Resource Insight, Inc.

Energy Plan

for the City of New York

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I. Executive Summary

New York City should be working toward the addition of at least 1,500 MW of new resources by 2008, beyond the 1,500 MW of resources the authors consider to be committed (see Table 22, below). In this effort the City should give priority to a large reduction in load from energy efficiency, distributed generation, and rate options. The remainder of the capacity requirement may be met by improved transmission connections to PJM and upstate New York, or combined-cycle and combustion turbine capacity located in or electrically connected to the City.

Failing to add any resources might well increase power-supply costs to City consumers by $600–800 million in 2008, or roughly 20–25%, compared to adding 1,500 MW of additional resources.

In most cases, commitments for resources to be added after 2008 need not be made for a couple more years. Those commitments should await developments in load, capacity, markets, prices, technology and regulation. The study suggests more general conceptual directions for later years.

This report stresses near-term decisions in the context of a long-term least-cost strategy for the City. The detailed analysis is performed for the year 2008, a horizon for which detailed planning must start in the near future. The year 2008 is also an appropriate period for analysis, since existing resources and those under construction are currently expected to be adequate to maintain reliable power supply through 2008, but not much longer.

This report identifies priorities, defines policies and guidelines for future actions, and provides insights into appropriate levels of commitment to various types of new resources. The authors do not attempt to develop recommendations regarding specific projects or program designs.

II. New York City Leads in Energy Efficiency

Energy-use data illustrate the principle that urban density permits energy efficiency (Energy Information Administration 2002 36–86 (Table 14)). City residents are the most efficient electricity consumers in the United States.

City residents consume less electricity per capita than the residents of any state (see Table 1) the customers of any other New York investor-owned utility (see Table 2), or the residents of any other major urban area (see Table 3).[1]

[1]A comparison of commercial and industrial use across utilities would be complicated by the lack of consistent units of activity (square footage, employees, GDP, sales, etc.) from utility to utility. The mix of activities also varies widely among commercial and industrial users.

Table 1: Residential Electricity Consumption—City, U.S. Average, and States

	Direct Residential Consumers, 2000[a]		
	Number of Consumers	Sales (MWh)	Average Usage (kWh)
New York City (Consolidated Edison)[b]	2,661,874	11,637,167	4,372
All U.S. (Fifty States)	110,505,820	1,183,137,429	10,707
New York	6,546,389	41,555,943	6,348
Rhode Island	413,746	2,664,399	6,440
New Hampshire	539,813	3,638,478	6,740
Massachusetts	2,524,406	17,534,355	6,946
California	10,953,845	78,011,108	7,122
Vermont	283,494	2,036,934	7,185
Michigan	4,099,051	30,700,485	7,490
New Jersey	3,143,146	24,064,446	7,656
Illinois	4,748,863	40,146,401	8,454
Connecticut	1,364,268	11,645,484	8,536
Pennsylvania	4,533,808	41,447,546	9,142
Ohio	4,684,127	46,488,137	9,925
Virginia	2,767,245	37,541,300	13,566
Texas	8,023,266	116,895,281	14,570

Source: U.S. Energy Information Administration (U.S. EIA 2002, 36–86 (Table 14)).

[a] *Excludes residential loads served through master meters on commercial rates.*

[b] *Consolidated Edison's service territory.*

The average New York City consumer uses approximately 43% less electricity than the average for the rest of New York State and 38% less than Niagara Mohawk consumers, the next-most efficient major New York utility.

Table 2: Comparison of Residential Consumption across New York State

	Direct Residential Consumers, 2000[a]		
	Number of Consumers	Sales (MWh)	Average Usage (kWh)
New York City (Consolidated Edison)[b]	2,661,874	11,637,167	4,372
Central Hudson Gas & Elec Corp	232,064	1,712,561	7,380
New York State Elec & Gas Corp	705,822	5,221,057	7,397
Niagara Mohawk Power Corp	1,391,591	9,838,852	7,070
Orange & Rockland Utils Inc.	165,990	1,231,851	7,421
Rochester Gas & Electric Corp	284,437	2,153,567	7,571
Long Island Power Authority	949,847	7,929,390	8,348
State Excluding Con Edison	3,884,515	29,918,776	7,702
State Total	6,546,389	41,555,943	6,348

Source: U.S. Energy Information Administration (U.S. EIA 2002, 36–86 (Table 14)).

[a]*Excludes residential loads served through master meters on commercial rates.*

[b]*Consolidated Edison's service territory.*

Other large urban metropolitan areas do not approach New York City's level of efficiency. Even the customers of the closest contender (Narragansett Electric) use 47% more electricity than Consolidated Edison's customers. The customers of Public Service Electric & Gas, across the Hudson, use 65% more electricity than New York City's consumers.

Table 3: Con Edison Compared to Utilities Serving Other U.S. Urban Areas[a]

	Direct Residential Consumers, 2000[b]		
	Number of Consumers	Sales (MWh)	Average Usage (kWh)
New York City (Consolidated Edison)	2,661,874	11,637,167	4,372
Providence (Narragansett Electric)	372,844	2,404,180	6,448
Cleveland (Cleveland Electric Illuminating)	372,450	2,403,471	6,453
Boston (Boston Edison)	589,410	3,896,825	6,611
Newark and Northern New Jersey (Public Service Electric & Gas)	284,955	2,056,367	7,216
Pittsburgh (Duquesne Light)	1,913,436	13,903,046	7,266
Chicago (Commonwealth Edison)	3,195,958	23,997,262	7,509
New Haven (United Illuminating)	667,838	5,060,993	7,578
Philadelphia (PECO Energy)	1,148,979	9,324,800	8,116
San Francisco (Pacific Gas & Electric)	3,477,734	28,256,305	8,125
Baltimore (Baltimore Gas & Electric)	1,028,519	11,674,592	11,351
Washington (Potomac Electric Power)	437,683	5,357,679	12,241

Source: U.S. Energy Information Administration (U.S. EIA 2002).

[a]*Each of these utilities serves both an urban core and suburban areas. The comparison does not include utilities that serve areas likely to have inherently high residential electricity use: sunbelt cities (e.g., Atlanta, Dallas, Phoenix) with very long cooling seasons, and Northwestern cities (e.g., Seattle, Portland) with high penetrations of electric heat.*

[b]*Excludes residential loads served through master meters on commercial rates.*

Transportation-fuel efficiency is another category in which the city leads the country. According to U.S. Census data aggregated by Bikes At Work (2002), the City has a wide lead in public transit use, even compared to the next-greatest-ridership regions of Washington, Boston, and San Francisco. New York City also is also among the top four areas in the percent of commuters walking to work. Bicycling is a small share of non-automobile commuting in all areas. See Table 4.

Table 4: Transportation Comparisons

	Population	Percent of Households Car-free	Transportation to Work		
			Bicycle	Walking	Public Transit
New York City	7,825,848	54%	0.4%	10%	58%
Rest of NYC PMSA[a]	1,272,491	11%	0.4%	3%	15%
Jersey City	599,525	34%	0.2%	7%	44%
Washington, DC	536,497	37%	1.5%	11%	36%
Boston	545,927	33%	1.5%	13%	35%
San Francisco	756,976	27%	1.9%	9%	34%
Philadelphia	1,462,819	37%	0.6%	11%	29%
Chicago	2,804,506	26%	0.5%	6%	28%
Baltimore	625,401	37%	0.3%	8%	23%
San Francisco PMSA[a]	1,689,490	15%	1.4%	6%	20%
Nassau-Suffolk, NY PMSA[a]	2,703,677	6%	0.3%	2%	13%
Philadelphia PMSA[a]	4,946,433	16%	0.3%	5%	11%
LA	3,627,789	14%	0.7%	3%	10%
Buffalo	259,729	30%	0.8%	7%	9%
Middlesex NJ PMSA[a]	1,139,966	6%	0.1%	2%	9%
LA PMSA[a]	9,344,086	11%	0.7%	3%	7%
US	273,643,274	9%	0.5%	3%	5%
LA CMSA[b]	16,063,431	9%	0.6%	3%	5%
Lowell PMSA[a]	291,526	7%	0.2%	1%	5%
Albany-Schenectady-Troy	842,912	10%	0.4%	3%	3%
Buffalo-Niagara Falls	1,135,102	13%	0.7%	3%	3%
Syracuse MSA[c]	705,131	9%	0.2%	3%	2%

[a]*Primary Metropolitan Statistical Area*

[b]*Consolidated Metropolitan Statistical Area (usually composed of multiple PMSAs)*

[c]*Metropolitan Statistical Area*

The illustrated efficiency metrics demonstrate that urban growth, and the electricity-demand increases that accompany such growth, are very much compatible with energy efficiency.

III. Integration of Resource Alternatives

This section describes the following:

- the resource alternatives modeled
- the framework used in evaluating alternatives
- treatment of the capacity market in New York City
- modeling of market energy prices
- initial resource evaluation results
- results for three refined combined plans
- special issues
- program and resource priorities.

All costs are in year-2002 dollars.

A. Resource Alternatives for 2008

The authors model eight initial cases for 2008. These cases examine the effects of three types of resource additions: new generating units, transmission additions, and efficiency programs. The following three cases are modeled that explore the effects of the following new generating resources:

- a new 1,000-MW combined-cycle gas plant,
- a new 500-MW combined-cycle gas plant,
- a new 500-MW combustion turbine plant,

- repowering an old 1,300-MW steam plant to a 1,820-MW combined-cycle gas plant, for a net addition of 520 MW.[2]

Three transmission cases are modeled to look at the effects of

- adding 500 MW of transmission capacity from New Jersey,
- adding 500 MW from NY Zone F,
- adding 2,000 MW from NY Zone F (simulating the effects of the line proposed by Conjunction, LLC).

The final initial scenario models a program that reduces peak loads by 500 MW (as an equal percentage reduction in load in every hour, at an effective capital cost of $2,000). That reduction could be a combination of energy efficiency, CHP, photovoltaics, demand-responsive rate programs, and peaking distributed generation.

Each initial case comprises the reference case plus the additional case-specific resources.

The results of these initial cases provided the bases for three integrated cases, as discussed below.

B. The Evaluation Framework

In the 1980s and 1990s, most utilities prepared long-range plans or integrated resource plans that, among other things, compared the costs of various resource options in terms of the costs to their ratepayers. The utilities usually made most of the decisions about building and operating plants, building transmission lines, and running energy-efficiency programs, and the utilities' costs flowed directly to their ratepayers in predictable ways. Consequently, determining a utility's revenue requirement and the total costs to customers for various alternatives was conceptually straightforward.

The situation is very different today for any party, and particularly the City, attempting resource planning in a restructured electric market. The City will not be building or operating resources. Generation will be built primarily by merchant developers and NYPA, generation is dispatched and priced through the NY ISO, transmission will be built by merchants or Consolidated Edison, and

[2]This option is based on the proposed Astoria repowering.

demand-side programs will be run by NYSERDA or Consolidated Edison. Most generation costs will flow to City energy consumers not at cost, but at market prices. Even though the City is interested in costs to customers, the framework for evaluating the costs of resources must be fundamentally different from the approach used by an integrated utility.

The authors compute the costs to City energy consumers as the sum of the following:

- Projected energy market revenues for the total load in Zone J (essentially New York City),
    - minus the energy market revenues from the power plants owned or controlled by Consolidated Edison and NYPA
    - plus the running costs of those non-market plants
- Projected capacity market revenues for the portion of the in-City capacity requirement that would be provided by market generation
- A credit for the reduction in the upstate capacity requirement due to any load reduction in the plan.
- The annualized cost of plan-specific resources, including
    - capital investment, annualized with an economic carrying charge.
    - fixed operating costs
- The annualized net revenues of plan-specific resources, including
    - credit for market energy revenues for the resources, minus variable production costs,
    - credit for market capacity revenues for the resources

Any excess of the annualized cost of plan-specific resources over their net revenues represents the amount, if any, that the City might need to subsidize the plan resources.

The authors do not include any energy revenues for transmission projects and DSM. Transmission developers might charge for the use of their lines with a range of tariff designs, including fixed reservation charges, constant dollars-per-MWh charges, and flexible charges on a daily or hourly basis. The authors (1) assume that transmission pricing will not interfere with the economic dispatch of energy; (2) model the variable charge for transmission at the loss factor; and (3) model transmission-project energy revenues at zero. Transmission developers will actually receive some revenues from load-serving entities related to the energy benefits of the line. Hence, market revenues will cover some of the net cost computed for transmission projects.

This analysis credits DSM with $100/kW-yr. for the value of local transmission and distribution investments avoided by load reductions.

C. The Capacity Market

Most of the difference between market prices in the City and outside (either upstate New York or PJM) has historically been due to capacity prices.

Entities serving load in the City must provide capacity equaling 80% of their forecasted summer peak demand from generation resources in the City. In-City generation requirements may be met with generation outside the City, so long as it has dedicated transmission.

The rest of the capacity required for in-City customers may be provided from resources elsewhere in the rest of the state (ROS) or (subject to specified limits) in other ISOs.

Capacity prices in the NY ISO have generally been set by market forces in regularly scheduled auctions administered by the NY ISO. In recognition of the tight supply situation in the City, capacity prices have been capped at a deficiency charge of $150/kW-year The units that Consolidated Edison divested (at Ravenswood, Astoria 2–6, Arthur Kill, Gowanus and Narrows) have been limited to bidding and receiving no more than $105/kW-year. In-City capacity prices have been maintained at or near the divested-unit bid cap, partially because the three owners of the divested generation have an interest in maintaining high prices. In one auction (for winter 2002–03), prices fell considerably below the bid cap ($7/kW-month of UCAP), suggesting that the oligopoly of owners of the divested generation could lose cohesion when in-City capacity exceeds the bare minimum.

In contrast, the ROS capacity prices have been around $15/kW-year.

The NY ISO, with the approval of FERC, has recently abandoned market forces, in favor of determining capacity prices administratively. This “demand-curve” formula will set the capacity price in each of three markets (the City, Long Island, and ROS) at the assumed cost of new peaking capacity at the required capacity supply, decreasing linearly to zero at a much higher supply level. These rules will be phased in, but seem likely to be in place by 2008.

The authors model the demand-curve approach if it applied to summer demand and supply of installed capacity. The ISO is likely to use higher dollars-per-kW prices but compute winter prices using higher winter ratings, so that annual costs will be very similar to this report's simpler model. The ISO will also use unforced capacity rather than installed capacity, but adjust prices downward to reflect forced outage rates and again keep annual payments essentially unchanged.

The model of City capacity prices is thus as follows:

- If in-City summer capacity is less than 80% of peak summer load, the ISO will set the in-City price at $159/kW-year and charge energy consumers for the shortfall at 50% more—or $239/kW-year.
- If the in-City capacity equals 80% of peak load, the ISO will set the in-City price at $159/kW-year.
- For each 1% of load that is available, the in-City capacity price will decline by $11/kW-year. However, in-City loads will be required to purchase all offered in-City capacity, and hence will pay the higher in-City price for more than 80% of peak load.
- If summer capacity in the City exceeds 91% of peak load, the in-City market will merge with the statewide market at approximately $35/kW-yr.
- Divested units (including the capacity of Astoria 3–5) receive the lesser of the in-City price or their $105 bid cap.
- New resources (other than DSM) will receive capacity revenues at the in-City price.

The statewide capacity price, with the model's reference reserve margin of 25%, would be about $50/kW-yr. Both PJM and ISO-NE will have higher reserve margins than New York, and neither of these neighboring ISOs has proposed to follow NY ISO in administratively increasing capacity costs above the market price. Consequently the authors assume that approximately 500 MW of additional capacity will be sold into the NY ISO to keep the statewide price from exceeding $35/kW-year.[3] If more generation is developed in the City, the authors think that imports will fall.

[3] ISO-NE is considering locational ICAP proposals, including a demand-curve computation, but has made no recommendations.

D. Market Energy Prices

The study uses the PROSYM production-costing model to determine the following:

- market prices with transmission constraints, realistic generator bidding behavior and security-constrained dispatch;
- the effects on prices of relaxing transmission constraints, adding generation, and reducing loads;
- the changes in power plant operation and emissions from various options.

The authors started by calibrating PROSYM to match current forward market prices for 2003 and inputting the baseline forecasts for 2008.

The PROSYM Model

The electricity market modeling for this study was done using the PROSYM Chronological Production Modeling System. PROSYM is the central component of the proprietary HESI Simulation Software Suite from Henwood Energy Services. In addition to PROSYM and its multi-region version MULTISYM, the suite includes a database of the loads, resources, and operating characteristics for each NERC region along with the EMSS data-management software, and additional packages for specialized analyses and reporting.[4]

PROSYM is a complete system for electric utility and regional pool analysis and accounting. It is designed for planning and operational studies and, as a result of its chronological structure, accommodates detailed hour-by-hour investigation of the operations of electric utilities and pools. This hour-by-hour simulation, respecting chronological, operational, and other constraints in the case of cost-based dispatch—and relevant pool or independent system operator (ISO) rules in the case of bid based dispatch—is the essence of the model. Because of its ability to handle detailed information in a chronological fashion, planning studies performed with PROSYM closely reflect actual operations. Electric utilities and generation pools operate generation resources, energy-storage devices, and load-control systems to match generation and load on an instantaneous basis. This real-time operation entails using highly sophisticated control systems that match generation levels with load virtually instantaneously. It is not analytically necessary to represent this level of time detail in performing planning studies, which have a time horizon of weeks to years. What is

[4]The most recent versions of each of these components were used in this study (PROSYM version 3.7.09, EMSS version 4.4.03, and NERC database version 6.3.0).

necessary is a level of time detail that allows the planning study to obtain a reasonable approximation of actual system operation.

The PROSYM model operates using hourly load data and simulates unit dispatch in chronological order. This study uses the bid-based unit-commitment-and-dispatch option to approximate the market structures of the power pools in the Northeast. PROSYM generates bids for each generating unit in ten capacity blocks based on each unit's capacity, operating costs, and operating strategy. Different operating strategies are used to represent different cost recovery schemes based on each unit's typical loading order (must-run units, baseload units, cycling units, or peaking units). The model dispatches generating units to meet load in each hour of the year in a way that minimizes costs while taking into account time-sensitive dynamics such as transmission constraints, plant outages, and the operating characteristics of specific generating units (e.g., ramp rates, minimum up and down times, etc.).[5] PROSYM simulates the effects of forced (i.e., random) outages probabilistically, using one of several Monte Carlo simulation modes. These simulation modes initiate forced outage events (full or partial) based on unit-specific outage probabilities and a Monte Carlo–type random-number draw. They allow for realistic representation of the stochastic properties of power generation.

PROSYM has a hierarchical geographical structure that comprises regions, control areas, transmission areas, and locations. Regions represent NERC reliability regions such as NPCC and MAAC. Regions contain one or more control areas that generally represent power pools or ISO territories such as New York ISO or PJM. Within control areas are transmission areas, defined by actual transmission constraints within a control area. That is, power flows from one area to another in a control area are governed by the operational characteristics of the actual transmission lines involved. Transmission areas contain one or more locations, which are the smallest level of aggregation of generation resources and loads. PROSYM has the capability to represent system operating constraints (e.g., reserves) at the region, control-area, or transmission-area level.

The geographic scope of this study includes all of NPCC and MAAC. NPCC includes New York, New England, Ontario, Quebec, and the Canadian Maritime provinces, while MAAC includes Pennsylvania, New Jersey, Maryland, and Delaware. There are 27 transmission areas within the study area. The eleven load

[5]The model minimizes the "costs" of serving loads, where costs are based upon generator bids. Bidding strategies which including offer generation into the market above short-run marginal cost are used in the model, and can be differentiated by generating unit or by unit type.

zones in New York (zones A through K) are represented by eight transmission areas: NY-AB, NY-C, NY-D, NY-E, NY-F, NY-GHI, NY-J, and NY-K.

Model Inputs

The zonal forecasts of load and generation, and of heat rates for new units, are described below in Sections IV and V.

PROSYM's assumptions about heat rates for most units are based on averages for the technology and vintage. However, some of these assumptions did not match historical data. Therefore, for select units in New York City, the heat rate was adjusted to approximate the historical average heat rate.

PROSYM's model of the bidding strategy for some cycling units would not have allowed these units to recoup their costs. Therefore, this bidding strategy for cycling steam and combined cycle units was adjusted to allow for some recovery of fixed costs.

Model Results

The model produces projections of numerous parameters: prices by transmission zone, transmission flows by interface, generation levels, emissions, and costs by generator. This analysis uses some aggregate results for Zone J in its valuation computation.

Energy Market Prices

Perhaps the most important outputs are the zonal prices for energy. The below tables summarize the peak and off-peak prices associated with each resource addition for the City, each upstate zone, and for representative zones in New England and PJM.[6] The differences between cases are small, so the authors show the effects of resources as reductions from the reference case. Negative numbers are increases in prices.

[6]The peak period is the standard sixteen-hour period Monday–Friday.

Table 5: Summary of 2008 Peak-Period Market Prices by Zone
(2002 Dollars per MWh)

	New York Zones							New England	PJM
	J	G H&I	F	E	D	C	A & B		
Reference ($/MWh)	54.2	47.1	46.3	44.3	39.1	43.5	43.1	50.0	44.1
Reduction in Dollars per MWh from Reference to									
1,000-MW CC	4.1	0.4	0.5	0.5	0.4	0.4	0.3	0.3	0.2
500-MW CC	2.5	0.1	0.2	0.2	0.1	0.1	(0.7)	0.1	0.1
500-MW GT	2.3	(0.1)	(0.0)	(0.0)	(0.0)	(0.1)	(0.1)	0.1	0.0
RPW	4.2	0.6	0.7	0.8	0.5	0.6	0.6	0.3	0.4
TransNJ	3.6	0.2	0.4	0.3	0.2	0.3	0.2	0.4	(0.5)
TransNYF	3.2	(0.4)	(0.3)	(0.2)	(0.2)	(0.3)	(0.3)	0.0	(0.1)
TransConj	5.1	(0.9)	(0.8)	(0.8)	(0.3)	(0.7)	(0.7)	0.1	(0.3)
DSM	3.4	0.3	0.4	0.4	0.2	0.4	0.2	0.2	0.2

Table 6: Summary of 2008 Off-Peak Market Prices, by Zone
(2002 Dollars per MWh)

	New York Zones							New England	PJM
	J	G H&I	F	E	D	C	A & B		
Reference ($/MWh)	38.4	37.3	36.8	35.3	34.2	34.2	33.8	37.7	29.4
Reduction in Dollars per MWh from Reference to									
1,000-MW CC	0.2	0.2	0.2	0.2	0.2	0.2	0.1	0.1	0.0
500-MW CC	0.0	0.1	0.1	0.0	0.1	0.1	0.0	0.1	0.0
500-MW GT	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.0)	(0.0)
RPW	0.1	(0.0)	(0.0)	(0.1)	(0.1)	(0.0)	(0.0)	(0.1)	(0.1)
TransNJ	0.7	0.6	0.6	0.5	0.5	0.6	0.5	0.4	(0.8)
TransNYF	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.0)
TransConj	0.2	(0.1)	(0.2)	(0.2)	(0.2)	(0.2)	(0.1)	(0.1)	(0.0)
DSM	0.5	0.5	0.5	0.4	0.4	0.4	0.4	0.3	(0.1)

The largest resources (the 2,000-MW transmission line and the 1,000-MW combined-cycle unit) have the largest effect on peak prices in the City. Among the 500-MW resources, repowering has the largest effect on peak prices in the City, due to the large amount of capacity that would be upgraded from steam to combined-cycle. However, repowering has negligible benefits in the off-peak period.[7] Among the other 500-MW resources, DSM and transmission have the greatest effects on peak market price, followed by the combined-cycle and the combustion turbines. Each of the larger resources (the 2,000-MW transmission

[7]To the extent that the steam plants are no longer required to remain on line overnight so as to be available the next day, the off-peak market prices would be increased. The authors have not estimated the benefits of reducing the costs of this standby operation; costs would be recovered in uplift.

line from Zone F and the 1,000-MW combined-cycle) would reduce on-peak prices in Zone J more than the smaller version of the same resource, but show diminishing returns.

Off-peak the transmission from PJM (with its abundant inexpensive off-peak energy) would reduce prices slightly more than would DSM, with the rest of the resources having very small effects. Combustion turbines and the upstate transmission line increase market energy prices in the off-peak, probably by reducing the need to keep steam plants on line overnight, but would decrease charges for that out-of-order dispatch.

The effects on other regions vary. The combined-cycle plants, repowering, and DSM all have generally similar effects on other zones as for Zone J.

Emissions

The below table provides emission results with each resource. The results for sulfur dioxides and oxides of nitrogen are estimates of the effects in the City, in the areas of most immediate concern to the City (all of New York, New England, PJM and Ontario), and the total modeled area. For carbon dioxide, which is important only on a global basis, the results cover the total model area. It is important to recall that emissions from power plants constitute a small portion of overall pollution in the City. Especially for smog precursors and fine particulates, vehicles are much more important sources than power plants.

Table 7: Emissions Changes by Resource

	SO_2 (1,000 T)			NOx (1,000 T)			CO_2 (M T)
	Zone J	NY, NE, PJM, ON	Total Area	Zone J	NY, NE, PJM, ON	Total Area	Total Area
Reference	8.0	1851.4	1983.7	7.3	517.1	564.9	389.9
Reduction from Reference to							
1,000-MW CC	1.1	5.8	6.2	0.9	2.4	2.5	0.9
500-MW CC	0.8	4.0	4.1	0.6	1.4	1.4	0.5
500-MW GT	0.3	0.9	1.0	0.2	0.3	0.4	0.1
RPW	2.3	7.9	8.3	2.3	4.3	4.4	1.7
TransNJ	0.6	-2.7	-2.1	0.4	-0.9	-0.7	-0.2
TransNYF	0.4	-1.2	-1.5	0.3	-0.3	-0.4	-0.1
TransConj	0.6	-1.7	-2.0	0.5	-0.3	-0.5	-0.1
DSM	1.0	8.0	8.7	0.8	2.8	3.0	2.8

Among the 500-MW options, repowering has the largest benefits in SO_2 and NOx, while DSM has the largest CO_2 benefits. The transmission lines from upstate have little net environmental effect, increasing total SO_2 emissions very slightly. The transmission line from New Jersey increases emissions in PJM and hence total emissions for all three pollutants.

E. Initial Resource Results

Capacity Market Results

The data in Table 8 below summarize the results for the capacity market. The authors assume that the divested units are paid no more than the $105/kW-year bid cap, although the authors assume that cap is raised with inflation. The analysis also assumes a $35 floor price in the statewide (rest-of-state, or ROS) market, which establishes a floor on the in-City market.

Table 8: Capacity Prices and Revenues

	Reference Case	Combined Cycle		Gas Turbine	RPW	Trans NJ	Trans NYF	Trans Conj	DSM
Load Reduction (MW)									500
Capacity Increase (MW)		1,000	500	500	520	500	500	2,000	500
Resources (MW)									
NRG	1,459	1,459	1,459	1,459	1,459	1,459	1,459	1,459	1,459
Reliant Divested	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900
Reliant Market	175	175	175	175	695	175	175	175	175
Keyspan	2,480	2,480	2,480	2,480	2,480	2,480	2,480	2,480	2,480
Non-Market	2,843	2,843	2,843	2,843	2,843	2,843	2,843	2,843	2,843
Other Market	656	1,656	1,156	1,156	656	1,156	1,156	2,656	656
Total Base	9,514	10,514	10,014	10,014	10,034	10,014	10,014	11,514	9,514
Load Base	11,960	11,960	11,960	11,960	11,960	11,960	11,960	11,960	11,460
80% of Load	9,568	9,568	9,568	9,568	9,568	9,568	9,568	9,568	9,168
Total Market Capacity (MW)	832	1,832	1,332	1,332	1,352	1,332	1,332	2,832	832
Surplus									
w.o. Poletti (MW)	-55	946	446	446	466	446	446	1,946	346
w. Poletti (MW)	801	1,500	1,301	1,301	1,321	1,301	1,301	2,801	1,201
w.o. Poletti	-0.5%	8%	4%	4%	4%	4%	4%	16%	3%
w. Poletti	7%	13%	11%	11%	11%	11%	11%	23%	10%
Demand-Curve Price (Dollars per kW-yr.) with $35/kW-Yr. ROS Floor[a]									
w.o. Poletti	$164	$72	$118	$118	$116	$118	$118	$35	$126
w. Poletti	$85	$35	$39	$39	$37	$39	$39	$35	$43
Capacity Revenues Without Poletti									
Divested	$613M	$419M	$613M	$613M	$613M	$613M	$613M	$204M	$613M
Market	$154M	$131M	$157M	$157M	$157M	$157M	$157M	$99M	$105M
Total	$767M	$550M	$770M	$770M	$770M	$770M	$770M	$303M	$718M
Capacity Revenues With Poletti									
Divested	$497M	$204M	$227M	$227M	$216M	$227M	$227M	$204M	$253M
Market	$75M	$64M	$52M	$52M	$50M	$52M	$52M	$99M	$36M
Total	$572M	$268M	$279M	$279M	$267M	$279M	$279M	$303M	$289M
Resource Revenues									
w.o. Poletti		$72M	$59M	$59M	$60M	$41M	$41M	–	–
w. Poletti		$35M	$19M	$19M	$19M	$6M	$6M	–	–
NYC Need for ROS Capacity (MW)[a]									
w.o. Poletti	5,676	4,676	5,176	5,176	5,156	5,176	5,176	3,676	5,041
w. Poletti	4,821	3,821	4,321	4,321	4,301	4,321	4,321	2,821	4,186
ROS cost[a]									
w.o. Poletti	$199M	$164M	$181M	$181M	$180M	$181M	$181M	$129M	$176M
w. Poletti	$169M	$134M	$151M	$151M	$151M	$151M	$151M	$99M	$146M

[a]*ROS is "rest of state," New York except for the City.*

These data suggest that for most of these cases keeping Poletti available for the capacity market would be worth hundreds of millions of dollars, certainly well more than its operating costs. With 1,500 MW or more of new in-City capacity above the reference case, Poletti has no effect on the capacity market and its value is limited to its own market capacity value, which may not cover the costs of keeping it available.

Second, the benefits to consumers of increasing in-City capacity beyond the 80% minimum are very great.

Third, the operation of the demand-curve formula results in the first 500 MW or so of additional resources having little effect on capacity costs, since the additional market purchases offset the lower prices. Resources beyond that point, up to about 1,500 MW, are very valuable.[8] The extra 20 MW of capacity in the repowering case with Poletti reduces the market costs by $13 million, or $650/kW-yr., compared to the 500-MW transmission and generation options. In excess of about 1,500 MW, the upstate and in-City capacity markets merge, and additional in-City resources no longer reduce in-City capacity charges.

This analysis assumes that the proposed demand-curve methodology replaces the competitive market, but that the bid caps for the divested units remain in place. If the demand curve is implemented without the existing bid caps, the capacity costs in many cases would be considerably higher, and the initial megawatts of in-City resources would be more valuable, since they would reduce prices paid to the divested units, in addition to the market resources.

Energy Costs

Table 9 summarizes the projection of energy market prices for all energy consumed in Zone J, minus the energy market revenues from the power plants owned or controlled by Consolidated Edison and NYPA, plus the running costs of those non-market plants.

[8] In the reference case, the demand-curve prices fall below the bid cap when in-City capacity equals 85% of load. At that point, an additional 700 MW would be required to push the price below the bid cap.

Table 9: Energy-Market Benefits of Alternative Resources
(Millions of Year-2002 Dollars)

	Cost of Serving All Load from Market	Savings from Non-Market Plants	Cost of Serving NYC	Net Revenues from New Plants
Reference	$2,988	$103	$2,885	–
1,000-MW CC	$2,810	$68	$2,742	$44
500-MW CC	$2,882	$82	$2,799	$25
500-MW GT	$2,885	$84	$2,801	$7
RPW	$2,813	$70	$2,743	$63
Trans NJ	$2,818	$72	$2,747	–
Trans NYF	$2,852	$77	$2,775	–
Trans Conj	$2,753	$58	$2,695	–
DSM	$2,639	$74	$2,565	–

By far the largest energy benefit would follow from the DSM, which would reduce not only market energy prices but also the amount of energy used in New York City.

Adding 500 MW of new combined-cycle capacity in the City would provide only slightly larger energy benefits than adding a similar amount of combustion turbines, and smaller energy benefits than the repowering or transmission lines.

Doubling the combined-cycle capacity added in the City, to 1,000 MW, would reduce energy costs by more than would the 500-MW combined-cycle, but at a slower rate. The first 500 MW would reduce prices by $86 million annually, while the second would increases savings by only another $57 million. The 1,000-MW combined-cycle would have about the same effect on energy prices as the 500-MW transmission lines and repowering.

The repowering of an existing steam plant in the City includes the conversion of 1,200 MW of steam plant to combined-cycle, which would be almost as valuable for energy purposes as the addition of 520 MW of incremental combined-cycle capacity. This effect would probably be even stronger if not for the fact that current indications in the futures market indicate that residual oil is likely to be less expensive than gas for most of the study period. If oil prices rise relative to gas prices, the addition of combined-cycle capacity and repowering will both be more advantageous.

Other than the DSM, the 2,000-MW transmission line from upstate would have the largest effect on energy costs in the City, although the effect is not even twice that of the first 500 MW of upstate transmission.

Resource Costs

The data in Table 10 below summarize the costs of the new resources modeled. The authors estimated the capital cost of the 500-MW transmission lines from Zone F and from PJM based on estimates for the costs of larger lines. The costs of the other options are described in the appropriate sections below. The negative O&M for DSM resource represents savings in local T&D at $100/kW-year; effects of the DSM investments on consumer O&M are reflected in the capital cost.

The analysis credits the three generation options with their energy revenues, net of fuel and variable O&M.

Table 10: Cost of New Resources

	Capacity (MW)	Capital ($/kW)	O&M ($/kW-yr.)	Capital (millions)	ECC	O&M ($M/year)	Total ($M/year)
Combined Cycle							
1,000-MW	1,000	$1,200	$40	$1,200	13.8%	$40	$206
500-MW	500	$1,200	$40	$600	13.8%	$20	$103
Gas Turbine	500	$800	$7	$400	14.6%	$3.5	$62
Repower	520	$800+	$40	$1456	13.8%	$20.8	$222
Trans NJ	500			$170	12%		$20
Trans NYF	500			$270	12%		$32
Trans Conj	2,000			$750	12%		$90
DSM	500	$2,000	-$100	$1,000	15%	-$50	$100

Summary of Benefits

The below tables summarize the benefits of the initial plans, compared to the reference case. Table 11 assumes Poletti is retired, Table 12 that it remains available for purposes of the capacity market. Both tables include a credit for DSM for avoiding upstate capacity.[9] "Net Plan Benefit" is the sum of the "Reduction in Market Costs" (Energy, Zone-J capacity, and rest-of-state capacity) minus the "Net Cost of New Resources" (if that is positive).

Table 11: Net Benefits by Resource, without Poletti
(Millions of Dollars)

	Combined Cycle		Gas Turbine	RPW	Trans NJ	Trans NYF	Trans Conj	DSM
	1,000 MW	500 MW	500 MW	520 MW	500 MW	500 MW	2,000 MW	500 MW
New Resource Costs								
Annual Cost	$206	$103	$62	$222	$20	$32	$90	$100
Energy Market Revenue	$44	$25	$7	$63	–	–	–	–
Capacity Market Revenue	$72	$59	$59	$60	$41	$41	$0	–
Net Cost	$90	$19	($4)	$99	($21)	($9)	$90	$100
Reduction in Market Costs								
Energy	$143	$86	$84	$142	$138	$110	$190	$320
Capacity Cost—Zone J	$217	($3)	($3)	($3)	($3)	($3)	$464	$50
Capacity Costs—ROS[a]	$35	$18	$18	$18	$18	$18	$70	$22
Net Plan Benefit	$306	$82	$98	$59	$153	$125	$634	$292

[a]*ROS is "rest of state," New York except for the City.*

Table 12: Net Benefits by Resource, with Poletti
(Millions of Dollars)

	Combined Cycle		Gas Turbine	RPW	Trans NJ	Trans NYF	Trans Conj	DSM
	1,000 MW	500 MW	500 MW	520 MW	500 MW	500 MW	2,000 MW	500 MW
New Resource Costs								
Annual Cost	$206	$103	$62	$222	$20	$32	$90	$100
Energy Market Revenue	$44	$25	$7	$63	–	–	–	–
Capacity Market Revenue	$35	$19	$19	$19	$6	$6	$0	–
Net Cost	$127	$58	$35	$140	$15	$27	$90	$100
Reduction in Market Costs								
Energy	$143	$86	$84	$142	$138	$110	$190	$320
Capacity Cost—Zone J	$304	$293	$293	$306	$293	$293	$269	$283
Capacity Costs—ROS[a]	$35	$18	$18	$18	$18	$18	$70	$22
Net Plan Benefit	$355	$338	$359	$326	$434	$394	$439	$525

[a]*ROS is "rest of state," New York except for the City.*

[9]The avoided upstate capacity is 118%–80% or 38% of peak, so a peak reduction of 500 MW avoids 190 MW, which at $35/kW-year is worth about $7 million.

This initial review of options suggests the following:

- Demand-side management is a very attractive option.
- Of the central-station options, new transmission from PJM is likely to lead to lower total costs to consumers than similar amounts of new generation.[10]
- Even in the above intentionally optimistic example, the higher cost of repowering more than offsets the greater energy benefits, compared to new combined-cycle plants or combustion turbines. Repowering would have air-quality benefits, as well as reducing the amount of real estate required for power generation in the City; those benefits must be weighed against the cost of the alternatives, as well as reduction in market power in the in-City capacity market from new entrants.
- The 500-MW combined-cycle, combustion-turbine, and upstate-transmission options all have greater net benefits than the repowering, with the transmission line preferable to the combustion turbine, which is preferable to the combined-cycle (although the differences between the combustion turbine and combined-cycle are small).
- Resources tend to show diminishing returns in the energy market, and the 2,000-MW transmission line proposed from Zone F to the City is larger than required within the time frame of this study, although most of its capability would be helpful in reducing capacity prices. On the other hand, so long as the developers of the larger resources do not require subsidies from City ratepayers, nothing in this analysis suggests that there is anything undesirable about a larger combined-cycle development or a larger transmission line.[11]

All of these resource costs are estimates for typical in-City installations. The ranking of the combined-cycle, combustion-turbine, repowering, and transmission options will vary with the cost of the resources. For example, reducing the assumed cost of the repowering by about 15% would make it comparable in total cost effect to the new combined-cycle capacity, so long as market-power problems can be mitigated. The combustion-turbine and combined-cycle options are particularly close, considering the uncertainty in the capital cost of

[10]Care must be taken to ensure that the pricing of energy over the lines, especially from PJM, does not interfere with economic transfers. Pricing with fixed reservation charges or split-savings arrangements is preferable to pricing at fixed dollars-per-megawatt rates.

[11]Larger options may entail larger environmental and land-use problems.

those resources. Any of these resources will reduce market capacity and energy prices, and will benefit City electricity consumers, so long as the resource does not require any subsidy from government or consumers.

F. Refined Plan Results

Based on the above analysis, the authors constructed the following three combined portfolios, each totaling 1,500 MW of resources:

- 500 MW of DSM load reductions, 500 MW of transmission from New Jersey, and 500 MW of transmission from New York Zone F.
- 500 MW of DSM load reductions, 500 MW of transmission from New Jersey, and 500 MW of new combined-cycle capacity.
- 500 MW of DSM load reductions, 500 MW of transmission from New Jersey, and 500 MW of new combustion turbines.

The costs of these plans are simply the sums of the costs of the resources in each plan: $153 million annually for the plan with transmission from Zone F, $223 million with the combined-cycle, and $182 million with the combustion turbines.

The below five tables provide the market-price, emissions, capacity-market, energy-market, and summary results for the three combined plans.

Table 13: Market Prices for Combined Plans
(Dollars per MWh)

	Zone J	Zones G, H & I	Zone F	Zone E	Zone D	Zone C	Zones A & B	Eastern New England	PJM PSE&G
On Peak									
Reference	54.2	47.1	46.3	44.3	39.1	43.5	43.1	50.0	44.1
Reduction in Dollar per MWh from Reference to									
DSM-NJ-NY	6.3	0.5	0.5	0.6	0.4	0.5	0.4	0.3	(0.2)
DSM-NJ-CC	6.5	0.8	1.0	0.9	0.5	0.9	0.8	0.3	0.2
DSM-NJ-GT	6.0	0.5	0.6	0.7	0.4	0.5	0.5	0.3	(0.2)
Off-Peak									
Reference	38.4	37.3	36.8	35.3	34.2	34.2	33.8	37.7	29.4
Reduction in Dollar per MWh from Reference to									
DSM-NJ-NY	1.5	1.1	1.1	1.0	0.9	1.0	0.9	0.8	(0.8)
DSM-NJ-CC	1.5	1.2	1.2	1.1	1.0	1.1	1.0	0.8	0.0
DSM-NJ-GT	1.4	1.1	1.1	0.9	0.9	1.0	0.9	0.8	(0.8)

Table 14: Emission Effects of Combined Plans

	SO_2 (1,000 T)			NOx (1,000 T)			CO_2 (M T)
	Zone J	NY, NE, PJM, ON	Total Area	Zone J	NY, NE, PJM, ON	Total Area	Total Area
Reference	74.7	1,849.8	1,982.0	37.3	517.8	565.6	390.2
Reduction from Reference to							
DSM-NJ-NY	1.3	4.1	5.3	1.1	1.5	1.9	2.5
DSM-NJ-CC	1.5	7.1	8.9	1.3	3.1	3.7	3.0
DSM-NJ-GT	1.3	4.7	5.8	1.1	2.0	2.5	2.7

Table 15: Capacity Prices and Revenues for Combined Plans

	Reference Case	DSM/ NJ/NY	DSM/ NJ/CC	DSM/ NJ/GT
Load Reduction (MW)		500	500	500
Capacity Increase (MW)		1,000	1,000	1,000
Resources (MW)				
NRG	1,459	1,459	1,459	1,459
Reliant Divested	1,900	1,900	1,900	1,900
Reliant Market	175	175	175	175
Keyspan	2,480	2,480	2,480	2,480
Non-Market	2,843	2,734	2,734	2,734
Other Market	656	1,656	1,656	1,656
Total Base	9,514	10,405	10,405	10,405
Load Base	11,960	11,460	11,460	11,460
80% of Load	9,568	9,168	9,168	9,168
Total Market Capacity (MW)	832	1,836	1,836	1,836
Surplus				
w.o. Poletti (MW)	-55	346	346	346
w. Poletti (MW)	801	2,201	2,201	2,201
w.o. Poletti	-0.5%	12%	12%	12%
w. Poletti	7%	19%	19%	19%
Demand-Curve Price (Dollars per kW-yr.) with $35/kW-Yr. ROS Floor[a]				
w.o. Poletti	$164	$35	$35	$35
w. Poletti	$85	$35	$35	$35
Capacity Revenues Without Poletti				
Divested	$613M	$205	$205	$205
Market	$154M	$64	$64	$64
Total	$767M	$268	$268	$268
Capacity Revenues With Poletti				
Divested	$497M	$205	$205	$205
Market	$75M	$64	$64	$64
Total	$572M	$268	$268	$268
Resource Revenues (Dollars per kW-yr.)				
w.o. Poletti		–	$18	$18
w. Poletti		–	$18	$18
NYC Need for ROS Capacity (MW)[a]				
w.o. Poletti	5,676	4,041	4,041	4,041
w. Poletti	4,821	3,186	3,186	3,186
ROS cost[a]				
w.o. Poletti	$199M	$141M	$141M	$141M
w. Poletti	$168M	$111M	$111M	$111M

[a]*ROS is “rest of state,” New York except for the City.*

Table 16: Energy-Market Benefits of Combined Plans
(Millions of Dollars)

	DSM/NJ/NY	DSM/NJ/CC	DSM/NJ/GT
Cost of Serving All Load from Market	$2,490	$2,485	$2,503
Savings from Non-Market Plants	$45	$44	$48
Cost of Serving New York City	$2,445	$2,441	$2,455
Net Revenues from New Plants	–	$17	$2

Table 17: Net Benefits of Combined Plans, without Poletti
(Millions of Dollars)

	DSM/ NJ/NY	DSM/ NJ/CC	DSM/ NJ/GT
New Resource Costs			
Annual Cost	$153	$223	$182
Market Energy Revenue	–	$17	$2
Market Capacity Revenue	–	$18	$18
Net Cost	$153	$189	$163
Reduction in Market Energy Costs			
Energy	$440	$444	$430
Capacity Cost for NYC—Zone J	$499	$499	$499
Capacity Cost for NYC—ROS[a]	$57	$57	$57
Net Plan Benefit	$843	$811	$823

[a]*ROS is "rest of state," New York except for the City.*

Table 18: Net Benefits of Combined Plans, with Poletti
(Millions of Dollars)

	DSM/ NJ/NY	DSM/ NJ/CC	DSM/ NJ/GT
New Resource Costs			
Annual Cost	$153	$223	$182
Market Energy Revenue	–	$17	$2
Market Capacity Revenue	–	$18	$18
Net Cost	$153	$189	$163
Reduction in Market Energy Costs			
Energy	$304	$304	$304
Capacity Cost for NYC—Zone J	$499	$499	$499
Capacity Cost for NYC—ROS[a]	$57	$57	$57
Net Plan Benefit	$648	$616	$628

[a]*ROS is "rest of state," New York except for the City.*

These results generally confirm those of the initial PROSYM runs. All three portfolios would reduce all emissions. The portfolios would have costs that are similar, considering the uncertainty in the resource costs. The order of resources remains essentially unchanged, with the greatest benefit from transmission.

G. Special Issues

Effect of Completing SCS Astoria

If Consolidated Edison's recent award of a 500-MW purchased-power contract to SCS Astoria allows that 1,000-MW plant to be financed and constructed, then in addition to the capacity included in the base case (East River, the Poletti combined-cycle, the Ravenswood cogenerator, and the PSEG transmission line), only about 500 MW of additional resources would be needed to minimize the cost of power supply for New York City, even with the retirement of the Poletti steam plant.

The order of resource preference would remain the same as in the base case: DSM, transmission, and then in-City generation.

Another possible outcome of Consolidated Edison's contract to SCS Astoria is that SCS will build its plant, but that PSEG will delay its transmission line. In that case, the City would require 1,000 MW of additional resources, with the same order of preference. Encouraging the completion of the PSEG line would be an attractive option.

Replacement of Old Combustion Turbines

The authors considered qualitatively the option of replacing some of the older combustion turbines in the City with modern higher-efficiency units. The very small effect on energy prices of adding new combustion turbines indicates that the replacement of old combustion turbines with new ones would have very little benefit. In addition, since the three major generation owners in the City own almost all the old combustion turbines, the new combustion turbines could be used to exercise market power.

Locational Priorities

New central generation, to the extent possible, should be connected to the most severely constrained load pockets within the City. These pockets are defined in part by geography, but also by voltage level, as follows:

- The entire system served by 138-kV transmission in the City;
- The networks served from Astoria East through Corona and Jamaica transmission system;
- A series of concentric load pockets consisting of the networks served from Astoria West through Queensbridge transmission system, especially
    - the portions served through Vernon—especially the portions served through Greenwood, and especially Staten Island

- The networks served from the 69-kV system around the East River plant in eastern Manhattan.[12]

The same priorities apply to the location of new transmission interconnections.

Location of DSM and distributed generation in the transmission-constrained load pocket would be desirable. However, the development of these resources may be most valuable where they can be targeted to networks for which Consolidated Edison would otherwise need to build new local transmission-and-distribution facilities to meet load growth.

H. Priorities and Goals

Capacity Goals

For the purpose of reducing the cost of capacity in Zone J, the City should endeavor to bring on at least 1,500 MW of additional resources over the next five years, beyond the 1,500 MW of resources in the reference case. SCS Astoria, if built, would account for 1,000 of the 1,500 MW of additional resources.

An additional 500 MW of capacity resources may have value if the statewide capacity price falls below the $35/kW-yr. value assumed as a floor on in-City capacity prices.

The City should resist the retirement of the Poletti steam plant until 1,500 MW in new resources is assured.

Order of Resource Preference

The general order of priorities in resource development for the City appears to be as follows:

1. energy efficiency,
2. distributed generation where cost-effective,
3. transmission from PJM,
4. transmission from upstate,
5. new combustion turbines in the City,
6. new combined-cycle in the City.

[12]This importance of this constraint should be reduced by the operation of the East River Repowering.

The ranking of the last three options is sensitive to the uncertainties in costs of the options. Any particular transmission or generation proposal may be undesirable due to location-specific environmental, land-use, and community effects.

Repowering should be encouraged only if its environmental benefits, and reduced use of developable land, outweigh the typically higher costs and greater problems of increased market power. Should Consolidated Edison's preliminary estimates prove to be realistic, the Hudson Avenue steam-system repowering would be the most attractive new generation option in the City, with a low cost, high efficiency (since it would cogenerate district-heating steam in periods of low electric demand), and lack of market power.[13]

The power plants and transmission lines that have been proposed would be more than sufficient to meet the City's requirements. With an aggressive DSM program and the SCS Astoria plant, New York City would need only a few hundred megawatts of additional resources through 2010. That could be satisfied by a combination of additional generation and transmission from PJM or upstate New York.

Even without any DSM program, the Conjunction transmission line would meet the City's capacity needs by itself, and SCS Astoria would meet more than half the need.

The suspension of developers' efforts to build additional transmission from New Jersey to New York City may follow from the sensitivity of facilities' economics to the price of capacity in the City. Since that transmission appears to be quite valuable to in-City electricity consumers, the City should encourage development of forward markets or contracts that would allow the developers sufficient price stability to finance economical lines.

The SCS Astoria Project has been approved, under conditions accepted by the communities, and would supply 1,000 MW of new combined-cycle capacity. The repowering of Astoria units 2–5 appears to be near approval, and would supply approximately 520 MW of incremental capacity. The basic problem for these plants is economic: analysis suggests that they cannot be built without some ratepayer subsidy, even if they are the only new resources being built. SCS Astoria has a contract with Consolidated Edison to provide 500 MW of power,

[13]The Hudson Avenue plant would also help keep the steam system viable, which keeps several hundred megawatts of cooling load off the electric system. Encouragement of steam and gas chilling should be integrated into energy-efficiency programs in the City.

which may allow it to be financed. Beyond the approved projects, the City needs less-expensive resource proposals, not more of the same.

While the City should remain open-minded with regard to competing proposals, there is no urgency in identifying or licensing additional generation sites unless the proponents can offer significantly lower costs, superior connections to the transmission system, or some other advantage.

Program Priorities

The City's program priorities, generally working with Consolidated Edison and NYSERDA, should include the following:

Enhance energy-efficiency investments in the City, including

- investments in City buildings
- improvements in efficiency standards and codes
- increased direct funding of City-wide energy efficiency
- integration of energy efficiency in Consolidated Edison's analysis of alternatives to local transmission and distribution investments.

Facilitate distributed generation, including

- seeking appropriate sites for distributed generation in City buildings
- identifying rate-design and regulatory barriers to distributed generation implementation and resolving them
- determining whether incentives for distributed generation are warranted, and if so, how those can most effectively be delivered.

Encourage development of photovoltaic applications for urban settings, including

- designs for rooftops and sheathing on tall buildings
- estimation of benefit in constrained urban settings, especially for supply delivered high on tall buildings, reducing internal distribution losses.

IV. Existing Conditions and Baseline Forecast

The data and assumptions detailed in this section are inputs to the modeling described above in Section III.

A. Load

For all transmission zones except those in New York, the authors used the zonal load forecasts provided by Henwood Energy Services as part of its PROSYM model. The Henwood forecasts for New York match those in the "New York ISO 2002 Load and Capacity Data" (NY ISO 2002a) also known as the "Gold Book."

The New York ISO's 2003 load forecast is not yet available, but new and higher forecasts of the 2003 zonal loads are provided in "New York ISO Locational Installed Capacity Requirements Study" ("ICAP Report") (NY ISO 2003b). These data are used to estimate the 2008 loads as the sum of the Gold Book forecasts for 2008, plus the difference between the Gold Book and ICAP Report for 2003. The data in Table 19 summarize these adjustments below.

Table 19: New York ISO Load (MW) Adjustments

Transmission Areas	Henwood 2003	From 2003 ICAP	Difference	Henwood 2008	2008 Adjusted[a]
NY-AB	4,693	5,041	348	4,938	5,286
NY-C	2,634	2,976	342	2,706	3,048
NY-D	980	993	13	1,026	1,039
NY-E	1,197	1,435	238	1,232	1,470
NY-F	1,964	2,268	304	2,024	2,328
NY-GHI	3,635	4,229	594	3,871	4,465
NY-J	10,621	11,020	399	11,255	11,960
NY-K	4,784	4,849	65	5,115	5,180

[a] *The 2008 Adjusted Load is the Henwood 2008 Load plus the difference between the Henwood 2003 Load and the 2003 ICAP Load.*

The 2008 forecast for Zone J is based on a Consolidated Edison forecast that matches the ICAP Report for 2003 but includes projections to 2008 and beyond.

Table 20 (below) summarizes the 2008 load and capacity for the reference case. The same values apply for all transmission areas other than Zone J in all other cases as well.

Table 20: Reference Case 2008 Load and Resource Summary

Transmission/Control Area	Energy (GWh)	Peak (MW)	Capacity (MW)	Reserve Margin
NY-AB	31,795	5,286	3,942	-25%
NY-C	20,120	3,048	6,314	107%
NY-D	6,887	1,039	3,774	263%
NY-E	9,766	1,470	760	-48%
NY-F	15,539	2,328	2,871	23%
NY-GHI	24,757	4,465	6,684	50%
NY-J	61,401	11,960	9,067	-24%
NY-K	23,504	5,180	5,522	7%
NY ISO	31,775	31,775	38,935	23%
Maritimes	30,475	5,493	6,935	26%
ISO New England	140,632	24,970	32,117	29%
Ontario	156,440	24,685	30,440	23%
PJM	302,768	60,373	76,317	26%
Quebec	191,410	35,890	38,597	8%

The peak loads for the New York transmission areas are not coincidental. Therefore the peak load for the New York ISO control area does not equal the sum of the transmission-area peak loads.

Effect of Resources on Load

The electric-utility-planning process generally assumes that loads are determined entirely separately from electric resources. However, this assumption is not strictly accurate. The cost of resources determines the cost of power, which in turn has two sets of effects. First, the price of electricity itself affects the economics of consuming and conserving electricity and the attractiveness of adding new electric uses. Second, a change in electric bills has an income effect on consumption. If electric bills are lower, households and businesses have more money to spend, some of which will be spent in ways that directly increase electricity use in New York City: increasing floor space, hiring more employees, buying more appliances. In addition, some of the spending will put more money in the hands of other parties in the City (such as the construction firms and workers who build the new floor space, the additional employees, and the appliance distributors and dealers). These parties will in turn spend some of those funds on energy use.[14]

Energy-efficiency programs can offset a large part of the price effect; increasing comfort levels can often be accomplished without increasing energy use. The income effect, on the other hand, is much more persistent. Almost any action that saves consumers money and stimulates the local economy will tend to increase electricity usage.

The load projections used in this analysis do not reflect the reduction in electricity use that would result from the high electricity prices that the City would experience in the base case, particularly due to the operation of the ISO's demand-curve method for setting capacity prices. The load projections appear more consistent with stable prices, which would require addition of significant amounts of new resources.

B. Generation in the City

Existing and Committed

The data in Table 21 (below) describe the existing in-City generation includes in the authors' benchmarking of the system for 2003.

[14]Of course, some of the additional spending will be in outside the City, such as dividends to shareholders, investment in branch offices, and rental of vacation homes.

Table 21: Existing Generating Facilities in New York City as of January 1, 2003

	Unit Type	Capacity (MW)	Installation Date	Retirement Date	Fuel
59th St GT	GT	21.50	6/1/69	1/1/24	Kerosene
74th St GT 1	GT	16.40	10/1/68	1/1/23	Kerosene
74th St GT 2	GT	18.00	10/1/68	1/1/23	Kerosene
Arthur Kill 2	ST	350.00	8/1/59	1/1/14	Natural Gas
Arthur Kill 3	ST	493.00	6/1/69	1/1/24	Natural Gas
Arthur Kill GT	GT	16.60	6/1/70	1/1/25	Kerosene
Astoria GTs	GT	756.70	7/1/67	1/1/22	Natural Gas
Astoria ST 2	ST	175.00	9/1/54	1/1/19	Gas/0.3% S FO#6
Astoria ST 3	ST	370.00	9/1/58	1/1/13	Gas/0.3% S FO#6
Astoria ST 4	ST	377.00	3/1/61	1/1/17	Gas/0.3% S FO#6
Astoria ST 5	ST	369.50	5/1/62	1/1/17	Gas/0.3% S FO#6
Cogen Tech-Linden 1	CG	159.00	5/1/92	1/1/47	Natural Gas
Cogen Tech-Linden 2	CG	159.00	5/1/92	1/1/47	Natural Gas
Cogen Tech-Linden 3	CG	159.00	5/1/92	1/1/47	Natural Gas
Cogen Tech-Linden 4	CG	159.00	5/1/92	1/1/47	Natural Gas
Cogen Tech-Linden 5	CG	159.00	5/1/92	1/1/47	Natural Gas
East River 6	ST	134.00	11/1/51	1/1/16	Gas/0.3% S FO#6
East River 7	ST	190.00	6/1/55	1/1/20	Gas/0.3% S FO#6
Gowanus GTs	GT	763.93	6/1/71	1/1/26	FO#2
Harlem River	GT	80.00	6/21/01	6/21/56	Natural Gas
Hell Gate	GT	80.00	6/1/01	6/1/56	Natural Gas
Hudson Ave GT 3	GT	17.20	7/1/70	1/1/25	FO#2
Hudson Ave GT 4	GT	15.50	7/1/70	1/1/25	FO#2
Hudson Ave GT 5	GT	16.60	7/1/70	1/1/25	FO#2
Hudson Ave Rpw	ST	60.00	6/1/01	1/1/56	0.3% S FO#6
Kent	GT	47.00	8/1/01	8/1/56	Natural Gas
KIAC (JFK)	CG	110.00	1/1/95	1/1/50	Natural Gas
Narrows GTs	GT	362.70	5/1/72	1/1/27	Natural Gas
Navy Yard GT	CG	293.00	4/1/96	1/1/51	Natural Gas
Poletti	ST	855.00	2/1/77	1/1/08	Gas/0.3% S FO#6
Pouch	GT	48.00	7/1/01	7/1/56	Natural Gas
Ravenswood 1	ST	385.00	2/1/63	1/1/18	Gas/0.3% S FO#6
Ravenswood 2	ST	390.00	5/1/63	1/1/18	Gas/0.3% S FO#6
Ravenswood 3	ST	980.00	6/1/65	1/1/20	Gas/0.3% S FO#6
Ravenswood GTs	GT	541.40	12/1/70	1/1/25	Natural Gas
Vernon Blvd.	GT	80.00	6/21/01	6/21/56	Natural Gas
York-Warbasse	CG	21.00	12/1/94	1/1/49	Natural Gas

Note that the East Coast Power IPP in Linden, New Jersey, connected to New York City by a dedicated transmission line, is treated (in this study, as well as by Consolidated Edison and the NY ISO) as being generation in the City.

Table 22 lists the new generating facilities installed in New York City by 2008 in all the reference and alternative cases for 2008.

Table 22: New Generating Facilities in New York City by 2008

	Unit Type	Capacity (MW)	Installation Date	Fuel
East River 1	CG	180[a]	1/04	Natural Gas
East River 2	CG	180[a]	1/04	Natural Gas
Poletti	CC	500	1/05	Natural Gas
Ravenswood	CG	250	11/03	Natural Gas
PSEG Bergen	CC	550	12/04	Natural Gas

[a] *NY ISO (2002a) reports 180 MW per unit; NY ISO (2003b) reports 144 MW per unit.*

The last unit on this list is not yet fully committed. PSEG Power has two combined-cycle units at its Bergen plant. It has approval to build a dedicated transmission line linking one of those units to Consolidated Edison's West 49th Street substation. This would effectively place the PSEG plant electrically in Zone J, in the same manner that the East Coast Power cogeneration plant is treated as being part of Zone J. The transmission line is scheduled for operation in the third quarter of 2004, but is not yet under construction.

The authors further assume the addition of 2,310 MW in the rest of New York and nearly 14,000 MW in PJM, New England, and Ontario. Most of this capacity consists of gas-fired combined-cycle plants. See Table 23 below.

Table 23: New Generating Capacity in NPCC and MAAC

Transmission-Control Area	**New Capacity** (MW)
NY_AB	0
NY_C	0
NY_D	0
NY_E	0
NY_F	750
NY_GHI	1,080
NY_J	1,110
NY_K	450
NY ISO	3,390
Maritimes	0
ISO New England	2,894
Ontario	1,020
PJM	10,040
Quebec	0
Total	17,344

The authors assume that fossil-fueled units will be retired 65 years after initial operation, unless the authors have specific knowledge of plans to retire a unit. Only units that are planned for retirement reach the 65-year limit. The analysis identifies 3,717 MW of retirements prior to the analysis year of 2008. Three of these stations (Albany, Linden, and Seward) will be repowered, Waterside will be replaced by the new East River plant, and the Poletti plant will remain available if required for New York City reliability. The data in Table 24 below summarize the plant retirements.

Table 24: Generating Facilities in NPCC and MAAC Retired Prior to 2008

	Control Area	State	Unit Type	Installation Date	Retirement Date	Capacity (MW)
Lakeview	Ontario	ON	ST	4/1/62	4/1/05	1,148
Devon	ISNE	CT	ST	1/1/56	10/1/03	215
Mason Steam	ISNE	ME	ST	1/1/52	12/31/07	98
So Norwalk	ISNE	CT	IC	1/1/40	1/1/03	5
Albany	NYIS	NY	ST	10/1/52	2/1/04	380
Poletti	NYIS	NY	ST	2/1/77	1/1/08[a]	855
Waterside	NYIS	NY	ST	11/1/92	12/31/02	166
Westover	NYIS	NY	ST	1/1/44	1/1/05	44
Bethlehem Steel NUG	PJM	MD	ST	7/1/35	1/1/03	153
Linden	PJM	NJ	ST	5/1/57	4/1/03	454
Seward	PJM	PA	ST	6/1/50	10/1/03	199
Total Capacity						3,717

[a] *The retirement of Poletti may be delayed to 2010, depending on the adequacy of capacity, but its operation will be limited.*

For energy purposes, this analysis assumes the retirement of the existing Poletti steam plant between the in-service date of the new Poletti combined-cycle plant (now projected for 2005) and 2008. Were the capacity situation in the City dangerously tight, the retirement of this unit would be deferred. The authors also recognize that the existing steam units at the Reliant Astoria plant would be retired if that proposed repowering is approved and completed.

Proposed Plants

At this point, the following major generation projects have been proposed for Zone J, but are not under construction:

- *SCS Energy's Astoria Energy project,* a 1,000-MW combined-cycle plant that received its Article X certificate in November of 2001 but has yet to gain financing or started construction. This plant could be completed by 2006 if it receives sufficient financial support. Consolidated Edison recently selected SCS Astoria for a contract covering 500 MW of capacity; the terms of this contract are not public, and it is not clear whether SCS will be able to finance the plant based on the contract.
- *Reliant Energy's repowering project for its Astoria plant,* which would replace roughly 1,280 MW of existing generation with about 1,800 MW of combined-cycle capacity. This project appears to be near a full settlement with intervenors in the Article X review. This project could be completed by 2008 if it receives financial support.

- *The 1,100-MW TransGas combined-cycle project in Greenpoint, Brooklyn,* which has been proposed to provide steam (to Consolidated Edison's district-heating system) and electricity. This project filed its Article X application in November 2002.
- *The Sunset Energy Fleet,* a 520-MW barge-mounted combined-cycle plant that recently submitted a revised application, more than two years after the Siting Board found its initial application to be deficient.

Fuel Prices

The authors use publicly available futures prices and historical ratios between the prices of various fuel types to construct a forecast of fuel prices delivered to power plants in the City and neighboring regions.

The authors base their projection of natural gas prices on current futures prices at Henry Hub. For southern and eastern New York, they use forward contract prices for gas swaps from Henry Hub to Transco pipeline's Zone 6 delivery point. For other areas, the analysis relies on Henwood's projection of delivery costs or differentials from Henry Hub to regional generators. See Table 25 below.

Table 25: 2008 Natural Gas Prices
(Dollars per MMBtu)

	NY GHIJK	NY ABCDEF	PJM	Maritime	NEPOOL	Ontario
Jan	6.729	5.391	5.919	4.699	6.724	4.699
Feb	6.574	5.268	5.783	4.659	6.569	4.659
Mar	4.978	4.511	4.692	4.499	4.973	4.499
Apr	4.633	4.279	4.415	4.309	4.628	4.309
May	4.482	4.198	4.306	4.209	4.477	4.209
Jun[a]	5.685	5.401	5.509	5.332	5.680	5.332
Jul	3.466	3.121	3.253	2.937	3.461	2.937
Aug	4.678	4.332	4.465	4.099	4.673	4.099
Sep	4.572	4.288	4.396	4.089	4.567	4.089
Oct	4.597	4.313	4.421	4.154	4.592	4.154
Nov	4.981	4.561	4.723	4.414	4.976	4.414
Dec	5.686	4.944	5.234	4.754	5.681	4.754

[a] *Gas prices are quite variable among months and years. While non-winter prices are generally lower than winter prices, gas prices are high in an occasional summer month. To capture this phenomenon, gas prices are modeled higher In June than in the rest of the non-winter season. Since this analysis focuses on annual results, the specific monthly prices are less important than include the range of price and dispatch conditions.*

The authors projected oil prices for generation from current futures prices for crude oil, the historical ratio of wholesale product prices to crude prices, and historical differentials between wholesale and delivered costs. The analysis derives oil prices by month from the seasonal ratio of oil-product prices to gas price in the Northeast. See Table 26 below.

Table 26: 2008 Petroleum Products Prices
(Dollars per MMBtu)

	0.8% S FO#6		**0.3% S FO#6**	**Kerosene**			**FO#2**		**Jet Fuel**
	NPCC	MAAC	NPCC	MAAC	NPCC	MAAC	NPCC	MAAC	NPCC
Jan	3.194	3.286	4.258	4.350	6.243	6.243	5.853	5.638	6.273
Feb	3.088	3.180	4.117	4.209	6.243	6.243	5.853	5.638	6.273
Mar	3.056	3.148	4.074	4.166	6.243	6.243	5.853	5.638	6.273
Apr	3.131	3.223	4.174	4.266	6.243	6.243	5.853	5.638	6.273
May	3.227	3.319	4.302	4.394	6.243	6.243	5.853	5.638	6.273
Jun	3.244	3.336	4.325	4.418	6.243	6.243	5.853	5.638	6.273
Jul	3.294	3.386	4.391	4.484	6.243	6.243	5.853	5.638	6.273
Aug	3.283	3.375	4.377	4.469	6.243	6.243	5.853	5.638	6.273
Sep	3.421	3.513	4.562	4.654	6.243	6.243	5.853	5.638	6.273
Oct	3.379	3.471	4.505	4.598	6.243	6.243	5.853	5.638	6.273
Nov	3.400	3.492	4.533	4.625	6.243	6.243	5.853	5.638	6.273
Dec	3.276	3.368	4.368	4.460	6.243	6.243	5.853	5.638	6.273

The authors assume that dual-fuel plants would burn the less-expensive fuel in each month. The Ravenswood and Astoria dual-fuel steam plants in New York City are required to burn a minimum amount of oil (during peak periods) as a precaution against the interruption of gas delivery. In summer months, when projected prices would result in these units burning natural gas, the model required that the units burn 10% oil to represent this requirement.

C. Existing and Planned Transmission

Transmission into the City

New York City's transmission connections to other transmission areas comprise the following:

- Transmission connections from NY ISO Zone I (southern Westchester) to Zone J (essentially New York City), which comprise five 345-kV transmission lines and three 138-kV transmission lines, for a combined transfer capability of 3,700 MW. The authors treated Zones G, H, and I as a single transmission area.

- Transmission connections from PJM to NY ISO Zone J (New York City), comprising three 345-kV transmission lines with a combined transfer capability of 1,000 MW.[15]
- Transmission connections from NY ISO Zone J (New York City) to NY ISO Zone K (Long Island), consist of four 138-kV transmission lines with a total transfer capability of 240 MW.

There is a dedicated 230-kV AC line from East Coast Generation in New Jersey to Goethals that acts as a generator lead into New York City with no PJM interconnection, essentially transferring the East Coast Generation plant electrically into Zone J.

Other Transmission Interfaces

Other transmission connections to Long Island include two 345 kV transmission lines from Zones G, H, and I with a total transfer capability of 760 MW; a planned 600-MW transmission interconnection with PJM; and 100 MW of existing and 330 MW of planned transmission-transfer capability from Connecticut.

This analysis assumes New England–to–New York transfer capability of 1,730 MW, split over five lines. NY ISO studies, records, and data show firm interface capacity of 1,325 MW in 2001, 1,250 MW in 2002, 1,800 MW in 2006, and 1,180 MW in 2007. Energy-transfer capability will tend to be somewhat higher than the firm capacity levels. The future estimates are very dependent on the installation of proposed new generation units and their related infrastructure, which are relatively speculative and can be expected to vary considerably from the assumptions used to develop these estimates.

The interfaces between New York and Canada are relatively static and uncontroversial. The authors' assumptions correspond closely with published transfer capability estimates.

The analysis accounts for a total transmission interface from PJM to New York of 3,370 MW, broken down between (1) PSE&G, with 2,443 MW (of which 1,000 MW are the lines to Zone J, discussed above), and (2) GPU, with 927 MW. The GPU transmission ties with western New York, while the PSE&G transmission ties with the City (Zone J), southeastern New York (Zones G, H, and I), and Long Island (Zone K). Historical estimates by NY ISO of existing transfer capability from PJM to NY are around 2,300 MW, while future pro-

[15]Additional transmission lines interconnect between PJM and NY ISO Zone G (Hudson Valley) and between PJM and western New York State and bring the total PJM–New York transfer capability to the vicinity of 3,000 MW.

jections range from 2,100 to 2,800 MW. As for the New York–to–New England connections, the PJM-NY ISO transmission-interface capabilities are higher than reported firm capacity limits, as is appropriate for energy transfers. Most importantly, the estimate of PSE&G's portion of PJM-to–New York transmission capacity is consistent with published estimates and studies. The GPU portion of PJM-to–New York transmission capacity will be of limited impact here, since it connects to western New York and does not materially affect what can be delivered to New York City.

V. Central-Resource Options

A. Generation

This study considers the following three central-station generation technologies for installation in the City:

- New combined-cycle plants, similar to those that have been proposed (e.g., TransGas), and in some cases approved (SCS Astoria, Poletti Expansion) for construction in the City;
- New combustion turbines, similar to the NYPA turbines;
- Repowering existing steam plants to combined-cycle operation, similar to the repowering of East River and the proposed repowering of Astoria 4–6.

The analysis includes estimates of construction costs, financing costs, O&M, fuel costs, efficiency and reliability.

Combined-Cycle Costs and Performance

Capital Costs

The authors develop estimates of the capital costs of combined-cycle units from the most reliable sources available. In the case of combined-cycle units, the capital-cost assumptions are based on the costs and performance of recent actual installations and projections by plant developers for projects that have received financing.

The plant costs of combined-cycle plants that are completed, under construction, or in development in New York City range from $1,000/kW to $1,335/kW (in 2002 dollars). This range may overstate actual cost differences; for example, there may be differences in reporting of such factors as owner's costs, installation costs, transmission interconnection costs, and the impact of wear and temperature on unit capacity. The authors adopted a capital cost of $1,200/kW.

Fixed and Variable Non-Fuel Operating Costs

Operating costs are broken into two categories: variable and fixed. The authors estimated total operating costs for new combined-cycle plants at $41/kW-yr. (in year-2002 dollars), including a 20%-overhead adder. Of the total, $35.5/kW-yr. is considered fixed, and $5.4/kW-yr. (applied as $1.10/MWh) is considered variable.[16]

The authors developed the estimate of the fixed operating costs through the following steps:

1. averaging the total 1995–1997 non-fuel O&M reported to FERC for all post-1990 combined cycle units that report to FERC ($28.26/kW-yr. in 2002 dollars),
2. subtracting a $1.10/MWh allowance for variable O&M ($5.40/kW-yr. at the capacity factors of the actual plants),
3. adding 20% overheads,
4. adding experience-weighted average capital additions for the same set of units ($8.05/kW-yr.).

The 20% overhead adder reflects administrative and general costs, including payroll taxes, benefits, personnel expenses, legal costs, and the like. Not much information is available on the overhead costs of competitive generation companies. The 20% overhead adder assumes that there will be some improvement over utility experience, including generation-only companies, which typically have administrative and general costs of more than 30% of O&M.

Operating Performance

This analysis assumed that new combined cycle units will have forced outage rates of 5%, maintenance outage rates of 5% (about eighteen days per year), and full-load heat rates of 7,100 Btu/kWh. The outage rates are almost certainly optimistic for the first few years of operation of new units, given recent experience, but may reflect mature operation.

In comparing this heat-rate projection to reports of anticipated efficiencies of future combined-cycle units, it is important to recognize that real operating

[16] The split between fixed and variable costs is based on Wong, Amelang, Cannella, et al. (1993) and Eisman (1997).

conditions will cause most plants to have higher heat rates (i.e., lower efficiency) than is anticipated under optimal conditions.[17] The following factors raise heat rates from theoretically achievable values:

- the energy used in operating plant auxiliaries,
- the loss of efficiency due to the use of evaporative or dry cooling, rather than the more-efficient once-through water cooling,
- the effect of ambient temperatures higher than the standard conditions,
- the effects of operation at partial load and start-up energy costs due to economic dispatch and outages,
- fouling of turbine blades and other equipment between maintenance outages,
- unrecoverable wear and tear, especially on turbine blades.

Consequently, an accurate statement about the heat rate achieved on a test bed may be irrelevant to estimating the efficiency of units in actual operations.

Cumulatively, these effects can be significant. While Siemens reports that its v84.2 turbine produces a combined-cycle heat rate of 6,630 Btu/kWh at lower heat value—the equivalent of 7,293 Btu/kWh at higher heat value—the operators of two combined-cycle plants that use the v84.2 (Bergen and Manchester Street) reported heat rates of 7,865–8,089 Btu/kWh in the years 1995–1997.

Financing and Cost Recovery

The authors assume a thirty-year recovery period for combined-cycle plants. Thirty years is shorter than the book life assumed by traditional utilities, but longer than typical financing periods for merchant plants. Pressure on developers to repay debt over fifteen–twenty-five year periods, and to maintain adequate coverage ratios above debt-service costs, will require higher annual

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[17] Some reported heat rates (especially from international sources) use the lower heating value (LHV) of the fuel, excluding the 10% of the energy in natural gas that is bound up in the vaporization of the water produced by combustion. Common U.S. practice is to report fuel prices and heat rates at the fuel's higher heating value (HHV), which are 10% lower than the same inputs at lower heating value. Natural gas has about 900 Btu/ft.^{3} in LHV, and about 1,000 Btu/ft.^{3} in HHVterms. A plant reported as using 6,300 Btu/kWh in LHVwould use seven cubic feet of gas per kilowatt-hour. In HHVterms, the same seven cubic feet of gas would be counted as using 7,000 Btus, and the plant would be reported as having a heat rate of 7,000 Btu/kWh. Changing the way one measures the Btus in the gas does not change the cost per cubic foot, the number of cubic feet required to produce a kWh of energy, or the fuel cost per kWh.

fixed charges than would longer financing periods. Consistent with current federal tax code, the financing costs reflect accelerated depreciation over a tax life of twenty years.

The assumed capital structure for new combined-cycle units is as follows:

Table 27: Assumed Capital Structure for New Merchant Plants

	Share	Rate
Equity	55%	12.0%
Debt	45%	7.5%

This financial structure is based on the following inputs:

- the return on BBB-rated bonds debt rate, which was about 7.5% in late 2002,
- the median percent indebtedness of generation companies with BBB bond ratings (Moulton 1997, 12),
- a projected return on equity that assumes that the market for power improves and the current industry accounting issues are resolved.

The authors also assume a federal income-tax rate of 34% and a state income-tax rate of 8%, for a combined rate of 39.3% and an after-tax cost of capital of 8.7%.

These assumptions, combined with property taxes (assumed to be 5% of initial plant investment) and the new unit's book-life and tax-life assumptions, yield a real-levelized carrying charge of 13.80% of the combined-cycle construction cost.

Combustion-Turbine Costs and Performance

Few combustion-turbine plants have been recently completed or are under construction or in development in the City. Most of those (in particular, the NYPA turbines) were built under severe time constraints, increasing costs. The analysis uses a combustion-turbine capital cost of $1,000/kW (in year-2002 dollars) based on information on the costs of new combustion turbines in and near the City

The analysis is based on an assumed total operating costs for the new combustion turbine units of $7/kW-yr. (in year-2002 dollars), all of which is treated as fixed.

This figure was developed by

- averaging the total 1992–96 non-fuel O&M reported to FERC for all post-1990 combustion turbines that report to FERC ($3.76/kW-yr. in 1998 dollars),
- adding 20% overheads,
- adding experience-weighted average net capital additions for the same set of units ($1.47/kW-yr.).

The authors assume that new combustion turbines have forced outage rates of 2%, maintenance rates of 5%, and full-load heat rates of 9,700 Btu/kWh.

The analysis is based on an assumed twenty-five-year book life for combustion turbines. Consistent with current federal tax code, the financing costs reflect accelerated depreciation over a tax life of fifteen years. That life, combined with the other financial assumptions, property taxes (assumed to be 5% of initial plant investment), and the new units' assumed book life and tax life, yields a real-levelized carrying-charge rate of 14.61% for the combustion-turbine plants.

Repowering Costs and Performance

Repowering generally refers to the replacement or enhancement of part of a power plant. While other approaches have been used, repowering generally means creating a combined-cycle power plant by some variant of one of the following:

- Replacing or supplementing the boiler of an operating unit with a heat-recovery steam generator fired by one or more combustion turbines, while reusing the existing steam turbine, generator, auxiliary systems, fuel supply and/or transmission connection.
- Performing the same work at a retired unit.
- Closing down an operating power plant, building a new plant next to it, and reusing the existing transmission and fuel facilities.[18]
- Tearing down a power plant, building a new plant on the site, and reusing the existing transmission and fuel facilities.

Only detailed engineering and economic analyses can determine the optimum size of the repowered unit and the extent to which existing facilities can be refurbished and reused. Repowering can be less expensive than building a new

[18] In many cases, repowered plants can reuse the existing cooling system. In New York City, this does not appear to be feasible, because the New York State DEC will not allow the continued use of existing once-through cooling systems in the City.

plant of the same capacity, avoiding the costs of land, transmission, fuel connections, and in some cases the steam turbine and generator. On the other hand, site limitations for repowering can increase costs, especially if an existing plant must be kept operating while the new plant is being built around it. Repowering typically both replaces older, inefficient generating plants and adds generating capacity.

Repowering older power plants can provide important environmental and electric-system-reliability benefits. These include improved plant availability, lower plant operating-and-maintenance costs; increased plant capacity and generation; reduced facility heat rates (which lead to significantly more-efficient fuel use); reuse of industrial sites; up to 98% reductions in water intake and related fish impacts; and large reductions in NOx and SO_2 emissions both overall and in terms of emissions per MWh of electricity.

Consequently, repowering an existing facility instead of building a new plant at a new site can provide a range of benefits. The owner gains a newer, much-more-efficient generating facility. The communities near the existing facility benefit through reduced air emissions and water usage. Other neighborhoods benefit from retaining other potential power-plant sites for developments of potentially higher value to the community. The reliability of City's electric system benefits from the replacement of aging power plants with more reliable new capacity. Electric energy costs can be reduced through the replacement of aging, inefficient, plants and the addition of new, high-efficiency, combined-cycle capacity.

The last factor—lower energy prices—is at least partially offset and may be overwhelmed by the potential for exercise of market power by the owner of the repowered unit. In the City, the three owners of divested Consolidated Edison generation can exercise market power in the markets for energy, ancillary services and (if the demand curve method for ICAP is eliminated in the future) capacity. Adding to the amount of capacity controlled by one of those owners would increase its market power.[19] Repowering the Consolidated Edison plants would not pose similar problems.[20]

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[19]That increase in concentration could be offset by divestiture of other generation, such as the combustion turbines owned by each of the three major generating companies in the City.

[20]The New York Power Authority is also unlikely to exert market power at Poletti steam, if that is repowered, both due to its public mission and its smaller market share compared to, for example, Reliant if that company repowered Astoria.

The repowering of existing power plants has become a common practice in the electric industry since the early 1990s. One repowering project is currently under construction in upstate New York, at the PSEG Bethlehem Energy Center outside Albany. When completed in 2005 this project will add 750 MW of combined-cycle capacity to the electric system, including 350 MW of new generating capacity beyond that provided by the older facilities being replaced.

In-City Repowering Projects, Proposals, and Possibilities

East River Repowering Project

Consolidated Edison is currently implementing a virtual repowering on its steam-distribution system, replacing a cogenerating boiler plant at the Waterside station with a combustion-turbine cogenerating plant at East River. Consolidated Edison's East River Generating Station is located in Manhattan between East 13th and East 15th Streets, from the FDR Drive to Avenue C. The repowering project will add two combustion turbines at the facility, each with a nominal electric capability of 180 MW. Heat-recovery steam generators will be added to provide steam for Consolidated Edison's district-heating steam system. The repowering will let Consolidated Edison retire the Waterside Station and sell its very desirable site, providing rate relief for its customers and allowing development that is likely to be beneficial to the City's economy. The repowered facility is currently projected to be in service by the fourth quarter of 2004.

Astoria Repowering Project

Reliant Energy has a proposal pending to repower its Astoria Generating Station. This repowering ultimately would add another 1,816 MW of combined-cycle capacity, including 562 MW of new capacity, to the electric system in New York City.

The existing Astoria Generating Station is located in northwest Queens. It has four units in operation (Units 2 through 5) that provide a total of 1,254 MW of electric generating capacity.[21] The repowering project will involve replacing the four boilers in Units 2 through 5 with six new Siemens Westinghouse combustion turbine generators and refurbishing and reusing the existing steam-turbine generators, condensers, and auxiliary equipment. Generating capacity of the station will increase by 562 MW, while the rate of air emissions will be reduced by more than 75%, according to Reliant. The amount of East River water used to cool the station will be reduced by more than 97%.

[21] Units 3, 4, and 5 are considered to be divested units. Unit 2 had been retired when Consolidated Edison sold the plant to Orion. The reactivation of Unit 2 is considered new generation.

A September 5 2000 press release from Orion (now owned by Reliant) estimated the total cost of the repowering at approximately $750 million.[22] This is about $414/kw for a 1,812-MW facility. Since that time, Reliant has redesigned the cooling system to satisfy concerns expressed by Consolidated Edison about salt deposition from the cooling tower. The authors do not believe that the cost estimate is realistic, and use a value of $800/kW as the optimistic end of the potential in-City repowering costs. For many plants, the cost of the repowered facility may $1,000/kW or more.

Poletti

As part of getting approval for its 500-MW Poletti Expansion combined-cycle plant, NYPA agreed to retire its existing 850-MW Poletti steam plant as early as February 1 2008, but no later than January 31 2010, depending upon a determination of when closing that facility would not impair electric-system reliability in New York City. At the same time, NYPA has committed to filing, by July 1 2005, an application to the Siting Board for a certificate to build a replacement combined cycle generation facility, unless it has been determined that such replacement capacity is not needed to meet NYPA's commercial obligations or to maintain system reliability.

NYPA (2000, 1) has suggested that it would build a new 750-MW combined-cycle plant to replace the existing 825-MW Poletti facility.

In 1997 and 1998, NYPA produced a series of Poletti repowering studies that used the following estimated capital costs, all in 1997 dollars:[23]

- $558/kW for a 900-MW repowered unit ($502 million)
- $508/kW for a 1,300-MW repowered unit ($660 million)
- $470/kW for a 2,000-MW repowered unit ($940 million)
- $558/kW for a new 240-MW combined-cycle unit ($134 million)

The documentation for these estimates (Haase 1997; NYPA 1998) is very limited.

NYPA (1998) analyzed two additional partial-repowering approaches.[24] It estimated that the cost of repowering the existing Poletti facility with three gas turbines and heat-recovery steam generators would be $367 million. In this

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[22]It is not clear whether this value was intended to include all costs of the plant, including inflation.

[23]These studies apparently led to NYPA's decision to pursue the 500-MW Poletti Expansion Unit.

[24]This study also weighed building combustion turbines or two new 252-MW combined-cycle units.

option, the flue gases of each gas turbine would feed a heat-recovery steam generator supplying supplementary steam to the existing Poletti turbine, whoch would reduce the fuel use of the existing Poletti boiler by approximately 28%. Total site capacity would increase by 504 MW.

A second option, called hot-windbox technology, would supply the hot exhaust gases of the gas turbines directly to the existing Poletti boiler. The constraints on the amount of hot exhaust gas that would be useful to the boiler limit this scheme to two gas turbines, providing approximately 336 MW of additional capacity. The Poletti boiler would be derated by approximately 45 MW by this option. The net increase of 191 MW would cost about $200 million, or about $670/kW.

These partial-repowering approaches would save on investment, preserve the existing plant capacity (and ability to fire some oil), and improve Poletti's efficiency. However, it is not clear that they would result in a plant either as efficient or as operationally flexible as a new combined-cycle or a fully re-powered plant.

Consolidated Edison Steam Sites

Other power plants in New York City also are potential candidates for re-powering. For example, as part of a settlement in New York Public Service Commission Case 99-S-1621 Consolidated Edison is studying the potential repowering of three of its remaining steam system plants, i.e. Hudson Avenue, 59th Street, and 74th Street. A number of repowering options are being examined for each of these facilities. For Hudson Avenue, Consolidated Edison is investigating the following options:

- replacement dual-fuel boilers;
- one small combustion turbine and three boilers, for a total electric capacity of 62 MW net;
- three small combustion turbines with a heat recovery steam generator, for a net electric capacity of 200 MW;
- two larger combustion turbines—a heat-recovery steam generator and a steam turbine—which would produce a 520-MW net facility.

The option of replacing dual fuel boilers and adding small combustion turbines (62 MW net output) at the existing 59th Street and 74th Street facilities also are being examined. These facilities appear too small, however, to add larger electric generating capacity.

The cost of each of these repowerings depends on the scope of the work being performed and the size of the existing and repowered facilities. For example, Consolidated Edison (2001b) has estimated that repowering Hudson Avenue to become a 520-MW net combined-cycle plant with a dry condenser would have a capital cost of $381 million in 2006 dollars, or about $670/kW in 2002 dollars. If this value is anywhere near correct, this would be a very attractive location for the next combined-cycle plant in the City.

Consolidated Edison is performing detailed engineering and economic analyses to determine the preferred option for each of these facilities.

Other In-City Repowering Possibilities

The Keyspan-owned Ravenswood Units 1–3 and the NRG-owned Arthur Kill Units also are potential candidates for repowering but there is no evidence that either company has studied the potential costs and benefits of undertaking such repowerings.

Other Repowering Assumptions

Other than capital costs, the authors assume that steam plants repowered to combined-cycle operation would have the same operating performance as new combined-cycle units. The analysis also assumes that, where operating generation would be replaced, the avoided O&M costs of the existing old steam plants would be approximately equal to the O&M of a like amount of new combined-cycle capacity.

B. Transmission

All of the proposed additional transmission ties for interconnections would be high-voltage DC connections, from PJM, upstate New York, or New England and the Maritimes. To the extent possible, the authors have avoided analyzing or endorsing specific proposals, and have instead analyzed standardized or typical interconnections, based on the actual proposals and other publicly available data.

Proposed DC Ties from PJM to NYC

A number of transmission lines have been proposed from New Jersey to New York City, including the following:

- The approved PSEG Power Cross-Hudson tie from Linden to West 49th Street, which would be interlocked to prevent general PJM-to–New York power flows, and would only serve to move a PSEG generator electrically from Bergen County New Jersey to Zone J.

- Transenergie's proposed 660-MW high-voltage DC line from PJM to West 49th Street or Farragut.[25]
- A similar proposal by PG&E Liberty Generating.
- The Neptune Phase 1 Project, for 600–750 MW of DC transmission capacity from Linden substation in New Jersey to W. 49th Street substation and a similar amount from Sayreville substation in New Jersey to either Consolidated Edison's W. 49th Street or Farragut substations, or to LIPA's Newbridge substation.[26]

Only the Cross-Hudson line is currently an active proposal, but these indicate the wide range of potential connections.

The authors estimate a likely project cost range of $400 to $500 million for the Neptune projects. If constructed alone, the Linden–City portion of the project is likely to range from $180 to $225 million, while the Sayreville–City portion of the project is likely to range from $240 to $300 million.

Proposed DC Ties from Albany to NYC

The Empire Connection high-voltage DC transmission project proposed by Conjunction LLC would span some 150 miles from Albany to lower Manhattan and provide 2,000 MW of maximum capacity. The transmission lines would be mostly overhead, with a small portion underground. The project's likely cost falls in a range of $750–$850 million. For a 1,000-MW project, the project's likely cost would range from $450 to $510 million, while the likely cost for a project with 500 MW of capability would range $270–$306 million.

Proposed DC Ties from New England and Canada

The authors estimate the potential cost of the Neptune Phase-1 project, with 1,500 MW of DC transmission capacity from Colson Cove (New Brunswick) to either Manhattan or Long Island (or some combination of the two) at $1.5–$2.0 billion. There are substantial risks and contingencies associated with this project that are difficult to evaluate. This estimated cost range should be considered as plus or minus $0.5 billion.

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[25]Transenergie later proposed terminating the line at the Rainey substation in Long Island City.

[26]The Neptune Projects' Article VII applications (NY PSC Case 02-T-0036) described them as providing 600 MW. The nominal 600-MW rating could be exceeded, if proper design considerations are taken into account. Yirga (2001a, I; 2001b, i) models the Neptune Projects at 750 MW per pole. Each could likely function at 750 MW for an indefinite period of time.

VI. Distributed Resources

A. Energy Efficiency

Achievable Potential

The authors developed estimates of the achievable demand-side-management potential within Zone J by sector (commercial, residential and industrial) and market segment (new construction, renovation, natural replacement and remodeling, and discretionary retrofit). "Achievable" in this sense refers to what can actually be installed and will be acceptable to consumers and other decision-makers, based on performance of past DSM programs. Economic screening was not central to developing this estimate, but the authors deleted a number of measures with relatively high costs from the residential sector.

The methodology for developing those estimates is discussed in Appendix A.

The data in Table 28 below indicate the cumulative annual MWh energy savings and MW peak savings achievable by 2008, for the industrial, commercial and residential sectors. These values represent the estimate of the reductions that could be achieved in 2008 from efficiency efforts started in the near future.

Table 28: Summary of Achievable Energy Efficiency Potential, NY City, 2008

	Annual Potential (GWh)	**Summer Peak** (MW)	**Winter Peak** (MW)	**Present Value of Net Cost**
Industrial	3	less than 1	less than 1	$0.2 M
Commercial	4,148	1,238	484	$1,872 M
Residential	680	236	98	$207 M
Total	4,831	1,474	583	$2,080 M

The commercial sector offers the major share of savings with more than 80% of annual energy and peak MW savings. The remaining savings are almost all from the residential sector. New York City's small industrial sector provides negligible savings.

Table 28 also provides lifetime present-value net costs in 2002 dollars for the industrial, commercial and residential sectors through 2008. Those costs include the capital and operating costs of the energy efficiency improvements, offset by savings in other fuels (mostly natural gas), water, operating and maintenance (such as labor for replacing light bulbs), and the deferred cost of replacement equipment.[27]

Magnitude of Demand-Side-Management Resources

Some of the achievable potential described above would be captured by continuation of existing energy efficiency programs, such as those administered by NYSERDA, and by improvements in energy codes and standards. It is the authors' understanding that the Consolidated Edison load forecast that underlies the analyses in this report does not incorporate any effects from future programs. To that extent, some substantial fraction of the potential would be captured by programs and initiatives that are likely to occur without any special effort by the City. The authors estimate this business-as-usual fraction to be about 20%, which would provide 250–300 MW of summer peak reduction.

In addition, the load reductions from energy-efficiency programs may be offset to some extent by rebound resulting from the income and price effects of the higher efficiency. Since energy efficiency reduces customer bills, they have more money to spend, some of which may be spent for more energy-consuming equipment, or for increased use of existing equipment. In addition, each additional hour of lighting, or degree of cooling, is less expensive with more-efficient equipment, so customers may choose to use more of the less-expensive energy service.

Estimates of the effect of rebound vary widely, from zero to as much as 50% of the efficiency improvement (for example, Gottron 2001). Rebound is apt to be low in New York City applications, for the following reasons:

- The City has an unusually large amount of space in which the energy user (the tenant, employee or hotel guest) does not pay the electric bill for any use, or at least for space conditioning. In these circumstances, a more-efficient cooling system in an office building or apartment tower has no effect on the tenants' choice of thermostat setting.

[27] If a fifteen-year-old chiller is replaced with a more-efficient one in 2005, for example, the cost computation takes credit for avoiding the replacement of the old unit at the end of its life, around 2010.

- Improved controls in large buildings may allow occupants to reduce cooling in over-cooled spaces and lighting and glare in over-lit spaces.
- Most commercial space in the city is probably lit and cooled to the point desired for occupant comfort. If a lighting retrofit reduces the cost of the same amount of lighting by 50%, occupants would be unlikely to install additional lighting to make the space much brighter (let alone twice as bright).
- Rebound is likely to be greatest in the low-income-housing market, where consumers may put up with a cold home in winter and a hot home in summer to reduce their utility bills. Space heating is not a major residential electric end-use in the City. For many low-income New Yorkers, air conditioning use is limited not by the cost of electricity, but by the cost of air conditioners. Even a program that eliminated the cost differential between standard and high-efficiency air conditioners, or allowed consumers to trade in old air conditioners for new ones, would not overcome the first-cost problem.
- Adding sub-metering of electricity on previously master-metered buildings typically results in a reduction in usage of about 25%, suggesting that making electricity entirely free (the equivalent to removing sub-meters) would increase usage about 33%. Efficiency improvements would have much smaller price effects.

It is also important to remember that while rebound decreases the load reduction from energy efficiency, it generally represents an improvement in service quality to the consumer. If, for example, some low-income residential customers who use their inefficient air conditioners only when the ambient temperature is over 95° upgraded to more efficient air conditioners and used them whenever the temperature is over 90°, the energy-efficiency program would not have been a waste of effort. In addition to the reduction of peak load, the program would have provided many hours of additional comfort to people who could not otherwise have afforded it.

B. Distributed Generation

Detailed development of distributed generation potential is very data-intensive and requires information about individual buildings. This plan, with its more-conceptual scope, discusses in general term the potential for cost-effective distributed generation in the City.

There are a number of applications for small generating units, in the range of a few kW to a few MW. These include using the waste heat in combined heat and power, relieving local transmission-and-distribution constraints, increasing customer reliability or power quality for critical operations, and reducing line losses in large buildings.

Promising distributed-generation technologies include microturbines (and other small combustion turbines), clean small reciprocating engines, fuel cells, Stirling engines (which are apparently close to commercial availability), and photovoltaics. All but the photovoltaics can provide waste heat for CHP. Fuel cells provide the best power quality and extremely high reliability, although all these technologies are likely to contribute to relief of peak load in summer-peaking areas, such as New York City. Photovoltaics are suitable for installations on rooftops, and Stirling engines are likely to be small and easily sited high in buildings, relieving load on internal distribution systems.

Avoiding Local T&D Costs

As load grows, utilities must add or upgrade equipment to carry the heavier flow: transmission lines (often at multiple voltages), substations that transform power from one voltage to another, primary distribution lines (which carry power from the last substation), line transformers (which reduce the primary voltage to the low voltages used in homes and businesses), and secondary lines. Some of this equipment, especially transformers and underground lines, also wears out faster when it is heavily loaded many hours a year.[28] Analyses of the costs of load-related T&D expansion run in the range of \$50–\$150/year for each kilowatt of load.

If distributed generation at or near customer loads reduces the peak flow of power through the transmission and distribution systems, the utility is likely to need fewer system upgrades, saving money. The question is: to what extent do distributed generators provide those reductions?

The T&D benefits of distributed generation vary over time and space. Any one distributed generation unit would have the same problem as a wind plant: So long as the owner and other customers want firm service even when the microturbine is not operating, the utility must build as though the distributed

[28]As load increases, so do losses, and the heat generated by those losses. The heat tends to break down the insulation around wires and in transformers, both in substations and along the street.

generation did not exist.[29] With many distributed generators in an area, the probability that all the units will be unavailable at one time falls.[30] If there are 15 units on a network, with a 10% outage rate, more than 6 will be out of service simultaneously only about 2 hours annually; with 25 units, more than 8 will be out simultaneously only about 3 hours annually. The chance that these simultaneous outages will fall on the peak hours is small. With these numbers of units, the reduced demand on the T&D system is about 60%–70% of the installed capacity.

The ability of distributed generation to reduce T&D investments will be greater for equipment that serves large areas and can be affected by many installations. The potential is high for much of Consolidated Edison's service territory, given the large amount of load served by most substations, primary network, and secondary networks.[31]

The actual benefits of distributed generation (microturbine or otherwise) will vary between networks within the City. Where local T&D capacity is much greater than load, and load is growing slowly, the benefit of distributed generation will be small. Where capacity is tighter, and load is growing, distributed generation is more likely to delay the need to add capacity.

Combined Heat and Power

Power generation with heat recovery, or Combined Heat and Power (CHP), is an important class of distributed generation that can reduce energy consumption, provide T&D benefits, and lessen environmental impacts.[32] Small power generation typically comprises an engine or prime mover that creates shaft power that drives an electric generator. A CHP application recovers the heat from the prime mover to produce steam or hot water for useful purposes. The combination of electrical and thermal energy generation boosts overall efficiency from 30–33% in simple-cycle generation to 70%–80% in cogeneration.

[29]Where the transmission-and distribution supply is adequate under most circumstances, and is only overloaded at very high-load hours in the event of a major equipment failure, even a single distributed generation unit may provide adequate reliability for back-up. Consolidated Edison depends on its own small turbines (such as those at 74th Street) to support some parts of the distribution system.

[30]This analysis assumes that the microturbines are either constantly on, or can be started quickly in response to load increases, outages on the T&D system, and outages of operating microturbines.

[31]A customer, such as a hospital, may accommodate many distributed generation units for CHP (cogeneration) and back-up generation.

[32]"Combined heat and power" is also known as cogeneration.

The penetration of CHP into commercial and smaller industrial markets has been slowed by a variety of market and regulatory barriers. Overcoming the barriers for small distributed CHP plants will require cooperation of regulators and local distribution utilities to ensure that the plants (or their hosts) receive credit for their T&D benefits, as well as finance sources. Developers of these plant may also require assistance in obtaining special financing, which could be supllied by public entities.

Hedman, Darrow, and Bourgeois (2002) evaluated the technical potential for new CHP by screening a facility database according to size and application criteria that would allow CHP system operation. They identified about 3,300 MW of potential for new CHP in Consolidated Edison's service territory at more than 10,000 sites. CHP's future market penetration will depend on CHP's economic advantage, siting potential, and development speed of new projects. Hedman, Darrow, and Bourgeois (2002, 6-5) estimate new CHP installations for 2007 and 2012, disaggregated to two large areas (upstate and downstate), for two policy cases: business-as-usual and "accelerated." They describe this as including

> gradual evolution from current to advanced technology, immediate reduction of standby charges to one-third to one-half of the base case levels (for downstate and upstate respectively), immediate implementation of CHP Initiatives that offer tax incentives equivalent to 10% of initial cost, and increase in customer awareness and adoption rates.

Interpolating to 2008, assuming that Consolidated Edison's portion of CHP additions is proportional to its share of downstate potential, and assuming that CHP is as attractive in the City as in Westchester, about 150 MW of CHP would be installed by 2008 in the business-as-usual case and 340 MW in the accelerated case.

The NYSERDA analysis (Hedman, Darrow, and Bourgeois 2002) is limited in many respects. It assumes that all electricity would be used on site, limits commercial applications of CHP to those providing thermal energy for space- and water-heating, considers only customer economics for energy supply, and does not reflect the value of CHP for

- reducing utility T&D costs,
- market prices for energy and capacity,
- improving customer power factor,
- providing on-site back-up power supply.

A similar study that included situations in which the generator sells power back to the utility (in which the is heat used for absorption chilling or regenerative dehumidification), and that reflected the additional benefits of CHP for the utility and the customer, might have found dramatically increases technical, economic, and achievable potential for CHP.[33]

Microturbines

Capital Costs

The authors developed estimates of the capital costs of microturbines from the most reliable sources available. Microturbines are an emerging technology with few manufacturers. As a result, data on the cost and performance of actual installations are scarce. Therefore, this analysis also relied on planning assumptions from government agencies.

To develop an estimate for the capital cost of microturbines, the authors reviewed estimates developed by government agencies for use in resource planning, in particular, the California Energy Commission (2002) and the Maine PUC (Resource Dynamics 2001). With the exception of a report from Bowman Power Systems, a microturbine manufacturer, the authors were unable to obtain actual project costs.

Table 29 below summarizes the range of cost estimates available. The cost per kW varies with the equipment components included in the unit, the cost of installation, and inversely with the size of the unit. The capital cost of a unit with a recuperator but without waste heat recovery ranges from $900/kW to $1,650/kW, averaging about $1,200/kW.[34] A combined-heat-and-power microturbine unit would cost on average $200/kW more.[35]

The capital costs reported in Table 29 are expressed in terms of dollars per kW measured at 59 degrees Fahrenheit. Ambient temperatures higher than these standard conditions would reduce the effective capacity of the unit, but the authors do not know by how much.

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[33]On the other hand, the study also did not consider the technical challenges of installing distributed generation in a dense urban area like New York City, where installation space may be limited and the proximity of residential neighbors may complicate noise abatement.

[34]A recuperator increases the efficiency of the unit by using exhaust gases to preheat the combustion air.

[35]In some applications, the cogeneration unit may be replacing an existing conventional boiler that is inefficient but reliable as a backup. In this case, the cost of the microturbine should be reduced to reflect the cost of a new boiler.

Table 29: Projected Capital Cost of Microturbines

Est.	Source	kW	Installed Cost ($/kW)	Equip Cost ($/kW)	Installation Cost ($/kW)	Installed Cost w/o Cogen $75–350 ($/kW)	Included in Source Estimate
Planners' Ratings							
2002	Resource Dynamics	30–400	1,000 –1,400			1,000–1,400	cogen, recuperator
2001	Resource Dynamics (for Maine PUC)	30–200		900 –1,300	250–600	*1,075–1,550*	cogen, recuperator
2002	California Energy Commission	25–500		700 –1,100	200–550	*900–1,650*	recuperator
Manufacturers' Ratings							
2002	Bowman Power Systems	80	1,125			*775–1,050*	cogen, recuperator
2002	Bowman Power Systems	50	1,500			*1,150–1,425*	cogen, recuperator

New York City installation costs are likely to be at the high end of the range, due to high service charges and space constraints.

Sources: Lemar (2002, 9); Resource Dynamics (2001, 25); California Energy Commission (2002); Mehrayin (2002, 4, 17, 20). Cost of heat recovery of $75–$350/kW from California Energy Commission (2002).

Values calculated from original source estimates are italicized.

The commercial production of microturbines is in its early stages. Manufacturers and planners, such as the Department of Energy and the California Energy Commission (2002), project that as the market improves and production increases, microturbine costs will decrease below $650 due to economies of scale.

Operating Costs and Performance

Based on review of government planning assumptions and manufacturers' design specifications, the analysis estimates fixed O&M costs for microturbines to be $5/kW and variable non-fuel O&M costs to be $0.01/kWh. Table 30 presents the estimates of O&M costs obtained. As the data in Table 30 indicate below, planners set a wide bandwidth about their estimate. This uncertainty reflects the limited operating experience of a new technology.

Table 30: Projected Microturbine Operation-and-Maintenance Costs

	Source	kW	Fixed O&M ($/kW-yr.)	Variable O&M non-fuel ($/kWh)	Components Included in Estimate
Planners' Ratings					
2001	Resource Dynamics (for Maine PUC)	30–200	3–10	0.005–0.010	cogen, recuperator
2001	Resource Dynamics (for Maine PUC)	30–200	3–10	0.005–0.010	cogen, no recuperator
2002	California Energy Commission	25–500		0.005–0.016	recuperator
Manufacturers' Ratings					
2002	Bowman Power Systems	80		Less than 0.015	cogen, recuperator
2002	Capstone Turbine Corporation	60	.	0.008	recuperator

Sources: Resource Dynamics (2001 25); Commission (2002); Bowman Power Systems (2001, 4) Grossman (2002, unnumbered 6th page).

Table 31, below, summarizes the authors' estimates of microturbine efficiency, which are based on planning assumptions and manufacturers' design specifications. Note that planners show less confidence in projections of the performance of microturbines than do manufacturers.

Based on this review, the authors estimate that the heat rate of a microturbine with a recuperator but without heat recovery is 13,300 Btu/kWh and the net heat rate of a unit with heat recovery is 5,600 Btu/kWh.[36] Depending on its electric efficiency and overall efficiency as well as the efficiency of the conventional boiler being displaced, the net heat rate of a unit with heat recovery could be as high as 6,630 Btu/kWh and as low as 3,676 Btu/kWh.

[36]The heat rate of 5,560 Btu/kWh is determined as follows: For the microturbine with heat recovery, the authors assume that the electric efficiency is 26% (or 13,300 Btu/kWh) and the overall efficiency is 75%, and the fuel energy recovered for heating is 49% (75%–26%), or 6,517 Btu. Each Btu of heat energy displaces more than a Btu of fuel, since the conventional boiler that the cogenerator displaces is less that perfectly efficient. The authors assume a boiler efficiency of 85%, so the recovered energy replaces 7,700 Btu of fuel (or 58% of the fuel energy input to the cogenerator). That leaves a net fuel use for generation of 13,300–7,700 = 5,600 Btu/kWh and a net electric efficiency of 61% (3,413 Btu out ÷ 5,633 net Btu in).

Table 31: Projected Microturbine Efficiency

Date of Estimate	Source	Size (kW)	Stand-Alone Heat Rate[a] (HHV)	Electric Efficiency (LHV)	Overall Efficiency (LHV)	Components Included in Estimate
Planners' Ratings						
2002	Resource Dynamics			25-30%		recuperator
2001	Resource Dynamics (for Maine PUC)	30–200		20–30%	60–75%	cogen, recuperator
2001	Resource Dynamics (for Maine PUC)	30–200		14–20%	75–85%	cogen, no recuperator
2002	California Energy Commission	25–500		20–30%		recuperator
Manufacturers' Ratings						
2002	Bowman Power Systems	80	*25,029*	15%		no recuperator
2002	Bowman Power Systems	80	*13,173*	27–30%	70–80%	cogen, recuperator
2002	Capstone Turbine Corporation	60	13,400	26–30%		recuperator
2002	Elliot Energy Systems	80	*13,420*	28%		recuperator
2002	Ingersoll-Rand	70	13,550	26–30%		recuperator
2002	Ingersoll-Rand	70	13,080	27–31%		recuperator
2002	Turbec	100	*12,514*	29–31%	77–79%	cogen, recuperator

Sources: Resource Dynamics (2002 9; 2001 25); California Energy Commission (2002); Mehrayin (2002, 5, 8, 10); Capstone Turbine (2003, 2); Elliot Energy Systems (2002, 2); Ingersol-Rand (2002a 1; 2002b 1); Turbec (2002, 1).

[a]Italicized values are calculated from original source estimates assuming 3,413 Btu/kWh and a 1.1 ratio of heat rate at HHV to heat rate at LHV.

Microturbine Fuel Costs

Wellhead commodity price is typically greater in the winter than for the year as a whole, and less than the annual average in the rest of year. Therefore, gas costs for a microturbine depend upon the seasonal use patterns of the unit. A CHP unit used for water heating or for space heating and chilling will have a fairly constant year round load; for this project, the average annual gas price is an appropriate measure of its gas costs. A unit without heat recovery, on the other hand, is likely to have its heaviest usage in the summer when the capacity is most valuable to the customer—and when the commodity cost of gas tends to be lower than average.

The gas-delivery costs to New York City for a microturbine similarly depend on seasonal load shape. A microturbine with heat recovery, operating at a high-load factor, would have a pipeline delivery cost per MMBtu comparable to that of a combined-cycle unit. A power-only microturbine system with its heaviest usage in the non-winter months would use more gas when the delivery charges are much lower than average. Assuming a winter (December through March) pipeline cost of $1.66/MMBtu and a non-winter cost of $0.56/MMBtu, the pipeline costs for a power-only microturbine system with two-thirds of its gas use in the summer months would be, on average, $0.93/MMBtu.

Unlike central generators, microturbines are served from the local gas distribution system. Therefore, microturbine gas costs will also include the local-distribution-company delivery charges. Commercial owners of micro-turbines are likely to be medium-sized or large retail gas customers. Based on Consolidated Edison and Keyspan tariffs for commercial customers in the City (Tables 32 and 33 below), the authors estimate that the local delivery charges for a microturbine CHP facility with constant year-round load will be about $1.34/MMBtu on average (in year-2002 dollars, rising with inflation).[37] A microturbine with a ten-year lifetime consumes almost 800 MMBtu per month, thus qualifying the customer for the lowest rate afforded to customers consuming in excess of 300 MMBtu per month.[38] A power-only unit with the majority of its gas use in the summer months would have a less costly average delivery charge than the constant year round load CHP unit.

To the extent that gas-utility charges exceed marginal costs, which is likely in the summer, some of the payments for gas delivery to distributed generation would tend to reduce the bills of other gas customers of Consolidated Edison and Keyspan (mostly in New York City). Thus these payments should not be included in the cost of distributed generation for the City as a whole (although gas charges may be a significant issue in determining the acceptability to participants and to the electric utility).

[37] A large microturbine CHP system with a high gas usage may be able to negotiate a lower delivery charge under a special contract.

[38] According to the manufacturer (Turbec 2002), the T100 microturbine CHP consumes fuel at a rate of 1,194,000 Btu/hour. If the average life of a microturbine CHP is about 80,000 hours (10 years), the micro-turbine operates approximately 670 hours per month and consumes about 8,000 therms per month.

Table 32: Consolidated Edison Gas Delivery Charges

Therms per Month	Charge
First 3	$11.00
Next 87	$0.4461 per therm
Next 160	$0.3414 per therm
Next 2,750t	$0.2277 per therm
In Excess of 3,000	$0.1138 per therm

Source: Firm Transportation Rates, Service Classification No. 9, SC 2 Rate II, 25

Table 33: Keyspan Brooklyn Gas Delivery Charges

Therms per Month	Charge
First 3	$11.28
Next 47	$0.5850 per therm
Next 200	$0.4770 per therm
Next 250	$0.4390 per therm
Next 500	$0.3880 per therm
In Excess of 1,000	$0.3180 per therm

Source: SC 16 CTBS 2-1 & SC 17 CTS 2-1 General Service Non-Heating

Financing and Cost Recovery

Manufacturers project that the microturbine equipment will have a life of 60,000 hours. This estimate is equivalent to an 8-year life for a cogeneration unit operating at an 85% capacity factor, and to a 20-year life for a generation-only unit operating at a 30% capacity factor. The authors assumed that about half the cogeneration investment would be replaced at eight years, with the rest lasting 20 years. The shorter equipment life (compared to central generation) requires higher annual capital-recovery charges.

There are many applications for microturbine systems. For example, a peaking power supply used to reduce the demand charges on commercial or industrial customer's electric bill; a combined power and space-heating, chilling, and water-heating system for residential apartment buildings, office buildings, fitness centers, hospitals or schools; a cogeneration system used to supply power and industrial process heat. These projects could be financed in many different ways, including commercial loans, leasing arrangements, and (in the case of an installation in a public school) tax-exempt bonds.

A typical application of the microturbine technology would be a CHP system in a residential complex or commercial building, financed through a secured commercial bank loan. The CHP project financing may also be included in a larger loan for a new building or as an extension of large existing loan. In 2002, NCS Commercial in Atlanta Georgia, a wholesale commercial mortgage lender, offered loans of $1 million or more at a rate of 200 to 350 basis points over a 10-year treasury note. This was 6% to 7.5% in 2002.

Since in this scenario the project would be completely debt-financed, its after-tax cost of capital would range from 3.6% to 4.6%. Assuming a commercial loan rate of 7.5% and a loan period of eight and ten years for units with and without heat recovery, respectively, combined with property and income taxes and plant lives based on 60,000 hours of operation, the real-levelized carrying charge on the cost of a microturbine would be as follows:

- 15.4% for a base-loaded cogenerating unit,
- 10.9% for a unit operating at 30% capacity factor or less.

Environmental Effects of Microturbines

The emissions of a microturbine would be very similar to those of larger central-station turbines. Since the microturbine would be unlikely to have as stringent NOx controls, its emissions of NOx would be higher than the central-station plant. Depending on the fuel, efficiency, and combustion controls of the avoided boiler, the microturbine's net emissions may be lower than the emissions of the central plant, especially reflecting the difference in line losses from the generator to loads.

Photovoltaics

While there are a number of different renewable generating technologies (e.g., wind, hydro, solar, biomass), many of them face significant barriers to development in heavily urbanized areas. However, photovoltaic (PV) panels are well suited to urban areas because they are small and produce no noise or pollution.

Photovoltaic panels generate electricity directly from sunlight using the photoelectric effect. The first PV cells used silicon as the active material, and the majority of PV systems in operation today contain silicon cells. However, during the past decade research has focused on lower-cost active materials. New thin-film technologies utilize an extremely thin layer of active material deposited on a lower-cost base material such as glass or ceramic. Minimizing the use of the more-expensive active materials lowers costs significantly.

The primary hurdle that PV systems face is high initial cost. While PV units have virtually no operating costs, they are expensive to manufacture. Current projections of PV costs range from approximately $4,000 to $7,000 per installed kW, depending on economies of scale in purchasing and installation. A utility-scale PV installation program should achieve prices toward the lower end of the range, although the logistical complications of installations on New York City rooftops may raise this price somewhat. State and federal renewable energy subsidies lower these prices somewhat, but even with these subsidies, the costs of PV remain well above the cost of large-scale fossil generation. However, having some PV in the electricity fuel mix reduces air emissions from electricity generation (especially on summer days when smog levels are high) and helps insulate consumers from spikes in fossil-fuel prices.

Nevertheless, PV systems offer considerable benefits relative to fossil- and nuclear-fueled generation. PV systems are modular, silent, create no pollution in operation, can be operated unattended and require little maintenance compared to other power plants. They are usually deployed on a small scale close to the location of electricity consumption, avoiding the need for investments in transmission infrastructure and reducing system line losses. One limitation of PV is that it is not dispatchable, meaning that it cannot generate electricity on demand. PV panels can only generate electricity when sunlight is available. However, this limitation is somewhat mitigated by the fact that their peak output generally coincides with afternoon peaks in electricity demand, when electricity is needed most (and is most valuable).

There are many small-scale PV systems currently in operation in the New York area, from large rooftop systems hundreds of kW in size to units a few hundred watts in size used to power highway signs and mobile equipment. While average levels of sunlight are not as high in the New York region as in regions like the Southwest, there is ample sunlight in the New York for PV generation, especially during the summer.

The power production from photovoltaics would be highly coincident with peak loads in the City, for determining capacity prices with the demand curve method, for setting market energy prices, and for determining peak loads on local T&D. Photovoltaics would be most valuable on heavily-loaded networks and high on tall buildings with heavily-loaded internal distribution. In both situations, the photovoltaic capacity would help to avoid the need to upgrade distribution, while achieve maximal reductions in line losses. Rooftop photovoltaic arrays may also be helpful in shading roofs and reducing heat gain.

Suitable rooftop locations that are not excessively shaded are likely to be limited; the City should consider encouraging a unified effort of public and private interests to identify sites and approach building owners to encourage photovoltaic installations.

The City should also try to eliminate regulatory obstacles to installation of photovoltaic building sheathing, and should encourage building owners to install photovoltaics on new and rehabilitated towers.

Other Renewables

Other than photovoltaics, opportunities for renewable-energy development in the City are limited.

- NYSERDA is partially funding a project by Verdant Power to develop a demonstration 25-kW tidal turbine system to be deployed in the East River east of Roosevelt Island. If the prototype works out, a mile-long (270-foot wide) field of the ten-foot-diameter turbines generating as much as 10 MW may be developed in the same area. If the effect of the turbines on aquatic organism is acceptable, additional tidal power development may be feasible in the East River and Hudson River.
- While New York Harbor is a shielded location, development in wave-power technology may allow for some wave-energy installations around the City.
- Wind development in the City, particularly on rooftops, would require light and very sturdy, safe turbines.
- Offshore wind development has been of great interest along the New England coast. Bailey, Kreiselman, and Snyder (2002) found significant technical potential for wind generation off the Long Island shore. Most of the best wind resources are relatively far from the City.

If the City or Consolidated Edison wants to encourage renewable generation, most of the environmental benefits can be pursued with statewide or even regional renewable acquisitions, such as under the renewable portfolio proposed by the Governor. A large part of the City's renewable energy may be generated at wind farms in upstate New York, Maine, or off Long Island. None of these locations would relieve the transmission-capacity constraints into the City, although generation serving Long Island would tend to reduce energy costs into the City.

Unlike photovoltaics, these renewables likely have only minimal transmission-and-distribution benefits. In any area as small as the City, wind (or wave, and certainly tidal) generation is likely to be near zero for at least a few high-load hours during the year. Hence, the transmission-and-distribution system must be able to carry the full load, without any help from the renewable plants. The renewable generation may reduce the frequency of overloading for some transformers and lines, extending their lives.

C. Rate Options

The NY ISO and Consolidated Edison offer a variety of demand-response programs that allow customers to respond to price signals either by reducing load in on-peak periods (by substituting on-site generation) or by shifting usage from on-peak to off-peak periods. The NY ISO offers the following demand-response programs:[39]

- Emergency Demand Response Program (EDRP);
- Installed Capacity Special Case Resources (SCR);
- Day-Ahead Demand-Response Program.

Consolidated Edison's programs include the following:

- Voluntary Real-Time Pricing Program;
- Voluntary Load Reduction Program;
- Residential Direct Load Control Program;
- Residential Time-of-Day (TOD) Rates.[40]

In 2002, subscribed load reductions in New York City for these programs amounted to approximately 310 MW. This figure excludes any load reduction associated with the residential TOD program, for which the authors lack information on performance. As discussed below, based on program experience elsewhere, the authors estimate that the residential TOD program could provide roughly 15 MW of load reduction.

Emergency Demand Response Program

The EDRP allows the NY ISO to curtail participant load whenever there is an expectation of operating-reserve deficiency. Load-reduction offers by program participants must be at least 100 kW, although participants may aggregate loads to meet the minimum requirement.[41] Participants are paid the greater of \$500/MWh or the real-time market-clearing price for reductions in load

[39]NYSERDA supports NY ISO's programs with funding and technical support to program participants, and by providing incentives to residential customers to install advanced metering.

[40]Unlike mandatory TOD rates for commercial and industrial customers, residential TOD rates are a potential source of new demand reductions to the extent that such customers choose to migrate from traditional flat rates to a TOD rate.

[41]Consolidated Edison has established an aggregation program for its end-use customers. The program will offset 75% of the cost of an interval meter (capped at \$2,000) and rebate approximately 90% of the NY ISO's EDRP payment for load reductions.

associated with an EDRP event. Program participants are not penalized for failing to respond to a NY ISO call for curtailment under the EDRP.

Neenan et al. (2002, 6-49) tallied 139 EDRP participants in New York City, representing approximately 180 MW of subscribed load reductions.[42] The NY ISO dispatched EDRP resources on two days in the summer of 2002. Neenan et al. (2002, 6-50) estimated the average load reduction for these two events as about 86 MW, or 48% of subscribed reductions.

Special Case Resources

The market rules of the NY ISO allow load curtailment of 100 kW or greater to participate in the ICAP market as "Special Case Resources."[43] Once qualified as an SCR, such load reductions can be sold bilaterally or offered into the ICAP auctions administered by the NY ISO. Program participants are penalized through a derating of their load reduction whenever actual curtailments at dispatch fall short of subscribed levels. Under current rules, load reductions can be both qualified as an SCR and be offered into the EDRP.

In 2002 there were 35 market participants in New York City that qualified load reductions as SCR, representing 27 MW of subscribed load curtailment.[44] The authors have not been able to determine the amount of SCR load in New York City that was actually curtailed when such resources were dispatched by the NY ISO in 2002.

Day-Ahead Demand Response Program

The NY ISO's Day-Ahead Demand Response Program is designed to allow market participants to bid load reductions into the day-ahead market essentially in the same fashion as generation bids into the day-ahead market. Under current rules, load reductions (other than self-generation) scheduled in the day-ahead market are paid the prevailing day-ahead-market-clearing price, plus any additional payments to cover the bid cost for curtailment initiation.

In 2002, there was slightly less than 20 MW of load curtailment registered in New York City (NY ISO 2000b). The authors have not been able to determine the number of market participants registered in the Day-Ahead Demand

[42]The figures cited include EDRP participants that also qualified their load reductions as special-case resources in the ICAP market.

[43]As with the EDRP, load reductions can be aggregated to meet the 100-kW minimum requirement.

[44]Neenan et al. (2002, 6-49). To avoid double counting, the figures cited exclude SCR participants that also offered their load curtailments into the EDRP.

Response Program in 2002, nor the amount of load reduction scheduled in the day-ahead market for New York City during 2002.

Real-Time Pricing

Commercial and industrial customers with demands greater than 100 kW and with interval metering are eligible to participate in Consolidated Edison's Real-Time Pricing program. Under the RTP program, Consolidated Edison will provide participants every day the day-ahead market prices for the following day, and will price hourly load at the prevailing day-ahead market prices.

There were no participants in the RTP program as of the end of 2002 (Consolidated Edison 2002).

Voluntary Load Reduction

The Voluntary Load Reduction Program allows Consolidated Edison to curtail load at times other than when the NY ISO dispatches EDRP resources for system-wide reserve shortages, to remedy violations of local reliability requirements. Like NY ISO's EDRP, load curtailments are paid the greater of $500/MWh or the prevailing real-time clearing price. In addition, Consolidated Edison offsets the cost of a new interval meter, paying the lesser of 75% of the cost or $2,000.

According to Consolidated Edison (2002), there were on average 113 customers—representing approximately 80 MW of load reduction—participating in the Voluntary Load Reduction Program in 2002. In July of 2002, 11 program participants responded to a curtailment request, providing an average load reduction of 2.7 MW during the event.

Residential Direct Load Control

Under the Residential Direct Load Control Program, Consolidated Edison will install at no cost to the customer a programmable thermostat that lets the utility remotely cycle the participant's central air-conditioner. To participate, eligible customers must allow Consolidated Edison to cycle their central air conditioners during NY ISO EDRP or Consolidated Edison's voluntary-load-reduction events.[45] Consolidated Edison currently offers participants a one-time $25 payment.

As of November 2002 Consolidated Edison had installed more than 5,600 thermostats, representing 6.8 MW of potential load reduction (Consolidated

[45]However, participants can adjust the thermostats to override the cycling dispatch signals.

Edison 2002).[46] The authors have not been able to determine Consolidated Edison's current plans for additional installations over the next few years.

Residential Time-of-Day Rates

Consolidated Edison offers an optional TOD rate for residential customers that prices consumption during on-peak periods of the day at a significantly higher rate than for off-peak consumption.[47] Residential customers electing TOD pricing have the opportunity to reduce electricity costs by shifting usage from higher-priced on-peak to less-expensive off-peak periods.

The authors currently lack information on the number of New York City consumers that have elected TOD pricing or Consolidated Edison's estimate of the likely load reduction achieved by program participants. Instead, this analysis uses estimates of customer response to TOD pricing based on previous studies of residential TOD programs. Such studies typically measure on-peak to off-peak shifts in usage as a function of the differential in on-peak to off-peak prices. Based on the results of these studies, and assuming a participation rate of 5–10%, the authors estimate that City consumers taking service under TOD rates could achieve an aggregate load reduction of around 15 MW.

[46]Consolidated Edison's (2001a, A-18) enrollment goal for 2003 is more than three times the actual enrollment as of November of 2002.

[47]Under the current TOD rate tariff, on-peak rates are approximately four times off-peak rates, where the on-peak period is defined as weekdays from 10 AM to 10 PM.

Appendix A: Energy-Efficiency-Potential Methodology

Overview

The study estimates the achievable efficiency savings from aggressive market intervention strategies over five years (from 2003 through 2008). The achievable savings projections in the study are not an analysis of technical potential, i.e., they do not represent theoretical savings assuming all customers install all technically feasible efficiency options. Rather, the estimate of achievable potential represents the market penetration of efficiency technologies that would result if New York City made a concerted, sustained campaign involving the following aggressive program strategies:

- sustained marketing to consumers and upstream suppliers (e.g., equipment manufacturers, distributors and/or retailers);
- generous financial incentives covering full technology costs, either incremental or installation with labor, depending on market;
- comprehensive technical and information services to all market participants;
- complete customer service delivery.

Approach

In the commercial sector, the analysis estimated savings for more than eighty efficiency technologies or technology combinations for nine building types in new construction, renovation, replacement, retrofit and retail purchase markets, along with their maximum and base case market penetrations over the next five years.[48] In the residential sector, the analysis covered over fifty efficiency technologies for lighting, refrigeration, air-conditioning, water and space heating, clothes washers and dishwashers, clothes dryers, and a variety of consumer electronics in new construction, retail products, and retrofit (analyzing two buildings types in new construction).

The commercial analysis drew on the following sources:

- The U.S. DOE EIA Commercial Building Energy Consumption Survey;
- The California Energy Commission measure cost and savings database;
- Publications from national organizations such as American Council for an Energy-Efficient Economy, Lawrence Berkeley National Laboratory and New Buildings Institute;
- NYSERDA, LIPA and regional baseline and market assessment studies for areas in the Northeast United States;
- Communication with manufacturers and vendors.

For the residential analysis, information sources included the following:

- U.S. EPA Energy Star program results;
- Residential Energy Consumption Survey database maintained by the US DOE Energy Information Administration (EIA).

Distinct load shapes are used for each end use and all nine commercial building types.[49] Professional judgment supplemented information from market assessments and past program experience elsewhere in order to project future market penetration over time.

The commercial and residential analysis methodologies are summarized below.

Commercial-Sector Energy-Efficiency Savings Analysis

The commercial analysis takes a "top-down" approach that begins with the total City electric sales forecast. The 2001 forecast was broken down into new and existing construction vintage, and then further disaggregated into nine building

[48]The commercial market included nine building types: Education, grocery, health, lodging, office, restaurant, retail, warehouse, and other.

[49]Load shapes were purchased from Regional Economic Research.

types and nine end uses categories. The breakout by vintage is based on regional forecast assumptions used by the U.S. EIA. Finally, the breakout by end use relied on energy intensities (kWh/sq. ft. for each building type and end use) from Regional Economic Research, calibrated to the overall City end-use forecast estimates.

Various technology factors are then applied to the new or existing building type/end use sales by year to derive the achievable potential for each of the technologies and for the four market types (new construction, renovation, replacement-remodel, and retrofit) resulting in over two thousand separate measure savings estimates for each of five years. The basic methodology is summarized by the following equation:

Annual Measure Achievable Potential =

New or Existing Building End Use Sales Per Year
× Applicability Factor
× Feasibility Factor
× Turnover Factor
× Baseline Adjustment Factor
× Savings Factor
× Annual Net (Achievable Base Case) Penetration

where:

- *Applicability Factor* is the fraction of the end-use-level sales that is attributable to equipment that could be replaced by the high-efficiency measure (e.g., for a packaged air conditioner it is the portion of total cooling load represented by packaged systems). These data come from a variety of baseline and market assessment data.
- *Feasibility Factor* is the fraction of the applicable end use that is technically feasible for conversion to the high efficiency technology. These data are based on engineering barriers from various studies or judgment.
- *Turnover Factor* is the portion of existing equipment that will be replaced each year and only applies to renovation, remodel and replacement. These data are based on the equipment-engineering-measure lives from various sources, and on estimated renovation and remodel activity.
- *Baseline Adjustment Factor* adjusts existing sales downward for replacement, remodel, and renovation to account for the fact that current standard-practice equipment efficiencies are higher than existing stock efficiencies and is based on the relative baseline efficiencies of new and existing stock

equipment, from current and historical baseline and market-assessment studies.

- *Savings Fraction* is the percent savings (as compared to either existing stock or new baseline equipment) of the high efficiency technology.
- *Annual Net Penetration* is the difference between the base-case measure penetration underlying the City forecast and the measure penetrations that could be achieved with sustained efficiency initiatives. These are estimated based on forecasting inputs, review of past programs and market assessments, combined with professional judgment.

The measure level savings are then applied to hourly load-shape data to derive energy impacts by rating period and coincident peak impacts by season. Finally, the costs (in dollars per kWh) for each of the more than two thousand measures are applied to secure societal measure costs (full installed cost for retrofit, incremental for other markets).

Some of the technologies modeled are mutually exclusive. For example, standard metal-halide high-bay fixtures can be replaced with pulse-start metal-halides or fluorescent high-bay fixtures. When two or more measures compete with one another, an estimate of the penetration of the measure offering the most per unit savings was first estimated. The penetration of the next competing measure is then estimated based on the remaining potential.

Individual measure savings are not additive. Because of interactions between measures, the total potential for all measures is less than the sum of individual measure opportunities. For example, installing window film to reduce cooling load will lower the savings opportunities for installing a high efficiency air conditioner because the air conditioner will not run as long as it otherwise would have. The total potential estimates take into account all the interactions between measures. However, were some measures eliminated the potential for remaining measures might increase depending on their original interactions with the removed measure.

In addition to estimating the societal measure costs, the analysis also estimates the measure incentive costs by initiative using a set of "achievable budget" penetration curves. These estimate the subset of the overall market activity for each measure that would participate directly in initiatives and collect incentives. Generally, as markets transform, this fraction declines.

The market-driven penetration rates reflect incremental percentages of the eligible remaining opportunities that occur each year. Some of the best historic programs have achieved similar rates. For example, National Grid Transco's Design 2000plus Commercial New Construction Program typically reaches 75–90% of new buildings built in National Grid's territory in Massachusetts. Buildings with comprehensive measures often perform 40–50% better than a typical building. Despite envisioning a more aggressive set of program strategies, estimates of lower ultimate penetration rates for new construction were used. This situation occurs because historic programs typically are not fully comprehensive with each participant.

The retrofit penetrations are cumulative figures that apply to the full existing stock of systems and equipment. As with market-driven estimates, these reflect maximum levels based on review of similar programs. For example, Citizens Utilities in Vermont offered a small commercial retrofit program that captured roughly 80% adoption of measures among targeted customers. Other small commercial programs had similar and sometimes higher penetration rates (Mosenthal and Wichenden 1999).

Residential-Sector Energy-Efficiency-Savings Analysis

The residential analysis is built from the ground up. It starts by characterizing a variety of efficiency measures—their typical costs, typical annual electricity savings, typical peak demand savings and typical duration of the savings (i.e. measure life). The size of each market was then assessed—i.e. how many of them could be installed. This typically boils down to either how many new dwelling units are built each year, how many appliances are purchased each year, and/or how many electric appliances are currently in use in each dwelling unit and (therefore) available for replacement with efficient alternatives. The third key step is estimating how often each of the efficiency measures examined would be installed without any new market intervention (i.e. baseline penetration rates). The fourth step is estimating how often the efficiency measures would be installed through aggressive market intervention (achievable penetration rates). The costs of such an intervention were estimated.

The residential analysis organized savings into three distinct market intervention opportunities: new construction, retail equipment and/or product sales (alternatively referred to as "time-of-purchase") and retrofit.

Average savings, incremental costs and other key "per unit" characteristics of each of the efficiency measures were then developed. For several measures—particularly those for which new minimum federal standards were predicted and emerging technologies—this included estimates of likely reductions in savings (which baselines increase) and/or costs (either due to increasing baselines or economies of scale relating to increasing market share) in future years.

Estimates of the size of the market were developed for each efficiency measure. In the case of new construction, the number of new dwelling units estimated to be built each year was based on changes in population incorporated in the City forecast. The size of retail and retrofit markets was generally based on estimates of appliance saturations from U.S. EIA's Residential Energy Consumption Survey and assumptions regarding the life of the efficiency measure (to gauge typical turnover rates for retail markets). The key to developing estimates of the size of the retrofit market for many efficiency measures was to estimate existing appliance-saturation rates for various electric end uses. Estimates of the size of the retail market for efficiency measures generally relied on the same appliance-saturation data to first estimate how many of each appliance was in use in existing dwelling units. Then an estimate of the annual sales of those appliances was made by dividing the number of appliances currently in use by its assumed life. For example, clothes washers were assumed to have a life of fourteen years. That led to an assumption that $1/14^{th}$ (i.e., 7.1%) of all consumers who currently own a clothes washer are in the market to buy a new model every year.

Some of the efficiency measures analyzed compete for the same efficiency upgrade opportunities. For instance, a fixture with an incandescent bulb can either be replaced with a hard-wired fluorescent lighting fixture or have its bulb replaced with a compact fluorescent light bulb (CFL). In such cases, estimates of the size of the eligible market were adjusted to ensure that savings were not overstated. Similarly, some efficiency measures could be installed through different market channels. Particularly important is potential overlap between retail markets and retrofit markets (e.g., as retrofit programs directly install CFLs in more and more dwelling units, the potential for retail sales of CFLs decreases). Where the potential for such overlap existed, the size of the retail markets was reduced by the number of efficiency measures predicted to be installed through retrofit activity.

Base case penetrations—the portion of the market that would buy or install the efficiency measure absent any new efficiency programs—were developed using several sources regarding "free rider" rates and the EPA's estimate of current and future market shares for a wide range of Energy Star products.

Achievable market penetrations were estimated assuming that consumers would either be provided the measure at no cost (retrofit) or provided a rebate equal to 100% of the incremental cost of the measure (retail or new construction). The only exception to this rule was retail sales of CFLs, where rebates were assumed to be equal to 75% of incremental cost. This exception was designed to ensure that the efficient product was not essentially free (which provides some assurance that products purchased will actually be used to generate savings).

Industrial-Sector Energy-Efficiency Savings Analysis

The authors determined the portion of total savings that would be attributed to each measure and industrial sub sector by estimating low, medium or high penetration rates of natural technology diffusion (in the absence of programmatic intervention) for New York City, for each measure. Based on these estimates the authors estimated the effect of the City programs on measure diffusion in excess of the natural rate. The bulk of New York City's industrial savings is attributable to the textile industry.

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