SECTION 3.4

ELECTRICITY RESOURCE ASSESSMENT

INTRODUCTION

This Electricity Resource Assessment evaluates the electric system infrastructure in New York State within the context of changes occurring in the structure of the industry. The Assessment begins with a review of the status of retail and wholesale competition in the State. It then assesses the current electricity system infrastructure and the impacts of various system changes that may be postulated for the planning period. This Assessment does not suggest that any of the scenarios studied will, in fact, occur, or are necessarily preferred, but they do represent a reasonable set of possible futures that provide a setting for analysis and policy making. Finally, the Assessment includes a description of how retail prices and loads might change over the planning period.

STATUS OF COMPETITIVE ELECTRIC MARKETS

New York State Retail Market

Customer Choice Programs. The State's retail electric industry is open to customer choice of energy service providers. Changes in the electric market allow customers in nearly all areas of the State to choose their supplier of electricity, while the delivery of electricity to homes and businesses remains the function of the local utility. The transition toward retail competition has been evolving for several years, and further evolution will occur. Most experts in energy policy agree that competition can produce innovations and bring forth technologies and new services that will result in customer benefits.

According to the Center for the Advancement of Energy Markets (CAEM), an independent, nonprofit group in Washington, DC, New York has consistently ranked among the top states in its efforts to restructure the electric industry.[1] Among the 22 attributes where New York scored high are the following: overall competition plan; percentage of customers eligible; safeguards to prevent utility/affiliate favoritism; competitive metering and billing choices; generation market structure; treatment of stranded costs; customer education programs; appropriateness of default rates; and distributed generation interconnection policies. The percentage of load switched so far to

[1] Other states ranked high by the Center include Pennsylvania, Texas, and Maine.

competitive suppliers is about 19%, which is relatively high compared to other states (currently, the third highest).

Customer Participation. Based on customer awareness surveys conducted annually by the Department of Public Service (DPS), about 60% of the State's electric consumers are now aware of electric competition. Overall, 5% of customers, representing nearly 20% of load, had switched from their local utilities to retail service providers as of the end of 2001. Significantly, however, over 25% of the load in the non-residential sector, but only 5% of the residential load, had switched as of that date, as shown in Table 1.

Table 1

RETAIL ACCESS PENETRATION IN NEW YORK STATE, DECEMBER 31, 2001			
Service Area	Number of Participants Currently Switched	Percent of Participants Switched	Percent of Electric Energy Load Switched
Statewide	**349,227**	**4.8%**	**16.6%**
Residential	295,865	4.6%	4.8%
Non-Residential	53,362	5.9%	23.4%
Central Hudson	**224**	**0.1%**	**0.1%**
Residential	122	0.1%	0.1%
Non-Residential	102	0.2%	0.1%
Con Edison	**151,050**	**5.0%**	**25.5%**
Residential	132,140	5.1%	5.7%
Non-Residential	18,910	4.5%	34.2%
NYSEG	**29,406**	**3.4%**	**15.9%**
Residential	21,783	2.9%	4.0%
Non-Residential	7,623	7.1%	27.4%
Niagara Mohawk	**49,452**	**3.2%**	**10.9%**
Residential	40,171	2.9%	1.8%
Non-Residential	9,281	5.9%	15.5%
O&R	**42,577**	**20.4%**	**25.6%**
Residential	37,076	20.6%	22.0%
Non-Residential	5,501	19.0%	27.6%
RG&E	**38,492**	**12.1%**	**27.8%**
Residential	30,829	10.7%	11.7%
Non-Residential	7,663	25.3%	38.0%
LIPA	**38,026**	**3.5%**	**5.4%**
Residential	33,744	3.5%	3.9%
Non-Residential	4,282	3.8%	6.7%

Three utility retail access programs have had substantially better participation than the others: Orange and Rockland (O&R) (26% of the load and 20% of customers have switched); Rochester Gas & Electric Corporation (RG&E) (28% of the load and 12% of customers have switched); and Con Edison (26% of the load and about 5% of the customers have switched). The switches in the RG&E and Con Edison territories were primarily among nonresidential customers, where customer savings would likely be greater and costs for energy service companies (ESCOs) to serve them might be less, both due to economies of scale. The O&R program, in contrast, has been highly successful with regard to switches of residential customers (22% of residential load has switched). The success for O&R might be particularly attributable to its consolidated billing for ESCOs. O&R has also reduced barriers to customer switching through its "Switch n' Save Program" where retail access customers that contact O&R are provided opportunities to switch to ESCOs and are guaranteed 7% savings for two months. Another important element might be that ESCOs in O&R's territory have conducted aggressive marketing campaigns, including telemarketing campaigns, direct mailings to customers, and door-to-door marketing.

Con Edison also has historically offered a consolidated billing option for ESCOs to use, albeit one in which the ESCO instead of the utility issues the consolidated bills.[2] Con Edison's version of consolidated billing, however, has proved to be somewhat more difficult and costly to implement than most ESCOs have been willing to accept. While there are significantly more residential customers enrolled in Con Edison's program than in any of the other utility programs, they represent only 5% of the company's residential customers, in contrast to the 20% of residential customers switched in O&R's program.

Marketer Participation. There are 26 ESCOs currently selling electricity to retail customers in New York State, including five that are affiliates of incumbent utilities (15 of the 26 provide service in Con Edison's service area). Several of the ESCOs tend to dominate in some service areas, while only one ESCO currently serves customers in RG&E's area, and only two serve customers in Central Hudson Gas and Electric's (Central Hudson) territory. Further, some of the ESCOs limit their services to specific customer classes, with some providing no service for residential consumers. Clearly, the ESCO interest and activity in the State is not evenly dispersed

Improvement Opportunities. Retail competition stakeholders report that obstacles to switching to retail access for customers (especially residential and small business customers) and obstacles to ESCO participation are numerous Specifically, these perceived obstacles include: utility rates that are not fully or properly unbundled; the lack of consolidated billing availability throughout the State; high financial security requirements; the volatility of the wholesale market; the continuation of utilities in some competitive functions; and the small size of the available profit margins. Many of these

[2] RG&E also offers a consolidated bill through its "Single Retailer Model" where the ESCOS provide customers with, and bill for, both commodity and delivery service.

barriers are being encountered in other states. Discussed below are initiatives underway in New York to address each of these concerns.

State Policies and Programs to Enhance Retail Electricity Competition.[3] The State has taken a number of actions to promote competition in retail electricity markets. The Public Service Commission (PSC) has opened electric metering in the regulated utility service areas to competition by ESCOs, competitive meter service providers (MSPs), and meter data service providers (MDSP). Moreover, billing will be open fully to competition as soon as the PSC completes work on Electronic Data Interchange (EDI) standards. Uniform Business Practices have been adopted to govern interactions between utilities and competitive suppliers, and modifications are being considered as the need arises. One of the more significant barriers to retail competition has been the fixed backout credits for commodity service provided by competitors that were incorporated into the rate and restructuring agreements of several utilities. The PSC has since directed that the fixed credits be replaced by market-based credits. Identified below are some of the other initiatives and programs that are now underway to enhance retail electricity competition.

Competitive Retail Electric Markets Case.[4] On March 21, 2000, the PSC instituted a proceeding to consider the next steps that should be taken to develop retail energy competition further, including the future role of regulated utilities in providing the energy commodity and other competitive or potentially competitive services. Also being examined are the utilities' future roles with respect to various public benefit programs (*e.g.*, low-income assistance, energy efficiency, research and development) and the utilities' responsibilities as providers of last resort (POLR). The PSC directed that a collaborative process be undertaken to examine these issues, that comprehensive public input be sought, and that a complete range of policy options be delivered in either a consensus report by the parties or a recommended decision.

On July 13, 2001, the Administrative Law Judges assigned to this case issued a recommended decision (RD). At issue are the future role of the regulated energy utilities in the end-state competitive markets, the actions needed during the transition to foster the development of such markets, and the future of system benefits programs. The RD recommends that the Commission first adopt three

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[3] The discussion in this section relates primarily to policies and programs authorized by the PSC for the regulated utilities. The Long Island Power Authority is also considering initiatives to enhance its retail access program.

[4] Case 00-M-0504, Proceeding on Motion of Commission Regarding Providing Last Resort Responsibilities, the Role of Utilities in Competitive Markets, and Fostering the Development of Retail Competition Opportunities.

overarching goals or principles to be used in guiding the development of competitive markets and to serve as a basis for determining an appropriate long range or end-state competitive model. Those goals are as follows:

1. The provision of safe, adequate, and reliable gas and electric service at just and reasonable rates should be the primary goal, with priority over others.

2. Where possible, all services and products should be provided by competitive markets and not by regulated utilities.

3 The regulation of rates, services, and competitive market activities should be appropriate for the status of the transition (with greater scrutiny being exercised at the outset, and less as the dominant players lose the ability to exercise market power) and for the status of the service provider (with greater scrutiny being exercised over those with greater market power).

Based on these principles, the RD recommends that the PSC adopt as its end-state vision of the competitive markets one in which the utilities no longer provide gas and electric commodity service and are removed from any other market that becomes workably competitive. Before any utility is removed from any market, however, certain preconditions should be met, including a determination that the wholesale and retail markets are operating without the exercise of market power. As a general matter, the judges recommended that a utility not be removed from any market until multiple suppliers offering a variety of products are available for the entire customer class throughout the utility's service territory. The PSC is now considering the case.

Unbundling.[5] For retail competition to proceed effectively, utility rates must be unbundled[6] appropriately to identify costs that can be avoided through the transfer of functions to competitive suppliers. By Order issued March 29, 2001, the PSC instituted a formal "unbundling track" as an extension of the Competitive Markets Case for the explicit purpose of establishing guidelines and principles for the utilities to follow in conducting updated cost of service studies. Those studies will eventually result in the establishment of fully unbundled, cost-based rates for electricity and gas services. The jurisdictional utilities have subsequently filed embedded cost studies and will subsequently file tariff amendments that provide unbundled rates.[7]

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[5] Case 00-M-0504, SUPRA, Order Directing Expedited Consideration of Rate Unbundling.

[6] Unbundling is the disaggregation of the utility rate into its components.

[7] Case 00-M-0504, SUPRA, Order Directing Filing of Embedded Cost Studies.

Electronic Data Interchange.[8] The accurate and timely interchange of information is necessary for retail competition to proceed effectively. In an Order issued April 12, 2000, the PSC required that Electronic Data Interchange (EDI) systems[9] be implemented statewide to facilitate the exchange of retail access data between ESCOs and utilities.

Uniform Business Practices.[10] Most of the participants in retail competition have recognized the need for standardization of business practices among the utility service areas. The PSC, consequently, put in place a set of business practices that most of the participants in retail access in New York State must follow. Utilities, ESCOs, and regulators from across the nation undertook a similar effort during 2000 to create uniform business practices for the entire country. Staff of the PSC assumed a leadership role, participating in a lengthy series of meetings held throughout the country that culminated in a national document for retail access business practices and competitive metering. The PSC is now in the process of harmonizing New York's business practices with the national consensus document. The PSC has also indicated that it will revisit the practices from time-to-time as more experience is gained.

Competitive Billing.[11] Consumers have expressed a strong preference for the convenience of a single or consolidated bill for their utility services rather than having to pay separate bills for each service received This preference, coupled with the PSC's commitment to push for competition wherever practicable, led the PSC on March 22, 2000, to order the major electric and gas utilities to file tariff amendments to accommodate the wishes of retail access customers who prefer to receive single bills from either their utility company or from their ESCO. Then, on April 25, 2001, the PSC adopted a set of uniform billing and payment processing practices to be incorporated into the utility tariffs, operating procedures, and billing service agreements of the large electric and gas distribution utilities in the State. The practices were based on recommendations of a national working group, as well as practices developed individually by the utilities and feedback from interested parties. The PSC also adopted individual billing backout credits[12] and billing service charges representing prices that

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[8] Case 98-M-0667, In the Matter of Electronic Data Exchange.

[9] EDI is the computer-to-computer exchange of routine business information in a standard form. In a retail access environment, examples of "routine" transactions include switching customers from one supplier to another and the exchange of customer history, usage, and billing data.

[10] Case 98-M-1343, In the Matter of Retail Access Business Practices.

[11] Case 99-M-0631, In the Matter of Customer Billing Arrangements.

[12] "Backout credits" are the amounts by which utility charges for a service are to be reduced as customers procure that service from competitors instead of from the utility. These amounts are "backed out" of the utility charges.

utilities could charge ESCOs if they were asked by ESCOs to issue the consolidated bills.

Competitive Metering.[13] Metering and metering services represent potentially competitive activities that historically have been performed only by utilities. On June 16 and September 15, 1999, the PSC issued Orders requiring that competitive metering services be made available for about 40,000 large New York State customers with peak demands of at least 50 kW. It also directed utilities to unbundle metering and provide a backout credit to participating customers. The tariffs have now been approved, and five competitive entities have so far received approval as MDSP in New York State.

Environmental Labeling.[14] ESCOs are able to differentiate the commodities or products they offer according to the sources of their generation, which should further enhance retail competition. Opinion 98-19, issued December 15, 1998, approved an environmental disclosure mechanism that will provide customers with verified data on the fuel mix sources and average emissions rates for the generation sources that their suppliers have used to meet their energy supply requirements. The first environmental labels were included in customer bills in early 2002.

Photovoltaic Law and Net Metering. In August of 1997, the New York State Legislature amended the Public Service Law to add a new Section 66-j requiring utilities to provide for net metering of residential photovoltaic (PV) systems with a generating capacity of 10 kW or less. Subsequently, in February 1998, the PSC instituted uniform interconnection standards for these systems and ordered the utilities to file tariffs implementing the requirements of the statute. Through other legislation, customers can also obtain tax credits for a portion of the cost of installing PV systems.

Distributed Generation. Distributed generation, including combined heat and power (CHP) applications, offers customers the promise of increased electric reliability, power quality, efficiency, and affordability, while potentially reducing supply and distribution costs. NYSERDA, the PSC, and the U.S. Department of Energy hosted a CHP workshop in Albany in 2001 for the purpose of providing a perspective on the economic and environmental benefits of the concurrent production of electrical and thermal energy, and identifying the barriers the CHP industry faces. Key governmental and private sector officials participated in the workshop. The PSC also extended and expanded the system benefits charge (SBC) in 2001, providing funding of $67 million over the next five years to

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[13] Case 94-E-0952, Competitive Opportunities Regarding Electronic Service, Order Providing for Competitive Metering.

[14] Case 94-E-0952, SUPRA, Opinion and Order Adopting Environmental Disclosure Requirements and Establishing a Tracking Mechanism.

improve the viability of distributed generation and CHP as economic energy options in New York State. The PSC's proceeding to investigate generic principles for designing equitable stand-by service delivery rates for customers with interconnected generation facilities has recently concluded. The decision approved a protocol for special "standby rates." Such rates will apply to distributed generation customers who remain connected to their local utility system for backup power. The guidelines rely on a more cost-based approach to charging for delivery service than rates that had previously applied to standby customers.

In a related proceeding, the PSC authorized a three-year distributed generation pilot program to begin in 2001. Its purpose is to provide for the objective and timely consideration of distributed generation projects as a resource in the delivery system planning processes. The decision establishes a process for utilities to award a set number of contracts for distributed generation projects that could take the place of delivery system construction.

Interconnection Standards. In December 1999, the PSC issued Standard Interconnection Requirements to streamline and facilitate the process for the installation of distributed generation of 300 kW or less operating in parallel with radial distribution systems. The standards were formally revised in November 2000 and another revision is planned for the near future. Contained in the standards is a "type testing" procedure to allow manufacturers to submit their equipment for testing. This will classify equipment as utility grade and thus acceptable for use at the grid interface point. Several units have now been listed as type tested, most of which are inverters for use in photovoltaic systems. It is intended that the standards promote an increase in on-site generation through a simple, quick, and well-defined application process and allow applicants to purchase units from the list of "type tested" equipment.

Standardized interconnection requirements within network systems and for facilities greater than 300 kW are more problematic due to the technical issues they pose. PSC Staff is monitoring efforts at the national level to establish and standardize interconnection requirements for these types of facilities.

Public Outreach and Education. The PSC's statewide public education program, **"Your Energy. . .Your Choice"**, is a key element in the Commission's efforts to introduce retail competition. The goal of the program is to establish and maintain a high level of awareness and understanding so that consumers can make an affirmative decision regarding the new choices available to them.

The program has used most of the communication tools available and has delivered its message through: (1) an aggressive PSC staff-directed program integrating a broad-based media campaign with a wide variety of grass roots educational initiatives; and (2) a concerted effort to encourage active utility customer education programs. Particularly important to these efforts have been numerous partnerships, combining the efforts of State and local government agencies, utilities, energy service companies, business and consumer groups, and other service providers.

The PSC has also conducted annual surveys of residential and business customers to monitor awareness, understanding, attitudes, and informational needs. General awareness of retail competition has remained fairly steady at approximately 60% of those surveyed, but an equal percentage implies that they do not yet have enough information on which to make a choice. Despite the continuing need for more information, most consumers believe they will benefit from competition.

In summary, important steps have been taken and the mechanisms have been established to support greater retail choice in New York State. As new supplies of electricity become available in 2004 and 2005, as is now projected, and as the initiatives discussed above progress, competition should become more viable for both customers and ESCOs.

New York State Wholesale Market

The Transition. In the mid-1990s, New York State developed a framework for restructuring the wholesale electric market. In the restructuring plans developed by the individual utilities, the utilities agreed to divest most of their generating stations, selling them through an auction process. The parties also agreed to create an Independent System Operator (ISO) to supersede the then-existing New York Power Pool. The ISO would be a not-for-profit organization with responsibility for administering the State's wholesale energy markets and operating the State's high-voltage electric transmission system, in accordance with reliability standards adopted by the New York State Reliability Council (NYSRC). The Federal Energy Regulatory Commission (FERC) eventually approved these proposals, with modifications, and on December 1, 1999, the New York Independent System Operator (NYISO) officially began operations.

In 2000, Staff from the DPS interviewed parties that deal routinely with the NYISO, reviewed the NYISO's operations, and subsequently developed a series of recommendations to help the NYISO operate more efficiently and effectively. The NYISO has implemented many of the recommendations and is developing solutions for other identified problems as well.

The first two years of operation of the competitive wholesale market in New York State were marked by sharp increases in the prices of fuel and tight supply conditions in some regions of the State, largely resulting from transmission congestion and a lack of construction of new generation in the previous years, and an unanticipated increase in demand (during this time, New York's economy was expanding rapidly). In response to these developments, the State, in cooperation with the utilities and other interested parties, encouraged the following to lower wholesale prices: adding new generation, upgrading transmission capacity, using energy more efficiently, enhancing customers' ability to respond to price changes, and improving the efficiency of NYISO operations.

Controlling Market Power. Market power is the ability of a single firm, or a group of firms acting jointly, to raise prices or restrict output beyond levels that would be expected if the market were fully competitive. To prevent the exercise of market power, the State has encouraged ownership of generation by multiple organizations, and the utilities have now sold most of their generating stations. The PSC examines new power plant proposals and merger petitions for potential market power issues. The Hierfandahl-Hirschman Index (or HHI), which measures the concentration of players in an industry, is one tool used to measure market power (scores over 1,000 are considered to be a potential problem; scores of over 1,800 are considered to be a potentially serious problem). New York's wholesale electric market's HHI value is less than 1,000 (for the entire State as a single theoretical market), which reflects the existence of acceptable competition potential. New York, however, does have pockets where concentration of ownership is an issue, either on a geographic or temporal basis. This is especially true in the New York City area. Consequently, the NYISO established specific in-City market power mitigation rules that govern the New York City electricity generators. These rules attempt to prevent generation owners in New York City from taking advantage of the limits on transmission of outside power into the metropolitan areas to exert market power on wholesale electricity markets.

The NYISO has also developed automated procedures (Automated Mitigation Procedures, or AMP) to prevent market abuse during times when day-ahead energy prices rise above $150/MWh. At such times, suppliers' bids are automatically reviewed to determine whether they are $100 or 300% higher than an energy reference price[15] and, in addition, the inflated bids could cause a price impact of $100 or more. While the AMP mechanism does not eliminate price spikes due to shortages, it mitigates attempts to inflate bids and exert undue market influence.[16]

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[15] Reference prices are computed based on the lower of the mean or median of the previous 90 days of accepted bids and are adjusted for fuel price changes. In instances where the AMP determines that a unit is economically withholding electricity in the day-ahead market, the unit's bid price is subject to being changed to its day-ahead reference price.

[16] A recent NYISO filing with FERC is intended to expand the application of the in-city mitigaton rules to more New York City generators and to the real-time market for New York City and make them more consistent with the rules for the rest of the State.

Wholesale Prices.[17] In New York State, electricity demand is greatest during the summer as customers rely on electrical air conditioning equipment for cooling. When demand is lower during other times of the year, only the most efficient, and thus cheapest to operate, electicity generators will typically be used. As demand increases, less efficient, and thus more expensive to operate, generators will then be required. The result is that, on average, wholesale prices will typically be greatest during the summer months. On an hourly basis, the highest peak prices can be expected at certain hours in the summer.

Prior to the December 1999 start-up date for the NYISO, and the power exchange operated by the NYISO, the wholesale electricity market consisted generally of bilateral contracts of varying lengths. The wholesale prices set by these contracts were not posted in any one place, were sometimes confidential, and were not easy to interpret or compare, especially if the contracts included delivery or other services. In addition, most of the electricity generation in New York State was owned by the utility companies or the New York Power Authority (NYPA) and supplied directly to customers at the utilities' regulated rates, which did not necessarily represent true wholesale market costs. As such, there were no formalized wholesale clearing prices to compare with the wholesale prices now available. However, it is intuitive that, because of the sudden increase in the price of natural gas used by many generators and the unavailability of the Indian Point 2 nuclear power plant, the wholesale spot market energy prices in the summer of 2000 were significantly higher than would likely have been visible if a power exchange had existed in prior years. Consequently, while the year 2000 wholesale energy prices may not have been typical, they are the only factual data available to use as a starting point for an analysis of future trends. As will be shown below, wholesale electric energy prices have decreased from the higher year 2000 levels, and the projections of this State Energy Plan are that they will continue to decrease.

Wholesale spot market prices for summer 2001, on average, decreased compared with the summer of 2000 in the New York City and Capital District areas, but increased in the western part of the State, as shown in Table 2.

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[17] The data presented here is for wholesale spot prices in New York State. Transition contracts and other bilateral wholesale contracts are not presented. The intent of this section is to show trends in the spot market.

Table 2

WHOLESALE ENERGY PRICE CHANGES IN NEW YORK STATE			
Region	**Summer 2000**	**Summer 2001**	**% Change**
New York City	$57.6/MWH	$52.6/MWH	9% decrease
Capital District	$54.0/MWH	$45.2/MWH	17% decrease
Western NY	$32.5/MWH	$39.1/MWH	19% increase

DPS Staff have analyzed these data to determine the extent to which these changes are due to fuel prices, changes in load level, or the availability of generation. Differences between the conditions present for the two summers that caused price decreases in the New York City and Capital District areas were: a decrease in natural gas prices (17% decrease on average); the availability of generation from Indian Point 2 nuclear plant during the summer of 2001 after being unavailable the previous summer; the addition of about 450 MW of gas turbines installed by NYPA for the summer of 2001; an increase in the rating of LIPA's cross-sound cable to Long Island; and implementation of demand reduction programs during the summer of 2001. Increases in the Western New York area were generally due to two factors: increased loads caused by hotter weather, which resulted in fewer than normal hours in which low-cost coal generation set energy prices; and fewer hours in 2001, as compared with 2000, in which the transmission constraints depressed Western New York prices.[18] The result, as can be seen from the data above, was that the difference in wholesale prices between Western New York and the Capital District area narrowed between 2000 and 2001 (lowering the Capital area prices and increasing the Western New York area prices).

While no one can accurately predict wholesale electricity prices over the planning period, use of a production simulation model can provide some insights. Based on the assumptions and the "Forecast" described later in this Assessment, this Plan forecasts that the running cost of electricity generation statewide should generally decline in real terms as new generation is added during the planning period, which should similarly influence wholesale prices. Table 21, provided later in this Assessment, shows the relative wholesale electricity real price changes one might expect over the planning period, relative to 2002.

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[18] Transmission constraints often limit west-to-east energy flows across New York, reducing Western New York prices while increasing Eastern New York prices. NYPA's installation of the first phase of its convertible static compensator (CSC), a flexible alternating current transmission system (FACTS) at its Clark Energy Center in Marcy, reduced the constraint. Completion of the second phase in 2002 will further ease the constraint.

Market Rules and Procedures. Participants in New York's wholesale electric market have identified a number of inefficiencies resulting from the way rules and procedures had been written and from less than optimal software implementation. The NYISO and other parties have been working to correct these problems. For example, the NYISO began offering virtual bidding in November 2001. Virtual bidding gives marketers that do not have physical generation or load in New York the ability to buy and sell energy on the NYISO's spot markets. This practice is expected to increase trading and bring market prices closer together.

Among the more intractable problems identified so far are "seams issues," which refer to problems created by differences in the scheduling and dispatch rules between neighboring ISOs. Some generators took advantage of these discrepancies to increase their profits. The most egregious of these problems, however, have now been corrected.

Having separate, adjoining ISO territories, as is now the case, can also lead to inefficiencies in each ISO's internal scheduling. For example, in some cases, due to loop flows of electricity, the best solution to a congestion problem would be to start up or adjust the schedule of a generator in an adjoining ISO territory. The ISOs in the Northeast have been investigating methods to more cooperatively to deal with this type of situation.

FERC has also suggested that competitive market efficiencies might be enhanced if markets could be combined to eliminate the seams. Further centralized scheduling of transactions, and the ability to share reserves among ISOs, have the potential to make the electrical systems operate more efficiently. Consequently, in July 2001, FERC issued an Order to begin a process to develop a single Northeast Regional Transmission Organization that would include the New York, New England, and the Pennsylvania-New Jersey-Maryland (PJM) ISOs. The ISOs, the states, and interested parties thereafter began to evaluate options to respond to the FERC Order.

New York State supports FERC's attempt to establish a regional common market in the Northeastern United States to run the daily power markets and oversee the flow of electricity. While states in the Northeast have previously been working to resolve "seams" issues that inhibit economic exchanges of power, the FERC Order should expedite that process and hasten the resolution of those issues. Over time, the regional common market approach will strengthen the reliability of the system, promote better transmission planning, and result in wholesale prices for electricity that reflect the most efficient operations.

A well-functioning regional common market should include in its planning process ample opportunities for market-based generation and transmission projects but should allow the regional common market flexibility to provide the proper incentives to implement cost-based transmission solutions necessary to ensure system reliability. Consumers will benefit from enhanced competition that would result from larger markets, but the pursuit of savings cannot come at a cost of degraded reliability. Maintaining reliability standards must be the highest priority.

In the process to develop a Northeast regional common market, New York State proposes that certain principles be established. Those principles include:

> System reliability is a paramount concern for state regulators. The new system must be designed to incorporate local requirements and to ensure that short-term economic pressures do not shortchange the reliable operation of the system. Until a more optimal system is developed, the current configuration of three physical control areas should be maintained.
>
> Consumers must be protected through effective market monitoring and mitigation in those areas where competition is inadequate.
>
> A body fully empowered to act by the regions should quickly work to identify the "best practices" of these markets so that uniform, regional rules can be in place as quickly as possible, consistent with the need for a safe and reliable transition.
>
> The work to pursue efficient commerce across the Northeast, which began in 1999, must continue during the transition to a regional common market.
>
> There should be a single, independent governing body that provides mechanisms for effective input from all of the stakeholders while maintaining the independence to act in the public interest.
>
> State regulators should have a meaningful role in the development and operation of a regional common market that reflects their responsibilities in siting of generation and transmission resources, local reliability, market monitoring, and protection of consumer interests.

In January 2002, the New York and the New England ISOs announced their intent to file a petition at FERC to form a common market for the two regions (*i.e.*, without PJM). If a regional common market that encompasses the entire northeast region, as FERC had originally proposed, is not possible, the Planning Board believes that approval of a New York/New England ISO should be predicated on the adoption of a regional energy market throughout the northeast region, including PJM.

Expected Resources. As previously noted, wholesale electrictiy prices should decline in real terms as new resources are added to the system. Below is a discussion of the various options available for adding new resources.[19]

Article X Projects. Major electric generating facilities of 80 MW or greater must be authorized by the New York State Board on Electric Generation Siting and the Environment (Siting Board) under Article X of the Public Service Law. The first Article X proceeding began in 1998 with the filing of an application for the Athens Generating Plant. As of May 1, 2002, 24 Article X power plant projects have been announced formally, for a total of over 15,000 MW (see Table 3).

Article X Siting Boards have approved seven projects that could add a net total of 3,626 MW to the New York system.[20] Decisions on the other projects should occur in 2002 and 2003, and one or more of the certified projects could be completed as early as 2003. Most of the other projects, those approved and those currently under active review, if carried forward, could become operational in the 2004 to 2006 time frame (but some delays or additional cancellations could occur if the developers consider market or financing conditions to be unfavorable).[21]

The Article X power plant siting law remains in effect until January 1, 2003. As noted in the "Promoting Energy Industry Competition" issue paper (Section 2.1 of this Energy Plan), the Planning Board recommends that the Law be extended.

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[19] The NYISO requires that load serving entities (LSEs) provide a schedule of resources sufficient to meet their load and reserve requirements or, in the event that LSEs don't procure adequate resources, make deficiency payments. These requirements are intended to ensure that generation resources will be available when needed. The NYISO is reviewing its procedures to ensure that they provide the necessary incentives for electricity resources to be available when needed.

[20] One of the seven projects has recently been cancelled, leaving the remaining six projects at 3,626 MW.

[21] Some delays and cancellations have recently been announced.

Table 3

ARTICLE X PROJECT STATUS (5/1/02)				
			Projected	
Project	Location	Capacity	Earliest Service	Status
Applications Filed				
East River	Manhattan	360 MW*	4 Q 2004	Certified
Ravenswood	Queens	250 MW	4 Q 2003	Certified
Athens	Greene Cty.	1,080 MW	3 Q 2003	Certified
Heritage	Oswego Cty.	800 MW	Cancelled	Certified
Astoria	Queens	1,000 MW	3 Q 2005	Certified
Bowline	Rockland Cty.	750 MW	3 Q 2005	Certified
Bethlehem	Albany Cty.	750 MW**	3 Q 2004	Certified
Poletti	Queens	500 MW	3 Q 2004	Hearings Complete
Brookhaven	Suffolk CTY.	580 MW	2004	Hearings Complete
Wawayanda	Orange CTY.	540 MW	2004	Hearings
Orion Astoria	Queens	1,816 MW***	2007	Hearings
Ramapo	Rockland Cty.	1,100 MW	2 Q 2004	Hearings
Kings Park	Suffolk Cty.	300 MW	3 Q 2004	Hearings
Spagnoli Road	Suffolk Cty.	250 MW	2004	Hearings
Glenville	Schenectady Cty.	520 MW	2 Q 2005	Hearings
Besicorp	Rensselaer Cty.	510 MW	3 Q 2004	Application Stage
Sunset	Brooklyn	520 MW	Unknown	Application Stage
Torne Valley	Rockland Cty.	827 MW	Unknown	Withdrawn
Pre-Application Reports Filed				
Grassy Point	Rockland Cty.	550 MW	Unknown	Inactive
Twin Tier	Tioga Cty.	520 MW	Unknown	Inactive
Preliminary Pre-Application Scoping Statements Filed				
Indian Pt Peaking	Westchester	330 MW	2004	Scoping Statement
TransGas	Brooklyn	1,100 MW	Unknown	Scoping Statement
Caithness	Suffolk Cty.	750 MW	Unknown	Inactive
Oak Point	Bronx	1,075 MW	Unknown	Inactive

Notes:
*less 164 MW replaced yields 196 MW net increase
**less 400 MW replaced yields 350 MW net increase
***less 1,254 MW replaced yields 562 MW net increase

Non-Article X Supply Options. In the near term (2002 and 2003), until new base load combined-cycle generation comes into service, the State will rely primarily on additional simple-cycle gas turbine generation under 80 MW (and demand reduction programs, as discussed below) to satisfy incremental peak load growth in transmission-constrained areas of the State. Most of the immediate need for generation capacity is on Long Island.

In September 2000, the DPS established the Pricing and Reliability Task Force (P&R Task Force) to ensure that our State will have reliable supplies of electricity at reasonable prices. The P&R Task Force consists of three specialized teams – the Independent System Operator (ISO) Pricing Team, the Demand and Supply Team, and the Article X Team.

The Demand and Supply Team's responsibility is to ensure that adequate supplies of electricity will be available until significant new base load generation can be built. The program's focus to meet the 2001 summer peak was satisfied by new generation resources in New York City, including NYPA's installation of approximately 450 MW of small gas turbine capability (less than 80 MW at a given site) in New York City and on Long Island. In addition, peak demand was reduced through the ISO's Demand Reduction response programs. These programs enabled the State to operate during the summer of 2001 without blackouts or brownouts. They also helped to hold down wholesale electricity prices in the State.

A similar demand and supply initiative is underway to meet the State's reliability requirements for the summer of 2002. To meet 2002 summer peak demand, DPS Staff is working with LIPA, other State agencies, and power developers to facilitate the installation of small electric generation units in the State, primarily on Long Island, and to continue to enhance demand reduction programs.

Distributed generation and renewable energy resources are also being added to the State's generation energy mix. As noted previously in the "New York State Retail Market" discussion, the State has developed initiatives and incentives to encourage the development of these technologies, has developed interconnection standards for distributed generation, has established guidelines for standby rates for on-site generators, and has required all transmission and distribution owners to include distributed generation in their delivery system planning evaluations.

With respect to renewable technologies, Governor Pataki has required all State agencies to obtain at least 10% of their power requirements from renewable resources by the year 2005 and 20% by the year 2010. NYSERDA has funded significant research and development work in the area of fuel cells, photovoltaic, wind power, biomass, and other renewable technologies. While such facilities currently make up only a small portion of New York's generation capacity, more will certainly be installed over time. As indicated in Section 1.3 of this Energy

Plan, the Planning Board expects, based on initiatives described in the Plan, the use of renewable energy in the State to increase by 50% by 2020 (from 10% of statewide primary energy use to 15%). Some portion of this increase will certainly occur in the electricity sector.

Demand Reduction Options. In March 2001, the PSC directed the major electric utilities to implement the NYISO's Emergency Demand Response Program (EDRP) and the Day-Ahead Demand Response Program (DADRP). These programs were developed to reduce demand for electricity, to improve overall reliability, and to moderate electricity prices throughout New York State with special emphasis on New York City. The PSC also directed all of the major electric utilities to submit plans to implement their own customer-incentive programs to reduce peak demand, expand the available supply of electricity, and moderate the price of wholesale electricity in the State. The PSC subsequently approved tariff changes implementing the NYISO programs, as well as utility specific programs. These actions allowed utility supply customers, in addition to ESCO customers, to take advantage of new demand reduction programs offered by the NYISO and the utilities. By the end of August of 2001, approximately 680 MW of demand reduction had registered in the NYISO's EDRP, which provided peak demand reductions of 456 MW (per NYISO's 12/4/01 Status Report to FERC in Docket ERR01-3001-000). The NYISO's DADRP similarly provided opportunity for relief during the 2001 summer. There were approximately 171 MW of potential demand reductions registered in the NYISO's DADRP, of which 25 MW of reduction was provided. In addition, the Systems Benefits Charge programs implemented by NYSERDA reduced demand by about 90 MW (these SBC programs enabled a large number of New York energy users to participate in the NYISO and utility programs). Further savings resulted from public appeals, plans developed to reduce the use of electricity by State government facilities during peak periods, LIPA and NYPA initiatives and other utility programs. Overall, statewide demand reductions during the summer of 2001 were approximately 1,665 MW. The PSC also required utilities to prepare detailed public awareness plans describing each company's steps to raise awareness and educate customers regarding the load and capacity situation and outlining actions consumers can take to control their energy use. Particular emphasis was directed toward the business community because that is where the greatest results might be expected in the shortest amount of time.

Transmission Options. Transmission additions and modifications can also impact the wholesale market. The installation of the flexible alternating current transmission system equipment at Marcy, mentioned previously in this Assessment, has already resulted in reduction of transmission constraints. Other such installations might be considered in the future where justified.

Where new generation is being installed, new lines or interconnections are needed, but new merchant lines from other areas are also being considered.

Currently, only one such project, the Transenergie Cross-Sound Line from Connecticut to Long Island, has been authorized by New York State, but several more are being considered (See the "Transmission" section later in this Assessment).

State Actions Option. There are various mechanisms available to provide a safety net in the event market forces do not provide sufficient demand reduction and supply resources in a timely and effective manner. For example, the Public Service Law authorizes the PSC to direct the utilities to use a variety of means to meet the needs of their customers. NYPA and LIPA, as State Authorities, are also authorized to initiate programs or call for additional resources, as they have both done during the past two years. While these State options remain available, the State will use them only if necessary to protect the public, the environment, and the industry.

STATUS OF UTILITY STRUCTURES/MERGERS

Since 1994, most of the major electric and gas utility companies in New York State have been allowed to enter into holding company structures. This permission was granted as part of the proceedings conducted to open the electric business to competition. These cases also produced extended rate plans wherein rates were either frozen or decreased over several years.

The PSC's policy toward mergers and acquisitions, consistent with the controlling statute, has long been that the merger must be determined to be in the public interest before it can be approved. In past mergers, this has generally meant that the ratepayer must be held harmless in the transaction and also that they should share in any synergy savings resulting from the merger.

The first merger between major electric utilities in New York since the 1940s occurred in 1997. In this transaction, Con Edison acquired Orange & Rockland. As part of the regulatory approval, the rates in the Orange & Rockland service territory were reduced and the company was required to refrain from requesting new rates for an additional two years beyond what it had previously accepted as part of its restructuring plans. Orange & Rockland and Con Edison's gas rates were reduced. Cost savings attributable to Con Edison's electric and steam operation, however, were deferred until the next rate proceeding.

Recently, two additional mergers involving New York electric and gas companies were announced. In September 2000, Niagara Mohawk Holdings, the parent of Niagara Mohawk Power Corporation, entered into a merger agreement with National Grid, whereby it would become a wholly owned subsidiary of National Grid. National Grid's principal subsidiary, The National Grid Company, PLC., owns and operates the high voltage transmission system in England and Wales. National Grid, through another subsidiary, National Grid USA, also has substantial transmission and distribution operations in the United States following its acquisitions of New England Electric System and Eastern Utilities Associates in early 2000.

The combination of Niagara Mohawk and National Grid more than doubles the size of National Grid's US operations with an electric customer base of approximately 3.3 million. On November 28, 2001, the merger received PSC approval. The Securities and Exchange Commission granted its approval January 16, 2002, and the merger was completed on January 31, 2002.

The merger conditions adopted by the PSC include a reduction in Niagara Mohawk's annual electricity delivery rates of about $152 million (approximately 8%). For a residential customer receiving both delivery and supply from Niagara Mohawk, the proposed 8% delivery rate reduction will result in an overall bill reduction of about 4.6%, on average, based on the current supply price of electricity.

Further, the lower electricity delivery rates will be stabilized under the merger plan for 10 years, subject to limited re-openers and adjustments for external events, such as changes in statutory, tax, or accounting requirements of extraordinary events. The supply costs of electricity provided by the utility to residential and small commercial customers will be stabilized through contracts that hedge the price of electricity.

Other conditions of the merger include the extension of a gas delivery rate freeze, originally approved in 1996, through December 31, 2004, and expansion of gas and electric low-income customer services through the creation of a low-income rate discount program for qualifying customers. Economic development will be encouraged by providing discounts, incentives, and other programs to small commercial and industrial customers designed to attract, expand, and retain businesses in Niagara Mohawk's area. National Grid will also implement a program to encourage marketing of renewable energy, and will modify its practices and rules to facilitate development of distributed generation. A comprehensive service quality assurance program will be established to ensure that Niagara Mohawk maintains quality customer service and service reliability. The rights of Niagara Mohawk's union employees will be preserved under the merger and the rights of the union to represent employees in future negotiations will be recognized. Under the Joint Proposal, all existing, legal, contractual protections of retiree's current pension and benefit programs remain in place

On February 27, 2002, the PSC issued an order approving the merger of RGS Energy Group, Inc. (parent of Rochester Gas and Electric Corporation), and Energy East Corporation (parent of New York State Electric & Gas Corporation). The merger awaits Securities and Exchange Commission approval. The combined company will be one of the largest, most diversified energy providers in the Northeast, serving nearly 3 million customers, including approximately 1.8 million electricity customers, almost one million natural gas customers, and approximately 200,000 other retail energy customers. The combined company will have annual revenues of approximately $5 billion and nearly $10 billion in assets. Together, Energy East and RGS Energy, through their operating subsidiaries, will serve half of upstate New York. By combining with RGS Energy, Energy East also strengthens their overall presence in the Northeast.

The merger is expected to generate annual cost savings of approximately $50 million, largely from the joint management of Energy East and RGS Energy subsidiaries in areas such as procurement, information systems, and other administrative and general areas. Net merger savings for the five-year period 2002-2006 were allocated among the various operating companies involved in the merger. NYSEG Electric: $75 million; NYSEG Gas: $32 million; RG&E Electric: $29 million; RG&E Gas: $29 million for total net merger savings of $165 million. The companies and ratepayers share the merger savings equally. The merger conditions adopted by the Commission include a reduction in NYSEG's annual delivery rates of about $205 million that commenced in March 2002. RG&E's rates will be settled in its current rate case. In addition to approving the merger, the PSC Order accepted the savings estimate from synergies expected to result from the merger, together with the costs to achieve those savings, for the period of five years following the anticipated closing of the merger. The PSC approved rules of conduct, which include relationships and transactions between operating companies, their affiliates, and third parties. No layoffs are planned as a result of the combination. Both companies have on-going cost reduction programs and, historically, have used reduced hiring and attrition to minimize any workforce effects. NYSEG will continue to offer economic development discounts of $8 million annually. Outreach and education initiatives will continue and the company will continue to comply with its Service Quality and Reliability Requirements.

STATUS OF ELECTRICITY INFRASTRUCTURES

<u>Transmission</u>

The 2001 Load & Capacity Report submitted by the NYISO to the New York State Energy Planning Board indicates that there are 10,805 miles of transmission facilities in New York State. That report is available on the NYISO website (www.NYISO.org).

These facilities are generally adequate to provide reliable electric system operations now and in the immediate future, but local transmission reinforcements may become necessary in the New York City and Long Island areas. In addition, there are system constraints that limit the amount of electric power that can be transmitted between regions within the State. In particular, there are limitations on the amount of power that can be moved from upstate to downstate, and into either New York City or onto Long Island from surrounding areas. Because the system is operated in a manner that these constraints are not violated, reliability is not jeopardized; but there are economic impacts as evidenced by the normally higher prices in downstate regions compared to upstate/western areas.

New York's existing transmission system facilities, delineated by voltage class and circuit miles, are shown in Table 4. The transmission system limits within New York State at designated internal interfaces points are shown in Table 5.[22]

Table 4

EXISTING TRANSMISSION LINE VOLTAGES (kV) AND CIRCUIT MILES						
Voltage	115 kV	138 kV	230 kV	345 kV	500 kV	765 kV
Miles	6,023	711	1,090	2,660	5	314

Table 5

MAJOR INTERFACE LIMITS	
CENTRAL EAST	3,100 MW
DYSINGER EAST	2,850 MW
TOTAL EAST	6,500 MW
UPNY CONED	5,100 MW
WEST CENTRAL	2,350 MW
SPRBROOK/DUN SOUTH	4,700 MW

[22] Data taken from NYISO 2001 Load and Capacity Report. An "Interface Limit" defines the amount of power that may be transferred from one geopgraphical area to another through all the transmission lines between those two areas. The NYISO has defined several of these "interfaces" and determined the amount of power that may flow across them from one area to another without violating reliability criteria.

While the 2001 Load & Capacity Report mentioned only one new transmission line (a direct current line from Connecticut to Long Island) and the re-building of one 69-kV line to 138-kV operation (near Middletown), various other transmission projects are in the planning stages. While some of these lines would be for the sole purpose of connecting a new generator to the existing transmission system, others are proposed by developers as merchant transmission lines that could provide new links to New York from New Jersey and other areas, including locations in the Canadian Maritime Provinces. Studies of the impact of such facilities on the New York State and Northeast transmission grids are performed by power system engineers and reviewed by the NYISO for acceptability. After approvals are obtained following the NYISO procedures, developers can apply to the PSC for approval under Article VII of the Public Service Law. Whether or not such lines are built will depend in large part on assessments of the likely economic opportunities associated with such ventures and on the engineering and environmental reviews necessary under Article VII. The Article VII process continues to be an effective mechanism for ensuring that such projects are compatible with the environment and meet public needs.

New York State is electrically connected with surrounding states (Pennsylvania, New Jersey, Connecticut, Massachusetts, Vermont) and Canadian provinces (Ontario and Quebec). Because peak loads occur in winter in Quebec and to a lesser extent in Ontario, and in summer in New York State (and New England and PA-NJ), significant amounts of power frequently flow from Canada to New York in the summer and in the opposite direction in the winter. There are frequently significant power flows between New York and PA-NJ for a variety of reasons, including economic transactions (in both directions) and local area support (in both directions). Lesser amounts of power move back and forth with New England for those same purposes. Depending on the construction of new generating plants and new transmission lines in parts of the Northeast, changes in rules set by the FERC, and the possible development of a Northeast regional common market (under FERC orders/approvals), it is likely that New York State will see increasing amounts of power transfers across its borders. Such increases would undoubtedly produce economic benefits and should maintain or increase levels of reliability throughout the Northeast region. Table 6 provides information from the 2001 Load & Capacity Report on transmission capabilities between New York and its neighbors.

Table 6

INTERPOOL TRANSFER CAPABILITIES	
OH-NYISO	2,325 MW
NYISO-OH	1,300 MW
PJM-NYISO	3,150 MW
NYISO-PJM	325 MW
NEPOOL-NYISO	1,600 MW
NYISO-NEPOOL	1,425 MW
HQ-NYISO	2,470 MW
NYISO-HQ	1,000 MW

Efforts are underway to examine ways to increase the transfer capabilities both within New York State and with its neighbors. For example, NYPA has installed the Convertible Static Compensator (CSC), one of the world's most advanced transmission control devices, at its Clark Energy Center in Marcy (Oneida County). Completion of the first phase of the project in 2001 increased transmission capacity by 60 megawatts on the heavily used lines between Utica and Albany and by 110 megawatts to all of eastern New York. When fully operational in 2002, the CSC is expected to permit total increases, including those already achieved, of 120 megawatts on the Utica-Albany lines and 240 megawatts to all of eastern New York. NYPA is investing $35 million in the CSC, with additional funding for the $48 million project from EPRI (the electricity industry's science and technology development organization), Siemens Transmission and Distribution, and about 30 electric utilities and independent system operators in the U.S., Canada, and New Zealand. The CSC is the latest in a series of transmission control technologies known as FACTS (Flexible Alternating Current Transmission Systems) that have been developed by EPRI in cooperation with several electric utilities, including NYPA.

Other efforts are underway to examine existing transmission lines and identify those that are good candidates for the replacement of limiting elements that could increase their ratings. Because numerous in-state transfer limits are in a linear path from upstate to downstate, reinforcement of a single transmission interface may provide only marginal benefit because the next interface on that path will become the next most limiting element for power transfers. Therefore, to move more power from upstate to downstate could require reinforcements over most of the path, not just reinforcing a single weakest link.

Electricity Generation[23]

The landscape of electric power generation in New York State, and the country as a whole, has shifted dramatically in recent years - from a preponderance of generation owned by investor-owned utilities to the present situation where most of the generation in the State is privately owned. Generators now compete directly with each other to supply power. Those generators with access to inexpensive fuels and low cost, efficient technology will compete successfully. Older, inefficient technologies will likely be driven out of the market.

New York has moved from an energy sector that was heavily dependent on coal and oil to a sector that is becoming increasingly dependent on natural gas. Almost all of the new generation proposed to be built in New York State is to be fired with natural gas. In addition, air quality requirements are reducing the operation of existing coal and oil facilities and leading to the retirement of some coal and oil plants. Most of the new combined-cycle gas-fired power plants can achieve efficiencies of greater than 50%, as compared to approximately 33% for existing generation. In some applications, older gas and oil-fired steam plants may be repowered into more efficient combined-cycle plants. While these higher efficiencies can mitigate, to some degree, the excessive demand for natural gas, a significant increase in the use of natural gas for electricity generation can still be expected.

The "capacity mix," by fuel type, that was available in 2000 in New York State is shown in Table 7.[24] Table 8 indicates the "energy mix" by the types of fuels that were used for generation in 2000. As indicated by the tables, both the capacity and energy mixes are distributed primarily among facilities that burn fossil fuels (*e.g.*, natural gas and coal), use the energy from moving water (hydropower generation), or use the energy from fission of uranium (nuclear generation).

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[23] The status and expectations for additional generation were presented above in the "New York State Wholesale Market" section of this Electricity Resource Assessment.

[24] The current "capacity mix" is not significantly different than the 2000 capacity mix.

Table 7

FUEL MIX BASED ON CAPACITY OF NYS INSTALLED UNITS IN % OF TOTAL	
Generators (by Fuel Used)	**2000**
Natural Gas	12%
Oil	11%
Natural Gas/Oil[25]	35%
Coal	11%
Nuclear	14%
Hydropower	15.5%
Other	1.5%
TOTAL	100%

Table 8

FUEL MIX BASED ON ENERGY PRODUCED FOR THE NEW YORK ELECTRICITY SYSTEM In % of Total	
Generation Fuel Used	**2000**
Natural Gas	25.0%
Oil	9.8%
Coal	15.7%
Nuclear	20.1%
Hydropower	15.5%
Other	2.0%
Net Imports	11.9%
TOTAL	100.0%

Other types of generation (*e.g.*, using wind, biomass, or wood), while not providing a large portion of the generation today, are important and will likely expand over time, especially if the goals and recommendations of this State Energy Plan are met.

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[25] The natural gas/oil generating units are facilities that are capable of burning either natural gas or oil. Generally, these units will burn natural gas as the dominant fuel.

Fossil Fueled Generation (Natural Gas, Oil, and Coal). In the year 2000, about 79,000 GWh of electricity, or slightly more than 50% of the electricity used in New York State, was produced by fossil fuel-fired generating plants in the State. On a statewide basis, 25 % came from natural gas, 15.7 % from coal and 9.8 % from oil. Over the last 20 years, natural gas usage more than doubled due to price, availability, and environmental considerations. By the year 2020, the State's dependence on natural gas for electric generation could increase to almost 40%.

The changing picture of the State's fuel generation mix can be traced back to the political, environmental, and economic events of the 1970s. In 1970, the federal government enacted the Clean Air Act (CAA), which set National Ambient Air Quality Standards (NAAQS) for the states. As part of this Act, the Federal Environmental Protection Agency (EPA) was established. The U.S. EPA subsequently required the states to prepare State Implementation Plans (SIP) to achieve and maintain the NAAQS. In response, the New York SIP set emission standards for all air pollution sources. For sulfur dioxide emissions, the standard translated into a limit of 0.3% sulfur content in the fuel for power plants burning oil in New York City and Nassau County. This new limit had a significant cost impact for downstate electric customers. The oil embargo of 1973 exacerbated this condition. Moreover, power plants in New York City were prohibited from burning coal in their boilers.

Also in the early 1970s, New York State enacted the Article VIII statute, which required all utilities planning generation additions to file siting applications with the New York Siting Board. These applications were adjudicated in proceedings that attempted to balance the need for the power plants against the plants' environmental impacts. Because of the oil embargo and the uncertainty surrounding the availability of low cost oil, as well as the unavailability of natural gas for newly installed power plants, all applications filed were for nuclear or coal generation. Only one power plant was sited under the Article VIII legislation - the 650 MW Somerset coal plant went into service in 1984. That plant was required by the Siting Board to have sulfur dioxide scrubbers to ensure compliance with the Clean Air Act emission standards.

Just prior to the implementation of the Article VIII legislation, many electric utilities began the process of constructing major steam electric generating facilities and/or applying for the environmental permits required at that time, which resulted in their being exempt from the requirements of Article VIII. These facilities involved approximately 8,500 MW of oil-fired and nuclear generation (Bowline, Roseton, Oswego, Poletti, Northport, Indian Point 2 and 3, and Fitzpatrick). Most of these plants went into service by 1977. Also exempt from the provisions of Article VIII was the Nine

Mile 2 nuclear plant, which went into service in 1988. All of this generation was planned to deal with the power shortages of the early 1970s, which were characterized by frequent brownouts, particularly downstate.

In addition, during the early 1970s, Con Edison and the Long Island Lighting Company (LILCO) installed over 2,000 MW of peaking gas turbines to ameliorate the capacity shortage. Thus, most of the generation that went into service prior to 1985 was planned before the enactment of the Article VIII legislation.

Other watershed events took place in 1978, when the U.S. Congress passed the following legislation:

The Public Utility Regulatory Policy Act (PURPA), which required utilities to purchase the electric output of qualified generation facilities at the utilities' projected long run avoided costs;

2. The Power Plant and Industrial Use Fuel Act, which restricted the use of natural gas in boilers. This Act prevented natural gas from being an option for new power plants at the time; and

3. The Natural Gas Policy Act, which focused on a phased-in deregulation of prices of natural gas at the wellhead.

In essence, items 2 and 3 above delayed the effective implementation of PURPA until 1985. By that time, the Power plant and Industrial Fuel Use Act had been rescinded and natural gas prices at the wellhead were completely deregulated. The result, commonly referred to as the "gas bubble", was to make gas available and economic to power plant developers.

With a plentiful gas supply at low prices, New York State saw the emergence of independent power producers (IPPs) who took advantage of the PURPA legislation and subsequent related State legislation. The IPP capacity added from 1985 to the present is slightly over 5,000 MW, with approximately 4,300 MW dependent on natural gas.

In 1992, the State enacted the Article X siting law as the successor to the Article VIII siting statute. Like the Article VIII law, the Article X law requires a thorough environmental assessment. In addition, it requires a determination that the facility will be reasonably consistent with the State's most recent long-range planning objectives and strategies and that it was selected according to an approved procurement process.

With the availability of natural gas, coupled with the development of high efficiency combined cycle technology and the restructuring of the electricity industry, new organizations devoted primarily to development of generation facilities emerged. The first application submitted by such an organization in New York State for approval under Article X was for the 1,080 MW combined cycle power plants now under construction in Athens, New York. The pre-application report was received in late 1997, and the plant and site were certified in June 15, 2000. Construction is now well underway for service in 2003 or 2004. Including the Athens filing, 23 power plant projects subject to Article X have been announced formally, for a total of over 15,000 MW of potential electricity generation capacity. Some of these projects, however, are on hold, some have been abandoned, and decisions to drop others could occur.

Because of recent, large increases in load, reserve generating capacity necessary to ensure reliable operation of the electric system, especially in the New York City and Long Island areas, were projected to be below acceptable levels. Consequently, the New York Power Authority installed about 450 MW of gas turbines at various sites in New York City and on Long Island for 2001. Similarly, LIPA has arranged for the installation of approximately 400 MW of additional gas turbine capacity for the summer of 2002.

Nuclear Generation. Nuclear power plants are a significant contributor to the generation of electricity in New York State. In 2000, about 31,500 GWh of electricity, or more than 20% of electricity used in New York State, was produced by the six operating nuclear power plants in the State. Nuclear power was second only to natural gas (25%) in terms of the relative contribution to electricity production (see Tables 7 and 8 above). Over the last 10 years, nuclear power's contribution to meeting New York's electricity needs ranged from a low of 16% in 1992, to a high of 23%, in 1996 and again in 1999. Nuclear power plants also provide about 5,000 MW of summer electricity generating capacity, which represented nearly 14% of the in-State summer capacity in 2000.

The analysis provided later in this Assessment with regard to nuclear generation facilities suggest that the closure or loss of the State's existing nuclear-powered electric generating capacity would likely result in increased energy prices, increased dependence on fossil fuels, and an increase in emissions of greenhouse gases, acid rain precursers and particulates, and an increase in the need for additional resources to overcome decreased system reliability.

Table 9 provides basic information on each of the six operating nuclear power plants in New York State.

Regulation and Oversight. Nuclear power plants are primarily regulated by the U.S. Nuclear Regulatory Commission (NRC), for purposes of protecting public health and safety, and the environment. The New York State Department of Health (DOH) routinely monitors the environment around the nuclear power plants, including milk, water, soil, vegetation, air samples, direct radiation, and milk produced by nearby dairy cows. The New York State Department of Environmental Conservation (DEC) regulates most non-radiological emissions from the nuclear power plants in the State (*e.g.*, State Pollution Discharge Elimination System, Air Permits, RCRA).

Table 9

Operating Nuclear Power Plants in New York State[1]					
Name	**Type**	**Owner/ Operator**	**Size (MWh)**	**Date of Initial Commercial Operation**	**Date of License Expiration**
Indian Point 2	PWR	Entergy Nuclear Opeations, Inc.	951	1974	2013
Indian Point 3	PWR	Entergy Nuclear Opeations, Inc.	965	1976	2015
James A. FitzPatrick	BWR	Entergy Nuclear Opeations, Inc.	813	1975	2014
Nine Mile Point 1	BWR	Constellation Nuclear, LLC	565	1969	2009
Nine Mile Point 2	BWR	Constellation Nuclear, LLC. LIPA also owns 18%.	1,142	1988	2026
R.E. Ginna	PWR	Rochester Gas and Electric	480	1970	2009

[1]Information obtained from United States Nuclear Regulatory Commission (NRC) Information Digest,

The PSC has historically regulated nuclear power plants in terms of their participation in New York's electricity system, primarily through regulation of utility rates and operations. However, since the issuance of the last Energy Plan in 1998, five of the six operating nuclear power plants in New York State have been sold to non-utility electricity generating companies and now participate in the competitive wholesale electricity market.

Relicensing.[26] The Atomic Energy Act and NRC regulations limit commercial nuclear power plant licenses to an initial 40-year term but also permit such licenses to be renewed. As plants have begun to approach the expiration of their initial licenses, the NRC established the regulatory requirements (10 CFR Part 54) and associated review process for extending licenses for an additional 20 years. Such license extensions are predicated on a finding by the NRC that the particular plant seeking extension can and will continue to operate in a manner that fully protects public health and safety, and the environment. The review process includes extensive opportunities for public participation.

As of the preparation of this Assessment, eight of the 103 operating nuclear power plants in the United States had already received license extensions and several more have initiated the process to obtain such extensions. The Nuclear Energy Institute, a nuclear industry trade organization, has stated that virtually all operating U.S. nuclear plants will eventually apply for license extension. Table 9 includes both the date of initial operation and the current date of license expiration for New York's nuclear power plants. RG&E initiated discussions with the NRC in March 2002 regarding the potential relicensing of its Ginna nuclear power plant.

Waste Generated by Nuclear Power Plants. During normal operations, nuclear power plants produce radioactive waste products that require special handling and disposal, including low-level radioactive waste and spent nuclear fuel. Low-level radioactive waste includes items that have become contaminated with radioactive material or have become radioactive through exposure to the nuclear reaction process. This waste typically consists of mildly radioactive or contaminated protective clothing, rags, filters, reactor water treatment residues, equipment and tools. However, it can also include highly radioactive reactor components. Low-level radioactive waste is typically stored on-site by licensees until sufficient quantities are accumulated for shipment to a waste processor or an approved low-level radioactive waste disposal site. There are currently two low-level radioactive waste disposal facilities in the U.S. that accept waste from New York's nuclear power plants: the Chem-Nuclear facility in South Carolina; and the Envirocare facility in Utah. The South Carolina facility is the host disposal site for the Atlantic Interstate Low-Level Radioactive Waste Compact, whose other members are Connecticut and New Jersey. As part of the terms of the Compact, access to the

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[26] In formulating a Reference Resource Scenario for this Electricity Resource Assessment, it was assumed that all operating nuclear power plants in New York would continue to operate during the full 20-year energy planning period. In a separate analysis, the potential closing of those plants at the end of their initial license periods, and the impact such closing would have on the State's projected electricity generating capacity reserves is presented later in this Assessment.

Compact's disposal site by low-level radioactive waste generators located in non-compact-member states, including New York, is being phased out and will cease in 2008. The Envirocare facility essentially operates as a commercial disposal facility but cannot currently accept the full spectrum of low-level radioactive waste generated by nuclear power plants.

Spent nuclear fuel is used fuel from a nuclear reactor that is no longer efficient in creating electricity. However, it is still thermally hot, highly radioactive, and must be handled and stored with care. At power plant sites, spent fuel is generally stored in large water-filled pools. Under the provisions of the Nuclear Waste Policy Act of 1982, as amended, the U.S. Department of Energy (DOE) has the responsibility for developing permanent disposal capacity for spent fuel. The Act further specifies that spent fuel will be disposed of in a deep geologic repository and directs DOE to evaluate Yucca Mountain, Nevada as a possible site for such a repository. DOE has been studying the Yucca Mountain site for about 20 years to determine whether it is scientifically suitable for use as an underground repository. Based on the findings and recommendations from DOE, President Bush recently declared that the site is suitable and approved DOE's proceeding with site development. The Governor of Nevada subsequently exercised that State's right, as provided by the Nuclear Waste Policy Act, to veto the President's declaration and the matter is now before Congress which has the authority to override Nevada's veto.

While the Act required DOE to begin accepting spent fuel from commercial nuclear power plants in 1998, DOE has yet to establish the capability to receive spent fuel, either for storage or disposal, and is not expected to be able to accept spent fuel until at least 2010.

As the storage capacity of the nuclear power plant spent fuel pools is reached, plant operators have turned to dry cask storage. These casks are typically steel cylinders that are either welded or bolted closed, providing a leak-tight containment for the spent fuel. Each cylinder is surrounded by additional steel, concrete, or other material to provide radiation shielding for workers and members of the public. The filled casks are usually stored in an open area of the plant site on a concrete pad. Some of the cask designs can be used for both storage and later transportation to an off-site storage facility or permanent repository. Twenty nuclear plant stations around the country have been approved to implement dry cask storage. The FitzPatrick nuclear plant was the first New York plant to utilize dry cask storage. It began moving spent fuel to dry casks in the Spring of 2002 in order to provide sufficient pool capacity for its next refueling, scheduled for the Fall of 2002.

Security. The NRC requires nuclear power plant operators to maintain comprehensive physical protection systems (10 CFR Part 73) including, but not limited to: (1) an armed security force; (2) controlled access; (3) continuous site surveillance; and (4) redundant off-site communications. The NRC regularly inspects and tests such security capabilities. In addition, all New York plants have existing arrangements with the New York State Police and/or local law enforcement agencies to assist on-site security forces when necessary.

Following the September 11, 2001 terrorist attacks on the United States, the NRC ordered all nuclear plants operators to bring their facilities to the highest level of readiness. The NRC has been working closely with plant operators to determine the most appropriate and effective security enhancements and recently codified the actions it expects plant operators to pursue in a generic order issued to all nuclear power plants.

On October 12, 2001, Governor Pataki directed that National Guard troops be used to augment security at New York's nuclear power plants. In addition, the new New York State Office of Public Security, discussed in Section 1 of the Energy Plan, with the assistance of the Federal Bureau of Investigation, conducted an assessment of security at the Indian Point nuclear power plants. That assessment, completed in December 2001, concluded that security at Indian Point is robust and recommended a number of measures that are now being taken to make security even stronger. The NRC is also conducting its own security reviews of all nuclear power plant sites in the country. Additionally, on February 25, 2002, the NRC issued an Order to all nuclear power plant operators to implement additional security measures. Full implementation is to be completed no later than August 31, 2002.

Emergency Preparedness. The NRC and the Federal Emergency Management Agency (FEMA) have established comprehensive emergency preparedness requirements for nuclear power plants which include close coordination between the plant operators and local and state government emergency response organizations. Since 1980, each operator of a commercial nuclear power plant in the United States has been required to have both an on-site and off-site emergency response plan as a condition for obtaining and maintaining a license to operate the plant. On-site emergency response plans are approved by the NRC. Off-site plans (which are closely coordinated with the utility's on-site emergency response plan) are evaluated by FEMA and the results are provided to the NRC. The State participates in emergency drills for these plans, as do all the affected counties. Such drills are evaluated by NRC and FEMA, which agencies have approved the emergency plans for all of the nuclear power plants in the State.

The New York State Emergency Management Office (SEMO) and DOH serve as the lead State agencies for nuclear power plant radiological emergency preparedness. In light of the September 11, 2001 terrorist attacks on the United States, the State requested NRC and FEMA to conduct a comprehensive review of federal planning standards and regulations for emergency plans at nuclear power plants.

Hydropower Generation. See Section 3.3 "Renewable Energy Assessment" for a discussion of hydropower generation. As can be seen by Tables 7 and 8 above, about 15% of the installed capacity in the State was hydropower, and about 15.5% of the energy produced during 2000 was from hydropower facilities These facilities are an important element of the State's generation mix and are beneficial in providing for a diverse energy mix. Their operation should be continued and, where practicable, expanded.

Other Generation. As shown in Tables 7 and 8, these "Other" forms of generation facilities (which include both renewable and non-renewable facilities that are not conveniently grouped in the previous categories, *e.g.*, wind, biomass, muncipal waste) made up only about 1.5% of the State's capacity infrastructure and provided only about 2.0% of the State's electric energy needs in 2000. Such facilities, which could proliferate over the planning period, particularly if the goals and strategies suggested in this Energy Plan are met, should provide the State with an important contribution in maintaining a balanced, diverse energy mix, a cleaner environment, and a healthy economy.

The greatest contributors to the "Other" generation category currently are municipal waste-to-energy facilities. These are facilities that incinerate municipal solid waste to convert water to steam, which is then typically used in conjuction with a turbine to generate electric power. Incineration technology is relatively mature, and dramatic advancements in technology are unlikely. Of future interest, however, is anaerobic digestion technology, which produces methane from the municipal waste to generate electric power, as opposed to burning the waste to obtain the power. While attempts have been made in the U.S. to develop anaerobic digestion, various obstacles to commercialization still exist.

During the U.S. EPA and NYS DEC Air and Solid Waste permitting processes for waste-to-energy facilities, no significant, unresolvable issues have been identified. Federal standards have reduced the potential for air impacts, and DOH has repeatedly conducted health assessments to ensure the public health is not at risk.

There are ten waste-to-energy facilities operating currently in New York, all of which became operational prior to 1994. In 2000, these facilities in New York represented 260 MW of installed capacity (231 MW net capacity). The facilities sold over 1.9 million MWh of electricity in 2000, representing about 1.4% of electricity sold in New York.

SYSTEM OPERATIONS

The NYISO has the responsibility for the reliable and lowest cost operation of the New York State power system. The NYISO operates the system according to rules and procedures approved by the FERC, which allow it to receive bids from generators and loads and to schedule generators according to the lowest cost combination for the State. This least cost scheduling is done both for a day-ahead commitment of generators and for the real time operation of the system within the constraints of maintaining system reliability at all times.

The NYISO continuously coordinates its operations with each of its neighboring control areas, including New England, PJM (Pennsylvania, New Jersey, Maryland), Quebec, and Ontario. Power flows are scheduled in advance to accommodate economically desirable transactions, and adjustments are made in real time to maintain reliability.

Reliability criteria for the operation of the New York State system are developed and monitored by the New York State Reliability Council. This organization has representatives from each of the transmission owning utilities, other market participants, and independent members. Each of the reliability rules, including local reliability rules, must be approved by this Council, which also has the responsibility for determining the statewide installed generation reserve margin necessary to meet generally accepted reliability criteria.

INFRASTRUCTURE SECURITY

Governor Pataki created the Office of Public Security in October 2001. That office is charged with developing a comprehensive statewide anti-terrorism strategy, including an assessment of the vulnerability of critical infrastructures to terrorist attack. That vulnerability assessment will include nuclear and other power plants, telecommunication systems, gas pipelines, and water systems. Strategies designed to protect these facilities from attack are being developed, and the plans will be augmented to provide rapid restoration of utility service in the event of terrorist attack.

Concurrently, the DPS established the Security Assessment Team to assess regulated utility efforts to maintain system reliability and security. This team is coordinating its activities with the Office of Public Security and appropriate federal agencies. The objective of the Department's team is to analyze each utility's security plans, policies, and procedures relating to the vulnerability and protection of critical utility operational and administrative facilities. The team will also be reviewing longer-term security plans and strategies, and the utilities' abilities to accomplish timely restoration, especially in the presence of biological and chemical agents.

ELECTRICITY LOAD AND RETAIL PRICE FORECASTS

Approach

The long-range forecasts (*i.e.,* through 2021) of electricity demand and retail prices were developed from forecasts prepared by the Department of Energy's Energy Information Administration (EIA) and captured in its *Annual Energy Outlook 2002 (AEO 2002)*. New York electricity demand forecasts are modified from the EIA Electricity Market Module forecast for the New York Control Area (NYCA). The outlook forecast is an estimate of future fuel market conditions, given current demand patterns, approved legislation, and predictable business cycles. The High and Low forecasts are derived from the *AEO 2002* national demand and price forecasts. The High and Low forecasts establish a range within which it is reasonable to believe demand and prices will fall. The High or Low case, does not necessarily infer a high or low demand or price case, but a High or Low Economic case. In the High Economic Case, the U.S. economy grows 3.4% annually, over the forecast period. In the Low Economic Case, the U.S. economy grows only 2.4% annually, over that same period. The methodologies used to develop the State Energy Plan projections of demand and retail prices for electricity are described in greater detail in the Forecast Summary (Section 3.1) and the Forecast Appendix.

Load

Growth in peak demand, depicted in Figure 1, is projected to be between 0.75% and 1.23% per year, with an Outlook Case growth rate of 0.92% per year. Growth in total electricity requirements, depicted in Figure 2, is projected to be between 0.76% and 1.32% per year, with an Outlook Case growth rate of 0.99% per year.

Figure 1

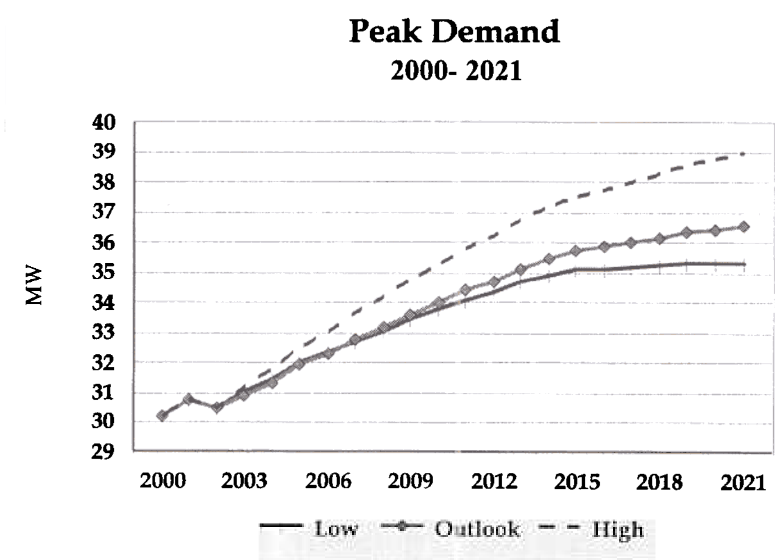
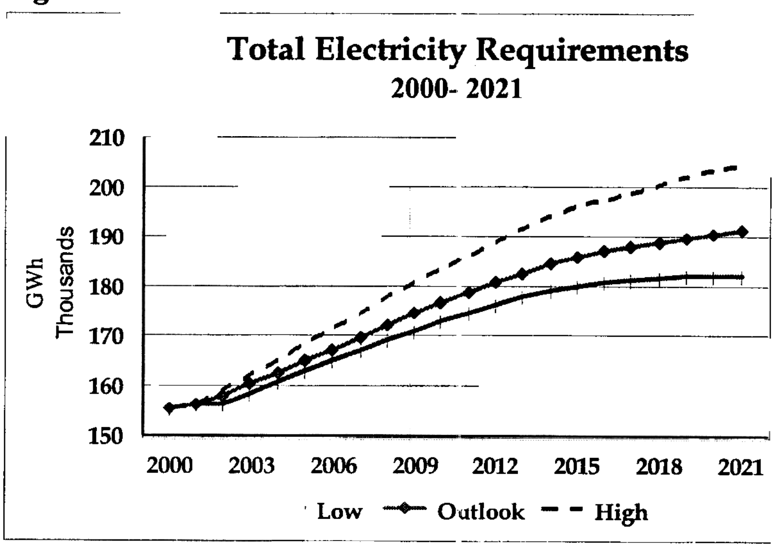


Figure 2



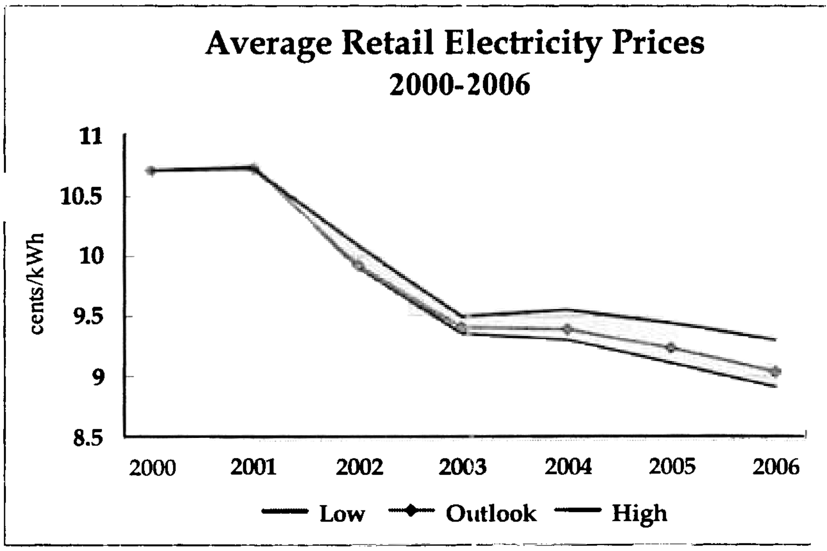
Retail Prices (Energy and Delivery)

During the past several years, the State's electric customers have received the benefits of significant reductions in their electric delivery rates, and these savings will continue to accumulate into the future. Since 1996, the PSC has issued orders that will result in cumulative customer savings of about $6 billion through 2003, with additional annual savings of about $1.5 billion expected thereafter. LIPA has similarly provided over $2 billion in base rate savings so far for its customers.

This section of the Electricity Resource Assessment forecasts average retail electricity prices over the planning period, which would include both the competitive energy and the regulated delivery components of customer bills.

Near-term average statewide retail electricity prices, through 2006, depicted in Figure 3, are projected to decrease by 3.64% per year in the Low Economic Case, 3.36% per year in the Outlook Case, and 2.80% per year in the High Economic Case, in constant 2000 dollars.

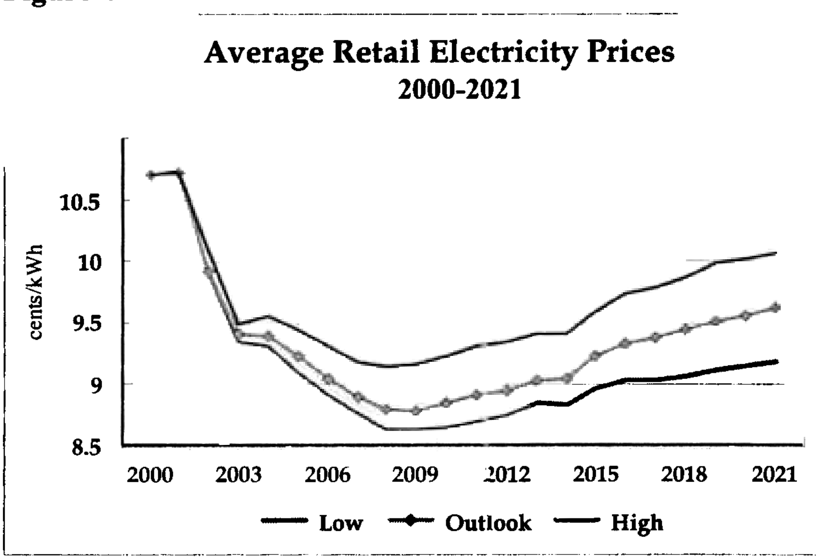
Figure 3



Long-term average statewide retail electricity prices, through 2021, depicted in Figure 4, are projected to decrease in constant 2000 dollars by 0.73% per year in the Low Economic Case, 0.51% per year in the Outlook Case, and 0.29% in the High Economic Case.

LONG-RANGE PLANNING SCENARIOS

Figure 4



The Energy Law requires forecasts and assessments over a 20-year period. Accordingly, this section of the Electricity Resource Assessment provides several long-range planning scenarios that provide insights about various possible energy futures and show trends that could occur as a result of decisions made at this time. The scenarios of the Draft Energy Plan were used as starting points for the development of the scenarios presented here, with assumptions modified to reflect changed conditions. Some of the

Draft Energy Plan scenarios, however, were not updated because the basic trends that were shown in the Draft are not expected to changed dramatically and no significant additional information would be derived from an updating exercise. Finally, several additional scenarios were developed to provide information in response to comments received on the Draft Energy Plan. For all the scenarios considered, however, one should understand that they are not intended to serve as an accurate predictor of the future (or even of the present, as some conditions may have changed between the time the analysis was performed and the time of publication) or necessarily to present preferred outcomes. Certainly, conditions will change over time, and some conditions will change based on policy decisions that the Planning Board is making in this Energy Plan.

For most of the scenarios considered below, projected changes in reserve margins, generation fuel use, wholesale electric energy price trends, and air emission trends are presented. For wholesale electric energy price trends, the analyses were based on "locational based marginal prices" (LBMPs) derived from computer simulations of the electric system. While these do not reflect the ultimate prices that would include such elements as ancillary service costs, capacity costs, and NYISO administrative charges, they do provide a reasonable method for comparison of trends resulting from different decisions about the future of the electric system.

All of the scenarios studied include provisions by 2008 to ensure compliance with expected emissions caps resulting from the Governor's Acid Deposition Reduction Program. No further specific system modifications to ensure compliance in the later years of the study period were included in the analyses undertaken here, primarily because plans for such modifications would be extremely speculative at this time. The analyses in this Assessment, instead, are based on assumptions that will provide emissions data in the absence of further emissions controls so that the various scenarios may be compared without the introduction of additional factors. Obviously, while some of the scenarios show emissions that would exceed the expected caps, these conditions would not be allowed to occur in actual practice. At some point, existing units would need to reduce emissions further, cease operations, or purchase emissions credits, if available, all of which would likely impact costs. Alternatively, the increase in emissions might be halted by reductions in demand, introduction of renewable energy technologies, or addition of new, more efficient, non-renewable generation to replace existing, less efficient generation (which would also be needed in most scenarios to maintain adequate reserve margins). Each of these solutions could impact the costs of wholesale energy and ultimately the retail costs for the consumer. All of the strategies will need to be considered over time as the need arises and system conditions become clearer.

No Additional Construction Scenario

As a starting point for analysis purposes, this scenario assumes that no additional generation or transmission, other than those facilities under construction at the time of this analysis or committed through the SBC program (about 2000 MW total), will be installed, no additional benefits from new demand reduction programs will be achieved during the planning period, and about 570 MW of existing capacity will be retired. Under these assumptions, and based on the load forecast presented later, the current statewide reserve margin[27] target of 18% would not be met by 2005 (see Table 10).[28] Additional resources would be needed even before that date if load should increase to a greater degree than projected or some of the expected interim resources do not materialize or are delayed. In particular, this scenario assumed:

1 The fuel price, load, and demand reductions described in the forecast section of this Energy Plan will occur;

2. Only 1,080 MW of additional generation certified under Article X of the Public Service Law, which is currently under construction, will be placed into operation during the planning period;

3. Approximately 693 MW of additional capacity from miscellaneous non-Article X generation will become available in 2002 and 2003 (432 MW in 2002 and 261 MW in 2003);

4. Approximately 222 MW of additional renewables will be added between 2002 and 2006 through use of the System Benefit Charge program;

5. Retirements or deactivation of 60 MW of generation in 2004 and 511 MW in 2005 will occur;

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[27] Reserve margins requirements (also known as installed reserve margin or system reserve margin requirements) are established by the New York State Reliability Council. The purpose of the reserve margin is to ensure reliability within the control system, that is, a system in which the probability of a customer outage due to lack of supply will be no greater than once in any 10-year period. The reserve margin is determined annually on February 1st, 90 days before the capability year beginning May 1. The reserve margin is defined as the ratio of required excess generation capacity to projected peak load demand within the control area. Currently, the reserve margin requirement for the New York Control Area has been established at 18%. The one day in ten year generation standard assumes that transmission os always available and that normal peak loads occur. Because extreme weather and transmission outages also have a probability of occurrence, meeting the generation standard results in actual probabilities of rolling blackouts that are higher than one day in ten years.

[28] Approximately 5,400 MW of additional resources would be needed by 2020 to maintain the 18% reserve margin requirement throughout the period.

6. All other existing units in the State will continue to operate, with relicensing of all operating nuclear and hydropower units occurring;

7. Firm purchases and sales, as described in the ISO's 2001 Load and Capability Analysis, filed with the New York State Energy Planning Board, will take place; and

8. No additional transmission interconnections, other than the Cross-Sound cable now under construction, will occur to provide for additional power and reserve interchanges.

Table 10

PROJECTED RESERVE MARGINS WITH NO ADDITIONAL RESOURCES										
2002	2003	2005	2007	2009	2011	2013	2015	2017	2019	2020
21.6%	21.1%	17.9%	14.8%	11.8%	9.3%	7.0%	5.3%	4.3%	3.5%	2.8%

More importantly, perhaps, is the fact that the necessary reliability requirements in critical load pocket areas such as New York City and Long Island would not be achieved.[29] Clearly, the system would not be reliable under these circumstances. Assuming for analysis purposes, however, that the system, although constrained, would actually function in accordance with this scenario, the following results might be seen.

Capacity and Energy Mix. Table 11 below shows how the system's "capacity mix" might change between the historical reference year 2000 and 2020 under the "No Additional Construction" scenario. Similarly, Table 12 shows how the system's "energy mix" might change between the reference year 2000 and 2020. The tables indicate that the use of natural gas would likely increase as a percentage of the State's energy mix (due in part to the addition of the Athens gas-fired facility and the various gas turbines being installed in the New York City and Long Island area to meet the 2002 and 2003 loads).

[29]As previously noted, an adequate statewide reserve margin does not necessarily translate into adequate reserves for specific areas within the State, such as New York City and Long Island. Efforts are underway to ensure that reliability criteria specific for New York City and Long Island are met for the summers of 2002 and 2003. The projections here assume that those efforts will be sucessful. An analysis of the New York City and Long Island areas is provided later.

Table 11

FUEL MIX CHANGES BASED ON CAPACITY OF INSTALLED UNITS (NO ADDITIONAL CONSTRUCTION SCENARIO)			
Generation Fuel	**2000 (Actual)**	**2002 (Projected)**	**2020 (Projected)**
Natural Gas	11.9%	15.0%	18.2%
Oil	10.9%	10.5%	10.1%
Natural Gas/Oil	34.8%	33.4%	32.6%
Coal	11.2%	10.8%	9.2%
Nuclear	14.0%	13.5%	13.2%
Hydropower	15.3%	14.8%	14.4%
Other	1.9%	2.0%	2.4%
TOTAL	100%	100%	100%

Table 12

GENERATION CHANGES BY FUEL TYPE In % of Total Energy Produced (NO ADDITIONAL CONSTRUCTION SCENARIO)									
Fuel	**2000** (Actual)	**2002**	**2003**	**2004**	**2005**	**2008**	**2012**	**2016**	**2020**
Natural Gas	25%	26.2%	26.9%	29.7%	32.4%	32.2%	33.5%	34.0%	34.4%
Oil	9.8%	5.0%	4.5%	3.6%	4.1%	5.5%	6.2%	7.1%	7.8%
Coal	15.7%	16.9%	16.7%	15.7%	10.8%	10.8%	10.7%	10.8%	10.8%
Nuclear	20.1%	20.6%	20.3%	20.1%	19.7%	18.9%	18.1%	17.5%	17.1%
Hydropower	15.5%	18.4%	18.1%	17.9%	17.6%	16.9%	16.0%	15.6%	15.4%
Other	2.0%	1.8%	1.9%	1.9%	2.0%	2.0%	1.9%	1.9%	1.9%
Net Imports	11.9%	11.1%	11.6%	11.2%	13.5%	13.8%	13.6%	13.2%	12.6%
TOTAL	100%	100%	100%	100%	100%	100%	100%	100%	100%

Wholesale Electric Energy Price Changes. Table 13 shows how wholesale electric energy prices (LBMPs in the NYISO lexicon) might change during the planning period under the "No Additional Construction" scenario. The table indicates that, assuming the electric system would continue to function, wholesale electric energy prices, in real or constant dollars, could increase on average about 40% over the planning period, with the greatest increases downstate (perhaps as much as 47%). These increases would result primarily because existing inefficient generating units would be called upon to operate more often. In addition, because of insufficient reserves, as well as the impact of emission caps, the total wholesale cost of electricity would likely be higher, especially downstate.

Table 13

RELATIVE PROJECTED WHOLESALE ENERGY PRICE INDEX CHANGES[30] (NO ADDITIONAL CONSTRUCTION SCENARIO)								
Transmission Zone	**2002**	**2003**	**2004**	**2005**	**2008**	**2012**	**2016**	**2020**
West	0.79	0.78	0.77	0.84	0.86	0.93	1.01	1.07
Genesee	0.84	0.84	0.81	0.88	0.91	0.97	1.04	1.11
Central	0.86	0.85	0.82	0.89	0.92	0.98	1.05	1.11
Mohawk	0.89	0.89	0.85	0.92	0.95	1.01	1.08	1.13
North	0.88	0.88	0.85	0.91	0.93	0.98	1.04	1.07
Capital	0.94	0.94	0.89	0.95	0.99	1.05	1.12	1.17
Hudson	0.98	0.99	0.98	1.04	1.08	1.14	1.23	1.28
Millwood	0.99	0.99	0.98	1.04	1.07	1.13	1.22	1.29
Dunwoodie	1.11	1.12	1.12	1.13	1.25	1.35	1.47	1.50
NYC	1.00	1.01	1.00	1.05	1.13	1.23	1.34	1.42
Long Island	1.10	1.13	1.16	1.19	1.24	1.34	1.47	1.57
Statewide Average	1.00	1.00	0.99	1.05	1.12	1.21	1.32	1.40

Emission Changes. Table 14 shows how emissions might change during the planning period under the "No Additional Construction" scenario, assuming that no emissions caps were in place. The tables indicate that emissions of SO_2, NO_x, and CO_2 should decline between now and 2005, primarily due to the changes in existing generation that were assumed in an attempt to meet the Governor's Acid Deposition Reduction Program, but then would (without the cap) begin to increase as the existing units are asked to produce more energy for increasing demand.[31] As discussed above,

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[30] Indexed to the statewide 2002 weighted average LBMP in constant 2000 dollars. The current 11 transmission zones used in NYISO operations are displayed in this table.

[31] The expected emission caps of the Governor's Program would not be met under this scenario.

wholesale price impacts under this scenario do not reflect the increased costs of compliance with air emission requirements to meet caps for SO_x and NO_x .

Table 14

PROJECTED EMISSION CHANGES (NO ADDITIONAL CONSTRUCTION SCENARIO)								
Emission (000s tons)	2002	2003	2004	2005	2008	2012	2016	2020
Annual $S0_2$	324.3	317.5	289.6	158.6	164.7	186.1	200.2	209.7
Annual $N0_x$	104.3	101.1	87.7	66.3	72.2	82.8	90.4	95.2
5-Month $N0_x$	40.1	38.0	35.3	30.3	33.6	38.1	42.6	45.0
Annual $C0_2$	59,422	59,422	58,092	52,427	56,749	62,103	66,743	69,991
PROJECTED EMISSION INDEX CHANGES (NO ADDITIONAL CONSTRUCTION SCENARIO)								
Emission	2002	2003	2004	2005	2008	2012	2016	2020
Annual $S0_2$	1	0.98	0.89	0.49	0.51	0.57	0.62	0.65
Annual $N0_x$	1	0.97	0.84	0.64	0.69	0.79	0.87	0.91
5-Month $N0_x$	1	0.95	0.88	0.763	0.84	0.95	1.06	1.12
Annual $C0_2$	1	1	0.98	0.88	0.96	1.05	1.12	1.18

High Resource Scenario

At the opposite end of the spectrum from the "No Additional Construction" scenario would be a scenario that postulates significantly greater reserves. Such a scenario was provided in the Draft Energy Plan as the "More Generation Sensitivity." It was based on the addition of capacity to the New York electricity system at a pace needed to reach a reasonably high reserve margin level (30%) for the New York electricity system. Based on updated assumptions, the "High Resource" scenario (or the "More Generation Sensitivity") would require about 9,000 MW of resources above the 2,000 MW assumed in the "No Additional Construction" scenario above (approximately 11,000 MW total between 2002 and 2020). If one were to assume that the additional resources would be gas-fired, consistent with current trends, and assume that they would be located in the appropriate locations in the State, the system's capacity and energy mix would show a marked increased reliance on gas-fired generation, wholesale energy prices would decline significantly in real terms throughout the planning period, and emissions would likely be reduced, making compliance with emissions caps less expensive (which could be reflected in a lower market price). One can question, however, the premise that developers would continue to add generation when reserve margins exceed 18% to such an extent.

Reference Resource Scenario

A more likely scenario is that generation will be built during the next few years to maintain the margin at or somewhat above 18%, but not sustained at the higher 30% level assumed in the "High Resource" scenario. Accordingly, Table 15 below provides the results of a statewide load and capability analysis using one reasonable set of minimum resource assumptions and three different forecasts of peak system loads (low-, mid-, and high-range forecasts, as set forth in the "Electricity Load and Price Forecasts" section in this Electricity Resource Assessment). The resources assumed in this analysis are the same as assumed for the "No Additional Construction" scenario plus others that might reasonably be expected (at the time of this analysis[32]) to be available during the planning period, based on planned projects that have been publicly announced as of this time.[33] For this scenario, 7,139 MW of new resources are assumed to be added during the time period 2002 through 2020 (more than the 2,000 MW assumed for the "No Additional Construction" scenario, but less than the 11,000 MW assumed for the "High Resource" scenario). In particular, the "Reference Resource" scenario includes the same assumptions as previously listed for the "No Additional Construction" scenario except that:

> Instead of only about 2,000 MW of additional generation, 7,139 MW is assumed to be placed into operation between 2002 and 2006 (5,224 MW of Article X projects, 1,000 MW of firm capacity from facilities located outside New York State, 693 MW of small scale generation under construction in New York City and on Long Island, and 222 MW of projects through the SBC program). It should be noted that the existence of a certificate to construct and operate a generation plant does not guarantee that the plant will in fact be built and

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[32] Subsequent to this analysis, one approved generation project has been cancelled and there have been indications that some others could be delayed or even cancelled. The "Reference Resource" scenario, however, was designed with an assumption that all the planned units will not be built, and it was not intended to represent the only viable or preferred expansion plan for the State. Even if some projects may ultimately be cancelled or delayed, or if more are built than modeled, or more are retired than assumed, the scenario remains valid as a base or reference for assessing the impacts of the other scenarios presented in this section of the Assessment.

[33] As noted, the "Reference Resource" scenario considers only known projects. It does not provide for additional resources to be added in the later years of the planning period as reserve margins begin to decline. One should expect, however, that such additional resources will be added when they are needed to maintain adequate reserve margins. For the limited purposes of the analyses presented here, however, no such additions are included.

operated. The assumptions for this scenario assume that only about half of the capacity of the plants that have filed for certificates under Article X will be developed. These assumptions, however, should not be interpreted as any prejudgment of particular applications.

Several new transmission interconnections will take place to provide for power interchanges and installed reserves.

Of course, many other resource scenarios might also be considered, and several such alternatives are discussed later. Further, the existence of an appropriate statewide reserve level does not necessarily ensure that adequate resources exist in every area, or any specific area, of the State. It is clear, however, that the greater the supply of generation in relation to demand (or the smaller the demand in relation to supply), within a reasonable range, the better consumers will likely be in terms of both price and reliability.

New York State Reliability. As can be seen in Table 15, the statewide reserve margins during the planning period might be as high as 33% or as low as 9.6%, depending on the load forecast assumed (and assuming no additional resources are added to maintain an 18% reserve margin). The data based on the Outlook (or Mid-Range) forecast, using the "Reference Resource" expansion scenario, shows that statewide reserve margins throughout the planning period could exceed the 18% level until about 2019 when additional resources would be needed.[34] Reserves could even exceed 33% in the 2005 time frame, but they would decline over time as load increases and no new generation or additional load reduction occurs under this specific scenario. As noted previously, however, these projections are made on a statewide basis; accordingly, conditions in the critical New York City and Long Island area must be examined separately.

New York City and Long Island Reliability. The "Reference Resource" scenario assumes that by 2006 and thereafter, 11,698 MW of generation capacity will be available within (or connected directly into) New York City (NYC) and 5,915 MW of generation capacity will be available on Long Island (LI). Table 16 shows how this capacity is projected to increase from now through 2006 (no additional resources are assumed in the "Reference Resource" scenario after 2006).

[34] Approximately 270 MW of additional resources would be needed by 2020 to maintain the 18% reserve margin requirement throughout the period.

Table 15

PROJECTED RESERVE MARGINS (%) (REFERENCE RESOURCE SCENARIO)											
Forecast	**2002**	**2003**	**2005**	**2007**	**2009**	**2011**	**2013**	**2015**	**2017**	**2019**	**2020**
Low-Range	21.6	20.5	33.0	30.8	27.8	25.4	23.3	21.8	21.4	21.0	21.0
Outlook Mid-Range	21.6	21.1	33.4	30.5	27.1	24.2	21.6	19.7	18.6	17.6	17.3
High-Range	21.6	19.8	31.0	27.1	23.0	19.4	16.2	13.8	12.4	10.8	10.2

Table 16

INSTALLED CAPACITY (MW IN EACH YEAR)								
Location/Year	2002	2003	2004	2005	2006	2010	2015	2020
NYC	8,760	8,974	9,836	11,357	11,548	11,548	11,548	11,548
LI	5,033	5,080	5,230	5,915	5,915	5,915	5,915	5,915

The generation increases shown between 2002 and 2003 are due to the addition of gas turbine units currently being installed at various sites in NYC and on LI, all of which are assumed to become available in time to serve loads. The larger increases for 2004 through 2006 are due to the addition of new or upgraded capacity authorized under Article X of the Public Service Law (see Table 3) or to be provided as firm capacity through proposed additional transmission line interconnections. For the New York City area, the analysis assumes that about 1,600 MW out of about 3,000 MW of new generation capacity subject to Article X will be constructed and in service during the 2004 to 2005 time period. It also assumes that 1,000 MW of additional firm generation capacity will also be available through new transmission interconnections with locations outside of New York City. For the Long Island area, the analysis assumes that about 800 MW out of 1,600 MW of new generation capacity subject to Article X will be constructed and in service during the 2004 and 2005 time period.

As previously noted, the assumptions of the "Reference Resource" scenario are not intended to represent any preferences or predictions concerning which projects might be certified and built. In addition, because of changing circumstances, the assumptions used for this analysis will not necessarily agree with actual conditions at any given time.

They do, however, provide a reasonable basis for undertaking the limited analysis below.

Customer loads in New York City and on Long Island have been projected by the NYISO through 2005 as shown in Table 17. The additional projections through 2020 have been added, for the limited purposes of this analysis, at an assumed 200 MW per year for New York City and 100 MW per year for Long Island.

Table 17

PROJECTED PEAK LOADS (MW in each year)								
Location/Year	2002	2003	2004	2005	2006	2010	2015	2020
NYC	10,665	10,930	11,105	11,245	11,445	12,245	13,245	14,245
LI	4,777	4,939	5,014	5,114	5,214	5,614	6,114	6,614

Under the New York State reliability rules, sufficient installed capacity must be located within the confines of each area (or connected directly to them) to meet the annually calculated locational requirements for New York City and Long Island, currently 80% and 93%, respectively, of the projected loads. As shown in Table 18, these criteria (assuming they remain the same) can be met through most of the planning period based on the projected generation additions and the assumed loads. If the loads should grow faster than assumed, or if less generation (either internal to the areas of connected directly with transmission lines) than projected becomes available, additional resources would be needed sooner than expected. On the other hand, the need date for additional generation in these areas would be extend further out in time if loads grow slower than projected, demand is reduced (either through conservation, demand management programs, or the use of distributed generation facilities to off-set system load), and/or a greater percentage of Article X generation (or transmission interconnections with dedicated generation) becomes operational.

Table 18

PERCENT OF LOAD COVERED BY LOCAL GENERATION (% EACH YEAR)								
Location/Year	2002	2003	2004	2005	2006	2010	2015	2020
NYC (80% Req'd)	82	82	89	101	101	94	87	81
LI (93% Req'd)	105	103	104	116	113	105	97	89

An on-going study funded by the NYSERDA and the NYISO to address the interrelationships of the natural gas and electricity systems is described in the "Natural Gas Assessment" and "Promoting Energy Industry Competition" issue paper sections of this Energy Plan. The results of that study and the analysis presented in those sections of the Energy Plan indicate that adequate pipeline capacity exists to serve electric generation needs, but that additional pipeline capacity now under consideration will be beneficial for ensuring reliability, allowing for reduced air emissions, and addressing matters that the study did not consider.

To the extent that the proposed new capacity is installed, and/or demand reduction efforts are successful, in a timely manner, the New York City and Long Island systems should continue to provide reliable service through most of the planning period, and emissions from older, less efficient generators will decline. Additional resources, however, will provide benefits to these areas and to the State as a whole through increased reliability, additional emission reductions, and potentially lower energy costs.[35] Finally, many other factors, such as transmission and distribution system maintenance, can affect system conditions. Most of those factors, however, are subject to regulatory oversight, with programs in place to monitor and upgrade such facilities as necessary to ensure reliable service.

Capacity and Energy Mix (statewide). Table 19 shows how the system's "capacity mix" might change between 2002 and 2020 under the "Reference Resource" scenario.

Similarly, Table 20 shows how the system's "energy mix" might change between 2002 and 2020. The tables indicate that natural gas use could increase significantly over the planning period. If this scenario unfolds as described, the State would become more and more reliant on natural gas. The potential for dependency on a single source, even though oil can be a back-up fuel in some cases, needs to be addressed through, for example, increased demand reduction efforts, additional renewables, and new technologies that do not rely on natural gas and oil.[36]

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[35] Wholesale power costs should decline in both New York City and on Long Island as new resources are added, as shown in Table 21 and discussed in the "Wholesale Price Changes" section below. Prices, however, could increase in the near term because of certain methodological changes in the LBMP calculation methodology the NYISO is proposing.

[36] This Energy Plan recommends such actions.

Table 19

FUEL MIX CHANGES BASED ON CAPACITY OF INSTALLED UNITS (REFERENCE RESOURCE SCENARIO)			
Generation Fuel	**2000**	**2002**	**2020**
Natural Gas	11.9%	15.0%	26.2%
Oil	10.9%	10.5%	9.1%
Natural Gas/Oil	34.7%	33.4%	29.4%
Coal	11.2%	10.8%	8.3%
Nuclear	14.0%	13.5%	11.9%
Hydropower	15.3%	14.8%	13.0%
Other	1.9%	2%	2.2%
TOTAL	100%	100%	100%

Table 20

GENERATION CHANGES BY FUEL TYPE In % of Total (REFERENCE RESOURCE SCENARIO)								
Generation Fuel	**2002**	**2003**	**2004**	**2005**	**2008**	**2012**	**2016**	**2020**
Natural Gas	26.2%	26.9%	31.2%	36.4%	37.5%	38.0%	38.8%	39.7%
Oil	5.0%	4.5%	3.1%	1.1%	1.2%	1.5%	2.0%	2.5%
Coal	16.9%	16.7%	15.3%	9.3%	9.0%	9.2%	9.6%	9.8%
Nuclear	20.6%	20.3%	20.1%	19.7%	18.9%	18.1%	17.5%	17.1%
Hydropower	18.4%	18.1%	17.8%	17.6%	17.0%	16.3%	15.8%	15.6%
Other	1.8%	1.9%	1.9%	2.0%	2.0%	1.9%	1.9%	1.8%
Net Imports	11.1%	11.6%	10.6%	13.9%	14.4%	15.0%	14.6%	13.5%
TOTAL	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

Wholesale Price Changes (statewide). Table 21 shows how wholesale electric energy prices (LBMPs) might change during the planning period under the "Reference Resource" scenario. The table indicates that under this scenario wholesale electric energy prices should decline in real terms in most areas of the State between now and some point between 2005 and 2008 as new, relatively efficient generation is added to the system, primarily downstate. Thereafter, as load continues to increase, but no additional generation is assumed to be added, wholesale electric energy prices would rise. The table suggests that on average there could be a 5% increase in real energy prices over the planning period if no significant additional generation units are added and no additional demand reduction techniques are employed after the 2004 - 2006 time period. This average is significantly less than the 40% increase expected with the "No Additional Construction" scenario. If additional resources were added in the later years of the planning period to maintain the 18% reserve margin, or to exceed that level as assumed in the "High Resource" scenario, wholesale electric energy prices would likely continue to fall throughout the planning period.

Table 21

RELATIVE PROJECTED WHOLESALE PRICE INDEX CHANGES[37]
(REFERENCE RESOURCE SCENARIO)

Transmission Zone	2002	2003	2004	2005	2008	2012	2016	2020
West	0.79	0.78	0.75	0.76	0.76	0.80	0.86	0.92
Genesee	0.84	0.84	0.78	0.78	0.78	0.81	0.87	0.92
Central	0.86	0.85	0.79	0.78	0.78	0.82	0.87	0.93
Mohawk	0.89	0.89	0.82	0.79	0.79	0.82	0.88	0.93
North	0.88	0.88	0.82	0.79	0.78	0.80	0.84	0.88
Capital	0.94	0.94	0.85	0.80	0.80	0.84	0.89	0.94
Hudson	0.98	0.99	0.96	0.83	0.82	0.86	0.91	0.97
Millwood	0.99	0.99	0.96	0.82	0.81	0.84	0.90	0.95
Dunwoodie	1.11	1.12	1.03	0.89	0.89	0.94	1.01	1.07
NYC	1.00	1.01	0.96	0.84	0.83	0.87	0.93	0.98
Long Island	1.16	1.13	1.17	0.94	0.98	1.05	1.16	1.25
Statewide Average	1.00	1.00	0.97	0.86	0.86	0.91	0.98	1.05

<u>Emission Changes (statewide)</u>. Table 22 shows how emissions might change during the planning period under the "Reference Resource" scenario. The table indicates

[37] Indexed to the statewide 2002 weighted average LBMP in constant 2000 dollars. The current 11 transmission zones used in NYISO operations are displayed in this table.

that significant emission reductions will occur in the early years of the planning period and then increase slightly after about 2008 (assuming no new generation is added that could displace less efficient generation), but will remain significantly below today's levels (except for CO_2, which decreases and then returns to approximately the same level as today).[38] The reductions are due primarily to the modifications of existing units resulting from the Governor's Acid Deposition Reduction Program, the introduction of efficient new gas-fired generation that off-sets existing generation, and new transmission interconnections. The subsequent increases occur because no additional resources are assumed added to off-set the need to use the older, less efficient generation for the increasing loads. Overall, the emission reduction benefits are greater than what would be obtained under the "No Additional Construction" scenario, but would likely be less than under the "High Resource" scenario.

Table 22

PROJECTED EMISSIONS CHANGES (REFERENCE RESOURCE SCENARIO)								
Emission (000s tons)	2002	2003	2004	2005	2008	2012	2016	2020
Annual SO_2	324.3	317.5	276.1	116.5	110.1	123.7	137.7	146.8
Annual NO_x	104.3	101.1	81.1	39.1	38.1	42.9	49.8	54.7
5-Month NO_x	40.1	38.0	32.2	18.3	18.4	21.7	25.4	27.7
Annual CO_2	59,422	59,422	57,778	46,213	48,210	52,705	57,075	60,541
PROJECTED EMISSION INDEX CHANGES (REFERENCE RESOURCE SCENARIO)								
Emission	2002	2003	2004	2005	2008	2012	2016	2020
Annual SO_2	1	0.98	0.85	0.36	0.34	0.38	0.42	0.45
Annual NO_x	1	0.97	0.78	0.37	0.37	0.41	0.48	0.52
5-Month NO_x	1	0.95	0.80	0.46	0.46	0.54	0.63	0.62
Annual CO_2	1	1	0.97	0..78	0.81	0.89	0.96	1.02

At some point during the next ten years, the U.S. electric power industry could face additional requirements to reduce emissions of NO_x, SO_2, CO_2, and mercury. Various "four-pollutant" (or "4-P") bills have been introduced at the federal level that

[38] In the later years of the planning period, system modification would be needed to maintain emissions below the cap, which could impact wholesale prices at that time.

would address all of these emissions simultaneously. The proposed bills vary widely with respect to timing and level of emission reductions for each pollutant. The 4-P approach is an alternative to regulations that would address each pollutant individually. Proponents have argued that a multi-pollutant strategy would lead to lower overall program and societal costs compared to pollutant-by-pollutant policies, and that it would provide greater regulatory certainty and lower industry investment risks.

The 4-P approach was not specifically modeled in the scenarios used for this Energy Plan because of the high uncertainty of timing and levels of control. In addition, there is considerable uncertainty about the cost and performance of mercury removal technologies because full-scale demonstrations have not yet been carried out.

The combination of new natural gas-fired generation capacity and implementation of the Governor's Acid Deposition Reduction Program will go a long way toward helping New York meet the emission reduction targets proposed in the more moderate of the 4-P bills, including emissions of CO_2. The cost and price impacts of reducing mercury emissions, however, are likely to be substantially larger than those of reducing SO_2 and NO_x. Overall, a 4-P bill could result in a substantial increase New York's electricity prices. From an acid rain perspective, this could benefit the State in that upwind State's emissions would be reduced.

Renewable Energy Scenario

As noted in the "Reference Resource" scenario discussion above, options to reverse the trend toward excessive dependency on natural gas need to be found. An option that should be considered is the expanded use of technologies that use renewable fuels (*e.g.*, biomass) or require no fuels (*e.g.*, wind). The "Reference Resource" scenario included a broad spectrum of electricity generation facilities that currently exist or might reasonably be expected to exist, including 222 MW of renewable resource capacity from wind which was based on conservative expectations resulting from the SBC initiatives. This "Renewable Energy" scenario includes all the facilities modeled in the "Reference Resource" scenario, plus an additional 2,278 MW of renewable resource facilities for a total renewable capacity of 2,500 MW. While this additional capacity represents a significant addition to the system, only a portion of it would contribute toward satisfying reserve margin requirements because much of it would not typically be available during peak load period. Even so, the addition of the renewable resources to the "Reference Resource" scenario capacity would provide much of the additional capacity needed in that scenario to maintain an 18% reserve margin during the last several years of the planning period when the "Reference Resource" scenario would otherwise be deficient.

These facilities would also help the State to meet expected emission caps.

The renewable generation technology selected for this scenario was based primarily upon information in the "Renewable Energy Assessment" (Section 3.3 of this Energy Plan). Table 23 lists the types and the cumulative capacity of facilities modeled in the "Renewable Energy" scenario.

Table 23

RENEWABLE ENERGY SCENARIO CUMULATIVE CAPACITY (MW)								
Renewable Category	**2002**	**2003**	**2004**	**2005**	**2008**	**2012**	**2016**	**2020**
Wind	45	195	595	795	1,295	2,045	2,045	2,045
Hydropower	0	35	50	75	110	135	150	162
Landfill Gas	56	61	67	73	77	77	77	77
Fuel Cells	0	0	0	0	10	50	100	150
Wood	0	0	0	36	36	36	36	36
Photovoltaics	1.2	3	5	8	13	18	24	30
Total	102.2	294	717	987	1,541	2,361	2,432	2,500

The following summarizes the "Renewable Energy" scenario assumptions for the respective technology.

Wind. The largest resource addition in this scenario is wind generation. A total of 1,645 MW of wind energy was modeled throughout upstate and 400 MW was modeled off the coast of Long Island, as these areas offer significant potential and promise for wind generators.

Hydropower. The second largest component of renewable capacity is based on hydropower. New York State has numerous opportunities for hydropower development at both existing hydropower facilities and at undeveloped sites. The 162 MW modeled in this scenario is based on retrofitting existing hydropower facilities. Efficiency improvements are currently being made to NYPA's Niagara and St. Lawrence hydropower facilities and are estimated to result in an additional 60 MW of capacity. The remaining 92 MW of additional hydropower capacity was modeled at the older, larger existing hydropower facilities.

Landfill Gas. The 56 MW of landfill gas capacity included in this scenario represents the existing landfill-gas-to-energy projects in New York State that were not included in the "Reference Resource" scenario. The additional landfill gas capacity was based on studies that identified economically viable landfill-gas-to-energy projects.

Fuel Cells. Currently, the costs of fuel cells limit their market share in the energy sector. As the technology develops, however, the cost should decrease and market share should increase. For this scenario, it was assumed that fuel cells will be most economically viable in 2008 in the highest electricity cost areas of the State (*i.e.,* predominately in New York City and on Long Island). As the technology matures and costs decrease, fuel cells will likely become economically viable throughout the State. For all locations, it was assumed the fuel cells will serve base loads.

Wood. This scenario also assumes one 36 MW wood facility would be constructed in the very northern portion of the State. This location was selected due to the proximity of a vast supply of wood for fuel.

Photovoltaics. The economic viability of a photovoltaic system depends on the relative cost of electricity and the availability of sunlight. For purposes of this analysis, it was assumed that, by 2020, 30 MW of photovoltaic electricity would be economically viable in New York City and on Long Island. While the other nine NYISO regions of the State may be economically viable for photovoltaic systems, it was not included in the analysis because the amount in any single region did not exceed the minimum threshold for modeling.

Generation Mix. Table 24 compares the generation mix of the "Reference Resource" scenario with the generation mix of the "Renewable Energy" scenario (*i.e.*, showing the impact of the addition of the 2,500 MW of renewable capacity). The additional hydropower capacity has been included in the "Hydropower" classification, while the remaining renewable generation has been classified as "Other."

Compared to the "Reference Resource" scenario, by 2020 when all the 2,500 MW of renewable generation is assumed to be operational, the use of natural gas, oil, and coal are reduced by 5%, 38%, and 1% respectively, resulting in a slightly improved fuel mix.

Table 24

Comparison of Generation Mix Based on Energy Produced Between the Renewable Energy and Reference Resource Scenarios In % of Total Generation				
	2002		2020	
Generation Fuels	Renewable Energy Scenario	Reference Resource Scenario	Renewable Energy Scenario	Reference Resource Scenario
Natural Gas	26.1%	26.2%	37.6%	39.7%
Oil	4.9%	5.0%	1.8%	2.5%
Coal	16.9%	16.9%	9.7%	9.8%
Nuclear	20.6%	20.6%	17.1%	17.1%
Hydropower	18.5%	18.4%	16.0%	15.6%
Other	2.1%	1.8%	5.9%	1.8%
Net Imports	10.9%	11.1%	11.8%	13.5%
Total	100%	100%	100%	100%

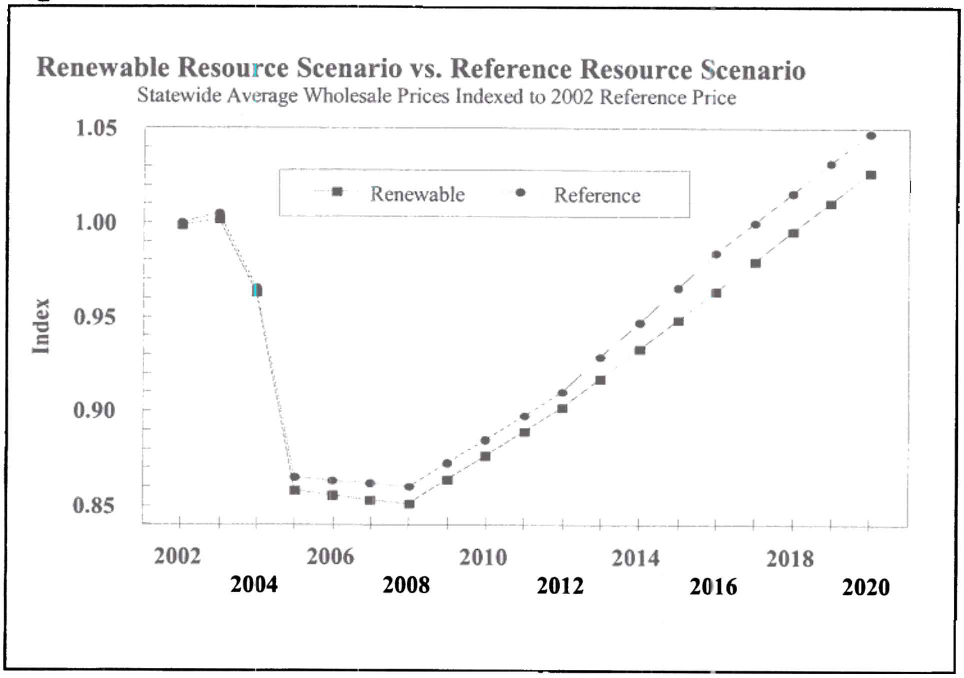
Wholesale Price Changes. In a competitive energy market, generators bid for the opportunity to supply electricity to the bulk transmission system. Certain types of generators operate only when it is cost-effective (*e.g.*, able to vary generation output). These generators are responsive to price and, under certain circumstances, are able to "set the price" for their respective zone. Other generators cannot modify their operations (*e.g.*, nuclear facility operates at a constant rate); those generators operate regardless of the cost to operate. These types of generators are not responsive to price and are "price takers."

Wind, hydropower, and landfill-gas-to-energy projects are not responsive to price. These technologies are reliant on the availability of their fuel source. For example, wind resources are intermittent resulting in a capacity factor of only about 30%. Within this "Renewable Energy" scenario, the wood burning generator is the only facility that responds to prices. Consequently, it is modeled as a standard generator. The remaining renewable technologies, fuel cells and photovoltaic, are modeled such that the demand is reduced.

Lower prices should occur from a load reduction situation, based on the economic supply/demand theory. The inability to vary operations such that the amount paid for the electricity reflects, at a minimum, the cost to produce the electricity, impacts the economic viability of a renewable energy project. As described in Section 3.3, a significant barrier to a renewable energy project is the premium cost of the electricity. Most, if not all, renewable energy projects receive some incentives in the form of tax credits and/or grants to improve their economic viability.

Figure 5 compares the projected wholesale electric energy prices over the planning period for the "Renewable Energy" scenario with the energy prices of the "Reference Resource" scenario. The weighted average of real wholesale electric energy prices in the State would increase to a somewhat lesser degree over the planning period with the renewables included (*i.e.*, the increase would be 3% instead of 5% at the end of the planning period).

Figure 5



The additional cost of the renewable energy facilities, however, is not reflected in these prices. Table 25 summarizes the premium costs (*i.e.*, the difference between the cost to produce electricity and the wholesale price) of the various renewable technologies simulated in this scenario over the planning period. If these costs to produce renewable electricity were incorporated into the statewide average wholesale price, the "Renewable Resource" scenario wholesale price would be higher by 2020.

Table 25

PREMIUM COST FOR RENEWABLE ENERGY IN CONSTANT 2000 $								
	2002	2003	2004	2005	2008	2012	2016	2020
Premium Cost for Renewable Energy (millions 2000$)	$3.9	$12.8	$38.8	$52.3	$108.9	$170.4	$175.5	$181.5
Premium Costs as a % of Total Cost to NYS	0.08%	0.26%	0.80%	1.20%	2.43%	3.41%	3.24%	3.09%

Emissions. Figures 6, 7, and 8 compare the changes in emissions that might be expected if the 2,500 MW of renewables are added to the "Reference Resource" scenario. Compared to the "Reference Resource" scenario with the renewables added, in 2002, SO_2, NO_x,, and CO_2 emissions increase slightly due to the additional 56 MW of landfill gas generation. Using landfill gas is beneficial in that methane (CH_4) emissions are reduced through combustion. However, landfill gas also has other constituents, such as the acid rain gases, SO_2 and NO_x. Installing air pollution control systems on such small generators would be cost-prohibitive for a landfill-gas-to-energy project. As more renewable energy is available, SO_2, NO_x, and CO_2 emissions decrease. For example, in the 2008 and 2020, SO_2 decreases by approximately 2% and 3%, the NO_x decreases by approximately 3% and 6%, and the CO_2 decreases by 3% and 6%, when compared to the "Reference Resource" scenario. Again, to the extent that the emissions are capped, forecast increases or decreases will not affect total emissions, but cost of compliance with the cap will be affected. This decreasing trend is associated with the additional non-thermal generation.

It should be noted again that while 2,045 MW of wind resource is a significant addition to the State's overall capacity, this capacity is only available when the wind resource is available. Consequently, during the peak demand months of the summer, especially on the hottest days, the wind capacity is likely to be significantly reduced. When demand is lower during other times of the year, only the most efficient, and thus lower emission rate generators will typically be used. As demand increases, less efficient, and thus higher emission rate, generators will then be required. During the higher demand periods, which occur during the summer months when the availability of wind resources are at the lowest, the less efficient, higher emission rate generators are used. Therefore, the emission reductions may not be as significant as one might anticipate.

Figure 6

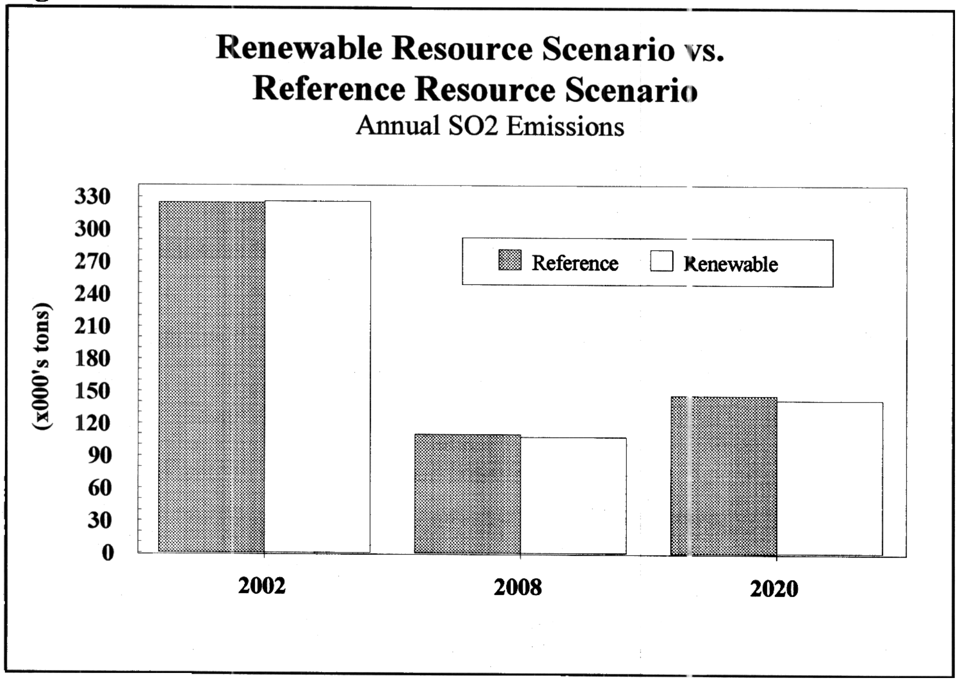


Figure 7

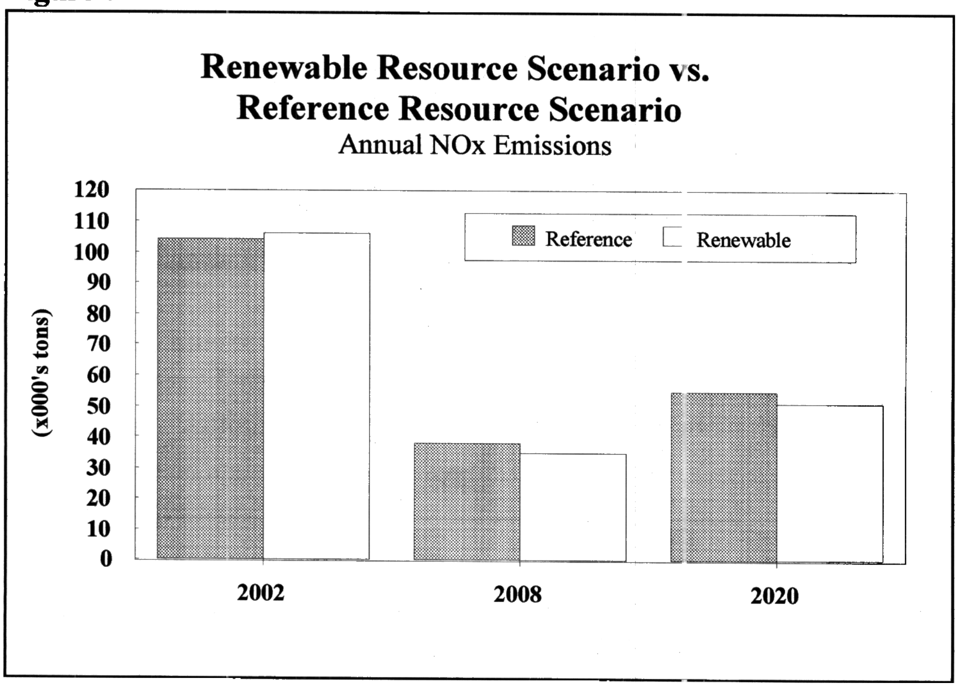
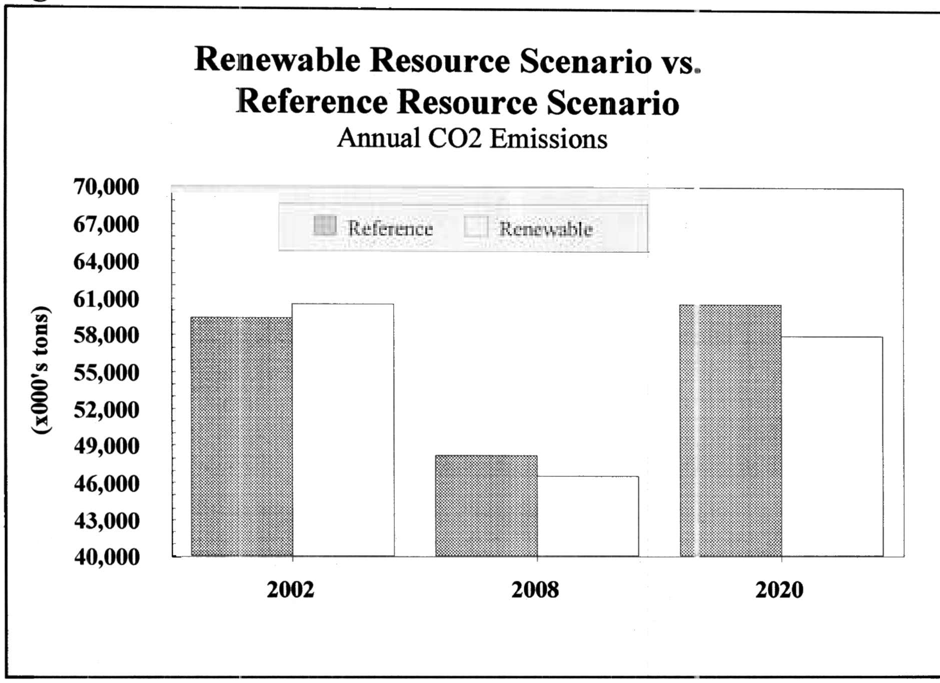


Figure 8



It should also be noted that the introduction of 2,500 MW of renewable generation could have significant consequences for the way the electric system is operated. This is because much of the renewable generation, particularly the 2,045 MW of wind power, cannot be scheduled with certainty, which would have an impact on the scheduling of the other units in the State. If a significant amount of non-dispatchable resources are to be added to the system, this issue will need to be addressed by the NYISO.

Advanced Coal Technology Scenario[39]

Another option to reverse the trend toward excessive dependence on natural gas is to consider the use of clean coal technologies. The "Coal Assessment" section of this Energy Plan describes the technologies and how they compare with other technologies. This section of the Electricity Assessment discusses how use of one form of advanced coal technology might impact the State as compared with the "Reference Resource" scenario. In particular, this analysis assumes that a developer installs a circulating

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[39] This Energy Plan recommends (see Section 1.3) support of advanced coal technology research, demonstration, and commercialization. The analyses presented here support the basis for that recommendation.

fluidized bed (CFB) coal facility at a site in the Hudson Valley instead of a gas-fired unit assumed in the "Reference Resource" scenario, both with the same generating capacity (approximately 1,000 MW). Unlike most other scenarios, only the year 2005 was examined, and no modeling software was used in the analysis. While this analysis does not attempt to determine if it would be economic for a developer to build such a unit, and does not suggest that the particular unit substitution used for the analysis is the optimal substitution, it does provide some insight that should help to determine if use of the technology is a reasonable option for the State.

Results. Total variable costs, or the "full load cost", is projected to be $17.13 per MWh for the CFB facility compared to $29.61 per MWh for the replaced combined cycle unit, a 42% reduction. Based on currently available information, it appears that capital costs and fixed operating costs for the CFB facility would be approximately 2 times and 4 times more, respectively, than such costs for the combined cycle natural gas plant.

The CFB facility replacing the combined cycle unit is projected to result in a net decrease of about 50,000 MMBtu of natural gas consumption (approximately 10% of New York State's projected use for electric generation) and a net increase of about 77,000 MMBtu of coal consumption (approximately 48% of New York State's projected use for electric generation) in 2005.

Wholesale electric energy prices are assumed to be unaffected as both units are assumed to produce the same amount of energy in 2005, and operate as "baseload" units, accepting payment for energy at whatever the market dictates.

On the other hand, NO_x and SO_x emission levels would likely rise if the combined cycle natural gas-fired plant were replaced with a CFB facility. Table 26 below compares the projected NO_x and SO_x emissions in 2005 for a combined cycle natural gas, CFB and traditional coal-fired electricity generation facility.

Table 26

Comparisons of NO_x and SO_x Emissions
Combine Cycle Natural Gas vs CFB vs Traditional Coal

Plant Type	NO_x (approximate tons)	SO_x (approximate tons)
Combined-Cycle Natural Gas	250	15
CFB	3,800	480
Traditional Coal Facility*	18,000	4,500

* assumes 1.8% sulfur content coal and no scrubbers, but with low-NOx burners.

CO_2 emissions would also likely be greater (more than double) if a CFB unit were substituted for a combined cycle unit, and only marginally lower (6%) than a traditional coal facility.

Decision makers must balance multiple considerations in determining the appropriate resources for meeting consumer needs. The analysis presented here indicates that the use of CFB would be beneficial to the State in comparison with conventional coal technologies. When compared with state-of-the-art natural gas technologies, CFB can be also beneficial in some respects (improved diversity and lower operating costs), but more costly in others (emissions). It should be noted, however, that other emerging Advanced coal technologies, such as integrated gasification combined cycle, which is discussed in the "Coal Resource Assessment" (Section 3.7) of this State Energy Plan, have even lower emission rates than CFB facilities.

Low Load Scenario

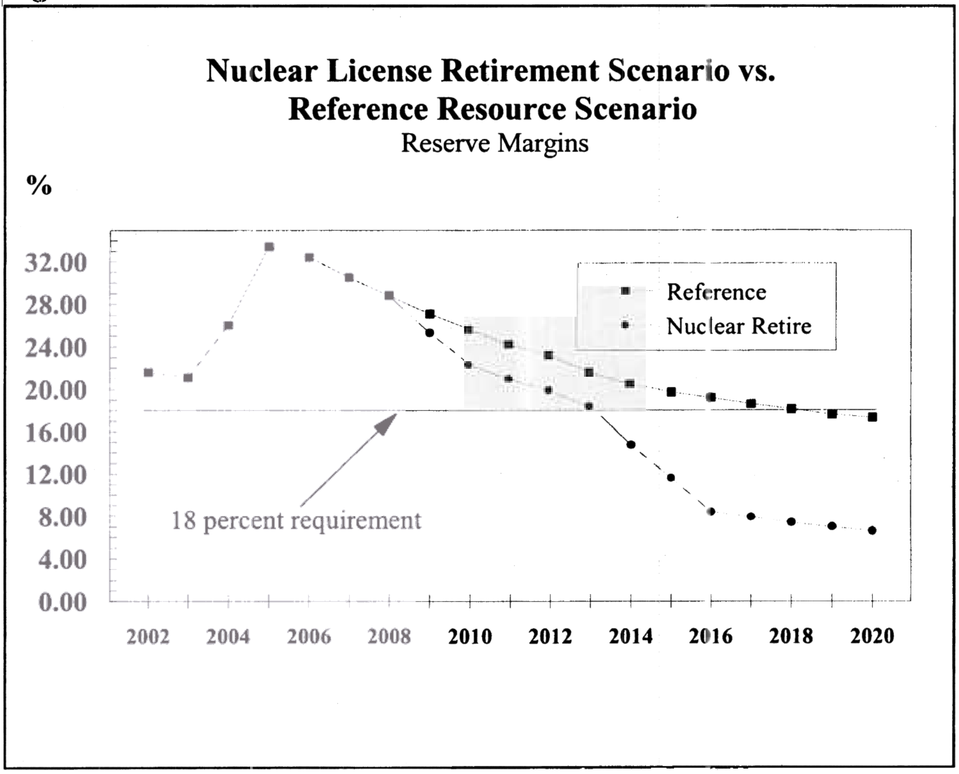
The "Reference Resource" scenario assumes that load will develop in accordance with the "Outlook" forecast presented elsewhere in this Plan. The "Low Load" scenario presented in the Draft State Energy Plan provided a sensitivity to show how conditions might change if the forecast turns out to be optimistic, or if demand reduction efforts grow. The Draft Energy Plan showed that the "Low Load" scenario would provide, as compared with the "Reference Resource" scenario, increased reserves, less reliance on natural gas, lower costs, and less emissions. Similar results can be expected if the analysis were repeated using the revised assumptions for the final Energy Plan. Clearly, load reduction, whether occurring naturally or through peak demand reduction and conservation efforts, will benefit the system. This Energy Plan supports such efforts (see recommendations in Section 1.3).

Nuclear License Retirement Scenario

The "Reference Resource" scenario assumes that all nuclear units in the State will continue to operate and will receive extensions of their operating licenses from the NRC (the license expiration dates are identified in Table 9, contained in the "Nuclear Generation" discussion of the "Electricity Generation" section of this Electricity Assessment). If the licenses are not extended, all other things being equal, additional resources would be needed to raise reserve margins to acceptable levels, the State's growing reliance on use of natural gas would be increased, wholesale electric energy prices would rise, and emissions would increase (subject to the limits of the statewide emission caps).

Figure 9 compares the projected reserve margins of the "Nuclear License Retirement" scenario with the "Reference Resource" scenario. As can be seen, additional capacity would be needed sooner than assumed in the "Reference Resource" scenario.

Figure 9



Tables 27 and 28 compare the resulting fuel mix changes over the planning period for the "Nuclear License Retirement" scenario with the fuel mix changes for the "Reference Resource" scenario that assumes continued operation of the units. The comparisons show that the trend toward reliance on natural gas would be increased. If additional gas-fired units were added to replace the retired capacity, the trend would be even greater.

Table 27

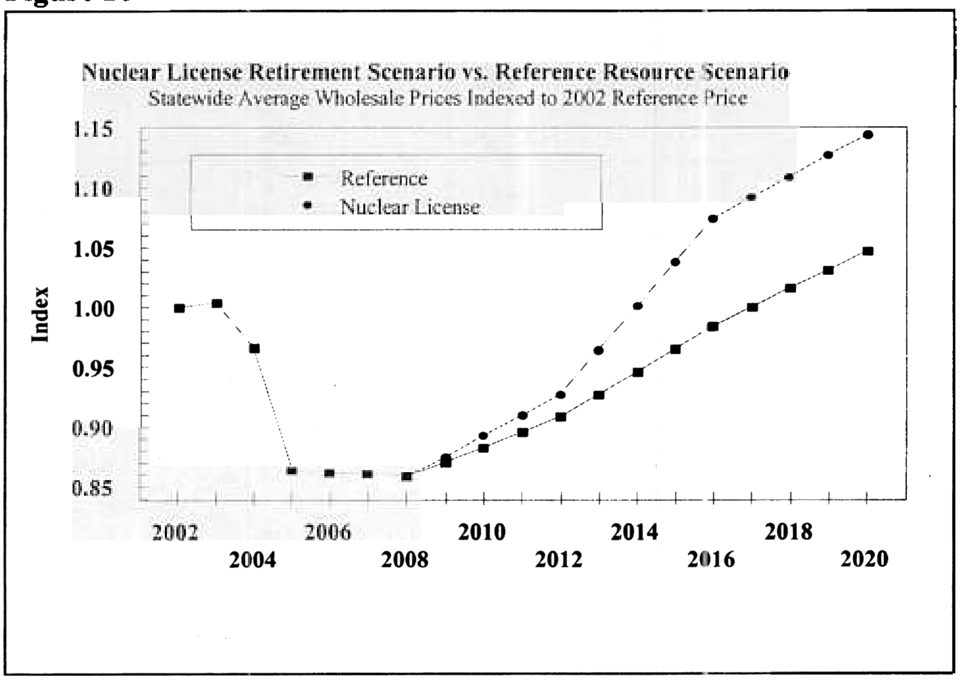
Comparison of Generation Mix Changes Based on Installed Capacity Between the Nuclear License Retirement and Reference Resource Scenarios In % of Total			
	2002	2020	
Generation Fuels	License Retirement and Reference Scenarios	License Retirement Scenario	Reference Scenario
Natural Gas	15.0%	29.7%	26.2%
Oil	10.5%	10.3%	9.1%
Natural Gas/Oil	33.4%	33.4%	29.4%
Coal	10.8%	9.4%	8.3%
Nuclear	13.5%	0.0%	11.9%
Hydropower	14.8%	14.8%	13.0%
Other	2.0%	2.5%	2.2%
Total	100%	100%	100%

Table 28

Comparison of Generation Mix Based on Energy Produced Between the Nuclear License Retirement and Reference Resource Scenarios In % of Total Generation			
	2002	2020	
Generation Fuels	License Retirement and Reference Scenario	License Retirement Scenario	Reference Scenario
Natural Gas	26.2%	46.6%	39.7%
Oil	5.0%	4.7%	2.5%
Coal	16.9%	10.4%	9.8%
Nuclear	20.6%	3.9%	17.1%
Hydropower	18.4%	15.6%	15.6%
Other	1.8%	1.8%	1.8%
Net Imports	11.1%	17.0%	13.5%
Total	100%	100%	100%

Figure 10 compares the trends in statewide weighted average wholesale energy prices for the "Nuclear License Retirement" scenario with the "Reference Resource" scenario. The comparison shows that statewide weighted average wholesale energy prices would be larger beginning in 2009 and would tend to increase to a greater extent, as more new resources are needed, and needed sooner, to meet reserve requirements. As with the "Reference Resource" scenario, the greatest increases would occur in the New York City and Long Island areas. If additional capacity were added to replace the retired nuclear units, the wholesale energy prices described here would be somewhat reduced but likely still above the prices for the "Reference Resource" scenario.

Figure 10



Emissions would also be expected to be greater. Figures 11, 12, and 13 compare the projected emissions of SO_2, NO_x, and CO_2 in selected years for the "Nuclear License Retirement" scenario and the "Reference Resource" scenario. Again, if additional capacity were added to replace the nuclear units as they retire, emissions would be somewhat less than described in this scenario, but they would be greater than for the "Reference Resource" scenario.

Figure 11

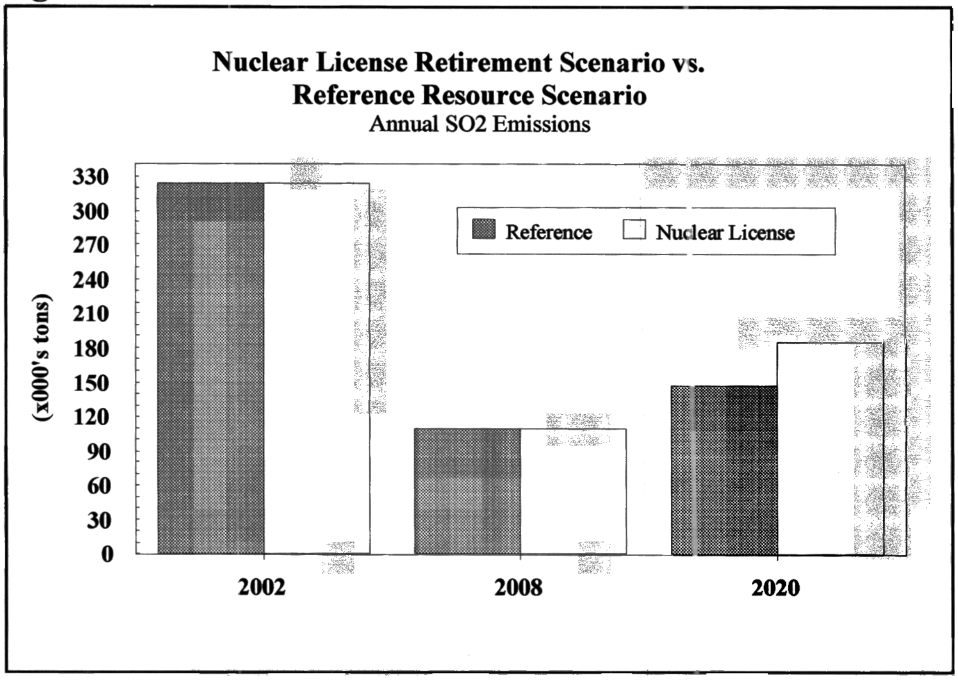


Figure 12

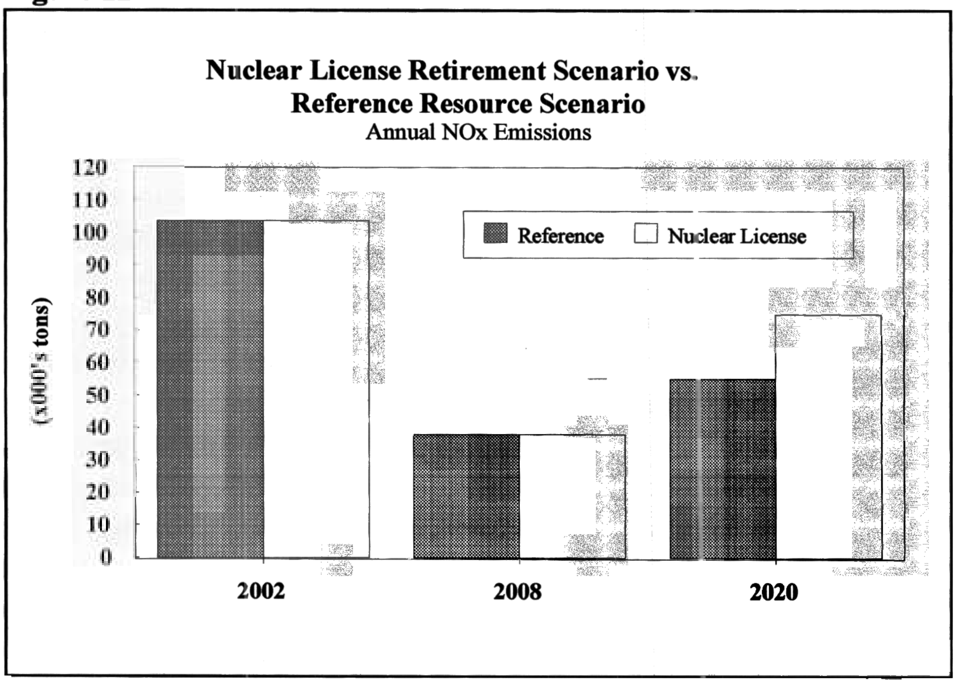
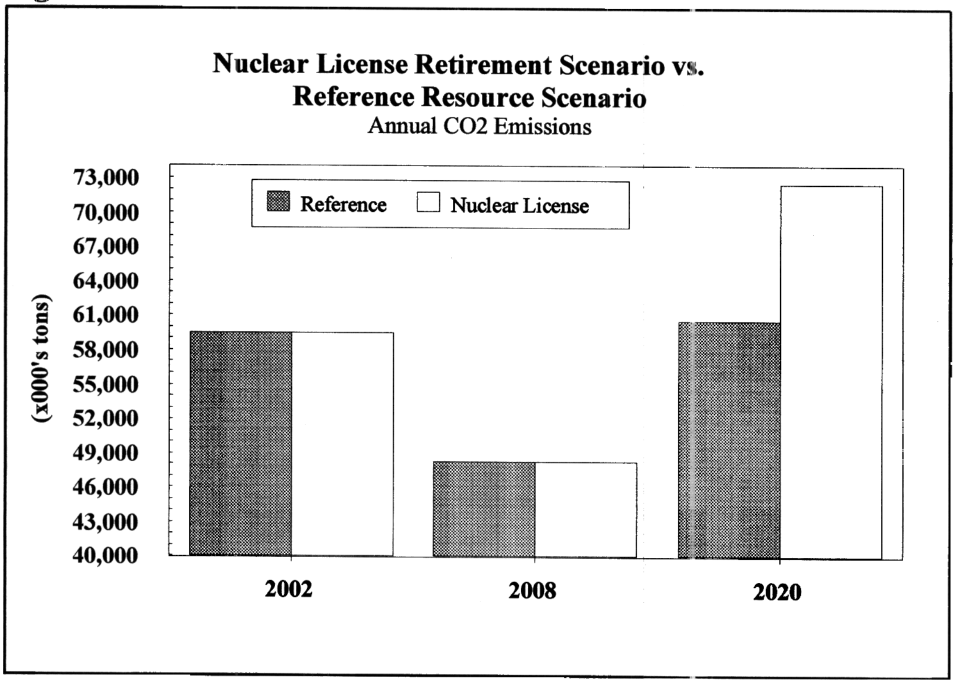


Figure 13



Transmission Upgrade Scenario

Transmission facilities are an important part of the bulk electricity system. They provide means for resources to be shared among regions to minimize costs, environmental impacts and system reliability concerns. Constraints that exist in the transmission system, however, can limit those benefits. The Draft Energy Plan explored a scenario that restricted trading with neighboring control areas. That scenario showed that such restriction would result in higher wholesale energy prices, a slightly greater reliance on fossil fuels in New York State, and somewhat higher in-State emissions. If transmission capability into other control areas were enhanced, rather than restricted, and assuming that trading rules were not tightened, opposite trends might be expected. Wholesale electric energy prices would likely be lower, the State's reliance on fossil fuels would be relieved somewhat, and emissions within the State would likely be reduced.

Many other alternative "Transmission Upgrade" scenarios can also be devised, including those that relieve some of the constraints that exist internal to the New York system. Similar to the upgrades of interfaces with neighboring control areas, upgrades of internal transmission might also result in lower overall statewide average wholesale energy prices, which might mean lower prices in some parts of the State, especially downstate, and somewhat higher prices in other parts of the State. Similarly, emissions could be increased from facilities in the western part of the State and eased in the downstate areas. Whether any such upgrades can be justified by those that must pay for them would depend on the specific modifications required, the costs, and the benefits that might result. As noted in the "Transmission" section of this Assessment, there is currently no requirement that transmission lines be upgraded for reliability purposes, except perhaps in the downstate areas to serve local needs.

Distributed Generation Scenario

A distributed generation (DG) scenario was developed for the Energy Plan based on data provided by the Center for Clean Air Policy (CCAP). This scenario provides a basis to analyze the impacts of adding small, customer-based, distributed electricity generation resources aggressively to the New York State electric system in addition to resources that might otherwise be installed.[40] For this analysis, CCAP provided forecasts for capacity additions, emission rates, O&M costs, fuel costs, heat rates, and outage rates. Eight different DG types (4 gas-fired and 4 diesel fired) were considered: diesel large grid (capacity greater than 500 KW); diesel small grid; diesel large emergency converted units (greater than 500 KW); diesel small emergency converted units; natural gas reciprocating engines; low-emission natural gas reciprocating engines; microturbines; and fuel cells. With the exception of fuel cells, the DG units modeled were assumed to be price sensitive and would be dispatched only when wholesale electric prices would be above a predetermined threshold, or "dispatch price." Fuel cells were modeled as "must run" units, which means they were assumed to operate regardless of the wholesale price of electricity.

It should be noted that the CCAP's forecasts do not include any combined heat and power (CHP) electricity generation units. While NYSERDA's R&D staff are separately developing estimates of future CHP potential and related unit characteristics, that effort was not sufficiently advanced to allow its ready inclusion in this analysis. Also, it was generally believed by CCAP and NYSERDA staff that CHP units would need to be modeled differently from DG units that are exclusively used for electricity generation. CHP units have a dual purpose (power and heat) and are more likely to operate irrespective of wholesale market electric prices. Also, there was concern that a

[40] 4,736 MW of DG were assumed to be added between 2002 and 2020 as supplements to the resources assumed in the "Reference Resource" scenario.

combined modeling exercise might mask important differences between the two distinctly different types of DG. A CHP analysis will be performed after the issuance of the State Energy Plan, and the results will be reported to the Energy Planning Board at a future Board meeting.

The CCAP also projected both aggregate statewide DG additions and DG additions by utility service territory. For analytical convenience, DG was grouped in blocks by utility service territory and spread across each territory at ten separate grid interconnections to simulate geographic distribution of projected units.

CCAP assigned a "dispatch price" to each unit type for each year, and units were assumed to be dispatched only when the wholesale electric energy price would be above the dispatch price for that hour. In determining the dispatch price, CCAP considered each DG types' projected cost structure and all possible revenue streams available to the units, including savings or revenue associated with wholesale market electric prices, and potential revenue from price responsive load programs, capacity market programs, and reserve market programs. CCAP also did not include "capital costs" in the dispatch price calculation as all initial capital costs are assumed to be "sunk costs." Additionally, units were not given any "minimum run times" or "minimum down times" in the analysis, which allowed the DG units maximum flexibility to adapt to changing market prices. Fuel cells (one of the 4 natural gas-fired unit types) were the exception to this rule and were modeled as "must run" units, given the nature of the technology and the general difficulty in turning the units on and off quickly.

The modeling analysis started with a 2001 DG capacity level of zero and began adding incremental DG in 2002. Previously existing DG was assumed to be "inherently" within the Reference Resource Scenario and assumed to be reflected in load and capacity forecasts.

Results. The results of the analysis suggest little change from the "Reference Resource" scenario in the first 5 model years (*i.e.,* through 2008). In later years, however, as DG capacity and DG capacity factors increase, DG generation began to "back down" generation from older, larger, and less flexible oil and gas units in the State.

The CCAP assumed that no NO_x control technologies were applied when projecting DG unit emission levels. Consequently, NO_x emission rates increased significantly in the DG scenario in later study years when compared to the "Reference Resource" scenario. These differences, however, were not severe until the 2012, 2016, and 2020 study years, when NO_x emissions increased by 14.5 (34 percent), 49.8 (82 percent), and 75.5 (138 percent) thousand tons, respectively This was because, as noted below, combined annual diesel capacity factors never exceeded 3 percent until 2012, but reached 21 percent by 2020.

SO_2 and CO_2 emission levels declined under the DG scenario compared to the Reference Resource Scenario. SO_2 emissions were lower for all model years, reaching a maximum reduction of 7.8 percent in 2020. Likewise, CO_2 emissions were lower for all model years, reaching a maximum reduction of 3.9 percent in model year 2012. Later model years (*i.e.,* 2016 and 2020) showed smaller reductions of 2.3 percent and 1.1 percent, respectively.

An examination of wholesale electricity prices (LBMPs) revealed minimal impact in the early model years (2002, 2003, 2004, 2005) when compared to the "Reference Resource" scenario, and was generally within plus or minus 1.5 percent. In model year 2008, prices outside of Long Island were as much as 2.4 percent higher, while prices for Long Island were 2.2 percent lower. In model years 2012 and 2016, a similar pattern emerged with prices lower by more than 7 percent on Long Island but as much as 2 percent higher elsewhere. In 2020, all areas of the State had wholesale electric energy prices lower in the DG scenario. Downstate LBMPs drop significantly in 2020, with the lower Hudson Valley (5.6 percent), New York City (2.8 percent), and Long Island (9.8 percent) experiencing the largest declines. DG capacity factors increased dramatically in later study years, because wholesale electric energy prices were rising faster than CCAP's projections for DG dispatch prices.

Another result observed in this analysis was the projected decline in internal interface limitations, particularly in the downstate areas, starting in 2016. Meeting statewide load with more DG generally reduces the need to carry power over internal interfaces, because more load is met locally. This helped reduce congestion on the critical downstate interfaces as downstate DG generation increased significantly in later study years.

Overall, the analysis indicates that a movement toward use of DG in New York State, especially after the new baseload generation now in the certification and construction process are operational, would provide benefits with regard to wholesale electric energy prices, SO_2 and CO_2 emissions, diversity, and transmission flexibility. On the other hand, NO_x emissions, particularly from diesel units, could increase unless NO_x control technologies were employed. Whether or not DG would be cost effective for unit owners was not determined by this analysis.

DEC has undertaken a rulemaking on the emissions controls to be required on DG units. Under this model, if such regulations increase the running costs of the DG technology in question, DG units would be dispatched less often, and the modeled effects would be reduced.

FINDINGS AND CONCLUSIONS

New York is a national leader in restructuring its electricity industry. Consumers have benefitted with savings in their delivery service charges, and further savings will occur during the planning period. The utilities in the State have divested most of their generation facilities to third parties who now operate them in a competitive wholesale market. Further, more than 16% of customer load has switched from local utilities to new service providers. Most switching in retail service providers has occurred in the commercial and industrial sectors with considerable variability throughout the State. More progress in increasing customer choice can be expected, especially when more supplies and demand reducing options become available.

The initial years of wholesale electricity market operations in New York coincided with periods of high fuel prices, significant transmission congestion, and tight supply conditions. Wholesale electricity prices reflected these conditions, but they have begun to moderate, although not in a uniform pattern, across the State. Average wholesale electricity prices are forecast to decline in real terms over the remainder of the decade, as are retail prices. This expectation is strongly conditioned on new demand and supply resources being added, especially at critical locations that will serve to reduce transmission congestion, and on continued expansion in natural gas resources.

Electricity peak demand is forecast to grow at annual average rates ranging from 0.75% to 1.23%, with a mid-range value of 0.92%. The loss of load in New York City resulting from the terrorist attack on the World Trade Center is not factored into the forecast. This load is expected to be restored gradually during rebuilding efforts and completely restored once rebuilding efforts are finished. Load is projected to be fully restored sometime in the early half of the forecast period.

Reserve margins, representing one measure of system reliability, are projected to exceed the current requirement of 18% throughout most of the planning period if a reasonable number of new resources are added and/or demand is reduced. A higher peak demand growth rate than projected, however, will require more resources, especially in the later years of the planning period.

In the near-term, simple-cycle gas turbines and demand reduction programs will be used to address growth in peak electricity demand. Over the longer-term, demand reduction programs will continue, and renewable generation facilities and distributed generation will be added, but the bulk of the new resources will likely come from gas-fired, combined-cycle base-load units subject to Article X of the Public Service Law. As of May 1, 2002, seven generating projects, which could add approximately 3,600 MW to the electric system, had been approved under Article X, and another 17 projects were in the regulatory review process or have been publicly announced.

The State's transmission system is generally adequate to provide reliable electricity service, provided that the system is operated in accordance with reliability rules established by the North American Reliability Council (NERC), the Northeast Power Coordinating Council (NPCC), and the New York State Reliability Council (NYSRC); however, there are reliability limitations in the use of the transmission system for the economic transfer of power between regions of the State for economic reasons. The siting of additional generation and transmission facilities can reduce price impacts attributed to economic congestion of the transmission system. This finding is consistent with the Planning Board's recent *"Report on the Reliability of New York's Electric Transmission and Distribution Systems."*[41] Some local transmission reinforcements might also be necessary in the New York City and Long Island areas.

A Northeast regional common market offers possibilities for enhanced market efficiencies and economic benefits for New Yorkers. A regional market structure may also offer a vehicle for developing new transmission lines to increase power transfers across New York's borders. There are certain principles for common market formation that should be followed to ensure benefits are realized by New York consumers.

The share of electricity generation fueled by natural gas could increase significantly over the planning period. This trend is consistent with other regions of the Northeast. A major force behind this trend is the decisions of merchant generators to select natural gas as the preferred fuel of choice. The choice is also influenced by environmental factors that recognize the relatively clean air emission profile of natural gas generation. This shift in primary fuel requirements for electricity could result in diminished diversity in the fuel requirements for electricity generation. Reduced fuel diversity increases risk exposure to fuel supply disruptions and price swings. This Energy Plan describes and recommends efforts to reverse or mitigate this trend.

Air pollutant emissions from electricity generation not under a cap in the State would be expected to decrease as new resources are added to the electric system, increasingly stringent environmental regulations are imposed, and increased electricity trading among regional electricity systems takes place. The Governor's Acid Deposition Reduction Program is a major factor in reducing the

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[41] Report of the New York State Energy Planning Board as required by Chapter 636 of the Laws of 1999.