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Investigation And Evaluation Of The Systemwide Economic Benefits Of Combined Heat And Power Generation In The New York State Energy Market

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INVESTIGATION AND EVALUATION OF THE SYSTEMWIDE ECONOMIC BENEFITS OF COMBINED HEAT AND POWER GENERATION IN THE NEW YORK STATE ENERGY MARKET

A Thesis Presented

by

RICARDO BAQUERO

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ABSTRACT

INVESTIGATION AND EVALUATION OF THE SYSTEMWIDE ECONOMIC BENEFITS OF COMBINED HEAT AND POWER GENERATION IN THE NEW YORK STATE ENERGY MARKET

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Combined Heat and Power (CHP) is the production of electricity and the simultaneous utilization of the heat produced by the generator prime mover. The energy efficiency advantages of CHP are undisputed, and yet, the continuously changing economic conditions make the implementation of such projects financially unviable if no incentives are available.

This thesis attempts to demonstrate the economic benefits associated with DG-CHP. The identification and quantification of both benefits and costs to the different system stakeholders will serve to illustrate that additional DG-CHP installed capacity results in positive system wide benefits. Furthermore, it will be shown that there is justification to re-evaluate a more balanced allocation - among the different system stakeholders - of the benefits resulting from the implementation of DG-CHP technology in the New York State region.

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LIST OF ABBREVIATIONS AND SYMBOLS

AC	Alternate Current
Btu	British Thermal Unit
CHP	Combined Heat and Power
CRPP	Comprehensive Reliability Planning Process
DAM	Day Ahead Market
DC	Direct Current
DER	Distributed Energy Resources
DG	Distributed Generation
EIA	Energy Information Agency
EGU	Electric Generating Units
ESCO	Energy Service Company
GIS	Geographic Information System
GT	Gas Turbine
HQ	Hydro Quebec
HV	High Voltage
HVAC	Heating, Ventilation and Air Conditioning
kV	Kilo Volt
kW	Kilo Watt
kWh	Kilo Watt hour
lb/lbs.	Pound/pounds
LBMP	Local Based Marginal Price

LI	Long Island
LIPA	Long Island Power Authority
LHV	Lower Hudson Valley
LOLE	Loss of Load Expectation
MARS	Multi-Area Reliability Simulation
MM	Million
MMBtu	Million Btu
MW	Mega Watt
MWh	Mega Watt hour
NYC	New York City
NYCA	New York Control Area
NYPA	New York Power Authority
NYISO	New York Independent System Operator
NYSERDA	New York State Energy Research and Development Authority
OASIS	Open Access Same Time Information System
OTC	Ozone Transport Commission
PJM	Pennsylvania, Jersey and Maryland
POI	Point of Injection
POW	Point of Withdrawal
PTID	Point Transmission ID
RGGI	Regional Greenhouse Gas Initiative
RNA	Reliability Needs Assessment
RT	Real Time

RTM	Real Time Market
SENY	South East New York
SIP	State Implementation Plan
TCC	Transmission Congestion Contract
TO	Transmission Owners
T&D	Transmission and Distribution
UCAP	Unforced Capacity
UHV	Upper Hudson Valley
UPNY	Up State New York

CHAPTER 1

DISTRIBUTED GENERATION AND COMBINED HEAT AND POWER

1.1 INTRODUCTION

- **Background**

The lifestyle of developed countries at the beginning of the 21st century relies on intensive energy consuming technologies. In the specific case of electricity markets, demand seems to steadily outgrow supply capacity. Consequently, large metropolitan centers such as New York City, and even multi-state regions as the US Northeast have experienced high electricity prices and blackouts in electric service, such as those which occurred in August 2003.

Until 1999, the New York Control Area (NYCA) market regulations allowed to purchase and sell electricity only to a handful of generators and wholesale clients. Since November 1999 and the creation of the New York Independent System Operator (NYISO), New York has maintained a deregulated power market. NYISO facilitates open access to the NYCA transmission system and ensures nondiscriminatory operation of electricity markets coordinated by the NYISO, thus improving the system capacity to adjust when unordinary events occur and sustaining the supply of the electric demand. This evolution is considered beneficial, since the NYISO procures sources of power and certain ancillary services through the deregulated power markets that it administers. By doing so, NYISO provides non-discriminatory open access to the New York State transmission system for all market participants, and allows meaningful involvement by market participants in the operation of NYISO.

However, although the reliability of the system and the market appear to be secured, the physical capacity of the generator and transmission facilities to produce or transport energy from cheap and clean sources to the most critical points of the grid is challenged on a day to day basis. The market reaction to these "congestion" events is, as expected, an increase in electricity prices.

In 2001, Raykar and Ilie estimated that the annual cost of congestion in the Day Ahead New York Power Pool for the period Nov-99 to Nov-00 was $377MM dollars. In October 2004, The NYISO "State of the Market Report 2003", estimated congestion costs for 2001, 2002 and 2003 to be $310MM, $525MM and $688MM respectively. Then, in the NYISO "Reliability Assessment Needs 2007", was calculated to be $85MM, $70MM and $110MM for the years 2003, 2004, and 2005 using the bid-production-cost-savings methodology.

The use of energy efficient technologies such as the combined heat and power generation (CHP) to decentralize the power generation from the most critical nodes of the system has frequently been considered to be a very plausible solution to the financial and physical stresses that the rapidly increasing demand for electric energy makes on the market and the system.

This project aims to illustrate that there are, in fact, positive externalities and/or economic benefits available with the installation of a Distributed Energy Resources (DER) or Distributed Generation (DG) that conventional analysis tend to ignore. These benefits arise from the impact the DG unit will have on system power capacity, the transmission and distribution system, energy costs, and emission reductions.

- **Problem Statement**

Quantify the system benefits generated from the installation of strategically-located CHP systems from the perspectives of: an End-User, the Utility, and Society.

- **Hypothesis**

The central hypothesis for this project is as follows: Strategically placing CHP units in congested markets will provide substantial quantifiable benefits to end-users, utilities, and society through increased energy conversion efficiency, increased market efficiency, electric grid upgrade mitigation, and decreased emissions.

- **Purpose and Objective**

This thesis attempts to demonstrate the economic benefits associated with DG-CHP. The identification and quantification of both benefits and costs to the different system stakeholders will serve to illustrate that additional DG-CHP installed capacity results in positive system wide benefits. Furthermore, it will be shown that there is justification to re-evaluate a more balanced allocation - among the different system stakeholders - of the benefits resulting from the implementation of DG-CHP technology in the New York State region

- **Methodology**

This project report will initially provide a review of the functioning and operating structure of the New York energy market, with particular emphasis on New York City. Beyond the traditional assessment of generation and Transmission and Distribution capacities versus present and future load requirements, special attention will be paid to statistical indicators such as the "system reliability", and electricity market parameters and terms such as the Local Based Marginal Price (LBMP) and "congestion", which significantly influence the behavior of electricity market prices.

In order to achieve the prime objective of the project, as previously defined, the physical and functional characteristics of the NewYork State power system and whole sale electricity market are analyzed. The information available to the public will be quoted and used to assess costs and benefits of nine different basic scenarios each of which depicts a different level of DG-CHP market penetration.

As an additional contribution, this project aimed to propose a reliable and repeatable methodology for determining the optimal location and amount of electric capacity to be added at strategic nodes of the grid. Both business and security secrecy resulted in essential information voids that needed to be addressed. On this line of research, this report also utilizes Generation and Transmission facilities geographical information and NYISO data and effectively employs the ArcGIS software in order to develop comprehensive and interactive maps that enhance the visualization of electric grid and markets behaviors, thus improving the accuracy of the recommended locations and required capacities to be added within the power grid.

The structure of this report is as follows:

Chapter 1 provides an introduction to CHP technology. Then, in Chapter 2, the New York System characteristics are presented, including a discussion about the reliability challenges that the New York Control Area faces in the next decade. Chapter 3 follows with a brief description of the New York energy resources market.

Chapter 4 and 5 present the challenges of, and operational justifications for adopting Combined Heat and Power as a sustainable solution to the New York energy problems in the future. The discussion will focus on the Local Based Marginal Price, "LBMP", and how it can be affected by the proposed CHP systems installation.

Finally, in Chapter 6, all the concepts previously discussed will be used to calculate costs and benefits for all system stakeholders assuming different levels of CHP market penetration. The New York City area will be used as an example to illustrate the method.

1.2 Distributed Energy Resources

1.2.1 Distributed Generation

The development of alternating current at the beginning of the 20th century made it possible to transport electric energy over long distances. Distributed Generation, the option of generating electricity in the vicinity of the final customer always existed, but large production volume savings led to the proliferation of large electricity generating centrals away from cities in order to supply energy to many consumers, resulting in increased reliance upon the capacity of the transmission and distribution systems. As the economy grew, so did the electricity demand and the installed generating capacity. However, constraints such as the right of use of the land have caused the development of new transmission lines to lag behind.

The scenario entering the 21st century is different for large generating centrals. The compliance of greenhouse gases emission limits, especially by large fossil fuel-fired generators, implies new costs that small generators are not bounded by. Additionally, the state of the art in small-scale electricity generation and related prime movers is such that

Distributed Generation projects are becoming more and more feasible, both technically and financially.

Distributed Generation is defined as the generation of electricity in a location nearby the final use of the electricity, regardless of the technology used to generate it.

1.3 Combined Heat and Power

1.3.1 Basic Concepts

Combined Heat and Power technology has been available since the beginning of thermal electricity generation. CHP, or cogeneration, is a special form of Distributed Generation because it simultaneously produces electricity (power) and useful thermal energy from a single energy source (fossil fuels, solar, etc.).

In conventional, centralized energy generation, approximately 60 percent of input energy is lost as waste heat and another 10 percent is lost through transmission and distribution. These losses dictate that electric generation at a central power plant only averages approximately 30 percent efficiency. On-site thermal needs are normally provided with a boiler, which has an efficiency of 80-85 percent if properly maintained. Based on an average facility, the simultaneous independent use of these two types of systems provides an overall energy efficiency of 49 percent efficiency.

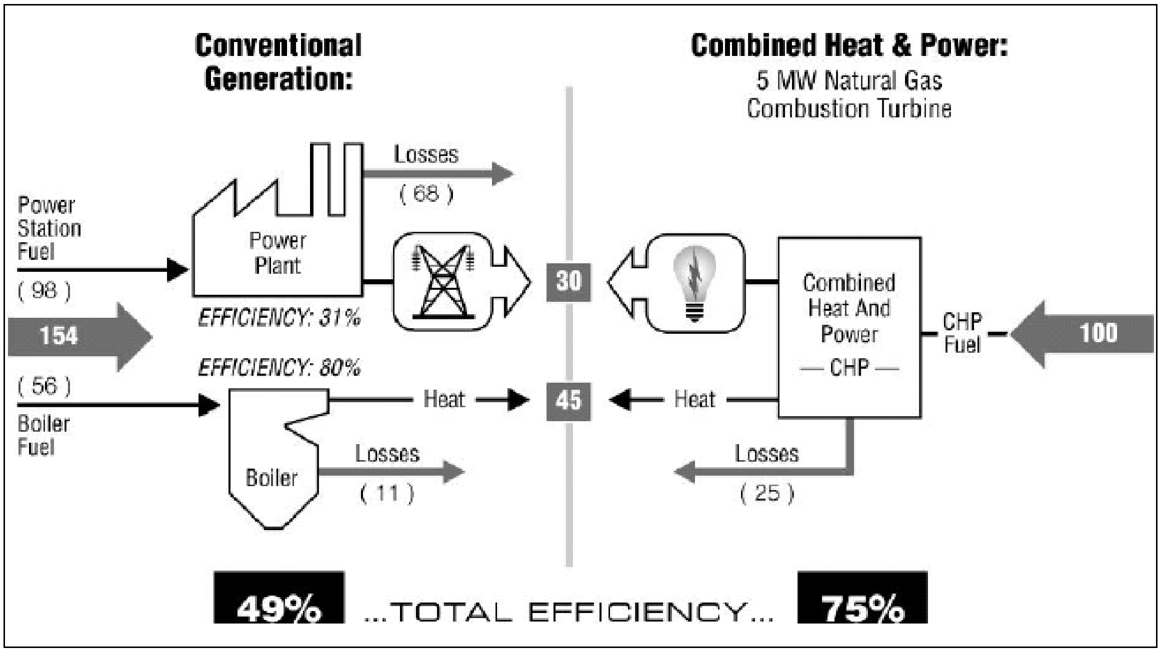

Figure 1. Conventional Generation vs. CHP Efficiency

A CHP system is capable of simultaneously providing both the required electric and thermal load. By recovering waste heat produced through electricity generation, the thermal load is supplied. Thus, for the same average facility, as shown in Figure 1, energy efficiency may be potentially increased to 75 percent, a 26 percent increase over conventional generation.

The installation of CHP can either partially or fully displace a facility's electric load. When the facility's electric load is only partially displaced, it must remain connected to the grid for parallel operation. If the electric load is completely provided by the CHP units, the facility has the option of completely disconnecting from the grid. The other option is to remain connected to the grid as backup in case the CHP units go off line. In the latter case, the facility may be subject of a different electric service tariff, which may include standby charges to pay the utility for the energy the facility may eventually require. If more electricity is generated, exceeding the customer requirements, the excess may be sold back to the grid. Figure 2 shows an example of a simplified cogeneration plant schematic with a utility grid connection. Note that the DER unit is connected to a 110 kV utility network.

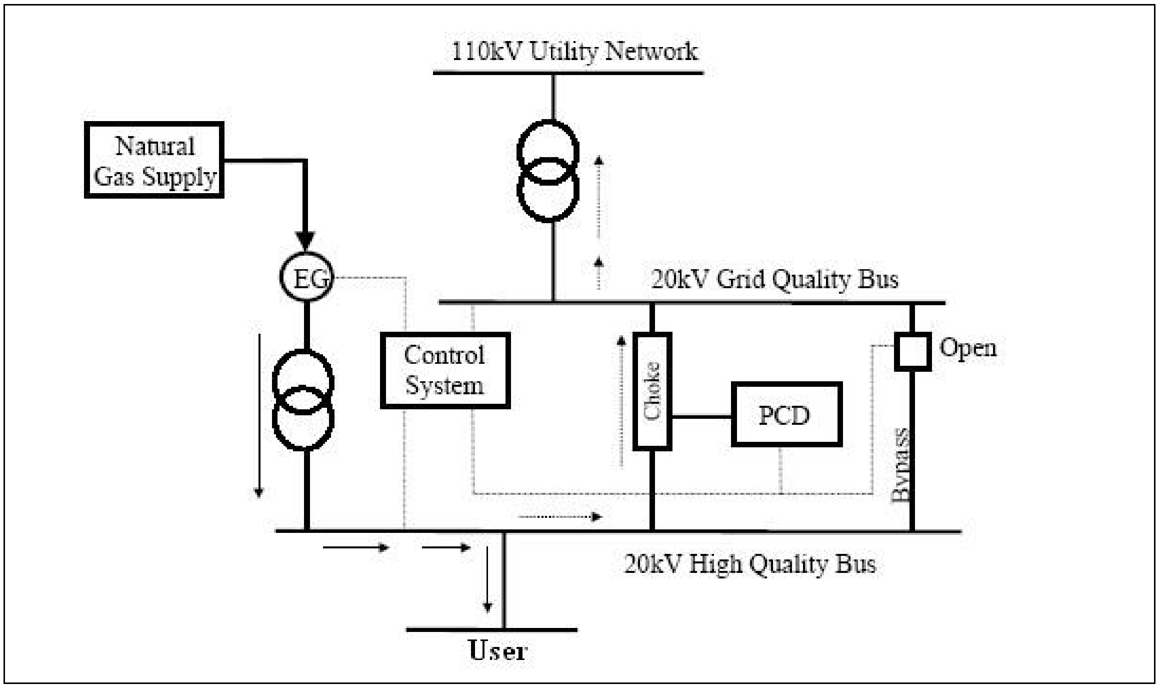

Figure 2: Simplified Cogeneration Plant Schematic. (Beebe, 2004)

1.3.2 Avoided Electricity Bill and Avoided Fuel Costs

By implementing on-site generation, the facility is effectively reducing the amount of electricity that must be purchased from the electric utility, thereby reducing the facilities annual electric costs. The avoided electricity bill savings are a function of energy reduction, demand reduction, and the utility rate structure.

1.3.3 Annual Capital Costs, Maintenance, and Fuel Costs

Estimates for the installed cost and operation and maintenance costs for a number of CHP technologies are shown below in Table 1. The annual capital cost is a function of the financing arrangement. Often times the financing period may be 10 years, at an annual interest rate of 5-10%.

Table 1: Combined Heat and Power (CHP) Technologies (Beebe, 2004)

	Steam Turbine	Diesel Engine	Natural Gas Engine	Gas Turbine	Microturbine	Fuel Cell
Power Efficiency	15-38%	27-45%	22-40%	22-36%	18-27%	30-63%
Overall Efficiency	80%	70-80%	70-80%	70-75%	65-75%	65-80%
Typical Capacity (MW)	0.2-800	0.03-5	0.05-5	1-500	0.03-0.35	0.01-2
Typical Power to Heat Ratio	0.1-0.3	0.5-1	0.5-1	0.5-2	0.4-0.7	0.2-0.7
Part-Load	ok	good	ok	poor	ok	good
CHP Installed Costs ($/kW)	300-900	900-1,500	900-1,500	800-1,800	1,300-2,500	2,700-5,300
O&M Costs ($/kWh)	<0.004	0.005-0.015	0.007-0.02	0.003-0.0096	0.01	0.005-0.04
Availability	~99%	90-95%	92-97%	90-98%	90-98%	>95%

Fuel consumption is a function of the size and type of the unit, along with operating hours. Fuel costs are then simply a function of supply and delivery costs.

1.3.4 CHP potential within NY Market

In 2002 the New York State Energy Research and Development Authority, NYSERDA, published the “Combined Heat an Power Market potential for New York State” report. The scope of the report included CHP technical potential in the manufacturing and commercial/institutional sectors of New York. The analysis considered only traditional hot water-steam/electric power CHP. This estimate included only applications using hot water or steam as heat sources. No application converting steam thermal energy back into mechanical energy (pistons, steam turbines) was considered. Up-state was considered to have a greater industrial sector potential and down-state a greater commercial sector potential. While existing CHP in New York had been characterized by a preponderance of very large plants, only 16 sites remaining in the state were considered fit to support a plant size greater than 20 MW for internal power consumption. Close to three-fourths of remaining capacity potential was below 5 MW in size. About 80% of the potential sites, and over 75% of the remaining technical potential, was in the commercial sector.

Table 2. CHP Potential in Industrial Sector – NYSERDA 2002

Table A-7 Consolidated Edison - Industrial Sector (Net Remaining CHP Potential)

SIC	Industry	50 to 500 kW		500 kW to 1 MW		1 MW to 5 MW		5 MW to 20 MW		> 20 MW		Total	
		Sites	MW	Sites	MW	Sites	MW	Sites	MW	Sites	MW	Sites	MW
20	Food	154	23.1	9	6.8	13	32.5	0	0.0	0	0.0	176	62.4
22	Textiles	245	27.6	7	3.9	7	13.1	0	0.0	0	0.0	259	44.6
24	Lumber	52	1.6	1	0.2	0	0.0	0	0.0	0	0.0	53	1.7
25	Furniture	48	2.2	0	0.0	0	0.0	0	0.0	0	0.0	48	2.2
26	Paper	89	13.4	15	11.3	6	15.0	0	0.0	0	0.0	110	39.6
28	Chemicals	102	15.3	14	10.5	18	45.0	4	50.0	0	0.0	138	120.8
29	Petroleum Refining	12	1.8	3	2.3	0	0.0	1	12.5	0	0.0	16	16.6
30	Rubber	87	3.9	7	1.6	1	0.8	0	0.0	0	0.0	95	6.2
33	Primary Metals	41	1.5	2	0.4	4	2.5	2	6.3	0	0.0	49	10.7
34	Fabricated Metal Products	137	6.2	4	0.9	0	0.0	0	0.0	0	0.0	141	7.1
35	Machinery	72	2.7	5	0.9	2	1.3	0	0.0	0	0.0	79	4.9
37	Transportation Equipment	25	1.9	2	0.8	2	2.5	0	0.0	0	0.0	29	5.1
38	Instruments	52	3.9	3	1.1	0	0.0	0	0.0	0	0.0	55	5.0
39	Miscellaneous	156	5.9	5	0.9	0	0.0	0	0.0	0	0.0	161	6.8
	Total	1272	110.8	77	41.4	53	112.6	7	68.8	0	0.0	1409	333.6

Table 3. CHP Potential in Commercial Sector – NYSERDA 2002

Table A-8 Consolidated Edison - Commercial Totals (Net Remaining CHP Potential)

SIC	Industry	50 to 500 kW		500 kW to 1 MW		1 MW to 5 MW		5 MW to 20 MW		> 20 MW		Total	
		Sites	MW	Sites	MW	Sites	MW	Sites	MW	Sites	MW	Sites	MW
4222	Refrigerated Warehouse	10	0.8	3	1.1	1	1.3	0	0.0	0	0.0	14	3.1
494/495	Water treatment/Sanitary	15	2.3	17	12.8	1	2.5	1	12.5	0	0.0	34	30.0
54	Food Sales	390	11.7	3	0.5	1	0.5	0	0.0	0	0.0	394	12.7
581	Full Service Restaurants	871	52.3	99	29.7	18	18.0	1	5.0	0	0.0	989	105.0
7011	Hotels/Motels	219	32.9	62	46.5	62	155.0	9	112.5	0	0.0	352	346.9
721	Laundries	35	5.3	7	5.3	0	0.0	0	0.0	0	0.0	42	10.5
7542	Carwashes	36	5.4	0	0.0	0	0.0	0	0.0	0	0.0	36	5.4
7991	Health Clubs	149	22.4	15	11.3	0	0.0	0	0.0	0	0.0	164	33.6
7992/7	Golf Clubs	47	7.1	10	7.5	0	0.0	0	0.0	0	0.0	57	14.6
805	Nursing Homes	68	10.2	108	81.0	46	115.0	0	0.0	0	0.0	222	206.2
806	Hospitals and Health Care	34	5.1	19	14.3	87	217.5	3	37.5	0	0.0	143	274.4
822	Colleges and Universities	88	13.2	24	18.0	17	42.5	12	150.0	0	0.0	141	223.7
821/4/9	Elementary and Secondary Schools	1,345	80.7	490	147.0	67	67.0	4	20.0	0	0.0	1,906	314.7
8412	Museums	45	4.1	12	5.4	4	6.0	0	0.0	0	0.0	61	15.5
9223	Prisons	4	0.6	5	3.8	15	37.5	1	12.5	0	0.0	25	54.4
	Apartments	388	58.2	86	64.5	43	107.5	9	112.5	0	0.0	526	342.7
	Office Buildings	3,016	181.0	795	238.5	230	230.0	42	210.0	3	90.0	4,086	949.5
	Total	6,760	492.9	1,755	686.9	592	1000.3	82	672.5	3	90.0	9,192	2942.5

1.3.5 Electric System benefits from CHP Units

As explained in following chapters, by strategically placing DG-CHP units within the transmission and distribution grid, it is possible to mitigate grid congestion. This relief in congestion can reduce wholesale energy price spikes associated with the dispatching of high production costs generators, thus reducing the value of losses and congestion components of the energy price.

Additionally, end users across the system may see an improvement in grid reliability. This improved grid reliability will reduce the expected (and actual) loss of load - that is, brown outs and black outs- which can have a widespread, devastating economic impact for many industries.

1.3.6 Emission of CHP Units

The increased local emission can be found by multiplying the electric output with the emission profile of the appropriate technology. The emission profiles from a number of CHP technologies are shown below in Table 4. The model-specific output analysis will be pursued later in this thesis.

Table 4.: Emission Factors for Various CHP Technologies.

Prime Mover	Fuel	Controls	CO2	CO	SO_2	NOx	PM	VOC
			lb/MMBtu	lb/MMBtu	lb/MMBtu	lb/MMBtu	lb/MMBtu	lb/MMBtu
Boilers	#6 Fuel Oil		178.6	0.0333	6.766	0.585	0.2665	
	#4 Fuel Oil		178.6	0.0333	6.468	0.213	0.0467	
	#2 Fuel Oil		159.2	0.0357	1.532	0.213	0.0143	
	Natural Gas	Uncontrolled	117.6	0.0824	0.000588	0.098	0.0075	0.0054
		Low NOx	117.6	0.0824	0.000588	0.049	0.0075	0.0054
		Low NOx - flue gas recirculation	117.6	0.0824	0.000588	0.031	0.0075	0.0054
Gas Turbines	Natural Gas	Uncontrolled	110	0.082		0.32	0.0066	0.0021
		Water-Steam Injection	110	0.03		0.13	0.0066	0.0021
		Lean-Premix	110	0.015		0.099	0.0066	0.0021
	#2 Fuel Oil	Uncontrolled	157	0.0033	1.01	0.88	0.012	0.00041
		Water-Steam Injection	157	0.076	1.01	0.24	0.012	0.00041
Reciprocating Engines	Natural Gas (Lean Burn)		109	0.38		3.2		
		Non-Selective Catalytic Reduction	109	2.4		0.58	0.0007	
	Natural Gas (Rich Burn)		109	1.6		2.3		
		Selective Catalytic Reduction	109	0.37		1.2		
	Gasoline		154	0.627	0.084	1.63	0.1	
	Diesel		164	0.95	0.29	4.41	0.29	
	Dual Fuel (Natural Gas w/Diesel)		110	1.16	0.02	2.7		

CHAPTER 2

NEW YORK ELECTRIC SYSTEM CHARACTERISTICS

2.1 The New York Control Area

2.1.1 The New York Power Grid History

On December 1, 1999, the New York Independent System Operator NYISO assumed responsibility for the operation of New York State's bulk power system and of the newly established electric energy markets. New York's wholesale energy markets were established coincident with the establishment of the NYISO. Prior to December 1, operation of the bulk power system was the responsibility of the New York Power Pool. The NYISO is charged with two overriding responsibilities: first, to maintain the safe and reliable operation of New York's bulk power system; and second, to operate fair, nondiscriminatory and effective wholesale electric markets. The latter can be described as a political and economical problem, constrained by both man-made rules and physical limitations.

2.1.2 The New York Power Grid Physical Characteristics

As described in the New York Power Authority "Niagara Power Project FERC No. 2216" report from August 2005, the New York Control Area is composed of the entire electric system within New York State. It encompasses all of the transmission and distribution facilities, generators and, customers (i.e. load) that make up the electric utility system. The system description is found in the NYISO CRPP 2005 report:

The New York Control Area is situated in the center of the Northeastern North America electrical grid, which includes the Mid-Atlantic and New England States in the

US, and the Canadian Provinces of Ontario, Quebec, and Maritimes. Figure 3 displays the major electricity markets operating in the region along with summary statistics. The nominal transfer capability between the control areas shown in Figure 3 is estimated at less than 5% of the total peak load of the region, and steadily declining[1].

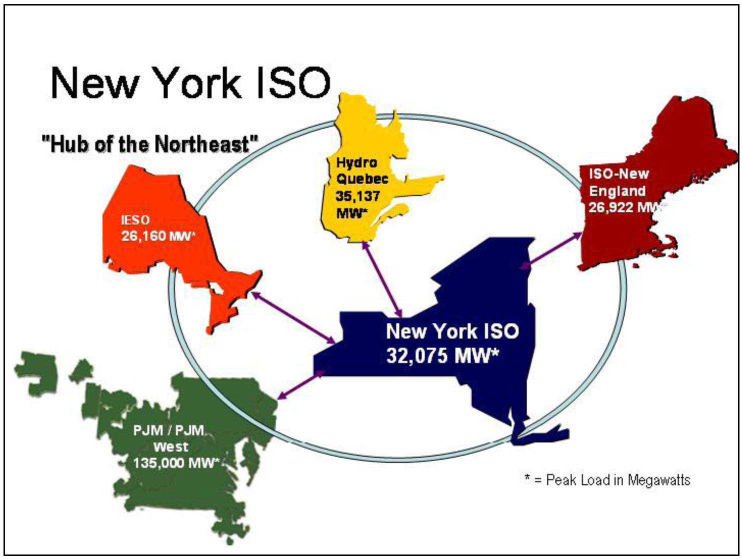

Figure 3: Northeast Grid In Context 2005 (NYISO 2005 CRPP)

Figure 4 displays the bulk power transmission system for the NYCA. It shows facilities operating at 230 kV and above. This represents more that 4,000 miles of high voltage transmission lines - approximately 10,000 miles if the underlying 138 and 115 kV transmission lines are included.

The NYCA contains nearly 11,000 miles of High Voltage Transmission lines, and by August 2006 it had 430+ individual electric generating units of widely varying size (from over 1,000 MW down to less than 1 MW). Total generating capacity installed in the NYCA exceeds 35,000 MW. The load (customer use) in New York is greater than 160,000,000 MWh per year. Peak demand (the single hour of highest electric use during

[1] HQ report on NYISO

the year) in July 2006 was 32,519 MW. The New York electric system serves the needs of 18.2 million people state-wide. The existing generating facilities list included in Appendix #1 as of April 1, 2006 is available at the NYISO website.

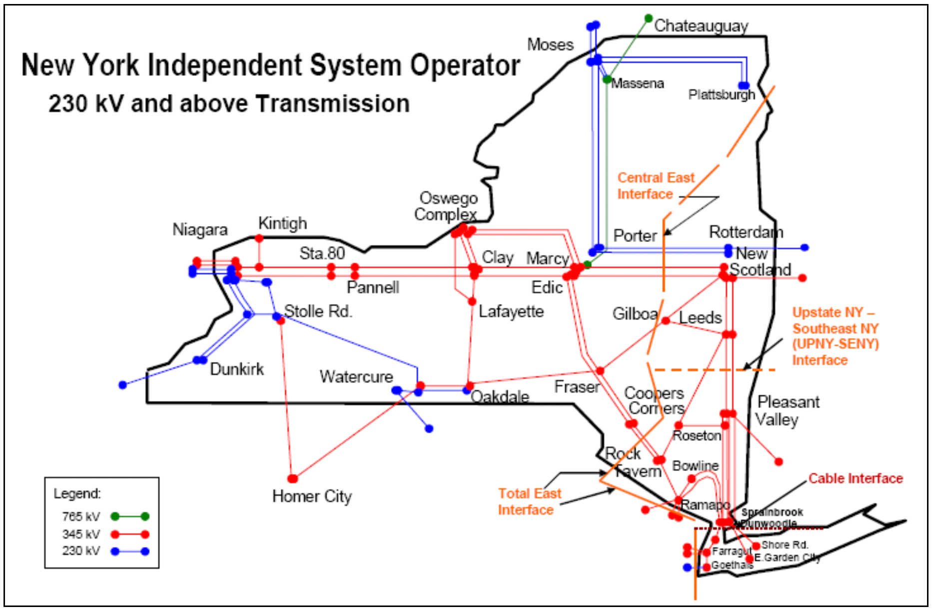

Figure 4: NYCA Bulk Transmission System (NYISO 2005 CRPP)

Figure 4 also displays key NYCA transmission interfaces. Transmission interfaces are groupings of transmission lines which measure the transfer capability between regions such as the transfer capability between the Northeastern control areas. Table 5 shows the different interfaces capacities. As shown in Figure 5, although energy may flow in both directions, interface capacities are not the same if flow direction changes.

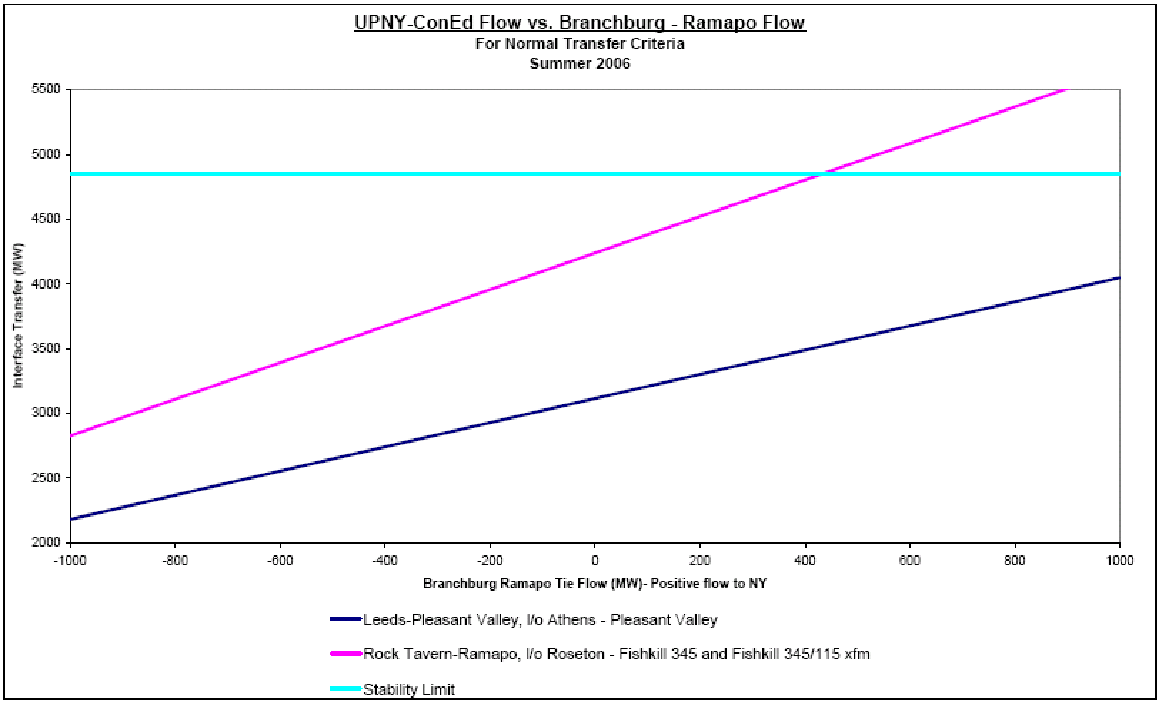

Figure 5. Example of Interface Transfer Capacity (NYISO Operating study Summer 2006)

Table 5. Interfaces capacities (NYISO Operating Study Summer 2006)

		SUMMER 2006	
Interface	**Rating**	**Limit (MW)**	**Contingency**
Dysinger East	Normal	2850	1
	Emergency	3175	2
West Central	Normal	1775	1
	Emergency	2075	2
UPNY - ConEd	Normal	3300	4
	Emergency	3950	5
Sprain Brook Dunwoodie-South	Normal	3775	6
	Emergency	3800	7
Con Ed - LIPA	Normal	900	8
	Emergency	1450	9
Central East	**MSC-7040 FLOW**	**1600 MW**	
	Normal	3125	10
	Emergency	3550	12
	MSC-7040 FLOW	**1200 MW**	
	Normal	3050	10
	Emergency	3500	13
	MSC-7040 FLOW	**800 MW**	
	Normal	2975	10
	Emergency	3400	13
Total East	**MSC-7040 FLOW**	**1600 MW**	
	Normal	5075	10
	Emergency	5950	12
	MSC-7040 FLOW	**1200 MW**	
	Normal	5025	10
	Emergency	5925	13
	MSC-7040 FLOW	**800 MW**	
	Normal	5075	10
	Emergency	5975	13
Moses - South	**MSC-7040 FLOW**	**1600 MW**	
	Normal	2550	14
	Emergency	2875	16
	MSC-7040 FLOW	**1200 MW**	
	Normal	2250	14
	Emergency	2575	16
	MSC-7040 FLOW	**800 MW**	
	Normal	1950	14
	Emergency	2300	16

2.1.3 The NYISO Jurisdiction

The New York wholesale electricity market is divided into eleven “pricing” or “load zones”. Figure 6 presents the geographical boundaries for these pricing zones. The development of these load zones was driven primarily by the topology or configuration of the transmission system, and secondarily by the franchise areas of the investor-owned utilities. These load areas were initially developed by the New York Power Pool after the 1965 Northeast blackout as part of a process of identifying critical bulk power system transmission interfaces. Subsequently, these load zones were utilized to define pricing zones for the wholesale electricity market.

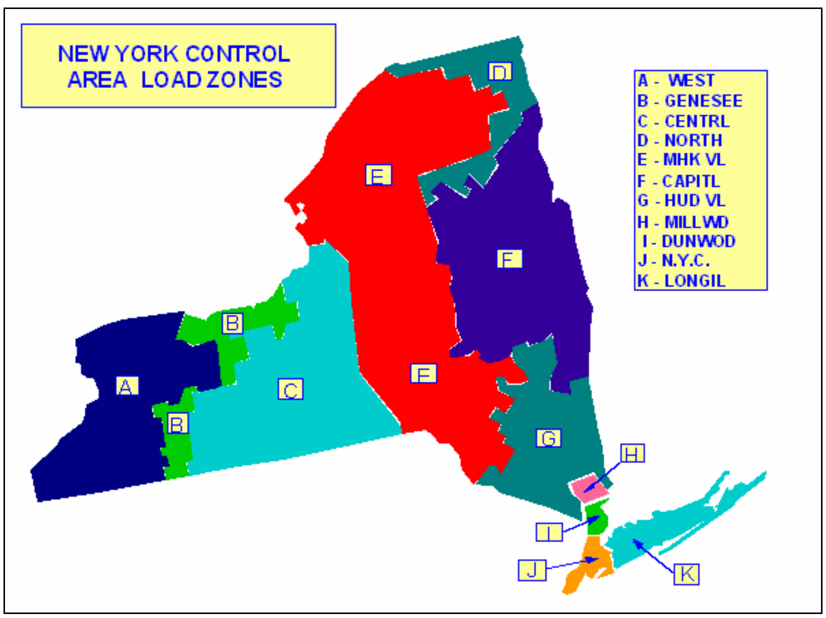

Figure 6: NYCA Load Zones (NYISO 2005 CRPP)

Price homogeneity and geographical location were used to define load super-zones. The interfaces between these super-zones are shown in Figure 4 as dotted lines. Below the UPNY – SENY interface is the *cable interface,* which includes the dotted line on the transmission map and also the lower end of the total East interface. This interface contains all the major underground and submarine cables supplying New York City and Long Island.

Table 6 presents the approximate non-coincident peak loads and generating capacity contained in the super zones defined for summer 2004. Table 7 presents the nominal transfer capability across the major transmission interfaces shown in Figure 4. The transmission facilities that make up these interfaces are the facilities that tie the zones together electrically.

Table 6. Approximate Summer Peak Load/ Generating Capacity for "Super Zones" (NYISO 2005 CRPP)

Zone	Peak Load (MW)	Capacity (MW)
West (A-E)	8,900	14,430
Upper Hudson Valley (F)	2,180	3,470
Lower Hudson Valley (G-I)	4,490	5,490
New York City (J)	11,150	8,940
Long Island (K)	5,050	5,180
Note: Numbers are approximate and based on the summer of 2004		

Table 7. Nominal Transfer Capability between "Super Zones" (NYISO 2005 CRPP)

Transmission Interface	Transfer Capability (MW)
Total East	6,100
Central East	2,850
UPNY – SENY	5,100
Cable Interface	
• New York City	4,700
• Long Island	1,270

"As a result of the distribution of load and capacity on the NYCA power system, power flows are primarily west to east and then southeast or, predominantly from the northwest to the southeast into the highly congested urban zones of New York City and Long Island. All power flows from the west including the transmission ties to the neighboring control areas of Ontario, Hydro Quebec and PJM must cross the Total East

Interface with large portions flowing across the Central East portion of the interface and then across the UPNY – SENY interface to reach the cable interface.” [2]

The New York City and Long Island zones' electricity generating infrastructure has the highest average age of generating units in the state (water turbines dating from early 1900's) and -recent plant additions notwithstanding- is still highly dependent on an aging fleet of combustion and gas turbine capacity in some cases dating from 1950 (East River generator).

“Also, the generation mix in Western NY has much larger proportions of hydro, nuclear and coal. This creates a high potential for economic transfer from West NY to New York City and Long Island (“Economic transfer” is understood as the transmission of power from a lower cost region to a higher cost region).”[3]

2.1.4 NYISO Load Growth

“The NYCA peak load grew from approximately 27,300 MW in 1994 on a weather adjusted basis to 31,400 MW in 2004, which totals approximately 4,100 MW. This represents a ten-year compound growth rate of approximately 1.21%. However, as shown in Table 8, the South East NY region accounts for 100% of the load growth in the state, in opposition to the actual load reduction of West NY and Upper Hudson Valley regions.

[2] NYISO 2005 CRPP
[3] NYISO 2005 CRPP

Table 8. 1994 to 2004 NYCA Load Growth (NYISO 2005 CRPP)

Zone	Load Increment (MW)
SENY (LHV+NYC+LI)	5,000
WestNY(A-E) + UHV	-900
Total NYCA	4,100

In the summer of 2005, the load growth increased by approximately 560 MW to a total 31,960 MW. "[4]

2.1.5 NYISO Installed Generating Capacity

On the Generating Capacity side, the story is very similar. Table 9 is a summary of the installed generating capability for the NYCA to the nearest 10 MW for the years 1994, 1999 and 2004.

The first observation that can be made is that, while the NYCA load has increased by 4,100 MW (4,660 MW by 2,005), generating capacity has increased by almost 2,900 MW, not including demand response. Including demand response, the approximately 4,660 MW of load growth will have been offset by actual capacity additions, totaling approximately 3,600 MW and 975MW of Load Reduction "Capacity".

Table 9. New York Installed Generating Capability by Super Zones (MW) (NYISO 2005 CRPP)

Zone	1994	1999	2004	Capacity Increment (MW)
West NY	13,660	14,480	14,430	770
UHV	2,400	2,440	3,470	1,070
LHV	5,700	5,530	5,490	-210
NYC	8,550	7,870	8,940	390
LI	4,320	4,370	5,180	860
Total	34,630	34,690	37,510	2,880

[4] NYISO 2005 CRPP

However, by the end of 2005, it was estimated that in the last decade, SENY load outgrew installed capacity by a factor of five. This information and the information shown in Table 10 lead to the conclusion that generating capacity has grown away from the new loads; thus, NYCA has become more dependent on the transmission system.[5]

Table 10. Load vs Capacity in NYCA (NYISO 2005 CRPP)

Zone	Load Increment (MW)	Capacity Increment (MW)
SENY (LHV+NYC+LI)	5,000	1,040
WestNY(A-E) + UHV	-900	1,840
Total NYCA	4,100	2,880

2.1.6 NYISO Transmission System

"While the NYCA has become more dependent on the transmission system, expansion of the transmission system has been minimal. The "1994 Load and Capacity Data" book reported approximately 10,795 miles of transmission lines in service operating at 115 kV or higher, while the "2005 Load and Capacity Data" book reported approximately 10,790 miles of transmission lines in service operating at 115 kV or higher. These numbers should not be interpreted to mean that the NYCA transmission system has not expanded; the transmission and sub-transmission (i.e., 69 kV and 34.5 kV) system has indeed been expanded to accommodate local load growth requirements."[6]

2.1.7 Value of Installed Capacity

From 2000 through 2005, Con Edison, the NYC transmission system owner, claims to have spent more than $6.7 billion on improvements to its electric system. Of this amount, $4 billion, or 60%, was allocated for improvements to the electric

[5] NYISO 2005 CRPP
[6] NYISO 2005 CRPP

transmission and distribution (T&D) system. Also, 2005 ConEd Reliability Study includes the values of substantial upgrades to the underground transmission system including phase regulators in and around NYC. The results are summarized in Table 11:

Table 11. Marginal Costs of Electric Grid Expansion

	Capital	O&M
In City Generation GT	$1,200/kW-$1,430/kW	$1,238/kW
Repowering in City GT	$1,087/kW	
Transmission High Voltage AC	$640/kW	
Trans Underground AC	$350/kW	
Trans Underground AC + phase reg	$500/kW	
HV-DC	$3MM/mi	
HV-AC	$15MM/mi	
DG Non-CHP vs. CHP	$230/kW[7]	

For the distribution system expansion, from 2000 through 2005, $2.8 billion were spent for improvements to the electric distribution system. For future expansions, as posted in press release available at http://www.coned.com/messages/pr20070504.asp, ConEd is planning to invest $3,234 million dollars over the next 10 years. With a 5% interest fix-rate project, the annual payment is $418 million dollars. These capital projects include the addition of new substations to meet the growing demand, estimated to be 5,000 MW over the same period. Hence the annual cost of the distribution system upgrade and expansion is $83.6/kW (=$418MM/5,000MW).

2.2 Electric System Reliability Considerations

The deregulation of electricity markets in New York State and in many parts of the North East divided the vertically-integrated and tightly-coordinated utility business format into independent electricity production, transmission and distribution units, each with different commercial and social goals. The independent system operator was

[7] Source: NYSERDA "combined heat and power market potential for NYS" Oct 2002

created, among other reasons, in order to fulfill this coordination task. NYISO's Open Access Same Time Information system (OASIS) coordinates the market supply and demand bids with the physical generation and transmission installed capacities such that the daily operation is stable. Additionally, NYISO must also provide for the future reliability of the bulk power system, as an equally important task.

With these goals in mind, the NYISO - in cooperation with the major state Transmission Owners - developped the CRPP. The first step of the CRPP was to identify the reliability needs for the following ten year study period, and to designate the Transmission Owners responsible for the development of solutions that address those needs. The latest results have been included in the 2007 CRPP Reliability Needs Assessment 2007 (RNA).

2.2.1 Reliability Criteria

New York system is designed to meet the "Loss of Load Expectation" adequacy criteria (LOLE), which is a probability concept. LOLE is measured in days per year. The system is planned to have no more than one involuntary disconnection in every 10 years, or 0.1 day per year.

2.2.2 Resources Needs Assessment Methodology

NYISO used the General Electric Multi-Area Reliability Simulation (GE-MARS) model to determine the year in which the loss-of-load criterion was violated and by what degree. Compensatory MWs were added to the system to resolve criteria violations, e.g., the Loss of Load Expectation (LOLE) of 0.1 days per year. As violations were found, compensatory MW needs for the NYCA were developed by adding generic 250 MW generating units to zones that are capable of addressing needs, based on a review of binding transmission and zonal LOLE constraints in an iterative process to determine when reliability criteria were satisfied. These additions were used to estimate the amount of resources needed to satisfy reliability needs. The additions were not intended to represent proposed solutions. Resource needs could potentially be met by many other combinations of resources in other areas including generation, transmission and demand side management. Due to the differing natures of supply and demand-side resources and transmission constraints, the amounts and locations of resources needed to match the level of compensatory MW needs identified would vary. In addition, resource needs could be met, in part, by transmission system reconfigurations that increase transfer limits, or by changes in operating protocols. Operating protocols could include such actions as using dynamic ratings for certain facilities, operating exceptions, or special protection systems.

2.2.3 Reliability Needs Assessment (RNA) Results

The results and NYISO analysis are quoted:

"The (Figure 7) below presents a summary of the LOLE results for the RNA study case, as well as the thermal power flow and and 'free flowing' sensitivities." RNA applies the most restrictive transmission limit determined from the dynamics analysis based on thermal, voltage and stability reliability criteria. Thermal sensitivity assumes that only transmission thermal limits are binding, and the 'free flowing' sensitivity assumes unconstrained flow.

"In general, an LOLE result above 0.1 days per year indicates that resources are required to maintain reliability, and therefore triggers a need to identify resources. These results indicate the first definitive year of need is 2011for the RNA study case and 2012 for the two other sensitivities that were studied. Further, the review of both the free-flowing transmission sensitivity (with LOLE of 0.08 in 2011, 0.12 in 2012 and 0.37 in 2016) and the thermally limited transmission sensitivity (with LOLE of 0.10 in 2011, 0.19 in 2012 and 0.60 in 2016) indicates that the need for 2011 results largely from transmission constraints and not an overall resource deficiency in NYCA. Beyond 2011, the need results from an overall resource deficiency in the NYCA as well as transmission constraints." (2007 RNA p. 13)

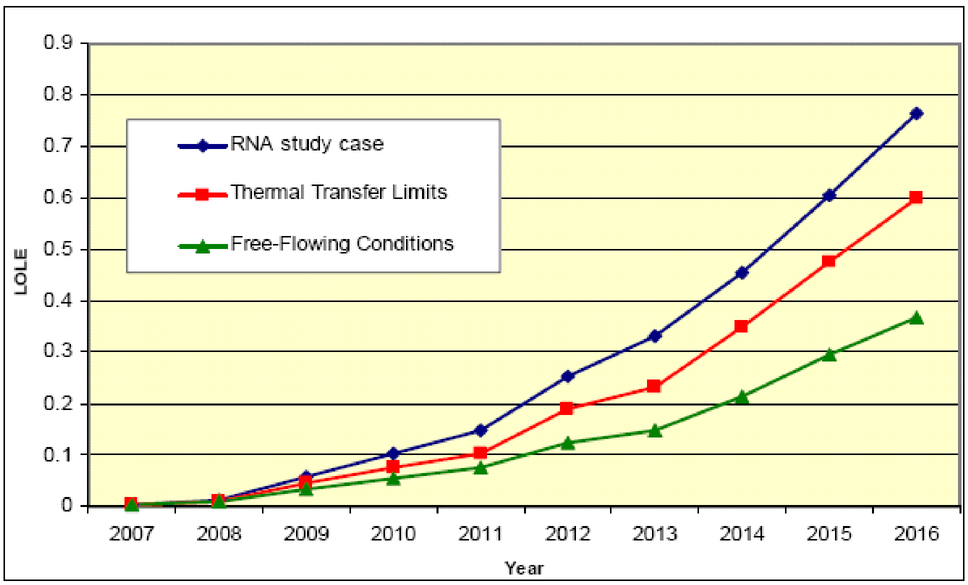

Figure 7. Summary of the LOLE Results for the RNA study case, thermal and "free flowing" sensitivities

The solution to those scenarios presenting LOLE above 0.1 was found by translating the detected deficiencies into compensatory MW's that could satisfy the needs. As stated in RNA 2007:

"To reduce the LOLE to below the 0.1 days per year criterion in 2011 requires compensatory MWs to be located in load Zones G through J, which are below the UPNY – SENY interface. In general and also because of the modeling of the availability of the cables feeding load Zones J and K, locating compensatory MWs downstream of the

Dunwoodie-South interface particularly in load Zone J is generally more effective in meeting LOLE requirements. However, MARS simulation shows that load Zone K export capability is being fully utilized to provide assistance to the Lower Hudson Valley and New York City, and would not be an effective location for compensatory MWs without additional transmission." (2007 RNA p.14). In other words, additional (compensatory) generating capacity is required in the Southeast New York area (SENY). However, interface transfer capacity limits narrow the optimal location of compensatory capacity to the NYC and area (Area-J).

The recommended level of compensatory capacity is shown in Table 12 and the associated LOLE results in Table 13:

Table 12. Required Compensatory Generating Capacity in MW (Alternatives A1 and A2) – RNA Study Case 2015

AREA	AREA-A	AREA-B	AREA-E	AREA-G	AREA-J	AREA-K	_NYCA_
2012 A1					500		500
2012 A2				500	250		750
2013 A1				250	500		750
2013 A2				500	500		1000
2014 A1	500			500	500		1500
2014 A2				750	500		1250
2015 A1				750	750		1500

Table 13. LOLE results for RNA Study Case 2015 alternatives

AREA	AREA-A	AREA-B	AREA-E	AREA-G	AREA-I	AREA-J	AREA-K	_NYCA_
2012 A1		0.05	0.02		0.07	0.10	0.01	0.10
2012 A2			0.01		0.05	0.11	0.01	0.11
2013 A1		0.05	0.02		0.07	0.12	0.02	0.12
2013 A2		0.04	0.01		0.05	0.08	0.01	0.09
2014 A1		0.03	0.01		0.05	0.09	0.02	0.10
2014 A2		0.04	0.01		0.05	0.10	0.02	0.10
2015 A1		0.04	0.01		0.05	0.09	0.04	0.11

Finally, LOLE was recalculated for different load forecasts, each extensively defined in the RNA report. The LOLE forecast are summarized in tables 14, 15 and 16. It is clear, especially for the NYC area, that LOLE reliability target is not achieved after 2008 in any of the proposed cases.

Table 14. RNA study case LOLE High Forecast

Year	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
AREA-A										
AREA-B		0.01	0.05	0.08	0.11	0.17	0.20	0.30	0.43	0.57
AREA-C										
AREA-D										
AREA-E			0.02	0.03	0.04	0.01	0.10	0.16	0.26	0.37
AREA-F										
AREA-G				0.01	0.01	0.01	0.01	0.02	0.03	0.05
AREA-H										
AREA-I		0.01	0.06	0.11	0.14	0.30	0.37	0.57	0.83	1.20
AREA-J		0.01	0.09	0.16	0.25	0.45	0.64	0.91	1.29	1.83
AREA-K				0.01	0.01	0.04	0.06	0.11	0.20	0.41
NYCA		0.02	0.10	0.17	0.26	0.46	0.67	0.94	1.34	1.91

Table 15. Coal Retirement Scenario LOLE Results

Year	2009	2010	2011	2012	2013	2014	2015	2016
AREA-A								
AREA-B	0.19	0.28	0.27	0.38	0.43	0.56	0.67	0.80
AREA-C								
AREA-D								
AREA-E	0.07	0.10	0.10	0.17	0.21	0.27	0.38	0.45
AREA-F								
AREA-G	0.03	0.05	0.05	0.08	0.08	0.12	0.16	0.20
AREA-H								
AREA-I	0.18	0.27	0.25	0.40	0.49	0.67	0.86	1.04
AREA-J	0.22	0.32	0.33	0.49	0.63	0.87	1.08	1.26
AREA-K	0.01	0.02	0.02	0.05	0.07	0.10	0.17	0.30
NYCA	0.26	0.37	0.39	0.54	0.67	0.91	1.14	1.34

Table 16. Non Utility Generators Retirement LOLE Results

Year	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
AREA-A										
AREA-B		0.01	0.07	0.11	0.13	0.21	0.24	0.43	0.78	0.93
AREA-C										
AREA-D										
AREA-E			0.03	0.04	0.05	0.09	0.11	0.21	0.44	0.54
AREA-F								0.01	0.03	0.04
AREA-G				0.01	0.01	0.01	0.01	0.03	0.05	0.06
AREA-H										
AREA-I		0.01	0.08	0.13	0.15	0.26	0.32	0.53	0.93	1.15
AREA-J		0.01	0.10	0.17	0.23	0.38	0.47	0.72	1.13	1.38
AREA-K			0.01	0.01	0.02	0.04	0.06	0.13	0.26	0.48
Total		0.01	0.11	0.17	0.23	0.39	0.49	0.74	1.18	1.45

The RNA 2007 concludes:

"The current New York ISO market rules recognize the need to have defined quantities of capacity specifically located on Long Island, within New York City and available as dedicated resources to the New York Control Area as a whole so that the system can perform reliably. The NYISO has implemented a capacity market that is designed to procure and pay for at least the minimum requirements in each area. If these mechanisms work as intended and continue to require resources at the same levels as have existed in the past, they should result in the addition of new resources to meet most or all of the New York City and Long Island needs identified in this RNA. The control area wide requirement would result in additions that are needed to meet statewide reliability requirements." (NYISO, RNA 2007, p.23).

2.2.4 The NYISO Installed Capacity Market

Indeed, NYISO runs an Installed Capacity Market. The NYISO capacity market considers the use of a distributed generator as a "load reduction special case resource", eligible to participate in the Unforced Capacity (UCAP) auctions. Auctions take place monthly but the main provisions take place in May and November prior to each summer and winter.

For the winter 2006-2007 1,023 MW of UCAP were awarded at $5.80/kW-mo For the summer 2007, the auction for NYC awarded 1,099 MW of UCAP at a price of $12.34/kW-mo. This means that installed capacity market value for the NYC zone averaged $9.18/kW-mo ($110/kW-yr) between November 2006 and November 2007.

2.2.5 The Cost of Reliability

As Stated in "The Economic Impacts of the August 2003 Blackout", prepared by the Electricity Consumers Resource Council (ELCON) - February 9, 2004:

"The New York City comptroller's office estimated that losses topped $1 billion, including $800 million in gross city product. The figure includes $250 million in frozen and perishable food that had to be dumped. The Restaurant Association calculated that the city's 22,000 restaurants lost between $75 and $100 million in wasted food and lost business. Broadway lost approximately $1 million because of cancelled performances. New York City's mayor estimated that the city would pay almost $10 million in overtime related to the outage".

This outage lasted approximately 6 hours, which is equivalent to a LOLE of 0.25 or 0.15 excess from the design point of 0.1 LOLE. For the purpose of this report, this means that an outage has a cost of $800MM per 0.15 of excess LOLE.

CHAPTER 3

ENERGY SOURCES MARKET

3.1 ELECTRICITY - Independent System Operator of New York (NYISO)

NYISO procures sources of power and certain ancillary services through deregulated power markets that it administers. By doing so, NYISO provides non-discriminatory open access to the New York State transmission system for all market participants, and allows meaningful involvement by market participants in the operation of NYISO. In this context, electricity can be sold and purchased either in the Day Ahead Market (DAM), in the Real Time Market (RTM) or with bilateral contracts. According to Dr. Robert Michaels[8], in 2001 approximately 50 percent of the power passing through the NYISO was bilateral contracts, 45 percent was DAM, and 5 percent RTM. In 2006, a report by Potomac Economics indicates that physical bilaterals were 50% of DAM schedules. Additional data posted by NYISO shows that DAM is around 30%-40% of total RT load.

In the DAM or in the RTM, generators bid for dispatching rights, specifying price and amounts for each hour (supply curve), and purchaser bid for load supply, specifying load requirements and the price they are willing to pay. Once the bid information is gathered, the system dispatches the most economical generators, following the logic explained in chapter 4.1.2.

The Agreement between New York Independent System Operator and Transmission Owners (TO) was established in 1999. The TO consist of: Central Hudson

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[8] Professor of Economics, California State University, Fullerton <rmichaels@fullerton.edu> and Affiliate, Tabors Caramanis & Associates, Cambridge MA.

Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation, Orange and Rockland Utilities, Inc., Rochester Gas and Electric Corporation (referred to collectively as the "Investor-Owned Transmission Owners"), NYPA, and LIPA (Long Island Power Authority.

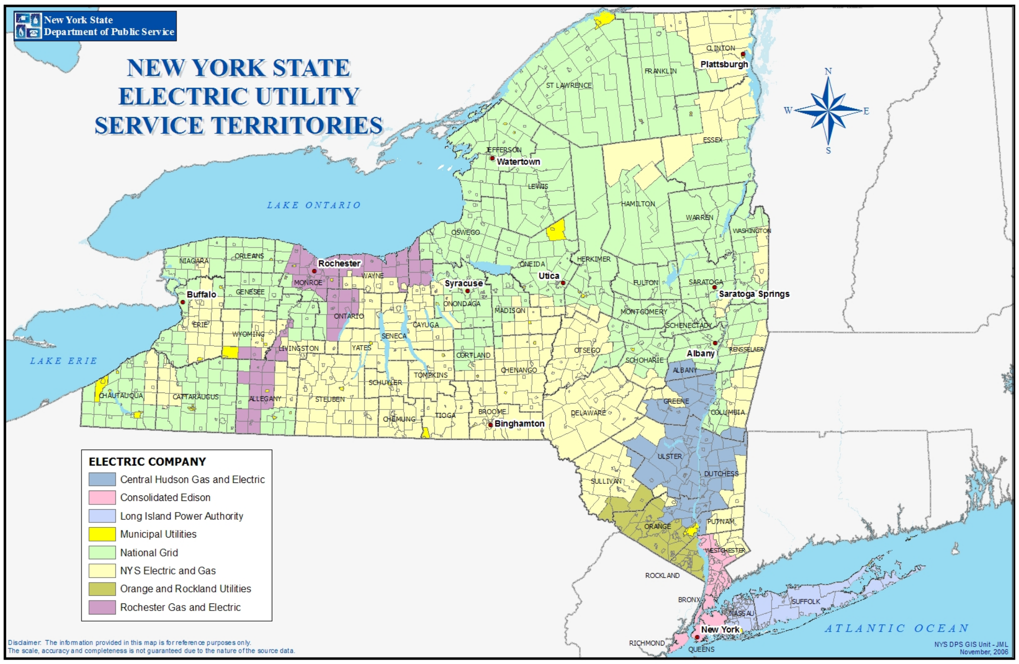


Figure 8. New York State Electric Utility Services Territories

The TO have for many years built, owned, operated and charged customers for the use of the electric transmission system in New York State. This Agreement describes the responsibilities of the Transmission Owners and the NYISO regarding ownership, maintenance, and physical operation of the transmission system including compliance by the Transmission Owners with legal, technical and financial obligations.

The responsibilities of the Transmission Owners are delineated in Aritcles 2 and 3 of the NYISO - Transmission Owners Agreement.

3.2 NATURAL GAS - Market Prices

Figure 9 shows the service territories for the different Natural Gas utilities established in the New York State Area.

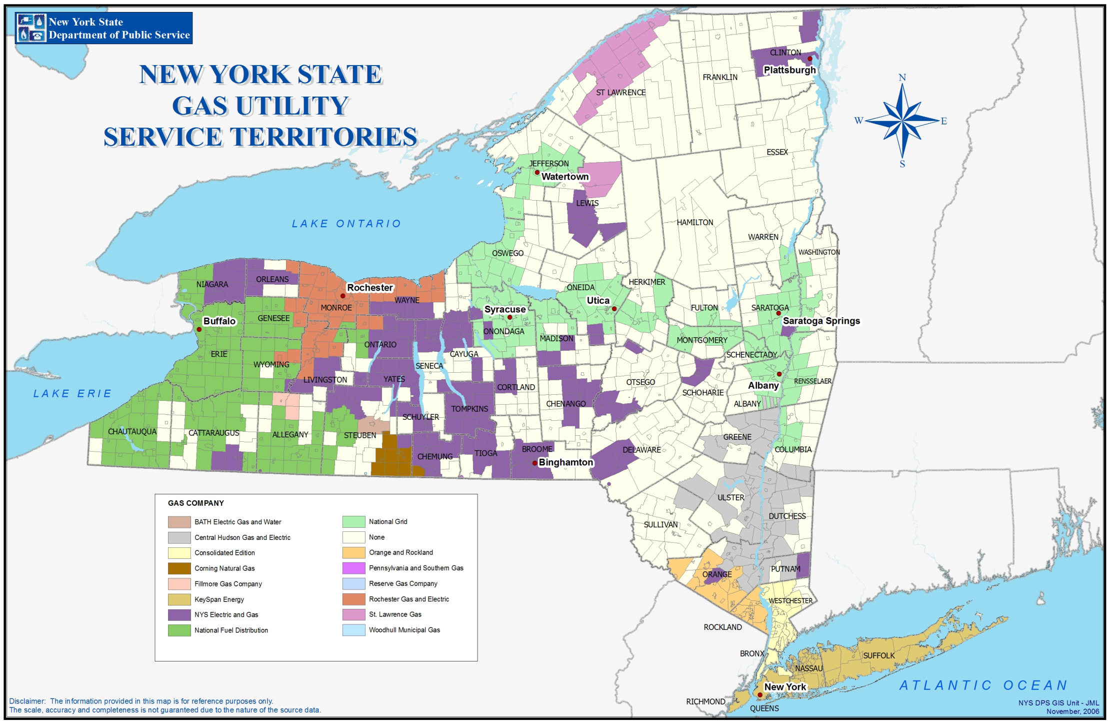


Figure 9. New York State Gas Utility Services Territories

In the case of NYC, the Natural Gas distribution is dominated by two companies, Con Edison serving Manhattan, Bronx and portions of Queens, and Keyspan serving the remainder[9]. The ensemble of ConEd's and Keyspan's local pipeline system is known as "the city gate". Third party companies may use the city gate to deliver gas to local customers however, competition is almost inexistent.

An example of the Natural Gas service rate for DG purposes is ConEd's PSC SC-9 Rider H. However, for the remaining applications there are several types of tariffs

[9] Sam Williams, http://www.gothamgazette.com/article/feature-commentary/20031013/202/558

changing according to the size and final application of the commodity. For the purpose of this thesis, this makes the use of Natural gas rates very unpractical and then, data provided by the EIA is used. According to EIA data, the Natural Gas prices for the period ending in Jan-07 are considerably lower for clients using the gas to produce electricity than for other industrial and commercial applications. The current applicable prices are shown in Table 17.

Table 17. Natural Gas Prices in NY area (EIA data, March 2007)

Type of End User	Price Jan-2007
Gate Price	$0.908/therm
Residential Price	$1.414/therm
Commercial Price	$1.19/therm
Industrial Price	$1.064/therm
Electric Generators Price	$0.828/therm

It is noticed that the Natural Gas price for Electric Generators is not only lower than the Industrial Price but it is lower than the Gate Price. This may be explained by the existence of Fuel Specific Federal Subsidies for electric generation, which nationwide average is $0.25/MWh[10] of electricity, and by monthly adjustments (credits) provided in the Natural Gas service rates applicable to power generation customers. In the case of Table 17, the difference between the Industrial Price and the Electric Generator Price is $0.236/therm or $2.36/MMBtu, which is approximately $2/MWh for an average generator.

Price volatility of natural gas, as with most fuel sources, is generally higher than the price of other types of commodities. Customers have limited ability to substitute fuel when the price fluctuates, which is likely responsible for high volatility. The volatility of

[10] Source: EIA Federal Financial Interventions and Subsidies in Energy Markets 2007 http://www.eia.doe.gov/oiaf/servicerpt/subsidy2/pdf/execsum.pdf

natural gas causes the price per MMBtu of natural gas to fluctuate widely, as shown in Figure 10.

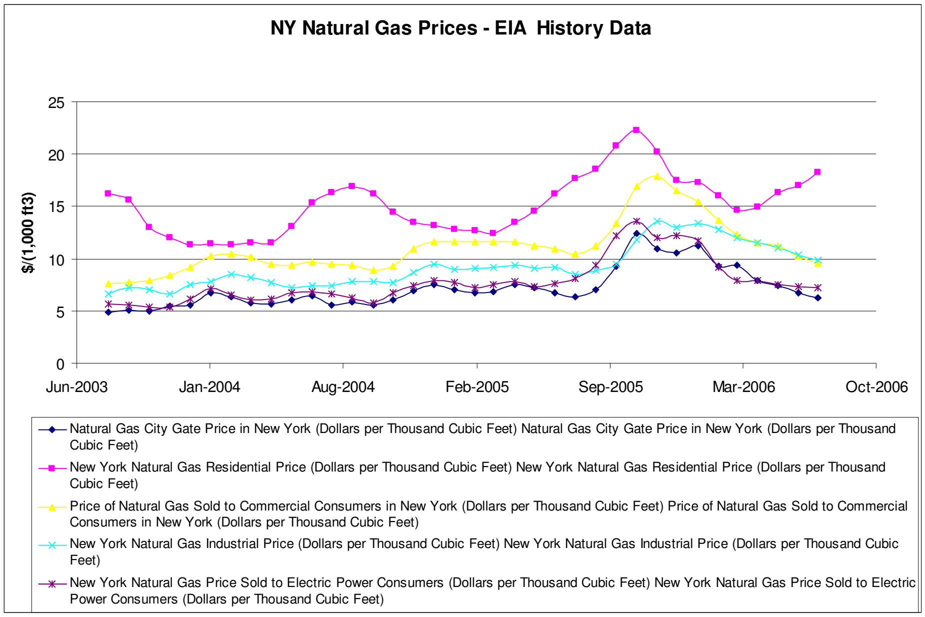


Figure 10. Example Price of Natural Gas Over a Year Long Period ($/MMBtu)

The uncertainty of future natural gas costs is a dominant concern when considering the economics of DG/CHP and must be given proper consideration.

3.3 STEAM - Market Prices

In the NYC region, in addition to the electricity and natural gas supply, ConEd also sells energy in the form of medium pressure steam. Current rates have been effective since October 1, 2005 and their description is available at ConEd website. Facilities purchasing steam service are not included in the scope of this report.

3.4 EMISSIONS MARKETS

The systems analyzed in this thesis are too small to participate in the emission reduction markets. However, it must be noticed that New York is member of emissions cap and trade and NOx-SIP programs. In both cases, small DG generators are not individually eligible to participate, but it is possible under special conditions that the sum of a few small generators emission-offsets compensate for the production of one large eligible generating facility. Therefore, the following information is shown as reference for possible future multi-party deals that might take place as the delays for emission budgets begin to expire.

3.4.1 RGGI, Cap & Trade Market and Emissions Reduction

Since December 2005, the State of New York is a participating member of the Multi-state Regional Greenhouse Gas Initiative (RGGI). The RGGI defines a cap-and-trade program in order to control the right to emit an emission cap, allowing companies to trade emission permits. The program will apply to fossil fuel-fired electric generators 25 megawatts (MW) and larger. The program first compliance period would begin on January 1, 2009.

The regional base annual CO2 emissions budget will be apportioned to the States so that each state's initial base annual CO2 emissions budget in tons is equivalent to 1990 emissions, as follows:

Table 18. CO_2 emissions budget ton/yr (source: RGGI's MOU)

State	CO2 ton/yr
Connecticut	10,695,036
Delaware	7,559,787
Maine	5,948,902
Massachusetts	26,660,204
New Hampshire	8,620,460
New Jersey	22,892,730
New York (5% below 1990 levels by 2010; 10% below 1990 levels by 2020)	64,310,805
Rhode Island	2,659,239
Vermont	1,225,830

For the years 2009 through 2014, each state's base annual CO2 emissions budget shall remain unchanged. In this context, DG/CHP technology plays an important role on two fronts:

As described in Figure 11, the use of DG/CHP does indeed reduce the overall operation emissions with respect to the conventional alternative.

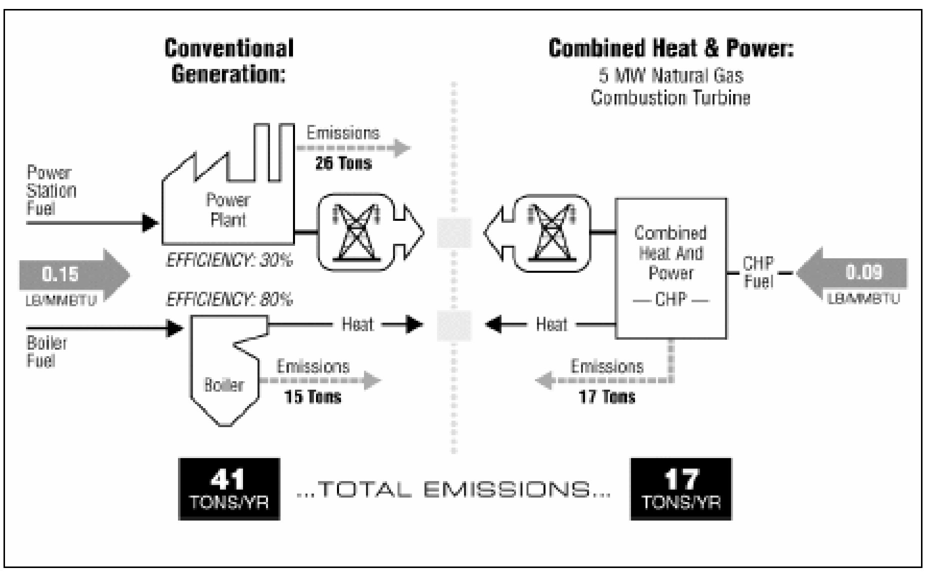


Figure 11. Comparative Emissions of Conventional and CHP Generation

Since the program will only apply to electric generators 25 MW and larger, the owners of those large generators may find emission relief by purchasing extra allowances from other, more efficient generators and/or by sponsoring approved CO_2 (or CO_2 equivalent) emissions offset projects. In either case, DG/CHP systems are a great source of emissions allowances or offsets. This is especially important for maintaining minimum potential emission leakage[11].

3.4.2 NOx Emissions Markets (source: www.evomarkets.com)

New York State also participates in the NOx-SIP Call Program. The NOx SIP Call program is implemented in two phases. On May 1, 2003, facilities regulated under the previous regulatory regime (OTC - affected sources) were required to reduce emissions by 35-40% as the standard was ratcheted down to 0.15 lbs NOx/MMBtu from approximately 0.23 lbs NOx/MMBtu. All wholesale electric generators with a nameplate rating of 25MW or larger (Electric Generating Units - EGUs), large industrial facilities such as steel, chemical, pulp and paper, and refining that have boilers with heat inputs of 250 MMBtu per hour and larger (non-EGUs), and in some states, cement kilns are affected under the trading program. The emissions reduction obligations are differentiated by industry sector, with EGUs making roughly 80-85% reductions from prevailing levels in the late 1990s, while non-EGUs are obligated to reduce NOx emissions by roughly 65% from the same baseline period. Cement kilns are required to make 35% reductions.

In 2004 the SIP NOx program entered a second phase. On May 31, 2004 (and May 1 each year thereafter), sources in an additional 11 states were required to control NOx to the same levels as sources in the original eight state region. The states that are

[11] Leakage refers to the shift of electricity generation from capped RGGI sources to uncapped non-RGGI sources; thus emissions are merely shifted rather than truly reduced. Full report available at http://www.rggi.org/emisleak.htm

currently affected under the final program are: AL, CT, DE, IL, IN, KY, MA, MD, MI, NC, NJ, NY, OH, PA, SC, TN, VA, WV, and DC.

Based upon a facility's emission reduction, or a number of facility's aggregated reduction, it is possible to produce economic revenue through the selling of per-ton credits. Conversely, if a generating facility is not in agreement with emission standards, it is required to purchase emission offsets. Current credit values are shown below in Table 19.

Table 19. NOx spot prices on Fri, 20-Apr-07 (www.evomarkets.com)

TERM	BID	OFFER	LAST
2007	$975.00	$985.00	$980.00
2008	$950.00	$975.00	$950.00
2009	$775.00	$825.00	

CHAPTER 4

DG-CHP NYS ELECTRICITY MARKET PENETRATION

4.1 What is Congestion? Local Congestion vs. Congestion Component

Special attention must be given to the congestion component of the energy price in the NYISO market. In this chapter, the concept of congestion will be explained following NYISO definitions. Then, an economic analysis of congestion as "market inefficiency" will be presented.

4.1.1 Definitions

In the NYISO deregulated market context, electricity is subject to supply and demand laws. As a natural result of these dynamics, electricity price depends on the location of the generator and the purchaser. This is why NYISO price information is referred to as LBMP, or Local based Marginal Price. At each location, LBMP is calculated as follows:

LBMP= Energy + Losses - Congestion[12] (eq. 1)

The meaning of the two first components is related to the physical characteristics the generation and transmission systems:

- The Energy component is the marginal cost of electricity production at the generator terminals- in other words, before it is injected into the transmission grid.
- The Losses component is the cost of the energy lost via heat dissipation because of the transmission through long cables and wires. Since real

[12] Congestion sign obeys to the LBMP definition referred to Marcy reference bus $LBMP=LBMP_{bus}+Losses+Congestion$

materials have finite conductivity, or positive resistance, a small - but - significant amount of energy is lost in the path from the point of injection to the point of withdrawal from the grid (purchaser terminals).

- The meaning of the Congestion component does not follow any law of physics. Although congestion occurs when the physical capacity of a facility is reached, the congestion component is a market-calculated variable. The Congestion component signals a clearing price difference between any given load zone or generator, and the Marcy reference bus. The LBMP at the Marcy reference bus is a weighted average of all the individual clearing prices. Therefore, it is possible that the congestion component be either positive or negative.

4.1.2 Clearing Price – Local Congestion – Congestion Rents

Based on equation 1 alone, it is clear that two different generators, with two different production costs, will bid for generation dispatch at two different prices, even if they are located side-by-side and connect to the same bus. The system assesses the total NYISO zone load to be supplied, how much generation is offered, and the transmission constraints, and selects the most economic generation, while also verifying in that transmission limits are not exceeded. The "market clearing price" at any given location is set by the production cost of the most expensive MW dispatched. All the dispatched generators injecting energy in this location (bus) are paid this clearing price, the load end, the purchaser pays the LBMP as expressed in (eq.1).

Congestion occurs when, after all calculation, the system-optimum solution is such that the transmission system is physically unable to transport energy from a low

LBMP zone to a high LBMP zone, requiring that generators with higher production costs but closer to the load to be dispatched. When this occurs, the system recalculates the local clearing prices at both ends of the limiting facility (transmission line) such that generators be paid the clearing price (LBMP) of the location where they inject the power into the grid and that loads be charged based on the zone where they are located.

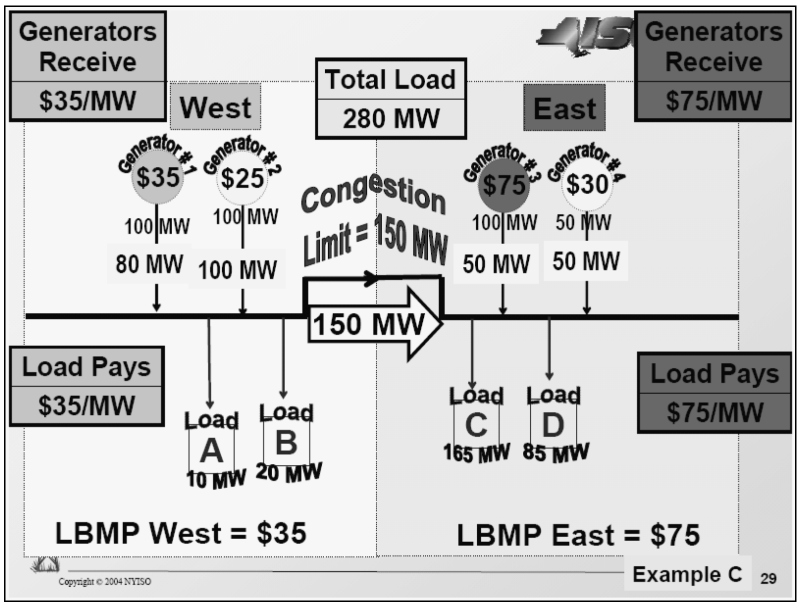


Figure 12. Congestion Example (source: NYISO training course LBMP 101 Introduction and definitions)

Figure 12 and Figure 13 depict the simplified congestion problem:

The transmission line between West and East has a 150 MW capacity.

- gen#1 and gen#2 are paid the west zone clearing price, $35/MW, despite the fact that 150MW are being purchased in the East Zone at a much higher price. This is a loss for gen#1 and gen#2.
- gen#3 sets the clearing price at the East Zone: $75/MW.
- gen#4 is paid at the East Zone price, $75/MW, despite the fact that its bid production cost was $30/MW

- Load C and D purchase all their energy at the East Zone LBMP, $75/MW, despite the fact that 150 MW are produced at much lower costs.

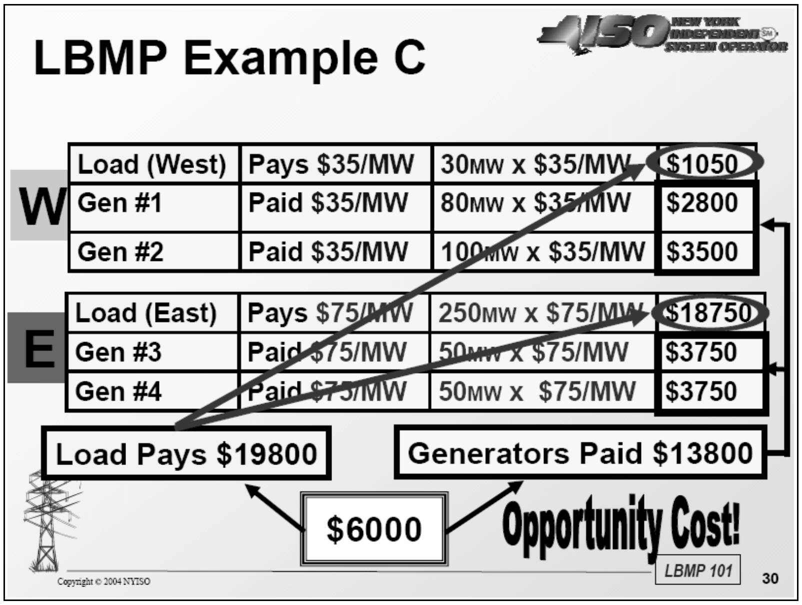


Figure 13. Congestion Rent (source: NYISO training course LBMP 101 Introduction and definitions)

As result of congestion, there is a difference of $6,000 between the amount paid by the load and the amount paid to the generators. That difference is defined as the cost of congestion, and is collected by the system operator.

These “Congestion Rents” are actually collected by NYISO via the Transmission Congestion Contract market, (TCC), a parallel financial mechanism designed to hedge the risk of congestions events and open to the public. As explained in the TCC 2005 Market Participants Guide:

“- The holder of a TCC collects (or pays if the TCC is negative) congestion rent calculated in the DAM and associated with transmitting one megawatt between the POI of the TCC and the POW.

- Customers in the DAM pay congestion charges. If the customer is buying LBMP energy, the congestion charge is embedded in the LBMP; if the customer is scheduling a bilateral transaction, the congestion charge is part of the Transmission Usage Charge. These congestion charges fund the congestion rents paid to TCC holders."

The congestion rent could be interpreted as the social welfare surplus that would be available if all congestion events in the area were to be eliminated.

4.1.3 Local Congestion is not a differentiable function

As stated in chapter 1, one of the objectives of this study is to determine how the inclusion of CHP systems in the NYISO region would affect the physical operation of the grid and the market behavior. The optimum location for a new CHP system in the example from Figure 12 is trivial:

Assume that the largest load in East Zone (that is Load C) partially reduces its electricity demand by installing a DG/CHP generator (with low production costs). The obvious benefit for Load C would then be that it would reduce its demand for the expensive energy that NYISO market supplies. More relevant, however, is the fact that Load D would also benefit from Load C new acquisition. Figure 14 shows the East Zone LBMP in Figure 12 as function of the zonal demand.

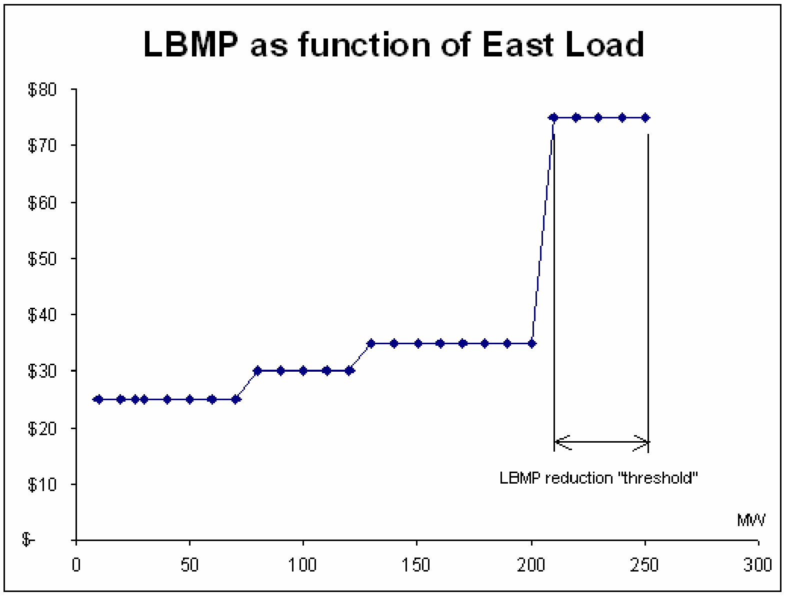


Figure 14. Example C East LBMP reduction as function of new DG system size

For the values and simplified conditions used in this example, it is clear that the East zone will pay $35/MW instead of $75/MW only if its neighbor Load D reduces its load by more than 50 MW. The real importance of this "threshold size" is that it marks the point at which the LBMP congestion component is mitigated in the East zone. Mathematically, this demonstrates the non-differentiability of congestion and thus of LBMP as function of the local loads.

Marginal load reductions might deliver marginal costs savings only for the DG system owner. As long as the transmission system stability and reliability is not compromised, NYISO will dispatch high cost generators. The importance of the congestion function discontinuity from the perspective of the goals of this study is that load reductions beyond "the threshold" will not only report marginal costs savings for the system owner, but more importantly, they may affect the market zonal clearing prices, to the benefit of the neighborhood (a positive externality).

The Congestion component, as posted by NYISO in the different price data summaries, is somehow related to the local congestion:

Local congestion (local generator production prices difference) leads to local LBMP which are averaged and posted as the reference bus LBMP. The difference between the reference LBMP and local LBMP after discounting transmission losses is the Congestion component.

4.2 Economic Interpretation

4.2.1 Local Analysis - Congestion Mitigation

There are many different ways of analyzing the effects of introducing distributed generation capacity in the Transmission and Distribution system. Since one of the initial objectives of this project was to calculate the effect of DG-CHP according to its location (following the "congestion" definition as explained in previous chapters), installing a DG-CHP system at the low-price end of the congested line (upstream) has different effects than it would at the high-price end of the congested line:

- If DG-CHP is installed upstream, the LBMP will not change because of the transmission capacity constraints.
- If the new DG-CHP capacity is installed downstream of the congested transmission line, the LBMP will change upon the assumption that the high price is being set by a very expensive generator of reduced capacity dispatched only during very high peak events.

The economic local effects for each congestion event and its mitigation can be explained with Figure 15:

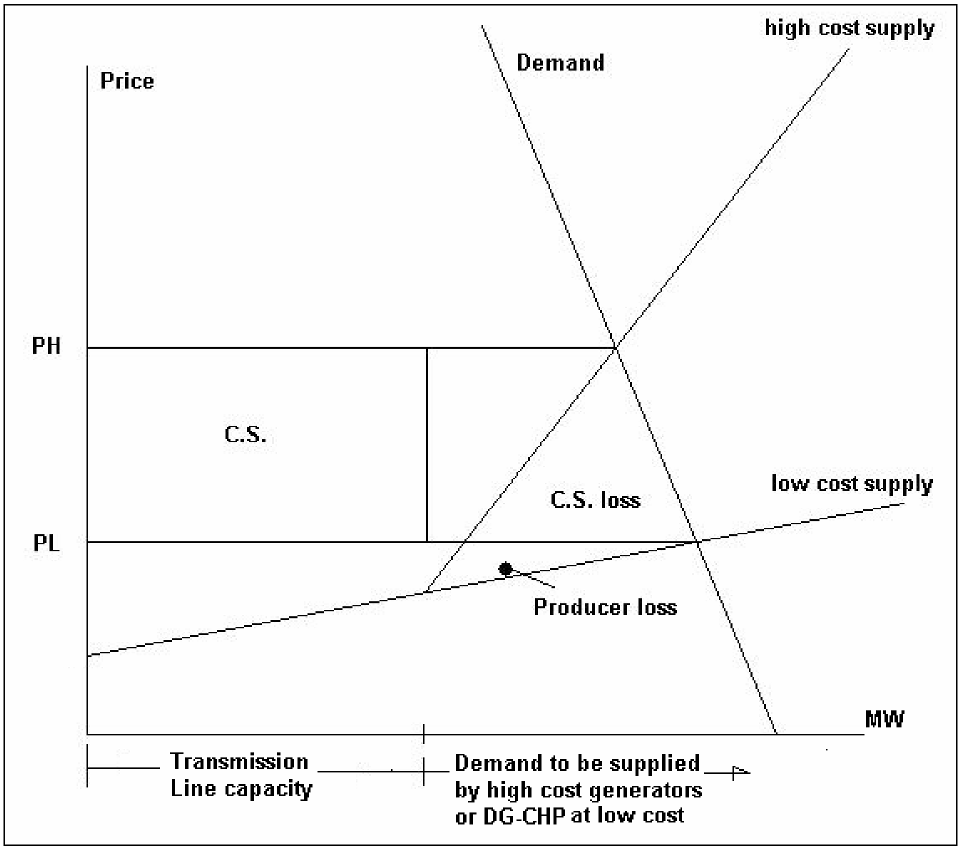


Figure 15. Congestion Mitigation – Local Analysis

In Figure 15 the Demand curve is not entirely vertical, denoting the fact that there is some elasticity, and prices cannot escalate without hurting demand. As long as the transmission capacity is not reached, supply will stay at low cost. The installation of DG-CHP allows for additional demand to be fulfilled at the low cost price, "PL" that is, without shifting to the high-cost supply curve (and its associated high clearing price, "PH").

This approach can be used only if all the variables of the transmission system are known. The geographical information shown in the Transmission system maps such as the different generators ratings and locations has been gathered with this goal in mind.

However, the anonymity of the NYISO bidding price and clearing price data was not possible to overcome in this project, thus, this approach is presented as reference for future developments of this research program.

4.2.2 Regional Average Analysis – Demand Reduction

During congestion events, the difference between the "PL" and "PH" curves is such that the resulting "local clearing price" curve is, at the very least, not differentiable at the local level. System wide however, the assumption that the supply curve can be approximated by a polynomial curve fit seems reasonable since the LBMP is calculated with reference to the Marcy bus price, which is a weighed average of the surrounding clearing prices.

The sum of the effects of all local congestion events-mitigation results in a smooth differentiable curve. In his analysis of the New England market in 2004, Beebe modeled this effect as a shift to the right of the supply curve. From an external market observer perspective, we believe that it is more accurate to state that the energy demand is reduced by an amount equal to the sum of all new DG-CHP generators capacities. As shown in Figure 16 the market demand curve shifts to the left, resulting in a lower market price.

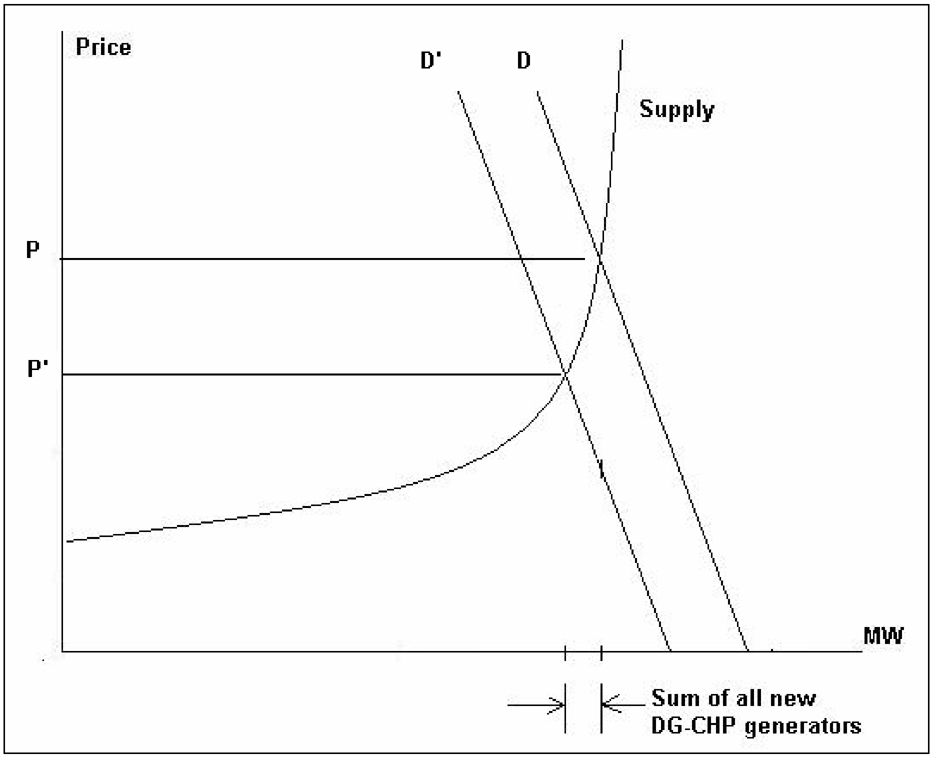


Figure 16. System Wide effect of DG- CHP market penetration

4.3 Market Characteristics: DAM and RT Market Supply Curve

The effect of introducing an amount of electric generating capacity in a one of the NYISO load zones will be described using the NYC load zone as example.

Previous works, such as Beebe's in 2004, proposed that the LBMP variations in the ISO-NE market could be determined with great accuracy by calculating the effect of "decongesting" some of the grid nodes. During this project, the attempt to use such methodology adjusting for the NYISO market particularities was explored. Further analysis then showed that definitions of concepts such as "congestion" and "congestion component" represented great obstacles to fulfill those goals: "congestion" data as found in the NYISO TCC market data is linked with congested lines, instead of nodes; and "congestion component", as defined in chapter 4.1, never disappears. In other other words, setting the "congestion component" to zero does not guarantee the lowest possible LBMP, which is the base assumption in the ISO-NE case study.

Therefore, the focus of the project was redirected to gathering both market and load information in order to determine the characteristics of the market.

4.3.1 LBMP - Zonal Average Approach

The hourly load and LBMP data for the DAM and RTM is available at the NYISO website. The posted price information includes the LBMP as zonal average, and the Losses component and the Congestion component of the price. These terms are defined by equation 1 in chapter 4.1.1.

Therefore, the DAM and RTM data available from the NYISO website allows one to calculate the average Energy component for each hour and to estimate the relation between LBMP, its components and the zonal average load.

- **The DAM data**

Figures 17 shows the DAM Load Commitment and Figure 18 thru 20 show LBMP and LBMP components data for 2006 DAM. Figure 20 shows the Congestion component. In the DAM case, its constant negative sign indicates that NYC zone LBMP is always higher than the reference bus LBMP. However, the congestion component may be either positive or negative (see Figure 26 for RTM data). Figure 21 shows the energy price calculated based on equation 1.

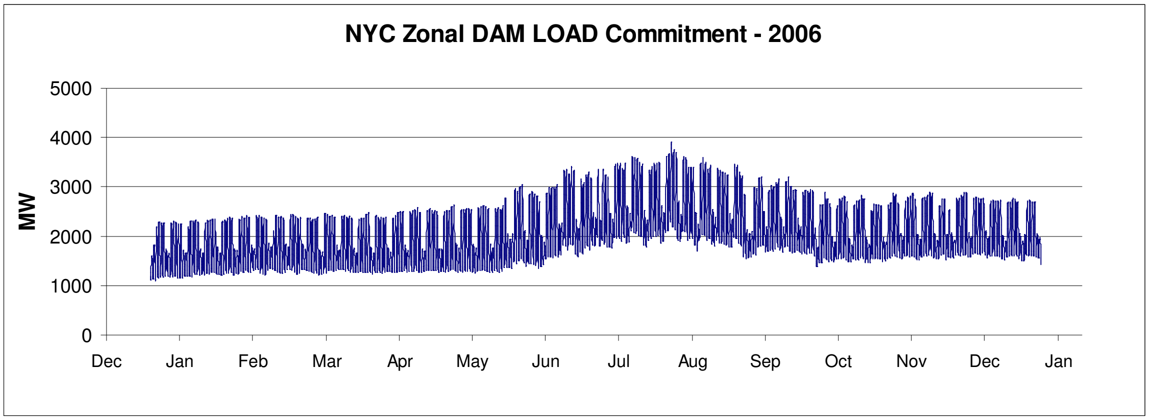


Figure 17. NYC DAM zonal load commitment 2006

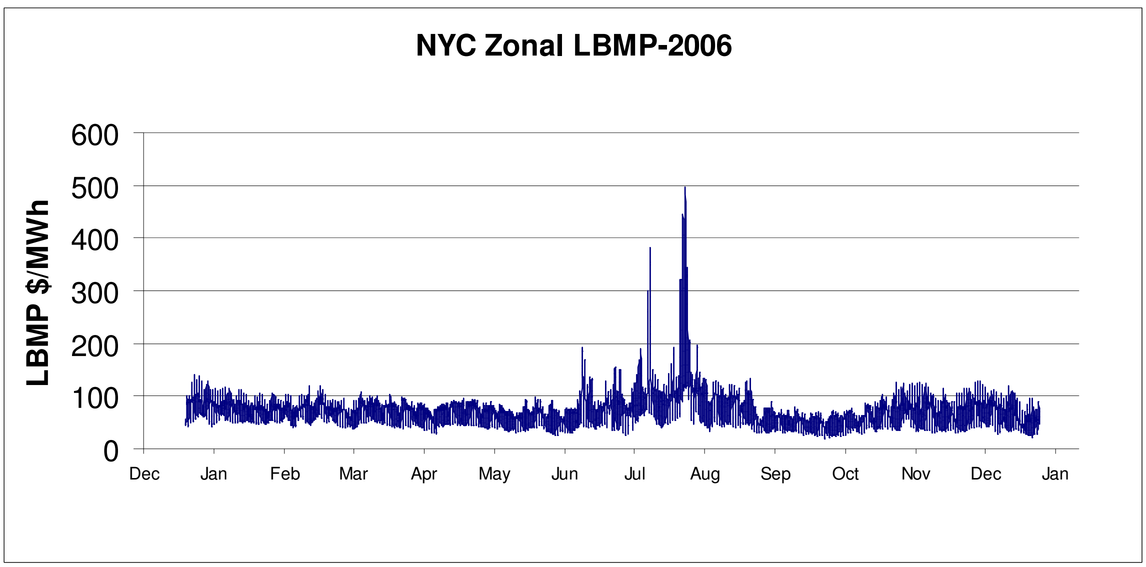


Figure 18. NYC Zonal LBMP 2006

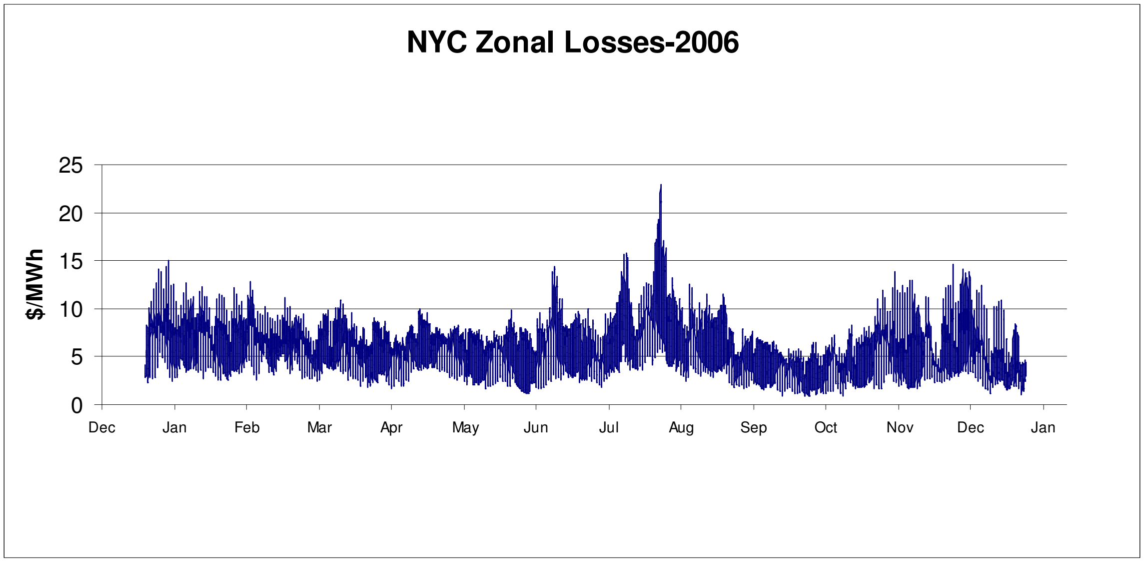


Figure 19. NYC Zonal Losses Component 2006

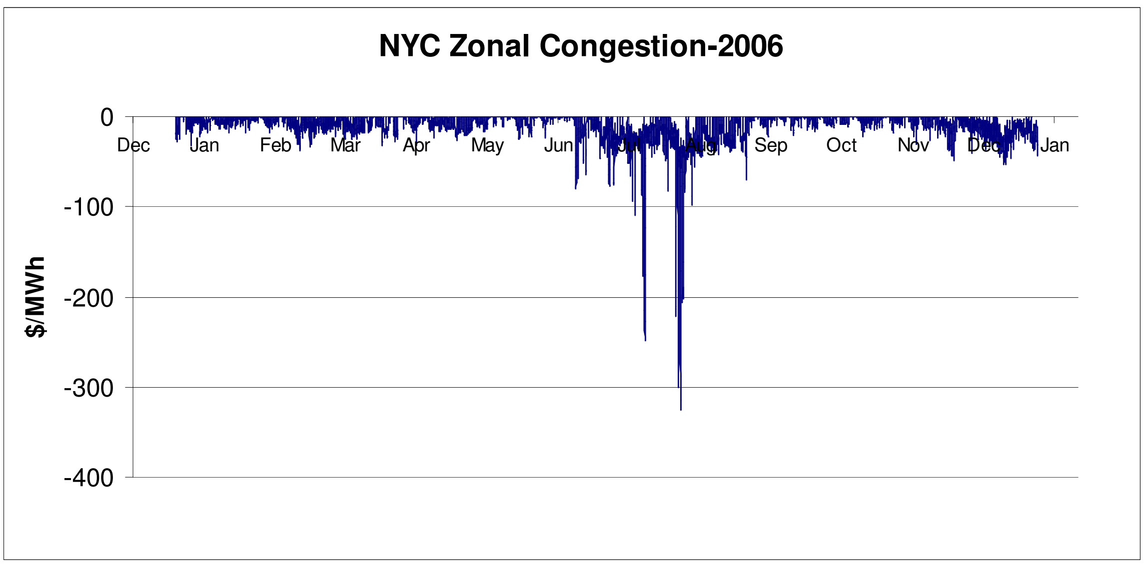


Figure 20. NYC Zonal Congestion Component 2006

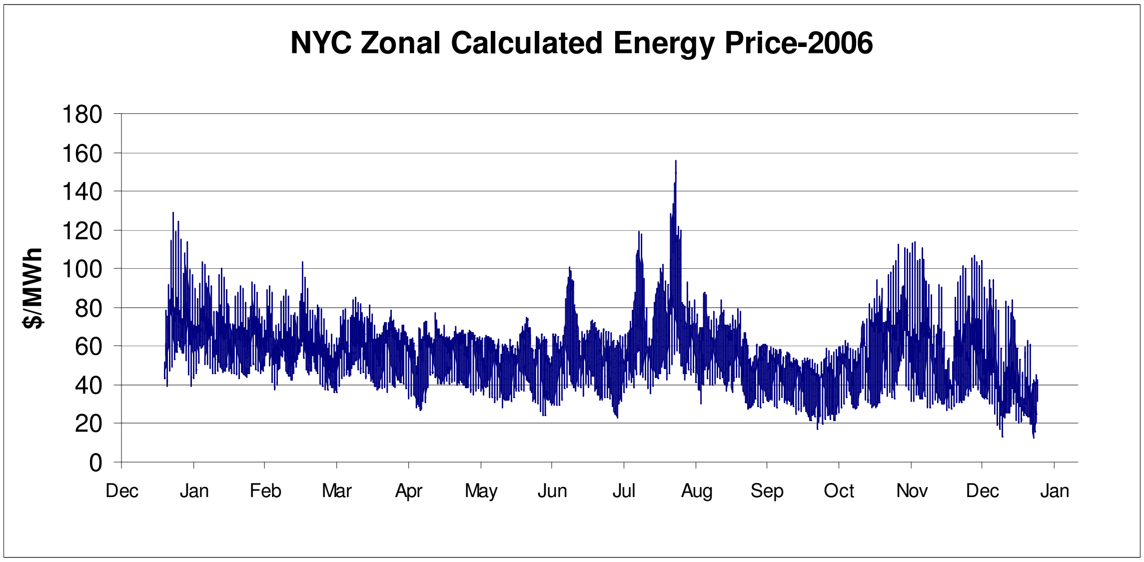


Figure 21. NYC Zonal Calculated Energy Price – 2006

The previous data is rearranged to display the relationship between LBMP and DAM Load Commitment. The result, and its polynomial curve fit, are shown in Figure 22.

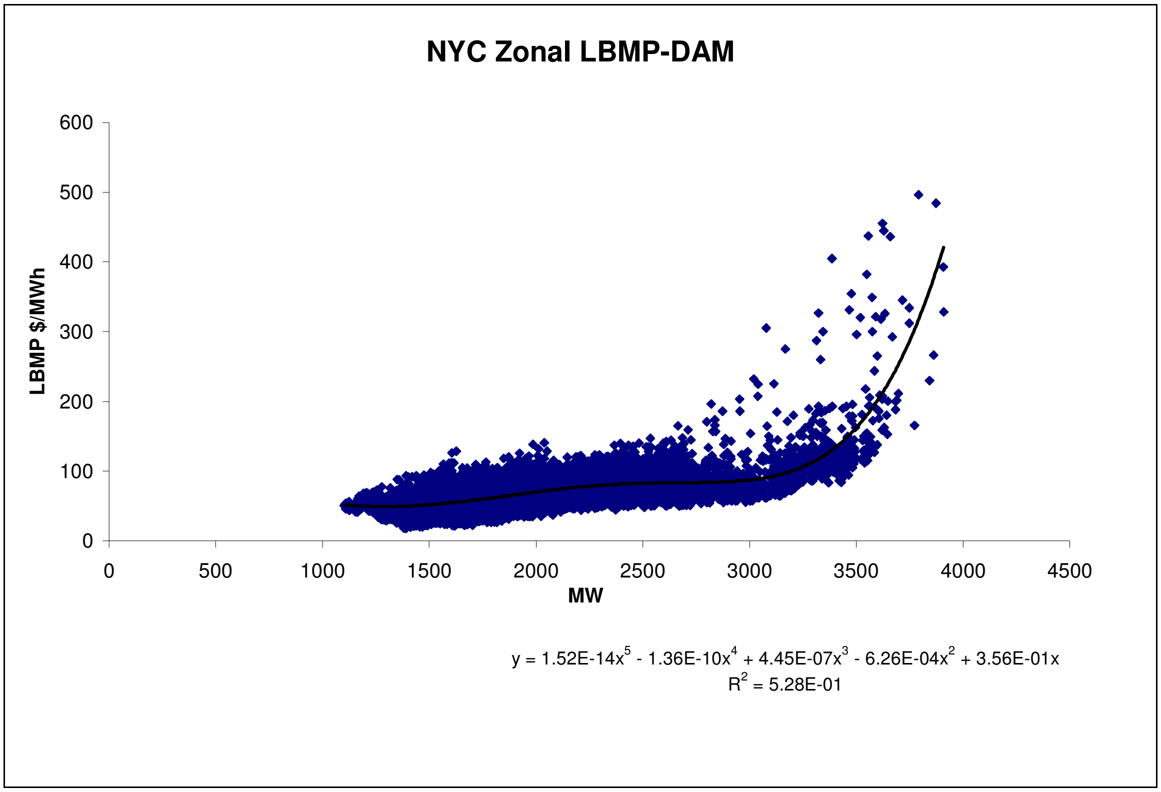


Figure 22. NYC Zonal LBMP-DAM vs. DAM load commitment

The DAM LBMP curve polynomial fit coefficients are:

Table 20. DAM LBMP curve Polynomial fit coefficients

DAM	Polynomial Coefficients
x6	0
x5	1.5232553458E-14
x4	-1.3649446652E-10
x3	4.4461500193E-07
x2	-6.2577639576E-04
x1	3.5638813539E-01
x0	0.0000000000E+00

The relationship between zonal load and the LBMP Congestion component is also estimated with a polynomial curve fit, as shown in Figure 23:

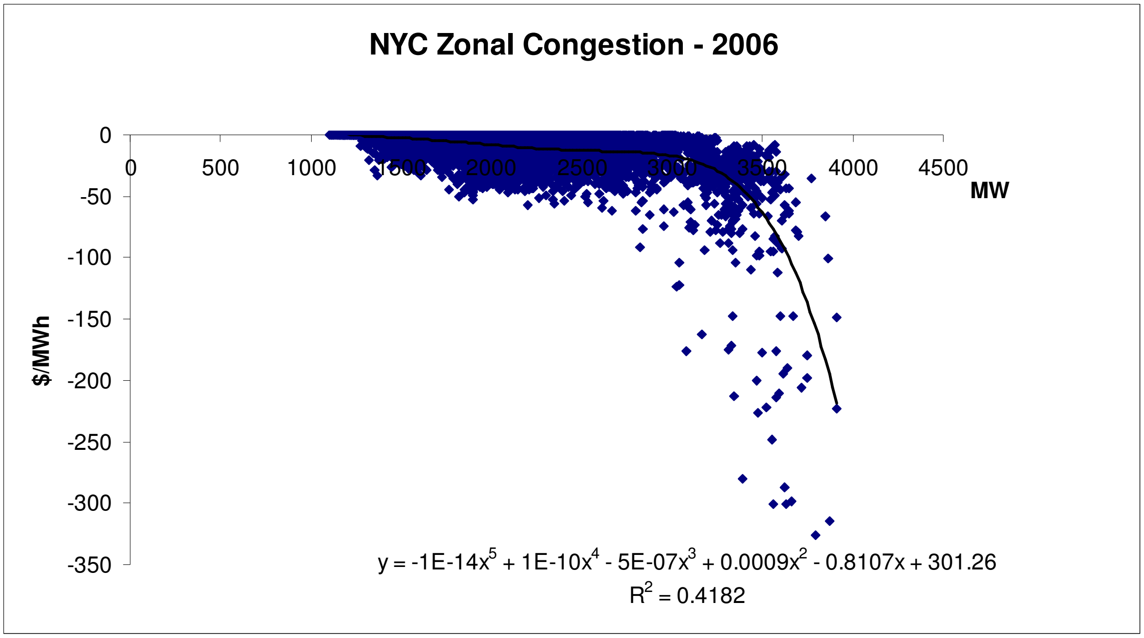


Figure 23. NYC Zonal Congestion DAM vs. DAM Load Commitment

The DAM congestion curve polynomial fit coefficients are:

Table 21. DAM congestion curve Polynomial fit coefficients

DAM Congestion	
	Polyn. Coeff
x6	0
x5	-1.154E-14
x4	1.162E-10
x3	-4.548E-07
x2	8.652E-04
x1	-8.107E-01
x0	3.013E+02

- **The RTM data**

Similarly, Figure 24 thru 27 show RTM LBMP and all its components data for 2006.

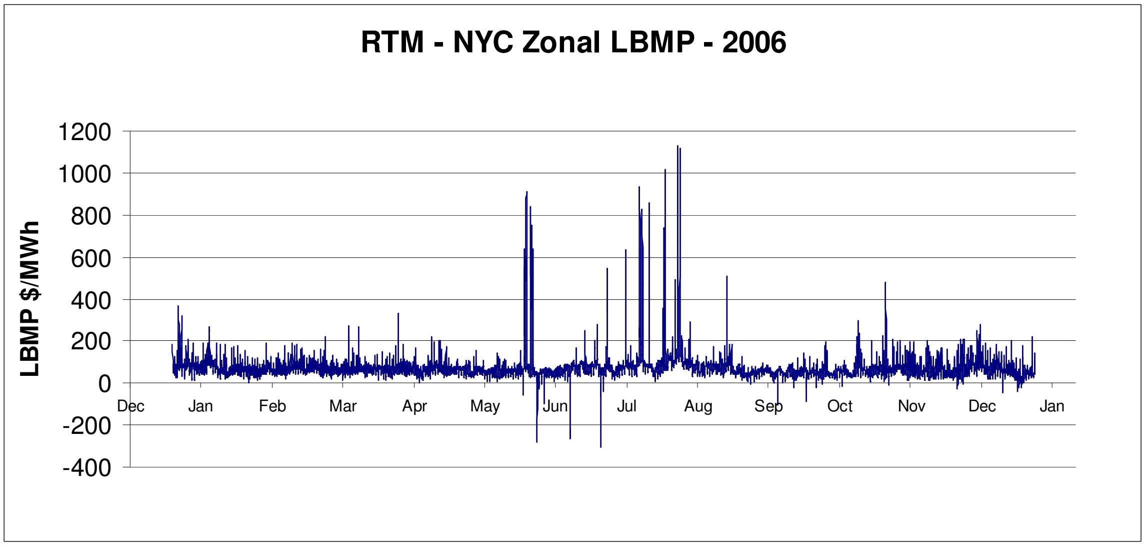


Figure 24. NYC Zonal LBMP RTM – 2006

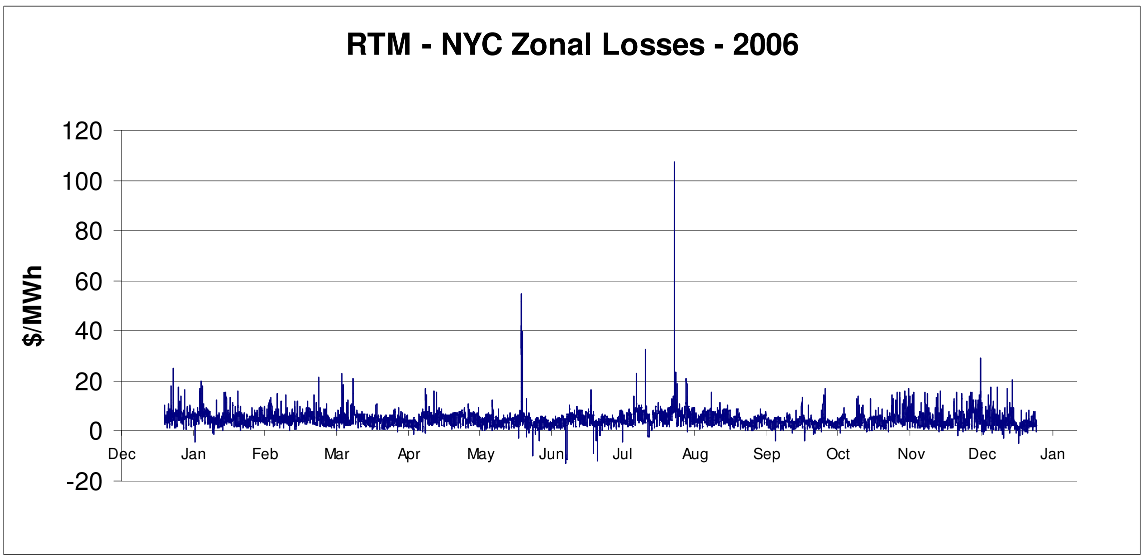


Figure 25. NYC Zonal Losses RTM - 2006

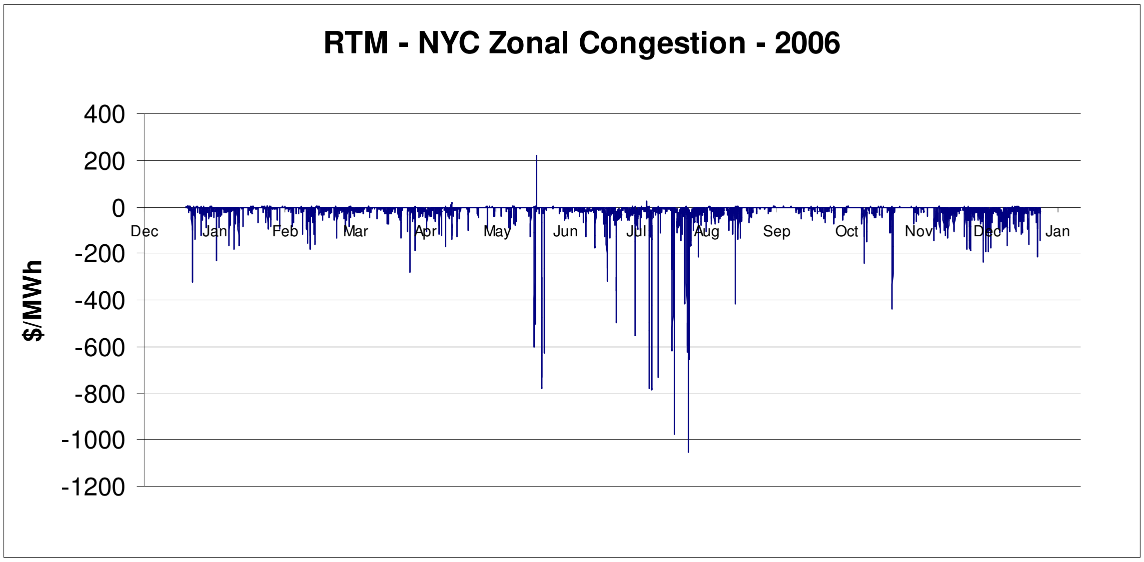


Figure 26. NYC Zonal Congestion Component RTM-2006

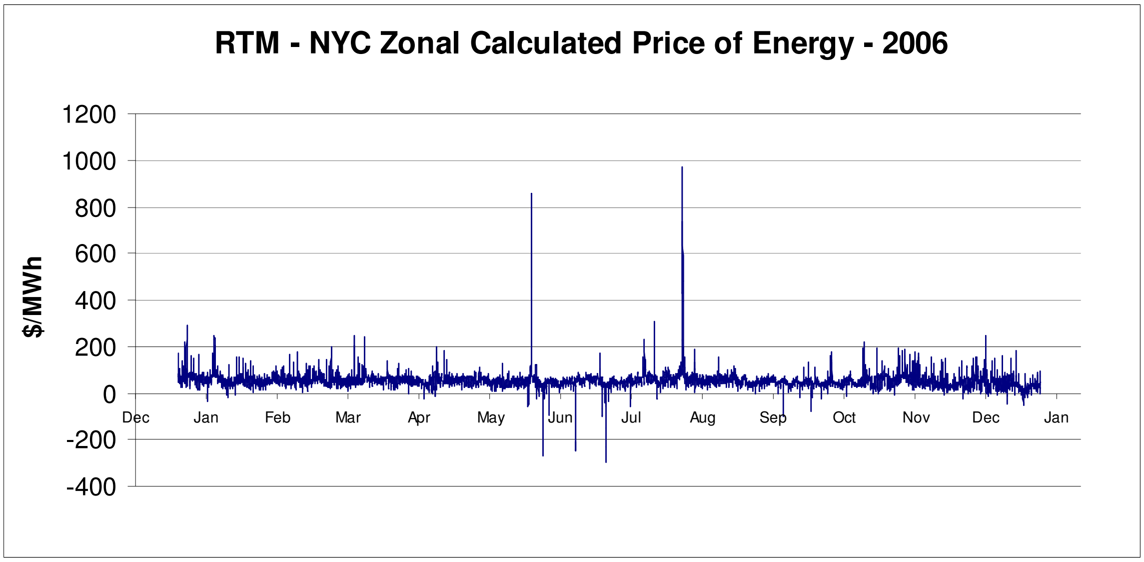


Figure 27. NYC Zonal Calculated Energy Price RTM - 2006

As for the DAM data, the RTM data is rearranged in order to estimate the average market supply curve and the influence of congestion upon any proposed load modifications. Figure 28 shows the RTM LBMP data polynomial curve fit:

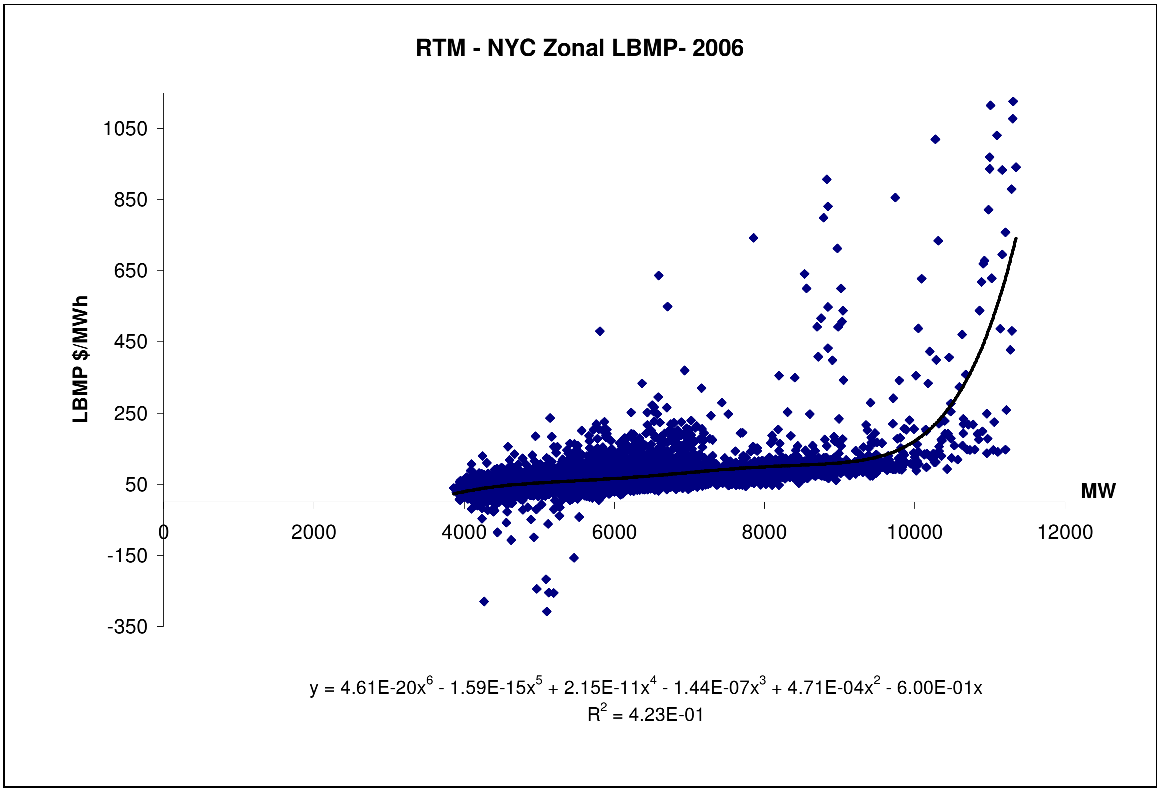


Figure 28. NYC - RTM Supply Curve estimation

The RTM LBMP curve polynomial fit coefficients are

Table 22. RTM LBMP Curve Polynomial fit coefficients

RT	Polynomial Coefficients
x6	4.6147295625E-20
x5	-1.5888727294E-15
x4	2.1535533962E-11
x3	-1.4358808391E-07
x2	4.7146697535E-04
x1	-5.9997123700E-01
x0	0.0000000000E+00

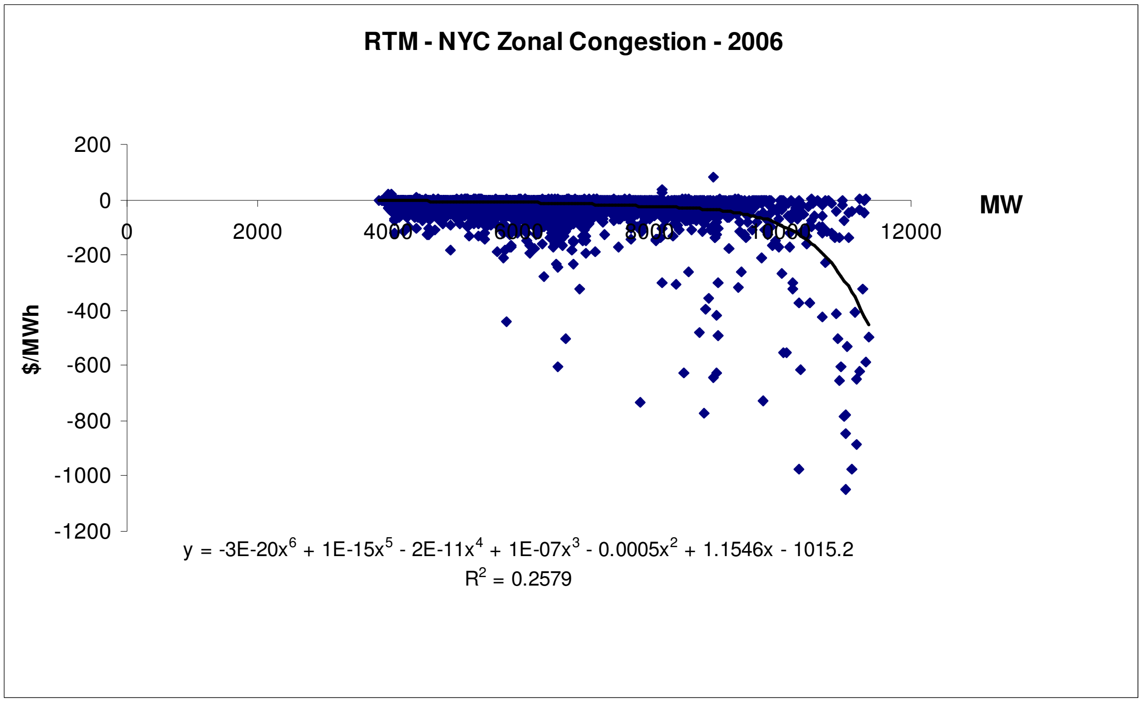


Figure 29. NYC Zonal Congestion Component estimation

RTM curve polynomial fit coefficients are:

Table 23. RTM Congestion curve Polynomial fit coeffienciencts

RT Congestion	
	Polyn. Coeff
x6	-2.89E-20
x5	1.063E-15
x4	-1.590E-11
x3	1.238E-07
x2	-5.265E-04
x1	1.155E+00
x0	-1.015E+03

- **DAM data analysis:**

The R^2 value of these LBMP and Congestion component curve fits are acceptable, especially in the case of the LBMP curve. Therefore, these results allow one to estimate the DAM behavior upon any variation of the load – as will be proposed in this report -

and if required, to calculate how much of the price variation can be "assigned" to the congestion component.

- **RTM data analysis:**

It must be noticed that the R^2 value for the RTM LBMP polynomial curve fit is somehow lower than the for the DAM-LBMP curve, but remains at an acceptable level - hence any RT market predictions based on this equation are acceptable as well.

The same cannot be said for the RTM Congestion component polynomial curve fit. The scattered appearance of the raw data is reflected in a very poor R^2 of the best polynomial curve fit offered by MS Excel (order 6). This reflects that in Real Time market conditions the LBMP varies due to effects beyond those of local congestion (as defined in chapter 4.1: difference in energy prices between two generating nodes). If the LBMP does changes due to factors other than price competition, the blame can be assigned to a non-competitive speculative behavior from all the regional generating facilities, leading to higher energy production costs - costs that must be accepted by customers, precisely because of the "real time" decision making environment.

These results remind us that there is more than one interpretation that may be given to "congestion": On the one hand, local congestion is the inability to transport cheap energy through a 'congested' line. On the other, "the congestion component" as posted in the different NYISO data files, refers to the difference in prices between the reference Marcy bus and any other load zone being analyzed. This relativity of the congestion component is misleading; the congestion component might be positive or negative, and yet, local energy price differences that DG-CHP could potentially offset do take place. This is the foundation for the decision of using only the DAM and RTM

LBMP data to consistently predict the market price behavior if the information available is that posted at the NYISO website.

4.4 Local Congestion mitigation

The main goal of this research is to quantify the costs and benefits associated with the installation of new DG-CHP systems within the NYS electricity market and to estimate how to redistribute the social surplus produced by the installation of new generators. The results of this analysis are contained in the model and case studies presented in the last chapter of this document.

Since ‘congestion’ is at the root of peaking prices, previous works have focused their efforts on the analysis of congestion mitigation on a node-by-node basis. The adaptation of such methods to the NYISO regulations and to the information available to the public has not been possible because of two fundamental factors:

1- The mathematical filters that exist between an actual physical grid congestion event and the congestion data, posted either as a DAM/RTM LBMP component or as a TCC constraint cost. With LBMP data, it has been already explained that congestion events are related to the congestion component, but that at least two averaging operations occur before the congestion component is posted and made public. The TCC constraint cost data gives information about congested lines, and is totally unrelated to DAM/RT LBMP data, making any systematic PTID association impossible.

2- The full knowledge of the geographical location of generators and loads is essential in order to determine the characteristics of power flow during congestion events. Public information about the location of generating transmission facilities is restricted, or at best, obsolete: the best map available - even with security clearance - is the 1993 NYPA T&D map.

The 'cost of congestion' is not by itself a practical quantity, independent of the methods and assumptions used to calculate its effects. If done properly, using reliable information and reasonable assumptions, the calculations of the LBMP variation should deliver the same results as the "Regional Average" method ($/kW incentives for new generators). Again, the value of previous works such as Beebe's[13] on the ISO-NE market was that it initially recommended, 5 candidate DG-CHP locations for the case of the Boston area. Only then, and based on further mathematical assumptions, were the system wide benefits calculated.

Therefore, in this chapter, with the goal of recommending optimal DG-CHP locations only, new methods and techniques are presented. More recent information is available in the form of "shapefiles" to be used with ArcGIS mapping tools; but this data, though better than the 1993 maps option, are still very raw and incomplete. It is hoped that the use of this tool and the addition of more complete generating and transmission facilities data in future developments of this study, will enhance that basic $/kW incentive information and, ideally, will be able to determine the optimal location of new DG-CHP generators.

For the case of NYC, a benchmark has been set by the local electric utlity, ConEd, which has published maps of the recommended locations for DG in each of the five NYC boroughs, as shown in figures 30 and 31. It is clear that the detail of such maps originates in the unique knowledge by ConEd of their own distribution grid. Although no

[13] Beebe, Christopher. Investigation and Evaluation of the Systemwide Economic Cost Benefits of Combined heat and Power Generation in the New York State energy Market. UMass - 2004

recommended capacity is indicated in ConEd's DG maps, they serve as a useful tool for calibrating future results of the methods proposed here.

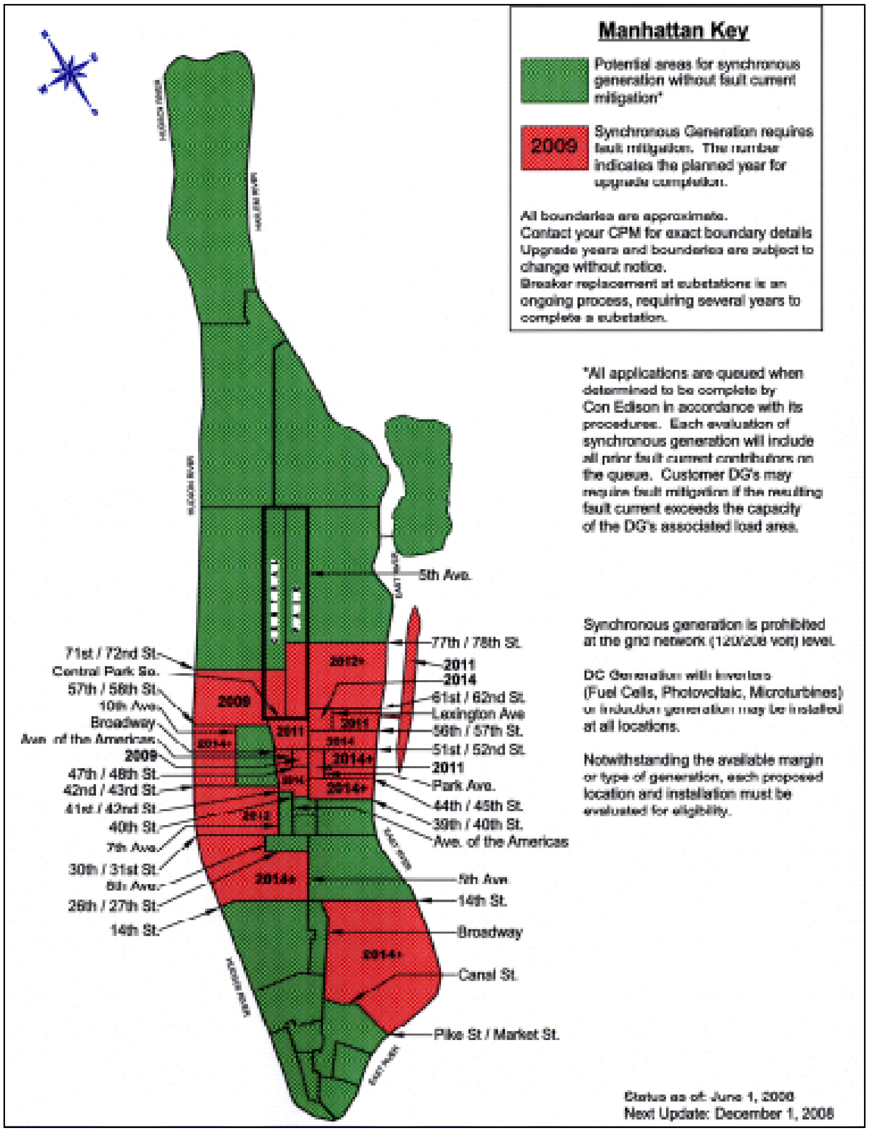


Figure 30. Manhattan Best DG locations (source: ConEd DG program)

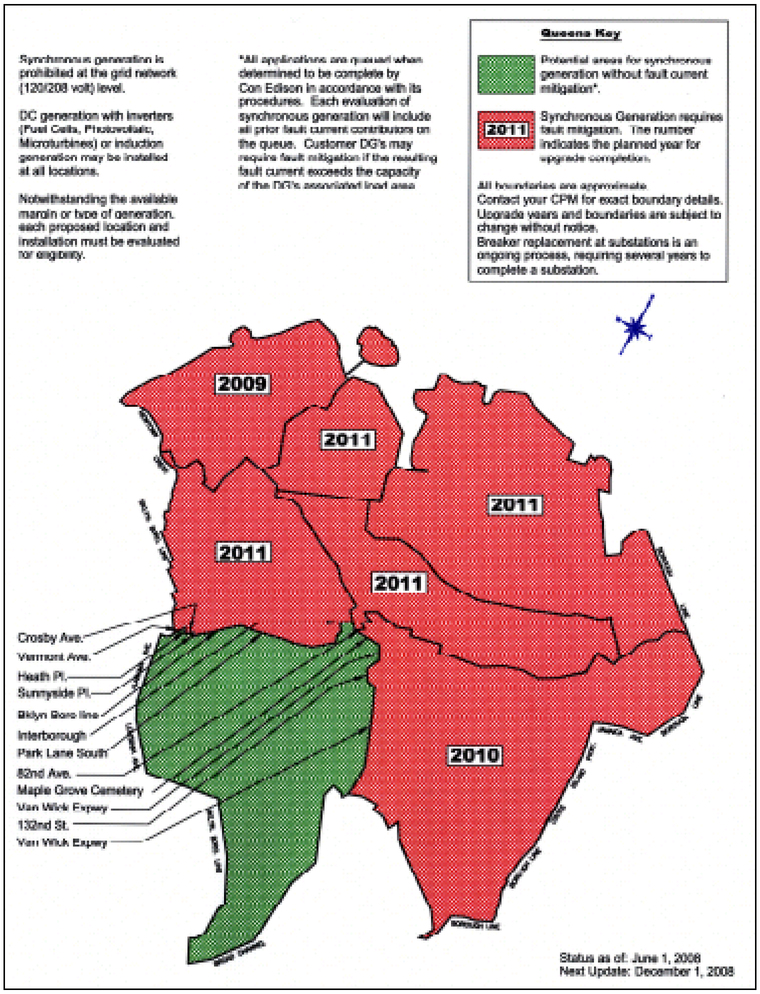


Figure 31. Queens Best DG locations (source: ConEd DG program)

4.5 Congestion Maps

4.5.1 Data Sources

- **Congestion Events Cost Data**

The practical use of concepts explained in chapter 4.4 is possible if the transmission lines capacities and congestion event-related costs are available. All the information published by NYISO makes reference to the PTID number, that is the ID number assigned to generators, loads, transmission facility and any other element within the system. The line capacities are published as Appendix D of the “NYISO Winter

Operating Study" each semester (for summer and winter). The cost of each hourly DAM limiting constraint is available at http://www.nyiso.com/public/market_data/power_grid_data.jsp?display=6. This data is presented in daily files that are compressed in monthly bundles. In order to collect the annual data, it is therefore necessary to put all the information in one single file. The use of the NYISO raw data is complicated by the fact that transmission facilities are only identified by PTID and name, requiring that the list of PTID's belonging to the NYC load zone be first manually determined; and this list then be used as a filter to sort out the desired facilities by location as shown in figures 33 and 34.

Each constraint or congestion event is characterized by the limiting facility name, description, PTID and constraint cost, expressed in $/MWh. Hence, the total cost of the congestion event can be determined with the following equation:

$$\text{Congestion Event Cost} = \text{Constraint Cost} \times \text{Limiting facility Normal Rating}$$

In the case of each individual NYISO load zones, the location of the most critical limiting transmission facilities can be schematically visualized in the electric diagram available in Appendix C of the NYISO seasonal operational reports. Figure 32 shows the results for NYC-ConEd load area. It should be noted that all facilities in Figure 32 are labeled with a different ID number than the PTID identification system used for DAM and RTM data by NYISO, which represents another obstacle to establishing consistent methodology.

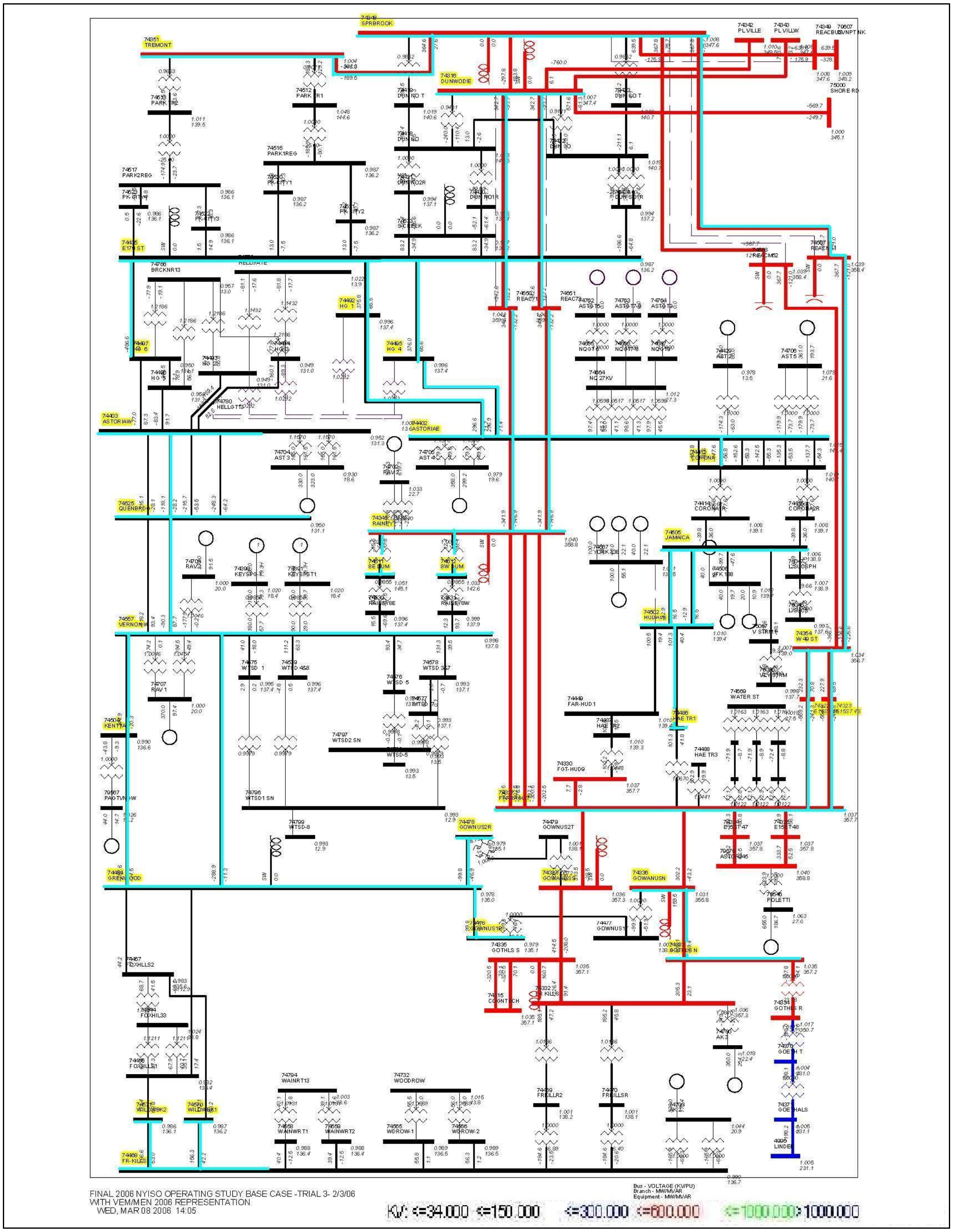


Figure 32. NYC – ConEd Area – NYISO Zone J Transmission Diagram (congested lines are highlighted in Turquoise)

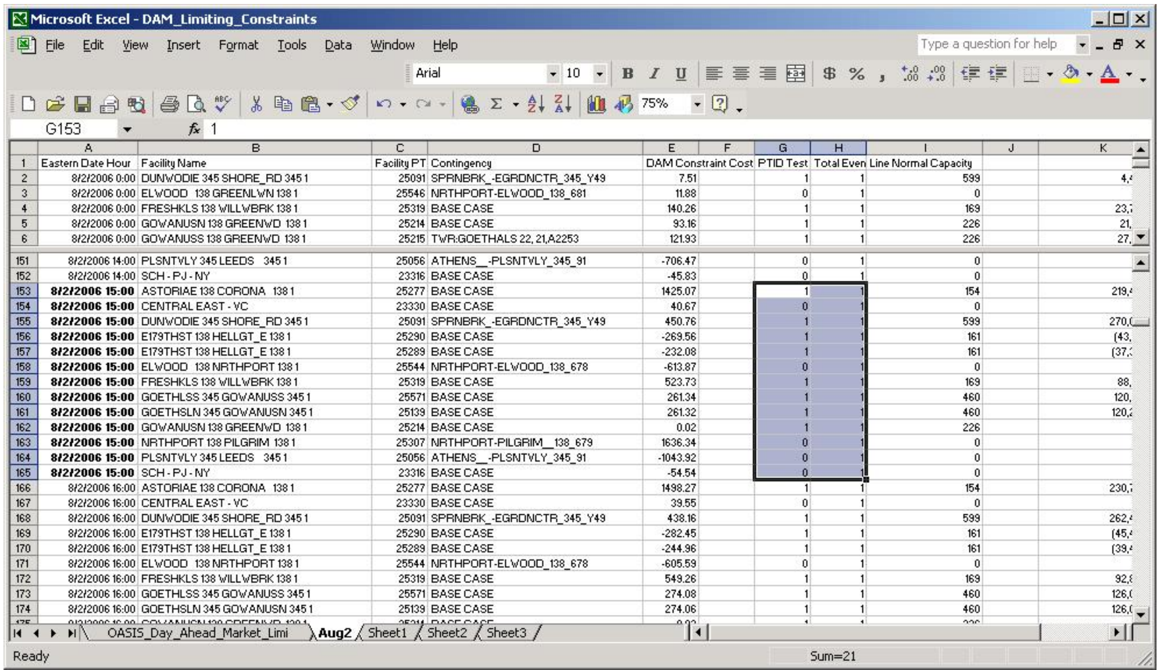


Figure 33. NYISO TCC Day Ahead Limiting Constraints Data

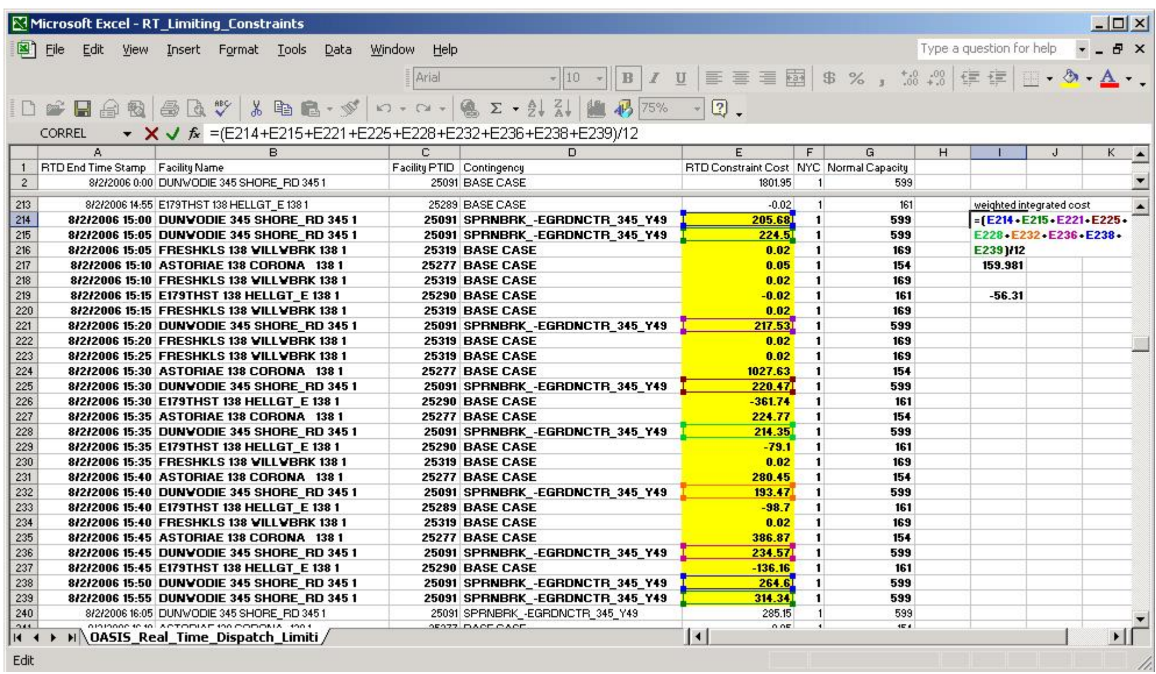
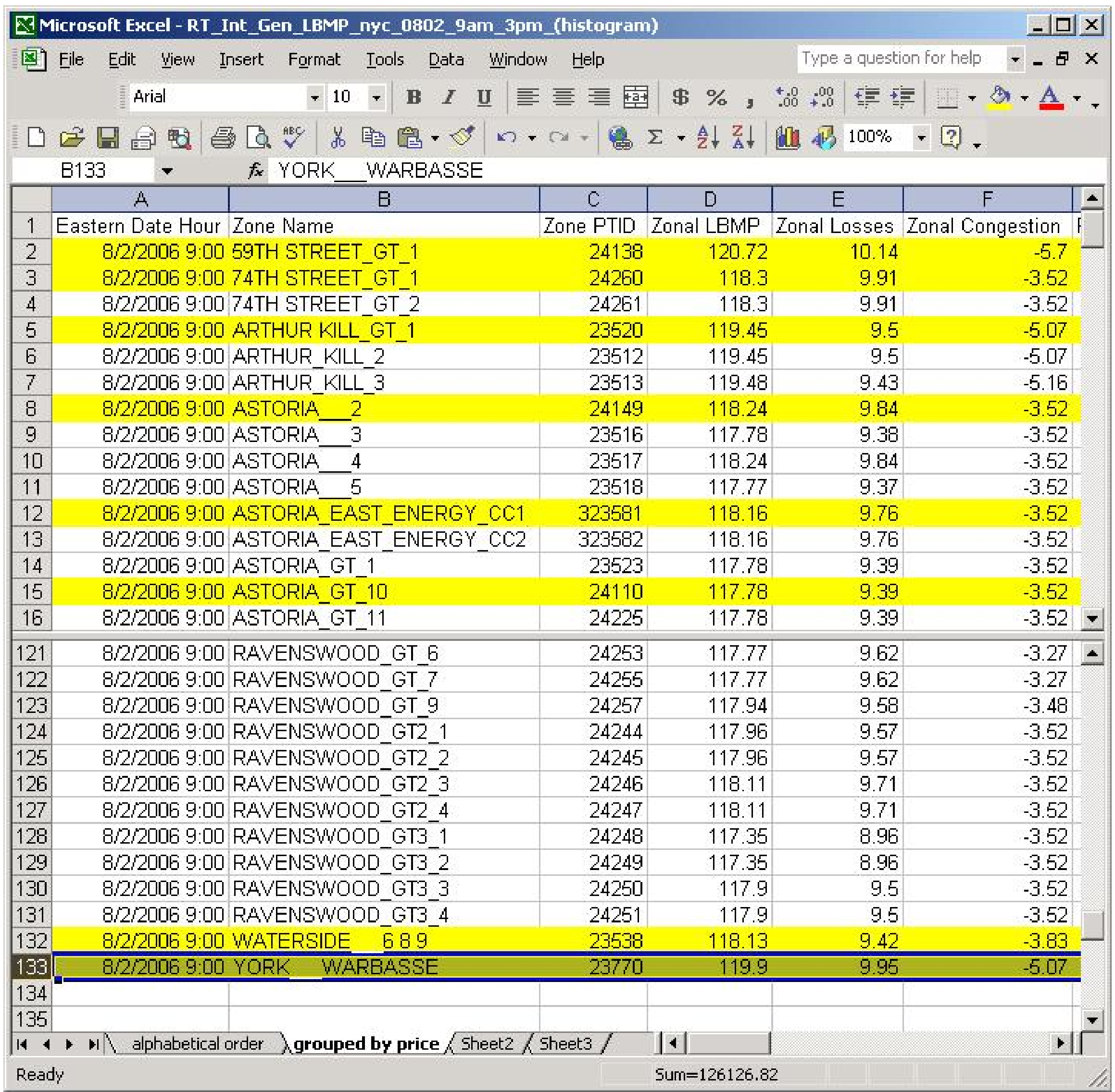


Figure 34. NYISO TCC Real Time average constraint cost calculation

- **DAM and RTM LBMP Data**

RT and DAM LBMP Generator hourly data is available at the NYISO website. As with any other NYISO published data, generators are identified by the PTID number so data must first be manipulated and filtered in order to sort data for a specific load zone, as shown in Figure 35 (manual sort).



	A	B	C	D	E	F
1	Eastern Date Hour	Zone Name	Zone PTID	Zonal LBMP	Zonal Losses	Zonal Congestion
2	8/2/2006 9:00	59TH STREET_GT_1	24138	120.72	10.14	-5.7
3	8/2/2006 9:00	74TH STREET_GT_1	24260	118.3	9.91	-3.52
4	8/2/2006 9:00	74TH STREET_GT_2	24261	118.3	9.91	-3.52
5	8/2/2006 9:00	ARTHUR KILL_GT_1	23520	119.45	9.5	-5.07
6	8/2/2006 9:00	ARTHUR_KILL_2	23512	119.45	9.5	-5.07
7	8/2/2006 9:00	ARTHUR_KILL_3	23513	119.48	9.43	-5.16
8	8/2/2006 9:00	ASTORIA___2	24149	118.24	9.84	-3.52
9	8/2/2006 9:00	ASTORIA___3	23516	117.78	9.38	-3.52
10	8/2/2006 9:00	ASTORIA___4	23517	118.24	9.84	-3.52
11	8/2/2006 9:00	ASTORIA___5	23518	117.77	9.37	-3.52
12	8/2/2006 9:00	ASTORIA_EAST_ENERGY_CC1	323581	118.16	9.76	-3.52
13	8/2/2006 9:00	ASTORIA_EAST_ENERGY_CC2	323582	118.16	9.76	-3.52
14	8/2/2006 9:00	ASTORIA_GT_1	23523	117.78	9.39	-3.52
15	8/2/2006 9:00	ASTORIA_GT_10	24110	117.78	9.39	-3.52
16	8/2/2006 9:00	ASTORIA_GT_11	24225	117.78	9.39	-3.52
121	8/2/2006 9:00	RAVENSWOOD_GT_6	24253	117.77	9.62	-3.27
122	8/2/2006 9:00	RAVENSWOOD_GT_7	24255	117.77	9.62	-3.27
123	8/2/2006 9:00	RAVENSWOOD_GT_9	24257	117.94	9.58	-3.48
124	8/2/2006 9:00	RAVENSWOOD_GT2_1	24244	117.96	9.57	-3.52
125	8/2/2006 9:00	RAVENSWOOD_GT2_2	24245	117.96	9.57	-3.52
126	8/2/2006 9:00	RAVENSWOOD_GT2_3	24246	118.11	9.71	-3.52
127	8/2/2006 9:00	RAVENSWOOD_GT2_4	24247	118.11	9.71	-3.52
128	8/2/2006 9:00	RAVENSWOOD_GT3_1	24248	117.35	8.96	-3.52
129	8/2/2006 9:00	RAVENSWOOD_GT3_2	24249	117.35	8.96	-3.52
130	8/2/2006 9:00	RAVENSWOOD_GT3_3	24250	117.9	9.5	-3.52
131	8/2/2006 9:00	RAVENSWOOD_GT3_4	24251	117.9	9.5	-3.52
132	8/2/2006 9:00	WATERSIDE___6 8 9	23538	118.13	9.42	-3.83
133	8/2/2006 9:00	YORK___WARBASSE	23770	119.9	9.95	-5.07
134						
135						

Figure 35. NYISO RT Integrated Generator LBMP for NYC – One PTID per location

Finally, NYISO also posts information about how the different generators around the state bid for dispatching rights. As shown in Figure 36, bid data may be visualized as the individual "supply curve". Such information is masked under a fake ID number and does not specify whether the bid is accepted or not; therefore, as of yet, no reliable association has been done regarding the identity behind each ID.

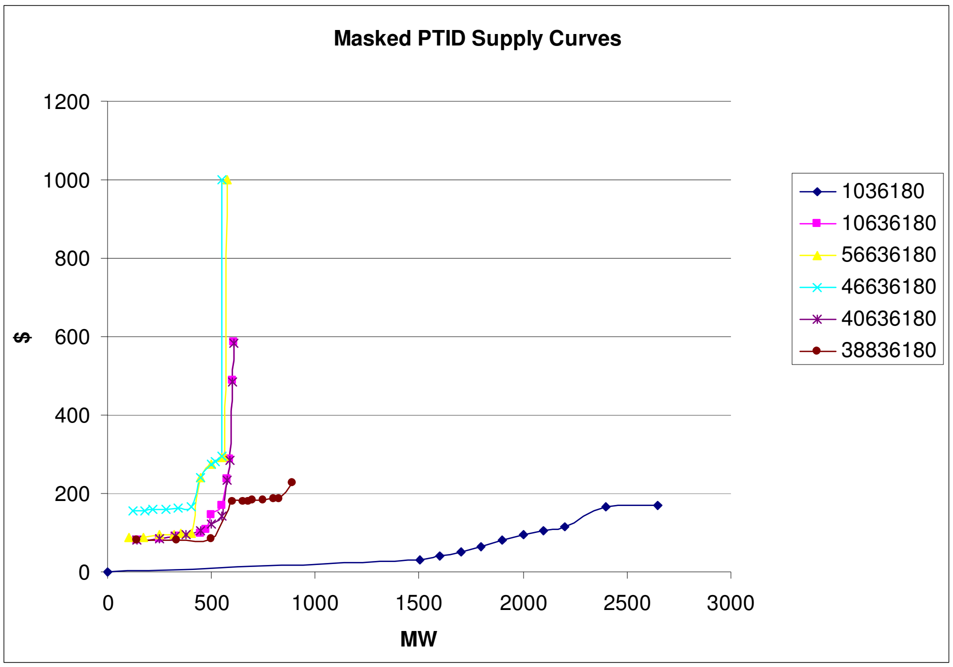


Figure 36. Bidding Supply Curve for different masked generatorsAug 1st 15:00

- **Generating and Transmission Facilities Location Data**

The most recent database for generating and transmitting facilities was found in the form of GIS shapefiles (*.shp). These files are to be used in conjuction with the ArcGIS software in order to produce simple maps and/or to generate more useful and complexe geographical information. The information included in these files was gathered and is protected with copyrights by Platts, the McGraw-Hill maps division.

Platts data was completed with generators RT LBMP, Transmission lines normal capacities and TCC's constraints cost to produce the maps shown in Figure 39 thru 41. Figure 37 shows a screen capture shot of ArcGIS being used as a data editing and data analysis tool. Once the identity of any given generator is established, LBMP data may be added to the "identity" table of attributes (i.e. bottom right corner, 9am and 3pm LBMP).

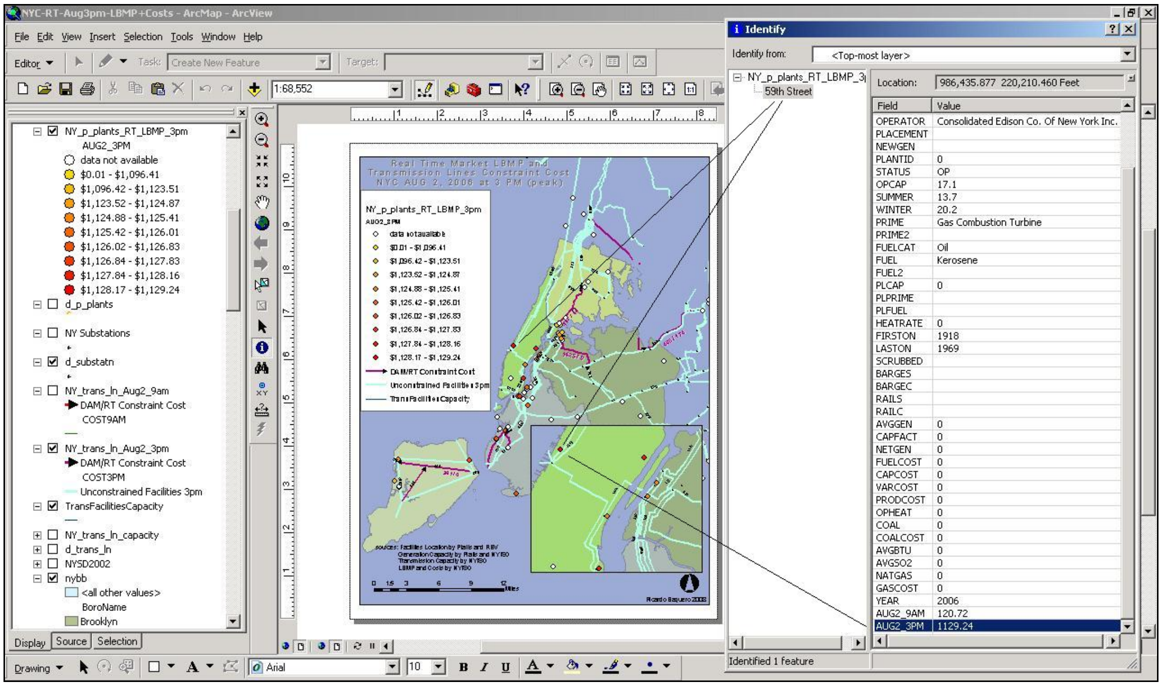


Figure 37. ArcGIS tool – Introducing NYISO data

By using a combination of NYISO and GIS data, as in the case of the example shown in Figure 37, it can be determined that, for example, the 59th Street generator is the most expensive generator dispatched on that day at that hour. The obvious conclusion would be to install DG-CHP around that location. This result is based on one hour. Having the same map for the remaining hours of the year would help visualize not only the behavior of that generator during the year (which can be done with excel alone) but also the behavior of this generator and its neighbor facilities.

4.5.2 Bid and LBMP Data to determine High Cost Generators[14]

This method relies in great measure on generators, substations and transmission lines ratings and geographical location, as well as in the deciphering of the masked identities of the NYISO bid data. As stated in the RNA 2007 conclusions (chapter 1.5.3), location is just as important as the size of the new generator, therefore, the initial steps towards the fulfillment of these goals – such as the elaboration of installed capacity maps and visual detection of congested lines – spent a great amount of working hours, in detriment of the attempt to decipher the masked identities. This pending task should be the first one to address as continuation of this report.

4.5.3 Congestion mitigation – Proposed Case Study Example

In the final chapter, a summary of the available information and of the proposed method to use it is presented. The NYISO publishes information about the price historic records. Such information is available both for generator buses and load buses. Additionally, it has been shown that congestion costs data can be linked to the transmission line constraining the operation, and, further more, that each congestion event can be translated to schematic graphical results by using electric diagrams. These results are not practically useful if the actual geographical location of generators, loads and transmission lines is not known and if, as stated in chapter 4.1.3, the congestion mitigation occurs in a step by step manner. Hence, in order to produce more accurate results, the analysis should consider the "congestion threshold" (measured in MW), how

[14] Future work

many generators and loads are located at each end of the congested line and the particular manner in which generators bid for dispatching rights. In tis way one could identify which generator is driving the price up in the congested area, and what the LBMP would be if this generator were not dispatched. The LBMP is assumed to be driven by the generator having the next highest production price (Energy Component). To illustrate this method, generator price data from a congestion event such as that in Aug-01 at15:00, shown in Figure 38, is analyzed. Figure 38 shows part of the DAM_LBMP_generators file for NYC generators. It is observed that the LBMP paid to some generators located in Down Town Manhattan, Brooklyn and Southern Queens is $459.76/MWh. It is highly improbable that the 74th Street, the Narrows, the Ravenwoods and York_Warbasse generators have the same fixed and marginal production costs; hence it is clear than one of these generators is driving the price up; however, with only this data in hand it is not possible to determine which one.

Time Stamp	Name	PTID	LBMP ($/MWHr)	Marginal Cost Losses ($/MWHr)	Marginal Cost Congestion ($/MWH
8/1/2006 15:00	NYPA_HARLEM__RVR__GT1	24160	328.98	18.89	-184.96
8/1/2006 15:00	NYPA_HARLEM__RVR__GT2	24161	328.98	18.89	-184.96
8/1/2006 15:00	NYPA_GOWANUS_____GT5	24156	459.62	18.89	-315.59
8/1/2006 15:00	NYPA_GOWANUS_____GT6	24157	459.62	18.89	-315.59
8/1/2006 15:00	59TH STREET_GT_1	24138	460.38	19.65	-315.61
8/1/2006 15:00	**74TH STREET_GT_1**	**24260**	**459.76**	**19.02**	**-315.61**
8/1/2006 15:00	**74TH STREET_GT_2**	**24261**	**459.76**	**19.02**	**-315.61**
8/1/2006 15:00	ASTORIA_GT_1	23523	459.38	18.64	-315.61
8/1/2006 15:00	ASTORIA_GT_10	24110	459.38	18.64	-315.61
8/1/2006 15:00	ASTORIA_GT_11	24225	459.38	18.64	-315.61
8/1/2006 15:00	ASTORIA_GT_12	24226	459.38	18.64	-315.61
8/1/2006 15:00	ASTORIA_GT_13	24227	459.38	18.64	-315.61
8/1/2006 15:00	ASTORIA___3	23516	459.38	18.64	-315.61
8/1/2006 15:00	ASTORIA___4	23517	459.38	18.64	-315.61
8/1/2006 15:00	BROOKLYN_NAVY_YARD	23515	459.63	18.89	-315.61
8/1/2006 15:00	CE_NYC2_DRP	24202	459.51	18.77	-315.61
8/1/2006 15:00	CE_NYC_DRP	24195	460.26	19.52	-315.61
8/1/2006 15:00	EAST RIVER___6	23660	460.01	19.27	-315.61
8/1/2006 15:00	EAST RIVER___7	23524	460.01	19.27	-315.61
8/1/2006 15:00	EAST_RIVER___1	323558	460.26	19.52	-315.61
8/1/2006 15:00	EAST_RIVER___2	323559	460.01	19.27	-315.61
8/1/2006 15:00	FARRAGUT___LBMP	323566	459.88	19.14	-315.61
8/1/2006 15:00	GOWANUS_GT1_1	24077	459.63	18.89	-315.61
8/1/2006 15:00	GOWANUS_GT1_2	24078	459.63	18.89	-315.61
8/1/2006 15:00	GOWANUS_GT1_3	24079	459.63	18.89	-315.61
8/1/2006 15:00	GOWANUS_GT1_4	24080	459.63	18.89	-315.61
8/1/2006 15:00	GOWANUS_GT1_5	24084	459.63	18.89	-315.61
8/1/2006 15:00	GOWANUS_GT1_6	24111	459.63	18.89	-315.61
8/1/2006 15:00	GOWANUS_GT1_7	24112	459.63	18.89	-315.61
8/1/2006 15:00	GOWANUS_GT1_8	24113	459.63	18.89	-315.61
8/1/2006 15:00	GOWANUS_GT2_1	24114	459.63	18.89	-315.61
8/1/2006 15:00	GOWANUS_GT2_2	24115	459.63	18.89	-315.61
8/1/2006 15:00	GOWANUS_GT2_3	24116	459.63	18.89	-315.61
8/1/2006 15:00	GOWANUS_GT2_4	24117	459.63	18.89	-315.61
8/1/2006 15:00	GOWANUS_GT2_5	24118	459.63	18.89	-315.61
8/1/2006 15:00	GOWANUS_GT2_6	24119	459.63	18.89	-315.61
8/1/2006 15:00	GOWANUS_GT2_7	24120	459.63	18.89	-315.61
8/1/2006 15:00	GOWANUS_GT2_8	24121	459.63	18.89	-315.61
8/1/2006 15:00	GOWANUS_GT3_1	24122	459.63	18.89	-315.61
8/1/2006 15:00	GOWANUS_GT3_2	24123	459.63	18.89	-315.61
8/1/2006 15:00	GOWANUS_GT3_3	24124	459.63	18.89	-315.61
8/1/2006 15:00	GOWANUS_GT3_4	24125	459.63	18.89	-315.61
8/1/2006 15:00	GOWANUS_GT3_5	24126	459.63	18.89	-315.61
8/1/2006 15:00	GOWANUS_GT3_6	24127	459.63	18.89	-315.61
8/1/2006 15:00	GOWANUS_GT3_7	24128	459.63	18.89	-315.61
8/1/2006 15:00	GOWANUS_GT3_8	24129	459.63	18.89	-315.61
8/1/2006 15:00	GOWANUS_GT4_1	24130	459.63	18.89	-315.61
8/1/2006 15:00	GOWANUS_GT4_2	24131	459.63	18.89	-315.61
8/1/2006 15:00	GOWANUS_GT4_3	24132	459.63	18.89	-315.61
8/1/2006 15:00	GOWANUS_GT4_4	24133	459.63	18.89	-315.61
8/1/2006 15:00	GOWANUS_GT4_5	24134	459.63	18.89	-315.61
8/1/2006 15:00	GOWANUS_GT4_6	24135	459.63	18.89	-315.61
8/1/2006 15:00	GOWANUS_GT4_7	24136	459.63	18.89	-315.61
8/1/2006 15:00	GOWANUS_GT4_8	24137	459.63	18.89	-315.61
8/1/2006 15:00	HUDSON AVE_GT_3	23810	460.01	19.27	-315.61
8/1/2006 15:00	HUDSON AVE_GT_4	23540	460.01	19.27	-315.61
8/1/2006 15:00	HUDSON AVE_GT_5	23657	460.01	19.27	-315.61
8/1/2006 15:00	HUDSON_AVE_10	24168	459.63	18.89	-315.61
8/1/2006 15:00	KIAC_JFK_GT1	23816	459.26	18.52	-315.61
8/1/2006 15:00	KIAC_JFK_GT2	23817	459.26	18.52	-315.61
8/1/2006 15:00	**NARROWS_GT1_1**	**24228**	**459.76**	**19.02**	**-315.61**
8/1/2006 15:00	**NARROWS_GT1_2**	**24229**	**459.76**	**19.02**	**-315.61**
8/1/2006 15:00	**NARROWS_GT1_3**	**24230**	**459.76**	**19.02**	**-315.61**
8/1/2006 15:00	**NARROWS_GT1_4**	**24231**	**459.76**	**19.02**	**-315.61**
8/1/2006 15:00	**NARROWS_GT1_5**	**24232**	**459.76**	**19.02**	**-315.61**
8/1/2006 15:00	**NARROWS_GT1_6**	**24233**	**459.76**	**19.02**	**-315.61**
8/1/2006 15:00	**NARROWS_GT1_7**	**24234**	**459.76**	**19.02**	**-315.61**
8/1/2006 15:00	**NARROWS_GT1_8**	**24235**	**459.76**	**19.02**	**-315.61**
8/1/2006 15:00	**NARROWS_GT2_1**	**24236**	**459.76**	**19.02**	**-315.61**
8/1/2006 15:00	**NARROWS_GT2_2**	**24237**	**459.76**	**19.02**	**-315.61**
8/1/2006 15:00	**NARROWS_GT2_3**	**24238**	**459.76**	**19.02**	**-315.61**
8/1/2006 15:00	**NARROWS_GT2_4**	**24239**	**459.76**	**19.02**	**-315.61**
8/1/2006 15:00	**NARROWS_GT2_5**	**24240**	**459.76**	**19.02**	**-315.61**
8/1/2006 15:00	**NARROWS_GT2_6**	**24241**	**459.76**	**19.02**	**-315.61**
8/1/2006 15:00	**NARROWS_GT2_7**	**24242**	**459.76**	**19.02**	**-315.61**
8/1/2006 15:00	**NARROWS_GT2_8**	**24243**	**459.76**	**19.02**	**-315.61**
8/1/2006 15:00	NYPA_KENT_____GT	24152	459.51	18.77	-315.61
8/1/2006 15:00	NYPA_VERNON_____GT2	24162	459.51	18.77	-315.61
8/1/2006 15:00	NYPA_VERNON_____GT3	24163	459.51	18.77	-315.61
8/1/2006 15:00	NYPA___ASTORIA_CC1	323568	459.38	18.64	-315.61
8/1/2006 15:00	NYPA___ASTORIA_CC2	323569	459.38	18.64	-315.61
8/1/2006 15:00	POLETTI____	23519	459.38	18.64	-315.61
8/1/2006 15:00	RAVENSWOOD_GT2_1	24244	459.51	18.77	-315.61
8/1/2006 15:00	RAVENSWOOD_GT2_2	24245	459.51	18.77	-315.61
8/1/2006 15:00	**RAVENSWOOD_GT2_3**	**24246**	**459.76**	**19.02**	**-315.61**
8/1/2006 15:00	**RAVENSWOOD_GT2_4**	**24247**	**459.76**	**19.02**	**-315.61**
8/1/2006 15:00	RAVENSWOOD_GT3_1	24248	459.51	18.77	-315.61
8/1/2006 15:00	RAVENSWOOD_GT3_2	24249	459.51	18.77	-315.61
8/1/2006 15:00	RAVENSWOOD_GT3_3	24250	460.01	19.27	-315.61
8/1/2006 15:00	RAVENSWOOD_GT3_4	24251	460.01	19.27	-315.61
8/1/2006 15:00	RAVENSWOOD_GT_1	23729	459.51	18.77	-315.61
8/1/2006 15:00	RAVENSWOOD_GT_10	24258	459.01	18.27	-315.61
8/1/2006 15:00	RAVENSWOOD_GT_11	24259	459.01	18.27	-315.61
8/1/2006 15:00	RAVENSWOOD_GT_4	24252	459.38	18.64	-315.61
8/1/2006 15:00	RAVENSWOOD_GT_5	24254	459.38	18.64	-315.61
8/1/2006 15:00	RAVENSWOOD_GT_6	24253	459.38	18.64	-315.61
8/1/2006 15:00	RAVENSWOOD_GT_7	24255	459.38	18.64	-315.61
8/1/2006 15:00	RAVENSWOOD_GT_8_TEMP G	24256	459.01	18.27	-315.61
8/1/2006 15:00	RAVENSWOOD_GT_9	24257	459.01	18.27	-315.61
8/1/2006 15:00	RAVENSWOOD___1	23533	459.51	18.77	-315.61
8/1/2006 15:00	RAVENSWOOD___2	23534	458.51	17.77	-315.61
8/1/2006 15:00	RAVENSWOOD___3	23535	459.51	18.77	-315.61
8/1/2006 15:00	RAVENSWOOD___4	23820	459.38	18.64	-315.61
8/1/2006 15:00	RCPI_TRUST___DRP	24196	460.38	19.65	-315.61
8/1/2006 15:00	WATERSIDE___6 8 9	23538	459.38	18.64	-315.61
8/1/2006 15:00	**YORK___WARBASSE**	**23770**	**459.76**	**19.02**	**-315.61**
8/1/2006 15:00	NYPA_POUCH1_____GT	24155	610.45	18.89	-466.42

Figure 38. Congestion LBMP Queens-Manhattan-Brooklyn area Aug 1st 15:00

Getting to the state of perfect market information - that is, knowing the generating, T&D infrastructure characteristics, and identifying all the facilities behind each ID and PTID number - is an overwhelming task if done manually (as shown in this chapter). It is at this point, that the algorithms for Excel and ArcGIS herein presented might be of great use. Ideally, all the steps can be automated using Excel "macro" programming and GIS programming. The Excel programming has already been used to produce the intermediate results shown in this report, however, the automatic map generation by using ArcGIS data programming features, is a task large enough for a separate independent project.

4.5.4 Results

Figure 39 shows the installed generating and transmitting capacity around the NYC area. This map, and the ArcGIS file supporting it, are a product of this project.

The other two maps, Figure 40 and 41, are the result of a first attempt to visualize all the information previously described. Each map describes the RTM LBMP situation and the local congestion events for two hours on August 2nd 2006, at 9am and 3pm. As suggested in the previous chapter, ArcGIS offers the potential for automatically produce the same map for each hour of the year. Such an increase in sophistication would greatly enhance the accuracy of the optimal DG-CHP location recommendation.

Map1

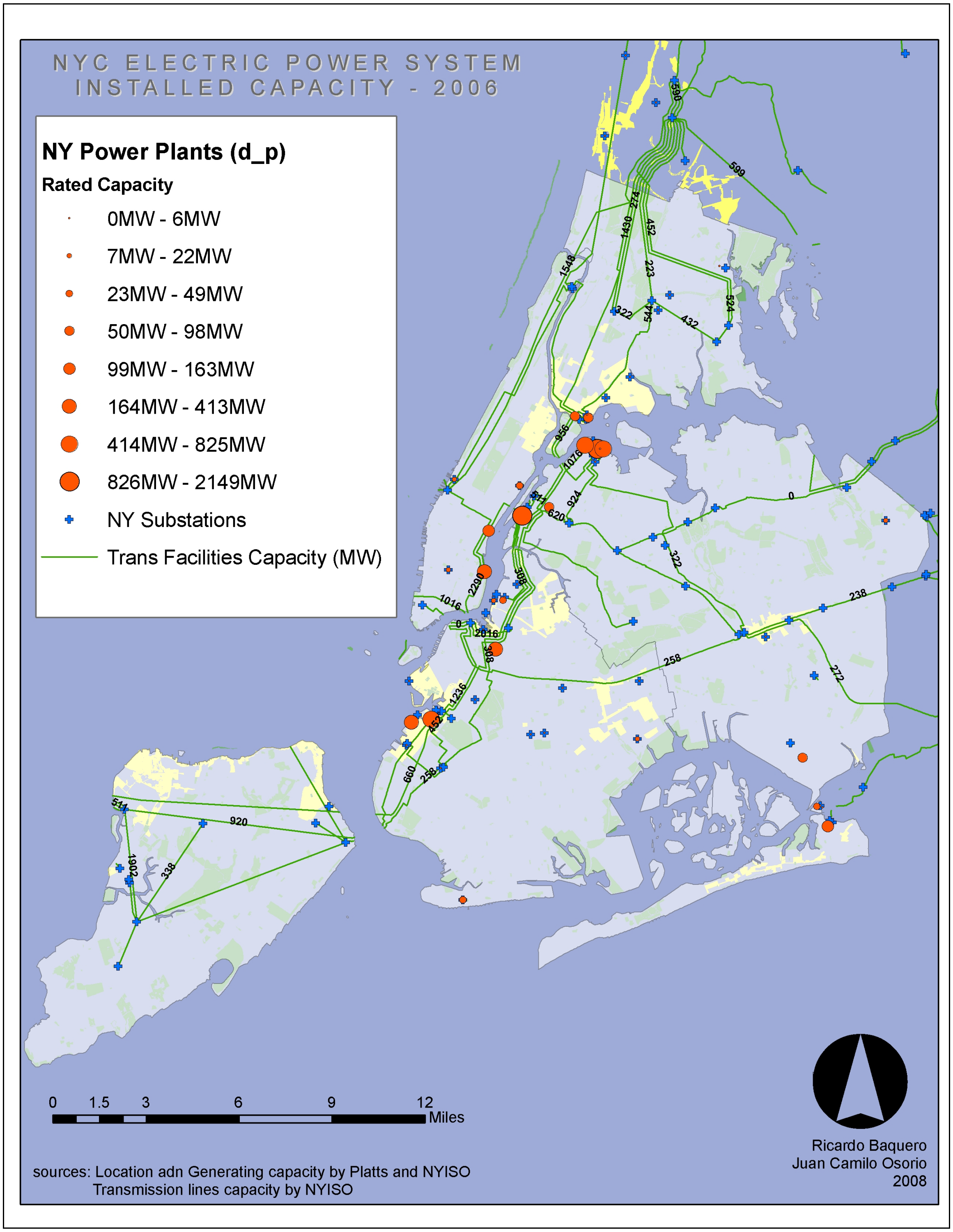


Figure 39. NYC Generators and Transmission Lines

Map2

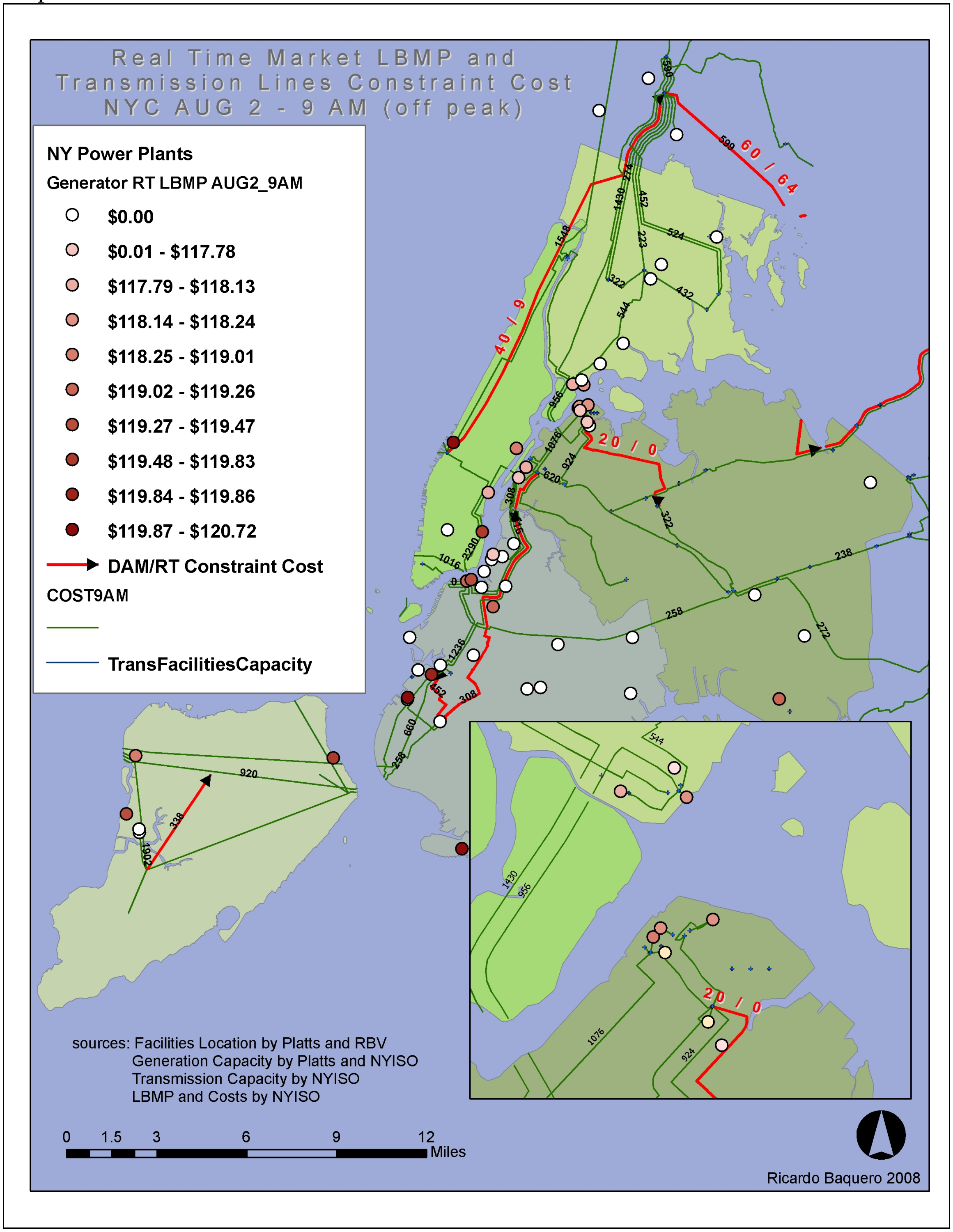


Figure 40. NYC Generators LBMP (RTM) and Constrained Lines Aug 2, 2006 at 9am

Map3

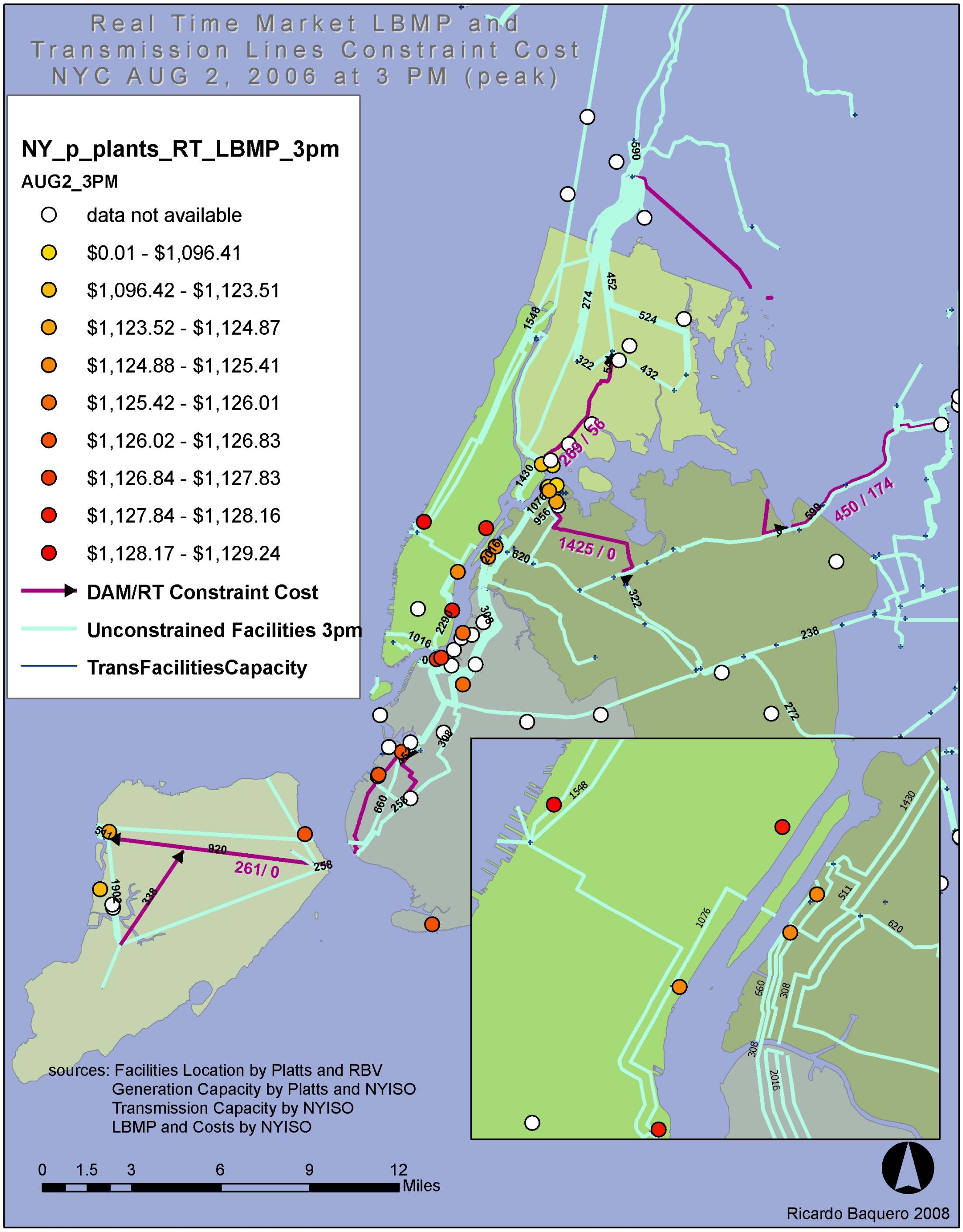


Figure 41. NYC Generators LBMP (RTM) and Constrained Lines Aug 2, 2006 at 3pm

CHAPTER 5

DG-CHP IMPLEMENTATION

5.1 Electric Tariffs – Stand-by Charges

Those customers installing electricity generation capacity to be operated in parallel with the local utility service may be subject to a change of electric rate. In the case of New York City, the electric utility, ConEd has been authorized by the New York Department of Public Services to charge stand-by charges by means of the retail service PSC. No.2, 14-RA rate.

The different scenarios considered in the following chapter will assume that the DG-CHP candidate customers are currently purchasing electricity under electric rate PSC.9 Service Description SC-9 (General Service – Large). Alternate scenarios will consider that 50% of the real time load corresponds to bilateral contracts.

The transition from Full Service to Retail Access service rates is not mandatory for every new DG system. The applicability of each rate is fully described in the respective rates descriptions, available at www.coned.com/rates/. The rates charges breakdown are shown in the Table 24:

Table 24. ConEd SC-9 General Service rate and 14- RA Stand-by rate

Rate SC-9, General Service - Large:	Rate 14-RA, for clients otherwise billed under SC-9, Rate I
- Market Supply Charge Usage - Adjustment factor MSC Usage - Market Supply Charge Demand - Adjustment factor MSC Demand - Monthly Adjustment Clause Usage - Adjustment factor MAC Usage - Monthly Adjustment Clause Demand - Adjustment factor MAC Demand - Low Tension Service Energy Delivery Usage - Low Tension Service Energy Delivery Demand - System benefits Charges - Renewable Portfolio	- Customer Charges - Reasonable connection charges - Connecting equipment amortization - Delivery Contract Demand - Delivery Contract demand MAC - Surcharge - Delivery Service Contract Demand - As-used daily period 1 - As-used daily period 2 - Energy delivery - Adjustment factor Market Supply Charges Demand - Energy – Market Supply Charges - Energy – Adjustment Factor MSC - System Benefits Charges - Renewable Portafolio

The main factors determining whether and how the migration from one rate to another occurs are:

1- Customers may stay with the otherwise applicable rate (in this case, SC-9) when they install an electric generator with nameplate capacity equal to no more than 15% of the total maximum demand - that is, of the sum of all the facility's electric applications name plates.

2- Some charges, such as "reasonable interconnection charges" are avoided if the electric nameplate capacity of the new generator is no greater than 2MW.

3- Since the 14-RA rate is designed to recover some fixed capital costs, and to protect system stability and availability, stand-by service is subject to severe penalties upon breach of the "contract demand". Penalties for demand surcharges are especially hard for surcharges over 10%, and doubled for surcharges over 20%.

The motivation leading customers to migrate to the stand-by rate is a matter of public debate wherein the different consumers and environmental councils have taken issue with the different regional utilities. Indeed, a very important factor to consider in future iterations of these calculations is the fact the suspicion that electric rates are designed to "disincentive the promotion of … energy efficiency technologies and Distributed Generation". The New York State Public Service Commission, in its session of April 18, 2007 on CASE 03-E-0640, ordered that electric rates be redesigned hopefully into one general rate such that customers not be discouraged by the analysis of different and complicated service classifications.

Electric utilities post basic electric bills samples for each service configuration. However, both SC-9 and 14-RA are not meant to used by the general public therefore, in order to calculate the marginal costs of energy and demand in $/kWh and $/kW, the items of each tariff were built into a spread sheet shown in Appendix 2.

The marginal costs per kWh and per kW for each rate are not explicitly stated in the rates description. Since some charges are meant to recover fixed costs for the utility, the energy and power charges vary with the size of the customer and the generator

Nonetheless, marginal costs were calculated for the average size of "good CHP candidate" facilities in combination with two different CHP engines.

In the case of rate 14-RA, reliability values for actual DG-CHP engines do not guarantee an outage-free operation; hence the risk of incurring a "contract demand" breach and the associated severe surcharge penalties is very high. These marginal cost values were obtained by setting the "contract demand" at the maximum possible level, thus avoiding any contract surcharge as described on PSC 14-RA leaf 139.

Additionally, facilities are assumed to present a load factor of 50%, and thus have an electricity demand equal to the sum of all electric applications nameplates less the installed CHP electric capacity. Accordingly, the average monthly usage is the maximum demand multiplied by the operating hours and by the load factor.

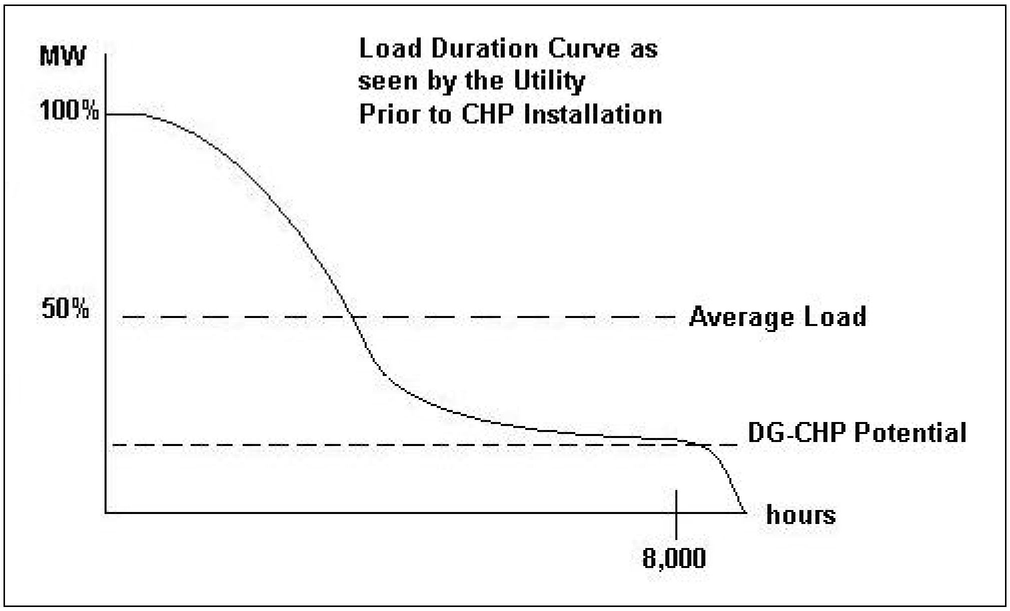


Figure 42. Average CHP Candidate Load Profile (not to scale)

The marginal costs for those customers installing a generator with nameplate ratings not greater than 15% of its maximum demand, thus staying with electric rate SC-9, are:

Table 25. SC-9 no CHP marginal costs

Marginal costs - SC-9 no CHP			
Usage		Demand	
summer	other mo	summer	other mo
$/kWh	$/kWh	$/kW	$/kW
$ 0.1197	$ 0.1274	24.75	$ 18.45
valid for all plant sizes			

Table 26. SC-9 CHP marginal costs

Marginal costs - SC-9 with CHP			
Usage		Demand	
summer	other mo	summer	other mo
$/kWh	$/kWh	$/kW	$/kW
$ 0.1197	$ 0.1274	24.85	$ 18.5500
valid for all plant sizes			

The marginal costs for those customers installing generators with nameplate ratings greater than 15% of their maximum demand, thus billed under electric rate 14-RA, are:

Table 27. 14-RA small generator marginal costs

Marginal costs - 14-RA					
generator smaller than 2MW					
Usage		Actual Demand		Contract Demand	
summer	other mo	summer	other mo	summer	other mo
$/kWh	$/kWh	$/kW	$/kW	$/kW	$/kW
$ 0.1146	$ 0.1240	$ 17.09	$ 4.56	$ 28.69	$ 22.39
based on a 2000kW plant w/ 800kW of DG					
4	8	4	8	4	8

Table 28. 14-RA large generator marginal costs

Marginal costs - 14-RA					
generator larger than 2MW					
Usage		Demand		Contract Demand	
summer	other mo	summer	other mo	summer	other mo
$/kWh	$/kWh	$/kW	$/kW	$/kW	$/kW
$ 0.1146	$ 0.1240	$ 17.09	$ 4.56	$ 28.31	$ 22.01
based on a 5000kW plant w/ 2000kW of DG					
4	8	4	8	4	8

CHAPTER 6

SYSTEM BENEFITS ANALYSIS

The convenience for the customer and for society of newer, cleaner and more efficient technologies has been discussed widely. The balance of the expenses and revenues involved in the development of a DG-CHP project affects not only the customer, but the utilities and the region hosting such a project as well. Such a variety of stakeholders, and the constant change in capital and operational costs justifies the establishment of a methodology to evaluate winners and losers in any given public policy. In this chapter, 9 different scenarios of CHP market penetration will be simulated. The results will be analyzed following a simple principle quoted by Beebe in his analysis of the New England energy market (2004):

"As suggested by the Electric Innovation Institute (E2I), if the overall benefits – that is when summed costs of all parties is subtracted from summed benefits of all parties – are positive, there is potential for reallocation of surplus. In this scenario, a party with large benefits can partially reallocate some of their revenue to those with large costs, so that the deal may move forward and all parties benefit.

The premise is that if all stakeholders are economically benefiting from the CHP installation there will be a win/win situation, and the installation will be greatly facilitated. "

The level of market penetration is calculated with the Integrated Real Time load data as posted for the 2006 NYISO Load Zone J market as reference. The 2006 average load for the NYC load zone is 6,059 MW, thus the capacity to be installed for each of the three levels of market penetration are:

Table 29. Proposed Levels of Market Penetration

% of Market Penetration	Sum of the new DG-CHP electric capacities
1%	60 MW
5%	300 MW
10%	600 MW

The size of the generator and the ratio of generator nameplate to facility maximum demand directly affects whether the installation of DG-CHP facilities leads to a change of electric rate under which the customer is billed, therefore, three different ways of achieving each level of DG-CHP market penetration will be analyzed:

- Case 1-a: 1% market penetration. All the new systems are rated under 15% capacity. No systems larger than 2 MW

- Case 1-b: 1% market penetration. 50% of the new systems stay under 15% capacity. 20% of the large systems are larger than 2 MW.

- Case 1-c: 1% market penetration. All the new systems are rated above 15% capacity. 20% of the new systems are larger than 2 MW.

- Case 2-a: 5% market penetration. All the new systems are rated under 15% capacity. No systems larger than 2 MW.

- Case 2-b: 5% market penetration. 50% of the new systems stay under 15% capacity. 20% of the large systems are larger than 2 MW.

- Case 2-c: 5% market penetration. All the new systems are rated above 15% capacity. 20% of the new systems are larger than 2 MW.

- Case 3-a: 10% market penetration. All the new systems are rated under 15% capacity. No systems larger than 2 MW.

- Case 3-b: 10% market penetration. 50% of the new systems stay under 15% capacity. 20% of the large systems are larger than 2 MW.

- Case 3-c: 10% market penetration. All the new systems are rated above 15% capacity. 20% of the new systems are larger than 2 MW.

The proposed new installed capacity target of the above scenarios is simulated by considering only two sizes of DG-CHP candidate facilities: 2000kW and 5000 kW. The DG-CHP capacity is achieved via three types of systems: 300 kW or 800kW at the small facilities and 2000kW at the large facilities. The number of facilities required in each case is shown in the Table 30:

Table 30. Different DG-CHP fleet configurations to achieve market penetration

Number of facilities considered in each market penetration level				
Facility size	2 MW		5MW	
CHP/ facility-size	<15%	>15%		
Generator	300 kW	800 kW	2000 kW	CHP Installed Capacity
1-a	200	0	0	60,000 kW
1-b	**102**	**22**	**6**	**60,200 kW**
1-c	0	70	2	60,000 kW
2-a	1000	0	0	300,000 kW
2-b	500	110	31	300,000 kW
2-c	0	300	30	300,000 kW
3-a	2000	0	0	600,000 kW
3-b	1000	300	30	600,000 kW
3-c	0	670	32	600,000 kW

Based on reliability results shown in Table 31, all systems will be assumed to run an average of 8,000 hours per year.

Table 31. Reciprocating engines reliabilitu statistics (Mark Gerrisk 2007)

Facility	Unit	Availability Factor	Forced Outage Rate	Sheduled Outage Fatctor	Service Factor	Mean Time Between Failures	Mean Down Time
		%	%	%	%	hours	hours
89	2	99.02%	0.00%	0.98%	18.38%	na	14.7
73	1	96.72%	1.79%	2.90%	20.89%	610.1	3.9
73	2	96.34%	1.81%	3.38%	14.87%	1,302.7	7.0
73	3	91.78%	0.80%	7.48%	91.99%	2,014.5	44.1
73	4	90.95%	0.77%	8.35%	90.56%	2,380.0	42.5
89	1	80.50%	1.29%	18.45%	80.58%	12,048.5	306.9
71	1	77.51%	8.32%	18.78%	40.85%	483.4	160.8
85	1	75.28%	8.13%	18.20%	73.69%	1,219.2	211.5
Average		88.25%	3.05%	10.08%	53.23%	1,490.9	45.5

As an example, the applicable equations used to calculate benefits and costs for case 1-b will be shown in the following chapters, so that values may be verified and changed, as seen fit in the remaining 8 cases and in future iterations. Benefits and costs sources, are shown below in Table 32.

The format in which the model results are presented below could lead to some misinterpretation. The following considerations must then be kept in mind:

- Each of the different values included in the "Benefits" or in the "Costs" columns of Table 32 represents an increment or a reduction in the stakeholder cash-flow.
- Thus, any increment in the stakeholder income or any reduction in the stakeholder expenses is called a "Benefit". By this definition, a stakeholder "benefit" must not be understood as a "profit".
- Accordingly, any reduction in the stakeholder income or any increment in the stakeholder expenses is called a "Cost". By this definition, a stakeholder "Cost" cannot be assimilated as a "loss".
- The order of Table 32 cells serves a diagramming purpose only e.g. two values right in front of each other are not necessarily related by an action/reaction bond.

The analysis of case 1-b will examine the deployment of 102 generators of 300 kW each, "102 x 300kW", plus "22 x 800 kW" and "6 x 2 MW" for a total capacity of 60,200 kW of new DG-CHP in the New York area. Both benefits and costs will be calculated based on marginal costs expressed in dollars. The candidate facilities are assumed to operate under the default rate both prior and after the DG-CHP implementation (SC-9 and 14-RA respectively as explained in chapter 5). Results will be recalculated to account for the fraction of the RT load traded outside the market via bilateral contracts. Utilities electric rates are assumed to be competitive with respect to the bilateral energy purchase contracts, therefore, although the fraction of energy in the market do change when recalculating total costs and benefits, the marginal costs used in with or without bilateral contracts are the same.

When applicable, large capital investments will be assumed as financial projects of 10 to 20 years, and all benefits will be listed on a ‘per year’ basis.

Table 32. Stakeholder System Benefit/Cost Model

	Benefits/Income			Costs/Expenses			
Customer	Annual Electricity Bill Savings (Avoided Charges from old rate based on full customer capacity)	Energy ACB_E		New Annual Electric Bill (full customer capacity-DG) @ Standby rate	Energy ACC_E		
		Demand ACB_D			Actual Demand ACC_D		
					Contract Demand ACC_{CD}		
				Annual Capital Cost	ACC_{CAP}		
	Annual Avoided Fuel Costs (Boiler Fuel, Industria rate)	ACB_F		Increased Annual Fuel Cost (DG-CHP, Generator rate)	ACC_{Fuel}		Customer Benefit
	Energy Sale back to Grid	n/a		Annual O&M Cost	$ACC_{O\&M}$		
	NYISO UCAP Auction Payment	ACB_{UCAP}		Interconnection Charges	ACC_{IC}		
		Sub-Total			Sub-Total		$ -
Electric Utility *	Annual Electric Standby (full facility capacity - CHP)	ACC_E $+ACC_D$ $+ACC_{CD}$		Annual Electric Sales (full customer capacity @ old rate)	ACB_E $+ACB_D$		
				Cost of Providing Standby Service	ACC_{CD}		
	Avoided Transmission Investments	AUB_T					
	Avoided Distribution Investments	AUB_D		System Upgrades	n/a		Electric Utility Benefit
	Decreased Spot Market Energy Price	AUB_{LBMP}		Incentives to DER Customers	n/a		
		Sub-Total			Sub-Total		$ -
Natural Gas Utility (Supply & Dist)	Increased Natural Gas Sales @ Industrial Rate	ACC_{Fuel} - ACB_F		Increased Wholesale Purchase			Natural Gas Utility Benefit
		Sub-Total			Sub-Total		$ -
Society	Avoided Installed Capacity Values	ASB_{Cap}		NYISO UCAP Auction	ASC_{UCAP}		
	Emission "Damage Costs"	ASB_{Emis}					
	Incresed Reliability LOLE						Society Benefit
		Sub-Total			Sub-Total		$ -
	Total Benefits:			Total Cost:			$ -
					Net Benefit Per Year		$ -
					Net benefit (per kW-yr)		$0 /kW-yr

Specifications of a standard 800 kW reciprocating natural gas unit are shown below in Table 33. It will be assumed that other DG-CHP capacities can be achieved with combinations and fractions of this engine.

Table 33. Specifications of 800 kW Reciprocating Natural Gas Generator With CHP - CAT 3516 derated for continous service

(CHP characteristics provided by Chris Beebe Thesis)

Cost and Performance Characteristics	
Electric Capacity	800 kW
Total Installed Cost ($/KW)	$1,730
Electric Heat Rate (Btu/kWh)	10,246
Electric Efficiency (%)	33.30%
Engine Speed (RPM)	1200
Fuel Input (MMBtu/hr)	7.60
Required Fuel Gas Pressure (psig)	<3

CHP Characteristics	
Exhaust Flow (1,000 lb/hr)	10.9
Exhaust Temperature (F)	1,067
Heat Recovered from Exhaust (MMBtu/hr)	2.12
Heat Recovered from Cooling Jacket (MMBtu/hr)	1.09
Heat Recovered from Lube System (MMBtu/hr)	0.29
Total Heat Recovered (MMBtu/hr)	3.50
Total Heat Recoved (kW)	1,025
Form of Recovered Heat	Hot Water
Total Efficiency (%)	76%
Power/Heat Ratio	0.78
Net Heat Rate (Btus/kWh)	4,774
Effective Electrical Efficiency	0.71

For the larger 2000 kW DG-CHP projects, customers can choose from many options: one single reciprocating engine, one single gas turbine or a set of two or three small engines with total capacity equal to the desired output. The first two options offer advantages for very specific applications; however, the latter provides more reliability and a lower risk of incurring surcharge penalties as per 14-RA rate provisions. Hence, the 800kW reciprocating engine performance characteristics will be used for all the nine cases analyzed.

6.1 CHP Customer

6.1.1 Customer Benefits

- **Annual Electricity Bill Savings (Avoided charges from old rate based on full customer capacity)**

This accounts for the sum of all customers' annual electricity bills reduction under the facility current rate structure as set by ConEd and authorized by the Department of Public Services. All three types of generators will benefit from the reduction in charges for electricity billed under ConEd's Service Classification SC-9 rate. In addition to the reduction in energy costs, there will be a reduction in demand charges.

It is assumed that the DG-CHP unit is installed in a facility with approximately 8,000 hours[15] of operation per year (666 hrs/mo). Additionally, a load factor of 50% will be used, as shown in Figure 42. The amount of electricity billed under the basic "no-CHP" SC-9 is the sum of the charges of all the facilities installing CHP units. All of them, including the small facilities, will see their electric service marginal costs switching to either SC-9 (modified with CHP) or to 14-RA values. For case 1-b, calculations are as follows:

The amount of energy used under SC-9 rate prior to the implementation of DG-CHP can be found through the following equation:

$$ACB_E = \left(\sum_i N_i \times ED_i \times M_i \right) \times H \times LF \times MCE_{SC9}$$

$$ACB_D = \sum_i \left(N_i \times ED_i \times M_i \times MCD_{SC9} \right)$$

[15] Gerrish, Mark, Impacts of Unit Reliability in Combined Heat and Power, UMass - 2006

Where,

ACB_E	=	Annual customer benefit, electricity; $
N_i	=	Number of facilities installing DG-CHP units of size "i"
ED_i	=	Electric demand of each of the N_i facilities; kW
H	=	Average monthly operating hours; 666.66 (8,000 h/yr)
MCE_{SC9}	=	Marginal cost, electricity, rate SC-9 prior to CHP; $/kWh (Table 25)
LF	=	Plant Load factor, 50% (assumed)
ACB_D	=	Annual customer benefit, demand; $
M_i	=	Operating months; (4 in summer, 8 for other months)
MCD_{SC9}	=	Marginal cost, demand; rate SC-9 prior to CHP; $/kW (Table 25)

Thus, for case 1-b,

$$ACB_E = \left(\left(102+22\right)\times 2{,}000+6\times 5{,}000\right)\times 666.66\times 0.5$$
$$\times\left(4\times \$0.1197+8\times \$0.1274\right)=\$138{,}813{,}279$$

$$ACB_D = \left(\left(102+22\right)\times 2{,}000+6\times 5{,}000\right)\times$$
$$\times\left(4\times \$24.75+8\times \$18.45\right)=\$68{,}554{,}800$$

Table 34. Summary of results Annual Avoided Customer electricity Usage and Demand charges - 9 cases

Case	Usage ACBE	Demand ACBD
1-a	$ 199,731,336	$ 98,640,000
1-b	$ 138,813,279	$ 68,554,800
1-c	$ 74,899,251	$ 36,990,000
2-a	$ 998,656,680	$ 493,200,000
2-b	$ 686,576,468	$ 339,075,000
2-c	$ 374,496,255	$ 184,950,000
3-a	$ 1,997,313,360	$ 986,400,000
3-b	$ 1,373,152,935	$ 678,150,000
3-c	$ 748,992,510	$ 369,900,000

- **Annual Avoided Fuel Costs (Process Heat)**

The facilities will be assumed to have a constant thermal load as part of their process. It is assumed that half of the waste heat provided by the CHP unit can be used in this process. It is also assumed that, in average, 50% of the recovered heat will be used in the process. As rated by the manufacturer, the total heat recovered from the exhaust, cooling jacket, and lube system is 3.50 MMBtu/hr per each 800kW, that is 0.004375 MMBtu/hr per kW. Thus, for case 1-b, over the operating 8,000 hours of the facility, approximately 2,107,000 MMBtu of heat can be generated by the CHP units and 50%, or 1,053,500 MMBtu of this heat, will be used in process. With a marginal cost of natural gas of $8.98/MMBtu (EIA Jan, 2007), the annual cost savings equated to this can be found as follows:

$$ACB_F = AFS_{NG} \times MC_{NG}$$

Where,

ACB_F = Annual cost benefit, natural gas; $

AFS_{NG} = Annual fuel savings; natural gas; MMBtu

MC_{NG} = Marginal cost; natural gas Industrial; $/MMBtu

Thus, for case 1-b,

$$ACB_F = 1,053,500 \times \$11.9 = \$12,536,650$$

(case 2.x ACB_F = \$62,475,000)

(case 3.x ACB_F = \$124,950,000)

- **Wholesale Energy Sales, Installed Capacity Market and Load Response Program**

This study considers only new CHP systems that are sized to cover a constant electric load (base load) and its associated thermal load. At no point is excess electricity to be injected back into the system and sold on the market. Allowing for such conditions to occur means a drastic change in the nature of the business.

Because of the uncertainty of the auction mechanism, the benefits awarded in the Installed Capacity Market are not considered in the cost-benefit analysis. However, a reference to such incentives will be included in our conclusions.

Therefore no benefits or costs resulting from energy sales or load response programs are considered for any of the nine cases.

- **NYISO Capacity Market Payments**

As explained in chapter 2.2.4, in 2007 NYISO UCAP auctions paid new generating capacity at $110/MW-yr. The annual payment to Customers can found as follows:

$$ACB_{UCAP} = EP_{CHP} \times AAP$$

Where,

ACB_{UCAP} = Annual Customer benefit, UCAP auction; $

EP_{CHP} = Electric Power of all the CHP units; kW

AAP_{UCAP} = Annual UCAP payment; $110/kW-yr

Thus, for case 1-b,

$$ACB_{UCAP} = 60,200 \times \$110 = \$6,622,000$$

(case 2.x ACB_{UCAP} = $33,000,000)

(case 3.x ACB_{UCAP} = $66,000,000)

6.1.2 Costs

- **Modified SC-9 marginal costs or Stand-by 14-RA rate**

As discussed in the previous chapter, the act of installing a generator to be operated in parallel with the grid service will either modify the marginal costs of electricity usage and the demand billed under rate SC-9 or, for larger projects, will require that facilities shift to the Stand-by retail service classification 14-RA. The amount of energy purchased by the utility will be the facility maximum usage minus the generator production at full capacity. The charges under the 14-RA tariff are calculated as follows:

$$ACC_E = \left(\sum_i N_i \times AED_i \times LF_i \times M_i\right) \times H \times MCE_{14,i}$$

$$ACC_D = \sum_i \left(N_i \times AED_i \times M_i \times MCD_{14,i}\right)$$

$$ACC_{CD} = \sum_i \left(N_i \times CED_i \times M_i \times MCC_{14,i}\right)$$

Where,

ACC_E = Annual customer cost, electric usage with standby-rate; $

AED_i = Actual Electric demand of each of the N_i facilities; kW

LF_i = Load factor according to source (plant 50% , CHP 100%)

$MCE14_{,}\ i$ = Marginal cost, electricity, rate 14-RA; \$/kWh

(Table 27 or 28 - summer and "other months" operation are considered separately, includes modified SC-9 with CHP)

ACC_D = Annual customer cost, demand, with standby-rate; \$/kW

$MCD_{14,}\ i$ = Marginal cost, actual demand, rate 14-RA; \$/kWh

(Table 27 or 28)

ACC_{CD} = Annual customer cost, contract demand rate 14-RA; \$/kW

CED_i = Contract demand, under stand-by rate; kW (calculated such that any ED_i <109% of CED_i

$MCD_{14,}\ i$ = Marginal cost, contract demand, rate 14-RA; \$/kWh

(Table 25 or 26)

Thus, for case 1-b,

$$ACC_E = \begin{pmatrix} 102\times(2{,}000\times0.5\text{-}300\times1.0)\times(4\times\$0.1197+8\times\$0.1274) \\ +22\times(2{,}000\times0.5\text{-}800\times1.0)\times(4\times\$0.1146+8\times\$0.1240) \\ +6\times(5{,}000\times0.5\text{-}2{,}000\times1.0)\times(4\times\$0.1146+8\times\$0.1240) \end{pmatrix}\times666.66 = \$93{,}738{,}769$$

$$ACC_D = \begin{pmatrix} 102\times(2{,}000\text{-}300)\times(4\times\$24.85+8\times\$18.55) \\ +22\times(2{,}000\text{-}800)\times(4\times\$17.09+8\times\$4.56) \\ +6\times(5{,}000\text{-}2{,}000)\times(4\times\$17.09+8\times\$4.56) \end{pmatrix} = \$47{,}623{,}416$$

$$ACC_{CD} = \begin{pmatrix} 22\times1{,}835\times(4\times\$28.69+8\times\$22.39) \\ +6\times4{,}587\times(4\times\$28.31+8\times\$22.01) \end{pmatrix} = \$15{,}049{,}349$$

Table 35. Summary of results Annual Customer Costs Stand By Service – 9 cases

Case	Usage ACCE	Actual Demand ACCD	Contract Demand ACCCD
1-a	$ 169,771,636	$ 84,252,000	$ -
1-b	$ 93,738,769	$ 47,623,416	$ 15,049,349
1-c	$ 14,503,855	$ 9,435,600	$ 38,810,690
2-a	$ 848,858,178	$ 421,260,000	$ -
2-b	$ 460,688,726	$ 234,219,000	$ 75,777,646
2-c	$ 72,519,275	$ 47,178,000	$ 177,708,006
3-a	$ 1,697,716,356	$ 842,520,000	$ -
3-b	$ 921,377,453	$ 468,438,000	$ 177,708,006
3-c	$ 145,038,550	$ 94,356,000	$ 378,299,636

Table 35-b. Total Stand By rate costs – 9 cases

Case	ACCE+ACCD+ACCCD
1-a	$ 254,023,636
1-b	$ 156,411,534
1-c	$ 62,750,145
2-a	$1,270,118,178
2-b	$ 770,685,373
2-c	$ 297,405,281
3-a	$2,540,236,356
3-b	$1,567,523,459
3-c	$ 617,694,186

- **Annual Capital Costs, Maintenance, Fuel Costs**

The average installed cost for a CHP capable engine is approximately $1,500/kW. The CHP attachments cost $230/kW. This value includes the engine itself as well as the surrounding connections and civil works; therefore, $1,730/kW will be used as the marginal cost for the generator considered in our cases. The total installed cost for case 1-b 60,200 kW is then $104,146,000. The financing period for this unit is assumed to be 10 years fixed-rate, with a 5% annual interest, and complete loss of value at the end of the life of the project. The annual payment cost for all the generating units in case 1-b is:

$$ACC_{CAP} = \frac{I \times C}{1-(1+I)^{-Y}}$$

Where,

ACC_{CAP} = Annual customer costs, capital; \$

C = Capital cost; \$

I = Interest rate;

Y = Financing period; years

Thus, for case 1-b,

$$ACC_{CAP} = \frac{\$104,146,000 \times 0.05}{1-(1+0.05)^{-10}} = \$13,487,383$$

(case 2.x ACC_{CAP}=\$67,212,872)

(case 3.x ACC_{CAP}=\$134,425,744)

- **DG-CHP Generator Fuel Costs**

Fuel costs can be found based on the consumption of the selected generator. As stated by the manufacturer, the full load fuel consumption of the unit is 7.60 MMBtu/hr. It is assumed that fuel consumption varies linearly with load. Thus, with a generator load factor of 100% (base load operation) assumed over 8,000 operating hours, the annual consumption is 60,800 MMBtu for each 800kW engine, that is 76 MMBtu/kW. The annual fuel cost is found as follows.

$$ACC_{Fuel}=SFC_{CHP}\times EP_{CHP}\times MC_{NG\text{-}E}$$

Where,

ACC_{Fuel} = Annual customer cost, Natural gas generator fuel; MMBtu

SFC_{CHP} = Specific Fuel Consumption of CHP unit; 76 MMBtu/kW.hr

EP_{CHP} = Electric Power of all the CHP units; kW

$MC_{NG\text{-}E}$ = Marginal cost; Natural gas generator fuel; \$/MMBtu

Thus, for case 1-b,

$$ACC_{Fuel} = 76 \times 60{,}200 \times \$8.28 = \$37{,}882{,}656$$

(case 2.x ACC_{Fuel}=\$188,784,000)

(case 3.x ACC_{Fuel}=\$377,568,000)

- **Annual O&M Costs**

Annual operation and maintenance costs are estimated to be \$0.01/kWh. Therefore these costs are as follows.

$$ACC_{O\&M} = AEC \times C_{O\&M}$$

Where,

$ACC_{O\&M}$ = Annual operation and maintenance cost; \$

AEC = Annual Electricity Displaced by CHP units,

$C_{O\&M}$ = Cost of operation and maintenance; \$/kWh

Thus, for case 1-b:

$$ACC_{O\&M} = 481{,}600{,}000 \times \$0.01 = \$4{,}816{,}000$$

(case 2.x $ACC_{O\&M}$=\$24,000,000)

(case 3.x $ACC_{O\&M}$=\$48,000,000)

- **Emission Offset Purchases**

Based on the location of the new CHP system, along with the effectiveness of emission control systems on the CHP unit, it may be necessary for the customer to purchase emission offsets in order to operate the generator in compliance with state ordinances. New York State is a Regional Green Gas Initiative participant. The RGGI as any other emission market can be seen as the cost society is willing to recognize for the effects of emissions on environment and on society itself. The RGGI will run a Cap and trade auction trade starting en September 2008. Initial Trade have set the price of CO_2 allowances to \$7/Ton. Additional US emission market prices are shown in Table 36:

Table 36. Market value of emissions (www.evomarkets.com)

	Reduction (Tons)	Damage Cost ($/Ton)	Damage Cost ($)
CO2	4,406	$7	$30,842
SO2	1,074	$352	$378,048
NOx	174	$2,650	$461,100

As control technologies improve, emission factors, most notably NOx, will decrease. The CHP units in question are natural gas fired, it is assumed that no emission offsets will need to be purchased.

- **Interconnection Study, Equipment, and Electric System Upgrade**

Before the customer can be connected to the grid, an interconnection study must be performed. The typical cost for the study, equipment, and electric system upgrades will usually run about \$2,000, but may be high as \$30,000. With a unit as small as 800 kW it is unlikely that any electric utility infrastructure upgrades will be required. The 2,000 kW set is large enough so that advanced control systems, high voltage switching gear and/or transformer may be necessary. Upgrade costs are therefore assumed to be zero in this analysis. Interconnection costs, which are assumed to average \$10,000 per facility, at 5% interest and 10 years fixed-rate, are \$1,295 per year per facility. The cost of interconnection study is then

$$ACC_{IC} = N \times C_{IC}$$

Where,

ACC_{IC}	=	Annual customer cost, interconnection; $
N	=	Number of DG-CHP facilities in case
C_{IC}	=	Cost of interconnection; $

Thus, for the case 1-b, with a total of 130 different facilities,

$$ACC_{IC} = 130 \times \$1,295 = \$168,350$$

Table 37. Summary of results Interconnection Charges ACC_{IC} – 9 cases

Case	Total Interconnection Studies
1-a	$ 259,000
1-b	$ 168,350
1-c	$ 93,240
2-a	$ 1,295,000
2-b	$ 830,095
2-c	$ 427,350
3-a	$ 2,590,000
3-b	$ 1,722,350
3-c	$ 909,090

- **Other Utility Infrastructure Costs and Operational Costs**

It is assumed that the facility has adequate access to natural gas lines, and that there are no significant upgrade requirements for any other utilities outside of the electric utility.

6.2 Electric Utility

6.2.1 Benefits

Electric Utilities play the role of broker between the customer and the different market participants. Certainly, utilities profit from this operation, however, it is once again noted that each of the following "costs" and "benefits" - as previously defined - only represent variations in the utility cash flow. None of the following values is a profit or a loss by itself; Profits or losses result from further operations not included in our calculations.

- **Electric Bill Charges - Standby Rate**

The utility charges the customer either with the full service SC-9 rate adjusted to the new facility peak demand or with charges under the retail access 14-RA rate. The benefit to the utility is equal to the cost to the customers, that is, for case 1-b $156,411,534.

Table 38. Summary of results Annual Utilities Benefits electricity – 9 cases

Case	Electric Utility AUBE	
1-a	$	254,023,636
1-b	$	156,411,534
1-c	$	62,750,145
2-a	$	1,270,118,178
2-b	$	770,685,373
2-c	$	297,405,281
3-a	$	2,540,236,356
3-b	$	1,567,523,459
3-c	$	617,694,186

- **Avoided Transmission and Distribution Capacity Investments**

The value of transmission upgrades is equal to $500/kW (ConEd 2005 RNA Study). The amortization of such value at 5% interest, 20 years fixed rate is $40.12/ kW. Thus, these benefits are calculated as follows.

$$AUB_T = TD \times ED$$

Where;

AUB_T	=	Annual utility benefit; $
TD	=	Transmission deferral value; $/kW
ED	=	Electric demand; kW

Thus, for case 1-b,

$$AUB_T = \$40.12 \times 60,200 = \$2,415,224$$

(case 2.x AUB_T=\$12,036,000)

(case 3.x AUB_T=\$24,072,000)

- **Avoided Distribution Capacity Investments and Demand reduction programs**

The annual utility benefit due to deferred investments is then calculated as follows:

$$AUB_D = DD \times ED$$

Where,

AUB_T	=	Annual utility benefit; \$
DD	=	Distribution deferral value; \$83.6/kW (chapter 2.1.7)
ED	=	Electric demand; kW

Thus, for case 1-b,

$$AUB_D = \$83.6 \times 60,200 = \$5,032,720$$

(case 2.x AUB_D=\$25,080,000)

(case 3.x AUB_D=\$50,160,000)

- **Decreased Wholesale Power Price**

As discussed in Chapter 4, there is potential for DG-CHP to impact transmission grid operation, resulting in a lower zonal LBMP and thus decreasing the cost utilities must pay on the wholesale Real Time and Day Ahead markets. Since utilities transfer these costs to the customers, this does not represent a profit for the utilities. It just accounts for the difference of purchasing a large amount of electricity at a given price on the NYISO markets and then purchasing less energy at a lower price. Energy cost is passed to customers with the charges included in the electric bills, and accounted for in this model as a fraction of the energy usage marginal costs (MCE_{SC9} and $MCE_{14,i}$).

The cases studied herein reduce the real time load by an amount equal to the sum of all the proposed CHP engines rated capacities.

A non-linear curve fit was used to estimate the Day Ahead Market and the Real Time Market non-linear fit polynomial coefficients of the 2006 "LBMP vs. Load" curves as shown in Figures 22 and 28. Once the curve coefficients are determined, the modified LBMP for each hour of the year is recalculated, taking into account the fraction of load traded in each of the two markets. In the case of case 1-b, the annual utility benefits because of LBMP reduction is:

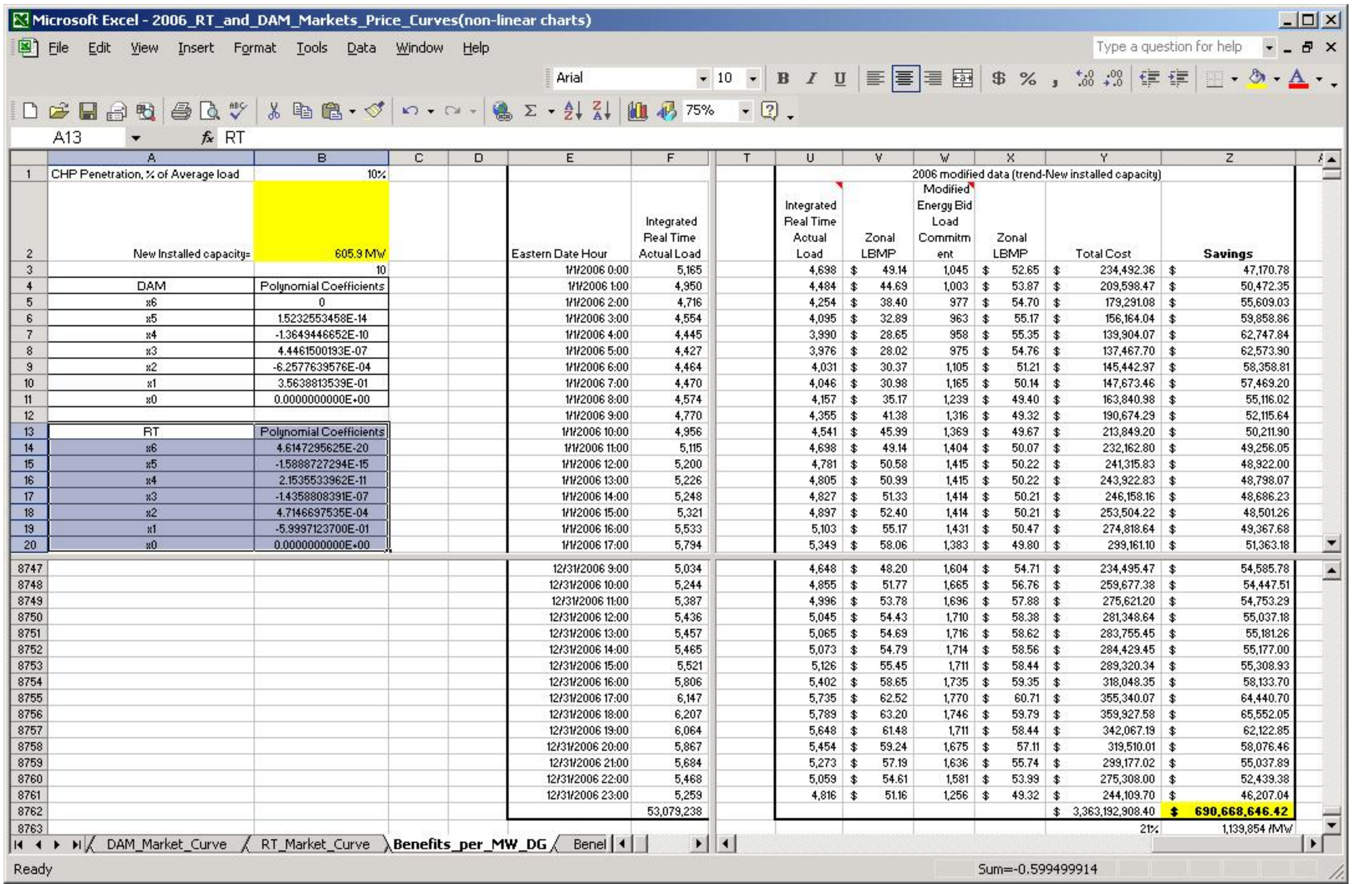
$$AUB_{LBMP} = \sum_{DAM} L_{DAM} \times LBMP_{(L)} + \sum_{RT} L_{RT} \times LBMP_{(RT)} - \left(\sum_{DAM\text{-}CHP} L_{DAM} \times LBMP_{(L)} + \sum_{RT\text{-}CHP} L_{RT} \times LBMP_{(RT)} \right)$$

where every sum is done over the 8,760 hours of the year (MS Excel model shown in figure 43). Thus, for case 1-b (1.x),

$$AUB_{LBMP} = \$75,867,690$$

(case 2.x AUB_{LBMP}=\$362,030,994)

(case 3.x AUB_{LBMP}=\$690,668,646)



Microsoft Excel - 2006_RT_and_DAM_Markets_Price_Curves(non-linear charts)

A13 RT

	A	B	C	D	E	F	T	U	V	W	X	Y	Z
1	CHP Penetration, % of Average load	10%						2006 modified data (trend-New installed capacity)					
2	New Installed capacity=	605.9 MW			Eastern Date Hour	Integrated Real Time Actual Load		Integrated Real Time Actual Load	Zonal LBMP	Modified Energy Bid Load Commitment	Zonal LBMP	Total Cost	Savings
3		10			1/1/2006 0:00	5,165		4,698	$ 49.14	1,045	$ 52.65	$ 234,492.36	$ 47,170.78
4	DAM	Polynomial Coefficients			1/1/2006 1:00	4,950		4,484	$ 44.69	1,003	$ 53.87	$ 209,598.47	$ 50,472.35
5	x6	0			1/1/2006 2:00	4,716		4,254	$ 38.40	977	$ 54.70	$ 179,291.08	$ 55,609.03
6	x5	1.5232553458E-14			1/1/2006 3:00	4,554		4,095	$ 32.89	963	$ 55.17	$ 156,164.04	$ 59,858.86
7	x4	-1.3649446652E-10			1/1/2006 4:00	4,445		3,990	$ 28.65	958	$ 55.35	$ 139,904.07	$ 62,747.84
8	x3	4.4461500193E-07			1/1/2006 5:00	4,427		3,976	$ 28.02	975	$ 54.76	$ 137,467.70	$ 62,573.90
9	x2	-6.2577639576E-04			1/1/2006 6:00	4,464		4,031	$ 30.37	1,105	$ 51.21	$ 145,442.97	$ 58,358.81
10	x1	3.5638813539E-01			1/1/2006 7:00	4,470		4,046	$ 30.98	1,165	$ 50.14	$ 147,673.46	$ 57,469.20
11	x0	0.0000000000E+00			1/1/2006 8:00	4,574		4,157	$ 35.17	1,239	$ 49.40	$ 163,840.98	$ 55,116.02
12					1/1/2006 9:00	4,770		4,355	$ 41.38	1,316	$ 49.32	$ 190,674.29	$ 52,115.64
13	RT	Polynomial Coefficients			1/1/2006 10:00	4,956		4,541	$ 45.99	1,369	$ 49.67	$ 213,849.20	$ 50,211.90
14	x6	4.6147295625E-20			1/1/2006 11:00	5,115		4,698	$ 49.14	1,404	$ 50.07	$ 232,162.80	$ 49,256.05
15	x5	-1.5888727294E-15			1/1/2006 12:00	5,200		4,781	$ 50.58	1,415	$ 50.22	$ 241,315.83	$ 48,922.00
16	x4	2.1535533962E-11			1/1/2006 13:00	5,226		4,805	$ 50.99	1,415	$ 50.22	$ 243,922.83	$ 48,798.07
17	x3	-1.4358808391E-07			1/1/2006 14:00	5,248		4,827	$ 51.33	1,414	$ 50.21	$ 246,158.16	$ 48,686.23
18	x2	4.7146697535E-04			1/1/2006 15:00	5,321		4,897	$ 52.40	1,414	$ 50.21	$ 253,504.22	$ 48,501.26
19	x1	-5.9997123700E-01			1/1/2006 16:00	5,533		5,103	$ 55.17	1,431	$ 50.47	$ 274,818.64	$ 49,367.68
20	x0	0.0000000000E+00			1/1/2006 17:00	5,794		5,349	$ 58.06	1,383	$ 49.80	$ 299,161.10	$ 51,363.18
8747					12/31/2006 9:00	5,034		4,648	$ 48.20	1,604	$ 54.71	$ 234,495.47	$ 54,585.78
8748					12/31/2006 10:00	5,244		4,855	$ 51.77	1,665	$ 56.76	$ 259,677.38	$ 54,447.51
8749					12/31/2006 11:00	5,387		4,996	$ 53.78	1,696	$ 57.88	$ 275,621.20	$ 54,753.29
8750					12/31/2006 12:00	5,436		5,045	$ 54.43	1,710	$ 58.38	$ 281,348.64	$ 55,037.18
8751					12/31/2006 13:00	5,457		5,065	$ 54.69	1,716	$ 58.62	$ 283,755.45	$ 55,181.26
8752					12/31/2006 14:00	5,465		5,073	$ 54.79	1,714	$ 58.56	$ 284,429.45	$ 55,177.00
8753					12/31/2006 15:00	5,521		5,126	$ 55.45	1,711	$ 58.44	$ 289,320.34	$ 55,308.93
8754					12/31/2006 16:00	5,806		5,402	$ 58.65	1,735	$ 59.35	$ 318,048.35	$ 58,133.70
8755					12/31/2006 17:00	6,147		5,735	$ 62.52	1,770	$ 60.71	$ 355,340.07	$ 64,440.70
8756					12/31/2006 18:00	6,207		5,789	$ 63.20	1,746	$ 59.79	$ 359,927.58	$ 65,552.05
8757					12/31/2006 19:00	6,064		5,648	$ 61.48	1,711	$ 58.44	$ 342,067.19	$ 62,122.85
8758					12/31/2006 20:00	5,867		5,454	$ 59.24	1,675	$ 57.11	$ 319,510.01	$ 58,076.46
8759					12/31/2006 21:00	5,684		5,273	$ 57.19	1,636	$ 55.74	$ 299,177.02	$ 55,037.89
8760					12/31/2006 22:00	5,468		5,059	$ 54.61	1,581	$ 53.99	$ 275,308.00	$ 52,439.38
8761					12/31/2006 23:00	5,259		4,816	$ 51.16	1,256	$ 49.32	$ 244,109.70	$ 46,207.04
8762						53,079,238						$ 3,363,192,908.40	$ 690,668,646.42
8763												21%	1,139,854 /MW

DAM_Market_Curve / RT_Market_Curve / Benefits_per_MW_DG / Benel

Ready Sum=-0.599499914

Figure 43. AUB_{LBMP} calculation

6.2.2 Utility Costs

- **Revenue Reduction (from the customers withdrawing from standard service)**

The amount of revenue reduction is equal to the electric saving seen by the customer. For case 1-b, customer savings ACB_E and ACB_D are respectively \$138,813,279 and \$68,554,800 respectively, for a total revenue reduction of \$207,368,079.

Table 39. Summary of results Annual Utility Benefits electricity Usage and Demand – 9 cases

Case	Total ACB_E+ACB_D
1-a	$ 298,371,336
1-b	$ 207,368,079
1-c	$ 111,889,251
2-a	$ 1,491,856,680
2-b	$ 1,025,651,468
2-c	$ 559,446,255
3-a	$ 2,983,713,360
3-b	$ 2,051,302,935
3-c	$ 1,118,892,510

- **Cost of Providing Standby Service**

As customers migrate to the standby rate (14-RA), the sales of electricity decrease, thus, the utilities 'return on equity' is affected as well. This represents a cost for the utility. As shown in Table 27, in addition to the actual energy consumption and actual peak demand charges, the stand by rate includes some charges based on the 'contract demand', which is a reference value that customer pledges never to exceed. This 'contract demand' charges are interpreted as the compensation for the costs that utility incur to provide the standby service. Thus, the cost of providing standby service is equal to the value previously calculated as ACC_{CD}.

- **System Upgrades**

It is assumed that there are no system upgrades required.

- **Incentives to DER Customers**

No incentives provided to the customer by the utility are considered.

6.3 Natural Gas Utility

6.3.1 Benefits

- **Increased Natural Gas Sales**

The CHP unit operates on natural gas, so there will be an increase in natural gas sales to the customer by the natural gas utility. The increase in sales will be equal to the fuel cost increase to the customer to fire the CHP unit minus the annual avoided fuel costs used in process. Therefore the benefit to the gas utility, "AGB_F", for case 1-b is:

$$AGB_F = ACC_{FUEL} - ACB_F = \$37{,}882{,}656 - \$12{,}536{,}650 = \$25{,}346{,}006$$

(case 2.x AGB_F = \$126,309,000)

(case 3.x AGB_F = \$252,618,000)

6.3.2 Costs

- **Increased Adjustment Credits for Power Generation**

Increase in customer demand means that the natural gas utility must supply and deliver more gas. As show by EIA data, the natural gas used for industrial general use is \$2.36/MMBtu more expensive than the gas intended for electric generation. It was also explained that most of this difference applies to adjustments that the utilities do with respect to the industrial rate. This cost is shared both by Society and, in greater proportion by the Natural Gas utilities. This will be accounted for as a loss of revenue for utilities upon the gas used to run the DG-CHP generators, despite the fact that some of it could also be interpreted as a subsidy offered by society (cost for Society). Thus, the natural gas utility cost is as follows,

$$AUC_{Fuel} = SFC_{CHP} \times EP_{CHP} \times \Delta MC_{NG\text{-}E}$$

Where,

SFC_{CHP} = Generator Specific Fuel Consumption; 76 MMBtu/kW

AUC_{NG} = Annual utility cost, natural gas; $

$\Delta MC_{NG\text{-}E}$ = Marginal-cost difference between rates; $/MMBtu

Thus, for case 1-b,

$$ACC_{Fuel} = 76 \times 60{,}200 \times \$2.36 = \$10{,}797{,}472$$

(case 2.x AGB_F = $53,808,000)

(case 3.x AGB_F = $107,616,000)

6.4 Society

6.4.1 Benefits

- **Avoided Installed Capacity Value**

The sum of many small DG-CHP projects might displace the need for installing large generation projects at the Transmission level. In the case of NewYork and New York City case, as quoted by the NYC Economic Development Corporation in May 2006, the recently commissioned Astoria Energy LLC 500 MW plant cost was $1 billion. This sets the cost of large generating facilities at $2,000/kW. At 5% fix-rate interest, the annual cost of such 20-years project is $160/kW. In addition, there are approximately 6.7% system losses throughout the grid, which indicates that the DG value is actually 6.7% higher than installed nameplate capacity because it is not subjected to these losses. Therefore, for case 1-b, the equivalent capacity that the 60,200 kW DG-CHP units would replace is 64,523kW as follows. The annual benefits for society per deferred installed capacity is:

$$ASB_{CAP} = EC_{CHP} \times MC_{CAP}$$

Where,

ASB_{CAP}	=	Annual Society benefit; installed capacity;
EC_{CHP}	=	Effective capacity of CHP unit;
MC_{CAP}	=	Marginal cost value of capacity;

Thus, for case 1-b,

$$ASB_{CAP} = 64,523 \times \$160 = \$10,323,680$$

(case 2.x ASB_{CAP} = \$51,446,945)

(case 3.x ACB_{CAP} = \$102,893,890)

- **Reduced Emissions**

The total amount of reduced emissions is equal to the displaced centrally generated electricity (including losses) plus the amount of locally displaced natural gas that was used for the on-site thermal process, minus the local natural gas increase due to the CHP unit.

$$ASB_{Emissions} = \left[\left(AEC_{kWh} \times EF_{NY\text{-}kWh}\right) + \left(AEC_{Boiler} \times EF_{Boiler}\right) - \left(AEC_{CHP} \times EF_{CHP}\right)\right] \times DC$$

Where,

$ASB_{Emissions}$	=	Annual society benefit, emissions;
AEC_{kWh}	=	Annual displaced utility electric load;
$EF_{NY\text{-}kWh}$	=	New York state generator emission factors;
AEC_{Boiler}	=	Annual displaced boiler fuel load;
EF_{Boiler}	=	Boiler emission factors;
AEC_{CHP}	=	Annual increased CHP load;

EF_{CHP} = CHP emission factors;

DC = Damage costs; (Table 40)

Using appropriate emission factors, the overall emission reduction can be found. The savings here will be determined based upon the Damage Costs determined in Ian Roth's Thesis. Roth's Thesis was developed for Massachusetts; however, results are provided in a "per TON" basis therefore, and since no other source is available as of yet, results will be assumed not to affect the accuracy of the present analysis.

Thus, for case 1-b,

Table 40. Reduction In Damage Costs Case 1-b (ASB_{CO}).

	Reduction (Tons)	Damage Cost ($/Ton)	Damage Cost ($)
CO2	4,079	$26.40	$107,685
CO		$1,055.87	
SO2	994	$1,869.77	$1,859,382
NOx	161	$7,919.03	$1,275,843
PM		$4,839.41	
VOCs		$5,265.79	
		Total ASB_{CO}:	**$3,242,910**

(case 2.x ASB_{CO}= $16,160,686)

(case 3.x ASB_{CO}=$32,321,372)

- **Increased Reliability**

The 2007 CRPP Reliability Needs Assessment 2007 alerted that the fact that LOLE accepted standard of 0.1 would not be met in N.Y.C. after year 2010, when the expected LOLE is 0.16. The valuation of this risk is done based on the aftermath of the NYC 2003 blackout. Based on the N.Y.C. comptroller's office, the 6 hours blackout event (0.25 LOLE or 0.15 excess LOLE from design 0.1 LOLE) resulted in $800 million in gross city product. Thus it is estimated that the mitigation of the 0.06 excess LOLE signifies $320 MM in avoided loss of gross city product.

It must be noted that this is the most conservative estimate possible, since it considers neither the inflation effects nor the worst LOLE values for following years. Finally, based on the RNA 2007 mitigation models, these benefits will be achievable only in cases 3-a, 3-b and 3-c.

Society benefits because of LOLE mitigation for case 1-b (1.x) are null.

Society benefits because of LOLE mitigation for case 2-x are null.

Society benefits because of LOLE mitigation for case 3-x are $320,000,000.

6.4.2 Costs

Society, by implementing the UCAP market and paying new installed generating capacity, is already assuming some costs. This Annual Cost for Society is equal to the benefits to Customers, previously calculated as ACB_{UCAP}.

Table 41. Case 1-b Cost - Benefit Model Results

60200	case 1-b							$/kW
	Benefits/Income			Costs/Expenses				
Customer	Annual Electricity Bill Savings (Avoided Charges from old rate based on full customer capacity)	**Energy ACB_{E}**	$ 138,813,279	New Annual Electric Bill (full customer capacity-DG) @ Standby rate	**Energy ACC_{E}**	$ 93,738,769		
		Demand ACB_{D}	$ 68,554,800		**Actual Demand ACC_{D}**	$ 47,623,416		
					Contract Demand ACC_{CD}	$ 15,049,349		
				Annual Capital Cost	ACC_{CAP}	$ 13,487,383		
	Annual Avoided Fuel Costs (Boiler Fuel, Industria rate)	ACB_{F}	$ 12,536,650	Increased Annual Fuel Cost (DG-CHP, Generator rate)	ACC_{Fuel}	$ 37,882,656		
	Energy Sale back to Grid	n/a	$ -	Annual O&M Cost	$ACC_{O\&M}$	$ 4,816,000	Customer Benefit	
	NYISO UCAP Auction Payment	ACB_{UCAP}	$ 6,622,000	Interconnection Charges	ACC_{IC}	$ 168,350		
		Sub-Total	$ 226,526,729		Sub-Total	$ 212,765,923	$ 13,760,806.00	$ 228.58
Electric Utility *	Annual Electric Standby (full facility capacity - CHP)	**ACC_{E} +ACC_{D} +ACC_{CD}**	$ 156,411,534	Annual Electric Sales (full customer capacity @ old rate)	**ACB_{E} +ACB_{D}**	$ 207,368,079		
				Cost of Providing Standby Service	**ACC_{CD}**	$ 15,049,349		
	Avoided Transmission Investments	AUB_{T}	$ 2,415,224					
	Avoided Distribution Investments	AUB_{D}	$ 5,032,720	System Upgrades	n/a		Electric Utility Benefit	
	Decreased Spot Market Energy Price	AUB_{LBMP}	$ 75,867,690	Incentives to DER Customers	n/a			
		Sub-Total	$ 239,727,168		Sub-Total	$ 222,417,428	$ 17,309,740.00	$ 287.54
Natural Gas Utility (Supply & Dist)	Increased Natural Gas Sales @ Industrial Rate	ACC_{Fuel} - ACB_{F}	$ 25,346,006	Increased Adjustment Credits for Power Generation	AUC_{Fuel}	$ 10,797,472	Natural Gas Utility Benefit	
		Sub-Total	$ 25,346,006		Sub-Total	$ 10,797,472	$ 14,548,534.00	$ 241.67
Society	Avoided Installed Capacity Values	ASB_{Cap}	$ 10,323,680	NYISO UCAP Auction	ASC_{UCAP}	$ 6,622,000		
	Emission "Damage Costs"	ASB_{Emis}	$ 3,242,910			$ -		
	Incresed Reliability LOLE		$ -			$ -	Society Benefit	
		Sub-Total	$ 13,566,590		Sub-Total	$ 6,622,000	$ 6,944,590.00	$ 115.36
	Total Benefits:		$ 505,166,493	Total Cost:		$ 452,602,823	$ 52,563,670	
					Net Benefit Per Year		$ 52,563,670	
					Net benefit (per kW-yr)		$873 /kW-yr	

6.5 Results

The following table summarizes the cost-benefit model results for the nine case studies. Results are shown in a per kW basis.

Table 42. DG-CHP Market penetration results - $ per installed kW

		Unit by size								
case	Market penetration	300 kW	800 kW	2000 kW	Proposed DG-CHP Capacity	Customer Benefits	Electric Utility / ESCO	Natural Gas Utility	Society Benefits	Total
1-a	1%	200	0	0	60,200	$ 117	$ 647	$ 242	$ 115	$ 1,122
1-b	1%	102	22	6	60,200	$ 229	$ 288	$ 242	$ 115	$ 873
1-c	1%	0	70	2	60,200	$ 200	$ (77)	$ 242	$ 115	$ 480
2-a	5%	1000	0	0	300,000	$ 120	$ 591	$ 242	$ 115	$ 1,068
2-b	5%	500	110	31	300,000	$ 232	$ 228	$ 242	$ 115	$ 817
2-c	5%	0	300	30	300,000	$ 257	$ (135)	$ 242	$ 115	$ 479
3-a	10%	2000	0	0	600,000	$ 120	$ 536	$ 242	$ 649	$ 1,546
3-b	10%	1000	300	30	600,000	$ 188	$ 172	$ 242	$ 649	$ 1,251
3-c	10%	0	670	32	600,000	$ 219	$ (191)	$ 242	$ 649	$ 918

Table 43 summarizes the cost-benefit model results for the nine case studies, recalculating upon the consideration that 50% of the real time load is traded via bilateral contracts. Results are shown in a per kW basis.

Table 43. DG-CHP Market penetration w/ bilateral contracts - $ per installed kW

50% Bilateral		Unit by size								
case	Market penetration	300 kW	800 kW	2000 kW	Proposed DG-CHP Capacity	Customer Benefits	Electric Utility / ESCO	Natural Gas Utility	Society Benefits	Total
1-a	1%	200	0	0	60,200	$ (251)	$ 1,016	$ 242	$ 115	$ 1,122
1-b	1%	102	22	6	60,200	$ (195)	$ 836	$ 242	$ 115	$ 998
1-c	1%	0	70	2	60,200	$ (208)	$ 654	$ 242	$ 115	$ 802
2-a	5%	1000	0	0	300,000	$ (250)	$ 961	$ 242	$ 115	$ 1,068
2-b	5%	500	110	31	300,000	$ (193)	$ 779	$ 242	$ 115	$ 943
2-c	5%	0	300	30	300,000	$ (180)	$ 598	$ 242	$ 115	$ 775
3-a	10%	2000	0	0	600,000	$ (250)	$ 905	$ 242	$ 649	$ 1,546
3-b	10%	1000	300	30	600,000	$ (215)	$ 724	$ 242	$ 649	$ 1,399
3-c	10%	0	670	32	600,000	$ (199)	$ 542	$ 242	$ 649	$ 1,233

- **Results Analysis – Base Case (Table 42) General Observations**

The behavior of ‘Total’ and each stakeholder’ benefits, on a per kW basis, must be analyzed:

- In all cases 'Total' system wide benefits are positive.
- The best results per installed kW are delivered by the small engines option (X-a), in great part because these small systems stay under the standard service rate, where no Standby costs for the utilities exist. The best 'Total' benefits per installed kW are delivered by the 10% market penetration (3-x).
- The above could suggest that benefits are maximized with as much DG-CHP systems as possible (e.g. 100% penetration). It must be noticed however, that 1% and 5% market penetration scenarios do not deliver system reliability benefits, as the 10% market penetration scenario does. Without such contribution the 10% market penetration 'Total benefits', in a per kW basis, would be less than those obtained with 5% and the 1% penetration. Certainly, with very large levels of market penetration, that is, going beyond 10% to 30% or even 100%, system reliability could be lowered far below 0.1 and greater benefits could be expected. However, this scenario not only is not supported by any RNA simulations, such values of market penetration are beyond the range of definition of some model parameters (e.g. electric rates would certainly change). Conversely, if the higher range of market penetration were to be modeled, some constraints that have not been considered in our model would certainly become binding (e.g. reliability vs. cost of generation redundancy). In conclusion, it must be noted that the cost benefit model as presented in this thesis is proposed for the lower range of DG market penetration.
- While Electric Utilities benefits per kW decrease with greater market penetrations, Customer benefits peak at 5% penetration (cases 2-x) and Society

benefits, as explained above, are the greatest with 10% penetration. Additionally, in all three levels of penetration, benefits are evenly distributed with the most heterogeneous fleet (cases X-b). Two conclusions may be drawn: First, DG-CHP must be implemented in all system sizes and, secondly, if no benefit reallocation is considered, programs should aim for a DG-CHP 5% market penetration. If Society benefits are reallocated in the form of incentives, a penetration of 10% may be reached. Again, results for greater levels of market penetration beyond the scope of the model.

- For cases X-a (small-engines only DG-CHP fleet), Electric Utility benefits are disproportionately larger than for the other stakeholders. This might be the case but it must be noted that the term “electric utility” - as used in the model – is a simplification including not only the Utility itself, but the T&D companies as well
- In all cases, Natural Gas benefits per kW are the same. Model should be revised to reflect this sensitivity.
- An unexpected result is that Electric Utility benefits may be negative with some fleet configurations. This somehow explains the alleged intentions of Utilities to obstruct massive migration of large customers from standard service rate to standby rate.

▪ **Results Analysis – Bilateral Contracts Load share**

- When the share of load traded with bilateral contracts is considered, ‘Total benefits’ are greater that with the default model. This is due to the fact that when the default service rates are considered, Electric Utilities incur in costs for providing the Standby service. By reducing the number of customers migrating from one rate to the other, the associated cost is reduced.

- However, attention must be paid to the following: Customer benefits are negative in all cases when the 50% bilateral contracts are considered, regardless of the market penetration level. This was predictable since the cost benefit model is based on the utilities default electric rates whereas terms and conditions of each bilateral contract are unknown. Some bilateral contracts might include provisions for CHP installation but the prediction of such values is beyond the scope of this thesis. However, it is unlikely that bilateral contract between a customer and an independent ESCO be designed to encourage customer to reduce the amount of electricity. Further research on bilateral contracts terms and conditions should clarify this point.
- When the bilateral contracts are considered, the distribution of benefits among Customer and Utilities is very unbalanced. This may be explained by the rate structure factors quoted in previous paragraphs however, it must be once again reminded that the term 'Electric Utility' as used in the model represents not one but many business units.

- **Results Analysis – Recommendations**

Several recommendations may be drawn from these observations:

1- To encourage customers to go beyond the 15% ICAP in order to maximize their benefits before incentives.

2- To modify the electric rate description. The current outline could disincentive properly-sized small DG-CHP projects, or incentive oversized expensive projects.

3- The system-wide benefits should be redistributed in order to incentive the individual customers to take the risk, and compensate for the financial load and risk. Those customers implementing the first projects (1% market penetration) should be compensated more that those doing it later (completing the 10% market penetration). At the very least, customers should receive from society incentives equal to the 'society benefits' herein calculated. Hence, If system wide benefits are redistributed among customers, electric utilities and gas utilities, the suggested incentives to Customers should be granted as follows:

- First 1% of market penetration: between $ 115/kW and $ 257/kW.
- Next 4% of market penetration: between $ 115/kW and $ 236 /kW.
- If the 10% of market penetration is reached: $ 649/kW for all systems.

4- Society benefits can be demonstrated and compensations to customers because of DG-CHP should not be determined by markets or auction mechanisms.

5- It is clear that, when bilateral contracts are accounted for, the average customer benefits are greatly reduced. This should be revised both by stakeholders signing bilateral contracts and by society regulations; On the one hand, bilateral contracts should ideally provide for important operative changes such as the installation of DG-CHP systems. Failing to do so, those customers would be missing the opportunity to benefit from society compensations such as the UCAP auction payments. On the other hand, society must reconsider how viable the competition against large utilities is. In the case of NYC, ConEd is a clear market leader and customers staying with ConEd's default rates are better off than those that do not. Given the dominant position of ConEd in the market, it appears very difficult to design alternative bilateral contracts terms and conditions capable of both competing with ConEd and encourage DG-CHP implementation.

CONCLUSIONS

A first view to all the markets with interests in the New York electric load variations was performed. The existence and purpose of most markets, such as the energy market or the installed capacity market, are easy to identify. A warning is raised regarding the effectiveness of the TCC market to prevent grid congestion. TCC market is open access and market rules and regulations are such that some participants actually benefit when congestion occurs.

The analysis of congestion mitigation was only possible from a regional average perspective.

The analysis of congestion mitigation from a local perspective will only be possible when "generator price" and "generator bid data" can be associated with the geographical location of each generator and transmission facility. Local utilities such as ConEd have already done such analyses; however, disclosed results do not include a methodology description. Thus, in order to compose a methodology that will be repeatable in all the remaining load zones, this report explored the ArcGIS software as a tool for achieving this goal.

The GIS analysis has the potential to enhance the accuracy of the recommended best DG-CHP locations. A first version of the updated NYC electric power system map and its supporting shapefile (*.shp), are left as contributions for future developments.

The determination of the identity of each generator behind the masked ID's as presented in the NYISO bidding data relies heavily on the availability of accurate information about generator characteristics and location. The information gathered so far, e.g. the GIS data, is not 100% complete or reliable as of yet. The completion of this data set requires extensive research and, eventually, field verification; therefore this task is proposed as the immediate next goal of this line of research.

The current reliability of an individual DG-CHP unit requires that the customer assuming the CHP challenge plan for at least one generator stop per month. Because of stand-by charges included in the RA-14 rate, under certain circumstances, the economic benefits to the customer may be negative. In the mean time, the benefits to utilities and to society of massive DG-CHP market penetration may be very excessively positives. This unequivocally supports the idea that system-wide benefits must be redistributed, that is, the implementation of individual DG-CHP projects must be actively supported (subsidized) by society.

APPENDIX A

NYC LOAD ZONE GENERATORS

Generator Name	PTID	Subzone	Zone
59TH STREET_GT_1	24138	CON ED NY CITY	N.Y.C.
74TH STREET_GT_1	24260	CON ED NY CITY	N.Y.C.
74TH STREET_GT_2	24261	CON ED NY CITY	N.Y.C.
ADK HUDSON___FALLS	24011	NMPC CAPITAL	CAPITL
ADK RESOURCE___RCVRY	23798	NMPC CAPITAL	CAPITL
ADK S GLENS___FALLS	24028	NMPC CAPITAL	CAPITL
ADK_NYS___DAM	23527	NMPC CAPITAL	CAPITL
AIR_PRODUCTS___DRP	24190	NMPC CAPITAL	CAPITL
ALBANY___1	23571	NMPC CAPITAL	CAPITL
ALBANY___2	23572	NMPC CAPITAL	CAPITL
ALBANY___3	23573	NMPC CAPITAL	CAPITL
ALBANY___4	23574	NMPC CAPITAL	CAPITL
ALCOA_RYNLDS___DRP	24188	NYPA NORTH	NORTH
ALLEGHENY___COGEN	23514	RG&E GENESEE	GENESE
AMERICAN_REF_FUEL	24010	NMPC WEST	WEST
ARTHUR_KILL_2	23512	CON ED NY CITY	N.Y.C.
ARTHUR_KILL_3	23513	CON ED NY CITY	N.Y.C.
ARTHUR KILL_GT_1	23520	CON ED NY CITY	N.Y.C.
ASHOKAN____	23654	CENT HUD HUDSON VLY	HUD VL
ASTORIA_EAST_ENERGY_CC1	323581	CON ED NY CITY	N.Y.C.
ASTORIA_EAST_ENERGY_CC2	323582	CON ED NY CITY	N.Y.C.
ASTORIA_GT_1	23523	CON ED NY CITY	N.Y.C.
ASTORIA_GT_10	24110	CON ED NY CITY	N.Y.C.
ASTORIA_GT_11	24225	CON ED NY CITY	N.Y.C.
ASTORIA_GT_12	24226	CON ED NY CITY	N.Y.C.
ASTORIA_GT_13	24227	CON ED NY CITY	N.Y.C.
ASTORIA_GT_5	24106	CON ED NY CITY	N.Y.C.
ASTORIA_GT_7	24107	CON ED NY CITY	N.Y.C.
ASTORIA_GT_8	24108	CON ED NY CITY	N.Y.C.
ASTORIA_GT2_1	24094	CON ED NY CITY	N.Y.C.
ASTORIA_GT2_2	24095	CON ED NY CITY	N.Y.C.
ASTORIA_GT2_3	24096	CON ED NY CITY	N.Y.C.
ASTORIA_GT2_4	24097	CON ED NY CITY	N.Y.C.
ASTORIA_GT3_1	24098	CON ED NY CITY	N.Y.C.
ASTORIA_GT3_2	24099	CON ED NY CITY	N.Y.C.
ASTORIA_GT3_3	24100	CON ED NY CITY	N.Y.C.
ASTORIA_GT3_4	24101	CON ED NY CITY	N.Y.C.
ASTORIA_GT4_1	24102	CON ED NY CITY	N.Y.C.
ASTORIA_GT4_2	24103	CON ED NY CITY	N.Y.C.
ASTORIA_GT4_3	24104	CON ED NY CITY	N.Y.C.
ASTORIA_GT4_4	24105	CON ED NY CITY	N.Y.C.
ASTORIA___2	24149	CON ED NY CITY	N.Y.C.
ASTORIA___3	23516	CON ED NY CITY	N.Y.C.
ASTORIA___4	23517	CON ED NY CITY	N.Y.C.
ASTORIA___5	23518	CON ED NY CITY	N.Y.C.
ATHENS_STG_1	23668	NMPC CAPITAL	CAPITL
ATHENS_STG_2	23670	NMPC CAPITAL	CAPITL
ATHENS_STG_3	23677	NMPC CAPITAL	CAPITL
BARRETT_IC_1	23704	LIPA LONG ISLAND	LONGIL
BARRETT_IC_10	23701	LIPA LONG ISLAND	LONGIL
BARRETT_IC_11	23702	LIPA LONG ISLAND	LONGIL
BARRETT_IC_12	23703	LIPA LONG ISLAND	LONGIL
BARRETT_IC_2	23705	LIPA LONG ISLAND	LONGIL
BARRETT_IC_3	23706	LIPA LONG ISLAND	LONGIL
BARRETT_IC_4	23707	LIPA LONG ISLAND	LONGIL
BARRETT_IC_5	23708	LIPA LONG ISLAND	LONGIL
BARRETT_IC_6	23709	LIPA LONG ISLAND	LONGIL
BARRETT_IC_7	23710	LIPA LONG ISLAND	LONGIL
BARRETT_IC_8	23711	LIPA LONG ISLAND	LONGIL
BARRETT_IC_9	23700	LIPA LONG ISLAND	LONGIL

BARRETT___1	23545	LIPA LONG ISLAND	LONGIL
BARRETT___2	23546	LIPA LONG ISLAND	LONGIL
BEAR_SWAMP___1	359	NPX-AC	NPX
BEAR_SWAMP___2	360	NPX-AC	NPX
BEAVER RIVER___HYD	24048	NMPC MOHAWK VLY	MHK VL
BEEBEE_GT_13	23619	RG&E GENESEE	GENESE
BERLIN___1	10424	NPX-AC	NPX
BETHLEHEM___GRP	23843	NMPC CAPITAL	CAPITL
BETHLEHEM___GS1	323560	NMPC CAPITAL	CAPITL
BETHLEHEM___GS2	323561	NMPC CAPITAL	CAPITL
BETHLEHEM___GS3	323562	NMPC CAPITAL	CAPITL
BETHLEHEM___STEEL	23779	NMPC WEST	WEST
BETHPAGE_CC_5	323564	LIPA LONG ISLAND	LONGIL
BINGHAMTON___COGEN	23790	NYSEG CENTRAL	CENTRL
BLACK RIVER___HYD	24047	NMPC MOHAWK VLY	MHK VL
BLUE_CIRC_CHEM_DRP	24182	NMPC CAPITAL	CAPITL
BOC_GAS_DRP	24189	NMPC CAPITAL	CAPITL
BORALEX_4TH_BRANCH	23824	NMPC CAPITAL	CAPITL
BOWLINE___1	23526	O&R HUDSON VLY	HUD VL
BOWLINE___2	23595	O&R HUDSON VLY	HUD VL
BROOKHAVEN___DRP	24191	LIPA LONG ISLAND	LONGIL
BROOKLYN_NAVY_YARD	23515	CON ED NY CITY	N.Y.C.
BROOKLYN___ARMY_DRP	323595	CON ED NY CITY	N.Y.C.
BURROWS___LYONSDAL	23803	NMPC MOHAWK VLY	MHK VL
CALPINE_BETH_PAGE_GT_4	323586	LIPA LONG ISLAND	LONGIL
CALPINE_BP_GT1	23823	LIPA LONG ISLAND	LONGIL
CALPINE BETH_PAGE_GT4	24209	LIPA LONG ISLAND	LONGIL
CALSPAN___DRP	24200	NMPC WEST	WEST
CARR STREET_E._SYR	24060	NMPC CENTRAL	CENTRL
CARTHAGE___PAPER	23857	NMPC MOHAWK VLY	MHK VL
CE_NYC_DRP	24195	CON ED NY CITY	N.Y.C.
CE_NYC2_DRP	24202	CON ED NY CITY	N.Y.C.
CE_DUNWOOD___DRP	24194	CON ED DUNWOODIE	DUNWOD
CE_MILLWOOD___DRP	24193	CON ED MILLWOOD	MILLWD
CH_MISC_IPPS	23765	CENT HUD HUDSON VLY	HUD VL
CH_RES_NIAGARA	23895	NMPC WEST	WEST
CH_RES_SYRACUSE	23985	NMPC CENTRAL	CENTRL
CHAT_HIGH_FALL_HYD	323578	NYSEG NORTH	NORTH
CH_MIDHUDSON___DRP	24192	CENT HUD HUDSON VLY	HUD VL
CH_RES_BVR_FALLS	23983	NMPC MOHAWK VLY	MHK VL
COLONIE_LFGE__	323577	NMPC CAPITAL	CAPITL
CORNELL____	23752	NYSEG CENTRAL	CENTRL
COXSACKIE___GT	23611	CENT HUD HUDSON VLY	HUD VL
CRESCENT___HYD	24018	NMPC CAPITAL	CAPITL
CRUCIBLE_METL_DRP	24180	NMPC CENTRAL	CENTRL
CSC___481_PGEN	24222	LIPA LONG ISLAND	LONGIL
DANSKAMMER___1	23586	CENT HUD HUDSON VLY	HUD VL
DANSKAMMER___2	23589	CENT HUD HUDSON VLY	HUD VL
DANSKAMMER___3	23590	CENT HUD HUDSON VLY	HUD VL
DANSKAMMER___4	23591	CENT HUD HUDSON VLY	HUD VL
DANSKAMMER___DIESEL	23592	CENT HUD HUDSON VLY	HUD VL
DARTMOUTH___1	2509	NPX-AC	NPX
DASHVILLE___HYD	23610	CENT HUD HUDSON VLY	HUD VL
DEEP_CREEK___1	501	PJM-AC	PJM
DEEP_CREEK___2	502	PJM-AC	PJM
DOGLEVILLE___HYD	23807	NMPC MOHAWK VLY	MHK VL
DOREEN____	2502	NPX-AC	NPX
DUNKIRK___1	23563	NMPC WEST	WEST
DUNKIRK___2	23564	NMPC WEST	WEST
DUNKIRK___3	23565	NMPC WEST	WEST
DUNKIRK___4	23566	NMPC WEST	WEST
EAST HAMPTON___GT	23717	LIPA LONG ISLAND	LONGIL
EAST RIVER___6	23660	CON ED NY CITY	N.Y.C.
EAST RIVER___7	23524	CON ED NY CITY	N.Y.C.
EAST_HAMPTON___DIESEL	23722	LIPA LONG ISLAND	LONGIL
EAST_RIVER___1	323558	CON ED NY CITY	N.Y.C.
EAST_RIVER___2	323559	CON ED NY CITY	N.Y.C.

ELEC_TRO_TEK	24086	LIPA LONG ISLAND	LONGIL
E_CANADA_CAP_HY	24051	NMPC CAPITAL	CAPITL
E_CANADA_MHWK_HY	24050	NMPC MOHAWK VLY	MHK VL
E_FISHKILL___LBMP	23776	CON ED MILLWOOD	MILLWD
FAR ROCKAWAY___4	23548	LIPA LONG ISLAND	LONGIL
FARRAGUT___LBMP	323566	CON ED NY CITY	N.Y.C.
FENNER___WINDPWR	24204	NMPC CENTRAL	CENTRL
FIBERTEK___ENERGY	23856	NMPC CENTRAL	CENTRL
FIFEBROOK___1	413	NPX-AC	NPX
FITZPATRICK____	23598	NMPC CENTRAL	CENTRL
FLUVANNA___1	940	PJM-AC	PJM
FLUVANNA___2	941	PJM-AC	PJM
FORT_DRUM_COGEN	23780	NMPC MOHAWK VLY	MHK VL
FORT ORANGE____	23900	NMPC CAPITAL	CAPITL
FPL FAR_ROCK_GT1	24212	LIPA LONG ISLAND	LONGIL
FPL FAR_ROCK_GT2	23815	LIPA LONG ISLAND	LONGIL
FRANKLIN_FALL_HYD	24054	NMPC NORTH	NORTH
FREEPORT_EQUS_GT1	23764	LIPA LONG ISLAND	LONGIL
FULTON COGEN____	23766	NMPC CENTRAL	CENTRL
Freeport___CT2	23818	LIPA LONG ISLAND	LONGIL
G.F.CEMENT___DRP	24184	NMPC CAPITAL	CAPITL
GARDENVILLE___LBMP	24039	NYSEG WEST	WEST
GENERAL___MILLS	23808	NMPC WEST	WEST
GE_PLASTICS___DRP	24183	NMPC CAPITAL	CAPITL
GILBOA___1	23756	NMPC CAPITAL	CAPITL
GILBOA___2	23757	NMPC CAPITAL	CAPITL
GILBOA___3	23758	NMPC CAPITAL	CAPITL
GILBOA___4	23759	NMPC CAPITAL	CAPITL
GILBOA____	23599	NMPC CAPITAL	CAPITL
GINNA____	23603	RG&E GENESEE	GENESE
GLEN PARK____	23778	NMPC MOHAWK VLY	MHK VL
GLENWOOD___4	23550	LIPA LONG ISLAND	LONGIL
GLENWOOD___5	23614	LIPA LONG ISLAND	LONGIL
GLENWOOD_IC_1_G5	23712	LIPA LONG ISLAND	LONGIL
GLENWOOD_IC_2_G1	23688	LIPA LONG ISLAND	LONGIL
GLENWOOD_IC_3_G1	23689	LIPA LONG ISLAND	LONGIL
GLOBAL GREEN_PORT_GT1	23814	LIPA LONG ISLAND	LONGIL
GOETHSLN___LBMP	323567	CON ED NY CITY	N.Y.C.
GOUDEY___7	23579	NYSEG CENTRAL	CENTRL
GOUDEY___8	23580	NYSEG CENTRAL	CENTRL
GOWANUS_GT1_1	24077	CON ED NY CITY	N.Y.C.
GOWANUS_GT1_2	24078	CON ED NY CITY	N.Y.C.
GOWANUS_GT1_3	24079	CON ED NY CITY	N.Y.C.
GOWANUS_GT1_4	24080	CON ED NY CITY	N.Y.C.
GOWANUS_GT1_5	24084	CON ED NY CITY	N.Y.C.
GOWANUS_GT1_6	24111	CON ED NY CITY	N.Y.C.
GOWANUS_GT1_7	24112	CON ED NY CITY	N.Y.C.
GOWANUS_GT1_8	24113	CON ED NY CITY	N.Y.C.
GOWANUS_GT2_1	24114	CON ED NY CITY	N.Y.C.
GOWANUS_GT2_2	24115	CON ED NY CITY	N.Y.C.
GOWANUS_GT2_3	24116	CON ED NY CITY	N.Y.C.
GOWANUS_GT2_4	24117	CON ED NY CITY	N.Y.C.
GOWANUS_GT2_5	24118	CON ED NY CITY	N.Y.C.
GOWANUS_GT2_6	24119	CON ED NY CITY	N.Y.C.
GOWANUS_GT2_7	24120	CON ED NY CITY	N.Y.C.
GOWANUS_GT2_8	24121	CON ED NY CITY	N.Y.C.
GOWANUS_GT3_1	24122	CON ED NY CITY	N.Y.C.
GOWANUS_GT3_2	24123	CON ED NY CITY	N.Y.C.
GOWANUS_GT3_3	24124	CON ED NY CITY	N.Y.C.
GOWANUS_GT3_4	24125	CON ED NY CITY	N.Y.C.
GOWANUS_GT3_5	24126	CON ED NY CITY	N.Y.C.
GOWANUS_GT3_6	24127	CON ED NY CITY	N.Y.C.
GOWANUS_GT3_7	24128	CON ED NY CITY	N.Y.C.
GOWANUS_GT3_8	24129	CON ED NY CITY	N.Y.C.
GOWANUS_GT4_1	24130	CON ED NY CITY	N.Y.C.
GOWANUS_GT4_2	24131	CON ED NY CITY	N.Y.C.
GOWANUS_GT4_3	24132	CON ED NY CITY	N.Y.C.

GOWANUS_GT4_4	24133	CON ED NY CITY	N.Y.C.
GOWANUS_GT4_5	24134	CON ED NY CITY	N.Y.C.
GOWANUS_GT4_6	24135	CON ED NY CITY	N.Y.C.
GOWANUS_GT4_7	24136	CON ED NY CITY	N.Y.C.
GOWANUS_GT4_8	24137	CON ED NY CITY	N.Y.C.
GRAHMSVILLE___HY	23607	CENT HUD HUDSON VLY	HUD VL
GREENIDGE___3	23582	NYSEG CENTRAL	CENTRL
GREENIDGE___4	23583	NYSEG CENTRAL	CENTRL
HAMPSHIRE___PAPER_HYD	323593	NMPC MOHAWK VLY	MHK VL
HARRISBURG_CT_1	987	PJM-AC	PJM
HARRISBURG_CT_2	992	PJM-AC	PJM
HARRISBURG_CT_3	993	PJM-AC	PJM
HARRISBURG_CT_4	994	PJM-AC	PJM
HARZA MOOSE___RIVER	24016	NMPC MOHAWK VLY	MHK VL
HEMPSTEAD____	23647	LIPA LONG ISLAND	LONGIL
HICKLING___1	23621	NYSEG CENTRAL	CENTRL
HICKLING___2	23622	NYSEG CENTRAL	CENTRL
HIGH FALLS___HY	23754	CENT HUD HUDSON VLY	HUD VL
HILLBURN___GT	23639	O&R HUDSON VLY	HUD VL
HOLTSVILLE_IC_1	23690	LIPA LONG ISLAND	LONGIL
HOLTSVILLE_IC_10	23699	LIPA LONG ISLAND	LONGIL
HOLTSVILLE_IC_2	23691	LIPA LONG ISLAND	LONGIL
HOLTSVILLE_IC_3	23692	LIPA LONG ISLAND	LONGIL
HOLTSVILLE_IC_4	23693	LIPA LONG ISLAND	LONGIL
HOLTSVILLE_IC_5	23694	LIPA LONG ISLAND	LONGIL
HOLTSVILLE_IC_6	23695	LIPA LONG ISLAND	LONGIL
HOLTSVILLE_IC_7	23696	LIPA LONG ISLAND	LONGIL
HOLTSVILLE_IC_8	23697	LIPA LONG ISLAND	LONGIL
HOLTSVILLE_IC_9	23698	LIPA LONG ISLAND	LONGIL
HOMER CITY___01	996	PJM-AC	PJM
HOMER CITY___02	997	PJM-AC	PJM
HOMER CITY___03	998	PJM-AC	PJM
HQ_GEN_CEDARS	23644	NMPC NORTH	NORTH
HQ_GEN_CHAT DC	23651	HQ-CHAT	H Q
HQ____	1000	HQ-CHAT	H Q
HUDSON_AVE_10	24168	CON ED NY CITY	N.Y.C.
HUDSON AVE_GT_3	23810	CON ED NY CITY	N.Y.C.
HUDSON AVE_GT_4	23540	CON ED NY CITY	N.Y.C.
HUDSON AVE_GT_5	23657	CON ED NY CITY	N.Y.C.
HUNTLEY___63	23557	NMPC WEST	WEST
HUNTLEY___64	23558	NMPC WEST	WEST
HUNTLEY___65	23559	NMPC WEST	WEST
HUNTLEY___66	23560	NMPC WEST	WEST
HUNTLEY___67	23561	NMPC WEST	WEST
HUNTLEY___68	23562	NMPC WEST	WEST
INDECK___CORINTH	23802	NMPC CAPITAL	CAPITL
INDECK___ILION	23567	NMPC MOHAWK VLY	MHK VL
INDECK___OLEAN	23982	NMPC WEST	WEST
INDECK___OSWEGO	23783	NMPC CENTRAL	CENTRL
INDECK___YERKES	23781	NMPC WEST	WEST
INDIAN POINT_GT_1	24139	CON ED MILLWOOD	MILLWD
INDIAN POINT_GT_2	23659	CON ED MILLWOOD	MILLWD
INDIAN POINT_GT_3	24019	CON ED MILLWOOD	MILLWD
INDIAN POINT___2	23530	CON ED MILLWOOD	MILLWD
INDIAN POINT___3	23531	CON ED MILLWOOD	MILLWD
IP___TICONDEROGA	23804	NMPC CAPITAL	CAPITL
IP CORINTH___1	23988	NMPC CAPITAL	CAPITL
JARVIS____	23743	NMPC MOHAWK VLY	MHK VL
JENNISON___1	23625	NYSEG MOHAWK VLY	MHK VL
JENNISON___2	23626	NYSEG MOHAWK VLY	MHK VL
KEDC_GLWD_GT4	24219	LIPA LONG ISLAND	LONGIL
KEDC_GLWD_GT5	24220	LIPA LONG ISLAND	LONGIL
KEDC PORT_JEFF_GT2	24210	LIPA LONG ISLAND	LONGIL
KEDC PORT_JEFF_GT3	24211	LIPA LONG ISLAND	LONGIL
KENSICO____	23655	CON ED DUNWOODIE	DUNWOD
KIAC_JFK_AIRPORT	23541	CON ED NY CITY	N.Y.C.
KIAC_JFK_GT1	23816	CON ED NY CITY	N.Y.C.

KIAC_JFK_GT2	23817	CON ED NY CITY	N.Y.C.
KINTIGH___	23543	NYSEG WEST	WEST
LAKEWOOD_CT_1	4000	PJM-AC	PJM
LAKEWOOD_CT_2	4001	PJM-AC	PJM
LEDERLE___	23769	O&R HUDSON VLY	HUD VL
LIEVRE RIVER___	1001	HQ-CHAT	H Q
LINDEN COGEN___	23786	CON ED NY CITY	N.Y.C.
LIPA_MISC_IPP	23656	LIPA LONG ISLAND	LONGIL
LITTLE FALLS__HYD	24013	NMPC MOHAWK VLY	MHK VL
LONG_LAKE_PHOENIX	24014	NMPC CENTRAL	CENTRL
LOVETT__3	23632	O&R HUDSON VLY	HUD VL
LOVETT__4	23642	O&R HUDSON VLY	HUD VL
LOVETT__5	23593	O&R HUDSON VLY	HUD VL
LOWER__HUDSON	24059	NMPC CAPITAL	CAPITL
LOWER RAQUET__HYD	24057	NMPC MOHAWK VLY	MHK VL
LWR__OSWEGATCHIE_HYD	23850	NMPC MOHAWK VLY	MHK VL
LYONS_FALL_HYD	23570	NMPC MOHAWK VLY	MHK VL
MAPLE_RIDGE_WT_1	323574	NMPC MOHAWK VLY	MHK VL
MARTINSCREEK__1	988	PJM-AC	PJM
MARTINSCREEK__2	989	PJM-AC	PJM
MARTINSCREEK__3	990	PJM-AC	PJM
MARTINSCREEK__4	995	PJM-AC	PJM
MG INDUSTRY__DRP	24185	NMPC CAPITAL	CAPITL
MID__OSWEGATCHIE_HYD	23849	NMPC MOHAWK VLY	MHK VL
MID__RAQUETTE_HYD	23851	NMPC MOHAWK VLY	MHK VL
MILLIKEN__1	23584	NYSEG CENTRAL	CENTRL
MILLIKEN__2	23585	NYSEG CENTRAL	CENTRL
MILLIKEN__DIESEL	23629	NYSEG CENTRAL	CENTRL
MODEL_CITY_ENERGY	24167	NMPC WEST	WEST
MODERN_LFGE__	323580	NMPC WEST	WEST
MOHAWK_PAPER__DRP	24187	NMPC CAPITAL	CAPITL
MONGAUP__HYD	23641	O&R HUDSON VLY	HUD VL
MONTAUK__DIESEL	23721	LIPA LONG ISLAND	LONGIL
N SALMON__HYD	24042	NMPC NORTH	NORTH
N.E._GEN_SANDY PD	24062	NPX-AC	NPX
NARROWS_GT1_1	24228	CON ED NY CITY	N.Y.C.
NARROWS_GT1_2	24229	CON ED NY CITY	N.Y.C.
NARROWS_GT1_3	24230	CON ED NY CITY	N.Y.C.
NARROWS_GT1_4	24231	CON ED NY CITY	N.Y.C.
NARROWS_GT1_5	24232	CON ED NY CITY	N.Y.C.
NARROWS_GT1_6	24233	CON ED NY CITY	N.Y.C.
NARROWS_GT1_7	24234	CON ED NY CITY	N.Y.C.
NARROWS_GT1_8	24235	CON ED NY CITY	N.Y.C.
NARROWS_GT2_1	24236	CON ED NY CITY	N.Y.C.
NARROWS_GT2_2	24237	CON ED NY CITY	N.Y.C.
NARROWS_GT2_3	24238	CON ED NY CITY	N.Y.C.
NARROWS_GT2_4	24239	CON ED NY CITY	N.Y.C.
NARROWS_GT2_5	24240	CON ED NY CITY	N.Y.C.
NARROWS_GT2_6	24241	CON ED NY CITY	N.Y.C.
NARROWS_GT2_7	24242	CON ED NY CITY	N.Y.C.
NARROWS_GT2_8	24243	CON ED NY CITY	N.Y.C.
NEG_PENN_ALLEGHNY	23528	NYSEG CENTRAL	CENTRL
NEG__GEN_MONROE	24207	NMPC GENESEE	GENESE
NEG CAPITAL__MECHNVIL	23645	NYSEG CAPITAL	CAPITL
NEG CENTRAL_HIGH_ACRES	23767	NYSEG CENTRAL	CENTRL
NEG CENTRAL__DRP	24199	NYSEG CENTRAL	CENTRL
NEG CENTRAL__INDECK	23768	NYSEG CENTRAL	CENTRL
NEG CENTRAL__SENECA	23627	NYSEG CENTRAL	CENTRL
NEG CENTRAL__STATE_STREET	24147	NYSEG CENTRAL	CENTRL
NEG MILLWOOD__DRP	24198	NYSEG MILLWOOD	MILLWD
NEG NORTH_FLCN_SEA	23793	NYSEG NORTH	NORTH
NEG NORTH_KES_CHATEGAY	23792	NYSEG NORTH	NORTH
NEG NORTH__ALICE_FALLS	23915	NYSEG NORTH	NORTH
NEG NORTH__LWR_SARANAC	23913	NYSEG NORTH	NORTH
NEG NORTH__PLATTSBURG	23628	NYSEG NORTH	NORTH
NEG WEST_LEA_LOCKPORT	23791	NYSEG WEST	WEST
NEG WEST__LANCASTR	23811	NYSEG WEST	WEST

NEPA__ENERGY	23901	NMPC WEST	WEST
NEVERSINK__HYD	23608	CENT HUD HUDSON VLY	HUD VL
NEWINTON___	2508	NPX-AC	NPX
NEWTON__FALLS_HYD	23847	NMPC MOHAWK VLY	MHK VL
NIAGARA___	23760	NMPC WEST	WEST
NINE_MILE_1	23575	NMPC CENTRAL	CENTRL
NINE_MILE_2	23744	NMPC CENTRAL	CENTRL
NM_CAPITAL__DRP	24208	NMPC CAPITAL	CAPITL
NM_CENTRAL__DRP	24181	NMPC CENTRAL	CENTRL
NM_FRONTIER__DRP	24179	NMPC WEST	WEST
NM_ST_REGIS__HYD	24053	NMPC NORTH	NORTH
NORTHPORT__1	23551	LIPA LONG ISLAND	LONGIL
NORTHPORT__2	23552	LIPA LONG ISLAND	LONGIL
NORTHPORT__3	23553	LIPA LONG ISLAND	LONGIL
NORTHPORT__4	23650	LIPA LONG ISLAND	LONGIL
NORTHPORT__IC	23718	LIPA LONG ISLAND	LONGIL
NPX_GEN_CSC	323557	NPX-CSC	NPX
NSINS_S._GLNS_FALLS	23858	NMPC CAPITAL	CAPITL
NUCOR_STEEL__DRP	24197	NYSEG CENTRAL	CENTRL
NYISO_LBMP_REFERENCE	24008	NMPC MOHAWK VLY	MHK VL
NYPA__ASTORIA_CC1	323568	CON ED NY CITY	N.Y.C.
NYPA__ASTORIA_CC2	323569	CON ED NY CITY	N.Y.C.
NYPA__HOLTSVILL	23794	LIPA LONG ISLAND	LONGIL
NYPA____HELLGATE_GT1	24158	CON ED NY CITY	N.Y.C.
NYPA____HELLGATE_GT2	24159	CON ED NY CITY	N.Y.C.
NYPA_BRENTWD____GT	24164	LIPA LONG ISLAND	LONGIL
NYPA_GOWANUS____GT5	24156	CON ED NY CITY	N.Y.C.
NYPA_GOWANUS____GT6	24157	CON ED NY CITY	N.Y.C.
NYPA_HARLEM__RVR__GT1	24160	CON ED NY CITY	N.Y.C.
NYPA_HARLEM__RVR__GT2	24161	CON ED NY CITY	N.Y.C.
NYPA_KENT____GT	24152	CON ED NY CITY	N.Y.C.
NYPA_POUCH1____GT	24155	CON ED NY CITY	N.Y.C.
NYPA_VERNON____GT2	24162	CON ED NY CITY	N.Y.C.
NYPA_VERNON____GT3	24163	CON ED NY CITY	N.Y.C.
NYS_BARGE__HYD	23848	NMPC WEST	WEST
O.H._GEN_BRUCE	24063	OH-AC	O H
OAK ORCHARD__HYD	24046	NMPC GENESEE	GENESE
OCC_CHEM__DRP	24175	NMPC WEST	WEST
OLIN_CORP_DRP	24177	NMPC WEST	WEST
ONONDAGA_REF_OCCRA	23987	NMPC CENTRAL	CENTRL
ONONDAGA__COGEN	23986	NMPC CENTRAL	CENTRL
ONTARIO__LFGE	23819	NYSEG CENTRAL	CENTRL
OSWEGATCHIE__HYD	24044	NMPC MOHAWK VLY	MHK VL
OSWEGO__5	23606	NMPC CENTRAL	CENTRL
OSWEGO__6	23613	NMPC CENTRAL	CENTRL
OUTOKUMPU-AB__DRP	24206	NMPC WEST	WEST
OXBOW___	24026	NMPC WEST	WEST
PARENT_SP_ARTKLGRP	923512	CON ED NY CITY	N.Y.C.
PARENT_SP_ASTGTGP2	924094	CON ED NY CITY	N.Y.C.
PARENT_SP_ASTGTGRP	924106	CON ED NY CITY	N.Y.C.
PARENT_SP_CAYUGGRP	923584	NYSEG CENTRAL	CENTRL
PARENT_SP_DANSKGRP	923586	CENT HUD HUDSON VLY	HUD VL
PARENT_SP_GOUDEY	923579	NYSEG CENTRAL	CENTRL
PARENT_SP_GOWANGRP	924077	CON ED NY CITY	N.Y.C.
PARENT_SP_GOWANUS	924157	CON ED NY CITY	N.Y.C.
PARENT_SP_GREENGRP	923582	NYSEG CENTRAL	CENTRL
PARENT_SP_GWANSGRP	924156	CON ED NY CITY	N.Y.C.
PARENT_SP_HARLMGRP	924160	CON ED NY CITY	N.Y.C.
PARENT_SP_HELGTGRP	924158	CON ED NY CITY	N.Y.C.
PARENT_SP_NARROGRP	924228	CON ED NY CITY	N.Y.C.
PARENT_SP_RAVENSWD	923533	CON ED NY CITY	N.Y.C.
PARENT_SP_ROSETON	923587	CENT HUD HUDSON VLY	HUD VL
PARENT_SP_VRNONGRP	924162	CON ED NY CITY	N.Y.C.
PEEKSKILL___	23653	CON ED MILLWOOD	MILLWD
PENOBSCOT__1	424	NPX-AC	NPX
PGE MADISON__WINDPWR	24146	NYSEG MOHAWK VLY	MHK VL
PIERCEFIELD__HYD	23852	NMPC MOHAWK VLY	MHK VL

PINELAWN_CC_1	323563	LIPA LONG ISLAND	LONGIL
PINEY___1	505	PJM-AC	PJM
PINEY___2	506	PJM-AC	PJM
PINEY___3	507	PJM-AC	PJM
PJM_GEN_KEYSTONE	24065	PJM-AC	PJM
PJM___ICAPUNIT	99999	PJM-AC	PJM
PLEASANTVLY___LBMP	24000	CON ED HUDSON VLY	HUD VL
POLETTI____	23519	CON ED NY CITY	N.Y.C.
PONDTOOK___1	539	NPX-AC	NPX
PORT_JEFF_3	23555	LIPA LONG ISLAND	LONGIL
PORT_JEFF_4	23616	LIPA LONG ISLAND	LONGIL
PORT_JEFF_IC	23713	LIPA LONG ISLAND	LONGIL
PPL_SHRM_GT3	24213	LIPA LONG ISLAND	LONGIL
PPL_SHRM_GT4	24214	LIPA LONG ISLAND	LONGIL
PPL PILGRIM_ST_GT1	24216	LIPA LONG ISLAND	LONGIL
PPL PILGRIM_ST_GT2	24217	LIPA LONG ISLAND	LONGIL
PROJECT___ORANGE	23990	NMPC CENTRAL	CENTRL
PROJECT___ORANGE 1	24174	NMPC CENTRAL	CENTRL
PROJECT___ORANGE 2	24166	NMPC CENTRAL	CENTRL
PYRITES___HYD	24023	NMPC MOHAWK VLY	MHK VL
RAMAPO___LBMP	323565	CON ED HUDSON VLY	HUD VL
RANKINE____	23646	NMPC WEST	WEST
RAVENSWOOD_GT_1	23729	CON ED NY CITY	N.Y.C.
RAVENSWOOD_GT_10	24258	CON ED NY CITY	N.Y.C.
RAVENSWOOD_GT_11	24259	CON ED NY CITY	N.Y.C.
RAVENSWOOD_GT_4	24252	CON ED NY CITY	N.Y.C.
RAVENSWOOD_GT_5	24254	CON ED NY CITY	N.Y.C.
RAVENSWOOD_GT_6	24253	CON ED NY CITY	N.Y.C.
RAVENSWOOD_GT_7	24255	CON ED NY CITY	N.Y.C.
RAVENSWOOD_GT_8 TEMP GRP(8-11)	24256	CON ED NY CITY	N.Y.C.
RAVENSWOOD_GT_9	24257	CON ED NY CITY	N.Y.C.
RAVENSWOOD_GT2_1	24244	CON ED NY CITY	N.Y.C.
RAVENSWOOD_GT2_2	24245	CON ED NY CITY	N.Y.C.
RAVENSWOOD_GT2_3	24246	CON ED NY CITY	N.Y.C.
RAVENSWOOD_GT2_4	24247	CON ED NY CITY	N.Y.C.
RAVENSWOOD_GT3_1	24248	CON ED NY CITY	N.Y.C.
RAVENSWOOD_GT3_2	24249	CON ED NY CITY	N.Y.C.
RAVENSWOOD_GT3_3	24250	CON ED NY CITY	N.Y.C.
RAVENSWOOD_GT3_4	24251	CON ED NY CITY	N.Y.C.
RAVENSWOOD___1	23533	CON ED NY CITY	N.Y.C.
RAVENSWOOD___2	23534	CON ED NY CITY	N.Y.C.
RAVENSWOOD___3	23535	CON ED NY CITY	N.Y.C.
RAVENSWOOD___4	23820	CON ED NY CITY	N.Y.C.
RCPI_TRUST___DRP	24196	CON ED NY CITY	N.Y.C.
RENSSELAER___COGEN	23796	NMPC CAPITAL	CAPITL
REVERE_CPPR_DRP	24186	NMPC MOHAWK VLY	MHK VL
ROCHESTER_9_IC	23652	RG&E GENESEE	GENESE
ROCK SPRINGS_CT_3	2506	PJM-AC	PJM
ROCK SPRINGS_CT_4	2507	PJM-AC	PJM
ROSETON___1	23587	CENT HUD HUDSON VLY	HUD VL
ROSETON___2	23588	CENT HUD HUDSON VLY	HUD VL
RUMFORD_FALL___1	2510	NPX-AC	NPX
RUSSELL___1	23602	RG&E GENESEE	GENESE
RUSSELL___2	23532	RG&E GENESEE	GENESE
RUSSELL___3	23549	RG&E GENESEE	GENESE
RUSSELL___4	23556	RG&E GENESEE	GENESE
RUSSELL___STATION	23914	RG&E GENESEE	GENESE
S SALMON___HYD	24043	NMPC CENTRAL	CENTRL
SELKIRK___II	23799	NMPC CAPITAL	CAPITL
SELKIRK___I	23801	NMPC CAPITAL	CAPITL
SENECA___ENERGY	23797	NYSEG CENTRAL	CENTRL
SENECA OSWGO___HYD	24041	NMPC CENTRAL	CENTRL
SHOEMAKER___GT	23640	O&R HUDSON VLY	HUD VL
SHOREHAM_IC_1	23715	LIPA LONG ISLAND	LONGIL
SHOREHAM_IC_2	23716	LIPA LONG ISLAND	LONGIL
SISSONVILLE____	23735	NMPC MOHAWK VLY	MHK VL
SITHE_IND_GS1	24169	NMPC CENTRAL	CENTRL

SITHE_IND_GS2	24170	NMPC CENTRAL	CENTRL
SITHE_IND_GS3	24171	NMPC CENTRAL	CENTRL
SITHE_IND_GS4	24172	NMPC CENTRAL	CENTRL
SITHE___BATAVIA	24024	NMPC GENESEE	GENESE
SITHE___INDEPEND	23800	NMPC CENTRAL	CENTRL
SITHE___MASSENA	23902	NMPC NORTH	NORTH
SITHE___OGDNSBRG	24021	NMPC MOHAWK VLY	MHK VL
SITHE___STERLING	23777	NMPC MOHAWK VLY	MHK VL
SOUTH CAIRO___GT	23612	CENT HUD HUDSON VLY	HUD VL
SOUTH HAMPTN___IC	23720	LIPA LONG ISLAND	LONGIL
SOUTHOLD___IC	23719	LIPA LONG ISLAND	LONGIL
ST LAWRENCE___	23600	NMPC NORTH	NORTH
STATION 5_MISC_HYD	23604	RG&E GENESEE	GENESE
STURGEON_POOL_HYD	23609	CENT HUD HUDSON VLY	HUD VL
SYRACUSE___POWER	24017	NMPC CENTRAL	CENTRL
Stony___Brook	24151	LIPA LONG ISLAND	LONGIL
UNION___PROCESSING_DRP	323587	RG&E GENESEE	GENESE
UPPER HUDSON___HYD	24058	NMPC CAPITAL	CAPITL
UPPER RAQUET___HYD	24056	NMPC MOHAWK VLY	MHK VL
VISCHER___FERRY HYD	24020	NMPC CAPITAL	CAPITL
WADING RIVER_IC_1	23522	LIPA LONG ISLAND	LONGIL
WADING RIVER_IC_2	23547	LIPA LONG ISLAND	LONGIL
WADING RIVER_IC_3	23601	LIPA LONG ISLAND	LONGIL
WALDEN___HYDRO	24148	NYSEG HUDSON VLY	HUD VL
WALLINGFORD___1	2000	NPX-AC	NPX
WALLINGFORD___2	2001	NPX-AC	NPX
WALLINGFORD___3	2002	NPX-AC	NPX
WALLINGFORD___4	2003	NPX-AC	NPX
WALLINGFORD___5	2004	NPX-AC	NPX
WARRENSBURG___	23737	NMPC CAPITAL	CAPITL
WATERSIDE___6 8 9	23538	CON ED NY CITY	N.Y.C.
WEST BABYLON___IC	23714	LIPA LONG ISLAND	LONGIL
WEST CANADA___HYD	24049	NMPC MOHAWK VLY	MHK VL
WESTERN_NY_WIND	24143	NMPC GENESEE	GENESE
WOODLAND___	2503	NPX-AC	NPX
WSPRINGFIELD___01	2504	NPX-AC	NPX
WSPRINGFIELD___02	2505	NPX-AC	NPX
WSPRINGFIELD___03	2500	NPX-AC	NPX
WSPRINGFIELD___10	2501	NPX-AC	NPX
YORK___WARBASSE	23770	CON ED NY CITY	N.Y.C.

APPENDIX B

CONED ELECTRIC RATES

Calculation of SC-9 tariff marginal costs

		SC-9 Rate I	
		Otherwise SC-9 Rate I	
		< 2 MW	
		summer	others months
Supply	Market Supply Charge Usage	$ 0.0982	$ 0.1076
	Adjustment factor MSC Usage	n/a	n/a
	Market Supply Charge Demand	$ 11.1500	$ 7.8613
	Adjustment factor MSC Demand	n/a	n/a
	Monthly Adjustment Clause Usage	$ 0.00513	$ 0.00341
	Adjustment factor MAC Usage	n/a	n/a
	Monthly Adjustment Clause Demand	$ 0.9725	$ 0.6413
	Adjustment factor MAC Demand	n/a	n/a
Delivery	Low Tension Service Energy Delivery Usage	$ 0.0142	$ 0.0142
	Low Tension Service Energy Delivery Demand	$ 12.7282	$ 10.0482
	System benefits Charges ($/kWh) July 2006	$ 0.0020	$ 0.0020
	Renewable Portfolio ($/kWh)	$ 0.0002	$ 0.0002
	Usage Charges	**$ 0.1197**	**$ 0.1274**
	Demand Charges	**$ 24.85**	**$ 18.55**

Calculation of 14-RA tariff marginal costs

On Site Generating capacity (kW)	800 kW			2000 kW	
Max Demand	2000 kW			5000 kW	
Purchased Power (kW)	1200 kW	Op.Hours	720	3000 kW	
	432,000 kWh	Load Factor	50%	1,080,000 kWh	
contract demand factor	153%	1.529051988	1.52905199	153%	
Contract Demand Client established or highest (kW)	1835 kW	1835 kW		4587 kW	4587 kW
Electric Rate			14-RA		
			Otherwise SC-9 Rate I		
MONTHLY CHARGES	< 2 MW			> 2 MW	
CHP electric size	June-September	Other Months			
Customer Charges	$ 62.88	$ 62.88		$ 62.88	$ 62.88
Interconnection charges					
"reasonable costs of connection" ($/kW)	$ 350.00	$ 350.00		$ 350.00	$ 350.00
taxes and others (11.4%) ($)	$ -	$ -		$ 6,650	$ 6,650
Contract Demand Charges					
Delivery Contract Demand ($/kW)	$ 12.6777	$ 9.9977		$ 12.2951	$ 9.6151
Delivery Contract Demand MAC ($/kW)	$ 0.9725	$ 0.6413		$ 0.9725	$ 0.6413
Sum of Demand Charges = Dch ($/kW)	$ 13.65	$ 10.64		$ 13.27	$ 10.26
Subtotal Demand Charges ($)	$ 25,046.15	$ 19,520.92		$ 60,860.37	$ 47,047.29
Surcharge DD (kW) = should not be considered	165 kW	165 kW		413 kW	413 kW
a) if 10%<DD<20% -> DDch ($)	$ 27,049.84	$ 21,082.59		$ 65,729.20	$ 50,811.08
b) if 20%<DD -> DDch ($)	$ 54,099.68	$ 42,165.18		$ 131,458.39	$ 101,622.15
Subtotal Subcharges a) or b) ($)	$ -	$ -		$ -	$ -
Delivery Service Contract Demand Charge ($/kW)	$ 3.89	$ 3.89		$ 3.89	$ 3.89
Subtotal Delivery Service ($)	$ 7,137.61	$ 7,137.61		$ 17,844.04	$ 17,844.04
As Used Daily Demand Charges (% demand contract)	0.9	0.6		0.9	0.6
Period 1 ($/kW)	$ 0.2893	$ -		$ 0.2893	$ -
Period 2 ($/kW)	$ 0.5736	$ 0.3454		$ 0.5736	$ 0.3454
Subtotal As Used daily Demand ($/kW)	$ 0.8629	$ 0.3454		$ 0.8629	$ 0.3454
Subtotal As Used daily Demand Charges ($)	$ 20,502.50	$ 5,471.14		$ 51,256.26	$ 13,677.84
Energy Delivery Charge ($/kWh)	$ 0.0142	$ 0.0142		$ 0.0142	$ 0.0142
Subtotal As Used daily Demand Charges ($)	$ 6,134.40	$ 6,134.40		$ 15,336.00	$ 15,336.00
Demand - MSC ($)	$ 20,458.72	$ 14,424.31		$ 51,146.79	$ 36,060.78
Adjustment factor MSC Demand	n/a	n/a		n/a	
Energy Supply - MSC ($/kWh)	$ 0.10	$ 0.11		$ 0.10	$ 0.11
Energy Supply - Adujtment Factor MSC ($/kWh)	n/a	n/a		n/a	n/a
System benefits Charges ($/kWh) July 2006	$ 0.0020	$ 0.0020		$ 0.0020	$ 0.0020
Renewable Portfolio ($/kWh)	$ 0.0002	$ 0.0002		$ 0.0002	$ 0.0002
Other Charges (Usage of purchased power 720) ($)	$ 43,362.00	$ 47,428.20		$ 108,405.00	$ 118,570.50
Total Usage charges	$ 49,496.40	$ 53,562.60		$ 123,741.00	$ 133,906.50
Total Actual Demand Charges	$ 20,502.50	$ 5,471.14		$ 51,256.26	$ 13,677.84
Total Contract Demand Charges	$ 52,642.48	$ 41,082.84		$ 129,851.19	$ 100,952.11
Customer and Interconnection	$ 62.88	$ 62.88		$ 6,712.88	$ 6,712.88
Total Charges	$ 122,704.26	$ 100,179.46		$ 311,561.33	$ 255,249.33

APPENDIX C

COST BENEFIT MODEL RESULTS - 9 CASES

60200 case 1-a

	Benefits/Income			Costs/Expenses			
Customer	Annual Electricity Bill Savings (Avoided Charges from old rate based on full customer capacity)	**Energy ACB_E**	$ 199,731,336	New Annual Electric Bill (full customer capacity-DG) @ Standby rate	**Energy ACC_E**	$ 169,771,636	
		Demand ACB_D	$ 98,640,000		**Actual Demand ACC_D**	$ 84,252,000	
					Contract Demand ACC_{CD}	$ -	
				Annual Capital Cost	ACC_{CAP}	$ 13,487,383	
	Annual Avoided Fuel Costs (Boiler Fuel, Industria rate)	ACB_F	$ 12,536,650	Increased Annual Fuel Cost (DG-CHP, Generator rate)	ACC_{Fuel}	$ 37,882,656	
	Energy Sale back to Grid	n/a	$ -	Annual O&M Cost	$ACC_{O\&M}$	$ 4,816,000	Customer Benefit
	NYISO UCAP Auction Payment	ACB_{UCAP}	$ 6,622,000	Interconnection Charges	ACC_{IC}	$ 259,000	
		Sub-Total	$ 317,529,986		Sub-Total	$ 310,468,675	$ 7,061,311.00
Electric Utility *	Annual Electric Standby (full facility capacity - CHP)	**ACC_E +ACC_D +ACC_{CD}**	$ 254,023,636	Annual Electric Sales (full customer capacity @ old rate)	**ACB_E +ACB_D**	$ 298,371,336	
				Cost of Providing Standby Service	**ACC_{CD}**	$ -	
	Avoided Transmission Investments	AUB_T	$ 2,415,224				
	Avoided Distribution Investments	AUB_D	$ 5,032,720	System Upgrades	n/a		
	Decreased Spot Market Energy Price	AUB_{LBMP}	$ 75,867,690	Incentives to DER Customers	n/a		Electric Utility Benefit
		Sub-Total	$ 337,339,270		Sub-Total	$ 298,371,336	$ 38,967,934.00
Natural Gas Utility (Supply & Dist)	Increased Natural Gas Sales @ Industrial Rate	ACC_{Fuel} - ACB_F	$ 25,346,006	Increased Adjustment Credits for Power Generation	AUC_{Fuel}	$ 10,797,472	Natural Gas Utility Benefit
		Sub-Total	$ 25,346,006		Sub-Total	$ 10,797,472	$ 14,548,534.00
Society	Avoided Installed Capacity Values	ASB_{Cap}	$ 10,323,680	NYISO UCAP Auction	ASC_{UCAP}	$ 6,622,000	
	Emission "Damage Costs"	ASB_{Emis}	$ 3,242,910			$ -	
	Incresed Reliability LOLE		$ -			$ -	Society Benefit
		Sub-Total	$ 13,566,590		Sub-Total	$ 6,622,000	$ 6,944,590.00
	Total Benefits:		$ 693,781,852	Total Cost:		$ 626,259,483	$ 67,522,369
					Net Benefit Per Year		$ 67,522,369
					Net benefit (per kW-yr)		$1,122 /kW-yr

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	Benefits/Income			Costs/Expenses			
Customer	Annual Electricity Bill Savings (Avoided Charges from old rate based on full customer capacity)	**Energy ACB_E**	$ 138,813,279	New Annual Electric Bill (full customer capacity-DG) @ Standby rate	**Energy ACC_E**	$ 93,738,769	
		Demand ACB_D	$ 68,554,800		**Actual Demand ACC_D**	$ 47,623,416	
					Contract Demand ACC_{CD}	$ 15,049,349	
				Annual Capital Cost	ACC_{CAP}	$ 13,487,383	
	Annual Avoided Fuel Costs (Boiler Fuel, Industria rate)	ACB_F	$ 12,536,650	Increased Annual Fuel Cost (DG-CHP, Generator rate)	ACC_{Fuel}	$ 37,882,656	
	Energy Sale back to Grid	n/a	$ -	Annual O&M Cost	$ACC_{O\&M}$	$ 4,816,000	Customer Benefit
	NYISO UCAP Auction Payment	ACB_{UCAP}	$ 6,622,000	Interconnection Charges	ACC_{IC}	$ 168,350	
		Sub-Total	$ 226,526,729		Sub-Total	$ 212,765,923	$ 13,760,806.00
Electric Utility *	Annual Electric Standby (full facility capacity - CHP)	**ACC_E $+ACC_D$ $+ACC_{CD}$**	$ 156,411,534	Annual Electric Sales (full customer capacity @ old rate)	**ACB_E $+ACB_D$**	$ 207,368,079	
				Cost of Providing Standby Service	**ACC_{CD}**	$ 15,049,349	
	Avoided Transmission Investments	AUB_T	$ 2,415,224				
	Avoided Distribution Investments	AUB_D	$ 5,032,720	System Upgrades	n/a		Electric Utility Benefit
	Decreased Spot Market Energy Price	AUB_{LBMP}	$ 75,867,690	Incentives to DER Customers	n/a		
		Sub-Total	$ 239,727,168		Sub-Total	$ 222,417,428	$ 17,309,740.00
Natural Gas Utility (Supply & Dist)	Increased Natural Gas Sales @ Industrial Rate	ACC_{Fuel} - ACB_F	$ 25,346,006	Increased Adjustment Credits for Power Generation	AUC_{Fuel}	$ 10,797,472	Natural Gas Utility Benefit
		Sub-Total	$ 25,346,006		Sub-Total	$ 10,797,472	$ 14,548,534.00
Society	Avoided Installed Capacity Values	ASB_{Cap}	$ 10,323,680	NYISO UCAP Auction	ASC_{UCAP}	$ 6,622,000	
	Emission "Damage Costs"	ASB_{Emis}	$ 3,242,910			$ -	
	Incresed Reliability LOLE		$ -			$ -	Society Benefit
		Sub-Total	$ 13,566,590		Sub-Total	$ 6,622,000	$ 6,944,590.00
	Total Benefits:		$ 505,166,493	Total Cost:		$ 452,602,823	$ 52,563,670
					Net Benefit Per Year		$ 52,563,670
					Net benefit (per kW-yr)		$873 /kW-yr

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	Benefits/Income			Costs/Expenses			
Customer	Annual Electricity Bill Savings (Avoided Charges from old rate based on full customer capacity)	**Energy ACB_E**	$ 74,899,251	New Annual Electric Bill (full customer capacity-DG) @ Standby rate	**Energy ACC_E**	$ 14,503,855	
		Demand ACB_D	$ 36,990,000		**Actual Demand ACC_D**	$ 9,435,600	
					Contract Demand ACC_{CD}	$ 38,810,690	
				Annual Capital Cost	ACC_{CAP}	$ 13,487,383	
	Annual Avoided Fuel Costs (Boiler Fuel, Industria rate)	ACB_F	$ 12,536,650	Increased Annual Fuel Cost (DG-CHP, Generator rate)	ACC_{Fuel}	$ 37,882,656	
	Energy Sale back to Grid	n/a	$ -	Annual O&M Cost	$ACC_{O\&M}$	$ 4,816,000	Customer Benefit
	NYISO UCAP Auction Payment	ACB_{UCAP}	$ 6,622,000	Interconnection Charges	ACC_{IC}	$ 93,240	
		Sub-Total	$ 131,047,901		Sub-Total	$ 119,029,424	$ 12,018,477.00
Electric Utility *	Annual Electric Standby (full facility capacity - CHP)	**ACC_E +ACC_D +ACC_{CD}**	$ 62,750,145	Annual Electric Sales (full customer capacity @ old rate)	**ACB_E +ACB_D**	$ 111,889,251	
				Cost of Providing Standby Service	**ACC_{CD}**	$ 38,810,690	
	Avoided Transmission Investments	AUB_T	$ 2,415,224				
	Avoided Distribution Investments	AUB_D	$ 5,032,720	System Upgrades	n/a		Electric Utility Benefit
	Decreased Spot Market Energy Price	AUB_{LBMP}	$ 75,867,690	Incentives to DER Customers	n/a		
		Sub-Total	$ 146,065,779		Sub-Total	$ 150,699,941	$ (4,634,162.00)
Natural Gas Utility (Supply & Dist)	Increased Natural Gas Sales @ Industrial Rate	ACC_{Fuel} - ACB_F	$ 25,346,006	Increased Adjustment Credits for Power Generation	AUC_{Fuel}	$ 10,797,472	Natural Gas Utility Benefit
		Sub-Total	$ 25,346,006		Sub-Total	$ 10,797,472	$ 14,548,534.00
Society	Avoided Installed Capacity Values	ASB_{Cap}	$ 10,323,680	NYISO UCAP Auction	ASC_{UCAP}	$ 6,622,000	
	Emission "Damage Costs"	ASB_{Emis}	$ 3,242,910			$ -	
	Incresed Reliability LOLE		$ -			$ -	Society Benefit
		Sub-Total	$ 13,566,590		Sub-Total	$ 6,622,000	$ 6,944,590.00
	Total Benefits:		$ 316,026,276	Total Cost:		$ 287,148,837	$ 28,877,439
					Net Benefit Per Year		$ 28,877,439
					Net benefit (per kW-yr)		$480 /kW-yr

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	Benefits/Income			Costs/Expenses			
Customer	Annual Electricity Bill Savings (Avoided Charges from old rate based on full customer capacity)	**Energy ACB_E**	$ 998,656,680	New Annual Electric Bill (full customer capacity-DG) @ Standby rate	**Energy ACC_E**	$ 848,858,178	
		Demand ACB_D	$ 493,200,000		**Actual Demand ACC_D**	$ 421,260,000	
					Contract Demand ACC_{CD}	$ -	
				Annual Capital Cost	ACC_{CAP}	$ 67,212,872	
	Annual Avoided Fuel Costs (Boiler Fuel, Industria rate)	ACB_F	$ 62,475,000	Increased Annual Fuel Cost (DG-CHP, Generator rate)	ACC_{Fuel}	$ 188,784,000	Customer Benefit
	Energy Sale back to Grid	n/a	$ -	Annual O&M Cost	$ACC_{O\&M}$	$ 24,000,000	
	NYISO UCAP Auction Payment	ACB_{UCAP}	$ 33,000,000	Interconnection Charges	ACC_{IC}	$ 1,295,000	
		Sub-Total	$ 1,587,331,680		Sub-Total	$ 1,551,410,050	$ 35,921,630.00
Electric Utility *	Annual Electric Standby (full facility capacity - CHP)	**ACC_E +ACC_D +ACC_{CD}**	$ 1,270,118,178	Annual Electric Sales (full customer capacity @ old rate)	**ACB_E +ACB_D**	$ 1,491,856,680	
				Cost of Providing Standby Service	**ACC_{CD}**	$ -	
	Avoided Transmission Investments	AUB_T	$ 12,036,000				
	Avoided Distribution Investments	AUB_D	$ 25,080,000	System Upgrades	n/a		Electric Utility Benefit
	Decreased Spot Market Energy Price	AUB_{LBMP}	$ 362,030,994	Incentives to DER Customers	n/a		
		Sub-Total	$ 1,669,265,172		Sub-Total	$ 1,491,856,680	$ 177,408,492.00
Natural Gas Utility (Supply & Dist)	Increased Natural Gas Sales @ Industrial Rate	ACC_{Fuel} - ACB_F	$ 126,309,000	Increased Adjustment Credits for Power Generation	AUC_{Fuel}	$ 53,808,000	Natural Gas Utility Benefit
		Sub-Total	$ 126,309,000		Sub-Total	$ 53,808,000	$ 72,501,000.00
Society	Avoided Installed Capacity Values	ASB_{Cap}	$ 51,446,945	NYISO UCAP Auction	ASC_{UCAP}	$ 33,000,000	
	Emission "Damage Costs"	ASB_{Emis}	$ 16,160,686			$ -	
	Incresed Reliability LOLE		$ -			$ -	Society Benefit
		Sub-Total	$ 67,607,631		Sub-Total	$ 33,000,000	$ 34,607,631.00
	Total Benefits:		$ 3,450,513,483	Total Cost:		$ 3,130,074,730	$ 320,438,753
					Net Benefit Per Year		$ 320,438,753
					Net benefit (per kW-yr)		$1,068 /kW-yr

300000 case 2-b

	Benefits/Income			Costs/Expenses			
Customer	Annual Electricity Bill Savings (Avoided Charges from old rate based on full customer capacity)	**Energy** **ACB_E**	$ 686,576,468	New Annual Electric Bill (full customer capacity-DG) @ Standby rate	**Energy** **ACC_E**	$ 460,688,726	
		Demand **ACB_D**	$ 339,075,000		**Actual Demand** **ACC_D**	$ 234,219,000	
					Contract Demand **ACC_{CD}**	$ 75,777,646	
				Annual Capital Cost	ACC_{CAP}	$ 67,212,872	
	Annual Avoided Fuel Costs (Boiler Fuel, Industria rate)	ACB_F	$ 62,475,000	Increased Annual Fuel Cost (DG-CHP, Generator rate)	ACC_{Fuel}	$ 188,784,000	
	Energy Sale back to Grid	n/a	$ -	Annual O&M Cost	$ACC_{O\&M}$	$ 24,000,000	Customer Benefit
	NYISO UCAP Auction Payment	ACB_{UCAP}	$ 33,000,000	Interconnection Charges	ACC_{IC}	$ 830,095	
		Sub-Total	$ 1,121,126,468		Sub-Total	$ 1,051,512,339	$ 69,614,129.00
Electric Utility *	Annual Electric Standby (full facility capacity - CHP)	**ACC_E +ACC_D +ACC_{CD}**	$ 770,685,372	Annual Electric Sales (full customer capacity @ old rate)	**ACB_E +ACB_D**	$ 1,025,651,468	
				Cost of Providing Standby Service	**ACC_{CD}**	$ 75,777,646	
	Avoided Transmission Investments	AUB_T	$ 12,036,000				
	Avoided Distribution Investments	AUB_D	$ 25,080,000	System Upgrades	n/a		Electric Utility Benefit
	Decreased Spot Market Energy Price	AUB_{LBMP}	$ 362,030,994	Incentives to DER Customers	n/a		
		Sub-Total	$ 1,169,832,366		Sub-Total	$ 1,101,429,114	$ 68,403,252.00
Natural Gas Utility (Supply & Dist)	Increased Natural Gas Sales @ Industrial Rate	ACC_{Fuel} - ACB_F	$ 126,309,000	Increased Adjustment Credits for Power Generation	AUC_{Fuel}	$ 53,808,000	Natural Gas Utility Benefit
		Sub-Total	$ 126,309,000		Sub-Total	$ 53,808,000	$ 72,501,000.00
Society	Avoided Installed Capacity Values	ASB_{Cap}	$ 51,446,945	NYISO UCAP Auction	ASC_{UCAP}	$ 33,000,000	
	Emission "Damage Costs"	ASB_{Emis}	$ 16,160,686			$ -	
	Incresed Reliability LOLE		$ -			$ -	Society Benefit
		Sub-Total	$ 67,607,631		Sub-Total	$ 33,000,000	$ 34,607,631.00
	Total Benefits:		$ 2,484,875,465	Total Cost:		$ 2,239,749,453	$ 245,126,012
					Net Benefit Per Year		$ 245,126,012
					Net benefit (per kW-yr)		$817 /kW-yr

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	Benefits/Income			Costs/Expenses			
Customer	Annual Electricity Bill Savings (Avoided Charges from old rate based on full customer capacity)	**Energy ACB_E**	$ 374,496,255	New Annual Electric Bill (full customer capacity-DG) @ Standby rate	**Energy ACC_E**	$ 72,519,275	
		Demand ACB_D	$ 184,950,000		**Actual Demand ACC_D**	$ 47,178,000	
					Contract Demand ACC_{CD}	$ 177,708,006	
				Annual Capital Cost	ACC_{CAP}	$ 67,212,872	
	Annual Avoided Fuel Costs (Boiler Fuel, Industria rate)	ACB_F	$ 62,475,000	Increased Annual Fuel Cost (DG-CHP, Generator rate)	ACC_{Fuel}	$ 188,784,000	Customer Benefit
	Energy Sale back to Grid	n/a	$ -	Annual O&M Cost	$ACC_{O\&M}$	$ 24,000,000	
	NYISO UCAP Auction Payment	ACB_{UCAP}	$ 33,000,000	Interconnection Charges	ACC_{IC}	$ 427,350	
		Sub-Total	$ 654,921,255		Sub-Total	$ 577,829,503	$ 77,091,752.00
Electric Utility *	Annual Electric Standby (full facility capacity - CHP)	**ACC_E $+ACC_D$ $+ACC_{CD}$**	$ 297,405,281	Annual Electric Sales (full customer capacity @ old rate)	**ACB_E $+ACB_D$**	$ 559,446,255	
				Cost of Providing Standby Service	**ACC_{CD}**	$ 177,708,006	
	Avoided Transmission Investments	AUB_T	$ 12,036,000				
	Avoided Distribution Investments	AUB_D	$ 25,080,000	System Upgrades	n/a		Electric Utility Benefit
	Decreased Spot Market Energy Price	AUB_{LBMP}	$ 362,030,994	Incentives to DER Customers	n/a		
		Sub-Total	$ 696,552,275		Sub-Total	$ 737,154,261	$ (40,601,986.00)
Natural Gas Utility (Supply & Dist)	Increased Natural Gas Sales @ Industrial Rate	ACC_{Fuel} - ACB_F	$ 126,309,000	Increased Adjustment Credits for Power Generation	AUC_{Fuel}	$ 53,808,000	Natural Gas Utility Benefit
		Sub-Total	$ 126,309,000		Sub-Total	$ 53,808,000	$ 72,501,000.00
Society	Avoided Installed Capacity Values	ASB_{Cap}	$ 51,446,945	NYISO UCAP Auction	ASC_{UCAP}	$ 33,000,000	
	Emission "Damage Costs"	ASB_{Emis}	$ 16,160,686			$ -	
	Incresed Reliability LOLE		$ -			$ -	Society Benefit
		Sub-Total	$ 67,607,631		Sub-Total	$ 33,000,000	$ 34,607,631.00
	Total Benefits:		$ 1,545,390,161	Total Cost:		$ 1,401,791,764	$ 143,598,397
					Net Benefit Per Year		$ 143,598,397
					Net benefit (per kW-yr)		$479 /kW-yr

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	Benefits/Income			Costs/Expenses			
Customer	Annual Electricity Bill Savings (Avoided Charges from old rate based on full customer capacity)	**Energy ACB_{E}**	$ 1,997,313,360	New Annual Electric Bill (full customer capacity-DG) @ Standby rate	**Energy ACC_{E}**	$ 1,697,716,356	
		Demand ACB_{D}	$ 986,400,000		**Actual Demand ACC_{D}**	$ 842,520,000	
					Contract Demand ACC_{CD}	$ -	
				Annual Capital Cost	ACC_{CAP}	$ 134,425,744	
	Annual Avoided Fuel Costs (Boiler Fuel, Industria rate)	ACB_{F}	$ 124,950,000	Increased Annual Fuel Cost (DG-CHP, Generator rate)	ACC_{Fuel}	$ 377,568,000	Customer Benefit
	Energy Sale back to Grid	n/a	$ -	Annual O&M Cost	$ACC_{O\&M}$	$ 48,000,000	
	NYISO UCAP Auction Payment	ACB_{UCAP}	$ 66,000,000	Interconnection Charges	ACC_{IC}	$ 2,590,000	
		Sub-Total	$ 3,174,663,360		Sub-Total	$ 3,102,820,100	$ 71,843,260.00
Electric Utility *	Annual Electric Standby (full facility capacity - CHP)	**ACC_{E} +ACC_{D} +ACC_{CD}**	$ 2,540,236,356	Annual Electric Sales (full customer capacity @ old rate)	**ACB_{E} +ACB_{D}**	$ 2,983,713,360	
				Cost of Providing Standby Service	**ACC_{CD}**	$ -	
	Avoided Transmission Investments	AUB_{T}	$ 24,072,000				
	Avoided Distribution Investments	AUB_{D}	$ 50,160,000	System Upgrades	n/a		Electric Utility Benefit
	Decreased Spot Market Energy Price	AUB_{LBMP}	$ 690,668,646	Incentives to DER Customers	n/a		
		Sub-Total	$ 3,305,137,002		Sub-Total	$ 2,983,713,360	$ 321,423,642.00
Natural Gas Utility (Supply & Dist)	Increased Natural Gas Sales @ Industrial Rate	ACC_{Fuel} - ACB_{F}	$ 252,618,000	Increased Adjustment Credits for Power Generation	AUC_{Fuel}	$ 107,616,000	Natural Gas Utility Benefit
		Sub-Total	$ 252,618,000		Sub-Total	$ 107,616,000	$ 145,002,000.00
Society	Avoided Installed Capacity Values	ASB_{Cap}	$ 102,893,890	NYISO UCAP Auction	ASC_{UCAP}	$ 66,000,000	
	Emission "Damage Costs"	ASB_{Emis}	$ 32,321,372			$ -	
	Incresed Reliability LOLE		$ 320,000,000			$ -	Society Benefit
		Sub-Total	$ 455,215,262		Sub-Total	$ 66,000,000	$ 389,215,262.00
	Total Benefits:		$ 7,187,633,624	Total Cost:		$ 6,260,149,460	$ 927,484,164
					Net Benefit Per Year		$ 927,484,164
					Net benefit (per kW-yr)		$1,546 /kW-yr

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	Benefits/Income			Costs/Expenses			
Customer	Annual Electricity Bill Savings (Avoided Charges from old rate based on full customer capacity)	**Energy ACB_E**	$ 1,373,152,935	New Annual Electric Bill (full customer capacity-DG) @ Standby rate	**Energy ACC_E**	$ 921,377,453	
		Demand ACB_D	$ 678,150,000		**Actual Demand ACC_D**	$ 468,438,000	
					Contract Demand ACC_{CD}	$ 177,708,006	
				Annual Capital Cost	ACC_{CAP}	$ 134,425,744	
	Annual Avoided Fuel Costs (Boiler Fuel, Industria rate)	ACB_F	$ 124,950,000	Increased Annual Fuel Cost (DG-CHP, Generator rate)	ACC_{Fuel}	$ 377,568,000	
	Energy Sale back to Grid	n/a	$ -	Annual O&M Cost	$ACC_{O\&M}$	$ 48,000,000	Customer Benefit
	NYISO UCAP Auction Payment	ACB_{UCAP}	$ 66,000,000	Interconnection Charges	ACC_{IC}	$ 1,722,350	
		Sub-Total	$ 2,242,252,935		Sub-Total	$ 2,129,239,553	$ 113,013,382.00
Electric Utility *	Annual Electric Standby (full facility capacity - CHP)	**ACC_E +ACC_D +ACC_{CD}**	$ 1,567,523,459	Annual Electric Sales (full customer capacity @ old rate)	**ACB_E +ACB_D**	$ 2,051,302,935	
				Cost of Providing Standby Service	**ACC_{CD}**	$ 177,708,006	
	Avoided Transmission Investments	AUB_T	$ 24,072,000				
	Avoided Distribution Investments	AUB_D	$ 50,160,000	System Upgrades	n/a		
	Decreased Spot Market Energy Price	AUB_{LBMP}	$ 690,668,646	Incentives to DER Customers	n/a		Electric Utility Benefit
		Sub-Total	$ 2,332,424,105		Sub-Total	$ 2,229,010,941	$ 103,413,164.00
Natural Gas Utility (Supply & Dist)	Increased Natural Gas Sales @ Industrial Rate	ACC_{Fuel} - ACB_F	$ 252,618,000	Increased Adjustment Credits for Power Generation	AUC_{Fuel}	$ 107,616,000	Natural Gas Utility Benefit
		Sub-Total	$ 252,618,000		Sub-Total	$ 107,616,000	$ 145,002,000.00
Society	Avoided Installed Capacity Values	ASB_{Cap}	$ 102,893,890	NYISO UCAP Auction	ASC_{UCAP}	$ 66,000,000	
	Emission "Damage Costs"	ASB_{Emis}	$ 32,321,372			$ -	
	Incresed Reliability LOLE		$ 320,000,000			$ -	Society Benefit
		Sub-Total	$ 455,215,262		Sub-Total	$ 66,000,000	$ 389,215,262.00
	Total Benefits:		$ 5,282,510,302	Total Cost:		$ 4,531,866,494	$ 750,643,808
					Net Benefit Per Year		$ 750,643,808
					Net benefit (per kW-yr)		$1,251 /kW-yr

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	Benefits/Income			Costs/Expenses			
Customer	Annual Electricity Bill Savings (Avoided Charges from old rate based on full customer capacity)	**Energy ACB_E**	$ 748,992,510	New Annual Electric Bill (full customer capacity-DG) @ Standby rate	**Energy ACC_E**	$ 145,038,550	
		Demand ACB_D	$ 369,900,000		**Actual Demand ACC_D**	$ 94,356,000	
					Contract Demand ACC_{CD}	$ 378,299,636	
				Annual Capital Cost	ACC_{CAP}	$ 134,425,744	
	Annual Avoided Fuel Costs (Boiler Fuel, Industria rate)	ACB_F	$ 124,950,000	Increased Annual Fuel Cost (DG-CHP, Generator rate)	ACC_{Fuel}	$ 377,568,000	
	Energy Sale back to Grid	n/a	$ -	Annual O&M Cost	$ACC_{O\&M}$	$ 48,000,000	Customer Benefit
	NYISO UCAP Auction Payment	ACB_{UCAP}	$ 66,000,000	Interconnection Charges	ACC_{IC}	$ 909,090	
		Sub-Total	$ 1,309,842,510		Sub-Total	$ 1,178,597,020	$ 131,245,490.00
Electric Utility *	Annual Electric Standby (full facility capacity - CHP)	**ACC_E +ACC_D +ACC_{CD}**	$ 617,694,186	Annual Electric Sales (full customer capacity @ old rate)	**ACB_E +ACB_D**	$ 1,118,892,510	
				Cost of Providing Standby Service	**ACC_{CD}**	$ 378,299,636	
	Avoided Transmission Investments	AUB_T	$ 24,072,000				
	Avoided Distribution Investments	AUB_D	$ 50,160,000	System Upgrades	n/a		
	Decreased Spot Market Energy Price	AUB_{LBMP}	$ 690,668,646	Incentives to DER Customers	n/a		Electric Utility Benefit
		Sub-Total	$ 1,382,594,832		Sub-Total	$ 1,497,192,146	$ (114,597,314.00)
Natural Gas Utility (Supply & Dist)	Increased Natural Gas Sales @ Industrial Rate	ACC_{Fuel} - ACB_F	$ 252,618,000	Increased Adjustment Credits for Power Generation	AUC_{Fuel}	$ 107,616,000	Natural Gas Utility Benefit
		Sub-Total	$ 252,618,000		Sub-Total	$ 107,616,000	$ 145,002,000.00
Society	Avoided Installed Capacity Values	ASB_{Cap}	$ 102,893,890	NYISO UCAP Auction	ASC_{UCAP}	$ 66,000,000	
	Emission "Damage Costs"	ASB_{Emis}	$ 32,321,372			$ -	
	Incresed Reliability LOLE		$ 320,000,000			$ -	Society Benefit
		Sub-Total	$ 455,215,262		Sub-Total	$ 66,000,000	$ 389,215,262.00
	Total Benefits:		$ 3,400,270,604	Total Cost:		$ 2,849,405,166	$ 550,865,438
					Net Benefit Per Year		$ 550,865,438
					Net benefit (per kW-yr)		$918 /kW-yr

	Bilateral Contracts						
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	Benefits/Income			Costs/Expenses			
Customer	Annual Electricity Bill Savings (Avoided Charges from old rate based on full customer capacity)	**Energy ACB_{E}**	$ 99,865,668	New Annual Electric Bill (full customer capacity-DG) @ Standby rate	**Energy ACC_{E}**	$ 84,885,818	
		Demand ACB_{D}	$ 49,320,000		**Actual Demand ACC_{D}**	$ 42,126,000	
					Contract Demand ACC_{CD}	$ -	
				Annual Capital Cost	ACC_{CAP}	$ 13,487,383	
	Annual Avoided Fuel Costs (Boiler Fuel, Industria rate)	ACB_{F}	$ 12,536,650	Increased Annual Fuel Cost (DG-CHP, Generator rate)	ACC_{Fuel}	$ 37,882,656	
	Energy Sale back to Grid	n/a	$ -	Annual O&M Cost	$ACC_{O\&M}$	$ 4,816,000	Customer Benefit
	NYISO UCAP Auction Payment	ACB_{UCAP}	$ 6,622,000	Interconnection Charges	ACC_{IC}	$ 259,000	
		Sub-Total	$ 168,344,318		Sub-Total	$ 183,456,857	$ (15,112,539.00)
Electric Utility *	Annual Electric Standby (full facility capacity - CHP)	**ACC_{E} +ACC_{D} +ACC_{CD}**	$ 127,011,818	Annual Electric Sales (full customer capacity @ old rate)	**ACB_{E} +ACB_{D}**	$ 149,185,668	
				Cost of Providing Standby Service	**ACC_{CD}**	$ -	
	Avoided Transmission Investments	AUB_{T}	$ 2,415,224				
	Avoided Distribution Investments	AUB_{D}	$ 5,032,720	System Upgrades	n/a		
	Decreased Spot Market Energy Price	AUB_{LBMP}	$ 75,867,690	Incentives to DER Customers	n/a		Electric Utility Benefit
		Sub-Total	$ 210,327,452		Sub-Total	$ 149,185,668	$ 61,141,784.00
Natural Gas Utility (Supply & Dist)	Increased Natural Gas Sales @ Industrial Rate	ACC_{Fuel} - ACB_{F}	$ 25,346,006	Increased Wholesale Purchase		$ 10,797,472	Natural Gas Utility Benefit
		Sub-Total	$ 25,346,006		Sub-Total	$ 10,797,472	$ 14,548,534.00
Society	Avoided Installed Capacity Values	ASB_{Cap}	$ 10,323,680	NYISO UCAP Auction	ASC_{UCAP}	$ 6,622,000	
	Emission "Damage Costs"	ASB_{Emis}	$ 3,242,910			$ -	
	Incresed Reliability LOLE		$ -			$ -	Society Benefit
		Sub-Total	$ 13,566,590		Sub-Total	$ 6,622,000	$ 6,944,590.00
	Total Benefits:		$ 417,584,366	Total Cost:		$ 350,061,997	$ 67,522,369
					Net Benefit Per Year		$ 67,522,369
					Net benefit (per kW-yr)		$1,122 /kW-yr

	Bilateral Contracts						
60200	case 1-b						
	Benefits/Income			Costs/Expenses			
Customer	Annual Electricity Bill Savings (Avoided Charges from old rate based on full customer capacity)	**Energy ACB_E**	$ 69,406,640	New Annual Electric Bill (full customer capacity-DG) @ Standby rate	**Energy ACC_E**	$ 46,869,385	
		Demand ACB_D	$ 34,277,400		**Actual Demand ACC_D**	$ 23,811,708	
					Contract Demand ACC_{CD}	$ 7,524,675	
				Annual Capital Cost	ACC_{CAP}	$ 13,487,383	
	Annual Avoided Fuel Costs (Boiler Fuel, Industria rate)	ACB_F	$ 12,536,650	Increased Annual Fuel Cost (DG-CHP, Generator rate)	ACC_{Fuel}	$ 37,882,656	
	Energy Sale back to Grid	n/a	$ -	Annual O&M Cost	$ACC_{O\&M}$	$ 4,816,000	Customer Benefit
	NYISO UCAP Auction Payment	ACB_{UCAP}	$ 6,622,000	Interconnection Charges	ACC_{IC}	$ 168,350	
		Sub-Total	$ 122,842,690		Sub-Total	$ 134,560,156	$ (11,717,466.50)
Electric Utility *	Annual Electric Standby (full facility capacity - CHP)	**ACC_E +ACC_D +ACC_{CD}**	$ 78,205,767	Annual Electric Sales (full customer capacity @ old rate)	**ACB_E +ACB_D**	$ 103,684,040	
				Cost of Providing Standby Service	**ACC_{CD}**	$ 7,524,675	
	Avoided Transmission Investments	AUB_T	$ 2,415,224				
	Avoided Distribution Investments	AUB_D	$ 5,032,720	System Upgrades	n/a		Electric Utility Benefit
	Decreased Spot Market Energy Price	AUB_{LBMP}	$ 75,867,690	Incentives to DER Customers	n/a		
		Sub-Total	$ 161,521,401		Sub-Total	$ 111,208,714	$ 50,312,687.00
Natural Gas Utility (Supply & Dist)	Increased Natural Gas Sales @ Industrial Rate	ACC_{Fuel} - ACB_F	$ 25,346,006	Increased Wholesale Purchase		$ 10,797,472	Natural Gas Utility Benefit
		Sub-Total	$ 25,346,006		Sub-Total	$ 10,797,472	$ 14,548,534.00
Society	Avoided Installed Capacity Values	ASB_{Cap}	$ 10,323,680	NYISO UCAP Auction	ASC_{UCAP}	$ 6,622,000	
	Emission "Damage Costs"	ASB_{Emis}	$ 3,242,910			$ -	
	Incresed Reliability LOLE		$ -			$ -	Society Benefit
		Sub-Total	$ 13,566,590		Sub-Total	$ 6,622,000	$ 6,944,590.00
	Total Benefits:		$ 323,276,687	Total Cost:		$ 263,188,342	$ 60,088,345
					Net Benefit Per Year		$ 60,088,345
					Net benefit (per kW-yr)		$998 /kW-yr

Bilateral Contracts

60200 case 1-c

	Benefits/Income			Costs/Expenses			
Customer	Annual Electricity Bill Savings (Avoided Charges from old rate based on full customer capacity)	**Energy ACB_E**	$ 37,449,626	New Annual Electric Bill (full customer capacity-DG) @ Standby rate	**Energy ACC_E**	$ 7,251,928	
		Demand ACB_D	$ 18,495,000		**Actual Demand ACC_D**	$ 4,717,800	
					Contract Demand ACC_{CD}	$ 19,405,345	
				Annual Capital Cost	ACC_{CAP}	$ 13,487,383	
	Annual Avoided Fuel Costs (Boiler Fuel, Industria rate)	ACB_F	$ 12,536,650	Increased Annual Fuel Cost (DG-CHP, Generator rate)	ACC_{Fuel}	$ 37,882,656	Customer Benefit
	Energy Sale back to Grid	n/a	$ -	Annual O&M Cost	$ACC_{O\&M}$	$ 4,816,000	
	NYISO UCAP Auction Payment	ACB_{UCAP}	$ 6,622,000	Interconnection Charges	ACC_{IC}	$ 93,240	
		Sub-Total	$ 75,103,276		Sub-Total	$ 87,654,352	$ (12,551,076.00)
Electric Utility *	Annual Electric Standby (full facility capacity - CHP)	**ACC_E +ACC_D +ACC_{CD}**	$ 31,375,073	Annual Electric Sales (full customer capacity @ old rate)	**ACB_E +ACB_D**	$ 55,944,626	
				Cost of Providing Standby Service	**ACC_{CD}**	$ 19,405,345	
	Avoided Transmission Investments	AUB_T	$ 2,415,224				
	Avoided Distribution Investments	AUB_D	$ 5,032,720	System Upgrades	n/a		Electric Utility Benefit
	Decreased Spot Market Energy Price	AUB_{LBMP}	$ 75,867,690	Incentives to DER Customers	n/a		
		Sub-Total	$ 114,690,707		Sub-Total	$ 75,349,971	$ 39,340,736.00
Natural Gas Utility (Supply & Dist)	Increased Natural Gas Sales @ Industrial Rate	ACC_{Fuel} - ACB_F	$ 25,346,006	Increased Wholesale Purchase		$ 10,797,472	Natural Gas Utility Benefit
		Sub-Total	$ 25,346,006		Sub-Total	$ 10,797,472	$ 14,548,534.00
Society	Avoided Installed Capacity Values	ASB_{Cap}	$ 10,323,680	NYISO UCAP Auction	ASC_{UCAP}	$ 6,622,000	
	Emission "Damage Costs"	ASB_{Emis}	$ 3,242,910			$ -	
	Incresed Reliability LOLE		$ -			$ -	Society Benefit
		Sub-Total	$ 13,566,590		Sub-Total	$ 6,622,000	$ 6,944,590.00
	Total Benefits:		$ 228,706,578	Total Cost:		$ 180,423,794	$ 48,282,784
					Net Benefit Per Year		$ 48,282,784
					Net benefit (per kW-yr)		$802 /kW-yr

Bilateral Contracts

300000 case 2-a

	Benefits/Income			Costs/Expenses			
Customer	Annual Electricity Bill Savings (Avoided Charges from old rate based on full customer capacity)	**Energy ACB_E**	$ 499,328,340	New Annual Electric Bill (full customer capacity-DG) @ Standby rate	**Energy ACC_E**	$ 424,429,089	
		Demand ACB_D	$ 246,600,000		**Actual Demand ACC_D**	$ 210,630,000	
					Contract Demand ACC_{CD}	$ -	
				Annual Capital Cost	ACC_{CAP}	$ 67,212,872	
	Annual Avoided Fuel Costs (Boiler Fuel, Industria rate)	ACB_F	$ 62,475,000	Increased Annual Fuel Cost (DG-CHP, Generator rate)	ACC_{Fuel}	$ 188,784,000	
	Energy Sale back to Grid	n/a	$ -	Annual O&M Cost	$ACC_{O\&M}$	$ 24,000,000	Customer Benefit
	NYISO UCAP Auction Payment	ACB_{UCAP}	$ 33,000,000	Interconnection Charges	ACC_{IC}	$ 1,295,000	
		Sub-Total	$ 841,403,340		Sub-Total	$ 916,350,961	$ (74,947,621.00)
Electric Utility *	Annual Electric Standby (full facility capacity - CHP)	**ACC_E +ACC_D +ACC_{CD}**	$ 635,059,089	Annual Electric Sales (full customer capacity @ old rate)	**ACB_E +ACB_D**	$ 745,928,340	
				Cost of Providing Standby Service	**ACC_{CD}**	$ -	
	Avoided Transmission Investments	AUB_T	$ 12,036,000				
	Avoided Distribution Investments	AUB_D	$ 25,080,000	System Upgrades	n/a		Electric Utility Benefit
	Decreased Spot Market Energy Price	AUB_{LBMP}	$ 362,030,994	Incentives to DER Customers	n/a		
		Sub-Total	$ 1,034,206,083		Sub-Total	$ 745,928,340	$ 288,277,743.00
Natural Gas Utility (Supply & Dist)	Increased Natural Gas Sales @ Industrial Rate	ACC_{Fuel} - ACB_F	$ 126,309,000	Increased Wholesale Purchase		$ 53,808,000	Natural Gas Utility Benefit
		Sub-Total	$ 126,309,000		Sub-Total	$ 53,808,000	$ 72,501,000.00
Society	Avoided Installed Capacity Values	ASB_{Cap}	$ 51,446,945	NYISO UCAP Auction	ASC_{UCAP}	$ 33,000,000	
	Emission "Damage Costs"	ASB_{Emis}	$ 16,160,686			$ -	
	Incresed Reliability LOLE		$ -			$ -	Society Benefit
		Sub-Total	$ 67,607,631		Sub-Total	$ 33,000,000	$ 34,607,631.00
	Total Benefits:		$ 2,069,526,054	Total Cost:		$ 1,749,087,301	$ 320,438,753
					Net Benefit Per Year		$ 320,438,753
					Net benefit (per kW-yr)		$1,068 /kW-yr

Bilateral Contracts

300000 case 2-b

	Benefits/Income			Costs/Expenses			
Customer	Annual Electricity Bill Savings (Avoided Charges from old rate based on full customer capacity)	**Energy ACB_E**	$ 343,288,234	New Annual Electric Bill (full customer capacity-DG) @ Standby rate	**Energy ACC_E**	$ 230,344,363	
		Demand ACB_D	$ 169,537,500		**Actual Demand ACC_D**	$ 117,109,500	
					Contract Demand ACC_{CD}	$ 37,888,823	
				Annual Capital Cost	ACC_{CAP}	$ 67,212,872	
	Annual Avoided Fuel Costs (Boiler Fuel, Industria rate)	ACB_F	$ 62,475,000	Increased Annual Fuel Cost (DG-CHP, Generator rate)	ACC_{Fuel}	$ 188,784,000	
	Energy Sale back to Grid	n/a	$ -	Annual O&M Cost	$ACC_{O\&M}$	$ 24,000,000	Customer Benefit
	NYISO UCAP Auction Payment	ACB_{UCAP}	$ 33,000,000	Interconnection Charges	ACC_{IC}	$ 830,095	
		Sub-Total	$ 608,300,734		Sub-Total	$ 666,169,653	$ (57,868,919.00)
Electric Utility *	Annual Electric Standby (full facility capacity - CHP)	**ACC_E +ACC_D +ACC_{CD}**	$ 385,342,686	Annual Electric Sales (full customer capacity @ old rate)	**ACB_E +ACB_D**	$ 512,825,734	
				Cost of Providing Standby Service	**ACC_{CD}**	$ 37,888,823	
	Avoided Transmission Investments	AUB_T	$ 12,036,000				
	Avoided Distribution Investments	AUB_D	$ 25,080,000	System Upgrades	n/a		
	Decreased Spot Market Energy Price	AUB_{LBMP}	$ 362,030,994	Incentives to DER Customers	n/a		Electric Utility Benefit
		Sub-Total	$ 784,489,680		Sub-Total	$ 550,714,557	$ 233,775,123.00
Natural Gas Utility (Supply & Dist)	Increased Natural Gas Sales @ Industrial Rate	ACC_{Fuel} - ACB_F	$ 126,309,000	Increased Wholesale Purchase		$ 53,808,000	Natural Gas Utility Benefit
		Sub-Total	$ 126,309,000		Sub-Total	$ 53,808,000	$ 72,501,000.00
Society	Avoided Installed Capacity Values	ASB_{Cap}	$ 51,446,945	NYISO UCAP Auction	ASC_{UCAP}	$ 33,000,000	
	Emission "Damage Costs"	ASB_{Emis}	$ 16,160,686			$ -	
	Incresed Reliability LOLE		$ -			$ -	Society Benefit
		Sub-Total	$ 67,607,631		Sub-Total	$ 33,000,000	$ 34,607,631.00
	Total Benefits:		$ 1,586,707,045	Total Cost:		$ 1,303,692,210	$ 283,014,835
					Net Benefit Per Year		$ 283,014,835
					Net benefit (per kW-yr)		$943 /kW-yr

	Bilateral Contracts						
300000	case 2-c						
	Benefits/Income			Costs/Expenses			
Customer	Annual Electricity Bill Savings (Avoided Charges from old rate based on full customer capacity)	**Energy ACB_E**	\$ 187,248,128	New Annual Electric Bill (full customer capacity-DG) @ Standby rate	**Energy ACC_E**	\$ 36,259,638	
		Demand ACB_D	\$ 92,475,000		**Actual Demand ACC_D**	\$ 23,589,000	
					Contract Demand ACC_{CD}	\$ 88,854,003	
				Annual Capital Cost	ACC_{CAP}	\$ 67,212,872	
	Annual Avoided Fuel Costs (Boiler Fuel, Industria rate)	ACB_F	\$ 62,475,000	Increased Annual Fuel Cost (DG-CHP, Generator rate)	ACC_{Fuel}	\$ 188,784,000	
	Energy Sale back to Grid	n/a	\$ -	Annual O&M Cost	$ACC_{O\&M}$	\$ 24,000,000	Customer Benefit
	NYISO UCAP Auction Payment	ACB_{UCAP}	\$ 33,000,000	Interconnection Charges	ACC_{IC}	\$ 427,350	
		Sub-Total	\$ 375,198,128		Sub-Total	\$ 429,126,863	\$ (53,928,735.00)
Electric Utility *	Annual Electric Standby (full facility capacity - CHP)	**ACC_E $+ACC_D$ $+ACC_{CD}$**	\$ 148,702,641	Annual Electric Sales (full customer capacity @ old rate)	**ACB_E $+ACB_D$**	\$ 279,723,128	
				Cost of Providing Standby Service	**ACC_{CD}**	\$ 88,854,003	
	Avoided Transmission Investments	AUB_T	\$ 12,036,000				
	Avoided Distribution Investments	AUB_D	\$ 25,080,000	System Upgrades	n/a		Electric Utility Benefit
	Decreased Spot Market Energy Price	AUB_{LBMP}	\$ 362,030,994	Incentives to DER Customers	n/a		
		Sub-Total	\$ 547,849,635		Sub-Total	\$ 368,577,131	\$ 179,272,504.00
Natural Gas Utility (Supply & Dist)	Increased Natural Gas Sales @ Industrial Rate	ACC_{Fuel} - ACB_F	\$ 126,309,000	Increased Wholesale Purchase		\$ 53,808,000	Natural Gas Utility Benefit
		Sub-Total	\$ 126,309,000		Sub-Total	\$ 53,808,000	\$ 72,501,000.00
Society	Avoided Installed Capacity Values	ASB_{Cap}	\$ 51,446,945	NYISO UCAP Auction	ASC_{UCAP}	\$ 33,000,000	
	Emission "Damage Costs"	ASB_{Emis}	\$ 16,160,686			\$ -	
	Incresed Reliability LOLE		\$ -			\$ -	Society Benefit
		Sub-Total	\$ 67,607,631		Sub-Total	\$ 33,000,000	\$ 34,607,631.00
	Total Benefits:		\$ 1,116,964,393	Total Cost:		\$ 884,511,993	\$ 232,452,400
					Net Benefit Per Year		\$ 232,452,400
					Net benefit (per kW-yr)		\$775 /kW-yr

	Bilateral Contracts						
600000	case 3-a						
	Benefits/Income			Costs/Expenses			
Customer	Annual Electricity Bill Savings (Avoided Charges from old rate based on full customer capacity)	**Energy ACB_E**	\$ 998,656,680	New Annual Electric Bill (full customer capacity-DG) @ Standby rate	**Energy ACC_E**	\$ 848,858,178	
		Demand ACB_D	\$ 493,200,000		**Actual Demand ACC_D**	\$ 421,260,000	
					Contract Demand ACC_{CD}	\$ -	
				Annual Capital Cost	ACC_{CAP}	\$ 134,425,744	
	Annual Avoided Fuel Costs (Boiler Fuel, Industria rate)	ACB_F	\$ 124,950,000	Increased Annual Fuel Cost (DG-CHP, Generator rate)	ACC_{Fuel}	\$ 377,568,000	
	Energy Sale back to Grid	n/a	\$ -	Annual O&M Cost	$ACC_{O\&M}$	\$ 48,000,000	Customer Benefit
	NYISO UCAP Auction Payment	ACB_{UCAP}	\$ 66,000,000	Interconnection Charges	ACC_{IC}	\$ 2,590,000	
		Sub-Total	\$ 1,682,806,680		Sub-Total	\$ 1,832,701,922	\$ (149,895,242.00)
Electric Utility *	Annual Electric Standby (full facility capacity - CHP)	**ACC_E +ACC_D +ACC_{CD}**	\$ 1,270,118,178	Annual Electric Sales (full customer capacity @ old rate)	**ACB_E +ACB_D**	\$ 1,491,856,680	
				Cost of Providing Standby Service	**ACC_{CD}**	\$ -	
	Avoided Transmission Investments	AUB_T	\$ 24,072,000				
	Avoided Distribution Investments	AUB_D	\$ 50,160,000	System Upgrades	n/a		Electric Utility Benefit
	Decreased Spot Market Energy Price	AUB_{LBMP}	\$ 690,668,646	Incentives to DER Customers	n/a		
		Sub-Total	\$ 2,035,018,824		Sub-Total	\$ 1,491,856,680	\$ 543,162,144.00
Natural Gas Utility (Supply & Dist)	Increased Natural Gas Sales @ Industrial Rate	ACC_{Fuel} - ACB_F	\$ 252,618,000	Increased Wholesale Purchase		\$ 107,616,000	Natural Gas Utility Benefit
		Sub-Total	\$ 252,618,000		Sub-Total	\$ 107,616,000	\$ 145,002,000.00
Society	Avoided Installed Capacity Values	ASB_{Cap}	\$ 102,893,890	NYISO UCAP Auction	ASC_{UCAP}	\$ 66,000,000	
	Emission "Damage Costs"	ASB_{Emis}	\$ 32,321,372			\$ -	
	Incresed Reliability LOLE		\$ 320,000,000			\$ -	Society Benefit
		Sub-Total	\$ 455,215,262		Sub-Total	\$ 66,000,000	\$ 389,215,262.00
	Total Benefits:		\$ 4,425,658,766	Total Cost:		\$ 3,498,174,602	\$ 927,484,164
					Net Benefit Per Year		\$ 927,484,164
					Net benefit (per kW-yr)		\$1,546 /kW-yr

	Bilateral Contracts						
600000	case 3-b						
	Benefits/Income			Costs/Expenses			
Customer	Annual Electricity Bill Savings (Avoided Charges from old rate based on full customer capacity)	**Energy ACB_E**	$ 686,576,468	New Annual Electric Bill (full customer capacity-DG) @ Standby rate	**Energy ACC_E**	$ 460,688,727	
		Demand ACB_D	$ 339,075,000		**Actual Demand ACC_D**	$ 234,219,000	
					Contract Demand ACC_{CD}	$ 88,854,003	
				Annual Capital Cost	ACC_{CAP}	$ 134,425,744	
	Annual Avoided Fuel Costs (Boiler Fuel, Industria rate)	ACB_F	$ 124,950,000	Increased Annual Fuel Cost (DG-CHP, Generator rate)	ACC_{Fuel}	$ 377,568,000	
	Energy Sale back to Grid	n/a	$ -	Annual O&M Cost	$ACC_{O\&M}$	$ 48,000,000	Customer Benefit
	NYISO UCAP Auction Payment	ACB_{UCAP}	$ 66,000,000	Interconnection Charges	ACC_{IC}	$ 1,722,350	
		Sub-Total	$ 1,216,601,468		Sub-Total	$ 1,345,477,824	$ (128,876,356.00)
Electric Utility *	Annual Electric Standby (full facility capacity - CHP)	**ACC_E +ACC_D +ACC_{CD}**	$ 783,761,730	Annual Electric Sales (full customer capacity @ old rate)	**ACB_E +ACB_D**	$ 1,025,651,468	
				Cost of Providing Standby Service	**ACC_{CD}**	$ 88,854,003	
	Avoided Transmission Investments	AUB_T	$ 24,072,000				
	Avoided Distribution Investments	AUB_D	$ 50,160,000	System Upgrades	n/a		Electric Utility Benefit
	Decreased Spot Market Energy Price	AUB_{LBMP}	$ 690,668,646	Incentives to DER Customers	n/a		
		Sub-Total	$ 1,548,662,376		Sub-Total	$ 1,114,505,471	$ 434,156,905.00
Natural Gas Utility (Supply & Dist)	Increased Natural Gas Sales @ Industrial Rate	ACC_{Fuel} - ACB_F	$ 252,618,000	Increased Wholesale Purchase		$ 107,616,000	Natural Gas Utility Benefit
		Sub-Total	$ 252,618,000		Sub-Total	$ 107,616,000	$ 145,002,000.00
Society	Avoided Installed Capacity Values	ASB_{Cap}	$ 102,893,890	NYISO UCAP Auction	ASC_{UCAP}	$ 66,000,000	
	Emission "Damage Costs"	ASB_{Emis}	$ 32,321,372			$ -	
	Incresed Reliability LOLE		$ 320,000,000			$ -	Society Benefit
		Sub-Total	$ 455,215,262		Sub-Total	$ 66,000,000	$ 389,215,262.00
	Total Benefits:		$ 3,473,097,105	Total Cost:		$ 2,633,599,294	$ 839,497,811
					Net Benefit Per Year		$ 839,497,811
					Net benefit (per kW-yr)		$1,399 /kW-yr

Bilateral Contracts

600000 case 3-c

	Benefits/Income			Costs/Expenses			
Customer	Annual Electricity Bill Savings (Avoided Charges from old rate based on full customer capacity)	**Energy ACB_E**	$ 374,496,255	New Annual Electric Bill (full customer capacity-DG) @ Standby rate	**Energy ACC_E**	$ 72,519,275	
		Demand ACB_D	$ 184,950,000		**Actual Demand ACC_D**	$ 47,178,000	
					Contract Demand ACC_{CD}	$ 189,149,818	
				Annual Capital Cost	ACC_{CAP}	$ 134,425,744	
	Annual Avoided Fuel Costs (Boiler Fuel, Industria rate)	ACB_F	$ 124,950,000	Increased Annual Fuel Cost (DG-CHP, Generator rate)	ACC_{Fuel}	$ 377,568,000	
	Energy Sale back to Grid	n/a	$ -	Annual O&M Cost	$ACC_{O\&M}$	$ 48,000,000	Customer Benefit
	NYISO UCAP Auction Payment	ACB_{UCAP}	$ 66,000,000	Interconnection Charges	ACC_{IC}	$ 909,090	
		Sub-Total	$ 750,396,255		Sub-Total	$ 869,749,927	$ (119,353,672.00)
Electric Utility *	Annual Electric Standby (full facility capacity - CHP)	**ACC_E +ACC_D +ACC_{CD}**	$ 308,847,093	Annual Electric Sales (full customer capacity @ old rate)	**ACB_E +ACB_D**	$ 559,446,255	
				Cost of Providing Standby Service	**ACC_{CD}**	$ 189,149,818	
	Avoided Transmission Investments	AUB_T	$ 24,072,000				
	Avoided Distribution Investments	AUB_D	$ 50,160,000	System Upgrades	n/a		Electric Utility Benefit
	Decreased Spot Market Energy Price	AUB_{LBMP}	$ 690,668,646	Incentives to DER Customers	n/a		
		Sub-Total	$ 1,073,747,739		Sub-Total	$ 748,596,073	$ 325,151,666.00
Natural Gas Utility (Supply & Dist)	Increased Natural Gas Sales @ Industrial Rate	ACC_{Fuel} - ACB_F	$ 252,618,000	Increased Wholesale Purchase		$ 107,616,000	Natural Gas Utility Benefit
		Sub-Total	$ 252,618,000		Sub-Total	$ 107,616,000	$ 145,002,000.00
Society	Avoided Installed Capacity Values	ASB_{Cap}	$ 102,893,890	NYISO UCAP Auction	ASC_{UCAP}	$ 66,000,000	
	Emission "Damage Costs"	ASB_{Emis}	$ 32,321,372			$ -	
	Incresed Reliability LOLE		$ 320,000,000			$ -	Society Benefit
		Sub-Total	$ 455,215,262		Sub-Total	$ 66,000,000	$ 389,215,262.00
	Total Benefits:		$ 2,531,977,256	Total Cost:		$ 1,791,962,000	$ 740,015,256
					Net Benefit Per Year		$ 740,015,256
					Net benefit (per kW-yr)		$1,233 /kW-yr

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