550 MW was required to bring the NYCA LOLE to 0.1 days/year.

Scenario A:	**No new generation after 2005 (5,126 MW)**					
	Low Load	**Base Load**	**High Load**	**Low Load**	**Base Load**	**High Load**
Demand	33,052	33,635	34,228	34,016	35,342	36,768
Capacity	40,715	40,715	40,715	40,715	40,715	40,715
Reserve Margin	23.19	21.05	**18.95**	19.69	15.20	**10.73**
Demand (J)			12,242			13,150
Capacity (J)			11,550			11,550
L-Cap (J)			**94.35**			**87.83**
Demand (K)			5,387			5,787
Capacity (K)			5,486			5,486
L-Cap (K)			**101.84**			**94.80**
LOLE (d/y) constrained						
NYCA		**0.022**	**0.042**		**0.101**	**0.353**

Zone J						0.060
Zone K						0.338
LOLE (d/y) unconstrained						
NYCA						**0.045**
Zone J						0.043
Zone K						0.039
100 MW – NYCA LOLE						**0.261**
200 MW – NYCA LOLE						0.195
300 MW – NYCA LOLE						0.156
400 MW – NYCA LOLE						0.128
500 MW – NYCA LOLE						0.107
550 MW – NYCA LOLE						**0.100**
Zone J						**0.061**
Zone K						**0.085**

12.2.4 Scenario-A-1 - No New Generation Beyond 2005 Except in Zone K

The assumption of this scenario is that no new generation will come on line in New York State after 2005, except for two plants in Zone K: KeySpan Spagnoli Road CC (250 MW) and PP&L Global Kings Park (300 MW). The total capacity of these two plants equals the increase in transfer capability into Zone-K in the previous scenario.

The table below shows the resulting NYCA LOLE to be 0.052 days/year. As would be expected, this shows that additional generation in Zone-K is worth more than the same amount of increase in transfer capability to Zone-K.

Scenario A-1:	**No new generation beyond 2005 except in Zone-K(4576 MW)**					
	Low Load	**Base Load**	**High Load**	**Low Load**	**Base Load**	**High Load**
Demand	33,052	33,635	34,228	34,016	35,342	36,768
Capacity	41,265	41,265	41,265	41,265	41,265	41,265
Reserve Margin	24.85	22.69	**20.56**	21.31	16.76	**12.23**
Demand (J)			12,242			13,150
Capacity (J)						11,550
Reserve Margin (J)						**87.83**
Demand (K)			5,387			5,787
Capacity (K)						6,036
L-Cap (K)						**104.31**
LOLE (d/y) constrained						
NYCA						**0.052**
Zone J						0.027
Zone K						0.039

12.2.5 Scenario-A-2 - No New Interconnections into Zone-J

This Scenario case is similar to Scenario case A-1, except that the two new interconnection ties to New York control area are also taken out. They are: the Liberty Radial Interconnection (400 MW) and the AE Neptune PJM-NYC DC line (600 MW). Both of these projects essentially added capacity directly into Zone_j.

Under High Load assumptions, the LOLE was found to be 0.023 days/year for 2008 and 0.251 days/year for 2013. Additional years 2010 and 2012 were run to see when the LOLE criterion would be exceeded. The results in the table below to show this occurring around 2011.

Scenario A-2:	**A-1 case with Liberty and Neptune out (5576 MW)**					
		2008			**2013**	
	Low Load	**Base Load**	**High Load**	**Low Load**	**Base Load**	**High Load**
Demand	33,052	33,635	34,228	34,016	35,342	36,768
Capacity	40,265	40,265	40,265	40,265	40,265	40,265
Reserve Margin	21.82	19.71	**17.64**	18.37	13.93	**9.51**
Demand (J)			12,242			13,150
Capacity (J)						10,550
L-Cap (J)						**80.22**
Demand (K)			5,387			5,787
Capacity (K)						6,036
L-Cap (K)						**104.31**
LOLE (d/y)						
NYCA			**0.023**			**0.251**
Zone J			0.021			0.226
Zone K			0.003			0.099

		2010			**2012**	
	Low Load	**Base Load**	**High Load**	**Low Load**	**Base Load**	**High Load**
Demand	33,551	34,411	35,306	33,892	35,051	36,285
Capacity	40,265	40,265	40,265	40,265	40,265	40,265
Reserve Margin	20.01	17.01	**14.04**	18.80	14.88	**10.97**
Demand (J)			12,627			13,150
Capacity (J)			10,550			10,550
L-Cap (J)			**83.55**			**80.22**
Demand (K)			5,557			5,787
Capacity (K)			6,036			6,036
L-Cap (K)			**108.63**			**104.31**
LOLE (d/y)						
NYCA			**0.042**			**0.161**
Zone J			0.035			0.146
Zone K			0.012			0.045

12.2.6 Scenario-A-2-B

This extreme scenario is the combination of Scenario A-2 (no new generation or interconnections in Zone-J) and Scenario B (nuclear retirements). The total capacity taken out before 2008 is 5,576 MW, while that out of service after 2009 is 10,654 MW.

The LOLE is found to be 9.141 days/year in 2013, with most of the problem concentrated in Zone-J.

Scenario A-2-B:	Combined cases A-2 and B (5576 MW in 2008 & 10654.4 MW after 2009)					
	Low Load	Base Load	High Load	Low Load	Base Load	High Load
Demand	33,052	33,635	34,228	34,016	35,342	36,768
Capacity	40,265	40,265	40,265	35,187	35,187	35,187
Reserve Margin	21.82	19.71	**17.64**	3.44	-0.44	**-4.30**
LOLE (d/y)						
NYCA			**0.023**			**9.141**
Zone J			0.021			8.844
Zone K			0.003			3.967

12.2.7 Scenario-C - No Assistance from Neighboring Areas

This Scenario assumes there are no ties between NYCA and the neighboring control areas, namely PJM, NE, OH and HQ. The capacity of New York control area is the same as in Base Case.

The LOLE was found to increase only slightly from the Base Case to 0.007 days/year, indicating little reliance by NYCA on the outside world under these assumptions.

Scenario C:	Zero tie with neighboring regional entities					
	Low Load	Base Load	High Load	Low Load	Base Load	High Load
Demand	33,052	33,635	34,228	34,016	35,342	36,768
Capacity	45,841	45,841	45,841	45,841	45,841	45,841
Reserve Margin	38.69	36.29	**33.93**	34.76	29.71	**24.67**
LOLE (d/y)						
NYCA						**0.007**
Zone J						0.000
Zone K						0.005

12.2.8 Scenario-E - Retirement of Existing Generation

The assumption of this case is that the largest plant in each zone, excluding nuclear units is retired in Jan 2007, without allowing reserve margins in any zone to drop below the 18% requirement in the study period. The total capacity taken out in this scenario is 3,866 MW. The list of these units retired is shown below.

TABLE- UNITS RETIRED IN SCENARIO E

Unit Name	Zone	Summer Rating (MW)
Huntley	A	67.6
		85.1
		86.5
		86.6
		195.7
		200.1
Russell	B	44.5
		63.8
		63.8
		75
Oswego	C	842.5
		838.3
Bowline	G	607.5
		562.5
UND15MW	H	46.5
Total Capacity		**3,866.0**

Because of the location of the capacity retired in this scenario, the resulting LOLE of 0.017 days/year shown in the table below is still well below the criterion. Most of the NYCA risk is now located in Zone-B with Zones J and K contributing only a slight amount.

Scenario E:	Retirement of existing generation (3867 MW) (per study, excluding Nuclear)					
	Low Load	Base Load	High Load	Low Load	Base Load	High Load
Demand	33,052	33,635	34,228	34,016	35,342	36,768
Capacity	41,974	41,974	41,974	41,974	41,974	41,974
Reserve Margin	26.99	24.79	**22.63**	23.39	18.77	**14.16**
Demand (B)			2,023			2,173
Capacity (B)						717
L-Cap (B)						**33.00**
Demand (J)			12,242			13,150
Capacity (J)						13,621
L-Cap (J)						**103.58**
Demand (K)			5,387			5,787
Capacity (K)						6,591
L-Cap (K)						**113.90**
LOLE (d/y)						
NYCA						**0.017**
Zone B						0.015
Zone J						0.001
Zone K						0.002

12.2.9 Scenario-E-1 - Case E with Existing Poletti Unit Retired

This is an extension of Scenario E with the existing unit Poletti unit in Zone-J (875 MW) also retired. This raises the NYCA LOLE to 0.024 days/year with most of the risk still situated in Zone-B.

Scenario E-1:	Case E with Poleti unit out (4742 MW)					
	Low Load	Base Load	High Load	Low Load	Base Load	High Load
Demand	33,052	33,635	34,228	34,016	35,342	36,768
Capacity	41,099	41,099	41,099	41,099	41,099	41,099
Reserve Margin	24.35	22.19	**20.07**	20.82	16.29	**11.78**
Demand (B)			2,023			2,173
Capacity (B)						717
L-Cap (B)						**33.00**
Demand (J)			12,242			13,150
Capacity (J)						12,743
L-Cap (J)						**96.90**
Demand (K)			5,387			5,787
Capacity (K)						6,591
L-Cap (K)						**113.90**
LOLE (d/y)						
NYCA						**0.024**
Zone B						0.021
Zone J						0.008
Zone K						0.006

12.2.10 Scenario-A-1-C-0 - No New Generation After 2005 and 0 MW of Assistance from Neighboring Areas

This case is similar to Scenario A-1 (no new generation installed after 2005) with the assumption that there is also no assistance available from the neighboring Areas.

Removal of outside assistance increased the NYCA LOLE from 0.052 days/year to 0.102 days/year, just slightly over criterion.

Scenario A-1-C-0: **A-1 case with zero MW limit of simultaneous imports to NY**

	Low Load	Base Load	High Load	Low Load	Base Load	High Load
Demand	33,052	33,635	34,228	34,016	35,342	36,768
Capacity	41,265	41,265	41,265	41,265	41,265	41,265
Reserve Margin	24.85	22.69	**20.56**	21.31	16.76	**12.23**
LOLE (d/y)						
NYCA						**0.102**
Zone J						0.075
Zone K						0.078

12.2.11 Scenario-A-1-C-1000 - No New Generation After 2005 Assistance from Neighboring Areas Limited to 1,000 MW

This case is similar to the previouis scenario except that the total amount of assistance from neighboring Areas was limited to 1,000 MW. This resulted in a NYCA LOLE of 0.052 days/year, which is the same as in Scenario A-1. This indicates that the maximum assistance that NYCA received from the outside Areas in Scenario A-1 was approximately 1,000 MW.

Scenario A-1-C-1000: **A-1 case with 1000 MW limit of simultaneous imports to NY**

	Low Load	Base Load	High Load	Low Load	Base Load	High Load
Demand	33,052	33,635	34,228	34,016	35,342	36,768
Capacity	41,265	41,265	41,265	41,265	41,265	41,265
Reserve Margin	24.85	22.69	**20.56**	21.31	16.76	**12.23**
LOLE (d/y)						
NYCA						**0.052**
Zone J						0.027
Zone K						0.039

12.3 Transmission Adequacy Assessment

Similarly, power flow analysis was performed for 2013 for each scenario replicating the Baseline System analysis, as described in Section 11 above. Since this assessment was not performed for as many scenarios as the Resource Adequacy Assessment, the results are summarized with the Baseline System results in Section 11.

12.4 Short Circuit Assessment

A scenario with a higher generation addition than the Base Case was not defined, therefore, no additional short circuit analysis was performed for any scenario.

13 Historical Congestion Reporting

13.1 Background

System congestion occurs when some of the interconnected load can not be served with economic generation due to transmission bottlenecks (constraints). One of the features of a locational marginal price (LMP)-based market is the ability to identify grid locations where congestion takes place and quantify the cost of such congestion. The NYISO continuously calculates and publishes LMP's that consist of three components

Energy – This is the marginal electricity cost without the congestion and losses cost adjustments.

Congestion – This is the marginal cost of out-of merit generation dispatch relative to an assumed unconstrained reference point at Marcy substation

Losses – This is the cost of supplying the losses from the accessible marginal generators to the grid point in question

The cost of congestion has been reported by the NYISO in previous years (for example in the Power Alert report). The reported congestion cost was the simple sum of the day ahead market LMP congestion component times the amount of load being affected (positively or negatively) by congestion. While this congestion cost was relatively simple to calculate with the data and calculation tools available at the time, this value is generally felt to be an over-simplified congestion impact metric because:

1. The calculation does not incorporate the effect of supply and demand response when the underlying congestion is removed.
2. Congestion cost is relative to an assumed uncongested reference point. If the reference point is moved, the LMP congestion cost is shifted to the LMP energy cost.
3. Attributing congestion cost to individual constraints can be difficult and subject to many assumptions unless many details, such as shadow prices, are available..
4. This figure does not account for the the effects of hedging (e.g. – TCC payments or bilateral contracts).

To provide more comprehensive information on the elements of historic congestion costs the NYISO, through the Electric System Planning Working Group (ESPWG) developed a detailed analytical protocol. The fundamental premise is to calculate what the day-ahead hourly clearing prices would be if there were <u>no</u> transmission constraints in New York using the same data and calculation approach used by the NYISO security constrained unit commitment software (SCUC) for the Day Ahead Market (DAM). Congestion cost is then defined as the difference between the actual SCUC transmission-constrained LMP's, reflecting all actual loads and bids, and the same calculation with all transmission constraints ignored. The calculation is performed on an hourly basis, consistent with the SCUC process.

The NYISO production SCUC model itself was not suited to performing the calculation of a transmission constraint free market clearing because of difficulties in manipulating input and output results, and the extensive time required for calculation. Also, SCUC by itself does not perform all the calculations required to quantify congestion, such as the hedging effect of Transmission Congestion Contracts (TCC's).

In place of using SCUC, software called PROBE was developed for the NYISO and used for this congestion analysis. PROBE performs a unit commitment with or without transmission constraints being enforced (other constraints such as generator ramp rates and minimum run times are always enforced), and reports the market quantities needed to assess the day-ahead market. The constrained and unconstrained results are compared to derive the cost of congestion. All calculations use the actual market bids and loads, account for all market segments (e.g. fixed load, virtual load and generation, imports and exports), and represent the actual hour-by-hour network status. PROBE also reports the actual hourly market results from SCUC, which can be used to perform congestion cost calculations, or verify PROBE results. Extensive efforts were made to match the modeling, calculation approach, and results of SCUC and PROBE as closely as possible. Comparisons between models indicate that the overall market difference between SCUC and PROBE are only a few percent, at most.

13.2 The Congestion Impact Metrics

To suit various needs for viewing the impact of congestion four congestion impact several metrics were developed by the ESPWG and approved by the NYISO Operating Committee in November 2003 . These are as follows:

1. Change in Bid Production Cost – This is the primary congestion impact metric chosen for use by the NYISO Operating Committee. The calculation compares the total bid production cost, based on mitigated bids, with and without transmission constraints limiting the unit commitment and dispatch. This measures the economic inefficiency introduced by the existence of transmission bottlenecks. In a sense, this is the *societal cost* of transmission congestion.

   An advantage of this metric is that the production cost will always decrease when constraints are removed. Minimizing bid production cost is the objective of the SCUC; LMP's are the result of the commitment and dispatch solution that achieves this objective under generating unit and transmission constrained conditions.
2. Change in Congestion Payments – This calculation process is identical in principle to the congestion costs reported in previous years. Since this calculation ignores the market response as some or all constraints are removed, it suffers from the deficiencies described above. There is no simulation required to arrive at this congestion impact metric., This quantity can be considered as the *accounting cost* of congestion, as measured by the LMP congestion component and the amount of load affected.

   Congestion payments in the New York market can be hedged with Transmission Congestion Contracts (TCC's). Both total and hedged congestion payments are reported. For this analysis it was assumed that all TCC's are owned by load and are available for hedging congestion payments. The TCC auction cost is ignored, as it is credited to the Transmission Service Charge (TSC) revenue requirement.

3. Change in Load Payments - The calculations for this metric use simulation to include the market supply and demand response when transmission constraints are removed. Whereas the first congestion metric measures efficiency, this

metric determines how much more New York load pays due to congestion under the particular design of the NYISO LMP based market; that is, the *bills impact*.

The load payments congestion impact includes necessarily the effect from all market-based costs that can be impacted when transmission constraints are relieved. These cost elements are:

- LMP Components: While the LMP congestion component will be pushed to zero when no transmission constraints exist, unbottled generation resources will sell more energy at a slightly higher price (in accordance with the bid curves), albeit at a lower bid than the units put on out-of-merit in the transmission limited case. This may result in an increase in the LMP energy component as the LMP congestion component decreases. The LMP loss component will also change depending on the location and prices of the generation unbottled when constraints are relieved. Ancillary service costs (e.g., reserves) also affect LMP's as a trade-off between selling ancillary services or energy occurs**.**
- TCC shortfall – In the event of a TCC shortfall (or surplus) the load pays for such differences, which varies as transmission constraints are relieved or removed. While this shortfall may be compensated for elsewhere in the Transmission Service Charge (TSC), from a NYISO reconciliation and congestion impact perspective this is considered a load payment. For zonal results shown later the total TCC shortfall is allocated pro rata by the zonal to total TCC payments**.**
- Other Market-Based Costs - – In accordance with the NYSIO OATT differences between day ahead market load and generator energy and loss payments are paid by load in proportion to the MWHr demand. Relieving or eliminating transmission constraints affects these charges (which are recovered from load under Rate Schedule 1 of the NYISO OATT) , and is thus considered a congestion impact in this analysis. (NOTE: There are actually many more components to the Schedule 1 payment The values reported here are for the day-ahead market sensitive components only**.**
- As with congestion payments, the total load payments can be hedged with TCC's. In this analysis it was assumed that all TCC's were credited to load. noted above. . (NOTE: This simplifying assumption ignores the TCC auction cost as well as the actual ownership of TCC's. In addition the effects of bilateral agreements between loads and suppliers as well as the effect ot TSC adjustments due to auction revenues, secondary market TCC sales and TCC shortfall revenues are not accounted for.)

It should be noted that relieving all or some of the constraints may or may not decrease the overall market based electricity cost to load. In LMP markets the load in a location pays the marginal price of the supply at that location, not the bid price of any particular unit. The result of constraint relief in an LMP market depends on how much load is affected, where the load is, and the response of supply and demand resources as constraints are relieved

4. <u>Change in Generation Payments</u> – This metric is the opposite side of the load payments calculation. In addition to the LMP payments to generation (or other supply sources, such as virtual generation, imports, or price capped load), generators are also paid a bid production cost guarantee (BPCG). BPCG

compensates generators that are committed despite the fact their bids are greater than the LMP at the generator location. This can happen if enforcement of ramp rates, minimum run times or other constraints necessitates unit operation, which minimizes overall production cost even including BPCG payments.

13.3 Results

The actual day-ahead market data and network models used to drive the NYISO SCUC calculation for all days of 2003 were the inputs to the PROBE calculation of commitment, dispatch, and resultant LMP's with and without transmission constraints. The four congestion metrics described above were calculated using the PROBE results and summed for the entire year 2003. The top-level view of congestion cost is displayed in Table 1.

Table 1
2003 Congestion Impact Metrics

1.1 Bid Production Cost Impact ($ Millions)

New York	$222	
Imports	-$153	
Total	**$68**	**+ Number Means Congestion Increased the Supply Production Cost**

1.2 Congestion Payments Impact ($ Millions)

Total Congestion Payments	**$960**	
TCC Hedge	**$683**	
Total Unhedged Congestion Payments	**$276**	**+ Number Means the Congestion Component of LMP Increased Due to Congestion**

1.3 Load Payments Impact ($ Millions)

Total Load Payments	**$472**	**+ Number Means Congestion Caused Load Payments to Increase**
Hedge	**$683**	
Total Unhedged Load Payments	**-$212**	**A Negative Number Means Unhedged Load Payments Went Down Due to Congestion**

1.4 Generation Payments Impact ($ Millions)
Total Generation Payments

New York	$36	
Imports	-$248	
Total	**-$212**	**A Negative Number Means Congestion Decreased Payments to Generators**

The table includes notation to assist in understanding the implication of the signs. The calculation always is the constrained minus the unconstrained value, therefore a positive value for a load payment means that the payments were higher when congestion was present; for example: a positive load payments number means that congestion increased the payments.

Among the many interesting observations from this analysis are:

1. Bid Production Cost Impact: (Tables 1.1, 2.1 & 3.1)

The primary congestion metric, the change in mitigated bid production cost (Table 1.1) shows that the total 2003 New York congestion impact was $ 68 million. One interpretation of this value is that if *all* transmission constraints were removed in New York the savings would be *at least* $68 million. Reducing or eliminating a constraint by adding or upgrading facilities will reduce this possible savings, but may or may not change load and generation payments (the bottleneck relief will certainly shift payments from zone to zone as shown in Table 2.1).

Examining the effect on New York generation, or preferably by examining the zonal congestion impacts shown in Table 2, what one sees is that congestion removal allows an increase of supply from imports and western New York sources. Zone J and K bid production cost is higher in the presence of congestion (by $251 and $84 million respectively; see Table 2.1). Imports, especially from PJM sell more into the New York market in the absence of transmission constraints, increasing their bid production cost (a negative impact). Even though bid production cost decreased for New York supply by $222 Million without congestion, it was offset by increased cost of imports of $153 million. All told, the cost of supply decreased $68 million without transmission congestion (or said alternatively, transmission congestion increased the cost of supply to load by the same $68 million).

2. Congestion Payments Impact: (Tables 1.2, 2.2 & 3.2) The congestion impact metric quoted in previous years, (i.e., "Total congestion payments") was $960 million for 2003, in the same range as reported in previous years. This payment was hedged by $683 million in TCC's, yielding an unhedged 2003 congestion payments impact of $276 million. (NOTE: this analysis assumes all TCC payments are credited to load).

3. Loaad Payment Impact: (Tables 1.3, 2.3 & 3.3) When the response of increased energy cost as congestion is relieved is factored into the congestion impact calculations some of the congestion impact payment of $960 million is offset by increased energy (and to a much lesser extent loss) payments. Netting the effects of supply and demand response when constraints are removed yields a load payments impact of $472 million (See Table 3.3). Examination of zonal impacts in Table 2.3 shows that only zones J and K load payments are increased by congestion. All other New York load zones benefit from congestion.

   The load payments picture changes significantly when the effect of hedging is included. Accounting for the TCC payments in load payments, attributing all TCC hedging to load, we see that load actually benefited $211 million from the presence of congestion. (NOTE: This conclusion should be used very carefully because the mixed ownership of TCC's, the neglecting of bilateral contract hedging, and the counteracting effect of TSC adjustments for TCC shortfall and TCC auction revenues and payments are not included in this calculation.)

Generation Payment Impact: Tables 1.4, 2.4 and 3.4) The generation payments impact metric results indicate that congestion actually resulted in a net decrease of payments to generators. The large increase in imports and western New York generation when congestion is removed increased payments to these suppliers. Payments to generators in Zones J and K were higher in the presence of congestion.

As an aid to understanding the meaning of the positive and negative impacts, and to assist in the examination of the details of congestion effects, Table 3 displays the components of the calculations under constrained and unconstrained (i.e., all transmission constraints removed) conditions. (NOTE: The congestion impact metrics always are the constrained minus the unconstrained values.)

Table 2
2003 Congestion Impact Metrics
Zonal Breakdown

2.1 Bid Production Cost Impact

A	WEST	-$20.2
B	GENESE	-$3.2
C	MHKVL	-$42.0
D	NORTH	-$1.2
E	CENTRL	-$9.2
F	CAPITL	-$9.7
G	HUDVL	-$27.7
H	MILLWD	-$0.1
I	DUNWOD	$0.0
J	N.Y.C.	$250.6
K	LONGIL	$84.4
	New York	**$221.7**
N	NPX	-$7.0
O	OH	-$14.3
P	PJM	-$85.3
Q	HQ	-$46.6
	Imports	**-$153.2**
	Total	**$68.4**

2.2 Congestion Payments Impact ($ Millions)

		Total Congestion Payments	TCC Hedge	Total Unhedged Congestion Payments
A	WEST	-$0.2	$3.8	-$4.0
B	GENESE	$1.6	$2.2	-$0.7
C	MHKVL	$1.8	$4.3	-$2.6
D	NORTH	-$0.1	-$0.5	$0.4
E	CENTRL	$0.2	$3.1	-$2.9
F	CAPITL	$14.2	$10.0	$4.2
G	HUDVL	$10.4	$26.3	-$15.9
H	MILLWD	$2.4	$20.4	-$18.1
I	DUNWOD	$3.0	$1.6	$1.4
J	N.Y.C.	$682.2	$519.6	$162.6
K	LONGIL	$247.2	$92.5	$154.8
	New York	**$962.7**	**$683.4**	**$279.3**
N	NPX	$0.7	$1.7	-$1.0
O	OH	-$0.2	-$0.1	-$0.2
P	PJM	-$3.1	-$0.7	-$2.5
Q	HQ	-$0.4	-$0.9	$0.5
	Imports	**-$3.1**	**$0.1**	**-$3.1**
	Total	**$959.6**	**$683.5**	**$276.2**

2.3 Load Payments Impact ($ Millions)

		Total Load Payments	Hedge	Total Unhedged Load Payments
A	WEST	-$136.8	$3.8	-$140.5
B	GENESE	-$39.6	$2.2	-$41.8
C	MHKVL	-$161.5	$4.3	-$165.9
D	NORTH	-$45.3	-$0.5	-$44.8
E	CENTRL	-$26.4	$3.1	-$29.5
F	CAPITL	-$33.2	$10.0	-$43.2
G	HUDVL	-$59.2	$26.3	-$85.5
H	MILLWD	-$39.7	$20.5	-$60.2
I	DUNWOD	-$7.9	$1.6	-$9.4
J	N.Y.C.	$804.3	$519.6	$284.7
K	LONGIL	$217.0	$92.5	$124.5
	Total	**$471.8**	**$683.5**	**-$211.7**

2.4 Generation Payments Impact ($ Millions)

		Total Generation Payments
A	WEST	-$111.9
B	GENESE	-$21.8
C	MHKVL	-$144.7
D	NORTH	-$36.1
E	CENTRL	-$20.1
F	CAPITL	-$25.6
G	HUDVL	-$72.0
H	MILLWD	-$54.9
I	DUNWOD	-$0.5
J	N.Y.C.	$365.8
K	LONGIL	$157.9
	New York	**$36.1**
N	NPX	-$13.9
O	OH	-$42.1
P	PJM	-$134.0
Q	HQ	-$57.9
	Imports	**-$247.9**
	Total	**-$211.7**

Table 3
2003 Congestion Impact Metrics
Calculation Components and Details

3.1 Bid Production Cost Impact ($ Millions)

	Constrained	Unconstrained	Difference
New York	-$788.6	-$1,010.3	**$221.7**
Imports	-$172.7	-$19.5	**-$153.2**
Total	-$961.3	-$1,029.8	**$68.4**

3.2 Congestion Payments Impact ($ Millions)

	Constrained	Unconstrained	Difference
Total Congestion Payments	$959.6	$0.0	**$959.6**
TCC Hedge	$683.5	$0.0	**$683.5**
Total Unhedged Congestion Payments	$276.2	$0.0	**$276.2**

3.3 Load Payments Impact ($ Millions)

	Constrained	Unconstrained	Difference
LMP Components			
Energy	$8,626.5	$9,273.7	**-$647.2**
Congestion	$959.6	$0.0	**$959.6**
Losses	$323.7	$352.5	**-$28.8**
Total LMP Components	$9,909.9	$9,626.3	**$283.6**
Schedule 1 DAM Component	-$84.4	-$116.3	**$31.9**
TCC Shortfall to TSC	$156.3	$0.0	**$156.3**
Total Load Payments	$9,981.7	$9,510.0	**$471.8**
Hedge	$683.5	0	**$683.5**
Total Unhedged Load Payments	**$9,298.3**	**$9,510.0**	**-$211.7**

3.4 Generation Payments Impact ($ Millions)

	Constrained	Unconstrained	Difference
New York			
LMP Components			
Energy	$7,481.0	$7,913.6	**-$432.6**
Ancillary Services	$126.6	$112.8	**$13.8**
Congestion	$453.1	$0.0	**$453.1**
Losses	$43.0	$22.8	**$20.2**
Total LMP Components	$8,103.7	$8,049.2	**$54.5**
Bid Production Cost Guarantee	$148.0	$166.4	**-$18.4**
Total New York	$8,251.8	$8,215.6	**$36.1**
Imports			
LMP Components			
Energy	$1,152.7	$1,395.0	**-$242.3**
Congestion	-$20.7	$0.0	**-$20.7**
Losses	-$85.6	-$100.7	**$15.1**
Total LMP Components	$1,046.5	$1,294.4	**-$247.9**
Total Imports	$1,046.5	$1,294.4	**-$247.9**
Total	$9,298.3	$9,510.0	**-$211.7**

13.4 Individual Constraint Analysis

Characterization of congestion impact for the State as a whole, or on a zonal basis provides a touchstone for the total amount of money at stake, but a planning process requires understanding which specific facilities cause congestion impacts. The PROBE simulation used in this analysis is capable of calculating the LMP congestion component for each constraint in every hour, and the amount of load impacted by each constraint. This is true whether there is a single constraint in play for a given hour, or whether there are multiple, interacting constraints.

The congestion payments for 2003 (the New York total is shown in Table 1.2) were calculated on a constraint by constraint basis, resulting in the totals shown in Table 4. A total of 36 facilities caused increased congestion payments in 2003, with Table 4 showing the top 10, in order of the unhedged portion. These top 10 represent 95% of the total positive congestion payments, and 97% of the unhedged positive congestion payments. For this calculation the monitored element was the summed quantity, even if the facility is limiting under a variety of contingency conditions. Also, strictly parallel facilities (for example the two Sprainbrook to 49th Street 345 kV circuit 1 and 2 cables) that were limiting in different hours were combined into a single facility total.

A complete list of limiting facilities in 2003 is displayed in Table 5. The reader will note that some of the congestion payments are negative; this occurs due to the pattern of bidding in some local situations, or because of the selection of Marcy as the reference point.

Table 4
2003 Congestion Payments
Top 10 Limiting Transmission Facilities

Facility	Total Congestion Payments	% of Total Congestion Payments	TCC Hedge	Unhedged Congestion Payments	% of Total Unhedged Congestion Payments
Dunwoodie - Shore Rd 345 kV	$155,190,223	16%	$58,912,153	$96,278,070	31%
Central East Voltage Limit	$105,836,469	11%	$37,334,293	$68,502,177	22%
Leeds to New Scotland 345 kV	$53,055,639	6%	$13,981,369	$39,074,269	13%
Rainey to Dunwoodie 345 kV	$192,767,907	20%	$154,413,248	$38,354,658	13%
Rainey to Vernon 345 kV	$162,561,196	17%	$124,514,332	$38,046,864	12%
UPNY - ConEd Interface	$18,737,644	2%	$6,203,515	$12,534,130	4%
Valley Stream to East Garden City 138 kV	$9,180,855	1%	$4,097,046	$5,083,809	2%
East 179th Street to Hellgate 138 kV	$46,901,529	5%	$43,607,377	$3,294,151	1%
Pleasant Valley to Leeds 345 kV	$4,085,494	0%	$1,232,741	$2,852,752	1%
Sprainbrook to West 49th Street 345 kV	$192,325,930	20%	$189,684,679	$2,641,251	1%
Cumulative Sum of Totals		**95%**		**97%**	

As expected from study of the congestion payments by zone, the total congestion payments were concentrated to and within Zones J and K. West to East transfer (especially the Central East interface and Upper Hudson Valley circuits limitation were also significantly constrained.

Table 5
2003 Congestion Payments
All Limiting Transmission Facilities

	Facility	Total Congestion Payments	% of Total Positive Congestion Payments	TCC Hedge	Unhedged Congestion Payments	% of Total Positive Unhedged Congestion Payments	Cum % of Total
1	DUNWODIE 345 SHORE_RD 345 1	$155,190,223	16%	$58,912,153	$96,278,070	31%	31%
2	CENTRAL EAST - VC	$105,836,469	11%	$37,334,293	$68,502,177	22%	52%
3	LEEDS___ 345 N.SCTLND 345 1	$53,055,639	5%	$13,981,369	$39,074,269	12%	65%
4	RAINEY__ 345 DUNWODIE 345	$192,767,907	19%	$154,413,248	$38,354,658	12%	77%
5	RAINEY__ 138 VERNON__ 138 1	$162,561,196	16%	$124,514,332	$38,046,864	12%	89%
6	UPNY CONED	$18,737,644	2%	$6,203,515	$12,534,130	4%	93%
7	VALLYSTR 138 EGRDNCTY 138 1	$9,180,855	1%	$4,097,046	$5,083,809	2%	95%
8	E179THST 138 HELLGT_E 138 1	$46,901,529	5%	$43,607,377	$3,294,151	1%	96%
9	PLSNTVLY 345 LEEDS___ 345 1	$4,085,494	0%	$1,232,741	$2,852,752	1%	96%
10	W49TH_ST 345 SPRNBRK_ 345	$192,325,930	19%	$189,684,679	$2,641,251	1%	97%
11	FRESHKLS 138 WILLWBRK 138 1	-$4,738,605	0%	-$7,272,731	$2,534,125	1%	98%
12	JAMAICA_ 138 VALLYSTR 138 1	$3,614,696	0%	$1,643,189	$1,971,508	1%	99%
13	SPRNBRK_ 345 EGRDNCTY 345	$1,244,371	0%	$559,995	$684,376	0%	99%
14	ROSLYN__ 138 EGRDNCTY 138 1	$1,130,406	0%	$463,001	$667,405	0%	99%
15	BUCHAN_N 345 EASTVIEW 345 1	$2,894,183	0%	$2,345,299	$548,884	0%	99%
16	NE - NY	-$147,645	0%	-$595,927	$448,282	0%	99%
17	VERNON__ 138 KENTAVE_ 138 1	$6,216,348	1%	$5,984,570	$231,778	0%	100%
18	GLENWDGT 138 ROSLYN__ 138 1	$363,564	0%	$163,443	$200,121	0%	100%
19	ROCKTVRN 345 RAMAPO__ 345 1	$217,242	0%	$24,543	$192,699	0%	100%
20	CARLPLCE 138 GLENWD__ 138 1	$268,833	0%	$87,623	$181,210	0%	100%
21	MILLWOOD 345 EASTVIEW 345 1	$390,421	0%	$212,125	$178,297	0%	100%
22	DUNWODIE 345 PLSNTVLE 345 1	$190,052	0%	$37,193	$152,859	0%	100%
23	ASTORIAE 138 ASTORIA3 138 1	$0	0%	-$120,970	$120,970	0%	100%
24	LADENTWN 345 RAMAPO__ 345 1	$175,811	0%	$69,413	$106,398	0%	100%
25	BUCHAN_S 345 LADENTWN 345 1	$1,319,048	0%	$1,215,948	$103,100	0%	100%
26	OAKDALE_ 345 FRASER__ 345 1	$307,367	0%	$220,892	$86,475	0%	100%
27	E13THSTA 345 FARRAGUT 345 1	$88,216	0%	$52,490	$35,726	0%	100%
28	JAMAICA_ 138 LAKSUCSS 138 1	$45,532	0%	$20,975	$24,557	0%	100%
29	SPR/DUN-SOUTH	$29,840	0%	$23,554	$6,286	0%	100%
30	GARDNVLA 230 STOLLERD 230 1	$9,935	0%	$5,477	$4,458	0%	100%
31	TREMONT_ 345 SPRNBRK_ 345 1	$174,158	0%	$171,607	$2,551	0%	100%
32	FARRAGUT 345 RAINEY__ 345 1	$2,375	0%	$904	$1,471	0%	100%
33	CENTRAL EAST	$781	0%	$217	$565	0%	100%
34	NIAGARA_ 230 BECK____ 230 1	$3,187	0%	$2,864	$323	0%	100%
35	PILGRIM_ 138 HAUPPAUG 138 1	$13	0%	$5	$8	0%	100%
36	ROBNSNRD 230 STOLLERD 230 1	$8	0%	$33	-$25		
37	NEWBRDGE 138 RULAND__ 138 1	-$132		-$33	-$99		
38	CLAY____ 345 PANNELL_ 345 2	-$92		$24	-$116		
39	ADIRNDCK 230 EDIC/PTR 230 1	-$39		$78	-$117		
40	ADIRNDCK 230 MOSES___ 230 1	-$71		$139	-$209		
41	ROCHESTR 345 PANNELL_ 345 1	-$1,292		$740	-$2,032		
42	SYOSSET_ 138 GREENLWN 138 1	-$4,998		-$2,136	-$2,862		
43	NEWBRDGE 138 FREEPORT 138 1	-$4,025		-$469	-$3,556		
44	FARRAGUT 138 HUDS_AVE 138 1	-$34,258		-$10,456	-$23,802		
45	QUENBRDG 138 VERNON__ 138 1	$1,156,867		$1,199,237	-$42,370		
46	NRTHPORT 138 ELWOOD_W 138 1	-$85,042		-$23,793	-$61,250		
47	SPRNBRK_ 345 EASTVIEW 345 1	$1,286,128		$1,440,662	-$154,535		
48	BARRETT_ 138 VALLYSTR 138	-$277,671		-$90,346	-$187,325		
49	WEST CENTRAL	-$164,659		$54,963	-$219,621		
50	GOETHSLN 345 GOWANUSN 345 1	-$59,345		$188,476	-$247,821		
51	OAKDALE_ 230 WATRCURE 230 1	-$140,377		$115,239	-$255,616		
52	NEWBRDGE 138 EGRDNCTY 138	-$403,842		-$127,010	-$276,832		
53	HQ - NY	$24,626		$439,395	-$414,769		
54	EDIC/PTR 345 MARCY___ 345 1	-$377,205		$65,778	-$442,984		
55	E13THSTA 345 W49TH_ST 345 1	$6,721,743		$7,212,360	-$490,616		
56	NIAGARA_ 345 ROCHESTR 345 1	-$364,184		$356,528	-$720,712		
57	OH - NY	-$17		$765,002	-$765,019		
58	GOETHLSS 345 GOWANUSS 345 1	-$184,447		$594,670	-$779,117		
59	CARLPLCE 138 EGRDNCTY 138 1	-$1,422,402		-$560,259	-$862,142		
60	HELLGATE 138 E179THST 138 1	$10,530,015		$11,638,388	-$1,108,373		
61	ELWOOD_W 138 GREENLWN 138 1	-$1,747,455		-$467,936	-$1,279,519		
62	HELLGT_W 138 E179THST 138 1	-$14,369,754		-$12,932,065	-$1,437,689		
63	HUDS_AVE 138 JAMAICA_ 138	$15,992,703		$19,356,586	-$3,363,883		
64	NRTHPORT 138 PILGRIM_ 138	-$5,468,731		-$1,182,452	-$4,286,278		
65	DYSINGER EAST	-$2,995,679		$2,818,466	-$5,814,145		
66	PJ - NY	-$626,970		$9,144,842	-$9,771,812		

When the constraint hedging is included in the calculation we find that much of the constraint payments to Zone J are hedged by TCC's. Hedging to Zone K is naturally limited by the few and heavily constrained connections to this zone.

13.5 Important Assumptions

A simulation and calculation process of the size and complexity behind the results reported here involved some important assumptions. (Just the background bid and network data is over 3 GB in compressed form) Many sensitivity analyses were performed to test the impact of assumptions on results reported, and where possible these assumptions were discussed and agreed upon with the ESPWG.

The first key assumption, as noted above, is that all results reflect the difference between the "as found" network and a totally unconstrained system. While this is useful benchmark to put these reporting statistics on a common basis, the achievement of a totally unconstrained transmission network is both economically and practically infeasible.

A critical assumption is that bids are not changing when transmission constraints are eliminated since it was felt that using actual bids gives a more realistic picture than assuming supply and demand behavior. When developing the unconstrained cases (i.e., by relieving transmission constraints) and calculating unconstrained values, bids remain the same as in the original, constrained case. The resulting metrics are thus based on a single bid profile, for all market segments, used for both the constrained and the unconstrained cases. However, it should be emphasized that a new commitment schedule is calculated for the unconstrained case, although based on the same set of bids and operating characteristics originally submitted for the constrained case.

The New York electricity market allows participants to hedge their price risk with bilateral contracts. The analysis reported here does not include the effect of the bilateral markets in any way. Such bilateral transactions have represented approximately 50% of the transactions in the NYISO's markets since inception.

TCC ownership and hedging effect is assumed to be entirely to load although there are some non-load serving entities that hold TCCs This simplifying assumption ignores the TCC auction cost as well as the actual ownership of TCC's. In addition the effects of bilateral agreements between loads and suppliers as well as the effect ot TSC adjustments due to auction revenues, secondary market TCC sales and TCC shortfall revenues are not accounted for.)

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In the PROBE simulation the individual market segments can be fixed at their original MWHr value, or vary in the minimization of bid production cost. Since the analysis protocol makes a severe assumption that all transmission constraints are removed, it was found that the most volatile market components, virtual load and virtual generation, and price capped load, tended to distort the unconstrained case results. To assure reasonable comparison of the constrained and unconstrained simulation results, the virtual load, virtual generation, and price capped load market segments were fixed at the initial MWHrs. Revenue in these market segment change with changing prices.

All analysis was performed for 2003 “as it was”. Of course load and generation magnitude and location can change in the future, greatly affecting the results reported.

No adjustment was made for “unusual” transmission outages. A separate analysis of 2003 transmission outages, statistically correlated to daily market results indicated that “unusual” transmission outages would account for about 10 to 15% of the congestion impact**.**

Although the above assumptions have provided some simplifications in the modeling of some aspects of the NY markets, they were necessary in order to develop the overall analytical framework to support this study. As this analysis goes on, some of these assumptions may be eliminated by additional research, analysis, and development efforts. .

13.6 Considerations for Future Investigation

The 2003 congestion impact metrics, the zonal results and implied zonal interactions, and the relative size of market components provide considerably more information on the elements of congestion costs to stakeholders and market participants in the NYISO’s wholesale markets than previously available. Nevertheless, there is still more work to be done to more fully understand the implications of this data in the context of the above assumptions. Some of these considerations include:

- Significant changes in loads and generation amount and location that may occur in the future can significantly impact the relative magnitude of these historic results for 2003. Large transmission investments (in this exercise enough to eliminate all transmission constraints) will decrease the load payments by some zones, but these savings may be offset by increased load payments in other zones. Additional generation or a change in generation bids in those zones where payments increased, as well as future load growth in those zones where load payments decreased would tend to increase the benefits of transmission investment.

  The exercise to calculate congestion impacts by removing all constraints was, by design, done to gauge the total savings that would have been realized in 2003 had the transmission investment been done. The tools and analysis approach can be used to test the financial implications of “what if” transmission improvements, maintenance practice and schedule changes, operating and market rule changes, etc. This type of analysis is planned, on a selective basis, beginning with the January 2004 data.
- The congestion impact in New York was caused by a relatively few facilities. Almost all of the total or unhedged congestion payment impact was concentrated in only 10 facilities. This does NOT mean that congestion impacts can be easily relieved with investments to upgrade only these facilities. Relief of one constraint almost always shifts the congestion to another facility, which may result in only a small net benefit to the region as a whole.

These results are only an early step in achieving an understanding of the effect of congestion on markets and markets on congestion. Further study of 2003 results, studies of congestion impact of selected facilities using the 2003 data as a base, and use of the data and analysis tool for further analysis are contemplated. Analysis of the sort reported here is ongoing for 2004.

- Allocation of the other congestion metrics (bid production cost change, load payments and generator payments) by constraint is complicated by the presence of non LMP components in these calculations. Presently there is no agreed upon way to allocate, by constraint, the increased energy cost change as constraints are relieved or eliminated, or to allocate multi-zone congestion costs such as the change in BPCG. Efforts are continuing to develop this allocation and provide further information on a constraint-by-constraint basis.

13.7 Notes on Calculation Accuracy

While extensive effort was put to mirror the market simulation results of the SCUC and the conventions of the NYISO accounts and settlement systems, some amount of modeling and data imprecision was encountered during the course of the analysis. When possible, PROBE results were compared to calculations from the NYISO accounting system. From this comparison and from sensitivity studies performed around some of the key study assumptions an accuracy to within $10 to $20 million on the New York total congestion impacts should be expected. Further refinements to modeling, data, and calculation protocols will be ongoing.

14 Final Report/Review Process

This report will be presented to ESPWG and TPAS for review and comment before presentation to the Operating Committee.