# SECURITIES AND EXCHANGE COMMISSION

**WASHINGTON, D.C. 20549**

# FORM 8-K

**CURRENT REPORT**
**PURSUANT TO SECTION 13 OR 15(d) OF THE**
**SECURITIES EXCHANGE ACT OF 1934**

**Date of Report (Date of earliest event reported) June 14, 2001**

# EXELON CORPORATION

(Exact name of registrant as specified in its charter)

| **Pennsylvania** | **1-16169** | **23-2990190** |
|---|---|---|
| (State or other jurisdiction of incorporation) | (Commission File Number) | (IRS Employer Identification No.) |

| **37th Floor, 10 South Dearborn Street, Post Office Box A-3005, Chicago, IL** | **60690-3005** |
|---|---|
| (Address of principal executive offices) | (Zip Code) |
| Registrant's telephone number, including area code | **(312) 394-4321** |

**N/A**
(Former name or former address, if changed since last report).

**Item 5. Other Events**

On June 14, 2001, Exelon Generation Company, LLC ("Exelon Generation"), an indirect wholly owned subsidiary of Exelon Corporation ("Exelon"), sold $700 million of unsecured Senior Notes (the "Senior Notes"). The Senior Notes bear interest of 6.95% per annum, mature on June 15, 2011 and are redeemable at the option of Exelon Generation at any time at the greater of (a) par plus interest accrued through the date of such redemption or (b) the sum of the present values of the remaining scheduled payments of principal on the Senior Notes redeemed (not including any portion of payments of interest accrued as of the date of such redemption), discounted to the date of redemption on a semi-annual basis at a rate equal to 0.25% plus the semi-annual yield of the U.S. Treasury selected by the initial purchasers of the Senior Notes and any other dealer of U.S. Government securities chosen by Exelon Generation, plus interest accrued through the date of such redemption. The Senior Notes were sold to Qualified Institutional Buyers in a private placement under Rule 144A and have not been registered under the Securities Act of 1933, as amended (the "Securities Act") or any state securities laws.

The proceeds of the Senior Notes will be used by Exelon Generation to repay an intercompany obligation of $696 million to Exelon, incurred to fund the acquisition of 49.9% interest in Sithe Energies in December 2000.

**Item 9. Regulation FD Disclosure**

The information in Item 9 of this Current Report on Form 8-K, including the exhibit listed below, is being furnished, not filed, pursuant to Regulation FD. The information in Item 9 of this report and in such exhibit shall not be incorporated by reference into any registration statement filed pursuant to the Securities Act. The furnishing of the information in Item 9 of this report and in such exhibit is not intended to, and does not, constitute a determination or admission that the information in this report is material, or that you should consider this information before making an investment decision with respect to any security of Exelon or its subsidiaries.

The information furnished in the exhibit was prepared in connection with the sale by Exelon Generation of $700,000,000 of its Senior Notes in a private placement as reported in Item 5. The information furnished in this Current Report on Form 8-K and in such exhibit relates to Exelon Generation. Information related to Exelon Generation set forth herein and in such exhibits presents Exelon Generation as an independent company. You should not assume that the information is indicative or meaningful with respect to Exelon taken as a whole or with respect to any of its other affiliates. Further, this information is not necessarily indicative of Exelon Generation's impact on Exelon's business, financial condition or prospects. For example, Exelon Generation's financial statements do not take into account, among other things, the elimination and consolidation adjustments reflected in Exelon's consolidated financial statements as reported on its Annual Report on Form 10-K. In addition, Exelon does not make any representation or warranty as to the accuracy or completeness of any of the information in this report, including the exhibits.

99.1
Information Relating to Exelon Generation Company, LLC dated June 11, 2001

**CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION**

Information in this Current Report on Form 8-K, including the exhibit hereto, includes "forward-looking statements" within the meaning of the Private Securities Litigation Reform Act of 1995. All statements, other than statements of historical facts, included in this Current Report on Form 8-K and in such exhibit that address activities, events or developments that Exelon Generation expects or anticipates will or may occur in the future, including such matters as projections, future capital expenditures, business strategy, competitive strengths, goals, future acquisitions, development or operation of generation assets, market and industry developments and the growth of Exelon



Generation's businesses and operations, are forward-looking statements. These statements are based on assumptions and analyses made in light of experience and other historical trends, current conditions and expected future developments, as well as various factors Exelon Generation believes are appropriate under the circumstances. However, actual results and developments may differ materially from Exelon Generation's expectations and predictions due to a number of risks and uncertainties, many of which are beyond our control. These risks and uncertainties include:

- significant considerations and risks discussed in this Current Report on Form 8-K, including the exhibit hereto;
- general and local economic, market or business conditions;
- demand (or lack thereof) for electricity, capacity and ancillary services in the markets served by Exelon Generation's generation units;
- increasing competition from other companies;
- acquisition and development opportunities (or lack thereof) that may be presented to and pursued by Exelon Generation;
- changes in laws or regulations that are applicable to Exelon Generation;
- environmental constraints on construction and operation;
- rapidly changing markets for energy products; and
- access to capital.

Consequently, all of the forward-looking statements made in this Current Report on Form 8-K and in the exhibit hereto are qualified by these cautionary statements and Exelon Generation cannot assure you that the results or developments anticipated by Exelon Generation or the projections will be realized or, even if realized, will have the expected consequences to or effects on Exelon Generation or our business, financial condition or results of operations. You should not place undue reliance on these forward-looking statements. Exelon Generation expressly disclaims any obligation or undertaking to release publicly any updates or revisions to these forward-looking statements to reflect events or circumstances that occur or arise or are anticipated to occur or arise after the date hereof. Exelon Generation is not making, and you should not infer, any representation about the likely existence of any particular future set of facts or circumstances.

Exelon does not endorse or adopt any of these forward-looking statements and does not make any representation or warranty as to the accuracy or completeness of the expectations expressed in the forward-looking statements. In addition, Exelon does not give any assurance as to future results, levels of activity, performance or achievements. Exelon does not undertake any duty to update or revise any forward-looking statement after the date of this report, whether as a result of new information, future events or otherwise.

The information in this Current Report on Form 8-K does not constitute a sale, an offer to sell or the solicitation of an offer to buy and security.



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**SIGNATURE**

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned hereunto duly authorized.

| | | |
|---|---|---|
| Date: June 14, 2001 | EXELON CORPORATION | |
| | By: | /s/ J. BARRY MITCHELL |
| | | J. Barry Mitchell<br>*Vice President and Treasurer* |



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## MARKET AND INDUSTRY DATA

Market data and certain industry forecasts used herein were obtained from internal surveys, market research, publicly available information and industry publications. Industry publications generally state that the information contained therein has been obtained from sources believed to be reliable, but that the accuracy and completeness of such information are not guaranteed. Similarly, internal surveys, industry forecasts and market research, while believed to be reliable, have not been independently verified, and neither we nor the initial purchasers make any representation as to their accuracy.

## SUMMARY

*The following summary contains basic information about Exelon Generation Company, LLC. It may not contain all of the information that may be important to you. Unless the context otherwise indicates, all references to "Generation," "we," "us" or "our" used herein mean Exelon Generation Company, LLC.*

### Exelon Generation Company, LLC

We are the largest competitive electric generation company in the United States, as measured by owned and controlled megawatts. We directly own generation assets in the Mid-Atlantic and Midwest regions with net capacity of 19,159 MW, including 13,949 MW of nuclear capacity. We also control another 16,013 MW of capacity in the Midwest, Southeast and South Central regions through long-term power purchase agreements.

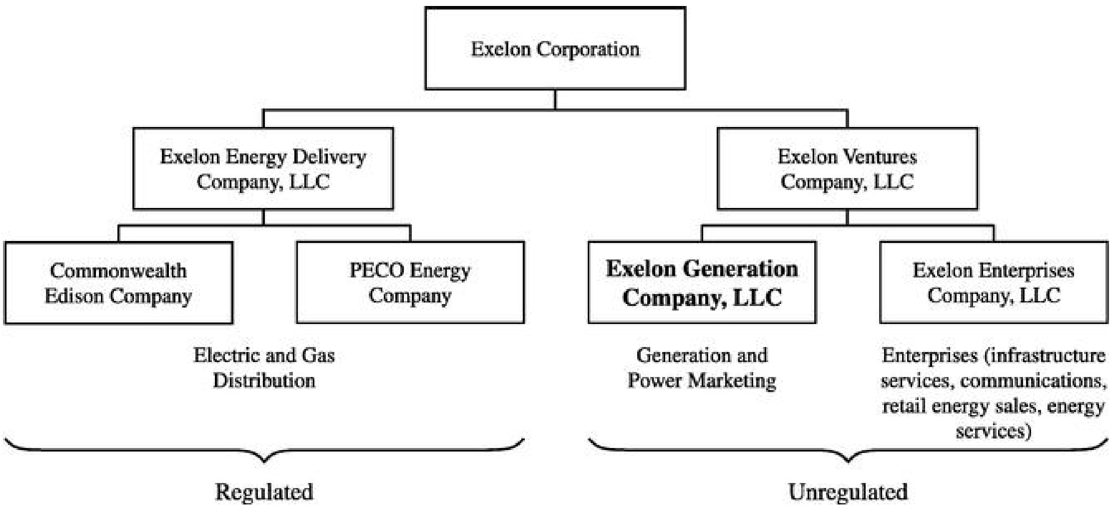
In addition to our own generation facilities, we have acquired a 49.9% interest in Sithe Energies, Inc. with an option, beginning in December 2002, to purchase the remaining 50.1% interest. Sithe develops, owns and operates generation facilities and currently has 9,879 MW of capacity in operation, under construction or in advanced development. We also own a 50% interest in AmerGen Energy Company, LLC, which owns three nuclear stations with total generation capacity of 2,378 MW.

Our Power Team division is a major wholesale marketer of energy that uses our generation portfolio, transmission rights and expertise to provide generation to wholesale customers under long- and short-term contracts. Power Team is responsible for supplying the load requirements of our utility affiliates ComEd and PECO. Power Team also buys and sells power in the wholesale spot markets.

### Corporate Structure

We were formed on December 27, 2000 as a Pennsylvania limited liability company. We are an indirect wholly owned subsidiary of Exelon Corporation, a public utility holding company ("Exelon"). Exelon is the result of the merger in October 2000 between Unicom Corporation, the former parent company of ComEd, and PECO. As part of a corporate restructuring of Exelon effective January 1, 2001, the power generation assets and the power marketing business of ComEd and PECO were transferred to us.






### Business Strategy

Our business strategy is to develop a national generation portfolio with fuel and dispatch diversity. To implement this strategy, we plan to:

*Grow Our Generation Portfolio.* We intend to continue to grow our generation portfolio through a disciplined approach to asset acquisitions, development of new plants, innovative applications of technology, joint ventures and long-term off-take contracts.

*Drive Cost and Operational Leadership through Proven Fleet Management and Economies of Scale.* Our goals are to increase fleet output and to improve fleet efficiency while sustaining operational safety. We intend to achieve these results in our nuclear fleet by increasing capacity factors over historic levels, reducing refueling outage duration and increasing our generation capacity through power uprates and other modifications. Longer-term, we intend to apply for extensions of the operating licenses for our nuclear plants.

*Optimize the Value of Our Low-Cost Generation Portfolio through Our Power Marketing Expertise.* Power Team is responsible for optimizing the revenues of our generation assets through long- and short-term contracts and spot-market sales. Power Team also contracts for access to additional generation through bilateral long-term power purchase agreements. By using real-time market information, Power Team manages the efficient dispatch of both our owned and contracted generation.

### Competitive Strengths

We believe that we are well positioned to play a leading role in the competitive energy industry because of a number of key strengths, including:

*Competitive, Low-Cost Fleet of Generation Assets.* Our low-cost advantage is driven by our ownership of or investment in 11 nuclear generation stations, consisting of 19 units, with net capacity totaling 15,138 MW. Our nuclear plants benefit from stable fuel costs, minimal environmental impact from operations and a safe operating history.

*Operating Experience and Expertise.* We have achieved superior operating performance in our generation business through the leadership of a deep and experienced management team. We benefit from a coordinated approach to fleet management that includes the sharing of "best-in-class" practices across our organization and broad employee recognition that exceptional performance is required to succeed in a competitive environment.



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*Critical Mass of Generation Capacity with Economies of Scale.* The generation assets of ComEd and PECO and our investments in Sithe and AmerGen provide critical mass and a leadership position in the new energy markets. As the largest generator of nuclear power in the United States, we can take advantage of our scale and scope to negotiate favorable terms for the materials and services that our business requires.

*Stable Revenue Streams under Long-Term Contracts with ComEd and PECO.* We have entered into agreements to supply the load requirements of ComEd and PECO through 2004 and 2010, respectively. We expect sales to ComEd and PECO under these agreements to account for approximately 60% of our revenues.

*Extensive Experience in Wholesale Power Markets.* Power Team has substantial experience in energy markets, generation dispatch and the requirements for the physical delivery of power. Starting from our large asset platforms in the Mid-Atlantic and Midwest regions, Power Team has established itself as a leading asset-based power marketer.

## Unaudited Historical Financial Information

We commenced operations effective January 1, 2001. The following table sets forth our selected unaudited historical financial information. The information as of March 31, 2001 and for the three-month period then ended has been derived from financial statements prepared by us and included herein. You should read the information set forth below in conjunction with "Management's Discussion and Analysis of Financial Condition and Results of Operations" and our financial statements and the accompanying notes appearing elsewhere herein.

| | Three Months Ended March 31, 2001 |
| --- | --- |
| | ($ in millions) |
| **Unaudited Income Statement Data** | |
| Operating Revenues | $ 1,628 |
| Operating Income | 269 |
| Net Income | 170 |
| **Unaudited Cash Flow Data** | |
| EBIT(1) | $299 |
| EBITDA(1) | 491 |
| Ratio of Earnings to Fixed Charges(2) | 5.7x |

| | As of March 31, 2001 | |
| --- | --- | --- |
| | Actual | Pro Forma |
| | (in millions) | |
| **Unaudited Balance Sheet Data(3)** | | |
| Total Current Assets | $ 1,352 | $ 1,352 |
| Total Assets | 10,261 | 10,261 |
| Note Payable to Parent | 696 | 696 |
| Total Long-Term Debt (4) | 209 | 261 |
| Total Member's Equity | 2,336 | 2,284 |

(1) EBIT is earnings before interest and income taxes, earnings from equity investments, and other income and expense recorded in other, net, with the exception of interest income. EBITDA is EBIT plus depreciation and amortization, including amortization of nuclear fuel. EBIT and EBITDA may differ from the calculation used by other companies and should not be considered as an alternative to net income, cash flows or any other item calculated in accordance with U.S. generally accepted accounting principles or as an indication of operating performance or liquidity.

(2) Ratio of earnings to fixed charges represents, on a pre-tax basis, the number of times earnings cover fixed charges. Earnings consist of net income, before the cumulative effect of a change in



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accounting principle, plus fixed charges and income taxes. Fixed charges consist of interest on indebtedness and other interest.

(3) The unaudited historical balance sheet data is presented (1) on an actual basis and (2) on a pro forma basis to reflect the transfer in April 2001 of $52 million of debt from PECO to us, through the refunding of pollution control notes.

(4) Includes long-term debt due within one year of $5 million.

## Reports of Independent Consultants

Sargent & Lundy Engineers, Ltd. ("Sargent & Lundy" or the "Independent Engineer") has prepared its Independent Engineer's Report (the "Independent Engineer's Report"), included as Appendix A to this information. Sargent & Lundy is an international engineering and consulting firm with expertise in the electric power industry. The Independent Engineer's Report includes a technical review of our generation assets and projections of our financial performance through 2020. You should read the entire Independent Engineer's Report.

PA Consulting Services, Inc. ("PA Consulting" or the "Independent Market Consultant") has prepared its Independent Market Consultant's Report (the "Independent Market Consultant's Report"), included as Appendix B to this information. The Independent Market Consultant's Report includes an analysis of the principal market regions in which we operate and price forecasts for our energy and capacity. You should read the entire Independent Market Consultant's Report.

In the preparation of the Independent Market Consultant's Report and the Independent Engineer's Report and the opinions contained in the reports, the Independent Market Consultant and the Independent Engineer have made the following qualifications about the information contained in their reports and the circumstances under which the reports were prepared: some information in the reports is necessarily based on predictions and estimates of future events and behaviors; such predictions or estimates may differ from that which other experts specializing in the electricity industry might present; actual results may differ, perhaps materially, from those projected; the provision of the reports does not eliminate the need for you to make further inquiries as to the information included in the reports or to undertake your own analysis; the reports are not intended to be a complete and exhaustive analysis of the subject issues, and therefore may not consider some factors that are important to your decision; and the Independent Market Consultant and the Independent Engineer accept no liability for loss, whether direct or consequential, suffered by you in reliance on their reports, and nothing in the reports should be taken as a promise or guarantee as to the occurrence of any future events.

The Independent Market Consultant's Report and Independent Engineer's Report rely on assumptions regarding material contingencies and other matters that are not within our control or the control of Sargent & Lundy, PA Consulting or any other person. While each of Sargent & Lundy and PA Consulting believes its assumptions to be reasonable for purposes of preparing its respective report, these assumptions are inherently subject to significant uncertainties and actual results may differ materially from those projected. The predictions, estimates and assumptions that underlie these reports may also differ from those that other experts specializing in the electricity industry might present.

## Selected Financial Projections

The financial projections prepared by Sargent & Lundy are summarized below to provide investors with information regarding our ability to make principal and interest payments on the Senior Notes. These projections were not prepared with a view toward complying with the guidelines established by the American Institute of Certified Public Accountants for preparation and presentation of financial projections or generally accepted accounting principles, but we believe that the projections are supported by the Independent Engineer's Report and the Independent Market Consultant's Report and were prepared on a reasonable basis. PricewaterhouseCoopers LLP, who have been appointed as our independent accountants and will perform an audit for the year ended December 31, 2001, have neither examined nor compiled these projections and, accordingly, PricewaterhouseCoopers LLP do not express an opinion or any other form of assurance with respect thereto.



We do not intend to update or otherwise revise the financial projections to reflect events or circumstances existing or arising after the date of this information, or to reflect the occurrence of unanticipated events. The projections should not be relied upon for any purpose after such date. You must make your own independent assessment of our ability to make principal and interest payments on the Senior Notes. We cannot assure you that our cash flows from operations will be sufficient to pay principal, premium (if any) or interest on the Senior Notes. See "Risk Factors—Our actual future performance may not meet projections."

The projections presented below are taken from the Independent Engineer's Report and are subject to the qualifications, limitations and exclusions set forth therein. The following information reflects the base case assumptions set forth in the Independent Engineer's Report.

| | Year Ending December 31, | | | | | | |
|---|---|---|---|---|---|---|---|
| | 2001 | 2002 | 2003 | 2004 | 2005 | 2010 | 2015 |
| | ($ in millions) | | | | | | |
| **Selected Projected Financial Data** | | | | | | | |
| Total Revenues(1) | $ 5,978 | $ 6,298 | $ 7,706 | $ 7,669 | $ 6,186 | $ 8,086 | $ 9,089 |
| Operating Income(2) | 1,767 | 1,645 | 1,690 | 1,625 | 1,669 | 3,047 | 3,551 |
| Capital Expenditures | 306 | 286 | 257 | 306 | 335 | 396 | 412 |
| Cash Available For Debt Service(3) | 1,461 | 1,368 | 1,428 | 1,325 | 1,329 | 2,642 | 3,130 |
| Total Debt(4) | 1,017 | 3,746 | 3,716 | 3,686 | 3,656 | 3,391 | 3,186 |
| Debt Service Coverage Ratio(5) | 31.8x | 19.6x | 4.3x | 4.0x | 4.1x | 7.7x | 12.5x |

| | Year Ending December 31, | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | 2001 | 2002 | 2003 | 2004 | 2005 | Average 2001-2005 | Average 2001-2010 | Average 2001-2020 |
| **Selected Projected Operating Data** | | | | | | | | |
| Expected Percentage Revenue Distribution by GWh Generated | | | | | | | | |
| Contract | 71 | 69 | 59 | 61 | 58 | 63 | 47 | 23 |
| Market | 29 | 31 | 41 | 39 | 42 | 37 | 53 | 77 |

(1) Projected revenues do not include certain marketing operations of the Power Team, including opportunistic spot-market purchases to reduce supply costs under the ComEd and PECO supply agreements and trading and hedging activities. We anticipate these activities will increase our revenues and purchased power costs above the levels shown in the Independent Engineer's Report.

(2) Revenues less Operating Expenses less Administrative and General Expenses, plus Net Earnings on Equity.

(3) Operating Income less Capitalized Costs less Changes in Working Capital.

(4) The financial projections prepared by Sargent & Lundy assume that we acquire the 50.1% of Sithe that we do not currently own in December 2002. As a consequence, Total Debt increases at year-end 2002 to reflect (1) approximately $2.2 billion of Sithe debt, of which $2 billion is non-recourse project debt, and (2) the issuance of debt to fund the purchase of the Sithe equity at an assumed cost of $900 million.

(5)

Cash Available for Debt Service divided by Debt Service.



## RISK FACTORS

*Each of the following factors could have a material adverse effect on our business.*

**Our financial performance depends on the operation of our generation assets.**

Deterioration in the operation of our power plants may adversely affect our financial performance as a result of lower revenues, increased operating expenses and higher maintenance costs.

Operating power generation facilities involves many risks, including:

- operator error and breakdown or failure of equipment or processes;
- operating limitations that may be imposed by environmental or other regulatory requirements;
- labor disputes;
- fuel supply interruptions; and
- catastrophic events such as fires, earthquakes, explosions, floods or other similar occurrences.

Deterioration in the operation of Sithe or AmerGen plants also may adversely affect our financial performance.

**We also depend on the performance of generation assets under contract.**

Energy supplied by third-party generators pursuant to long-term agreements represents a significant portion of our overall capacity. The assets owned by these generators are subject to the same operational risks described above. In addition, performance under these power supply agreements may depend on the generator's financial condition. As a result, our financial performance depends on the ability of these generators to deliver capacity and energy under their contracts. Our largest power supply contract is with Midwest Generation, LLC, an affiliate of Southern California Edison Company, whose troubled financial condition has recently been the subject of much media attention. To the extent the financial condition of Southern California Edison or its parent, Edison International, deteriorates, we cannot predict what impact, if any, this would have on Midwest Generation's ability to supply capacity and energy to us.

**Our actual future performance may not meet projections.**

The projections contained in the Independent Engineer's Report prepared by Sargent & Lundy attempt to present our future operating performance. Sargent & Lundy has reviewed the performance and the technical operating parameters of our generation stations and our operating and maintenance budgets and has made forecasts based on a review of certain technical, environmental, economic and licensing aspects. The projections are based on certain assumptions and forecasts of our generation capacity, generation revenues, the market prices for energy, capacity and ancillary services and the costs associated with our operations.

The assumptions made about future market prices for energy and capacity are based on a market analysis prepared by PA Consulting. The Independent Market Consultant's Report contains qualifications about the information in the report prepared by PA Consulting and the circumstances under which PA Consulting performed its analysis. These assumptions and the other assumptions upon which the projections are based are inherently subject to significant uncertainties. No inference should be made about the likely existence of any particular future set of facts or circumstances. Potential investors should carefully review the Independent Engineer's Report and the Independent Market Consultant's Report, as well as the qualifications in those reports.



The projections are not necessarily indicative of our future performance or the performance of any individual generation station. We do not intend to provide investors with any revised projections or analysis of the differences between the projections and actual operating results.

**Our revenues depend on sales to ComEd and PECO.**

We have agreed to supply our affiliates ComEd and PECO with their respective load requirements through 2004 and 2010, respectively. Both ComEd and PECO are obligated to provide energy to all customers in their service territories who do not select an alternative energy supplier. As a result of these agreements, we expect to derive approximately 60% of our revenues from sales to ComEd and PECO.

Our supply agreements with ComEd and PECO are expected to provide us with a stable source of revenue; they do not, however, provide us with any guaranteed level of customer sales. As long as we have commitments to ComEd and PECO, our revenues will be a function of the cost of fulfilling these obligations and how much electricity is available to sell in wholesale markets after fulfilling those contracts. Generally, to the extent market prices decrease, customers may have an incentive to obtain electricity from alternative energy suppliers. To the extent that customers choose alternative energy suppliers, our revenues from contracts with ComEd and PECO will be reduced and our revenues will depend more on prices in the wholesale markets. If market prices increase substantially and our load requirements exceed our generation capacity, we may be required to purchase expensive power in the wholesale markets. Thus, any dramatic change in electricity prices combined with switching by customers could have an adverse effect on our results of operations or financial condition.

Further, while our affiliate contracts are currently a substantial portion of our business, we cannot predict whether they will be renewed at the end of their respective terms or what the terms of any renewals may be.

**We are subject to electricity price risk.**

After we have met our contractual commitments, we sell energy in the wholesale markets. These sales expose us to the risks of rising and falling prices in those markets, and cash flows may vary accordingly. After our contracts with ComEd and PECO expire, our cash flows will largely be determined by our ability to successfully market energy, capacity and ancillary services and by wholesale prices of electricity.

**The marketing, trading and risk management activities of our Power Team may not be successful.**

The principal function of Power Team is to manage our long asset-based position in the markets for energy and capacity. Power Team's risk management and other activities may not yield the planned or expected results. As a consequence, we are exposed to the risks of the commodity market for electricity that can exhibit extremely high volatility.

In addition, we are exposed to the risk that a counterparty with whom we transact business does not perform under its obligations. While we employ a rigorous counterparty credit evaluation methodology, the failure of one of our counterparties to perform its obligations could have a material adverse effect on our results of operations or financial condition.



**We may incur substantial cost and liabilities due to our ownership and operation of nuclear facilities.**

The ownership and operation of nuclear facilities involve certain risks. These risks include: mechanical or structural problems; inadequacy or lapses in maintenance protocols; the impairment of reactor operation and safety systems due to human error; the costs of storage, handling and disposal of nuclear materials; limitations on the amounts and types of insurance coverage commercially available; and uncertainties with respect to the technological and financial aspects of decommissioning nuclear facilities at the end of their useful lives. The following are among the more significant of these risks:

- *Operational risk.* Operations at any nuclear generation plant could degrade to the point where we have to shut down the plant. If this were to happen, the process of identifying and correcting the causes of the operational downgrade to return the plant to operation could require significant time and expense, resulting in both lost revenue and increased fuel and purchased power expense to meet our supply commitments. For plants operated by us but not wholly owned by us, we could also incur liability to the co-owners. We may choose to close a plant rather than incur substantial costs to restart the plant.

- *Regulatory risk.* The NRC may modify, suspend or revoke licenses and impose civil penalties for failure to comply with the Atomic Energy Act, the regulations under it or the terms of the licenses of nuclear facilities. Changes in regulations by the NRC that require a substantial increase in capital expenditures or that result in increased operating or decommissioning costs could adversely affect our results of operations or financial condition.

- *Nuclear accident risk.* Although the safety record of nuclear reactors generally has been very good, accidents and other unforeseen problems have occurred both in the United States and elsewhere. The consequences of an accident can be severe and include loss of life and property damage. Any resulting liability from a nuclear accident could exceed our resources, including insurance coverage.

**Our investment, acquisition and development activities may not be successful.**

We currently intend to grow our generation portfolio through investments, acquisitions and the development of new energy projects, the completion of any of which is subject to substantial risk. The competitive energy market is emerging following deregulation and we may not be successful in anticipating appropriate market opportunities. It is possible that, due to a variety of factors, including purchase price, operating performance and future market conditions, we would be unable to achieve our projected returns. We may not be able to successfully integrate our acquisitions or investments with our existing businesses. Successful acquisition and development are contingent upon, among other things, negotiation of contracts satisfactory to us with other project participants and receipt of required governmental approvals and consents. Successful development of new projects depends on our ability to obtain permits and equipment and complete the projects within budget in a timely fashion. Further, we may be unable to obtain the substantial debt and equity capital required to invest in, acquire and develop new generation projects, to refinance existing projects or to complete projects under construction.

**Our business may be adversely affected by regulatory changes in the electric power industry.**

The regulation of the electric power industry continues to undergo substantial changes at both the state and Federal level. These changes have significantly affected the industry and the manner in which its participants conduct their businesses.

Future changes in laws and regulations may have an effect on our business in ways that we cannot predict. Some restructured markets have recently experienced supply problems and price volatility that have been the subject of a significant amount of media coverage, much of which has been critical of the restructuring initiatives. In some of these markets, including California, government agencies and



other interested parties have made proposals to re-regulate portions of the utility industry that have previously been deregulated and, in California, legislation has been passed placing a moratorium on the sale of generation plants by regulated utilities. Other proposals to re-regulate our industry may be made, and legislative or other attention to the electric power restructuring process may cause the process to be delayed, discontinued or reversed in the states in which we currently, or may in the future, operate. If competition in the electric power industry is discontinued, or our business re-regulated, we cannot predict the impact on our business.

**We may not be able to respond effectively to competition or new technologies.**

We may not be able to respond in a timely or effective manner to the many changes in the power industry that may occur as a result of regulatory initiatives to increase competition. As a result, additional competitors in our industry may be created, and we may not be able to maintain our revenues and earnings levels or pursue our growth strategy. In addition, new technologies may be developed that impact the competitiveness of our generation facilities. To the extent that competition increases, our profit margins may be negatively affected.

While demand for electricity is generally increasing throughout the United States, the rate of construction and development of new, more efficient electric generation facilities may exceed increases in demand in some regional electric markets. The introduction of new participants with better technologies in our regional markets could increase competition, which could lower prices and have a material adverse effect on our results of operations or financial condition.

**We have a limited operating history as a stand-alone power generator.**

We have operated as a separate, stand-alone entity since January 1, 2001. We depend on Exelon for some of our liquidity, capital resource and credit support needs, and on our affiliates for certain general corporate and other services. We are still in the process of integrating the generation assets and operations we acquired from ComEd and PECO. Additionally, we may not be able to successfully integrate our acquisitions or developments with our existing business.

**We are subject to control by Exelon.**

Our sole limited liability company member, Exelon Ventures Company, LLC, is controlled by Exelon and, therefore, ultimately Exelon controls the decision of all matters submitted for member approval and has control over our management and affairs. In circumstances involving a conflict of interest between Exelon, on the one hand, and our creditors, on the other, Exelon could exercise its power to control us in a manner that would benefit Exelon to the detriment of our creditors, including the holders of the Senior Notes.

**Conflicts of interest may arise between us and our affiliates.**

We rely on sales to our affiliates ComEd and PECO under long-term contracts for a majority of our revenues. Conflicts of interest may arise if we need to enforce the terms of agreements between us and ComEd and PECO. Decisions concerning the interpretation or operation of these agreements could be made from perspectives other than the interests solely of our company or its creditors, including the holders of the Senior Notes.

**We are subject to regulation by the SEC under the Public Utility Holding Company Act.**

We are subject to regulation by the SEC under the Public Utility Holding Company Act of 1935. Under PUHCA, we cannot issue debt or equity securities or guaranties without the SEC's approval. Under PUHCA, generally, we can invest only in traditional electric and gas utility businesses and related businesses. The acquisition of the voting stock of other gas or electric utilities is subject to prior



SEC approval. PUHCA also imposes restrictions on transactions among affiliates. The limitations imposed on us by PUHCA may limit our ability to pursue acquisition or development opportunities.

## USE OF PROCEEDS

We intend to use the proceeds from the sale of the Senior Notes, after deducting discounts to the initial purchasers and estimated fees and expenses, to repay intercompany obligations of $696 million to Exelon incurred to fund the acquisition of our interest in Sithe. The intercompany obligation to Exelon is a demand note that bears interest at a floating rate, which is currently 5%, and is due no later than December 16, 2001.

## CAPITALIZATION

The following table sets forth our capitalization as of March 31, 2001 (1) on an actual basis, (2) on a pro forma basis to reflect the transfer in April 2001 of $52 million of debt from PECO to us, through the refunding of pollution control notes, and (3) on a pro forma as adjusted basis to give effect to the issuance of the Senior Notes offered hereby and the use of the net proceeds of the Senior Notes.

| | As of March 31, 2001 (unaudited) | | |
|---|---|---|---|
| | Actual | Pro Forma | Pro Forma as Adjusted |
| | | (in millions) | |
| Short-Term Debt | $ 701(1) | $ 701 | $ 5(2) |
| Long-Term Debt: | | | |
| Senior Notes due 2011 | — | — | 700 |
| Other Long-Term Debt | 204 | 256 | 256 |
| Total Debt | 905 | 957 | 961 |
| Total Member's Equity | 2,336 | 2,284 | 2,284 |
| Total Capitalization | 3,241 | 3,241 | 3,245 |

(1) Includes note payable to parent of $696 million and long-term debt due within one year of $5 million.

(2) Pro forma as adjusted to show the application of $695 million of net proceeds, plus an additional $1 million from available cash balances, to repay note payable to parent of $696 million.



## SELECTED HISTORICAL FINANCIAL DATA

The following table sets forth selected historical financial data. The historical financial data for the three months ended March 31, 2001 have been derived from our unaudited financial statements included elsewhere in this information. The information set forth below should be read in conjunction with Management's Discussion and Analysis of Financial Condition and Results of Operations and the Financial Statements and accompanying Notes to the Financial Statements included elsewhere in this information. This data represents only one fiscal quarter of information and is not necessarily indicative of the results of operations or net cash flows for an entire year.

| | Three Months Ended March 31, 2001 |
|---|---|
| | (in millions) |
| **Statement of Income Data** | |
| Operating Revenues: | |
| Wholesale Revenues | $ 710 |
| Wholesale Revenues—Affiliates | 911 |
| Other | 7 |

| | |
|---|---|
| Total Operating Revenues | 1,628 |
| Total Operating Expenses | 1,359 |
| Operating Income | 269 |
| Net Income | 170 |

| | | As of March 31, 2001 |
|---|---|---|
| | | (in millions) |
| **Balance Sheet Data** | | |
| Current Assets | $ | 1,352 |
| Property, Plant and Equipment, net | | 3,398 |
| Nuclear Fuel, net | | 869 |
| Deferred Debits and Other Assets | | 4,642 |
| Total Assets | | 10,261 |
| Current Liabilities | | 1,753 |
| Long-Term Debt | | 204 |
| Deferred Credits and Other Liabilities | | 5,968 |
| Total Member's Equity | | 2,336 |
| Total Liabilities and Member's Equity | | 10,261 |



## MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

### General

On October 20, 2000, Exelon became the parent corporation of each of ComEd and PECO as a result of the completion of the merger between PECO and Unicom Corporation, the former parent of ComEd. Effective January 1, 2001, Exelon undertook a restructuring to separate its generation and other competitive businesses from its regulated energy delivery business. The restructuring streamlines the process for managing, operating and tracking the financial performance of each of Exelon's businesses. As part of the restructuring, the generation-related operations, assets and liabilities of ComEd and PECO, including its investments in Sithe and AmerGen, were transferred to us.

### Results of Operations

*Revenues.* During the first quarter of 2001, our revenues benefited from increases in wholesale market prices particularly in the Pennsylvania New Jersey Maryland ("PJM") and Mid-America Interconnected Network ("MAIN") regions, and the operation of our nuclear plants at high capacity levels.

The increase in wholesale market prices was primarily driven by significant increases in natural gas prices. Our large concentration of nuclear generation allowed us to capture the higher prices for wholesale market sales, with minimal exposure to these higher natural gas prices. Average realized prices for wholesale market sales were $12 per MWh higher in the quarter ended March 31, 2001, compared to the same period in 2000.

During the first quarter, our nuclear facilities operated at a capacity factor of 99.2%. Our nuclear capacity factor for the first quarter of 2001 benefited from the absence of any refueling outages. We plan to complete seven refueling outages during 2001.

In the first three months of 2001, we sold 48,254 GWh, with 29,966 GWh supplied by nuclear units, 2,726 GWh supplied by fossil generation units, and 15,562 GWh from purchases. Fifty-six percent of our first quarter sales were to affiliates.

*Operating Expenses.* The following table presents certain expense items and operating income as a percentage of operating revenues:

| | Three Months Ended March 31, 2001 |
|---|---|
| Operating Revenues | 100% |
| Operating Expenses: | |
| Fuel and Purchased Power | 50% |
| Operating and Maintenance | 25% |
| Depreciation and Amortization | 5% |
| Taxes Other Than Income | 3% |
| Operating Income | 17% |



The efficient operation of our nuclear plants during the first quarter of 2001 reduced our need to purchase power to meet our supply commitments. The high capacity factor for our nuclear plants also reduced our per MWh operating costs, resulting in strong gross margins on energy sales.

For the first quarter, fuel and purchased power expense was $818 million, or 50% of operating revenues. Fuel and purchased power expense included $100 million of amortization of nuclear fuel.

For the first quarter, operating and maintenance expense was $403 million, or 25% of operating revenues. Operating and maintenance expense as a percentage of operating revenues benefited from the higher level of nuclear output and the higher wholesale market prices.

For the first quarter of 2001, depreciation and amortization was $92 million, or 5% of operating revenues. We expect depreciation and amortization to remain a relatively small percentage of operating revenues due to the relatively low book value ($177 per kW) and the long lives of our owned generation assets.

Taxes other than income for the first quarter were $46 million, consisting primarily of real estate and payroll taxes.

*Interest Expense.* Interest expense for the first quarter of 2001 was $33 million. Interest expense primarily related to a $696 million note payable to Exelon and the spent nuclear fuel liability.

*Income Taxes.* Our effective income tax rate was 40% for the three months ended March 31, 2001. Our effective income tax rate exceeds the Federal statutory rate due to the impact of state income taxes.

*Cumulative Effect of a Change in Accounting Principle.* On January 1, 2001, we adopted Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities," resulting in a benefit of $18 million ($11 million, net of income taxes).

*Net Income.* Our net income for the first quarter of 2001 was $159 million, before giving effect to the cumulative effect of a change in accounting principle. Net income, inclusive of the cumulative effect of a change in accounting principle of $11 million, was $170 million.

*Earnings Before Interest and Taxes.* Exelon evaluates the performance of its business segments, including our generation business, based on earnings before interest and income taxes ("EBIT"). In addition to components of operating income as shown on the consolidated statements of income, EBIT includes earnings from equity investments, and other income and expense recorded in other, net, with the exception of interest income. For the first quarter of 2001, our EBIT was $299 million.

*Comprehensive Income.* Our comprehensive income for the first quarter of 2001 was $50 million. This amount principally reflects a $124 million (net of income taxes) unrealized loss on marketable securities. The loss is associated with declines in market value, during the first quarter of 2001, of securities held in our nuclear decommissioning trust funds. Given the size of our trust funds, approximately $3 billion, and the recent volatility experienced in the U.S. securities markets generally, we expect our comprehensive income to fluctuate from quarter to quarter.

**Liquidity and Capital Resources**

Cash flows provided by operating activities for the three months ended March 31, 2001 were $342 million.

Cash flows used in investing activities for the three months ended March 31, 2001 were $118 million.



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Cash flows used in financing activities were $36 million for the three months ended March 31, 2001. Cash flows used in financing activities in 2001 primarily represent net distributions to Exelon.

Our capital resources are primarily provided by internally generated cash flows from operations and external financing and, to the extent necessary, capital contributions and loans from Exelon. Capital resources are used primarily to fund capital requirements, including construction, investments in new and existing ventures, repayments of maturing debt and payments of distributions to Exelon.

Estimated capital expenditures and other investments in 2001 are approximately $840 million principally for major maintenance, nuclear fuel and increases in capacity at existing plants. Proposed capital expenditures and other investments are subject to periodic review and revision to reflect changes in economic conditions and other factors. We and British Energy have each agreed to provide up to $100 million to AmerGen at any time for operating expenses. We anticipate that our capital expenditures and any required additional investment in AmerGen will be provided by internally generated funds.

We have an option to purchase, and Sithe's other stockholder groups have the right to require us to purchase, the remaining 50.1% interest in Sithe during the period from December 2002 through December 2005. With respect to 70% of this remaining interest, the purchase price will be at fair market value, subject to a $430 million floor and a $650 million ceiling. With respect to the other 30% of this remaining interest, the purchase price will be at fair market value. The purchase price of this remaining 50.1% interest will accrue interest from December 2002. The acquisition of this remaining interest in Sithe would require external financing, or capital contributions or loans from Exelon.

**Quantitative and Qualitative Disclosures About Market Risk**

We are exposed to market risks associated with commodity price, credit and security prices.

*Commodity Price Risk.* We utilize contracts for the forward sale and purchase of energy to manage available generation capacity and physical delivery obligations to wholesale and retail customers. Energy option contracts and energy swap arrangements are used to limit the market price risk associated with forward contracts. Market price risk exposure is the difference between the fixed price commitments in the contracts and the market price of the commodity. As of December 31, 2000, the estimated market price exposure associated with a 10% decrease in the average around the clock market price of electricity is a $60 million decrease in net income. In the second quarter of 2001, we began using financial and commodity contracts for trading. We have established risk policies, procedures and limits to manage our exposure to market risk.

*Credit Risk.* We manage credit risks through established policies, including establishing counterparty credit limits, and in some cases, requiring deposits and letters of credit to be posted by certain counterparties to bilateral contractual arrangements. For sales into the spot markets, the administrators (generally, independent system operators ("ISOs")) of those markets maintain financial assurance policies that are established and enforced by those administrators. Such policies may not protect us from credit risk of load-serving entities purchasing services in the spot markets, particularly load-serving entities that have a statutory obligation to serve customers.

*Equity Price Risk.* We maintain trust funds, as required by the NRC, to fund certain costs of decommissioning our nuclear plants. As of March 31, 2001, these funds were invested primarily in domestic equity securities and fixed rate, fixed income securities and are reflected at fair value on the Consolidated Balance Sheet. The mix of securities is designed to provide returns to be used to fund decommissioning costs and to compensate for inflationary increases in decommissioning costs. However, the equity securities in the trusts are exposed to price fluctuations in equity markets, and the value of fixed rate, fixed income securities are exposed to change in interest rates. We actively monitor the investment performance and periodically reviews asset allocation in accordance with our nuclear



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decommissioning trust investment policy. As of December 31, 2000, a 10% increase in interest rates and decrease in equity prices would have resulted in a $224 million reduction in the fair value of the trust assets.

**Outlook**

Our strategy is to develop a national generation portfolio with fuel and dispatch diversity, to recognize the cost savings and operational benefits of owning and operating substantial generation capacity and to optimize the value of our low-cost generation capacity through power marketing expertise.

We have agreed to supply ComEd and PECO with their respective load requirements for customers through 2004 and 2010, respectively. As a result, we expect that approximately 60% of our revenues will be from sales to ComEd and PECO. Our contracts with ComEd and PECO are at established prices. Revenues from these contracts will depend on the number of customers who do not choose an alternative energy supplier, but continue to purchase generation services from ComEd and PECO. If retail energy prices decrease, ComEd and PECO's customers will have an incentive to choose alternative suppliers, which may reduce our revenues from these contracts and increase our dependence on market sales. In addition, we have contracts to sell energy and capacity to third parties and to purchase capacity and energy from third parties. To the extent that our resources exceed our contractual commitments, we market these resources on a short-term basis or sell them in the spot market. In addition, we have agreed to provide ComEd with capacity and energy in 2005 and 2006 from its formerly owned nuclear plants at market rates to be negotiated.

Our future results of operations depend on our ability to operate our generation facilities efficiently to meet our contractual commitments and to sell energy services in the wholesale markets. A substantial portion of our capacity, including all of our nuclear capacity, is base-load generation designed to operate for extended periods. Nuclear generation is currently the most effective way for us to meet our commitments for sales to affiliates and others. To meet our long-term commitments to provide energy, including our commitments to ComEd and PECO, we must operate our nuclear generation facilities at planned capacity levels that are at or above 90%. Failure to achieve these capacity levels may require us to contract or purchase more expensive energy in the spot market to meet these commitments. Because of our reliance on nuclear facilities, any changes in regulations by the NRC requiring additional investments or resulting in increased operating or decommissioning costs could adversely affect us.

Our operating results depend on our level of sales and, for market sales, on the price of electricity. Our sales and market prices both depend on the demand for electricity. Consequently, we expect operating results to be stronger in the first and third quarters of each year when the winter and summer peak periods occur. Additionally, we schedule the biannual refueling outages of our nuclear units during non-peak periods.

Because our revenues depend on the contracts with ComEd and PECO and the market prices of electricity, we do not expect to be able to increase prices to reflect inflation.

If we purchase the remaining interest in Sithe, it will become a consolidated subsidiary and its results of operations will be included in our financial results from the date of purchase. For the year ended December 31, 2000, Sithe had annual revenues (excluding revenues from operations disposed of during 2000) of approximately $1 billion. If we purchase the remaining interest, our long-term debt would include all of Sithe's long-term debt. At March 31, 2001, Sithe had long-term debt of $1.7 billion, including $1.4 billion of non-recourse project debt. Since March 31, 2001, Sithe has incurred approximately $35 million of additional non-project debt. All of Sithe's non-project debt is due, and certain letters of credit issued for its account expire, on or prior to August 20, 2001. Sithe is currently negotiating new credit facilities and considering other alternatives to meet its capital resource and liquidity requirements.



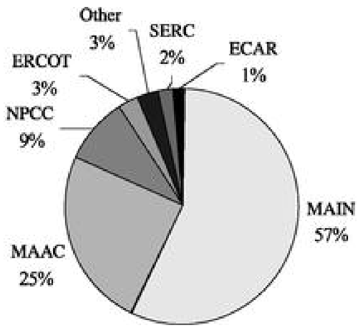
## BUSINESS

### Overview

We are the largest competitive electric generation company in the United States, as measured by owned and controlled megawatts. We combine our large, low-cost generation fleet with an experienced wholesale power marketing operation. We directly own generation assets in the Mid-Atlantic and Midwest regions with a net capacity of 19,159 MW, including 13,949 MW of nuclear capacity. We also control another 16,013 MW of capacity in the Midwest, Southeast and South Central regions through long-term contracts.

In addition to our own generation facilities, we have acquired a 49.9% interest in Sithe Energies, Inc. with an option, beginning in December 2002, to purchase the remaining 50.1% interest. Sithe develops, owns and operates generation facilities. Currently, Sithe has 3,748 MW of capacity in operation and 6,131 MW under construction or in advanced development. We also own a 50% interest in AmerGen Energy Company, LLC, a joint venture with British Energy plc. AmerGen owns three nuclear stations with total generation capacity of 2,378 MW.

The following chart reflects the geographic location of our generation portfolio by North American Electric Reliability Council Regions (see inside cover), including our long-term contracts and investments.




Power Team is a major wholesale marketer of energy that uses our generation portfolio, transmission rights and expertise to ensure delivery of generation to our wholesale customers under long-term and short-term contracts. Power Team is responsible for supplying the load requirements of our utility affiliates ComEd and PECO and markets the remaining energy in the wholesale markets. Power Team also buys and sells power in the wholesale spot markets.

### Business Strategy

Our business strategy is to develop a national generation portfolio with fuel and dispatch diversity. To implement this strategy, we plan to:

- grow our generation portfolio;
- drive cost and operational leadership through proven fleet management and economies of scale; and
- optimize the value of our low-cost generation portfolio through our power marketing expertise.

*Grow Our Generation Portfolio.* We intend to continue to grow our generation portfolio through asset acquisitions, development of new plants, innovative applications of technology, joint ventures and long-term off-take contracts. Regardless of the approach employed, we remain disciplined in our evaluation of opportunities to grow our business. We use sophisticated analytical tools to evaluate the potential returns on investments as well as the risks of these investments.

*Drive Cost and Operational Leadership through Proven Fleet Management and Economies of Scale.* Our facilities have achieved superior performance through a proven fleet management model, an experienced management team, highly trained employees and economies of scale. Our goals are to increase fleet output and to improve efficiency, while sustaining operational safety. We intend to achieve these results in our nuclear fleet by increasing capacity factors over historic levels, reducing refueling outage duration and increasing our generation capacity through power uprates and other modifications.

In addition, we expect to reduce operating and maintenance costs by capturing merger synergies, achieving economies of our fleet scale at single-unit sites, implementing planned staff reductions and reducing costs of equipment and services through consolidated purchasing programs. In addition, we expect to reduce fuel costs through both contract management and improved fuel design and management.

Finally, we intend to apply for extensions of the operating licenses for our nuclear plants.

*Optimize the Value of Our Low-Cost Generation Portfolio through Our Power Marketing Expertise.* Power Team is responsible for marketing all the energy and capacity of our owned generation facilities, long-term contracts and the three AmerGen plants. We seek to maintain a net positive supply of capacity through ownership of generation assets and power purchase agreements. In 2000, Power Team had open-market sales of 48 million MWh. In addition to supplying ComEd and PECO, Power Team markets energy, capacity and ancillary services from our owned and contracted generation.

Power Team has also contracted for access to additional generation through bilateral long-term power purchase agreements. These agreements relate to the power from specific generation plants that Power Team dispatches in a manner similar to our owned assets. We enter into power purchase agreements with the objective of obtaining low-cost energy supply sources to meet our physical delivery obligations to customers. Power Team's operations also provide our generation facilities with real-time market information, including energy demand levels, supply availability, market pricing, weather expectations and the anticipated timing and duration of peak demand periods.

**Competitive Strengths**

We believe that we are well positioned to play a leading role in the competitive energy industry because of our:

- competitive, low-cost fleet of generation assets;
- operating experience and expertise;
- critical mass of generation capacity with economies of scale;
- stable revenue streams under long-term contracts with ComEd and PECO; and
- extensive experience in the wholesale power markets.

*Competitive, Low-Cost Fleet of Generation Assets.* Our 41,291 MW fleet of generation assets makes us the largest competitive electric generation company in the United States. Our low-cost advantage is driven by our ownership of or investment in 11 nuclear generation stations, consisting of 19 units, with net capacity totaling 15,138 MW. The production costs of our nuclear fleet are significantly below the average prices of electricity in the markets where we operate. The nuclear plants benefit from stable fuel costs, minimal environmental impact from operations and a safe operating history.



*Operating Experience and Expertise.* We have achieved superior operating performance in our generation business through the leadership of a deep and experienced management team. We use a coordinated approach to fleet management, sharing of "best-in-class" practices across our organization and broad employee recognition that exceptional performance is required to succeed in a competitive environment. Using this experience and coordinated approach, we are increasing the capacity of our generation units through power uprates and other modifications.

*Critical Mass of Generation Capacity with Economies of Scale.* We believe that a limited number of substantial competitors will emerge from the consolidation and transformation of the energy industry. The generation assets of ComEd and PECO and our investments in Sithe and AmerGen provide critical mass and a leadership position in the new energy markets. As the largest generator of nuclear power in the United States, we can take advantage of our scale and scope to negotiate favorable terms for the materials and services that our business requires.

*Stable Revenue Streams under Long-Term Contracts with ComEd and PECO.* Under electric utility restructuring legislation in Illinois and Pennsylvania, ComEd and PECO are obligated to supply generation services to customers who do not or cannot choose an alternative energy supplier during the transition periods to a competitive supply marketplace. We have entered into long-term agreements to supply the load requirements of ComEd and PECO through 2004 and 2010, respectively. We expect sales to ComEd and PECO under these agreements to account for approximately 60% of our revenues. Our contracts with ComEd and PECO provide us with an appropriate balance in our exposure between long- and short-term commitments and wholesale market exposure.

*Extensive Experience in Wholesale Power Markets.* Power Team has substantial experience in energy markets, generation dispatch and the requirements for the physical delivery of power. Operating from our large asset platforms in the Mid-Atlantic and Midwest regions, Power Team has established itself as a leading asset-based power marketer. Because of our substantial asset base, Power Team has been able to distinguish itself within these regions as a reliable supplier. Currently, we are expanding our operations and generation portfolio through power purchase contracts and also opportunistically pursuing the acquisition of generation assets nationally. With our investment in Sithe, we have established a base for future growth in New England and New York.

**Overview of Generation Assets and Investments**

Our generation assets and investments consist of the following:

| | Capacity (MW) |
|---|---|
| Owned Generation Assets | 19,159 |
| Investments | 6,119 |

| | |
|---|---|
| Long-Term Contracts | 16,013 |
| Total | 41,291 |

Our owned generation assets are the nuclear generation stations in the Midwest region that we acquired from ComEd and the nuclear, fossil and hydroelectric stations in the Mid-Atlantic region that we acquired from PECO.

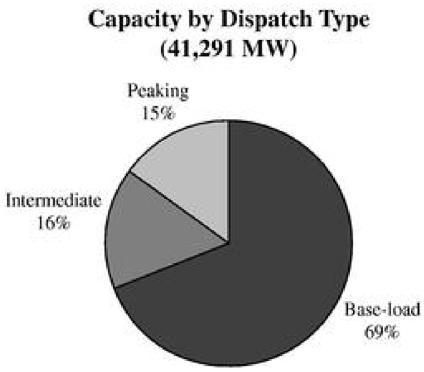
Our investments in generation assets consist of a 49.9% interest in Sithe and a 50% interest in AmerGen. Sithe, an independent power producer, owns and operates 27 power generation facilities in North America with approximately 3,748 MW of net generation capacity and has approximately 6,131 MW of capacity under construction or in advanced development. AmerGen owns three nuclear plants with a total capacity of 2,378 MW.

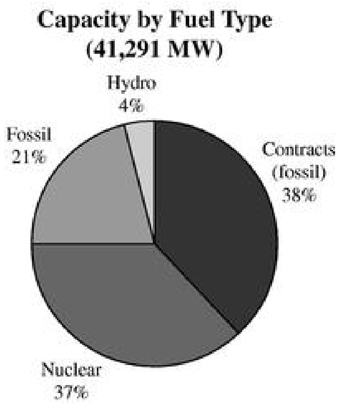


We also have access to generation capacity through contractual commitments. In particular, when ComEd sold its fossil generation assets to Midwest Generation, LLC, a subsidiary of Edison Mission Energy, ComEd entered into contracts for energy and capacity from these fossil assets, which contracts were transferred to us. In addition, we have entered into long-term power purchase agreements with independent power producers.

*Dispatch and Fuel Types.* Power generation facilities can generally be categorized into three classes based on the amount of time that the facilities are operating and their variable costs to produce electricity. A facility's variable cost to produce electricity, in turn, determines the order in which it is used to meet fluctuations in electricity demand. Base-load facilities are those that typically have low variable costs and provide power at all times when available. Base-load facilities are used to satisfy the base level of demand for power, or "load," that is not dependent upon time of day or weather. Peaking facilities have the highest variable cost to generate electricity and typically are used only during periods of highest demand for power. Intermediate facilities have cost and usage characteristics in between those of base-load and peaking facilities.

The following charts provide a breakdown of our generation assets and investments by dispatch and fuel type, as of May 31, 2001:




**Overview of Power Marketing**

Power Team, our wholesale marketing division, has more than ten years of marketing experience. Marketing power nationally 24 hours a day, seven days a week, Power Team schedules power for customers and dispatches our owned and operated generation facilities, including the AmerGen facilities, but excluding the Sithe facilities. Power Team has the experience and resources capable of meeting the energy needs of customers throughout the country.

We have entered into bilateral long-term contracts for sales of energy to load-serving entities, including electric utilities, municipalities, electric cooperatives, and retail load aggregators. We have also entered into agreements to deliver energy to wholesale market participants who primarily focus on the resale of energy products for delivery. We deliver our energy to these customers through access to transmission assets or rights for transmission service.

We compete nationally in the wholesale electric generation markets on the basis of service offerings and price, using our generation assets to assure customers of energy delivery. To the extent that our resources exceed our contractual commitments, we market those resources on a short-term basis.



**Owned Generation Assets**

The following table sets forth at May 31, 2001 the net generation capacity of, and other information about, the stations that we own directly:

| Fuel/Technology | Station | Location | No. of Units | % Owned(1) | Primary Fuel Type | Dispatch Type | Net Generation Capacity (MW)(2) |
|---|---|---|---|---|---|---|---|
| Nuclear(3) | Braidwood | Braidwood, IL | 2 | | Uranium | Base-load | 2,308 |
| | Byron | Byron, IL | 2 | | Uranium | Base-load | 2,304 |
| | Dresden | Morris, IL | 2 | | Uranium | Base-load | 1,592 |
| | LaSalle County | Seneca, IL | 2 | | Uranium | Base-load | 2,291 |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| | Limerick | Limerick Twp., PA | 2 | | Uranium | Base-load | 2,312 |
| | Peach Bottom | Peach Bottom Twp., PA | 2 | 46.245 | Uranium | Base-load | 1,028 |
| | Quad Cities | Cordova, IL | 2 | 75.00 | Uranium | Base-load | 1,172 |
| | Salem | Hancock's Bridge, NJ | 2 | 42.59 | Uranium | Base-load | 942 |
| Fossil (Steam Turbines) | Cromby 1 | Phoenixville, PA | 1 | | Coal | Base-load | 144 |
| | Cromby 2 | Phoenixville, PA | 1 | | Oil | Intermediate | 201 |
| | Delaware | Philadelphia, PA | 2 | | Oil | Peaking | 250 |
| | Eddystone 1, 2 | Eddystone, PA | 2 | | Coal | Base-load | 581 |
| | Eddystone 3, 4 | Eddystone, PA | 2 | | Oil | Intermediate | 760 |
| | Schuylkill | Philadelphia, PA | 1 | | Oil | Peaking | 166 |
| | Conemaugh | New Florence, PA | 2 | 20.72 | Coal | Base-load | 352 |
| | Keystone | Shelocta, PA | 2 | 20.99 | Coal | Base-load | 357 |
| | Fairless Hills | Falls Twp., PA | 2 | | Landfill Gas | Peaking | 60 |
| Fossil (Combustion Turbines) | Chester | Chester, PA | 3 | | Oil | Peaking | 39 |
| | Croydon | Bristol Twp., PA | 8 | | Oil | Peaking | 380 |
| | Delaware | Philadelphia, PA | 4 | | Oil | Peaking | 56 |
| | Eddystone | Eddystone, PA | 4 | | Oil | Peaking | 60 |
| | Falls | Falls Twp., PA | 3 | | Oil | Peaking | 51 |
| | Moser | Lower Pottsgrove Twp., PA | 3 | | Oil | Peaking | 51 |
| | Pennsbury | Falls Twp., PA | 2 | | Landfill Gas | Peaking | 6 |
| | Richmond | Philadelphia, PA | 2 | | Oil | Peaking | 96 |
| | Schuylkill | Philadelphia, PA | 2 | | Oil | Peaking | 30 |
| | Southwark | Philadelphia, PA | 4 | | Oil | Peaking | 52 |
| | Salem | Hancock's Bridge, NJ | 1 | 42.59 | Oil | Peaking | 16 |
| Fossil (Internal Combustion) | Cromby | Phoenixville, PA | 1 | | Oil | Peaking | 3 |
| | Delaware | Philadelphia, PA | 1 | | Oil | Peaking | 3 |
| | Schuylkill | Philadelphia, PA | 1 | | Oil | Peaking | 3 |
| | Conemaugh | New Florence, PA | 4 | 20.72 | Oil | Peaking | 2 |
| | Keystone | Shelocta, PA | 4 | 20.99 | Oil | Peaking | 2 |
| Hydroelectric | Conowingo | Harford Co., MD | 11 | | Hydro | Base-load | 512 |
| Pumped Storage | Muddy Run | Lancaster Co., PA | 8 | | Hydro | Intermediate | 977 |
| Total | | | 97 | | | | 19,159 |

(1) 100%, unless otherwise indicated.

(2) For nuclear stations, capacity reflects the annual mean rating. All other stations reflect a summer rating.

(3) All nuclear stations are boiling water reactors except Braidwood, Byron and Salem, which are pressurized water reactors.

We operate all of the facilities except for Salem, which is operated by PSEG Nuclear LLC, Keystone and Conemaugh, which are operated by Reliant Energy.



***Nuclear Facilities***

Nuclear facilities represent 73% of our directly owned generation capacity. Nuclear facilities are base-load plants. In 2000, approximately 59% of Exelon's electric output (including output of ComEd and PECO prior to the merger) was generated from the nuclear facilities.

The following table sets forth the capacity factors for our nuclear facilities for the last five years.

| | Year Ended December 31, | | | | |
|---|---|---|---|---|---|
| **Capacity Factors of Our Nuclear Facilities** | **1996** | **1997** | **1998** | **1999** | **2000** |
| Nuclear facilities previously owned by PECO(1) | 66% | 90% | 86% | 93% | 92% |
| Nuclear facilities previously owned by ComEd(2) | 62 | 49 | 65 | 89 | 93 |

(1) The capacity factor for 1996 reflects the shutdown of Salem.

(2) The capacity factors for 1996 through 1999 reflect the shutdown of LaSalle and Zion for portions of the period.

Nuclear facilities are subject to comprehensive regulation by the NRC under the Atomic Energy Act of 1954. See "Regulation." Nuclear units are operated under licenses granted by the NRC, which specify permitted operations of the unit and which must be amended to reflect certain changes in operation and plant modifications.

*Licenses.* We have 40-year operating licenses for each of our nuclear units. We intend to apply for the extension of the operating license for each of our nuclear generation units. The operating license renewal process takes approximately four to five years. Each requested license extension will be for 20 years. The following table summarizes operating license expiration dates for our nuclear facilities in service.

| Station | Unit | In-Service Date | Current License Expiration |
|---|---|---|---|
| Braidwood | 1 | 1988 | 2026 |
| | 2 | 1988 | 2027 |
| Byron | 1 | 1985 | 2024 |
| | 2 | 1987 | 2026 |
| Dresden | 2 | 1970 | 2009 |
| | 3 | 1971 | 2011 |
| LaSalle | 1 | 1984 | 2022 |
| | 2 | 1984 | 2023 |
| Quad Cities | 1 | 1973 | 2012 |
| | 2 | 1973 | 2012 |
| Limerick | 1 | 1986 | 2024 |
| | 2 | 1990 | 2029 |
| Peach Bottom | 2 | 1974 | 2013 |

| | | | |
|---|---|---|---|
| | 3 | 1974 | 2014 |
| Salem | 1 | 1977 | 2016 |
| | 2 | 1981 | 2020 |

*Fuel Management.* The fuel costs for nuclear generation are substantially lower than those of fossil-fuel generation. Consequently, nuclear generation is the most cost-effective way for us to meet our commitment to supply the requirements of ComEd and PECO and for sales to others.

The cycle of production of nuclear fuel includes the mining and milling of uranium ore into uranium concentrates; the conversion of uranium concentrates to uranium hexafluoride; the enrichment of the uranium hexafluoride; and the fabrication of fuel assemblies.



We have uranium concentrate inventory and supply contracts sufficient to meet all of our uranium concentrate requirements through 2001. Our contracted conversion services are sufficient to meet all of our uranium conversion requirements through 2002. All of our enrichment requirements have been contracted through 2004. Contracts for fuel fabrication have been obtained through 2005. We do not anticipate difficulty in obtaining the necessary uranium concentrates or conversion, enrichment or fabrication services for our nuclear units.

We obtain approximately 25% of our enrichment services from European suppliers. There is an ongoing trade action by USEC, Inc. alleging dumping in the United States against European enrichment services suppliers. If the trade action is resolved unfavorably against the European suppliers, it could increase our cost of enrichment services.

The capacity factor of a nuclear unit depends in part on the duration of the unit's refueling outage. Each of our nuclear units has a scheduled refueling outage every two years. We have become an industry leader in reducing the duration of our refueling outages.

*Other Matters.* In October 1990, General Electric ("GE") reported that crack indications were discovered near the seam welds of the core shroud assembly in a GE Boiling Water Reactor ("BWR") located outside the United States. As a result, GE issued a letter requesting that the owners of GE BWRs take interim actions, including a review of fabrication records and visual examinations of accessible areas of the core shroud seam welds. We participate in an industry-wide BWR vessel inspection program to develop long-term corrective actions, which we will apply to our BWR units at Limerick, Dresden and Quad Cities and all of the AmerGen units. See "—Regulation."

***Fossil and Hydroelectric Facilities***

Our fossil units include:

- *base-load units*—the coal-fired units at Eddystone and Cromby and our interests in the Keystone and Conemaugh Stations;
- *intermediate units*—the Eddystone and Cromby units that have dual fuel (oil/gas) capability; and
- *peaking units*—oil-fired steam turbines, combustion turbines and internal combustion units at various locations.

Our hydroelectric facilities include:

- *a base-load unit*—the Conowingo run-of-river hydroelectric facility on the Susquehanna River in Harford County, Maryland; and
- *an intermediate unit*—the Muddy Run pumped-storage hydroelectric facility in Lancaster County, Pennsylvania.

We operate all of our fossil and hydroelectric facilities other than Keystone and Conemaugh. In 2000, approximately 6% of our electric output (including output of ComEd and PECO prior to the merger) was generated from our owned fossil and hydroelectric generation facilities. The majority of this output was dispatched by the Power Team to support our power marketing activities.

We are in the process of upgrading Muddy Run. The project will be completed in 2001 and is expected to add 80 MW of capacity. Extensive renovations are also underway at Conowingo. The controls at all our combustion turbine facilities have been re-configured to provide remote start capability for all units, enabling immediate response time.

*Fuel Management.* Coal is obtained for our coal-fired plants primarily through annual contracts with the remainder supplied through either short-term contracts or spot-market purchases.

Natural gas is procured through annual, monthly and spot-market purchases. Some of our fossil generation stations can use either oil or gas as fuel. Fuel oil inventories are managed such that in the



winter months sufficient volumes of fuel are available in the event of extreme weather conditions and during the remaining months inventory levels are managed to take advantage of favorable market pricing. Power Team recently started to use financial instruments to mitigate price risk associated with multi-commodity price exposures. We have begun hedging forward price risk with both over-the-counter and exchange-traded instruments.

*Licenses.* Fossil generation plants are generally not licensed and, therefore, the decision on when to retire plants is fundamentally an economic one. Hydroelectric plants are licensed by FERC. The Muddy Run and Conowingo facilities have licenses that expire in September 2014. We are considering applying to FERC for license extensions of 40 years for both plants, but the duration of any license extension will depend on then-current policies at FERC. The process of applying for an extension to an existing hydroelectric license generally takes at least eight years.

**Long-Term Contracts**

In addition to our own generation assets, we sell electricity that we purchase under the long-term contracts described below:

| Seller | Location | Capacity (MW) | Expiration |
|---|---|---|---|
| Midwest Generation, LLC | Various in Illinois | 9,460 | 2004 |
| Kincaid Generation, LLC | Kincaid, Illinois | 1,108 | 2012 |
| Tenaska Georgia Partners, LP(1) | Franklin, Georgia | 900 | 2029 |
| Tenaska Frontier, Ltd | Shiro, Texas | 830 | 2020 |
| Others | Various | 3,715 | 2002 to 2022 |

| | |
|---|---|
| Total | 16,013 |

(1) Scheduled to be in operation in mid-2001.

***Midwest Generation Contract***

We are a party to contracts with Midwest Generation, LLC, a subsidiary of Edison Mission Energy. Under the contracts, we have the right to purchase through 2004 the capacity and energy associated with approximately 9,460 MW of fossil-fired generation stations located in Northern Illinois, formerly owned by ComEd. The generation units include base-load, intermediate and peaking units. Under the contracts, we pay a fixed capacity charge that varies by season and a fixed energy charge. The capacity charge is reduced to the extent the plants are unable to generate and deliver energy when requested. Under the contracts, we have the annual right to reduce the capacity and related energy we are obligated to purchase. We will decide whether to exercise this yearly option depending on our projected need for capacity and energy to fulfill our obligations under our agreement with ComEd or otherwise. We are currently in arbitration with Midwest Generation under the contract relating to the unavailability of certain units in January 2001.

**Investments**

***Sithe Energies, Inc.***

We own 49.9% of Sithe Energies, Inc. Another subsidiary of Exelon acquired the Sithe interest on December 18, 2000 for $696 million and transferred it to us in January 2001 in connection with Exelon's corporate restructuring. Sithe, headquartered in New York, is a leading independent power producer, with ownership interests in 27 facilities in North America. Sithe has net generation capacity of 3,748 MW, primarily in New York and Massachusetts, 2,651 MW under construction and 3,480 MW in advanced development.



For the year ended December 31, 2000, Sithe had annual revenues (excluding revenues from operations disposed of during 2000) of approximately $1 billion. At March 31, 2001, Sithe had long-term debt of $1.7 billion, including $1.4 billion of non-recourse project debt. Since March 31, 2001, Sithe has incurred approximately $35 million of additional non-project debt. All of Sithe's non-project debt is due, and certain letters of credit issued for its account expire, on or prior to August 20, 2001. Sithe is currently negotiating new credit facilities and considering other alternatives to meet its capital resource and liquidity requirements.

The following table shows Sithe's principal assets as of May 31, 2001.

| Type of Plant | Station | Location | No. of Units | Fuel | Dispatch Type | Net Generation Capacity (MW) |
|---|---|---|---|---|---|---|
| Merchant Plants | Batavia | New York | 1 | Gas | Intermediate | 50 |
| | ForeRiver 1, 2 | Massachusetts | 2 | Oil | Peaking | 26 |
| | Framingham 1, 2, 3 | Massachusetts | 3 | Oil | Peaking | 37 |
| | Massena | New York | 1 | Gas/Oil | Intermediate | 66 |
| | Mystic 4, 5, 6, 7 | Massachusetts | 4 | Oil | Intermediate | 973 |
| | Mystic CT | Massachusetts | 1 | Oil | Peaking | 11 |
| | New Boston 1, 2 | Massachusetts | 2 | Gas/Oil | Intermediate | 700 |
| | New Boston 3 | Massachusetts | 1 | Oil | Peaking | 20 |
| | Ogdensburg | New York | 1 | Gas/Oil | Intermediate | 71 |
| | West Medway 1, 2, 3 | Massachusetts | 3 | Gas/Oil | Peaking | 177 |
| | Wyman 4 | Maine | 1 | Oil | Intermediate | 36 |
| | Cardinal | Canada | 1 | Gas | Base-load | 152 |
| Qualifying Facilities | Allegheny 5, 6, 8, 9 | Pennsylvania | 4 | Hydro | Intermediate | 51 |
| | Bypass | Idaho | 1 | Hydro | Base-load | 10 |
| | Elk Creek | Idaho | 1 | Hydro | Base-load | 2 |
| | Greeley | Colorado | 1 | Gas | Base-load | 72 |
| | Hazelton | Idaho | 1 | Hydro | Base-load | 9 |
| | Independence | New York | 1 | Gas | Base-load | 1,042 |
| | Ivy River | North Carolina | 1 | Hydro | Base-load | 1 |
| | Kenilworth | New Jersey | 1 | Gas/Oil | Base-load | 26 |
| | Montgomery Creek | California | 1 | Hydro | Base-load | 3 |
| | Naval Station | California | 1 | Gas/Oil | Base-load | 45 |
| | Naval Training Center | California | 1 | Gas/Oil | Base-load | 23 |
| | North Island | California | 1 | Gas/Oil | Base-load | 37 |
| | Oxnard | California | 1 | Gas | Base-load | 48 |
| | Rock Creek | California | 1 | Hydro | Base-load | 4 |
| | Sterling | New York | 1 | Gas | Intermediate | 56 |
| Under Construction | ForeRiver 3 | Massachusetts | 1 | Gas/Oil | Base-load | 807 |
| | Mystic 8, 9 | Massachusetts | 2 | Gas | Base-load | 1,614 |
| | TEG 1, 2 | Mexico | 2 | Coke | Base-load | 230 |
| Under Advanced Development | Goreway | Canada | 1 | Gas | Base-load | 800 |
| | Heritage 1, 2 | New York | 2 | Gas | Base-load | 800 |
| | Medway 1, 2, 3 | Massachusetts | 3 | Gas | Peaking | 540 |
| | Southdown | Canada | 1 | Gas | Base-load | 800 |
| | Torne Valley/Sentry | New York | 1 | Gas/Oil | Base-load | 540 |
| Total | | | 52 | | | 9,879 |

Sithe also holds other international assets, which are accounted for by Sithe as "held for sale" consistent with Sithe's strategy to exit the international power-development business and are not shown on the table. Revenues from these assets and any proceeds from their sale are solely for the account of the holders of the remaining 50.1% interest in Sithe.

A majority of Sithe's merchant capacity is located in the Boston area. These facilities were purchased from Boston Edison Company in 1997. Prior to the purchase of these facilities, Sithe received authority from FERC to sell energy capacity and ancillary services at market-based rates.

*Purchase Option.* Beginning December 18, 2002, we will have the right to purchase all (but not less than all) of the remaining outstanding shares of the Sithe common stock. The option expires on December 18, 2005. In addition, each of Sithe's other stockholder groups has the right to require us to



purchase all (but not less than all) of its shares during the same period in which we can exercise our option. At the end of that period, if no stockholder has exercised its option, we will have a one-time option to purchase shares from the other stockholders to bring our holdings to 50.1% of the total outstanding shares. If we exercise our option or if all the stockholder groups exercise their put rights, the purchase price for 70% of the remaining 50.1% of the Sithe stock will be set at a fair market value plus a 10% premium in the case of a call or 10% discount in the case of a put, subject to a floor of $430 million and a ceiling of $650 million, and the remaining portion will be valued at fair market value without being subject to the floor or ceiling prices, plus, in each case, interest accrued from the beginning of the exercise period.

Under the terms of a stockholders' agreement, Sithe's board of directors consists of six directors, of which we have the right to nominate three. The approval of the majority of the entire board is required for certain actions, including approval of any agreement to purchase or sell electricity that will not be fully performed, or that is not terminable without penalty, before December 18, 2003. The approval of two-thirds of the stockholders is required to take certain actions, including incurring recourse debt in excess of $25 million.

Sithe's qualifying facilities (each a "QF") generally have been financed with non-recourse project finance debt and have entered into long-term, fixed rate contracts with various utilities. The debt and the contracts with the utilities are secured by the QF assets.

We are restricted under PUHCA from owning more than 50% of any QF. Accordingly, Sithe has agreed to use commercially reasonable efforts to sell or otherwise restructure each QF so as not to prohibit the purchase from occurring. Sithe is undertaking a comprehensive review of each QF.

*Construction.* Sithe's most significant construction projects are the plants at Mystic 8 and 9 and ForeRiver, located in the Boston area. Both projects are intended to be merchant facilities and have been financed with non-recourse project finance debt.

Washington Group International ("WGI"), as a result of its purchase of Raytheon Construction & Engineering, served as the engineering, procurement, and construction ("EPC") contractor. In March 2001, WGI, claiming cost over-runs, defaulted on its responsibilities as EPC contractor. Raytheon, as parent guarantor of the project, ensured performance of the EPC contract for the construction projects and, on April 2, 2001, subsequently selected Duke/Fluor Daniel as the EPC contractor for the Mystic and ForeRiver construction projects. Although Sithe believes that Mystic 8, 9 and ForeRiver will begin commercial operation in the summer of 2002 and in line with budgeted amounts, it cannot guarantee that such objectives will be met.

*Other Matters.* NSTAR Electric & Gas Corporation, the successor entity to Boston Edison, filed a complaint with FERC against Sithe, contesting Sithe's market-based rate authority for energy sales on the basis that Sithe possesses market power in the Northeastern Massachusetts Area ("NEMA"). In its complaint, NSTAR proposed that Sithe's market-based rate authority in NEMA be revoked, or, if Sithe wishes to retain market-based rate authority, it divest sufficient resources in NEMA to create a competitive market for generation. Alternatively, NSTAR proposed that NEPOOL be paid the higher of its energy market clearing price or its marginal cost based on the operating characteristics of each plant. NSTAR has also requested that FERC order Sithe to refund amounts collected by it in excess of the applicable NEPOOL energy market clearing price. On June 4, 2001, Sithe filed its answer to the NSTAR complaint. In its filing, Sithe asserted that NSTAR's complaint is without merit and that the governing precedents support continuance of Sithe's market-based rate authority and preclude the grant of the refunds sought by NSTAR.

The Independence power station is a wholly owned, gas-fired power plant located in Scriba, New York. Sithe recognizes fuel expense for gas consumed at Independence based on pricing provided for in Sithe's 20-year supply agreement with Enron Power Services, Inc.



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Enron maintains a notional tracking account to account for differences between the contract price and spot gas prices for the Independence power station. The tracking account is increased if the then-current spot gas price is greater than the contract price and is decreased if the then-current spot gas price is lower than the contract price. The tracking account bears interest at 1% over the prime rate. Enron has been given a security interest in Independence, which is subordinated to payments for secured debt service and certain letter of credit reimbursement obligations, to secure any tracking account balance. As of March 31, 2001, Sithe estimates that the balance in the tracking account amounted to approximately $389 million. If at any time the tracking account balance exceeds 50% of Independence's then fair market value, Independence will be required to reduce the tracking account balance by paying Enron 50% of certain cash-flows produced by the plant.

***AmerGen Energy Company, LLC***

AmerGen Energy Company, LLC was formed in 1997 by PECO and British Energy plc, a Scottish corporation, to acquire and operate nuclear generation facilities in North America. Currently, AmerGen owns three single-unit nuclear generation facilities which are described in the table below. AmerGen operates these nuclear facilities; however, we provide AmerGen with many services, including management services, in connection with the operation and support of these facilities under a Services Agreement dated March 1, 1999. In addition, our chief nuclear officer holds the same position at AmerGen. See "Certain Transactions—AmerGen Services Agreement." PECO transferred its 50% interest in AmerGen to us in January 2001.

| Station | Year Acquired | Location | Net Generation Capacity (MW) | License Expiration Date |
|---|---|---|---|---|
| Clinton Nuclear Power Station | 1999 | Clinton, IL | 933 | 2026 |
| Unit 1 of Three Mile Island ("TMI") Nuclear Station | 1999 | Londonderry Twp., PA | 814 | 2010 |
| Oyster Creek Nuclear Generation Facility | 2000 | Forked River, NJ | 630 | 2009 |
| Total | | | 2,378 | |

The capacity factors for the AmerGen plants for 1999 and 2000 were 57% and 87%, respectively. The 1999 capacity factor reflects the shutdown of Clinton for the portion of 1999 prior to our acquisition.

As part of each acquisition of its nuclear facilities, AmerGen entered into a power sales agreement with the seller. The agreement with Illinois Power for Clinton is for 75% of the output for a term expiring at the end of 2005. The agreement with GPU, Inc. for TMI and Oyster Creek are for all of the output. The agreement for the output of TMI expires at the end of 2001 and the agreement for the output of Oyster Creek expires March 31, 2003.

AmerGen maintains a decommissioning trust fund for each of its plants in accordance with NRC regulations and believes that amounts in these trust funds, together with investment earnings thereon, will be sufficient to meet its decommissioning obligations.

Under its LLC Agreement, AmerGen is managed by or at the direction of a management committee, which consists of six voting representatives, three of whom are appointed by British Energy and three by us. In addition, we appoint the chairman of the management committee. Action by the management committee generally requires the affirmative vote of a majority of members.



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British Energy and Exelon Generation may each transfer its interest in AmerGen subject to a right of first refusal of the other party and to the right of the other party to require a third party buying the interest to also purchase the other party's interest.

**Portfolio Growth**

We are growing our portfolio by investing in plant modifications through investments and acquisitions, among them our investments in Sithe and AmerGen. In addition, we intend to seek license extensions for our nuclear plants.

We are in the process of increasing the capacity of our nuclear fleet through power uprates, plant modifications and refinements. These projects, which have the potential of adding up to 885 MW of capacity by the end of 2003, require NRC approval. We constantly seek opportunities to improve the power output of each station by applying new technology, engineering upgrades and design improvements.

We are developing a 160 MW peaking plant in LaPorte, Texas that is scheduled for commercial operation in July 2001. Through a joint venture, we are also currently in the permitting process for a peaking plant in Chicago, Illinois.

We have agreed to purchase an additional 3.755% interest in the Peach Bottom Station from Atlantic City Electric Company for $9 million. We expect to complete the purchase in 2001 upon receipt of the remaining necessary regulatory approval.

In addition, we have invested $13 million in a new design for nuclear generation facilities—pebble-bed modular reactors—in partnership with Eskom Enterprises and others in a pebble-bed test project in South Africa. Eskom Enterprises is the unregulated affiliate of South Africa's state-owned utility. Exelon engineers have met with NRC staff members to discuss how the NRC might handle a license application for a site in the United States using this new technology.

**Power Team**

Power Team conducts our power marketing activities by:

- managing our supply obligations to ComEd and PECO and our other customers;
- marketing owned and contracted-for generation resources not utilized to meet our supply commitments in the bilateral and regional wholesale markets; and
- managing the market and price risks of our generation resources and commitments, including fossil fuel prices, through hedging and other power marketing and trading activities.

Power Team manages our supply obligations to ComEd, PECO and other wholesale customers by:

- scheduling and dispatching our generation units and capacity under contract using transmission rights to deliver power;
- entering into bilateral contracts for capacity, energy and other services; and
- trading in the regional spot markets to reduce supply expenses.

Power Team competes nationally in wholesale power marketing on the basis of price and service offerings, using our generation assets, transmission access, reservations and its knowledge of the interconnected bulk power systems and developing markets to assure customers of energy delivery. Through Power Team, we enter into bilateral arrangements for the purchase, sale and delivery of capacity, energy and ancillary services. Sales agreements are with load-serving entities, including electric



utilities, municipalities, electric cooperatives, retail load aggregators and other wholesale market participants. Through Power Team, we also compete in the wholesale spot markets for electricity.

Power Team also manages the price and supply risks for energy and fuel associated with our generation assets and the risks of our power marketing of activities. Through Power Team, we engage in financial trading, primarily to complement the marketing of the output of our generation assets. Power Team's principal risk management strategy is to maintain a long asset-based position. Power Team uses portfolio stress tests to guard against price movements and identify potential risks and hedging and risk management strategies to protect against volatile markets. We have a financial risk management policy and a corporate risk group to monitor the financial risks of our power marketing activities.

**Energy Markets**

In the United States, there are four established, real-time power markets, which are administered by independent system operators: Pennsylvania, New Jersey, Maryland, LLC ("PJM"), which is in the Mid-Atlantic Area Council ("MAAC") region; New England and New York, which are both in the Northeast Power Coordinating Council ("NPCC") region and California, which is in the Western Systems Coordinating Council ("WSCC") region. In each of these areas, power is traded through bilateral agreements between buyers and sellers and on the spot markets operated by independent system operators. In areas where there is no spot market, electricity is purchased and sold solely through bilateral agreements. The facilities that were transferred to us by PECO, as well as two of AmerGen's facilities, are located in the PJM market. To the extent that these facilities have capacity available after our obligations to customers, including PECO and ComEd, have been met, Power Team sells into the PJM market, as well as under bilateral agreements inside and outside of the market. The facilities that were transferred to us by ComEd, the facilities that supply electricity to us under our agreements with Midwest Generation and AmerGen's Clinton facility are located in the Mid-America Interconnected Network region ("MAIN"), where there is no independently operated regional spot market. To the extent that these facilities have capacity available after our obligations to our customers, including ComEd, have been met, Power Team sells electricity in the wholesale markets. Sithe sells into the New England Power Pool ("NEPOOL") and, to a lesser degree, the New York market.

In addition to selling energy in PJM, NEPOOL and New York markets, generators can sell other energy-related products. These products differ from market to market and include, among others, regulation (and/or automatic generation control), unbundled capacity, and operating reserves. The Independent Market Consultant's Report includes descriptions of these and the other products for which markets exist.

*PJM.* The PJM market covers all or part of the states of Pennsylvania, New Jersey, Maryland, Delaware, Virginia, and the District of Columbia. PJM, one of the largest centrally dispatched power pools in the world, handles about 8% of U.S. electricity. The PJM market is expected to grow at an annual rate of 1.4% through 2020. PJM requires load-serving entities, such as PECO, to own or contract for capacity to cover their peak demand and reserve margins required by PJM, currently, 18%. According to the Independent Market Consultant's Report, 18 GW of new generation will be required to meet load growth and reserve margins over the 20-year period ending in 2020. The PJM market structure includes markets for energy, regulation, capacity credit and fixed transmission rights.

*MAIN.* The Mid-American Interconnected Network region includes Illinois and parts of Missouri, Wisconsin and Michigan. According to the Independent Market Consultant's Report, the forecasted average annual load growth in MAIN through 2020 is 1.4%. MAIN has a policy, but not a requirement, that companies maintain a reserve of at least 17% to 20%. MAIN currently has a wholesale market consisting largely of informal arrangements, with most electricity sold through bilateral agreements, not



a power exchange, but is rapidly progressing toward the formation of an independent system operator that will manage regional transmission assets and establish spot market trading centers.

*NEPOOL.* The NEPOOL market is one of the two established markets in the Northeast Power Coordinating Council. The NEPOOL market covers the six New England states. Peak demand in the NEPOOL market is forecasted to grow at an annual rate of 1.47% through 2020. The NEPOOL market structure includes markets for energy, automatic generation control, ten-minute spinning reserve, ten-minute non-spinning reserve and thirty-minute operating reserve.

*New York.* The New York market, also located in the NPCC region, covers the State of New York. Peak demand in the New York market is forecasted to grow at an annual rate of 0.8% through 2020. The New York market structure includes markets for installed capacity, day-ahead and real-time energy, day-ahead and real-time ancillary services, including reserves and regulation and installed capacity.

*Other Regions.* We also have long-term contracts for the purchase of energy in the Electric Reliability Council of Texas region (1,060 MW), the Southeastern Electric Reliability Council region (1,000 MW) and the Southwest Power Pool region (800 MW). None of these regions has an established spot market.

**Regulation**

***Federal Regulation of Nuclear Power Generation***

We are subject to the jurisdiction of the NRC with respect to our nuclear generation stations. The Atomic Energy Act empowers the NRC to issue, modify, suspend and revoke licenses for the construction and operation of nuclear generation stations and impose civil penalties for failure to comply with the Act, the regulations under it or the terms of those licenses. The NRC subjects nuclear generation stations to continuing review and regulation covering, among other things, operations, maintenance, and environmental and radiological aspects of those stations. The NRC also adopts regulations regarding nuclear accidents, including a regulation requiring that, within 30 days of stabilizing a reactor, a licensee must submit a report to the NRC that provides a clean-up plan, identifying all clean-up operations necessary to decontaminate the reactor to permit either the resumption of operation or decommissioning of the facility.

The NRC has revamped its inspection, assessment and enforcement programs for commercial nuclear power plants. The new oversight process uses more objective, timely and safety-significant criteria in assessing performance, while seeking to more effectively and efficiently regulate the industry. It also takes into account improvements in the performance of the nuclear industry over the past twenty years. Nuclear plant performance is measured by a combination of objective performance indicators and by the NRC inspection program. These are closely focused on those plant activities having the greatest impact on safety and overall risk. In addition, the NRC conducts both periodic and annual review of the effectiveness of each operator's programs to identify and correct problems. The inspection program is designed to verify the accuracy of performance indicator information and to assess performance based on Safety Cornerstones that include:

- initiating events;
- mitigating systems;
- integrity of barriers to release of radioactivity;
- emergency preparedness;
- occupational radiation safety;



- public radiation safety; and
- physical protection.

The performance indicator data are evaluated and integrated with findings of the NRC inspection program. A "green" coding indicates performance within an expected performance level in which the related cornerstone objectives are met. A "white" coding indicates performance outside an expected range of nominal utility performance but related cornerstone objectives are still being met. A "yellow" coding indicates related cornerstone objectives are being met, but with a minimal reduction in safety margin. A "red" coding indicates a significant reduction in safety margin in the area measured by the performance indicator. Green coded plants typically require only routine oversight by the NRC. Plants which do not meet the "safety cornerstone" objectives, measured by performance indicator and inspection findings, receive increased inspection, focusing on areas of declining performance. There are also inspections beyond the baseline program, even at plants performing well, if there are operational problems or events the NRC believes require greater scrutiny. Generic problems, affecting some or all plants, may also require additional inspections. The performance indicators are reported to the NRC on a quarterly basis and posted on the NRC's web site.

All of our plants and those of AmerGen reported 100% "green" coding in the first quarter of 2001.

***Nuclear Waste Disposal***

There are no commercial facilities for the reprocessing of spent nuclear fuel ("SNF") currently in operation in the United States, nor has the NRC licensed any such facilities. We currently store all SNF generated by our nuclear generation facilities in on-site storage pools and, in the case of Peach Bottom, some SNF has been placed in dry-cask storage facilities. Our SNF storage pools do not have sufficient storage capacity for the life of the plant and we are developing dry-cask storage facilities.

As of December 31, 2000, we had 35,900 SNF assemblies (8,800 tons) stored on site in SNF pools. The following table describes the current status of our SNF storage facilities:

**Spent Nuclear Fuel Pool Capacity**

| Site | (% full) | Date for Loss of Full Core Discharge |
|---|---|---|
| Dresden | 79 | 2001 (Dry-cask storage project underway) |
| Quad Cities | 74 | 2006 |
| Byron | 52 | 2011 |
| LaSalle | 47 | 2012 |
| Braidwood | 44 | 2014 |
| Clinton | 49 | 2006 (Plans to re-rack to increase SNF pool capacity) |
| Peach Bottom | 83 | Dry-cask storage in operation to extend capacity to 2014 |
| Limerick | 61 | 2007 (Plans to re-rack to increase SNF pool capacity) |
| Oyster Creek | 86 | 2000 (Dry-cask storage project underway) |
| TMI | 63 | 2009 |
| Salem | 52 | 2011 |

Under the Nuclear Waste Policy Act of 1982 (the "NWPA"), the U.S. Department of Energy (the "DOE") is responsible for the disposal of SNF and other high-level radioactive waste. ComEd and PECO each signed contracts with the DOE (each, a "Standard Contract") to provide for disposal of SNF from their respective nuclear generation stations. The Standard Contracts were assigned to us as part of Exelon's corporate restructuring. Under the Standard Contracts, the DOE receives one mill ($.001) per kWh of net nuclear generation to cover the cost of SNF disposal. The Standard Contract requires ComEd and PECO to pay the DOE a one-time fee applicable to nuclear generation through



April 6, 1983. PECO has paid this fee while ComEd exercised its option to pay the one-time fee of $277 million, with interest, just prior to the first delivery of SNF to the DOE. As of March 31, 2001, the liability for the one-time fee with interest was $821 million. We have assumed the Standard Contracts. This fee may be adjusted in order to ensure full disposal cost recovery by the DOE.

In July 1996, the U.S. Court of Appeals for the District of Columbia ("D.C. Court of Appeals"), in response to a suit filed by a group of utilities, ruled that the DOE had an unequivocal obligation to begin to accept SNF in 1998. In November 1997, the D.C. Court of Appeals issued a decision in which it confirmed its earlier decision that the DOE had an unconditional obligation to begin disposal of SNF by January 31, 1998, but directed utilities to pursue contractual remedies for the DOE's likely (and, subsequently, actual) failure to perform.

In July 1998, ComEd filed a complaint against the DOE in the U.S. Court of Federal Claims seeking to recover damages caused by the DOE's failure to honor its contractual obligation to begin disposing of SNF in January 1998. In August 2000, the U.S. Court of Appeals for the Federal Circuit decided two other similar cases, granting partial summary judgment on liability for the plaintiff utility. ComEd has requested that the U.S. Court of Federal Claims grant its pending summary judgment motion on liability, particularly in light of this Federal Circuit's decision.

In July 2000, PECO entered into an agreement with the DOE relating to Peach Bottom to address the DOE's failure to begin removal of SNF in January 1998, as required by the Standard Contract. Under that agreement, the DOE agreed to provide credits against future contributions to the nuclear waste fund to compensate for SNF storage costs incurred as a result of the DOE's breach of the Standard Contract. The agreement also provides that, upon PECO's request, the DOE will take title to the SNF and the interim storage facility at Peach Bottom, provided certain conditions are met.

In November 2000, eight utilities with nuclear power plants filed a Joint Petition for Review against the DOE with the U.S. Court of Appeals for the Eleventh Circuit seeking to invalidate the portion of the agreement that provides for credits against nuclear waste fund payments on the ground that such provision is a violation of the NWPA. PECO intervened as a defendant in that case, which is ongoing.

As a by-product of their operations, nuclear generation units produce low-level radioactive waste ("LLRW"). LLRW is accumulated at each generation station and permanently disposed of at a Federally licensed disposal facility. The Federal Low-Level Radioactive Waste Policy Act of 1980 (the "Waste Policy Act") provides that states may enter into agreements to provide regional disposal facilities for LLRW and restrict use of those facilities to waste generated within the region. Illinois and Kentucky have entered into an agreement, although neither state currently has an operational site, and none is currently expected to be operational until after 2011. Pennsylvania, which had agreed to be the host site for LLRW disposal facilities for generators located in Pennsylvania, Delaware, Maryland and West Virginia, has suspended the search for a permanent disposal site.

We have temporary on-site storage capacity at our nuclear generation stations for limited amounts of LLRW and have been shipping such waste to LLRW disposal facilities in South Carolina and Utah. The number of LLRW disposal facilities is decreasing, and we anticipate the possibility of continuing difficulties in disposing of LLRW. We are also pursuing alternative disposal strategies for LLRW, including a LLRW reduction program to minimize cost impacts.

The National Energy Policy Act of 1992 (the "Energy Policy Act") requires that the owners of nuclear reactors pay for the decommissioning and decontamination of the DOE nuclear enrichment facilities. The total cost to domestic owners is estimated to be $150 million per year through 2006, of which our share is approximately $22 million per year.



***Nuclear Facility Decommissioning***

As of December 31, 2000, our estimate of aggregate decommissioning costs was $6.9 billion. On December 31, 2000, ComEd and PECO held $3.1 billion in trust accounts to fund future decommissioning costs. The two utilities pooled this amount from amounts recovered from ratepayers and net realized and unrealized investment earnings on these amounts. The decommissioning liabilities and related trust funds were transferred to us as of January 1, 2001 pursuant to Exelon's corporate restructuring. Amounts collected by ComEd and PECO to fund decommissioning costs will continue to be paid into the nuclear decommissioning trust funds. On March 31, 2001, our nuclear decommissioning trust fund balance was $2.9 billion.

Effective January 1, 2001, we recorded a receivable from ComEd of approximately $440 million representing ComEd's legal requirement to remit funds to us that ComEd is authorized to collect from customers through 2006. This amount also included collections from customers prior to the establishment of external decommissioning trust funds in 1989. All amounts collected and remitted to us will be deposited into the decommissioning trust.

As of December 31, 2000, PECO's Condensed Consolidated Balance Sheet included an estimated liability for decommissioning its nuclear plants of $412 million that was recorded as a component of accumulated depreciation. Investments in nuclear decommissioning trust fund assets were $440 million. Both the liability and the trust fund investments were transferred to us as of January 1, 2001. Annual decommissioning cost recovery of $29 million, collected through regulated rates, will continue, and all amounts collected will be remitted to us to be deposited into the decommissioning trust funds.

Zion, a two-unit nuclear generation station formerly owned by ComEd, permanently ceased power generation operations in 1998. ComEd transferred Zion to us as part of Exelon's corporate restructuring. The plant is currently being maintained in a secure and safe condition until final decommissioning, which is scheduled to begin in 2013. Zion's spent nuclear fuel is currently being stored in the on-site storage pool until a permanent repository under the NWPA is completed. At March 31, 2001, $1.3 billion of our $3.9 billion decommissioning liability related to Zion.

***Environmental Regulation***

*General.* Certain of our operations are subject to regulation regarding environmental matters by the Federal government, the states of Illinois, Pennsylvania, New Jersey and Iowa and local jurisdictions where we operate our facilities. The Illinois Pollution Control Board ("IPCB") has jurisdiction over environmental control in Illinois, together with the Illinois Environmental Protection Agency, which enforces regulations of the IPCB and issues environmental permits. The Pennsylvania Department of Environmental Protection ("PDEP") has jurisdiction over environmental control in Pennsylvania. State regulation includes the authority to regulate air, water and noise emissions and solid waste disposals. The United States Environmental Protection Agency ("EPA") administers certain Federal statutes relating to such matters.

When the generation assets of PECO and ComEd were transferred to us, we agreed to assume environmental liabilities arising out of any violation of environmental laws, environmental permits or environmental claims related to any real property or asset transferred to us and to indemnify PECO and ComEd, their permitted assigns and their respective officers, directors, stockholders and employees against all fines or penalties, liabilities, damages and losses related to environmental claims. PECO and ComEd transferred to us all indemnities, hold harmless agreements and funds, reserves, escrows and other repositories of funds related to environmental obligations associated with the units we acquired and kept all liabilities for all substantial transmission and distribution facilities.

*Water.* Under the Federal Clean Water Act, National Pollutant Discharge Elimination System ("NPDES") permits for discharges into waterways are required to be obtained from the EPA or from



the state environmental agency to which the permit program has been delegated. Those permits must be renewed periodically. We either have NPDES permits for all of our generation stations or have pending applications for such permits. We are also subject to the jurisdiction of certain other interstate agencies, including the Delaware River Basin Commission and the Susquehanna River Basin Commission.

*Solid and Hazardous Waste.* The Comprehensive Environmental Response, Compensation, and Liability Act of 1980, as amended ("CERCLA"), provides for immediate response and removal actions coordinated by the EPA in the event of threatened releases of hazardous substances into the environment and authorizes the U.S. Government either to clean up sites at which hazardous substances have created actual or potential environmental hazards or to order persons responsible for the situation to do so. Under CERCLA, generators and transporters of hazardous substances, as well as past and present owners and operators of hazardous waste sites, are strictly, jointly and severally liable for the cleanup costs of waste at sites, most of which are listed by the EPA on the National Priorities List ("NPL"). These potentially responsible parties ("PRPs") can be ordered to perform a cleanup, can be sued for costs associated with an EPA-directed cleanup, may voluntarily settle with the U.S. Government concerning their liability for cleanup costs, or may voluntarily begin a site investigation and site remediation under state oversight prior to listing on the NPL. Various states, including Illinois, have enacted statutes that contain provisions substantially similar to CERCLA. In addition, the Resource Conservation and Recovery Act ("RCRA") governs treatment, storage and disposal of solid and hazardous wastes and cleanup of sites where such activities were conducted.

By notice issued in November 1986, the EPA notified over 800 entities, including PECO and ComEd, that they may be PRPs under CERCLA with respect to releases of radioactive and/or toxic substances from the Maxey Flats disposal site, a LLRW disposal site near Moorehead, Kentucky, where PECO and ComEd wastes were deposited. Approximately 90 PRPs, including PECO, formed a steering committee to investigate the nature and extent of possible involvement in this matter. A settlement was reached among the Federal and private PRPs, the Commonwealth of Kentucky and the EPA concerning their respective roles and responsibilities in conducting remedial activities at the site. Under the settlement, the private PRPs agreed to perform the initial remedial work at the site and the Commonwealth of Kentucky agreed to assume responsibility for long-range maintenance and final remediation of the site. We estimate that we will be responsible for approximately $1.4 million of the remediation costs to be incurred by the private PRPs. On April 18, 1996, a consent decree, which included the terms of the settlement, was entered by the United States District Court for the Eastern District of Kentucky. The PRPs have entered into a contract for the design and implementation of the remedial plan and work has commenced. As a result of the restructuring of Exelon, we have agreed to assume ComEd's and PECO's liability and obligations arising from the Maxey Flats site.

*Air.* Air quality regulations promulgated by the EPA, the Pennsylvania Department of Environmental Protection and the City of Philadelphia in accordance with the Federal Clean Air Act and the Clean Air Act Amendments of 1990 (the "Amendments") impose restrictions on emission of particulates, sulfur dioxide ($SO_2$), nitrogen oxides ($NO_x$) and other pollutants and require permits for operation of emission sources. We have obtained such permits and they must be renewed periodically.

The Amendments establish a comprehensive and complex national program to substantially reduce air pollution. The Amendments include a two-phase program to reduce acid rain effects by significantly reducing emissions of $SO_2$ and $NO_x$ from electric power plants. Flue-gas desulfurization systems (scrubbers) have been installed at all of our coal-fired units other than the Keystone Station. Keystone is subject to, and in compliance with, the Phase II $SO_2$ and $NO_x$ limits of the Amendments, which became effective January 1, 2000. We and the other Keystone co-owners are purchasing $SO_2$ emission allowances to comply with the Phase II limits.



We have completed implementation of measures, including the installation of $NO_x$ emissions controls and the imposition of certain operational constraints, to comply with the Amendments. We expect that the cost of compliance with anticipated air-quality regulations may be substantial due to further limitations on permitted $NO_x$ emissions.

The EPA has issued two regulations to limit nitrogen oxide ($NO_x$) emissions from power plants in the eastern United States to address the "ozone transport" issue. The first regulation was issued on September 24, 1998. The original $NO_x$ regulation covered power plants in the 22 eastern states and had an effective date of May 1, 2003. As a result of litigation at the D.C. Circuit Court of Appeals, the original $NO_x$ regulation was revised to cover 19 eastern states (rather than the original 22) and the effective date was delayed by approximately one year to May 31, 2004. In most other respects, the original $NO_x$ regulation was substantively upheld by the Court. Both Pennsylvania and Illinois power plants are covered by the original $NO_x$ regulation.

The second EPA regulation, referred to as the "Section 126 Petition Regulation," was issued on May 25, 1999. This regulation was issued by the EPA in response to downwind state (Connecticut, Maine, Massachusetts, New Hampshire, New York, Pennsylvania, Rhode Island, Vermont) complaints under Section 126 of the Clean Air Act that upwind state $NO_x$ emissions were negatively impacting downwind states' ability to attain the Federal ozone standard. The Section 126 Petition Regulation requires substantively the same $NO_x$ reduction requirement for the power generation sector as the original $NO_x$ regulation. However, the Section 126 Petition Regulation covers fewer states (Delaware, Indiana, Kentucky, Maryland, Michigan, North Carolina, New Jersey, New York, Ohio, Virginia and West Virginia). It does not cover power plants in Illinois. The compliance date of the Section 126 Petition Regulation is May 1, 2003, one year earlier than states covered only under the original $NO_x$ regulation. The Section 126 Petition Regulation was litigated in the D.C. Circuit Court of Appeals. On May 15, 2001, the D.C. Circuit Court of Appeals upheld the legal basis of the Section 126 Petition Regulation, remanding two narrow technical issues to the EPA for further rulemaking.

On September 23, 2000, Pennsylvania issued final state $NO_x$ reduction regulations for power plants that satisfy both the original $NO_x$ regulation and the Section 126 Petition Regulation. The Pennsylvania regulation is effective May 1, 2003. For Keystone, the co-owners have approved and started preliminary work for the installation of selective catalytic reduction units to comply with the new regulations.

Many other provisions of the Amendments affect our business activities. The Amendments establish stringent control measures for geographical regions which have been determined by the EPA to not meet National Ambient Air Quality Standards; establish limits on the purchase and operation of motor vehicles and require increased use of alternative fuels; establish stringent controls on emissions of toxic air pollutants and provide for possible future designation of some utility emissions as toxic; establish new permit and monitoring requirements for sources of air emissions; and provide for significantly increased enforcement power, and civil and criminal penalties.

***Federal Power Act***

The Federal Power Act gives FERC exclusive rate-making jurisdiction over wholesale sales of electricity and the transmission of electricity in interstate commerce. Pursuant to the Federal Power Act, all public utilities subject to FERC's jurisdiction are required to file rate schedules with FERC with respect to wholesale sales or transmission of electricity. Because we sell power in the wholesale markets, we are deemed to be a public utility for purposes of the Federal Power Act and are required to obtain FERC's acceptance of our rate schedules for wholesale sales of electricity. We have received authorization from FERC to sell energy at market-based rates. FERC is also authorized to order refunds if it finds that market-based rates are unreasonable.

In addition, FERC, as is customary with market-based rate schedules, reserved the right to suspend market-based rate authority on a retroactive basis if it is subsequently determined that we or any of our



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affiliates exercised market power. If FERC were to suspend our market-based rate authority, it would most likely be necessary to file, and obtain FERC acceptance of, cost-based rate schedules. In addition, the loss of market-based rate authority would subject us to the accounting, record-keeping and reporting requirements that are imposed on public utilities with cost-based rate schedules.

In April 1996, FERC issued Order 888. The intent of Order 888 was to open the transmission grid subject to FERC's jurisdiction to all persons in the continental United States seeking transmission services. The order requires that owners of transmission facilities provide access to their transmission facilities at cost.

In December 1999, FERC issued Order 2000 which encourages the voluntary restructuring of transmission operations through the use of independent system operators and regional transmission organizations. A result of establishing these entities is to eliminate or reduce transmission charges imposed by successive transmission systems when wholesale generators cross several transmission systems to deliver capacity. Tariffs established under FERC regulation give us access to transmission lines that enable us to participate in competitive wholesale markets.

***Public Utility Holding Company Act***

We are subject to regulation under the Public Utility Holding Company Act ("PUHCA") as a registered public utility holding company and as a wholly owned subsidiary of Exelon, which is also a registered public utility holding company. The restrictions under PUHCA generally involve financing, investments and affiliate transactions. Under PUHCA, we cannot issue debt or equity securities or guaranties without the approval of the SEC. Exelon and its subsidiaries currently have approval to issue up to an aggregate of $4 billion of common stock, preferred securities, long- and short-term debt, and to issue up to $4.5 billion of guaranties. Under PUHCA, generally, we can invest only in traditional electric and gas utility businesses and related businesses. Our investments in exempt wholesale generators and foreign utility companies are limited to $4 billion in the aggregate. The acquisition of the voting stock of other gas or electric utilities is subject to prior SEC approval. In addition, PUHCA requires that all of a registered holding company's utility subsidiaries constitute a single system that can be operated in an efficient, coordinated manner. PUHCA also imposes restrictions on transactions among affiliates.

**Insurance**

The Price-Anderson Act (which currently expires in 2002) limits the liability of nuclear reactor owners to $9.5 billion for claims arising from a single nuclear incident. The limit is adjusted to account for inflation and changes in the number of licensed reactors. We carry the maximum available commercial insurance of $200 million and the remaining $9.3 billion is provided through mandatory participation in a financial protection pool. Under the Price-Anderson Act, all nuclear reactor licensees can be assessed up to $89 million per reactor per incident, payable at a rate of no more than $10 million per reactor per incident per year. This assessment is subject to inflation and state premium taxes. In addition, the U.S. Congress could impose revenue raising measures on the nuclear industry to pay claims if the damages from a nuclear incident exceed $9.5 billion. The Price-Anderson Act and the extensive regulation by the NRC do not preclude claims under state law for personal, property or punitive damages related to radiation hazards.

We maintain property insurance for each nuclear power plant in which we have an ownership interest. We are responsible for our respective proportionate share of premiums for such insurance based on our ownership interest. Our insurance policies provide coverage for decontamination liability expense, premature decommissioning and loss or damage to nuclear facilities. These policies require that insurance proceeds first be applied to assure that, following an accident, the facility is in a safe and stable condition and can be maintained in such condition. Under our insurance policies, proceeds not



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already expended to place the reactor in a stable condition must be used to decontaminate the facility. If, as a result of an accident, the decision is made to decommission the facility, a portion of the insurance proceeds will be allocated to a decommissioning fund that we or AmerGen, as the case may be, are required to maintain by the NRC. (See "Federal Regulation of Nuclear Facility Decommissioning.") These proceeds would be paid to the fund to make up any difference between the amount of money in the fund at the time of the early decommissioning and the amount that would have been in the fund if contributions had been made over the normal life of the facility. We are unable to predict what effect these requirements may have on the timing of the availability of insurance proceeds to creditors and the amount of such proceeds. Under the terms of the various insurance agreements, we could be assessed up to $69 million for losses incurred at any plant insured by the insurance companies. We are self-insured to the extent that any losses may exceed the amount of insurance maintained.

We are a member of an industry mutual insurance company that provides replacement power cost insurance in the event of a major accidental outage at a nuclear station. The policy contains a waiting period before recovery of costs can commence. The premium for this coverage is subject to assessment for adverse loss experience, with a maximum assessment of $18 million per year.

In addition, we participate in the American Nuclear Insurers Master Worker Program, which provides coverage for worker tort claims filed for bodily injury caused by a nuclear energy accident. This program was modified, effective January 1, 1998, to provide coverage to all workers whose nuclear-related employment began on or after the commencement date of reactor operations. We will not be liable for a retroactive assessment under this new policy. However, in the event losses incurred under the small number of policies in the old program exceed accumulated reserves, a maximum retroactive assessment of up to $50 million could apply.

**Employees**

We currently have approximately 7,500 employees. Of those employees, 2,200 are subject to collective bargaining agreements with Local 15 of the International Brotherhood of Electrical Workers. On April 20, 2001, Exelon and Local 15 officials signed an agreement for a new three-year collective bargaining agreement, effective April 1, 2001 through March 31, 2004. The new agreement covers our 2,200 employees who are subject to the agreement with Local 15. Local 15 membership ratified the agreement.

**Litigation**

We are involved in a number of judicial and regulatory proceedings (including the ones described below) concerning matters arising out of the conduct of our business. We believe, based on currently available information, that the ultimate outcome of any proceedings known to us at this time will not have a material adverse effect on our financial condition or results of operations.

*Cajun Electric Power Cooperative, Inc.* On May 27, 1998, the United States Department of Justice, on behalf of the Rural Utilities Service and the Chapter 11 Trustee for the Cajun Electric Power Cooperative, Inc. (Cajun), filed an action claiming breach of contract against PECO in the United States District Court for the Middle District of Louisiana arising out of PECO's termination of the contract to purchase Cajun's interest in the River Bend nuclear power plant, and seeking damages of $50 million, plus interest and consequential damages. While PECO cannot predict the outcome of this matter, we believe that PECO validly exercised its right of termination and did not breach the agreement. As a result of the restructuring of Exelon, we have agreed to assume any liability and obligation arising from this proceeding.

*Cotter Corporation.* During 1989 and 1991, actions were brought in Federal and state courts in Colorado against ComEd and its subsidiary, Cotter Corporation ("Cotter"), seeking unspecified



damages and injunctive relief based on allegations that Cotter permitted radioactive and other hazardous material to be released from its mill into areas owned or occupied by the plaintiffs, resulting in property damage and potential adverse health effects. In 1994, a Federal jury returned nominal dollar verdicts against Cotter on eight plaintiffs' claims in the 1989 cases, which verdicts were upheld on appeal. The remaining claims in the 1989 actions have been settled or dismissed. In 1998, a jury verdict was rendered against Cotter in favor of 14 plaintiffs in the 1991 cases, totaling approximately $6 million in compensatory and punitive damages and interest. Medical monitoring was also ordered. On appeal, the Tenth Circuit Court of Appeals reversed the jury verdict, remanding the case for a new trial. These plaintiffs' cases were consolidated with the remaining 26 plaintiffs' case, which had not been tried. This new trial is currently underway. In November 2000, another trial involving a separate sub-group of 13 plaintiffs, seeking $19 million in damages plus interest, was completed in Federal district court in Denver. The jury awarded nominal damages of $42,000 to 11 of 13 plaintiffs, but awarded no damages for any personal injury or health claims, other than requiring Cotter to perform periodic medical monitoring at minimal cost. The plaintiffs appealed the verdict to the Tenth Circuit.

On February 18, 2000, ComEd sold Cotter to an unaffiliated third party. As part of the sale, ComEd agreed to indemnify Cotter for any liability incurred by Cotter as a result of these actions, as well as any liability arising in connection with the West Lake Landfill discussed in the next paragraph.

The EPA has advised Cotter that it is potentially liable in connection with radiological contamination at a site known as the West Lake Landfill in Missouri. Cotter is alleged to have disposed of approximately 39,000 tons of soils mixed with 8,700 tons of leached barium sulfate at the site. Cotter and three other companies identified by the EPA have agreed to share equally the costs of a remedial study of the site; those costs could exceed $2 million in total. Future costs related to site remediation are not presently known.

As a result of the restructuring of Exelon, we have agreed to assume any liability and obligation arising from the Cotter matters.

*Pennsylvania Real Estate Tax Appeals.* We are involved in tax appeals challenging the assessed value of two of our nuclear facilities, Limerick (Montgomery County) and Peach Bottom (York County). AmerGen is involved in the tax appeal challenging the assessed value of Unit No. 1 at Three Mile Island Nuclear Station (Dauphin County).



## CERTAIN TRANSACTIONS

We are an indirect subsidiary of Exelon. The following describes our material relationships and agreements with Exelon and other affiliates.

*Restructuring and Asset Transfers.* During January 2001, Exelon undertook a restructuring to separate its generation and other competitive businesses from its regulated energy delivery business. As part of this restructuring, both ComEd and PECO transferred their assets and liabilities unrelated to energy delivery to other subsidiaries of Exelon, including us. In the case of ComEd, the assets and liabilities transferred to us included nuclear generation facilities, wholesale power marketing operations, rights under certain power purchase agreements and nuclear decommissioning trust funds. In the case of PECO, the assets and liabilities transferred related to nuclear, fossil and hydroelectric generation facilities and wholesale power marketing operations, rights under certain power purchase agreements and nuclear decommissioning trust funds. The liabilities that we assumed include: decommissioning costs for nuclear facilities; obligations to comply with all liabilities connected with or arising out of permits, licenses, exemptions, allowances, approvals and other items obtained or required in connection with the generation assets; obligations and liabilities arising under contracts assigned to us, including power purchase agreements and pollution control revenue bonds after January 1, 2001; all employment related obligations and liabilities to employees of PECO and ComEd who became our employees in connection with the restructuring; and certain litigation matters described under "Our Business—Litigation."

*Power Purchase and Related Agreements with ComEd.* We are a party to a power purchase agreement and other agreements with ComEd, under which we provide ComEd with all of ComEd's energy, capacity and ancillary services needs through December 31, 2004 (after taking into account deliveries from other suppliers of electricity and capacity that ComEd is required to accept under any requirement of law). ComEd will use such energy, capacity and ancillary services to meet its service obligations to its retail and wholesale customers and to provide energy imbalance service as part of its obligation to operate the ComEd control area. During the period from January 1, 2005 to December 31, 2006, the agreement changes to a partial requirements arrangement under which we will provide ComEd with all of the electric energy and capacity from the nuclear facilities formerly owned by ComEd that we now own and operate. Through 2004, ComEd will pay us fixed energy prices only, which vary depending on the time of day and the season. The prices for the portion of the term during 2005 and 2006 are not specified in the agreement, but the agreement does provide that the parties will meet before the end of 2004 to set the prices for that period, and that the intent is that such prices will reflect expected market prices for energy and capacity during that period. The agreement provides that if we and ComEd cannot agree on prices by July 1, 2004 (or on any agreed to later date), then ComEd may terminate the agreement as of December 31, 2004. We have also entered into an Ancillary Services and other Control Area Services Resource Purchase Agreement with ComEd. This agreement contains additional terms under which we provide ancillary and related services to ComEd.

*Power Purchase Agreement with PECO.* The power purchase agreement between PECO and us, dated January 1, 2001, requires us to deliver energy to PECO to meet PECO's hourly load obligations for provider-of-last-resort ("PLR") customers and provide PECO with rights to capacity sufficient to meet PECO's daily Unforced Capacity obligation as determined by PJM through the year 2010. To ensure long-term generation reliability within the PJM control area, PJM rules require that load-serving entities such as PECO have rights to capacity in amounts based on PECO's load plus a reserve margin. The bundled price for both the energy and capacity that we provide to PECO is a function of the amount PECO is able to charge its PLR customers. PECO will arrange for transmission service and all other transmission service products with PJM and pay PJM for these services.

*Market Operations Services Arrangement.* As a generator connected to the regional transmission system controlled by PJM, we are obligated to conduct certain market operation services, which, prior



to PECO's restructuring, were performed by PECO directly. Pursuant to the terms of a Market Operations Services Arrangement, PECO has agreed to continue to provide us with these services, which include, among other things, operation of generation dispatch function, troubleshooting generation problems and scheduling of generation units outages. Our estimated annual cost is approximately $1.4 million for employee services. In addition to charges for employee services, we will be charged for those costs, properly allocable to us, associated with the use of PECO-owned facilities and/or equipment (*e.g.*, telecommunications equipment) in the performance of the market operations services under the terms of the agreement. The agreement can be terminated by either party upon 120 days prior written notice.

*Interconnection Agreements.* Following the corporate restructuring and the disaggregation of Exelon's distribution and generation businesses, interconnection agreements between ComEd and us and between PECO and us were filed with FERC to establish the requirements, terms and conditions for the continuing interconnection of the generation facilities assigned to us with the transmission and distribution systems owned and operated by each of PECO and ComEd. The agreements govern interconnection solely, and it is our responsibility or the responsibility of the purchaser of our capacity or energy output to make arrangements for transmission service.

*Generation Reliability Services.* Pursuant to the terms of certain Call Contracts for Generator Reliability Services between us and PECO dated as of January 10, 2001, we have agreed that, when called upon by PECO to do so in accordance with the terms of the Call Contracts, we will generate energy to PECO's distribution system in order to preserve the reliable operations of the distribution system. In exchange for providing such services, we are entitled to receive our net out-of-pocket costs associated with providing the services. The agreements are for terms of ten years, unless terminated earlier by either party upon 90 days' prior written notice, and relate to the Delaware Generation Station and the Moser Generation Station.

*Transmission Services.* We purchase transmission services from our affiliates at price terms set under FERC open-access transmission tariffs. For the first quarter of 2001, our affiliated transmission purchases totaled $6.6 million.

*Transition Services Agreements.* Under transition service agreements, between each of ComEd and PECO and us, we are entering into short-term wholesale power transactions on an interim basis to ensure that (1) we can obtain from ComEd and PECO the energy and related services being purchased by ComEd and PECO under certain wholesale power agreements that have not yet been transferred to us and (2) ComEd and PECO fulfill their obligations to supply energy and related services under other wholesale power agreements not yet transferred to us. These wholesale power agreements will be transferred to us once we obtain the counterparty consent to such transfer.

*Operating Guidelines and License Agreement.* In connection with the corporate restructuring of ComEd, ComEd transferred to us two synchronous condensers and related equipment located at Zion nuclear station. These synchronous condensers are used to provide voltage support on ComEd's transmission system. Pursuant to the terms of the Operating Guidelines and License Agreement, we license to ComEd all of our rights to the synchronous condensers and agree to operate and maintain the synchronous condensers as required by ComEd.

*AmerGen Services Agreement.* We provide operation and support services to the nuclear facilities owned by AmerGen pursuant to a Services Agreement dated as of March 1, 1999. The Services Agreement has an indefinite term and may be terminated by us or by AmerGen on 90 days' notice. Under work orders issued under the Services Agreement, we provide such services as administrative and management services, human resource services, legal services, financial and accounting services, information technology and computer services and laboratory analysis services. We are compensated for



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these services in an amount agreed to in the work order but not less than the higher of our fully allocated costs for performing the services or the market price.

*Agreement with Exelon Energy Company, LLC.* Under a power purchase agreement between Exelon Energy Company, LLC ("Exelon Energy") and us for the period January 1, 2001 through December 31, 2001, we are obligated to provide the majority of the energy and Unforced Capacity requirements of Exelon Energy in the PJM region at market-based prices. Exelon Energy is an affiliate of Exelon Corporation that provides competitive retail generation service to customers in the PJM region and elsewhere. Under a separate power purchase agreement between Exelon Energy and us for the period January 1, 2001 through March 31, 2003, we are obligated to provide all the energy and capacity requirements of Exelon Energy to enable Exelon Energy to fulfill its competitive retail load obligations in Massachusetts at market-based prices.

*Capital Contributions and Distributions.* The total capital contributions to us from Exelon in connection with the transfer and purchase of operating assets were $2,398 million in 2001. We have paid $69 million in distributions to Exelon since January 1, 2001.

*Affiliated Services Agreements.* There are several contracts among Exelon and its affiliates, including us, under which services are provided and received. Exelon Business Services Company, a wholly owned subsidiary of Exelon, provides business services, such as legal, accounting, purchasing and information technology, to Exelon and its affiliates, including us, at cost. ComEd and PECO currently provide services to or receive services from Exelon affiliates, including us, at market prices, or if there is no prevailing price, then at fully distributed cost. We also provide and receive from ComEd and PECO services, at cost, pertaining to the interface between the generation function conducted by us and the transmission and distribution functions provided by ComEd and PECO. These services are limited to those necessary for the efficient operation of the facilities located at the generation station sites where generation facilities are connected to the transmission and distribution facilities (primarily switchyard facilities). We also provide supply planning services, at cost, to ComEd and PECO and assist them in obtaining energy supply resources to the extent energy supply is not provided by us.

*Pollution Control Notes.* On April 25, 2001, PECO transferred to us $52 million of debt, through a refunding of pollution control notes. We anticipate the transfer of an additional $69 million of tax-exempt debt, through refundings, later this year.

*Consolidated Tax Return and Tax Sharing Agreement.* We join with Exelon and its subsidiaries in filing a consolidated federal income tax return. The consolidated tax liability will be allocated among participants in accordance with a Tax Sharing Agreement to be entered into with the other members of the Exelon Consolidated Group (including PECO and ComEd). This agreement will provide an equitable method for determining the share of the affiliated group's consolidated federal tax burdens and benefits to be attributed to each member.



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## INDEPENDENT ACCOUNTANTS

Exelon Generation Company, LLC, a wholly owned subsidiary of Exelon Corporation, had no assets or operations prior to January 1, 2001. PricewaterhouseCoopers LLP have not audited any financial statements of Exelon Generation Company, LLC as of any date, but have been appointed as our independent accountants for the year ended December 31, 2001.



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## INDEX TO UNAUDITED CONSOLIDATED FINANCIAL STATEMENTS

**EXELON GENERATION COMPANY, LLC AND SUBSIDIARY COMPANIES**

**CONSOLIDATED STATEMENT OF INCOME**

**FOR THE THREE MONTHS ENDED MARCH 31, 2001**

**(Dollars in Millions)**
**Unaudited**

| | | |
|---|---|---|
| **Operating Revenues:** | | |
| Wholesale Revenues | $ | 710 |
| Wholesale Revenues—Affiliates | | 911 |
| Other | | 7 |
| Total Operating Revenues | | 1,628 |
| **Operating Expenses** | | |
| Fuel and Purchased Power | | 818 |
| Operating and Maintenance | | 390 |
| Operating and Maintenance—Affiliates | | 13 |
| Depreciation and Amortization | | 92 |
| Taxes Other Than Income | | 46 |
| Total Operating Expenses | | 1,359 |
| **Operating Income** | | 269 |
| **Other Income and Deductions** | | |
| Interest Expense | | (18) |
| Interest Expense—Parent | | (15) |
| Earnings from Equity Investments | | 26 |
| Other, Net | | 4 |
| Total Other Income and Deductions | | (3) |
| **Income Before Income Taxes and Cumulative Effect of a Change in Accounting Principle** | | 266 |
| **Income Taxes** | | 107 |
| **Income before Cumulative Effect of a Change in Accounting Principle** | $ | 159 |
| Cumulative Effect of a change in Accounting Principle (net of income taxes of $7) | | 11 |
| Net Income | $ | 170 |

The accompanying notes are an integral part of these financial statements.



**EXELON GENERATION COMPANY, LLC AND SUBSIDIARY COMPANIES**

**CONSOLIDATED STATEMENT OF CASH FLOWS**

**FOR THE THREE MONTHS ENDED MARCH 31, 2001**

**(Dollars in Millions)**
**Unaudited**

| | | |
|---|---|---|
| **Cash Flows from Operating Activities** | | |
| Net Income | $ | 170 |
| Adjustments to Reconcile Net Income to Net Cash Flows Provided by Operating Activities: | | |
| Depreciation and Amortization | | 192 |
| Cumulative Effect of a Change in Accounting Principle (net of income taxes) | | (11) |
| Provision for Uncollectible Accounts | | 3 |
| Marked-to-Market Derivatives | | (17) |
| Deferred Income Taxes | | (13) |
| Earnings from Equity Investments | | (26) |
| Other Operating Activities | | (44) |
| Changes in Working Capital: | | |

| | |
|---|---|
| Accounts Receivable | 54 |
| Accounts Receivable from Affiliates | 12 |
| Inventories | 4 |
| Other Current Assets | (17) |
| Accounts Payable, Accrued Expenses & Other Current Liabilities | 35 |
| **Net Cash Flows provided by Operating Activities** | 342 |
| **Cash Flows from Investing Activities** | |
| Investment in Nuclear Fuel | (78) |
| Investment in Plant | (40) |
| **Net Cash Flows used in Investing Activities** | (118) |
| **Cash Flows from Financing Activities** | |
| Contributions from Member | 33 |
| Distribution to Member | (69) |
| **Net Cash Flows used in Financing Activities** | (36) |
| **Increase in Cash and Cash Equivalents** | 188 |
| **Cash and Cash Equivalents at beginning of period** | — |
| **Cash and Cash Equivalents at end of period** | $ 188 |

The accompanying notes are an integral part of these financial statements.



**EXELON GENERATION COMPANY, LLC AND SUBSIDIARY COMPANIES**

**CONSOLIDATED BALANCE SHEET**

**AS OF MARCH 31, 2001**

**(Dollars in Millions)**
**Unaudited**

| | |
|---|---|
| **Assets** | |
| **Current Assets** | |
| Cash and Cash Equivalents | $ 188 |
| Accounts Receivable, net | |
| Customer | 168 |
| Other | 325 |
| Receivables from Affiliates | 318 |
| Inventories, at average cost | |
| Fossil Fuel | 88 |
| Materials and Supplies | 197 |
| Deferred Income Taxes | 43 |
| Other | 25 |
| Total Current Assets | 1,352 |
| **Property, Plant and Equipment, net** | 3,398 |
| **Nuclear Fuel, net of accumulated amortization of $1,550** | 869 |
| **Deferred Debits and Other Assets** | |
| Deferred Income Taxes | 389 |
| Nuclear Decommissioning Trust Funds | 2,943 |
| Emission Allowances | 82 |
| Investments | 783 |
| Receivables from Affiliate | 364 |
| Other | 81 |
| Total Deferred Debits and Other Assets | 4,642 |
| **Total Assets** | $ 10,261 |
| **Liabilities and Member's Equity** | |
| **Current Liabilities** | |
| Note Payable to Parent | $ 696 |
| Long-Term Debt Due Within One Year | 5 |
| Accounts Payable | 627 |
| Accrued Expenses | 293 |
| Other | 132 |
| Total Current Liabilities | 1,753 |

| | | |
|---|---|---|
| **Long-Term Debt** | | 204 |
| **Deferred Credits and Other Liabilities** | | |
| Unamortized Investment Tax Credits | | 242 |
| Nuclear Decommissioning Liability | | 3,942 |
| Pension Obligations | | 234 |
| Non-Pension Postretirement Benefits Obligation | | 391 |
| Spent Nuclear Fuel Obligation | | 821 |
| Other | | 338 |
| **Total Deferred Credits and Other Liabilities** | | 5,968 |
| **Commitments and Contingencies** | | |
| **Member's Equity** | | |
| Membership Interest | | 2,398 |
| Retained Earnings | | 101 |
| Accumulated Other Comprehensive Income (Loss) | | (163) |
| Total Member's Equity | | 2,336 |
| **Total Liabilities and Member's Equity** | $ | 10,261 |

The accompanying notes are an integral part of these financial statements.



**EXELON GENERATION COMPANY, LLC AND SUBSIDIARY COMPANIES**

**CONSOLIDATED STATEMENTS OF CHANGES IN MEMBER'S EQUITY AND OTHER COMPREHENSIVE INCOME**

**FOR THE THREE MONTHS ENDED MARCH 31, 2001**

**(Dollars in Millions)**
**Unaudited**

| | | |
|---|---|---|
| **Member's Equity** | | |
| Balance at Beginning of Year | $ | — |
| Contributions from Member | | 2,398 |
| Balance at March 31, 2001 | $ | 2,398 |
| **Retained Earnings** | | |
| Balance at Beginning of Year | $ | — |
| Net Income | | 170 |
| Distribution to Member | | (69) |
| Balance at March 31, 2001 | | 101 |
| **Accumulated Other Comprehensive Income** | | |
| Balance at Beginning of Year | $ | — |
| Transfer of Other Comprehensive Income | | (43) |
| Other Comprehensive Income (net of income taxes of $83): | | |
| Transition adjustment related to adoption of SFAS No. 133 | | 4 |
| Unrealized loss on marketable securities | | (124) |
| Accumulated Other Comprehensive Income | | (163) |
| **Comprehensive Income** | | |
| Net Income | $ | 170 |
| Other Comprehensive Income (net of income taxes of $83): | | |
| Transition adjustment related to adoption of SFAS No. 133 | | 4 |
| Unrealized loss on marketable securities | | (124) |
| Total Comprehensive Income | $ | 50 |

The accompanying notes are an integral part of these financial statements.



**EXELON GENERATION COMPANY, LLC AND SUBSIDIARY COMPANIES**

**NOTES TO UNAUDITED CONSOLIDATED FINANCIAL STATEMENTS**

(Dollars in millions, unless otherwise noted)

## 1. Significant Accounting Policies

### Description of Business

Exelon Generation Company, LLC ("Exelon Generation") is a limited liability company engaged principally in the production and wholesale marketing of electricity in various regions of the United States. In connection with Exelon Corporation's ("Exelon") restructuring, effective January 1, 2001, Exelon Generation began operations as a wholly owned subsidiary of Exelon (See Note 2—Corporate Restructuring). Exelon Generation owns a 50% investment in AmerGen Energy Company, LLC ("AmerGen") and a 49.9% investment in Sithe Energies, Inc. ("Sithe"). See Note 3.

### Consolidation Policy and Use of Estimates

The accounting and financial reporting policies of Exelon Generation and its subsidiaries conform to generally accepted accounting principles and prevailing industry practices. The consolidated financial statements include the accounts of all majority-owned subsidiaries of Exelon Generation after elimination of significant intercompany accounts and transactions. Exelon Generation consolidates its proportionate interest in jointly owned electric utility plants (see Note 5). Exelon Generation accounts for its 20% to 50% owned investments and joint ventures, in which it exerts significant influence, under the equity method of accounting (see Note 3).

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

### Depreciation and Decommissioning

Depreciation is provided using the straight-line method over the estimated useful service lives of the property, plant and equipment, currently ranging from 2 to 100 years. Nuclear power stations operate under licenses granted by the Nuclear Regulatory Commission ("NRC") for fixed periods of time. Nuclear plant service lives may be limited by the expiration of the license.

Exelon Generation's current estimate of the costs for decommissioning its ownership share of its nuclear generation stations is charged to operations over the expected service life of the plant. Amounts collected for decommissioning by Exelon Generation's affiliates are remitted to Exelon Generation and are deposited in trust accounts and invested for funding of future decommissioning costs.

### Income Taxes

Deferred Federal and state income taxes are provided on all significant temporary differences between book bases and tax bases of assets and liabilities, transactions that reflect taxable income in a year different from book income and tax carryforwards. Investment tax credits previously utilized for income tax purposes have been deferred on Exelon Generation's Consolidated Balance Sheet and are recognized in book income over the life of the related property. As part of Exelon's consolidated group, Exelon Generation and its subsidiaries file a consolidated Federal income tax return with Exelon. Income taxes are generally allocated to Exelon Generation and each of its subsidiaries within the consolidated group based on the separate return method.



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### Cash and Cash Equivalents

Exelon Generation considers all temporary cash investments purchased with an original maturity of three months or less to be cash equivalents.

### Marketable Securities

Marketable securities are classified as available-for-sale securities and are reported at fair value, with the unrealized gains and losses, net of tax, reported in other comprehensive income. Realized gains and losses are recognized in current period income. At March 31, 2001, Exelon Generation had no held-to-maturity or trading securities.

### Property, Plant and Equipment

Property, plant and equipment is recorded at cost. Exelon Generation evaluates the carrying value of property, plant and equipment and other long-term assets based upon current and anticipated undiscounted cash flows, and recognizes an impairment when it is probable that such estimated cash flows will be less than the carrying value of the asset. Measurement of the amount of impairment, if any, is based upon the difference between carrying value and fair value. The cost of maintenance, repairs and minor replacements of property are charged to maintenance expense as incurred.

The cost and accumulated depreciation of property, plant and equipment retired or otherwise disposed of are removed from the related accounts and included in the determination of the gain or loss on disposition.

### Revenue Recognition

Operating revenues are generally recorded as service is rendered or energy is delivered to customers. Exelon Generation utilizes contracts for the forward sale and purchase of energy to manage the utilization of its available generation capacity and the provision of wholesale energy to its retail affiliates. Additionally, Exelon Generation's wholesale activities include short-term and long-term commitments to purchase and sell energy and energy-related products in the wholesale markets with the intent and ability to deliver and take delivery. Revenues and expenses associated with these forward sales and purchases of energy are reported at the time the underlying physical transaction occurs.

Exelon Generation also utilizes energy option financial swap contracts to limit the market price risk associated with forward energy contracts. Premiums received and paid on option contracts and financial swap arrangements are amortized to revenue and expense over the life of these contracts. Additionally, in accordance with the provisions of SFAS 133 "Accounting for Derivative Instruments and Hedging Activities" ("SFAS 133"), certain of these contracts are considered derivative instruments and are recorded at market value with changes in market value recognized as revenues and expenses for the period.

Commodity derivatives utilized for trading purposes are accounted for using the marked-to-market method. Under this methodology, these instruments are adjusted to market value, and the unrealized gains and losses are recognized in current period income.



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### Hedge Accounting

Hedge accounting is applied only if the derivative reduces the risk of the underlying hedged item and is designated at inception as a hedge, with respect to the hedged item. If a derivative instrument ceases to meet the criteria for deferral, any gains or losses are recognized in income. Ineffective portions of the hedge are recognized in net income.

**Comprehensive Income**

Comprehensive income includes all changes in equity during a period except those resulting from investments by and distributions to members. Comprehensive income is reflected in the Consolidated Statements of Changes in Member's Equity. Comprehensive income primarily relates to unrealized gains or losses on securities held in nuclear decommissioning trust funds.

**Nuclear Fuel**

The cost of nuclear fuel is capitalized and charged to fuel expense using the unit of production method. Estimated costs of nuclear fuel disposal are charged to fuel expense as the related fuel is consumed.

**Emission Allowances**

Emission allowances are charged to fuel expense as they are used in operations. Allowances held can be used in 2002 to 2028.

**Cumulative Effect of a Change in Accounting Principle**

In June 1998, the Financial Accounting Standards Board ("FASB") issued SFAS No. 133 to establish accounting and reporting standards for derivatives. The new standard requires recognizing all derivatives as either assets or liabilities on the balance sheet at their fair value and specifies the accounting for changes in fair value depending upon the intended use of the derivative. Exelon Generation adopted SFAS No. 133 on January 1, 2001, which resulted in after-tax income of $11 million that is reflected in Exelon Generation's Consolidated Statement of Income as a cumulative effect of a change in accounting principle. In addition, the adoption of SFAS No. 133 resulted in $4 million of other comprehensive income associated with the fair value of cash flow hedges.

For the quarter ended March 31, 2001, Exelon Generation recognized a net gain of $17 million in Exelon Generation's Consolidated Statement of Income, which represents the valuation at March 31, 2001 of its derivative contracts. Additionally, there was an immaterial change in other comprehensive income for the three months ended March 31, 2001 related to cash flow hedges.

As of March 31, 2001, $4 million of deferred net gains on derivative instruments accumulated in other comprehensive income are expected to be reclassified to earnings during the next twelve months. Amounts in accumulated other comprehensive income related to energy commodity cash flows are reclassified into earnings when the forecasted purchase or sale of the energy commodity occurs.



**2. Corporate Restructuring**

During January 2001, Exelon undertook a corporate restructuring to separate its generation and other competitive businesses from its regulated energy delivery businesses at Commonwealth Edison Company ("ComEd") and PECO Energy Company ("PECO"). As part of the restructuring, the generation-related operations, employees, assets and liabilities of ComEd and PECO were transferred to Exelon Generation.

The assets and liabilities transferred to Exelon Generation as of January 1, 2001 are as follows:

| | | |
|---|---|---|
| **Assets** | | |
| Current assets | $ | 1,242 |
| Property, plant and equipment | | 3,432 |
| Nuclear fuel | | 896 |
| Nuclear decommissioning trust funds | | 3,109 |
| Investments | | 844 |
| Deferred income taxes | | 276 |
| Note Receivable from Affiliate | | 364 |
| Other noncurrent assets | | 96 |
| Total assets transferred | | 10,259 |
| **Liabilities** | | |
| Note Payable to Parent | | 696 |
| Current liabilities | | 1,020 |
| Long-term debt | | 205 |
| Decommissioning obligation | | 3,878 |
| Other noncurrent liabilities | | 2,062 |
| Total liabilities transferred | | 7,861 |
| Net assets transferred | $ | 2,398* |

* Amount includes loss in other comprehensive income of $43 million.

In connection with the restructuring, ComEd and PECO assigned their respective rights and obligations under various power purchase and fuel supply agreements to Exelon Generation. Additionally, Exelon Generation entered into power purchase agreements ("PPAs") to supply the capacity and energy requirements of ComEd and PECO.

Under the PPA between Exelon Generation and ComEd, Exelon Generation supplies all of ComEd's load requirements through 2004. Prices for energy vary depending upon the time of day and month of delivery, as specified in the PPA. During 2005 and 2006, ComEd will purchase energy and capacity from Exelon Generation, up to the available capacity of the nuclear generation plants formerly owned by ComEd and transferred to Exelon Generation. Under the terms of the PPA with ComEd, Exelon Generation is responsible for obtaining the required transmission for its supply. The PPA with ComEd also specifies that prior to 2005, ComEd and Exelon Generation will jointly determine and agree on a market-based price for energy delivered under the PPA for 2005 and 2006. In the event that the parties cannot agree to market-based prices for 2005 and 2006 prior to July 1, 2004, ComEd has the option of terminating its PPA effective December 31, 2004.

Exelon Generation has also entered into a PPA with PECO whereby Exelon Generation will supply all of PECO's load requirements through 2010. Prices for energy are equivalent to the net proceeds from sales of unbundled generation to PECO's provider of last resort customers at rates PECO is allowed to charge customers who do not choose an alternate generation supplier. Under the terms of PPA, PECO is responsible for obtaining the required transmission for its supply.

**3. Equity Investments**

**Sithe Energies, Inc.**

On December 18, 2000, PECO acquired 49.9% of the outstanding common stock of Sithe through an intercompany transaction with Exelon for $696 million in cash and $8 million of acquisition costs. Sithe is an independent power producer with ownership interests in 27 facilities in North America with net generation capacity of 3,768 MW, primarily in New York and Massachusetts, and 2,630 MW under construction and 3,340 MW in advanced development. As a result of the corporate restructuring, the investment in Sithe was transferred to Exelon Generation. As of March 31, 2001, Exelon Generation's investment in Sithe was $714 million.

Beginning December 18, 2002, Exelon Generation will have the right to purchase all (but not less than all) of the remaining outstanding shares of the Sithe common stock. The option expires on December 18, 2005. In addition, each of Sithe's other stockholder groups will have the right to require Exelon Generation to purchase all (but not less than all) of the remaining shares of Sithe during the same period in which Exelon Generation can exercise its option. At the end of that period, if no stockholder has exercised its option, Exelon Generation will have a one-time option to purchase shares from the other stockholders to bring Exelon Generation's holdings to 50.1% of the total outstanding shares. If Exelon Generation exercises this option or if all the stockholder groups exercises their put rights, the purchase price for 70% of the remaining 50.1% of the Sithe stock will be set at a fair market value, subject to a floor of $430 million and a ceiling of $650 million, and the remaining portion will be sold at fair market value without being subject to the floor or ceiling prices, plus, in each case, interest accrued from the beginning of the exercise period.

The Independence power station is a wholly owned, gas-fired power plant located in Scriba, New York. Sithe recognizes fuel expense for gas consumed at Independence based on pricing provided for in a 20-year supply agreement with Enron Power Services, Inc. ("Enron"). Enron maintains a notional tracking account to account for differences between the contract price and spot gas prices for the Independence power station. The tracking account is increased if the then-current spot gas price is greater than the contract price and is decreased if the then-current spot gas price is lower than the contract price. The tracking account bears interest at 1% over the prime rate. Enron has been given a security interest in Independence, which is subordinated to payments for secured debt service and certain letter of credit reimbursement obligations, to secure any tracking account balance. As of March 31, 2001, Sithe estimates that the balance in the tracking account amounted to approximately $389 million. If at any time the tracking account balance exceeds 50% of Independence's then fair



market value, Independence will be required to reduce the tracking account balance by paying Enron 50% of certain cash-flows produced by the plant. As of March 31, 2001, no such requirement existed.

**AmerGen Energy Company, LLC**

Exelon Generation and British Energy, Inc, a wholly owned subsidiary of British Energy, plc each own a 50% equity interest in AmerGen. Established in 1997, AmerGen was formed to pursue opportunities to acquire and operate nuclear generation facilities in the North America. Currently, AmerGen owns and operates three nuclear generation facilities located in Illinois, Pennsylvania and New Jersey. Exelon Generation's investment in AmerGen as of March 31, 2001 was $64 million. Under a Services Agreement dated March 1, 1999, Exelon Generation provides AmerGen with certain management, operating, business and other professional services related to the operation of its nuclear facilities. For the three months ended March 31, 2001, the amount billed to AmerGen for these services was $1 million.

**4. Property, Plant and Equipment**

A summary of property, plant and equipment by classification as of March 31, 2001, is as follows:

| | |
|---|---|
| Generation Plant | $ 4,137 |
| Construction Work in Progress | 432 |
| Total Property, Plant and Equipment | 4,569 |
| Less: Accumulated Depreciation | 1,171 |
| Property, Plant and Equipment, net | $ 3,398 |

**5. Jointly Owned Electric Utility Plant**

Exelon Generation's ownership interests in jointly owned electric utility plant at March 31, 2001 were as follows:

| | Peach Bottom | Salem | Keystone | Conemaugh | Quad Cities | Other |
|---|---|---|---|---|---|---|
| **Operator** | Exelon Generation | PSEG | Reliant | Reliant | Exelon Generation | Various |
| Participating interest | 46.245% | 42.59% | 20.99% | 20.72% | 75.00% | 21% to 43% |
| **Exelon Generation's share:** | | | | | | |
| Utility plant | $ 380 | $ 3 | $ 120 | $ 190 | $ 105 | $ 80 |
| Accumulated depreciation | $ 217 | $ 3 | $ 97 | $ 121 | $ 2 | $ 31 |
| Construction work in progress | $ 8 | $ 66 | $ 4 | $ 11 | $ 23 | $ — |

Exelon Generation's undivided ownership interests are financed with Exelon Generation funds and, when placed in service, all operations are accounted for as if such participating interests were wholly owned facilities.

On September 30, 1999, PECO reached an agreement to purchase an additional 7.51% ownership interest in Peach Bottom Atomic Power Station ("Peach Bottom") from Atlantic City Electric Company and Delmarva Power & Light Company for $18 million. As a result of the restructuring, the purchase agreement has been assigned to Exelon Generation. Delmarva's 3.755% interest was purchased in December 2000 by PECO and transferred to Exelon Generation as part of the restructuring. The purchase of Atlantic City Electric Company's 3.755% ownership interest is still pending regulatory approval.

**6. Long-Term Debt**

Long-term debt at March 31, 2001 is comprised of the following:

| | Rates | Maturity Date | Amount Outstanding at March 31, 2001 |
|---|---|---|---|
| Notes payable | 7.25% | 2003-2004 | $ 14 |
| Pollution control notes: | | | |
| Floating rates | 3.50%—5.155% | 2016-2034 | 195 |
| **Total Long-Term Debt** | | | 209 |
| Due within one year | | | (5) |
| **Long-Term Debt** | | | $ 204 |

Long-term debt maturities in the period 2001 through 2005 and thereafter are as follows:

| | |
|---|---|
| 2001 | $ 5 |
| 2002 | 4 |
| 2003 | 4 |
| 2004 | 1 |
| 2005 | – |
| Thereafter | 195 |
| Total | $ 209 |

**7. Income Taxes**

Income tax expense (benefit) is comprised of the following components for the three months ended March 31, 2001:

| | |
|---|---|
| Included in operations: | |
| Federal | |
| Current | $ 96 |
| Deferred | (10) |
| State | |
| Current | 24 |
| Deferred | (3) |
| | $ 107 |



The total income tax provisions differed from amounts computed by applying the Federal statutory tax rate to pretax income for the three months ended March 31, 2001 is as follows:

| | |
|---|---|
| Included in cumulative effect of a change in accounting principle | |
| Federal—Deferred | $ 6 |
| State—Deferred | 1 |
| | $ 7 |
| Income before cumulative effect of a change in accounting principle | $ 159 |
| Income taxes | 107 |
| Income before income taxes and cumulative effect of a change in accounting principle | $ 266 |
| Income taxes on above at Federal statutory rate of 35% | $ 93 |
| Increase (decrease) due to: | |
| State income taxes, net of Federal income tax benefit | 15 |
| Other, net | (1) |
| Income Taxes | $ 107 |
| Effective income tax rate | 40.22% |

Provisions for deferred income taxes consist of the tax effects of the following temporary differences for the three months ended March 31, 2001:

| | | |
|---|---|---|
| Depreciation and amortization | $ | (8) |
| Nuclear decommissioning and decontamination | | (14) |
| Marked to market | | 7 |
| Other | | 2 |
| Total | $ | (13) |



The tax effect of temporary differences giving rise to Exelon Generation's net deferred tax liability as of March 31, 2001 is as follows:

| | | |
|---|---|---|
| Nature of temporary difference: | | |
| Plant, net of accumulated depreciation and amortization | $ | (431) |
| Deferred investment tax credit | | 99 |
| Deferred pension and postretirement obligations | | 212 |
| Decommissioning and decontamination | | 432 |
| Long-term incentive plan | | 27 |
| Emission allowances | | (34) |
| Obsolete inventory | | 32 |
| Other | | 95 |
| Deferred income taxes (net) on the balance sheet | $ | 432 |

**8. Retirement Benefits**

Exelon and its subsidiaries sponsor defined benefit pension plans and postretirement benefit plans that cover essentially all employees. Benefits under pension plans reflect each employee's compensation, years of service and age at retirement. Funding is based upon actuarially determined contributions that take into account the amount deductible for income tax purposes and the minimum contribution required under the Employee Retirement Income Security Act of 1974, as amended. Prior service cost is amortized on a straight line basis over the average remaining service period of employees expected to receive benefits under the plans.

Exelon provides certain health care and life insurance benefits for retired employees. In general, Exelon employees become eligible for these benefits if they retire from Exelon with at least ten years of service. The health care plans covering active and retired employees are self-insured. Life insurance and disability benefits for active employees are provided by several insurance companies whose premiums are based upon the benefits paid during the year.

Exelon sponsors a 401(k) plan that covers the majority of its employees. The plan allows employees to contribute a portion of their pretax income in accordance with specified guidelines. Exelon matches a percentage of the employee contribution up to certain limits.

As part of Exelon's corporate restructuring, approximately 4,800 ComEd employees and 2,600 PECO employees were transferred to Exelon Generation. As a result of the transfer, Exelon Generation recorded a pension obligation and a non-pension postretirement benefits obligation of $240 million and $377 million, respectively, as of January 1, 2001.



**9. Financial Instruments**

Fair values of financial instruments, including liabilities, are estimated based on quoted market prices for the same or similar issues. The carrying amounts and fair values of Exelon Generation's financial instruments as of March 31, 2001 were as follows:

| | 2001 | |
|---|---|---|
| | Carrying Amount | Fair Value |
| **Non-derivatives:** | | |
| Assets | | |
| Cash and cash equivalents | $ 188 | $ 188 |
| Trust accounts for decommissioning nuclear plants | $ 2,943 | $ 2,943 |
| Liabilities | | |
| Long-term debt (including amounts due within one year) | $ 209 | $ 209 |
| **Derivatives:** | | |
| Energy Options | $ 9 | $ 9 |
| Other Energy Derivatives | $ 4 | $ 4 |

Financial instruments that potentially subject Exelon Generation to concentrations of credit risk consist principally of cash equivalents, decommissioning trust funds and customer accounts receivable. Exelon Generation places its cash equivalents and decommissioning trust funds with high-credit quality financial institutions. Generally, such investments are in excess of the Federal Deposit Insurance Corporation limit.

The fair value of derivatives generally reflects the estimated amounts that Exelon Generation would receive or pay to terminate the contracts at the reporting date, thereby taking into account the current unrealized gains or losses of open contracts.

Exelon Generation's activities expose it to a variety of market risks primarily related to the effects of changes in commodity prices. These financial exposures are monitored and managed by Exelon Generation as an integral part of its overall risk management program.

Exelon Generation's commodity price, risk management strategy includes the use of derivatives to minimize significant, unanticipated earnings and cash flow fluctuations caused by commodity price volatility. Exelon Generation utilizes contracts for the forward purchase and sale of energy and energy-related commodities to manage its generation and physical delivery obligations to its wholesale customers. Energy option contracts and energy and energy-related swap agreements are used to limit the price risk associated with these forward contracts.

By using derivative financial instruments to hedge exposure to changes in energy prices, Exelon Generation exposes itself to credit risk and market risk. Credit risk is the risk of a counterparty failing to perform according to contract terms. When the value of a contract is positive, the counterparty owes Exelon Generation, which creates repayment risk for Exelon Generation. When the value of a derivative contract is negative, Exelon Generation owes the counterparty and, therefore, the derivative contract does not create repayment risk. Exelon Generation minimizes the credit (or repayment) risk by (1) entering into transactions with high-quality counterparties, (2) limiting the amount of exposure to each counterparty, (3) monitoring the financial condition of its counterparties, and (4) seeking credit enhancements to improve counterparty credit quality.



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Market risk is the effect on the value of Exelon Generation's outright and contingent commitments that result from a change in interest rates or commodity prices. The market risk associated with interest-rate and energy and energy-related contracts is managed by the establishment and monitoring of parameters that limit the types and degree of market risk that may be undertaken.

Exelon Generation's derivative activities are subject to the management, direction, and control of the corporate Exelon Risk Management Committee ("RMC"). The RMC is chaired by Exelon's chief risk officer and includes the chief financial officer, general counsel, treasurer, vice president of corporate planning and officers from each of Exelon's business units. The RMC reports to the Exelon board of directors on the scope of Exelon Generation's derivative activities. The RMC (1) sets forth risk management philosophy and objectives through a corporate policy, and (2) establishes procedures for control and valuation, counterparty credit approval, and the monitoring and reporting of derivative activity.

**10. Commitments and Contingencies**

**Capital Commitments**

Exelon Generation estimates that it will spend approximately $840 million for capital expenditures and other investments in 2001, principally for major maintenance, nuclear fuel and increases in capacity at existing plants.

**Nuclear Insurance**

The Price-Anderson Act limits the liability of nuclear reactor owners for claims that could arise from a single incident. The current limit is $9.5 billion and is subject to change to account for the effects of inflation and changes in the number of licensed reactors. Through its subsidiaries, Exelon Generation carries the maximum available commercial insurance of $200 million and the remaining $9.3 billion is provided through mandatory participation in a financial protection pool. Under the Price-Anderson Act, all nuclear reactor licensees can be assessed up to $89 million per reactor per incident, payable at no more than $10 million per reactor per incident per year. This assessment is subject to inflation and state premium taxes. In addition, the U.S. Congress could impose revenue-raising measures on the nuclear industry to pay claims.

Exelon Generation carries property damage, decontamination and premature decommissioning insurance for each station loss resulting from damage to its nuclear plants. In the event of an accident, insurance proceeds must first be used for reactor stabilization and site decontamination. If the decision is made to decommission the facility, a portion of the insurance proceeds will be allocated to a fund, which Exelon Generation is required by the Nuclear Regulatory Commission ("NRC") to maintain, to provide for decommissioning the facility. Exelon Generation is unable to predict the timing of the availability of insurance proceeds to Exelon Generation and the amount of such proceeds which would be available. Under the terms of the various insurance agreements, Exelon Generation could be assessed up to $69 million for losses incurred at any plant insured by the insurance companies. Exelon Generation is self-insured to the extent that any losses may exceed the amount of insurance maintained. Such losses could have a material adverse effect on Exelon Generation's financial condition and results of operations.



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Additionally, Exelon Generation is a member of an industry mutual insurance company that provides replacement power cost insurance in the event of a major accidental outage at a nuclear station. The premium for this coverage is subject to assessment for adverse loss experience. Exelon Generation's maximum share of any assessment is $18 million per year.

In addition, Exelon Generation participates in the American Nuclear Insurers Master Worker Program, which provides coverage for worker tort claims filed for bodily injury caused by a nuclear energy accident. This program was modified, effective January 1, 1998, to provide coverage to all workers whose "nuclear-related employment" began on or after the commencement date of reactor operations. Exelon Generation will not be liable for a retrospective assessment under this new policy. However, in the event losses incurred under the small number of policies in the old program exceed accumulated reserves, a maximum retroactive assessment of up to $50 million could apply.

**Nuclear Decommissioning and Spent Fuel Storage**

The obligation for decommissioning the nuclear facilities and the related trust fund assets were transferred from ComEd and PECO to Exelon Generation as part of the transfer of generation plants and the related NRC operating licenses as of January 1, 2001. Additionally, obligations for spent nuclear fuel disposal, and provisions for nuclear insurance were assumed by Exelon Generation under terms and conditions commensurate with those previously borne by ComEd and PECO.

Exelon Generation's current estimate of its nuclear facilities' decommissioning cost is $6.9 billion. At March 31, 2001, Exelon Generation had recorded $3.9 billion for nuclear decommissioning liabilities, including $1.3 billion for retired plants. In order to fund future decommissioning costs, at March 31, 2001, Exelon Generation held $2.9 billion in trust accounts.

Effective January 1, 2001, Exelon Generation recorded a receivable from ComEd of approximately $440 million representing ComEd's legal requirement to remit funds to Exelon Generation that ComEd is authorized to collect from customers and for collections from customers prior to the establishment of external decommissioning trust funds in 1989 to be remitted to Exelon Generation for deposit into the decommissioning trust through 2006.

PECO's collects annual decommissioning costs of $29 million through customer's regulated rates. Such collections will continue through 2010 and all amounts collected will be remitted to Exelon Generation to be deposited into the decommissioning trust funds.

The National Energy Policy Act of 1992 requires that the owners of nuclear reactors pay for the decommissioning and decontamination of the U.S. Department of Energy (the "DOE) nuclear enrichment facilities. The total cost to domestic owners is estimated to be $150 million per year through 2006, of which our share is approximately $22 million per year.

Under the Nuclear Waste Policy Act of 1982 ("NWPA"), the U.S. Department of Energy ("DOE") is responsible for the selection and development of repositories for, and the disposal of, spent nuclear fuel and high-level radioactive waste ("SNF"). ComEd and PECO, as required by the NWPA, signed a contract with the DOE (Standard Contract) to provide for disposal of SNF from their respective nuclear generation stations. Effective with the corporate restructuring, the contracts were assigned to Exelon Generation(See Note 2-Corporate Restructuring). In accordance with the NWPA and the

Standard Contract, Exelon Generation pays the DOE one mill ($.001) per kilowatt-hour of net nuclear generation for the cost of nuclear fuel long-term storage and disposal. This fee may be adjusted prospectively in order to ensure full cost recovery. The Standard Contract with the DOE also requires PECO and ComEd to pay the DOE a one-time fee applicable to nuclear generation through April 6, 1983. The fee for the former PECO plants has been paid. Pursuant to the Standard Contract, ComEd elected to pay the one-time fee of $277 million with interest to the date of payment just prior to the first delivery of SNF to the DOE. As of March 31, 2001, the liability for the one-time fee with interest was $821 million. The NWPA and the Standard Contract required the DOE to begin taking possession of SNF generated by nuclear generation units by no later than January 1998. The DOE, however, failed to meet that deadline and its performance is expected to be delayed significantly. The DOE's current estimate for opening an SNF facility is 2010. This extended delay in SNF acceptance by the DOE has led to Exelon Generation's consideration of additional dry storage alternatives.

In July 2000, PECO entered into an agreement with the DOE relating to the Peach Bottom nuclear generation station to address the DOE's failure to begin removal of SNF in January 1998 as required by the Standard Contract. Under that agreement, the DOE agrees to provide credits against future contributions to the nuclear waste fund over the next ten years to compensate for SNF storage costs incurred as a result of the DOE's breach of the contract. The agreement also provides that, upon request, the DOE will take title to the SNF and the interim storage facility at Peach Bottom provided certain conditions are met.

In November 2000, eight utilities with nuclear power plants filed a Joint Petition for Review against the DOE with the United States Court of Appeals for the Eleventh Circuit seeking to invalidate that portion of the agreement providing for credits against nuclear waste fund payments on the ground that such provision is a violation of the NWPA. PECO has intervened as a defendant in that case, which is ongoing.

Exelon Generation's Zion Station permanently ceased power generation operations in 1998. The plant is currently being maintained in a secure and safe condition until final decommissioning, which is scheduled to begin in 2013.

**Energy Commitments**

Exelon Generation's wholesale operations include the physical delivery and marketing of power obtained through its generation capacity, and long, intermediate and short-term contracts. Exelon Generation maintains a net positive supply of energy and capacity, through ownership of generation assets and power purchase and lease agreements, to protect it from the potential operational failure of one of its owned or contracted power generation units. Exelon Generation has also contracted for access to additional generation through bilateral long-term power purchase agreements. These agreements are firm commitments related to power generation of specific generation plants and/or are dispatchable in nature—similar to asset ownership. Exelon Generation enters into power purchase agreements with the objective of obtaining low-cost energy supply sources to meet its physical delivery obligations to its customers. Exelon Generation has also purchased firm transmission rights to ensure that it has reliable transmission capacity to physically move its power supplies to meet customer delivery needs. The intent and business objective for the use of its capital assets and contracts are to provide Exelon Generation with physical power supply to enable it to deliver energy to meet customer



needs. In 2001, Exelon Generation anticipates the use of financial contracts to manage the risk surrounding trading for profit activities.

Exelon Generation has entered into bilateral long-term contractual obligations for sales of energy to ComEd, PECO and other load-serving entities, including electric utilities, municipalities, electric cooperatives, and retail load aggregators. Exelon Generation also enters into contractual obligations to deliver energy to wholesale market participants who primarily focus on the resale of energy products for delivery. Exelon Generation provides delivery of its energy to these customers through rights for firm transmission.

In addition, Exelon Generation has entered into long-term power purchase agreements with Independent Power Producers ("IPP") under which Exelon Generation makes fixed capacity payments to the IPP in return for exclusive rights to the energy and capacity of the generation units for a fixed period.

At March 31, 2001, Exelon Generation had long-term commitments relating to the net purchase and sale of energy and capacity and the purchase of transmission rights from unaffiliated and affiliated entities as expressed in the tables below:

| | Unaffiliated | | | Affiliated |
|---|---|---|---|---|
| | Net Power Sales | Net Purchased Capacity | Transmission Rights Purchases | Power Sale/Capacity |
| 2001 | $ 557 | $ 713 | $ 112 | $ 3,364 |
| 2002 | 204 | 860 | 42 | 4,232 |
| 2003 | 192 | 770 | 32 | 4,364 |
| 2004 | 119 | 775 | 25 | 4,385 |
| 2005 | 87 | 411 | 25 | 1,226 |
| Thereafter | 6 | 5,192 | 80 | 4,223 |
| Total | $ 1,165 | $ 8,721 | $ 316 | $ 21,794 |

**Environmental Issues**

Exelon Generation's operations have in the past and may in the future require substantial capital expenditures in order to comply with environmental laws. Additionally, under Federal and state environmental laws, Exelon Generation is generally liable for the costs of remediating environmental contamination of property now owned and of property contaminated by hazardous substances generated by Exelon Generation.

As of March 31, 2001, Exelon Generation had accrued $16 million for environmental investigation and remediation costs. Exelon Generation cannot reasonably estimate whether it will incur other significant liabilities for additional investigation and remediation costs at these or additional sites identified by Exelon Generation, environmental agencies or others, or whether such costs will be recoverable from third parties.



**Leases**

Minimum future operating lease payments as of March 31, 2001 were:

| | |
|---|---|
| 2001 | $ 10 |
| 2002 | 19 |

| | | |
|---|---|---|
| 2003 | | 28 |
| 2004 | | 17 |
| 2005 | | 23 |
| Remaining years | | 528 |
| Total minimum future lease payments | $ | 625 |

Rental expense under operating leases totaled $2 million for the three months ended March 31, 2001.

**Litigation**

*Cajun Electric Power Cooperative, Inc.* On May 27, 1998, the United States Department of Justice, on behalf of the Rural Utilities Service and the Chapter 11 Trustee for the Cajun Electric Power Cooperative, Inc. ("Cajun"), filed an action claiming breach of contract against PECO in the United States District Court for the Middle District of Louisiana arising out of PECO's termination of the contract to purchase Cajun's interest in the River Bend nuclear power plant. This action seeks the full purchase price of the 30% interest in the River Bend nuclear plant, and seeking damages of $50 million, plus interest and consequential damages. Effective with the corporate restructuring described in note 2, Exelon Generation has agreed to assume any liability and obligation arising from this litigation. While Exelon Generation cannot predict the outcome of this matter, Exelon Generation believes that it validly exercised its right of termination and did not breach the agreement.

*Cotter Corporation* During 1989 and 1991, actions were brought in Federal and state courts in Colorado against ComEd and its subsidiary, Cotter Corporation ("Cotter"), seeking unspecified damages and injunctive relief based on allegations that Cotter permitted radioactive and other hazardous material to be released from its mill into areas owned or occupied by the plaintiffs, resulting in property damage and potential adverse health effects. In 1994, a Federal jury returned nominal dollar verdicts against Cotter on eight plaintiffs' claims in the 1989 cases, which verdicts were upheld on appeal. The remaining claims in the 1989 actions have been settled or dismissed. In 1998, a jury verdict was rendered against Cotter in favor of 14 plaintiffs in the 1991 cases, totaling approximately $6 million in compensatory and punitive damages and interest. Medical monitoring was also ordered. On appeal, the Tenth Circuit Court of Appeals reversed the jury verdict, remanding the case for a new trial. These plaintiffs' cases were consolidated with the remaining 26 plaintiffs' case, which had never been tried. This new trial is currently underway. In November 2000, another trial involving a separate sub-group of 13 plaintiffs, seeking $19 million in damages plus interest, was completed in Federal district court in Denver. The jury awarded nominal damages of $42,000 to 11 of 13 plaintiffs, but awarded no damages for any personal injury or health claims, other than requiring Cotter to perform periodic medical monitoring at minimal cost. The plaintiffs appealed the verdict to the Tenth Circuit.



On February 18, 2000, ComEd sold Cotter to an unaffiliated third party. As part of the sale, ComEd agreed to indemnify Cotter for any liability incurred by Cotter as a result of these actions, as well as any liability arising in connection with the West Lake Landfill discussed in the next paragraph.

The EPA has advised Cotter that it is potentially liable in connection with radiological contamination at a site known as the West Lake Landfill in Missouri. Cotter is alleged to have disposed of approximately 39,000 tons of soils mixed with 8,700 tons of leached barium sulfate at the site. Cotter and three other companies identified by the EPA have agreed to share equally the costs of a remedial study of the site; those costs could exceed $2 million. Future costs related to site remediation are not presently known.

As a result of the restructuring of Exelon, Exelon Generation agreed to assume any liability and obligation arising from these Cotter matters.

*Pennsylvania Real Estate Tax Appeals.* Exelon Generation is involved in tax appeals regarding two of its nuclear facilities, Limerick (Montgomery County) and Peach Bottom (York County). AmerGen is involved in the tax appeal for Unit No. 1 at Three Mile Island Nuclear Station (Dauphin County). Exelon Generation does not believe the outcome of these matters will have a material adverse effect on Exelon Generation's results of operations or financial condition.

*General.* Exelon Generation is involved in various other litigation matters. The ultimate outcome of such matters, while uncertain, is not expected to have a material adverse effect on Exelon Generation's financial condition or results of operations.

**11. Related-Party Transactions**

At March 31, 2001, Exelon Generation had a short-term receivable of $409 million and a long-term receivable of $364 million from ComEd resulting from the restructuring which are included in current assets and deferred debits and other assets, respectively, on Exelon Generation's Consolidated Balance Sheet.

In connection with the restructuring transaction, ComEd and PECO entered into PPAs with Exelon Generation. Intercompany power purchases pursuant to the PPAs for the three months ended March 31, 2001 for ComEd and PECO were $609 million and $245 million, respectively.

In addition, at March 31, 2001, Exelon Generation had a $696 million demand note payable, that is due no later than December 16, 2001, with Exelon related to the acquisition of Sithe (See Note 3), which is reflected in current liabilities in Exelon Generation's Consolidated Balance Sheet. The average annual interest rate on this note for the three months ended March 31, 2001 was 7.4%. Interest expense on the payable was $15 million for the three months ended March 31, 2001.

Effective January 1, 2001, upon the corporate restructuring, Exelon Generation receives a variety of corporate support services from the Business Services Company ("BSC"), a subsidiary of Exelon, including legal, human resources, financial and information technology services. Such services are provided at cost including applicable overheads. Costs charged to Exelon Generation by BSC for the three months ended March 31, 2001 were $22 million.



**12. Supplemental Financial Information**

**Supplemental Income Statement Information**

Taxes Other Than Income for the three months ended March 31, 2001 were as follows:

| | | |
|---|---|---|
| Real estate | $ | 25 |
| Payroll | | 16 |
| Other | | 5 |
| Total | $ | 46 |

Other, Net for the three months ended March 31, 2001 is primarily interest income of $4 million.

**Supplemental Cash Flow Information**

| | | |
|---|---|---|
| Cash paid during the quarter: | | |
| Interest | $ | 1 |
| Noncash investing and financing: | | |
| Contribution from Member | | 2,365 |
| Depreciation and amortization: | | |
| Property, plant and equipment | | 47 |
| Nuclear fuel | | 100 |
| Decommissioning | | 45 |

**13. Subsequent Event**

On April 25, 2001, Exelon Generation issued $52 million of floating-rate pollution control notes.



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**APPENDIX A**

**INDEPENDENT ENGINEER'S REPORT**



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Exelon Generation Company LLC Debt Offering
**Independent Engineer's Report**

Prepared for
Exelon Generation Company

**SL-5509**
June 2001

**Sargent & Lundy**

55 East Monroe Street
Chicago, IL 60603-5780 USA

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**LEGAL NOTICE**



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**INDEPENDENT ENGINEER'S REPORT**

**CONTENTS**

## 1. INTRODUCTION

Sargent & Lundy performed an independent review of the power stations owned, directly or indirectly, in whole or in part, by Exelon Generation Company, LLC (Exelon Generation). This report contains a description of the electric generating assets reviewed, an overview of the scope of work performed, an analysis of the operating and financial performance of the assets, and the findings and conclusions.

### 1.1 EXISTING GENERATION ASSETS

Exelon Generation has three distinct asset groups: the Nuclear Asset Group, including all Exelon Generation nuclear assets formerly owned by ComEd and PECO and all nuclear assets owned by AmerGen; the PECO Asset Group, including all non-nuclear Exelon Generation assets formerly owned by PECO; and the Sithe Asset Group including all assets owned by Sithe Energies, Inc. These groups represent a total of 142 units at 52 stations located in 10 states and Ontario, with a combined generating capacity of over 34,000 MW. In addition, Exelon Generation has an additional 13,900 MW in capacity available under long-term contracts.

#### 1.1.1 Nuclear Asset Group

The Nuclear Asset Group represents the largest number of nuclear holdings by a single company in the United States. It consists of 16 units at 8 nuclear stations formerly owned and operated by ComEd and PECO, as well as three units at three sites owned and operated by AmerGen (50% owned by Exelon Generation and 50% owned by British Energy plc).

#### 1.1.2 PECO Asset Group

The PECO Asset Group of Exelon Generation consists of the coal-, oil-, and natural-gas-fired stations and hydroelectric units in the Philadelphia area. This asset group includes 81 units at 17 stations formerly owned and operated by PECO.

#### 1.1.3 Sithe Asset Group

The Sithe Asset Group consists of those stations owned by Sithe Energies, Inc. Exelon Generation owns 49.9% of the common stock of Sithe and has an option to purchase, and Sithe's other shareholders have an option to put to Exelon Generation, the remaining shares commencing December 2002. The Sithe units are located mainly in the northeastern portion of the United States. The assets in this group represent 42 units at 24 stations including oil- and natural-gas-fired stations and hydroelectric units.

#### 1.1.4 Existing Units Not Considered in the Financial Projections

As part of its review, Sargent & Lundy excluded certain existing units from the financial projections. The excluded units, from both the PECO Asset Group and the Sithe Asset Group, are small units as measured by net capacity, comprising only 0.5% and 9.8% of total net capacity, respectively. As a percentage of total electrical generation, these units represent less than 1% of the energy produced. As a result of their marginal size, their respective impact on cash flow was deemed negligible and consequently excluded. In addition, certain units reside in market areas not contiguous to the primary market areas considered in the financial model.



The PECO Asset Group units excluded from the financial projections are listed in the table below. These units are all small and have negligible dispatch and have no material impact on cash flow.

| Small Plants | Small Diesel Units |
|---|---|
| Pennsbury 1 & 2 | Conemaugh A, B, C, D<br>Cromby IC1<br>Delaware IC1<br>Keystone 3, 4, 5, 6<br>Schuylkill IC1 |

The Sithe Asset Group units excluded from the financial projections are listed in the following table. These units are either small units or in market areas not contiguous with the primary market regions considered in the financial model. The classification of the excluded units is as follows:

| Ontario Unit | Western Units | North Carolina Unit | Other Small Units |
|---|---|---|---|
| Cardinal | Greeley<br>Oxnard<br>Naval Station<br>NTC MRD<br>Bypass<br>Hazelton<br>Elk Creek<br>Rock Creek<br>Montgomery Creek | Ivy River | Allegheny |

The Ontario, Western, and North Carolina units were deemed to be outside the primary market areas of Exelon. The hydroelectric units at Allegheny, located in Western Pennsylvania, have a combined total net capability of 48.6 MW, with an annual average net capacity factor of approximately 50%. They were deemed to be small and to have a negligible impact on cash flow.

## 1.2 NEW ELECTRIC GENERATING ASSETS

### 1.2.1 New Units Considered in the Financial Projections

Exelon Generation identified the following three development projects, which are either under construction or in advanced stages of development, that are certain to proceed. All five proposed units will be owned by Sithe and are located at or adjacent to existing stations.

| Station Name | Location | Type of Equipment |
|---|---|---|
| Fore River 3 | At the existing Fore River Station in North Weymouth, Massachusetts | One 2x1 combined-cycle unit with a total capacity of 800 MW |
| Heritage 1 and 2 | Adjacent to the Independence Station in Oswego, New York | Two 1x1 combined-cycle units, each with a capacity of 400 MW |
| Mystic 8 and 9 | At the existing Mystic Station in Everett, Massachusetts | Two 2x1 combined-cycle units, each with a capacity of 800 MW |



### 1.2.2 New Units Not Considered in the Financial Projections

The following units under development were not reviewed by Sargent & Lundy and not included in the financial projections:

- Torne Valley (California)
- Medway (Massachusetts)
- Brampton and Mississauga (Ontario)

Exelon Generation indicated that these projects are still under review.

## 1.3 OWNERSHIP AND LOCATION OF GENERATING ASSETS

### 1.3.1 Nuclear Asset Group

The Nuclear Asset Group consists of three sets of units: the former ComEd nuclear stations, comprising 10 units; the former PECO nuclear stations, comprising 6 units; and the AmerGen nuclear stations, comprising 3 single-unit plants. Unless otherwise noted, the stations in the Nuclear Asset Group are 100% owned and operated by Exelon Generation.

| Station Name | Location | Number of Units | Other Comments |
|---|---|---|---|
| *ComEd Nuclear Stations* | | | |
| Braidwood Nuclear Station | Southwest of Joliet, Illinois, in Will County near the Kankakee River | Two units | These units are designed as duplicates of the Byron Nuclear Station. |
| Byron Nuclear Station | Southwest of Rockford, Illinois, near the Rock River | Two units | — |
| Dresden Nuclear Station | Just east of Morris, Illinois, on the Kankakee River | Two operating units and one retired unit | — |
| LaSalle Nuclear Station | Southeast of Ottawa, Illinois, near the Illinois River | Two units | — |
| Quad Cities Nuclear Station | North of Moline, Illinois, on the Mississippi River | Two units | Units are 75% owned by Exelon Generation and are operated by Exelon Generation. |
| *PECO Nuclear Stations* | | | |
| Limerick Station | 21 miles from Philadelphia, on the Schuylkill River | Two units | — |
| Peach Bottom Station | South of Lancaster, Pennsylvania, on the shore of Conowingo Pond | Two operating units and one retired unit | These units are 46.245% owned by Exelon Generation and are operated by Exelon Generation. |
| Salem Station | In southwestern New Jersey on the Delaware River, southeast of Wilmington, Delaware | Two nuclear units and one combustion turbine | These units are 42.59% owned by Exelon and are operated by PSEG Nuclear LLC. |
| *AmerGen Nuclear Stations* | | | |

| | | | |
|---|---|---|---|
| Clinton Station | In central Illinois north of Decatur | Single unit | 100% owned by AmerGen, in which Exelon Generation is a 50% partner; Exelon Generation operates the units. |
| Oyster Creek Station | South of Toms River, New Jersey, on Barnegat Bay | Single unit | 100% owned by AmerGen, in which Exelon Generation is a 50% partner; Exelon Generation operates the units. |
| Three Mile Island Station | 10 miles southeast of Harrisburg, Pennsylvania, on the Susquehanna River | Two units: one operating and one retired | AmerGen owns the operating Unit 1 but not Unit 2, which was damaged and retired in place.<br><br>100% owned by AmerGen, in which Exelon Generation is a 50% partner; Exelon Generation operates the units. |

### 1.3.2 PECO Asset Group

The PECO Asset Group consists of the non-nuclear units formerly owned by PECO. These units consist of a number of large fossil-fueled stations, one hydroelectric unit, one pumped storage plant, and a number of small distributed generation units and peaker units. Unless otherwise noted, the stations in the PECO Asset Group are 100% owned and operated by Exelon Generation.

| Station Name | Location | Type of Equipment | Other Comments |
|---|---|---|---|
| City Stations (Delaware and Schuylkill) | Philadelphia, Pennsylvania | The Delaware units consist of two steam units, four combustion turbine-generators, and one diesel unit.<br><br>The Schuylkill units consist of one steam unit, two combustion turbines, and one diesel engine. | — |



| | | | |
|---|---|---|---|
| Conemaugh Station | 13 miles northwest of Johnstown, Pennsylvania, on the Conemaugh River | Two coal-fired units and four diesel generators | This station has several owners—Exelon Generation owns 20.72% of the station—and is operated by Reliant Energy Mid-Atlantic Power Holdings, LLC. |
| Conowingo Station | Approximately 70 miles west of Philadelphia, on the Susquehanna River | 11 run-of-river hydropower units | — |
| Cromby Station | Approximately 30 miles northwest of Philadelphia, on the Schuylkill River | Two thermal generation units and one diesel generator | — |
| Croydon Station | Approximately 15 miles northeast of Philadelphia | Eight thermal generation units | — |
| Eddystone Station | Southeast of Philadelphia, Pennsylvania, along the Delaware River | Four coal-, oil-, and natural-gas-fired units and four combustion turbine peaking units | — |
| Keystone Station | 35 miles northwest of Johnstown, Pennsylvania, on Crooked Creek | Two coal-fired units and four diesel engines | This station has several owners—Exelon Generation owns 20.99% of the station—and is operated by Reliant Energy Mid-Atlantic Power Holdings, LLC. |
| Muddy Run Station | In Pennsylvania, approximately 90 miles west of Philadelphia, on the Susquehanna River | Pumped-storage hydroelectric. The station has eight units | — |
| Richmond Station | Two miles north of Philadelphia | Two combustion turbines | — |



The following small PECO Asset Group units are 100% owned by Exelon Generation:

| Station Name | Location | Type of Equipment | Other Comments |
|---|---|---|---|
| Chester Station | Delaware County, Pennsylvania | Three simple-cycle combustion turbines | — |
| Fairless Hills Station | Fairless Hills, Bucks County, Pennsylvania, 30 miles north of Philadelphia | Three cogeneration boilers and two steam turbines | Provides steam to an adjacent United States Steel facility. |
| Falls Station | Bucks County, Pennsylvania, 30 miles north of Philadelphia | Three simple-cycle combustion turbines | — |

| | | | |
|---|---|---|---|
| Moser Station | Montgomery County, Pennsylvania | Three simple-cycle combustion turbines | — |
| Pennsbury Station | Bucks County, Pennsylvania, 30 miles north of Philadelphia | Two combustion turbines in a combined cycle configuration | Plant uses landfill derived gas as main fuel. |
| Southwark Station | Philadelphia, Pennsylvania | Four simple-cycle combustion turbines | — |

**1.3.3 Sithe Asset Group**

The Sithe Asset Group is located primarily in the northeastern United States, but several units are located in western states. Most of the Sithe generation assets utilize combustion turbine technology, but there are also several steam and hydroelectric installations.

Exelon Generation owns 49.9% of the common stock of Sithe and has an option to purchase the remaining common stock commencing December 2002. The financial projections assume that Exelon exercises its option to acquire the remaining 50.1% of Sithe at market price. Unless otherwise indicated, Sithe has a 100% ownership share of and operates the following stations:

| Station Name | Location | Type of Equipment | Other Comments |
|---|---|---|---|
| Allegheny Station | North of Pittsburgh, Pennsylvania, on the Allegheny River | Four hydroelectric units | — |
| Batavia Station | Batavia, New York | Cogeneration unit | Station is 90% owned and operated by Sithe. Eastern American Electric owns the other 10% of the station.<br><br>Originally constructed as a Qualifying Facility.<br><br>Supplies steam on as-needed basis to Milk Products Cooperative. |



| | | | |
|---|---|---|---|
| Bypass and Hazelton A Stations | North Side Canal in Jerome County, Idaho | Small hydroelectric stations. Each station is equipped with three turbines | This canal is used for irrigation so the units can operate only when irrigation water is available. |
| Cardinal Station | St. Lawrence River in the City of Cardinal, Ontario, Canada | Cogeneration unit | The unit supplies steam to the Canada Starch Company and to Benson School. |
| Elk Creek Station | Little Elk Creek near Boise, Idaho | Hydroelectric unit | — |
| Fore River Station | North Weymouth, Massachusetts | Two combustion turbine units | — |
| Framingham Station | Framingham, Massachusetts | Three combustion turbine units | — |
| Greeley Station | Greeley, Colorado | Cogeneration unit | Originally constructed as a Qualifying Facility.<br><br>Supplies steam on an as-needed basis to the University of Northern Colorado. |
| Independence Station | Oswego, New York | Four combustion turbine units | Originally constructed as a Qualifying Facility.<br><br>Supplies steam on an as-needed basis to Alcan Rolled Products Company. |
| Ivy River Station | On Ivy River in Madison County, North Carolina | Hydroelectric unit | — |
| Kenilworth Station | Kenilworth, New Jersey | One combustion turbine unit and one steam turbine | Originally constructed as a Qualifying Facility.<br><br>Supplies steam on an as-needed basis to Schering Plough. |
| Massena Station | Massena, New York | One combustion turbine unit and one steam turbine | Originally constructed as a Qualifying Facility.<br><br>Previously supplied steam to Alcoa Inc., but Alcoa currently takes no steam. |



| | | | |
|---|---|---|---|
| Montgomery Creek and Rock Creek Stations | Shasta County and El Dorado County, California | Montgomery Creek Station has four | These units operate on rainwater |

| | | | |
|---|---|---|---|
| | | turbines, and Rock Creek Station has two turbines. | runoff; thus, they can operate only when water is available. |
| Mystic Station | Everett, Massachusetts | One combustion turbine and four boiler units | — |
| Naval Station | San Diego, California | One combustion turbine unit and one steam turbine | Originally constructed as a Qualifying Facility.<br><br>Supplies steam and electricity to the U.S. Navy. |
| New Boston Station | South Boston, Massachusetts | One combustion turbine and two boiler units with a total nominal capacity of 720 MW | — |
| NTC/MCRD Station | San Diego, California | One combustion turbine unit and one steam turbine | Originally constructed as a Qualifying Facility.<br><br>The station supplies steam and electricity to the U.S. Navy. |
| Ogdensburg Station | Ogdensburg, New York | Cogeneration unit | Station is 85% owned and operated by Sithe. Iroquois Power owns the other 15% of the station.<br><br>Originally constructed as a Qualifying Facility.<br><br>Supplies steam on an as-needed basis to the St. Lawrence Psychiatric Center. |
| Oxnard Station | Oxnard, California | A single combined-cycle train | Constructed as a Qualifying Facility.<br><br>The unit manufactures refrigerated ammonia for supply to Boskovich Farms Inc. |



| | | | |
|---|---|---|---|
| Sterling Station | Sherrill, New York | Cogeneration unit | Originally constructed as a Qualifying Facility.<br><br>Supplies steam on an as-needed basis to Oneida Ltd. |
| West Medway Station | West Medway, Massachusetts | Three combustion turbine units | — |
| Wyman Station Unit 4 | Yarmouth, Maine | Boiler plant | Station is 5.89% owned by Sithe. Operator is FPL Energy, Inc., which owns a 59.15% share of the plant. The remaining ownership interests are held by 13 other entities. |



## 2. SARGENT & LUNDY SCOPE OF WORK

### 2.1 SCOPE AND APPROACH

Sargent & Lundy was retained to prepare an Independent Engineer's Report in connection with the proposed debt financing by Exelon Generation. Sargent & Lundy's scope of work included the development of a financial model and obtaining the technical inputs to the financial model. The technical data obtained from the individual stations and the Exelon Generation central offices formed the basis of Sargent & Lundy's reviews, and is the source of the technical inputs to the financial model. Only partial year 2000 data were available because of the early 2001 schedule for the review. Sargent & Lundy made site visits to the major units, including the nuclear plants and the large fossil and hydroelectric units. At each station, Sargent & Lundy typically met with lead station engineering, operations, maintenance, and business planning personnel to review the operational condition of the major equipment, discuss planned upgrades and overhauls, and review the past and future operating cost budgets and capital investment plans. The Sithe Asset Group information was made available by Exelon Generation and supplemented with telephone interviews with Sithe plant staff.

Using the results of these technical reviews, five years of historical information was used to project the capital investments required to keep the units in acceptable condition to maintain their generation capability for the next 20 years. Capital costs were estimated using two approaches that were combined to develop capital investment cost projections annually for each station. The first method was to identify known projects and those investments that could reasonably be required based upon station conditions and regulatory requirements. The second method was to apply general guideline values for the U.S. power industry capital expenditures, based upon typical expenditures for past years on similar unit types. Using the known capital projects list, as well as estimates for future refurbishments as determined independently by Sargent & Lundy, capital cost budgets were established for each station. In later years of the financial model, most of the expenditures were unable to be specifically identified, and generic capital expenditure values were assigned. In early years, where projects were identified by Exelon Generation and through Sargent & Lundy's independent review, most of the capital investment is assigned to specific projects.

In consideration of these investments and the fixed operation and maintenance costs of each station, Sargent & Lundy developed unit capability factors and generation inputs for each unit, which were provided to PA Consulting for use in its development of the market model. PA Consulting was retained by Exelon Generation as the market consultant and provided the revenue estimates for each unit that were used in the financial model. Financial inputs to the model covering items applying to the generation company as a whole were established by Exelon Generation during this same time period and were provided to Sargent & Lundy.

Sargent & Lundy performed a technical review for each of the nuclear units. For the fossil and hydro power stations, the units were separated into four groups: large PECO units, large Sithe units, units under development, and smaller units. For the large PECO and Sithe units, detailed reviews were completed. For the purpose of limiting efforts to significant financial impact areas, Sargent & Lundy did not perform detailed station reviews of the units under development or smaller units. Sargent & Lundy believes this was a reasonable approach because the necessary information could be obtained without visiting the stations for the units in development and because the small units do not represent a significant income or expense stream.

For those units classified as under development, the technical reviews were limited to obtaining available information on the construction schedule, expected performance of the units when they are placed in service, and the pro forma financial model for the stations.



For the smaller units, Sargent & Lundy gathered the critical performance data, cost data, and any available information related to the generation records. This information was summarized for inclusion into the model but detailed reviews of unit performance and future expenditure were not done. These units were sampled to verify the unit performance, operation, and cost information.

During the early stages of the reviews the Wyman 4 unit, a large unit, was identified as one in which Sithe had only a small interest and accordingly was removed from the scope of detailed technical reviews. At the same time, the Croydon and Richmond units were identified by Sargent & Lundy as large stations warranting a detailed technical review, in spite of their status as stations with individually small peaking units.

The set of units in the scope of the financial projections and the set of units in the scope of detailed technical reviews were not identical. Units which were not included in the financial projections have been identified in Section 1.

### 2.2 TECHNICAL REVIEWS PERFORMED

Sargent & Lundy performed reviews of the condition of the Nuclear Asset Group through a review of operating data for the last five years as well as an evaluation of the Nuclear Regulatory Commission's operations assessment reports. This information was reviewed to determine the historical causes of outages and the relationship between the outages and the equipment installed in the plant. In addition, Sargent & Lundy reviewed the history of critical equipment and the status of the units relative to federally mandated activities. The reviews focused on the large components in each unit, such as the reactor vessel, steam generators, turbine, and generator, where equipment can become aged or reach end-of-life and which would require significant replacement capital investment. Our reviews also included control systems and active equipment that could become obsolete and require replacement because parts are no longer available.

The expected remaining life of a nuclear unit was established by assessing the existing license status of the plant, the fuel storage capacity of the unit, and the status of license extension activities. Using this information, Sargent & Lundy assessed the remaining operating life of each unit and estimated the possible costs that would be required to extend the unit's life beyond the current license end date. Environmental impacts caused by potential thermal discharges, including the effects of planned power uprates on the operational performance of the unit, were reviewed against the existing permit limits. The effects of any new or pending environmental requirements that could effect a unit were reviewed to determine what impact on plant operations could occur. Sargent & Lundy also examined in detail, the decommissioning funding mechanisms in place for each nuclear plant and included these costs in the financial model.

For the PECO Asset Group and the Sithe Asset Group, Sargent & Lundy reviewed the existing station performance test records, plant maintenance records, and equipment failure reports to determine what components were reaching end-of-life. The equipment that can be repaired or refurbished was reviewed to determine the capital investments required so that the component life will not limit unit life. The review of fossil units focused on the major equipment items such as boilers, turbines, generators, and transformers. Each fossil unit's environmental review included a review of existing permitted limits and emissions based on plant reporting conditions. In addition, the units were reviewed against current or pending requirements, and the cost of updating the operations or equipment for the plant was assessed to determine what the impacts of the pending regulations would be. Any known requirements or limits that are expected to be instituted in the near future were investigated to determine what actions might be required for compliance. The capital investments necessary were reviewed against those typically required to maintain the generation capability of the unit. The condition of dams, spillways, and reservoirs was discussed with the station staff to determine whether major expenditures in maintaining these structures would be required. The hydroelectric units were reviewed to determine whether any were located in environmental areas that are subject to increasing pressure to either regulate the discharge of the unit or to protect sensitive aquatic species and whether monitoring of the structures for their operating permits is required.



## 3. TECHNICAL DESCRIPTION OF ASSETS

### 3.1 KEY TECHNICAL DATA

Tables 3-1 through 3-4 summarize the key technical data for the generating assets. The information includes the station name, number of units, type of facility/technology, primary fuel, year of commercial operation, rated capacity, percent and capacity ownership, and operating mode (such as baseload, intermediate, or peaking). This data contains information on all units owned in whole or in part by Exelon Generation. However, as noted, some units were not included in the financial projections.

**Table 3-1—Exelon Generation Generating Assets—Nuclear Asset Group**

| Station | Unit | Facility Type* | Primary Fuel | Year of Commercial Operation | Total Net Capacity MW | Exelon Generation Share of Total Net Capacity % | Exelon Generation Share of Total Net Capacity MW | Mode of Operation |
|---|---|---|---|---|---|---|---|---|
| Braidwood | 1 | PWR | Uranium | 1988 | 1,120 | 100.0% | 1,120 | Base Load |
| | 2 | PWR | Uranium | 1988 | 1,120 | 100.0% | 1,120 | Base Load |
| Byron | 1 | PWR | Uranium | 1985 | 1,120 | 100.0% | 1,120 | Base Load |
| | 2 | PWR | Uranium | 1987 | 1,120 | 100.0% | 1,120 | Base Load |
| Dresden | 2 | BWR | Uranium | 1970 | 794 | 100.0% | 794 | Base Load |
| | 3 | BWR | Uranium | 1971 | 794 | 100.0% | 794 | Base Load |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| LaSalle | 1 | BWR | Uranium | 1984 | 1,093 | 100.0% | 1,093 | Base Load |
| | 2 | BWR | Uranium | 1984 | 1,093 | 100.0% | 1,093 | Base Load |
| Quad Cities | 1 | BWR | Uranium | 1973 | 789 | 75.0% | 592 | Base Load |
| | 2 | BWR | Uranium | 1973 | 789 | 75.0% | 592 | Base Load |
| *Total ComEd Nuclear Stations* | | | | | 9,832 | | 9,438 | |
| Limerick | 1 | BWR | Uranium | 1986 | 1,134 | 100.0% | 1,134 | Base Load |
| | 2 | BWR | Uranium | 1990 | 1,115 | 100.0% | 1,115 | Base Load |
| Peach Bottom | 1 | BWR | Uranium | 1974 | 1,119 | 46.3% | 518 | Base Load |
| | 2 | BWR | Uranium | 1974 | 1,119 | 46.3% | 518 | Base Load |
| Salem | 1 | PWR | Uranium | 1977 | 1,115 | 42.6% | 475 | Base Load |
| | 2 | PWR | Uranium | 1981 | 1,115 | 42.6% | 475 | Base Load |
| *Total PECO Nuclear Stations* | | | | | 6,717 | | 4,234 | |
| Clinton | 1 | BWR | Uranium | 1987 | 933 | 50.0% | 467 | Base Load |
| Oyster Creek | 1 | PWR | Uranium | 1969 | 640 | 50.0% | 320 | Base Load |
| Three Mile Island | 1 | PWR | Uranium | 1974 | 819 | 50.0% | 410 | Base Load |
| *Total AmerGen Nuclear Stations* | | | | | 2,392 | | 1,197 | |
| **Total Nuclear Asset Group** | | | | | **18,941** | | **14,869** | |

*

BWR = Boiling Water Reactor

PWR = Pressurized Water Reactor



**Table 3-2—Exelon Generation Generating Assets—PECO Asset Group**

| Station | Unit | Facility Type | Primary Fuel | Year of Commercial Operation | Total Net Capacity | Exelon Generation Share of Total Net Capacity % | MW | Mode of Operation |
|---|---|---|---|---|---|---|---|---|
| Conemaugh | 1 | Steam Boiler | Coal | 1970 | 850 | 20.7% | 176 | Base Load |
| | 2 | Steam Boiler | Coal | 1971 | 850 | 20.7% | 176 | Base Load |
| Conowingo | 1-11 | Hydro | Water | 1926-1965 | 512 | 100.0% | 512 | Base Load |
| Cromby | 1 | Steam Boiler | Coal | 1954 | 144 | 100.0% | 144 | Intermediate |
| | 2 | Steam Boiler | No. 6 Fuel Oil | 1955 | 201 | 100.0% | 201 | Peaking |
| Croydon | 11 | Combustion Turbine | No. 2 Fuel Oil | 1974 | 49 | 100.0% | 49 | Peaking |
| | 12 | Combustion Turbine | No. 2 Fuel Oil | 1974 | 49 | 100.0% | 49 | Peaking |
| | 21 | Combustion Turbine | No. 2 Fuel Oil | 1974 | 45 | 100.0% | 45 | Peaking |
| | 22 | Combustion Turbine | No. 2 Fuel Oil | 1974 | 49 | 100.0% | 49 | Peaking |
| | 31 | Combustion Turbine | No. 2 Fuel Oil | 1974 | 49 | 100.0% | 49 | Peaking |
| | 32 | Combustion Turbine | No. 2 Fuel Oil | 1974 | 45 | 100.0% | 45 | Peaking |
| | 41 | Combustion Turbine | No. 2 Fuel Oil | 1974 | 49 | 100.0% | 49 | Peaking |
| | 42 | Combustion Turbine | No. 2 Fuel Oil | 1974 | 45 | 100.0% | 45 | Peaking |
| Delaware | 7 | Steam Boiler | No. 6 Fuel Oil | 1953 | 126 | 100.0% | 126 | Peaking |
| | 8 | Steam Boiler | No. 6 Fuel Oil | 1953 | 124 | 100.0% | 124 | Peaking |
| | 9 | Combustion Turbine | No. 2 Fuel Oil | 1970 | 17 | 100.0% | 17 | Peaking |
| | 10 | Combustion Turbine | No. 2 Fuel Oil | 1969 | 13 | 100.0% | 13 | Peaking |
| | 11 | Combustion Turbine | No. 2 Fuel Oil | 1969 | 13 | 100.0% | 13 | Peaking |
| | 12 | Combustion Turbine | No. 2 Fuel Oil | 1969 | 13 | 100.0% | 13 | Peaking |
| Eddystone | 1 | Steam Boiler | Coal | 1960 | 279 | 100.0% | 279 | Base Load |
| | 2 | Steam Boiler | Coal | 1960 | 302 | 100.0% | 302 | Base Load |
| | 3 | Steam Boiler | No. 6 Fuel Oil | 1974 | 380 | 100.0% | 380 | Peaking |
| | 4 | Steam Boiler | No. 6 Fuel Oil | 1976 | 380 | 100.0% | 380 | Peaking |
| | 10 | Combustion Turbine | No. 2 Fuel Oil | 1967 | 13 | 100.0% | 13 | Peaking |
| | 20 | Combustion Turbine | No. 2 Fuel Oil | 1967 | 13 | 100.0% | 13 | Peaking |
| | 30 | Combustion Turbine | No. 2 Fuel Oil | 1970 | 17 | 100.0% | 17 | Peaking |
| | 40 | Combustion Turbine | No. 2 Fuel Oil | 1970 | 17 | 100.0% | 17 | Peaking |
| Keystone | 1 | Steam Boiler | Coal | 1967 | 850 | 21.0% | 178 | Base Load |
| | 2 | Steam Boiler | Coal | 1968 | 850 | 21.0% | 178 | Base Load |
| Muddy Run | 1 | Pumped Storage | Water | 1968 | 134 | 100.0% | 134 | Intermediate |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | 2 | Pumped Storage | Water | 1968 | 134 | 100.0% | 134 | Intermediate |
| | 3 | Pumped Storage | Water | 1968 | 134 | 100.0% | 134 | Intermediate |
| | 4 | Pumped Storage | Water | 1968 | 134 | 100.0% | 134 | Intermediate |
| | 5 | Pumped Storage | Water | 1968 | 110 | 100.0% | 110 | Intermediate |
| | 6 | Pumped Storage | Water | 1968 | 110 | 100.0% | 110 | Intermediate |
| | 7 | Pumped Storage | Water | 1968 | 134 | 100.0% | 134 | Intermediate |
| | 8 | Pumped Storage | Water | 1968 | 134 | 100.0% | 134 | Intermediate |
| Richmond | 91 | Combustion Turbine | No. 2 Fuel Oil | 1973 | 48 | 100.0% | 48 | Peaking |
| | 92 | Combustion Turbine | No. 2 Fuel Oil | 1973 | 48 | 100.0% | 48 | Peaking |
| Schuylkill | 1 | Steam Boiler | No. 6 Fuel Oil | 1958 | 166 | 100.0% | 166 | Peaking |
| | 10 | Combustion Turbine | No. 2 Fuel Oil | 1969 | 13 | 100.0% | 13 | Peaking |
| | 11 | Combustion Turbine | No. 2 Fuel Oil | 1971 | 17 | 100.0% | 17 | Peaking |
| *Total PECO Large Stations* | | | | | 7,660 | | 4,969 | |
| Chester | 7 | Combustion Turbine | No. 2 Fuel Oil | 1969 | 13 | 100.0% | 13 | Peaking |
| | 8 | Combustion Turbine | No. 2 Fuel Oil | 1969 | 13 | 100.0% | 13 | Peaking |
| | 9 | Combustion Turbine | No. 2 Fuel Oil | 1969 | 13 | 100.0% | 13 | Peaking |



| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Fairless Hills | A | Steam Boiler | Landfill Gas | 1952 | 30 | 100.0% | 30 | Intermediate |
| | B | Steam Boiler | Landfill Gas | 1952 | 30 | 100.0% | 30 | Intermediate |
| Falls | 1 | Combustion Turbine | No. 2 Fuel Oil | 1970 | 17 | 100.0% | 17 | Peaking |
| | 2 | Combustion Turbine | No. 2 Fuel Oil | 1970 | 17 | 100.0% | 17 | Peaking |
| | 3 | Combustion Turbine | No. 2 Fuel Oil | 1970 | 17 | 100.0% | 17 | Peaking |
| Moser | 1 | Combustion Turbine | No. 2 Fuel Oil | 1970 | 17 | 100.0% | 17 | Peaking |
| | 2 | Combustion Turbine | No. 2 Fuel Oil | 1970 | 17 | 100.0% | 17 | Peaking |
| | 3 | Combustion Turbine | No. 2 Fuel Oil | 1970 | 17 | 100.0% | 17 | Peaking |
| Pennsbury | 1* | Combustion Turbine | Landfill Gas | 1996 | 3 | 100.0% | 3 | Peaking |
| | 2* | Combustion Turbine | Landfill Gas | 1996 | 3 | 100.0% | 3 | Peaking |
| Salem | 3 | Combustion Turbine | No. 2 Fuel Oil | 1973 | 38 | 42.6% | 16 | Peaking |
| Southwark | 3 | Combustion Turbine | No. 2 Fuel Oil | 1967 | 13 | 100.0% | 13 | Peaking |
| | 4 | Combustion Turbine | No. 2 Fuel Oil | 1967 | 13 | 100.0% | 13 | Peaking |
| | 5 | Combustion Turbine | No. 2 Fuel Oil | 1967 | 13 | 100.0% | 13 | Peaking |
| | 6 | Combustion Turbine | No. 2 Fuel Oil | 1967 | 13 | 100.0% | 13 | Peaking |
| *Total PECO Small Stations* | | | | | 297 | | 275 | |
| Conemaugh | A* | Diesel Engine | No. 2 Fuel Oil | 1970 | 2.7 | 20.7% | 0.6 | Peaking |
| | B* | Diesel Engine | No. 2 Fuel Oil | 1970 | 2.7 | 20.7% | 0.6 | Peaking |
| | C* | Diesel Engine | No. 2 Fuel Oil | 1970 | 2.7 | 20.7% | 0.6 | Peaking |
| | D* | Diesel Engine | No. 2 Fuel Oil | 1970 | 2.7 | 20.7% | 0.6 | Peaking |
| Cromby | C1* | Diesel Engine | No. 2 Fuel Oil | 1967 | 2.6 | 100.0% | 2.6 | Peaking |
| Delaware | C1* | Diesel Engine | No. 2 Fuel Oil | 1967 | 3.0 | 100.0% | 3.0 | Peaking |
| Keystone | 1* | Diesel Engine | No. 2 Fuel Oil | 1968 | 2.7 | 21.0% | 0.6 | Peaking |
| | 2* | Diesel Engine | No. 2 Fuel Oil | 1968 | 2.7 | 21.0% | 0.6 | Peaking |
| | 3* | Diesel Engine | No. 2 Fuel Oil | 1968 | 2.7 | 21.0% | 0.6 | Peaking |
| | 4* | Diesel Engine | No. 2 Fuel Oil | 1968 | 2.7 | 21.0% | 0.6 | Peaking |
| Schuylkill | C1* | Diesel Engine | No. 2 Fuel Oil | 1967 | 3.0 | 100.0% | 3.0 | Peaking |
| *Total PECO Diesel Units* | | | | | 30 | | 13 | |
| **Total PECO Asset Group** | | | | | **7,987** | | **5,257** | |
| **Total PECO Asset Group minus excluded units** | | | | | **7,951** | | **5,238** | |

* Units not included in financial projections



**Table 3-3—Exelon Generation Generating Assets—Sithe Asset Group**

| Station | Unit | Facility Type | Primary Fuel | Year of Commercial Operation | Total Net Capacity | Exelon Generation Share of Total Net Capacity % | Exelon Generation Share of Total Net Capacity MW | Mode of Operation |
|---|---|---|---|---|---|---|---|---|
| Allegheny | 5* | Hydro | Water | 1988 | 10 | 49.9% | 4.7 | Base Load |
| | 6* | Hydro | Water | 1988 | 9 | 49.9% | 4.3 | Base Load |
| | 8* | Hydro | Water | 1990 | 14 | 49.9% | 6.8 | Base Load |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | 9* | Hydro | Water | 1990 | 18 | 49.9% | 8.9 | Base Load |
| Batavia | | Combined Cycle | Natural Gas | 1992 | 58 | 44.9% | 29 | Base Load |
| Bypass | 1* | Hydro | Water | 1988 | 10 | 44.9% | 4.7 | Base Load |
| Cardinal | 1* | Combined Cycle | Natural Gas | 1995 | 152 | 49.9% | 76 | Base Load |
| Elk Creek | 1* | Hydro | Water | 1986 | 2 | 49.9% | 1.1 | Base Load |
| Fore River | 1 | Combustion Turbine | No. 2 Fuel Oil | 1969 | 13 | 49.9% | 6.5 | Peaking |
| | 2 | Combustion Turbine | No. 2 Fuel Oil | 1969 | 13 | 49.9% | 6.5 | Peaking |
| Framingham | 1 | Combustion Turbine | No. 2 Fuel Oil | 1969 | 11 | 49.9% | 5.4 | Peaking |
| | 2 | Combustion Turbine | No. 2 Fuel Oil | 1969 | 11 | 49.9% | 5.4 | Peaking |
| | 3 | Combustion Turbine | No. 2 Fuel Oil | 1969 | 11 | 49.9% | 5.4 | Peaking |
| Greeley | 1* | Combined Cycle | Natural Gas | 1988 | 72 | 49.9% | 36 | Base Load |
| Hazelton | A* | Hydro | Water | 1990 | 8.7 | 49.9% | 4.3 | Base Load |
| Independence | 1 | Combined Cycle | Natural Gas | 1994 | 477 | 49.9% | 238 | Base Load |
| | 2 | Combined Cycle | Natural Gas | 1994 | 477 | 49.9% | 238 | Base Load |
| Ivy River | 1* | Hydro | Water | 1918 | 1.2 | 49.9% | 0.6 | Base Load |
| Kenilworth | | Combined Cycle | Natural Gas | 1989 | 26 | 49.9% | 13 | Base Load |
| Massena | | Combined Cycle | Natural Gas | 1993 | 88 | 49.9% | 44 | Base Load |
| Montgomery Creek | | Hydro | Water | 1986 | 2.6 | 49.9% | 1.3 | Base Load |
| Mystic | 1 | Combustion Turbine | No. 2 Fuel Oil | 1969 | 14 | 49.9% | 7.1 | Peaking |
| | 4 | Steam Boiler | No. 6 Fuel Oil | 1957 | 135 | 49.9% | 67 | Peaking |
| | 5 | Steam Boiler | No. 6 Fuel Oil | 1959 | 135 | 49.9% | 67 | Peaking |
| | 6 | Steam Boiler | No. 6 Fuel Oil | 1961 | 135 | 49.9% | 67 | Peaking |
| | 7 | Steam Boiler | Natural Gas | 1975 | 565 | 49.9% | 282 | Base Load |



| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Naval Station | 1* | Combined Cycle | Natural Gas | 1989 | 45 | 49.9% | 22 | Base Load |
| New Boston | J1 | Combustion Turbine | No. 2 Fuel Oil | 1966 | 20 | 49.9% | 10 | Peaking |
| | 1 | Steam Boiler | Natural Gas | 1965 | 350 | 49.9% | 175 | Intermediate |
| | 2 | Steam Boiler | Natural Gas | 1967 | 350 | 49.9% | 175 | Intermediate |
| NTC MCRD | 1* | Combined Cycle | Natural Gas | 1989 | 23 | 49.9% | 11 | Base Load |
| Ogdensburg | | Combined Cycle | Natural Gas | 1994 | 83 | 42.4% | 41 | Base Load |
| Oxnard | 1* | Combined Cycle | Natural Gas | 1990 | 48 | 49.9% | 24 | Base Load |
| Rock Creek | 1* | Hydro | Water | 1986 | 3.6 | 49.9% | 1.8 | Base Load |
| Sterling | | Combined Cycle | Natural Gas | 1991 | 55 | 49.9% | 28 | Base Load |
| West Medway | 1 | Combustion Turbine | Natural Gas | 1970 | 63 | 49.9% | 32 | Peaking |
| | 2 | Combustion Turbine | Natural Gas | 1970 | 63 | 49.9% | 32 | Peaking |
| | 3 | Combustion Turbine | Natural Gas | 1970 | 63 | 49.9% | 32 | Peaking |
| Wyman | 4 | Steam Boiler | No. 6 Fuel Oil | 1978 | 617 | 2.9% | 18 | Base Load |
| Total Sithe Asset Group | | | | | 4,251 | | 1,832 | |
| Total Sithe Asset Group minus units excluded from financial projections | | | | | 3,835 | | 1,626 | |

* Units not included in financial projections



**Table 3-4a—Exelon Generation Generating Assets—Units Under Construction**

| Station | Unit | Facility Type | Primary Fuel | Year of Commercial Operation | Total Net Capacity | Exelon Generation Share of Total Net Capacity | | Mode of Operation |
|---|---|---|---|---|---|---|---|---|
| | | | | | | % | MW | |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Fore River 3 | 3 | Combined Cycle | Natural Gas | 2002 | 800 | 49.9% | 399 | Base Load |
| Mystic | 8 | Combined Cycle | Natural Gas | 2002 | 800 | 49.9% | 399 | Base Load |
| | 9 | Combined Cycle | Natural Gas | 2002 | 800 | 49.9% | 399 | Base Load |
| Heritage | 1 | Combined Cycle | Natural Gas | 2004 | 400 | 49.9% | 200 | Base Load |
| | 2 | Combined Cycle | Natural Gas | 2004 | 400 | 49.9% | 200 | Base Load |
| Total Units under Construction | | | | | 3,200 | | 1,597 | |

**Table 3-4b—Exelon Generation Generating Assets—Units Under Development**

| Station | Unit | Facility Type | Primary Fuel | Year of Commercial Operation | Total Net Capacity | Exelon Generation Share of Total Net Capacity % | MW | Mode of Operation |
|---|---|---|---|---|---|---|---|---|
| Fronter | * | Combined Cycle | Natural Gas | N/A | N/A | 49.9% | N/A | Base Load |
| Jenks | * | Combined Cycle | Natural Gas | N/A | N/A | 49.9% | N/A | Base Load |
| Heard County | * | Combined Cycle | Natural Gas | N/A | N/A | 49.9% | N/A | Base Load |
| Medway | * | Combined Cycle | Natural Gas | N/A | N/A | 49.9% | N/A | Base Load |
| Brampton | * | Combined Cycle | Natural Gas | N/A | N/A | 49.9% | N/A | Base Load |
| Mississauga | * | Combined Cycle | Natural Gas | N/A | N/A | 49.9% | N/A | Base Load |
| Torne Valley | * | Combined Cycle | Natural Gas | N/A | N/A | 49.9% | N/A | Base Load |
| Total Units under Development | | | | | N/A | | N/A | |

* Units under development not included in financial projections

## 3.2 NET CAPACITY AND GENERATION PROJECTIONS

Net capacity (in MW) and generation (in MWh) projections made covering the generating assets can be grouped into various categories, as follows:

- Mode of Operation (baseload, intermediate, peaking)
- Primary Source of Energy (nuclear, coal, fuel oil, gas, or water)

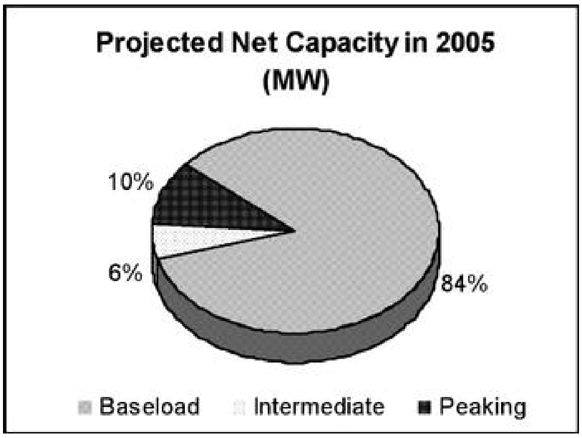


- Type of Technology (nuclear, steam electric, hydroelectric, combustion turbine, combined cycle, or diesel engine)
- Geographic Location (by state and by market region)

Figures 3-1 through 3-5 summarize the breakdown of the above categories on both a capacity and a generation basis as projected for 2005. The capacity and generation figures utilized are based on the Exelon Generation ownership share in each station. Data was obtained from the base case of the financial model. Units not included in the financial model are not reflected in these figures.

Figure 3-1 shows the projected capacity and generation breakdown by mode of operation. As shown, baseload operation dominates the Exelon Generation generating portfolio. Baseload operation represents 84% of total capacity and 96% of projected output. The nuclear fleet contributes 59% of projected baseload capacity, and 74% of the projected baseload generation output in 2005.

**Figure 3-1—Projected Annual Net Capacity and Generation in 2005 by Mode of Operation**



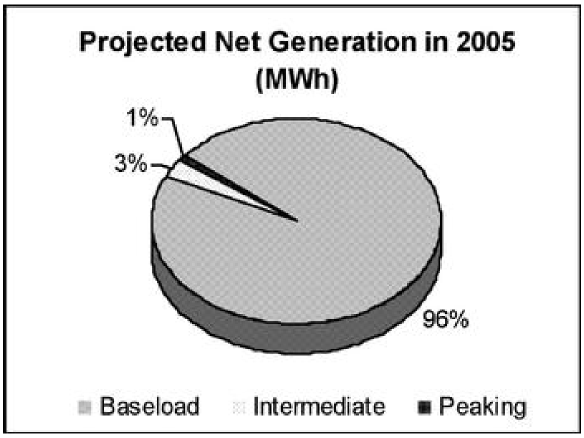
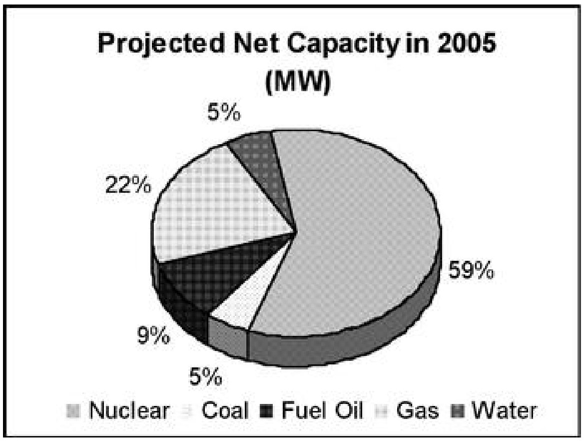
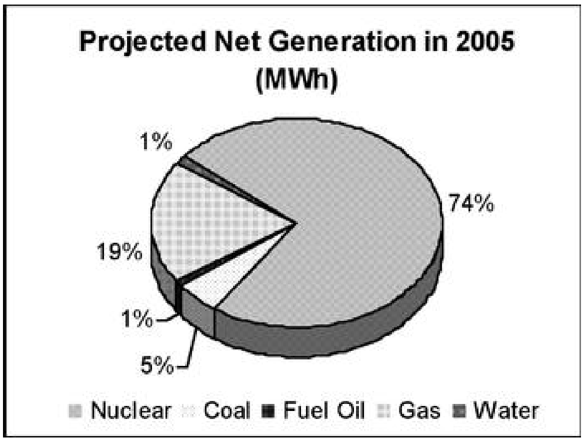




Figure 3-2 illustrates the projected capacity and generation breakdown by primary fuel source. Again, the nuclear fleet dominates the projected generation with 74% of the total generation output.

**Figure 3-2—Projected Annual Net Capacity and Generation in 2005 by Primary Source of Energy**

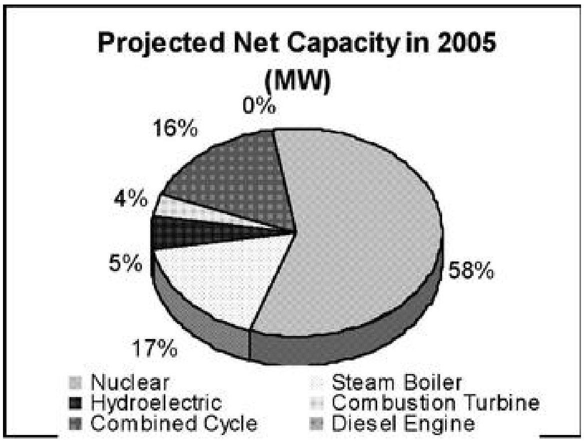





On a technology-type basis, Figure 3-3 indicates again the nuclear plant domination of the generating mix in 2005.

**Figure 3-3—Projected Net Capacity and Generation in 2005 by Type of Technology**



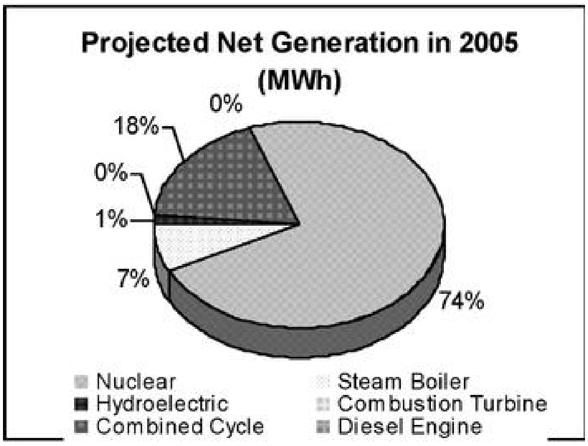
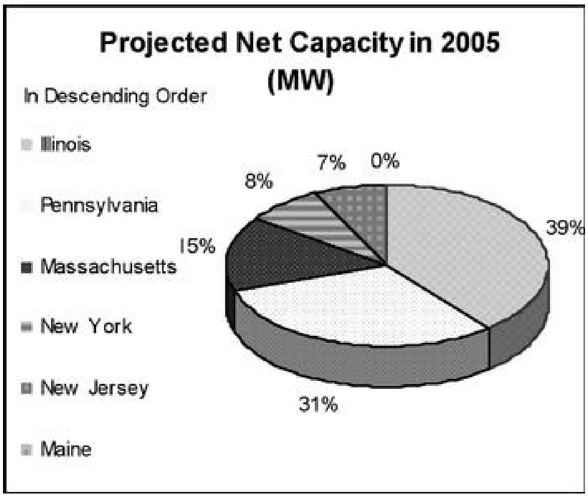




Figure 3-4 illustrates the geographic diversity of the Exelon Generation generating fleet by state or province. Illinois, consisting of the former ComEd nuclear units and the AmerGen Clinton nuclear plant, makes up 39% of the 2005 projected generating capacity. The former PECO nuclear, hydroelectric, and fossil-fueled plants in Pennsylvania make up 31% of the total capacity.

**Figure 3-4—Projected Capacity and Generation in 2005 by State**



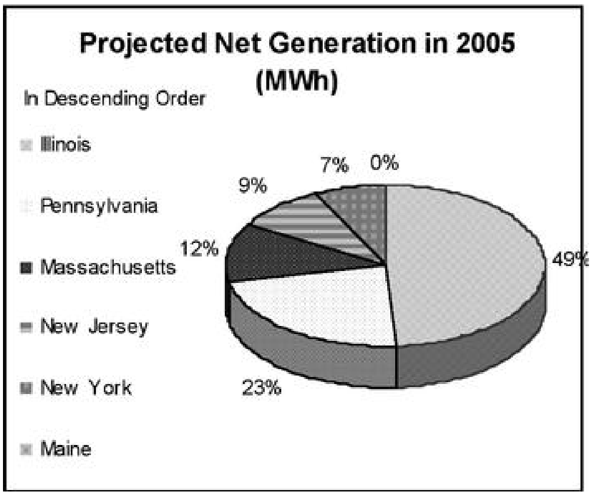
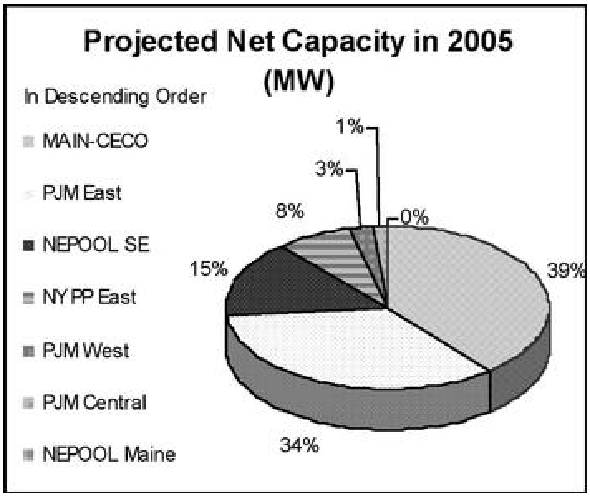
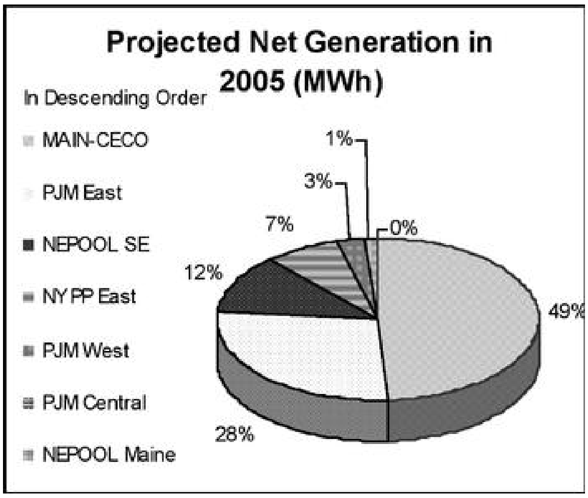






Figure 3-5 presents the distribution of the generating fleet by market region. MAIN-CECO consists of the former ComEd nuclear units and the AmerGen Clinton nuclear plant. The PJM East region consists of the former PECO nuclear and fossil units in Pennsylvania and Exelon Generation's share in the Salem and Oyster Creek nuclear units in New Jersey.

**Figure 3-5—Projected Capacity and Projected Generation in 2005 by Market Region**




### 3.3 FUEL PROCUREMENT

Table 3-5 summarizes the fuel procurement status for Exelon Generation's generating plants. Fuel procurement contract status for the small PECO and Sithe units or the PECO diesels was not reviewed in detail and not reported.

**Table 3-5—Fuel Procurement Status**

| Station Name | Units | Facility Type | Primary/ Secondary Fuel | Fuel Contract Type |
|---|---|---|---|---|
| **Nuclear Asset Group** | | | | |
| *ComEd Nuclear Stations:* | | | | |
| Braidwood | 1&2 | PWR | Uranium | Long-term contract |
| Byron | 1&2 | PWR | Uranium | Long-term contract |
| Dresden | 2&3 | BWR | Uranium | Long-term contract |
| LaSalle | 1&2 | BWR | Uranium | Long-term contract |
| Quad Cities | 1&2 | BWR | Uranium | Long-term contract |
| *PECO Nuclear Stations:* | | | | |
| Limerick | 1&2 | BWR | Uranium | Long-term contract |
| Peach Bottom | 2&3 | BWR | Uranium | Long-term contract |
| Salem | 1&2 | PWR | Uranium | Long-term contract |
| *AmerGen Nuclear Stations:* | | | | |
| Clinton | 1 | BWR | Uranium | Long-term contract |

| | | | | |
|---|---|---|---|---|
| Oyster Creek | 1 | PWR | Uranium | Long-term contract |
| Three Mile Island | 1 | PWR | Uranium | Long-term contract |



| | | | | |
|---|---|---|---|---|
| **PECO Asset Group** | | | | |
| *Large Stations:* | | | | |
| Conemaugh | 1&2 | Steam Electric | Coal | Flexible long-term contracts and spot market. Local supply, delivered by rail and truck. |
| Conowingo | 1-11 | Hydroelectric | | Run-of-river hydro plant |
| Cromby | 1 | Steam Electric | Coal | 80% through 1-yr. contracts, balance on spot market. |
| | 2 | Steam Electric | Heavy Fuel Oil/ Natural Gas | Oil: 80% short-term (<1 year) contracts, 20% spot market. Gas: primarily spot market. |
| Croydon | 11/12<br>21/22<br>31/32<br>41/42 | Comb. Turbine | Fuel Oil No. 2 | 80% short-term (<1 year) contracts, 20% spot market. Delivered by trucks or barges. |
| Delaware | 7/8 | Steam Electric | Heavy Fuel Oil | 80% short-term (<1 year) contracts; |
| | 9-12 | Comb. Turbine | Fuel Oil No. 2 | 20% spot market. |
| Eddystone | 1, 2 | Steam Electric | Coal | 80% through 1-yr. contracts, balance on spot market. |
| | 3, 4 | Steam Electric | Fuel Oil/Nat. Gas | Oil: 80% short-term (<1 year) contracts, 20% spot market. |
| | 10, 20, 30, 40 | Comb. Turbine | Natural Gas | Gas: primarily spot market. |
| Keystone | 1&2 | Steam Electric | Coal/ Fuel Oil/Nat. Gas (minor) | Coal: Flexible long-term contracts and spot market. Local supply, delivered by rail and truck. |
| Muddy Run | 1-8 | Hydroelectric | | Pumped storage hydro plant. |
| Richmond | 91&92 | Comb. Turbine | Fuel Oil No. 2 | 80% short-term (<1 year) contracts, 20% spot market. Delivered by trucks. |
| Schuylkill | 1 | Steam Electric | Heavy Fuel Oil | 80% short-term (<1 year) contracts; |
| | 10&11 | Comb. Turbine | Fuel Oil No. 2 | 20% spot market. |



## 4. PROJECTED PERFORMANCE AND CONDITION OF ASSETS

Tables 4-1 through 4-4 summarize the historical and projected availability and capacity factor data for Exelon Generation's operating generating assets as well as those assets considered in the financial model which are under construction or development. The equivalent availability factor represents the equivalent annual percentage of time that the unit is able to produce full output. The capacity factor represents the annual percentage of the total generation capability of the station that is actually developed. The projected data represent the average value for each unit over the 20-year assessment time horizon. "N/A" in the following tables indicates that data for the respective item was either not available, in the case of historical data, or not applicable, in the case of projected values. Units that were not included in the financial projections are listed here, but projected values are not given.

**Table 4-1—Equivalent Availability and Capacity Factors—Nuclear Asset Group**

| | | Historical (1995-1999) | | Projected (2001-2020) | |
|---|---|---|---|---|---|
| **Station Name** | **Unit** | **Equivalent Availability Factor (%)** | **Capacity Factor (%)** | **Equivalent Availability Factor (%)** | **Capacity Factor (%)** |
| *ComEd Nuclear Stations:* | | | | | |
| Braidwood | 1 | 80.2 | 81.0 | 92.2 | 92.2 |
| | 2 | 89.6 | 90.6 | 91.7 | 91.7 |
| Byron | 1 | 78.1 | 87.0 | 92.2 | 92.2 |
| | 2 | 78.2 | 87.4 | 91.3 | 91.3 |
| Dresden | 2 | 62.1 | 62.6 | 89.6 | 89.6 |
| | 3 | 65.8 | 65.5 | 89.8 | 89.8 |
| LaSalle | 1 | 48.1 | 48.5 | 90.7 | 90.7 |
| | 2 | 38.1 | 38.3 | 91.1 | 91.1 |
| Quad Cities | 1 | 68.4 | 68.2 | 89.8 | 89.8 |
| | 2 | 58.4 | 58.2 | 90.0 | 90.0 |
| *PECO Nuclear Stations:* | | | | | |
| Limerick | 1 | 91.1 | 88.2 | 93.0 | 93.0 |
| | 2 | 92.2 | 88.6 | 93.3 | 93.3 |
| Peach Bottom | 1 | 95.3 | 89.7 | 92.1 | 92.1 |
| | 2 | 93.6 | 89.8 | 92.1 | 92.1 |

| | | | | | |
|---|---|---|---|---|---|
| Salem | 1 | 37.3 | 37.4 | 86.5 | 86.5 |
| | 2 | 46.9 | 47.0 | 87.8 | 87.8 |
| *AmerGen Stations:* | | | | | |
| Clinton | | 40.1 | 39.0 | 87.7 | 87.7 |
| Oyster Creek | | 84.7 | 89.3 | 88.0 | 88.0 |
| Three Mile Island | | N/A | 92.7 | 92.7 | 92.7 |



**Table 4-2—Equivalent Availability and Capacity Factors—PECO Asset Group**

| | | Historical (1995-1999) | | Projected | |
|---|---|---|---|---|---|
| **Station Name** | **Unit** | **Equivalent Availability Factor (%)** | **Capacity Factor (%)** | **Equivalent Availability Factor (%)** | **Capacity Factor (%)** |
| *PECO Large Stations:* | | | | | |
| Conemaugh | 1 | 86.8 | 82.2 | 85.8 | 82.1 |
| | 2 | 86.8 | 82.2 | 85.8 | 82.0 |
| Conowingo | 1-7 | 90.7 | 44.4 | 90.7 | 40.4 |
| | 8-11 | 88.5 | 34.5 | 88.5 | 40.4 |
| Cromby | 1 | 83.3 | 59.8 | 85.5 | 67.0 |
| | 2 | 77.8 | 13.4 | 84.2 | 23.3 |
| Croydon | 11 | 83.5 | 1.6 | 90.6 | 0.2 |
| | 12 | 86.9 | 1.6 | 90.6 | 0.2 |
| | 21 | 77.8 | 1.3 | 90.6 | 0.7 |
| | 22 | 85.2 | 2.9 | 90.6 | 0.2 |
| | 31 | 90.1 | 2.0 | 90.6 | 0.2 |
| | 32 | 82.9 | 1.7 | 90.6 | 0.4 |
| | 41 | 90.4 | 1.9 | 90.6 | 0.2 |
| | 42 | 74.4 | 1.7 | 90.6 | 0.5 |
| Delaware | 7 | 80.9 | 7.4 | 84.6 | 10.6 |
| | 8 | 77.3 | 4.7 | 84.6 | 2.3 |
| | 9 | 82.1 | 4.0 | 88.6 | 0.0 |
| | 10 | 82.1 | 4.0 | 91.6 | 0.0 |
| | 11 | 82.1 | 4.0 | 91.6 | 0.0 |
| | 12 | 82.1 | 4.0 | 91.6 | 0.0 |
| Eddystone | 1 | 75.0 | 53.2 | 84.6 | 73.8 |
| | 2 | 75.0 | 53.2 | 81.6 | 73.7 |
| | 3 | 90.0 | 9.6 | 80.3 | 8.3 |
| | 4 | 90.0 | 9.6 | 80.3 | 6.8 |
| | 10 | N/A | N/A | 91.6 | 0.0 |
| | 20 | N/A | N/A | 91.6 | 0.0 |
| | 30 | N/A | N/A | 88.6 | 0.0 |
| | 40 | N/A | N/A | 88.6 | 0.0 |
| Keystone | 1 | 89.6 | 85.8 | 85.8 | 80.7 |
| | 2 | 89.6 | 85.8 | 85.8 | 80.6 |
| Muddy Run | 1-8 | 83.0 | 18.4 | 83.0 | 8.69 |
| Richmond | 91 | 83.8 | 1.4 | 90.6 | 0.02 |
| | 92 | 84.9 | 1.6 | 90.6 | 0.01 |
| Schuylkill | 1 | 82.1 | 4.0 | 84.6 | 9.3 |
| | 10 | 96.1 | 0.6 | 91.6 | 0.0 |
| | 11 | 96.1 | 0.6 | 88.6 | 0.0 |
| *PECO Small Stations:* | | | | | |
| Chester | 7 | N/A | N/A | 91.6 | 0.0 |
| | 8 | N/A | N/A | 91.6 | 0.0 |
| | 9 | N/A | N/A | 91.6 | 0.0 |



| | | | | | |
|---|---|---|---|---|---|
| Fairless Hills | A | N/A | N/A | 88.8 | 0.4 |
| | B | N/A | N/A | 88.8 | 0.4 |
| Falls Station | 1 | N/A | N/A | 88.6 | 0.0 |
| | 2 | N/A | N/A | 88.6 | 0.0 |
| | 3 | N/A | N/A | 88.6 | 0.0 |
| Moser | 1 | N/A | N/A | 88.6 | 0.0 |
| | 2 | N/A | N/A | 88.6 | 0.0 |
| | 3 | N/A | N/A | 88.6 | 0.0 |
| Pennsbury | 1* | N/A | N/A | N/A | N/A |
| | 2* | N/A | N/A | N/A | N/A |
| Salem | 3 | N/A | N/A | 88.6 | 0.0 |
| | | N/A | N/A | | |
| | | N/A | N/A | | |
| Southwark | 3 | N/A | N/A | 91.6 | 0.0 |
| | 4 | N/A | N/A | 91.6 | 0.0 |
| | 5 | N/A | N/A | 91.6 | 0.0 |
| | 6 | N/A | N/A | 91.6 | 0.0 |
| *PECO Diesel Units:* | | | | | |
| Conemaugh | A* | N/A | N/A | N/A | N/A |
| | B* | N/A | N/A | N/A | N/A |

| | | | | | |
|---|---|---|---|---|---|
| | C* | N/A | N/A | N/A | N/A |
| | D* | N/A | N/A | N/A | N/A |



| | | | | | |
|---|---|---|---|---|---|
| Cromby | IC1* | N/A | N/A | N/A | N/A |
| Delaware | IC1* | N/A | N/A | N/A | N/A |
| Keystone | 3* | N/A | N/A | N/A | N/A |
| | 4* | N/A | N/A | N/A | N/A |
| | 5* | N/A | N/A | N/A | N/A |
| | 6* | N/A | N/A | N/A | N/A |
| Schuylkill | IC1* | N/A | N/A | N/A | N/A |

*Not included in projections.

**Table 4-3—Equivalent Availability and Capacity Factors—Sithe Asset Group**

| | | Historical (1995-1999) | | Projected (2001-2020) | |
|---|---|---|---|---|---|
| **Station Name** | **Unit** | **Equivalent Availability Factor (%)** | **Capacity Factor (%)** | **Equivalent Availability Factor (%)** | **Capacity Factor (%)** |
| Allegheny | 5* | 95.5 | 58.8 | N/A | N/A |
| | 6* | 95.5 | 58.8 | | |
| | 8* | 95.5 | 58.8 | | |
| | 9* | 95.5 | 58.8 | | |
| Batavia | 1 | N/A | 51.5 | 92.2 | 35.1 |
| Bypass | 1* | N/A | 34.2 | N/A | N/A |
| Cardinal | 1* | 96.5 | 96.7 | N/A | N/A |
| Elk Creek | 1* | N/A | 24.3 | N/A | N/A |
| Fore River | 1 | N/A | <1.0 | 92.2 | 0.1 |
| Framingham | 1 | N/A | <1.0 | 91.6 | 0.8 |
| Greeley | 1* | 98.1 | 98.3 | N/A | N/A |
| Hazelton | A* | N/A | 32.4 | N/A | N/A |
| Independence | 1 | 95.0 | 87.2 | 90.6 | 60.9 |
| Ivy River | 1* | N/A | 29.5 | N/A | N/A |
| Kenilworth | 1 | 97.2 | 90.5 | 88.8 | 26.3 |
| Massena | 1 | 84.0 | 62.6 | 92.2 | 38.4 |



| | | | | | |
|---|---|---|---|---|---|
| Montgomery Creek | 1* | N/A | 51.1 | N/A | N/A |
| Mystic | J1 | | <1.0 | | 0.1 |
| | 4 | 81.9 | 36.4 | 85.2 | 14.8 |
| | 5 | 69.6 | 11.8 | 85.7 | 1.0 |
| | 6 | 80.2 | 39.0 | 85.2 | 15.4 |
| | 7 | 86.4 | 51.8 | 82.5 | 21.6 |
| Naval | 1* | 94.7 | 95.9 | N/A | N/A |
| New Boston | J1 | N/A | <1.0 | N/A | 0.19 |
| | 1 | 87.9 | 45.7 | 80.3 | 19.7 |
| | 2 | 82.5 | 44.7 | 80.3 | 17.0 |
| NTC/MCRD | 1* | 97.6 | 101.1 | N/A | N/A |
| Ogdensburg | 1 | 98.3 | 78.6 | 92.2 | 38.3 |
| Oxnard | 1* | 96.1 | 43.3 | N/A | N/A |
| Rock Creek | 1* | N/A | 13.6 | N/A | N/A |
| Sterling | 1 | 97.1 | 47.9 | 92.2 | 37.4 |
| West Medway | 1 | N/A | <1.0 | 90.6 | 0.1 |
| Wyman | 4 | 77.4 | 13.5 | 82.9 | 7.0 |

*Not included in the projections.

**Table 4-4—Equivalent Availability and Capacity Factors—Units Under Construction or Development**

| | | Historical (1995-1999) | | Projected | |
|---|---|---|---|---|---|
| **Station Name** | **Unit** | **Equivalent Availability Factor (%)** | **Capacity Factor (%)** | **Equivalent Availability Factor (%)** | **Capacity Factor (%)** |
| Fore River | 3 | N/A | N/A | 92.2 | 84.9 |
| Heritage | 1 | N/A | N/A | 92.2 | 80.2 |
| | 2 | N/A | N/A | 92.2 | 80.2 |
| Mystic | 8 | N/A | N/A | 92.2 | 89.0 |
| | 9 | N/A | N/A | 92.2 | 87.8 |

The Frontier, Jenks, Heard County, Medway, Brampton, Mississauga, and Torne Valley projects under development were not included in the financial projections.

## 4.1 NUCLEAR ASSET GROUP

Sargent & Lundy believes that the stations are presently well maintained and operated. Those stations that have had problems in the past with long outages have improved, as shown by their outstanding performance in 2000. It is believed that all of the units can operate, on average, in the top two quartiles of the U.S. nuclear fleet over the long term. This level of performance requires that management continue its aggressive improvement projects and takes the steps outlined in the stations' and nuclear organizations' business plans. Only with management's vigilance in ensuring proper safety, maintenance, and staffing practices can the units continue their improvement. We believe, based on the recent results at many of the Exelon Generation stations, that a significant trend of improvement has been established while maintaining the excellent station operation in the fleet. The trend of improvement has resulted in several of the units becoming top performers in the United States and the world. Based on the year 2000 rankings of top performing nuclear units, as published in *Nucleonics Week*, the Exelon Generation units included 9 of the top 50 units in the world as measured by capacity factor. This top performance is a clear indication that several of the Exelon Generation units could rank in the top quartile of U.S. nuclear units over the long term if current management actions continue and adequate budgets are maintained for future investments and maintenance. Based on our reviews, Sargent & Lundy has projected the average capacity factor of the Exelon Generation nuclear fleet to be approximately 90% to 91%. This projected capacity factor is above average for the U.S. nuclear fleet, which in 2000 was 87.2%. In addition to the high capacity factors, cost savings through staff reductions and predictive and preventative maintenance programs (which improve a unit's availability during peak generation periods) will improve the operational competitiveness of the units.

The reviews found all of the nuclear units to be in excellent condition and improving in operational performance. Each station indicated that steps were being taken to reduce operating costs while maintaining or improving the safety and performance of the units. One of the key indicators critical to the generation capability of the plants is the duration of refueling outages. The average refueling outage duration of the units is decreasing to less than 25 days, and most plants are targeting outages of less than 20 days within five years. This reduction is an aggressive goal. The model reflects improved outage duration at each unit (compared to historical performance) based on Sargent & Lundy's estimate of outage activities required and reasonable allowances for unforeseen events. The stations are also taking steps to perform more maintenance activities while the units are in service.

While there are favorable trends, and the goals being established by the stations and the Exelon Generation's management are thought to be well founded, we believe that several of the goals may be too aggressive given the plant age and equipment condition. The staffing goals and shortened outage goals appear to be among the most aggressive. We have included longer outages in the future to accommodate expected major equipment overhauls and have conservatively included these longer outages in Sargent & Lundy's model. Sargent & Lundy reviewed the staffing targets, and made adjustments in both permanent and contracted staff levels in light of expected increased levels of operations and maintenance attention resulting from plant and equipment aging considerations. These adjustments result in staffing projections slightly higher than these goals developed by Exelon Generation. These projections result in conservative estimates of the stations' cost and income for use in the financial model.

It is believed that Exelon Generation will achieve efficiencies in staffing that were not obtainable when the generation assets were separately owned by ComEd and PECO. In addition, each station is reviewing its staffing practices with the goal of reducing long-term staffing. The long-term permanent staff targets are 670 for dual-unit stations and 450 for single-unit stations. The model uses more conservative staffing levels that average approximately 700 employees at dual-unit stations and approximately 550 at single-unit stations, with reductions occurring over a somewhat longer time span. We believe that such staffing goals are feasible given a stable regulatory environment, sufficient and timely maintenance and capital investment, and continued long-term planning. The model allows for a



reasonable number of outside contractors, based on assessments of upcoming activities and current practices at the stations.

Sargent & Lundy also reviewed the recent regulatory performance of each of the stations. Overall performance has been very good, with significant improving trends evident in stations such as Dresden and LaSalle where past performance had been troubled. The stations have measurably demonstrated over the past five years that they are improving and moving towards the level of industry leaders. Improved material conditions, augmented by a proactive and goals-oriented management team, have improved the stations' safety and operational performance. Recent findings resulting from the NRC inspections have been addressed promptly and satisfactorily, and there have been minimal equipment-related enforcement actions in the last two years. If the stations' safety and maintenance practices are continued and current management trends continue, it is considered unlikely that any significant regulatory enforcement action would be imposed that would affect the stations' availability in the future.

All of the stations have indicated that they are in the process of reviewing operating license extension options. Each station has more than enough time in the current license to gather the necessary data and perform the evaluations and analyses required for the submittals and reviews. Many of the units are also being uprated to increase electrical output, either with or without significant changes to equipment. These uprates are generally the result of equipment changes and upgrades, thermal efficiency improvements, and operational monitoring improvements. Several of the units will require additional capital investments in the condenser cooling systems, such as cooling tower additions. These improvements indicate the confidence that station management has in the ability of the plant staff to operate the stations safely and reliably in the future. As part of the power uprate process, General Electric reviewed the capability of the transmission system to handle the increased power and determined that no physical modifications to the transmission system were required as part of this these power uprates. None of the nuclear units is expected to be decommissioned in the 20-year review period due to any end-of-life events. Long-term spent fuel storage at each site has been addressed through either dry cask storage planning or through a re-racking of the spent fuel pools.

## 4.2 PECO ASSET GROUP

The fossil and hydroelectric units in the PECO Asset Group are mostly older units that have been well maintained for units of their age. The capacity factors on several of the units are low due to high heat rates, but generally the units have maintained a high availability, which indicates that the units, although not dispatched at base load, are able to respond to dispatch requests. The typical availability for these units is greater than 85%, and most of the outage time was caused by aging equipment, which has been largely replaced over the last few years at the larger stations and the more efficient units. Those units that are dispatched for peaking service have been maintained for starting reliability and, due to the lack of dispatch, have not had significant equipment failures. Several of the boiler units currently in peaking service were not designed for cycling or peaking operation and have the potential to have problems related to thermal fatigue and embrittlement. The maintenance staffing of the plants and the operational performance of the units were generally within the expected parameters for units of this type and age in the fleet. Although some operational performance improvements could be made on some of the units, most were limited by either site constraints or fuel options related to the cost of generation. Generally, the PECO Asset Group had an emissions control philosophy to comply with the expected emissions control requirements for $NO_X$ and $SO_2$. In general, this program resulted in the system having balanced emissions when compared to the generation expected at the units. Costs for capital upgrades for environmental control additions have been included in the financial projections.

The PECO fossil unit group is generally located in the eastern Pennsylvania region and provides power to the PJM transmission system. These units have typically been owned, operated, and maintained by PECO staff. Most of the large units are more than 30 years old and have been well



maintained to supply reliable power to the PECO service territory. The older units, with several exceptions, are oil-fired units, which use low-sulfur heavy fuel oil in the intermediate mode of operation. The newest of the large units are coal-fired with state-of-the-art emissions control equipment. These units perform well and produce very competitively priced power, as evidenced by their high capacity factors. In addition to the large units, there is a fleet of small combustion turbines, mostly fired by No. 2 fuel oil. Eleven small internal combustion units are also part of the PECO Asset Group. The diesel units are located at some of the large-unit sites and can provide black-start capability for these units. The combustion turbine and diesel engine units are only used in peaking operation and have very low capacity factors. The total system includes 17 stations with a total of 79 units and a generation capability of approximately 8,190 MW. Of this total generation capability, nearly 4,125 MW is from base-loaded coal-fired units and approximately 1,420 MW is from hydroelectric or pumped-storage facilities. The remaining 2,645 MW is generated by oil- and gas-fired generation at intermediate service and peaking installations and base-loaded boilers. Typically, a utility's portfolio consists of between 50% to 55% base-load generation and approximately 10% peak load capability with the remaining generation being intermediate service capacity. Considering the nuclear capability and the interconnected grid within PJM, the mix of units in the PECO Asset Group is appropriate.

The PECO Asset Group includes minority shares of the Conemaugh and Keystone coal-fired stations. These dual-unit stations have operating profiles similar to that of the nuclear assets with historical equivalent availability factors in excess of 85% and capacity factors in excess of 80%.

The Eddystone and Cromby stations are the only fossil stations that function in an intermediate service capacity. These stations have capacity factors around 40% to 60% and include both coal- and oil-fired units. The oil units at these stations provide mostly peaking service, while the coal units generally have provided intermediate service. In the future, these coal units are projected to provide base load service. These units have performed well in this service and maintained station heat rates near 11,000 Btu/kWh, which is acceptable given the operational constraints.

The condition of the peaking units has been improved by recent maintenance practices at the stations to overcome problems with the starting and operation of the units. In general, the availability of the units has improved in the last two years. The combustion turbine units have extremely low capacity factors, less than 2% on average, but they are targeted to operate only a few days each year when the system is under stress. For this reason there are more units than would actually be required if 100% availability could be achieved to allow for some problems with starting reliability. The oldest units in the system, which fire heavy oil, are in need of boiler and turbine rebuilds and electrical and controls upgrades if they are to operate at capacity factors in excess of their current 10% to 20% range.

The hydroelectric units, including both the Conowingo and Muddy Run stations, are efficient units with very high availability. Conowingo Units 1 through 7 were placed in service between 1926 and 1928. They have had major investments and upgrades over the past few years and have maintained excellent operational performance. Units 8 through 11 were placed in service in 1965 and are more efficiently designed. The station has achieved an availability factor of more than 90% in the last several years with capacity factors in excess of 30%. These numbers are higher than industry averages for similar units. The dam was improved after Hurricane Agnes in 1972 and is regularly inspected to ensure good operational performance. The Muddy Run Station is a pumped-storage station that uses low-cost electricity at night to fill a reservoir and then discharges the water during periods of peak demand to supply power to the grid. This unit was originally constructed in 1967 and has been improved during the middle 1990s to restore equipment. The production costs are higher than are those of traditional hydroelectric installations, but they are still significantly lower than fossil unit production costs.

The operation of the Conowingo Dam and Muddy Run pumped hydro facilities fall under the purview of the Susquehanna River Basin commission. The Pennsylvania Department of Environmental



Protection is looking at regulations for control of total maximum daily loadings of phosphorus and sediment, but these should not affect operations at either facility. Exelon Generation is currently cooperating with Pennsylvania and Maryland on the collection of debris washed down the river into the dam, so this consideration will not be an environmental problem either. In summary, there are no significant environmental impacts related to either the Conowingo or Muddy Run stations.

Generally the PECO Asset Group is considered to be well maintained and in excellent condition for the age of the units. Most of the generation cost in the system is driven by oil prices, which can result in high generation costs, but many of the units burn lower-cost heavy fuel oil. The environmental emissions control improvements for the total system will be limited due to the mix of units and technologies in place at the stations. The units as a group should be able to meet the environmental requirements that currently exist without significant purchases of emissions credits considering the environment improvement plans being implemented.

### 4.3 SITHE ASSET GROUP

The units in this asset group are generally newer than the fossil and hydroelectric units in the PECO Asset Group. There are a total of 24 stations in this asset group with 43 units that have an aggregate generating capability of 4,251 MW, of which Exelon Generation's share is 1,831 MW. The largest unit in this asset group is the Wyman Station, which is capable of generating 617 MW of which Sithe owns 5.89%, or 18 MW. The hydro stations represent 15 of these units but have a combined capacity of only 77.3 MW. The remaining 27 units represent 3,655 MW of capacity.

The generation technology is generally established and has been proven in power station service. Many of the units were placed in service in the late 1980s or early 1990s as Qualifying Facilities (QF). The QF designation indicates that the unit is a cogeneration unit and is given credit in the dispatch order as a "must run" unit rather than as a "merit" dispatch unit. At the time of this review, several of these QF units had lost their QF status and thus were no longer "must run" units. Since this has occurred, several of these units have changed from base-load operation to peaking. Most of these units are natural gas or light fuel oil fired, and their economic dispatch is dependent upon the price of fuel. The only potential environmental issue facing the units that operate on natural gas is $NO_X$ emissions. Most of the Sithe units have state-of-the-art air emissions control equipment installed, such as selective catalytic reduction (SCR) systems. Most of these units are likely to meet environmental emission limitations without modification.

There are several units in this portfolio that were acquired from Boston Edison by Sithe in 1998. These units are generally older steam turbine power stations fueled by heavy fuel oil. These units are located in the central Boston load area. Due to their location, these units are dispatched at much higher rates than other, more-efficient units to support grid stability. These units have comparatively higher heat rates than newer combined-cycle units, but due to lower fuel costs remain competitive. In addition to the current station use, these units are prime candidates for site expansion or unit replacement with combined-cycle units, which burn cleaner fuels such as light fuel oil or natural gas.

The hydroelectric units are generally smaller sized units placed to take advantage of water flow requirements for other purposes. Generally, the hydroelectric units are in better condition and have come on-line later than the majority of the U.S. fleet. The capacity factors for these units are low compared to larger hydro units with their own reservoirs. In general, the availability is high for all of the stations. Since these units do not have their own reservoirs, there are generally no environmental concerns with these units.



## 5. REMAINING LIFE OF UNITS

Based on the technical reviews performed, with the exception of Mystic 5, all of Exelon Generation's units were determined to have projected retirement dates beyond the 20-year time horizon of this assessment. Mystic 5 is scheduled to be retired in 2003. On that basis, with the exception of the nuclear units, a detailed determination of specific projected retirement dates was not made. Furthermore, based on our reviews, Sargent & Lundy has concluded that none of the large units in the Exelon Generation fleet is in danger of having end-of-life events over the next 5 to 10 years. Appropriate operation and maintenance (O&M) budgets and projected capital expenditures have been accounted for in the financial projections to support the expected maintenance and/or replacement of equipment necessary to keep the units operating throughout the 20-year period.

Table 5-1 summarizes the current ages, current operating license expiration dates, and projected license extension dates for the Exelon Generation nuclear fleet. License extension and nuclear decommissioning are further discussed below.

**Table 5-1—Remaining Life—Nuclear Asset Group**

| Station Name | Unit | In Service Date | Current Age | Current License | Projected License |
|---|---|---|---|---|---|

| | | | (Years) | Expiration | Extension |
|---|---|---|---|---|---|
| *ComEd Nuclear Stations:* | | | | | |
| Braidwood | 1 | 1988 | 13 | 2026 | 2046 |
| | 2 | 1988 | 13 | 2027 | 2047 |
| Byron | 1 | 1985 | 16 | 2024 | 2044 |
| | 2 | 1987 | 14 | 2026 | 2046 |
| Dresden | 2 | 1970 | 31 | 2009 | 2029 |
| | 3 | 1971 | 30 | 2011 | 2031 |
| LaSalle | 1 | 1984 | 17 | 2022 | 2042 |
| | 2 | 1984 | 17 | 2023 | 2043 |
| Quad Cities | 1 | 1973 | 28 | 2012 | 2032 |
| | 2 | 1973 | 28 | 2012 | 2032 |
| *PECO Nuclear Stations:* | | | | | |
| Limerick | 1 | 1986 | 15 | 2024 | 2044 |
| | 2 | 1990 | 11 | 2029 | 2049 |
| Peach Bottom | 2 | 1974 | 17 | 2013 | 2033 |
| | 3 | 1974 | 17 | 2014 | 2034 |
| Salem | 1 | 1977 | 24 | 2016 | 2036 |
| | 2 | 1981 | 20 | 2020 | 2040 |
| *AmerGen Nuclear Stations:* | | | | | |
| Clinton | 1 | 1987 | 14 | 2026 | 2046 |
| Oyster Creek | 1 | 1969 | 32 | 2009 | 2029 |
| Three Mile Island | 1 | 1974 | 17 | 2014 | 2034 |

### 5.1 NUCLEAR PLANT LICENSE EXTENSION

All of the Exelon Generation nuclear units are projected to pursue operating license extensions of 20 years. Assuming that the units with licenses due to expire before 2020 have their licenses renewed, all of the units will continue to operate in a baseload mode throughout the 20-year horizon of this assessment. License extension is considered to be a high priority initiative. The necessary license renewal engineering costs and capital expenditures involved to assess and upgrade the individual units have been accounted for in Sargent & Lundy's model.

### 5.2 SITE DEVELOPMENT AND EXPANSION

Sargent & Lundy's review of the Exelon Generation nuclear fleet indicated an appropriate level of management attention and funding for site development and expansion issues. In addition to the power



uprate initiatives discussed above, site development is focused primarily on plant reliability and aging issues and on spent fuel storage. Site expansion per se is not a factor at any of the nuclear plants.

Aside from the units under construction or development discussed above, no site development or expansion plans exist at any of the fossil or hydroelectric stations.

### 5.3 NUCLEAR DECOMMISSIONING

The decommissioning funding of each of Exelon Generation's operating nuclear units was reviewed to assess the adequacy of funding with respect to NRC requirements and with respect to any anticipated site-specific decommissioning costs. For each plant, Sargent & Lundy's assessment included an examination of the funds accumulated, the collection rate currently in effect, the estimated net earnings rate, and the projected fund balances at the end of each unit's current license. Sargent & Lundy assumed that the current collection rate would continue to the end of the current operating license (or that the individual states would adjust the decommissioning tariffs appropriately), and utilized a conservative net return on investment for this period. Where available, site-specific studies were reviewed for consistency with generally accepted industry averages and methodologies, with consideration for site-unique requirements.

Sargent & Lundy's review determined that the decommissioning funds are adequate with respect to the NRC-required minimum funding amounts if the units are retired at the end of their current licenses. If the licenses are extended (as expected), the funding would be more than adequate. Table 5-2 summarizes the status of decommissioning funding for Exelon Generation's operating nuclear fleet. Note that for stations where Exelon Generation has partial ownership, the decommissioning funding amounts shown represent the totals for the entire station, and not just Exelon Generation's proportionate ownership share.

**Table 5-2—Nuclear Decommissioning Funding Status ($000s)**

| Station Name | Unit | NRC Minimum Required Funding | Actual Accumulated (12/31/1999) | Projected Total at End of Current License | Surplus vs. NRC Minimum Required Amount |
|---|---|---|---|---|---|
| *ComEd Nuclear Stations:* | | | | | |
| Braidwood | 1 | 286,500 | 154,273 | 317,932 | 32,432 |
| | 2 | 286,500 | 154,449 | 483,859 | |
| Byron | 1 | 286,500 | 169,660 | 314,540 | 197,359 |
| | 2 | 286,500 | 156,560 | 447,042 | |
| Dresden | 2 | 336,500 | 288,233 | 532,252 | 28,040 |
| | 3 | 336,500 | 262,232 | 507,831 | 160,542 |
| LaSalle | 1 | 355,600 | 226,263 | 493,130 | 195,752 |
| | 2 | 355,600 | 221,885 | 571,582 | 171,331 |
| Quad Cities | 1 | 252,500 | 192,150 | 338,963 | 137,530 |
| | 2 | 252,500 | 193,209 | 374,822 | 215,982 |
| *PECO Nuclear Stations:* | | | | | |
| Limerick | 1 | 374,493 | 94,127 | 329,651 | (44,842)* |
| | 2 | 374,493 | 59,687 | 422,155 | 47,662* |
| Peach Bottom | 2 | 374,493 | 167,787 | 333,302 | (41,192)* |
| | 3 | 374,493 | 172,976 | 439,345 | 64,851* |
| Salem | 1 | 296,894 | 126,572 | 303,679 | 6,785 |
| | 2 | 296,894 | 106,047 | 316,749 | 19,855 |

| | | | | | |
|---|---|---|---|---|---|
| *AmerGen Nuclear Stations:* | | | | | |
| Clinton | 1 | 359,025 | 95,000 | 506,903 | 147,877 |
| Oyster Creek | 1 | 623,000** | 319,849 | 661,319 | 38,319 |
| Three Mile Island | 1 | 446,085** | 173,980 | 573,584 | 127,780 |

*

Total accumulated amount at end of current license meets NRC minimum requirement on a station basis.

**

An NRC minimum required amount was not identified; however, the site-specific estimate was judged to be appropriate and was used in the assessment.



## 6. OPERATION AND MAINTENANCE

Sargent & Lundy reviewed the O&M and major project expense information provided by Exelon Generation. The O&M expenses appear reasonable and adequate to meet Exelon Generation's operation, maintenance, and performance objectives. The non-fuel O&M and capital expenses for selected years in the period 2001-2020 are shown in Tables 6-1 through 6-3.

**Table 6-1—Projected Exelon Generation Non-Fuel Variable O&M Expenses 2001-2020 ($000s)**

| | 2001 | 2002 | 2003* | 2004 | 2005 | 2010 | 2015 | 2020 |
|---|---|---|---|---|---|---|---|---|
| Nuclear—ComEd | 122,482 | 129,573 | 136,347 | 140,394 | 144,650 | 167,656 | 194,379 | 225,364 |
| Nuclear—PECO | 44,264 | 46,895 | 48,505 | 50,462 | 51,984 | 60,264 | 71,272 | 82,613 |
| Nuclear—AmerGen | 18,550 | 19,489 | 20,167 | 21,321 | 22,589 | 26,968 | 31,276 | 36,249 |
| Fossil—PECO | 43,142 | 44,454 | 44,699 | 44,759 | 44,567 | 54,375 | 61,480 | 72,685 |
| Fossil—Sithe | 8,144 | 8,145 | 15,482 | 13,412 | 17,459 | 25,337 | 28,244 | 29,568 |
| Small Stations—PECO | 7 | 6 | 3 | 0 | 3 | 4 | 0 | 0 |
| Small Stations—Sithe | 352 | 386 | 929 | 1,316 | 2,293 | 3,146 | 3,187 | 3,366 |
| Fossil—Under Development | 0 | 12,182 | 33,883 | 52,972 | 57,918 | 67,361 | 77,480 | 89,191 |
| **Total Variable O&M** | **236,941** | **261,131** | **300,014** | **324,634** | **341,462** | **405,111** | **467,319** | **539,036** |

*

Assumed exercise of Exelon option to purchase remainder of Sithe equity.

**Table 6-2—Projected Exelon Generation Non-Fuel Fixed O&M Expenses 2001-2020 ($000s)**

| | 2001 | 2002 | 2003* | 2004 | 2005 | 2010 | 2015 | 2020 |
|---|---|---|---|---|---|---|---|---|
| Nuclear—ComEd | 585,882 | 640,372 | 560,942 | 610,539 | 630,067 | 758,446 | 907,785 | 1,158,311 |
| Nuclear—PECO | 300,734 | 318,252 | 318,261 | 317,807 | 333,377 | 372,249 | 425,455 | 493,230 |
| Nuclear—AmerGen | 145,400 | 145,724 | 137,967 | 126,065 | 139,072 | 138,736 | 176,401 | 206,311 |
| Fossil—PECO | 65,971 | 67,950 | 69,989 | 72,088 | 74,251 | 86,077 | 99,787 | 115,681 |
| Fossil—Sithe | 32,199 | 29,115 | 59,005 | 60,775 | 62,540 | 72,367 | 83,893 | 97,255 |
| Small Stations—PECO | 5,547 | 5,714 | 5,885 | 6,062 | 6,243 | 7,238 | 8,391 | 9,727 |
| Small Stations—Sithe | 5,763 | 5,936 | 12,252 | 12,619 | 12,998 | 15,068 | 17,468 | 20,250 |
| Fossil—Under Development | 0 | 13,022 | 44,337 | 51,162 | 54,019 | 69,426 | 88,998 | 114,129 |
| **Total Fixed O&M** | **1,141,496** | **1,226,085** | **1,208,638** | **1,257,117** | **1,312,567** | **1,519,608** | **1,808,178** | **2,214,895** |

*

Assumed exercise of Exelon option to purchase remainder of Sithe equity.

**Table 6-3—Projected Exelon Generation Capital Expenditures 2001-2020 ($000s)**

| | 2001 | 2002 | 2003* | 2004 | 2005 | 2010 | 2015 | 2020 |
|---|---|---|---|---|---|---|---|---|
| Nuclear—ComEd | 146,505 | 131,196 | 94,726 | 124,364 | 126,390 | 213,918 | 234,747 | 372,149 |
| Nuclear—PECO | 58,865 | 57,490 | 58,966 | 71,418 | 90,242 | 65,637 | 71,695 | 71,374 |
| Nuclear—AmerGen | 61,361 | 44,558 | 45,526 | 24,249 | 29,537 | 25,534 | 27,031 | 29,349 |
| Fossil—PECO | 53,447 | 49,092 | 44,982 | 39,241 | 45,198 | 36,300 | 22,383 | 27,483 |
| Fossil—Sithe | 4,674 | 3,358 | 6,003 | 16,820 | 17,092 | 14,842 | 7,858 | 10,736 |
| Small Stations—PECO | 1,761 | 990 | 603 | 1,199 | 1,235 | 1,431 | 1,659 | 1,924 |
| Small Stations—Sithe | 1,413 | 1,456 | 3,005 | 3,095 | 3,188 | 3,696 | 4,284 | 4,967 |
| Fossil—Under Development | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Corporate | 45,500 | 47,100 | 48,700 | 50,161 | 51,666 | 59,895 | 69,435 | 80,494 |
| **Total Capital Expenses** | **373,527** | **335,241** | **302,511** | **330,547** | **364,547** | **421,253** | **439,091** | **598,475** |

*

Assumed exercise of Exelon option to purchase remainder of Sithe equity.

Both the O&M and capital expenditures were grouped into fossil and nuclear categories. These were further categorized as follows:

- Nuclear units formerly owned by ComEd (Nuclear—ComEd)



- Nuclear units formerly owned by PECO Energy (Nuclear—PECO)
- Nuclear units of AmerGen (Nuclear—AmerGen)
-

- Fossil units formerly owned by PECO Energy (Fossil—PECO, which includes Exelon Generation's share of Conemaugh and Keystone stations)
- Fossil units associated with Exelon Generation's share of assets owned by Sithe (Fossil—Sithe)
- Smaller peaking stations formerly owned by PECO Energy (Small Stations—PECO)
- Smaller peaking stations of Exelon Generation's share of assets owned by Sithe (Small Stations—Sithe)
- Units presently under development (Fossil—Under Development)

Exelon Generation operates all of its large assets except the Conemaugh, Keystone, and Salem stations.

### 6.1 O&M EXPENSES

For the assets considered, O&M expenses were categorized into fixed and variable portions.

Projections of fixed O&M costs at each station are based on actual expenditures over the past five years, Exelon Generation's business plan, discussions with Exelon Generation staff, industry benchmarks, and our independent assessments. Fixed O&M costs typically include staffing, maintenance materials, supplies and expenses, and related fixed expenditures. This value includes the costs of projects which will be funded on an expense basis and outage costs. The fixed O&M cost data for each station includes general and administrative (G&A) and miscellaneous costs at the plant site, such as the plant manager's office, support staff, and overhead burdens on plant labor. Other G&A costs for Exelon Generation are offsite or shared between multiple plants and were projected separately.

Variable O&M costs are costs that are proportional to plant megawatt-hour generation, and include variable O&M, fuel, and emission costs. Variable O&M costs were estimated by the market consultant, PA Consulting, and verified by Sargent & Lundy for modeling purposes. Variable O&M costs, together with fuel costs converted to a dollar-per-megawatt basis, determine the marginal production costs and merit order dispatch of each unit. The following estimates were used:

- Coal with FGD: $4.00/MWh
- Coal without FGD: $3.00/MWh
- Steam Gas/Oil: $2.00/MWh
- Combined Cycle: $2.00/MWh
- Simple Cycle: $5.00/MWh
- Pumped Storage: $2.00/MWh

Variable O&M costs for nuclear units were not required in the analysis since, except for outage periods, they are dispatched continuously in the model. The following values were estimated by the market consultant and verified by Sargent & Lundy for presentation of O&M data in the results:

- Braidwood: $0.98/MWh
- Byron: $1.10/MWh
- Clinton: $1.89/MWh
- Dresden: $2.33/MWh



- LaSalle: $1.54/MWh
- Limerick: $0.92/MWh
- Oyster Creek: $2.24/MWh
- Peach Bottom: $1.43/MWh
- Quad Cities: $2.53/MWh
- Salem: $1.83/MWh
- Three Mile Island: $1.72/MWh

Fuel costs were calculated on the basis of an hourly dispatch simulation and the unit heat rate inputs. The resulting annual fuel consumption was multiplied by the fuel prices to determine fuel expenditures per year.

Annual $SO_2$ and $NO_X$ costs were calculated from the tons of emissions multiplied by the $/ton market price of allowances. These emission costs do not include the offsetting value of the Exelon Generation allowance pool, which is accounted for in the income model. The income model results summarized in the following subsection indicate that the net emission costs, accounting for the offsetting value of the allowance pool, are relatively insignificant throughout the evaluation period.

Additional O&M expenses were projected for the Keystone station due to installation of SCR systems on each unit. These costs are those estimated by the Keystone-Conemaugh Projects Office (KCPO) and reviewed by Sargent & Lundy.

### 6.2 CAPITAL EXPENDITURES

In addition to station capital expenditures, capital expenditures at the corporate level are also included in the financial projections. However, cash flows associated with Sithe units under construction are covered as part of the principal associated with the present financing.

Capital expenditures refer to relatively large or non-routine expenditures that typically upgrade plant performance. Projections of these costs have greater uncertainty compared with routine O&M expenses.



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## 7. ENVIRONMENTAL ASSESSMENT

### 7.1 GENERAL CONDITIONS

The environmental assessment provided in this report is based on interviews with Exelon Generation's environmental personnel and a review of available environmental documents and records.

The environmental assessment addresses issues related to air quality and water quality. All of the assets operate under valid environmental permits. There are no enforcement issues regarding operation without required permits or any other compliance issues with state and local regulatory agencies. The largest issues related to environmental compliance involve air quality. The greatest source of $SO_2$ emissions is from the coal units (Cromby 1, Eddystone 1-2, Conemaugh 1-2, and Keystone 1-2) and the units firing No. 6 fuel oil (Cromby 2, Delaware 7-8, Eddystone 3-4, Schuylkill 1, Mystic 4-7, New Boston 1-2, and Wyman 4). The greatest source of $NO_X$ emissions is from units with high generating output without selective catalytic reduction (SCR), including coal-fired and oil-fired steam units and older combined-cycle units.

Sargent & Lundy did not find evidence of major contamination on the Exelon Generation sites.

### 7.2 AIR POLLUTION

#### 7.2.1 $SO_2$ Emissions

Eddystone Units 1 and 2, Conemaugh Units 1 and 2, Keystone Units 1 and 2, and Cromby Unit 1 comprise the coal-fired units considered among the assets. Each of these units, with the exception of Keystone Units 1 and 2, is equipped with a scrubber to control emissions of sulfur oxides.

The Keystone Station Plan expects that Keystone will require an average of 167,151 $SO_2$ allowances annually from 2000 to 2005, resulting in an average deficit of 108,907 allowances. The allowances provided by the owners will make up the difference between the allocated allowances and the allowances actually consumed by the plant. Over the same period, Conemaugh Station expects to operate with a surplus of 46,250 allowances. All of the owners of Keystone are also owners of Conemaugh and can be expected to use their surplus allowances toward the operation of Keystone. However, even if all such allowances are applied, there will still be an average deficit of 62,657 allowances, which will need to be purchased in the allowance market or obtained from other sources available to the owners. Exelon Generation maintains a bank of allowances to meet its share of compliance obligations through 2008.

Wyman 4, an oil-fired unit in Maine, is a Phase II unit under Title IV of the Clean Air Act (the Acid Rain Program), and has been provided with 6,274 tons of allowances for the years 2000-2009. In 1999, the unit had emissions of 6,515 tons of $SO_2$. Assuming that $SO_2$ emissions for the year 2000 are equal to those for 1999, the facility will have a shortfall of 241 allowance credits. Procuring lower sulfur No. 6 fuel oil could be an alternative method of controlling emissions.

None of the other Exelon Generation units appear to have concerns related to $SO_2$ emissions.

#### 7.2.2 $NO_X$ Emissions

Conemaugh 1 and 2, Keystone 1 and 2, and Cromby 1 have been equipped with low-$NO_X$ burners (LNB) and separated over-fire air (OFA). The installation of SCR systems is planned for Keystone 1 and 2. This system will generate sufficient credits to meet allowance requirements of the Conemaugh units.

$NO_X$ control systems have been installed on all coal-fired units and further additions are planned.

Eddystone 1's boiler is equipped with LNB and OFA. Installation of a selective noncatalytic reduction (SNCR) system would reduce $NO_X$ emissions by about 30%. Eddystone 2's boiler is equipped



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with LNB and OFA. Installation of an SNCR system would reduce $NO_X$ emissions by about 30%. Eddystone 3's boiler is equipped with LNB and OFA. Eddystone 4's boiler is equipped with OFA.

$NO_X$ emissions from Mystic Units 4-7 are controlled with LNB. Although the station holds enough $NO_X$ emission reduction credits (ERCs) to provide for the first five years of the proposed new units, it is likely that the station will have a shortage of $NO_X$ credits once Phase III of the Massachusetts $NO_X$ Budget Plan begins. Assuming that Unit 7 will continue to operate as it did in 1998 and 1999, $NO_X$ emissions from Unit 7 will be approximately 1,000 to 1,100 tons per year (tpy). $NO_X$ emissions from a 1,600-MW combined-cycle combustion turbine plant will be approximately 350 tpy. $NO_X$ emissions from Units 4, 5, and 6 (assuming a limit of 720 hours each per year) will continue to be approximately 100 tpy each. Total $NO_X$ emissions from the station, after construction of the new units, will be approximately 1,650 to 1,750 tpy, resulting in a shortage of approximately 650 to 750 $NO_X$ allowances per year. Estimates provided by Exelon Generation show that Unit 7 will not continue to operate at historic values and will fall off after Units 8 and 9 come online. At the projected lower capacity factors, it is unlikely that Unit 7 would require the installation of an SCR to control $NO_X$ emissions.

Wyman 4 has combustion controls (low excess air) to control $NO_X$ emissions. In 1999, Unit 4 emitted 2,541 tons of $NO_X$ at an emission rate of 0.25 pounds per million Btu (lb/mmBtu). Pursuant to Maine's $NO_X$ Reasonably Available Control Technologies (RACT) regulations, a large unit must meet a $NO_X$ emission rate of 0.2 lb/mmBtu during the ozone season and 0.3 lb/mmBtu for the remainder of the year. If Maine adopts more stringent $NO_X$emission regulations, or develops a $NO_X$ Budget Rule, it is likely that the $NO_X$ emission requirements would become more stringent. At that time, alternatives for $NO_X$ reduction or purchasing of $NO_X$ credits would have to be studied.

#### 7.2.3 Water Pollution

Braidwood Station is only capable of delivering approximately one-half of the design blowdown flow from the cooling lake. As a result, the station cannot meet the cooling lake discharge pH requirements during the summer months because the pond cycles up to a pH of 9.1 (NPDES permit limit is 6.0-9.0). The station is currently considering the feasibility of overflowing the cooling lake as an alternate means of blowing down the lake. This overflow will require a revision to the NPDES permit as well as additional environmental investigations. It is our judgment that this problem is solvable and should not affect the ability of the station to operate both units at full capacity now or in the future.

Cooling water intake flow to Dresden Station comes from the Kankakee River, and cooling water discharge flow from the station is released to the Illinois River. The site incorporates a large cooling lake to cool the discharge flow from the station before it is released to the Illinois River. Thermal limits on the discharge flow from the cooling lake have caused the units to undergo major derates during hot summer conditions in previous years. To alleviate this condition, mechanical draft cooling towers were installed on the flow canals leading to and from the cooling lake. In hot summer conditions, these cooling towers are used in conjunction with the cooling lake to cool the station discharge flow to meet the thermal limits on the flow released to the Illinois River. The power uprating of both units will put an additional burden on the cooling tower—cooling lake system during hot summer conditions. Because of this uprating, additional cooling towers will be added to the site in 2001. Their costs are reflected in our projections.

The LaSalle County site contains a cooling lake to cool the water discharged from the condensers of both units. Within this lake is the ultimate heat sink for both units. Makeup water for the cooling lake is pumped from the Illinois River. The Illinois Department of Natural Resources manages the lake as a sport fishery.

A recent power uprate and a major increase in the capacity factor of each LaSalle unit have added significant "steady-state" heat load to the cooling lake. The performance of the lake was computer-modeled assuming "worst-case" weather conditions. The results showed that the condenser inlet flow



coming from the coolest portion of the lake would exceed the temperature limitation on the ultimate heat sink. This lake temperature would also be detrimental to the sport fish in the lake. The same lake model was run assuming a 50-MW uprate in the power level of each unit. These results showed that in order for the lake to stay below its temperature limitation, the units would have to take a major derating at certain times during the "worst-case" weather conditions.

These results indicate that the LaSalle cooling lake, as it currently exists, is operating near its capacity and that future unit uprates may not be feasible without alterations to the lake to increase its cooling capability. No modifications to the cooling lake are included in our projected costs.

The Quad Cities units take their cooling water from the Mississippi River and discharge the warm water back into the Mississippi River through diffuser pipes located near the river bottom. The units' emergency core cooling system also has its water inlet from the Mississippi River and discharges its waters back to the Mississippi River. Quad Cities Station may be affected by the proposed rules for cooling water intake structures and for limits on thermal discharges, established under Section 316(a) of the Clean Water Act (CWA), especially because of the uprating of the units. The Quad Cities Station has additional diffuser capability for its cooling water discharge to the Mississippi River. It would be possible to activate these additional diffusers; however, opening the diffusers underwater will require an extended outage while this work is being performed. This installation could have a capital impact of approximately $12-14 million, which is not included in our projected costs.

The Clinton unit uses a 5,000-acre reservoir (Lake Clinton) as the source of its cooling water. This lake is managed by the Illinois Department of Natural Resources, and used by them as a fishery. The site's NPDES permit restricts the plant to a maximum discharge temperature (instantaneous) of 110.7°F and no more than 90 days operations at temperatures of 99°F.

The planned capacity uprating of the Clinton reactor will either necessitate an increase in the cooling water flow from the plant, or an increase in the discharge temperature of the water. In order to stay in compliance with its NPDES permit or proposed new rules for thermal discharge and water intakes, it may be necessary to perform capital modifications of the cooling water system. This determination will only be made once operation with capacity uprated has begun. Sargent & Lundy estimates a maximum cooling water modification cost in 2001 dollars of $20 million. Due to the uncertainty associated with the decision to perform the modification, this sum has not been included in the financial projections.

**7.2.4 Other Contamination and Related Remediation Expenditures**

There are no immediate major environmental remediation projects at any of the facilities. While certain facilities may require remediation in the future, such activities will not be performed until the facilities are no longer used for electric generation. Since all facilities are planned to be used throughout the study period, no remediation costs have been included in the financial projections.

**7.2.5 Retrofitting Expenditures**

The following retrofitting expenditures were included in the projections:

- Keystone Station SCR system installation ($36.7 million over the period 2002-2004). Additional operating costs have also been included in the projections.
- Dresden Station additional cooling towers ($15.5 million in 2001).
- The estimated capital cost of equipping Eddystone 1 with SNCR is about $3.25 million. The fixed O&M costs for the SNCR are estimated to be $107,000 and the variable O&M are estimated to be $897,000.



- The estimated capital cost of equipping Eddystone 2 with SNCR is about $3.25 million. The fixed O&M costs for the SNCR are estimated to be $107,000 and the variable O&M are estimated to be $897,000.

If the capacity factor of Mystic 7 does not fall off as projected, then the installation of an SCR on Mystic 7 will reduce $NO_X$ emissions from Unit 7 to approximately 110 tpy, and reduce total station $NO_X$ emissions to approximately 760 tpy. The estimated cost of equipping Mystic Unit 7 with an SCR is about $41 million. Fixed O&M costs for the SCR are estimated to be approximately $310,000 and the average annual variable O&M costs are estimated to be $2,585,000. All fixed and variable O&M increments are covered by the amounts assumed in the projections.



## 8. FINANCIAL PROJECTIONS

Sargent & Lundy developed a financial model to project Exelon Generation's performance in connection with its financing proposal. The financial model calculates annual income, cash flow, and debt service coverage ratios for Exelon Generation on the basis of projections of revenues, expenses, capital expenditures, taxes, and debt service. Revenue projections were provided by the market consultant according to model simulations of plant generation and forward pricing in 13 market regions. Sargent & Lundy provided technical input assumptions for this market model and made estimates of operating, maintenance, and capital expenditures for the Exelon Generation financial model. Projections of taxes and debt service were calculated on the basis of information provided by Exelon Generation.

Sargent & Lundy took the market consultant's projections, which were in real dollars, and converted them to nominal dollars using an annual inflation rate of 3.0%.

Sargent & Lundy prepared financial projections for Exelon Generation from 2001 to 2020. The projections include a base case and three sensitivity analyses. The results of the base-case financial projections are shown below for selected years during the study period:

**Table 8-1—Financial Projections ($000s)**

| | 2001 | 2002 | 2003 | 2004 | 2005 | 2010 | 2015 | 2020 |
|---|---|---|---|---|---|---|---|---|
| *Revenues* | | | | | | | | |
| Revenues from Market Sales | 1,757,543 | 1,979,292 | 3,163,719 | 3,014,162 | 2,581,089 | 6,324,760 | 9,085,546 | 10,475,045 |
| Revenues from Affiliate Sales | 4,218,176 | 4,317,097 | 4,540,600 | 4,653,003 | 3,602,327 | 1,758,771 | 0 | 0 |
| Steam Revenues | 2,016 | 2,076 | 2,138 | 2,203 | 2,269 | 2,630 | 3,049 | 3,535 |
| **Total Revenues[1]** | **5,977,735** | **6,298,465** | **7,706,458** | **7,669,368** | **6,185,685** | **8,086,161** | **9,088,595** | **10,478,579** |
| *Operating Expenses* | | | | | | | | |
| Operation and Maintenance | 1,168,028 | 1,253,216 | 1,350,517 | 1,434,366 | 1,492,369 | 1,759,013 | 2,067,820 | 2,511,370 |
| Fuel Costs | 686,649 | 682,813 | 1,509,421 | 1,560,260 | 1,500,798 | 1,871,580 | 2,175,225 | 2,497,780 |
| Purchased Power | 1,715,123 | 2,042,307 | 2,455,363 | 2,337,444 | 783,934 | 681,355 | 510,403 | 490,600 |
| $SO_2$ Emission Costs | 9,602 | 16,728 | 24,359 | 23,565 | 25,144 | 35,958 | 40,295 | 46,730 |
| $NO_X$ Emission Costs | 6,390 | 6,574 | 25,662 | 27,510 | 30,350 | 37,780 | 41,696 | 47,702 |
| $SO_2$ Allowance Credits | (5,114) | (9,263) | (23,796) | (26,914) | (30,518) | (38,526) | (44,662) | (51,775) |
| $NO_X$ Allowance Credits | (5,974) | (6,154) | (26,923) | (27,730) | (28,562) | (33,111) | (38,385) | (44,499) |
| **Total Operating Expenses** | **3,574,704** | **3,986,221** | **5,314,605** | **5,328,501** | **3,773,515** | **4,314,049** | **4,752,391** | **5,497,908** |
| *Administrative, General, and Other Expenses* | | | | | | | | |
| Insurance, Administrative, General, and Allocated Central Office Costs | 544,026 | 555,912 | 576,242 | 594,330 | 609,881 | 704,967 | 817,544 | 948,121 |
| Property Taxes | 113,000 | 109,000 | 138,679 | 140,431 | 140,640 | 138,239 | 139,029 | 139,919 |
| Decommissioning Funding | 75,117 | 75,731 | 75,731 | 75,731 | 75,731 | 61,156 | 32,689 | 30,421 |
| **Total Administrative and General Expenses** | **732,143** | **740,643** | **790,652** | **810,492** | **826,252** | **904,362** | **989,262** | **1,118,462** |
| Net Earnings on Sithe Equity[2] | 8,016 | 3,814 | 0 | 0 | 0 | 0 | 0 | 0 |
| Net Earnings on AmerGen Equity[3] | 88,144 | 69,435 | 88,461 | 94,727 | 83,124 | 179,638 | 204,335 | 243,769 |
| Operating Income[4] | 1,767,048 | 1,644,849 | 1,689,662 | 1,625,102 | 1,669,042 | 3,047,388 | 3,551,276 | 4,105,979 |
| Capitalized Costs | 306,079 | 285,868 | 256,985 | 306,298 | 335,010 | 395,719 | 412,061 | 569,126 |
| Total Changes in Working Capital | 0 | (8,556) | 4,940 | (5,756) | 4,646 | 9,368 | 9,441 | (2,419) |
| Cash Available for Debt Service[5] | 1,460,969 | 1,367,537 | 1,427,737 | 1,324,560 | 1,329,386 | 2,642,301 | 3,129,774 | 3,539,272 |
| Debt Service Coverage Ratio | 31.75x | 19.62x | 4.31x | 4.03x | 4.08x | 7.68x | 12.45x | 14.08x |



Notes:

1 Projected revenues do not include the marketing operations of the Power Team. These activities include utilizing spot market purchases as opportunities arise to reduce supply costs under the ComEd and PECO supply agreements and trading and hedging activities. We anticipate these activities would increase the revenues and purchase power costs above the levels indicated herein.

2 Revenues less Expenses for the 49.9% Sithe equity share. After January 1, 2003, Sithe Revenues and Expenses are consolidated with Exelon Generation's other plants.

3 Revenues less Expenses for the 50% AmerGen equity share. O&M expenses shown do not reflect AmerGen O&M expenses. These are reflected in the Net Earnings on AmerGen Equity.

4 Revenues less Operating Expenses less Administrative and General Expenses, plus Net Earnings on Equity.

5 Operating Income less Capitalized Costs less Changes in Working Capital.

New debt in the amount of $821 million and $2.73 billion is assumed to be consolidated by the end of 2001 and 2002, respectively. The drop in Debt Service Coverage Ratio during the period 2001-2003 reflects the beginning of principal and interest payments on these sums in 2002 and 2003, respectively. The structure of this debt is covered in Section 8.1.1.

## 8.1 BASE CASE ASSUMPTIONS FOR MAJOR CATEGORIES

### 8.1.1 Financing Assumptions

Annual principal and interest payments for Exelon Generation debt are incorporated into the model. As of the beginning of 2001, there was $98,325,000 in PECO Energy Company fixed rate bonds that will transfer to Exelon Generation in the near term, and $247,850,000 in variable and adjustable rate bonds that will also transfer to Exelon Generation in the near term. There is also $700,000,000 in full-recourse debt associated with the 49.90% Sithe ownership share, and $900,000,000 in full-recourse debt associated with the acquisition of the remaining 50.10% share by 2003. Sithe has $1,800,000,000 in debt that will transfer to Exelon Generation in 2003 and remain as non-recourse to Exelon Generation. The amounts, interest rates, transfer dates, and maturity dates for each of the bond tranches are summarized in Table 8-2. The maturity dates for all bond tranches are beyond the 20-year evaluation period. This is representative of corporate finance debt in which bonds are refinanced and reissued upon maturity.



**Table 8-2—Financing Assumptions**

| Bonds Outstanding | Amount ($) | Interest Rate | Type | Transfer Date | Maturity Date | Repayment Period (years) |
|---|---|---|---|---|---|---|
| *PECO Energy Company—Fixed Rate Bonds* | | | | | | |
| Montgomery Co. Industrial Dev. Auth. | 68,795,000 | 6.700% | Fixed rate | 12/1/01 | 12/1/21 | 20.000 |
| Montgomery Co. Industrial Dev. Auth. | 29,530,000 | 6.625% | Fixed rate | 6/1/02 | 6/1/22 | 20.000 |
| Subtotal | 98,325,000 | | | | | |
| *Exelon Generation Company—Variable and Adjustable Rate Bonds* | | | | | | |
| Delaware Co. Industrial Dev. Auth. | 39,235,000 | 3.05% | Variable rate | 4/25/01 | 4/1/21 | 20.000 |
| Delaware Co. Industrial Dev. Auth. | 24,125,000 | 4.500%* | Variable rate | 1/1/01 | 1/1/22 | 21.000 |
| York Co. Industrial Dev. Auth. | 18,440,000 | 4.500%* | Variable rate | 1/1/01 | 1/1/22 | 21.000 |
| Montgomery Co. Industrial Dev. Auth. | 82,560,000 | 4.500%* | Variable rate | 1/1/01 | 6/1/29 | 28.417 |
| Montgomery Co. Industrial Dev. Auth. | 13,340,000 | 4.500%* | Variable rate | 1/1/01 | 6/1/29 | 28.417 |
| Montgomery Co. Industrial Dev. Auth. | 34,000,000 | 4.500%* | Variable rate | 1/1/01 | 3/1/34 | 33.167 |
| Montgomery Co. Industrial Dev. Auth. | 13,150,000 | 3.10% | Variable rate | 4/25/01 | 10/1/34 | 33.000 |
| Salem Co. Industrial PC Fin. Auth. | 23,000,000 | 5.200% | Adjustable rate | 1/1/01 | 3/1/25 | 24.167 |
| Subtotal | 247,850,000 | | | | | |
| *Sithe Acquisition* | | | | | | |
| Initial 24.95% Share—Issue 1 | 350,000,000 | 7.500% | Fixed rate | 5/1/01 | 5/1/21 | 20.000 |
| Initial 24.95% Share—Issue 2 | 350,000,000 | 7.750% | Fixed rate | 5/1/01 | 5/1/21 | 20.000 |
| Additional 25.05% Share—Issue 1 | 450,000,000 | 7.500% | Fixed rate | 1/1/03 | 1/1/23 | 20.000 |
| Additional 25.05% Share—Issue 2 | 450,000,000 | 7.750% | Fixed rate | 1/1/03 | 1/1/23 | 20.000 |
| Existing Sithe Debt | 151,000,000 | 8.500% | Fixed rate | 1/1/03 | 1/1/08 | 5.000 |
| Existing Sithe Debt | 409,000,000 | 9.000% | Fixed rate | 1/1/03 | 1/1/14 | 11.000 |
| Existing Sithe Debt | 1,150,000,000 | 9.000% | Fixed rate | 1/1/03 | 1/1/23 | 20.000 |
| Existing Sithe Debt | 90,000,000 | 9.680% | Fixed rate | 1/1/03 | 1/1/23 | 20.000 |
| Subtotal | 3,400,000,000 | | | | | |
| Total | 3,746,175,000 | | | | | |

* Interest rates for variable bonds are estimated by averaging the results of the remarketing agents for the immediately preceding year.

### 8.1.2 Revenues

Based upon the technical inputs and assumptions regarding the performance of other new and existing plants in the region, regional fuel prices, load demand profiles, and other assumptions, the



market consultant developed forecasts of operations and revenues for Exelon Generation's plants. These include market energy revenues, market capacity revenues, revenues from contract sales, and steam revenues. The major results of the market model that are used in the financial model include the unit generation, emissions, variable O&M costs, and revenues.

Annual generation from the nuclear units is based on the capacity factor inputs to the market model. This methodology is unlike the capacity factor methodology for all other units, which calculates capacity factor as model outputs.

Over 70% of the total megawatt-hour generation of the owned assets in the Exelon Generation (Base Case Scenario) is by the nuclear units, which have average capacity factors between 86% to 93%. Of the fossil units, the coal units (Cromby 1, Eddystone 1-2, Conemaugh 1-2, and Keystone 1-2) tend to have the highest capacity factors, typically between 65% and 80%. The combined-cycle units (Fore River 3, Mystic 8-9, Independence 1-2, Heritage, Batavia, Massena, Ogdensburg, and Sterling) have the next highest capacity factors, typically between 40% and 80%. Peaking units, which are typically simple-cycle gas turbines and diesel units with high heat rates, generally have capacity factors below 1%.

Market energy and capacity revenues generated from each Exelon Generation unit are based on the forecasted unit dispatch and market prices for capacity and energy. Forward prices are a function of the system load demand profiles and the marginal production costs of all units in the market. Hourly power prices are based on the merit order dispatch of units available to meet the hourly demand.

Revenues from contract sales arise because, in some cases, power purchase agreements are in place that supersede the dispatch and pricing assumptions in the market model. The market consultant accounted for the system-wide impact of these contracts in its market model runs. In addition, the market consultant determined the effect of each contract on Exelon Generation's operating income. The detailed derivation of these contract valuations is discussed in the market consultant's report.

The market consultant estimated the effect of Exelon Generation contracts involving third-party owned plants totaling approximately 13,900 MW. The contracts were treated as call options where the fixed contract payments represent the call option price and the variable contract costs represent the strike price. The decision to exercise the option is based on an hourly comparison between the strike price and the market energy price, taking into account minimum run time and minimum take constraints. For each contract year, the operating income is affected by the market energy and capacity revenues, less the contract costs (option costs). The revenue portion of these contracts was included, along with the capacity and energy revenues from Exelon Generation's plants, in the revenues from market sales. The expense portion was included in the purchased power expenses.

In addition, power is sold to ComEd and PECO under transition power sales contracts until 2004 and, respectively, 2010. For each contract year, the operating income is affected by the PPA sales revenue less the capacity and energy costs associated with the Exelon Generation's plants supplying the power. The revenue portion of these contracts was included in the revenues from affiliate sales. The expense portion was included as a net reduction in the revenues from market sales.

Steam revenues are associated with steam produced at the Fairless Hills plant that is sold to an adjacent USX steel finishing plant.

**8.1.3 Operating Expenses**

Operations and Maintenance costs for Exelon Generation include the stations' fixed and variable non-fuel O&M costs, as well as fuel, purchased power, and environmental costs.

The fixed O&M cost data for each station include general and administrative (G&A) and miscellaneous costs at the plant site, such as the plant manager's office, support staff, and overhead burdens on plant labor. Projections of fixed O&M costs at each station were based on a consideration



of actual expenditures over the past five years, Exelon Generation business plan data, discussions with Exelon Generation staff, industry benchmarks, and our independent assessments. Fixed O&M costs typically include staffing, maintenance materials, supplies and expenses, and related fixed expenditures.

Variable costs are costs that are proportional to plant megawatt-hour generation and include variable O&M, fuel, and emission costs. Variable O&M costs were calculated in the market model on the basis of the $/MWh inputs and the unit generation.

Fuel costs were calculated on the basis of an hourly dispatch simulation and the unit heat rate inputs. The resulting annual fuel consumption was multiplied by the fuel prices to determine fuel expenditures per year.

Purchased Power is the cost of power purchased from third parties.

Annual $SO_2$ and $NO_X$ emission costs were calculated from the tons of emissions multiplied by the $/ton market price of allowances. These emission costs are offset in the financial model by the value of the Exelon Generation $SO_2$ and $NO_X$ allowance pools.

**8.1.4 General, Administrative, and Other Expenses**

Allocated central office costs for Exelon Generation are shared among the multiple plants. These other G&A costs are represented as shown above in the financial model.

Property taxes are those required to be paid on the property that Exelon Generation's assets occupy.

Nuclear plant decommissioning costs are represented in the model by the required annual funding amounts. The required annual funding amounts were determined in various evaluations performed by Exelon Generation and consultants. Sargent & Lundy independently verified that the amounts indicated in those evaluations are sufficient to accumulate an adequate reserve by the normal unit retirement date.

**8.1.5 Net Earnings on Sithe Equity**

The Net Earnings on Sithe Equity was calculated by the operating income associated with the 49.90% ownership share of Sithe during 2001 and 2002. Beginning in 2003, when Exelon Generation's ownership share of Sithe is projected to increase to 100%, the Sithe revenues and expenses are consolidated with the other Exelon Generation plants.

**8.1.6 Net Earnings on AmerGen Equity**

The Net Earnings on AmerGen Equity was calculated by the operating income associated with the 50.00% ownership share of AmerGen. The AmerGen ownership share does not change during the evaluation period.

**8.1.7 Operating Income**

In all cases, Operating Income was calculated as Revenues less the sum of Operating Expenses, G&A, and Other Expenses.

**8.1.8 Capitalized Costs**

Capitalized Costs are the amounts of capital expenses required at the plants less the amounts of capital expenses for Sithe assets until 2003 and less the amounts of capital expenses for AmerGen assets for each year through the length of the study period. Capital expenses for these assets during these time periods will not be funded by Exelon Generation. Funds will come from other sources.



**8.1.9 Total Changes in Working Capital**

Total Changes in Working Capital arise from changes in fuel and other inventories as well as changes in receivables and payables accounts due to varying amounts of generation as time goes on.

### 8.1.10 Cash Available for Debt Service

Cash Available for Debt Service was calculated as Operating Income less Capitalized Costs less Total Changes in Working Capital.

### 8.1.11 Debt Service Coverage Ratios

Debt Service Coverage Ratios are equal to the Cash Available for Debt Service divided by the annual Debt Service, the latter equal to Interest Expenses plus Principal Repayment. Debt Service Coverage Ratios are unitless quantities.

## 8.2 SENSITIVITY ANALYSES

The financial model calculates annual income, cash flow, and debt service coverage ratios for Exelon Generation on the basis of the projected revenues, expenses, capital expenditures, taxes, and debt service.

Sensitivity cases were developed by the market consultant to measure the impact of external market conditions on the revenues generated by Exelon Generation. Three sensitivity cases were run in addition to the Base Case:

- The High Fuel Price Case uses natural gas prices in constant dollar terms that remain unchanged from their historically high 2001 values.
- The Low Fuel Price Case uses natural gas prices in constant dollar terms that are lower by $0.50/mmBtu from their 2001 values, escalating thereafter at the Base Case rates.
- The Overbuild Case includes merchant plant capacity in addition to the amount of new capacity assumed for the Base Case. This additional merchant plant capacity was added in 2004 to the following regions:

| | | | |
|---|---|---|---|
| — | PJM | 4,160 | MW |
| — | NEPOOL | 1,040 | MW |
| — | NYPP | 2,080 | MW |
| — | MAIN | 5,200 | MW |

Coverage ratios and cash available for debt service for 2001-2010 for the base case and the various sensitivity cases are summarized in Table 8-2 and Table 8-3 as follows:

**Table 8-2—Debt Service Coverage Ratios (x)**

| | Base Case | High Fuel Price Case | Low Fuel Price Case | Overbuild Case |
|---|---|---|---|---|
| 2001 | 31.75 | 31.68 | 29.75 | 31.70 |
| 2002 | 19.62 | 21.90 | 18.53 | 19.70 |
| 2003 | 4.31 | 5.32 | 4.12 | 4.35 |
| 2004 | 4.03 | 5.59 | 3.85 | 3.86 |
| 2005 | 4.08 | 6.57 | 4.20 | 3.33 |
| 2006 | 5.02 | 7.89 | 5.12 | 4.04 |
| 2007 | 6.31 | 9.32 | 6.30 | 5.08 |
| 2008 | 5.99 | 9.50 | 5.57 | 4.48 |
| 2009 | 7.28 | 10.70 | 6.80 | 5.17 |
| 2010 | 7.68 | 11.13 | 7.00 | 5.16 |



**Table 8-3—Cash Available for Debt Service ($000s)**

| | Base Case | High Fuel Price Case | Low Fuel Price Case | Overbuild Case |
|---|---|---|---|---|
| 2001 | 1,460,969 | 1,458,040 | 1,369,174 | 1,458,949 |
| 2002 | 1,367,537 | 1,526,312 | 1,291,069 | 1,373,024 |
| 2003 | 1,427,737 | 1,761,671 | 1,365,294 | 1,440,082 |
| 2004 | 1,324,560 | 1,837,886 | 1,265,017 | 1,267,545 |
| 2005 | 1,329,386 | 2,141,828 | 1,369,953 | 1,085,682 |
| 2006 | 1,623,008 | 2,551,524 | 1,655,849 | 1,308,462 |
| 2007 | 2,024,728 | 2,991,334 | 2,020,561 | 1,629,925 |
| 2008 | 2,135,190 | 3,384,055 | 1,986,266 | 1,595,962 |
| 2009 | 2,550,634 | 3,746,798 | 2,380,428 | 1,809,162 |
| 2010 | 2,642,301 | 3,830,637 | 2,408,360 | 1,775,655 |

The ratios increase significantly after 2010 through the end of the study period, as existing debt is retired. In the High Fuel Price Case, energy prices in Exelon Generation's market regions tend to increase as a result of higher natural gas prices. This trend is advantageous for Exelon Generation, which has a high proportion of nuclear and coal units that can generate higher energy revenues. Conversely, in the Low Fuel Price Case, energy prices in Exelon Generation's market regions tend to decrease, thereby reducing Exelon Generation's energy revenues. In the Overbuild Case, market prices for capacity and energy prices are suppressed as a result of excess capacity in the Exelon Generation's market regions. In all cases, however, the coverage ratios indicate high levels of potential debt-carrying capacity for Exelon Generation.

## 9. CONCLUSIONS

Included below are the principal opinions we have reached regarding Exelon Generation and its assets. For a complete understanding of the opinions and the assumptions on which they are based, the Independent Engineer's Report should be consulted in its entirety. Sargent & Lundy's opinions are as follows:

1. Sargent & Lundy believes the assets to be well maintained and in generally good condition when compared to facilities of similar ages. With the continuation of existing maintenance practices and procedures, as well as the capital expenditures that we have projected, the assets should be able to remain in service for the life of the study period.

2. Sargent & Lundy reviewed and provided data that were used as inputs to the market consultant's market dispatch model. The key input data, such as claimed capacity, equivalent forced outage rate, scheduled outage rate, and heat rate, were generally reasonable, except as noted below in Paragraph 3.

3. Sargent & Lundy believes that some of Exelon Generation's goals related to nuclear station scheduled outage lengths may be too aggressive. In the financial projections, Sargent & Lundy included conservative outage lengths to accommodate its concerns.

4. The normal claimed capacities of the assets are based on values reported to PJM, MAIN, and other control regions. With continued maintenance and operating procedures and practices, these claimed capacities would not be expected to change over the study period, except those for nuclear units where capacity uprates are currently in progress or are planned. Sargent & Lundy does not foresee any impediment to the planned capacity uprates.

5. The full load rates for the assets that were provided to the market consultant for use in its model were developed from data provided by Exelon Generation. This information was reviewed and amended by Sargent & Lundy as necessary to reflect projections for unit thermal efficiency, which were based on historical performance. The heat rates reflected in the financial projections accurately account for the current and future conditions and capabilities of the assets during the study period.

6. All assets are technically capable of supporting the capacity factors projected by the market consultant. Nuclear capacity factors were adjusted to account for longer scheduled outage lengths as described above.

7. The fixed non-fuel operating and maintenance costs employed in the model are based on Exelon Generation's projections for non-fuel O&M projected budgets. These budgets are consistent with the staffing and operating plans and recent historical expenses for the assets, except in regard to projected staffing levels at Exelon Generation's nuclear stations. Sargent & Lundy believes the staffing level targets proposed by Exelon Generation may be too aggressive and too difficult to achieve. In the financial projections, Sargent & Lundy employed its conservative estimates for projected staffing levels and adjusted fixed operating and maintenance costs accordingly.

8. Sithe has five units under development at three sites: Fore River 3, Heritage 1 and 2, and Mystic 8 and 9. The Fore River and Mystic units are projected to employ Mitsubishi Heavy Industries (MHI) 501 G combustion turbines in combined-cycle mode. This machine has a limited operating history, and there is some risk associated with employing the new-design, high-technology equipment. However, Sargent & Lundy believes that design, manufacturing, and startup problems associated with this machine will be resolved with prototype units, which are already in operation, and that it is reasonable to expect that these combustion turbines will provide satisfactory service. The General-Electric-designed Heritage Plant is proposed to employ the new General Electric 7H



machine. Presently, Sithe's financial exposure is quite limited and will only acquire an ownership share of the plant after the first year of commercial operation.

9. Exelon Generation provided the required funding amounts allocated for nuclear decommissioning. Sargent & Lundy independently verified that the amounts indicated are sufficient to accumulate an adequate reserve upon the various normal unit retirement dates.

10. The assets are in compliance with current permit requirements. Exelon Generation has an extensive environmental program that is able to recognize and anticipate environmental issues.

11. The are no immediate major environmental remediation projects at any of the facilities. While certain facilities may require remediation in the future, such activities will not be performed until the facilities are no longer used for electric generation. Since all facilities are planned to be used throughout the study period, no remediation costs have been included in the financial projections.

12. Station procedures are similar to those encountered in Sargent & Lundy's experience. Sargent & Lundy is confident that Exelon Generation complies with all regulations.

13. The base case financial projections resulted in average cash available for debt service during the study period of $1,813 million (in 2001 dollars). The cash available ranged from a minimum of $1,147 million in 2005 to a maximum of $2,140 million in 2011 (in 2001 dollars). The average Debt Service Coverage Ratio (DSCR) over the study period was 10.77x. The minimum DSCR was 4.03x.

14. On average, the financial projections are most sensitive to the assumptions in the Low Fuel Price Case. The average DSCR over the study period was 9.84x, while the minimum was 3.85x. However, the minimum DSCR for the Overbuild Case was lower than the value in the Low Fuel Price Case, at 3.33x. The average DSCR was, however, higher, at 10.02x. The High Fuel Price Case resulted in higher DSCRs than the Base Case in all years except the first.

## Appendix A

## Financial Projections

### Sargent & Lundy
### Table 1—Income Summary (Base Case)
### (Current $'s)

| | Projected (Current $'s) | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 |
| Inflation | 3.00% | 3.00% | 3.00% | 3.00% | 3.00% | 3.00% | 3.00% | 3.00% | 3.00% | 3.( |
| Inflation Factor | 1.0300 | 1.0609 | 1.0927 | 1.1255 | 1.1593 | 1.1941 | 1.2299 | 1.2668 | 1.3048 | 1.34 |
| **Revenues ($)** | | | | | | | | | | |
| Revenues from Market Sales | 1,757,543,478 | 1,979,291,560 | 3,163,719,493 | 3,014,162,066 | 2,581,089,095 | 2,668,351,972 | 5,238,325,078 | 5,595,062,462 | 6,000,748,894 | 6,324,759,8 |
| Revenues from Affiliate Sales | 4,218,176,000 | 4,317,096,960 | 4,540,600,033 | 4,653,003,372 | 3,602,327,170 | 3,850,878,805 | 1,638,678,936 | 1,677,718,595 | 1,718,042,815 | 1,758,771,1 |
| Steam Revenues | 2,015,710 | 2,076,181 | 2,138,467 | 2,202,621 | 2,268,699 | 2,336,760 | 2,406,863 | 2,479,069 | 2,553,441 | 2,630,0 |
| Total Revenues | 5,977,735,188 | 6,298,464,701 | 7,706,457,993 | 7,669,368,058 | 6,185,684,964 | 6,521,567,538 | 6,879,410,878 | 7,275,260,126 | 7,721,345,150 | 8,086,161,0 |
| **Operating Expenses ($)** | | | | | | | | | | |
| Operation and Maintenance | 1,168,028,249 | 1,253,216,321 | 1,350,517,340 | 1,434,365,694 | 1,492,369,149 | 1,543,779,816 | 1,503,508,555 | 1,690,412,285 | 1,644,279,994 | 1,759,013,4 |
| Fuel Costs | 686,649,215 | 682,813,248 | 1,509,421,437 | 1,560,259,777 | 1,500,798,092 | 1,572,676,373 | 1,621,325,033 | 1,682,616,587 | 1,768,682,539 | 1,871,579,7 |
| Purchased Power | 1,715,123,062 | 2,042,306,656 | 2,455,363,031 | 2,337,444,493 | 783,933,779 | 746,267,625 | 717,241,667 | 687,110,371 | 670,692,343 | 681,355,0 |
| $SO_2$ Costs | 9,602,239 | 16,728,497 | 24,358,799 | 23,565,493 | 25,143,934 | 28,880,011 | 30,337,882 | 31,731,842 | 33,891,068 | 35,958,0 |
| $NO_x$ Costs | 6,389,632 | 6,573,705 | 25,662,339 | 27,510,304 | 30,349,959 | 31,706,103 | 31,963,020 | 33,216,590 | 34,597,623 | 37,779,5 |
| deduct $SO_2$ Allowances | (5,113,551) | (9,263,391) | (23,795,714) | (26,914,007) | (30,517,536) | (34,559,911) | (35,596,709) | (36,664,610) | (37,764,548) | (38,525,6 |
| deduct $NO_x$ Allowances | (5,974,384) | (6,153,615) | (26,922,607) | (27,730,285) | (28,562,194) | (29,419,060) | (30,301,631) | (31,210,680) | (32,147,001) | (33,111,4 |
| Total Operating Expenses | 3,574,704,461 | 3,986,221,420 | 5,314,604,625 | 5,328,501,468 | 3,773,515,184 | 3,859,330,957 | 3,838,477,816 | 4,057,212,385 | 4,082,232,017 | 4,314,048,8 |
| **Administrative, General, and Other Expenses ($)** | | | | | | | | | | |
| Insurance, Administrative, General, and Allocated Central Office Costs | 544,025,913 | 555,912,086 | 576,242,255 | 594,329,925 | 609,880,724 | 627,201,214 | 646,060,199 | 664,407,782 | 684,386,771 | 704,967,1 |
| Property Taxes | 113,000,000 | 109,000,000 | 138,678,827 | 140,431,039 | 140,639,870 | 140,801,365 | 139,696,174 | 138,792,958 | 138,091,752 | 138,238,8 |
| Decommissioning Funding | 75,117,001 | 75,731,132 | 75,731,132 | 75,731,132 | 75,731,132 | 75,731,132 | 61,155,832 | 61,155,832 | 61,155,832 | 61,155,8 |
| Total Administrative and General Expenses | 732,142,915 | 740,643,218 | 790,652,213 | 810,492,095 | 826,251,726 | 843,733,711 | 846,912,204 | 864,356,571 | 883,634,355 | 904,361,8 |
| **Net Earnings on Sithe Equity[1]** | 8,015,723 | 3,814,067 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| **Net Earnings on Amergen Equity** | 88,144,349 | 69,434,559 | 88,460,800 | 94,727,366 | 83,123,898 | 98,761,113 | 122,472,266 | 123,415,981 | 135,233,613 | 179,637,6 |
| **Operating Income ($)[2]** | 1,767,047,884 | 1,644,848,689 | 1,689,661,955 | 1,625,101,860 | 1,669,041,953 | 1,917,263,983 | 2,316,493,124 | 2,477,107,150 | 2,890,712,391 | 3,047,388,0 |
| Tax Depreciation | 206,338,932 | 223,270,872 | 393,041,051 | 351,339,896 | 313,066,834 | 319,707,351 | 322,717,919 | 329,412,840 | 333,461,367 | 344,324,8 |
| Interest Expenses | 46,020,647 | 69,686,719 | 300,983,870 | 298,416,870 | 295,849,870 | 293,282,870 | 290,715,870 | 288,148,870 | 282,013,870 | 275,878,8 |
| **Taxable Income ($)** | 1,514,688,304 | 1,351,891,098 | 995,637,034 | 975,345,094 | 1,060,125,249 | 1,304,273,762 | 1,703,059,335 | 1,859,545,441 | 2,275,237,154 | 2,427,184,4 |
| Federal Income Tax Rate | 35.00% | 35.00% | 35.00% | 35.00% | 35.00% | 35.00% | 35.00% | 35.00% | 35.00% | 35.( |
| State Income Tax Rate | 5.00% | 5.00% | 5.00% | 5.00% | 5.00% | 5.00% | 5.00% | 5.00% | 5.00% | 5.( |
| Income Taxes | 579,368,276 | 517,098,345 | 380,831,165 | 373,069,499 | 405,497,908 | 498,884,714 | 651,420,196 | 711,276,131 | 870,278,211 | 928,398,0 |
| Capitalized Costs | 306,078,649 | 285,868,005 | 256,985,321 | 306,298,325 | 335,010,159 | 274,860,222 | 261,778,869 | 328,686,157 | 306,654,107 | 395,718,8 |
| Principal Repayment | 0 | 0 | 30,200,000 | 30,200,000 | 30,200,000 | 30,200,000 | 30,200,000 | 68,166,667 | 68,166,667 | 68,166,6 |
| **Cash Flow After Taxes ($)** | 835,580,311 | 772,195,620 | 720,661,599 | 617,117,167 | 602,484,017 | 820,036,178 | 1,082,378,190 | 1,080,829,325 | 1,363,599,536 | 1,379,225,6 |
| **Changes in Working Capital ($)** | | | | | | | | | | |
| Accounts Receivable | 840,717,349 | 880,636,753 | 1,023,391,267 | 1,030,987,698 | 639,366,857 | 677,148,733 | 713,739,404 | 752,430,633 | 796,508,570 | 835,259,2 |
| Accounts Payable | 685,800,281 | 734,275,821 | 872,090,340 | 885,442,976 | 489,176,103 | 507,562,453 | 514,166,666 | 539,627,303 | 550,281,373 | 579,663,8 |
| Changes in Accounts Receivable | 0 | 39,919,404 | 142,754,513 | 7,596,431 | (391,620,841) | 37,781,876 | 36,590,671 | 38,691,229 | 44,077,937 | 38,750,6 |
| Changes in Parts and Materials Inventory | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| Changes in Fuel Inventory | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| Changes in Accounts Payable | 0 | 48,475,539 | 137,814,520 | 13,352,635 | (396,266,873) | 18,386,350 | 6,604,213 | 25,460,637 | 10,654,070 | 29,382,4 |
| Total Changes in Working Capital | 0 | (8,556,135) | 4,939,993 | (5,756,204) | 4,646,033 | 19,395,526 | 29,986,458 | 13,230,591 | 33,423,867 | 9,368,2 |
| **Debt Financing—Consolidated Totals ($)** | | | | | | | | | | |
| Principal Balance at Start of Year | 195,465,000 | 1,016,645,000 | 3,746,175,000 | 3,715,975,000 | 3,685,775,000 | 3,655,575,000 | 3,625,375,000 | 3,595,175,000 | 3,527,008,333 | 3,458,841,6 |
| Principal Paid | 0 | 0 | 30,200,000 | 30,200,000 | 30,200,000 | 30,200,000 | 30,200,000 | 68,166,667 | 68,166,667 | 68,166,6 |
| Interest | 46,020,647 | 69,686,719 | 300,983,870 | 298,416,870 | 295,849,870 | 293,282,870 | 290,715,870 | 288,148,870 | 282,013,870 | 275,878,8 |
| New Debt Issued During Year | 821,180,000 | 2,729,530,000 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| Balance at End of Year | 1,016,645,000 | 3,746,175,000 | 3,715,975,000 | 3,685,775,000 | 3,655,575,000 | 3,625,375,000 | 3,595,175,000 | 3,527,008,333 | 3,458,841,667 | 3,390,675,0 |
| **Cash Available for Debt Service ($)[3]** | 1,460,969,235 | 1,367,536,819 | 1,427,736,641 | 1,324,559,740 | 1,329,385,762 | 1,623,008,236 | 2,024,727,797 | 2,135,190,402 | 2,550,634,418 | 2,642,301,0 |
| **Debt Service ($)** | 46,020,647 | 69,686,719 | 331,183,870 | 328,616,870 | 326,049,870 | 323,482,870 | 320,915,870 | 356,315,537 | 350,180,537 | 344,045,5 |
| **Debt Service Coverage Ratio[4]** | 31.75 | 19.62 | 4.31 | 4.03 | 4.08 | 5.02 | 6.31 | 5.99 | 7.28 | 7.( |
| Minimum DSCR = | 4.03 | | | | | | | | | |
| 20-Year Average DSCR = | 10.77 | | | | | | | | | |

**Notes:**

1 Revenues less Expenses for the 49.9% Sithe equity share. After 1/1/03, Sithe Revenues and Expenses are consolidated with the other Genco plants.

2 Revenues less Operating Expenses less Administrative and General Expenses, plus Net Earnings on Equity.

3 Operating Income less Capitalized Costs less Changes in Working Capital.

4 Cash Available for Debt Service divided by Debt Service.



**Sargent & Lundy**
**Table 1—Income Summary (Base Case)**
**(Current $'s)**

| | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|---|---|---|---|
| Inflation | 3.00% | 3.00% | 3.00% | 3.00% | 3.00% | 3.00% | 3.00% | 3.00% | 3.00% |
| Inflation Factor | 1.4258 | 1.4685 | 1.5126 | 1.5580 | 1.6047 | 1.6528 | 1.7024 | 1.7535 | 1.8061 |
| **Revenues ($)** | | | | | | | | | |
| Revenues from Market Sales | 8,404,338,453 | 8,556,756,756 | 8,885,109,969 | 9,085,545,730 | 9,285,539,411 | 9,611,602,058 | 9,947,953,333 | 10,173,684,210 | 10,475,044,618 |
| Revenues from Affiliate Sales | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Steam Revenues | 2,790,214 | 2,873,920 | 2,960,138 | 3,048,942 | 3,140,411 | 3,234,623 | 3,331,662 | 3,431,611 | 3,534,560 |
| Total Revenues | 8,407,128,667 | 8,559,630,676 | 8,888,070,107 | 9,088,594,673 | 9,288,679,821 | 9,614,836,680 | 9,951,284,994 | 10,177,115,821 | 10,478,579,178 |
| **Operating Expenses ($)** | | | | | | | | | |
| Operation and Maintenance | 1,886,132,584 | 1,839,266,265 | 2,046,910,552 | 2,067,819,712 | 2,127,723,407 | 2,197,833,918 | 2,331,100,688 | 2,282,946,713 | 2,511,369,927 |
| Fuel Costs | 1,985,035,246 | 2,061,942,478 | 2,129,824,147 | 2,175,224,764 | 2,216,954,822 | 2,286,608,243 | 2,373,765,249 | 2,413,141,436 | 2,497,780,254 |
| Purchased Power | 548,146,531 | 485,291,706 | 511,261,394 | 510,402,910 | 509,300,983 | 515,734,743 | 513,572,573 | 502,648,393 | 490,599,522 |
| $SO_2$ Costs | 37,178,944 | 38,586,125 | 39,737,679 | 40,294,830 | 41,273,410 | 42,585,505 | 43,961,318 | 45,030,209 | 46,730,302 |
| $NO_x$ Costs | 39,345,137 | 40,843,103 | 41,927,794 | 41,696,115 | 41,869,570 | 43,303,509 | 44,913,149 | 44,810,044 | 47,702,432 |
| deduct $SO_2$ Allowances | (40,871,839) | (42,097,994) | (43,360,934) | (44,661,762) | (46,001,615) | (47,381,664) | (48,803,113) | (50,267,207) | (51,775,223) |
| deduct $NO_x$ Allowances | (35,127,896) | (36,181,732) | (37,267,184) | (38,385,200) | (39,536,756) | (40,722,859) | (41,944,544) | (43,202,881) | (44,498,967) |
| Total Operating Expenses | 4,419,838,708 | 4,387,649,950 | 4,689,033,448 | 4,752,391,368 | 4,851,583,822 | 4,997,961,396 | 5,216,565,319 | 5,195,106,708 | 5,497,908,247 |
| **Administrative, General, and Other Expenses ($)** | | | | | | | | | |
| Insurance, Administrative, General, and Allocated Central Office Costs | 748,005,198 | 770,500,769 | 793,673,611 | 817,544,147 | 842,133,417 | 867,463,096 | 893,555,516 | 920,433,681 | 948,121,293 |
| Property Taxes | 138,543,737 | 138,701,678 | 138,863,408 | 139,029,033 | 139,198,656 | 139,372,389 | 139,550,343 | 139,732,633 | 139,919,381 |
| Decommissioning Funding | 46,239,682 | 40,866,082 | 32,688,582 | 32,688,582 | 32,688,582 | 30,421,090 | 30,421,090 | 30,421,090 | 30,421,090 |
| Total Administrative and General Expenses | 932,788,617 | 950,068,528 | 965,225,601 | 989,261,761 | 1,014,020,655 | 1,037,256,575 | 1,063,526,948 | 1,090,587,404 | 1,118,461,764 |
| **Net Earnings on Sithe Equity**[1] | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Net Earnings on Amergen Equity** | 171,637,283 | 194,213,517 | 187,299,478 | 204,334,598 | 221,254,936 | 219,171,470 | 227,700,443 | 253,021,588 | 243,769,356 |
| **Operating Income ($)**[2] | 3,226,138,625 | 3,416,125,715 | 3,421,110,536 | 3,551,276,141 | 3,644,330,281 | 3,798,790,179 | 3,898,893,169 | 4,144,443,297 | 4,105,978,524 |
| Tax Depreciation | 367,392,686 | 378,764,421 | 392,986,992 | 408,370,177 | 415,000,903 | 416,853,269 | 421,936,704 | 433,304,171 | 451,264,051 |
| Interest Expenses | 263,608,870 | 257,473,870 | 251,338,870 | 251,338,870 | 251,338,870 | 251,338,870 | 251,338,870 | 251,338,870 | 251,338,870 |
| **Taxable Income ($)** | 2,595,137,069 | 2,779,887,425 | 2,776,784,674 | 2,891,567,094 | 2,977,990,507 | 3,130,598,040 | 3,225,617,595 | 3,459,800,256 | 3,403,375,603 |
| Federal Income Tax Rate | 35.00% | 35.00% | 35.00% | 35.00% | 35.00% | 35.00% | 35.00% | 35.00% | 35.00% |
| State Income Tax Rate | 5.00% | 5.00% | 5.00% | 5.00% | 5.00% | 5.00% | 5.00% | 5.00% | 5.00% |
| Income Taxes | 992,639,929 | 1,063,306,940 | 1,062,120,138 | 1,106,024,414 | 1,139,081,369 | 1,197,453,750 | 1,233,798,730 | 1,323,373,598 | 1,301,791,168 |
| Capitalized Costs | 371,231,017 | 374,439,187 | 440,432,195 | 412,060,596 | 400,333,924 | 431,700,689 | 443,994,315 | 553,206,639 | 569,125,547 |
| Principal Repayment | 68,166,667 | 68,166,667 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Cash Flow After Taxes ($)** | 1,530,492,143 | 1,652,739,051 | 1,667,219,333 | 1,781,852,262 | 1,853,576,117 | 1,918,296,870 | 1,969,761,254 | 2,016,524,190 | 1,983,722,939 |
| **Changes in Working Capital ($)** | | | | | | | | | |
| Accounts Receivable | 700,594,056 | 713,302,556 | 740,672,509 | 757,382,889 | 774,056,652 | 801,236,390 | 829,273,750 | 848,092,985 | 873,214,932 |
| Accounts Payable | 430,653,659 | 429,845,893 | 456,892,255 | 464,161,293 | 474,476,437 | 488,785,374 | 509,176,736 | 509,628,366 | 537,169,128 |
| Changes in Accounts Receivable | (4,791,542) | 12,708,501 | 27,369,953 | 16,710,380 | 16,673,762 | 27,179,738 | 28,037,359 | 18,819,236 | 25,121,946 |
| Changes in Parts and Materials Inventory | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Changes in Fuel Inventory | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Changes in Accounts Payable | 6,153,859 | (807,766) | 27,046,362 | 7,269,038 | 10,315,144 | 14,308,938 | 20,391,362 | 451,629 | 27,540,763 |
| Total Changes in Working Capital | (10,945,401) | 13,516,266 | 323,591 | 9,441,342 | 6,358,619 | 12,870,800 | 7,645,998 | 18,367,606 | (2,418,816) |
| **Debt Financing—Consolidated Totals ($)** | | | | | | | | | |
| Principal Balance at Start of Year | 3,322,508,333 | 3,254,341,667 | 3,186,175,000 | 3,186,175,000 | 3,186,175,000 | 3,186,175,000 | 3,186,175,000 | 3,186,175,000 | 3,186,175,000 |
| Principal Paid | 68,166,667 | 68,166,667 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Interest | 263,608,870 | 257,473,870 | 251,338,870 | 251,338,870 | 251,338,870 | 251,338,870 | 251,338,870 | 251,338,870 | 251,338,870 |
| New Debt Issued During Year | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Balance at End of Year | 3,254,341,667 | 3,186,175,000 | 3,186,175,000 | 3,186,175,000 | 3,186,175,000 | 3,186,175,000 | 3,186,175,000 | 3,186,175,000 | 3,186,175,000 |
| **Cash Available for Debt Service ($)**[3] | 2,865,853,009 | 3,028,170,262 | 2,980,354,750 | 3,129,774,203 | 3,237,637,738 | 3,354,218,690 | 3,447,252,857 | 3,572,869,052 | 3,539,271,793 |
| **Debt Service ($)** | 331,775,537 | 325,640,537 | 251,338,870 | 251,338,870 | 251,338,870 | 251,338,870 | 251,338,870 | 251,338,870 | 251,338,870 |
| | 8.64 | 9.30 | 11.86 | 12.45 | 12.88 | 13.35 | 13.72 | 14.22 | 14.08 |

**Debt Service Coverage Ratio[4]**

Minimum DSCR =

20-Year Average DSCR =

**Notes:**

1 Revenues less Expenses for the 49.9% Sithe equity share. After 1/1/03, Sithe Revenues and Expenses are consolidated with the other Genco plants.

2 Revenues less Operating Expenses less Administrative and General Expenses, plus Net Earnings on Equity.

3 Operating Income less Capitalized Costs less Changes in Working Capital.

4 Cash Available for Debt Service divided by Debt Service.



## Sargent & Lundy
## Table 2—Income Summary (High Fuel Price Case)
## (Current $'s)

| | Projected (Current $'s) | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 |
| Inflation | 3.00% | 3.00% | 3.00% | 3.00% | 3.00% | 3.00% | 3.00% | 3.00% | 3.00% | 3.00% | 3.00% |
| Inflation Factor | 1.0300 | 1.0609 | 1.0927 | 1.1255 | 1.1593 | 1.1941 | 1.2299 | 1.2668 | 1.3048 | 1.3439 | 1.3842 |
| **Revenues ($)** | | | | | | | | | | | |
| Revenues from Market Sales | 1,758,176,847 | 2,149,325,845 | 3,650,085,451 | 3,949,005,641 | 3,787,287,273 | 3,990,228,719 | 6,613,284,943 | 7,288,935,191 | 7,636,493,144 | 7,997,991,581 | 11,147,652,755 |
| Revenues from Affiliate Sales | 4,218,176,000 | 4,317,096,960 | 4,540,600,033 | 4,653,003,372 | 3,602,327,170 | 3,850,878,805 | 1,638,678,936 | 1,677,718,595 | 1,718,042,815 | 1,758,771,125 | 0 |
| Steam Revenues | 2,015,710 | 2,076,181 | 2,138,467 | 2,202,621 | 2,268,699 | 2,336,760 | 2,406,863 | 2,479,069 | 2,553,441 | 2,630,044 | 2,708,946 |
| Total Revenues | 5,978,368,557 | 6,468,498,987 | 8,192,823,951 | 8,604,211,633 | 7,391,883,143 | 7,843,444,285 | 8,254,370,742 | 8,969,132,855 | 9,357,089,401 | 9,759,392,750 | 11,150,361,701 |
| **Operating Expenses ($)** | | | | | | | | | | | |
| Operation and Maintenance | 1,167,930,066 | 1,253,267,013 | 1,352,954,831 | 1,432,432,978 | 1,489,498,515 | 1,541,808,727 | 1,502,060,389 | 1,690,148,790 | 1,644,860,783 | 1,760,077,577 | 1,771,230,624 |
| Fuel Costs | 684,700,313 | 684,887,915 | 1,578,503,296 | 1,798,146,618 | 1,948,258,966 | 2,057,936,922 | 2,133,825,183 | 2,228,159,455 | 2,355,050,631 | 2,508,277,946 | 2,611,230,960 |
| Purchased Power | 1,717,640,376 | 2,090,358,870 | 2,545,545,318 | 2,557,354,979 | 774,786,913 | 730,247,530 | 701,147,762 | 670,097,417 | 651,000,149 | 657,980,280 | 648,244,316 |
| $SO_2$ Costs | 9,571,633 | 16,585,965 | 22,868,287 | 25,825,266 | 30,765,184 | 35,908,137 | 37,312,067 | 39,043,272 | 41,660,756 | 43,410,611 | 45,909,268 |
| $NO_x$ Costs | 6,373,623 | 6,534,663 | 25,423,470 | 26,153,575 | 28,661,577 | 30,306,445 | 31,486,441 | 33,633,750 | 35,658,735 | 38,885,898 | 40,470,648 |
| deduct $SO_2$ Allowances | (5,113,551) | (9,263,391) | (23,795,714) | (26,914,007) | (30,517,536) | (34,559,911) | (35,596,709) | (6,664,610) | (37,764,548) | (38,525,628) | (39,681,397) |
| deduct $NO_x$ Allowances | (5,974,384) | (6,153,615) | (26,922,607) | (27,730,285) | (28,562,194) | (29,419,060) | (30,301,631) | (31,210,680) | (32,147,001) | (33,111,411) | (34,104,753) |
| Total Operating Expenses | 3,575,128,077 | 4,036,217,419 | 5,474,576,880 | 5,785,269,123 | 4,212,891,425 | 4,332,228,791 | 4,339,933,503 | 4,593,207,393 | 4,658,319,505 | 4,936,995,273 | 5,043,299,666 |
| **Administrative, General, and Other Expenses ($)** | | | | | | | | | | | |
| Insurance, Administrative, General, and Allocated Central Office Costs | 544,025,913 | 555,912,086 | 576,242,255 | 594,329,925 | 609,880,724 | 627,201,214 | 646,060,199 | 664,407,782 | 684,386,771 | 704,967,159 | 726,167,076 |
| Property Taxes | 113,000,000 | 109,000,000 | 138,678,827 | 140,431,039 | 140,639,870 | 140,801,365 | 139,696,174 | 138,792,958 | 138,091,752 | 138,238,829 | 138,389,487 |
| Decommissioning Funding | 75,117,001 | 75,731,132 | 75,731,132 | 75,731,132 | 75,731,132 | 75,731,132 | 61,155,832 | 61,155,832 | 61,155,832 | 61,155,832 | 61,155,832 |
| Total Administrative and General Expenses | 732,142,915 | 740,643,218 | 790,652,213 | 810,492,095 | 826,251,726 | 843,733,711 | 846,912,204 | 864,356,571 | 883,634,355 | 904,361,820 | 925,712,394 |
| **Net Earnings on Sithe Equity[1]** | 5,910,401 | 39,195,763 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Net Earnings on Amergen Equity** | 87,110,350 | 82,775,102 | 113,197,990 | 142,617,943 | 152,806,441 | 185,144,274 | 217,618,198 | 238,100,999 | 263,555,147 | 316,907,137 | 310,654,998 |
| **Operating Income ($)[2]** | 1,764,118,316 | 1,813,609,214 | 2,040,792,848 | 2,151,068,358 | 2,505,546,433 | 2,852,626,057 | 3,285,143,234 | 3,749,669,890 | 4,078,690,687 | 4,234,942,794 | 5,492,004,638 |
| Tax Depreciation | 206,338,932 | 223,270,872 | 393,041,051 | 351,339,896 | 313,066,834 | 319,707,351 | 322,717,919 | 329,412,840 | 333,461,367 | 344,324,804 | 356,795,949 |
| Interest Expenses | 46,020,647 | 69,686,719 | 300,983,870 | 298,416,870 | 295,849,870 | 293,282,870 | 290,715,870 | 288,148,870 | 282,013,870 | 275,878,870 | 269,743,870 |
| **Taxable Income ($)** | 1,511,758,736 | 1,520,651,623 | 1,346,767,926 | 1,501,311,592 | 1,896,629,729 | 2,239,635,836 | 2,671,709,445 | 3,132,108,180 | 3,463,215,450 | 3,614,739,120 | 4,865,464,819 |
| Federal Income Tax Rate | 35.00% | 35.00% | 35.00% | 35.00% | 35.00% | 35.00% | 35.00% | 35.00% | 35.00% | 35.00% | 35.00% |
| State Income Tax Rate | 5.00% | 5.00% | 5.00% | 5.00% | 5.00% | 5.00% | 5.00% | 5.00% | 5.00% | 5.00% | 5.00% |
| Income Taxes | 578,247,717 | 581,649,246 | 515,138,732 | 574,251,684 | 725,460,871 | 856,660,707 | 1,021,928,863 | 1,198,031,379 | 1,324,679,910 | 1,382,637,714 | 1,861,040,293 |
| Capitalized Costs | 306,078,649 | 285,868,005 | 256,985,321 | 306,298,325 | 335,010,159 | 274,860,222 | 261,778,869 | 328,686,157 | 306,654,107 | 395,718,820 | 345,967,546 |
| Principal Repayment | 0 | 0 | 30,200,000 | 30,200,000 | 30,200,000 | 30,200,000 | 30,200,000 | 68,166,667 | 68,166,667 | 68,166,667 | 68,166,667 |
| **Cash Flow After Taxes ($)** | 833,771,303 | 876,405,245 | 937,484,925 | 941,901,479 | 1,119,025,533 | 1,397,622,258 | 1,680,519,632 | 1,866,636,817 | 2,097,176,134 | 2,112,540,723 | 2,947,086,262 |
| **Changes in Working Capital ($)** | | | | | | | | | | | |
| Accounts Receivable | 840,106,546 | 902,702,012 | 1,085,499,486 | 1,148,300,880 | 755,833,100 | 816,428,112 | 859,204,961 | 926,911,692 | 971,285,778 | 1,016,275,974 | 929,196,808 |
| Accounts Payable | 685,171,999 | 746,337,889 | 906,999,084 | 962,916,498 | 541,740,518 | 576,093,589 | 586,840,207 | 617,618,552 | 636,753,851 | 673,156,781 | 480,788,895 |
| Changes in Accounts Receivable | 0 | 62,595,466 | 182,797,473 | 62,801,394 | (392,467,780) | 60,595,012 | 42,776,848 | 67,706,732 | 44,374,085 | 44,990,197 | (87,079,166) |
| Changes in Parts and Materials Inventory | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Changes in Fuel Inventory | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Changes in Accounts Payable | 0 | 61,165,890 | 160,661,196 | 55,917,414 | (421,175,980) | 34,353,071 | 10,746,618 | 30,778,345 | 19,135,298 | 36,402,930 | (192,367,886) |
| Total Changes in Working Capital | 0 | 1,429,576 | 22,136,278 | 6,883,981 | 28,708,201 | 26,241,941 | 32,030,230 | 36,928,387 | 25,238,787 | 8,587,266 | 105,288,720 |
| **Debt Financing—Consolidated Totals ($)** | | | | | | | | | | | |
| Principal Balance at Start of Year | 195,465,000 | 1,016,645,000 | 3,746,175,000 | 3,715,975,000 | 3,685,775,000 | 3,655,575,000 | 3,625,375,000 | 3,595,175,000 | 3,527,008,333 | 3,458,841,667 | 3,390,675,000 |
| Principal Paid | 0 | 0 | 30,200,000 | 30,200,000 | 30,200,000 | 30,200,000 | 30,200,000 | 68,166,667 | 68,166,667 | 68,166,667 | 68,166,667 |

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Interest | 46,020,647 | 69,686,719 | 300,983,870 | 298,416,870 | 295,849,870 | 293,282,870 | 290,715,870 | 288,148,870 | 282,013,870 | 275,878,870 | 269,743,870 |
| New Debt Issued During Year | 821,180,000 | 2,729,530,000 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Balance at End of Year | 1,016,645,000 | 3,746,175,000 | 3,715,975,000 | 3,685,775,000 | 3,655,575,000 | 3,625,375,000 | 3,595,175,000 | 3,527,008,333 | 3,458,841,667 | 3,390,675,000 | 3,322,508,333 |
| **Cash Available for Debt Service ($)**[3] | 1,458,039,667 | 1,526,311,633 | 1,761,671,249 | 1,837,886,053 | 2,141,828,074 | 2,551,523,895 | 2,991,334,135 | 3,384,055,346 | 3,746,797,794 | 3,830,636,707 | 5,040,748,372 |
| **Debt Service ($)** | 46,020,647 | 69,686,719 | 331,183,870 | 328,616,870 | 326,049,870 | 323,482,870 | 320,915,870 | 356,315,537 | 350,180,537 | 344,045,537 | 337,910,537 |
| **Debt Service Coverage Ratio**[4] | 31.68 | 21.90 | 5.32 | 5.59 | 6.57 | 7.89 | 9.32 | 9.50 | 10.70 | 11.13 | 14.92 |
| Minimum DSCR = | 5.32 | | | | | | | | | | |
| 20-Year Average DSCR = | 17.24 | | | | | | | | | | |

Notes:

1 Revenues less Expenses for the 49.9% Sithe equity share. After 1/1/03, Sithe Revenues and Expenses are consolidated with the other Genco plants.

2 Revenues less Operating Expenses less Administrative and General Expenses, plus Net Earnings on Equity.

3 Operating Income less Capitalized Costs less Changes in Working Capital.

4 Cash Available for Debt Service divided by Debt Service.



## Sargent & Lundy
## Table 2—Income Summary (High Fuel Price Case)
## (Current $'s)

| | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 |
|---|---|---|---|---|---|---|---|---|
| Inflation | 3.00% | 3.00% | 3.00% | 3.00% | 3.00% | 3.00% | 3.00% | 3.00% |
| Inflation Factor | 1.4258 | 1.4685 | 1.5126 | 1.5580 | 1.6047 | 1.6528 | 1.7024 | 1.7535 |
| **Revenues ($)** | | | | | | | | |
| Revenues from Market Sales | 11,179,155,575 | 11,511,055,749 | 12,030,997,729 | 12,487,191,124 | 12,921,842,890 | 13,492,520,173 | 13,929,839,528 | 14,309,335,626 |
| Revenues from Affiliate Sales | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Steam Revenues | 2,790,214 | 2,873,920 | 2,960,138 | 3,048,942 | 3,140,411 | 3,234,623 | 3,331,662 | 3,431,611 |
| Total Revenues | 11,181,945,789 | 11,513,929,669 | 12,033,957,867 | 12,490,240,066 | 12,924,983,301 | 13,495,754,796 | 13,933,171,189 | 14,312,767,237 |
| **Operating Expenses ($)** | | | | | | | | |
| Operation and Maintenance | 1,890,942,888 | 1,844,854,717 | 2,052,972,055 | 2,076,977,891 | 2,140,259,645 | 2,211,633,211 | 2,342,760,709 | 2,297,618,197 |
| Fuel Costs | 2,696,818,977 | 2,804,301,732 | 2,887,061,682 | 2,981,629,177 | 3,081,326,360 | 3,187,859,130 | 3,267,248,349 | 3,358,387,392 |
| Purchased Power | 539,078,514 | 485,291,706 | 511,261,394 | 510,402,910 | 509,300,983 | 515,734,743 | 513,572,573 | 502,648,393 |
| $SO_2$ Costs | 47,413,524 | 49,386,236 | 50,959,363 | 52,867,681 | 54,627,678 | 56,436,659 | 58,394,906 | 59,988,204 |
| $NO_x$ Costs | 42,143,596 | 43,501,851 | 44,807,330 | 46,740,901 | 48,615,843 | 50,075,804 | 51,033,704 | 52,151,662 |
| deduct $SO_2$ Allowances | -40,871,839 | -42,097,994 | -43,360,934 | -44,661,762 | -46,001,615 | -47,381,664 | -48,803,113 | -50,267,207 |
| deduct $NO_x$ Allowances | -35,127,896 | -36,181,732 | -37,267,184 | -38,385,200 | -39,536,756 | -40,722,859 | -41,944,544 | -43,202,881 |
| Total Operating Expenses | 5,140,397,763 | 5,149,056,515 | 5,466,433,707 | 5,585,571,599 | 5,748,592,138 | 5,933,635,025 | 6,142,262,584 | 6,177,323,761 |
| **Administrative, General, and Other Expenses ($)** | | | | | | | | |
| Insurance, Administrative, General, and Allocated Central Office Costs | 748,005,198 | 770,500,769 | 793,673,611 | 817,544,147 | 842,133,417 | 867,463,096 | 893,555,516 | 920,433,681 |
| Property Taxes | 138,543,737 | 138,701,678 | 138,863,408 | 139,029,033 | 139,198,656 | 139,372,389 | 139,550,343 | 139,732,633 |
| Decommissioning Funding | 46,239,682 | 40,866,082 | 32,688,582 | 32,688,582 | 32,688,582 | 30,421,090 | 30,421,090 | 30,421,090 |
| Total Administrative and General Expenses | 932,788,617 | 950,068,528 | 965,225,601 | 989,261,761 | 1,014,020,655 | 1,037,256,575 | 1,063,526,948 | 1,090,587,404 |
| **Net Earnings on Sithe Equity**[1] | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Net Earnings on Amergen Equity** | 330,237,151 | 364,936,567 | 366,873,271 | 398,431,184 | 427,960,218 | 440,303,710 | 457,612,178 | 491,065,725 |
| **Operating Income ($)**[2] | 5,438,996,560 | 5,779,741,194 | 5,969,171,830 | 6,313,837,890 | 6,590,330,726 | 6,965,166,906 | 7,184,993,836 | 7,535,921,798 |
| Tax Depreciation | 367,392,686 | 378,764,421 | 392,986,992 | 408,370,177 | 415,000,903 | 416,853,269 | 421,936,704 | 433,304,171 |
| Interest Expenses | 263,608,870 | 257,473,870 | 251,338,870 | 251,338,870 | 251,338,870 | 251,338,870 | 251,338,870 | 251,338,870 |
| **Taxable Income ($)** | 4,807,995,003 | 5,143,502,903 | 5,324,845,967 | 5,654,128,843 | 5,923,990,952 | 6,296,974,768 | 6,511,718,262 | 6,851,278,757 |
| Federal Income Tax Rate | 35.00% | 35.00% | 35.00% | 35.00% | 35.00% | 35.00% | 35.00% | 35.00% |
| State Income Tax Rate | 5.00% | 5.00% | 5.00% | 5.00% | 5.00% | 5.00% | 5.00% | 5.00% |
| Income Taxes | 1,839,058,089 | 1,967,389,860 | 2,036,753,583 | 2,162,704,282 | 2,265,926,539 | 2,408,592,849 | 2,490,732,235 | 2,620,614,124 |
| Capitalized Costs | 371,231,017 | 374,439,187 | 440,432,195 | 412,060,596 | 400,333,924 | 431,700,689 | 443,994,315 | 553,206,639 |
| Principal Repayment | 68,166,667 | 68,166,667 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Cash Flow After Taxes ($)** | 2,896,931,917 | 3,112,271,609 | 3,240,647,182 | 3,487,734,142 | 3,672,731,392 | 3,873,534,499 | 3,998,928,416 | 4,110,762,164 |
| **Changes in Working Capital ($)** | | | | | | | | |
| Accounts Receivable | 931,828,816 | 959,494,139 | 1,002,829,822 | 1,040,853,339 | 1,077,081,942 | 1,124,646,233 | 1,161,097,599 | 1,192,730,603 |
| Accounts Payable | 490,700,247 | 493,296,440 | 521,675,610 | 533,592,979 | 549,227,130 | 566,758,177 | 586,318,175 | 591,479,787 |
| Changes in Accounts Receivable | 2,632,007 | 27,665,323 | 43,335,683 | 38,023,517 | 36,228,603 | 47,564,291 | 36,451,366 | 31,633,004 |
| Changes in Parts and Materials Inventory | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Changes in Fuel Inventory | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Changes in Accounts Payable | 9,911,352 | 2,596,194 | 28,379,170 | 11,917,369 | 15,634,151 | 17,531,047 | 19,559,998 | 5,161,612 |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Total Changes in Working Capital | (7,279,344) | 25,069,130 | 14,956,514 | 26,106,148 | 20,594,452 | 30,033,244 | 16,891,368 | 26,471,392 |
| **Debt Financing—Consolidated Totals ($)** | | | | | | | | |
| Principal Balance at Start of Year | 3,322,508,333 | 3,254,341,667 | 3,186,175,000 | 3,186,175,000 | 3,186,175,000 | 3,186,175,000 | 3,186,175,000 | 3,186,175,000 |
| Principal Paid | 68,166,667 | 68,166,667 | 0 | 0 | 0 | 0 | 0 | 0 |
| Interest | 263,608,870 | 257,473,870 | 251,338,870 | 251,338,870 | 251,338,870 | 251,338,870 | 251,338,870 | 251,338,870 |
| New Debt Issued During Year | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Balance at End of Year | 3,254,341,667 | 3,186,175,000 | 3,186,175,000 | 3,186,175,000 | 3,186,175,000 | 3,186,175,000 | 3,186,175,000 | 3,186,175,000 |
| **Cash Available for Debt Service ($)[3]** | 5,075,044,887 | 5,380,232,877 | 5,513,783,121 | 5,875,671,147 | 6,169,402,349 | 6,503,432,974 | 6,724,108,153 | 6,956,243,766 |
| **Debt Service ($)** | 331,775,537 | 325,640,537 | 251,338,870 | 251,338,870 | 251,338,870 | 251,338,870 | 251,338,870 | 251,338,870 |
| **Debt Service Coverage Ratio[4]** | 15.30 | 16.52 | 21.94 | 23.38 | 24.55 | 25.88 | 26.75 | 27.68 |
| Minimum DSCR = | | | | | | | | |
| 20-Year Average DSCR = | | | | | | | | |

**Notes:**

1 Revenues less Expenses for the 49.9% Sithe equity share. After 1/1/03, Sithe Revenues and Expenses are consolidated with the other Genco plants.

2 Revenues less Operating Expenses less Administrative and General Expenses, plus Net Earnings on Equity.

3 Operating Income less Capitalized Costs less Changes in Working Capital.

4 Cash Available for Debt Service divided by Debt Service.



## Sargent & Lundy
## Table 3—Income Summary (Low Fuel Price Case)
## (Current $'s)
## Projected (Current $'s)

| | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Inflation | 3.00% | 3.00% | 3.00% | 3.00% | 3.00% | 3.00% | 3.00% | 3.00% | 3.00% | 3.00% | 3.00% |
| Inflation Factor | 1.0300 | 1.0609 | 1.0927 | 1.1255 | 1.1593 | 1.1941 | 1.2299 | 1.2668 | 1.3048 | 1.3439 | 1.3842 |
| **Revenues ($)** | | | | | | | | | | | |
| Revenues from Market Sales | 1,638,133,999 | 1,863,449,560 | 2,988,733,908 | 2,859,991,823 | 2,564,159,843 | 2,636,191,564 | 5,169,398,556 | 5,370,020,272 | 5,752,076,165 | 5,994,279,752 | 8,038,940,595 |
| Revenues from Affiliate Sales | 4,218,176,000 | 4,317,096,960 | 4,540,600,033 | 4,653,003,372 | 3,602,327,170 | 3,850,878,805 | 1,638,678,936 | 1,677,718,595 | 1,718,042,815 | 1,758,771,125 | 0 |
| Steam Revenues | 2,015,710 | 2,076,181 | 2,138,467 | 2,202,621 | 2,268,699 | 2,336,760 | 2,406,863 | 2,479,069 | 2,553,441 | 2,630,044 | 2,708,946 |
| Total Revenues | 5,858,325,709 | 6,182,622,701 | 7,531,472,408 | 7,515,197,816 | 6,168,755,713 | 6,489,407,130 | 6,810,484,355 | 7,050,217,936 | 7,472,672,421 | 7,755,680,921 | 8,041,649,540 |
| **Operating Expenses ($)** | | | | | | | | | | | |
| Operation and Maintenance | 1,168,073,656 | 1,253,433,280 | 1,351,487,883 | 1,436,027,659 | 1,492,592,332 | 1,543,810,438 | 1,503,520,199 | 1,690,814,669 | 1,643,621,215 | 1,757,582,880 | 1,766,068,262 |
| Fuel Costs | 682,173,681 | 687,577,150 | 1,448,840,697 | 1,514,666,226 | 1,438,204,593 | 1,502,713,514 | 1,548,882,205 | 1,608,035,150 | 1,679,250,121 | 1,766,505,796 | 1,815,917,391 |
| Purchased Power | 1,680,506,034 | 1,999,501,007 | 2,387,327,978 | 2,276,247,679 | 776,922,585 | 743,276,504 | 717,367,609 | 680,762,224 | 665,232,699 | 677,100,638 | 669,979,647 |
| $SO_2$ Costs | 9,690,183 | 17,153,306 | 25,020,756 | 24,654,200 | 24,951,648 | 28,589,197 | 30,019,923 | 31,311,066 | 32,779,717 | 34,557,017 | 35,396,107 |
| $NO_x$ Costs | 6,393,282 | 6,607,397 | 25,996,525 | 27,012,808 | 30,387,329 | 31,769,571 | 31,832,189 | 33,309,972 | 33,930,831 | 36,828,722 | 36,610,089 |
| deduct $SO_x$ Allowances | (5,113,551) | (9,263,391) | (23,795,714) | (26,914,007) | (30,517,536) | (34,559,911) | (35,596,709) | (36,664,610) | (37,764,548) | (38,525,628) | (39,681,397) |
| deduct $NO_x$ Allowances | (5,974,384) | (6,153,615) | (26,922,607) | (27,730,285) | (28,562,194) | (29,419,060) | (30,301,631) | (31,210,680) | (32,147,001) | (33,111,411) | (34,104,753) |
| Total Operating Expenses | 3,535,748,901 | 3,948,855,133 | 5,187,955,519 | 5,223,964,279 | 3,703,978,757 | 3,786,180,253 | 3,765,723,784 | 3,976,357,792 | 3,984,903,034 | 4,200,938,013 | 4,250,185,346 |
| **Administrative, General, and Other Expenses ($)** | | | | | | | | | | | |
| Insurance, Administrative, General, and Allocated Central Office Costs | 544,025,913 | 555,912,086 | 576,242,255 | 594,329,925 | 609,880,724 | 627,201,214 | 646,060,199 | 664,407,782 | 684,386,771 | 704,967,159 | 726,167,076 |
| Property Taxes | 113,000,000 | 109,000,000 | 138,678,827 | 140,431,039 | 140,639,870 | 140,801,365 | 139,696,174 | 138,792,958 | 138,091,752 | 138,238,829 | 138,389,487 |
| Decommissioning Funding | 75,117,001 | 75,731,132 | 75,731,132 | 75,731,132 | 75,731,132 | 75,731,132 | 61,155,832 | 61,155,832 | 61,155,832 | 61,155,832 | 61,155,832 |
| Total Administrative and General Expenses | 732,142,915 | 740,643,218 | 790,652,213 | 810,492,095 | 826,251,726 | 843,733,711 | 846,912,204 | 864,356,571 | 883,634,355 | 904,361,820 | 925,712,394 |
| **Net Earnings on Sithe Equity [1]** | 6,924,391 | 16,257,002 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Net Earnings on Amergen Equity** | 77,894,019 | 59,164,130 | 76,866,146 | 84,710,065 | 79,604,315 | 89,643,913 | 111,381,231 | 106,344,674 | 115,774,859 | 157,563,864 | 139,135,962 |
| **Operating Income ($)[2]** | 1,675,252,303 | 1,568,545,482 | 1,629,730,823 | 1,565,451,506 | 1,718,129,544 | 1,949,137,079 | 2,309,229,598 | 2,315,848,247 | 2,719,909,891 | 2,807,944,951 | 3,004,887,763 |
| Tax Depreciation | 206,338,932 | 223,270,872 | 393,041,051 | 351,339,896 | 313,066,834 | 319,707,351 | 322,717,919 | 329,412,840 | 333,461,367 | 344,324,804 | 356,795,949 |
| Interest Expenses | 46,020,647 | 69,686,719 | 300,983,870 | 298,416,870 | 295,849,870 | 293,282,870 | 290,715,870 | 288,148,870 | 282,013,870 | 275,878,870 | 269,743,870 |
| **Taxable Income ($)** | 1,422,892,723 | 1,275,587,891 | 935,705,902 | 915,694,739 | 1,109,212,840 | 1,336,146,858 | 1,695,795,809 | 1,698,286,537 | 2,104,434,654 | 2,187,741,278 | 2,378,347,944 |
| Federal Income Tax Rate | 35.00% | 35.00% | 35.00% | 35.00% | 35.00% | 35.00% | 35.00% | 35.00% | 35.00% | 35.00% | 35.00% |
| State Income Tax Rate | 5.00% | 5.00% | 5.00% | 5.00% | 5.00% | 5.00% | 5.00% | 5.00% | 5.00% | 5.00% | 5.00% |
| Income Taxes | 544,256,467 | 487,912,368 | 357,907,507 | 350,253,238 | 424,273,911 | 511,076,173 | 648,641,897 | 649,594,600 | 804,946,255 | 836,811,039 | 909,718,089 |
| Capitalized Costs | 306,078,649 | 285,868,005 | 256,985,321 | 306,298,325 | 335,010,159 | 274,860,222 | 261,778,869 | 328,686,157 | 306,654,107 | 395,718,820 | 345,967,546 |
| Principal Repayment | 0 | 0 | 30,200,000 | 30,200,000 | 30,200,000 | 30,200,000 | 30,200,000 | 68,166,667 | 68,166,667 | 68,166,667 | 68,166,667 |
| **Cash Flow After Taxes ($)** | 778,896,540 | 725,078,390 | 683,654,125 | 580,283,073 | 632,795,604 | 839,717,814 | 1,077,892,963 | 981,251,952 | 1,258,128,993 | 1,231,369,556 | 1,411,291,591 |
| **Changes in Working Capital ($)** | | | | | | | | | | | |
| Accounts Receivable | 830,985,226 | 859,929,343 | 997,155,874 | 1,013,380,925 | 638,094,548 | 670,715,469 | 702,665,589 | 728,808,892 | 769,646,347 | 799,996,942 | 670,137,462 |
| Accounts Payable | 682,772,651 | 720,108,053 | 849,882,988 | 871,972,291 | 483,519,862 | 497,713,330 | 502,773,891 | 528,021,195 | 536,031,129 | 562,515,630 | 414,696,035 |
| Changes in Accounts Receivable | 0 | 28,944,118 | 137,226,531 | 16,225,051 | (375,286,378) | 32,620,921 | 31,950,120 | 26,143,303 | 40,837,456 | 30,350,595 | (129,859,481) |
| Changes in Parts and Materials Inventory | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Changes in Fuel Inventory | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Changes in Accounts Payable | 0 | 37,335,402 | 129,774,935 | 22,089,303 | (388,452,429) | 14,193,468 | 5,060,561 | 25,247,304 | 8,009,934 | 26,484,501 | (147,819,595) |
| Total Changes in Working Capital | 0 | (8,391,284) | 7,451,596 | (5,864,252) | 13,166,052 | 18,427,453 | 26,889,559 | 895,999 | 32,827,521 | 3,866,094 | 17,960,114 |
| **Debt Financing—Consolidated Totals ($)** | | | | | | | | | | | |
| Principal Balance at Start of Year | 195,465,000 | 1,016,645,000 | 3,746,175,000 | 3,715,975,000 | 3,685,775,000 | 3,655,575,000 | 3,625,375,000 | 3,595,175,000 | 3,527,008,333 | 3,458,841,667 | 3,390,675,000 |
| Principal Paid | 0 | 0 | 30,200,000 | 30,200,000 | 30,200,000 | 30,200,000 | 30,200,000 | 68,166,667 | 68,166,667 | 68,166,667 | 68,166,667 |
| Interest | 46,020,647 | 69,686,719 | 300,983,870 | 298,416,870 | 295,849,870 | 293,282,870 | 290,715,870 | 288,148,870 | 282,013,870 | 275,878,870 | 269,743,870 |
| New Debt Issued During Year | 821,180,000 | 2,729,530,000 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Balance at End of Year | 1,016,645,000 | 3,746,175,000 | 3,715,975,000 | 3,685,775,000 | 3,655,575,000 | 3,625,375,000 | 3,595,175,000 | 3,527,008,333 | 3,458,841,667 | 3,390,675,000 | 3,322,508,333 |
| **Cash Available for Debt Service ($)**[3] | 1,369,173,654 | 1,291,068,761 | 1,365,293,906 | 1,265,017,433 | 1,369,953,334 | 1,655,849,405 | 2,020,561,171 | 1,986,266,090 | 2,380,428,264 | 2,408,360,037 | 2,640,960,102 |
| **Debt Service ($)** | 46,020,647 | 69,686,719 | 331,183,870 | 328,616,870 | 326,049,870 | 323,482,870 | 320,915,870 | 356,315,537 | 350,180,537 | 344,045,537 | 337,910,537 |
| **Debt Service Coverage Ratio**[4] | 29.75 | 18.53 | 4.12 | 3.85 | 4.20 | 5.12 | 6.30 | 5.57 | 6.80 | 7.00 | 7.82 |
| Minimum DSCR = | 3.85 | | | | | | | | | | |
| 20-Year Average DSCR = | 9.84 | | | | | | | | | | |

**Notes:**

1 Revenues less Expenses for the 49.9% Sithe equity share. After 1/1/03, Sithe Revenues and Expenses are consolidated with the other Genco plants.

2 Revenues less Operating Expenses less Administrative and General Expenses, plus Net Earnings on Equity.

3 Operating Income less Capitalized Costs less Changes in Working Capital.

4 Cash Available for Debt Service divided by Debt Service.



## Sargent & Lundy
## Table 3—Income Summary (Low Fuel Price Case)
## (Current $'s)

| | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|---|---|---|---|
| Inflation | 3.00% | 3.00% | 3.00% | 3.00% | 3.00% | 3.00% | 3.00% | 3.00% | 3.00% |
| Inflation Factor | 1.4258 | 1.4685 | 1.5126 | 1.5580 | 1.6047 | 1.6528 | 1.7024 | 1.7535 | 1.8061 |
| **Revenues ($)** | | | | | | | | | |
| Revenues from Market Sales | 7,994,014,810 | 8,129,404,983 | 8,435,033,498 | 8,617,328,765 | 8,799,524,879 | 9,103,051,565 | 9,407,707,552 | 9,636,965,253 | 9,920,332,009 |
| Revenues from Affiliate Sales | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Steam Revenues | 2,790,214 | 2,873,920 | 2,960,138 | 3,048,942 | 3,140,411 | 3,234,623 | 3,331,662 | 3,431,611 | 3,534,560 |
| Total Revenues | 7,996,805,024 | 8,132,278,903 | 8,437,993,636 | 8,620,377,707 | 8,802,665,289 | 9,106,286,188 | 9,411,039,213 | 9,640,396,865 | 9,923,866,568 |
| **Operating Expenses ($)** | | | | | | | | | |
| Operation and Maintenance | 1,884,925,844 | 1,838,001,881 | 2,045,461,387 | 2,067,021,403 | 2,126,183,319 | 2,196,790,543 | 2,329,534,699 | 2,280,828,267 | 2,509,352,661 |
| Fuel Costs | 1,874,264,934 | 1,942,675,520 | 2,003,134,932 | 2,049,444,261 | 2,085,688,735 | 2,158,079,960 | 2,236,292,993 | 2,272,721,042 | 2,359,478,137 |
| Purchased Power | 542,705,507 | 487,170,249 | 505,668,272 | 502,900,707 | 503,343,726 | 507,481,158 | 504,449,675 | 503,568,216 | 483,435,952 |
| $SO_2$ Costs | 35,753,495 | 37,241,967 | 38,376,989 | 38,737,410 | 39,632,850 | 41,134,653 | 42,320,486 | 43,520,536 | 45,440,502 |
| $NO_x$ Costs | 38,021,144 | 39,316,709 | 40,186,786 | 40,169,616 | 39,863,319 | 41,470,335 | 42,639,991 | 42,206,761 | 44,979,913 |
| deduct $SO_2$ Allowances | (40,871,839) | (42,097,994) | (43,360,934) | (44,661,762) | (46,001,615) | (47,381,664) | (48,803,113) | (50,267,207) | (51,775,223) |
| deduct $NO_x$ Allowances | (35,127,896) | (36,181,732) | (37,267,184) | (38,385,200) | (39,536,756) | (40,722,859) | (41,944,544) | (43,202,881) | (44,498,967) |
| Total Operating Expenses | 4,299,671,190 | 4,266,126,598 | 4,552,200,247 | 4,615,226,434 | 4,709,173,579 | 4,856,852,127 | 5,064,490,186 | 5,049,374,735 | 5,346,412,975 |
| **Administrative, General, and Other Expenses ($)** | | | | | | | | | |
| Insurance, Administrative, General, and Allocated Central Office Costs | 748,005,198 | 770,500,769 | 793,673,611 | 817,544,147 | 842,133,417 | 867,463,096 | 893,555,516 | 920,433,681 | 948,121,293 |
| Property Taxes | 138,543,737 | 138,701,678 | 138,863,408 | 139,029,033 | 139,198,656 | 139,372,389 | 139,550,343 | 139,732,633 | 139,919,381 |
| Decommissioning Funding | 46,239,682 | 40,866,082 | 32,688,582 | 32,688,582 | 32,688,582 | 30,421,090 | 30,421,090 | 30,421,090 | 30,421,090 |
| Total Administrative and General Expenses | 932,788,617 | 950,068,528 | 965,225,601 | 989,261,761 | 1,014,020,655 | 1,037,256,575 | 1,063,526,948 | 1,090,587,404 | 1,118,461,764 |
| **Net Earnings on Sithe Equity**[1] | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Net Earnings on Amergen Equity** | 148,999,496 | 170,684,894 | 162,201,375 | 177,513,096 | 194,072,717 | 189,899,057 | 196,582,945 | 222,600,781 | 212,223,351 |
| **Operating Income ($)**[2] | 2,913,344,712 | 3,086,768,671 | 3,082,769,163 | 3,193,402,607 | 3,273,543,773 | 3,402,076,543 | 3,479,605,024 | 3,723,035,506 | 3,671,215,181 |
| Tax Depreciation | 367,392,686 | 378,764,421 | 392,986,992 | 408,370,177 | 415,000,903 | 416,853,269 | 421,936,704 | 433,304,171 | 451,264,051 |
| Interest Expenses | 263,608,870 | 257,473,870 | 251,338,870 | 251,338,870 | 251,338,870 | 251,338,870 | 251,338,870 | 251,338,870 | 251,338,870 |
| **Taxable Income ($)** | 2,282,343,156 | 2,450,530,380 | 2,438,443,300 | 2,533,693,560 | 2,607,203,999 | 2,733,884,405 | 2,806,329,450 | 3,038,392,465 | 2,968,612,259 |
| Federal Income Tax Rate | 35.00% | 35.00% | 35.00% | 35.00% | 35.00% | 35.00% | 35.00% | 35.00% | 35.00% |
| State Income Tax Rate | 5.00% | 5.00% | 5.00% | 5.00% | 5.00% | 5.00% | 5.00% | 5.00% | 5.00% |
| Income Taxes | 872,996,257 | 937,327,870 | 932,704,562 | 969,137,787 | 997,255,530 | 1,045,710,785 | 1,073,421,015 | 1,162,185,118 | 1,135,494,189 |
| Capitalized Costs | 371,231,017 | 374,439,187 | 440,432,195 | 412,060,596 | 400,333,924 | 431,700,689 | 443,994,315 | 553,206,639 | 569,125,547 |
| Principal Repayment | 68,166,667 | 68,166,667 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Cash Flow After Taxes ($)** | 1,337,341,901 | 1,449,361,076 | 1,458,293,535 | 1,560,865,355 | 1,624,615,448 | 1,673,326,200 | 1,710,850,825 | 1,756,304,879 | 1,715,256,575 |

**Changes in Working Capital ($)**

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| Accounts Receivable | 666,400,419 | 677,689,909 | 703,166,136 | 718,364,809 | 733,555,441 | 758,857,182 | 784,253,268 | 803,366,405 | 826,988,881 |
| Accounts Payable | 420,639,699 | 419,718,947 | 445,489,488 | 452,730,882 | 462,608,916 | 477,026,269 | 496,503,808 | 497,484,035 | 524,544,522 |
| Changes in Accounts Receivable | (3,737,043) | 11,289,490 | 25,476,228 | 15,198,673 | 15,190,632 | 25,301,742 | 25,396,085 | 19,113,138 | 23,622,475 |
| Changes in Parts and Materials Inventory | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Changes in Fuel Inventory | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Changes in Accounts Payable | 5,943,664 | (920,752) | 25,770,541 | 7,241,394 | 9,878,035 | 14,417,352 | 19,477,540 | 980,226 | 27,060,488 |
| Total Changes in Working Capital | (9,680,707) | 12,210,242 | (294,313) | 7,957,279 | 5,312,597 | 10,884,389 | 5,918,546 | 18,132,911 | (3,438,012) |
| **Debt Financing—Consolidated Totals ($)** | | | | | | | | | |
| Principal Balance at Start of Year | 3,322,508,333 | 3,254,341,667 | 3,186,175,000 | 3,186,175,000 | 3,186,175,000 | 3,186,175,000 | 3,186,175,000 | 3,186,175,000 | 3,186,175,000 |
| Principal Paid | 68,166,667 | 68,166,667 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Interest | 263,608,870 | 257,473,870 | 251,338,870 | 251,338,870 | 251,338,870 | 251,338,870 | 251,338,870 | 251,338,870 | 251,338,870 |
| New Debt Issued During Year | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Balance at End of Year | 3,254,341,667 | 3,186,175,000 | 3,186,175,000 | 3,186,175,000 | 3,186,175,000 | 3,186,175,000 | 3,186,175,000 | 3,186,175,000 | 3,186,175,000 |
| **Cash Available for Debt Service ($)**[3] | 2,551,794,402 | 2,700,119,242 | 2,642,631,281 | 2,773,384,733 | 2,867,897,251 | 2,959,491,466 | 3,029,692,164 | 3,151,695,956 | 3,105,527,646 |
| **Debt Service ($)** | 331,775,537 | 325,640,537 | 251,338,870 | 251,338,870 | 251,338,870 | 251,338,870 | 251,338,870 | 251,338,870 | 251,338,870 |
| **Debt Service Coverage Ratio**[4] | 7.69 | 8.29 | 10.51 | 11.03 | 11.41 | 11.77 | 12.05 | 12.54 | 12.36 |
| Minimum DSCR = | | | | | | | | | |
| 20-Year Average DSCR = | | | | | | | | | |

**Notes:**

1 **Revenues less Expenses for the 49.9% Sithe equity share. After 1/1/03, Sithe Revenues and Expenses are consolidated with the other Genco plants.**

2 **Revenues less Operating Expenses less Administrative and General Expenses, plus Net Earnings on Equity.**

3 **Operating Income less Capitalized Costs less Changes in Working Capital.**

4 **Cash Available for Debt Service divided by Debt Service.**



**Sargent & Lundy**
**Table 4—Income Summary (Overbuild Case)**
**(Current $'s)**

| | Projected (Current $'s) | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | **2001** | **2002** | **2003** | **2004** | **2005** | **2006** | **2007** | **2008** | **2009** | **2010** | **2011** |
| Inflation | 3.00% | 3.00% | 3.00% | 3.00% | 3.00% | 3.00% | 3.00% | 3.00% | 3.00% | 3.00% | 3.00% |
| Inflation Factor | 1.0300 | 1.0609 | 1.0927 | 1.1255 | 1.1593 | 1.1941 | 1.2299 | 1.2668 | 1.3048 | 1.3439 | 1.3842 |
| **Revenues ($)** | | | | | | | | | | | |
| Revenues from Market Sales | 1,757,516,765 | 1,979,322,543 | 3,177,185,381 | 2,794,562,511 | 2,214,717,238 | 2,250,521,049 | 4,737,320,933 | 4,960,035,852 | 5,138,664,339 | 5,357,367,406 | 7,747,043,989 |
| Revenues from Affiliate Sales | 4,218,176,000 | 4,317,096,960 | 4,540,600,033 | 4,653,003,372 | 3,602,327,170 | 3,850,878,805 | 1,638,678,936 | 1,677,718,595 | 1,718,042,815 | 1,758,771,125 | 0 |
| Steam Revenues | 2,015,710 | 2,076,181 | 2,138,467 | 2,202,621 | 2,268,699 | 2,336,760 | 2,406,863 | 2,479,069 | 2,553,441 | 2,630,044 | 2,708,946 |
| Total Revenues | 5,977,708,475 | 6,298,495,684 | 7,719,923,881 | 7,449,768,504 | 5,819,313,108 | 6,103,736,614 | 6,378,406,732 | 6,640,233,516 | 6,859,260,595 | 7,118,768,575 | 7,749,752,935 |
| **Operating Expenses ($)** | | | | | | | | | | | |
| Operation and Maintenance | 1,168,028,249 | 1,253,216,321 | 1,350,517,340 | 1,425,298,818 | 1,481,433,281 | 1,532,808,305 | 1,492,507,890 | 1,680,800,158 | 1,634,073,566 | 1,748,967,230 | 1,760,692,933 |
| Fuel Costs | 686,649,215 | 682,813,248 | 1,509,421,437 | 1,440,983,610 | 1,382,723,286 | 1,455,182,611 | 1,501,707,467 | 1,577,269,806 | 1,651,944,899 | 1,764,419,912 | 1,849,465,596 |
| Purchased Power | 1,715,123,018 | 2,042,305,489 | 2,455,364,263 | 2,292,802,213 | 784,864,885 | 748,111,552 | 719,184,106 | 688,886,962 | 671,888,813 | 683,082,465 | 675,740,252 |
| $SO_2$ Costs | 9,602,239 | 16,728,497 | 24,358,799 | 21,492,670 | 22,282,127 | 25,579,758 | 26,979,786 | 28,859,301 | 30,857,117 | 32,715,767 | 34,831,760 |
| $NO_x$ Costs | 6,389,632 | 6,573,705 | 25,662,339 | 22,716,536 | 22,573,321 | 24,339,061 | 25,933,695 | 28,012,542 | 29,155,830 | 33,050,891 | 34,437,199 |
| deduct $SO_2$ Allowances | (5,113,551) | (9,263,391) | (23,795,714) | (26,914,007) | (30,517,536) | (34,559,911) | (35,596,709) | (36,664,610) | (37,764,548) | (38,525,628) | (39,681,397) |
| deduct $NO_x$ Allowances | (5,974,384) | (6,153,615) | (26,922,607) | (27,730,285) | (28,562,194) | (29,419,060) | (30,301,631) | (31,210,680) | (32,147,001) | (33,111,411) | (34,104,753) |
| Total Operating Expenses | 3,574,704,418 | 3,986,220,254 | 5,314,605,857 | 5,148,649,554 | 3,634,797,170 | 3,722,042,317 | 3,700,414,605 | 3,935,953,478 | 3,948,008,678 | 4,190,599,225 | 4,281,381,590 |
| **Administrative, General, and Other Expenses ($)** | | | | | | | | | | | |
| Insurance, Administrative, General, and Allocated Central Office Costs | 544,025,913 | 555,912,086 | 576,242,255 | 594,329,925 | 609,880,724 | 627,201,214 | 646,060,199 | 664,407,782 | 684,386,771 | 704,967,159 | 726,167,076 |
| Property Taxes | 113,000,000 | 109,000,000 | 138,678,827 | 140,431,039 | 140,639,870 | 140,801,365 | 139,696,174 | 138,792,958 | 138,091,752 | 138,238,829 | 138,389,487 |
| Decommissioning Funding | 75,117,001 | 75,731,132 | 75,731,132 | 75,731,132 | 75,731,132 | 75,731,132 | 61,155,832 | 61,155,832 | 61,155,832 | 61,155,832 | 61,155,832 |
| Total Administrative and General Expenses | 732,142,915 | 740,643,218 | 790,652,213 | 810,492,095 | 826,251,726 | 843,733,711 | 846,912,204 | 864,356,571 | 883,634,355 | 904,361,820 | 925,712,394 |
| **Net Earnings on Sithe Equity**[1] | 6,021,982 | 9,273,733 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Net Earnings on Amergen Equity** | 88,144,349 | 69,434,559 | 88,460,800 | 73,026,117 | 51,415,140 | 60,350,267 | 83,744,142 | 85,386,071 | 103,801,763 | 147,261,512 | 138,870,238 |
| **Operating Income ($)**[2] | 1,765,027,474 | 1,650,340,505 | 1,703,126,611 | 1,563,652,971 | 1,409,679,352 | 1,598,310,853 | 1,914,824,065 | 1,925,309,537 | 2,131,419,327 | 2,171,069,041 | 2,681,529,189 |
| Tax Depreciation | 206,338,932 | 223,270,872 | 393,041,051 | 351,339,896 | 313,066,834 | 319,707,351 | 322,717,919 | 329,412,840 | 333,461,367 | 344,324,804 | 356,795,949 |
| Interest Expenses | 46,020,647 | 69,686,719 | 300,983,870 | 298,416,870 | 295,849,870 | 293,282,870 | 290,715,870 | 288,148,870 | 282,013,870 | 275,878,870 | 269,743,870 |
| **Taxable Income ($)** | 1,512,667,894 | 1,357,382,914 | 1,009,101,690 | 913,896,205 | 800,762,648 | 985,320,632 | 1,301,390,276 | 1,307,747,827 | 1,515,944,090 | 1,550,865,367 | 2,054,989,370 |
| Federal Income Tax Rate | 35.00% | 35.00% | 35.00% | 35.00% | 35.00% | 35.00% | 35.00% | 35.00% | 35.00% | 35.00% | 35.00% |
| State Income Tax Rate | 5.00% | 5.00% | 5.00% | 5.00% | 5.00% | 5.00% | 5.00% | 5.00% | 5.00% | 5.00% | 5.00% |

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Income Taxes | 578,595,470 | 519,198,965 | 385,981,396 | 349,565,299 | 306,291,713 | 376,885,142 | 497,781,781 | 500,213,544 | 579,848,614 | 593,206,003 | 786,033,434 |
| Capitalized Costs | 306,078,649 | 285,868,005 | 256,985,321 | 306,298,325 | 335,010,159 | 274,860,222 | 261,778,869 | 328,686,157 | 306,654,107 | 395,718,820 | 345,967,546 |
| Principal Repayment | 0 | 0 | 30,200,000 | 30,200,000 | 30,200,000 | 30,200,000 | 30,200,000 | 68,166,667 | 68,166,667 | 68,166,667 | 68,166,667 |
| **Cash Flow After Taxes ($)** | 834,332,708 | 775,586,817 | 728,976,024 | 579,172,478 | 442,327,611 | 623,082,620 | 834,347,546 | 740,094,299 | 894,736,069 | 838,098,681 | 1,211,617,672 |
| **Changes in Working Capital ($)** | | | | | | | | | | | |
| Accounts Receivable | 840,715,123 | 880,639,335 | 1,024,513,424 | 988,110,158 | 589,921,720 | 620,269,587 | 651,373,342 | 684,357,235 | 719,226,906 | 749,988,915 | 645,812,745 |
| Accounts Payable | 685,800,278 | 734,275,723 | 872,090,443 | 845,877,739 | 458,702,119 | 474,061,830 | 482,045,681 | 514,367,880 | 533,654,811 | 564,722,066 | 417,295,722 |
| Changes in Accounts Receivable | 0 | 39,924,212 | 143,874,089 | (36,403,266) | (398,188,437) | 30,347,867 | 31,103,755 | 32,983,892 | 34,869,672 | 30,762,009 | (104,176,171) |
| Changes in Parts and Materials Inventory | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Changes in Fuel Inventory | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Changes in Accounts Payable | 0 | 48,475,446 | 137,814,720 | (26,212,704) | (387,175,620) | 15,359,711 | 7,983,851 | 32,322,199 | 19,286,931 | 31,067,255 | (147,426,344) |
| Total Changes in Working Capital | 0 | (8,551,233) | 6,059,369 | (10,190,562) | (11,012,818) | 14,988,156 | 23,119,904 | 661,694 | 15,582,741 | (305,246) | 43,250,173 |
| **Debt Financing—Consolidated Totals ($)** | | | | | | | | | | | |
| Principal Balance at Start of Year | 195,465,000 | 1,016,645,000 | 3,746,175,000 | 3,715,975,000 | 3,685,775,000 | 3,655,575,000 | 3,625,375,000 | 3,595,175,000 | 3,527,008,333 | 3,458,841,667 | 3,390,675,000 |
| Principal Paid | 0 | 0 | 30,200,000 | 30,200,000 | 30,200,000 | 30,200,000 | 30,200,000 | 68,166,667 | 68,166,667 | 68,166,667 | 68,166,667 |
| Interest | 46,020,647 | 69,686,719 | 300,983,870 | 298,416,870 | 295,849,870 | 293,282,870 | 290,715,870 | 288,148,870 | 282,013,870 | 275,878,870 | 269,743,870 |
| New Debt Issued During Year | 821,180,000 | 2,729,530,000 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Balance at End of Year | 1,016,645,000 | 3,746,175,000 | 3,715,975,000 | 3,685,775,000 | 3,655,575,000 | 3,625,375,000 | 3,595,175,000 | 3,527,008,333 | 3,458,841,667 | 3,390,675,000 | 3,322,508,333 |
| **Cash Available for Debt Service ($)[3]** | 1,458,948,825 | 1,373,023,734 | 1,440,081,921 | 1,267,545,209 | 1,085,682,011 | 1,308,462,475 | 1,629,925,293 | 1,595,961,686 | 1,809,182,479 | 1,775,655,467 | 2,292,311,469 |
| **Debt Service ($)** | 46,020,647 | 69,686,719 | 331,183,870 | 328,616,870 | 326,049,870 | 323,482,870 | 320,915,870 | 356,315,537 | 350,180,537 | 344,045,537 | 337,910,537 |
| **Debt Service Coverage Ratio[4]** | 31.70 | 19.70 | 4.35 | 3.86 | 3.33 | 4.04 | 5.08 | 4.48 | 5.17 | 5.16 | 6.78 |
| Minimum DSCR = | 3.33 | | | | | | | | | | |
| 20-Year Average DSCR = | 10.02 | | | | | | | | | | |

**Notes:**

1 Revenues less Expenses for the 49.9% Sithe equity share. After 1/1/03, Sithe Revenues and Expenses are consolidated with the other Genco plants.

2 Revenues less Operating Expenses less Administrative and General Expenses, plus Net Earnings on Equity.

3 Operating Income less Capitalized Costs less Changes in Working Capital.

4 Cash Available for Debt Service divided by Debt Service.



## Sargent & Lundy
## Table 4—Income Summary (Overbuild Case)
## (Current $'s)

| | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|---|---|---|---|
| Inflation | 3.00% | 3.00% | 3.00% | 3.00% | 3.00% | 3.00% | 3.00% | 3.00% | 3.00% |
| Inflation Factor | 1.4258 | 1.4685 | 1.5126 | 1.5580 | 1.6047 | 1.6528 | 1.7024 | 1.7535 | 1.8061 |
| **Revenues ($)** | | | | | | | | | |
| Revenues from Market Sales | 7,874,032,441 | 8,305,070,911 | 8,680,258,545 | 9,011,207,097 | 9,235,993,716 | 9,573,969,877 | 9,911,989,406 | 10,180,623,254 | 10,480,212,330 |
| Revenues from Affiliate Sales | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Steam Revenues | 2,790,214 | 2,873,920 | 2,960,138 | 3,048,942 | 3,140,411 | 3,234,623 | 3,331,662 | 3,431,611 | 3,534,560 |
| Total Revenues | 7,876,822,655 | 8,307,944,831 | 8,683,218,683 | 9,014,256,039 | 9,239,134,127 | 9,577,204,500 | 9,915,321,067 | 10,184,054,866 | 10,483,746,890 |
| **Operating Expenses ($)** | | | | | | | | | |
| Operation and Maintenance | 1,880,909,243 | 1,835,232,507 | 2,045,023,439 | 2,068,063,333 | 2,127,856,719 | 2,198,774,267 | 2,330,672,676 | 2,283,958,752 | 2,511,759,500 |
| Fuel Costs | 1,928,753,138 | 2,017,962,579 | 2,109,917,102 | 2,177,042,395 | 2,218,316,745 | 2,295,470,080 | 2,365,476,900 | 2,420,509,418 | 2,499,165,306 |
| Purchased Power | 548,384,017 | 485,291,706 | 511,261,394 | 510,402,910 | 509,300,983 | 515,734,743 | 513,572,573 | 502,648,393 | 490,599,522 |
| $SO_2$ Costs | 36,530,835 | 38,291,281 | 39,557,655 | 40,349,132 | 41,427,159 | 42,771,981 | 43,920,709 | 45,067,886 | 46,795,185 |
| $NO_x$ Costs | 36,617,556 | 38,488,300 | 40,630,607 | 42,278,082 | 41,858,788 | 43,584,293 | 45,077,907 | 44,937,733 | 47,133,270 |
| deduct $SO_2$ Allowances | (40,871,839) | (42,097,994) | (43,360,934) | (44,661,762) | (46,001,615) | (47,381,664) | (48,803,113) | (50,267,207) | (51,775,223) |
| deduct $NO_x$ Allowances | (35,127,896) | (36,181,732) | (37,267,184) | (38,385,200) | (39,536,756) | (40,722,859) | (41,944,544) | (43,202,881) | (44,498,967) |
| Total Operating Expenses | 4,355,195,056 | 4,336,986,647 | 4,665,762,079 | 4,755,088,890 | 4,853,222,022 | 5,008,230,842 | 5,207,973,107 | 5,203,652,094 | 5,499,178,592 |
| **Administrative, General, and Other Expenses ($)** | | | | | | | | | |
| Insurance, Administrative, General, and Allocated Central Office Costs | 748,005,198 | 770,500,769 | 793,673,611 | 817,544,147 | 842,133,417 | 867,463,096 | 893,555,516 | 920,433,681 | 948,121,293 |
| Property Taxes | 138,543,737 | 138,701,678 | 138,863,408 | 139,029,033 | 139,198,656 | 139,372,389 | 139,550,343 | 139,732,633 | 139,919,381 |
| Decommissioning Funding | 46,239,682 | 40,866,082 | 32,688,582 | 32,688,582 | 32,688,582 | 30,421,090 | 30,421,090 | 30,421,090 | 30,421,090 |
| Total Administrative and General Expenses | 932,788,617 | 950,068,528 | 965,225,601 | 989,261,761 | 1,014,020,655 | 1,037,256,575 | 1,063,526,948 | 1,090,587,404 | 1,118,461,764 |
| **Net Earnings on Sithe Equity[1]** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Net Earnings on Amergen Equity** | 153,778,290 | 191,530,878 | 184,572,244 | 203,346,458 | 220,717,484 | 218,368,955 | 228,176,908 | 256,476,327 | 245,575,027 |
| **Operating Income ($)[2]** | 2,742,617,272 | 3,212,420,534 | 3,236,803,247 | 3,473,251,847 | 3,592,608,934 | 3,750,086,037 | 3,871,997,919 | 4,146,291,694 | 4,111,681,561 |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| Tax Depreciation | 367,392,686 | 378,764,421 | 392,986,992 | 408,370,177 | 415,000,903 | 416,853,269 | 421,936,704 | 433,304,171 | 451,264,051 |
| Interest Expenses | 263,608,870 | 257,473,870 | 251,338,870 | 251,338,870 | 251,338,870 | 251,338,870 | 251,338,870 | 251,338,870 | 251,338,870 |
| **Taxable Income ($)** | 2,111,615,716 | 2,576,182,243 | 2,592,477,385 | 2,813,542,799 | 2,926,269,160 | 3,081,893,899 | 3,198,722,346 | 3,461,648,653 | 3,409,078,640 |
| Federal Income Tax Rate | 35.00% | 35.00% | 35.00% | 35.00% | 35.00% | 35.00% | 35.00% | 35.00% | 35.00% |
| State Income Tax Rate | 5.00% | 5.00% | 5.00% | 5.00% | 5.00% | 5.00% | 5.00% | 5.00% | 5.00% |
| Income Taxes | 807,693,011 | 985,389,708 | 991,622,600 | 1,076,180,121 | 1,119,297,954 | 1,178,824,416 | 1,223,511,297 | 1,324,080,610 | 1,303,972,580 |
| Capitalized Costs | 371,231,017 | 374,439,187 | 440,432,195 | 412,060,596 | 400,333,924 | 431,700,689 | 443,994,315 | 553,206,639 | 569,125,547 |
| Principal Repayment | 68,166,667 | 68,166,667 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Cash Flow After Taxes ($)** | 1,231,917,707 | 1,526,951,102 | 1,553,409,583 | 1,733,672,260 | 1,821,638,186 | 1,888,222,062 | 1,953,153,437 | 2,017,665,575 | 1,987,244,565 |
| **Changes in Working Capital ($)** | | | | | | | | | |
| Accounts Receivable | 656,401,888 | 692,328,736 | 723,601,557 | 751,188,003 | 769,927,844 | 798,100,375 | 826,276,756 | 848,671,239 | 873,645,574 |
| Accounts Payable | 425,266,688 | 425,623,951 | 454,952,974 | 464,386,086 | 474,612,953 | 489,641,162 | 508,460,719 | 510,340,481 | 537,274,990 |
| Changes in Accounts Receivable | 10,589,143 | 35,926,848 | 31,272,821 | 27,586,446 | 18,739,841 | 28,172,531 | 28,176,381 | 22,394,483 | 24,974,335 |
| Changes in Parts and Materials Inventory | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Changes in Fuel Inventory | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Changes in Accounts Payable | 7,970,966 | 357,263 | 29,329,023 | 9,433,112 | 10,226,867 | 15,028,208 | 18,819,557 | 1,879,763 | 26,934,509 |
| Total Changes in Working Capital | 2,618,178 | 35,569,585 | 1,943,798 | 18,153,334 | 8,512,974 | 13,144,323 | 9,356,824 | 20,514,720 | (1,960,174) |
| **Debt Financing—Consolidated Totals ($)** | | | | | | | | | |
| Principal Balance at Start of Year | 3,322,508,333 | 3,254,341,667 | 3,186,175,000 | 3,186,175,000 | 3,186,175,000 | 3,186,175,000 | 3,186,175,000 | 3,186,175,000 | 3,186,175,000 |
| Principal Paid | 68,166,667 | 68,166,667 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Interest | 263,608,870 | 257,473,870 | 251,338,870 | 251,338,870 | 251,338,870 | 251,338,870 | 251,338,870 | 251,338,870 | 251,338,870 |
| New Debt Issued During Year | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Balance at End of Year | 3,254,341,667 | 3,186,175,000 | 3,186,175,000 | 3,186,175,000 | 3,186,175,000 | 3,186,175,000 | 3,186,175,000 | 3,186,175,000 | 3,186,175,000 |
| **Cash Available for Debt Service ($)**[3] | 2,368,768,077 | 2,802,411,762 | 2,794,427,254 | 3,043,037,917 | 3,183,762,036 | 3,305,241,026 | 3,418,646,781 | 3,572,570,334 | 3,544,516,188 |
| **Debt Service ($)** | 331,775,537 | 325,640,537 | 251,338,870 | 251,338,870 | 251,338,870 | 251,338,870 | 251,338,870 | 251,338,870 | 251,338,870 |
| **Debt Service Coverage Ratio**[4] | 7.14 | 8.61 | 11.12 | 12.11 | 12.67 | 13.15 | 13.60 | 14.21 | 14.10 |
| Minimum DSCR = | | | | | | | | | |
| 20-Year Average DSCR = | | | | | | | | | |

**Notes:**

1 Revenues less Expenses for the 49.9% Sithe equity share. After 1/1/03, Sithe Revenues and Expenses are consolidated with the other Genco plants.

2 Revenues less Operating Expenses less Administrative and General Expenses, plus Net Earnings on Equity.

3 Operating Income less Capitalized Costs less Changes in Working Capital.

4 Cash Available for Debt Service divided by Debt Service.



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**APPENDIX B**

**INDEPENDENT MARKET CONSULTANT'S REPORT**

B–1

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# Exelon Generation

## Independent Market Expert's Report for the PJM, MAIN, NEPOOL, and New York Regions

## June 1, 2001

## Condensed Version of March 12 Report

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# Exelon Generation

## Independent Market Expert's Report for the PJM, MAIN, NEPOOL, and New York Regions

## June 1, 2001

## Condensed Version of March 12 Report

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Version: Final

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***DISCLAIMER***

This report presents the analysis of PA Consulting Services (PA) for the following North American Electric Reliability Council (NERC) regions:

- ***PJM***—Pennsylvania-New Jersey-Maryland Interconnection LLC
- ***MAIN***—Mid-America Interconnected Network
- ***NPCC-NEPOOL***—New England Power Pool component of the Northeast Power Coordinating Council region
- ***NPCC-New York***—New York component of the Northeast Power Coordinating Council region.

In addition, summary price forecasts are provided for regions where Exelon Generation (ExGen) has power contracts:

- ***ERCOT***—Electric Reliability Council of Texas
- ***SERC***—Southeastern Electric Reliability Council
- ***SPP***—Southwest Power Pool.

(i) some information in the report is necessarily based on predictions and estimates of future events and behaviors,

(ii) such predictions or estimates may differ from that which other experts specializing in the electricity industry might present,

(iii) the provision of a report by PA does not obviate the need for potential investors to make further appropriate inquiries as to the accuracy of the information included therein, or to undertake an analysis of their own,

(iv) this report is not intended to be a complete and exhaustive analysis of the subject issues and therefore will not consider some factors that are important to a potential investor's decision making, and

(v) PA and its employees cannot accept liability for loss suffered in consequence of reliance on the report. Nothing in PA's report should be taken as a promise or guarantee as to the occurrence of any future events.



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**TABLE OF CONTENTS**

# 1. INTRODUCTION

## 1.1 BACKGROUND

PA Consulting Services (PA) was retained by Exelon Generation (ExGen) to assess future prices for electric energy and capacity in the markets where ExGen owns, has rights to, or is developing generating assets, as shown in Table 1-1. The markets analyzed in this report include:

- ***PJM***—Pennsylvania-New Jersey-Maryland Interconnection LLC
- ***MAIN***—Mid-America Interconnected Network
- ***NPCC-NEPOOL***—New England Power Pool component of the Northeast Power Coordinating Council region
- ***NPCC-New York***—New York component of the Northeast Power Coordinating Council region.

In addition, summary price forecasts are provided for regions where ExGen has contracts for the purchase of energy:

- ***ERCOT***—Electric Reliability Council of Texas
- ***SERC***—Southeastern Electric Reliability Council
- ***SPP***—Southwest Power Pool.

This report assesses the price projections based on stated assumptions for electric prices in the markets mentioned above and presents the results of PA's analysis. The actual unit specific results were provided to the independent engineer (Sargent & Lundy) for the development of financial projections for the entire fleet of ExGen assets.

### 1.2 ASSET PORTFOLIO DESCRIPTION

ExGen owns or has ownership interests in companies with 31,632 MW of generation capacity in the aggregate, as summarized in Table 1-1. Load serving requirements and contracts are not included in this amount and are discussed in Appendix B.

**Table 1-1**
**Regional Market Location of**
**ExGen Generating Assets**

| Regional Market | Asset Type Distribution | Total Capacity[1] (MW) |
|---|---|---|
| PJM | Nuclear—68%<br>Gas/Oil—20%<br>Coal—12%<br>Hydro/PS—10% | 13,448 |
| MAIN | Nuclear—100% | 11,495 |
| NEPOOL | Nuclear—10%<br>Gas/Oil—90% | 4,617 |
| New York | Gas/Oil—100% | 2,072 |

1 Summer rating in 2001.

### 1.3 KEY ASSUMPTIONS

There are many important assumptions in the development of the price projections. However, three critical input assumptions that affect energy pricing in this analysis include, demand growth, fuel



prices, and capacity additions and retirements. Variations in these three factors, as well as other assumptions, can lead to significant variations in the end price results. PA has tested the forecasts presented herein for variations of these three assumptions, which represent the high fuel, low fuel, and overbuild sensitivity cases analyzed in Chapter 2.

Another key fundamental assumption on which this analysis is based is the concept of a competitive wholesale market. These results are based on the assumptions that rational markets for electricity exist, that markets are attempting to adjust to economic equilibrium, and that market players make decisions based on sound economic judgment.

***Demand.*** Peak demand in the PJM, MAIN, NEPOOL, and New York regions is forecasted to grow at annual compound growth rates of approximately 1.4%, 1.4%, 1.5%, and 0.8%, respectively, from 2001 through 2020.

***Fuel prices.*** Forecasts for natural gas and oil use futures prices in the near term and a consensus fuel price forecast derived from published fuel price forecasts in the long term. The natural gas and oil fuel price forecasts used are found in Chapter 3. The marginal nuclear fuel costs were assumed to be $5.70/MWh, while the marginal coal prices were developed for each individual unit.

**Capacity additions and retirements.** PA estimates capacity additions and retirements based on three main principles. First, near-term (2001 through 2003) capacity additions are based upon PA's investigation of new capacity addition announcements through a review of publicly available information, including newspapers, trade journals, developer and utility web sites and contacts, industry news publications, etc. PA has developed a database that tracks the status of new capacity additions and evaluates the probability of announced projects actually being constructed. Second, capacity additions from 2004 through 2020 are based on economic analyses of generic new units, Third, units that are not competitive are retired in accordance with the methodology described in Appendix C.

PA's base case results incorporate PA's best estimate of new capacity additions and retirements. The capacity and online dates for specific projects are identified in Chapter 3. These unit assumptions are based on PA's best estimate at the time the analyses are prepared. Due to deregulation of the electric industry, changes in economic conditions, the volatile nature of the industry, and the lead times associated with building new plants, these assumptions are likely to deviate from what actually transpires. Individual unit characteristics such as online dates, capacities, and even the projects themselves may change. Projects may be canceled or new ones may be added.

The assumed capacity additions and retirements included in this analysis are summarized in Table 1-2.

**Table 1-2**
**Capacity Additions and Retirements**

| Region | Capacity Additions 2001-2003 (MW) | Capacity Additions 2004-2020 (MW) | Capacity 2001-2020 2001-2020 (MW) |
|---|---|---|---|
| PJM | 5,730 | 15,915 | 2,149 |
| MAIN | 7,105 | 14,525 | 4,205 |

| | | | |
|---|---|---|---|
| NEPOOL | 8,741 | 6,585 | 7,498 |
| New York[1] | 1,880 | 4,680 | 6,345 |

1 Does not include In-City or Long Island.

A more complete discussion of the three key assumptions of demand growth, fuel prices, and capacity additions and retirements may be found in Chapter 3.



## 1.4 RESULTS

PA produced forecasts of generation prices by examining two components of value in our fundamental analysis:

- Energy based on a production-cost model with prices reflecting marginal cost in each hour.
- Compensation for capacity, which represents the additional margin necessary to keep an economic amount of capacity in the market. This compensation for capacity is not the same as a capacity price in a traded capacity market.

The ***energy price*** forecasts for each region represent the average annual system marginal cost of generating energy in these markets. The ***compensation for capacity*** forecasts are an estimation of the total compensation for capacity that generators need to receive over and above the system marginal cost energy price in order to keep a minimum amount of generation in the market. Not all generators will receive the full capacity compensation outlined herein. Finally, an ***all-in price*** forecast combines the energy price and the compensation for capacity (assuming 100% load). This price reflects PA's estimate of the total market price that generators must receive to keep the market in equilibrium. Compensation for capacity and energy prices are inversely related; as one rises the other falls, so that the all-in price remains somewhat in balance.

PA modeled the generation asset portfolio under four scenarios. First, using the assumptions presented in Chapter 3, PA developed a base case for each region that reflects PA's best assessment of future market conditions. It should be recognized that these cases will vary to the extent the input assumptions change, and such assumptions should be reviewed with the same rigor as the resulting forecast. The base case is described below:

- The ***base case*** incorporates the actual spot and futures gas and oil prices through December 2003. Prices then decrease linearly to the consensus forecast price in year 2005. The base case is constructed using generation and load growth data stated in the EIA Form 411s combined with PA's merchant plant and in-house fuel forecast. This method is discussed in further detail in Chapter 3.

In addition to the base case, PA developed three other sensitivity cases. These sensitivity cases are intended to provide an indication as to how changes in certain input parameters such as fuel prices and new capacity additions affect forecasted price results. These sensitivities are not intended to be bounding, or worst case scenarios. Their purpose is to determine the impact of an assumed change on the price forecast results. The magnitude of the changes in input parameters may be greater than or less than those assumed in the sensitivities. However, the sensitivity cases can be used to provide some indication as to how the assumed change in the input parameter affects the forecasted price value. The three sensitivity cases evaluated are as follows:

- The ***low fuel case*** evaluates the effects of lower gas and oil prices represented as a $0.50/MMBtu reduction in the 2001 gas and oil prices with escalation remaining unchanged (coal prices are not changed).
- The ***high fuel case*** evaluates the effects of higher gas and oil prices throughout the study period. Gas and oil prices are held at the 2001 NYMEX value throughout the study period.
- The ***overbuild case*** evaluates an over-exuberance of merchant plant development in the regions reviewed. Capacity additions in 2001-2003 are the same as in the base case. However, in 2004,

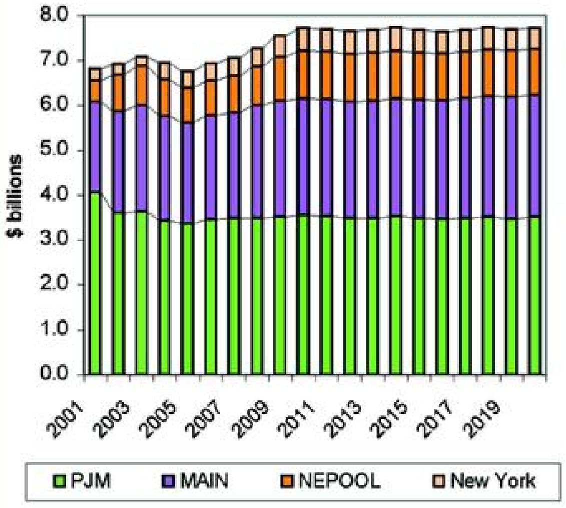


the overbuild case assumes that excess merchant plant capacity is constructed in the following regions:

| | |
|---|---|
| PJM | 4,160 MW |
| MAIN | 5,200 MW |
| NEPOOL | 1,040 MW |
| New York | 2,080 MW |

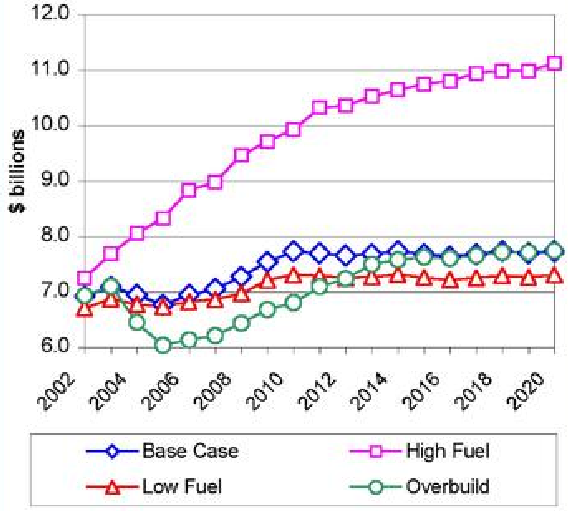
Figure 1-1 shows the summary of total revenues for the base case. Total projected revenues for all of ExGen's assets for each sensitivity case for the period 2002-2020 are compared in Figure 1-2.

**Figure 1-1**
**Summary of Total Revenues[1] ($ billions)**




[1] Revenues do not reflect the effect of contracts.

**Figure 1-2**
**Summary of Total Revenues by Case[1]**



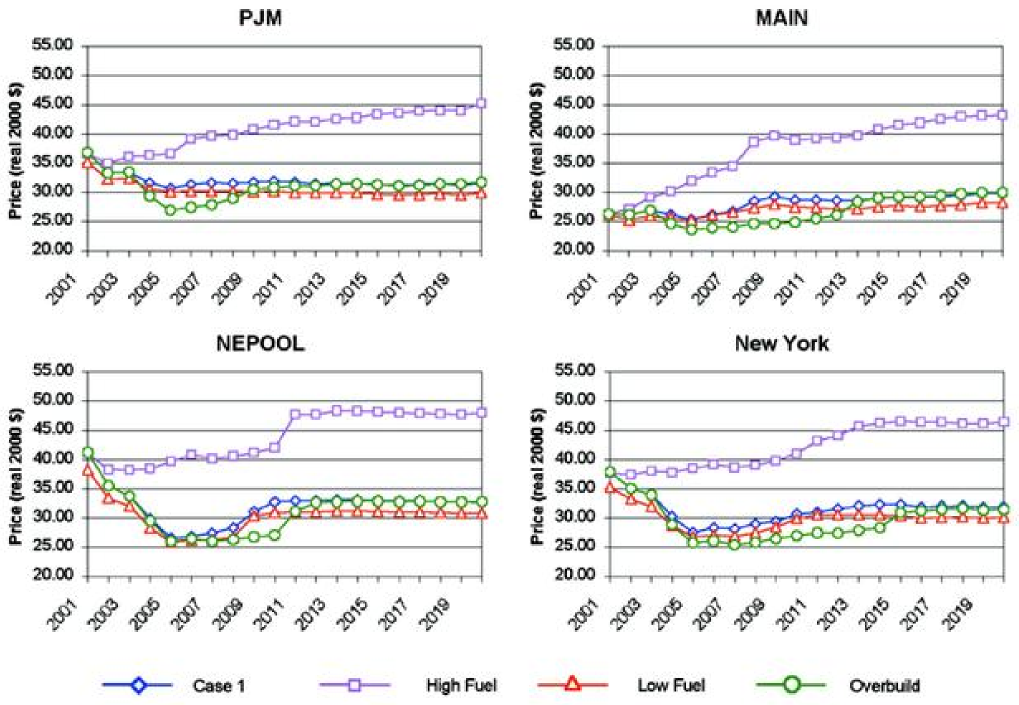

[1] Revenues do not reflect the effect of contracts.

The all-in market price combines the energy price with the price received by generators for other relevant generation services and energy products in the market. The all-in price reflects PA's estimate of



the total market price that generators will recover in the markets at a 100% capacity factor. The all-in price results of the study are summarized in Figure 1-3.

**Figure 1-3**
**Average Regional All-In Price Forecasts**




[1] Results are expressed in real 2000 dollars.

## 1.5 REPORT STRUCTURE

Chapter 2 contains a discussion of each of the relevant generation markets organized by NERC transmission regions and subregions. Each market discussion includes an overview of the market with a discussion of the current generation mix and a summary of PA's fundamental load and generation requirements forecast for the period of 2001-2020. The forecasts of energy prices and capacity compensation for the base case as well as associated sensitivity cases are provided. Dispatch curves are provided for 2004 and 2010 for the regions of interest. These curves illustrate the marginal cost of the last generator for the given load shown on the horizontal axis. The location of the assets in the generating portfolio are identified on the curves.

Key assumptions that drive the forecast results are provided in Chapter 3.

Appendix A provides historical electricity prices for the regions of interest while Appendix B provides an analysis of power contracts. Appendix C reviews the methodology used to develop the forecasts presented in Chapter 2. Appendix D contains a glossary divided into two sections: definitions of relevant terms and definitions of acronyms.

# 2. *REGIONAL ANALYSIS*

## 2.1 INTRODUCTION

Over the past two decades, the structure of the electric power industry has been dramatically changed by the emergence of a networked industry. A market trend that has paralleled the integration of the transmission network is the introduction of wholesale and retail competition in formerly regulated markets. These market developments have added new dimensions to the risk of owning and operating generation plants. This chapter examines the current and projected development of wholesale power markets in each target regions before summarizing the market price projections for the pricing areas evaluated for ExGen (see Table 2-1).

**Table 2-1**
**ExGen Asset Pricing Areas**

| NERC Region | Pricing Area |
|---|---|
| PJM | Central<br>East<br>West |
| MAIN | CECO<br>SCIL |
| NEPOOL | Maine<br>Southeast<br>West |
| New York | East<br>West |

One mechanism for understanding risk is to examine how market prices and generation requirements could change under different scenarios. These scenarios, termed sensitivity cases, are described in this chapter as well as their effect on the projected market power prices.

## 2.2 RISK ISSUES AND SENSITIVITY CASES

Analysis of possible variances in fundamental variables is essential when forecasting market prices in the United States today. Initially a base case was developed for each region using the assumptions outlined in Chapter 3. The base case is not defined as the most likely case. Three sensitivity cases were then developed to aid in understanding some of the downside risks of operating generation assets. It should be recognized that these cases will vary to the extent the input assumptions change, and such assumptions should be reviewed with the same rigor as the resulting forecast. The four cases are outlined below:

- The ***base case*** incorporates the actual spot and futures gas and oil prices through December 2003. Prices then decrease linearly to the consensus forecast price in year 2005. This method is discussed in further detail in Chapter 3.
- The ***low fuel case*** evaluates the effects of lower gas and oil prices represented as a $0.50/MMBtu reduction in the 2001 gas and oil prices.
- The ***high fuel case*** evaluates the effects of higher gas prices throughout the study period. Gas prices are held at the 2001 NYMEX value throughout the study period.
- The ***overbuild case*** evaluates an exuberance of merchant plant development. For purposes of this case, excess entry is presumed to occur early in the study period. PA assumed an additional 4,160 MW and 5,200 MW, and 2,080 MW of new capacity in 2004 in PJM, MAIN, and New York, respectively. New England exceeds the target reserve margins in the base case; however,



an additional 1,040 MW of capacity was added in 2004. (See Table 2-2.) Subsequent to this period of capacity abundance, as the regions experience load growth, we assume the markets eventually return to economic equilibrium.

**Table 2-2**
**Overbuild Case Merchant Plant Capacity Additions (MW)[1]**

| Region | 2001 | 2002 | 2003 | 2004 |
|---|---|---|---|---|
| PJM | 1,296 | 3,232 | 1,202 | 4,160 |
| MAIN | 5,935 | 650 | 520 | 5,200 |
| NEPOOL | 3,256 | 3,990 | 1,495 | 1,040 |
| New York[2] | 0 | 0 | 1,880 | 2,080 |

1 Capacity additions in 2001-2003 are the same as in the Base Case.

2 Does not include In-City and Long Island.

These variances from the base case influence the resulting projections of market price forecasts and subsequent valuation of generation plants. It should be noted that the level of the sensitivities can vary and that there are other areas that can vary in the forecast, including, but not limited to: demand forecasts, new entrant technologies and construction costs, environmental costs, and regulatory structures.

The remaining sections of this chapter are regional sections with of the results of the various cases. Each section begins with a brief summary of the region's background with figures that illustrate the energy and capacity by fuel type. The energy generated by fuel type is estimated based on results of the PA regional models. The capacity by fuel type is based on Energy Information Administration (EIA) Form EIA-411 data or its equivalent. The capacity includes additional new generating capacity additions assumed by PA to be online in 2000. The specific sources from which the information was obtained and the year the information is based upon are provided in the sources listed under the figures. Following the background section is a description of the current power market structure in each of the relevant NERC regions and a brief update on transmission system issues. Market price projections for each region follow the summaries.

For comparison purposes, Appendix A provides recent electricity price information obtained from *Power Markets Week*. The values are the on-peak daily index values for 1999 and 2000. These prices are provided to show recent trends in electricity prices.

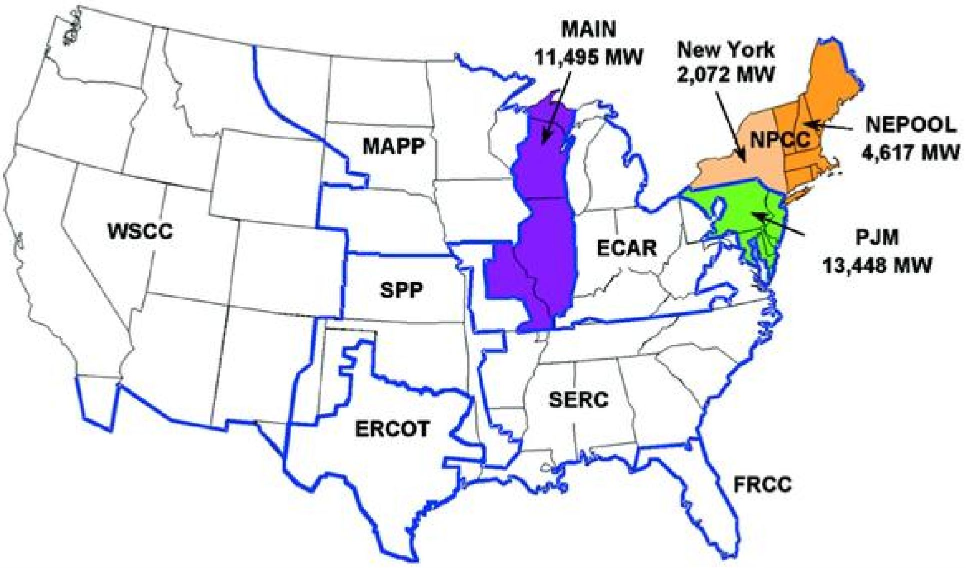
**2.3 OVERVIEW OF THE REGIONAL MARKETS**

Competition and deregulation is progressing piecemeal in the United States and there are significant differences between regions. These differences are largely due to the division of authority over various aspects of the electric power industry between state and federal legislative and regulatory bodies. Competition in the wholesale markets is, in part, defined and shaped by North American Electric Reliability Council (NERC) regions. There are nine major regions. WSCC, the biggest geographic region, is subdivided into four subregions. MAIN and the East Central Area Reliability Coordination Agreement (ECAR) are considered one region. In the Northeast, the NPCC region is



subdivided into two subregions—New York and NEPOOL. Figure 2-1 shows the locations of the regional markets that are analyzed in this report.

Figure 2-1
ExGen Assets in Generation Portfolio by NERC Region




**2.4 PJM**

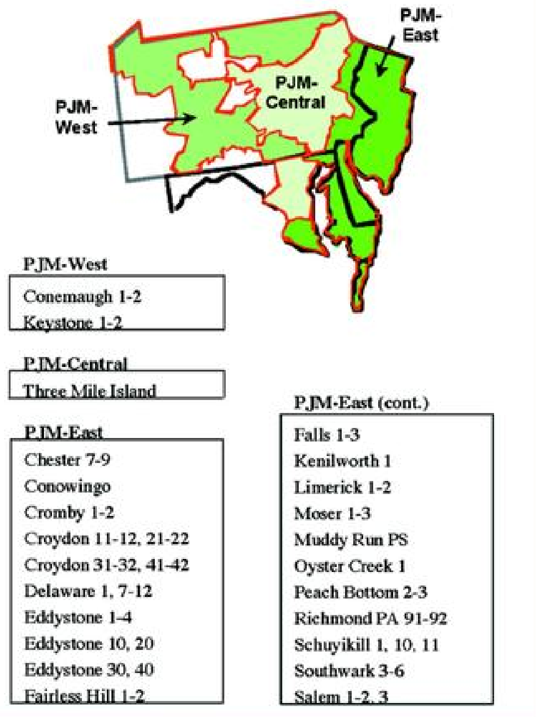
**2.4.1 Background**

PJM is the only control area in the Mid-Atlantic Area Council (MAAC) region, which covers all or part of the states of Pennsylvania, New Jersey, Maryland, Delaware, Virginia, and the District of Columbia. Its members include IOUs, public utilities, independent power marketers, and regulators. The PJM Power Pool is one of the largest centrally dispatched power pool in the world, handling about



8% of U.S. electricity with a combined capacity of over 56,000 MW. Figure 2-2 shows the PJM region and the location of ExGen's generation assets by pricing area.

**Figure 2-2**
**PJM Region**




PJM began operations on April 1, 1998. Its stated objectives are to ensure reliability of the bulk power transmission system and to facilitate an open, competitive wholesale electricity market. To achieve its objectives, PJM manages the PJM Open Access Transmission Tariff, which provides comparative pricing and access to the transmission system. PJM also operates the PJM Interchange Energy Market, which is the region's spot market (power exchange or PX) for wholesale electricity. PJM also provides ancillary services for its transmission customers and performs transmission planning for the region.

The relative mix of the energy generation and capacity in PJM is illustrated in Figures 2-3 and 2-4. Coal dominates the generation in PJM, accounting for 51% of the total energy produced. Nuclear units also comprise a large portion (39%) of the total energy produced. Gas- and oil-fired generation units



represent 37% of PJM's total installed capacity, while coal represents 32% and nuclear facilities account for 22%.

**Figure 2-3**
**PJM Energy – Year 2001**

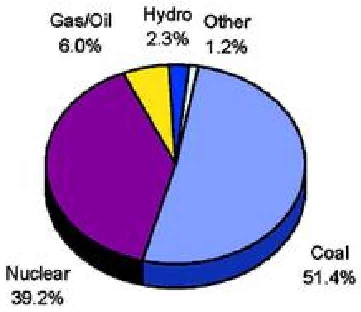
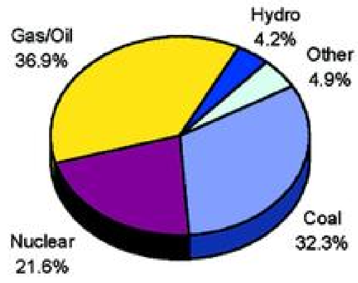



**Figure 2-4**
**PJM Capacity – Year 2001**




**Sources: Figure 2-3: PA Consulting Services Inc. Regional Modeling results. Figure 2-4: 2000 Regional Reliability Council, EIA-411; MAAC Annual Electric Control and Planning Area Report, 2000; and PA Consulting Services Inc.**

### 2.4.2 Power Markets

*A. INTRODUCTION*

The ExGen assets in PJM are located the following pricing areas: PJM-East, PJM-West, and PJM-Central. (See Figure 2-2.)

The PJM wholesale market structure includes the following markets for the services of generators:

*i.* Energy Market

— Day-Ahead Market

— Balancing Market (Real Time)

*ii.* Regulation Market

*iii.* Capacity Credit Market

— Daily Market Operation

— Monthly Market Operation

*iv.* Fixed Transmission Rights (FTRs).

Until recently, payments for providing ancillary services were grounded in cost-based formulas. PJM has now implemented new market-based pricing for the ancillary services. Payments for providing operating reserves are included in daily energy market reconciliation.

Load serving entities (LSEs) have the obligation to provide or acquire installed capacity, regulation, and operating reserves. In addition to PJM market purchases, bilateral transactions are also allowed. While bilateral transactions are not subject to the market-clearing prices, they are subject to the same charges for transmission congestion included in the market-clearing prices.



Generators are compensated for providing energy and ancillary services through the PJM Power Exchange as follows:

- locational marginal prices (LMPs) are determined based on the applicable energy bids.
- Regulation prices that generators receive are based on their Unit Regulation Offer and estimated opportunity cost for being available for regulation.
- Energy imbalance and operating reserves are compensated according to bids submitted to the PJM Power Exchange.
- Other ancillary services are compensated based on cost.
- Any shortfall payments continue to be determined based on the difference between total revenue and total revenue requirement.

*B. MARKETS*

*i. Energy Market*

On June 1, 2000, PJM implemented a new system for its interchange Energy Market. PJM's Energy Market has been converted from a real-time transaction market into a dual settlement operation. The new market is split into essentially two pieces: The Day-Ahead Market and the Balancing (Real-time) market.

*The Day-Ahead Market*

The advantage of this new system is that it allows participants to achieve greater price certainty by being able to buy and sell energy and capacity at binding day-ahead (future) prices. It also allows for the scheduling of congestion charges a day in advance. Bilateral agreements will also be able to schedule congestion charges in the Day-Ahead Market. The congestion charges can be calculated by taking the difference in LMP between the load bus and generation bus.

LSEs submit hourly demand schedules for the next day. All bids and offers must be made by noon the day before the day of operations. By 16:00, all prices are posted and the real-time market bidding is then opened. At 18:00, the Real-Time and Regulations markets are closed.

Generators must submit their schedules if they are capacity resources, unless they are self-scheduled or have planned outages. All other generators can bid into the market as they wish. The PJM Independent System Operator (ISO) will calculate, based on bids, offers and market conditions, the LMPs for each hour of the day.

A bid to supply generation consists of an incremental energy bid curve composed of three parts: start-up costs, no load costs, and operating costs. For each generation level, the bid curve represents the minimum price a bidder is willing to accept to be dispatched at the generation level. The bid curve is specified by up to 10 price-quantity pairs.

*The Balancing Market (real-time)*

After all bids and offers are settled and the marginal prices have been calculated, generators that were not used can bid into this market at new prices. Prices are again determined by market conditions. Essentially because the actual demand that will occur in real time is not known the previous day, scheduled generation will often differ from actual generation dispatch and so the balancing market corrects for the differences.

LSEs will pay balancing prices for any unscheduled demand and receive revenue for demand less than the scheduled quantity from the Day-Ahead Market. Generators will be paid for generation above their scheduled obligations at balancing prices and are not compensated for unused generation. Transmission customers pay for congestion charges for any quantity deviations.



Transmission customers may submit external bilateral transaction schedules and may indicate willingness to pay congestion charges into either the Day-Ahead Market or Balancing Market. In the Day-Ahead Market, a customer shall indicate willingness to pay congestion charges by submitting the transaction as an "up to" congestion bid.

On April 1, 1999, the spot market replaced its cost-based pricing system with a market-based pricing approach, and starting June 2000 the spot market was switched to the Two-Settlement Market. Generators continue to provide three-part bids, but these bids are not necessarily capped at cost. While bids are no longer capped at cost, they are subject to a $1,000/MWh ceiling cap. The PJM PX bidding rules allow generators to submit different energy bids for each hour, and generators can submit a new set of bids daily. However, a generator's start-up and no-load bids, once submitted, remain in effect for six months at a time.

PJM also uses the energy bids to determine in real time the LMPs for each point of energy injection/withdrawal on the system for each hour. LMPs reflect the costs associated with the out-of-order dispatch due to transmission congestion. Congestion occurs when the transmission system becomes constrained, and some generating capacity is dispatched while other generating capacity with lower bids is not dispatched. The result is that the market-clearing prices may differ from location to location. LMPs are quoted in dollars per megawatt-hour ($/MWh) and are based on bids for generation, actual loads, scheduled bilateral transactions, and transmission congestion.

*ii. Regulation Market*

PJM has just created a market for providing regulation of the system. For these units made available to meet performance standards and the short-term load fluctuations in the PJM control area they are now able to realize benefits above their opportunity costs for being a regulating generator. To be eligible for regulation, generators must be within the

PJM control area. Information about regulating status, capability, limits, and price (capped at $100/MWh) applicable for the entire 24-hour period for which it is submitted, must be provided by 18:00 through the Two-Settlement Market User Interface. The offer of the last unit needed to fulfill the MW regulation requirement (the marginal unit) will set the market price for that hour.

The PJM Regulation Requirement is 1.1% of the day-ahead peak load forecast for the on-peak period and the valley load forecast for the off-peak period. LSEs may fulfill their regulation obligations by self-scheduling their own resources, entering into contractual arrangements with other market participants, or purchasing regulation from the regulation market just described. The regulation obligation for each LSE is determined by its load ratio share.

*iii. Capacity Credit Market*

To ensure that sufficient capacity is available in the market to meet reliability standards, PJM requires LSEs to own or contract with the owner of generation capacity to cover their peak demand and reserve margins.

There are two capacity obligations. An LSE's installed capacity obligation is determined two years in advance by PJM based on forecast conditions. This obligation remains in place and is known as the "planned-for" obligation. The "planned-for" obligation is then adjusted for actual conditions. This adjusted obligation is known as the "accounted-for" obligation.

The amount of capacity each generator can supply is determined by a twelve-month rolling average of availability, calculated two months in advance of the period for which the capacity is supplied. Availability statistics are kept by PJM. These statistics are averaged over the past twelve months and applied to the "planned-for" obligation two months hence.

External resources may be designated as resources to meet the capacity requirement. These resources, however, must: (1) be rated on the extent to which they improve the ability of the PJM pool



to obtain emergency assistance from other control areas and (2) be made available to PJM for scheduling and dispatch. Should the resource not be made available to PJM, it adversely affects the resource's availability rating. If an LSE fails to meet its capacity requirement, a penalty will be assessed.

The PJM Capacity Credit Market allows Market Participants to buy and sell Capacity Credits through a process that establishes a market-clearing price. Capacity acquired in the Capacity Credit Market satisfies the "accounted-for" obligation. The PJM Capacity Credit Market consists of both the Daily and Monthly Markets. Each installed capacity market has a single market-clearing price for each day the market is in operation.

*Daily Market Operation*

The Daily Market is a Day-Ahead Market (i.e., the bids are for the following day). Currently, a mandatory aspect to the Day-Ahead Market is in effect. If a participant does not submit adequate "bids to buy" or "offers to sell" to cover its projected deficient or excess position, PJM will submit a corresponding "bid" or "offer" to cover the projected position. Mandatory Buy Bids will be submitted at a price equal to the prevailing Capacity Deficiency Rate.

Buy Bids or Sell Offers are accepted between 7:00 and 10:00 on the day the market is run. PJM strives to clear the market and post market results by 12:00 on the day the market is run.

The Daily Market is conducted based on the position of a participant for the market day estimated at 10:05 on the day the market is run. If a participant has a deficient position, PJM will only accept buy bids up to the deficiency amount. If a participant has an excess position, PJM will only accept sell offers up to the excess amount. Buy Bids or Sell Offers are accepted into the Daily Market in order of time submitted.

*Monthly Market Operation*

In addition to the Daily Market, the Capacity Credit Market currently operates both Monthly and Multi-Monthly Markets. These Monthly Markets are voluntary, and participants may submit Buy Bids and Sell Offers in the same market.

Similar to the Daily Market, Buy Bids and Sell Offers are accepted between 7:00 and 10:00 on the day that the market accepts bids. PJM strives to clear the market and post market results by 12:00 on the same day. On three scheduled days each month, Monthly Market bids are accepted for the three respective succeeding months. There are currently two Multi-Monthly Markets, a seven-month and a twelve-month. Multi-Monthly Market bids are accepted on a scheduled day approximately four months prior to the beginning of the multi-monthly period.

*iv. Fixed Transmission Rights*

Fixed Transmission Rights (FTRs) are available to all PJM Firm Transmission Service customers (Network Integration Service or Firm Point-to-Point Service), since these customers pay the embedded cost of the PJM transmission system. The purpose of FTRs is to protect Firm Transmission Service customers from increased cost due to transmission congestion when their energy deliveries are consistent with their firm reservations. Essentially, FTRs are financial instruments that entitle Firm Transmission customers to rebates of congestion charges paid by the Firm Transmission Service customers. FTRs do not represent a right for physical delivery of power. The holder of the FTR is not required to deliver energy in order to receive a congestion credit. If a constraint exists on the transmission system, the holders of FTRs receive a credit based on the FTR MW reservation and the LMP difference between point of delivery and point of receipt. This credit is paid to the holder regardless of who delivered energy or the amount delivered across the path designated in the FTR.

In July 1999, the first financially binding FTR auction was held in PJM. Participants are now able to view all prices and constraints on the Internet at the eFTR. Prices are set on the first of every



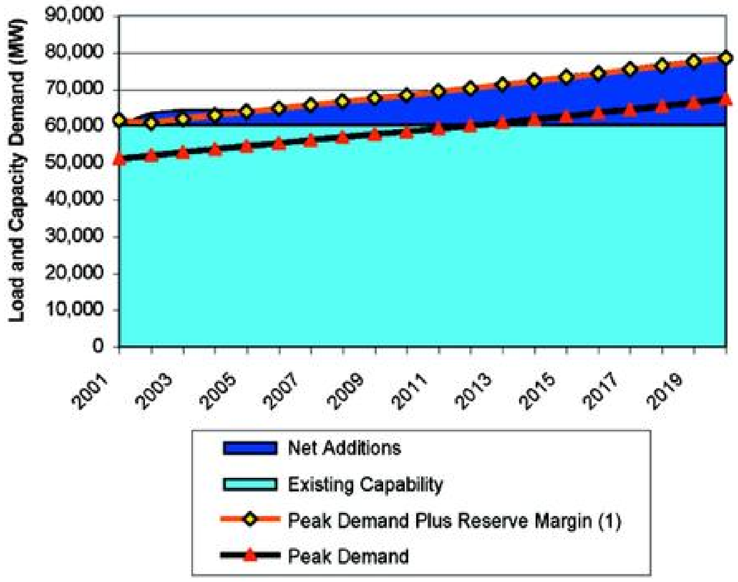
month and their values are determined based on day-ahead LMPs between generation and load busses. Each monthly period has an auction for both the trading of FTRs for on-peak and off-peak periods in the week. On-peak times are from 7:00 to 23:00, Monday through Friday, and off-peak times include all other hours and weekends.

### 2.4.3 Market Dynamics

ExGen's PJM assets in this report represent 13,448 MW of capacity.

Figure 2-5 illustrates the load and resource balance for PJM through the end of the study period. During the period of 1991-2000, peak demands have grown at an average annual rate of 1.8%. The PJM market is forecasted to grow at an annual compound rate of approximately 1.4% per year from 2001 through 2020. A required system-wide reserve margin of 18% is assumed through 2001. Subsequent to 2001, the system-wide reserve margin is assumed to be 15% as PA believes the market will mature and the required reserve margins will be lowered. The graph illustrates that approximately 18 GW of new generation is required to meet load growth and reserve margins over the 20 years. There are no significant capacity retirements anticipated in the near term.

**Figure 2-5**
**PJM Load and Resource Balance**




Source: 2000 MAAC Regional Reliability Council, EIA-411; MAAC Annual Electric Control and Planning Area Report, 2000.

(1) Reserve Margin is assumed to be 18% in 2001, decreasing to 15% in 2002 through 2020. Net additions are net of retirements.

Historical prices for PJM are presented in Appendix A.

**2.4.4 Transmission System**

In response to FERC Order 888, the members of the PJM Power Pool developed a restructuring proposal and pool-wide open-access transmission tariff. This restructuring proposal created an ISO to operate the regional bulk power system, maintain system reliability, administer specified electricity



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markets, and facilitate open access to the regional transmission system under the PJM tariff. All transmission owners were required to transfer operation of their assets to the ISO; however, the ISO was to remain completely free of interests in any market participant, including both transmission and generation owners.

In late 1999, FERC issued Order 2000. This Order called for the creation of broader, more potent regional transmission organizations (RTOs) with more explicit and stringent standards of independence, scope, and functionality than ISOs. In PJM's October 11 Order 2000 filing, it noted that its ISO already exhibited many of the FERC-defined RTO functions and characteristics. PJM was described as a "fully functional" RTO that acts as the security coordinator and control area operator for the region; the transmission provider responsible for all scheduling, dispatch, and ancillary services for transmission customers; and the entity responsible for all regional transmission planning.

In late December 2000, the Mid-Atlantic Power Supply Association (MAPSA) filed with FERC their objections to PJM's Order 2000 filing. MAPSA feels that PJM's filing gives the transmission owners in PJM too much market power. It complains of numerous instances of discriminatory market rules demonstrating that PJM's transmission owners have undue influence over the operation of the PJM system. MAPSA has other concerns regarding the proposed RTO as well, and the current Order 2000 filing by PJM may need to be re-worked before FERC makes its final ruling.

**2.4.5 Price Forecasts for the PJM Market**

*A. BASE CASE*

This case models near-term fuel prices (gas and oil) based on recent actual spot prices and futures prices through December 2003, decreasing linearly to the long-term consensus view by 2005.

The all-in price represents a combined compensation for capacity and energy price (assuming a 100% load factor). The compensation for capacity contribution to the all-in price ranges between approximately $6.00/MWh and $7.50/MWh.



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The base case compensation for capacity, energy, and all-in market price forecasts are presented in Figure 2-6 and Table 2-3 for the PJM-East, PJM-West, and PJM-Central pricing areas.

**Figure 2-6**

**PJM Base Case Compensation for Capacity, Energy, and All-In Price Forecasts**[1]

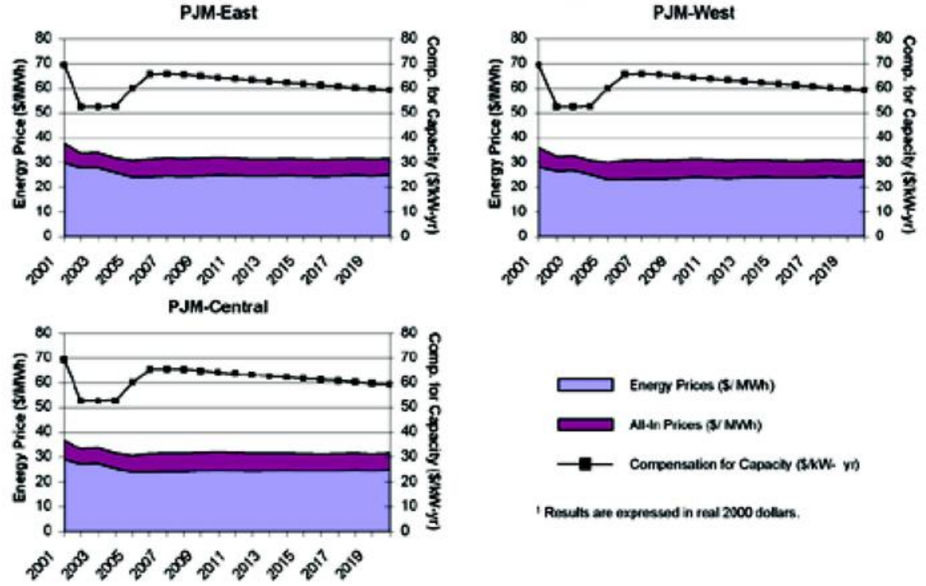





**Table 2-3**

**PJM Base Case Compensation for Capacity, Energy, and All-In Price Forecasts**[1]

| | | PJM-East | | PJM-West | | PJM-Central | |
|---|---|---|---|---|---|---|---|
| **Year** | **Compensation for Capacity ($/kW-yr)** | **Energy Price ($/MWh)** | **All-In Price ($/MWh)** | **Energy Price ($/MWh)** | **All-In Price ($/MWh)** | **Energy Price ($/MWh)** | **All-In Price ($/MWh)** |
| 2001 | 69.20 | 29.70 | 37.60 | 28.10 | 36.00 | 29.10 | 37.00 |
| 2002 | 52.60 | 27.90 | 33.90 | 26.50 | 32.50 | 27.40 | 33.40 |
| 2003 | 52.60 | 28.10 | 34.10 | 26.80 | 32.80 | 27.60 | 33.60 |
| 2004 | 52.70 | 26.10 | 32.10 | 25.00 | 31.10 | 25.70 | 31.70 |
| 2005 | 60.10 | 24.20 | 31.00 | 23.40 | 30.20 | 23.90 | 30.70 |
| 2006 | 65.50 | 24.20 | 31.70 | 23.40 | 30.90 | 23.90 | 31.40 |
| 2007 | 65.60 | 24.50 | 32.00 | 23.70 | 31.10 | 24.20 | 31.60 |
| 2008 | 65.40 | 24.40 | 31.90 | 23.60 | 31.10 | 24.10 | 31.60 |
| 2009 | 64.80 | 24.60 | 32.00 | 23.90 | 31.30 | 24.40 | 31.80 |
| 2010 | 64.30 | 24.90 | 32.20 | 24.20 | 31.50 | 24.70 | 32.00 |
| 2011 | 63.80 | 24.80 | 32.00 | 24.00 | 31.30 | 24.50 | 31.80 |
| 2012 | 63.30 | 24.50 | 31.70 | 23.80 | 31.10 | 24.30 | 31.60 |
| 2013 | 62.70 | 24.50 | 31.70 | 24.00 | 31.20 | 24.50 | 31.60 |
| 2014 | 62.20 | 24.70 | 31.80 | 24.10 | 31.20 | 24.60 | 31.70 |
| 2015 | 61.70 | 24.50 | 31.50 | 24.00 | 31.00 | 24.50 | 31.50 |
| 2016 | 61.20 | 24.40 | 31.40 | 23.90 | 30.90 | 24.40 | 31.40 |
| 2017 | 60.80 | 24.60 | 31.60 | 24.00 | 30.90 | 24.50 | 31.40 |
| 2018 | 60.30 | 24.90 | 31.80 | 24.30 | 31.10 | 24.80 | 31.60 |
| 2019 | 59.80 | 24.60 | 31.50 | 24.00 | 30.80 | 24.50 | 31.30 |
| 2020 | 59.30 | 25.10 | 31.80 | 24.40 | 31.20 | 24.90 | 31.70 |

1 Results are expressed in real 2000 dollars.

*B. Sensitivity Cases Analysis*

The all-in prices for the three sensitivity cases described in Section 2.2 are shown in Figure 2-7 and Table 2-4 for the PJM-East, PJM-West, and PJM-Central pricing areas. These sensitivities are not meant to reflect bounding or worst case scenarios.

The base case projections decrease initially as new merchant plants come on-line and gas prices decrease to the consensus forecast. The high fuel case results in substantially higher all-in prices over time, as much as $14/MWh, as more gas units move on the margin for a greater number of hours. The low fuel case results in lower all-in prices by $1/MWh to $2/MWh. The overbuild case assumes that in addition to the 5,730 MW of merchant plants added in the Base Case, an additional 4,160 MW is added to the PJM region in 2004. This additional capacity results in a 2% to 12% reduction in the all-in price in 2004 through 2011. By approximately 2012, the additional capacity is absorbed into the market and the prices are approximately the same as in the base case.

**Figure 2-7**
**PJM Sensitivity Cases All-In Price Forecasts[1] ($/MWh)**

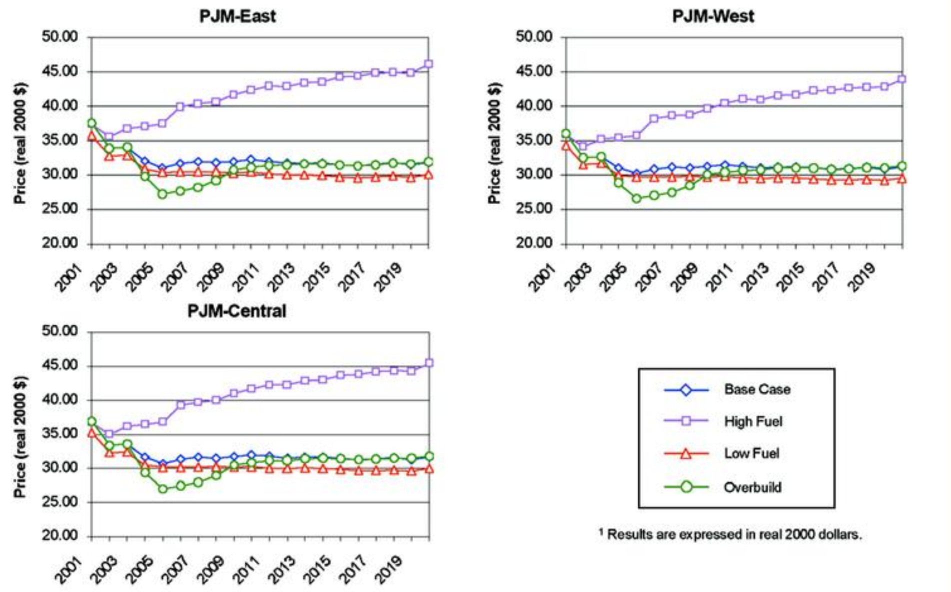



**Table 2-4**
**PJM Sensitivity Cases All-In Price Forecasts[1] ($/MWh)**

| | PJM-East | | | | PJM-West | | | | PJM-Central | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Year** | **Base Case** | **High Fuel** | **Low Fuel** | **Over-build** | **Base Case** | **High Fuel** | **Low Fuel** | **Over-build** | **Base Case** | **High Fuel** | **Low Fuel** | **Over-build** |
| 2001 | 37.60 | 37.40 | 35.80 | 37.60 | 36.00 | 35.90 | 34.30 | 36.00 | 37.00 | 36.80 | 35.20 | 37.00 |
| 2002 | 33.90 | 35.60 | 32.80 | 33.90 | 32.50 | 34.20 | 31.60 | 32.50 | 33.40 | 35.00 | 32.30 | 33.40 |
| 2003 | 34.10 | 36.80 | 32.90 | 34.10 | 32.80 | 35.20 | 31.70 | 32.80 | 33.60 | 36.20 | 32.40 | 33.60 |
| 2004 | 32.10 | 37.10 | 30.90 | 29.80 | 31.10 | 35.50 | 30.00 | 28.90 | 31.70 | 36.50 | 30.50 | 29.40 |
| 2005 | 31.00 | 37.50 | 30.40 | 27.20 | 30.20 | 35.80 | 29.70 | 26.60 | 30.70 | 36.80 | 30.20 | 27.00 |
| 2006 | 31.70 | 39.90 | 30.50 | 27.70 | 30.90 | 38.20 | 29.70 | 27.00 | 31.40 | 39.30 | 30.20 | 27.50 |
| 2007 | 32.00 | 40.40 | 30.50 | 28.20 | 31.10 | 38.70 | 29.80 | 27.50 | 31.60 | 39.80 | 30.20 | 28.00 |
| 2008 | 31.90 | 40.60 | 30.50 | 29.20 | 31.10 | 38.80 | 29.80 | 28.50 | 31.60 | 40.00 | 30.30 | 29.00 |
| 2009 | 32.00 | 41.70 | 30.30 | 30.80 | 31.30 | 39.60 | 29.80 | 30.10 | 31.80 | 41.00 | 30.20 | 30.50 |
| 2010 | 32.20 | 42.40 | 30.50 | 31.10 | 31.50 | 40.40 | 29.80 | 30.40 | 32.00 | 41.70 | 30.30 | 30.90 |
| 2011 | 32.00 | 43.00 | 30.20 | 31.40 | 31.30 | 41.00 | 29.60 | 30.70 | 31.80 | 42.30 | 30.00 | 31.20 |
| 2012 | 31.70 | 42.90 | 30.00 | 31.50 | 31.10 | 41.00 | 29.50 | 30.70 | 31.60 | 42.30 | 30.00 | 31.20 |
| 2013 | 31.70 | 43.40 | 30.00 | 31.60 | 31.20 | 41.60 | 29.60 | 31.00 | 31.60 | 42.80 | 30.10 | 31.50 |
| 2014 | 31.80 | 43.60 | 30.00 | 31.60 | 31.20 | 41.70 | 29.60 | 31.10 | 31.70 | 43.00 | 30.00 | 31.50 |
| 2015 | 31.50 | 44.30 | 29.70 | 31.50 | 31.00 | 42.30 | 29.40 | 31.00 | 31.50 | 43.70 | 29.90 | 31.50 |
| 2016 | 31.40 | 44.40 | 29.60 | 31.40 | 30.90 | 42.40 | 29.30 | 30.80 | 31.40 | 43.80 | 29.70 | 31.30 |
| 2017 | 31.60 | 44.90 | 29.80 | 31.50 | 30.90 | 42.70 | 29.30 | 30.90 | 31.40 | 44.20 | 29.70 | 31.40 |
| 2018 | 31.80 | 44.90 | 29.90 | 31.70 | 31.10 | 42.80 | 29.40 | 31.10 | 31.60 | 44.30 | 29.80 | 31.60 |
| 2019 | 31.50 | 44.90 | 29.70 | 31.60 | 30.80 | 42.80 | 29.20 | 31.00 | 31.30 | 44.20 | 29.60 | 31.50 |
| 2020 | 31.80 | 46.10 | 30.10 | 31.90 | 31.20 | 43.90 | 29.60 | 31.30 | 31.70 | 45.50 | 30.00 | 31.80 |

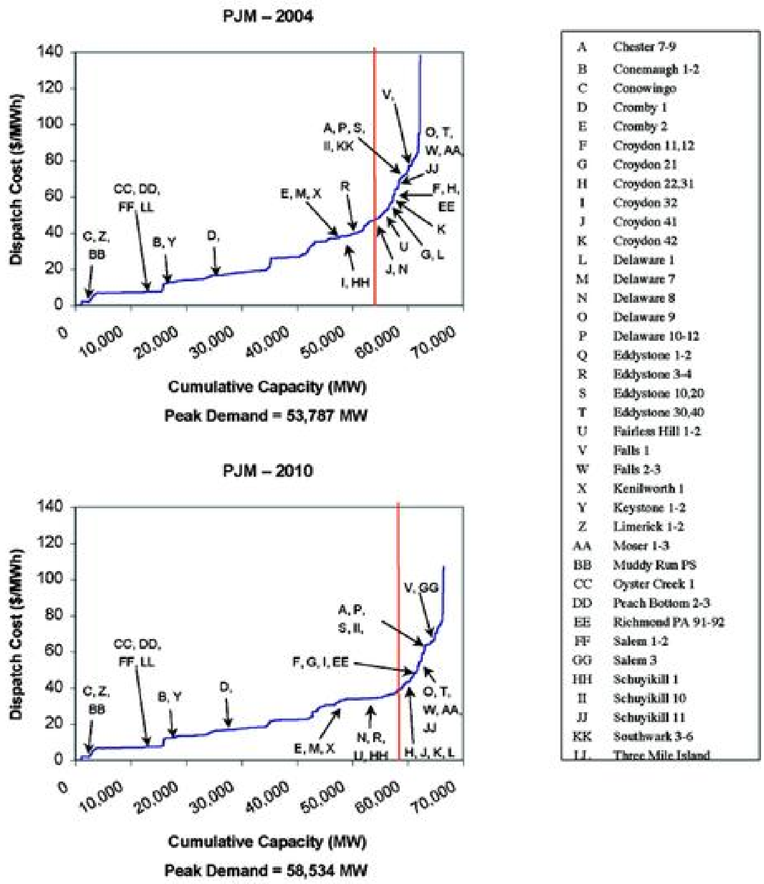
1 Results are expressed in real 2000 dollars.



## 2.4.6 Dispatch Curves

The dispatch curves for 2004 and 2010 are shown in Figure 2-8. These curves order generation plants based upon short run variable cost (fuel and O&M). The relative ranking of the ExGen plants are included on the graphs. The dispatch curves represent the annual average marginal dispatch cost of the target assets as compared to the other generators in the market.

Figure 2-8
PJM Dispatch Curves for 2004 and 2010



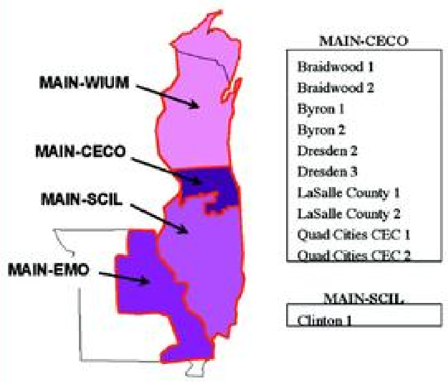



## 2.5 MAIN

### 2.5.1 Background

The MAIN region includes Illinois and parts of Missouri, Wisconsin, and Michigan. MAIN's membership is comprised of owned utilities, public utilities, independent power marketers, and regulators. The area served over 19 million customers and accounted for over 240,000 GWh of electric generation in 1999. There is a lack of widespread pooling of generation or transmission in the MAIN region. MAIN is a relatively small transmission region in terms of both geographical scope and wholesale market size. MAIN has a financial market hub for trading electricity futures. The Commonwealth Edison (CECO) futures hub is operated by the Chicago Board of Trade and provides a mechanism for hedging Midwest electricity contracts. In addition, the Automated Power Exchange is implementing a regional spot market for electricity in Illinois. Figure 2-9 shows the MAIN region and the location of ExGen's generation assets by pricing area.

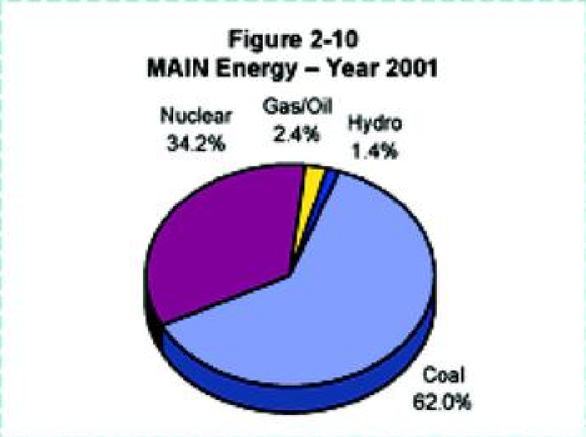
Figure 2-9
Generation Assets in the MAIN Region

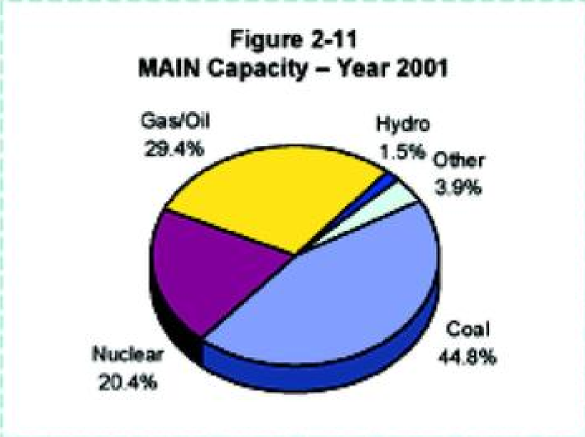



As illustrated in Figures 2-10 and 2-11, MAIN is largely dependent on coal-fired and nuclear resources for baseload generation. Coal-fired generation is the predominant resource in terms of both installed capacity and energy production in MAIN, accounting for 45% of the capacity in the region and 62% of the energy produced. Nuclear facilities account for 20% of the installed capacity and produce 34% of the energy in the region. Gas- and oil-fired generation make up 29% of the installed



capacity, but represent only 2% of the region's energy production. This indicates that nearly all of the gas- and oil-fired generation is utilized for peaking.




**Sources: Figure 2-10: PA Consulting Services Inc. Regional Modeling results. Figure 2-11: 2000 Coordinated Bulk Power Supply & Demand — Regional Summary Report; and PA Consulting Services Inc.**

### 2.5.2 Power Markets

*A. INTRODUCTION*

The ExGen assets in MAIN are located in the following pricing areas: Commonwealth Edison (MAIN-CECO) and South Central Illinois (MAIN-SCIL). (See Figure 2-9.)

*B. MARKETS*

The MAIN wholesale market is informally organized and characterized by largely informal market arrangements with the majority of power sold through bilateral agreements, not a power exchange or some other formal marketplace. Short- and long-term bilateral contracts typically include both an energy and capacity payment. In 1996, MAIN adopted a policy suggesting its companies maintain a minimum reserve of 17-20% for long-term planning, but there is no strong mechanism currently in place forcing utilities in MAIN to meet these requirements.

While there is no formalized market structure in place, MAIN is rapidly progressing toward the formation of an ISO as discussed above. It will serve the purpose of managing regional transmission assets and establishing spot market trading centers to serve as regional marketplaces. However, it should be noted that there are a variety of market models that are currently being pursued in this region. A market's evolution over time may result in a finalized structure that differs from those described here.

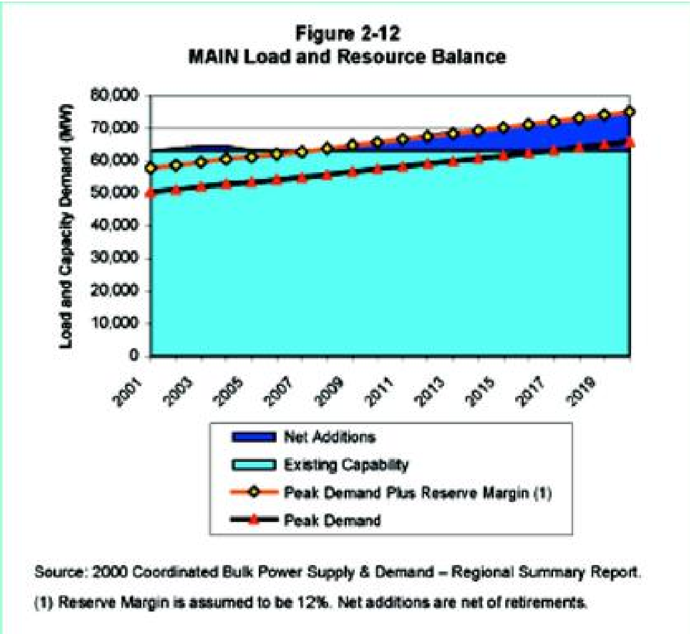
### 2.5.3 Market Dynamics

ExGen's MAIN assets in this report represent 11,495 MW of capacity.

Figure 2-12 shows the projected load and resource forecast for the MAIN region. Forecasted average annual load growth in MAIN is 1.4% for the study period as compared to the historical



average annual load growth of 1.7% for the last decade. A required system-wide reserve margin of 12% is assumed through the study period.




Historical prices for MAIN are presented in Appendix A.

### 2.5.4 Transmission System

Most of the utilities in MAIN, MAPP, and ECAR have filed and gained approval from FERC to establish a Midwest ISO to operate and manage the transmission assets in the region. Currently, however, only ECAR utilities offer "open access" to their individual high voltage transmission lines as mandated by FERC Order 888.

In late 2000 and early 2001, several utilities located in MAIN announced their intent to leave the Midwest ISO and join the Alliance RTO, an ISO variant comprised mainly of utilities in ECAR. These utilities argue that joining the Alliance RTO would allow them to benefit from the RTO's huge geographic scope, thereby making it easier for them to manage loop flows.

On January 16, 2001, the Midwest ISO filed with FERC to qualify as an RTO. In its filing, the ISO noted that requests from members to withdraw from the ISO will jeopardize the ISO's ability to meet FERC's Order 2000 requirements.

### 2.5.5 Price Forecasts for the MAIN Market

*A. BASE CASE*

This case models near-term fuel prices based on recent actual spot prices and futures prices through December 2003, decreasing linearly to the long-term consensus view by 2005.

The all-in price represents a combined compensation for capacity and energy price (assuming a 100% load factor). The compensation for capacity contribution to the all-in price ranges between approximately $2.00/MWh and $6.80/MWh.



The forecasts of energy prices, capacity compensation, and all-in prices for the base case are shown in Figure 2-13 and Table 2-5 for the MAIN-CECO and MAIN-SCIL pricing areas. All-in prices are anticipated to remain relatively constant over the twenty-year planning period.

**Figure 2-13**
**MAIN Base Case Compensation**
**for Capacity, Energy, and All-In Price**
**Forecasts[1]**

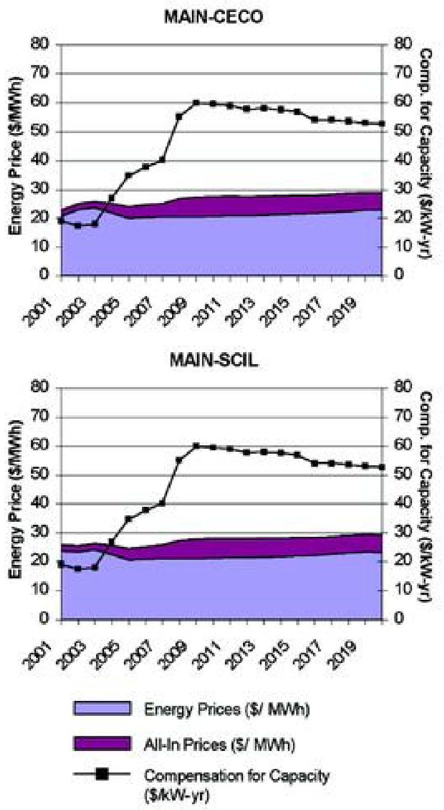





**Table 2-5**
**MAIN Base Case Compensation**
**for Capacity, Energy, and All-In Price Forecasts[1]**

| Year | Comp. for Capacity ($/kW-yr) | MAIN-CECO Energy ($/MWh) | MAIN-CECO All-In ($/MWh) | MAIN-SCIL Energy ($/MWh) | MAIN-SCIL All-In ($/MWh) |
|---|---|---|---|---|---|
| 2001 | 19.10 | 20.60 | 22.80 | 23.60 | 25.80 |
| 2002 | 17.50 | 23.00 | 25.00 | 23.40 | 25.40 |
| 2003 | 18.00 | 23.70 | 25.70 | 24.30 | 26.30 |
| 2004 | 26.90 | 22.00 | 25.00 | 22.50 | 25.60 |
| 2005 | 34.70 | 20.10 | 24.00 | 20.70 | 24.60 |

| | | | | | |
|---|---|---|---|---|---|
| 2006 | 37.80 | 20.40 | 24.70 | 21.00 | 25.30 |
| 2007 | 40.10 | 20.50 | 25.10 | 21.10 | 25.70 |
| 2008 | 55.20 | 20.50 | 26.80 | 21.10 | 27.40 |
| 2009 | 60.00 | 20.50 | 27.30 | 21.00 | 27.90 |
| 2010 | 59.50 | 20.80 | 27.50 | 21.20 | 28.00 |
| 2011 | 59.00 | 20.90 | 27.60 | 21.40 | 28.10 |
| 2012 | 57.70 | 21.00 | 27.50 | 21.50 | 28.00 |
| 2013 | 58.00 | 21.10 | 27.70 | 21.60 | 28.20 |
| 2014 | 57.60 | 21.30 | 27.90 | 21.80 | 28.30 |
| 2015 | 56.90 | 21.50 | 28.00 | 21.90 | 28.40 |
| 2016 | 54.00 | 21.80 | 27.90 | 22.20 | 28.40 |
| 2017 | 54.00 | 22.20 | 28.30 | 22.70 | 28.80 |
| 2018 | 53.60 | 22.50 | 28.60 | 23.00 | 29.10 |
| 2019 | 53.00 | 22.90 | 28.90 | 23.30 | 29.40 |
| 2020 | 52.70 | 22.90 | 28.90 | 23.30 | 29.30 |

1 Results are expressed in real 2000 dollars.

The price projections for the MAIN pricing areas are influenced by activities in the ECAR region. The model used to generate the price projections incorporates all of the Midwest NERC regions. Due to the close proximity of MAIN to ECAR, activities in ECAR do influence price projections in MAIN and their effects are incorporated in the MAIN price forecasts that are provided.



*B. SENSITIVITY CASES ANALYSIS*

The all-in prices for the sensitivity cases described in Section 2.2 are shown in Figure 2-14 and Table 2-6 for the MAIN-CECO and MAIN-SCIL pricing areas. These sensitivities are not meant to reflect bounding or worst case scenarios.

**Figure 2-14**
**MAIN Sensitivity Cases**
**All-In Price Forecasts[1] ($/MWh)**

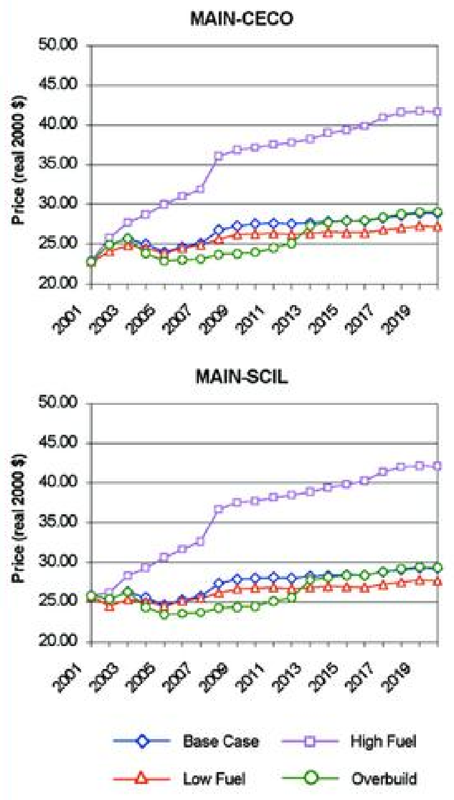





**Table 2-6**
**MAIN Sensitivity Cases**
**All-In Price Forecasts[1] ($/MWh)**

| Year | Base Case | High Fuel | Low Fuel | Overbuild |
|---|---|---|---|---|
| MAIN-CECO | | | | |
| 2001 | 22.80 | 22.80 | 22.80 | 22.80 |
| 2002 | 25.00 | 25.80 | 24.10 | 25.00 |

| | | | | |
|---|---|---|---|---|
| 2003 | 25.70 | 27.70 | 24.80 | 25.70 |
| 2004 | 25.00 | 28.70 | 24.50 | 23.90 |
| 2005 | 24.00 | 30.00 | 23.90 | 22.90 |
| 2006 | 24.70 | 31.00 | 24.60 | 23.00 |
| 2007 | 25.10 | 31.90 | 24.90 | 23.10 |
| 2008 | 26.80 | 36.10 | 25.70 | 23.70 |
| 2009 | 27.30 | 36.90 | 26.20 | 23.80 |
| 2010 | 27.50 | 37.10 | 26.30 | 24.00 |
| 2011 | 27.60 | 37.50 | 26.40 | 24.50 |
| 2012 | 27.50 | 37.80 | 26.20 | 25.10 |
| 2013 | 27.70 | 38.30 | 26.30 | 27.30 |
| 2014 | 27.90 | 39.00 | 26.50 | 27.70 |
| 2015 | 28.00 | 39.40 | 26.50 | 27.90 |
| 2016 | 27.90 | 39.90 | 26.50 | 28.00 |
| 2017 | 28.30 | 40.90 | 26.80 | 28.40 |
| 2018 | 28.60 | 41.60 | 27.10 | 28.80 |
| 2019 | 28.90 | 41.70 | 27.30 | 29.00 |
| 2020 | 28.90 | 41.60 | 27.30 | 29.00 |
| MAIN-SCIL | | | | |
| 2001 | 25.80 | 25.80 | 25.70 | 25.80 |
| 2002 | 25.40 | 26.20 | 24.50 | 25.40 |
| 2003 | 26.30 | 28.30 | 25.40 | 26.30 |
| 2004 | 25.60 | 29.30 | 25.10 | 24.40 |
| 2005 | 24.60 | 30.60 | 24.60 | 23.50 |
| 2006 | 25.30 | 31.70 | 25.20 | 23.60 |
| 2007 | 25.70 | 32.60 | 25.50 | 23.70 |
| 2008 | 27.40 | 36.70 | 26.20 | 24.30 |
| 2009 | 27.90 | 37.50 | 26.70 | 24.40 |
| 2010 | 28.00 | 37.70 | 26.80 | 24.50 |
| 2011 | 28.10 | 38.20 | 26.80 | 25.10 |
| 2012 | 28.00 | 38.50 | 26.70 | 25.60 |
| 2013 | 28.20 | 38.90 | 26.90 | 27.80 |
| 2014 | 28.30 | 39.40 | 27.00 | 28.10 |
| 2015 | 28.40 | 39.80 | 26.90 | 28.40 |
| 2016 | 28.40 | 40.30 | 26.80 | 28.40 |
| 2017 | 28.80 | 41.40 | 27.20 | 28.80 |
| 2018 | 29.10 | 42.00 | 27.50 | 29.20 |
| 2019 | 29.40 | 42.10 | 27.80 | 29.50 |
| 2020 | 29.30 | 42.10 | 27.70 | 29.40 |

[1] Results are expressed in real 2000 dollars.

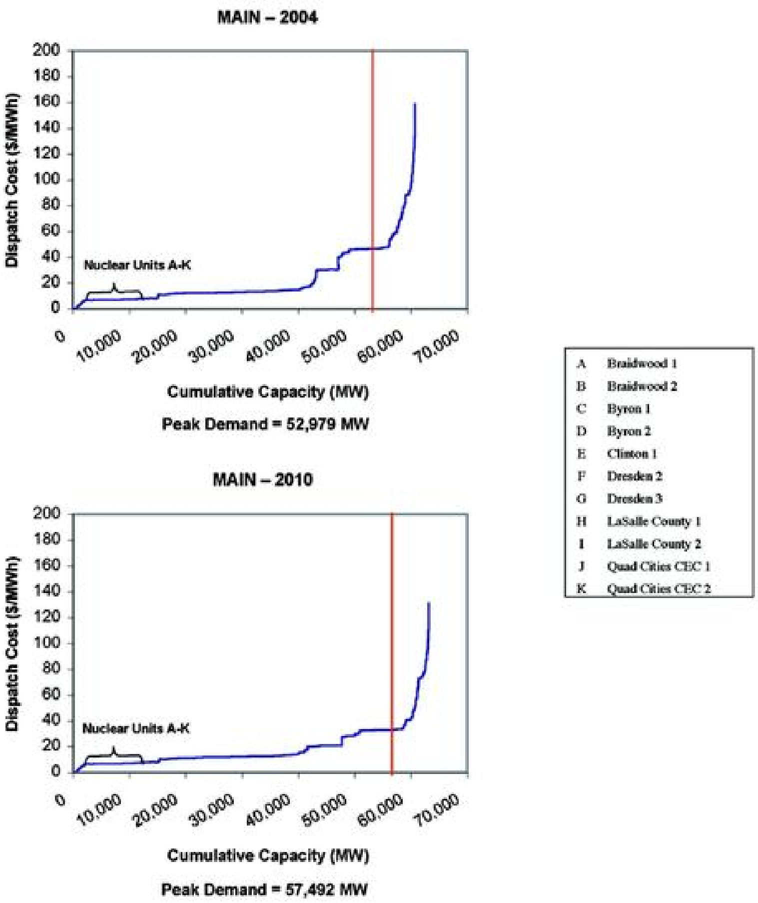


The high fuel case results in substantially higher prices over time as compared to the base case due to the hours that gas sets the marginal price. As additional gas units come into the marketplace, the effect of higher gas prices is magnified as more gas units move to the margin in more hours. The low fuel case parallels the base case. The overbuild case assumes that in addition to the 7,105 MW of merchant plants added in the base case, an additional 5,200 MW is added to the MAIN region in 2004. This additional capacity results in a 4% to 13% reduction in the all-in price in 2004 through 2012. By approximately 2013, the additional capacity is absorbed into the market and the prices are approximately the same as in the base case.

### 2.5.6 Dispatch Curves

Dispatch curves for the MAIN region for 2004 and 2010 are shown in Figure 2-15. The dispatch curves represent the annual average marginal dispatch cost of the target assets as compared to the other generators in the market.

**Figure 2-15**
**MAIN Dispatch Curves for 2004 and 2010**






## 2.6 NPCC-NEPOOL

### 2.6.1 Background

This section describes the New England Power Pool (NEPOOL) component of the Northeast Power Coordinating Council (NPCC), which was formed in 1971 to coordinate and maximize the efficiency of the planning and operation of electric systems in New York, New England, and the eastern Canadian Provinces in order to ensure system stability and reliability. This cooperative system in the Northeast evolved into two ISOs, NEPOOL and New York.

NEPOOL's voluntary membership includes municipal and consumer-owned systems, IOU systems, power marketers, joint-marketing agencies, IPPs, load aggregators, and exempt wholesale generators. NEPOOL coordinates, monitors, and directs the operations of the major generation and transmission bulk power supply facilities in New England. NEPOOL's annual peak load exceeds 23,000 MW with resulting capacity requirements over 28,000 MW (2000). NEPOOL participants own and operate over 1,800 miles of 345-kV transmission lines, 400 miles of 230-kV lines and nearly 6,000 miles of 115-kV lines. NEPOOL's two primary objectives are to assure the reliability of the bulk power supply in the New England region while minimizing costs and fairly allocating them. It achieves these two objectives primarily through central planning and dispatch of all of the bulk power facilities in the region. Figure 2-16 shows the NEPOOL region and the location of ExGen's generation assets by pricing area.

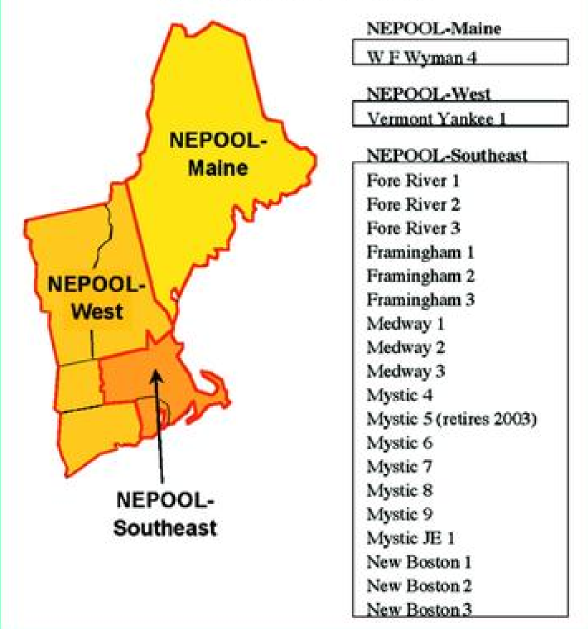



**Figure 2-16**
**NPCC-NEPOOL Region**

As illustrated in Figure 2-17 and 2-18, the NEPOOL area is highly dependent on gas- and oil-fired resources for baseload generation, accounting for 39% of the energy produced in New England. Nuclear generation represents approximately 30% of the total generation and coal represents



approximately 19%. Gas- and oil-fired generation units account for 55% of the installed capacity in NEPOOL.

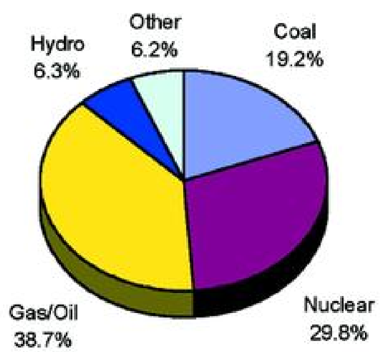



**Figure 2-17**
**NEPOOL Energy – Year 2001**

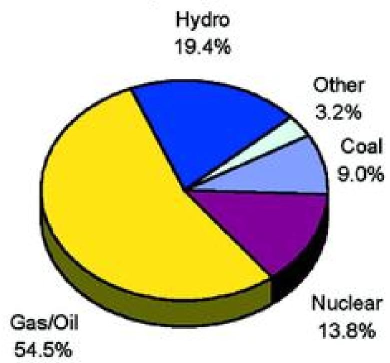



**Figure 2-18**
**NEPOOL Capacity – Year 2001**

**Sources: Figure 2-17: PA Consulting Services Inc. Regional Modeling results. Figure 2-18: NPCC Load, Capacity, Energy, Fuels, and Transmission Report, Forecast Data as of January 1, 2000, April 1, 2000; and PA Consulting Services Inc.**

### 2.6.2 Power Markets

*A.* *INTRODUCTION*

The ExGen assets in NEPOOL are located the following pricing areas: NEPOOL-Maine, NEPOOL-Southeast, and NEPOOL-West. (See Figure 2-16.)

The NEPOOL market structure is currently going through significant changes. The Operable Capability Market was disbanded on March 1, 2000 and the Installed Capability Market was disbanded on August 1, 2000. The following five markets were in existence at the end of the year 2000:

*i.* Energy

*ii.* Automatic Generation Control (AGC)

*iii.* Ten Minute Spinning Reserve (TMSR)

*iv.*

Ten Minute Non-Spinning Reserve (TMNSR)

*v.*

Thirty-Minute Operating Reserve (TMOR).

New England's Independent System Operator (ISO-NE) oversees the Internet-based trading of the five wholesale electricity products that are bought and sold in New England daily. FERC is currently hearing proposed changes in the NEPOOL Market presented by ISO-NE and the generators that produce the region's power.

A bid is comprised of all the information submitted by a participant that relates to bid price, quantity, technical bid parameters, and timing of offers for a generator or dispatchable load to provide specific services in one or more of the defined markets. The bid price is the amount that a participant



offers to accept in a notice furnished to the system operator, in this case ISO-NE. The bid price is meant to compensate for:

- preparing the start up or starting up or increasing the level of operation of a generator or units to provide energy to other participants
- having a generator or units available to provide Operating Reserve to other participants
- having a generator or units available to provide AGC to other participants
- providing to other participants Energy, Operating Reserve, or AGC.

*B.*

*MARKETS*

*i.*

*The Energy Market*

The energy market is currently structured so generators submit $/MWh hourly bids on a day-ahead basis for the next 24 hours. Based on these bids, ISO-NE schedules the generating units that will provide energy on the following day with the objective of minimizing total costs in the energy market. Hourly settlement occurs after the fact. Suppliers receive and buyers pay amounts equal to the MWh sold and bought, respectively, multiplied by the *ex post facto* energy clearing price. Compensation to the out-of-merit unit is the higher of the bid or market clearing price. There is only one financial settlement, based on the actual energy quantity bought/sold in real time. In the event that transmission constraints occur, congestion costs will be apparent in the difference in energy prices between or among nodes and will reflect the marginal cost of supplying additional demand at each node in any given hour. The payment that generators will receive will be the nodal price at the point of injection into the system. Load will pay the load-weighted average of the nodal prices in the zone in which it withdraws energy from the system. This system is currently under review, as will be discussed in the Anticipated Market Changes section.

*ii.*

*Automatic Generation Control (AGC) Market*

AGC is a measure of the ability of a generating unit to provide instantaneous control balance between load and generation and help maintain proper tie line bias. This is done to control frequency and to maintain currently proper power flows into and out of the NEPOOL Control Area. In short, AGC is basically a ramping service to follow the second-to-second fluctuations in load and supply. AGC responds to the NEPOOL Area Control Error (calculated every four seconds) in an effort to continuously balance the NEPOOL Control Area's supply resources with minute to minute load variations in order to meet the NERC and NPCC Control Performance Standards. AGC performs the ancillary service known as regulation. In the absence of AGC services, interconnected control area operation and control area frequency control could not be adequately maintained. Participants give one day advance bids for a generator supplying AGC to the market in terms of $/MWh. Each generator must have a separate AGC bid for each hour of the following day. An AGC Bid may include up to four Regulating Ranges for a single generator, each defined by an Automatic High and Low Limit and an Automatic Response Rate.

ISO-NE calculates a lost opportunity payment and a production cost charge for AGC if the resource is committed to AGC. The system operator ranks generators according to their AGC bid, the generator's opportunity cost payment, and the AGC production cost change to select resources for AGC service. Generators successful in the AGC market are paid for the revenues they would otherwise have received plus compensation for the loss in efficiency of their units. However, given the large number of generators in NEPOOL that have AGC capability, PA does not expect that the AGC market will yield substantial margins to generators.

Operating reserves are the necessary level of generation capability that must be available at all times for increased generation output. Operating reserves are needed to maintain system reliability in



the event of an instantaneous loss of a generating unit or transmission interconnection with surrounding control areas. NERC and NPCC require operating reserve availability in all control areas to protect against significant contingencies such as changes or reductions in supply sources. The three types of operating reserves are Ten-Minute Spinning Reserve, Ten-Minute Non-Spinning Reserve, and Thirty-Minute Operating Reserve. All three combine with the AGC market to produce the four bid-based ancillary service markets. Each reserve has its own market and bidding process. The values for the three ancillary services and energy generally correlate to the following relationships.

*iii.*

*Ten-Minute Spinning Reserve (TMSR)*

TMSR provides contingency protection to ISO-NE's system. TMSR is measured as the kilowatts of operable capability that an electrical generating unit can provide. This unit, unloaded during all or part of the hour, is able to load to supply energy on demand (within ten minutes), reach its maximum generating capacity in under ten minutes, and able to sustain the maximum output level for over thirty minutes. A TMSR unit is also capable of providing contingency protection by immediately reducing energy requirements within ten minutes and maintaining the reduced requirements ISO-NE determines.

In the initial market, bidding in the ten-minute spinning reserve market is restricted to hydroelectric, pumped storage, and dispatchable load resources. All on-line generation that is capable of raising generation can supply TMSR. Bidders submit hourly bids in $/MW for the next day and designate the reserve market for their bids. The ISO-NE ranks generators from least to most expensive. In the case of TMSR, this includes consideration of lost opportunity cost and production cost differences should the unit be committed to TMSR instead of the energy market.

A generator providing ten-minute spinning reserve receives the market clearing price for TMSR. The TMSR market clearing price is based on the marginal lost opportunity cost, which is calculated as the difference between the real-time energy price and the energy bid price.

*iv.*

*Ten-Minute Non-Spinning Reserve (TMNSR)*

TMNSR is generation that can reliably be connected to the network and loaded, or load that can reliably be removed from the network, within ten minutes of activation on a sustainable basis. TMNSRs are any resources and requirements that were able to be designated for the TMSR but were not designated by the system operator for such duties during the a specific hour. Surplus TMSR can be counted as TMNSR.

*v.*

*Thirty-Minute Operating Reserve (TMOR)*

TMOR is generation output that is available to the system operator within 30 minutes after request or load that can reliably be removed from the network within 30 minutes on a sustainable basis. TMORs are any resources and requirements that were able to be designated for the TMSR and TMNSR but were not designated by the system operator for such duties during a specific hour. Surplus TMSR and TMNSR can be counted as TMOR. The NE-ISO may contract for additional ancillary services as needed.

*vi.*

*Anticipated Market Changes*

The entire NEPOOL Market is currently undergoing significant changes. It now claims five bid-based markets after two were laid to rest during the year 2000. Neighboring regions of PJM and New York appear to be tracked to a highly efficient, de-regulated system. New England has built a solid market structure over the past four years. NEPOOL is continually changing in an effort to achieve further reliability and cost gains. ISO-NE is proposing various market revisions be implemented as soon as possible. As of late 2000, the optimistic estimate for when full implementation of a Congestion Management/Multi-Settlement System (CMS/MSS) could be in place was sometime in 2003. The completion would occur in two phases. Phase I deals with the Congestion Management System's details and is scheduled for completion sometime in mid-2002. Phase II's schedule deals with the forming of



the Multi Settlement System. Details are still being resolved and will not be concrete until late 2001. There is speculation that Phase II will take at least 12 months to fully implement after the completion of Phase I. Hence the optimistic 2003 completion date for full implementation of the envisioned CMS/MSS system. The CMS/MSS plans contain numerous new market design elements. A discussion of some of the major changes follows.

A multi-settlement system (MSS) is being proposed. This will be a two-settlement system involving a day-ahead market and a real-time market for energy and ancillary services. It is expected to run as follows. Prices and scheduled quantities for each product will be established based on a day-ahead bid that binds the participant into a financial settlement on the following day. Separate prices will be determined for real time operations, and a second binding financial settlement will be made based on changes in real time from the day-ahead schedule.

A permanent Congestion Management System (CMS) is expected to be implemented sometime in 2002. ISO-NE would manage transmission congestion based on LMPs. Hourly energy prices paid to generators would vary at each node (300 to 600 locations are currently envisioned) to reflect transmission congestion. ISO-NE would establish eight load zones based on reliability regions. Loads would pay the weighted average of the nodal prices in the zone, based on historical load patterns for that zone. Zonal pricing of load is needed for two reasons. The majority of New England's distribution companies are required to provide uniform pricing in their region of operation and the necessary metering is not in place in all areas to implement nodal pricing of loads. Transmission customers would not bid for transmission; instead, a customer taking transmission service would be required to pay the applicable transmission congestion charge. FERC accepted ISO-NE's proposal for a permanent CMS, requiring it to contain a choice between zonal and nodal bidding by the completion of Phase II. However, full CMS implementation is not expected for almost two years.

ISO-NE plans to have generators submit a three-part bid on a daily basis. The three parts will be comprised of energy production, no-load, and start-up. Generators would be scheduled over the day to minimize total bid costs, but the energy price would be set based only on the energy bid of the marginal supplier. The logic behind this pricing is it reflects the marginal bid-cost of producing energy. The three-part bid should allow generators to bid a more accurate representation of their cost functions. This three-part bid has been approved by FERC with the requirement ISO-NE submit an evaluation of its efficiency after the MSS has been in operation for six months.

On August 28, 2000, the three northeast ISOs (New England, New York and Ontario) jointly issued a Request for Proposal (RFP). The RFP requested a feasibility study for a regional day-ahead electric market that would establish energy prices and schedules for the next day. The goal is to offer additional capability for market participants to buy and sell electricity across a broader region than is presently available within the ISO markets. The RFP falls in line with FERC's Order 2000, which calls for the formation of RTOs. In that same order, FERC indicated that it favors larger regional ISO markets that reduce what they refer to as "seams" between existing markets. There are three phases to the study. The first phase is to analyze various options and recommend something to be approved by all three ISOs. Once the first phase is accepted, the second phase would incorporate a system reliability study. The third phase would then produce functional specifications based on the outcomes of the first two phases. The first phase should be completed on or before March 30, 2001.

Proposed changes to the ancillary service markets include a system where generators submit combined bids for both energy and spinning reserves. Currently, generators submit separate bids for energy and each of the four ancillary services. ISO-NE considers all of these bids jointly in determining how to schedule and dispatch generators to meet the energy and ancillary services requirements while minimizing total cost. Under the proposed system, three-part bids would be submitted into the auction. ISO-NE would decide which participant provides energy and which distributes spinning reserves. (The ISO would continue to consider all bids jointly when developing a least total cost schedule.) The price



paid for spinning reserves would then reflect the opportunity cost of not selling energy. The opportunity cost would be calculated by taking the difference between the applicable energy price and the generator's energy bid. However, until ISO-NE can demonstrate market power exists in the spinning reserve market, this proposal was denied by FERC on June 28, 2000.

ISO-NE is proposing to take price into consideration in determining how much of each ancillary service to purchase in the day-ahead market. Currently, ISO-NE purchases the required amount of ancillary services regardless of the price. It is feasible for suppliers to set prices arbitrarily high in times of limited excess capacity. Under the new plan, a demand curve will be derived for each ancillary service. This would be accomplished by predicting the amount of each ancillary service that loads would be willing to buy at numerous prices. ISO-NE would coordinate this estimated demand curve with supply bids to determine how much of each ancillary service to purchase daily. ISO-NE states that the demand curves will help avoid overpaying for an ancillary service. ISO-NE is the first independent system operator to propose using demand curves in procuring ancillary services. Given the current plan's ambiguity (derivation of demand curves and exact benefits of the proposal are still unclear), FERC has approved requests to apply price or bid caps.

The four-hour reserve is a non-spinning reserve designed to encourage accurate demand-side bidding in the day-ahead market. ISO-NE anticipates it will provide adequate capacity in the real-time market. ISO-NE wants to make its own forecast on demand and compare the forecast to the quantity of energy scheduled in the day-ahead market. If ISO-NE's demand forecast exceeds the day-ahead scheduled quantity, purchases made on the four-hour reserve market would allow them to make up the difference. The plan calls for operating reserves to be substituted for four-hour reserves if the cost is cheaper. The cost of four-hour reserves is allocated to participants who underbid their load day-ahead. ISO-NE projects the real-time price will be typically higher than the day-ahead price, and thus will provide an adequate penalty for non-performance. FERC has approved the proposal for four-hour reserves, recognizing it could improve reliability. Some areas have to be worked on before implementation, such as the fact that ISO-NE will determine the amount of four-hour reserves based on its forecast, but it does not pay for the reserves. ISO-NE will work with New York and PJM ISOs in designing this market.

### 2.6.3 Market Dynamics

ExGen's NEPOOL assets in this report represent 4,617 MW of capacity. Figure 2-19 illustrates the load and resource balance for NEPOOL through the end of the study period. During the period 1998-2000, peak demands have grown at an average annual rate of 4.2%. Peak demand in the NEPOOL market is forecasted to grow at an annual compound rate of 1.47% per year from 2001 through the end of the study period. A required system-wide reserve margin of 15.2% is assumed



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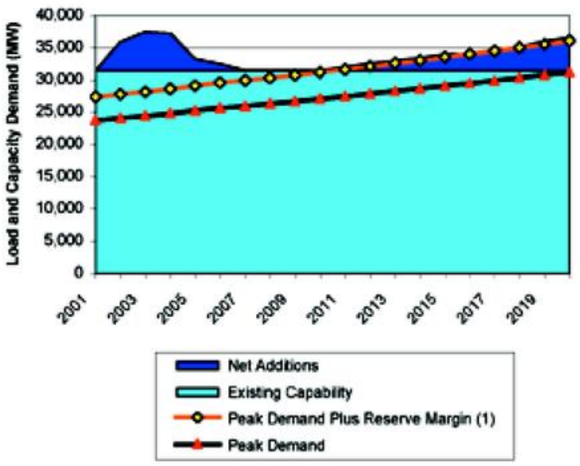
through the study period. As depicted in Figure 2-19, NEPOOL is projected to have significant surplus capacity in the initial years of the study period.

**Figure 2-19**
**NEPOOL Load and Resource Balance**




Source: NPCC Load, Capacity, Energy, Fuels, and Transmission Report, Forecast Data as of January 1, 2000, Data Submitted April 1, 2000.

(1) Reserve Margin is assumed to be 15.2%. Net additions are net of retirements.

Historical prices for NEPOOL are presented in Appendix A.

### 2.6.4 Transmission System

On July 1, 1997, ISO-NE was established by NEPOOL as a non-profit corporation responsible for the management of the region's bulk power generation and transmission systems. ISO-NE has responsibilities that are defined in an independent system operator contract, and administers transmission facilities in a neutral manner, with reliability and cost-effectiveness as the two driving forces.

Three transmission interfaces exist between ISO-NE and neighboring regions—New York, Hydro-Quebec, and New Brunswick.

On January 16, 2001, ISO-NE, and six New England transmission owners filed jointly with FERC to form the New England RTO. The six transmission owners are Bangor Hydro-Electric, Central Maine Power, National Grid USA, Northeast Utilities Service, United Illuminating, and Vermont Electric Power. The RTO would consist of two operating entities, an ISO, and a new independent transmission company (ITC). Under the plan the ISO will be the system operator for the regional control area, administer the wholesale markets in the region, and provide most ancillary services through its tariff. The ITC will have primary responsibility for the existing New England transmission facilities, offer transmission service under the requirements of the tariff, and arrange for construction of new transmission facilities in the region and generator interconnections.

### 2.6.5 Price Forecasts for the NEPOOL Market

*A.* *BASE CASE*

This case models near-term fuel prices based on recent actual spot prices and futures prices through December 2003, decreasing linearly to the long-term consensus view by 2005.



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The all-in price represents a combined compensation for capacity and energy price (assuming a 100% load factor). The compensation for capacity contribution to the all-in price ranges between approximately $2.10/MWh and $7.70/MWh.

The base case compensation for capacity, energy, and all-in market price forecasts are presented in Figure 2-21 and Table 2-7 for the NEPOOL-Maine, NEPOOL-Southeast, and NEPOOL-West pricing areas. The prices decline and bottom out in 2005 due to the current level of operation expansion. Based on the assumptions presented herein, the market begins to rebound in 2006, reaching equilibrium in 2009.

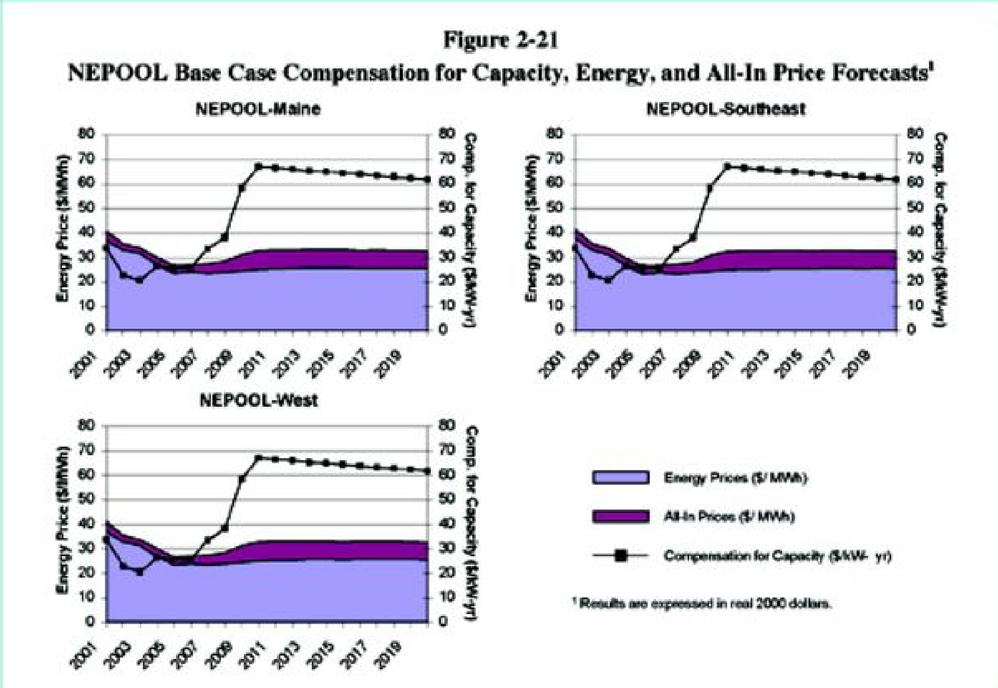





**Table 2-7**
**NEPOOL Base Case Compensation for Capacity, Energy, and All-In Price Forecasts[1]**

| Year | Compensation for Capacity ($/kW-yr) | NEPOOL-Maine Energy Price ($/MWh) | NEPOOL-Maine All-In Price ($/MWh) | NEPOOL-Southeast Energy Price ($/MWh) | NEPOOL-Southeast All-In Price ($/MWh) | NEPOOL-West Energy Price ($/MWh) | NEPOOL-West All-In Price ($/MWh) |
|---|---|---|---|---|---|---|---|
| **2001** | 33.80 | 36.90 | 40.80 | 37.80 | 41.70 | 37.20 | 41.10 |
| **2002** | 22.70 | 32.90 | 35.50 | 33.00 | 35.60 | 32.90 | 35.50 |
| **2003** | 20.60 | 31.50 | 33.90 | 31.20 | 33.60 | 31.40 | 33.70 |
| **2004** | 26.50 | 27.00 | 30.00 | 26.70 | 29.80 | 26.90 | 29.90 |
| **2005** | 25.90 | 23.70 | 26.60 | 23.40 | 26.40 | 23.70 | 26.60 |
| **2006** | 25.50 | 24.10 | 27.00 | 23.80 | 26.70 | 24.00 | 27.00 |
| **2007** | 33.50 | 23.50 | 27.30 | 23.30 | 27.10 | 23.60 | 27.50 |
| **2008** | 38.20 | 24.00 | 28.30 | 23.70 | 28.10 | 24.10 | 28.40 |
| **2009** | 58.40 | 24.50 | 31.20 | 24.30 | 31.00 | 24.70 | 31.30 |
| **2010** | 67.10 | 25.10 | 32.80 | 24.80 | 32.50 | 25.20 | 32.90 |
| **2011** | 66.60 | 25.40 | 33.00 | 25.00 | 32.60 | 25.40 | 33.00 |
| **2012** | 66.10 | 25.50 | 33.10 | 25.10 | 32.60 | 25.50 | 33.00 |
| **2013** | 65.30 | 25.80 | 33.20 | 25.40 | 32.90 | 25.70 | 33.20 |
| **2014** | 65.00 | 25.80 | 33.30 | 25.40 | 32.80 | 25.70 | 33.10 |
| **2015** | 64.50 | 25.80 | 33.10 | 25.30 | 32.70 | 25.60 | 33.00 |
| **2016** | 63.90 | 25.50 | 32.80 | 25.50 | 32.80 | 25.80 | 33.10 |
| **2017** | 63.40 | 25.70 | 32.90 | 25.50 | 32.80 | 25.90 | 33.10 |
| **2018** | 62.90 | 25.70 | 32.80 | 25.40 | 32.60 | 25.80 | 33.00 |
| **2019** | 62.40 | 25.60 | 32.80 | 25.50 | 32.60 | 25.80 | 32.90 |
| **2020** | 61.90 | 25.60 | 32.70 | 25.50 | 32.50 | 25.70 | 32.70 |

1 Results are expressed in real 2000 dollars.



*B. SENSITIVITY CASES ANALYSIS*

The all-in prices for the three sensitivity cases described in Section 2.2 are shown in Figure 2-22 and Table 2-8 for the NEPOOL-Maine, NEPOOL-Southeast, and NEPOOL-West pricing areas. These sensitivities are not meant to reflect bounding or worst case scenarios.

**Figure 2-22**

**NEPOOL Sensitivity Cases All-In Price Forecasts[1] ($/MWh)**

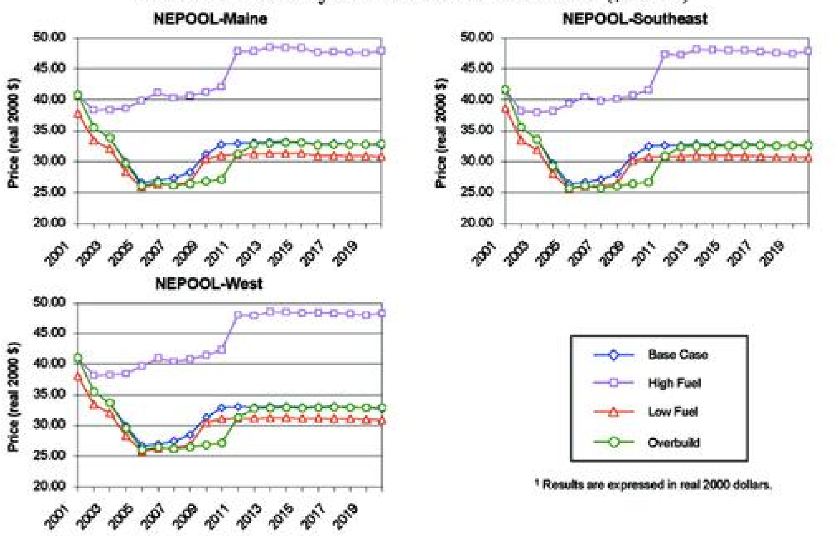



**Table 2-8**

**NEPOOL Sensitivity Cases All-In Price Forecasts[1] ($/MWh)**

| | NEPOOL-Maine | | | | NEPOOL-Southeast | | | | NEPOOL-West | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Year** | **Base Case** | **High Fuel** | **Low Fuel** | **Over-build** | **Base Case** | **High Fuel** | **Low Fuel** | **Over-build** | **Base Case** | **High Fuel** | **Low Fuel** | **Over-build** |
| **2001** | 40.80 | 40.80 | 37.90 | 40.80 | 41.70 | 41.60 | 38.70 | 41.70 | 41.10 | 41.00 | 38.10 | 41.10 |
| **2002** | 35.50 | 38.30 | 33.40 | 35.50 | 35.60 | 38.20 | 33.50 | 35.60 | 35.50 | 38.20 | 33.40 | 35.50 |
| **2003** | 33.90 | 38.40 | 32.10 | 33.90 | 33.60 | 38.00 | 31.90 | 33.60 | 33.70 | 38.30 | 32.00 | 33.70 |
| **2004** | 30.00 | 38.60 | 28.30 | 29.70 | 29.80 | 38.20 | 28.10 | 29.30 | 29.90 | 38.50 | 28.30 | 29.60 |
| **2005** | 26.60 | 39.90 | 25.90 | 26.20 | 26.40 | 39.40 | 25.60 | 25.70 | 26.60 | 39.70 | 25.80 | 26.00 |
| **2006** | 27.00 | 41.10 | 26.30 | 26.60 | 26.70 | 40.50 | 26.00 | 26.10 | 27.00 | 41.00 | 26.30 | 26.50 |
| **2007** | 27.30 | 40.30 | 26.30 | 26.20 | 27.10 | 39.80 | 26.10 | 25.70 | 27.50 | 40.40 | 26.40 | 26.20 |
| **2008** | 28.30 | 40.70 | 26.70 | 26.50 | 28.10 | 40.20 | 26.50 | 26.00 | 28.40 | 40.80 | 26.80 | 26.50 |
| **2009** | 31.20 | 41.30 | 30.40 | 26.90 | 31.00 | 40.80 | 30.20 | 26.50 | 31.30 | 41.40 | 30.50 | 26.90 |
| **2010** | 32.80 | 42.10 | 31.00 | 27.10 | 32.50 | 41.60 | 30.80 | 26.70 | 32.90 | 42.30 | 31.10 | 27.10 |
| **2011** | 33.00 | 47.80 | 31.10 | 31.30 | 32.60 | 47.30 | 30.80 | 30.90 | 33.00 | 48.10 | 31.20 | 31.30 |
| **2012** | 33.10 | 47.90 | 31.20 | 32.80 | 32.60 | 47.30 | 30.80 | 32.30 | 33.00 | 47.90 | 31.20 | 32.80 |
| **2013** | 33.20 | 48.50 | 31.30 | 32.90 | 32.90 | 48.10 | 31.00 | 32.50 | 33.20 | 48.50 | 31.20 | 32.80 |
| **2014** | 33.30 | 48.40 | 31.40 | 33.00 | 32.80 | 48.00 | 31.00 | 32.60 | 33.10 | 48.50 | 31.30 | 32.90 |
| **2015** | 33.10 | 48.40 | 31.30 | 33.00 | 32.70 | 47.90 | 30.90 | 32.60 | 33.00 | 48.40 | 31.20 | 32.90 |
| **2016** | 32.80 | 47.60 | 30.90 | 32.70 | 32.80 | 48.00 | 30.90 | 32.70 | 33.10 | 48.40 | 31.20 | 32.90 |
| **2017** | 32.90 | 47.80 | 31.00 | 32.80 | 32.80 | 47.80 | 30.80 | 32.70 | 33.10 | 48.30 | 31.10 | 33.00 |
| **2018** | 32.80 | 47.70 | 30.90 | 32.80 | 32.60 | 47.60 | 30.70 | 32.60 | 33.00 | 48.20 | 31.10 | 33.00 |
| **2019** | 32.80 | 47.60 | 30.90 | 32.80 | 32.60 | 47.40 | 30.70 | 32.60 | 32.90 | 48.00 | 31.00 | 32.90 |
| **2020** | 32.70 | 47.90 | 30.90 | 32.90 | 32.50 | 47.90 | 30.70 | 32.70 | 32.70 | 48.30 | 30.90 | 32.90 |

1 Results are expressed in real 2000 dollars.



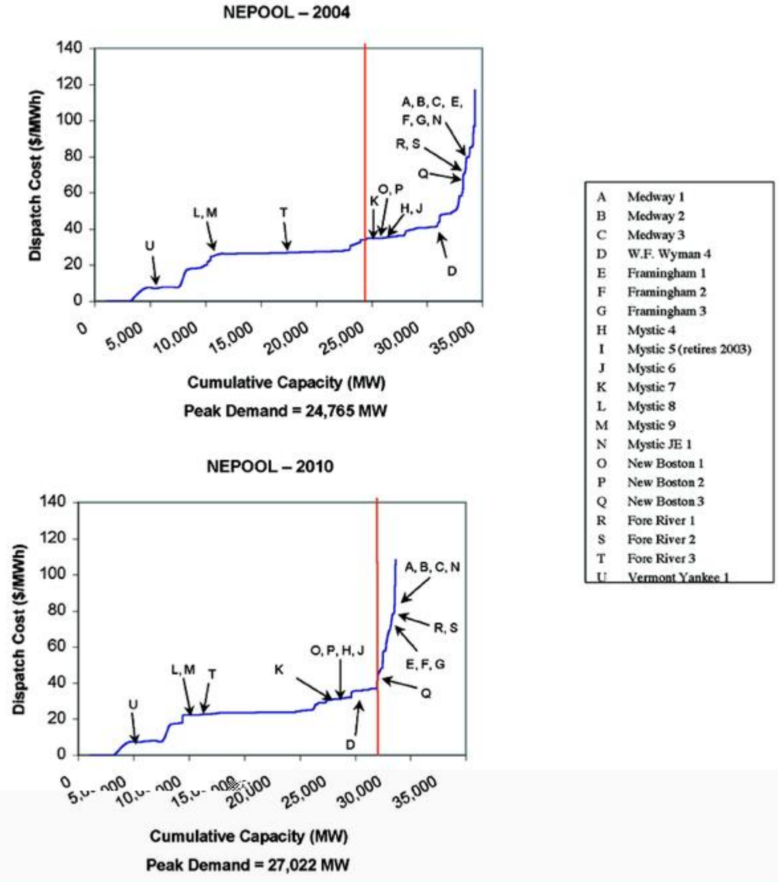
All-in prices for the high fuel case are approximately $10 to $15/MWh higher than the base case for the majority of the study period. Low fuel all-in prices follow a slightly lower parallel path as compared to the base case.

The overbuild case assumes that in addition to the 8,741 MW of merchant plants added in the base case, an additional 1,040 MW is added to the NEPOOL region in 2004. This additional capacity results in a 1% to 17% reduction in the all-in price in 2004 through 2011. By approximately 2012, the additional capacity is absorbed into the market and the prices are approximately the same as in the base case.

### 2.6.6 Dispatch Curves

Dispatch curves for the NEPOOL region for 2004 and 2010 are shown in Figure 2-23. The relative position of the plants in this report are located along the dispatch curve. The dispatch curves represent the annual average marginal dispatch cost of the target assets as compared to the other generators in the market.

Figure 2-23
NEPOOL Dispatch Curves for 2004 and 2010






## 2.7 NPCC-NEW YORK

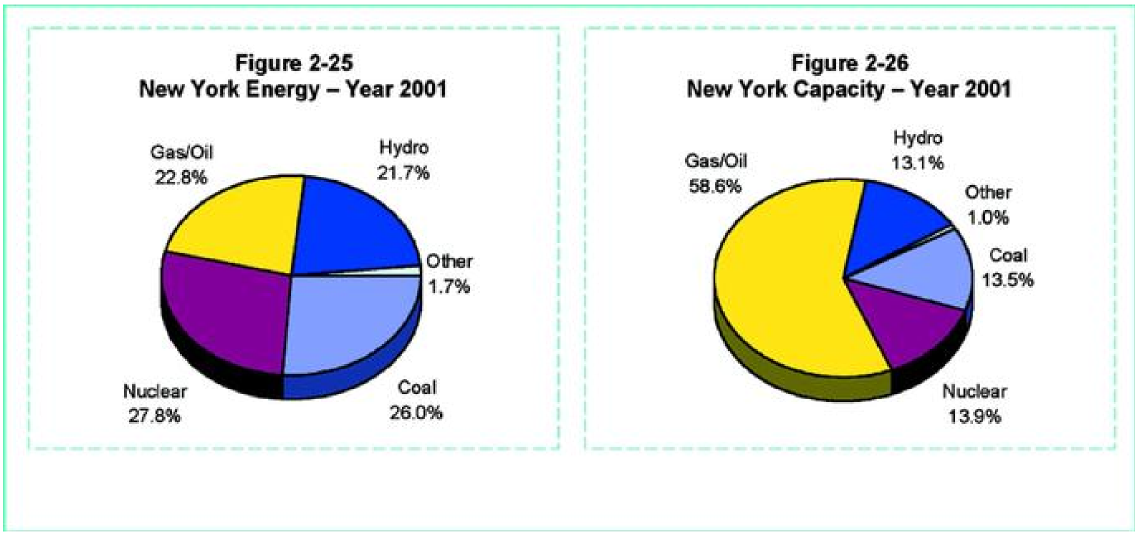
### 2.7.1 Background

This section describes the current, proposed, and potential future structure of the power market within the New York component of the NPCC. The New York ISO (NY-ISO), formed in 1998, is the replacement for the New York Power Pool (NYPP). The NYPP was formed by New York's eight largest electric utilities following the Northeast Blackout of 1965. The NYPP operated as a centrally dispatched power pool with a "split-the-savings" pricing methodology. In response to the FERC Open Access Rule (Order 888), the members of NYPP developed a restructuring proposal and a pool-wide open access tariff, which were submitted to FERC in January 1997. This restructuring proposal created the NY-ISO to operate the New York bulk power system, maintain system reliability, administer specified electricity markets, and facilitate open access to the New York transmission system. Figure 2-24 shows the NPCC-New York region and the location of ExGen's generation assets by pricing area.

Figure 2-24
NPCC-New York Region


On January 28, 1999, FERC gave conditional approval of the NY-ISO's proposed tariff, market rules, and market-based rates with some modifications. On November 18, 1999, the NY-ISO officially assumed control and operation of the NYPP grid and began administering the wholesale market for the sale and purchase of electricity in the region. The NY-ISO also provides statewide transmission service under a single tariff, which eliminates the cumulative transmission charges for each individual utility that is involved in a transaction.

As Figures 2-25 and 2-26 indicate, NY-ISO uses a balance of natural resources for baseload generation. Production comes from nuclear (28%), coal (26%), gas and oil (23%), and hydro-based (22%). Gas- and oil-fired units account for the majority of NY-ISO's installed capacity, totaling 59%.




**Sources: Figure 2-25: PA Consulting Services Inc. Regional Modeling results. Figure 2-26: Report of the Member Electric Systems of the New York Power Pool Load and Capacity Data, 2000; and PA Consulting Services Inc.**

**2.7.2 Power Markets**

*A. INTRODUCTION*

The ExGen assets in New York are located the New York-East and New York-West pricing areas. (See Figure 2-24.)

Activity in the wholesale power markets has been enhanced as a result of retail market restructuring. Several of the IOUs in New York were required to divest a portion of their generation assets. In addition, generators in New York City were required to adopt certain market power mitigation measures. These market power mitigation measures are intended to alleviate concerns that the divested generation might be able to exercise localized market power due to the current configuration of loads, generation, and transmission facilities in New York City and related local reliability rules and transmission constraints. These market power mitigation measures were approved by FERC in Docket No. ER98-3169-000, issued September 22, 1998, and are being implemented by the NY-ISO.

The new wholesale market structure in New York created the following markets for the services of generators:

i. installed capacity
ii. day-ahead energy
iii. real-time energy
iv. ancillary services (day-ahead and real-time)
v. operating reserves
vi. regulation
vii. In-City market power mitigation measures



viii. In-City unit commitment
ix. installed capacity
x. spinning reserves.

*B. MARKETS*

*i. Installed Capacity Market*

To ensure that sufficient installed capacity is available in the market to meet reliability standards, the NY-ISO requires LSEs to own or contract with physical generation capacity to cover their peak demand and a share of the installed reserve requirement for the upcoming capability period.

Important features of the installed capacity market include the following:

- The market is a semi-annual market.
- The installed capability obligation for each participant is determined on a semi-annual basis by the NY-ISO.
  - The NY-ISO determines the minimum amount of capability that must be obtained internal to the LSE's locality.
  -

— The NY-ISO determines the maximum amount of capability that may be obtained by the LSE from other zones in the New York Control Area.

— The NY-ISO determines the maximum capability that may be obtained from all neighboring control areas.

— All resources must be either bilaterally scheduled to meet load within the New York Control Area or be bid into the New York day-ahead market.

- Installed capacity may be acquired by an LSE through bilateral transactions with generators or other LSEs.
- An LSE may acquire installed capacity at any time during the year, including after the occurrence of its peak load.
- An LSE lacking installed capacity will be required to purchase it at a special auction held by the NY-ISO.
- If an LSE fails to meet its installed capacity requirement, a substantial penalty will be assessed.

The NY-ISO conducts installed capacity auctions 45 days prior to both the summer and winter capability periods (referred to as Obligation Procurement Periods). The auction takes place in three stages. First, installed capacity is bought and sold in six-month blocks covering the entire Obligation Procurement Period. Then a subsequent auction facilitates transactions for specific months within the period. In the event that any LSEs have not certified to the NY-ISO that they have met their installed capacity requirements, the NY-ISO will conduct a third "Deficiency Procurement Auction" to secure installed capacity credits on behalf of the deficient LSEs.

The NY-ISO conducted its first auction in April 2000. In the New York City area, over 5,000 MW was awarded for the six-month block covering May through October at a market-clearing price averaging $8.75 per kW-month. In the month-by-month auction, demand far exceeded supply in New York City. Only 59.4 MW was offered each month, whereas demand ranged from 308 MW in several months to nearly 2,000 MW in July and August. As a result market-clearing prices reached the ISO-imposed ceiling of $12.50 per kW-month in every month. Other areas in the ISO territory saw much less activity in the auction. In some areas, no MW were offered at all, and in others prices reached no higher than $2.25 per kW-month.



The NY-ISO also plans to conduct monthly auctions to allow LSEs that have gained load to acquire additional installed capacity credits. If necessary, monthly Deficiency Procurement Auctions will also be held.

*ii. Day-Ahead Energy Market*

In the day-ahead energy market, 24 separate hourly energy prices are determined for each location. The closing time for submitting bids to the NY-ISO is 5:00 for the energy markets the following day (for example, 5:00 Tuesday morning for bids on energy to be generated on Wednesday). A bid to supply generation consists of an incremental energy bid curve. For each generation level, the curve represents the minimum price a bidder is willing to accept to be dispatched at that generation level. Distinct curves may be submitted for each hour. Bidders may specify constraints on their units, such as minimum up time, minimum down time, and ramp rates. Bidders are able to separately specify start-up costs and minimum load costs.

The NY-ISO runs a security-constrained unit commitment program[1] to determine which generating units will be committed (designated to be available for dispatch the next day). Locational-based marginal prices (LBMPs) are determined for each hour. A location-specific price represents the cost of serving an increment of load at that location for that hour, as represented in the NY-ISO's day-ahead schedule. The NY-ISO determines its day-ahead schedule by minimizing total cost (as bid) over the course of the day, while meeting the load quantities bid day-ahead by LSEs. The location-specific prices include any charges for transmission losses and congestion.

A winning bid results in a financial forward at the location-specific day-ahead price for the quantity accepted by the NY-ISO. If a winning bidder delivers an amount of energy other than that accepted by the NY-ISO in the day-ahead energy market, the difference in energy between the amount delivered and the amount bid is paid (either to or from the generator) at the real-time energy price.

Important features of the day-ahead market include the following:

- Only the incremental energy bid curve is used in determining the LBMPs. If the difference between the market clearing price times the scheduled generation and the bid price times the scheduled generation does not cover as-bid start-up and minimum load costs, the generator receives the shortfall as a make whole payment.
- A generator participating in the centrally coordinated financial settlement process is paid the hourly day-ahead price at its location for all energy it is scheduled to produce in the day-ahead market in that hour.
- An LSE participating in the centrally coordinated financial settlement process pays the hourly day-ahead price for its zone, which is an average of locational prices within that zone, for all energy it is scheduled to consume in the day-ahead market in that hour.
- Bilateral transactions are not subject to the centrally coordinated financial settlement process for energy purchases. However, participants making bilateral transactions pay for transmission service based on the same charges for transmission losses and transmission congestion (which results in the differences in prices based on their location).

On August 28, 2000, the three northeast ISO's (New England, New York, and Ontario) jointly issued a Request for Proposal (RFP). The RFP requested a feasibility study for a regional day-ahead electric market that would establish energy prices and schedules for the next day. The goal is to offer additional capability for market participants to buy and sell electricity across a broader region than is

1 The security-constrained unit commitment program is a complex mathematical optimization program that identifies a set of generation units whose availability minimizes anticipated cost while meeting the security (reliability) constraints.



presently available within the ISO markets. The RFP falls in line with FERC Order 2000, which calls for the formation of RTOs. In that same order, FERC indicated that it favors larger regional ISO markets that reduce what they refer to as "seams" between existing markets. There are three phases to the study. The first phase is to analyze various options and recommend something to be approved by all three ISOs. Once the first phase is accepted, the second phase would incorporate a system reliability study. The third phase would then produce functional specifications based on the outcomes of the first two phases. The first phase should be completed on or before March 30, 2001.

In compliance with FERC's preferences stated in FERC Order 2000, the New England and New York ISO board of directors announced the approval of a joint resolution on January 16, 2001. The resolution establishes a joint task force on inter-control area market coordination. The two groups have pledged that both regions' ISOs cooperate to enhance interregional coordination and reduce barriers to transactions between the two wholesale electricity markets. The joint resolution was made in accordance to previous RTO filings that occurred in both NEPOOL and New York.

*iii. Real-Time Energy Market*

In the real-time energy market, the closing time for submitting bids to the NY-ISO is 90 minutes in advance of the hour; these bids are known as hour-ahead bids. The NY-ISO uses a security-constrained dispatch program to meet load on a 5-minute basis. The locational price of energy at each location is the bid-based cost of meeting incremental load at that location in the security-constrained least-cost dispatch. For each 5-minute interval, a generator is paid a location-specific price for the energy generated in that interval at the market-clearing location-specific price for that 5-minute interval.

Important features of the real-time energy market include the following:

- Hour-ahead bids are valid from market close through the scheduled hour of delivery, which allows such bids to be exercised by the NY-ISO in real-time.
- For resources previously scheduled by the NY-ISO day-ahead, hour-ahead bids may be no greater than the day-ahead bids.
- Bilateral transactions involving energy purchases and sales are not settled through the centrally coordinated process. Participants may, however, purchase transmission on the same basis and are subject to the same charges for transmission losses and transmission congestion.
- Generators, loads, and bilateral transactions are subject to real-time locational prices only to the extent that their actual injections and/or withdrawals differ from their schedules submitted the day before.
- The essence of real-time operation lies in the SCD (Security-Constrained Dispatch) software package. The SCD program works to identify the winning bid and commits it to provide transmission services.

*iv. Ancillary Services Market*

Six specific support services compose the sector known as the Ancillary Services Market. These unbundled services support the transmission of energy and reactive power from resources to loads; they are essential to maintain reliable operation of the New York power system. Some of these services are market-based, meaning they are bid for in a market much like that of installed capacity or other previously mentioned markets. Other services are provided by the NY-ISO at embedded costs. A summary of the NY-ISO Ancillary Services is provided in Table 2-9.

Only a few of these services, as Table 2-9 illustrates, provide a market from which profits can be generated. Of these market-based services, the market for the Operating Reserve Service provides the most opportunity for profit.



**Table 2-9**
**NY-ISO Ancillary Services Summary**

| Ancillary Services | Service Location Dependent? | Service Provider | Pricing Method |
|---|---|---|---|
| Scheduling, System Control, and Dispatch Service | No | NY-ISO | Embedded |
| Voltage Support Service | Yes | NY-ISO | Embedded |
| Regulation and Frequency Response Service | Yes | NY-ISO or Third Party | Market-based |
| Energy Imbalance Service | No | NY-ISO | Market-based and Energy payback |
| Operating Reserve Service | Yes | NY-ISO or Third Party | Market-based |
| Black Start Service | Yes | NY-ISO | Embedded |

*v. Operating Reserves Market*

There are three types of operating reserves in the NY-ISO (ten-minute spinning, ten-minute non-spinning, thirty-minute operating), with each occupying one-third of the market. Each type of operating reserve has a day-ahead and real-time market for each hour of system operations. Important features of the operating reserves markets include the following:

- Each day-ahead operating reserve market is bid-based, and bids are in $/MW. A generator may submit operating reserve bids for any and all markets for which it qualifies. Using its security-constrained unit commitment program, the NY-ISO determines the winning bids for each market. The market-clearing price for each day-ahead operating reserve market is that market's highest winning bid.
- If the NY-ISO recognizes in real-time a need for additional operating reserves, real-time prices are determined by hour-ahead bids in each operating reserve market. If no additional operating reserves are acquired in real-time by the NY-ISO, the real-time prices for operating reserves are equal to zero.
- Spinning reserve payments to generators on security-constrained dispatch by the NY-ISO may include lost opportunity costs if the NY-ISO directs those units to reduce generating levels in order to provide spinning reserves. Spinning reserve payments to non-dispatchable generators do not include lost opportunity costs.
- Capacity assigned to provide operating reserves, and then dispatched by the NY-ISO to provide energy, is paid the real-time LBMP for the energy market.
- Generators face penalties for failure to perform.

*vi. Regulation Markets*

Regulation service provides ramping service to follow the second-to-second fluctuations in load and supply. Regulation service is provided by generators on automatic generation control (AGC). There are day-ahead and real-time markets for regulation.

Important features of the regulation market include the following:

- Bids are in $/MW, based on a unit's regulation response rate in MW/min.
- Compensation for regulation includes an availability component and a component for energy used in regulation.
- The real-time market for regulation may clear at a price of zero when there is no additional need for regulation beyond that which is scheduled the day before.
- A generator that does not follow its day-ahead schedule is levied a charge for the necessary regulation it imposes on the system.
- Generators face penalties for failure to perform.

*vii. In-City (New York) Market Power Mitigation Measures*

Energy bids are market-based and congestion management is achieved through locational-based marginal pricing. The bid prices of In-City generators are relied on to compute the In-City market clearing price, unless the bid prices are 5% greater than the price at the Indian Point 2 bus (which is located outside of the City of New York). When this happens, mitigation measures are invoked and the In-City generator's effective bid prices are not used. In this case, the bids are capped at the amount that those same generators have bid during unconstrained hours in the prior 90 days.[2] Any portion of the 90-day period that reflects periods when mitigation measures were invoked is not used in this calculation. The price is based on the unit's variable operating costs[3] if there are not 15 days of data when mitigation measures were not invoked.

*viii. In-City Unit Commitment*

In-City generating units may be committed to meet reliability requirements. If a unit is committed and proves to be the cheapest alternative, it is dispatched the next day to deliver energy and, therefore, no market power mitigation measure is necessary. However, if a unit is committed and is not dispatched the next day to deliver energy, it is entitled to a unit commitment payment, which is capped at the unit's variable cost.

*ix. Installed Capacity*

LSEs serving load In-City may be subject to local reliability rules that specify the portion of the installed capacity requirement that must be satisfied from In-City generating resources. In-City installed capacity has a price cap of $105.00/kW-yr and shall be revised only as permitted by FERC.

*x. Spinning Reserves*

All spinning reserve suppliers are paid the higher of their spinning reserve bids or their lost opportunity costs associated with providing spinning reserves (i.e., the revenues they would have earned had the units been dispatched to deliver energy rather than operated as spinning reserves). All In-City generators with spinning reserve capability are required to participate in the spinning reserve markets and to use bid prices of zero in all hours. If directed to supply spinning reserves, the generators are compensated as if their units had been dispatched to make energy sales.

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2 The cap is an average that is adjusted up or down by a fuel index to account for changes in fuel costs over the 90-day period.

3 The formula uses a fuel price index, the unit's heat rate, and other operating characteristics, as well as a $1/MWh adder for operation and maintenance costs.

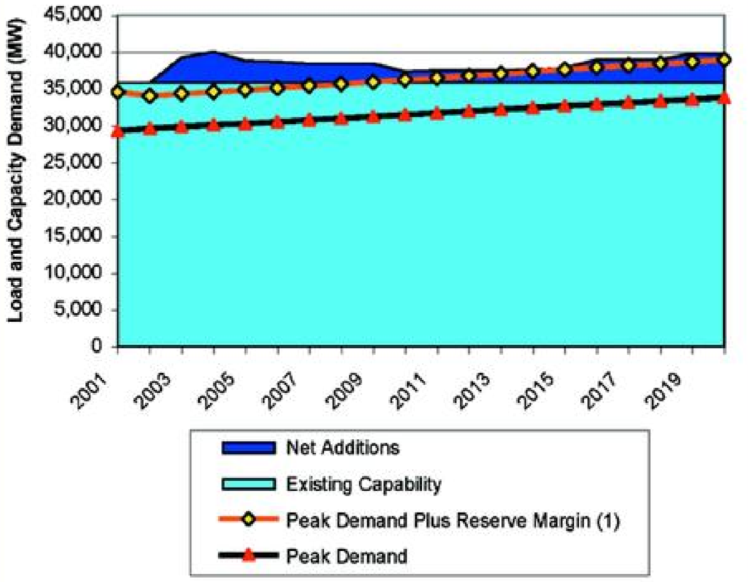


### 2.7.3 Market Dynamics

ExGen's New York assets in this report represent 2,072 MW of capacity.

The ExGen assets in the New York region will participate in the New York-East and New York-West wholesale electricity markets. Figure 2-27 illustrates the load and resource balance for the New York region.

**Figure 2-27**
**New York Load and Resource Balance**




Source: Northeast Power Coordinating Council Load, Load, Capacity, Energy, Fuels, and Transmission Report, Forecast Data as of January 1, 2000, Data Submitted April 1, 2000.

(1) Reserve Margin is assumed to be 18% in 2001, decreasing to 15% in 2002 through 2020. Net additions are net of retirements.

From 1991 to 2000, the New York market had an average annual peak demand growth rate of 1.9%. However, the forecast indicates that the growth will slow to an average annual compound rate of 0.8% for 2001-2020. A required system-wide reserve margin of 18% in 2001, decreasing to 15% in 2002 through 2020, is assumed. The New York market is projected to be in a surplus from 2002 to 2009 due to a significant number of merchant plants being developed in the region.

Historical prices for New York are presented in Appendix A.

**2.7.4 Transmission System**

Currently, the New York ISO is responsible for the operation, planning, and coordination of New York's bulk transmission system for seven member transmission owning companies and two member transmission operators. On January 17, 2001, the NY-ISO and six other transmission owners in New York filed jointly with FERC to form the New York RTO. A major component of the filing proposes that the NY-ISO assume "ultimate responsibility" for planning and coordinating transmission expansions, additions, and upgrades.



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**2.7.5 Price Forecasts for the New York Market**

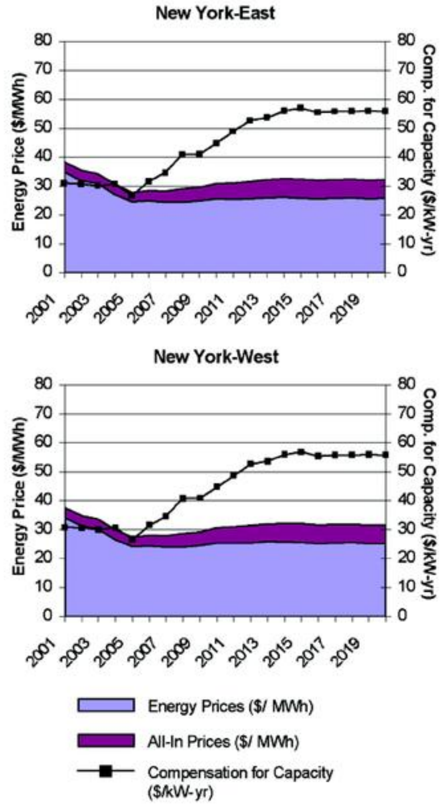
*A. BASE CASE*

This case models near near-term fuel prices based on recent actual spot prices and futures prices through December 2003, decreasing linearly to the long-term consensus view by 2005.

The all-in price represents a combined compensation for capacity and energy price (assuming a 100% load factor). The compensation for capacity contribution to the all-in price ranges between approximately $3.00/MWh and $6.50/MWh.

The base case compensation for capacity, energy, and all-in market price forecasts are presented in Figure 2-28 and Table 2-10 for the New York-East and New York-West pricing areas.

**Figure 2-28**
**New York Base Case Compensation for Capacity, Energy, and All-In Price Forecasts[1]**




[1] Results are expressed in real 2000 dollars.



**Table 2-10**
**New York Base Case Compensation for Capacity, Energy, and All-In Price Forecasts[1]**

| | | New York-East | | New York-West | |
|---|---|---|---|---|---|
| Year | Comp. for Capacity ($/kW-yr) | Energy ($/MWh) | All-In ($/MWh) | Energy ($/MWh) | All-In ($/MWh) |
| 2001 | 30.90 | 34.80 | 38.30 | 34.10 | 37.60 |
| 2002 | 30.60 | 31.90 | 35.40 | 31.30 | 34.70 |
| 2003 | 30.10 | 30.70 | 34.10 | 30.20 | 33.60 |
| 2004 | 30.60 | 27.10 | 30.50 | 26.60 | 30.10 |
| 2005 | 26.70 | 24.60 | 27.60 | 24.30 | 27.30 |
| 2006 | 31.60 | 24.80 | 28.40 | 24.50 | 28.10 |
| 2007 | 34.60 | 24.30 | 28.30 | 24.00 | 27.90 |
| 2008 | 40.80 | 24.40 | 29.10 | 24.10 | 28.70 |
| 2009 | 40.90 | 24.90 | 29.50 | 24.60 | 29.30 |
| 2010 | 44.80 | 25.60 | 30.70 | 25.50 | 30.60 |
| 2011 | 48.80 | 25.50 | 31.10 | 25.50 | 31.00 |
| 2012 | 52.70 | 25.50 | 31.50 | 25.50 | 31.50 |
| 2013 | 53.70 | 26.00 | 32.10 | 26.00 | 32.10 |
| 2014 | 56.00 | 26.00 | 32.40 | 25.80 | 32.20 |
| 2015 | 56.90 | 25.80 | 32.30 | 25.70 | 32.20 |
| 2016 | 55.50 | 25.70 | 32.00 | 25.40 | 31.70 |
| 2017 | 55.70 | 25.80 | 32.20 | 25.50 | 31.80 |
| 2018 | 55.80 | 25.90 | 32.20 | 25.50 | 31.90 |
| 2019 | 56.00 | 25.70 | 32.10 | 25.30 | 31.70 |
| 2020 | 55.90 | 25.70 | 32.10 | 25.40 | 31.70 |

1 Results are expressed in real 2000 dollars.

## *B. SENSITIVITY CASES ANALYSIS*

The all-in prices for the three sensitivity cases described in Section 2.2 are shown in Figure 2-29 and Table 2-11 for the New York-East and New York-West pricing areas. These sensitivities are not meant to reflect bounding or worst case scenarios. The spread between all-in prices for the high fuel case and base case grows from $11/MWh in 2005, to $15/MWh by 2020 as the number of hours that gas is on the margin increases. The low fuel case prices are $1 to $3/MWh lower than the base case prices throughout the study period. The overbuild case assumes that in addition to the 1,880 MW of merchant plants added in the base case, an additional 2,080 MW is added to the New York region in 2004. The additional capacity added in the overbuild case resulted in a 4% to 13% reduction in the



all-in price in 2004 through 2015. By approximately 2016, the additional capacity is absorbed into the market and the prices are approximately the same as in the base case.

**Figure 2-29**
**New York Sensitivity Cases**
**All-In Price Forecasts[1] ($/MWh)**

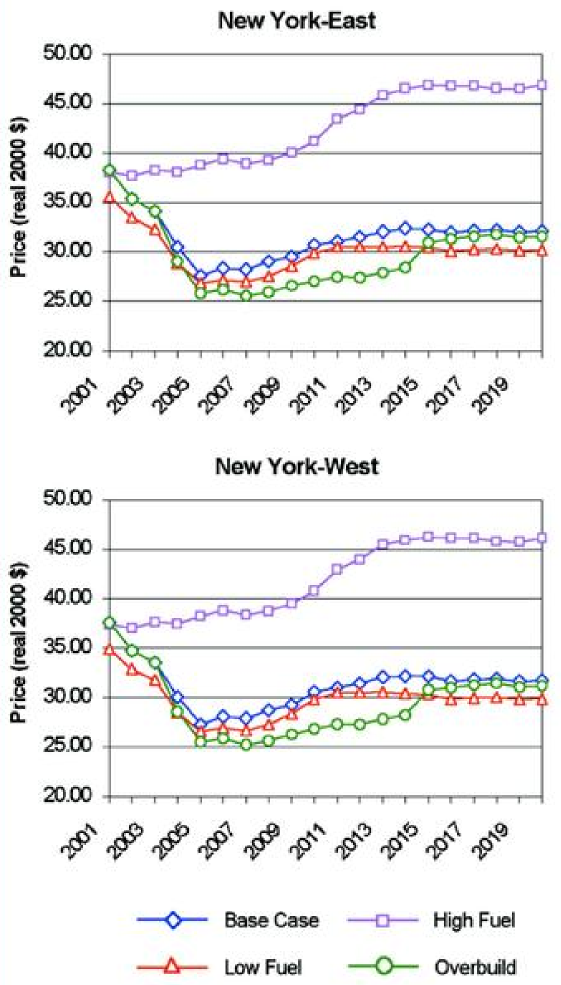





**Table 2-11**
**New York Sensitivity Cases All-In Price Forecasts[1] ($/MWh)**

| Year | Base Case | High Fuel | Low Fuel | Overbuild |
|---|---|---|---|---|
| **New York-East** | | | | |
| 2001 | 38.30 | 38.10 | 35.60 | 38.30 |
| 2002 | 35.40 | 37.70 | 33.50 | 35.40 |
| 2003 | 34.10 | 38.30 | 32.30 | 34.10 |
| 2004 | 30.50 | 38.10 | 28.90 | 29.10 |
| 2005 | 27.60 | 38.80 | 26.90 | 25.90 |
| 2006 | 28.40 | 39.40 | 27.10 | 26.20 |
| 2007 | 28.30 | 38.90 | 27.00 | 25.60 |
| 2008 | 29.10 | 39.30 | 27.60 | 26.00 |
| 2009 | 29.50 | 40.00 | 28.60 | 26.60 |
| 2010 | 30.70 | 41.20 | 29.90 | 27.00 |
| 2011 | 31.10 | 43.50 | 30.50 | 27.50 |
| 2012 | 31.50 | 44.40 | 30.50 | 27.40 |
| 2013 | 32.10 | 45.90 | 30.50 | 27.90 |
| 2014 | 32.40 | 46.50 | 30.60 | 28.40 |

| | | | | |
|---|---|---|---|---|
| 2015 | 32.30 | 46.80 | 30.50 | 31.00 |
| 2016 | 32.00 | 46.80 | 30.10 | 31.40 |
| 2017 | 32.20 | 46.80 | 30.30 | 31.60 |
| 2018 | 32.20 | 46.50 | 30.30 | 31.80 |
| 2019 | 32.10 | 46.50 | 30.20 | 31.50 |
| 2020 | 32.10 | 46.90 | 30.20 | 31.60 |
| **New York-West** | | | | |
| 2001 | 37.60 | 37.40 | 35.00 | 37.60 |
| 2002 | 34.70 | 37.10 | 32.90 | 34.70 |
| 2003 | 33.60 | 37.60 | 31.80 | 33.60 |
| 2004 | 30.10 | 37.50 | 28.50 | 28.60 |
| 2005 | 27.30 | 38.20 | 26.60 | 25.50 |
| 2006 | 28.10 | 38.80 | 26.90 | 25.90 |
| 2007 | 27.90 | 38.40 | 26.70 | 25.30 |
| 2008 | 28.70 | 38.80 | 27.30 | 25.60 |
| 2009 | 29.30 | 39.50 | 28.40 | 26.30 |
| 2010 | 30.60 | 40.80 | 29.80 | 26.80 |
| 2011 | 31.00 | 43.00 | 30.50 | 27.30 |
| 2012 | 31.50 | 44.00 | 30.50 | 27.30 |
| 2013 | 32.10 | 45.50 | 30.60 | 27.80 |
| 2014 | 32.20 | 45.90 | 30.40 | 28.20 |
| 2015 | 32.20 | 46.30 | 30.30 | 30.80 |
| 2016 | 31.70 | 46.10 | 29.90 | 31.00 |
| 2017 | 31.80 | 46.10 | 30.00 | 31.30 |
| 2018 | 31.90 | 45.80 | 30.10 | 31.50 |
| 2019 | 31.70 | 45.80 | 29.80 | 31.10 |
| 2020 | 31.70 | 46.10 | 29.90 | 31.20 |

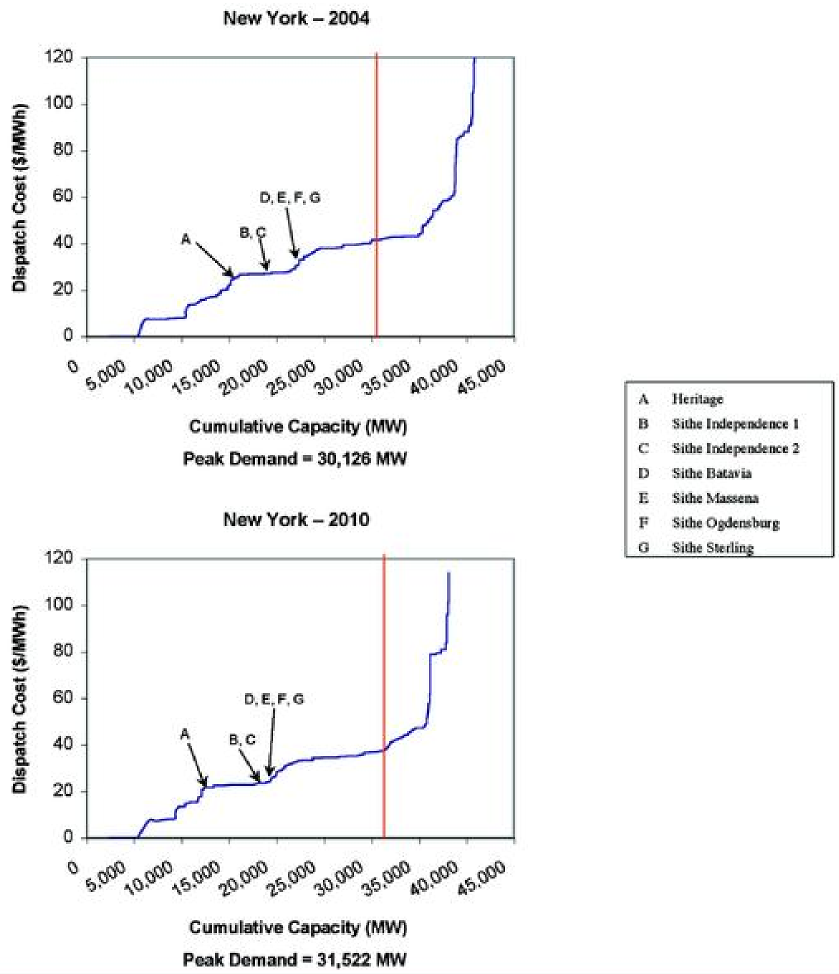
1 Results are expressed in real 2000 dollars.



### 2.7.6 Dispatch Curves

Dispatch curves for the New York region for 2004 and 2010 are shown in Figure 2-30. The relative position of the plants in this report are located along the dispatch curve. The dispatch curves represent the annual average marginal dispatch cost of the target assets as compared to the other generators in the market.

**Figure 2-30**
**New York Dispatch Curves for 2004 and 2010**



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## 2.8 PRICE FORECASTS FOR OTHER REGIONS OF INTEREST

ExGen has contractual agreements in three additional NERC regions:

- ***ERCOT*—**Electric Reliability Council of Texas
- ***SERC*—**Southeastern Electric Reliability Council
- ***SPP***—Southwest Power Pool.

The forecasts of energy prices and capacity compensation for the base case as well as associated sensitivity cases are provided in the following sections for the relevant pricing areas in each of these regions.

### 2.8.1 ERCOT

*A. BASE CASE*

This case models near-term fuel prices based on recent actual spot prices and futures prices through December 2003, decreasing linearly to the long-term consensus view by 2005. The prices decline rapidly through 2005 due to the assumed gas price decreases and the projected surplus capacity in ERCOT. Prices rebound and stabilize after 2006.

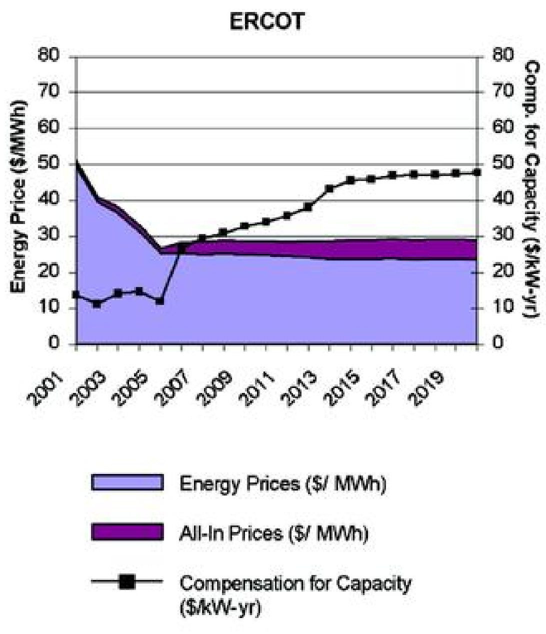
The all-in price represents a combined compensation for capacity and energy price (assuming a 100% load factor). The compensation for capacity contribution to the all-in price ranges between $1.30/MWh and $5.40/MWh.



---

The base case compensation for capacity, energy, and all-in market price forecasts are presented in Figure 2-31 and Table 2-12 for ERCOT.

Figure 2-31
ERCOT Base Case Compensation
for Capacity, Energy, and All-In Price Forecasts[1]




[1] Results are expressed in real 2000 dollars.



Table 2-12
ERCOT Base Case Forecasts[1]

| Year | Compensation for Capacity ($/kW-yr) | Energy Price ($/MWh) | All-In Price ($/MWh) |
|---|---|---|---|
| **2001** | 13.70 | 49.50 | 51.00 |
| **2002** | 11.30 | 39.70 | 41.00 |
| **2003** | 14.10 | 36.60 | 38.20 |
| **2004** | 14.60 | 31.40 | 33.10 |
| **2005** | 11.90 | 25.30 | 26.70 |
| **2006** | 26.70 | 25.30 | 28.30 |
| **2007** | 29.40 | 25.10 | 28.40 |
| **2008** | 31.00 | 25.20 | 28.80 |
| **2009** | 32.80 | 24.90 | 28.60 |
| **2010** | 34.10 | 24.80 | 28.70 |
| **2011** | 35.80 | 24.40 | 28.50 |
| **2012** | 38.10 | 24.20 | 28.50 |
| **2013** | 43.20 | 23.80 | 28.70 |
| **2014** | 45.60 | 23.80 | 29.00 |
| **2015** | 45.90 | 23.70 | 28.90 |
| **2016** | 47.00 | 23.90 | 29.30 |
| **2017** | 47.10 | 23.70 | 29.00 |
| **2018** | 47.20 | 23.70 | 29.10 |
| **2019** | 47.50 | 23.70 | 29.10 |
| **2020** | 47.70 | 23.50 | 29.00 |

1 Results are expressed in real 2000 dollars.

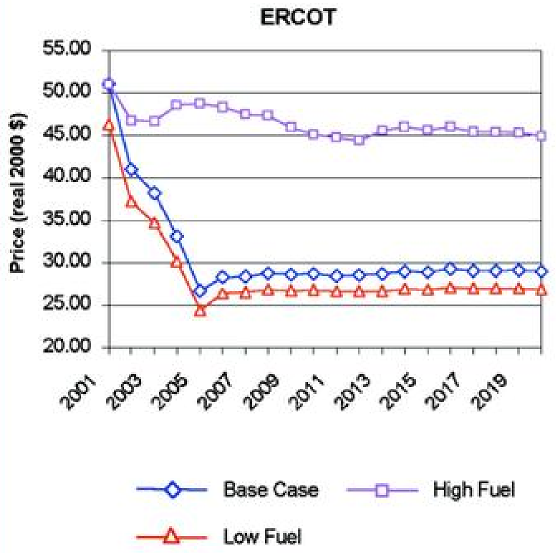
*B. SENSITIVITY CASES ANALYSIS*

The all-in prices for high fuel and low fuel sensitivity cases described in Section 2.2 are shown in Figure 2-32 and Table 2-13. These sensitivities are not meant to reflect bounding or worst case scenarios.

All-in prices for the high fuel case do not experience the slight decrease in 2005 associated with the drop to consensus fuel in the base case. Since ERCOT relies on gas/oil for much of its generation, high fuel prices escalate the all-in prices to almost $20/MWh greater than the base case. The low fuel case results in an all-in price drop of approximately $2/MWh throughout the study period.

The greater effect of the high fuel case as compared to the low fuel case is largely due to the severity of the change in fuel prices. The high fuel case assumes an average 75% increase in gas prices over the study period compared to a 10% decrease for the low fuel case.

**Figure 2-32**
**ERCOT Sensitivity Cases**
**All-In Price Forecasts ($/MWh)**




[1] Results are expressed in real 2000 dollars.



**Table 2-13**
**ERCOT Sensitivity Cases**
**All-In Price Forecasts[1] ($/MWh)**

| Year | Base Case | High Fuel | Low Fuel |
|---|---|---|---|
| **2001** | 51.00 | 51.00 | 46.30 |
| **2002** | 41.00 | 46.70 | 37.30 |
| **2003** | 38.20 | 46.60 | 34.70 |
| **2004** | 33.10 | 48.60 | 30.20 |
| **2005** | 26.70 | 48.80 | 24.50 |
| **2006** | 28.30 | 48.30 | 26.40 |
| **2007** | 28.40 | 47.50 | 26.50 |
| **2008** | 28.80 | 47.40 | 26.90 |
| **2009** | 28.60 | 45.90 | 26.70 |
| **2010** | 28.70 | 45.10 | 26.80 |
| **2011** | 28.50 | 44.70 | 26.60 |
| **2012** | 28.50 | 44.40 | 26.70 |
| **2013** | 28.70 | 45.60 | 26.70 |
| **2014** | 29.00 | 46.00 | 26.90 |
| **2015** | 28.90 | 45.60 | 26.90 |
| **2016** | 29.30 | 46.00 | 27.10 |
| **2017** | 29.00 | 45.50 | 27.00 |
| **2018** | 29.10 | 45.40 | 27.00 |
| **2019** | 29.10 | 45.30 | 27.00 |
| **2020** | 29.00 | 44.90 | 26.90 |

1

Results are expressed in real 2000 dollars.

### 2.8.2 SERC

*A. BASE CASE*

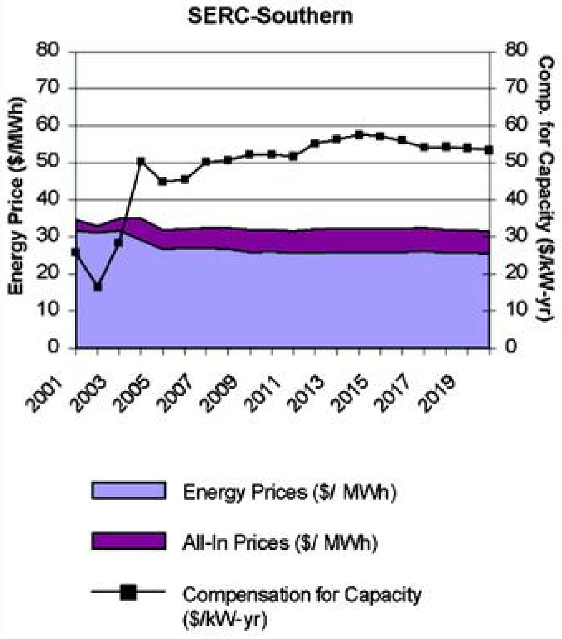
This case models near-term fuel prices based on recent actual spot prices and futures prices through December 2003, decreasing linearly to the long-term consensus view by 2005.

The all-in price represents a combined compensation for capacity and energy price (assuming a 100% load factor). The compensation for capacity contribution to the all-in price ranges between approximately $1.90/MWh and $6.50/MWh. The forecasts of energy prices, capacity compensation, and



all-in prices for the base case are shown in Figure 2-33 and Table 2-14 for the SERC-Southern pricing area.

**Figure 2-33**
**SERC-Southern Base Case Compensation for Capacity, Energy, and All-In Price Forecasts[1]**




[1] Results are expressed in real 2000 dollars.



**Table 2-14**
**SERC-Southern Compensation for Capacity,**
**Energy, and All-In Price Base Case Forecasts[1]**

| Year | Compensation for Capacity ($/kW-yr) | Energy Price ($/MWh) | All-In Price ($/MWh) |
|---|---|---|---|
| **2001** | 25.70 | 31.80 | 34.70 |
| **2002** | 16.50 | 31.10 | 33.00 |
| **2003** | 28.30 | 31.80 | 35.00 |
| **2004** | 50.40 | 29.30 | 35.00 |
| **2005** | 45.00 | 26.70 | 31.80 |
| **2006** | 45.50 | 26.80 | 32.00 |
| **2007** | 50.20 | 26.80 | 32.50 |
| **2008** | 50.70 | 26.70 | 32.50 |
| **2009** | 52.30 | 25.90 | 31.90 |
| **2010** | 52.30 | 26.00 | 31.90 |
| **2011** | 51.70 | 25.70 | 31.60 |
| **2012** | 55.30 | 25.80 | 32.10 |
| **2013** | 56.20 | 25.80 | 32.20 |
| **2014** | 57.60 | 25.80 | 32.40 |
| **2015** | 57.20 | 25.80 | 32.30 |
| **2016** | 56.00 | 25.90 | 32.30 |
| **2017** | 54.20 | 26.20 | 32.40 |
| **2018** | 54.30 | 25.70 | 31.90 |
| **2019** | 53.90 | 25.70 | 31.80 |
| **2020** | 53.50 | 25.50 | 31.60 |

1

Results are expressed in real 2000 dollars.

*B. SENSITIVITY CASES ANALYSIS*

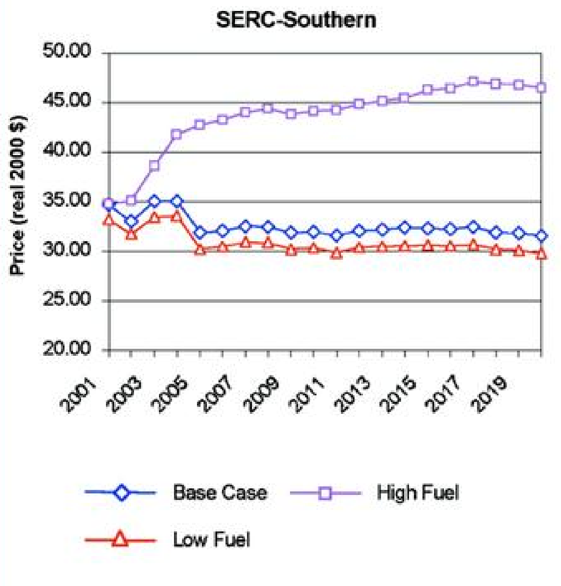
The all-in prices for high fuel and low fuel sensitivity cases described in Section 2.2 are shown in Figure 2-34 and Table 2-15 for the SERC region. These sensitivities are not meant to reflect bounding or worst case scenarios.

The high fuel case yields consistently higher all-in prices (in the range of $11 to $15/MWh) compared the base case after 2004, as the percentage of gas on the margin remains flat. Gas units are on the margin in the base, high fuel, and low fuel cases. Thus, the all-in price differences are consistent



with the fuel price change. The low fuel case produces slightly lower all-in prices parallel to the base case.

**Figure 2-34**
**SERC-Southern Sensitivity Cases**
**All-In Price Forecasts ($/MWh)**




[1] Results are expressed in real 2000 dollars.



**Table 2-15**
**SERC-Southern Sensitivity Cases**
**All-In Price Forecasts[1] ($/MWh)**

| Year | Base Case | High Fuel | Low Fuel |
|---|---|---|---|
| **2001** | 34.70 | 34.80 | 33.20 |
| **2002** | 33.00 | 35.10 | 31.70 |
| **2003** | 35.00 | 38.60 | 33.50 |
| **2004** | 35.00 | 41.80 | 33.60 |
| **2005** | 31.80 | 42.70 | 30.20 |
| **2006** | 32.00 | 43.30 | 30.50 |
| **2007** | 32.50 | 44.00 | 30.90 |
| **2008** | 32.50 | 44.40 | 30.90 |
| **2009** | 31.90 | 43.80 | 30.20 |
| **2010** | 31.90 | 44.10 | 30.30 |
| **2011** | 31.60 | 44.20 | 29.80 |
| **2012** | 32.10 | 44.80 | 30.40 |
| **2013** | 32.20 | 45.20 | 30.50 |
| **2014** | 32.40 | 45.50 | 30.50 |
| **2015** | 32.30 | 46.30 | 30.60 |
| **2016** | 32.30 | 46.40 | 30.50 |
| **2017** | 32.40 | 47.10 | 30.70 |
| **2018** | 31.90 | 46.90 | 30.20 |
| **2019** | 31.80 | 46.70 | 30.10 |
| **2020** | 31.60 | 46.50 | 29.80 |

1

Results are expressed in real 2000 dollars.

### 2.8.3 SPP

*A. BASE CASE*

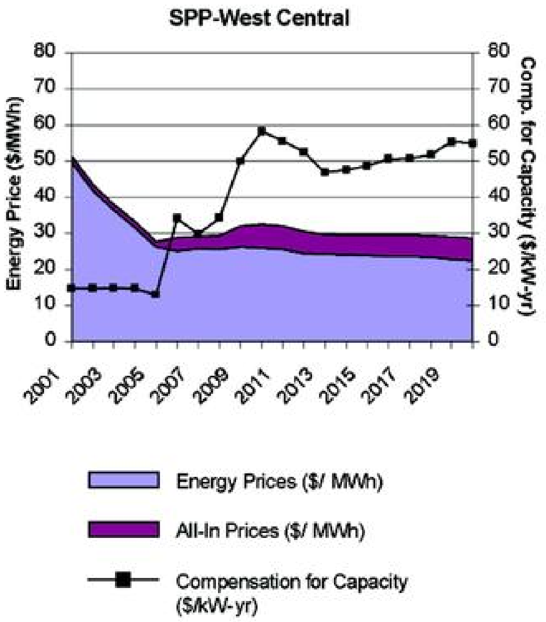
This case models near-term fuel prices based on recent actual spot prices and futures prices through December 2003, decreasing linearly to the long-term consensus view by 2005.

The all-in price represents a combined compensation for capacity and energy price (assuming a 100% load factor). The compensation for capacity contribution to the all-in price ranges between approximately $1.50/MWh and $6.60/MWh.



The forecasts of energy prices, capacity compensation, and all-in prices for the base case are shown in Figure 2-35 and Table 2-16 for the SPP-West Central pricing area.

**Figure 2-35**
**SPP-West Central Compensation for Capacity, Energy, and All-In Price Base Case Forecasts[1]**




[1] Results are expressed in real 2000 dollars.



**Table 2-16**
**SPP-West Central Compensation for Capacity, Energy, and All-In Price Base Case Forecasts[1]**

| Year | Compensation for Capacity ($/kW-yr) | Energy Price ($/MWh) | All-In Price ($/MWh) |
|---|---|---|---|
| 2001 | 14.70 | 49.60 | 51.20 |
| 2002 | 14.70 | 41.90 | 43.50 |
| 2003 | 14.90 | 36.60 | 38.30 |
| 2004 | 14.80 | 31.60 | 33.30 |
| 2005 | 13.00 | 26.20 | 27.70 |
| 2006 | 34.10 | 25.00 | 28.90 |
| 2007 | 29.80 | 25.70 | 29.10 |
| 2008 | 34.20 | 25.50 | 29.40 |
| 2009 | 50.00 | 26.10 | 31.80 |
| 2010 | 58.20 | 25.90 | 32.50 |
| 2011 | 55.60 | 25.50 | 31.80 |
| 2012 | 52.60 | 24.50 | 30.50 |
| 2013 | 46.90 | 24.30 | 29.70 |
| 2014 | 47.60 | 24.10 | 29.50 |

| | | | |
|---|---|---|---|
| **2015** | 48.60 | 23.90 | 29.50 |
| **2016** | 50.60 | 23.70 | 29.50 |
| **2017** | 50.70 | 23.60 | 29.40 |
| **2018** | 51.80 | 23.50 | 29.40 |
| **2019** | 55.30 | 22.80 | 29.10 |
| **2020** | 54.90 | 22.40 | 28.70 |

1 Results are expressed in real 2000 dollars.

*B. SENSITIVITY CASES ANALYSIS*

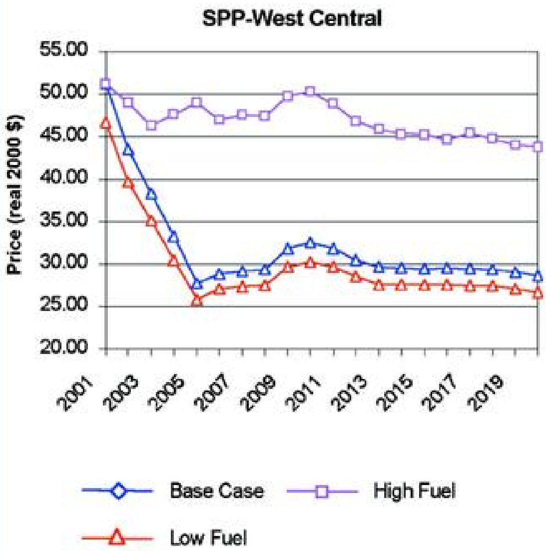
The all-in prices for high fuel and low fuel sensitivity cases described in Section 2.2 are shown in Figure 2-36 and Table 2-17 for the SPP region. These sensitivities are not meant to reflect bounding or worst case scenarios.

The high fuel case yields consistently higher all-in prices (in the range of $15 to $21/MWh) compared the base case after 2003, as the percentage of gas on the margin remains flat. Gas units are on the margin in the base, high fuel, and low fuel cases. Thus, the all-in price differences are consistent



with the fuel price change. The low fuel case produces slightly lower all-in prices parallel to the base case.

**Figure 2-36**
**SPP Sensitivity Cases**
**All-In Price Forecasts[1] ($/MWh)**




[1] Results are expressed in real 2000 dollars.



**Table 2-17**
**SPP Sensitivity Cases**
**All-In Price Forecasts[1] ($/MWh)**

| Year | Base Case | High Fuel | Low Fuel |
|---|---|---|---|
| **2001** | 51.20 | 51.20 | 46.70 |
| **2002** | 43.50 | 49.00 | 39.70 |
| **2003** | 38.30 | 46.40 | 35.20 |
| **2004** | 33.30 | 47.70 | 30.50 |
| **2005** | 27.70 | 49.00 | 25.80 |
| **2006** | 28.90 | 47.00 | 27.10 |
| **2007** | 29.10 | 47.60 | 27.30 |
| **2008** | 29.40 | 47.50 | 27.50 |
| **2009** | 31.80 | 49.80 | 29.70 |
| **2010** | 32.50 | 50.30 | 30.20 |
| **2011** | 31.80 | 48.90 | 29.70 |

| | | | |
|---|---|---|---|
| **2012** | 30.50 | 46.80 | 28.50 |
| **2013** | 29.70 | 45.90 | 27.60 |
| **2014** | 29.50 | 45.30 | 27.60 |
| **2015** | 29.50 | 45.30 | 27.60 |
| **2016** | 29.50 | 44.70 | 27.60 |
| **2017** | 29.40 | 45.50 | 27.50 |
| **2018** | 29.40 | 44.80 | 27.40 |
| **2019** | 29.10 | 44.10 | 27.10 |
| **2020** | 28.70 | 43.80 | 26.70 |

1 Results are expressed in real 2000 dollars.



## 3. *KEY ASSUMPTIONS*

### 3.1 INTRODUCTION

This chapter describes the key assumptions used in the development of the annual energy and capacity market price forecasts. Based on the assumptions below, PA Consulting Services Inc. simulates the hourly market-clearing price of energy using MULTISYM™ (developed by Henwood Energy Services, Inc.), a production-costing framework that allows the characterization of multiple pricing areas within larger transmission regions. Each major generating unit within a transmission area is represented individually in the MULTISYM™ production-costing model using unit-specific cost and operating characteristics. The MULTISYM™ model is used to perform an hour-by-hour chronological simulation of the commitment and dispatch of generation resources. As discussed in Appendix C, the output of this model is then used in PA's Capacity Compensation Simulation Model to develop the annual capacity contribution.

The key assumptions in this analysis are grouped into five categories: demand growth, fuel prices, $NO_x$ and $SO_2$ emissions costs, capacity additions and retirements, and financial parameters. These assumptions drive the fundamental model of energy prices and capacity compensation.

The following general assumptions were utilized in this study:

- The hourly market-clearing price of energy was developed using MULTISYM™, a production-cost model that allows the characterization of multiple transmission areas.
- The analysis has been prepared in 2000 real dollars. All results are in 2000 real dollars unless specified otherwise.

### 3.2 DEMAND AND ENERGY FORECASTS

The projected average annual demand and energy growth for the period 2001 through 2020 is summarized in Table 3-1.

**Table 3-1**
**Projected Average Annual Load Growth Rates**

| Region | Demand | Energy |
|---|---|---|
| PJM | 1.4% | 1.5% |
| MAIN | 1.4% | 1.4% |
| NEPOOL | 1.5% | 1.5% |
| New York | 0.8% | 0.9% |

The hourly data for the analysis is based on a synthetic hourly load shape based on five years of actual hourly data (1992-1996) provided with the MULTISYM™ production-costing model to represent the native load requirements for each of the pricing areas. The annual demand and energy forecast values are applied to the native hourly load requirements to develop the forecasted hourly loads for each year of the analysis.

### 3.3 FUEL PRICES

All fuel types were analyzed on either a regional (natural gas and oil) or plant location (coal) basis in order to capture pricing variations among major delivery points. The forecast prices for each fuel includes the cost of transportation to the power plant site. Two additional sections describe hydroelectric and nuclear units.



#### 3.3.1 Natural Gas

The primary inputs into the analysis were forecasts[4] from the Energy Information Administration (EIA),[5] The Gas Research Institute (GRI),[6] Standard and Poor's (S&P), and the WEFA Group (WEFA). Table 3-2 outlines the Henry Hub projection from each of the four source forecasts as well as the consensus forecast of natural gas prices at the Henry Hub.

**Table 3-2**
**Henry Hub Projections (real 2000 $/MMBtu)**

| | 2000 | 2005 | 2010 | 2015 | 2020 | Average Annual Growth Rate |
|---|---|---|---|---|---|---|
| EIA | 2.56 | 2.76 | 3.06 | 3.19 | 3.31 | 1.29% |
| GRI | 2.44 | 2.15 | 2.09 | 1.97 | 1.85 | -1.37% |
| S&P | 2.61 | 2.24 | 2.36 | 2.57 | 2.75 | 0.26% |

| | | | | | | |
|---|---|---|---|---|---|---|
| WEFA | 2.65 | 2.50 | 2.70 | 2.79 | 2.86 | 0.38% |
| Consensus | 2.56 | 2.41 | 2.55 | 2.63 | 2.69 | 0.25% |

The projections above represent industry standard market information on long-run equilibrium price. However, the natural gas market can exhibit extended periods where supply and demand are not in balance and prices can fluctuate significantly. The recent unprecedented price levels indicate that the market is currently in just such a period of transition. Figure 3-1 shows historical gas prices for the Henry Hub for 1999 and 2000. Gas prices have increased substantially in recent months.

4 EIA, Annual Energy Outlook 2000, December 1999; GRI 2000 Baseline Projection, November 1999; The WEFA Group, Natural Gas Outlook 2000, April 2000; S&P Platt's US Energy Outlook, Fall-Winter 1999-2000.

5 The EIA does not explicitly forecast a Henry Hub price. The EIA Henry Hub projection is an estimate based on the EIA lower-48 wellhead price forecast and the historic relationship between that wellhead price and the Henry Hub price.

6 The GRI forecast includes price projections only through 2015. The 2020 price is an estimate based on the 2015 price and the GRI price escalation pattern from 2010-2015.



**Figure 3-1**
**Henry Hub Gas Prices 1999-2000**


As a result of the recent gas price increase, PA has modeled near-term prices based on recent actual spot prices and futures prices through December 2003, decreasing linearly to the long-term consensus view in 2005. Table 3-3 displays the near-term price projection.

**Table 3-3**
**Henry Hub Projections Using NYMEX Prices[1]**
**(real 2000 $/MMBtu)**

| Year | Henry Hub Projection |
|---|---|
| 2001 | 4.81 |
| 2002 | 4.19 |
| 2003 | 3.84 |
| 2004 | 3.13 |

1 Based on average daily closing prices from 9/13/00 to 12/12/00.

Regional prices throughout the United States were projected based on this consensus Henry Hub forecast. For all regions modeled, the delivered price is the sum of the Henry Hub projection, the projected regional basis differential, and other natural gas supply costs including all taxes.

*A. BASIS DIFFERENTIALS*

The Henry Hub forecast is used as a basis for projecting regional market center prices. The Henry Hub forecast, plus the basis differential to a particular region, equals the commodity component of each region's natural gas forecast. Regional market prices for natural gas are based on this Henry Hub forecast and historic (1994-1999) and projected spot price differentials. Projected changes in the basis differentials are a result of increased integration of natural gas supply centers, changes in regional demand levels, and increased deliverability in some areas resulting from new pipeline construction.

*B. ADDITIONAL GAS SUPPLY COSTS*

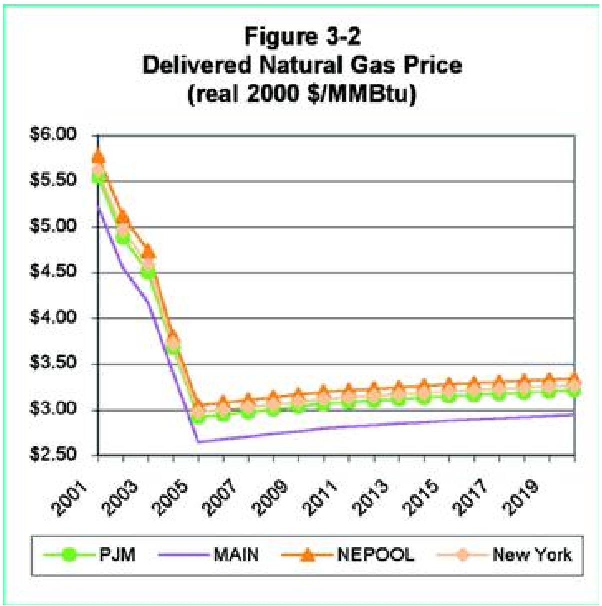
In addition to the regional commodity cost, natural gas price inputs also include an additional liquidity premium designed to account for the fact that units are not necessarily located at a major trading hub. As a result, units are likely to pay some premium over prices available at major pipeline



intersections. For all of the regions, this premium is expected to remain constant at $0.05/MMBtu (2000 $) over the forecast horizon.

As electric industry deregulation pressures generators to reduce costs, new gas-fired applications will be located so as to minimize fuel costs. As a result, new capacity will have an incentive to locate on the interstate pipeline system in order to avoid both Local Distribution Company (LDC) charges and operating pressure concerns. Therefore, it is assumed that new plants will be sited to take advantage of direct connections to interstate pipeline systems. Existing units in the model are assumed to incur LDC charges. For all of the regions, the LDC charge is assumed to be $0.10/MMBtu in 2000 declining to $0.05/MMBtu by 2020. In addition, New York City units pay an additional tax on all natural gas consumed.

Some baseload gas-fired plants, however, may incur fixed costs to ensure firm natural gas supplies. The EIA projects that as industry restructuring increasingly puts pressure on generators to reduce costs, generating stations will rely on interruptible deliveries and will ensure fuel supplies by using oil as a backup fuel.[7] The total delivered price of natural gas in each market region is shown in Figure 3-2.




*C. NATURAL GAS PRICE SEASONALITY*

Natural gas prices exhibit significant and predictable seasonal variation. Consumption increases in the winter as space heating demand increases and falls in the summer. Prices follow this pattern as well; the seasonal pattern is most striking in cold weather locations. Dispatch prices in the model reflect the seasonal effects based on five-year historic price patterns exhibited at the regional market centers.

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7 EIA, Challenges of Electric Power Industry Restructuring for Fuel Suppliers, September 1998, p. 65.



### 3.3.2 Fuel Oil

The fuel oil forecast methodology is described below for No. 2 Fuel Oil and No. 6 Fuel Oil. Prices are developed based on a consensus of crude oil by major forecasters as presented in Table 3-4.[8] These widely used sources present a broad perspective on the potential changes in commodity fuel markets. Each forecast was equally weighted in an effort to arrive at an unbiased consensus projection of fuel prices.

**Table 3-4**
**Crude Oil Price Projections (real 2000 $/bbl)**

| | 2000 | 2005 | 2010 | 2015 | 2020 | Average Annual Growth Rate |
|---|---|---|---|---|---|---|
| EIA | 21.92 | 21.19 | 21.72 | 22.27 | 22.80 | 0.20% |
| GRI | 18.42 | 18.42 | 18.42 | 18.42 | 18.42 | 0.00% |
| S&P | 21.14 | 16.50 | 17.32 | 19.31 | 20.72 | -0.10% |
| WEFA | 24.22 | 18.74 | 18.84 | 19.80 | 20.81 | -0.76% |
| Consensus | 21.42 | 18.71 | 19.07 | 19.95 | 20.68 | -0.18% |

As is the case with natural gas, today's oil markets are in a period of transition as OPEC wrestles with its production targets. As a result, PA has modeled near-term prices to reflect recent actual oil prices and futures prices through December 2003, rather than the long-run equilibrium price. In this case, prices return to the long-run consensus in 2005. The near-term price projection is shown in Table 3-5.

**Table 3-5**
**Crude Oil Price Projection Using NYMEX Prices[1] (real 2000 $/bbl)**

| Year | Price Projection |
|---|---|
| 2001 | 29.73 |
| 2002 | 25.72 |
| 2003 | 23.56 |
| 2004 | 21.13 |

1

Based on average daily closing prices from 9/13/00 to 12/12/00.

*A. NO. 2 FUEL OIL*

Prices for No. 2 Fuel Oil were derived from EIA data on historical delivered-to-utility prices for the period 1994 through 1998, on a regional basis. Fuel costs are comprised of commodity costs and transportation costs. Each region in the analysis was assigned to a reference terminal. The commodity component is calculated by escalating the historic reference terminal prices at the escalation rate implicit in the crude oil forecast outlined in Tables 4-4 and 4-5.

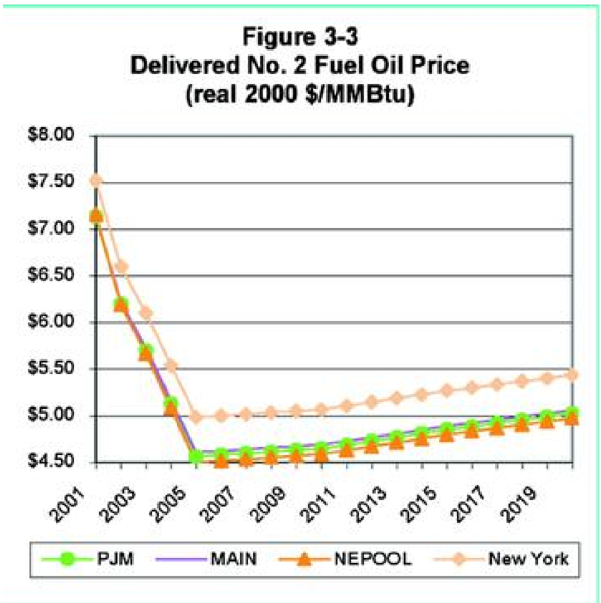
Transportation costs are calculated as the five-year average premium for delivered Fuel Oil in each region above the market center price for the terminal assigned to that region. This transportation cost is held fixed over the forecast horizon. This methodology captures both the commodity and

8

The source forecasts are as follows: 2000 Annual Energy Outlook, EIA; 2000 Baseline Projection, GRI; 2000 Natural Gas Outlook, WEFA; Standard & Poor's World Energy Service U.S. Outlook, Fall-Winter 1999-2000.



transportation components of delivered costs. Representative final delivered prices for No. 2 Fuel Oil are shown in Figure 3-3.




*B. NO. 6 FUEL OIL*

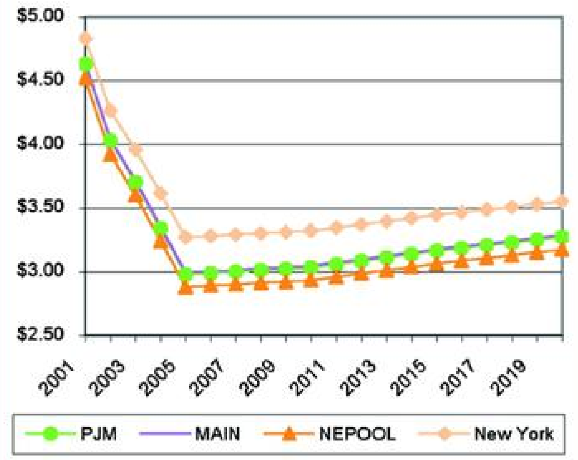
Prices for No. 6 Fuel Oil were derived using an identical methodology as that employed for No. 2 Fuel Oil prices. Because residual oil is so thinly traded, it is difficult to identify significant regional price premiums. As a result, all eastern regions were assigned to the New York Harbor reference terminal. As a result, commodity prices for all regions were based on 1% sulfur residual oil at New York Harbor and are therefore the same. Transportation costs for each region, however, do vary.

The transportation costs for each region were based on an analysis of historic New York Harbor prices and delivered residual oil at electric generating stations in the region. Transportation costs equal the five-year average premium for delivered No. 6 Fuel Oil above the New York Harbor price. This



transportation cost is held fixed over the forecast horizon. Final delivered prices for No. 6 Fuel Oil are shown in Figure 3-4.

**Figure 3-4**
**Delivered No. 6 Fuel Oil Price**
**(real 2000 $/MMBtu)**




Price projections for lower sulfur oil products[9] were also calculated to generate model inputs for regions that have more stringent environmental regulations. The premium for lower sulfur products was derived from a comparison of historic price data.

### 3.3.3 Coal

PA developed a forecast of marginal delivered coal prices (in real 2000 dollars) for the period 2001 through 2020 on a unit-by-unit basis for electric generators in each region. Delivered coal prices were projected in two components: (1) coal prices at the mine and (2) transportation rates.

Mine prices were projected with consideration of productivity increases and supply and demand economics. Real prices are expected to decrease over the forecast period for all of the major coal types. The rate of decrease varies based on specific considerations such as supply and expected depletion of reserves, market demand, and the sulfur content of the coals.

In general, prices for low-sulfur coals decline the least, and prices for mid-sulfur coals decline the most. Low- and mid-sulfur coals currently receive a price premium relative to high-sulfur coals based on their lower sulfur content. However, higher $SO_2$ allowance prices are expected to reduce demand for mid-sulfur coals at unscrubbed plants, which will reduce the price difference between mid- and high-sulfur coals over time.

Projected transportation rates are based on available delivery options at each plant for the coal types selected for each unit. Transportation modes include rail, barge, truck transportation, and conveyor transportation for minemouth plants. Rates for different transportation modes in different regions of the country are projected to vary at different rates over time.

Table 3-6 depicts the estimated annual decrease in coal prices by coal-type (based on real prices).

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9 Includes 0.3% residual oil, low sulfur 2-oil, and jet fuel.



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**Table 3-6**
**Estimated Annual Decrease in Coal Prices**

| Coal | Real Escalation Rate per Annum |
| --- | --- |
| Eastern | -0.4% to -1.0% |

### 3.3.4 Hydroelectric

The hydroelectric plants are consolidated by utility and categorized as peaking or baseload. Similar to the thermal units, the maximum capacity for each unit was taken from the sources cited above for summer and winter capabilities. Monthly energy patterns were developed from the 1993-1998 EIA Forms 759, which contain monthly generation and (for pumped storage units) net inflows.

### 3.3.5 Nuclear

PA evaluated the operation of nuclear plants in the regions covered by this study on the basis of going-forward costs to determine which plants would remain in service based on their economic performance.

PA estimated the annual going-forward costs (fixed O&M, property taxes, and annualized incremental capital costs) associated with each unit. The incremental capital costs do not include the original investment in the plant. The original investment is treated as a sunk cost and is not considered in the determination of the future competitiveness of a station. Incremental capital costs only include modifications made to the plant each year. These costs are very difficult to track due to the reporting methods. However, in recent years, the number of modifications to nuclear power stations has decreased and these costs are relatively low compared to O&M costs.

There are a number of other non-economic issues that might affect a shutdown date. Politics of the region plays an important part in the premature shutdown of the units. Equipment failures and poor overall performance can also cause a utility to shut down a unit before its license expires. As the units age, the amount of investment required to continue operating the unit becomes an important factor.

Historical performance as well as recent trends in forced outage rates at each unit were reviewed. Future forced outage rates were forecast for each year, and each unit's scheduled outages during the year were also considered. From this information, and noting that outages are becoming shorter as the industry improves outage planning, the duration of outages for each unit was forecast. For refueling outages, sources included refueling outage schedules, published every six months in *Nuclear News* for all U.S. units.

The decision whether to retire a unit prior to its license expiration date was made based on a thorough review of the unit's projected future economic performance. Nuclear unit retirements were made based on the same process applied to all other units as described in Appendix C in Section C.3.4. A summary of nuclear unit retirements is provided in Section 3.5.



### 3.4 $SO_2$/$NO_x$ EMISSION COSTS

#### 3.4.1 Sulfur Dioxide Emission Costs

PA's forecast of $SO_2$ allowance prices is shown in Table 3-7. The price of $SO_2$ allowances starts at $165 per ton in 2001, and increases to $420 per ton by 2006, with the largest annual increase occurring in 2002.

**Table 3-7**
**$SO_2$ Cost Curves (2000 $/ton)**

| Year | $SO_2$ |
| --- | --- |
| 2001 | $ 165 |
| 2002 | $ 287 |
| 2003 | $ 316 |
| 2004 | $ 347 |
| 2005 | $ 382 |
| 2006-2020 | $ 420 |

The relatively low current prices for $SO_2$ allowances (below our expected long-term value of allowances, on a discounted basis) reflects the accumulation of a large bank of $SO_2$ allowances, which resulted from over-compliance with Phase I of the Clean Air Act $SO_2$, and a number of political and regulatory uncertainties (including the outcome of the New Source Review litigation, the Supreme Court's ruling on EPA's proposed fine particulate regulations, and proposed regional haze regulations) that could reduce the value of $SO_2$ allowances. PA expects that the outcome of these uncertainties will be known by 2002. Assuming that these issues are resolved in a manner that essentially preserves the current market-based regulatory system for $SO_2$ (rather than moving toward command-and-control policies), and that additional regulations do not suppress $SO_2$ prices, PA would expect $SO_2$ allowance prices to increase substantially from 2001 to 2002.

The $SO_2$ allowance price trajectories for 2001 and 2003 to 2005 reflect PA's expectation that, since $SO_2$ allowances are relatively risky, they will generally escalate at a discount rate consistent with such risky investments. For this forecast, PA has assumed a 10% expected annual real rate of return on holding "banked" allowances during these periods, which produces our price trajectories for 2001 and 2003 to 2005.

The real cost of $SO_2$ allowances is projected to plateau at $420 per ton for 2006 and later years. This price level is determined by the marginal cost of installing scrubbers at existing plants.[10] PA estimates that this price level will be reached in 2006 because the "bank" of $SO_2$ allowances will be almost fully depleted by 2006. (Only a small "bank" will remain, for transactional liquidity purposes.)

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10 This assumes a continuation of current regulations under the 1990 Clean Air Act Amendments. As noted above, some proposals under consideration by EPA (such as controls on fine particulates) could change these regulations.



#### 3.4.2 Development of $NO_x$ Control Costs and Emission Rates

PA forecast of $NO_x$ allowance prices is shown in Table 3-8. This forecast includes both an estimate of $NO_x$ compliance costs for units in the Ozone Transport Region for 2001-2002, and an estimate of the $NO_x$ control costs for all of the units affected by EPA's $NO_x$ State Implementation Plan (SIP) Call from 2003 forward. The $NO_x$ allowance price forecast begins at the 2001 ozone season[11] price, which is approximately $1,000/ton (see Table 3-8). The price is expected to remain at $1,000/ton in 2002, and then rise to approximately $4,000/ton in 2003 as the tighter $NO_x$ regulations proposed in the SIP Call go into effect.

---

11 The ozone season, for purposes of assessing $NO_x$ costs, is defined as May 1 through September 30.

**Table 3-8**
**$NO_x$ Cost Curves (real 2000 $/ton)**

| Year | $NO_x$ |
| --- | --- |
| 2001 | $ 1,000 |
| 2002 | $ 1,000 |
| 2003-2020 | $ 4,000 |

### 3.5 Capacity Additions and Retirements

It is necessary to assess the feasibility and timing of new capacity additions as well as the exit of uneconomic existing capacity. PA's proprietary modeling approach serves two purposes:

- First, it identifies generating units that are not able to recover their going-forward costs in the energy and capacity markets and are, therefore, at risk of abandoning the markets.

- Second, it provides a rational method for ascertaining the amount, timing, and type of capacity additions.

The transfer capabilities for the PJM, MAIN, NEPOOL, and New York regions are shown in Figure 3-5. Capacity additions through 2003 are based on publicly announced or planned additions. The additions assumed in this analysis are shown in Table 3-9. These capacity additions are a best estimate of what units will be developed during this period. Actual additions may differ from those indicated.

From 2004 through 2020, PA's approach uses a financial model to assess the decision to add new capacity and to retire existing capacity. The approach to plant additions is based on a set of generic plant characteristics, financing assumptions, and economic parameters. This "add/retire" analysis is an iterative process performed simultaneously with the development of the energy price forecast and the projected compensation for capacity.

The methodology assesses the feasibility of annual capacity additions based on a Discounted Cash Flow (DCF) model using net energy revenues determined in the production-cost simulations and compensation for capacity determined from the Capacity Compensation Simulation approach. For each increment of new capacity, a "Go" or "No Go" decision is made based on whether the entrant would experience sufficient returns (developed in the DCF model) to merit entry. In addition, economic retirement decisions are made at each step in the iterative process based on the specific financial and operating characteristics of the existing plant.

Table 3-10 describe the timing and amount of market entry and exit (retirements) for the base case (best estimate) for the four regions.



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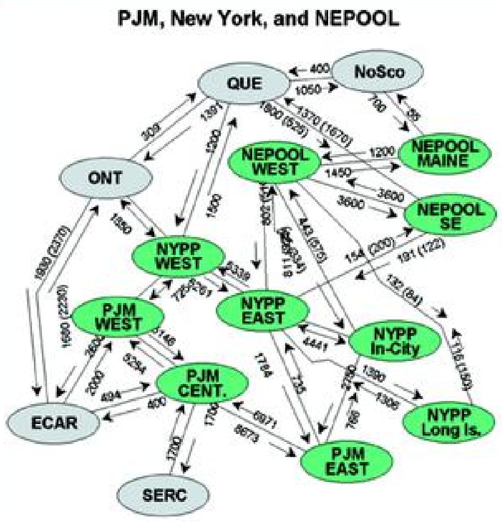
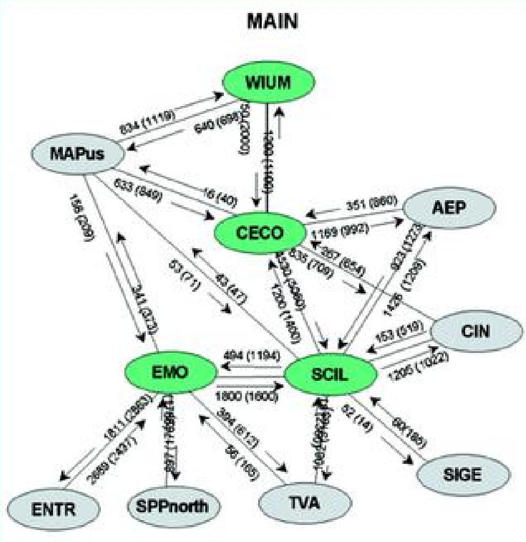
Nuclear unit retirement assumptions are shown in Table 3-11. A nuclear units is retired at its license expiration date unless its economic performance results in early retirement.

**Figure 3-5**
**Transfer Capability[1] (MW)**




| Abbreviation | Full Name |
|---|---|
| QUE | Quebec |
| NoSco | Nova Scotia |
| ONT | Ontario |
| NEPOOL West | New England Power Pool West |
| NEPOOL Maine | New England Power Pool East |
| NEPOOL SE | New England Power Pool Southeast |
| NYPP West | New York Power Pool West |
| NYPP East | New York Power Pool East |
| NYPP In-City | New York Power Pool In the City |
| NYPP Long Is. | New York Power Pool Long Island |
| PJM West | Pennsylvania, New Jersey, Maryland West |
| PJM Cent. | Pennsylvania, New Jersey, Maryland Central |
| PJM East | Pennsylvania, New Jersey, Maryland East |
| ECAR | East Central Area Reliability |
| SERC | Southeastern Electric Reliability Council |

= in region = out of region




| Abbreviation | Full Name |
|---|---|
| WIUM | Wisconsin Upper Michigan |
| MAPus | Mid-Continent Area Power Pool United States |
| CECO | Commonwealth Edison Company |
| AEP | American Electric Power Company |
| EMO | Eastern Missouri |
| SCIL | South Central Illinois |
| CIN | Cinergy |
| ENTR | Entergy |
| SPP north | Southwest Power Pool North |
| TVA | Tennessee Valley Authority |
| SIGE | Southern Illinois Gas and Electric |

= in region = out of region

[1] Capabilities represent Summer and (Winter) where applicable.



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**Table 3-9**
**Capacity Additions (MW), 2001-2003**

| Developer (Plant) | Size (MW)[1] | Unit Type | On-Line Year |
|---|---|---|---|
| **PJM—Total = 5,730 MW** | | | |
| TM Power (Chesapeake 2) | 177 | CT | 2001 |
| Williams (Hazleton) | 250 | CC | 2001 |
| AES (Ironwood) | 705 | CC | 2001 |
| PSEG (Kearney 1-4) | 164 | GT | 2001 |
| Conectiv (Hay Road) | 550 | CC | 2002 |
| PSEG (Bergen 2) | 546 | CC | 2002 |
| Orion (Liberty) | 520 | CC | 2002 |
| PSEG (Mantua Creek) | 800 | CC | 2002 |
| AES (Red Oak) | 816 | CC | 2002 |
| PSEG (Linden 1) | 601 | CC | 2003 |
| PSEG (Linden 2) | 601 | CC | 2003 |
| **MAIN—Total = 7,105 MW** | | | |
| Mid-American (Cordova) | 500 | CC | 2001 |
| Primary En. (Ind. Harbor) | 50 | CT | 2001 |
| Constellation (Univ. Park) | 300 | CC | 2001 |
| Wisvest/SkyGen (Calumet) | 300 | CC | 2001 |
| Primary (Whiting) | 525 | CG | 2001 |
| DENA (Lee County) | 640 | CT | 2001 |
| Reliant (Aurora) | 870 | CT | 2001 |
| LS Power (Kendall) | 1,100 | CC | 2001 |
| AmerGen (Petoka) | 234 | CT | 2001 |
| AmerGen (Grand Tower) | 326 | CC | 2001 |
| SkyGen (Rock Gen) | 450 | CT | 2001 |
| DENA (Audrain) | 640 | CT | 2001 |
| Constellation (Holland) | 650 | CC | 2002 |
| Generic | 520 | CC | 2003 |
| **NEPOOL—Total = 8,741 MW** | | | |
| Power Dev Corp (Milford) | 544 | CC | 2001 |
| Calpine (Westbrook) | 540 | CC | 2001 |
| PG&E (Lake Road) | 792 | CC | 2001 |
| ANP (Blackstone) | 550 | CC | 2001 |
| PPL (Wallingford) | 250 | CT | 2001 |
| ANP (Bellingham) | 580 | CC | 2001 |
| ExGen (Fore River) | 750 | CC | 2002 |
| FPL (Rise) | 500 | CC | 2002 |
| AES (Londonderry) | 720 | CC | 2002 |
| PDC/EP (Meriden/Berlin) | 520 | CC | 2002 |
| ExGen (Mystic 8) | 750 | CC | 2002 |
| ExGen (Mystic 9) | 750 | CC | 2002 |
| Con Ed (Newington) | 525 | CT | 2003 |
| ExGen (Medway Exp.) | 450 | CT | 2003 |
| Generic | 520 | CC | 2003 |
| **New York—Total = 1,880 MW** | | | |
| (excluding In-City & Long Island) | | | |
| PG&E (Athens) | 1,080 | CC | 2003 |
| ExGen (Torne Valley) | 800 | CC | 2003 |

1 Summer rating.



**Table 3-10**
**Capacity Additions and Retirements (MW), 2004-2008**

| Year[1] | CC Plants Added | CC Plants Added | Retirements[2] | Cumulative Capacity Additions |
|---|---|---|---|---|
| **PJM** | | | | |
| 2004 | 0 | 0 | 80 | -80 |
| 2005 | 0 | 0 | 393 | -473 |
| 2006 | 520 | 690 | 254 | 483 |
| 2007 | 0 | 1,035 | 146 | 1,372 |
| 2008 | 520 | 1,035 | 489 | 2,438 |
| 2009 | 520 | 345 | 0 | 3,303 |
| 2010 | 0 | 690 | 0 | 3,993 |
| 2011 | 1,040 | 0 | 0 | 5,033 |
| 2012 | 1,040 | 0 | 2 | 6,072 |
| 2013 | 1,040 | 0 | 0 | 7,112 |
| 2014 | 520 | 0 | 0 | 7,632 |
| 2015 | 1,040 | 345 | 0 | 9,017 |
| 2016 | 520 | 345 | 0 | 9,882 |
| 2017 | 1,040 | 0 | 0 | 10,922 |
| 2018 | 520 | 690 | 41 | 12,091 |
| 2019 | 1,040 | 0 | 41 | 13,090 |
| 2020 | 0 | 1,380 | 288 | 14,182 |

| | | | | |
|---|---|---|---|---|
| Total | 9,360 | 6,555 | 2,149 | 13,766 |
| **MAIN** | | | | |
| 2004 | 0 | 0 | 142 | -142 |
| 2005 | 0 | 0 | 1,289 | -1,431 |
| 2006 | 0 | 0 | 174 | -1,605 |
| 2007 | 0 | 0 | 0 | -1,605 |
| 2008 | 520 | 345 | 0 | -740 |
| 2009 | 520 | 345 | 23 | 102 |
| 2010 | 1,040 | 0 | 2 | 1,140 |
| 2011 | 1,040 | 345 | 505 | 2,020 |
| 2012 | 520 | 690 | 16 | 3,214 |
| 2013 | 1,040 | 0 | 76 | 4,178 |
| 2014 | 520 | 1,035 | 1,183 | 4,550 |
| 2015 | 520 | 690 | 0 | 5,760 |
| 2016 | 520 | 345 | 3 | 6,622 |
| 2017 | 520 | 345 | 30 | 7,457 |
| 2018 | 0 | 1,035 | 122 | 8,370 |
| 2019 | 0 | 1,380 | 344 | 9,406 |
| 2020 | 520 | 690 | 286 | 10,320 |
| Total | 7,280 | 7,245 | 4,205 | 10,320 |



| | | | | |
|---|---|---|---|---|
| **NEPOOL** | | | | |
| 2004 | 0 | 0 | 196 | -196 |
| 2005 | 0 | 0 | 4,048 | -4,244 |
| 2006 | 0 | 0 | 737 | -4,981 |
| 2007 | 0 | 0 | 949 | -5,930 |
| 2008 | 0 | 0 | 1 | -5,931 |
| 2009 | 0 | 0 | 0 | -5,931 |
| 2010 | 0 | 0 | 0 | -5,931 |
| 2011 | 520 | 0 | 23 | -5,434 |
| 2012 | 520 | 0 | 1 | -4,915 |
| 2013 | 1,040 | 0 | 664 | -4,539 |
| 2014 | 520 | 0 | 0 | -4,019 |
| 2015 | 520 | 0 | 0 | -3,499 |
| 2016 | 1,040 | 0 | 871 | -3,330 |
| 2017 | 520 | 0 | 0 | -2,810 |
| 2018 | 520 | 0 | 4 | -2,294 |
| 2019 | 520 | 345 | 4 | -1,433 |
| 2020 | 520 | 0 | 0 | -913 |
| Total | 6,240 | 345 | 7,498 | -913 |
| **New York (excluding In-City and Long Island)** | | | | |
| 2004 | 750 | 0 | 0 | 750 |
| 2005 | 0 | 0 | 1,222 | -472 |
| 2006 | 0 | 0 | 136 | -608 |
| 2007 | 0 | 0 | 730 | -1,338 |
| 2008 | 0 | 0 | 0 | -1,338 |
| 2009 | 0 | 0 | 0 | -1,338 |
| 2010 | 0 | 0 | 1,117 | -2,455 |
| 2011 | 520 | 0 | 372 | -2,307 |
| 2012 | 0 | 0 | 0 | -2,307 |
| 2013 | 0 | 0 | 0 | -2,307 |
| 2014 | 1,040 | 0 | 931 | -2,198 |
| 2015 | 1,040 | 0 | 820 | -1,978 |
| 2016 | 1,560 | 0 | 970 | -1,388 |
| 2017 | 0 | 0 | 0 | -1,388 |
| 2018 | 0 | 0 | 0 | -1,388 |
| 2019 | 520 | 0 | 47 | -915 |
| 2020 | 0 | 0 | 0 | -915 |
| Total | 5,430 | 0 | 6,345 | -915 |

1 2001 through 2003 additions are shown in Table 3-9.

2 Retirements are assumed to occur on January 1 of year.



**Table 3-11**
**Nuclear Unit Retirements**

| Unit Name | Capacity (MW) | Year[1] |
|---|---|---|
| **PJM** | | |
| Oyster Creek 1 | 610 | * |
| Peach Bottom 3 | 1,093 | * |
| Three Mile 1 | 796 | * |
| Peach Bottom 2 | 1,093 | 2014 |

| | | |
|---|---|---|
| Salem 1 | 1,122 | * |
| Salem 2 | 1,106 | * |
| Susquehanna 1 | 1,090 | * |
| Calvert Cliffs 1 | 835 | * |
| Calvert Cliffs 2 | 840 | * |
| Susquehanna 2 | 1,094 | * |
| Hope Creek | 1,031 | * |
| Limerick 1 | 1,143 | * |
| Limerick 2 | 1,143 | * |
| **MAIN** | | |
| Dresden 2 | 792 | * |
| Point Beach 1 | 505 | 2010 |
| Dresden 3 | 784 | * |
| Quad Cities 1 | 762 | * |
| Quad cities 2 | 775 | * |
| Kewaunee | 494 | 2013 |
| Point Beach 2 | 495 | 2013 |
| LaSalle County 1 | 1,128 | * |
| LaSalle County 2 | 1,131 | * |
| Byron 1 | 1,170 | * |
| Callaway 1 | 1,143 | * |
| Braidwood 2 | 1,153 | * |
| Byron 2 | 1,159 | * |
| Clinton | 930 | * |
| Braidwood 2 | 1,145 | * |
| **NEPOOL** | | |
| Vermont Yankee | 500 | * |
| Pilgrim | 664 | 2012 |
| Millstone 2 | 871 | 2015 |
| Millstone 3 | 1,140 | * |
| Seabrook 1 | 1,162 | * |
| **New York** | | |
| Ginna 1 | 499 | 2009 |
| Nine Mile 1 | 619 | 2009 |
| Indian Point 2 | 931 | 2013 |
| J A Fitzpatrick | 820 | 2014 |
| Indian Point 3 | 970 | 2015 |
| Nine Mile 2 | 1,142 | * |

* Indicates that the unit retires after the study period (2001-2020).

1 Retirements occur on December 31 of year indicated.



## 3.6 FINANCIAL ASSUMPTIONS

### 3.6.1 Generic Plant Characteristics

The starting point for the DCF calculation is the generic unit-specific operating parameters for new combined cycle and combustion turbine units. The generic parameters and assumptions assumed in the model are shown in Tables 4-12 and 4-13. The first year in which new generic capacity can be added to the model is 2004. Capital costs are assumed to decrease at 1% per annum (real 2000 $). Table 3-14 indicates the assumed schedule and effect of technology improvement on new unit heat rates.

**Table 3-12**
**New CC Generating Characteristics (real 2000 $)**

| | Capital Cost ($/kW) | Fixed O&M ($/kW-year) | Variable O&M ($/MWh) | Size (MW) |
|---|---|---|---|---|
| PJM | $ 590 | $ 11.50 | $ 2.00 | 520 |
| MAIN | $ 560 | $ 10.50 | $ 2.00 | 520 |
| NEPOOL | $ 610 | $ 11.50 | $ 2.00 | 520 |
| New York | $ 610 | $ 11.50 | $ 2.00 | 520 |

**Table 3-13**
**New CT Generating Characteristics (real 2000 $)**

| | Capital Cost ($/kW) | Fixed O&M ($/kW-year) | Variable O&M ($/MWh) | Size (MW) |
|---|---|---|---|---|
| PJM | $ 410 | $ 6.00 | $ 5.00 | 345 |
| MAIN | $ 380 | $ 5.50 | $ 5.00 | 345 |
| NEPOOL | $ 430 | $ 6.00 | $ 5.00 | 345 |
| New York | $ 430 | $ 6.00 | $ 5.00 | 345 |

**Table 3-14**

**Full Load Heat Rate Improvement (Btu/kWh)[1]**

| | 2001-2003 | 2004-2008 | 2009-2013 | 2014-2018 | 2019+ |
|---|---|---|---|---|---|
| Combined Cycle | 6,700 | 6,566 | 6,435 | 6,306 | 6,180 |
| Combustion Turbine | 10,400(W) | 10,192(W) | 9,988(W) | 9,788(W) | 9,593(W) |
| | 10,700(S) | 10,487(S) | 10,277(S) | 10,070(S) | 9,871(S) |

1

Degradation of 2% for CC units and 3% for CT units was assumed (not included in numbers shown).

(W) = winter, (S) = summer

### 3.6.2 Other Expenses

Information on fixed costs, depreciation, and taxes is also developed and incorporated within the DCF analysis to determine the economic viability of the new unit additions. Environmental costs and overhaul expenses are not included, due to expectations that such expenses would be minimal in early years of operation.



- Property taxes are assumed to be 1% to 2% of the initial capital costs.

- Depreciation of the initial all-in cost of the new additions is based on a standard 20-year Modified Accelerated Cost Recovery System (150 DB) with mid-year convention.

### 3.6.3 Economic and Financial Assumptions

- Minimum internal rate of return is assumed to be 13.5%.

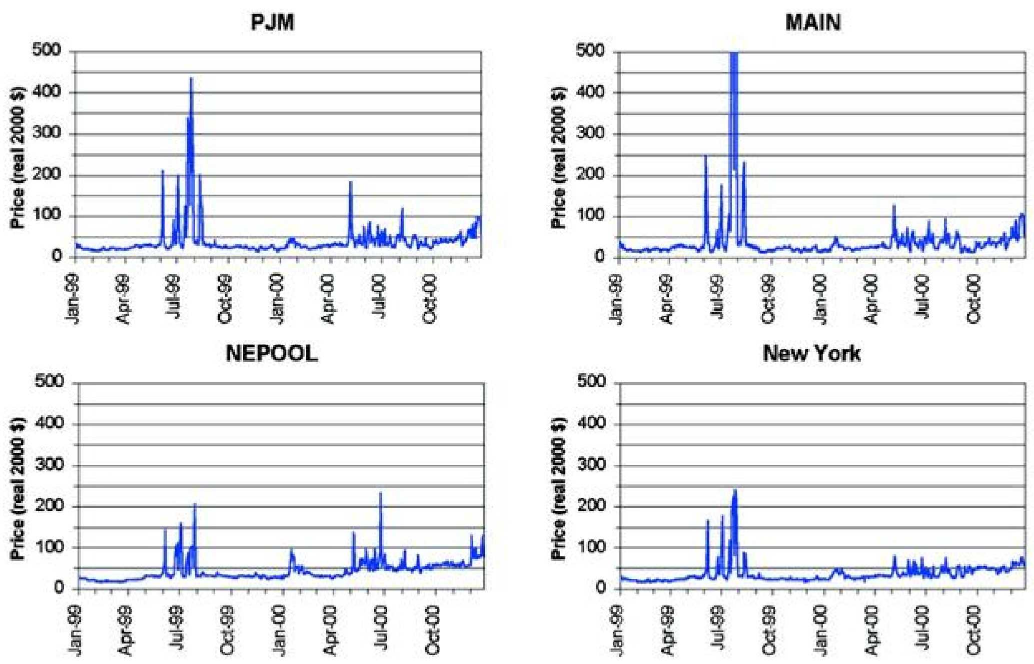
- Financing assumptions are assumed to be 60% debt and 40% equity for combined cycle units, and 50% debt and 50% equity for combustion turbine units.

- Debt interest rate is assumed to be 9.1%. Debt terms and project lives are 20 years with mortgage-style amortization for combined cycle units and 15 years for combustion turbine units.



## *APPENDIX A: HISTORICAL ENERGY PRICES*

**Figure A-1**
**Historical Electricity Prices (Daily On-Peak Index) (real 2000 $)**




Source: *Power Markets Week.*

*APPENDIX B: ANALYSIS OF CONTRACTS*

## B.1 OVERVIEW

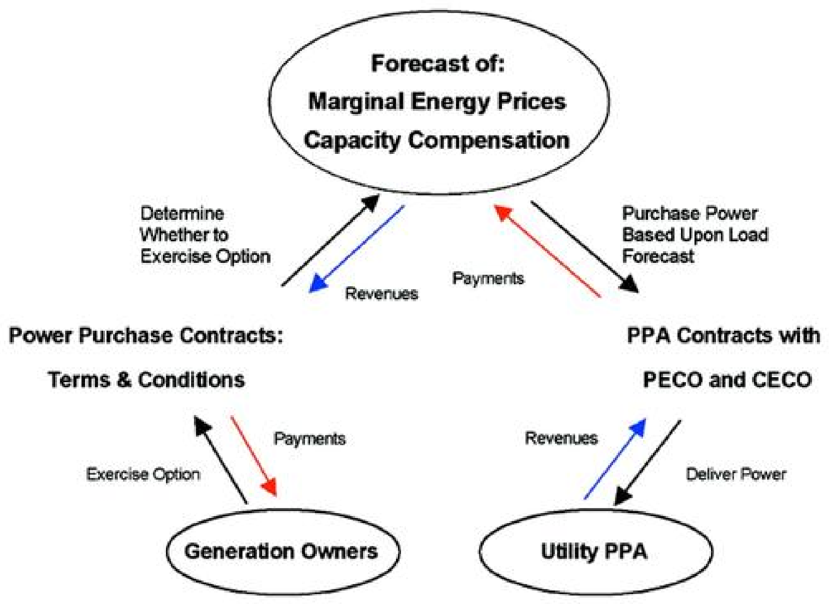
ExGen has options of varying time commitments to purchase over 15.6 GW of generation under power contracts. In addition, there are contracts to initially sell a peak of 30 GW of power under utility transition power contracts with the Commonwealth Edison Company (ComEd) and PECO Energy (PECO). PA analyzed the value of the contract options and obligations by marking these obligations to market using the market energy prices and capacity compensation prices developed to assess the value of ExGen's physical assets. The analysis marking the contracts to market was completed for the Base Case and three alternative scenarios (Overbuild, Low Fuel, and High Fuel).

The valuation of these power contracts is based upon summary information provided by ExGen. PA did not review the terms and conditions of the contracts, hence key assumptions in the analysis including price, minimum and maximum take provisions, duration, and operational constraints were all based upon summary information provided by ExGen.

## B.2 METHODOLOGY

The power purchase and sale contracts were modeled as separate transactions using a consistent forecast of marginal energy prices and capacity compensation. This is shown schematically in Figure B-1.

**Figure B-1**
**Contract Valuation Methodology**




The value of the contracts listed in Table B-1 was evaluated by treating each contract as a call option with an option price (typically the fixed capacity payment) and a strike price (the sum of the variable cost obligations associated with each contract including generator start costs). The assessment factored in key power contract constraints including minimum run times, minimum and maximum take requirements, and regional generation requirements. (PA relied upon information provided by ExGen to complete this assessment.) The contracts were valued based upon the contract terms and not on the



cost structure and forecasted operation of the underlying generation unit. As a result, the energy take from the contract may be more, or less, than the assumed operation of the generator. It is assumed that the differences between the simulated unit performance and contract performance are made up through other market operations so that supply and demand equilibrium is maintained. This assumption preserves the underlying fundamental constraint that the least cost generation is dispatched to meet the market demand. The value of each contract was calculated by comparing the contract strike price with the forecast of hourly marginal energy prices. The revenue from the contract was the sum of market revenues when the option was exercised plus the market capacity compensation. The associated costs are the exercise price and the option cost.

The transition power obligations were valued by determining the revenue from selling to the utility versus the cost of supplying the power at market prices. The cost of providing the power was calculated applying the 1998 historic hourly load shape for ComEd and PECO to the forecast of loads and peak demand in each year during the contract obligation. The hourly load was priced at the forecast of hourly marginal energy prices and the capacity compensation was added to this cost to get the total annual cost. The assessment of the revenues from sales under these contracts was based upon the summarized terms and conditions provided by ExGen.

**Table B-1**
**Contracts Evaluated**

| | Contract Term | | Capacity (MW) | VOM ($/MWh) | Start ($/event) | Energy Cost ($/MWh) | Annual Capacity Payment ($/kW-mo) | 2001 Capacity Payment ($M) |
|---|---|---|---|---|---|---|---|---|
| **Frontier** | In Service | 09/01/20 | 830 | 2.50 | incl. in VOM | gas indexed | 6.50 | 64.74 |
| **Heard County** | In Service | 06/30/30 | 900 | 5.00 | incl. in VOM | gas indexed | 3.50 | 18.90 |
| **Jenks** | 01/01/02 | 12/31/21 | 800 | 1.65 | incl. in VOM | gas indexed | 5.25 esc @1.5% | 54.24 |
| **EME Collins** | In Service | 12/15/04 | 2,698 | incl. in Energy Cost | 7500 cold, 10,500 warm | 31.00 | 3.33 | 107.90 |
| **EME Peakers** | In Service | 12/16/04 | 1,117 | incl. in Energy Cost | incl. in VOM | 45.00 | 3.33 | 37.76 |
| **EME Coal** | In Service | 12/17/04 | 5,645 | incl. in Energy Cost | various, average 10,000 | 17.00 | 5.26 | 356.00 |
| **Stateline** | In Service | 03/01/12 | 515 | incl. in Energy Cost | 0 | 12.50 | 7.83 | 48.40 |
| **Kincaid** | In Service | 04/01/12 | 1,108 | incl. in Energy | 0 | 12.50 | 4.92 | 65.37 |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | | | Cost | | | | |
| **Enron—Lincoln Center** | In Service | 09/30/02 | 600 | incl. in Energy Cost | 0 | into ComEd | 1.67 | 12.00 |
| **Indeck** | In Service | 05/31/05 | 300 | incl. in Energy Cost | 8,000 | indexed | 6.67 | 24.00 |
| **Elwood** | In Service | 12/31/04 | 300 | incl. in Energy Cost | 2,500 | 30.00 | 5.17 | 18.60 |
| **Engage** | In Service | 12/31/04 | 300 | incl. in Energy Cost | 2,500 | 30.00 | 5.17 | 18.60 |
| **Hoosier 1** | In Service | 12/31/06 | 200 | 0.00 | 0 | 15.61, 12.26 esc @2.7% | 4.50 + 0.50 esc./yr | 10.80 |
| **Duquesne** | In Service | 12/31/05 | 100 | 0.00 | 0 | 20.29 esc @5% | 0.00 | 0.00 |
| **Hoosier 2** | In Service | 12/31/07 | 200 | 0.00 | 0 | 15.61, 12.26 esc @2.7% | 4.50 + 0.50 esc./yr | 10.80 |



## *APPENDIX C: APPROACH TO MARKET PRICE FORECASTING*

### C.1 INTRODUCTION

This appendix discusses PA's approach to forecasting market prices for the services of generating units. The first section discusses the issues faced while forming these forecasts, namely the distinction between capacity and energy markets and the evolution of market structures. The second section describes the approach PA uses in forecasting market prices. The third section summarizes the methodology and how it relates to ExGen's portfolio.

### C.2 ISSUES IN FORECASTING MARKET PRICES

This section discusses several issues that form the basis for PA's approach to market price forecasting. The first of these issues is the concept of economic equilibrium and how it suggests that the market will react to returns on equity (or lack thereof). The second has to do with the components of revenue that are present in our forecasts. Each of these topics is addressed below.

#### C.2.1 Economic Equilibrium and Market Price Forecasting

A fundamental tenet of PA's market price forecasting approach is that markets are attempting to adjust to economic equilibrium conditions.

While the concept of economic equilibrium is sound in principle, actual markets may not follow economic equilibrium exactly. Many industries have shown cycling returns, where high returns are followed by excess entry resulting in low returns which are followed by a disincentive to invest which results in high returns.

To explore the implication of such "disequilibrium" conditions, we generally construct an overbuild scenario where excess entry is presumed to occur. Excess entry is presumed to occur early in the study period, as the impacts on generation assets are likely to be most severe in this timeframe. Subsequent to this period of capacity abundance, we then examine how the market might return to economic equilibrium.

#### C.2.2 Forecasting Generation Service Prices

PA produces forecasts of generation service prices by examining two components of value in our fundamental analysis:

- Energy based on a production-cost model with prices reflecting marginal cost in each hour.
- Compensation for capacity, which represents the additional margin necessary to keep an economic amount of capacity in the market. This compensation for capacity is not the same as a capacity price in a traded capacity market.

Compensation for capacity may take many forms. Payments could be in the form of a capacity price arising from a capacity market, a regulated payment fee, bilateral option contracts, payments by the ISO for ancillary services, or in the form of energy prices above the marginal cost of the price-setting plant. Regardless of the form, the sum of the compensation for capacity and the market price for energy will ultimately reflect what customers are willing to pay for both energy services and reliability.

The terms "compensation for capacity" and "energy price" as used in this report reflect the prices needed by the marginal units to recover their variable and going-forward costs. These prices together form the all-in price received by generators to meet all of their going-forward costs. Compensation for capacity and energy prices are inversely related; as one rises the other falls, so that the all-in price remains somewhat in balance.



### C.3 APPROACH TO MARKET PRICE FORECASTING

Projecting electric market prices (and generation product sales) requires PA to consider not only price formation in the market, but also the issues of market entry and exit. The process begins with a definition of the characteristics of the market, including the electric generating units currently in operation, their production efficiencies (including heat rate curves), a projection of plant additions (based, in part, on announcements and, in part, on an equilibrium evaluation of market price signals and new investments), consumer demand and load, and generation fuel prices.

Thus, this process develops prices based on a dynamic examination of market entry and exit (including retirement) decisions made by the supply-side players in the market.

#### C.3.1 Predicting Energy Prices and Dispatch

PA uses a detailed chronological production-cost model to simulate energy price formation in the market area of interest based on short-run marginal costs.

From the energy price analysis, PA determines the net energy margins (price minus variable cost) for each generating unit in the market. These margins, along with estimates of "going-forward costs," are used in the Capacity Compensation Simulation Model to predict the additional margins related to the provision of capacity.

#### C.3.2 Predicting Prices Related to Capacity: The Capacity Compensation Simulation Model

Compensation for capacity is a mechanism for supporting an appropriate amount of generating capability in the system.

PA predicts a value for compensation of capacity using PA's proprietary Capacity Compensation Simulation Model. This model presumes that the market will retain a sufficient amount of capacity to meet economic reliability targets. In other words, PA simulates a capacity market consisting of a supply curve and a demand curve for reliability (or capacity) services. PA assumes a competitive market, and that the market-clearing compensation for capacity is determined by the intersection of the supply and demand curves. PA constructs supply and demand curves for each year in the simulation time horizon.

### C.3.3 Market Entry and Exit

It is necessary to assess the feasibility and timing of new capacity additions as well as the exit of uneconomic existing capacity. PA's proprietary modeling approach serves two purposes:

- First, it identifies generating units that are not able to recover their going-forward costs in the energy and capacity market and are, therefore, at risk of abandoning the market.
- Second, it provides a rational method for ascertaining the amount, timing, and type of capacity additions.

Capacity additions through 2003 are based on known, planned additions. Thereafter, PA's approach uses a financial model to assess the decision to add new capacity and to retire existing capacity. The approach to plant additions is based on a set of generic plant characteristics, financing assumptions, and economic parameters. This "add/retire" analysis is an iterative process performed simultaneously with the development of the energy price forecast and the projected compensation for capacity.

## C.4 SUMMARY

Different generating units have different capabilities of responding to electricity and fuel price volatility. Thus, the same price patterns for electricity and fuel may yield different option values for different generating units, depending on the operating costs and characteristics of the generating units. Those generating units with the greatest flexibility to respond to different market prices and that often set energy prices will have the highest option values, while those plants that never set energy prices have little or no ability to respond and will have virtually no option value. The ExGen portfolio is primarily nuclear and coal-based generation. These types of units will generally capture the average market prices and will not be run to capture price spikes, thus we relied upon the fundamental forecast rather than the volatility analysis.



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# *APPENDIX D: GLOSSARY*

## D.1 RELEVANT TERMS DEFINITIONS

***Ancillary Services.*** Those services that are necessary to support the transmission of capacity and energy from resources to loads, while maintaining the reliable operation of the transmission provider's transmission system in accordance with good utility practice.

***Automatic Generation Control (AGC).*** A measure of the ability of a generating unit to provide instantaneous control balance between load and generation and help maintain proper tie line bias. This is done to control frequency and to maintain currently proper power flows into and out of a Control Area. In short, AGC is basically a ramping service to follow the second-to-second fluctuations in load and supply.

***Bilateral Transaction.*** An agreement between two entities for the sale and delivery of a service.

***British Thermal Unit (Btu).*** A standard unit for measuring the quantity of heat energy equal to the quantity of heat required to raise the temperature of one pound of water by one degree Fahrenheit.

***Bus.*** The point at which transmission lines connect to a substation.

***Capacity.*** The amount of electric power delivered or required for which a generator, turbine, transformer, transmission circuit, station, or system is rated by the manufacturer.

***Combined Cycle Unit (CC).*** An electric generating unit that consists of one or more combustion turbines and one or more boilers with a portion of the required energy input to the boiler(s) provided by the exhaust gas of the combustion turbine(s).

***Combustion Turbine Unit (CT).*** A combustion turbine typically consists of an axial-flow air compressor and one or more combustion chambers, where liquid or gaseous fuel is burned and the hot gases are passed to the turbine and where the hot gases expand to drive the generator and are then used to run the compressor.

***Control Area.*** An electric system or systems, bounded by interconnection metering and telemetry, capable of controlling generation to maintain its interchange schedule with other control areas and contributing to frequency regulation of the interconnection.

***Divestiture.*** Occurs when a corporation separates a portion of its business and assets, such as power plants, transmission facilities, or distribution system, from the existing company. This can occur through a sale, spin-off, or other transfer line of business. Divestiture can occur voluntarily as a business decision driven by the market or by government mandate that a utility sell certain assets to diminish perceived market power.

***Energy Imbalance Service.*** Used to supply energy for mismatch between scheduled delivery and actual loads that have occurred over an hour.

***Firm Point-to-Point Transmission Service.*** Transmission service that is reserved and/or scheduled between specified points of receipt and delivery that is of the same priority as that of the Transmission Provider's firm use of the transmission system.

***Forced Outage.*** The failure rate of equipment (transmission lines or generators) due to unplanned events.

***Generating Unit.*** Any combination of physically connected generator(s), reactor(s), boiler(s), combustion turbine(s), or other prime mover(s) operated together to produce electric power.



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***Gigawatt (GW).*** One billion watts.

***Gigawatt-Hour (GWh).*** One billion watt-hours.

***Independent Power Producer (IPP).*** A corporation, person, agency, authority, or other legal entity or instrumentality that owns electric generating capacity and is not an electric utility.

***Independent System Operator (ISO).*** Generally, an ISO is a voluntarily formed entity that ensures comparable and non-discriminatory access by power suppliers to regional electric transmission systems. As currently envisioned, ISOs would be governed in a manner that renders them "independent" of the commercial interests of power suppliers who also may be owners of transmission facilities in the region. The ISO assumes operational control of the use of transmission facilities, administers a system-wide transmission tariff applicable to all market participants, and maintains short-term system reliability.

***Kilowatt (kW).*** One thousand watts.

***Kilowatt-Hour (kWh).*** One thousand watt-hours.

***Load (electric).*** Energy demand or the amount of electric power delivered or required at any specific point or points on a system.

***Load Serving Entity (LSE).*** An entity, including a load aggregator or power marketer, serving end-users within a Control Area, that has been granted the authority or has an obligation pursuant to state or local law, regulation, or franchise to sell electric energy to end-users located within the Control Area or the duly designated agent of such an entity.

***Local Distribution Company (LDC).*** Independent company delivering wholesale natural gas inside the city gate to the end-user.

***Locational Marginal Price (LMP).*** The marginal cost of supplying the next increment of electric energy at a specific location bus on the electric power network taking into account both generation marginal cost and the physical aspects of the transmission system (PJM).

***Locational-Based Marginal Price (LBMP).*** The marginal cost of supplying the next increment of electric energy at a specific location bus on the electric power network taking into account both generation marginal cost and the physical aspects of the transmission system (NY-ISO).

***Megawatt (MW).*** One million watts.

***Megawatt-Hour (MWh).*** One million watt-hours.

***Merchant Plant.*** An independent power producer selling generated electric power on the open market.

***MULTISYM™.*** A production-cost model developed by Henwood Energy Services, Inc. that allows the characterization of multiple transmission areas.

***Natural Gas.*** A naturally occurring mixture of hydrocarbon and non-hydrocarbon gases found in porous geological formations beneath the earth's surface, often in association with petroleum. The principal constituent is methane.

***Network Integration Transmission Service.*** Allows a transmission customer to integrate, plan, economically dispatch, and regulate its network resources to serve its network load in a manner comparable to that in which the transmission provider utilizes its transmission system to serve its native load customers. Network integration transmission service also may be used by the transmission customer to deliver non-firm energy purchases to its network load without additional charge.



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***Open Transmission Access (Open Access).*** Enables all participants in the wholesale market equal access to transmission service, as long as capacity is available, with the objective of creating a more competitive wholesale power market. The Energy Policy Act of 1992 gave FERC the authority to order utilities to provide transmission access to third parties in the wholesale electricity market.

***Point-to-Point Transmission Service.*** The reservation and transmission of capacity and energy on either firm or non-firm basis from the point(s) of receipt to the point(s) of delivery.

***Power Exchange (PX).*** A spot price pool that is governed and operated separately from the independent system operator. In a power exchange/ISO model, the spot price pool schedules generation and provides price bids to the ISO. The ISO may then use the sets of price bids provided by the power exchange to establish congestion prices, match actual demand to available supply, and facilitate the efficient short-term operation of the integrated generation and transmission system.

***Power Pool.*** An association of two or more interconnected electric systems planned and operated to supply power in the most reliable and economical manner for their combined load requirements and maintenance programs.

***Regional Transmission Organization (RTO).*** An entity whose purpose is to promote efficiency and reliability in the operation and planning of the electric transmission grid and ensuring non-discrimination in the provision of electric transmission services. The RTO must satisfy minimum characteristics and perform functions as set forth in FERC Order Number 2000 while accommodating open architecture conditions.

***Regulation.*** The capability of a specific generating unit with appropriate telecommunications, control, and response capability to increase or decrease its output in response to a regulating control signal.

***Reliability.*** The degree to which electric power is made available to those who need it in sufficient quantity and quality to be dependable and safe. The degree of reliability may be measured by the frequency, duration, and magnitude of adverse effects on consumer services.

***Spinning Reserve.*** That reserve generating capacity running at a zero load and synchronized to the electric system.

***System (electric).*** Physically connected generation, transmission, and distribution facilities operated as an integrated unit under one central management, or operating supervision.

***Ten-Minute Spinning Reserve (TMSR).*** Refers to the kWs of generating capacity of an electric generator that is synchronized to the system, unloaded during all or part of the hour, and capable of providing contingency protection by loading to supply energy immediately on demand, increasing the energy over no more than 10 minutes to the full amount of generating capacity designated.

***Ten-Minute Non-Spinning Reserve (TMNSR).*** Refers to the kWs of generating capacity that are not synchronized to the system and capable of providing contingency protection by loading to supply energy within ten minutes to the full amount of generating capacity designated.

***Thirty-Minute Operating Reserve (TMOR).*** Refers to the kWs of generating capacity that are capable of providing contingency protection by loading to supply energy within 30 minutes of demand at an output equal to the full amount of generating capacity designated.

***Transmission Company (TRANSCO).*** A regulated entity that owns, and may construct and maintain, wires used to transmit wholesale power. It may or may not handle the power dispatch and coordination functions. It is regulated to provide non-discriminatory connections, comparable service, and cost recovery.

***Watt.*** The electrical unit of power. The rate of energy transfer equivalent to one ampere flowing under a pressure of one volt at unity power factor.

***Watt-Hour (Wh).*** An electrical energy unit of measure equal to one watt of power supplied to, or taken from, an electric circuit steadily for one hour.

## D.2 ACRONYMS DEFINITIONS

***AGC*** Automatic Generation Control

***Btu*** British Thermal Units

***CC*** Combined Cycle Combustion Turbine

***CECO*** Commonwealth Edison (subregion of MAIN)

***ComEd*** Commonwealth Edison Company

***CT*** Simple Cycle Combustion Turbine

***DB*** Declining Balance

***DCF*** Discounted Cash Flow

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

***EIA*** Energy Information Administration

***EPA*** Environmental Protection Agency

***ERCOT*** Electric Reliability Council of Texas

***FERC*** Federal Energy Regulatory Commission

***FRCC*** Florida Reliability Coordinating Council

***FTRs*** Fixed Transmission Rights

***GRI*** Gas Research Institute

***GW*** Gigawatts

***GWh*** Gigawatt-Hours

***ISO*** Independent System Operator

***ISO-NE*** New England's Independent System Operator

***ITC*** Independent Transmission Company

***kW*** Kilowatts

***kWh*** Kilowatt-Hours

***LBMP*** Locational-Based Marginal Pricing

***LDC*** Local Distribution Company

***LMP*** Locational Marginal Price

***LSE*** Load Serving Entity



***MAAC*** Mid-Atlantic Area Council

***MAIN*** Mid-America Interconnected Network

***MAPSA*** Mid-Atlantic Power Supply Association

***MMBtu*** Million British Thermal Units

***MW*** Megawatts

***MWh*** Megawatt-Hours

***NEPOOL*** New England Power Pool (subregion of NPCC)

***NERC*** North American Electric Reliability Council

***New York*** New York subregion of NPCC

***$NO_x$*** Nitrogen Oxide

***NPCC*** Northeast Power Coordinating Council

***NYMEX*** New York Mercantile Exchange

***NYPP*** New York Power Pool

***O&M*** Operation and Maintenance

***OPEC*** Operating Plant Evaluation Code

***PJM*** Pennsylvania-New Jersey-Maryland Interconnection LLC

***PX*** Power Exchange

***RTO*** Regional Transmission Organization

***SCD*** Security-Constrained Dispatch

***SCIL*** South Central Illinois (subregion of MAIN)

***SERC*** Southeastern Electric Reliability Council

***SIP*** State Implementation Plan

***$SO_2$ Sulfur Dioxide***

***SPP*** Southwest Power Pool

***S&P*** Standard and Poor's

***TMOR*** Thirty-Minute Operating Reserve

***TMNSR*** Ten-Minute Non-Spinning Reserve

***TMSR*** Ten-Minute Spinning Reserve

***TVA*** Tennessee Valley Authority (subregion of SERC)

***VOM*** Variable Operation and Maintenance

***WEFA*** The WEFA Group

***WSCC*** Western Systems Coordinating Council



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QuickLinks