UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

New York Independent System Operator, Inc. Docket No. ER10-____-000

AFFIDAVIT OF
EUGENE T. MEEHAN

Mr. Eugene T. Meehan declares:

1. I have personal knowledge of the facts and opinions herein and if called to testify could and would testify competently hereto.

I. Purpose of this Affidavit

2. The purpose of my affidavit is to present and describe the independent report and analyses that the NYISO relied on in its instant filing to update the Demand Curves.[1] I was, as described later herein, responsible for preparing that report and those analyses. The report includes an independent statistical analysis of Energy and Ancillary Service revenues, an independent assessment of construction costs of peaking technologies, a methodology for determining an appropriate amortization period to reflect generating unit owner risk that was integrated with the zero crossing point of the Demand Curves, and assumptions to implement the methodology for determining an appropriate amortization period to reflect generating unit owner risk.

II. Qualifications

3. I am a Senior Vice President with NERA Economic Consulting (NERA) and have over thirty years of experience consulting with electric and gas companies. I have testified as an expert witness before numerous state and federal regulatory agencies, and in federal court and arbitration proceedings.

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[1] Capitalized terms that are not specifically defined in this Affidavit shall have the meaning set forth in filing letter, and if not defined therein, as defined in the Market Administration and Control Area Services Tariff ("Services Tariff").

4. My consulting practice at NERA focuses on the areas of electricity tariff design, electricity procurement, wholesale power market design, electricity costing and pricing, market power analysis and mitigation, power contract analysis, and power cost risk management.

5. I have worked extensively on electric utility and electricity market issues in New York State. I have provided consulting services for New York electric companies on a continuous basis since 1980, advising the companies on production cost modeling, transmission expansion, competitive bidding and reliability and marginal generating capacity cost quantification. In 1987, I prepared and sponsored the New York Power Pool's position paper on competitive bidding for independent power producer supplies. That paper set forth the New York Power Pool's policy position on the establishment of competitive bidding processes, power purchase contracts based on avoided cost, and the various implementation issues. Many of these positions were adopted by the New York Public Service Commission ("NYPSC"). I provided testimony on behalf of the New York State investor-owned electric utilities concerning the proper methodology to use when analyzing the cost-effectiveness of conservation programs. This methodology was adopted by the NYPSC and used as the basis for demand-side management evaluation in New York from 1982 through 1988.

6. I worked with the NYISO as well PJM Interconnection ("PJM") and ISO New England Inc. ("ISO-NE") in 2003 and 2004 to study the joint capacity market design proposal known as the Centralized Resource Adequacy Market or (CRAM) and was a co-author of NERA's CRAM report.

7. I was retained by National Grid to advise the load serving entities in New England with respect to the ISO-NE forward capacity market settlement negotiations and attended many of the settlement sessions.

8. I directed NERA's efforts in 2007 with respect to the update of the NYISO's ICAP Demand Curves for the 2008/2009 – 2010/2011, including developing the methodology for converting the total capital costs of the peaking unit to a levelized cost.

9. My Curriculum Vitae is attached as Exhibit A hereto.

III. Overview of the Independent ICAP Demand Curve Report and Process

10. In accordance with the Services Tariff, in the third quarter of 2009, the NYISO solicited proposals from qualified consultants to identify appropriate methodologies and to develop the ICAP Demand Curve parameters for the three Capability Years beginning in May 2011. The NYISO selected the team of NERA, with Sargent and Lundy (S&L) as a subcontractor to NERA. We began our analysis in December 2009 and met, either in person or telephonically, with stakeholders at Installed Capacity Working Group meetings on thirteen occasions between December 2009 and August 2010. In addition to the ICAP Working Group meetings, we had separate conversations with stakeholders at their request in respect of the development of the Demand Curves. We evaluated and considered all oral and written comments received. All NYISO stakeholders had an opportunity to provide input to, and comments on, our proposed assumptions, analysis, methodology, cost estimates, and preliminary and final results for the study. On September 3, 2010, NYISO released our final report for stakeholder review and comment.[2] A minor correction to the report was issued on September 7, 2010; and on October 28, 2010 the report was revised to reflect new information from the equipment manufacturer which was disseminated to the NYISO's ICAP Working Group and is incorporated into the November 15, 2010 version of the Report along with ministerial corrections. The report as revised on November 15, 2010 ("NERA/S&L Report") is attached to this Affidavit as Exhibit B.

11. The NERA/S&L Report contains four basic elements. These elements are: (1) an independent statistical analysis of Energy and Ancillary Service revenues, (2) an independent assessment of construction costs of peaking technologies, (3) a methodology for determining an appropriate amortization period to reflect generating unit owner risk that was integrated with the zero crossing point of the Demand Curves, and (4)

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[2] "Independent Study to Establish Parameters of the ICAP Demand Curve for the New York Independent System Operator," September 7, 2010, prepared by NERA Economic Consulting, *available at* http://www.nyiso.com/public/webdocs/committees/bic_icapwg/meeting_materials/2010-09-16/ICAPWG_Demand_Curve_Study_Report_clean_9-3-10.pdf.

assumptions to implement the methodology for determining an appropriate amortization period to reflect generating unit owner risk.

12. The statistical analysis of Energy and Ancillary Services revenues used the most recent three years of hourly electricity prices by location and daily gas prices. The analysis considered both day ahead and real time prices and unit operating constraints including start times. The analysis was employed to estimate net energy revenues for the peaking unit as a function of reserve margin in order to be able to estimate the net energy revenues at an installed capacity level at or just slightly above the target reserve level. The method was supplemented by a separate estimate of the potential future use of Special Case Resources (SCRs) and the impact of SCRs on energy prices.

13. The independent assessment of the construction costs of new peaking units was conducted by the engineering firm of S&L and represents a thorough cost estimate based on a conceptual design. S&L performs this work in its normal cost of business for entities contemplating construction of power plants and maintains the data needed to develop such estimates. S&L informed its analysis through interactions with the New York Department of Environmental Conservation to determine local environmental requirements and reviewed information provided by entities currently developing power plants in NYISO and NYISO Transmission Owners.

14. The methodology for determining an appropriate amortization period to reflect generating unit owner risk that is integrated with the zero crossing point of the Demand Curves is a carry over from the prior reset. A primary benefit of this methodology is that it internally and automatically adjusts the reference price to reflect the slope of the Demand Curve and can account for the revenue volatility associated with alternate slopes. This methodology was reviewed extensively with FERC Staff after the filing of the prior reset and was accepted by the Commission.

15. The assumptions to implement the methodology for determining an appropriate amortization period to reflect generating unit owner risk require judgment and the inputs used in the report reflect my opinion as to the best estimates for these factors. As explained on page 74 of Exhibit B, I believe that the results determined from these inputs

are reasonable for three reasons. First, the increase in costs over those associated with a fully regulated recovery are modest. Second, the implied amortization periods are all at the point where the carrying charge curve begins to flatten out. Third, the amortization periods are in line with and, adjusting for the real versus nominal levelization differences, longer than those approved by the Commission for PJM.

This concludes my Affidavit.

ATTESTATION

I am the witness identified in the foregoing affidavit. I have read the affidavit and am familiar with its contents. The facts set forth therein are true to the best of my knowledge, information, and belief.

Eugene Thomas Meehan

Eugene T. Meehan

Washington, District of Columbia

The foregoing instrument was subscribed and sworn before me this 30th day of November, 2010 by Eugene T. Meehan

Notary Public

My commission expires

Rosalind Brown
Notary Public, District of Columbia
My Commission Expires 12/14/2014

NOTARY PUBLIC · DISTRICT OF COLUMBIA

NERA
Economic Consulting

EXHIBIT A

Eugene T. Meehan
Senior Vice President

National Economic Research Associates, Inc.
1255 23rd Street NW
Washington, DC 20037

EUGENE T. MEEHAN
Senior Vice President

Mr. Meehan is a Senior Vice President at NERA. He has over thirty years of experience consulting with electric and gas utilities and has testified as an expert witness before numerous state and federal regulatory agencies, as well as appeared in federal court and arbitration proceedings.

At NERA, Mr. Meehan's practice concentrates on serving energy industry clients, with a focus on helping clients manage the transition from regulatory to more competitive environments. He has performed consulting assignments for over fifty large electric, gas, and combination utilities in the areas of retail access, regulatory strategy, strategic planning, financial and economic analysis, merger and acquisition advisory services, power contract analysis, market power and market definition, stranded cost analysis, power pooling, power markets and risk management, ISO and PX development, and costing and pricing. In addition, he has advised numerous utilities on power procurement issues and administered power procurements on behalf of utilities and regulators.

Mr. Meehan has experience leading NERA's advisory work on several major restructuring and unbundling assignments. These assignments were multi-year projects that involved integration of regulatory and business strategy, as well as development of regulatory filings associated with the recovery of stranded cost and rate unbundling.

Education

Boston College, BA, Economics, *cum laude*
New York University (NYU), Graduate School of Business, completed core courses for the doctoral program.

Professional Experience

	NERA Economic Consulting
1999-	Senior Vice President
1996-1999	Vice President
1973-1980	Senior Economic Analyst; Research Assistant
	Deloitte & Touche Consulting Group
1994-1996	Principal
	Energy Management Associates, Inc.
1980-1994	Vice President

Areas of Expertise

Restructuring/Stranded Cost Recovery

Mr. Meehan has directed several multi-year projects associated with restructuring and stranded cost recovery. These projects involved facilitating the development of an integrated regulatory and business strategy and formulating regulatory filings to accomplish strategy. As part of these assignments, Mr. Meehan facilitated sessions with senior management to set and track filing strategy. Clients include Public Service Gas & Electric and Baltimore Gas and Electric.

Unbundling/Generation Pricing

Mr. Meehan has formulated unbundling strategies, with a specialization in generation pricing. He has advised several utilities in standard offer pricing and has testified on shopping credits on behalf of First Energy and Baltimore Gas and Electric.

Power Procurement

Mr. Meehan has been involved in power procurement activities for a variety of utilities and regulatory agencies. He has advised utilities in developing and implementing evaluation processes for new generation, with the objective of achieving the best portfolio evaluation. He has helped regulators in Ireland and Canada design and implement portfolio evaluation processes. He has testified before FERC and state regulatory agencies on competitive power procurement. In addition, Mr. Meehan helped to design and implement the New Jersey BGS auction process.

Power Contracts

Mr. Meehan has extensive experience with power contracts and power contract issues. He has reviewed and testified on the three principal types of power contracts: integrated utility to integrated utility contracts, IPP to utility contract, and integrated or wholesale utility to distribution utility contracts. He has testified in power contracts disputes on behalf of Carolina Power and Light, Duke Power Company, Southern Company, Orange and Rockland Utilities, and Tucson Electric Power. He has also advised Oglethorpe Power Corporation in the reform of its wholesale contracts with its distributor cooperative members.

Retail and Wholesale Settlements

In addition to his expertise on power pooling issues, Mr. Meehan has significant experience with assignments related to the settlement process. He has focused on the issues of credit management as new entrants appear in retail and wholesale markets and has designed efficient specifications for retail settlement systems, including the use of load profiling, and examined the risk and cost allocation issues of alternative settlement systems.

Risk Management

Mr. Meehan has advised several large utilities on price risk management. These assignments have included evaluation of price management service offers solicited from power marketers in association with management of assets and entitlements, as well as provision of price managed service for various terms.

Marginal Costs

Mr. Meehan has provided comprehensive marginal cost analyses for over 25 North American Utilities. These assignments required detailed knowledge of utility operations and planning.

Power Supply and Transmission Planning

Mr. Meehan has advised electric utilities on economic evaluations of generation and transmission expansion. He has testified on the economics of particular investments, the prudence of planning processes, and the prudence of particular investment decisions.

Generation Strategy

Mr. Meehan has led NERA efforts on a client task force charged with developing an integrated generation asset/power marketing strategy.

Power Pooling

Mr. Meehan has in-depth working knowledge of the operating, accounting, and settlement processes of all United States power pools and representative international power pools. He has provided consulting services for New York Power Pool members on a continuous basis since 1980, advising the Pool and its members on production cost modeling, transmission expansion, competitive bidding and reliability, and marginal generating capacity cost quantification. In NEPOOL, he has quantified the benefits of continued utility membership in the Pool and the impact of the Pool settlement process on marginal cost. He has worked with a major PJM utility to explore the impact of PJM restructuring proposals upon generating asset valuation and examine the implications of alternative restructuring proposals. He has consulted for Central and Southwest Corporation, Entergy, and Southern Company on issues that involved the internal pooling arrangements of the utility operating companies of those holding companies, as well as for various utilities on the impact of pooling arrangements on strategic alternatives.

Representative Assignments

Worked with Public Service Electric & Gas Company (PSE&G) to direct a three year NERA advisory effort on restructuring. Facilitated a two-day senior management meeting to set regulatory strategy in 1997. Throughout 1997 and 1998, worked over half time at PSE&G to help implement that strategy and advised on testimony preparation, cross-examination, and briefing. Also advised PSE&G on business issues related to securitization, energy settlement and credit requirements for third party suppliers. During 1999, advised PSE&G during settlement negotiations and litigation of the settlement. PSE&G achieved a restructuring outcome that involved continued ownership of generation by an affiliate and the securitization of $2.5 billion in stranded costs.

Worked on separate assignments for a large utility in the Northeast and a large utility in the Southeast, advising on the evaluation of risk management offers from power marketers. The assignments included reviewing proposals, attending interviews with marketers and providing advice on these, and the developing analytical software to evaluate offers.

Worked with government of Ontario beginning in 2004 to help design the RFP and economic evaluation process for the solicitation of 2500 Mw of new generating capacity. Supervising NERA's portfolio-based economic evaluation on behalf of the Ontario Ministry of Energy.

Testified on behalf of Pacific Gas & Electric Company before the FERC in a case benchmarking the PSA between the distribution utility and a soon-to-be-created generating company. This effort involved developing detailed expertise in applying the Edgar standard and a detailed review of DWR procurement during the western power crisis. In addition, this effort involved the review of more than 100 power contracts in the WECC.

Directed NERA's efforts, on behalf of the electricity regulator in Ireland, to design an RFP and implementation process for the purchase of 500 Mw of new generating capacity in 2003. NERA advised on the RFP, the portfolio evaluation method, and the power contract and also conducted the economic evaluation.

Reviewed the economic evaluation conducted by Southern Company Service for affiliated operating companies in connection with an RFP for over 2000 Mw of new generating capacity. Submitted testimony before FERC on behalf of Southern Company Service.

Worked with Baltimore Gas and Electric (BG&E) to conduct a one and one-half year consulting assignment that involved providing restructuring advice. The project began in March/April 1998 with senior management discussions and workshops on plan development and filing strategy. Advised BG&E in the development of testimony, rebuttal testimony, and public information dissemination. Worked to review and coordinate testimony from all witnesses and offered testimony on shopping credits and in defense of the case settlement. BG&E achieved a restructuring outcome enabling it to retain generation ownership. As part of this assignment, advised BG&E on generation valuation and unregulated generation business strategy.

Directed the efforts of a large Southeastern utility to develop a short-term power contract portfolio and to evaluate the relative value of power options, forwards, and unit contracts to determine the optimal mix of instruments to manage price risk.

Testified for XCEL Energy on the use of competitive bids for new generation needs. Examined whether XCEL was prudent not to explore a self-build plan and the reasonableness of relying on ten-year or shorter contracts as opposed to life-of-facility contracts, in order to meet needs and facilitate a possible future transition to competition. This project addressed the comparability of fixed bids to rate base plant additions.

Advised and testified on behalf of First Energy in the Ohio restructuring proceeding on the issues of generation unbundling and stranded cost. Defended the First Energy shopping credit proposal.

Advised Consolidated Edison and Northeast Utilities on merger issues and testified in Connecticut and New Hampshire merger proceedings. Testimony focused on retail competition in gas and electric commodity markets.

Directed NERA's effort to train selected representatives of a major European power company in American power marketing and risk management practices. The project involved numerous meetings and interviews with power marketing firms.

Led NERA's effort to advise the New England ISO on the development of an RTO filing. Examined performance-based ratemaking for transmission and market operator functions.

Examined ERCOT power market conditions during the period of time from 1997 to 1999 and testified on behalf of Texas New Mexico Power Company for the prudence of its power purchase activity.

Advised a Midwestern utility on restructuring of a wholesale contract with an affiliate. Involved forecasting of the unbundled wholesale cost-of-service and market prices, as well as development of a regulatory strategy for gaining approval of contract restructuring and the transfer of generation from regulated to EWG states.

Performed market price forecasts for numerous utility clients. These forecasts have employed both traditional modeling and newly developed statistical approaches.

Examined the credit issues associated with the entry of new entities into retail and wholesale settlement market. These assignments involved a review of current Pool credit procedures, examination of commodity and security trading credit requirements, coordination with financial institutions, and recommendations concerning credit exposure monitoring, credit evaluation processes, and credit requirements.

Oversight of EMA's consulting and software team in designing and implementing the LOLP capacity payment, a portion of the UK wholesale settlement system.

Advised Oglethorpe Power Corporation in the reform of its contracts with its distribution cooperative members and the evolution of full requirement power wholesale power contracts into contracts that preserve Oglethorpe's financial integrity and are suitable for a competitive environment.

Developed long run marginal and avoided costs of natural gas service, as well as avoided cost methods and procedures. These costs have been used primarily for the analysis of gas DSM opportunities. Clients include Consolidated Edison Company, Southern California Edison Company, Niagara Mohawk Power Corporation, and Elizabethtown Gas Company.

Review of power contracts and testimony in numerous power contract disputes.

Development of long run avoided costs of electricity service and avoided cost methods and procedures. These costs have been used to assess DSM and cogeneration, as well as to develop integrated resource plans. Clients include Public Service Company of Oklahoma, Central Maine Power Company, Duquesne Light Company, and the New York investor-owned utilities.

Advised Central Maine Power Company (CMP) on the development of a competitive bidding framework. This framework was implemented in 1984 and was the first of its kind in the nation. CMP adopted the framework outlined in EMA's report and won prompt regulatory approval.

Advised a utility in the development of an incentive ratemaking plan for a new nuclear facility. This assignment involved strategic analysis of alternate proposals and quantification of the financial impact of various ratemaking alternatives. Presented strategic and financial results in order to convince senior management to initiate negotiations for the incentive plan.

Advised and testified on behalf of the New York Power Pool utilities on the methodology for measuring pool marginal capacity costs. This work included development of the methodology and implementation of the system for quantifying LOLP-based marginal capacity costs.

Provided testimony on behalf of the investor-owned electric utilities in New York State, concerning the proper methodology to use when analyzing the cost-effectiveness of conservation programs. This methodology was adopted by the Commission and used as the basis for DSM evaluation in New York from 1982 through 1988.

Developed the functional design of a retail access settlement system and business processes for a major PJM combination utility. This design is being used to construct a software system and develop business procedures that will be used for retail settlements beginning January 1999.

Reviewed the power pool operating and interchange accounting procedure of the New York Power Pool, the Pennsylvania, New Jersey, Maryland Interconnection, Allegheny Power System, Southern Company, and the New England Power Pool as part of various consulting assignments and in connection with the development of production simulation software.

Summarized and analyzed the operational NEPOOL to examine the feasibility of incorporating NEPOOL interchange impacts with Central Maine and accounting procedure of the New England Power Pool Power Company's buy-back tariffs.

Developed and presented a two-day seminar delivered to electric industry participants in the UK (prior to privatization), outlining the structure and operation of power pools and bulk power market transactions in North America.

Benchmark analysis and FERC testimony of PGE's proposed twelve-year contract between PG&E and Electric Gen LLC (contract value in excess of $15 billion).

Responsible for NERA's overall efforts in advising New Jersey's Electric Distribution Companies on the structuring and conduct of the Basic Generation Service auctions (the 2002 auction involved $3.5 billion, and the 2003 and 2004 auctions involved over $4.0 billion).

Publications, Speeches, Presentations, and Reports

Capacity Adequacy in New Zealand's Electricity Market, published in *Asian Power*, September 18, 2003

Central Resource Adequacy Markets For PJM, NY-ISO AND NE-ISO, a report written February 2004

Ex Ante or *Ex Post*? Risk, Hedging and Prudence in the Restructured Power Business, The Electricity Journal, April 2006

Distributed Resources: Incentives, a white paper prepared for Edison Electric Institute, May 2006

Restructuring Expectations and Outcomes, a presentation presented at the Saul Ewing Annual Utility Conference: The Post Rate Cap and 2007 State Regulatory Environment, Philadelphia, PA, May 21, 2007

Making a Business of Energy Efficiency: Sustainable Business Models for Utilities, prepared for Edison Electric Institute, August 2007

Restructuring at a Crossroads, presented at Empowering Consumers Through Competitive Markets: The Choice Is Yours, Sponsored by COMPETE and the Electric Power Supply Association, Washington, DC, November 5, 2007

*Competitive Electricity Markets: The Benefits for Customers and the Environmen*t, a white paper prepared for COMPETE Collation, February 2008

The Continuing Rationale for Full and Timely Recovery of Fuel Price Levels in Fuel Adjustment Clauses, The Electricity Journal, July 2008

Impact of EU Electricity Competition Directives on Nuclear Financing presented to: SMI – Financing Nuclear Power Conference, London, UK, May 20, 2009

Testimony

Forums

Arkansas Public Service Commission

Federal Energy Regulatory Commission

Florida Public Service Commission

Maine Public Utilities Commission

Minnesota Public Service Commission

Nevada Public Service Commission

New York Public Service Commission

Nuclear Regulatory Commission – Atomic Safety and Licensing Board

Oklahoma Public Service Commission

Public Service Commission of Indiana

Public Utilities Commission of Ohio

Public Utilities Commission of Nevada

Public Utilities Commission of Texas

Public Utilities Commission of New Hampshire

United States District Court

United States Senate Committee on Energy and Natural Resources

Various arbitration proceedings

Clients

Arkansas Power & Light Company

Baltimore Gas & Electric Company

Carolina Power & Light Company

Central Maine Power Company

Consolidated Edison Company of New York, Inc.

Dayton Power and Light Company

Florida Coordinating Group

Houston Lighting & Power Company

Minnesota Power and Light Company

Nevada Power Company

Niagara Mohawk Power Corporation

Northern Indiana Public Service Company

Oglethorpe Power Corporation

Pacific Gas and Electric Company

Power Authority of the State of New York

Public Service and Electric Company

Public Service Company of Oklahoma

Sierra Pacific Power Company

Southern Company Services, Inc.

Tucson Electric Power Company

Texas-New Mexico Power Company

Recent Expert Testimony and Expert Reports

Supplemental Testimony on behalf of Texas-New Mexico Power Company, Docket No. 15660, September 5, 1996.

Direct Testimony on behalf of Long Island Lighting Company before the Federal Energy Regulatory Commission, September 29, 1997.

Rebuttal Testimony on behalf of Texas-New Mexico Power Company, SOAH Docket No. 473-97-1561, PUC Docket No. 17751, March 2, 1998.

Prepared Testimony and deposition testimony on behalf of Central Maine Power Company, United Stated District Court Southern District of New York, 98-civ-8162 (JSM), March 5, 1999.

Prepared Direct Testimony Before the Public Service Commission of Maryland on behalf of Baltimore Gas & Electric Company, PSC Case Nos. 8794/8804, June 1999.

Rebuttal Testimony Before the Maryland Public Service Commission, on behalf of Baltimore Gas & Electric Company, PSC Case Nos. 8794/8804, March 22, 1999.

NORCON Power Partners LP v. Niagara Mohawk Energy Marketing, before the United States District Court, Southern District of New York, June 1999.

Prepared Supplemental Testimony Before the Maryland Public Service Commission, on behalf of Baltimore Gas & Electric Company, PSC Case Nos. 8794/8804, July 23, 1999.

Prepared Supplemental Reply Testimony Before the Maryland Public Service Commission, on behalf of Baltimore Gas & Electric Company, PSC Case Nos. 8794/8804, August 3, 1999.

Direct Testimony on behalf of Niagara Mohawk, Before the New York State Public Service Commission, PSC Case No. 99-E-0681, September 3, 1999.

Rebuttal Testimony on behalf of Niagara Mohawk, PSC Case No. 99-E-0681 Before the New York State Public Service Commission, November 10, 1999.

Arbitration deposition on behalf of Oglethorpe Power Corporation, last quarter of 1999.

Direct Testimony Before the Public Utilities Commission of Ohio on behalf of FirstEnergy Corporation, Ohio Edison Company, The Cleveland Electric Illuminating Company and The Toledo Edison Company, Case No. 99-1212-EL-ETP re: Shopping Credits.

Direct Testimony on behalf of Niagara Mohawk, Before the New York State Public Service Commission, PSC Case No. 99-E-0990, February 25, 2000.

Testimony on behalf of Consolidated Edison Company of New York, Inc., State of Connecticut, Department of Public Utility Control, Docket No.: 00-01-11, April 28, 2000 and June 30, 2000.

Testimony on behalf of Texas-New Mexico Power Company, Fuel Reconciliation Proceeding before the Texas PUC, June 30, 2000.

Testimony on behalf of Consolidated Edison Company of New York, Inc., Before the New Hampshire Public Service Commission, Docket No.: DE 00-009, June 30, 2000.

Rebuttal Testimony Before the Public Utilities Commission of the State of Colorado, Docket No. 99A-549E, November 22, 2000.

Testimony Before the Public Utilities Commission of the State of Colorado, Docket No. 99A-549E, January 19, 2001.

DETM Management, Inc. Duke Energy Services Canada Ltd., And DTMSI Management Ltd., Claimants vs. Mobil Natural Gas Inc., And Mobil Canada Products, Ltd., Respondents. American Arbitration Association Cause No. 50 T 198 00485 00, August 27, 2001.

State of New Jersey Board of Public Utilities, In the Matter of the Provision of Basic Generation Service Pursuant to the Electric Discount and Energy Competition Act of 1999, Before President Connie O. Hughes, Commissioner Carol Murphy on Behalf of the Electric Distribution Companies (Public Service Electric and Gas Company, GPU Energy, Consolidate Edison Company and Conectiv) Docket No.: EX01050303, October 4, 2001.

Direct Testimony Before the Federal Energy Regulatory Commission on behalf of Pacific Gas and Electric Company, Docket No.: ER02-456-000, November 30, 2001.

Fourth Branch Associates/Mechanicville vs. Niagara Mohawk Power Corporation, January 2002 (Expert Report).

Arbitration Deposition on behalf of Oglethorpe Power Corporation, March 2002.

Direct Testimony and Deposition Testimony Before the Federal Energy Regulatory Commission on behalf of Electric Generation LLC in Response to June 12 Commission Order, Docket No.: ER02-456-000, July 16, 2002.

Rebuttal Testimony Before the Federal Energy Regulatory Commission on behalf of Electric Generation LLC in Response to June 12 Commission Order, Docket No.: ER02-456-000, August 13, 2002.

Direct Testimony Before the Public Utilities Commission of Nevada on behalf of Nevada Power Company, in the matter of the Application of Nevada Power Company to Reduce Fuel and Purchased Power Rates, PUCN Docket No. 02-11021, November 8, 2002 and subsequent Deposition Testimony.

Direct Testimony Before the Public Utilities Commission of Nevada on behalf of Sierra Pacific Power Company's Deferred Energy Case, Docket No. 03-1014, January 10, 2003.

Direct Testimony Before the Public Utility Commission Of Texas on behalf of Texas-New Mexico Power Company, Application Of Texas-New Mexico Power Company For Reconciliation Of Fuel Costs, April 1, 2003.

Rebuttal Testimony Before the Public Utilities Commission of Nevada on behalf of Nevada Power Company, PUCN Docket No. 02-11021, April 1, 2003.

Rebuttal Testimony Before the Public Utilities Commission of Nevada on behalf of Sierra Pacific Power Company, Docket No. 03-1014, May 5, 2003.

Testimony on behalf of Consolidated Edison Company of New York, Inc., Before the Public Service Commission of New York, Case No.: 00-E-0612, September 19, 2003.

State of New Jersey Board of Public Utilities, In the Matter of the Provision of Basic Generation Service Pursuant to the Electric Discount and Energy Competition Act of 1999, Before President Connie O. Hughes, Commissioner Carol Murphy on Behalf of the Electric Distribution Companies (Public Service Electric and Gas Company, GPU Energy, Consolidate Edison Company and Conectiv), September 2003.

Direct Testimony Before the Public Utilities Commission of Nevada on behalf of Nevada Power Company's Deferred Energy Case, November 12, 2003.

Direct Testimony Before the Public Utilities Commission of Nevada on behalf of Sierra Pacific Power Company's Deferred Energy Case, January 12, 2004.

Rebuttal Testimony Before the Public Utilities Commission of Nevada on behalf of Sierra Pacific Power Company's Deferred Energy Case, May 28, 2004.

Direct Testimony on behalf of Texas-New Mexico Power Company, First Choice Power Inc. and Texas Generating Company LP to Finalize Stranded Cost under PURA § 39.262, January 22, 2004.

Rebuttal Testimony on behalf of Texas-New Mexico Power Company, First Choice Power Inc. and Texas Generating Company LP to Finalize Stranded Cost under PURA § 39.262, April, 2004.

State of New Jersey Board of Public Utilities, In the Matter of the Provision of Basic Generation Service Pursuant to the Electric Discount and Energy Competition Act of 1999, Before President Connie O. Hughes, Commissioner Carol Murphy on Behalf of the Electric Distribution Companies (Public Service Electric and Gas Company, GPU Energy, Consolidate Edison Company and Conectiv), September 2004.

Direct Testimony Before the Public Utilities Commission of Nevada on behalf of Nevada Power Company's Deferred Energy Case, November 9, 2004.

Direct Testimony Before the Public Utilities Commission of Nevada on behalf of Sierra Pacific Power Company's Deferred Energy Case, January 7, 2005.

Expert Report on behalf of Oglethorpe Power Corporation, March 23, 2005.

Arbitration deposition on behalf of Oglethorpe Power Corporation, April 1, 2005.

Direct Testimony Before the Public Utilities Commission of Nevada on behalf of Sierra Pacific Power Company's December 2005 Deferred Energy Case.

Direct Testimony Before the Public Utilities Commission of Nevada on behalf of Nevada Power Company's 2006 Deferred Energy Case, January 13, 2006.

Remand Rebuttal for Public Service Company of Oklahoma before the Corporation Commission of the State of Oklahoma, Cause No. PUD 200200038, **Confidential**, March 17, 2006

Answer Testimony on behalf of the Colorado Independent energy Association, AES Corporation and LS Power Associates, LP, Docket No. 05A-543E, April 18, 2006.

Cross-Answer Testimony on behalf of the Colorado Independent energy Association, AES Corporation and LS Power Associates, LP, Docket No. 05A-543E, May 22, 2006.

Distributed Resources: Incentives, a report prepared for Edison Electric Institute, May 2006

Rebuttal Testimony Before the Public Utilities Commission of Nevada on behalf of Nevada Power Company's 2006 Deferred Energy Case, Docket No. 06-01016, June 2006.

Direct Testimony Before the Public Utilities Commission of Nevada on behalf of Sierra Pacific Power Company's Deferred Energy Case, December 2006.

Direct Testimony Before the Public Utilities Commission of Nevada on behalf of Sierra Pacific Power Company's Application for Recovery of Costs of Achieving Final Resolution of Claims Associated with Contracts Executed During the Western Energy Crisis, December 2006.

Direct Testimony Before the Public Utilities Commission of Nevada on behalf of Nevada Power Company's Application for Recovery of Costs of Achieving Final Resolution of Claims Associated with Contracts Executed During the Western Energy Crisis, December 2006.

Direct Testimony Before the Public Utilities Commission of the State of Hawaii, on behalf of Hawaiian Electric Company, Inc., Docket No. 2006-0386, December 22, 2006.

Direct Testimony Before the Public Utilities Commission of the State of Hawaii, on behalf of Hawaiian Electric Company, Inc., Docket No. 05-0315, December 29, 2006.

Rebuttal Testimony Before the Public Utilities Commission of Nevada on behalf of Nevada Power Company's 2007 Deferred Energy Case, January 2007.

Declaration Before the State of New York Public Service Commission, on behalf of Consolidated Edison Company of New York, Inc.'s Long Island City Electric Network, Case 06-E-0894 – Proceeding on Motion of the Commission to Investigate the Electric Power Outage and Case 06-E-1158 – In the Matter of Staff's Investigation of Consolidated Edison Company of New York, Inc.'s Performance During and Following the July and September Electric Utility Outages. July 24, 2007

Direct Testimony Before The Public Utilities Commission of Colorado, In The Matter of the Application of Public Service Company of Colorado for Approval of its 2007 Colorado Resource Plan, April 2008

Answer Testimony Before the Public Utilities Commission of the State of Colorado on behalf of Trans-Elect Development Company, LLC, and The Wyoming Infrastructure Authority, Docket No. 07A-447E, April 28, 2008

Direct Testimony Before the Public Utilities Commission of Nevada on behalf of Sierra Pacific Power Company's 2008 Deferred Energy Case, February 2009.

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Direct Testimony Before the Public Utilities Commission of Nevada on behalf of Nevada Power Company's 2010 – 2029 Integrated Resource Plan, Docket No. 09-07003, July 2010

Direct Testimony Before the Public Utilities Commission of Nevada on behalf of Sierra Pacific Power Company's Eighth Amendment to its 2008 – 2027 Integrated Resource Plan, Docket No. 10-03____, July 2010

Independent Study to Establish Parameters of the ICAP Demand Curve for the New York Independent System Operator

NERA
Economic Consulting

Final

September 3, 2010 (Revised September 7, 2010, November 15, 2010)

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REVISION SUMMARY

September 7 - This report was revised to correct a double-counting of insurance costs in the case of the NYC Demand Curve with property tax abatement. That Demand Curve was developed with carrying charges using implicit property taxes. Those carrying charges also included insurance costs which were then also added to the model as a line item. All other cases were not developed using carrying charges with implicit property taxes and are unaffected. The result is a reduction in the gross and net CONE of approximately $ 8 per kW year for the NYC case with property tax abatement.

November 15 - Revisions were made to the report due to the LMS100 CO emissions issue.

- Table II-1, p17 revised to change cost ranges on LMS100. Also corrected the $/kW cost for the LM6000PG model.
- Table II-2, p20 with text changes on pp 20-22. Updated max operating hours and text for LMS100 cases.
- Table II-3, p 26-27 updated capital costs for LMS100 cases
- Table II-6, p 31-32 updated CO catalyst cost component of variable O&M for LMS100 cases.
- Table A-2, pgs 92, 93, 97, 98 updated costs for capital, fixed and variable O&M for LMS100 cases.
- Table A-3, p100 updated capital cost breakdown for LMS100 cases

- Table A-10, p107 updated comparison of 2010 DCR LMS100 costs with 2007 DCR

- Table A-11, p108, updated NYC LMS100 cost breakdown

- Table A-12, p109 updated LI LMS100 cost breakdown• Table II-4, p28 revised the NYC maintenance staff and LHV operating staff to correspond to the numbers used to develop the fixed O&M costs used by NERA.

- Tables A-5 through A-7, pp102-104, these tables were never updated from the draft issued to the ICAP working group for comment in early July. A number of changes were made since that time, including Oxidation catalyst on LM6000, revised social justice costs in some cases, NYC site remediation costs, and revised ERC costs.

Table of Contents

I. Executive Summary

In 2003, the NYISO implemented an Installed Capacity[1] (ICAP) Demand Curve mechanism. The ICAP Demand Curve is used in the ICAP Spot Market Auction conducted for each month. The ICAP Demand Curves act as offers to buy capacity in the ICAP Spot Market Auctions.

The NYISO updated the Demand Curves in 2004 for the 2005/06, 2006/07 and 2007/08 Capability Years. That update was based upon an independent study conducted by Levitan & Associates, Inc. (LAI), input from the NYISO Market Advisor and input from stakeholders. The NYISO updated the Demand Curves again in 2007 for the 2008/09, 2009/10 and 2010/11 Capability Years. That update was based upon an independent study conducted by NERA Economic Consulting (NERA) assisted by Sargent & Lundy LLC (S&L) and input from the NYISO Market Advisor and input from stakeholders. The Demand Curve process calls for the Demand Curves to be updated every three years. The NYISO again retained NERA assisted by S&L to perform an independent Demand Curve parameter update study applicable to Capability Years 2011/12, 2012/13 and 2013/14.

NERA was responsible for the overall conduct of the study and led the effort with respect to formulating the financial assumptions, estimating energy and ancillary services net revenues and developing the recommended Demand Curves. S&L was primarily responsible for developing construction cost estimates, operating cost data and plant operating characteristics. NERA and S&L collaborated to identify the potential technology choice for each region[2].

In considering the study, the Services Tariff was the primary guide. In particular, we relied on Section 5.14.1(b) of that Tariff. That section of the Tariff specifies that the update shall be based upon and consider the following:

[1] Terms with initial capitalization used but not defined herein have the meaning set forth in the NYISO's Market Administration and Control Area Services Tariff (Services Tariff) or if not defined in the Services Tariff, as defined in the Open Access Transmission Tariff.

[2] The Demand Curve process calls for a Demand Curve for New York City (NYC), Long Island (LI) and the New York Control Area (NYCA). NERA and S&L developed the net cost of new entry for NYC, LI, the Capital Region, the Central Region and the lower Hudson valley (Lower Hudson Valley). For the NYCA the Capital Region has been used. The Lower Hudson Valley estimate is for informational purposes only. ROS is the term used herein to refer to supply in the part of the New York Control Area that does not include the New York City and Long Island Localities and to the NYCA Demand Curve.

- the current localized levelized embedded cost of a peaking unit in each NYCA Locality and the Rest of State to meet minimum capacity requirements;

- the likely projected annual Energy and Ancillary Services revenues of the peaking unit over the period covered by the adjusted ICAP Demand Curves, net of the costs of producing such Energy and Ancillary Services, under conditions in which the available capacity would equal or slightly exceed the minimum Installed Capacity requirement;

- the appropriate shape and slope of the ICAP Demand Curves, and the associated point at which the dollar value of the ICAP Demand Curves should decline to zero; and

- the appropriate translation of the annual net revenue requirement of the peaking unit determined from the factors specified above, into monthly values that take into account seasonal differences in the amount of capacity available in the ICAP Spot Market Auctions.

The Services Tariff further specifies that:

> "a peaking unit is defined as the unit with technology that results in the lowest fixed costs and highest variable costs among all other units' technology that are economically viable."

It is clear that the Services Tariff requires the update to identify the peaking unit with the lowest fixed costs and highest variable costs that is economically viable. This unit will not necessarily be the lowest "net-cost"[3] unit under current conditions. It is possible that a more expensive capital cost unit with a lower variable or operating cost would have a lower net cost. For example, a combined cycle unit may have a lower net cost as a result of higher energy net revenues. The Tariff, however, does not call for the lowest net-cost unit. Rather, it requires that the update be based upon the net-cost of the lowest capital cost and highest operating cost unit that is economically viable.

As part of this study, we assumed that only a unit that could be practically constructed in a particular location would qualify. We further assumed the Tariff to apply to reasonably large scale generating facilities that are standard and replicable, which excludes dispersed generators and Special Case Resources. Through the stakeholder process, the prevalent understanding was that in

[3] Net-cost refers to the difference between the annual fixed cost and annual energy and ancillary service net revenues.

the next reset, NYISO would consider whether Special Case Resources should be considered as the possible peaking unit.

This study examines three types of units, which between them represent two technology options. The first technology options are frame units, specifically the Frame 7FA. These are large scale combustion turbines with low capital costs and high operating costs. They are relatively inflexible with respect to starts and stops. The second are aeroderivatives – the Rolls Royce Trent, GE LM6000 and GE LMS100. These units are more flexible combustion turbines, but have higher per kilowatt capital costs than frame units and have lower operating costs.

A review of these units showed the following:

1. The Frame 7FA has lower capital and higher operating costs than the LMS100. The LMS100 has lower capital and lower operating costs than the Trent or LM6000.

2. The Frame 7FA would not practically be constructed as a peaking unit in the Lower Hudson Valley, NYC or LI. This is the case because in those particular locations a selective catalytic reduction (SCR) would be required to avoid severe operating restrictions and when operated in simple cycle mode; the Frame 7FA exhaust temperature is too hot for an SCR. Hence, a Frame 7 is not a practical choice in the Lower Hudson Valley, NYC and LI regions. The LMS100 has become a more mature technology with numerous North American and worldwide installations.[4]

Based on the above, the Frame 7FA was selected as the peaking unit for the ROS area and the LMS100 was selected as the peaking unit for NYC and LI. A comparison of results for the first year of the current update to the Demand Curve to the last year of the previous update period is presented below.

[4] In the prior update an "immaturity" adjustment was specified for the LMS 100. Given the greater experience with the technology, this adjustment is not included in this analysis.

Table I-1

Demand Curve Values at Reference Point:

Values for Capacity Years 2011/2012

	2007 DC Value for 2010/2011 2010 dollars/kW-year			*2010 Update for 2011/2012 2011 dollars/kW-year*		
	Annual Fixed Cost	Energy and AS Net Revenues	Net Costs	Annual Fixed Cost	Energy and AS Net Revenues	Net Costs
ROS Frame 7	107.33	10.87	**96.46**	122.47	27.44	**95.03**
ROS Frame 7 (w/ Deliverability)				149.42	27.44	**121.98**
NYC LMS100 (w/revised Abatement)	218.55	75.41	**143.15**	286.65	101.67	**184.99**
NYC LMS100 (w/o Abatement)				364.64	101.67	**262.98**
LI LMS100	194.05	104.56	**89.47**	280.91	168.77	**112.14**

We present the values above in 2010 dollars for the current curve and 2011 dollars for the updated curve as the curves are stated on that basis. As can be seen above the Demand Curves are reasonably stable absent potential changes for deliverability and in NYC for the tax abatement program established since the last Demand Curve reset, which has a lower impact than the previous abatement program. This result is attributable to a combination of factors including:

1. an increase in construction and equipment costs somewhat beyond that assumed in the prior reset; and,

2. offsetting increases in energy and ancillary services net revenues resulting from market experience over the past three years.

Note that the table above provides options with respect to inter zonal deliverability and the NYC property tax abatement. In particular we have been requested by NYISO to provide updated Demand Curves with and without inter zonal deliverability and with and without NYC property tax abatement.

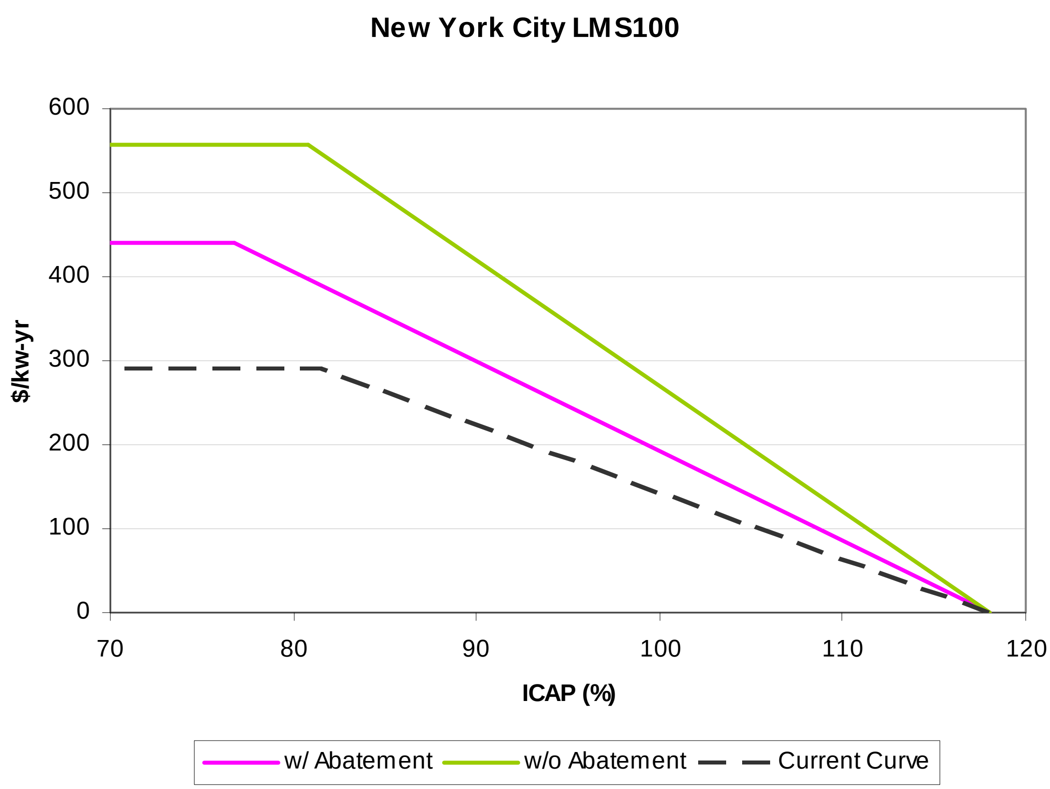
The Demand Curves were developed explicitly analyzing risks. Risks that could reasonably be considered to be symmetrical have no impact on expected value and were not considered in the risk analysis. Risks that were not symmetrical were analyzed in a Monte Carlo risk analysis model described later in the report and made available to stakeholders in executable form.

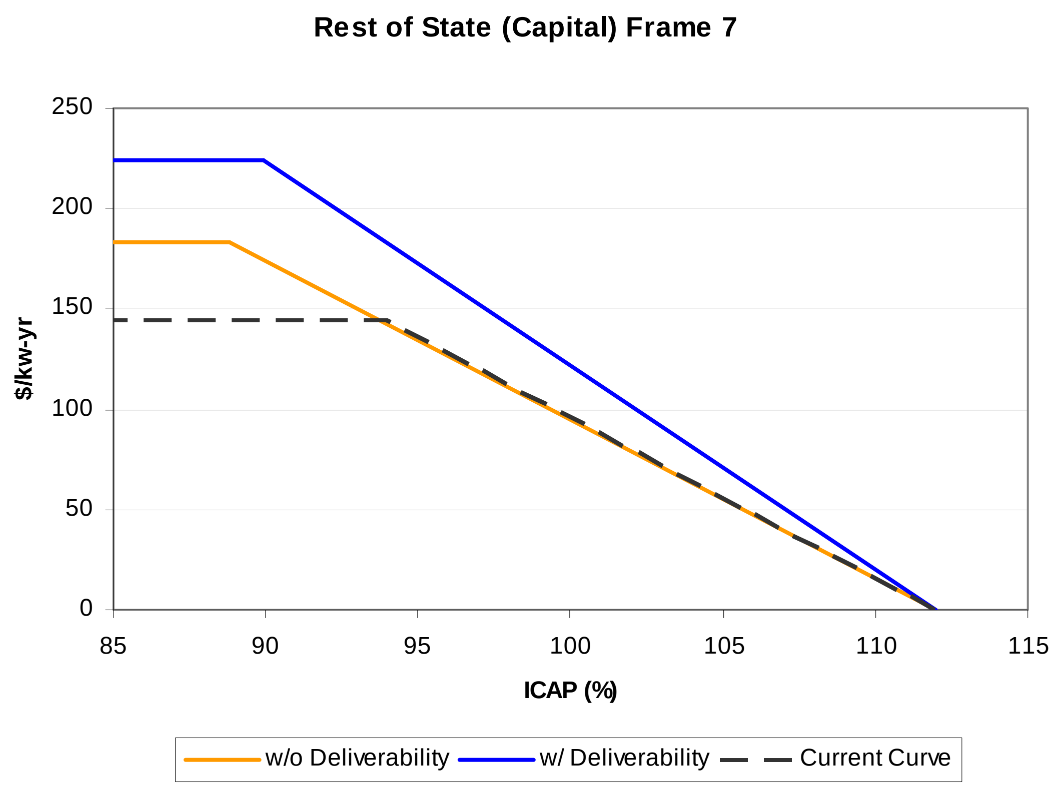
The model recognizes that the NYISO has in place planning and response procedures to prevent capacity from falling short. Hence, over time, there should be a bias toward surplus capacity conditions. If there is expected to be surplus capacity, the Demand Curve should be adjusted to reflect the fact that over time the expected clearing price would be below the target reserve point. Absent such an adjustment, the Demand Curve would not produce adequate expected revenues to recover cost and would not induce the proper level of investment. The model we have developed to set the Demand Curve accounts for these factors.

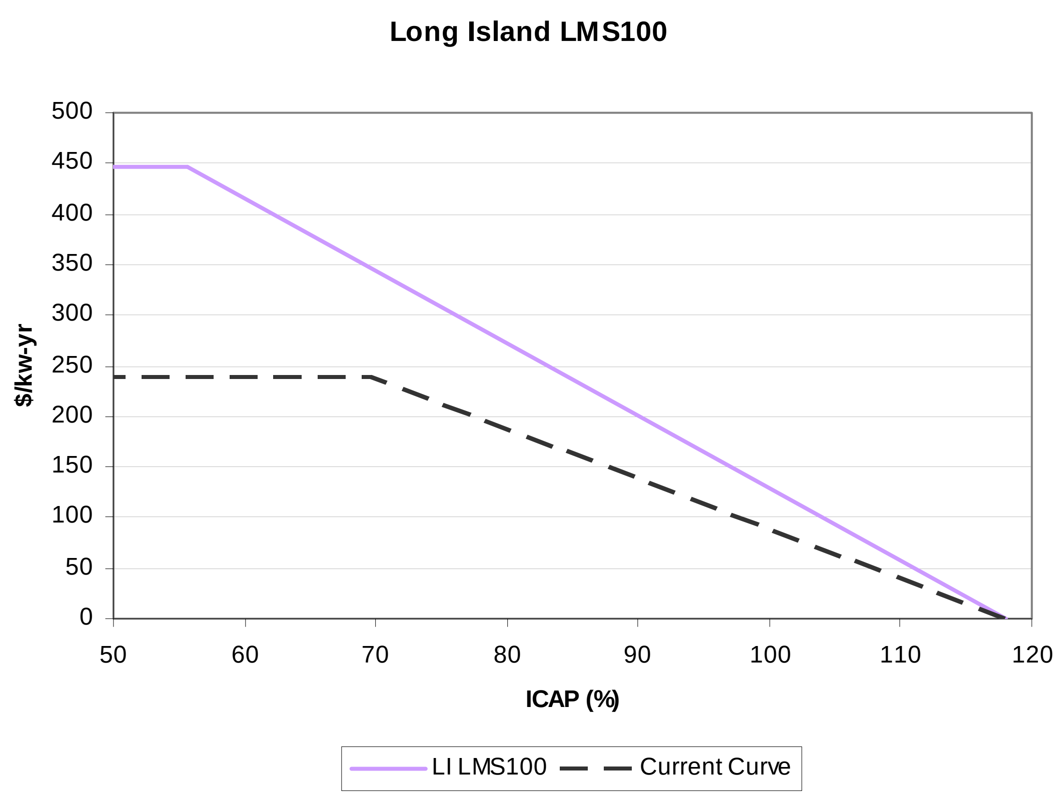
When using the risk model, the slope of the Demand Curve has a measurable influence on the levelization and the Demand Curve reference point. With a bias toward excess capacity, a steep slope requires a higher reference point if there is to be an expectation of full cost recovery. In surplus capacity periods, the Demand Curve will clear below the reference price, and if there is a steep slope, revenues will decline more rapidly than if there is flatter slope. To provide the same expected revenue over the life of the investment, a higher reference point must accompany a steeper slope. For example, if the NYC x-intercept was applied to the NYCA Demand Curve, the reference value would fall by $5.34 per kW-year.

The recommended Demand Curves are presented below. For each region the chart shows the current Demand Curve and the 2011/12 recommendation for the Demand Curve. With and without tax abatement curves are shown for NYC and with and without inter zonal deliverability curves are shown for ROS.

NERA examined the issue of the Demand Curve slope, which is a function of the zero crossing point and shape. The current curves have a single linear slope from the reference value at the target reserve level to zero at 112% of the minimum requirement for ROS and 118% of the minimum requirement for NYC and LI. As will be addressed in more detail later, we recommend retaining the current shape and slope. The current outlook for at least the next five years is for significant capacity surpluses. If the shape and slope were altered at a time when the effect was clearly a reduction in capacity compensation, we believe this would be viewed as opportunistic, would significantly increase the risk perceived by entrants and significantly raise the levelized costs of entry. However, quantification of these effects is difficult and uncertain and while any revision to the shape and slope would need to account for these effects, such accounting would be largely guesswork at this time. To the extent that a change in the shape and or slope is desirable, such a change is best made when there is not a chronic surplus and when the impact of the change is more likely to be neutral.




Rest of State (Capital) Frame 7
250
200
150
100
50
0
$/kw-yr
85
90
95
100
105
110
115
ICAP (%)
w/o Deliverability
w/ Deliverability
Current Curve


Long Island LMS100
500
450
400
350
300
250
200
150
100
50
0
$/kw-yr
50
60
70
80
90
100
110
120
ICAP (%)
LI LMS100
Current Curve

II. Technology Choice and Construction Cost

The ICAP Demand Curve is derived from the levelized cost of a hypothetical new peaking unit at various locations throughout the State of New York. The reference peaking facility is a gas-fired combustion turbine operating in simple-cycle mode. A range of combustion turbine options, based upon recent peaking applications and design requirements, were evaluated at each location. The levelized cost analysis described in this section accounts for the location-specific factors affecting the total capital investment, the cost inputs and economic parameter inputs for the levelized cost analysis, and the annual operating cost and performance characteristics for each technology.

Levelized costs generally refer to the capital-related carrying charges, operation and maintenance (O&M), and fuel costs incurred over the plant operating life. For the ICAP Demand Curve analysis, costs are divided into variable costs (those that vary with operation) and non-variable (fixed) costs. The Demand Curve analysis uses the fixed cost components, consisting of the capital-related carrying charges, property taxes, insurance, and fixed O&M. Variable costs, consisting of fuel and variable O&M, are used to develop net energy and ancillary service revenues in NERA's econometric model of NYISO market prices. Once the levelized annual fixed costs for the unit are established, they indicate a reference point in the Demand Curve at which the net revenues from the energy and ancillary service markets offset the fixed costs. Input assumptions for the cost components are described in the following subsections.

A. Tariff Requirements

The Services Tariff states that the periodic review of the ICAP Demand Curves shall assess "the current localized levelized cost of a peaking unit in each NYCA Locality and the Rest of State to meet minimum capacity requirements." The Services Tariff defines a peaking unit as "the unit with technology that results in the lowest fixed costs and the highest variable costs among all other units' technology that are economically viable."

It is clear from the Tariff language that the requirement is to identify the lowest fixed cost, highest variable cost peaking unit that is economically viable. This unit will not necessarily be the lowest "net-cost" unit under current conditions. It is possible that a more expensive capital cost unit with a lower variable or operating cost would have a lower net cost. For example, a combined-cycle unit may have a lower net cost as a result of higher energy net revenues.

The Tariff, however, does not call for the lowest net-cost unit. Rather, it requires that the update be based upon the net-cost of the lowest capital cost and highest operating cost unit that is economically viable. For the purposes of this study, we assumed that only a unit that realistically could be constructed in a locality would qualify. We also assumed the Services Tariff to apply to reasonably large scale generating facilitates that are standard and replaceable. This excludes dispersed generators and Special Case Resources.

B. Alternate Technologies Examined

In conducting the study, one heavy-duty frame unit, the 7FA, and three aeroderivative peaking units, the LM6000, LMS100, and the Trent 60, were examined.[5]

Heavy-duty frame units such as the 7FA are large-scale combustion turbines oriented to industrial applications with lower capital costs (on a $/kW basis) and higher operating costs (on a $/MWh basis). Maintenance costs are affected by the duty cycle experienced in operations. As a unit is subjected to more starts and stops, the time between major overhauls decreases. Nitrogen oxide (NO_X) emissions are reduced by equipping the units with dry low NO_X (DLN) combustors. The use of selective catalytic reduction (SCR) technology for NO_X control is problematic because exhaust gas temperatures in simple-cycle mode exceed 850°F, above which the catalyst is damaged irreversibly. It is technically feasible to design and install a system of ductwork, and air dampers to lower the exhaust temperature of an "F" class turbine by mixing it with ambient air before introducing the exhaust air to an SCR sized to handle the larger gas flow rate. There are very few examples of SCRs installed on "F" class turbines in simple cycle, and few if any of these have been operating successfully.[6] The efficiency of frame units can be improved by configuring units in a

[5] Three of the four peaking technologies examined in this study are manufactured by GE Energy. The selection of the units for the study was based on the units that were studied in the last Demand Curve review, technologies currently being developed for participation in the NYISO markets, and the comments and suggestions of ICAP Working Group members during the conduct of the study. Based on data from Platts, approximately 56% of combustion turbine capacity in the United States and 56% of combustion turbine capacity in the NYCA was manufactured by GE. There are several competing manufacturers and models for "F" frame machines and aeroderivatives. The units chosen for the study have representative cost and performance characteristics of similar products from other manufacturers. The choice of frame and aeroderivative units in this study does not constitute a recommendation by Sargent & Lundy to choose any specific manufacturer or model for projects.

[6] Permit to Construct Application, Bridgeport Peaking Station, Bridgeport, CT, prepared for Bridgeport Energy II, LLC, by Earth Tech, Inc., June 2007, pages 4-6 to 4-7.

combined-cycle mode, where the exhaust of one or more units is directed to a heat recovery steam generator, which drives another steam turbine. This configuration was not evaluated in the study.

Aeroderivative units such as the LM6000, LMS100 and Trent 60 are derived from aircraft engines and have operating characteristics that better match the needs of aircraft owners. Aeroderivatives are more efficient (lower heat rate) and are maintained based on hours of operations regardless of the number of starts and stops, but have higher capital costs (on a $/kW basis). NO_X emissions can be reduced by injecting water into the combustion zone; however, aeroderivative exhaust temperatures are low enough to permit use of SCR for NO_X control. Dry low NOx combustion is available on aeroderivative units to reduce the amount of water used in the NOx emissions control process. However, the models examined fitted with dry low NOx combustion do not support dual fuel operation.

1. 7FA

General Electric's installed fleet of more than 950 "F" technology combustion turbines has reached 27 million hours of commercial operation in power plants worldwide. The F technology combustion turbines were introduced in 1988. The 7FA.05 combustion turbine, with a nominal rating of 200 MW, is capable of operating on 100% natural gas or 100% diesel fuel. DLN combustors reduce NO_X emissions. Water injection is used for NO_X control in the combustion process when firing fuel oil. The wide range of power generation applications for the 7FA gas turbine include combined cycle, cogeneration, simple-cycle peaking and integrated gasification combined cycle (IGCC) in both cyclic and baseload operation with a wide range of fuels. The reliability of the 7FA gas turbine has been consistently 98% or better.

2. LM6000

Since the introduction of the LM6000 into GE's aeroderivative combustion turbine product line, GE has produced more than 600 units with an operating history of 10 million hours. Engine reliability is 98% or better. Units are typically fired on natural gas, but can be fired with fuel oil for backup. The LM6000 is a dual-rotor, "direct drive" combustion turbine, which was derived from GE's CF6-80C2, high-bypass, turbofan aircraft engine. For this study, the LM6000 was configured with SPRINT™ (Spray Inter-cooled Turbine) technology to significantly enhance power. Both the PG model, which reduces NO_X emissions levels by using water injection, and the PH model, which uses dry low NOx combustion, were examined in this study.

3. LMS100

The LMS100 is a General Electric aeroderivative combustion turbine that combines the technology of heavy-duty frame engines and aeroderivative turbines to provide cycling capability without the maintenance impact experienced by frame machines; higher simple-cycle efficiency than current aeroderivative machines; fast starts (10 minutes); and high availability and reliability. The LMS100™ system, developed by General Electric in 2004, combines the 6FA compressor technology with CF6®/LM6000™ technology. The airflow from the low pressure compressor enters an intercooler, which reduces the temperature of the airflow before it enters the high-pressure compressor (HPC). Consequently, the HPC discharges into the combustor at ~250°F (140°C) lower than the LM6000™ aeroderivative gas turbine. The combination of lower inlet temperature and less work per unit of mass flow results in a higher pressure ratio and lower discharge temperature, providing significant margin for existing material limits and higher efficiency. The HPC airfoils and casing have been strengthened for this high-pressure condition.

Since the first unit was commissioned in 2006, there are now over 20 LMS100s installed with 35,000+ cumulative hours as of end of 2009. Both wet low NOx combustion (the PA model) and dry low NOx combustion (the PB model) are available. All of the currently installed LMS100s are the PA model. For this study, only the PA model was examined.

4. Trent 60

The Trent 60 gas turbine, manufactured by Rolls Royce, has a high degree of commonality with its aero parent, the Trent 800, which uses three-shaft technology and has over 14 million hours in aircraft service. The Trent 60 engine retains the core of the aero engine - the IP and HP compressors and turbines. The industrial design first entered service in 1998 for base load and peaking power production.

The Trent 60 was initially launched with a dry low emissions (DLE) combustor system. A water injection (WLE) option was developed in 2005 for dual fuel operation. The first Trent 60 in the U.S. began operation in late 2008 in Lowell, MA. The number of Trent 60s sold or reserved by operators now totals 78 in 19 countries, for both power generation and oil and gas installations, with 31 engines in service in 11 countries.

5. Comparison

The key characteristics of the four technologies evaluated for this study are shown below. The direct costs are the costs typically within the scope of engineer, procure, and construct (EPC) contracts, and do not include owner's costs, financing costs, or working capital and inventories.

Table II-1 Key Characteristics of Evaluated Technologies[7]

	Frame	**Aeroderivative**			
Technology	**7FA.05**	**LM6000 PG Sprint**	**LM6000 PH Sprint**	**LMS100 PA**	**Trent 60**
Zones	C, F	J	C, F, G, K	C, F, G, J, K	G, J, K
Capacity of a 2-Unit Addition	413	104	96	195	117
Total Cost ($M)	308-310	198	137-198	262-326	174-203
Total Cost ($/kW)	818-820	2085	1592-2168	1456-1807	1627-1907
Heat Rate (Btu/kWh HHV)	10,206	10,102	9,475	9,023	9,548
Pressure Ratio	17.8:1	30:1	32.1:1	43.3:1	,37.9:1
Exhaust Temperature (°F)	1109	885	885	769	378
Water Use (gpm)	30	50	50	60	75

The direct cost ($/kW) and heat rate data show that the LMS100 had lower capital and operating cost than other aeroderivative technologies. The 7FA has lower capital and higher fuel and operating costs than the LMS100. Appendix 1 shows more detailed information on the cost and

[7] Based on 90% Load, ISO Conditions (59F, 60% RH, 14.7 psia), Evaporative cooling, 0.85 Power Factor

performance characteristics of the LMS100, LM6000, Trent 60, and 7FA technologies. The following section addresses the impact of emissions limitations on technology choice.

C. Technology Choice by Region

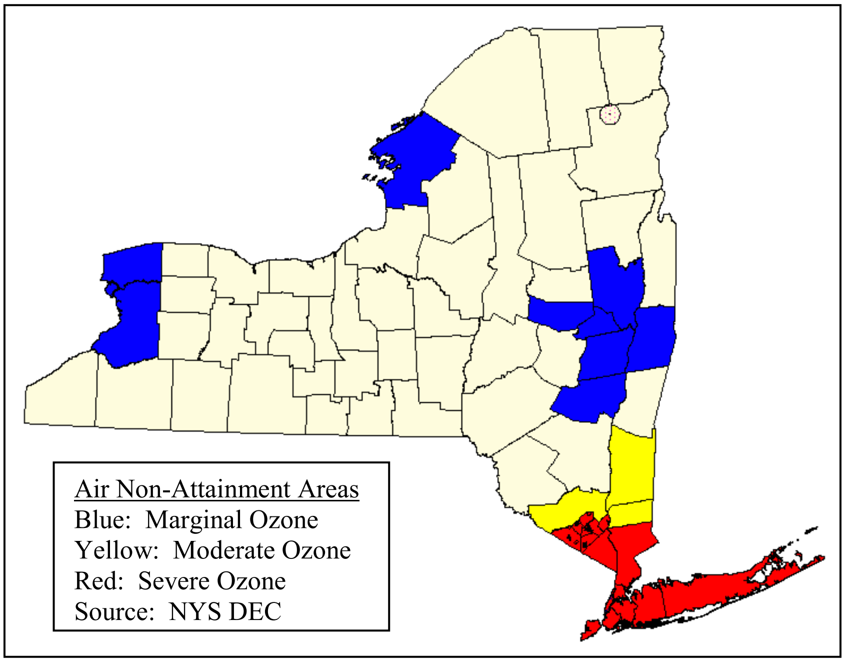
All four technologies are subject to the Title V operating permit regulations in NYCRR Subpart 201.6,[8] and the Title IV Acid Deposition Reduction regulations in NYCRR Parts 237 and 238.[9]

The figure below shows the status of ozone nonattainment areas in New York State. The amount of annual emissions that triggers the major source New Source Review (NSR) regulations in NYCRR Part 231 is 25 tons per year (NO_X) in New York City, Long Island and two counties of the Lower Hudson Valley (Westchester County and lower Rockland County). The threshold is 100 tons per year (NO_X) in other locations. Major stationary sources located in an ozone nonattainment area are required to control NO_X emissions using technology capable of achieving the Lowest Achievable Emissions Rate (LAER). Major stationary sources located in an attainment area are required to control NO_X emissions using Best Available Control Technology (BACT). SO_2 emissions are not significant from turbines using natural gas, and there no longer are carbon monoxide attainment issues in New York.

Figure II-1 — Ozone Non-attainment Areas in New York State

[8] The Subpart 201-6 Title V operating permit regulations apply to any major source (as defined under Subpart 201-2 of the regulations), and any stationary source subject to a standard or limitation, or other requirement, under the Federal New Source Performance Standards (NSPS) in 40 CFR Part 60, *et seq*. Natural gas-fired combustion turbines and combined cycle units are subject to a Federal NSPS (60 CFR Part 60 Subpart KKKK), and are therefore subject to the Subpart 201-6 Title V operating permit regulations.

[9] In general, the Part 237 and 238 Acid Deposition Reduction regulations apply to any fossil fuel-fired unit that serves a generator with a nameplate capacity equal to or greater than 25 MW and generates electricity for sale. See, NYCRR §237-1.4, §238-1.4, and 42 U.S.C. Section 7651a(2).



The table below shows estimates of the maximum annual hours of operation for the each of the technologies by zone configured to meet emissions requirements. Use of an SCR on a simple-cycle 7FA is not economically or technically practical.[10] Current, proven, SCR catalyst has a maximum operating temperature of approximately 850°F. [11] [12] 7FA gas temperatures are in excess of 1100°F (see Table II-1). To reduce the temperature entering the SCR to 850°F, approximately 1,000,000 lb/hr of dilution air (at 59°F) would be required. The total flow entering the SCR would result in approximately 30% increased size of the SCR. Costs would increase due to the larger SCR, dilution fan, dilution ductwork and dampers, and associated controls. The dilution air fan would be about a 2 MW addition to the auxiliary power load. This additional auxiliary power, in addition to reducing unit output, increases the net heat rate by around 150 Btu/kWh.

[10] Refer to Footnote 5 on page 16.

[11] US. Environmental Protection Agency, Air Pollution Control Technology Fact Sheet, EPA-452/F-03-032

[12] GE Power Generation, "Gas Turbine NO_x Emissions Approaching Zero—Is it Worth the Price?" GER4172, September 1999.

Table II-2 — Estimated Maximum Annual Hours of Operation for LM6000, LMS100, Trent 60, and 7FA

			LM6000	LMS100	RR Trent	7FA SC
Syracuse Zone C	SCR		no	yes		no
	Oxidation Catalyst		no	yes		no
	Maximum Hours	(hrs)	2,477	6,143		1,468
	Maximum CF	(%)	28%	70%		17%
Albany Zone F	SCR		yes	yes		no
	Oxidation Catalyst		yes	yes		no
	Maximum Hours	(hrs)	8,760	6,151		1,461
	Maximum CF	(%)	100%	70%		17%
Hudson Valley Zone G	SCR		yes	yes	yes	
	Oxidation Catalyst		yes	yes	no	
	Maximum Hours	(hrs)	4,304	1,546	2,390	
	Maximum CF	(%)	49%	18%	27%	
New York City Zone J	SCR		yes	yes	yes	
	Oxidation Catalyst		yes	yes	no	
	Maximum Hours	(hrs)	4,278	1,532	2,390	
	Maximum CF	(%)	49%	17%	27%	
Long Island Zone K	SCR		yes	yes	yes	
	Oxidation Catalyst		yes	yes	no	
	Maximum Hours	(hrs)	4,275	1,526	2,390	
	Maximum CF	(%)	49%	17%	27%	

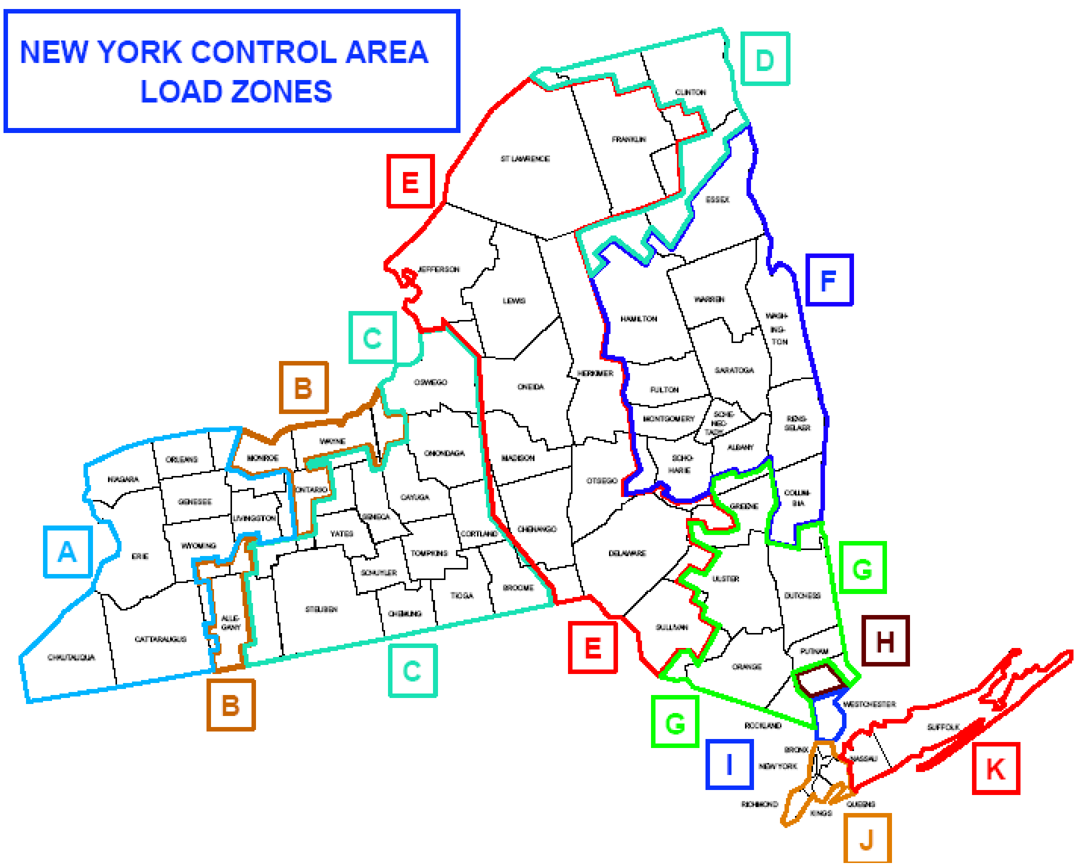
A 7FA without an SCR, sited downstate in Zones G through K, would be severely restricted in operating hours, but could be operated in Zones A through F for as many as 1,468 hours annually. Section III calculations show that the 7FA would operate upstate in zones A through F for a maximum of 1,243 hours annually. Operation of a simple cycle 7FA as a peaker with a 25 Ton Limit on NO_x emissions would result in very low allowed hours of operation. Hence, we considered it impractical to construct a 7FA as a peaker in the Lower Hudson Valley, New York City, and Long Island.

An LMS100 can be operated with an SCR and Oxidation Catalyst upstate with a capacity factor as high as 70%. An LM6000 in Zone C can be operated without an SCR up to a 28% capacity factor; Section III results show that it operates 19% of the hours. An LM6000 in Zone F configured with an SCR and Oxidation Catalyst has no restrictions in operating hours. In the Lower Hudson Valley, New York City, and Long Island, the LM6000, LMS100 or the Trent 60 can be operated as peaking units with appropriate controls. All technologies require an SCR in these zones. The LM6000 and LMS100 are configured with an Oxidation Catalyst (OC) to reduce carbon monoxide (CO) emissions. Emissions Reductions Credits (ERCs) were included in the cost in these three zones to allow for increased operating hours in accordance with economic dispatch. This capacity factor was between 45% and 60% in Zones G and J and between 65% and 75% in Zone K.

D. Construction Schedule and Costs

Cost estimates were prepared for the construction of a new greenfield two-unit simple-cycle combustion turbine peaking plant at each of five New York load zones: C, F, G, J, and K. Figure II-2 shows the location of these zones.

Figure II-2 — Map of New York Control Area Load Zones



These estimates reflect plant features typically found in modern peaking facilities and are intended to reflect representative costs for new plants of their type, in year 2010 dollars. The estimates are conceptual and are not based on preliminary engineering activities for any specific site. The estimates reflect projects awarded on an Engineering, Procurement, and Construction (EPC) basis, with combustion turbines and SCR systems (if included) purchased directly by the owner. The scope includes all site facilities for power generation and distribution, including a 345-kVswitchyard (138-kV switchyard in New York City) and interconnection costs.

1. Principal Assumptions

The key assumptions are discussed below.

a. Technology and SCR Systems

Pursuant to the discussion in the previous section, estimates were prepared using LM6000 and LMS100 technologies with an SCR and Oxidation Catalyst in all zones (except for the LM6000 in Zone C where SCR and Oxidation Catalyst are not needed), using the Trent 60 technology with an SCR in zones G, J and K, and using the 7FA technology without an SCR in Zones C and F. .

b. Site Conditions

In all zones except Zone J, the study is based on greenfield site conditions to incorporate all of the normally expected costs to develop a new entrant peaking plant. Land and water requirements for greenfield conditions are summarized in Table II-5 and Table II-1, respectively. A new entrant peaking unit could be installed at a lower cost at an existing site where already-constructed common facilities may be utilized. Although such brownfield sites exist, the number of these is limited in these zones.

In Zone J, greenfield site conditions are rarely found and brownfield sites are the norm for new generating facilities. For this study, it is assumed that an existing generating or industrial site would be developed, but that no common facilities were available for use. Costs were included to remove existing structures and provide for site remediation of contaminated soils.

c. Number of Units

The cost per kilowatt of new capacity is reduced if multiple units are constructed and share common facility costs. A two-unit site is a reasonable tradeoff between the higher cost of a single unit and the higher incremental addition for a total of three or more units.

d. Inlet Air Cooling

Inlet air evaporative cooling was assumed for all technologies because it increases capacity. Dry cooling was assumed for the intercooler for the LMS100. Inlet air chillers were not included in the configuration due to cost considerations.

e. Dual vs. Single Fuel

The capability to burn natural gas or fuel oil reduces the risk of not having peaking capacity available when needed due to fuel supply interruption, and adds capital cost while lowering operating costs. However, current NYISO rules do not require dual-fuel capability. Gas availability is more likely a problem in the winter when reliability is less an issue. In New York City, Consolidated Edison Service Classification No. 9 appears to require dual fuel capability to qualify for Power Generation Transportation Service[13]. Given that obtaining new firm gas transportation is prohibitively expensive in New York City, a new peaking unit in New York City would realistically have this capability; therefore, dual fuel capability has been assumed for Zone J. Firing only with natural gas was assumed for Long Island (Zone K) and the NYCA.

f. Gas Compression

Fuel gas compressors have been included based on a local supply pressure of 250 psig in New York City and 450 psig elsewhere.

g. Contingency

Contingency is added to cover undefined variables in both scope definition and pricing that are encountered within the original scope parameters. Contingency should always be treated as "spent money." Examples of where it is applied would include nominal adjustments to material quantities in accordance with the final design, items clearly required by the initial design parameters that were overlooked in the original estimate detail, and pricing fluctuations like the run-up in copper prices. A contingency of 10% was applied to the total of direct and indirect project costs, which is consistent with industry custom and practice, is typical for construction projects of this type and is the same level that was used in cost of new entry estimates in PJM, which has been approved by the Federal Energy Regulatory Commission (FERC).

h. Basis for Equipment, Materials, and Labor Costs

All equipment and material costs are based on S&L in-house data, vendor catalogs, or publications. Labor rates have been developed based on union craft rates in 2010.[14] Costs have been added to

[13] Consolidated Edison Company of New York, Inc. (Con Edison), Service Classification No. 9, Transportation Service (TS), Leaf 266.

[14] Base pay and supplemental (fringe) benefits were obtained from the Prevailing Wage Rate Schedules – New York State Department of Labor using the latest available data as of March 2010.

cover FICA, fringe benefits, workmen's compensation, small tools, construction equipment, and contractor site overheads. Work is assumed to be performed on a 50-hour work week by qualified craft labor available in the plant area. Labor rates are based on Onondaga County for Zone C, Albany County for Zone F, Dutchess County for Zone G, New York County for Zone J, and Suffolk County for Zone K. An allowance to attract and keep labor was included. A labor productivity adjustment of 1.40 has been applied to Zone J, 1.35 for Zone K and 1.10 for other zones.[15] Materials costs are based on data for Syracuse in Zone C, Albany in Zones F and G, New York City in Zone J, and Riverhead in Zone K.

i. Miscellaneous

Black start capability has not been included. Pile foundations were assumed for Zone J because most available sites are along the East River. Spread footing foundations were assumed elsewhere. Use of rental trailer-mounted water treating equipment was assumed. Potable water is available from a municipal supply. Wastewater treatment is not included; contaminated wastewater will be collected locally for tanker truck disposal. A control/administration building is included.

2. Capital Investment Costs

Capital investment costs for each peaking unit option include direct costs, owner's costs, financing costs during construction, and working capital and inventories:

- Direct costs are costs typically within the scope of an EPC contract. These costs are estimated in detail in Appendix 1.
- Owner's costs include items not covered by the EPC scope such as development costs, oversight, legal fees, financing fees, startup and testing, and training. On the basis of data extracted from recent independent power projects, these costs have been estimated as 11% of direct capital costs, plus the cost of emission reduction credits (ERCs), less the mortgage recording tax waiver in New York City. In addition, social justice costs were estimated to be 0.9% of EPC costs in New York City for the LM6000 and Trent 60; 0.2% of EPC costs for the LM6000, LMS100 and Trent 60 elsewhere; 0.4% of EPC costs in New York City for the 7FA; and 0.1% of EPC costs for the 7FA elsewhere.

[15] Based on ranges obtained from the 2010 Global Construction Cost Yearbook published by Compass International.

— ERC's were included in the LM6000, LMS100 and Trent 60 owner's costs in Zones G, J, and K to align with operating hours provided in Section III results. This capacity factor was between 45% and 60% in Zones G and J and between 65% and 75% in Zone K.

— Mortgage recording taxes of 2.8% of the debt financing amount are exempt under the Third Amended and Restated Uniform Tax Exemption Policy (UTEP) of the New York City Industrial Development Agency (NYCIDA), as approved on August 3, 2010 by the Agency's Board of Directors.

— Financing costs during construction refer to the cost of debt and equity required over the periods from each construction expenditure date through the plant in-service date. These costs have been calculated from the monthly construction cash flows associated with the capital cost estimates in Appendix 1, and the cost of debt and equity presented in Section IV.B. A 20-month construction period is assumed, with cash flows peaking in the 14th month. Over 70% of the total cash flow occurs in the second half of the construction period.

— Working capital and inventories refer to the initial inventories of fuel, consumables, and spare parts that are normally capitalized. It also includes working capital cash for the payment of monthly operating expenses. On the basis of recent independent power projects, these costs have been estimated as 2% of direct capital costs.

Capital investment costs for each location and combustion turbine option are summarized below in Table II-3. . Capital investment costs also are shown for the following cases, which are provided for information purposes only:

- One unit LMS100 PA in New York City; and
- Two unit Trent 60 located in New Jersey with generator leads into a Zone J substation.

Table II-3 — Capital Investment Costs for Greenfield Site (2010 $)

	Syracuse 2 x LM6000 No SCR	**Syracuse 2 x LMS100 With SCR**	**Syracuse 2 x 7FA No SCR**	**Albany 2 x LM6000 With SCR**	**Albany 2 x LMS100 With SCR**	**Albany 2 x 7FA No SCR**
Direct Costs	115,539,000	220,926,000	259,447,000	134,698,000	222,704,000	261,488,000
Owner's Costs	12,941,000	24,744,000	28,799,000	15,087,000	24,943,000	29,027,000
Financing Costs During Construction	6,437,000	12,308,000	14,441,000	7,504,000	12,407,000	14,555,000
Working Capital and Inventories	2,311,000	4,419,000	5,189,000	2,694,000	4,454,000	5,230,000
Total	137,228,000	262,397,000	307,876,000	159,983,000	264,508,000	310,300,000
Net Degraded ICAP MW	86.2	180.26	376.43	86.13	181.34	378.39
$/kW	$1,592	$1,456	$818	$1,858	$1,459	$820

	Lower Hudson Valley 2 x LM6000 With SCR	**Lower Hudson Valley 2 x LMS100 With SCR**	**Lower Hudson Valley 2 x Trent 60 With SCR**	**NYC 2 x LM6000 With SCR**	**NYC 2 x LMS100 With SCR**	**NYC 2 x Trent 60 With SCR**
Direct Costs	141,913,000	233,942,000	145,933,000	168,211,000	276,318,000	172,468,000
Owner's Costs	15,894,000	26,882,000	16,556,000	17,248,000	29,062,000	17,943,000
Financing Costs During Construction	7,906,000	13,067,000	8,140,000	9,291,000	15,300,000	9,540,000
Working Capital and Inventories	2,838,000	4,679,000	2,919,000	3,364,000	5,526,000	3,449,000
Total	168,551,000	278,574,000	173,548,000	198,114,000	326,206,000	203,400,000
Net Degraded ICAP MW	87.04	183.24	106.68	95.04	180.50	106.68
$/kW	$1,936	$1,520	$1,627	$2,085	$1,807	$1,907

	Long Island 2 x LM6000 With SCR	Long Island 2 x LMS100 With SCR	Long Island 2 x Trent 60 With SCR		NYC 1 x LMS100 With SCR	NYC (in NJ) 2 x Trent 60 With SCR
Direct Costs	158,576,000	259,859,000	163,155,000		162,326,000	222,275,000
Owner's Costs	17,890,000	30,156,000	19,874,000		17,015,000	16,048,000
Financing Costs During Construction	8,841,000	14,530,000	9,170,000		8,895,000	8,518,000
Working Capital and Inventories	3,172,000	5,197,000	3,263,000		3,247,000	3,079,000
Total	188,479,000	309,742,000	195,462,000		191,573,000	249,920,000
Net Degraded ICAP MW	86.94	183.28	106.7		90.25	106.68
$/kW	$2,168	$1,690	$1,832		$2,123	$2,343

E. Other Plant Costs

Other costs associated with each peaking unit option include fixed O&M costs, variable O&M costs, and fuel costs. These costs are estimated in detail in Appendix 1, Table A-2. The basis for these estimates is described in the following subsections.

1. Fixed O&M Costs

Fixed O&M costs include costs directly related to the turbine design (labor, materials, contract services for routine O&M, and administrative and general costs) and other fixed operating costs related to the location (site leasing costs, property taxes, and insurance). Design-related costs were derived from a variety of sources, including the State-of-the-Art Power Plant Combustion Turbine Workstation, v 8.0, developed by the Electric Power Research Institute (EPRI), data for existing plants reported on FERC Form 1, and confidential data from other operating plants. The number of operating staff was estimated based on projected number of operating hours from Section III results. The number of maintenance staff in Zone J was increased by one FTE due to onsite fuel oil storage requirements. The resulting cost assumptions are summarized in Table II-4.

Table II-4 — Fixed O&M Assumptions (2010 $)

	Long Island, NYC	**Long Island, NYC**	**Long Island, NYC**
	LM6000 PG or PH Sprint	LMS100 PA	Trent 60
Average Labor Rate, incl. Benefits ($/hour)	$67.00	$67.00	$67.00
Operating Staff (full-time equivalents)	5	5	5
Maintenance Staff (full-time equivalents)	3 LI 4 NYC	3 LI 4 NYC	3 LI 4 NYC
Routine Materials and Contract Services	$250,000	$320,000	$270,000
Administrative and General	$350,000	$350,000	$350,000

	Lower Hudson Valley	**Syracuse, Albany, Lower Hudson Valley**	**Syracuse, Albany, Lower Hudson Valley**	**Syracuse, Albany**
	Trent 60	LM6000 PH Sprint	LMS100 PA	GE 7FA.05 Simple Cycle
Average Labor Rate, incl. Benefits ($/hour)	$54.00	$54.00	$54.00	$54.00
Operating Staff (full-time equivalents)	5	4.5 Syr, Alb, 5 LHV	4.5 Syr, Alb 5 LHV	4.5
Maintenance Staff (full-time equivalents)	3	3	3	3
Routine Materials and Contract Services	$270,000	$250,000	$320,000	$390,000
Administrative and General	$350,000	$350,000	$350,000	$350,000

Other fixed operating costs are described below and summarized in Table II-5.

a. Site Leasing Costs

Site leasing costs are equal to the annual lease rate ($/acre-year) multiplied by the land requirement in acres. The values used for all zones except Zone J were from the 2007 Demand Curve Reset Study, escalated by inflation. Site leasing costs in Zone J were based on market data.

b. Property Taxes and Insurance

Property taxes are equal to the unadjusted property tax rate for the given jurisdiction, multiplied by an assessment ratio, and multiplied by the market value of the plant. The assessment ratio is the percentage of market value applied in the tax calculation. The property tax rates and assessment ratios for this analysis were selected as typical values currently in effect for jurisdictions in each location, as follows:

NYC: (City of New York website), Class 4 Property (10.426%) x 45% assessment ratio = 4.69% effective rate. Power plant equipment that is not rate regulated by the New York Public Service Commission should be treated as general commercial real property (Class 4).[16]

LI: According to Suffolk County website, each town sets its own property tax rate. The limit on the effective rate is 1.5% in the county, but villages have a 2.0% limit, and towns have no limit. An effective value of 2.00% was chosen as representative for LI.

ROS: From the wide range of values posted for Ulster County (in the Hudson Valley) and Onondaga County (Syracuse area) on their websites, a typical rate and assessment ratio of: 4.0% and 50%, respectively, were chosen for a 2.00% effective rate.

Under the tax exemption policy (UTEP) recently approved by the NYCIDA an exemption from property taxes for the first 12 years is available for new peaking units constructed in New York City. The exemptions delineated are nearly identical to the now expired Industrial and Commercial Incentive Program (ICIP) except for the gradual phase-out of the exemption in years 12 through 15. The UTEP removes the entire exemption after year 12.

[16] In the Matter of Astoria Gas Turbine Power, LLC v. Tax Commission of City of New York, 7 NY3d 451, 857 N.E.2d 510, 824 N.Y.S.2d 189 (2006).

Insurance costs are estimated to be 0.30% of the initial capital investment, escalating each year with inflation, on the basis of actual data for recent independent power projects.

Property taxes and insurance are commonly considered to be part of the carrying charge rate because their value is directly related to the plant capital cost. The carrying charge rates in Section II.F.3 of this report are derived both with and without property taxes and insurance.

Table II-5 — Other Fixed Operating Cost Assumptions (2010 $)

	NYC	Long Island	ROS
Land Requirement - Simple Cycle (acres)	3.5	4.5	4.5
Land Requirement - 2 x LMS100 PA (acres)	6.0	6.0	6.0
Lease Rate ($/acre-year)	240,000	22,000	18,000
Property Tax Rate	10.426%	2.00%	4.00%
Assessment Ratio	45.00%	100.00%	50.00%
Effective Property Tax Rate	4.69% *	2.00%	2.00%
Insurance Rate	0.30%	0.30%	0.30%

* The effective property tax rate excluding the NYCIDA UTEP property tax exemption granted during the first 12 years of operation.

2. Variable O&M Costs

Over the long-term operating life of a peaking facility, the largest component of variable O&M is the allowance for major maintenance expenses. Each major maintenance cycle for a combustion turbine typically includes regular combustor inspections, periodic hot gas path inspections, and one major overhaul. For the aeroderivative units, a major maintenance overhaul every 50,000 factored operating hours was assumed. For the frame units, major overhauls are every 48,000 operating hours or 2,400 factored starts, whichever occurs first. Normal operating hours and normal starts are factored, that is, increased to account for severe operating conditions. For example, operating hours are factored for operation on fuel oil instead of natural gas and starts are factored as a result of trips or emergency starts. For peaking duty, major maintenance intervals thus tend to be hours-based for the aeroderivative units and starts-based for the frame units.

Since major maintenance activities and costs are spaced irregularly over the long-term, the cost in a given year represents an annual accrual for future major maintenance. For hours-based maintenance, the average major maintenance cost in $/MWh is equal to the total cost of parts and labor over a complete major maintenance interval divided by the factored operating hours between overhauls, divided by the unit capacity in megawatts. For starts-based maintenance, the average major maintenance cost in $/factored start is equal to the total cost of parts and labor over a complete major maintenance interval divided by the factored starts between overhauls.

Other variable O&M costs are directly proportional to plant generating output, such as unscheduled maintenance, SCR catalyst and ammonia, Oxidation catalyst, water, and other chemicals and consumables. SCR and Oxidation Catalyst costs were applied to the technologies and locations identified in Section II.C. Variable O&M assumptions for each turbine model and location are summarized in Table II-6.

Table II-6 — Variable O&M Assumptions (2010 $)

	Syracuse	Albany, Lower Hudson Valley, Long Island	NYC	Albany Syracuse
	2 x LM6000 PH Sprint	2 x LM6000 PH Sprint	2 x LM6000 PG Sprint	2 x LMS100 PA
Major Maintenance Interval (Operating Hours)	50,000	50,000	50,000	50,000
Major Maintenance Interval (Factored Starts)	N/A	N/A	N/A	N/A
Cost of Parts Required for Complete Major Maintenance Interval				
- Combustion Turbines (per turbine) *	7,435,000	7,435,000	7,435,000	12,167,000
- Balance of Plant	0	0	0	0
Labor-Hours Required for Complete Major Maintenance Interval *				
- Combustion Turbines (per turbine) *	12,000	12,000	12,000	14,000
- Balance of Plant	0	0	0	0
Unscheduled Maintenance ($/MWh)	0.81	0.81	0.81	0.81
SCR Catalyst and Ammonia ($/MWh)	0.00	1.00	1.00	1.00
CO Oxidation Catalyst ($/MWh)	0.00	0.35	0.35	0.35

	Syracuse	Albany, Lower Hudson Valley, Long Island	NYC	Albany Syracuse
	2 x LM6000 PH Sprint	2 x LM6000 PH Sprint	2 x LM6000 PG Sprint	2 x LMS100 PA
Other Chemicals and Consumables ($/MWh)	0.18	0.18	0.18	0.18
Water ($/MWh)	0.75	0.75	0.70	0.07

- Includes combustion inspections, hot gas path inspections, and major inspection required, on average, for one complete interval.

	Lower Hudson Valley Long Island NYC	Lower Hudson Valley Long Island NYC	Albany Syracuse
	2 x LMS100 PA	2 x Trent 60	2 x 7FA
Major Maintenance Interval (Operating Hours)	50,000	50,000	48,000
Major Maintenance Interval (Factored Starts)	N/A	N/A	2400
Cost of Parts Required for Complete Major Maintenance Interval			
- Combustion Turbines (per turbine) *	12,167,000	8,900,000	20,812,000
- Balance of Plant	0	0	0
-Hours Required for Complete Major Maintenance Interval *			
- Combustion Turbines (per turbine) *	14,000	13,000	15,000
- Balance of Plant	0	0	0
Unscheduled Maintenance ($/MWh)	0.81	0.81	0.55
SCR Catalyst and Ammonia ($/MWh)	1.00	1.00	0.00
CO Oxidation Catalyst ($/MWh)	0.35	0.00	0.00
Other Chemicals and Consumables ($/MWh)	0.18	0.18	0.18
Water ($/MWh)	0.07	0.62	0.14

- Includes combustion inspections, hot gas path inspections, and major inspection required, on average, for one complete interval.

3. Fuel Costs

The fuel costs for each peaking unit option are derived from the delivered price of fuel in each region, the net plant heat rate, and the plant dispatch. Fuel prices are derived on a statistical basis, using the historical correlation between daily New York gas costs by location and load and electricity price, as presented in Section III. The statistical approach is used to capture the effects of extreme conditions in the electricity markets on daily and seasonal gas prices. This approach incorporates fuel prices that are consistent with the hours of the year the peaking unit is actually dispatched.

The fuel price forecasts in Section III account for the transportation cost differences by location. These prices are tied to commodity pricing at delivery points in New York from a major interstate pipeline system that transports natural gas from producing regions along the U.S. Gulf Coast. Local fuel transportation charges were added to the price at the nearest trading point. The applicable local transportation rates include the rate set forth in the following gas distribution company tariff leaves: Con Edison PSC No. 9-Gas (Leaf 277) for New York City, Keyspan PSC No. 1-Gas, Service Classification No. 14 (Leaf 189) for Long Island, Central Hudson Gas & Electric PSC No. 12 – Gas, Service Classification No. 14 (Leaf 196) for Lower Hudson Valley, and Niagara Mohawk PSC No. 219 – Gas, Service Classification No. 14 (Leaf 217) for Albany and Syracuse. In those regions, the total delivered fuel price to an end user for interruptible service is the sum of the following:

- Transco Z6, for NYC and LI, or Texas Eastern Transmission Market Area 3 (TET-M3) for ROS
- System Cost Component
- Marginal Cost Component
- Value Added Charge
- Taxes
- Imbalance Charges

The System Cost Component, Marginal Cost Component, Value Added Charge, and Taxes are all subject to a minimum monthly bill that is based upon a 55% capacity factor for Long Island and a 50% capacity factor for New York City and the ROS. If Imbalance Charges are incurred in the ROS, however, there would be no minimum bill. Conversely, if a minimum bill (at least 50% capacity factor) is incurred in the Rest of State, then Imbalance Charges would not apply.

According to discussions with representatives from Con Edison and National Grid (in respect of its Keyspan New York City tariffs), the Imbalance Charges are minimal in the day-ahead market. Imbalance Charges for the real-time market would be proportional to the degree of imbalances above a 10% threshold. The imbalances are measured by the difference between the customer's nomination schedule for the next day's deliveries and the actual quantity of gas transported. Those same representatives indicated that firm transportation service is not commonly provided because of the prohibitive costs of system reinforcement. Interruptible service gives Con Edison and National Grid (in NYC) the right to curtail gas supply up to 720 hours per year. The risk of gas supply interruption is greatest in the winter months when electric system reliability is less of an issue.

Local fuel transportation charges for each study region are summarized in Table II-7. The tariffs for NYC and Long Island are unchanged from the 2007 Demand Curve Reset Study. The tariffs for the ROS had been estimated from all-in values derived from independent power projects in the region. These have since been revised to match the current published tariffs for National Grid (Niagara Mohawk) and Central Hudson.

Table II-7 — Fuel Transportation Charges (2010 $)

	NYC	Long Island	ROS
Gas Transportation Service ($/mmBtu) *			
System Cost Component	0.100	0.100	0.100
Marginal Cost Component	0.092	0.140	0.170
Value Added Charge	0.005	0.005	—
Taxes	0.007	0.008	—

* The minimum bill must be based on a capacity factor of 55% in Long Island and 50% in NYC and ROS. For a peaking unit, the effective $/mmBtu cost is thus higher than the indicated rates.

The net plant heat rates and startup fuel consumption rates for each peaking unit option are summarized in Appendix 1, Table A-2.

The modeling of the peaking unit dispatch in connection with the derivation of energy and ancillary service revenues, and the associated fuel consumption and costs, are discussed in Section III.

F. Development of Real Levelized Carrying Charges

Capital investment costs are converted to annual capacity charges using annual carrying charge rates. The annual carrying charge rate multiplied by the original capital investment yields the annual carrying charges. Carrying charges typically include all annual costs that are a direct function of the capital investment amount: principal and interest payments on project debt, equity returns, income taxes, property taxes, and insurance. The assumptions used for property taxes were discussed above. Income tax and financing assumptions are presented in the following subsections.

1. Income Tax Assumptions

Income taxes are a significant component of carrying charge rates. A portion of these charges must be grossed up to account for the income taxes due on plant revenues such that the desired return on equity is achieved. Income taxes include the federal corporate tax rate of 35.00%, the New York State corporate tax rate of 7.50%, and the New York City income tax rate of 8.85%. The composite tax rate is the sum of these rates, reduced by the portion that is deductible from taxable income. Income tax assumptions for each region are summarized in Table II-8.

Table II-8 — Income Tax Assumptions

	NYC	**Long Island and ROS**
Federal Tax Rate	35.00%	35.00%
State Tax Rate	7.10%	7.10%
City Tax Rate	8.85%	0.00%
Composite Tax Rate *	45.37%	39.62%

* Federal tax rate + State tax rate + City tax rate – [Federal tax rate x (State tax rate + City tax rate)], to account for the deductibility of state and local taxes from federal taxable income.

2. Financing Assumptions

Financing assumptions for each region are discussed in Section IV.B and summarized in Table II-9. The values are identical for each region except for the after-tax weighted average cost of capital, which is lower in New York City because of the city income tax. The costs of debt and equity are shown on a nominal basis and a real basis. Real rates are derived by removing the inflation component of 2.40%, and are subsequently used to calculate the real weighted average cost of capital (WACC) and the real levelized carrying charge rates.

Table II-9 — Financing Assumptions

	NYC	Long Island and ROS
Equity Fraction	0.50	0.50
Debt Fraction	0.50	0.50
Cost of Equity (nominal)	12.48%	12.48%
Cost of Debt (nominal)	7.25%	7.25%
Cost of Equity (real)	9.84%	9.84%
Cost of Debt (real)	4.74%	4.74%
Weighted Average Cost of Capital *		
Pre-Tax (nominal)	9.87%	9.87%
After-Tax (nominal)	8.43%	8.43%
Pre-Tax (real)	7.29%	7.29%
After-Tax (real)	6.35%	6.35%
Tax Depreciation **	15-year MACRS	15-year MACRS
Inflation Rate	2.40%	2.40%

* (Equity Fraction x Cost of Equity) + (Debt Fraction x Cost of Debt), before tax; and (Equity Fraction x Cost of Equity) + [(Debt Fraction x Cost of Debt) x (1 – Composite Tax Rate)], after tax.

** Federal tax code schedule (Modified Accelerated Cost Recovery System or MACRS) for a simple-cycle combustion turbine, adjusted for residual depreciation if the amortization period is less than 15 years.

Consistent with the 2007 Demand Curve Reset Study, this study uses a methodology that determines a separate amortization period for each region. The difference by region considers the risk of excess capacity, the slope of the Demand Curve, and the slope of the energy and ancillary service net revenue function. This method from the prior Demand Curve reset ties together the risk and the slope of the Demand Curve and provides for an internally consistent consideration of the Demand Curve slope, which affects risk, and the amortization period.

3. Levelized Cost Results

For each case, the annual carrying charges were calculated over the amortization period. Annual carrying charges are equal to the sum of the following components:

— **Principal.** Based upon mortgage style amortization.

— **Interest.** Equal to the cost of debt multiplied by the loan balance for the given year.

— **Target Cash Flow to Equity.** Equal to the initial equity investment multiplied by an annuity factor over the amortization period, using the cost of equity as the annuity rate.

— **Income Taxes.** Calculated by the formula: [t/(1-t)] x [Target Cash Flow to Equity + Principal – Annual Tax Depreciation], where t = Composite Tax Rate. Annual tax depreciation is based on 15-year MACRS depreciation in accordance with the federal tax code for a simple-cycle combustion turbine.

— **Property Taxes.** The effective property tax rate multiplied by the original capital investment amount, escalating year with inflation.

— **Insurance.** The insurance rate multiplied by the original capital investment amount, escalating each year with inflation.

Annual carrying charge rates on a hypothetical $1,000,000 capital investment are derived in Appendix 2, Table B-1. Carrying charges derived on this basis result in the specified target cash flow to equity, as verified by the income statement shown in Table II-10.

Table II-10 — Income Statement

	Carrying Charges
minus	Tax Depreciation
minus	Interest
=	Taxable Income
minus	Taxes
minus	Principal
Add back	Depreciation
=	**Target Cash Flow to Equity**

The levelized carrying charge is equal to the annual carrying charges over the amortization period converted to an annuity using the after-tax WACC. In other words, the annual carrying charges are considered to be "revenue requirements" that are discounted at the after-tax WACC. The real levelized carrying charges are expressed in reference year price levels. Nominal carrying charge rates for future years are equal to the reference year real rate escalated by the inflation rate of 2.40%/year.

The real levelized carrying charge rates as a function of amortization period are summarized in Table II-11. The rates are shown without property taxes and insurance. For reference, the rates in NYC with property taxes and tax abatement under UTEP are shown.

Table II-11 — Real Levelized Carrying Charge Rates

Levelized Carrying Charge Rates – Without Property Taxes and Insurance Unless Indicated:	**Long Island ROS**	**NYC**	**NYC with Property Taxes and UTEP**
10-year amortization	16.89	17.53	17.53
15-year amortization	13.16	13.68	14.31
20-year amortization	11.27	11.69	12.94
25-year amortization	10.20	10.57	12.16

Levelized Carrying Charge Rates – Without Property Taxes and Insurance Unless Indicated:	**Long Island ROS**	**NYC**	**NYC with Property Taxes and UTEP**
30-year amortization	9.54	9.88	11.68
35-year amortization	9.11	9.42	11.36

In addition to the effects of region and property taxes and insurance, the sensitivity of the carrying charge rates over a range of amortization periods (10 to 35 years) and for higher costs of debt and equity (base case, base case + 200 basis points, and base case + 400 basis points) are shown in Appendix 2, Table B-2.

III. Estimating Energy Net Operating Revenues

The next task is to estimate the annual net operating revenues of the hypothetical peaker. The net operating revenues are required by the Services Tariff to be based on "conditions in which the available capacity would equal or slightly exceed the minimum Installed Capacity requirement."[17]

A. Overview of Approach

We have used historical data for zonal Day-Ahead and Real Time LBMP values from November 1, 2006 through October 31, 2009 to benchmark the operation of the NYISO system. We then statistically estimate the effect of various cost drivers, including the installed reserve margin, on the observed zonal LBMP values. This statistical model allows us to conceptually vary any causal variable to create an estimate of price under different conditions with respect to that variable. We start with estimates of prices analyzed under various levels of Installed Capacity including the specified Services Tariff conditions in which Capacity would equal or slightly exceed the minimum Installed Capacity requirement.

We then use these prices to dispatch the hypothetical unit, calculating both Day-Ahead and real-time energy revenues. In so doing we must create a hypothetical operating strategy for this unit and make decisions as to the degree of foresight the unit operator will have in choosing between

[17] Services Tariff §5.14.1.2.

commitments to the Day-Ahead Market versus opportunistic behaviour in the Real-Time Market. In addition, we must be mindful of real operating constraints on the unit with regard to startup cost and start times. These calculations are performed by zone.

We considered and rejected the other prominent competing method for estimating net operating revenues, namely production cost modelling. There are two prominent problems with production cost modelling. The first is that it may not mirror actual price experience, especially at peak loads under tight supply conditions, without undue effort devoted to calibration. Production cost models by their very nature tend to understate actual prices in deregulated markets at such times, since they reflect a system which always behaves optimally, never has to adjust for unexpected contingencies in real time and may not reflect difficult to analyze costs such as the probability of damaging equipment by operating at high loading levels. These adjustments have real costs, and these costs are often substantial. The second problem is that for practical purposes, production cost models must be run at expected conditions and cannot be run as a system actually runs, *i.e.,* with widely varying gas prices, weather and demand conditions and transient transmission irregularities. The effect of these factors not linear, particularly under peak conditions and thus do not average out.

Thus, our approach assumes that the best evidence of what electric prices will be is what electric prices have been. We note that there is no perfect method to generate a forecast. Because the net revenue calculation is a hypothetical abstraction, we strive to model the important parts of the problem, but recognize that there are numerous small effects which are not modelled and which, by the law of large numbers, should roughly cancel one another out. Excessive focus on particular small issues raise the possibility of an unbalanced look at the problem in which the noise generated by the estimation process exceeds the signal generated. Consequently, the generation of net revenue estimates, while scientific, nonetheless calls for the exercise of professional judgment, as does almost any hypothetical modelling.

Looming even larger (at least in this reset) is the question of what should be controlled for and what should not. In particular, commenters in the review process have focused on three issues which will be discussed in more detail below: adjustments for changes in gas prices, adjustments for the “Lake Erie Loop Flow” problem from January-July 2008, and adjustments for low load levels in 2009 caused by recession and mild weather.

Our basic philosophical approach is not to make any adjustments except for reserve margin, *i.e.,* to adjust only for the main thing that the Services Tariff requires. The basic principles which underlie this theory are as follows:

- Large measurable effects may not even out over a three year period, but they will even out over the long run. Unique events which have large impact (positive or negative) on price will go away over time, perhaps being replaced by large effects which go the other way. Hence, limiting adjustments contributes to a measure of stability.

- Such adjustments are complex and call for substantial analytical judgment. For example, how should we adjust for unanticipated changes in load in the historic period due to weather and recession? There are literally hundreds of ways to do so, each of which involves the estimation of some new model of what demand *ought* to have been in the 2006-2009 period and then substituting those new demands for the ones actually observed. These models themselves are likely to be contentious, and their application into the overarching model adds model prediction error to the problem which could well outstrip the supposed error for which it is intended to correct. Adjustment for anomalous periods, like the Lake Erie Loop flow problem, would also be subject to considerable judgment. Simply dropping the period from the analysis, explicitly or implicitly, while leaving in the 2009 period loads which were affected by the recession and mild summer weather would provide for a partial and biased adjustment.

That said, there is at least one adjustment which we feel compelled to make: the historic period contains no adjustment to Real-Time LBMPs for times when Special Case Resources are called. These resources, when called will affect prices significantly, would not be called given the capacity excesses in the historic period. The obligation to reflect the market that will prevail at or slightly above the minimum Installed Capacity level requires that we consider, however imperfectly, the impact of this market change.

By making no other adjustments other than for Installed Capacity levels, however, we are effectively using econometrics to answer the question "what would the peaker unit net revenues have been for the three-year historic period had the system been at capacity levels equal to or slightly in excess of the minimum Installed Capacity requirement?" We do so understanding that the next three years will not precisely mirror the last three. However, each adjustment that could be made, whether it be for gas price, weather, economic conditions or specific operating conditions is of uncertain accuracy and has the possibility of introducing error. As only so many adjustments are feasible, some not made may include those that would counteract those that have been made, thereby introducing bias. We believe not adjusting to attempt to normalize out potential anomalies or more exactly predict conditions for the next three years provides the most objective set of net revenue parameters, reduces estimation errors and should be expected to smooth out so that over time the estimates based on historic data adjusted only for Installed Capacity levels are the best estimates of the net operating revenues that will prevail over the future at or near the minimum Installed Capacity level. Using actual experienced conditions tracks, albeit with a lag, the revenue opportunities that existing generators actually encountered. An entrant can be assured that the net revenues used in setting the Demand Curve will over time reflect events in the market, whether increasing or decreasing net revenues that it will be able to experience, and will not face the uncertainty of judgmental adjustments to "normal conditions" or "forecast conditions". This methodology is precisely the methodology followed in the 2007 Demand Reset process, and we recommend it as the most accurate way, on balance, of applying the Demand Curve Tariff provisions.

B. Data

The hourly Day-Ahead and real-time hourly integrated zonal LBMPs are publicly available at the NYISO website, as are zonal loads. These prices were augmented by daily gas prices taken from Bloomberg (Texas Eastern Transmission M3 price for all but New York City and Long Island, and by Transco Z6 prices for NYC and Long Island) which were then linearly interpolated across non-trading days. Temperatures used were from data supplied by National Oceanic and Atmospheric Administration. Long Island and New York temperatures were taken at JFK airport. ROS temperatures were taken at Albany Airport. The final addition was a series of excess purchases of capacity, by month, supplied by the NYISO in three capacity regions: New York City, Long Island, and the New York Control Area. In the 2007 reset, gas transportation costs were estimated from confidential data supplied by IPP projects. For NYC and LI, these values were very close to the relevant tariffs. For ROS, the values were considerably higher than the tariffs, presumably representing imbalance costs and other charges. We have maintained the gas tariff charges for Zones J and K as in Table A-2, since the vast majority of the usage by the units in Zones j and K is relatively predictable in the day-ahead market, and gas buyers would be expected to manage their supplies in order to minimize intraday and imbalance costs. For New York City, the Transco Z6 prices were raised by 6.9 percent to reflect fuel taxes.

Gas transportation costs in ROS have been somewhat controversial in the stakeholder process. First, we should note that the gas transportation charge employed in the ROS analysis (40.5 cents) is substantially in excess of the tariff price (27 cents). This addition was based on S&L's confidential observations of a number of projects in 2007; however, they have not been updated in the current study. As such, gas transportation costs already include any Real Time adjustment or rebalancing charges actually observed and have been averaged over *all* gas purchases because it was not feasible to attribute the data from S&L's observations to either Real-Time or Day-Ahead purchases. Thus, if any adjustment is to be made for Real Time purchases of gas, the transportation charges must be *lowered* for Day-Ahead gas purchases in order to maintain consistency.

We have received submissions from two stakeholders on the subject of a Real-Time gas adder, one public and the other confidential. Shell provided data outside of New York State for the Transco pipeline (as opposed to the Tetco pipeline which ROS units utilize) which suggest that, on 85 dates over a three year period, real-time gas averaged about 10 percent above than the day-ahead price. We are not convinced that this data is directly usable here. First, the coverage (85 days in approximately 700 trading days) is too sporadic to be reliable. Second, as Shell notes, the actual adders, if any, are highly dependent on the specific topography of the gas network which makes extrapolations from a different pipeline in a different state problematic. Third, it is unclear if the conditions under which Shell asked for such Real-Time quotes which form the substance of their study, are the same conditions under which the proxy ROS peaking units would seek to purchase Real-Time gas. Finally, the effect cited is quite large, and if it were this large could probably be arbitraged by the trading desk of the entrant or marketers with which it interacts, or by the market as a whole.

The second submission was from a ROS generating unit which provided evidence that its unit had Real-Time gas costs which averaged 31.1 cents higher than their Day-Ahead purchases. This data arrived too late (September 1, 2010) to be included in the study in full, but a quick simulation of the results is instructive: we have simulated Energy and Ancillary Services revenues for the Frame 7 Capital unit in which we lower the Day-Ahead transportation charge to 27 cents and increase the Real-Time transportation charge to 58.1 cents reflecting the 31.1 cent differential. At equilibrium, net energy revenues fall by only 30 cents per kW-year. Thus, we kept our initial assumption of 40.5 cents for all gas purchases in ROS. We would recommend, nonetheless, that this issue be studied in more detail with a wider range of data in the next reset process.

C. Statistical Estimation

The fitting of a statistical equation to predict electricity prices is a reasonably straightforward exercise. Electricity price in any hour in any zone is determined by the intersection of offers to supply power and the estimated (if Day Ahead) or actual (if real time) demand for power, adjusted for limitations, if any, of the transmission system to minimize total resource costs. The supply curve of electricity is largely fixed, but moves somewhat from hour-to-hour as transmission conditions change, the availability of units change, and from other transient factors, *e.g.*, temperature. If, as a first approximation, we regard the supply curve is fixed, then varying demand traces out the supply curve. Thus, our estimation strategy is to use load to identify the supply curve while varying the supply curve from hour-to-hour to reflect underlying technical supply differentials. The remainder of unmeasured effects, which are substantial, are left as residuals in the underlying model. Thus,

$\text{Log}(\text{LBMP}_{hz})$= f(NYCA Load, Zonal Load, Attributes of Hour h, Attributes of Zone z, Gas Price, Reserve Margin, Temperature) + ε

We choose to use the logarithm of LBMP rather than raw LBMP (which represents a change from the 2007 update) for several reasons:

- Prices are normally thought of as behaving multiplicatively – external drivers on price are, for the most part, expected to affect those prices in percentage terms rather than absolute terms, and a logarithmic specification reflects this.

- Logarithmic specifications reduce inherent issues in heteroskedasticity in the observed data, in which large errors are far more likely at high prices than at low prices.

- Logarithmic models prevent the estimation of prices below zero. While the LBMP can in theory fall below zero, it did not in the reference period and is unlikely to in the structure of the NYISO market. Even very good regressions in levels have the undesirable (though not for our purposes, fatal) objection that they occasionally predict substantial negative prices. This effect is particularly prevalent when the regression has underpredicted price and the observed absolute residual is applied to a hypothetical variation around that price.

The complete specification is given in Appendix 3. The standard indicia of model fit are quite good. The basic regression model explains about 88 percent of the underlying variation in electric prices[18]. This result implies that given the zone, the hour, the NYCA and zonal load, Gas Price, reserve margin and temperature, we can capture about 88 percent of the variation in electricity price around its mean. The remaining 12 percent of the variation that is unexplained are implicitly accounted for by a combination of variables excluded from the estimation process; these might include levels of outages, transient system conditions, among other qualitative and quantitative factors.

Almost all causal factors work as expected. Thus, for example, price increases as load increases, and increases faster the more load increases[19]. Prices are generally higher on the weekends and in the shoulder months (adjusting for load differences) to reflect outage patterns on deferrable maintenance. Temperature has a slightly anomalous effect, in that one would expect high temperatures to lead to higher prices. Instead, there is a moderately small effect in which higher minimum temperatures lead to lower prices, while the maximum temperature effect is small and insignificant. Finally, and most important, prices fall as reserve margins rise: at the margin, a one percentage point rise in excess margin yields a one percent decrease in price.

Levitan and Associates (LAI) provided comments in the stakeholder review process which suggest that the econometric methodology used is inappropriate and inaccurate. We have considered LAI's

[18] The equivalent figure for the similarly structured 2007 model was 83 percent.

[19] This result follows from the strongly positive effects on the cube of load.

points, and have implemented one of them – a unified regression for all regions. For those points which focus on functional form, however, we are in substantial disagreement and we believe that the modern econometric literature supports our position[20]. Further, the experimentation we have done with respect to functional form suggests that the OLS technique we have employed yields results squarely in the midst of the various methods that LAI has suggested.

The notion that one must "correct" for heteroskedasticity, autocorrelation or correlation across panels in the estimates, while once generally accepted, is no longer the prevalent view. The current view as expressed in current textbooks is as follows:

> In recent years, it has become more popular to estimate models by OLS but to correct the standard errors for fairly arbitrary forms of serial correlation (and heteroskedasticity). Even though we know OLS is inefficient, there are some good reasons for taking this approach. First, the explanatory variables may not be strictly exogenous. In this case, FGLS is not even consistent, let alone efficient. Second, in most applications of FGLS, the errors are assumed to follow an AR(1) model. It may be better to compute the standard errors for the OLS estimates that are robust to more general forms of serial correlation. (Wooldridge, J.M.: Introductory Econometrics: A Modern Approach, 2009, p. 428.)

The success using OLS, which is a consistent estimator of the true effects under the minimal number of assumptions is stressed by Angrist and Pischke in the lead article in the Spring Journal of Economic Perspectives:

> Others writing at about the same time often seemed distracted by concerns related to functional form and generalized least squares. Today's applied economists have the benefit of a less dogmatic understanding of regression analysis. Specifically, an emerging grasp of the sense in which regression and two-stage least squares produce average effects even when the underlying relationship is heterogeneous and/or nonlinear has made functional form concerns less central. The linear models that constitute the workhorse of contemporary empirical practice usually turn out to be remarkably robust, a feature many applied researchers have long sensed and that econometric theory now does a better job of explaining. Robust standard errors, automated clustering, and larger samples have also taken the steam out of issues like heteroskedasticity and serial correlation. A legacy of White's (1980a) paper on robust standard errors, one of the most highly cited from the period, is the near death of generalized least squares in cross-sectional applied work. In the interests of replicability, and to reduce the scope for errors, modern applied researchers often

[20] The issue concerns whether it is better to use Ordinary Least Squares (OLS) and correct for errors explicitly or use Generalized Least Squares (GLS) without a correction. Current academic literature supports the former approach.

> prefer simpler estimators though they might be giving up asymptotic efficiency. (Angrist and Pischke, *Journal of Economic Perspectives, Vol 24, No.2, Spring 2010)*

Finally, while LAI cites their results from an FGLS run (not correcting for autocorrelation which lowers the reserve margin coefficient from 1 to approximately 0.24, they do not cite the result that, when autocorrelation corrections are made using FGLS, the coefficient rises to between 1.4 and 1.7. It is the supposed “corrections” to OLS which induce instability, not the OLS estimates themselves. There is little question that electric prices are strongly autocorrelated, although the effects of that autocorrelation dwindle to insignificance within a few hours, making it unclear why such an effect should radically affect estimates of the effect of reserve margin on prices. Since there is no reason to believe that AR(1) is the actual autocorrelation of electricity prices, we follow the general prescription that when OLS and “corrected” estimates differ, it is the correction that is suspect

We have implemented the more current methodologies for calculating standard errors. Beyond being substantially more time-consuming, they amply verify that the standard errors for the reserve margin variable are very small, as would be expected in a data set this size. That said, we should be mindful that, by themselves, these small standard errors are in fact contingent on the model being correct. While we believe that we have a good model which well represents to the best of our ability a host of important factors, we cannot argue that the result is robust to specification, only to econometric methodology.

Finally, the New York Transmission Owners, New York Power Authority, and Long Island Power Authority (“TOs”) argued that the reserve margin variable may in fact vary with peak, offpeak or load level. We have carried out tests of this proposition and in fact find that the coefficients are virtually unchanged across the day or by load level.

D. Price Estimates

The Services Tariff requires conditions at or slightly above minimum Installed Capacity requirement. In the period observed, capacity offered was substantially in excess of the requirement. Thus, to estimate what prices would have been at the required Services Tariff conditions, we can recalculate prices using the statistical equation to calculate the change in prices attributable to a shrinking (or growth) of the observed reserve margin holding all other factors constant. We should note in particular that holding all other factors constant necessitates holding the unmeasured factors constant as well. Thus, we do not set the error terms (which reflect the unmeasured factors) to their average level of zero, but allow them to take whatever value they actually took in the data. This approach is important as peaker net operating revenues could be understated if we were to smooth prices out by not reflecting the variability that gives rise to the error terms.

Gas prices average around $8/MMBTU over the study period, which is somewhat above currently-observed forward prices for natural gas over the forecast period, though there were certainly periods in the historic period considerably higher than currently forecast. This data also can have important implications for the peaking unit's net revenues, as discussed below.

Having produced estimates of Day-Ahead prices, we make equivalent estimates of real-time prices. We do this by adding the change in Day-Ahead prices to the observed Real- Time integrated LBMP. The obvious alternative, proportional changes in the real-time price is problematic, as it causes enormous changes in the real-time which are probably not justifiable; for example, if the Day-Ahead price were $45 and the predicted change were to $60, we would add $15 to the real-time price; in a period in which, for some reason, the observed real-time price were $300, $315 is a much more reasonable estimate of the effect of new LBMP than $400. Even worse effects which are trivial at very small Day-Ahead prices would enormously inflate any real-time prices which happened to spike in those hours. This follows the assumption that substantial divergences between real-time and Day-Ahead price are probably due to system conditions, *e.g.* thunderstorm activity, which is largely unrelated to the level of Day-Ahead prices at the time.

One additional adjustment is made to real-time prices to reflect a program not operating in the historic period which will operate in the forecast period: a Special Case Resource adjustment to the Real-Time LBMP. We adjust Real-Time LBMPs upward by an amount which reflects the mean expected adjustment in the 500 highest load hours in each zone. These hours are adjusted upward by the difference between the estimated LBMP and $500 (if the LBMP is not already above $500.) This difference is then discounted by the probability that this hour is Special Case Resource adjusted hour, which is an exponential function of reserve margin, calibrated so that at the Installed Capacity requirement, 110 hours are called out of the top 500 hours. The 110 hour estimate is based on the 2009 New York State Reliability Council Installed Reserve Margin study and reflects over 2500 MW of Special Case Resources. While we recognize that Special Case Resource calls would be expected to increase and more revenue expected to be shifted to the energy market as Special Case Resource penetration increases, those increases will materialize over time and be recognized over time. LAI has criticized this adjustment as being poorly calibrated. There is indeed a paucity of evidence to precisely characterize this effect. As the program is actually implemented, the effects will eventually emerge. Our methodology, however, which credits all of the top 500 hours with a probabilistic share is quite conservative for the Frame 7 units upstate, since this adder does little to overcome the fixed costs of starting the unit. It is not surprising, therefore, that this adjustment raises Energy and Ancillary Services revenues by less than $1 per kW-yr. For Zones J and K, units which receive most of the revenues in the Day-Ahead Market, the effect is even smaller in magnitude and *de minimis* as a fraction of revenues.

E. Hypothetical Dispatch

We have assumed that the peaking unit is bid into the Day-Ahead Market at a price which reflects the observed daily gas price, estimated variable O&M, and Regional Greenhouse Gas Initiative and NOx emission costs calibrated to the most recent auction. If taken, the unit runs in those hours and earns operating net revenue equal to the difference between price and cost. We separately count starts and reduce net operating revenues by a startup gas cost.

LAI has suggested a substantially more complicated hypothetical dispatch which adjusts for heat rate curves as presented above. We have considered these adjustments, but believe, just as for gas price adjustments themselves, the additional “accuracy” induced is likely spurious. The effects are small, and a truly accurate assessment of the values would require far more data than we possess on the interpolation of temperature and the addition of humidity and other atmospheric conditions. We believe that the methodology employed yields an averaged value which further refinement would not justify in terms of effort or accuracy.

In line with the engineering assumptions, we have assumed that the overhaul maintenance costs are captured in a variable O&M value, which implies that the maintenance is largely hours of operation, not starts. This assumption is not appropriate for the Frame 7 unit in ROS which runs at a capacity factor far more consistent with a dollars-per-start criterion. We have used $15,289 per start to reflect the various possibilities for these units. In the Day-Ahead Market, any block of operating hours which fail to earn back this startup cost earn zero net revenues, reflecting either a rejection of the unit in that block of hours for Day-Ahead operation, or inclusion with a production cost guarantee to bring the unit to zero net revenues.

In the hours in which the unit is not dispatched in the Day-Ahead Market, it considers operation in the Real-Time Market. Hours accepted in the Day-Ahead Market are not available to accept a real-time price. We then calculate for other hours whether a profit could be earned on the real-time price, using daily gas prices just as in the day-ahead calculations.

We next adjust for startup time. If the unit was operating day-ahead in the previous hour, we allow it to continue running without an incremental start if the operating profit from the real-time price is positive, and allow it to continue running as long as the real-time profit is positive. If, however, the unit was not running in the first hour of positive net revenues, we allow it to continue running for contiguous blocks of profitable operation, but subtract startup fuel costs and reduce the expected net revenue in the first hour by 50 percent in New York City and Long Island to reflect a 30 minute startup time. If the total value of the contiguous block is positive, we include those hourly net revenues.

This logic is not appropriate for the Frame 7 units owing to their high startup costs and the methods of guaranteed commitment at the NYISO. We have modified the commitment logic to reflect these factors. For blocks which abut a Day-Ahead commitment period, there is no change. For blocks which consist entirely of real-time hours, however, the block does not start until the entirety of startup costs is recouped in an hour.

Finally, we have included adjustments for Ancillary Services revenues for reserves and Voltage Support. The NYISO supplied us with average Ancillary Service revenues over the last several years. We have added these values in. They total about $3.50/kW-yr. in NYC and about one third of that in the ROS.

F. Results

The results, excluding Ancillary Services revenues, are summarized in the Excel model, on the tab labelled "Energy Curve Raw". Presented are the unit type and region, the margin above or below the Capacity requirement, and aggregate net revenues, which can be broken down into real time and net Day-Ahead revenues, where startup costs are netted out of gross net revenues. The value for "tprofit" is the annual net energy operating revenue estimated per MW per year assuming constant annual capability. The adjustments further made to these values are as follows: 1) the values are multiplied by the average of the summer and winter capability over the ICAP capability to adjust for the fact that all costs are stated per kW of ICAP and the unit will participate in energy markets at higher levels; 2) the energy profits which are from 2006 to 2009 are adjusted for three years of assumed inflation; 3) profits are reduced by the Equivalent Demand Forced Outage Rate (EFORd); and, 4) the Ancillary Services revenues are added to the energy profits.

G. Other Considerations: Lake Erie Loop Flow and Recession/Weather Effects on Load and Other Miscellaneous Potential Adjustments

1. Overview of Other Considerations

In this section we discuss several suggested adjustments raised during the stakeholder process. We determined that these adjustments are inappropriate, as an unadjusted quantification is superior to an adjusted quantification for the reasons discussed above. Nonetheless, in this section we discuss the specific proposed adjustments as they were raised during the stakeholder process and, although contrary to our recommendation that adjustments not be made to normalize or forecast, alternate views on that fundamental issue may be reasonably held.

2. Lake Erie Loop Flow Reversal

Some stakeholders have argued that the extraordinary conditions in the first half of 2008 resulting from scheduling patterns which caused Lake Erie loop flow to reverse ought to be adjusted for. The rationale is that the event was so extraordinary it will never be repeated. While that event may never be repeated, we hesitate to adjust even if we were inclined to make an adjustment. First, there is no obvious way to adjust. Second, extraordinary though the effects were, it is unclear that they were the cause of any material rise in compensation to peaking units in ROS.

a. How to Adjust

The NYISO report on the Lake Erie Loop Flow and accompanying report from its market monitor give no insight as to how to adjust prices for this phenomenon. The reports discuss changes in uplift, not LBMPs. The Lake Erie loop flow reversal apparently affected mostly real-time prices in the early part of period, and Day-Ahead prices in the latter part of the period, with no clear line of demarcation. Hence, there is no obvious adjustment.

b. Would Adjustment be Significant?

While it is true that May - July 2008 is the only May - July period with significant Day-Ahead revenues, the average Day-Ahead net revenues, even including this assumedly anomalous period, is only $1/kW-yr. It is certainly plausible that revenues this high in the Day-Ahead Market could possibly be this high absent the anomaly.

In the Real-Time Market, outcomes also are not clear cut. March and April 2008 had lower real-time expected net revenues than did the corresponding months in 2007, while January, February and May 2008 were larger than the corresponding months in 2007. While this data suggests that scheduling problems might have affected the markets, it is far from conclusive proof that other “anomalies” might not await in the future. Moreover, existing capacity cannot be prejudiced by not normalizing for this event as it was there to experience the event. New capacity will not be discouraged by not normalizing as it will be confident that events in the future, even ones in the opposite price-effect direction, will not be normalized, but that the Demand Curve will reflect actual market conditions as they evolve over time.

3. Future Gas Prices

Gas prices in the historic period average $8.00/MMBTU. This level is considerably above the average gas prices observed in the currently observed futures data, which suggests average prices in the next three years of approximately $6.70/MMBTU. Some stakeholders have argued that we should adjust for this effect by using forward gas prices in the regression to simulate future price conditions in the market. They expressed this desire with an intuition that lower gas prices would lower profits.

We have experimented with implementing the requested change in gas prices and the results are just the reverse, at least for the Frame 7 units upstate. For the LMS100 units in New York City and Long Island, there is very little difference.

First it should be noted that adjusting prices hour-by-hour is not an uncontroversial process by itself. The obvious alternative is to simply substitute expected November 2010 gas prices for November 2006 prices, December 2010 gas prices for December 2006, and so forth. The problem here is that it actually matters. Looking at the futures, the highest expected future prices are three years out, while the lowest historic prices are in 2009. Thus, direct substitution creates a mix of changes in which 2009 gas prices are raised quite a bit while 2006 and 2007 prices fall substantially. This alternative method creates changes in LBMPs which increase in some periods and fall in others. For peaking units which are highly sensitive to high gas prices, the effects are mixed.

Second, there is no measure of intramonth price volatility. The most sensible adjustment is to simply replicate the observed proportional pricing relative to the mean. This adjustment has the effect, however, of halving the standard deviation of gas prices and there is no obvious solution to this problem.

Third, the regression estimates demonstrate quite conclusively that the elasticity of LBMP changes with respect to gas price changes is clearly lower than one, so that a ten percent reduction in gas price yields much less than a ten percent reduction in LBMP. Thus, in high-priced hours in which peakers were earning profits before, reduction in gas prices increases profits substantially.

Fourth, while the regression results with respect to gas prices are quite sensible generally, the regression makes an odd prediction for November. For whatever reason, November LBMPs on average do not respond to gas prices at all; and in the early morning hours higher gas prices lead to lower LBMPs: the (insignificant) results are actually negative. This problem is fairly easy to adjust for -- by constraining the November changes to zero -- but represents yet another adjustment.

Adjusting LBMPs for changes in gas prices appears to be a mistake. What the experiment does demonstrate, however, is that the host of decisions which must be made to make *any* such adjustment ought to be approached with extreme caution, and fully justifies our decision in 2007 and revisited and applied again here, to make no adjustments other than adjustments to the observed reserve margin and the change to adjust for Special Case Resources which cannot be observed at excess reserve levels in the historic data.

4. Recession/Cool Weather Adjustments

Some stakeholders also have argued for adjusting loads to reflect milder than expected summers in 2008 and 2009 and to adjust loads for the recession of 2009.

While it is clearly possible to imagine modelling which would elicit these effects, we firmly believe that such adjustments cannot be implemented objectively enough to introduce additional clarity to the estimates. That said, we do believe that if we are going to make some adjustments, we probably should make all the adjustments we are capable of making, and it is certainly feasible to substitute higher loads, with concomitantly higher prices and profits into the equation, possibly by adjusting every hour's load upward by an amount representing some estimated shortfall from a long-term trendline.

We choose not to do so for exactly the same reasons we choose not to make any of the other adjustments we have discussed here.

5. Summary with Respect to Lake Erie Loop Flow, Gas Price and Recession/Cool Weather Adjustments

While we recommend that none of these adjustments be made, we do note that, if made, the adjustments would go in both directions. It is unlikely that the net effect would be material and there would be considerable uncertainty with respect to the accuracy of such adjustments.

6. New York City Adjustments

In the 2007 reset, several market participants raised the issue that the larger size of the LMS100 vis-à-vis the LM6000 makes it more likely that it will collapse prices in New York City load pockets if such a plant is built in a load pocket, and that these load pockets substantially contribute to the high level of prices in NYC. We have revisited this assumption in this report and have realized that the effect has essentially been double-counted. The Demand Model spreadsheet already reflects the fact that larger units tend to reduce prices more than smaller ones through the standard deviation effect. Thus, we have removed this adjustment in the simulation of Energy and Ancillary Services revenues directly.

We have assumed that the units in NYC are dual-fuelled. We have once again ignored that distinction in our net revenue modelling. Fuel switching is an example of the phenomenon cited above in which more detail will not necessarily make the estimate more precise, but instead will likely simply raise the noise level of the estimate. First, we have no idea how often generators will in fact be restricted from using gas; even if we knew, the results may be site-specific. Second, the shift to oil physically necessitates shutdown on conversion back to gas in order to clean the generating unit. Against this, there is a benefit from economic switching to oil should prices of oil fall sufficiently relative to gas prices. While in concept all of these (and other effects) might be measured, we have no confidence that our measurement of them would illuminate the ultimate question: what is the net energy revenue of a peaking unit in New York City? Errors in any part of these calculations are far more likely to introduce error than they are to improve the expected value of the estimate.

Table III-1. Variables in the Regression Model

lbmp	Zonal LBMP in $/MWh

Independent Variables:

_cons	Indicator variable =1
dow	Indicator variable for day of week, 1=Monday, etc.
zone	Indicator variable for zone, 1=Capital, 2=Central, 3=Dunwood, 4=Genesee, 5=Hudson Valley, 6= Long Island, 7=Mohawk Valley, 8=Millwood, 9=NYC, 10=North, 11=West
tmin	Daily minimum temperature in degrees Fahrenheit
tmax	Daily maximum temperature in degrees Fahrenheit
load	Hourly zonal load for the hour in MW
aggload	Aggregate hourly NYISO load in MW
aggload2	$aggload^2$ divided by 10^8
aggload3	$aggload^3$ divided by 10^{12}
region	Indicator variable for region, 0=Rest of State, 1=NYC, 2=Long Island
h	Indicator variable for hour: 1=Midnight-1 am, 2=1 am-2am, etc.
m	Indicator variable for month: 1= January, etc.
lgasp	Natural logarithm of gasp price plus gas transportation cost in log $/MMBTU
rm	Supplied reserves divided by required reserves, measured monthly

H. Calibration

While there is no direct calibration available for the results, there are some comparisons we can make to test the reasonableness. First, the results are broadly similar to the results reported by the Market Monitoring Unit in its 2009 State of the Market Report (issued in 2010). The second is a comparison to PJM. PJM uses a three year historical period and actual prices. PJM measures over $ 40 per kW-year in energy and ancillary service net revenues for a Frame 7 with an SCR and higher heat rate than that used in this study. While it is true that PJM's method makes no effort to dispatch considering risks of startup cost recovery, the result would indicate that the estimate we have developed is certainly in the zone of reasonableness. Third, the NYISO has had tight capacity years in the past; one such year was 2002. We have taken actual 2002 LBMPs and daily gas prices and determined the resulting net energy revenue for the 7FA unit. In this case, the Frame 7 Capital unit would have earned over $23/kW-yr in the Day-Ahead Market alone. When a reasonable allowance is added for real time net revenue, it further indicates that our total Day-Ahead and real time net operating revenue of $ 25 per kW year is in the zone of reasonableness. In short, actual

NYISO experience in a period with a relatively tight capacity market confirms that the Frame 7 net energy revenue estimate we make is reasonable.

IV. Developing the Demand Curves and Calculating Carrying Charges

A. Approach Overview

The Demand Curve Model is designed to find the annual CONE at the reference point that will provide for the full recovery of capital costs over a thirty-year capital recovery period, using the financial assumptions of a 50%/50% capital structure and 7.25%/12.48% debt/equity cost. The CONE consists of two items. First, an implied annual capital cost that will provide for the full recovery described above, recognizing that there will be a tendency to clear at capacity values above the reference value and at prices below the reference value, as well as a tendency in the long term to earn energy revenues consistent with a degree of excess capacity. And second, an energy offset based on energy revenues over the three-year reset period, assuming capacity levels at one-half of one percent above the minimum or target[21] capacity level.

The model allows for a wide array of scenarios by incorporating numerous variables that can be changed to accommodate different market conditions, target levels of capacity and Demand Curve shapes (intercept and kink). In addition, various regions (*e.g.*, New York City, Capital) and two types of generator units (LMS100 or Frame 7) can be simulated. This flexibility allows the user to compare the effect of a variable over multiple scenarios.

The model includes results for the Lower Hudson Valley. The Lower Hudson Valley is not a capacity zone and hence we have not incorporated results for the Lower Hudson Valley in this report. Were the Lower Hudson valley a capacity zone, the demand curve would be higher than the NYCA demand curve and lower than the New York City demand curve. Results for the Lower Hudson Valley are available in the model provided to all market participants. Results for the LMS100 in the Lower Hudson Valley and the Frame 7 in the Capital Region with inter-zonal deliverability impacts added are similar.

The model reports the CONE at the reference point, the implied annual capital cost, the carrying charge and the implied amortization period. The zero crossing point affects all these values. A

[21] We use the terms minimum and target interchangeably when referring to installed capacity or installed reserve levels.

lower zero crossing point (i.e., closer to 100%) produces a shorter amortization period and higher carrying charge, as demand revenues go down faster for a given level of excess capacity.

Many of the inputs to the Demand Curve Model requirements are based on judgment. The inputs used will be described below. As a result of the judgmental nature of the inputs, it is important to note that in selecting inputs, we are guided also by the result produced. The results produced using the current shape and slope of the Demand Curve show implied amortization periods of just over 19 years in ROS, and just over 15 years in NYC and just over 15 years in LI. These results reflect measurable, but not extreme implied merchant risks. Were the zero crossing points closer to the origin, the amortization periods would decrease, raising the reference point to reflect added merchant risk.

B. Financial Parameters

The development of financial parameters, the capital structure and costs of capital was an issue that received significant attention at the stakeholder meetings and that remains an area on which there is not a consensus. The review with stakeholders started at the April 22, 2010 ICAP Working Group meeting, where NERA proposed using a weighted average cost of capital (WACC) of 9.50% for merchant generators to establish the Demand Curve. This WACC was based on an assumed corporate capital structure for a generation company consisting of 50% debt and 50% equity with a 7.0% cost of debt and a 12.0% cost of equity.

The cost of debt was based upon a range of 6.50%[22] to 7.25%[23], which reflected the average yield on long-term BBB and BB corporate bonds of 6.28% and 7.04%, respectively, as of April 15, 2010, adjusted upward slightly to reflect the likelihood that a merchant generator would be at the lower end of either ratings level.

The cost of equity was based upon a range of 10.33% to 13.26% derived using the capital asset pricing model (CAPM). The low end of this range was based upon a risk-free rate of 3.86% (10-year US treasury yield as of April 15, 2010) and an equity beta of 1.0 (equal to the beta used in the

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[22] Federal Reserve Statistical Release. Selected Interest Rates (daily); Release Date April 16, 2010. Available at http://www.federalreserve.gov/releases/h15/update/.

[23] Factset, Barclays BB index US corporate bond yield (April 15, 2010).

2007 demand curve). The high end of the range was based upon a risk-free rate of 4.72% (30-year US treasury yield) and an estimated equity beta of 1.32 for a generation company with 50% debt leverage. A market risk premium of 6.47% was used in each of the CAPM calculations[24].

The 1.32 equity beta used for the high end of the range was based on the equity betas reported in the Value Line Investment Survey for AES, NRG, and RRI[25]. The Value Line beta for each of these companies was converted to an equity beta by adjusting to remove the effects of the actual financial leverage employed by each company. The average asset beta was then re-levered assuming a 50% debt ratio to determine the estimated equity beta consistent with the BBB credit rating assumption. The stakeholders have raised a number of issues concerning specific assumptions used in NERA's initial (April 22, 2010) proposal.

US Power Generating Company, NRG Energy (NRG), and TC Ravenswood (the "Responding Generators") contend that the cost of capital should be based upon a B credit rating to reflect the assumed rating for a stand-alone project, significant upfront fees should be included in the cost of debt, debt amortization should be sufficient to leave only $150-$200/kW of debt outstanding after a 7-year debt maturity, and the implied cost of equity after risk adjustments should be in the range of 16-18%.

The TOs state that the cost of capital should be based on a corporate capital structure that most likely will be used rather than a stand-alone project financing, the cost of debt should reflect a combination of bonds and lower-cost bank debt, and the equity beta should be no greater than the 1.0 used in the 2007 demand curve.

Competitive Power Ventures (CPV) believes that it is appropriate to assume a merchant business model, but asserts that many of NERA's assumptions may not be reflective of the actual capital structure and costs that would be required of a new merchant peaking resource seeking project financing in today's markets. CPV asserts that NERA's assumptions are reasonable for a project with a long-term power sales agreement, but are not realistic for a resource operating under a pure

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[24] Ibbotson Associates Stocks, Bonds, Bills and Inflation 2008 Yearbook. (Long Horizon Equity Risk Premium from 1926 to 2008).

[25] The Value Line Investment Survey, Ratings and Reports, April 2, 2010.

merchant model or even a shorter-term hedge (e.g., 5 years). CPV indicates that the credit and risk profile of a pure merchant project would result in significantly lower leverage potential, higher debt interest rates, and higher equity return requirements than are currently modeled. CPV argues that NERA's assumptions should be revised to better approximate the current costs of financing a stand-alone project based solely on the strength of project revenues. Based on the feedback from the stakeholders, there were four major issues raised concerning our initial proposal. The issues, our analysis of the issues, and the approach we used in the Model are as follows:

Corporate versus project financing – We agree with the TOs that a merchant generator project would likely be financed on balance sheet as part of a larger corporate entity, rather than as a stand-alone project entity. It is unlikely in the current capital market that this type of merchant project could be financed as a stand-alone project. As a result, we believe the best starting point for determining financing assumptions is to consider the capital structure and cost of capital for the publicly traded, unregulated generation companies with assets that are most similar to the demand curve unit project (*i.e.,* The AES Corporation (AES), NRG, RRI Energy (RRI), Calpine (CPN), and Mirant (MIR)). We also believe it is important to recognize, as the Responding Generators point out, that a stand-alone peaking plant is likely to involve greater business risk than the average of the assets owned by these generation companies. These business risks include development and construction risk (as compared with these generating companies, which have large portfolios of operating assets), the duty cycle of the plant (peaking unit versus portfolios of baseload, intermediate, and peaking assets), and the plant's pure market exposure (versus at least partial hedging of the power at most of the generation companies). While it is difficult to precisely determine the appropriate adjustments to recognize these risks, we recommend adopting a slightly lower debt ratio, slightly higher cost of debt, and slightly higher cost of equity than the observed values for the generation companies in order to establish the financial parameters for the peaking project that underlies the demand curve. We believe that it would not be reasonable to base the financial parameters on the narrow assumption of how a single project could be financed in isolation of a larger generation company. It is reasonable, however, to base the parameters on how a generation company could finance the project, allowing for a modicum of risk that may be unique to the peaker project. Hence, we use a merchant approach but not a stand-alone project approach. Note that we use as comparables companies that are predominantly in the electric generation business but are not affiliated with transmission and distribution companies. There are also a number of corporate developers of merchant generation that are part of entities that also have regulated transmission and distribution businesses. We do not use the generation companies that are affiliated with transmission and distribution companies as comparables because the financial parameters associated with their generation businesses cannot be observed separately in the market.

Below we provide the key financial parameters for the five publicly-traded generation companies listed above. Three of these companies have Standard & Poor's Financial Services, LLC (S&P) senior secured ratings of BB or BB+ (AES, NRG, and RRI), while the other two are very similar (CPN is B+ and MIR has a LT issuer rating of B+, equivalent to a senior secured rating of BB). We believe it is reasonable to focus on senior secured ratings since the project could be used as collateral in a bond financing. (see the Generation Company Ratings and Asset Betas table at the end of this section). These companies have an average debt ratio of 63% (excluding AES, which has a 74% debt ratio but is comprised of significant transmission and distribution utility and long-term contract assets). These debt ratios are based on market value capital structure ratios (market value of equity and, as a simplifying assumption, book value of debt). The average market value debt ratio is somewhat higher than the average debt ratio on a book value basis. The market value capital structure ratios are appropriate to use since we are attempting to estimate the market-required cost of capital. We believe it is reasonable to assume that these generation companies with approximately BB ratings could finance a peaking plant on-balance sheet using 50% debt without impacting their credit ratings. Consistent with this assumption, we recommend using a debt cost of 7.25%. This cost is based on the Barclays Capital index yield for BB US corporate debt of 7.04% as of April 15, 2010, adjusted upward slightly to reflect the higher risk associated with the project.

We have reviewed the terms of the recent $1.3 billion term loan financing obtained by Calpine to finance its acquisition of 4,490 MW of generation assets from Pepco. This transaction is a relevant comparable because the assets are at least partially dependent on revenues from the capacity market. These assets face no construction risk, but construction risk is not likely a major differentiating factor since the construction risk associated with a peaking project is lower than for many other types of generating assets. The Calpine financing is a 7-year term loan priced at LIBOR plus 550bp with a 150bp LIBOR floor. While this pricing may appear high for a 7-year term, we note that the debt appears to fund over 78% of the purchase price. Given this high leverage, we do not believe this information suggests a higher cost of debt than we assumed for the peaking unit.

The Calpine financing also includes a debt amortization schedule that will reduce debt to approximately $160/kW at its maturity. Since we are assuming in the demand curve that the financing is accomplished through an upstream corporate entity (that is, rather than on a project basis) and is long-term, we do not believe it is necessary to adjust the amortization to achieve a target debt per kW amount at the end of a hypothetical interim debt maturity. Instead, our assumptions result in full debt amortization over the assumed life of the asset. It is worth noting, however, that the Calpine financing would leave the debt ratio at about 44% at maturity, or only modestly lower than our proposed 50% initial debt ratio assumption. We recognize that our amortization assumption would likely not be feasible with a bank loan or to finance a stand-alone merchant project. However, we do not believe that merchant implies project finance. Instead, we believe that the least cost financing option is likely to be the addition of the peaking unit to an existing merchant portfolio, albeit with a recognition of a somewhat higher cost of capital to compensate for the incremental risks.

The TOs note that merchant generation companies typically use a combination of bank and bond financing and argue that our proposal to use only bond yields overstates the cost of debt. However, we would point out that bank financing typically has a much shorter maturity than bond financing, so including a component of bank financing would require that we also assume that up-front fees are incurred at regular intervals (*e.g.*, every 5 years or so) during the life of the project. Bank financing would also involve interest rate risk during the term of the assumed loan unless we add the cost of an interest rate swap. Finally, bank financing would require an assumption about the level of interest rates at each refinancing. Since current short-term interest rates are well below the long-term average, it would be reasonable to assume higher rates for future refinancing of bank loans. Taking these considerations into account, we believe the all-in cost differential, if any, between bank and bond financing over the life of the project is likely to be much smaller than the difference between the initial annual interest costs of the two sources of financing might suggest. Since the long-term cost of bond financing can be more easily quantified using published data, we recommend using the BB index bond yield as the basis for the cost of debt.

The TOs exclude RRI from their estimate of beta because, in their view, its high equity beta skews the sample. We do not believe RRI should be excluded merely because it has a high beta. Including RRI, the companies in our sample have an average asset beta of 0.48. However, AES is the least relevant comparable since it has significant regulated transmission and distribution utility businesses and long-term contract assets that likely contribute to a lower asset beta than a merchant generation business. Excluding AES, the average asset beta would be 0.52 for the group of companies with primarily merchant generation business with diverse portfolios and some hedged output (see the Generation Company Ratings and Asset Betas table at the end of this section). To check this result, we also looked at a sample of other companies that own both regulated transmission and distribution companies and merchant generation assets. The average asset beta for these companies is 0.46, which suggests that an asset beta in excess of 0.50 for a company primarily in the merchant generation business appears reasonable. Since it is reasonable to assume that the demand curve project would have a riskier business profile than the average of the merchant generation companies on the Generation Company Ratings table, we propose using an asset beta of 0.60 for the project. Adjusting this asset beta for 50% debt leverage (market value basis) results in an equity beta of 1.20, and a cost of equity of 12.48%.

Assuming a corporate financing structure and a credit rating of BB, we use a 50% debt ratio, 7.25% cost of debt, 12.48% cost of equity and a resulting WACC of 9.87% as the financing assumptions for the generation project underlying the Demand Curve.

We have elected to continue to base bond yields on data from April 15, 2010. This date in retrospect seems to be a time of relative calm in capital markets. While an update could be performed easily, it would reflect the potentially transient reaction to the euro and debt crisis in Greece. Additionally, there would be moves in different directions. Risk free interest rates have fallen, which would lower equity costs, while credit spreads have widened, which would raise the cost of debt. Additionally, the financing cost assumptions must be consistent with the assumed inflation rate. As we discuss below in this report, we use a consensus inflation rate forecast of 2.4%. Current 10 year United States Treasury yields are 2.6%. We believe it would be unrealistic to use an implied long term real interest rate of 0.2%.

The components of the WACC calculation are detailed below:

Debt/Capital	50%
Debt Cost	7.25%
Asset Beta	0.60
Equity Beta	1.20
Equity Risk Premium	6.47%
Risk-Free Rate (30 yr)	4.72%
Cost of Equity	12.48%
WACC	9.87%
Tax Rate (illustrative)	40.0%
Pretax WACC	14.03%

We believe that several areas still are the subject of disagreements. First, the Responding Generators view their cost of equity as considerably higher than 12.5%. However, it is important to note that had we assumed the project could be financed using 63% debt (equal to the average of the sample generation companies excluding AES), the cost of equity would have been 15.21% due to the greater financial leverage. The cost of equity is very sensitive to the level of leverage. So while they may be correct that they face much higher costs of equity, we believe that leverage explains the difference. If we assumed 63% debt leverage and a 15.21 % equity costs, the pre-tax WACC (which is the value that is reflected in revenue requirements) would have been 13.95% in that case due to the lower equity component and smaller allowance for taxes. Hence to the extent that the Responding Generators concerns over the cost of equity are based on actual leverage for these companies, adjusting for the leverage and raising the costs of equity to 15.21% would in fact lower not raise carrying charges. Second, the Responding Generators remain dissatisfied with the degree to which individual merchant project risk is reflected in the financing assumptions. The TOs are also dissatisfied from the opposite perspective, suggesting that when using CAPM, all non diversifiable risk is accounted for through the observed beta. While our recommended approach relies heavily on CAPM and represents non diversifiable risks through betas, we do believe that is reasonable to allow for the peaking unit potentially adding some additional risk to the portfolio of the merchant generators that we observe. We have adjusted for this incremental risk by shading the asset beta to 0.6 and using the higher end of the range of BB debt costs.

Generation Company Ratings and Asset Betas

Company	S&P LT Issuer Rating	S&P Sr. Sec. Rating	Capital structure ($MM) Equity Mkt Cap	ST Debt	LT Debt	Total Debt	Debt/Cap	Equity Beta	Asset Beta
Generation Companies									
AES	BB-	BB+	7,353	2,336	18,306	20,642	74%	1.20	0.32
NRG	BB-	BB+	5,474	152	7,846	7,998	59%	1.15	0.47
RRI	B+	BB	1,304	401	1,950	2,351	64%	1.65	0.59
CPN	B	B+	5,266	305	9,239	9,544	64%	1.11	0.39
MIR	B+	n/a	1,563	26	2,538	2,564	62%	1.63	0.62
Average							65%		0.48
Average ex AES							63%		0.52
Hybrid Utilities/Generation Companies									
AYE	BBB-		3,900	167	4,398	4,565	54%	0.95	0.44
CEG	BBB-		7,060	78	4,220	4,298	38%	0.80	0.50
D	A-		24,670	1,549	15,364	16,913	41%	0.70	0.42
EXC	BBB		28,931	1,712	11,198	12,910	31%	0.85	0.59
FE	BBB-		11,916	2,669	11,847	14,516	55%	0.80	0.36
PPL	BBB		10,472	589	7,652	8,241	44%	0.70	0.39
PEG	BBB		14,936	267	7,906	8,173	35%	0.80	0.52
Average							43%		0.46

Notes:

a) Ratings from standardandpoors.com (retrieved June 1, 2010)

b) Equity market capitalization and debt from Bloomberg.com as of March 31, 2010

c) Equity betas from Value Line (April 2, 2010 and May 28, 2010), except for CPN and MIR which are from Yahoo Finance (not covered by Value Line)

d) Assumes debt beta = 0

C. Model Description

The Demand Curve Model works by simulating revenues and expenditures given a set of input parameters, energy functions, the region and the type of unit. The revenues are cash flows that the owner of a new unit would expect to receive over the thirty-year economic life of the unit. Similarly, the expenditures represent expenses and the required return on equity and debt. The Model solves for the Demand Curve by finding capacity payments (also referred to as demand payments in the model) that satisfy the zero supernormal profit criteria (revenues equal expenditures). Supernormal net revenues are those above the normal cost of equity capital.

A new generating unit can expect to receive revenues from two main sources. Energy and ancillary service net revenues represent sales in the NYISO energy and Ancillary Service markets. These net revenues are modeled using a Monte Carlo analysis. The model uses the user-defined expected value and standard deviation of supply to generate 100 possible values for capacity. These capacity values are put through an energy and ancillary service net revenue function. The function is region- and unit-specific and calculates expected energy and ancillary services net revenue given a level of supply. The revenues will be lower when there is surplus capacity and higher when there is not enough capacity. The model is designed to simulate this scenario and to adjust the Demand Curve so that, given an expectation of surplus capacity, the new entrant will be able to fully recover costs over thirty years.

Demand payments approximate payments the owner of a new unit could expect to make through NYISO ICAP auctions. Like the energy and ancillary service payments, they are determined through a Monte Carlo analysis. User-defined parameters are used to determine possible values for supply in the auction from which an expected capacity value payment is derived. Since these payments are simulated by the Demand Curve, which is also an output of the Model, the demand payments are endogenous to the Model. For this update we have added to the model a Summer Capability Period and Winter Capability Period demand simulator. We compute Summer and Winter demand revenues using the NYISO formula to adjust the annual Demand at Reference to a Demand Curve Monthly value. We then simulate forecast demand revenues against this curve clearing at Summer and Winter capacity values.

Expenditures are fixed O&M, property tax and insurance, and levelized fixed charges (carrying charge). Fixed O&M and property tax and insurance are defined by input parameters and the cost of new entry. The carrying charge is calculated by Sargent & Lundy assuming a 50% debt share cost of capital at 7.25% and a 50% equity share at 12.48%.

From these revenues and expenditures, a Demand Curve is derived such that revenues equal expenditures (binding constraint). As the Demand Curve in part determines demand payments, which is one of the sources of revenue, the model solves for both using a goal seek.

Once the model solves for the Demand Curve, it calculates net revenues as percentage of the cost of new entry. The model then looks up the amortization period that matches this percentage in the table of levelized fixed charges. The real levelized carrying charge is determined using this amortization period.[26]

While the approach is complex, we believe the complexity is necessary. Although a new peaking unit will likely physically last thirty years or more, investors will use a shorter time horizon in determining the levelized cost. PJM uses a single assumption of 20 years in setting CONE. A single assumption is not suitable for the NYISO as the NYISO is commonly acknowledged by stakeholders to have a bias toward excess and that bias presents different risk depending upon the shape and slope of the Demand Curve. Hence, we believe that a model that considers the interaction between the Demand Curve shape and slope and the amortization period is required.

D. Model Inputs

The model's thirty plus variables can be broken down into the following categories:

Demand curve variables determine the x-axis intercept of the curve and can also be used to kink the Demand Curve.

As described later, we believe that it is appropriate to continue using the existing shape and zero crossing point and use 112% for NYCA and 118% for NYC and LI.

[26] As will be described below, the model has been expanded to allow the user to input a vector of property taxes. When used in this mode, the model can produce the correct value for the demand at reference, but does not have the information to report the amortization rate correctly.

Technological progress variables can be used to determine how the cost of new entry increases or decreases over time.

The DOE forecasts roughly a minimum learning effect by 2015 for combustion turbines of 5%. This minimum per year improvement equates to an annual value of 0.325%. We round to 0.25% to allow for non technical factors that may go in the other direction. While we model technical progress as smooth, experience shows that this may not be the case. For example, the LMS 100 produced a Demand Curve that was approximately one third below that which would have been produced by the LM6000 in the prior reset. This would be annual technical progress of roughly 10% per year. As we have no way to forecast such discrete changes, we use a smoother forecast based on information from a neutral party, the United States Department of Energy.

Plant variables determine the location, type and performance of the generating unit and are used to select the appropriate cost of new entry from those provided by Sargent & Lundy.

Residual value is the value of the unit at the end of the thirty-year life. For aeroderivatives, we use a residual value of 5% of the initial investment. We use no residual value for the less efficient Frame units.

Monte Carlo variables used to calculate expected values for Capacity payments and Energy and Ancillary Service revenue. These values are the average percent excess and the standard deviation of that excess. We develop these values by first multiplying the ICAP of the peaking unit by 1.5 and then dividing that value by the minimum capacity requirement for the region. This results in Capacity of 570 MW for ROS and 270 for NYC and LI. After dividing by the locational minimum Capacity and rounding to a number in 0.5% increments, we determine a ROS average excess of 1.5%, a NYC average excess of 3.0% and a LI average excess of 6.0%. The excess percentages are rounded from the division of 1.5 times the peaking unit size divided by the rounded minimum requirement for late 2009 and early 2010 of 36,000 MW for ROS, 8575 MW for NYC and 4700 MW for LI. We set the standard deviation at half these levels to reflect the assumption that there will be only a 2.5 percent probability the market will actually be short. The new element of this method is that we tie the excess percentage assumption to the size of the peaking unit addition. The excess percent variable is intended to model the bias toward excess associated with strong reliability signals that would prevent the market from going short on capacity. As noted above, not all RTOs have this bias. PJM has no special procedures to ensure that its RPM auctions provide for capacity above the target capacity, although PJM does set its RPM Demand Curve so that CONE is at a value 1% above the target capacity level – a value in PJM's market roughly 1,500 MW over the required capacity level. New York has strong preference for ensuring capacity adequacy and has measures in place to make sure the market is not short. We believe that it is reasonable to tie the excess to the proxy peaking unit as it is the proxy peaking unit that would represent the efficient addition to maintain reliability. We believe it is reasonable to use 1.5 times the peaking unit as the average level of excess given the conservatism attendant to ensuring that the market has at least the minimum amount of capacity. We also note that actual capacity excesses shown in the table below are much greater than the average level we assume. This modeling assumption is appropriate as we are not attempting to hold the entrant harmless from excess capacity that results because load growth slows, developers enter the market even with an excess or technologies other than the peaker are the lowest net cost. The NYISO tendency to not allow the market to go short is the only factor we adjust for.

Summer Average
Monthly Excess Percent

	2003	2004	2005	2006	2007	2008	2009	Avg	stddv
NYCA	6.56%	9.63%	9.60%	6.92%	6.85%	8.45%	8.08%	8.01%	1.29%
NYC	0.00%	2.54%	3.50%	2.91%	3.10%	10.50%	8.54%	4.44%	3.69%
LI	8.70%	3.50%	3.72%	8.52%	8.63%	13.76%	12.27%	8.44%	3.87%

Winter Average
Monthly Excess Percent

	2003	2004	2005	2006	2007	2008	2009	Avg	Stddv
NYCA	7.50%	9.45%	11.17%	9.73%	8.92%	9.33%	10.94%	9.58%	1.24%
NYC	6.84%	7.34%	8.88%	10.33%	11.15%	15.21%	17.62%	11.05%	4.03%
LI	1.82%	4.72%	7.48%	8.86%	13.07%	14.98%	19.71%	10.09%	6.20%

As can be seen from the above, NYCA (ROS) has on average been 8.75% excess. The excess parameter in the model is 1.5% with a 0.75% standard deviation. The excess adjustment is clearly not designed to compensate for actual excesses, but only for excesses that will occur near the minimum installed capacity requirement.

Regulatory Risks – the Demand Curve is an administered value subject to regulatory risk. We assume no percent probability that the Demand Curve will yield only 50% of the required revenue.

Regulatory risks include items such as regulated rate-supported long-term contracts that may be added even when there are surpluses or to create surpluses. While regulatory risks are certainly plausible and we allow for them in the model, the NYISO Board did not believe in 2007 that such risks should be accounted for in the Demand Curve. The NERA study is independent of the Board's determination, and is not bound by that position. However, the Demand Curve has now been in place for seven years and does not appear to have artificially suppressed by arbitrary intervention. Hence, we believe it is reasonable in this reset to not add an adjustment for such risk,

Energy function variables can be used to change the shape of the energy function and can also be used to change the way energy and ancillary service net revenues in the first three years are calculated.

The energy net revenue functions are described in Section III. In developing the recommendation, we use an energy and ancillary service net revenue offset at 100.5% of the target installed capacity level. Essentially, we assume energy net revenues at this level for the first three years. As noted above, we have adjusted for ancillary service net revenues for voltage support by adding $1.18 per KW year. For NYC and LI we add $3.66 per KW year and $1.71 per KW year to reflect slightly higher voltage support payments as well as 10 minute non spinning and for 30 minute reserves.

Property taxes for NYC may be used with or without tax abatement. The effect is very significant. We model the without tax abatement scenario using the policy recently adopted by the New York City Economic Development Corporation (EDC) which indicates an intent to provide 11 years of zero property tax, and full property tax at year 12. This scenario and the no abatement scenario use the current effective rate of 4.69% of plant value. The EDC policy statement appears to indicate an inclination to provide the above-described abatement to the peaking unit that will be used in the Demand Curve reset, but does not provide the right to an abatement. Hence we provide results with and without the abatement.

Deliverability – the technology-specific estimates developed by S&L all include system upgrade costs. These costs do not, however, include deliverability including the inter-zonal deliverability associated with crossing the UPNY/SENY interface. In order to participate in the capacity market a unit must be deliverable to all zones in the Capacity Region as defined in NYISO Services Tariff Attachment S (Zone J, Zone K and all Zones other than J and K collectively as a single region).

Currently new units north and west of UPNY/SENY could not deliver to Zones G to I and hence could not participate in the capacity market for ROS without obtaining deliverability. The NYISO has determined that the cost of deliverability is an investment of $178 per kW. This is roughly 20% of the non-deliverability investment in a Frame 7 in the Capital region. The model has been constructed to add deliverability as a separate line item and we report NYCA results both with and without deliverability. We have been advised by NYISO that the decision on how deliverability will be reflected in the reset Demand Curves is under consideration by NYISO. Note that we assume deliverability costs to be financed by the peaking unit owner and recovered over the life of the peaking unit. The cost impact of deliverability would be lower if these costs were financed by a regulated transmission owner and recovered over a longer, say 40 year, period.

E. Analysis of Results

The complexity of the model we use is required to tie together the shape and slope of the Demand Curve and to produce a reference value consistent with the risk implied by such shape and slope. The Demand Curves are implemented to solve the binary nature (i.e., clearing at the highest allowed price or at a zero price) of market results obtained from a vertical Demand Curve. The risks of investing with a vertical Demand Curve are extreme and difficult to quantify. While judgment is required in developing assumptions to the model that ties together the shape and slope of the Demand Curve to the amortization period, the results can be analyzed for reasonableness. The implied amortization period for ROS using a real levelized carrying charge that escalates at 2.4% per year is 19.5 years. The implied amortization period is 15.5 years for NYC and LI. We note that the FERC approved PJM Demand Curves that use a nominal levelized carrying charge based on an amortization period of 20 years. That translates to a real levelized carrying charge at 2.4% inflation using an amortization period of between 15 and 16 years. Hence, the results are certainly within the reasonable range. The results are also at the point where the amortization life is beginning to have a diminished impact. For reference, the ROS carrying charge at 10 years is 19.19%. The function begins to flatten at 15 years where the value is 15.46%, but is sharply sloped prior to that point and more gradually sloped after that point, much like a mortgage. At 20 years the carrying charge is 13.57% and it declines to 11.84% at 30 years and 11.41% at 35 years. Were the investment financed by a regulated entity, customers would likely pay the 35 year amortized value of 11.84% of the investment each and every year without regard to excess capacity levels or changes in technology that may erode the economics of the investment. Under the Demand Curve scheme customers pay based on a somewhat higher value, for ROS about 2% more per year of the investment, but do not pay the full amount if there is excess capacity at any time or if there is a technology change that results in a lower cost peaking unit. The price paid for shifting the risk from customers to suppliers seems reasonable relative to the risk that they are protected from. While some may argue that supplier risk should have an even greater impact on the amortization period and carrying charge than we allow, there are several factors that argue against this. First, there is a benefit to maintaining continuity. As the Demand Curve becomes more established and parameters are not arbitrarily or opportunistically changed, risk perceptions should decrease. An implied capital cost based on an amortization period of 19 years in ROS is consistent with relatively low risk. The somewhat lower amortization periods in NYC and LI are appropriate given the greater risk of smaller markets. Hence, assuming market risks are reasonably modeled the resulting amortization periods are an indication that the price result is reasonable and the system is producing a reasonable risk/price balance. Additionally, the Demand Curve must be sustainable. While the Demand Curve could be established based on a higher degree of risk and require prices that implied shorter amortization periods such as those associated with 10-year amortization, such prices would probably be unsustainable in equilibrium. For example, at a very steep slope, the amortization period would drop as low as 10 years. We see little value in developing a Demand Curve that is not reasonably sustainable. The entire package of results from this reset including the reference price levels, the shape and slope and the implied amortization levels all form a package that is sustainable and should induce entry that provides for capacity adequacy. In summary, the results judged from the implied amortization periods are reasonable for several reasons. First, the increase in cost over that associated with a cost-of-service regulated situation where customers pay 100% of all prudent costs without regard to excess capacity or unit economics is modest. Second, the implied amortization periods are all at the point where the carrying charge curve begins to flatten out. We do not see ten year amortization periods and 19% carrying charges. Third, the amortization periods are in line and, adjusting for the real versus nominal levelization differences, longer than those approved by the FERC for PJM.

There have been stakeholder comments that the results for Long Island have not been scrutinized to the extent that the results for other areas have been. While we have applied the same methodology to Long Island, we do acknowledge that estimation of net energy revenue for Long Island is more difficult. As Long Island has had very substantial capacity excesses over the past three years, we are unable to observe near equilibrium conditions and are required to extrapolate significantly. Hence, while the estimates for Long Island are the best we can make given the data and use an identical methodology to the other regions, the reliability of those results may well be lower, though there is no reason the results are biased in either direction.

F. Demand Curve Shape and Slope Recommendations

The Demand Curves that are recommended for each technology and region have been presented in the Executive Summary. We have not recommended changing the Demand Curve zero crossing points or slopes. We use the term slope to refer to the zero crossing point.

The method that we use to develop the demand curve produces curves that contain a consistent slope and reference point that are expected to yield the same present value of revenue to generators as any other consistent combination given the tendency toward not letting the market go short. Hence, if we increase the zero crossing point we would reduce the reference point and vice versa. These consistent combinations also yield the same expected value of payments to generators. Hence, alternate zero crossing points would all have the same price impact. As the zero crossing point is moved in towards the origin, the reference price will rise and as the zero crossing point is pushed away from the origin, the reference price will decline. With neither buyer cost nor generator revenue a deciding factor, the basis for slope selection is narrowed.

One criterion for slope selection in the past has been market power. As NYISO has made considerable progress in mitigating market power in NYC and monitoring capacity bids in other areas, we do not believe that market power is any longer a driving rationale for slope and shape determination.

We do remain concerned, however, that moving the zero crossing point towards the origin increases the importance of having accurate information on the average excess level and standard deviation. With a steep slope, if there is an understatement of the average level of excess and standard deviation, the demand curve will be under-compensatory and sufficient capacity may not develop. Similarly if there is an overstatement of the average level of excess, a steep slope will exaggerate the required increase in demand at reference. Steeper slopes increase risk and uncertainty for both the buyer and seller. Steeper slopes can also be counterproductive if a little excess in additions or a decline in growth leads to clearing at prices well below the reference point. At such prices, retaining existing plants may be difficult as the economics of mothballing and retirement could become attractive for older marginal plants. To the extent that such scenarios occur, any decrease in payments that would arise from a steeper slope may well be offset by retirements or mothballing. The same applies to Special Case Resources: in 2009 there were over 2500 MW of Special Case Resources. Capacity excess levels in 2009 were on average in excess of 9, 13 and 14 percent in ROS, NYC and LI, respectively. Changes in the slope and shape which reduce the capacity price at these excess levels would be expected to lower Special Case Resource participation.

Most importantly we look at the rationale underlying the Demand Curve construct. The Demand Curve is designed to induce new capacity when required by supplementing the shortfall in the energy market and providing a reasonably predictable stream of revenue to new generators based on the entry costs of a new peaking unit. The payment is set exactly to that level at the target capacity level and to a linearly higher level at lower capacity values and a linearly lower value at higher capacity levels. As the value of capacity on either side of the target is not linear but exponential, the Demand Curve was clearly not constructed to approximate the value of capacity, but to reduce the volatility of capacity payments and to provide a framework for encouraging investment. Although it may be possible to change the slope and still provide proper investment signals, it would also need to be recognized that steeper slopes increase risk and entry costs. The slopes in the current Demand Curves are reasonable as they result in implied amortization periods just over 19, 15 and 15 years in NYCA, NYC and LI, respectively, resulting in sustainable market system. Note that despite the more gradual slope in NYC and LI, the risk evidenced by the implied amortization period is actually greater due the size of the respective markets. We hesitate to recommend slopes that yield shorter implied amortization periods. Much like a mortgage payment, the annual cost begins to flatten out at 15 years and by 20 years is in a gradual trajectory toward its lowest point. Hence, slopes that yield amortization periods of 15 to 20 years are as steep as is advisable if the point to develop a reasonable cost of entry and a sustainable market system. We noted above that PJM uses a single assumption of a 20 year amortization period. Hence, we conclude that the current slopes should not be increased by moving the zero crossing point toward the origin. Further, even if the amortization periods were indicating implied amortization periods that equaled or exceeded 30 years and indicated room to adjust the slope, we would not recommend such an adjustment at this time. As we show above excess capacity levels for 2009 are already near the zero crossing point. We would expect that similar levels would apply in the reset period. Adjusting the curve to steepen the slope when it is almost certain to depress revenues would appear opportunistic and would likely undermine confidence in the objectivity of the capacity market. Any significant adjustment to the slope is best done at a time when the immediate impact will be relatively neutral so that it is clear that the adjustment is being made to improve the market not to reach a desired outcome. In summary, we recommend against any adjustments to the slope of the Demand Curve as the implied amortization periods produced by the current slopes are reasonable, and would, even if the desirability of an adjustment was observed, recommend deferring it until such time as the impact would be relatively neutral.

The same applies to the shape of the curve. While a kink could be placed in the curve beyond the point where the model recognizes excess and the amortization period unaffected, a kink in the curve which would reduce capacity payments beyond the kink point would clearly be expected to significantly lower capacity revenues during the reset period. This is the case because the average 2009 ROS excess of 9% would likely be well beyond any kink that has a zero crossing point at 12%, the average NYC and LI excesses of 13% and 16%, respectively, would be beyond any kink that has a zero crossing point of 18%. A kink would be nearly certain to lower capacity payments. As past investment was induced without such a kink we view this as opportunistic and likely to add significantly to investment risk. We recommend that the implementation of a kink be considered when the near term impact would be neutral. Further, we are concerned over the stability of the price signals particularly for Special Case Resources. The impact of a kinked Demand Curve, which could result in sharp changes in capacity clearing prices around the kinked point could result in a non stable price environment and discourage these resources. While the kink feature remains in the model, we recommend that it be used with caution as the way in which NYISO translate an annual net costs to the Demand Curve reference point with a kink is not known.

We do recognize that in NYC and Long Island the 18% crossing point does mean that at a 9% excess capacity level, customers pay half the net annual cost of a new peaking unit through the Demand Curves. Even at a 12% excess capacity level, customers pay one-third of the net annual cost of a new peaking unit through the Demand Curve. At these excess levels, from a reliability perspective, there is almost no value to Capacity. Hence, there are valid arguments that a steeper Demand Curve slope would lower customer costs and provide stronger signals for older units to retire for fewer MW of new supply entry, and would better align what customers pay for Capacity with the marginal value of Capacity. On the other hand we also recognize that the gradual slope was intended to eliminate the problems of the vertical Demand Curve and ensure a degree of revenue stability. A kinked Demand Curve that maintains the gradual slope for levels of excess capacity up to, by way of example only, 8%, would serve the purpose of revenue stability and also align customer payments in time of large excesses with the marginal value of Capacity, while providing for better price signals for retirement and demand response program participation. Additionally, as the Demand Curves are based on the net costs of a new peaking unit and not the net cost of a the lowest net cost entrant, and as it appears that the lowest net cost entrant is not a peaking unit, but is a combined cycle unit, a steeper or kinked Demand Curve would reduce the incentive for excess entry by combined cycle units. While there are attractive features of a kinked Demand Curve, weighing all factors is complex, especially when the dynamic effects are difficult to predict. Reducing expected Capacity payments at larger excess levels by steepening the slope after a kink point may appear to reduce customer payments but could have the opposite effect if it reduces entry by new combined cycle units, which would in turn lower energy costs and environmental exposure, and also result in retirements of existing units and lower participation in demand response programs. Hence, it is not clear that a kinked curve would reduce customer payments for energy and Capacity combined. When we consider the uncertainty of the dynamic impacts with the fact that we believe that a change in the slope when there are large excesses would lead to an increased perception of regulatory risk, we do not recommend a change at this time. However, as noted above the kinked Demand Curve does appear to provide a way to achieve both revenue stability and to better reflect the marginal value of Capacity at higher excess levels. We recommend that analysis of the shape and slope issue, and consideration thereof, begin before the initiation of the next Demand Curve reset process. That earlier timing would provide an opportunity to consider the dynamic effects including customer total energy and Capacity payments, and an opportunity if appropriate, to implement the change if approved in the reset process. For example, beginning that analysis five years from the next Demand Curve determination would provide an opportunity so that the result would be knowable with relative certainty at the time of the decision and the decision could be made on its long term merits.

V. Sensitivity Analyses

Numerous sensitivity analyses were conducted using the Demand Curve and carrying charge model in order to identify variables that would have a significant impact on results. Further, the model is available to stakeholders to conduct sensitivities. Two related variables and one interacting variable dominate the assumption sensitivities. Those variables are the standard deviation of capacity relative to the installed capacity level and the average Installed Capacity level relative to the required level. Relatively small changes in those variables have a significant impact on results. For all other variables, except slope, impacts are moderate.

For example, the ROS demand at the reference point with deliverability is $121.98/kW-year using a 0.75% standard deviation and 101.5% average capacity level and the amortization period is 19.5 years. If we use a standard deviation of 1.5% and an average capacity level of 103% the price rises to $145.52 and the amortization period changes to 14.5 years. If we use a 100.5% average capacity level and standard deviation of 0.25%, the price drops to $109.48 and the amortization period increases to 24.5 years. While we have selected variables for these values that are both plausible and consistent with the NYISO's Reliability Needs Assessment process and that produce results that introduce a reasonable but not excessive degree of merchant risk, we do not claim that they are the only plausible values for these variables. We are guided in the selection of these variables by the results that they produce and as discussed above believe an implied amortization period of just over 20 years for ROS is sustainable. We then use the Demand Curve Model to produce results that are consistent with and responsive to other assumptions – for example, the Demand Curve zero crossing point and technical progress assumption.

We have tested all key assumptions. We provide here examples for NYCA. Moving the NYCA zero crossing point to 108% from 112% would increase the reference value by $15.59/kW-year assuming deliverability and reduce the amortization period by 4 years. Increasing the technical progress rate to 0.5% would increase this reference point by $3.38/kW-year. In sum, most input variables or assumptions have a moderate impact. The primary exceptions are the average capacity levels and the slope of the Demand Curve.

As we have provided the model to the stakeholders to enable them to conduct their own sensitivities, we do not summarize all the sensitivities herein.

VI. Appendices

A. Appendix 1 – Construction Cost and Unit Operating Cost Details

Appendix 1 provides more detailed information about the capital and operating costs and performance characteristics of the peaking technologies evaluated in this study.

Table A-1, Figures A-1 through A-9, and Table A-2 provide information on the capacity and heat rates for the LMS100, 7FA, and LM6000 PG and PH Sprint, and Trent 60 as a function of elevation, temperature, and humidity. Figures A-1 through A-9 show capacity and heat rate at 60% relative humidity and mean sea level. Table A-2 provides capacity and heat rate information by technology and by location in tabular form. It also shows data for outage rates, start fuel, annual fixed O&M cost, annual site leasing, property taxes and insurance costs, and variable O&M costs.

Tables A-3 through A-6 provide capital cost estimates for each technology by location. Cost breakdown is provided for both EPC and non-EPC costs. The definition of most cost categories is self-evident. Owner's Project Management and Miscellaneous Engineering refers to the cost of preliminary engineering, owner's engineer during construction, and general oversight. Owner's Development Costs refer to the owner's internal costs for all development activities from the initial feasibility studies through start-up. Financing Fees are sometimes built into the interest rate, but here are explicitly broken out.

Tables A-7 through A-9 provide a comparison of LM6000 and 7FA capital cost estimates for this study with the published cost estimates of the previous Demand Curve Resets (DCR) in 2007 and 2004. Cost categories from this study and the 2007 DCR have been aligned with the 2004 study report as best as possible. Table A-10 compares capital cost estimates from this study and the 2007 DCR for the LMS100 in New York City.

Tables A-11 through A-13 provide a breakdown of EPC costs for the LMS100 in New York City and Long Island and for the 7FA in Albany. The EPC Project Cost shown in Tables A-11 through A-13 correspond to the Subtotal – EPC Costs for the same estimate in Tables A-3 for the LMS100 and Table A-4 for the 7FA.

Table A-1 — Site Assumptions for Capacity and Heat Rate Calculations

Load Zone	Weather Basis	Elev. (Feet)	Season	Ambient Temp. °F	Relative Humidity
C - Central	Syracuse	421	Summer	79.7	67.7
			Winter	17.3	73.7
			Spring-Fall	59.0	60.0
			ICAP	90.0	70.0
F - Capital	Albany	275	Summer	80.7	67.2
			Winter	15.3	70.7
			Spring-Fall	59.0	60.0
			ICAP	90.0	70.0
G - Hudson Valley	Poughkeepsie	165	Summer	82.3	77.7
			Winter	19.3	74.0
			Spring-Fall	59.0	60.0
			ICAP	90.0	70.0
J - New York City	New York City	20	Summer	83.0	64.3
			Winter	28.0	61.7
			Spring-Fall	59.0	60.0
			ICAP	90.0	70.0
K - Long Island	Long Island	16	Summer	80.7	69.3
			Winter	28.0	66.2
			Spring-Fall	59.0	60.0
			ICAP	90.0	70.0

Figure A-1 — LMS100 PA: Net kW vs. Ambient Temperature

Average Degradation, 60% Relative Humidity

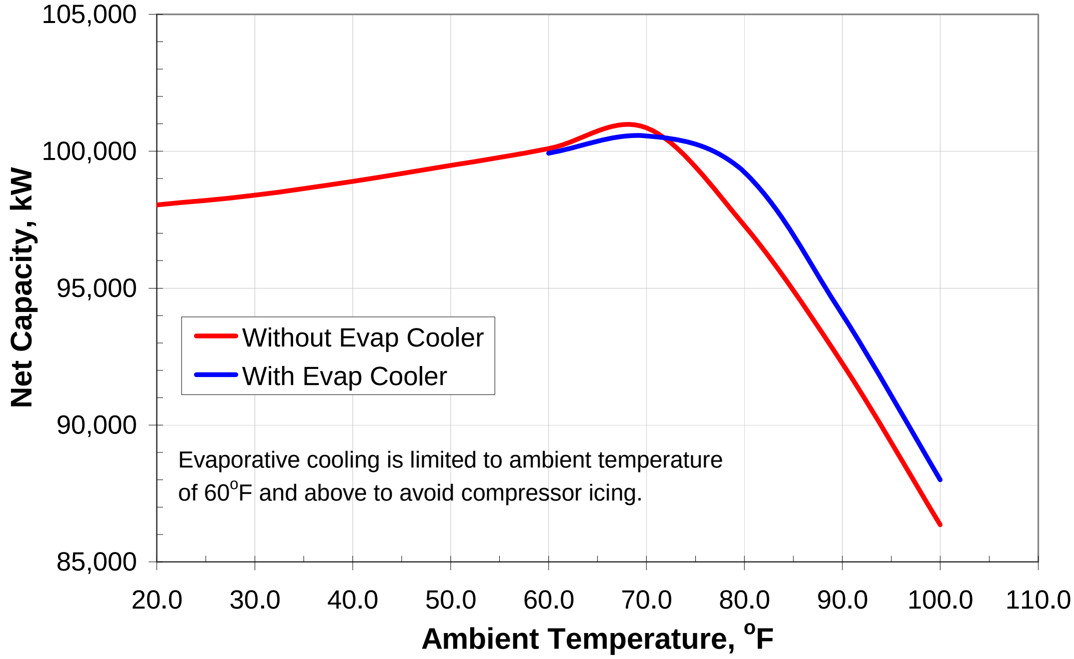


Figure A-2 — LMS100 PA: Net Capacity vs. Net Heat Rate

Average Degradation

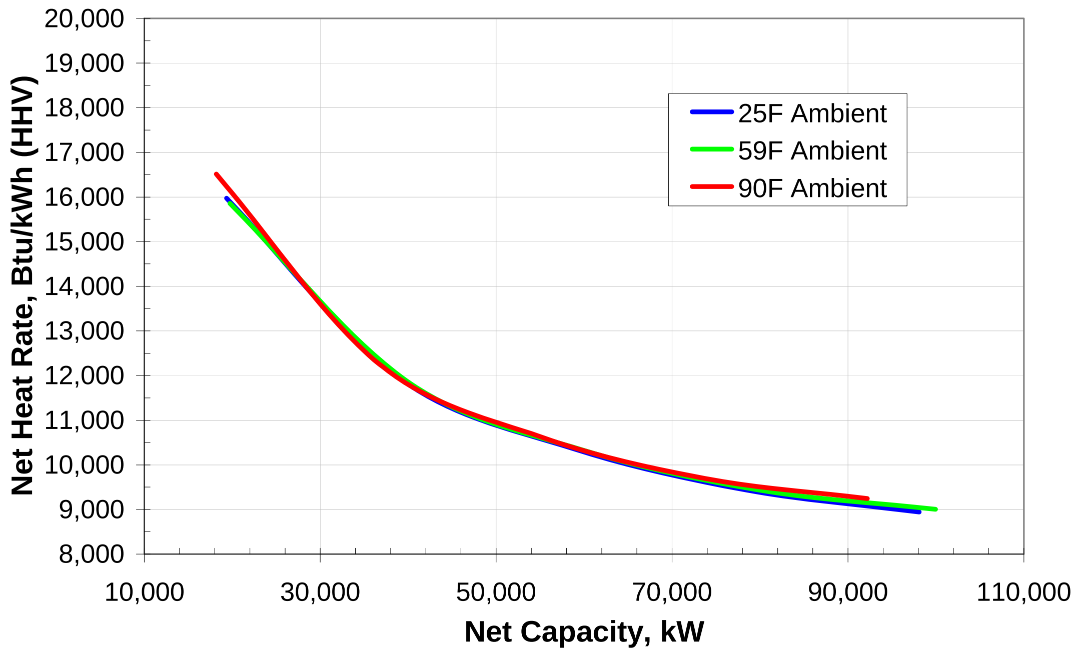


Figure A-3 — 7FA.05: Net kW vs. Ambient Temperature

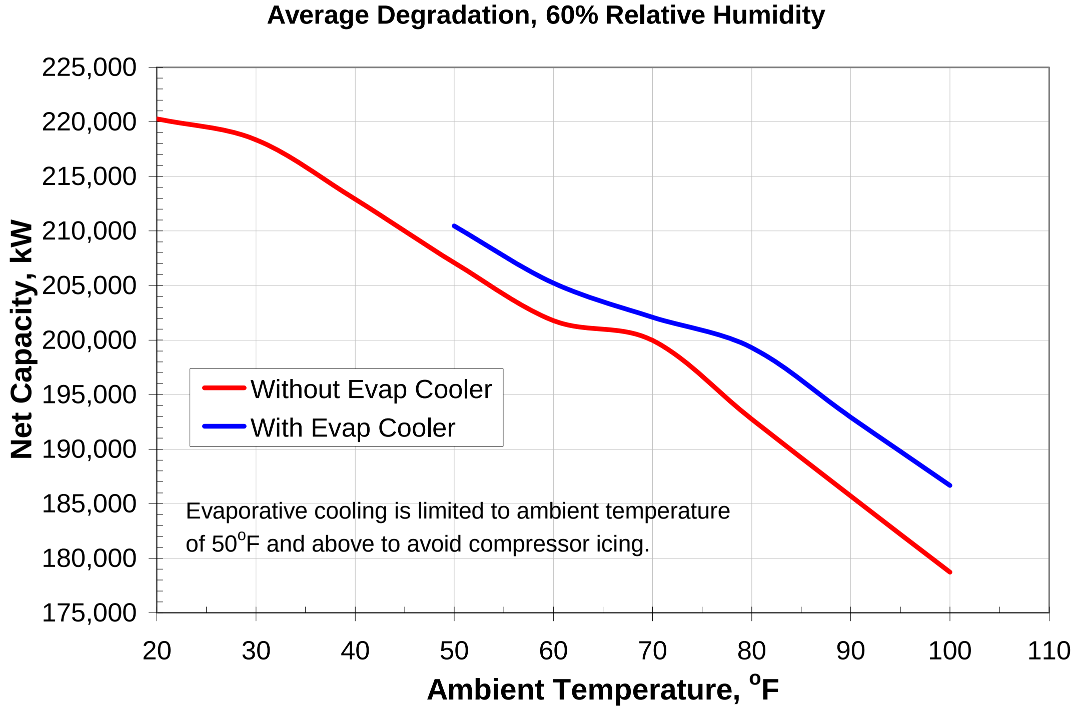


Figure A-4 — 7FA.05: Net Capacity vs. Net Heat Rate

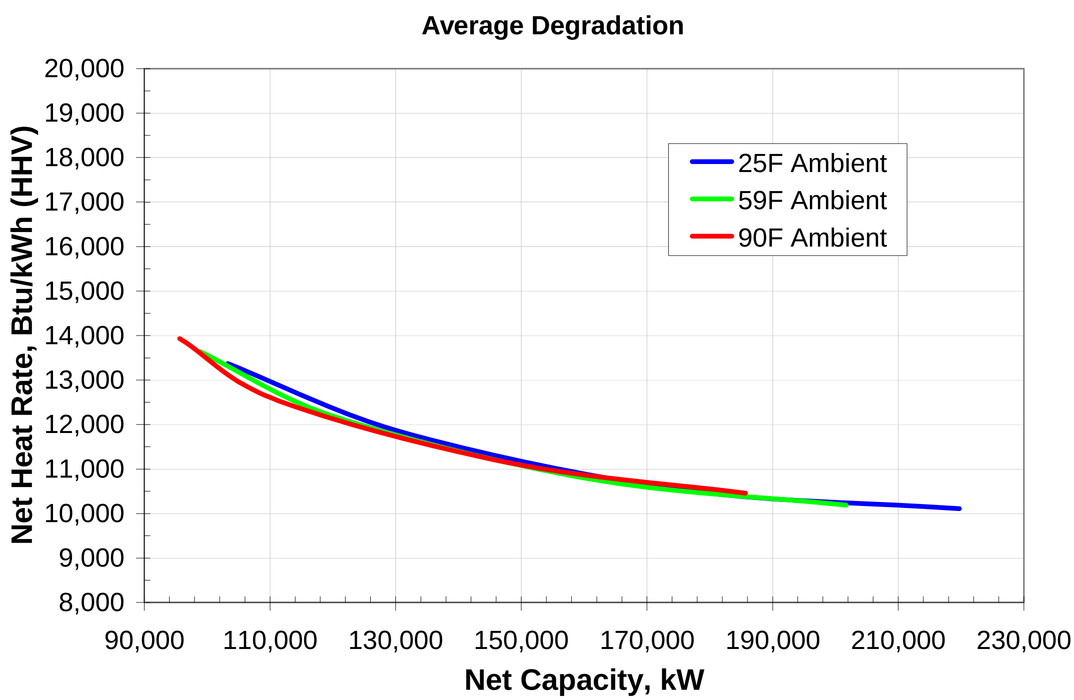


Figure A-5 — LM6000 PG Sprint: Net kW vs. Ambient Temperature

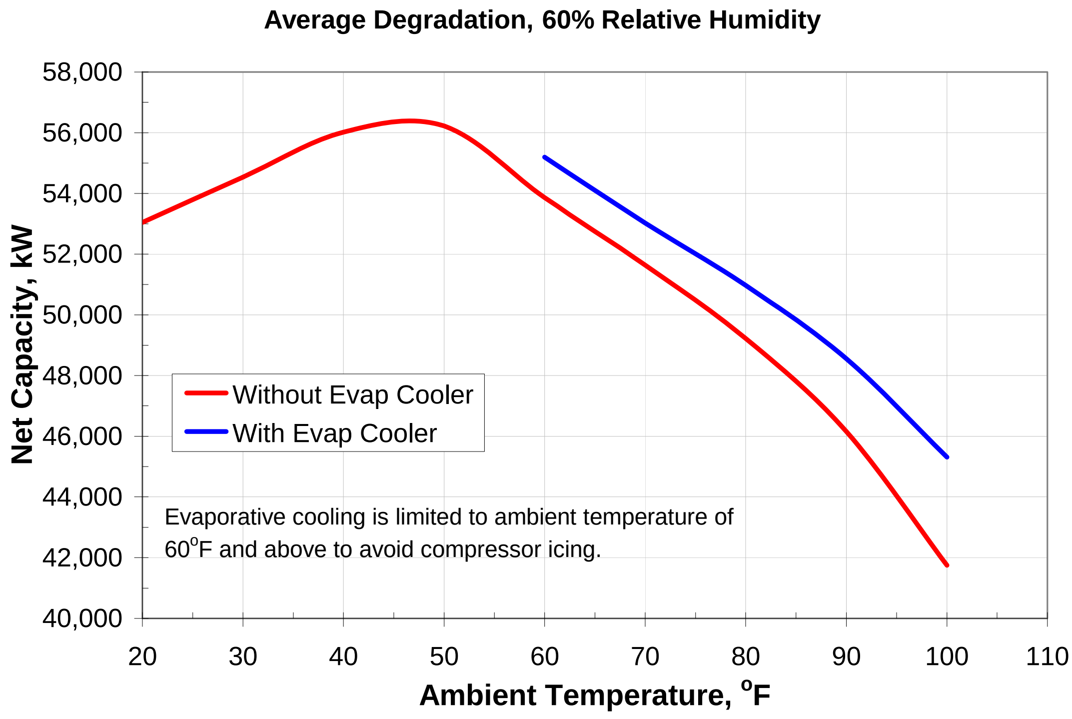


Figure A-6 — LM6000 PG Sprint: Net Capacity vs. Net Heat Rate

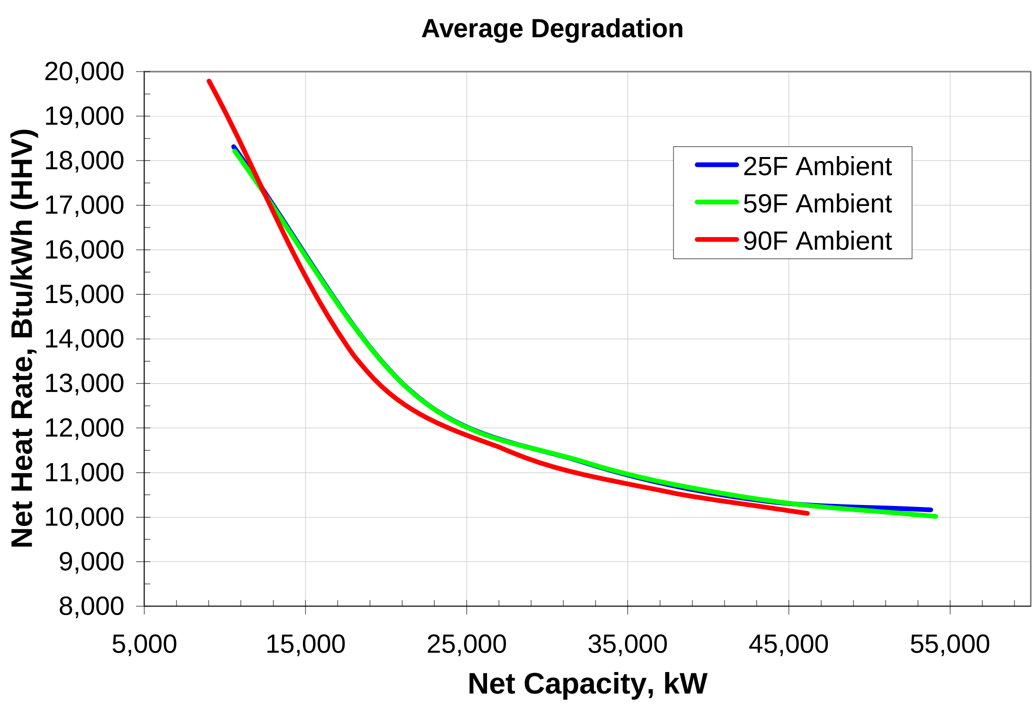
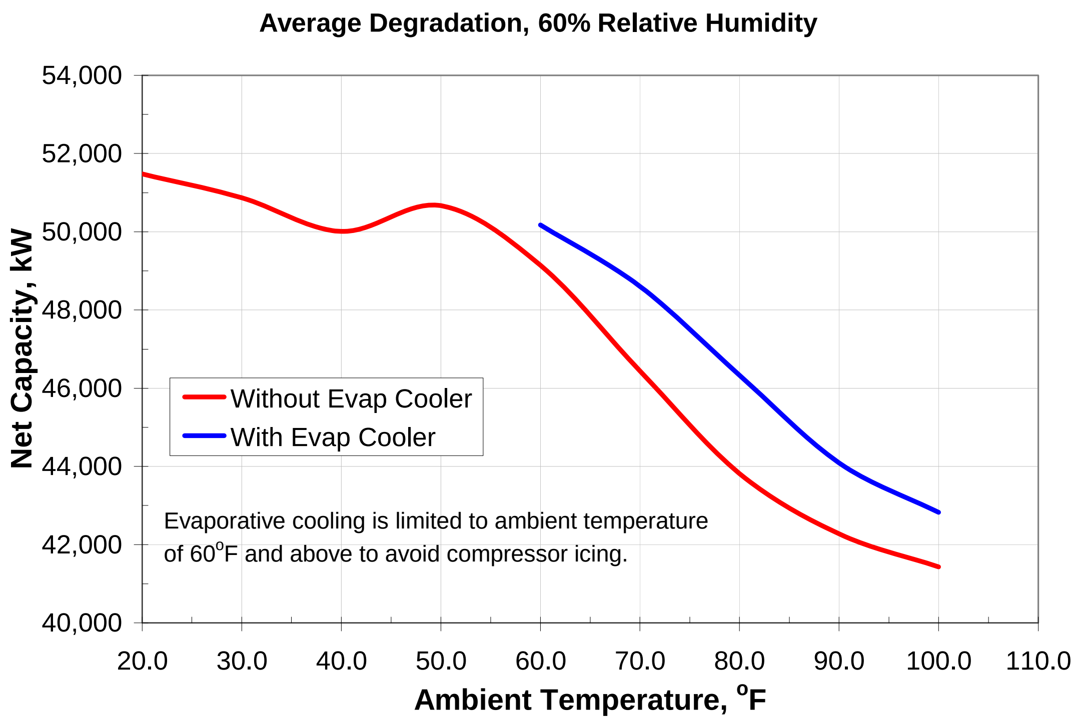


Figure A-7 — LM6000 PH Sprint: Net kW vs. Ambient Temperature



Net Heat Rate vs. Net Capacity Curve for the LM6000 PH Sprint is not available from GE.

Figure A-8 — Trent 60 WLE: Net kW vs. Ambient Temperature

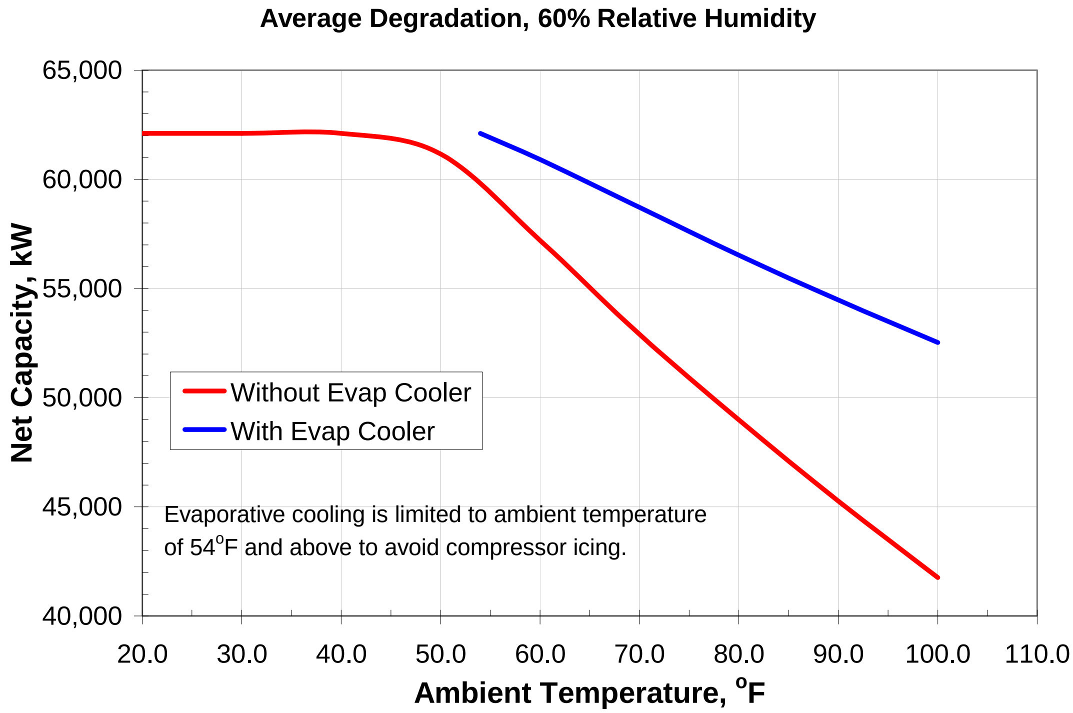


Figure A-9 — Trent 60 WLE: Net Capacity vs. Net Heat Rate

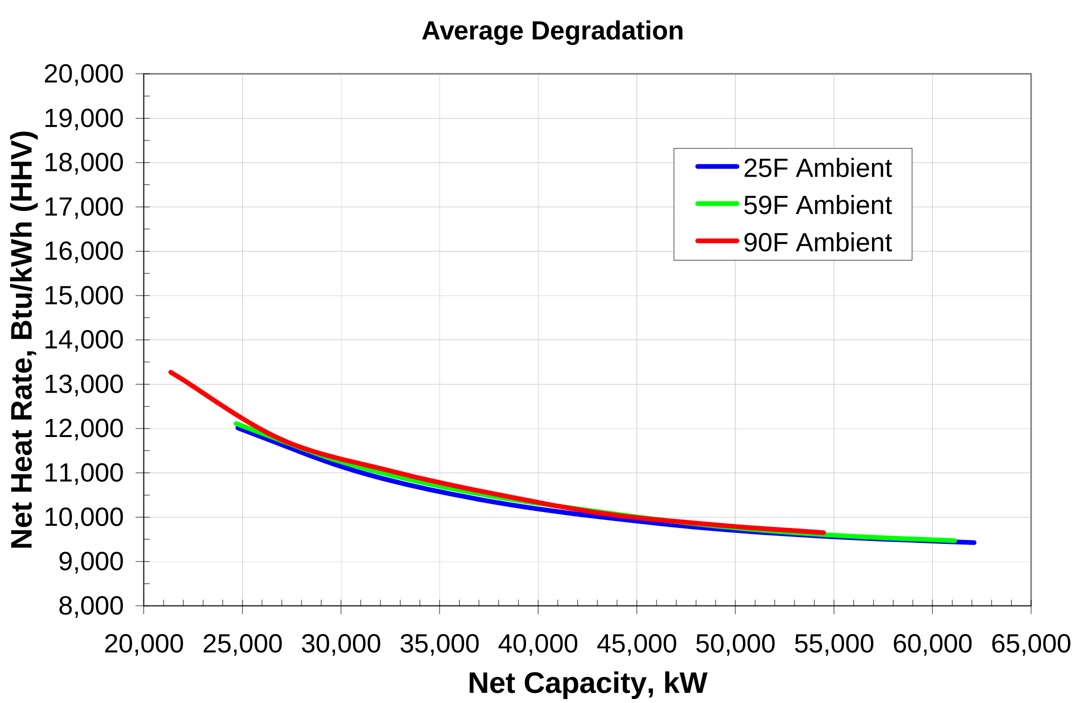


Table A-2— Performance and Operating Cost Characteristics by Technology and Location

	Long Island	NYC	Hudson Valley	Albany	Syracuse	Long Island	NYC	NYC	Comments
Combustion Turbine Model	LM6000 PH	LM6000 PG	LM6000 PH	LM6000 PH	LM6000 PH	LMS100 PA	LMS100 PA one unit	LMS100 PA	
Plant Performance (per Unit)									
Net Plant Capacity - Summer (MW)	45.4	49.8	44.6	45.1	45.3	97.1	95.2	95.2	Avg. degraded value; with evaporative cooling.
Net Plant Capacity - Winter (MW)	50.9	54.1	51.2	51.0	50.8	98.0	98.0	98.0	Avg. degraded value; evaporative cooler off.
Net Plant Capacity – ISO Conditions (MW)	48.1	51.9	47.9	48.6	48.1	97.5	96.6	96.6	Avg. degraded value.
Net Plant Capacity - ICAP (MW)	43.5	47.5	43.5	43.1	43.1	91.6	90.3	90.3	Avg. degraded value; with evaporative cooling.
Net Plant Heat Rate - Summer (MW)	9,697	10,014	9,680	9,692	9,617	9,155	9,156	9,156	Avg. degraded value; with evaporative cooling.
Net Plant Heat Rate - Winter (MW)	9,323	10,190	9,286	9,324	9,286	8,973	8,975	8,975	Avg. degraded value; evaporative cooler off.

	Long Island	NYC	Hudson Valley	Albany	Syracuse	Long Island	NYC	NYC	Comments
Combustion Turbine Model	LM6000 PH	LM6000 PG	LM6000 PH	LM6000 PH	LM6000 PH	LMS100 PA	LMS100 PA one unit	LMS100 PA	
Net Plant Heat Rate – ISO Conditions (MW)	9,510	10,102	9,483	9,486	9,452	9,064	9,066	9,066	Avg. degraded value.
Net Plant Heat Rate - ICAP (MW)	9,806	10,032	9,736	9,809	9,742	9,259	9,261	9,261	Avg. degraded value; with evaporative cooling.
Equivalent Forced Outage Rate - Demand Based (EFORd)	3.84%	3.84%	3.84%	3.84%	3.84%	3.84%	3.84%	3.84%	Long-term average.
Natural Gas Consumed During Start (mmBtu/start)	110	110	110	65	65	215	215	215	
Fixed O&M (2 Units, $/year)									
Labor - Routine O&M	1,115,000	1,254,000	899,000	842,000	842,000	1,115,000	1,254,000	1,254,000	

	Long Island	NYC	Hudson Valley	Albany	Syracuse	Long Island	NYC	NYC	Comments
Combustion Turbine Model	LM6000 PH	LM6000 PG	LM6000 PH	LM6000 PH	LM6000 PH	LMS100 PA	LMS100 PA one unit	LMS100 PA	
Materials and Contract Services - Routine	250,000	250,000	250,000	250,000	250,000	320,000	320,000	320,000	
Administrative and General	350,000	350,000	350,000	350,000	350,000	350,000	350,000	350,000	
Subtotal Fixed O&M	1,715,000	1,854,000	1,499,000	1,442,000	1,442,000	1,785,000	1,924,000	1,924,000	
$/kW-year	19.73	19.51	17.22	16.74	16.73	9.74	21.32	10.66	Based on net degraded ICAP capacity.
Other Fixed Costs (2 Units, $/year)									
Site Leasing Costs	99,000	840,000	81,000	81,000	81,000	132,000	840,000	1,440,000	
Subtotal Fixed O&M	1,814,000	2,694,000	1,580,000	1,523,000	1,523,000	1,917,000	2,764,000	3,364,000	
$/kW-year	20.86	28.35	18.15	17.68	17.67	10.46	30.63	18.64	Based on net degraded ICAP capacity.

	Long Island	NYC	Hudson Valley	Albany	Syracuse	Long Island	NYC	NYC	Comments
Combustion Turbine Model	LM6000 PH	LM6000 PG	LM6000 PH	LM6000 PH	LM6000 PH	LMS100 PA	LMS100 PA one unit	LMS100 PA	
Property Taxes	3,770,000	9,295,000	3,371,000	3,200,000	2,745,000	6,195,000	8,988,000	15,305,000	Full amount, not accounting for the NYC phased property tax exemption with the NYCIDA UTEP.
Insurance	565,000	594,000	506,000	480,000	412,000	929,000	575,000	979,000	
Total Fixed O&M (2 Units)	6,149,000	12,583,000	5,457,000	5,203,000	4,680,000	9,401,000	12,327,000	19,648,000	Alternatively, property taxes and insurance may be included in the fixed charge rate, which would account for the phasing of the NYC property tax exemption with the NYCIDA UTEP.
$/kW-year	70.73	132.40	62.70	60.41	54.29	49.33	136.59	108.85	Based on net degraded ICAP capacity.
Variable O&M ($/MWh)									
Major Maintenance Parts	3.09	2.86	3.11	3.06	3.09	2.49	2.52	2.52	
Major Maintenance Labor	0.33	0.31	0.27	0.27	0.27	0.19	0.19	0.19	Labor rates consistent with capital cost estimates.
Unscheduled Maintenance	0.81	0.81	0.81	0.81	0.81	0.81	0.81	0.81	

	Long Island	NYC	Hudson Valley	Albany	Syracuse	Long Island	NYC	NYC	Comments
Combustion Turbine Model	LM6000 PH	LM6000 PG	LM6000 PH	LM6000 PH	LM6000 PH	LMS100 PA	LMS100 PA one unit	LMS100 PA	
SCR Catalyst and Ammonia	1.00	1.00	1.00	1.00	0.00	1.00	1.00	1.00	
CO Oxidation Catalyst	0.35	0.35	0.35	0.35	0.00	0.35	0.35	0.35	
Other Chemicals and Consumables	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18	
Water	0.75	0.70	0.76	0.75	0.76	0.07	0.07	0.07	
Total Variable O&M ($/MWh)	6.52	6.21	6.47	6.41	5.11	5.10	5.13	5.13	Based on net degraded summer/winter avg. capacity.
Variable O&M - Cost per Start:									Excluding natural gas consumed (shown above).
Major Maintenance Parts	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	.
Major Maintenance Labor	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	Labor rates consistent with capital cost estimates.
Total ($/factored start)	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	Factored starts include representative weighting factors for peaking operation.

	Long Island	NYC	Hudson Valley	Albany	Syracuse	Long Island	NYC	NYC	Comments
Combustion Turbine Model	LM6000 PH	LM6000 PG	LM6000 PH	LM6000 PH	LM6000 PH	LMS100 PA	LMS100 PA one unit	LMS100 PA	
NOx Emissions (lb/hr per CT)									
Summer	4.8	4.8	4.7	4.8	23.7	16.2	16.5	16.5	
Winter	5.2	5.2	5.2	5.2	25.8	16.4	15.9	15.9	
ISO Conditions	5.1	5.1	5.0	5.0	25.0	16.5	16.5	16.5	
ICAP	4.6	4.6	4.6	4.6	22.9	15.5	16.3	16.3	
CO2 Emissions (lb/hr per CT)									
Summer	52,601	52,657	51,754	52,380	52,076	106,627	108,276	108,276	
Winter	56,800	57,025	57,194	57,137	56,504	107,740	104,367	104,367	
ISO Conditions	55,640	55,849	55,540	55,327	54,795	108,066	108,062	108,062	
ICAP	50,943	51,149	50,841	50,658	50,175	101,802	106,989	106,989	

	Hudson Valley	Albany	Syracuse	Long Island	NYC	NYC (NJ)	Hudson Valley	Albany	Syracuse	Comments
Combustion Turbine Model	LMS100 PA	LMS100 PA	LMS100 PA	Trent 60 WLE	Trent 60 WLE	Trent 60 WLE	Trent 60 WLE	7FA.05	7FA.05	
Plant Performance (per Unit)										
Net Plant Capacity - Summer (MW)	94.8	96.4	96.3	55.5	55.2	55.2	53.8	195.7	195.2	Avg. degraded value; with evaporative cooling.
Net Plant Capacity - Winter (MW)	98.7	98.3	98.7	62.1	62.1	62.1	62.1	218.3	217.1	Avg. degraded value; evaporative cooler off.
Net Plant Capacity – ISO Conditions (MW)	96.7	100.1	100.5	58.8	58.7	58.7	58.0	207.0	206.2	Avg. degraded value.
Net Plant Capacity - ICAP (MW)	91.6	90.7	90.1	53.4	53.3	53.3	53.3	189.2	188.2	Avg. degraded value; with evaporative cooling.
Net Plant Heat Rate - Summer (MW)	9,146	9,150	9,138	9,646	9,652	9,652	9,652	10,326	10,319	Avg. degraded value; with evaporative cooling.
Net Plant Heat Rate - Winter (MW)	8,896	8,936	8,924	9,473	9,473	9,473	9,392	10,088	10,091	Avg. degraded value; evaporative cooler off.
Net Plant Heat Rate – ISO Conditions (MW)	9,021	8,986	8,973	9,560	9,563	9,563	9,522	10,207	10,205	Avg. degraded value.
Net Plant Heat Rate - ICAP (MW)	9,208	9,263	9,264	9,721	9,721	9,721	9,678	10,411	10,411	Avg. degraded value; with evaporative cooling.
Equivalent Forced Outage Rate - Demand Based (EFORd)	3.84%	3.84%	3.84%	3.84%	3.84%	3.84%	3.84%	3.00%	3.00%	Long-term averages in NYCA.
Natural Gas Consumed During Start (mmBtu/start)	215	135	135	140	140	140	140	360	360	

	Hudson Valley	Albany	Syracuse	Long Island	NYC	NYC (NJ)	Hudson Valley	Albany	Syracuse	Comments
Combustion Turbine Model	LMS100 PA	LMS100 PA	LMS100 PA	Trent 60 WLE	Trent 60 WLE	Trent 60 WLE	Trent 60 WLE	7FA.05	7FA.05	
Fixed O&M (2 Units, $/year)										
Labor - Routine O&M	899,000	842,000	842,000	1,115,000	1,254,000	1,115,000	899,000	842,000	842,000	
Materials and Contract Services - Routine	320,000	320,000	320,000	270,000	270,000	270,000	270,000	390,000	390,000	
Administrative and General	350,000	350,000	350,000	350,000	350,000	350,000	350,000	350,000	350,000	
Subtotal Fixed O&M	1,569,000	1,512,000	1,512,000	1,735,000	1,874,000	1,735,000	1,519,000	1,582,000	1,582,000	
$/kW-year	8.56	8.34	8.39	16.26	17.57	16.26	14.24	4.18	4.20	Based on net degraded ICAP capacity.
Other Fixed Costs (2 Units, $/year)										
Site Leasing Costs	108,000	108,000	108,000	99,000	840,000	77,000	81,000	81,000	81,000	
Subtotal Fixed O&M	1,677,000	1,620,000	1,620,000	1,834,000	2,714,000	1,812,000	1,600,000	1,663,000	1,663,000	
$/kW-year	9.15	8.93	8.99	17.19	25.44	16.99	15.00	4.39	4.42	Based on net degraded ICAP capacity.
Property Taxes	5,571,000	5,290,000	5,248,000	3,909,000	9,543,000	4,998,000	3,471,000	6,206,000	6,158,000	Full amount, not accounting for the NYC phased property tax exemption with the **NYCIDA UTEP**.
Insurance	836,000	794,000	787,000	586,000	610,000	750,000	521,000	931,000	924,000	

	Hudson Valley	Albany	Syracuse	Long Island	NYC	NYC (NJ)	Hudson Valley	Albany	Syracuse	Comments
Combustion Turbine Model	LMS100 PA	LMS100 PA	LMS100 PA	Trent 60 WLE	Trent 60 WLE	Trent 60 WLE	Trent 60 WLE	7FA.05	7FA.05	
Total Fixed O&M (2 Units)	8,084,000	7,704,000	7,655,000	6,329,000	12,867,000	7,560,000	5,592,000	8,800,000	8,745,000	Alternatively, property taxes and insurance may be included in the fixed charge rate, which would account for the phasing of the NYC property tax exemption with the **NYCIDA UTEP**.
$/kW-year	44.12	42.48	42.47	59.32	120.61	70.87	52.42	23.26	23.23	Based on net degraded ICAP capacity.
Variable O&M ($/MWh)										
Major Maintenance Parts	2.52	2.48	2.48	3.03	3.03	3.03	3.07	n/a	n/a	
Major Maintenance Labor	0.16	0.15	0.15	0.30	0.30	0.30	0.24	n/a	n/a	Labor rates consistent with capital cost estimates.
Unscheduled Maintenance	0.81	0.81	0.81	0.81	0.81	0.81	0.81	0.55	0.55	
SCR Catalyst and Ammonia	1.00	1.00	1.00	1.00	1.00	1.00	1.00	0.00	0.00	
CO Oxidation Catalyst	0.35	0.35	0.35	0.00	0.00	0.00	0.00	0.00	0.00	
Other Chemicals and Consumables	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18	
Water	0.07	0.07	0.07	0.62	0.62	0.62	0.63	0.14	0.14	
Total Variable O&M ($/MWh)	5.09	4.99	4.98	5.93	5.94	5.94	5.93	0.87	0.87	Based on net degraded summer/winter avg. capacity.

	Hudson Valley	**Albany**	**Syracuse**	**Long Island**	**NYC**	**NYC (NJ)**	**Hudson Valley**	**Albany**	**Syracuse**	**Comments**
Combustion Turbine Model	LMS100 PA	LMS100 PA	LMS100 PA	Trent 60 WLE	Trent 60 WLE	Trent 60 WLE	Trent 60 WLE	7FA.05	7FA.05	
Variable O&M - Cost per Start:										Excluding natural gas consumed (shown above).
Major Maintenance Parts	n/a	n/a	n/a	n/a	n/a	n/a	n/a	15,236	15,236	.
Major Maintenance Labor	n/a	n/a	n/a	n/a	n/a	n/a	n/a	593	593	Labor rates consistent with capital cost estimates.
Total ($/factored start)	n/a	n/a	n/a	n/a	n/a	n/a	n/a	15,829	15,829	Factored starts include representative weighting factors for peaking operation.
NOx Emissions (lb/hr per CT)										
Summer	15.8	16.1	16.1	10.2	10.2	10.2	10.2	65.5	65.4	
Winter	16.0	16.0	16.1	10.7	10.7	10.7	10.7	73.1	72.8	
ISO Conditions	16.4	16.4	16.5	10.5	10.5	10.5	10.5	67.5	67.2	
ICAP	15.4	15.3	15.3	10.0	10.0	10.0	10.0	63.9	63.6	
CO2 Emissions (lb/hr per CT)										
Summer	104,027	105,844	105,630	65,681	65,681	65,681	65,810	232,995	232,399	
Winter	105,335	105,410	105,674	68,941	68,941	68,941	69,082	259,694	258,212	
ISO Conditions	107,816	107,979	108,198	67,626	67,626	67,626	67,767	240,030	238,791	
ICAP	101,205	100,763	100,179	64,792	64,792	64,792	64,916	227,157	225,918	

Table A-3 — Capital Cost Estimates for LMS100 - (2010 $)

	Overnight Capital Cost - 2010$s					
	K - Long Island	**J - NYC (two units)**	**J - NYC (one unit)**	**G - Hudson Valley**	**F - Capital**	**C - Central**
EPC Cost Components						
Equipment						
Equipment	114,095,000	117,943,000	61,717,000	114,095,000	114,095,000	114,095,000
Spare Parts	1,061,000	1,061,000	1,061,000	1,061,000	1,061,000	1,061,000
Subtotal	115,156,000	119,004,000	62,778,000	115,156,000	115,156,000	115,156,000
Construction						
Construction Labor & Materials	86,456,000	94,244,000	59,413,000	66,658,000	58,008,000	56,701,000
Electrical Connection & Substation	6,721,000	5,925,000	4,775,000	5,446,000	4,947,000	4,801,000
Electrical Interconnect & Upgrades	4,700,000	4,800,000	3,200,000	4,400,000	4,400,000	4,400,000
Gas Interconnect & Reinforcement	4,879,000	5,740,000	4,018,000	4,879,000	4,879,000	4,879,000
Site Prep	3,444,000	6,017,000	4,577,000	2,857,000	2,504,000	2,455,000
Engineering & Design	11,186,000	11,792,000	6,846,000	10,037,000	9,532,000	9,452,000
Construction Mgmt. / Field Engr.	2,797,000	2,948,000	1,712,000	2,509,000	2,383,000	2,363,000
Subtotal	120,183,000	131,466,000	84,541,000	96,786,000	86,653,000	85,051,000
Startup & Testing						
Startup & Training	1,864,000	1,965,000	1,141,000	1,673,000	1,589,000	1,575,000
Testing	-	-	-	-	-	-
Subtotal	1,864,000	1,965,000	1,141,000	1,673,000	1,589,000	1,575,000
Contingency	22,656,000	23,883,000	13,866,000	20,327,000	19,306,000	19,144,000
Subtotal - EPC Costs	259,859,000	276,318,000	162,326,000	233,942,000	222,704,000	220,926,000
Non-EPC Cost Components						
Owner's Costs						
Permitting	2,599,000	2,763,000	1,623,000	2,339,000	2,227,000	2,209,000
Legal	5,197,000	5,526,000	3,247,000	4,679,000	4,454,000	4,419,000
Owner's Project Mgmt. & Misc. Engr.	5,197,000	5,526,000	3,247,000	4,679,000	4,454,000	4,419,000
Social Justice	520,000	2,487,000	1,461,000	468,000	445,000	442,000
Owner's Development Costs	7,796,000	8,290,000	4,870,000	7,018,000	6,681,000	6,628,000
Financing Fees	5,197,000	956,000	563,000	4,679,000	4,454,000	4,419,000
Financial Advisory	650,000	691,000	406,000	585,000	557,000	552,000
Environmental Studies	650,000	691,000	406,000	585,000	557,000	552,000
Market Studies	650,000	691,000	406,000	585,000	557,000	552,000
Interconnection Studies	650,000	691,000	406,000	585,000	557,000	552,000
Emission Reduction Credits	1,050,000	750,000	380,000	680,000	0	0
Subtotal	30,156,000	29,062,000	17,015,000	26,882,000	24,943,000	24,744,000
Financing (incl. AFUDC, IDC)						
EPC Portion	13,019,000	13,844,000	8,133,000	11,720,000	11,157,000	11,068,000
Non-EPC Portion	1,511,000	1,456,000	852,000	1,347,000	1,250,000	1,240,000
Working Capital and Inventories	5,197,000	5,526,000	3,247,000	4,679,000	4,454,000	4,419,000
Subtotal - Non-EPC Costs	49,883,000	49,888,000	29,247,000	44,628,000	41,804,000	41,471,000
Total Capital Investment	309,742,000	326,206,000	191,573,000	278,570,000	264,508,000	262,397,000

Table A-4 — Capital Cost Estimates for GE 7FA - (2010 $)

	Overnight Capital Cost - 2010$s		Costs as a % of Zone C
	F - Capital (SC)	C - Central	F - Capital
EPC Cost Components			
Equipment			
Equipment	136,922,000	136,922,000	100%
Spare Parts	1,061,000	1,061,000	100%
Subtotal	137,983,000	137,983,000	100%
Construction			
Construction Labor & Materials	66,789,000	65,267,000	102%
Electrical Connection & Substation	4,947,000	4,801,000	103%
Electrical Interconnect & Upgrades	4,200,000	4,200,000	100%
Gas Interconnect & Reinforcement	5,740,000	5,740,000	100%
Site Prep	3,129,000	3,071,000	102%
Engineering & Design	11,243,000	11,152,000	101%
Construction Mgmt. / Field Engr.	2,811,000	2,788,000	101%
Subtotal	98,859,000	97,019,000	102%
Startup & Testing			
Startup & Training	1,874,000	1,859,000	101%
Testing	-	-	N/A
Subtotal	1,874,000	1,859,000	101%
Contingency	22,772,000	22,586,000	101%
Subtotal - EPC Costs	261,488,000	259,447,000	101%
Non-EPC Cost Components			
Owner's Costs			
Permitting	2,615,000	2,594,000	101%
Legal	5,230,000	5,189,000	101%
Owner's Project Mgmt. & Misc. Engr.	5,230,000	5,189,000	101%
Social Justice	261,000	259,000	101%
Owner's Development Costs	7,845,000	7,783,000	101%
Financing Fees	5,230,000	5,189,000	101%
Financial Advisory	654,000	649,000	101%
Environmental Studies	654,000	649,000	101%
Market Studies	654,000	649,000	101%
Interconnection Studies	654,000	649,000	101%
Emission Reduction Credits	0	0	
Subtotal	29,027,000	28,799,000	101%
Financing (incl. AFUDC, IDC)			
EPC Portion	13,101,000	12,998,000	101%
Non-EPC Portion	1,454,000	1,443,000	101%
Working Capital and Inventories	5,230,000	5,189,000	101%
Subtotal - Non-EPC Costs	48,812,000	48,429,000	101%
Total Capital Investment	310,300,000	307,876,000	101%

Table A-5 — Capital Cost Estimates for LM6000 - (2010 $)

	Overnight Capital Cost - 2010$s					Costs as a % of Zone C			
	K - Long Island	**J - NYC (PG model)**	**G - Hudson Valley**	**F - Capital**	**C - Central**	**K - Long Island**	**J - NYC**	**G - Hudson Valley**	**F - Capital**
EPC Cost Components									
Equipment									
Equipment	65,275,000	66,354,000	65,275,000	65,275,000	54,750,000	119%	121%	119%	119%
Spare Parts	1,061,000	1,061,000	1,061,000	1,061,000	1,061,000	100%	100%	100%	100%
Subtotal	66,336,000	67,415,000	66,336,000	66,336,000	55,811,000	119%	121%	119%	119%
Construction									
Construction Labor & Materials	52,821,000	58,717,000	40,483,000	35,055,000	29,542,000	179%	199%	137%	119%
Electrical Connection & Substation	5,679,000	4,775,000	4,561,000	4,124,000	3,996,000	142%	119%	114%	103%
Electrical Interconnect & Upgrades	4,700,000	4,800,000	4,400,000	4,400,000	4,400,000	107%	109%	100%	100%
Gas Interconnect & Reinforcement	3,903,000	4,592,000	3,903,000	3,903,000	3,903,000	100%	118%	100%	100%
Site Prep	2,131,000	3,731,000	1,751,000	1,516,000	1,484,000	144%	251%	118%	102%
Engineering & Design	6,684,000	7,025,000	5,950,000	5,626,000	4,766,000	140%	147%	125%	118%
Construction Mgmt. / Field Engr.	1,671,000	1,756,000	1,487,000	1,406,000	1,191,000	140%	147%	125%	118%
Subtotal	77,589,000	85,396,000	62,535,000	56,030,000	49,282,000	157%	173%	127%	114%
Startup & Testing									
Startup & Training	1,114,000	1,171,000	992,000	938,000	794,000	140%	147%	125%	118%
Testing	-	-	-	-	-	N/A	N/A	N/A	N/A
Subtotal	1,114,000	1,171,000	992,000	938,000	794,000	140%	147%	125%	118%
Contingency	13,537,000	14,229,000	12,050,000	11,394,000	9,652,000	140%	147%	125%	118%
Subtotal - EPC Costs	158,576,000	168,211,000	141,913,000	134,698,000	115,539,000	137%	146%	123%	117%
Non-EPC Cost Components									
Owner's Costs									
Permitting	1,586,000	1,682,000	1,419,000	1,347,000	1,155,000	137%	146%	123%	117%
Legal	3,172,000	3,364,000	2,838,000	2,694,000	2,311,000	137%	146%	123%	117%
Owner's Project Mgmt. & Misc. Engr.	3,172,000	3,364,000	2,838,000	2,694,000	2,311,000	137%	146%	123%	117%
Social Justice	317,000	1,514,000	284,000	269,000	231,000	137%	655%	123%	116%
Owner's Development Costs	4,757,000	5,046,000	4,257,000	4,041,000	3,466,000	137%	146%	123%	117%
Financing Fees	3,172,000	589,000	2,838,000	2,694,000	2,311,000	137%	25%	123%	117%
Financial Advisory	396,000	421,000	355,000	337,000	289,000	137%	146%	123%	117%
Environmental Studies	396,000	421,000	355,000	337,000	289,000	137%	146%	123%	117%
Market Studies	396,000	421,000	355,000	337,000	289,000	137%	146%	123%	117%
Interconnection Studies	396,000	421,000	355,000	337,000	289,000	137%	146%	123%	117%
Emission Reduction Credits	130,000	5,000	0	0	0				
Subtotal	17,890,000	17,248,000	15,894,000	15,087,000	12,941,000	138%	133%	123%	117%
Financing (incl. AFUDC, IDC)									
EPC Portion	7,945,000	8,427,000	7,110,000	6,748,000	5,789,000	137%	146%	123%	117%
Non-EPC Portion	896,000	864,000	796,000	756,000	648,000	138%	133%	123%	117%
Working Capital and Inventories	3,172,000	3,364,000	2,838,000	2,694,000	2,311,000	137%	146%	123%	117%
Subtotal - Non-EPC Costs	29,903,000	29,903,000	26,638,000	25,285,000	21,689,000	138%	138%	123%	117%
Total Capital Investment	188,479,000	198,114,000	168,551,000	159,983,000	137,228,000	137%	144%	123%	117%

Table A-6 — Capital Cost Estimates for Trent 60 - (2010 $)

	Overnight Capital Cost - 2010$s				Costs as a % of Zone G		
	NJ w/HV Cable to NYC	K - Long Island	J - NYC	G - Hudson Valley	New Jersey w/HV Cable to NYC	K - Long Island	J - NYC
EPC Cost Components							
Equipment							
Equipment	68,113,000	67,118,000	68,165,000	67,118,000	101%	100%	102%
Spare Parts	1,061,000	1,061,000	1,061,000	1,061,000	100%	100%	100%
Subtotal	69,174,000	68,179,000	69,226,000	68,179,000	101%	100%	102%
Construction							
Construction Labor & Materials	45,924,000	54,684,000	60,310,000	41,875,000	110%	131%	144%
Electrical Connection & Substation	4,885,000	5,679,000	4,775,000	4,561,000	107%	125%	105%
Electrical Interconnect & Upgrades	4,800,000	4,700,000	4,800,000	4,400,000	109%	107%	109%
Gas Interconnect & Reinforcement	4,098,000	4,098,000	4,822,000	4,098,000	100%	100%	118%
Site Prep	2,994,000	2,131,000	3,731,000	1,751,000	171%	122%	213%
Engineering & Design	6,419,000	6,881,000	7,206,000	6,121,000	105%	112%	118%
Construction Mgmt. / Field Engr.	1,605,000	1,720,000	1,802,000	1,530,000	105%	112%	118%
Subtotal	70,725,000	79,893,000	87,446,000	64,336,000	110%	124%	136%
Startup & Testing							
Startup & Training	1,070,000	1,147,000	1,201,000	1,020,000	105%	112%	118%
Testing		-	-	-	N/A	N/A	N/A
Subtotal	1,070,000	1,147,000	1,201,000	1,020,000	105%	112%	118%
Contingency	13,001,000	13,936,000	14,595,000	12,398,000	105%	112%	118%
Subtotal - EPC Costs	153,970,000	163,155,000	172,468,000	145,933,000	106%	112%	118%
Non-EPC Cost Components							
Owner's Costs							
Permitting	1,540,000	1,632,000	1,725,000	1,459,000	106%	112%	118%
Legal	3,079,000	3,263,000	3,449,000	2,919,000	105%	112%	118%
Owner's Project Mgmt. & Misc. Engr.	3,079,000	3,263,000	3,449,000	2,919,000	105%	112%	118%
Social Justice	1,386,000	326,000	1,552,000	292,000	475%	112%	532%
Owner's Development Costs	4,619,000	4,895,000	5,174,000	4,378,000	106%	112%	118%
Financing Fees	535,000	3,263,000	600,000	2,919,000	18%	112%	21%
Financial Advisory	385,000	408,000	431,000	365,000	105%	112%	118%
Environmental Studies	385,000	408,000	431,000	365,000	105%	112%	118%
Market Studies	385,000	408,000	431,000	365,000	105%	112%	118%
Interconnection Studies	385,000	408,000	431,000	365,000	105%	112%	118%
Emission Reduction Credits	270,000	1,600,000	270,000	210,000	129%	762%	129%
Subtotal	16,048,000	19,874,000	17,943,000	16,556,000	97%	120%	108%
Financing (incl. AFUDC, IDC)							
EPC Portion	7,714,000	8,174,000	8,641,000	7,311,000	106%	112%	118%
Non-EPC Portion	804,000	996,000	899,000	829,000	97%	120%	108%
Working Capital and Inventories	3,079,000	3,263,000	3,449,000	2,919,000	105%	112%	118%
Subtotal - Non-EPC Costs	27,645,000	32,307,000	30,932,000	27,615,000	100%	117%	112%
Submarine Cable Installation	68,305,000						
Total Capital Investment	249,920,000	195,462,000	203,400,000	173,548,000	144%	113%	117%

Table A-7 — Comparison of Capital Cost Estimates – LM6000 in NYC

	Capital Cost Comparison 2 x LM6000 Zone J - New York City					
	2010 DC Reset		2007 DC Reset[1]		2004 DC Review[2]	
	Cost (2010$)	Non-EPC as % of EPC	Cost (2007$)	Non-EPC as % of EPC	Cost (2004$)	Non-EPC as % of EPC
EPC Cost Components						
Equipment						
Equipment	66,354,000		44,059,000		40,500,000	
Spare Parts	1,061,000		1,000,000		1,000,000	
Subtotal	67,415,000		45,059,000		41,500,000	
Construction						
Construction Labor & Materials	58,717,000		42,524,000		44,980,000	
Electrical Connection & Substation	4,775,000		3,549,000		3,500,000	
Electrical System Upgrades	4,800,000		500,000		2,500,000	
Gas Interconnect & Reinforcement	4,592,000		4,000,000		4,000,000	
Site Prep	3,731,000		1,526,000		2,200,000	
Engineering & Design	7,025,000		4,755,000		4,000,000	
Construction Mgmt. / Field Engr.	1,756,000		1,189,000		0	
Subtotal	85,396,000		58,043,000		61,180,000	
Startup & Testing						
Startup & Training	1,171,000		793,000		750,000	
Testing	-		-		250,000	
Subtotal	1,171,000		793,000		1,000,000	
Contingency	14,229,000		9,459,000		0	
Subtotal - EPC Costs	168,211,000		113,354,000		103,680,000	100%
Non-EPC Cost Components						
Owner's Costs						
Permitting	1,682,000	1.00%	1,134,000	1.00%	4,050,000	3.91%
Legal	3,364,000	2.00%	2,267,000	2.00%	1,285,714	1.24%
Owner's Project Mgmt. & Misc. Engr.	3,364,000	2.00%	2,267,000	2.00%	1,333,333	1.29%
Social Justice	1,514,000	0.90%	1,000,000	0.88%	500,000	0.48%
Owner's Development Costs	5,046,000	3.00%	3,401,000	3.00%	0	0.00%
Financing Fees	589,000	0.35%	2,267,000	2.00%	0	0.00%
Financial Advisory	421,000	0.25%	283,000	0.25%	0	0.00%
Environmental Studies	421,000	0.25%	283,000	0.25%	0	0.00%
Market Studies	421,000	0.25%	283,000	0.25%	0	0.00%
Interconnection Studies	421,000	0.25%	283,000	0.25%	0	0.00%
Emission Reduction Credits	5,000	0.00%	0	0.00%	0	
Subtotal	17,248,000	10.25%	13,468,000	11.88%	7,169,047	6.91%
Financing (incl. AFUDC, IDC) (2)						
EPC Portion	8,427,000	5.01%	5,158,000	4.55%	3,169,895	3.06%
Non-EPC Portion	864,000	0.51%	613,000	0.54%	0	0.00%
Working Capital and Inventories	3,364,000	2.00%	2,267,000	2.00%	0	0.00%
Subtotal - Non-EPC Costs	29,903,000	17.78%	21,506,000	18.97%	10,338,942	9.97%
Total Capital Investment	198,114,000	117.78%	134,860,000	118.97%	114,018,942	109.97%

Notes:

1. NERA Economic Consulting, "Independent Study to Establish Parameters of the ICAP Demand Curve for the New York Independent System Operation, August 15, 2007.

2. Levitan & Associates, "Independent Study to Establish Parameters of the ICAP Demand Curves for the New York Independent System Operator," August 16, 2004, p. 6, and Letter to John Charlton, NYISO, "ICAP Demand Curve Review - Capital Cost Details and Update," September 1, 2004.

Table A-8 — Comparison of Capital Cost Estimates – LM6000 in Syracuse

	Capital Cost Comparison 2 x LM6000 Zone C - Syracuse					
	2010 DC Reset		2007 DC Reset[1]		2004 DC Review[2]	
	Cost (2010$)	Non-EPC as % of EPC	Cost (2007$)	Non-EPC as % of EPC	Cost (2004$)	Non-EPC as % of EPC
EPC Cost Components						
Equipment						
Equipment	54,750,000		36,072,000		40,500,000	
Spare Parts	1,061,000		1,000,000		1,000,000	
Subtotal	55,811,000		37,072,000		41,500,000	
Construction						
Construction Labor & Materials	29,542,000		21,335,000		33,960,000	
Electrical Connection & Substation	3,996,000		2,257,000		2,750,000	
Electrical System Upgrades	4,400,000		500,000		1,250,000	
Gas Interconnect & Reinforcement	3,903,000		3,400,000		3,400,000	
Site Prep	1,484,000		888,000		1,300,000	
Engineering & Design	4,766,000		3,278,000		3,000,000	
Construction Mgmt. / Field Engr.	1,191,000		819,000		0	
Subtotal	49,282,000		32,477,000		45,660,000	
Startup & Testing						
Startup & Training	794,000		546,000		750,000	
Testing	-		-		250,000	
Subtotal	794,000		546,000		1,000,000	
Contingency	9,652,000		6,520,000		0	
Subtotal - EPC Costs	115,539,000		76,615,000		88,160,000	100%
Non-EPC Cost Components						
Owner's Costs						
Permitting	1,155,000	1.00%	766,000	1.00%	1,050,000	1.19%
Legal	2,311,000	2.00%	1,532,000	2.00%	1,000,000	1.13%
Owner's Project Mgmt. & Misc. Engr.	2,311,000	2.00%	1,532,000	2.00%	1,000,000	1.13%
Social Justice	231,000	0.20%	125,000	0.16%	125,000	0.14%
Owner's Development Costs	3,466,000	3.00%	2,298,000	3.00%	0	0.00%
Financing Fees	2,311,000	2.00%	1,532,000	2.00%	0	0.00%
Financial Advisory	289,000	0.25%	192,000	0.25%	0	0.00%
Environmental Studies	289,000	0.25%	192,000	0.25%	0	0.00%
Market Studies	289,000	0.25%	192,000	0.25%	0	0.00%
Interconnection Studies	289,000	0.25%	192,000	0.25%	0	0.00%
Emission Reduction Credits	0	0.00%	0	0.00%	0	0.00%
Subtotal	12,941,000	11.20%	8,553,000	11.16%	3,175,000	3.60%
Financing (incl. AFUDC, IDC) (2)						
EPC Portion	5,789,000	5.01%	3,486,000	4.55%	1,899,500	2.15%
Non-EPC Portion	648,000	0.56%	389,000	0.51%	0	0.00%
Working Capital and Inventories	2,311,000	2.00%	1,532,000	2.00%	0	0.00%
Subtotal - Non-EPC Costs	21,689,000	18.77%	13,960,000	18.22%	5,074,500	5.76%
Total Capital Investment	137,228,000	118.77%	90,575,000	118.22%	93,234,500	105.76%

1. NERA Economic Consulting, "Independent Study to Establish Parameters of the ICAP Demand Curve for the New York Independent System Operation, August 15, 2007.

2. Levitan & Associates, "Independent Study to Establish Parameters of the ICAP Demand Curves for the New York Independent System Operator," August 16, 2004, p. 6, and Letter to John Charlton, NYISO, "ICAP Demand Curve Review - Capital Cost Details and Update," September 1, 2004.

Table A-9 — Comparison of Capital Cost Estimates – 7FA in Syracuse

	Capital Cost Comparison 2 x 7FA Zone C - Syracuse					
	2010 DC Reset		2007 DC Reset[1]		2004 DC Review[2]	
	Cost (2010$)	Non-EPC as % of EPC	Cost (2007$)	Non-EPC as % of EPC	Cost (2004$)	Non-EPC as % of EPC
EPC Cost Components						
Equipment						
Equipment	136,922,000		86,652,000		118,000,000	
Spare Parts	1,061,000		1,000,000		3,500,000	
Subtotal	137,983,000		87,652,000		121,500,000	
Construction						
Construction Labor & Materials	65,267,000		46,036,000		37,935,900	
Electrical Connection & Substation	4,801,000		2,470,000		6,500,000	
Electrical System Upgrades	4,200,000		500,000		1,500,000	
Gas Interconnect & Reinforcement	5,740,000		5,000,000		6,210,709	
Site Prep	3,071,000		1,790,000		3,000,000	
Engineering & Design	11,152,000		7,413,000		7,125,000	
Construction Mgmt. / Field Engr.	2,788,000		1,853,000		0	
Subtotal	97,019,000		65,062,000		62,271,609	
Startup & Testing						
Startup & Training	1,859,000		1,235,000		1,900,000	
Testing	-		-		700,000	
Subtotal	1,859,000		1,235,000		2,600,000	
Contingency	22,586,000		14,745,000		0	
Subtotal - EPC Costs	259,447,000		168,694,000		186,371,609	100%
Non-EPC Cost Components						
Owner's Costs						
Permitting	2,594,000	1.00%	1,687,000	1.00%	1,697,000	0.91%
Legal	5,189,000	2.00%	3,374,000	2.00%	1,414,000	0.76%
Owner's Project Mgmt. & Misc. Engr.	5,189,000	2.00%	3,374,000	2.00%	2,239,000	1.20%
Social Justice	259,000	0.10%	125,000	0.07%	400,000	0.21%
Owner's Development Costs	7,783,000	3.00%	5,061,000	3.00%	0	0.00%
Financing Fees	5,189,000	2.00%	3,374,000	2.00%	0	0.00%
Financial Advisory	649,000	0.25%	422,000	0.25%	0	0.00%
Environmental Studies	649,000	0.25%	422,000	0.25%	0	0.00%
Market Studies	649,000	0.25%	422,000	0.25%	0	0.00%
Interconnection Studies	649,000	0.25%	422,000	0.25%	0	0.00%
Emission Reduction Credits	0	0.00%	0	0.00%	0	0.00%
Subtotal	28,799,000	11.10%	18,683,000	11.08%	5,750,000	3.09%
Financing (incl. AFUDC, IDC) (2)						
EPC Portion	12,998,000	5.01%	7,676,000	4.55%	8,333,186	4.47%
Non-EPC Portion	1,443,000	0.56%	850,000	0.50%	0	0.00%
Working Capital and Inventories	5,189,000	2.00%	3,374,000	2.00%	0	0.00%
Subtotal - Non-EPC Costs	48,429,000	18.67%	30,583,000	18.13%	14,083,186	7.56%
Total Capital Investment	307,876,000	118.67%	199,277,000	118.13%	200,454,795	107.56%

1. NERA Economic Consulting, "Independent Study to Establish Parameters of the ICAP Demand Curve for the New York Independent System Operation, August 15, 2007.

2. Levitan & Associates, "Independent Study to Establish Parameters of the ICAP Demand Curves for the New York Independent System Operator," August 16, 2004, p. 6, and Letter to John Charlton, NYISO, "ICAP Demand Curve Review - Capital Cost Details and Update," September 1, 2004.

Table A-10 — Comparison of Capital Cost Estimates – LMS100 in NYC

	Capital Cost Comparison 2 x LMS100 Zone J - NYC			
	2010 DC Reset		2007 DC Reset[1]	
	Cost (2010$)	Non-EPC as % of EPC	Cost (2007$)	Non-EPC as % of EPC
EPC Cost Components				
Equipment				
Equipment	117,943,000		89,050,000	
Spare Parts	1,061,000		1,000,000	
Subtotal	119,004,000		90,050,000	
Construction				
Construction Labor & Materials	94,244,000		68,129,000	
Electrical Connection & Substation	5,925,000		3,793,000	
Electrical System Upgrades	4,800,000		500,000	
Gas Interconnect & Reinforcement	5,740,000		5,000,000	
Site Prep	6,017,000		2,491,000	
Engineering & Design	11,792,000		8,562,000	
Construction Mgmt. / Field Engr.	2,948,000		2,140,000	
Subtotal	131,466,000		90,615,000	
Startup & Testing				
Startup & Training	1,965,000		1,427,000	
Testing	-		-	
Subtotal	1,965,000		1,427,000	
Contingency	23,883,000		17,031,000	
Subtotal - EPC Costs	276,318,000		199,123,000	
Non-EPC Cost Components				
Owner's Costs				
Permitting	2,763,000	1.00%	1,991,000	1.00%
Legal	5,526,000	2.00%	3,982,000	2.00%
Owner's Project Mgmt. & Misc. Engr.	5,526,000	2.00%	3,982,000	2.00%
Social Justice	2,487,000	0.90%	2,000,000	1.00%
Owner's Development Costs	8,290,000	3.00%	5,974,000	3.00%
Financing Fees	956,000	0.35%	3,982,000	2.00%
Financial Advisory	691,000	0.25%	498,000	0.25%
Environmental Studies	691,000	0.25%	498,000	0.25%
Market Studies	691,000	0.25%	498,000	0.25%
Interconnection Studies	691,000	0.25%	498,000	0.25%
Emission Reduction Credits	750,000	0.27%	0	0.00%
Subtotal	29,062,000	10.52%	23,903,000	12.00%
Financing (incl. AFUDC, IDC) (2)				
EPC Portion	13,844,000	5.01%	9,060,000	4.55%
Non-EPC Portion	1,456,000	0.53%	1,088,000	0.55%
Working Capital and Inventories	5,526,000	2.00%	3,982,000	2.00%
Subtotal - Non-EPC Costs	49,888,000	18.05%	38,033,000	19.10%
Total Capital Investment	326,206,000	118.05%	237,156,000	119.10%

1. NERA Economic Consulting, "Independent Study to Establish Parameters of the ICAP Demand Curve for the New York Independent System Operation, August 15, 2007.

Table A-11 — EPC Cost Breakdown for LMS100 in New York City - (2010 $)

Description	Scope Definition	Total Equipment or Material Cost	Total Man-hours	Total Construction & Erection Cost	Total Projected Cost
Combustion Turbines w/ Accessories	GE LMS100-PA	85,900,000	43,400	6,585,516	92,485,516
SCR w/ Exhaust Stack		14,000,000	35,252	5,349,138	19,349,138
Aqueous Ammonia Storage & Forwarding		280,000	980	148,705	428,705
Inlet Air Chillers	Not Included	0	0	0	0
Pumps		763,000	2,654	405,566	1,168,566
Field Erected Tanks	Turnkey Subcontracts	1,820,000	0	0	1,820,000
Shop Fabricated Tanks		82,000	323	48,921	130,921
Cranes & Hoists	Allowance for Misc. Hoists Only	15,000	210	32,086	47,086
Fuel Gas Compressors	2x100%	3,600,000	4,200	637,308	4,237,308
Fuel Gas Supply & Metering	Gas Interconnection and Metering Station Assumed by Fuel Gas Supplier	0	0	0	0
Fuel Gas Conditioning		1,050,000	1,064	161,451	1,211,451
Bulk Gas Storage Provisions		10,000	196	29,741	39,741
Air Compressors & Dryers		184,000	392	59,482	243,482
Water Treating	Not Included	0	0	0	0
Fire Protection	Turnkey Subcontract	450,000	0	0	450,000
B.O.P. Mechanical (Miscellaneous)		100,000	560	84,974	184,974
BOP Piping	Shop Fab LB and Field Fab SB. Includes all Hangers & Insulation	1,105,910	43,621	6,645,998	7,751,908
Valves & Specialties		477,325	1,712	270,356	747,681
Electrical Major Equipment		6,295,000	16,450	2,175,464	8,470,464
Electrical BOP		1,850,036	62,548	8,601,563	10,451,599
Instrumentation & Controls		1,185,000	6,370	890,590	2,075,590
Switchyard	Allowance - Based on 138kV 4-Breaker GIS	3,850,000	14,930	1,901,882	5,751,882
Steel	Excluding Building Framing	185,083	1,890	307,662	492,745
Buildings	Includes Buildings, HVAC, & Interior Finishes	935,900	14,248	2,161,961	3,097,861
Foundations	Includes Excavation and Foundation Pile Allowance	2,158,347	26,957	3,639,657	5,798,004
Demolition & Mods to Existing Structures	None	0	0	0	0
Site Preparation, Drainage, & Yard Work		1,281,200	16,959	2,671,929	3,953,129
Heavy Haul Subcontracts		0	0	800,000	800,000
Indirect and Startup Craft Support		0	62,383	515,916	515,916
Allowances to Attract Labor		0	31,069	8,824,869	8,824,869
Erection Contractors G&A and Profit		0	0	13,114,281	13,114,281
Total Equipment, Material and Labor Costs		127,577,800	388,369	66,065,018	193,642,818
Consumables					637,900
Freight, Duties, Taxes, Etc.	Freight Only				2,253,501
Total Direct Project Costs					196,534,219
Indirect Project Costs					42,294,000
Contingency & Escalation	Contingency Only				23,883,000
Spare Parts Cost					1,061,000
Electrical Interconnection & Upgrades					4,800,000
Gas Interconnect & Reinforcement					5,740,000
Site Remediation					2,005,500
Total EPC Project Cost					276,317,719

Table A-12 — EPC Cost Breakdown for LMS100 in Long Island - (2010 $)

Description	Scope Definition	Total Equipment or Material Cost	Total Man-hours	Total Construction & Erection Cost	Total Projected Cost
Combustion Turbines w/ Accessories	GE LMS100-PA	84,400,000	41,580	6,265,690	90,665,690
SCR w/ Exhaust Stack		13,500,000	33,534	5,053,238	18,553,238
Aqueous Ammonia Storage & Forwarding		280,000	945	142,402	422,402
Inlet Air Chillers	Not Included	0	0	0	0
Pumps		688,000	2,020	305,727	993,727
Field Erected Tanks	Turnkey Subcontracts	700,000	0	0	700,000
Shop Fabricated Tanks		70,000	258	38,347	108,347
Cranes & Hoists	Allowance for Misc. Hoists Only	15,000	203	30,654	45,654
Fuel Gas Compressors	2x100%	2,300,000	2,970	447,549	2,747,549
Fuel Gas Supply & Metering	Gas Interconnection and Metering Station Assumed by Fuel Gas Supplier	0	0	0	0
Fuel Gas Conditioning		1,050,000	1,026	154,608	1,204,608
Bulk Gas Storage Provisions		10,000	189	28,480	38,480
Air Compressors & Dryers		184,000	378	56,961	240,961
Water Treating	Not Included	0	0	0	0
Fire Protection	Turnkey Subcontract	350,000	0	0	350,000
B.O.P. Mechanical (Miscellaneous)		100,000	540	81,373	181,373
BOP Piping	Shop Fab LB and Field Fab SB. Includes all Hangers & Insulation	1,071,110	40,524	6,008,395	7,079,505
Valves & Specialties		437,450	1,509	232,206	669,656
Electrical Major Equipment		7,195,000	15,863	1,987,766	9,182,766
Electrical BOP		1,776,830	59,770	7,509,129	9,285,959
Instrumentation & Controls		1,185,000	6,143	794,655	1,979,655
Switchyard	Allowance - Based on 345kV 4-Breaker Ring Bus	2,800,000	31,253	3,794,679	6,594,679
Steel	Excluding Building Framing	171,084	1,823	293,765	464,850
Buildings	Includes Buildings, HVAC, & Interior Finishes	668,500	9,813	1,478,744	2,147,244
Foundations	Includes Excavation and Foundation Pile Allowance	1,788,531	23,553	2,978,605	4,767,136
Demolition & Mods to Existing Structures	None	0	0	0	0
Site Preparation, Drainage, & Yard Work		1,201,200	15,057	2,188,988	3,390,188
Heavy Haul Subcontracts		0	0	800,000	800,000
Indirect and Startup Craft Support		0	61,190	512,346	512,346
Allowances to Attract Labor		0	30,447	8,381,436	8,381,436
Erection Contractors G&A and Profit		0	0	12,256,117	12,256,117
Total Equipment, Material and Labor Costs		121,941,706	380,584	61,821,860	183,763,566
Consumables					609,700
Freight, Duties, Taxes, Etc.	Freight Only				2,067,377
Total Direct Project Costs					186,440,643
Indirect Project Costs					40,122,000
Contingency & Escalation	Contingency Only				22,656,000
Spare Parts Cost					1,061,000
Electrical Interconnect & Upgrades					4,700,000
Gas Interconnect & Reinforcement					4,879,000
Total EPC Project Cost					259,858,643

Table A-13 — EPC Cost Breakdown for 7FA Simple Cycle in Albany - (2010 $)

Description	Scope Definition	Total Equipment or Material Cost	Total Man-hours	Total Construction & Erection Cost	Total Projected Cost
Combustion Turbines w/ Accessories	GE 7FA.05	115,400,000	68,200	6,026,152	121,426,152
Simple Cycle Exhaust Stack		3,200,000	3,740	330,466	3,530,466
Aqueous Ammonia Storage & Forwarding	Not Required	0	0	0	0
Inlet Air Chillers	Not Included	0	0	0	0
Pumps		652,000	1,426	126,707	778,707
Field Erected Tanks	Turnkey Subcontracts	700,000	0	0	700,000
Shop Fabricated Tanks		70,000	210	18,814	88,814
Cranes & Hoists	Allowance for Misc. Hoists Only	15,000	165	14,665	29,665
Fuel Gas Compressors	Not Included - Assume 450 psi Supply Pressure	0	0	0	0
Fuel Gas Supply & Metering	Gas Interconnection and Metering Station Assumed by Fuel Gas Supplier	0	0	0	0
Fuel Gas Conditioning		1,700,000	1,210	106,916	1,806,916
Bulk Gas Storage Provisions		10,000	154	13,607	23,607
Air Compressors & Dryers		290,000	748	66,093	356,093
Water Treating	Not Included	0	0	0	0
Fire Protection	Turnkey Subcontract	500,000	0	0	500,000
B.O.P. Mechanical (Miscellaneous)		125,000	561	49,570	174,570
BOP Piping	Shop Fab LB and Field Fab SB. Includes all Hangers & Insulation	1,472,550	43,923	4,072,102	5,544,652
Valves & Specialties		523,400	1,503	146,008	669,408
Electrical Major Equipment		11,580,000	16,115	1,260,044	12,840,044
Electrical BOP		2,353,843	62,656	5,256,433	7,610,275
Instrumentation & Controls		1,180,000	5,412	445,029	1,625,029
Switchyard	Allowance - Based on 345kV 4-Breaker Ring Bus	2,800,000	25,465	2,021,157	4,821,157
Steel	Excluding Building Framing	212,110	1,837	192,826	404,936
Buildings	Includes Buildings, HVAC, & Interior Finishes	220,000	3,194	282,257	502,257
Foundations	Includes Excavation. Piles Not Included	751,816	19,296	1,565,091	2,316,906
Demolition & Mods to Existing Structures	None	0	0	0	0
Site Preparation, Drainage, & Yard Work		1,554,880	14,554	1,504,412	3,059,292
Heavy Haul Subcontracts		0	0	950,000	950,000
Indirect and Startup Craft Support		0	59,874	512,488	512,488
Allowances to Attract Labor		0	28,717	6,106,051	6,106,051
Erection Contractors G&A and Profit		0	0	8,876,623	8,876,623
Total Equipment, Material and Labor Costs		145,310,598	358,958	39,943,512	185,254,110
Consumables					726,600
Freight, Duties, Taxes, Etc.	Freight Only				1,408,977
Total Direct Project Costs					187,389,687
Indirect Project Costs					40,326,000
Contingency & Escalation	Contingency Only				22,772,000
Spare Parts Cost					1,061,000
Electrical Interconnect & Upgrades					4,200,000
Gas Interconnect & Reinforcement					5,740,000
Total EPC Project Cost					261,488,687

B. Appendix 2 – Financial Assumptions

Table B-1 — Real Carrying Charges on Capital Investment

Merchant Generator Example

Calendar Year			2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Operating Year			1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Loan Period Parameter			1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Equity Period Parameter			1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Evaluation Period Factor			1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Property Tax and Insurance Escalation Factor			1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
NYC Property Tax Exemption			1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Effective Income Tax Rate		39.615%	39.615%	39.615%	39.615%	39.615%	39.615%	39.615%	39.615%	39.615%	39.615%	39.615%	39.615%	39.615%	39.615%	39.615%	39.615%	39.615%	39.615%	39.615%	39.615%	39.615%
Total Project Capitalized Cost			1,000,000																			
Market Value			1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000
Tax Depreciation			5.000%	9.500%	8.550%	7.700%	6.930%	6.230%	5.900%	5.900%	5.910%	5.900%	5.910%	5.900%	5.910%	5.900%	5.910%	2.950%	0.000%	0.000%	0.000%	0.000%
Effective Tax Depreciation			5.000%	9.500%	8.550%	7.700%	6.930%	6.230%	5.900%	5.900%	5.910%	5.900%	5.910%	5.900%	5.910%	5.900%	5.910%	2.950%	0.000%	0.000%	0.000%	0.000%
Depreciated Value			1,000,000	950,000	855,000	769,500	692,500	623,200	560,900	501,900	442,900	383,800	324,800	265,700	206,700	147,600	88,600	29,500	0	0	0	0
Financing																						
DEBT SERVICE:			500,000																			
Loan Balance Start of Year			500,000	484,452	468,168	451,113	433,250	414,541	394,946	374,423	352,927	330,414	306,834	282,138	256,271	229,180	200,806	171,087	139,961	107,361	73,217	37,455
Principal			15,548	16,284	17,055	17,863	18,709	19,595	20,523	21,495	22,513	23,580	24,697	25,866	27,091	28,375	29,718	31,126	32,600	34,144	35,761	37,455
Interest			23,682	22,945	22,174	21,366	20,520	19,634	18,706	17,734	16,716	15,649	14,533	13,363	12,138	10,855	9,511	8,103	6,629	5,085	3,468	1,774
Balance at End of Year			484,452	468,168	451,113	433,250	414,541	394,946	374,423	352,927	330,414	306,834	282,138	256,271	229,180	200,806	171,087	139,961	107,361	73,217	37,455	0
EQUITY:			500,000																			
TOTAL FINANCING			1,000,000																			
Income Statement (Check)																						
Carrying Charge Revenues:			112,851	83,812	90,550	96,657	102,263	107,437	110,211	110,848	111,451	112,216	112,883	113,716	114,454	115,361	116,177	136,520	156,840	157,853	158,914	160,025
Capital Related Expenses:																						
Property Taxes			0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Insurance			0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Tax Depreciation			50,000	95,000	85,500	77,000	69,300	62,300	59,000	59,000	59,100	59,000	59,100	59,000	59,100	59,000	59,100	29,500	0	0	0	0
Interest Expenses			23,682	22,945	22,174	21,366	20,520	19,634	18,706	17,734	16,716	15,649	14,533	13,363	12,138	10,855	9,511	8,103	6,629	5,085	3,468	1,774
Taxable Income			39,169	-34,133	-17,124	-1,709	12,443	25,503	32,505	34,115	35,635	37,566	39,250	41,353	43,216	45,507	47,567	98,916	150,211	152,768	155,446	158,251
Income Taxes			15,517	-13,522	-6,784	-677	4,929	10,103	12,877	13,514	14,117	14,882	15,549	16,382	17,120	18,027	18,844	39,186	59,506	60,519	61,580	62,691
Principal			15,548	16,284	17,055	17,863	18,709	19,595	20,523	21,495	22,513	23,580	24,697	25,866	27,091	28,375	29,718	31,126	32,600	34,144	35,761	37,455
Cash Flow to Equit Equity IRR =	**9.84%**	-500,000	58,105	58,105	58,105	58,105	58,105	58,105	58,105	58,105	58,105	58,105	58,105	58,105	58,105	58,105	58,105	58,105	58,105	58,105	58,105	58,105
Derivation of Carrying Charges																						
Target Equity IRR =	**9.84%**																					
Principal		-	15,548	16,284	17,055	17,863	18,709	19,595	20,523	21,495	22,513	23,580	24,697	25,866	27,091	28,375	29,718	31,126	32,600	34,144	35,761	37,455
Interest Expenses		-	23,682	22,945	22,174	21,366	20,520	19,634	18,706	17,734	16,716	15,649	14,533	13,363	12,138	10,855	9,511	8,103	6,629	5,085	3,468	1,774
Target Cash Flow to Equity		-	58,105	58,105	58,105	58,105	58,105	58,105	58,105	58,105	58,105	58,105	58,105	58,105	58,105	58,105	58,105	58,105	58,105	58,105	58,105	58,105
Income Taxes		-	15,517	-13,522	-6,784	-677	4,929	10,103	12,877	13,514	14,117	14,882	15,549	16,382	17,120	18,027	18,844	39,186	59,506	60,519	61,580	62,691
Property Taxes and Insurance			0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Carrying Charges		-	112,851	83,812	90,550	96,657	102,263	107,437	110,211	110,848	111,451	112,216	112,883	113,716	114,454	115,361	116,177	136,520	156,840	157,853	158,914	160,025
Annual Rate (% of initial capital investment)			11.29%	8.38%	9.06%	9.67%	10.23%	10.74%	11.02%	11.08%	11.15%	11.22%	11.29%	11.37%	11.45%	11.54%	11.62%	13.65%	15.68%	15.79%	15.89%	16.00%
After-Tax Cost of Capital =	6.35%																					
Present Value Factor			0.9403	0.8841	0.8313	0.7817	0.7350	0.6911	0.6498	0.6110	0.5745	0.5402	0.5079	0.4776	0.4491	0.4222	0.3970	0.3733	0.3510	0.3301	0.3103	0.2918
Present Value			106,111	74,100	75,276	75,553	75,161	74,248	71,616	67,728	64,029	60,618	57,336	54,310	51,398	48,711	46,126	50,965	55,054	52,100	49,318	46,696
Cumulative Present Value			106,111	180,210	255,486	331,039	406,200	480,448	552,063	619,791	683,820	744,438	801,775	856,084	907,482	956,193	1,002,319	1,053,284	1,108,338	1,160,438	1,209,756	1,256,452
Levelized Carrying Charges (Real)		112,693																				
Levelized Carrying Charge Rate (Real) =		**11.27%**																				

Table B-2 — Real Levelized Carrying Charge Rates - Results of Sensitivity Analysis

Amortization Years	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35
Base Case:																										
Without Property Taxes and Insurance:																										
non-NYC:	16.89%	15.89%	15.05%	14.33%	13.71%	13.16%	12.68%	12.26%	11.89%	11.56%	11.27%	11.01%	10.78%	10.57%	10.38%	10.20%	10.05%	9.90%	9.77%	9.65%	9.54%	9.44%	9.35%	9.26%	9.18%	9.11%
NYC:	17.53%	16.50%	15.63%	14.89%	14.24%	13.68%	13.18%	12.73%	12.34%	12.00%	11.69%	11.42%	11.17%	10.95%	10.75%	10.57%	10.41%	10.26%	10.12%	9.99%	9.88%	9.77%	9.67%	9.58%	9.50%	9.42%
With Property Taxes and IDA Tax Exemption Policy; Without Insurance:																										
NYC - 50% Abatement:	19.87%	18.84%	17.98%	17.36%	16.82%	16.34%	15.92%	15.54%	15.21%	14.92%	14.66%	14.43%	14.22%	14.03%	13.87%	13.71%	13.57%	13.45%	13.33%	13.22%	13.12%	13.03%	12.95%	12.87%	12.80%	12.73%
NYC - 70% Abatement:	18.93%	17.91%	17.04%	16.47%	15.97%	15.53%	15.13%	14.79%	14.48%	14.21%	13.97%	13.76%	13.56%	13.39%	13.23%	13.09%	12.96%	12.84%	12.74%	12.64%	12.55%	12.46%	12.39%	12.31%	12.25%	12.18%
NYC - 80% Abatement:	18.46%	17.44%	16.57%	16.02%	15.54%	15.12%	14.74%	14.41%	14.12%	13.86%	13.63%	13.42%	13.23%	13.07%	12.92%	12.78%	12.66%	12.54%	12.44%	12.35%	12.26%	12.18%	12.10%	12.03%	11.97%	11.91%
NYC - 100% Abatement:	17.53%	16.50%	15.63%	15.13%	14.70%	14.31%	13.96%	13.66%	13.39%	13.15%	12.94%	12.75%	12.58%	12.42%	12.29%	12.16%	12.05%	11.94%	11.85%	11.76%	11.68%	11.61%	11.54%	11.47%	11.41%	11.36%
200 bp higher on nominal debt and equity cost:																										
Without Property Taxes and Insurance:																										
non-NYC:	18.71%	17.70%	16.85%	16.13%	15.50%	14.96%	14.48%	14.06%	13.69%	13.36%	13.08%	12.82%	12.60%	12.39%	12.21%	12.05%	11.90%	11.76%	11.64%	11.53%	11.43%	11.33%	11.25%	11.17%	11.10%	11.03%
NYC:	19.47%	18.43%	17.55%	16.80%	16.15%	15.58%	15.07%	14.63%	14.24%	13.90%	13.59%	13.33%	13.08%	12.87%	12.68%	12.50%	12.34%	12.20%	12.07%	11.95%	11.84%	11.74%	11.65%	11.56%	11.48%	11.41%
With Property Taxes and IDA Tax Exemption Policy; Without Insurance:																										
NYC - 50% Abatement:	21.82%	20.78%	19.90%	19.26%	18.70%	18.21%	17.78%	17.39%	17.05%	16.76%	16.50%	16.26%	16.06%	15.87%	15.70%	15.55%	15.41%	15.29%	15.18%	15.07%	14.98%	14.89%	14.81%	14.74%	14.67%	14.61%
NYC - 70% Abatement:	20.88%	19.84%	18.96%	18.37%	17.85%	17.39%	16.98%	16.62%	16.30%	16.03%	15.78%	15.56%	15.37%	15.19%	15.04%	14.90%	14.77%	14.65%	14.54%	14.45%	14.36%	14.28%	14.20%	14.13%	14.07%	14.01%
NYC - 80% Abatement:	20.41%	19.37%	18.49%	17.92%	17.42%	16.98%	16.58%	16.23%	15.93%	15.66%	15.42%	15.21%	15.02%	14.86%	14.70%	14.57%	14.44%	14.33%	14.23%	14.13%	14.05%	13.97%	13.90%	13.83%	13.77%	13.71%
NYC - 100% Abatement:	19.47%	18.43%	17.55%	17.02%	16.56%	16.15%	15.78%	15.46%	15.18%	14.93%	14.71%	14.51%	14.34%	14.18%	14.04%	13.91%	13.80%	13.69%	13.59%	13.51%	13.43%	13.35%	13.29%	13.22%	13.16%	13.11%
400 bp higher on nominal debt and equity cost:																										
Without Property Taxes and Insurance:																										
non-NYC:	20.57%	19.56%	18.71%	17.99%	17.37%	16.83%	16.35%	15.94%	15.58%	15.26%	14.99%	14.74%	14.53%	14.33%	14.16%	14.01%	13.87%	13.74%	13.63%	13.53%	13.44%	13.35%	13.28%	13.21%	13.14%	13.09%
NYC:	21.47%	20.42%	19.54%	18.78%	18.13%	17.56%	17.06%	16.62%	16.23%	15.90%	15.60%	15.34%	15.11%	14.90%	14.72%	14.55%	14.40%	14.27%	14.14%	14.03%	13.93%	13.84%	13.76%	13.68%	13.61%	13.55%
With Property Taxes and IDA Tax Exemption Policy; Without Insurance:																										
NYC - 50% Abatement:	23.81%	22.77%	21.88%	21.23%	20.66%	20.16%	19.72%	19.34%	19.00%	18.70%	18.44%	18.21%	18.01%	17.83%	17.67%	17.52%	17.39%	17.27%	17.16%	17.06%	16.98%	16.90%	16.82%	16.75%	16.69%	16.64%
NYC - 70% Abatement:	22.88%	21.83%	20.94%	20.33%	19.80%	19.33%	18.91%	18.55%	18.23%	17.95%	17.70%	17.49%	17.29%	17.12%	16.97%	16.83%	16.71%	16.59%	16.49%	16.40%	16.32%	16.24%	16.17%	16.11%	16.05%	15.99%
NYC - 80% Abatement:	22.41%	21.36%	20.48%	19.88%	19.37%	18.91%	18.51%	18.15%	17.84%	17.57%	17.33%	17.12%	16.94%	16.77%	16.62%	16.49%	16.37%	16.26%	16.16%	16.07%	15.99%	15.91%	15.84%	15.78%	15.72%	15.67%
NYC - 100% Abatement:	21.47%	20.42%	19.54%	18.98%	18.50%	18.08%	17.70%	17.36%	17.07%	16.82%	16.59%	16.40%	16.22%	16.06%	15.92%	15.80%	15.68%	15.58%	15.49%	15.40%	15.33%	15.26%	15.19%	15.13%	15.08%	15.03%

C. Appendix 3 – STATA Output

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                                           Statistics/Data Analysis
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\Stata Files\appendix.smcl
log type: **smcl**
opened on: **30 Jun 2010, 13:55:20**

1 anova llbmp m#zone c.load#zone c.aggload#c.load#zone c.aggload#region c.agglo
> ad2#region c.aggload3#region c.lgasp#m#h c.rm h#m dow zone c.tmin c.tmax

Number of obs = **288002**   R-squared = **0.8843**
Root MSE = **.162086**   Adj R-squared = **0.8840**

Source	Partial SS	df	MS	F	Prob > F
Model	**57662.0275**	**735**	**78.4517381**	**2986.14**	**0.0000**
m#zone	**627.215038**	**121**	**5.18359536**	**197.31**	**0.0000**
zone#load	**56.0359586**	**11**	**5.09417806**	**193.90**	**0.0000**
zone#aggload#load	**94.0604695**	**11**	**8.55095177**	**325.48**	**0.0000**
region#aggload	**126.100418**	**3**	**42.0334727**	**1599.94**	**0.0000**
region#aggload2	**79.5568136**	**3**	**26.5189379**	**1009.40**	**0.0000**
region#aggload3	**50.7511624**	**3**	**16.9170541**	**643.92**	**0.0000**
m#h#lgasp	**18772.3405**	**288**	**65.181738**	**2481.04**	**0.0000**
rm	**45.0914212**	**1**	**45.0914212**	**1716.34**	**0.0000**
h#m	**100.064661**	**276**	**.362553118**	**13.80**	**0.0000**
dow	**32.7624834**	**6**	**5.4604139**	**207.84**	**0.0000**
zone	**97.8412245**	**10**	**9.78412245**	**372.42**	**0.0000**
tmin	**73.0492232**	**1**	**73.0492232**	**2780.51**	**0.0000**
tmax	**.029050733**	**1**	**.029050733**	**1.11**	**0.2930**
Residual	**7547.02773**	**287266**	**.026271914**		
Total	**65209.0552**	**288001**	**.226419545**		

2 .regress

Source	SS	df	MS
Model	**57662.0275**	**735**	**78.4517381**
Residual	**7547.02773**	**287266**	**.026271914**
Total	**65209.0552**	**288001**	**.226419545**

Number of obs = **288002**
F(735,287266) = **2986.14**
Prob > F = **0.0000**
R-squared = **0.8843**
Adj R-squared = **0.8840**
Root MSE = **.16209**

llbmp		Coef.	Std. Err.	t	P>ItI	[95% Conf.	Interval]
m#zone							
2	1	**-.0663132**	**.0598947**	**-1.11**	**0.268**	**-.1837052**	**.0510788**
2	2	**-.0183166**	**.0598946**	**-0.31**	**0.760**	**-.1357083**	**.0990751**
2	3	**-.0555994**	**.0598945**	**-0.93**	**0.353**	**-.1729911**	**.0617922**
2	4	**.0511176**	**.0598948**	**0.85**	**0.393**	**-.0662746**	**.1685098**
2	5	**-.05263**	**.0598948**	**-0.88**	**0.380**	**-.1700221**	**.064762**
2	6	**-.0458995**	**.0598755**	**-0.77**	**0.443**	**-.1632538**	**.0714548**
2	7	**-.0265994**	**.0598959**	**-0.44**	**0.657**	**-.1439938**	**.0907949**
2	8	**-.0477646**	**.0598951**	**-0.80**	**0.425**	**-.1651573**	**.069628**
2	9	**-.0020097**	**.0598636**	**-0.03**	**0.973**	**-.1193408**	**.1153213**

	2 10	-.0287272	.0598947	-0.48	0.631	-.1461192	.0886647
	2 11	.0499449	.0598946	0.83	0.404	-.0674469	.1673367
3	1	-.2088401	.055337	-3.77	0.000	-.317299	-.1003812
3	2	-.1488795	.0553401	-2.69	0.007	-.2573445	-.0404145
3	3	-.1681528	.0553363	-3.04	0.002	-.2766103	-.0596952
3	4	-.070318	.0553359	-1.27	0.204	-.1787748	.0381388
3	5	-.1716874	.0553362	-3.10	0.002	-.2801448	-.0632299
3	6	-.2350752	.0553083	-4.25	0.000	-.3434779	-.1266724
3	7	-.1606975	.0553385	-2.90	0.004	-.2691595	-.0522355
3	8	-.1504441	.055336	-2.72	0.007	-.2589011	-.0419871
3	9	-.1727743	.0553086	-3.12	0.002	-.2811777	-.0643709
	3 10	-.1723419	.055337	-3.11	0.002	-.2808008	-.063883

3	11	-.0933023	.0553371	-1.69	0.092	-.2017615	.0151568
4	1	-.3066459	.0534991	-5.73	0.000	-.4115025	-.2017892
4	2	-.3318185	.0535059	-6.20	0.000	-.4366886	-.2269483
4	3	-.2851348	.0534915	-5.33	0.000	-.3899766	-.1802929
4	4	-.2528833	.0534928	-4.73	0.000	-.3577276	-.148039
4	5	-.2837251	.0534879	-5.30	0.000	-.3885599	-.1788903
4	6	-.3724472	.0534626	-6.97	0.000	-.4772324	-.267662
4	7	-.3557039	.0535094	-6.65	0.000	-.4605809	-.250827
4	8	-.2652179	.0534929	-4.96	0.000	-.3700626	-.1603733
4	9	-.284574	.0534778	-5.32	0.000	-.3893891	-.179759
4	10	-.3703778	.0534949	-6.92	0.000	-.4752264	-.2655293
4	11	-.2876753	.0534947	-5.38	0.000	-.3925233	-.1828272
5	1	-.4319526	.0533594	-8.10	0.000	-.5365356	-.3273696
5	2	-.5006263	.0533753	-9.38	0.000	-.6052404	-.3960122
5	3	-.4270369	.0533452	-8.01	0.000	-.531592	-.3224817
5	4	-.5234997	.0533537	-9.81	0.000	-.6280716	-.4189279
5	5	-.4194133	.0533452	-7.86	0.000	-.5239684	-.3148581
5	6	-.4416299	.0533629	-8.28	0.000	-.5462197	-.3370402
5	7	-.525682	.0533731	-9.85	0.000	-.6302918	-.4210723
5	8	-.4063979	.0533476	-7.62	0.000	-.5109577	-.301838
5	9	-.4752142	.0534108	-8.90	0.000	-.579898	-.3705304
5	10	-.6075374	.0533633	-11.38	0.000	-.7121281	-.5029467
5	11	-.5197413	.0533643	-9.74	0.000	-.6243338	-.4151488
6	1	-.6433682	.0522843	-12.31	0.000	-.745844	-.5408924
6	2	-.561546	.052328	-10.73	0.000	-.6641074	-.4589846
6	3	-.5843038	.0522868	-11.17	0.000	-.6867844	-.4818232
6	4	-.5319281	.0522864	-10.17	0.000	-.6344079	-.4294482
6	5	-.5801156	.0522773	-11.10	0.000	-.6825776	-.4776536
6	6	-.7105505	.0523321	-13.58	0.000	-.81312	-.6079809
6	7	-.5768685	.052295	-11.03	0.000	-.6793652	-.4743718
6	8	-.5568362	.0522858	-10.65	0.000	-.6593149	-.4543574
6	9	-.6408991	.052386	-12.23	0.000	-.7435743	-.538224
6	10	-.5556103	.0523496	-10.61	0.000	-.6582141	-.4530065
6	11	-.5155502	.0523069	-9.86	0.000	-.6180702	-.4130301
7	1	-.7643136	.0515503	-14.83	0.000	-.8653508	-.6632764
7	2	-.6529619	.0516368	-12.65	0.000	-.7541687	-.5517552
7	3	-.7507026	.051547	-14.56	0.000	-.8517333	-.6496719
7	4	-.5945354	.0515607	-11.53	0.000	-.6955929	-.4934778
7	5	-.731051	.051532	-14.19	0.000	-.8320524	-.6300496
7	6	-.8999122	.0516205	-17.43	0.000	-1.001087	-.7987375
7	7	-.6838475	.0515597	-13.26	0.000	-.7849032	-.5827918
7	8	-.7121487	.0515424	-13.82	0.000	-.8131703	-.611127
7	9	-.7994624	.0516799	-15.47	0.000	-.9007536	-.6981712
7	10	-.6392685	.0516084	-12.39	0.000	-.7404195	-.5381175
7	11	-.5733952	.0515958	-11.11	0.000	-.6745216	-.4722688
8	1	-.7494136	.0528682	-14.18	0.000	-.8530338	-.6457934
8	2	-.6053365	.0529431	-11.43	0.000	-.7091036	-.5015695
8	3	-.7275908	.0528573	-13.77	0.000	-.8311896	-.623992
8	4	-.5391464	.0528713	-10.20	0.000	-.6427726	-.4355202
8	5	-.7098064	.0528521	-13.43	0.000	-.813395	-.6062179
8	6	-.8728867	.0528989	-16.50	0.000	-.976567	-.7692064
8	7	-.635564	.0528729	-12.02	0.000	-.7391934	-.5319345
8	8	-.6979917	.0528609	-13.20	0.000	-.8015975	-.5943858
8	9	-.7904638	.0529445	-14.93	0.000	-.8942335	-.686694
8	10	-.5565269	.0529293	-10.51	0.000	-.6602669	-.4527868
8	11	-.512901	.0529001	-9.70	0.000	-.6165837	-.4092183
9	1	-.8329619	.0525908	-15.84	0.000	-.9360384	-.7298855
9	2	-.6723625	.0526472	-12.77	0.000	-.7755495	-.5691755
9	3	-.8116324	.0525946	-15.43	0.000	-.9147164	-.7085483
9	4	-.5913861	.0525904	-11.25	0.000	-.6944618	-.4883104
9	5	-.7889032	.0525879	-15.00	0.000	-.891974	-.6858324
9	6	-.8893801	.0525948	-16.91	0.000	-.9924645	-.7862957
9	7	-.6963261	.0525919	-13.24	0.000	-.7994047	-.5932474
9	8	-.7882468	.0525918	-14.99	0.000	-.8913253	-.6851683
9	9	-.8898345	.0526593	-16.90	0.000	-.9930453	-.7866236
9	10	-.6429786	.0526492	-12.21	0.000	-.7461695	-.5397876
9	11	-.5754725	.0526077	-10.94	0.000	-.6785821	-.4723629
10	1	-.9758111	.0601918	-16.21	0.000	-1.093785	-.8578367
10	2	-.876622	.0602111	-14.56	0.000	-.9946341	-.7586099

10	3	-.9715591	0601921	-16.14	0.000	-1.089534	-.8535842
10	4	-.7916039	0601891	-13.15	0.000	-.9095729	-.6736348
10	5	-.9541911	0601889	-15.85	0.000	-1.07216	-.8362226
10	6	-.9925474	0601656	-16.50	0.000	-1.11047	-.8746245
10	7	-.9008955	0601899	-14.97	0.000	-1.018866	-.7829249
10	8	-.9490612	0601916	-15.77	0.000	-1.067035	-.8310873
10	9	-1.024103	0601972	-17.01	0.000	-1.142088	-.906118
	10 10	-.9174882	0602392	-15.23	0.000	-1.035555	-.799421
	10 11	-.7760539	0601927	-12.89	0.000	-.8940298	-.6580779
11	1	2.037419	2009934	10.14	0.000	1.643477	2.431361
11	2	2.178242	2009978	10.84	0.000	1.784292	2.572193
11	3	2.061936	2009938	10.26	0.000	1.667993	2.455878
11	4	2.26635	2009932	11.28	0.000	1.872409	2.660291
11	5	2.075152	2009938	10.32	0.000	1.68121	2.469095
11	6	1.990757	2009119	9.91	0.000	1.596975	2.384539
11	7	2.171124	.200997	10.80	0.000	1.777176	2.565073
11	8	2.08122	2009936	10.35	0.000	1.687278	2.475162
11	9	2.012565	.200888	10.02	0.000	1.61883	2.4063
	11 10	2.188431	2009933	10.89	0.000	1.79449	2.582372
	11 11	2.246343	2009938	11.18	0.000	1.852401	2.640286
12	1	-.4348615	.077913	-5.58	0.000	-.5875688	-.2821542
12	2	-.3979415	0779139	-5.11	0.000	-.5506507	-.2452324
12	3	-.4312893	0779122	-5.54	0.000	-.5839951	-.2785834
12	4	-.3583009	0779123	-4.60	0.000	-.5110068	-.2055949
12	5	-.4283704	0779124	-5.50	0.000	-.5810765	-.2756642
12	6	-.4416489	0778856	-5.67	0.000	-.5943025	-.2889953
12	7	-.4097439	0779149	-5.26	0.000	-.5624549	-.2570328
12	8	-.4238704	0779113	-5.44	0.000	-.5765744	-.2711664
12	9	-.4347156	0778725	-5.58	0.000	-.5873436	-.2820876
	12 10	-.4094398	0779126	-5.26	0.000	-.5621463	-.2567333
	12 11	-.3880816	.077913	-4.98	0.000	-.540789	-.2353743
	zone#c.load						
	1	.0001072	.0000274	3.91	0.000	.0000535	.0001609
	2	-.0000304	.0000231	-1.32	0.187	-.0000757	.0000148
	3	-.0007917	.0000453	-17.46	0.000	-.0008805	-.0007028
	4	-1.24e-06	.0000337	-0.04	0.971	-.0000674	.0000649
	5	-.0003671	.0000332	-11.05	0.000	-.0004322	-.0003019
	6	.000456	.0000445	10.26	0.000	.0003689	.0005432
	7	-.0002727	.0000363	-7.52	0.000	-.0003438	-.0002017
	8	-.002565	.0000705	-36.39	0.000	-.0027032	-.0024269
	9	-.0000259	.00002	-1.30	0.195	-.0000651	.0000133
	10	-.0001968	.000031	-6.36	0.000	-.0002575	-.0001361
	11	-.0000232	.0000227	-1.02	0.308	-.0000677	.0000214
	zone# c.aggload# c.load						
	1	1.03e-08	9.24e-10	11.21	0.000	8.54e-09	1.22e-08
	2	1.16e-08	7.22e-10	16.11	0.000	1.02e-08	1.30e-08
	3	5.49e-08	1.55e-09	35.40	0.000	5.19e-08	5.80e-08
	4	1.78e-08	1.12e-09	15.95	0.000	1.56e-08	2.00e-08
	5	2.87e-08	1.05e-09	27.25	0.000	2.67e-08	3.08e-08
	6	-1.10e-08	2.03e-09	-5.41	0.000	-1.50e-08	-7.00e-09
	7	2.95e-08	1.32e-09	22.31	0.000	2.69e-08	3.20e-08
	8	1.42e-07	3.01e-09	47.18	0.000	1.36e-07	1.48e-07
	9	6.15e-09	9.48e-10	6.48	0.000	4.29e-09	8.00e-09
	10	4.26e-08	1.42e-09	29.99	0.000	3.98e-08	4.53e-08
	11	1.25e-08	7.31e-10	17.11	0.000	1.11e-08	1.39e-08
	region# c.aggload						
	0	.0004559	7.01e-06	65.05	0.000	.0004421	.0004696
	1	.0004771	.0000178	26.87	0.000	.0004423	.0005119
	2	.0004835	.000017	28.46	0.000	.0004502	.0005168
	region# c.aggload2						
	0	-.0001722	3.37e-06	-51.10	0.000	-.0001788	-.0001655

	1	-.0001794	8.67e-06	-20.69	0.000	-.0001964	-.0001624
	2	-.0001925	8.18e-06	-23.52	0.000	-.0002085	-.0001764
region# c.aggload3							
	0	.0000207	5.22e-07	39.69	0.000	.0000197	.0000217
	1	.0000203	1.31e-06	15.57	0.000	.0000178	.0000229
	2	.0000291	1.37e-06	21.28	0.000	.0000264	.0000317
m#h#c.lgasp							
1	0	.4744123	.0211858	22.39	0.000	.4328888	.5159359
1	1	.4758305	.0211879	22.46	0.000	.4343029	.5173581
1	2	.4775311	.0211896	22.54	0.000	.4360002	.5190621
1	3	.4485093	.021191	21.17	0.000	.4069756	.490043
1	4	.4747882	.0211916	22.40	0.000	.4332533	.5163231
1	5	.4925606	.0211891	23.25	0.000	.4510306	.5340906
1	6	.4616729	.0211863	21.79	0.000	.4201484	.5031974
1	7	.5469706	.0211856	25.82	0.000	.5054473	.5884938
1	8	.5532034	.0211858	26.11	0.000	.5116799	.5947269
1	9	.5261612	.0211858	24.84	0.000	.4846377	.5676848
1	10	.5202758	.0211857	24.56	0.000	.4787523	.5617992
1	11	.4849116	.0211858	22.89	0.000	.443388	.5264351
1	12	.4665506	.0211858	22.02	0.000	.4250271	.5080742
1	13	.4551907	.0211859	21.49	0.000	.4136668	.4967145
1	14	.4385449	.0211861	20.70	0.000	.3970208	.480069
1	15	.4926138	.0211864	23.25	0.000	.451089	.5341386
1	16	.5518704	.0211864	26.05	0.000	.5103456	.5933951
1	17	.5656855	.0211875	26.70	0.000	.5241585	.6072125
1	18	.626115	.0211884	29.55	0.000	.5845863	.6676437
1	19	.595949	.0211885	28.13	0.000	.5544202	.6374779
1	20	.5909292	.0211884	27.89	0.000	.5494006	.6324578
1	21	.5212541	.021188	24.60	0.000	.4797262	.562782
1	22	.4541145	.0211874	21.43	0.000	.4125878	.4956413
1	23	.3891494	.0211881	18.37	0.000	.3476212	.4306775
2	0	.4521006	.0173136	26.11	0.000	.4181664	.4860347
2	1	.4494013	.0173148	25.95	0.000	.4154648	.4833379
2	2	.4394254	.0173159	25.38	0.000	.4054868	.473364
2	3	.4224633	.0173164	24.40	0.000	.3885236	.456403
2	4	.4221169	.0173162	24.38	0.000	.3881777	.4560561
2	5	.4352437	.0173143	25.14	0.000	.4013081	.4691793
2	6	.4748671	.0173137	27.43	0.000	.4409328	.5088014
2	7	.5532416	.0173146	31.95	0.000	.5193054	.5871777
2	8	.5907754	.0173151	34.12	0.000	.5568383	.6247126
2	9	.5510922	.0173161	31.83	0.000	.5171531	.5850313
2	10	.5709906	.0173167	32.97	0.000	.5370503	.6049309
2	11	.5559565	.0173167	32.11	0.000	.5220162	.5898967
2	12	.543001	.0173168	31.36	0.000	.5090605	.5769415
2	13	.52379	.0173168	30.25	0.000	.4898495	.5577305
2	14	.5135406	.017317	29.66	0.000	.4795998	.5474815
2	15	.5804916	.0173174	33.52	0.000	.54655	.6144332
2	16	.625536	.0173187	36.12	0.000	.5915918	.6594803
2	17	.6597716	.0173212	38.09	0.000	.6258225	.6937207
2	18	.5891886	.0173216	34.01	0.000	.5552387	.6231385
2	19	.6842569	.0173209	39.50	0.000	.6503085	.7182054
2	20	.6307303	.0173197	36.42	0.000	.5967841	.6646765
2	21	.5731322	.0173182	33.09	0.000	.5391891	.6070754
2	22	.5442782	.0173162	31.43	0.000	.5103389	.5782175
2	23	.4786485	.0173155	27.64	0.000	.4447106	.5125863
3	0	.6493234	.0143827	45.15	0.000	.6211336	.6775132
3	1	.6448974	.0143865	44.83	0.000	.6167003	.6730946
3	2	.6046497	.0146287	41.33	0.000	.575978	.6333215
3	3	.6452937	.0143908	44.84	0.000	.6170881	.6734993
3	4	.5989555	.0143896	41.62	0.000	.5707521	.6271588
3	5	.6449984	.0143836	44.84	0.000	.616807	.6731899
3	6	.5523424	.0143762	38.42	0.000	.5241655	.5805193
3	7	.6441467	.0143743	44.81	0.000	.6159735	.6723198
3	8	.7101783	.0143746	49.41	0.000	.6820046	.7383521
3	9	.6245832	.0143751	43.45	0.000	.5964084	.652758
3	10	.6753686	.0143753	46.98	0.000	.6471934	.7035437

3	11	.6599872	.0143755	45.91	0.000	.6318116	.6881627
3	12	.6391934	.0143756	44.46	0.000	.6110177	.6673691
3	13	.6056258	.0143758	42.13	0.000	.5774497	.6338019
3	14	.5802788	.0143761	40.36	0.000	.552102	.6084555
3	15	.5713976	.0143766	39.75	0.000	.5432199	.5995753
3	16	.6023877	.0143774	41.90	0.000	.5742083	.630567
3	17	.7398354	.0143792	51.45	0.000	.7116526	.7680182
3	18	.6927777	.014383	48.17	0.000	.6645874	.720968
3	19	.6425715	.0143804	44.68	0.000	.6143864	.6707566
3	20	.681179	.0143784	47.38	0.000	.6529977	.7093602
3	21	.6390155	.0143779	44.44	0.000	.6108352	.6671959
3	22	.6488194	.014378	45.13	0.000	.6206389	.6769998
3	23	.5903332	.0143808	41.05	0.000	.5621472	.6185192
4	0	.7718174	.01269	60.82	0.000	.7469454	.7966894
4	1	.8221376	.0126906	64.78	0.000	.7972643	.8470108
4	2	.8101918	.0126912	63.84	0.000	.7853174	.8350661
4	3	.7808639	.0126916	61.53	0.000	.7559888	.8057391
4	4	.7909276	.0126915	62.32	0.000	.7660525	.8158026
4	5	.8178814	.0126906	64.45	0.000	.7930081	.8427546
4	6	.7445139	.0126892	58.67	0.000	.7196434	.7693844
4	7	.8104031	.0126885	63.87	0.000	.7855339	.8352723
4	8	.8444131	.0126884	66.55	0.000	.8195442	.869282
4	9	.8716136	.0126884	68.69	0.000	.8467446	.8964825
4	10	.8492198	.0126885	66.93	0.000	.8243507	.8740889
4	11	.8621084	.0126885	67.94	0.000	.8372393	.8869775
4	12	.8649852	.0126883	68.17	0.000	.8401164	.889854
4	13	.8424757	.0126884	66.40	0.000	.8176067	.8673446
4	14	.8304002	.0126886	65.44	0.000	.8055309	.8552696
4	15	.8347818	.0126887	65.79	0.000	.8099123	.8596512
4	16	.8299733	.0126886	65.41	0.000	.8051039	.8548427
4	17	.8228648	.0126886	64.85	0.000	.7979955	.8477341
4	18	.8499698	.0126886	66.99	0.000	.8251005	.8748391
4	19	.7998347	.0126886	63.04	0.000	.7749653	.8247041
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4	22	.777246	.0126888	61.25	0.000	.7523763	.8021156
4	23	.7148541	.0126894	56.33	0.000	.6899832	.7397249
5	0	.6090425	.0122803	49.60	0.000	.5849734	.6331115
5	1	.7240093	.0122819	58.95	0.000	.699937	.7480815
5	2	.7209412	.0122835	58.69	0.000	.696866	.7450165
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5	4	.7376126	.0122851	60.04	0.000	.7135341	.7616911
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5	6	.7748608	.0122809	63.09	0.000	.7507905	.798931
5	7	.7274926	.0122784	59.25	0.000	.7034273	.7515579
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5	9	.7977888	.012277	64.98	0.000	.7737263	.8218514
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	6 13	.8763884	.0110563	79.27	0.000	.8547184	.8980585
	6 14	.8861478	.0110582	80.14	0.000	.8644741	.9078214
	6 15	.8495227	.0110596	76.81	0.000	.8278462	.8711993
	6 16	.8901696	.0110611	80.48	0.000	.8684902	.9118489
	6 17	.8616033	.01106	77.90	0.000	.839926	.8832805
	6 18	.8276618	.0110582	74.85	0.000	.8059879	.8493357
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	6 20	.8188869	.0110557	74.07	0.000	.7972182	.8405557
	6 21	.8104968	.0110573	73.30	0.000	.7888247	.8321688
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7	2	.906622	.0109123	83.08	0.000	.8852342	.9280098
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7	4	.9492804	.0109177	86.95	0.000	.927882	.9706789
7	5	.9253994	.0109089	84.83	0.000	.9040183	.9467805
7	6	.8922173	.0108952	81.89	0.000	.870863	.9135716
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	7 17	.9569446	.0109154	87.67	0.000	.9355508	.9783385
	7 18	.9571474	.0109061	87.76	0.000	.9357718	.9785231
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8	2	.908857	.0132547	68.57	0.000	.8828781	.9348359
8	3	.9526483	.013255	71.87	0.000	.9266687	.9786278
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1	1	-.0113033	.0655833	-0.17	0.863	-.1398447	.1172381
1	2	.1273157	.0531171	2.40	0.017	.0232077	.2314237
1	3	-.0616141	.0421474	-1.46	0.144	-.1442217	.0209935
1	4	-.1800809	.0370557	-4.86	0.000	-.2527091	-.1074527
1	5	.0585419	.0366773	1.60	0.110	-.0133445	.1304284
1	6	.0468886	.0334294	1.40	0.161	-.0186321	.1124092
1	7	-.0041224	.0309539	-0.13	0.894	-.0647913	.0565464
1	8	-.0551514	.035081	-1.57	0.116	-.1239091	.0136063
1	9	.116126	.0344096	3.37	0.001	.0486843	.1835678
	1 10	.3768763	.0537025	7.02	0.000	.2716208	.4821318
	1 11	-.6557262	.2725757	-2.41	0.016	-1.189967	-.1214854
	1 12	-.1886699	.0882606	-2.14	0.033	-.3616583	-.0156816
2	1	-.0226198	.0655868	-0.34	0.730	-.151168	.1059285
2	2	.1470043	.0531218	2.77	0.006	.042887	.2511216
2	3	.0071343	.0425286	0.17	0.867	-.0762206	.0904892
2	4	-.1667912	.03707	-4.50	0.000	-.2394473	-.0941351
2	5	.0474503	.0366969	1.29	0.196	-.0244745	.1193752
2	6	-.0555117	.0334724	-1.66	0.097	-.1211166	.0100933
2	7	-.0918608	.030982	-2.96	0.003	-.1525847	-.0311369
2	8	-.1208909	.0350861	-3.45	0.001	-.1896587	-.052123
2	9	-.1525217	.0344356	-4.43	0.000	-.2200144	-.0850289
	2 10	.5855904	.0537261	10.90	0.000	.4802887	.6908921
	2 11	1.077119	.2762523	3.90	0.000	.5356718	1.618565
	2 12	-.1494511	.0882745	-1.69	0.090	-.3224667	.0235645
3	1	.0318217	.0655895	0.49	0.628	-.0967319	.1603753
3	2	.1912328	.0531244	3.60	0.000	.0871104	.2953551
3	3	-.076514	.0421648	-1.81	0.070	-.1591558	.0061278
3	4	-.1040354	.037079	-2.81	0.005	-.1767092	-.0313616
3	5	.0349377	.0367102	0.95	0.341	-.0370133	.1068887
3	6	-.1055803	.0335001	-3.15	0.002	-.1712395	-.0399211
3	7	-.178911	.0310043	-5.77	0.000	-.2396786	-.1181434
3	8	-.2117396	.0350903	-6.03	0.000	-.2805156	-.1429636

3	9	-.2489961	.0344523	-7.23	0.000	-.3165216	-.1814706
	3 10	.5256667	.0537389	9.78	0.000	.4203399	.6309935
	3 11	1.130941	.2762615	4.09	0.000	.5894762	1.672406
	3 12	-.1765707	.088283	-2.00	0.045	-.3496028	-.0035386
4	1	-.0153076	.0655892	-0.23	0.815	-.1438607	.1132455
4	2	.1872386	.0531224	3.52	0.000	.0831202	.291357
4	3	.0312776	.0421604	0.74	0.458	-.0513556	.1139109
4	4	-.117369	.0370757	-3.17	0.002	-.1900364	-.0447016
4	5	.0355007	.0367077	0.97	0.333	-.0364454	.1074467
4	6	-.0611158	.033494	-1.82	0.068	-.126763	.0045315
4	7	-.1943547	.0310059	-6.27	0.000	-.2551254	-.1335841
4	8	-.2345498	.0350912	-6.68	0.000	-.3033275	-.1657721
4	9	-.0771548	.0344501	-2.24	0.025	-.1446761	-.0096335
	4 10	.4677028	.0537333	8.70	0.000	.3623871	.5730185
	4 11	1.090767	.2762598	3.95	0.000	.5493051	1.632228
	4 12	-.2401017	.0882814	-2.72	0.007	-.4131308	-.0670726
5	1	-.0214168	.0655835	-0.33	0.744	-.1499586	.1071251
5	2	.1806222	.0531145	3.40	0.001	.0765192	.2847252
5	3	-.026385	.0421413	-0.63	0.531	-.1089808	.0562107
5	4	-.1518971	.037054	-4.10	0.000	-.2245219	-.0792723
5	5	.0614679	.0366818	1.68	0.094	-.0104274	.1333632
5	6	-.10582	.033447	-3.16	0.002	-.1713752	-.0402649
5	7	-.1416849	.0309821	-4.57	0.000	-.2024089	-.080961
5	8	-.106135	.0350864	-3.02	0.002	-.1749034	-.0373666
5	9	.0878841	.034417	2.55	0.011	.0204277	.1553405
	5 10	.3334	.0537004	6.21	0.000	.2281486	.4386514
	5 11	1.010314	.2762467	3.66	0.000	.4688784	1.55175
	5 12	-.2348527	.0882642	-2.66	0.008	-.4078482	-.0618573
6	1	.0940604	.0655836	1.43	0.152	-.0344816	.2226025
6	2	.1474112	.0531148	2.78	0.006	.0433076	.2515147
6	3	.1998477	.0421362	4.74	0.000	.1172619	.2824335
6	4	.0678424	.0370404	1.83	0.067	-.0047557	.1404405
6	5	.0126545	.0366568	0.35	0.730	-.0591918	.0845008
6	6	.0585977	.0333849	1.76	0.079	-.0068358	.1240311
6	7	-.1066476	.0309452	-3.45	0.001	-.1672994	-.0459959
6	8	-.2531306	.0350792	-7.22	0.000	-.3218848	-.1843764
6	9	-.0152277	.034384	-0.44	0.658	-.0826194	.0521639
	6 10	.3206247	.0536717	5.97	0.000	.2154297	.4258198
	6 11	.8144121	.2762407	2.95	0.003	.272988	1.355836
	6 12	.1771196	.0882505	2.01	0.045	.004151	.3500882
7	1	-.1061878	.0655883	-1.62	0.105	-.2347391	.0223634
7	2	-.0687407	.0531187	-1.29	0.196	-.1728518	.0353705
7	3	-.0143358	.0421434	-0.34	0.734	-.0969356	.068264
7	4	-.1155836	.037041	-3.12	0.002	-.188183	-.0429842
7	5	.1158813	.0366551	3.16	0.002	.0440383	.1877243
7	6	-.06172	.0333726	-1.85	0.064	-.1271294	.0036894
7	7	-.0676844	.0309258	-2.19	0.029	-.1282981	-.0070707
7	8	-.1256294	.0350743	-3.58	0.000	-.194374	-.0568848
7	9	.0255789	.0343778	0.74	0.457	-.0418006	.0929583
	7 10	.3336444	.053674	6.22	0.000	.2284448	.4388439
	7 11	-.9246814	.2762371	-3.35	0.001	-1.466098	-.3832644
	7 12	-.0075913	.0882499	-0.09	0.931	-.1805588	.1653761
8	1	-.1535629	.0655916	-2.34	0.019	-.2821206	-.0250053
8	2	-.1678536	.0531225	-3.16	0.002	-.2719723	-.0637349
8	3	-.1842978	.0421482	-4.37	0.000	-.2669071	-.1016885
8	4	-.1963893	.037046	-5.30	0.000	-.2689984	-.1237802
8	5	.0227522	.0366634	0.62	0.535	-.049107	.0946114
8	6	-.1255074	.0333839	-3.76	0.000	-.190939	-.0600758
8	7	-.0912013	.03093	-2.95	0.003	-.1518232	-.0305794
8	8	-.0779867	.0350743	-2.22	0.026	-.1467314	-.0092421
8	9	-.044768	.0343834	-1.30	0.193	-.1121585	.0226225
	8 10	.2654836	.0536832	4.95	0.000	.160266	.3707012
	8 11	-.9449738	.276246	-3.42	0.001	-1.486408	-.4035392
	8 12	-.1275964	.0882521	-1.45	0.148	-.300568	.0453752
9	1	-.0929511	.065595	-1.42	0.156	-.2215154	.0356132
9	2	-.0910792	.0531248	-1.71	0.086	-.1952023	.013044
9	3	.0196922	.0421523	0.47	0.640	-.0629251	.1023095
9	4	-.2419917	.0370501	-6.53	0.000	-.314609	-.1693744
9	5	-.0318446	.036671	-0.87	0.385	-.1037188	.0400296

9	6	-.1377756	.0333971	-4.13	0.000	-.2032331	-.0723181
9	7	-.0592429	.0309415	-1.91	0.056	-.1198873	.0014015
9	8	-.0404322	.0350793	-1.15	0.249	-.1091867	.0283224
9	9	.080914	.0343924	2.35	0.019	.0135059	.1483221
	9 10	.3886842	.053692	7.24	0.000	.2834495	.493919
	9 11	-.9083293	.2762522	-3.29	0.001	-1.449776	-.3668827
	9 12	-.2056816	.0882547	-2.33	0.020	-.3786583	-.0327048
10	1	-.0931511	.0655972	-1.42	0.156	-.2217198	.0354177
10	2	-.1600513	.0531261	-3.01	0.003	-.2641771	-.0559256
10	3	-.1176484	.0421549	-2.79	0.005	-.2002708	-.035026
10	4	-.2012105	.0370525	-5.43	0.000	-.2738325	-.1285886
10	5	-.0443178	.0366761	-1.21	0.227	-.1162019	.0275662
10	6	-.0968637	.0334084	-2.90	0.004	-.1623432	-.0313843
10	7	-.0830699	.030956	-2.68	0.007	-.1437428	-.0223969
10	8	-.0500499	.0350871	-1.43	0.154	-.1188196	.0187199
10	9	.1181597	.0343994	3.43	0.001	.0507377	.1855816
	10 10	.3919112	.0536977	7.30	0.000	.2866651	.4971573
	10 11	-.8498005	.2762544	-3.08	0.002	-1.391251	-.3083496
	10 12	-.2410153	.0882567	-2.73	0.006	-.4139959	-.0680346
11	1	-.0502063	.0655981	-0.77	0.444	-.1787767	.078364
11	2	-.1661365	.0531262	-3.13	0.002	-.2702623	-.0620107
11	3	-.1171792	.0421548	-2.78	0.005	-.1998014	-.0345569
11	4	-.240647	.0370531	-6.49	0.000	-.31327	-.168024
11	5	-.0684863	.0366785	-1.87	0.062	-.1403751	.0034026
11	6	-.1087667	.0334162	-3.25	0.001	-.1742615	-.0432718
11	7	-.1190468	.0309702	-3.84	0.000	-.1797476	-.058346
11	8	-.0176854	.0350966	-0.50	0.614	-.0864737	.0511029
11	9	.1317243	.034404	3.83	0.000	.0642934	.1991553
	11 10	.3524069	.0537002	6.56	0.000	.2471561	.4576578
	11 11	-1.098486	.2762532	-3.98	0.000	-1.639935	-.5570377
	11 12	-.2598576	.0882573	-2.94	0.003	-.4328394	-.0868758
12	1	-.0576642	.065598	-0.88	0.379	-.1862344	.070906
12	2	-.1784602	.0531248	-3.36	0.001	-.2825833	-.0743371
12	3	-.1091588	.0421535	-2.59	0.010	-.1917784	-.0265392
12	4	-.2666737	.0370526	-7.20	0.000	-.3392958	-.1940515
12	5	-.0452313	.0366795	-1.23	0.218	-.117122	.0266594
12	6	-.1109116	.0334206	-3.32	0.001	-.1764151	-.0454081
12	7	-.1559441	.030981	-5.03	0.000	-.2166661	-.0952222
12	8	-.0032618	.0351055	-0.09	0.926	-.0720677	.065544
12	9	.1498718	.0344066	4.36	0.000	.0824358	.2173077
	12 10	.2563783	.0537006	4.77	0.000	.1511267	.3616299
	12 11	-1.056694	.2762506	-3.83	0.000	-1.598137	-.5152502
	12 12	-.339579	.0882567	-3.85	0.000	-.5125597	-.1665982
13	1	-.0633734	.0655976	-0.97	0.334	-.1919429	.0651961
13	2	-.1763818	.0531234	-3.32	0.001	-.2805023	-.0722614
13	3	-.0690282	.0421514	-1.64	0.102	-.1516438	.0135873
13	4	-.2249222	.0370517	-6.07	0.000	-.2975425	-.1523019
13	5	-.0124587	.0366793	-0.34	0.734	-.084349	.0594317
13	6	-.1038406	.0334241	-3.11	0.002	-.1693509	-.0383304
13	7	-.1944628	.0309908	-6.27	0.000	-.2552038	-.1337217
13	8	-.0473358	.0351133	-1.35	0.178	-.1161569	.0214853
13	9	.136494	.0344085	3.97	0.000	.0690543	.2039337
	13 10	.1320321	.0537003	2.46	0.014	.026781	.2372832
	13 11	-1.169738	.2762485	-4.23	0.000	-1.711177	-.6282983
	13 12	-.3658204	.0882559	-4.14	0.000	-.5387995	-.1928412
14	1	-.0442126	.065597	-0.67	0.500	-.172781	.0843557
14	2	-.1782288	.0531217	-3.36	0.001	-.2823459	-.0741117
14	3	-.0450617	.0421487	-1.07	0.285	-.127672	.0375485
14	4	-.2228431	.0370504	-6.01	0.000	-.2954607	-.1502254
14	5	-.0063928	.0366785	-0.17	0.862	-.0782817	.0654962
14	6	-.120671	.0334254	-3.61	0.000	-.186184	-.0551581
14	7	-.15179	.0309969	-4.90	0.000	-.2125431	-.0910369
14	8	-.026439	.0351193	-0.75	0.452	-.0952718	.0423938
14	9	.1116441	.0344088	3.24	0.001	.0442038	.1790844
	14 10	.0506324	.0536989	0.94	0.346	-.054616	.1558808
	14 11	-1.451379	.2762464	-5.25	0.000	-1.992814	-.9099435
	14 12	-.3402175	.088255	-3.85	0.000	-.5131948	-.1672401
15	1	-.1569476	.0655974	-2.39	0.017	-.2855166	-.0283785
15	2	-.3412827	.0531207	-6.42	0.000	-.4453979	-.2371675

15 3	-.0302982	.0421471	-0.72	0.472	-.1129053	.0523088
15 4	-.2418579	.0370493	-6.53	0.000	-.3144735	-.1692422
15 5	-.026944	.0366776	-0.73	0.463	-.0988311	.044943
15 6	-.0430397	.0334262	-1.29	0.198	-.1085542	.0224748
15 7	-.1777803	.0310013	-5.73	0.000	-.238542	-.1170186
15 8	-.0323263	.0351218	-0.92	0.357	-.101164	.0365114
15 9	.1093505	.0344086	3.18	0.001	.0419105	.1767904
15 10	.0135243	.0536981	0.25	0.801	-.0917225	.1187711
15 11	-1.749886	.2762477	-6.33	0.000	-2.291324	-1.208448
15 12	-.4772354	.0882552	-5.41	0.000	-.6502132	-.3042575
16 1	-.1902624	.0656011	-2.90	0.004	-.3188387	-.0616861
16 2	-.3932119	.0531221	-7.40	0.000	-.4973297	-.289094
16 3	-.0842954	.0421474	-2.00	0.045	-.166903	-.0016877
16 4	-.2300177	.0370494	-6.21	0.000	-.3026334	-.157402
16 5	-.0253662	.0366776	-0.69	0.489	-.0972533	.0465209
16 6	-.0947422	.033428	-2.83	0.005	-.1602601	-.0292243
16 7	-.171653	.0310022	-5.54	0.000	-.2324164	-.1108895
16 8	.0143942	.0351185	0.41	0.682	-.0544371	.0832254
16 9	.1619563	.0344092	4.71	0.000	.0945153	.2293973
16 10	.123407	.0536994	2.30	0.022	.0181577	.2286562
16 11	-1.768618	.2762686	-6.40	0.000	-2.310096	-1.227139
16 12	-.2577756	.08826	-2.92	0.003	-.4307627	-.0847886
17 1	-.0259954	.0656079	-0.40	0.692	-.1545851	.1025943
17 2	-.2946654	.0531288	-5.55	0.000	-.3987963	-.1905345
17 3	-.3208974	.0421489	-7.61	0.000	-.4035081	-.2382867
17 4	-.216887	.0370497	-5.85	0.000	-.2895035	-.1442706
17 5	-.0216738	.0366773	-0.59	0.555	-.0935603	.0502127
17 6	-.0663927	.0334242	-1.99	0.047	-.1319033	-.0008822
17 7	-.1203815	.0309929	-3.88	0.000	-.1811268	-.0596362
17 8	-.098381	.0351104	-2.80	0.005	-.1671963	-.0295656
17 9	.0497277	.0344079	1.45	0.148	-.0177109	.1171663
17 10	.1854453	.0537015	3.45	0.001	.080192	.2906987
17 11	-2.366232	.2763078	-8.56	0.000	-2.907787	-1.824676
17 12	.0363949	.0882683	0.41	0.680	-.1366084	.2093982
18 1	-.211818	.0656079	-3.23	0.001	-.3404077	-.0832283
18 2	-.0734175	.0531356	-1.38	0.167	-.1775618	.0307268
18 3	-.0870622	.0421519	-2.07	0.039	-.1696788	-.0044456
18 4	-.2903082	.0370492	-7.84	0.000	-.3629236	-.2176929
18 5	-.0198428	.0366752	-0.54	0.588	-.0917252	.0520395
18 6	-.0461997	.0334131	-1.38	0.167	-.1116884	.0192891
18 7	-.1724331	.030969	-5.57	0.000	-.2331315	-.1117346
18 8	-.1561681	.035098	-4.45	0.000	-.2249593	-.087377
18 9	.0830434	.0344042	2.41	0.016	.0156122	.1504747
18 10	.5850449	.0537073	10.89	0.000	.4797801	.6903098
18 11	-1.887647	.2763063	-6.83	0.000	-2.429199	-1.346094
18 12	-.0686527	.0882678	-0.78	0.437	-.2416551	.1043496
19 1	-.205984	.0656059	-3.14	0.002	-.3345697	-.0773982
19 2	-.3813923	.0531333	-7.18	0.000	-.4855322	-.2772524
19 3	.0255983	.0421588	0.61	0.544	-.0570317	.1082283
19 4	-.1196827	.0370521	-3.23	0.001	-.1923038	-.0470616
19 5	-.0322986	.0366744	-0.88	0.378	-.1041794	.0395822
19 6	-.0511244	.0334056	-1.53	0.126	-.1165985	.0143496
19 7	-.1497751	.0309515	-4.84	0.000	-.2104391	-.0891111
19 8	-.1448773	.0350923	-4.13	0.000	-.2136573	-.0760973
19 9	.2244635	.0344077	6.52	0.000	.1570253	.2919017
19 10	.53456	.0537112	9.95	0.000	.4292874	.6398325
19 11	-1.450535	.2762957	-5.25	0.000	-1.992067	-.9090029
19 12	-.0408548	.0882654	-0.46	0.643	-.2138526	.132143
20 1	-.2348955	.0656032	-3.58	0.000	-.3634759	-.1063151
20 2	-.2980902	.0531288	-5.61	0.000	-.4022212	-.1939591
20 3	-.1142982	.0421586	-2.71	0.007	-.1969279	-.0316685
20 4	-.1981389	.0370568	-5.35	0.000	-.2707692	-.1255087
20 5	-.0432268	.0366778	-1.18	0.239	-.1151142	.0286607
20 6	-.0216685	.0334058	-0.65	0.517	-.0871429	.0438058
20 7	-.1007834	.0309477	-3.26	0.001	-.16144	-.0401268
20 8	-.0292529	.0350938	-0.83	0.405	-.0980358	.03953
20 9	.1436888	.0344085	4.18	0.000	.0762491	.2111285
20 10	.1242556	.0537053	2.31	0.021	.0189948	.2295164
20 11	-1.253252	.2762787	-4.54	0.000	-1.794751	-.7117538

20	12	-.1397632	0882629	-1.58	0.113	-.312756	.0332296
21	1	-.1522248	0655986	-2.32	0.020	-.2807962	-.0236534
21	2	-.2489426	0531224	-4.69	0.000	-.353061	-.1448242
21	3	-.1157464	0421498	-2.75	0.006	-.1983588	-.033134
21	4	-.2828249	0370511	-7.63	0.000	-.355444	-.2102058
21	5	-.0884475	.036673	-2.41	0.016	-.1603256	-.0165693
21	6	-.0519476	0334027	-1.56	0.120	-.117416	.0135208
21	7	-.1331926	0309457	-4.30	0.000	-.1938452	-.0725399
21	8	-.1248997	0350862	-3.56	0.000	-.1936677	-.0561317
21	9	.0438757	0343974	1.28	0.202	-.0235423	.1112937
21	10	.0948281	0536936	1.77	0.077	-.0104098	.200066
21	11	-.9937776	2762524	-3.60	0.000	-1.535225	-.4523306
21	12	-.3050285	0882586	-3.46	0.001	-.4780129	-.1320441
22	1	-.0375811	0655911	-0.57	0.567	-.1661378	.0909757
22	2	-.1932382	0531148	-3.64	0.000	-.2973417	-.0891346
22	3	-.1936781	0421375	-4.60	0.000	-.2762665	-.1110897
22	4	-.1876114	0370414	-5.06	0.000	-.2602115	-.1150112
22	5	-.0983374	0366596	-2.68	0.007	-.1701892	-.0264857
22	6	-.0857284	0333818	-2.57	0.010	-.1511558	-.0203011
22	7	-.0326883	0309285	-1.06	0.291	-.0933074	.0279307
22	8	-.0271291	0350761	-0.77	0.439	-.0958772	.0416191
22	9	.0694397	0343833	2.02	0.043	.0020494	.13683
22	10	.1119517	0536772	2.09	0.037	.0067458	.2171575
22	11	-.5277729	2762265	-1.91	0.056	-1.069169	.0136233
22	12	-.278592	0882512	-3.16	0.002	-.4515619	-.1056221
23	1	.1397351	0655838	2.13	0.033	.0111927	.2682775
23	2	(omitted)					
23	3	(omitted)					
23	4	(omitted)					
23	5	(omitted)					
23	6	(omitted)					
23	7	(omitted)					
23	8	(omitted)					
23	9	(omitted)					
23	10	(omitted)					
23	11	(omitted)					
23	12	(omitted)					
dow							
	1	-.0054048	.001234	-4.38	0.000	-.0078243	-.0029853
	2	-.0157742	.001258	-12.53	0.000	-.0182406	-.0133077
	3	-.0234116	.001255	-18.65	0.000	-.025872	-.0209511
	4	-.0169819	.001254	-13.54	0.000	-.0194405	-.0145232
	5	-.0011211	.001239	-0.90	0.366	-.0035513	.001309
	6	.0141294	.001141	12.38	0.000	.0118926	.0163662
zone							
	2	-.2049195	.027796	-7.37	0.000	-.2593999	-.150439
	3	.2363038	.021504	10.99	0.000	.194156	.2784516
	4	-.3526663	.024564	-14.36	0.000	-.4008116	-.3045209
	5	.1746793	.025087	6.96	0.000	.1255088	.2238498
	6	-.3112287	.109643	-2.84	0.005	-.526127	-.0963304
	7	-.0507928	.022488	-2.26	0.024	-.0948689	-.0067167
	8	.3390985	.019393	17.49	0.000	.3010884	.3771087
	9	-.1211986	.109778	-1.10	0.270	-.3363615	.0939642
	10	-.3046407	.020369	-14.96	0.000	-.3445647	-.2647167
	11	-.4047238	.026517	-15.26	0.000	-.456698	-.3527496
tmin		-.0038897	.000073	-52.73	0.000	-.0040343	-.0037451
tmax		.0000665	.000063	1.05	0.293	-.0000575	.0001906
_cons		.166804	.073026	2.28	0.022	.0236738	.3099343

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        log: \\nera-nycfs\work\projects\energy\NYISO DEMAND CURVE UPDATE (R782) > \Stata
 Files\appendix.smcl
   log type: smcl
  closed on: 30 Jun 2010, 13:56:32
```

D. Appendix 4 – Guide to Demand Curve Development Model

The model is a Microsoft Excel workbook that simulates revenues and expenditures given a set of user-defined and built-in input parameters. The workbook can be divided into three parts: (1) input sheets, (2) the "Model" sheet and (3) output sheets. The input sheets supply parameters produced by outside sources. The "Model" sheet is where the actual calculations of revenues and expenditures are performed. The output sheets show the results of simulations that NERA has performed.

Input Sheets: The sheets to the right of the "Model" sheet (e.g. "Reference Tables", "Energy Curve Raw") contain functions and parameters produced by outside sources. The energy curve is the result of a simulation performed on STATA. The "Current Curve" sheet contains FERC-approved values for the current NYISO demand curve. The "Reference Tables" sheet contains levelized fixed charges and overnight capital costs calculated by Sargent & Lundy. The values in these input sheets are not meant to be changed by users.

"Model" Sheet: The "Model" sheet allows users to alter certain parameters and run the simulation. User-defined input parameters can be found in the tan areas of the "Model" sheet. Users can change these values to simulate different market conditions. Values in yellow are dependent on other parameters and should not be altered. Values that are shaded out are not relevant given the other parameters. For example, the "kink" variable that determines where the curve kinks is not relevant if there is no kink specified (i.e., if the x-intercept of the first and second slanted segments are identical).

To run the simulation, users click the "Calculate Demand" Button, which solves for the demand curve that allows for full cost recovery given the inputs and parameters. Values in the areas shaded blue are the results of intermediate calculations, including revenue and expenditure streams. Outputs such as the amortization period and demand curve reference values are shown in the pastel green rectangle. The supernormal net revenue variable should always be zero after clicking "Calculate Demand".

Output Sheets: The "High Level Summary" and "Results Summary" sheets show the results of certain runs that NERA has performed.

The NYISO capacity model uses a Monte Carlo simulation to estimate capacity levels for demand payment and energy payment calculations. This simulation assumes capacity levels are normally distributed. In each run of the model, the normal distribution is specified by two parameters, the expected value and standard deviation assumptions. These assumptions are explained in Section IV of this report.

New Features: The model was enhanced from the version used in 2007 to incorporate a seasonal view of the Demand Curve. If the seasonal toggle is set to true, inputs are required for the seasonal capacity ratios that NYISO would use to develop the Demand Curve. The model will then simulate Summer Capability Period and Winter Capability Period demand revenue separately using the relevant ratio and seasonal peaking unit capacity. This feature has been used in developing this report. For 2010, the model was enhanced further to allow for an input vector of property taxes, option of deliverability and option of Summer and Winter Capability Period minimum payments. The user can elect to input a vector of property taxes by toggling the user-input property tax option and inputting the annualized tax rates into the corresponding cells indicated by year. This feature will be automatically disabled if the user attempts to activate the user-input property tax toggle in conjunction with property taxes implicit in the levelized carrying charge, however, it is possible to utilize both a fixed or extra tax in addition to the user-input property tax option.