Combined Heat and Power Market Potential for New York State

Final Report 02-12

October 2002

New York State
Energy Research and
Development Authority

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Final Report

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ABSTRACT

Businesses and industry in New York State that employ on-site power generation with heat recovery can dramatically reduce both energy consumption and its associated environmental impacts. This approach, called *combined heat and power* (CHP – also known as cogeneration), is already an important generating resource in New York with approximately 5,000 MW of capacity installed at 210 sites. The industrial sector accounts for 78% of the existing CHP capacity in the State and is represented by a few facilities that have very large CHP systems. Important questions include: how much new CHP could be installed in the next decade in New York State, what benefits would this yield, and what actions can policymakers and planners pursue in order to promote market penetration of clean and efficient CHP?

The technical potential for new CHP is an estimation of the remaining market size constrained only by technological limits—the ability of CHP technologies to fit existing customer energy needs. This report evaluates the technical potential for new CHP in commercial, institutional, and industrial sites by screening a comprehensive facility database according to size and application criteria that would allow for operation of a CHP system which employs both a high-load factor and high-thermal utilization. The report identifies nearly 8,500 MW of technical potential for new CHP in New York at 26,000 sites. While existing CHP in New York is concentrated in very large plants, only 16 sites remain that could support a plant size greater than 20 MW for internal power consumption. Close to 74% of remaining capacity is below 5 MW and is primarily at commercial and institutional facilities.

Market penetration of CHP will depend on the degree of economic advantage for CHP compared to separately purchased fuel and power, the prevailing size of the CHP market, the speed with which the current market can ramp-up in the development of new projects, and the sites remaining with economic potential. These factors were combined into a simple market-estimating model that show in the *Base Case* scenario an estimated 764 MW of CHP will be installed by the year 2012, whereas in the *Accelerated Case* scenario market penetration reaches nearly 2,200 MW during the same timeframe.

Penetration of CHP into the commercial/institutional and light industrial markets has been minimal to-date. This is likely due to a combination of factors: Deficiencies in small CHP technologies and systems, lack of an adequate sales and service infrastructure for small systems, low familiarity of users and building owners of CHP systems and benefits, and a number of critical market and regulatory hurdles. These hurdles encompass a variety of concerns that typically face new entrants offering competing products and services in markets with well-established incumbents. Implementation of CHP creates a complicated interaction between the user and the local power distribution utility. The CHP system must meet interconnection regulations and requirements that are, in some cases, not well defined and costly to meet. The tariffs for backup and supplementary power services are higher in New York than in other large states where CHP has

made an impact – such as California, Texas, and Illinois. Securing the necessary permits for a CHP system can be an expensive and time-consuming process. Local building codes often don't adequately address the needs of CHP systems, creating delays, expense, and uncertainty for project developers. Financing capital-intensive CHP processes is also a hurdle. There are perceived risks that limit the availability of capital for these projects and also make the financing cost more expensive.

To support the widespread adoption of CHP and clean distributed generation technologies, public policy should focus on a greater degree of uniformity, transparency, and simplicity to these processes, while at the same time protecting the public interest in air quality, safe and secure operation of the electric network, and genuine local safety and land use issues. There are specific areas where policy decisions can promote CHP market penetration. The dialogue regarding the appropriate regulatory treatment of CHP/ Clean Distributed Generation (DG) has only recently been initiated. The issue areas covered in this report are a select subset that are offered as potentially productive topics for ongoing inquiry and study by regulators and policymakers - this report provides data and analysis to facilitate such a dialogue.

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EXECUTIVE SUMMARY

Businesses and industry in New York State that employ on-site power generation with heat recovery can dramatically reduce both energy consumption and its associated environmental impacts. This approach, called *combined heat and power* (CHP – also known as cogeneration), is already an important generating resource in New York with approximately 5,000 MW of capacity installed at 210 sites. The industrial sector accounts for 78% of the existing CHP capacity in the State. Over half (54%) of the capacity is concentrated in the metals, paper, and chemicals industries. The remaining capacity (46%) is divided equally between other industrial processes and the commercial/institutional sector. Important questions include: how much new CHP could be installed in the next decade in New York State, what benefits would this yield, and what actions can policymakers and planners pursue in order to promote market penetration of clean and efficient CHP?

CHP TECHNOLOGY

There are numerous commercial and emerging technologies that can be used for combined heat and power. In most cases, small power generation consists of a heat engine, or prime mover that creates shaft power that, in turn, drives an electric generator. In a CHP application, the heat from the prime mover is recovered to provide steam or hot water to meet on-site needs. In some cases, the heat can be used directly in place of process heat. By combining the electrical and thermal energy generation in one process, CHP can have an overall efficiency of 70-80% compared with 30-33% for simple-cycle electric generation.

CHP technologies are capable of burning a variety of fuels, but in the United States, and especially in New York State, the economics, availability, and environmental cleanliness of using natural gas make it by far the most preferred fuel for CHP technologies. Selecting a CHP technology for a specific application depends on many factors, including the amount of power needed, the duty cycle, space constraints, thermal needs, emission regulations, fuel availability, utility prices and interconnection issues. **Table ES-1** summarizes the characteristics of each CHP technology. The table shows that CHP covers a wide capacity range from 50 kW reciprocating engines to 50 MW gas turbines.

Table ES-1. Comparison of CHP Technologies

	IC Engine	Steam Turbine	Gas Turbine	Micro-turbine	Fuel Cells
Technology Status	Commercial (3% of existing CHP capacity in NY, 66% of sites)	Commercial (14% of existing capacity, 13% of sites)	Commercial (83% of existing capacity*, 21% of sites)	Early entry	Early entry/ development
Electric Efficiency (LHV)	25-45%	5-15%	25-40% (simple) 40-60% (combined)	20-30%	40-70%
Size (MW)	0.05-5	0.01-100	0.5 -50	0.025-0.25	0.2-2
Installed cost ($/kW)	800-1500	800-1000	700-900	500-2000	>3000
O&M Cost ($/kWh)	0.007-0.015	0.004	0.002-0.008	0.005-0.015	0.003-0.015
Availability	92-97%	Near 100%	90-98%	90-98%	>95%
Start-up Time	10 sec	1 hr-1 day	10 min –1 hr	60 sec	3 hrs-8 hrs
Fuels	natural gas, biogas, propane, liquid fuels	All	natural gas, biogas, propane, distillate oil	natural gas, biogas, propane, distillate oil	hydrogen, natural gas, propane
NO_x Emissions (lb/MWh)	0.4-10	Function of boiler emissions	0.3-2	0.4-2	<0.05
Uses for Heat Recovery	hot water, LP steam, district heating	LP-HP steam, district heating	direct heat, hot water, LP-HP steam, district heating	direct heat, hot water, LP steam	hot water, LP-HP steam
Thermal Output (Btu/kWh)	1,000-5,000	n/a	3,400-12,000	4,000-15,000	500-3,700
Useable Temp (F)	200-500	n/a	500-1,100	400-650	140-700

* 94% of gas turbine CHP capacity in New York State combines gas turbine topping cycle and a steam turbine bottoming cycle for higher electrical efficiency

TECHNICAL POTENTIAL FOR NEW CHP

This report evaluates the technical potential[1] for new CHP in commercial, institutional, and industrial sites by screening a comprehensive facility database according to size and application criteria that would allow a high-load factor, high-thermal utilization CHP system to operate. The technical potential for new CHP is an estimation of the remaining market size constrained only by technological limits—the ability of CHP technologies to fit existing customer energy needs. The technical potential for new CHP includes sites that have the energy consumption characteristics that could apply CHP. The technical potential for new CHP does not consider screening for other factors such as ability to retrofit, owner interest in applying CHP, capital availability, natural gas availability, and variation of energy consumption within customer application/size class. All of these factors affect the feasibility, cost and ultimate acceptance of CHP at a site and are critical in the actual economic implementation of CHP. The technical potential for new CHP as outlined in this report can be useful in understanding the general sense of the opportunity for CHP in New York State, and providing information on applications, sizes and regional distribution of the market.

Table ES2 summarizes the application-by-application analysis of the technical potential for new CHP for the downstate and upstate regions in five size ranges. The report identifies nearly 8,500 MW technical potential for new CHP in New York at 26,000 sites. This technical potential for new CHP is split evenly between the upstate and downstate markets. Upstate has a greater industrial sector potential and downstate has greater commercial sector potential. While existing CHP in New York is concentrated in very large plants, only 16 sites remain that could support a plant size greater than 20 MW for internal power consumption. Close to 74% of remaining capacity is below 5 MW.

[1] Existing CHP was subtracted from the total number of sites in estimating the technical potential for new CHP. While there are 5,000 MW of existing CHP, only about 1,500 MW is used to directly offset customer needs. The remaining 3,500 MW are available to be sold into the electric grid system.

Table ES2. Summary of Remaining Industrial and Commercial Technical Potential for New CHP (MW)

Size Range	Industrial		Commercial		Total	
	Sites	MW	Sites	MW	Sites	MW
State Total						
50 to 500 kW	3,894	300	16,048	1,240	19,942	1,540
500 kW to 1 MW	428	195	3,867	1,584	4,295	1,778
1 MW to 5 MW	434	685	1,280	2,256	1,714	2,940
5 MW to 20 MW	63	488	149	1,240	212	1,728
> 20 MW	9	280	7	210	16	490
Total	4,828	1,948	21,351	6,529	26,179	8,477
Downstate*						
50 to 500 kW	2,160	185	9,919	723	12,079	909
500 kW to 1 MW	143	73	2,520	977	2,663	1,050
1 MW to 5 MW	111	211	804	1,335	915	1,546
5 MW to 20 MW	10	88	108	848	118	935
> 20 MW	0	0	5	150	5	150
Total	2,424	556	13,356	4,033	15,780	4,589
Upstate						
50 to 500 kW	1,734	115	6,129	517	7,863	632
500 kW to 1 MW	285	122	1,347	606	1,632	728
1 MW to 5 MW	323	474	476	920	799	1,394
5 MW to 20 MW	53	401	41	393	94	793
> 20 MW	9	280	2	60	11	340
Total	2,404	1,392	7,995	2,496	10,399	3,887

* Downstate market consists of LIPA, Consolidated Edison and Orange and Rockland service areas. Upstate is made up of the remainder of the state.

The analysis of CHP technical potential for new CHP reveals the following characteristics:

- **The bulk of the technical potential for new CHP exists at commercial/institutional facilities** – Unlike existing CHP installations in which 78% of the capacity is in industrial applications, almost 70% of the technical potential for new CHP (6,500 MW) is in commercial and institutional facilities.

- **The majority of the technical potential for new CHP is in the smaller size range** – 74% of the technical potential for new CHP is below 5 MW in size. 39% is below 1 MW in size. For

commercial/institutional applications, 43% of the remaining capacity is below 1 MW in size. 25% is below 1 MW in size for the remaining industrial sector potential.

- **The majority of the technical potential for new CHP is in three utility service areas** – 78% of the CHP technical potential for new CHP in terms of capacity is included in Consolidated Edison (38%), Niagara Mohawk (28%) and Long Island Power Authority (12%) service areas.

Analysis of the results shows that existing market penetration of CHP is small except for large industrial applications. Penetration of CHP into the commercial/institutional and light industrial markets has been minimal to-date. This is likely due to a combination of factors: Deficiencies in small CHP technologies and systems, lack of an adequate sales and service infrastructure for small systems, low familiarity of users and building owners of CHP systems and benefits, and a number of critical market and regulatory hurdles as outlined in Section 8.

It should also be noted that the technical market for CHP could be further expanded in the commercial/institutional sectors with advanced technologies that utilize thermal energy for non-traditional applications. The technical potential for new CHP is limited in commercial/institutional applications due to the lack of adequate thermal energy needs in many building types. Advanced technologies such as heat-activated cooling and thermally regenerated desiccants can expand the economic applications of CHP by providing a base thermal load in building types that do not currently have adequate thermal needs. Cost effective CHP systems in smaller sizes (below 100 kW) would also expand the potential market and increase application of CHP.

CHP ECONOMICS

A general economic analysis of CHP was performed for five size ranges. For each size range, an appropriate current and advanced CHP technology was characterized and the application parameters of sites (operating factor and thermal utilization) were estimated. Net power costs were estimated from these CHP systems based on the following assumptions: 80-90% load factor, 70-90% thermal utilization, and natural gas fuel cost of $5.00-6.00/MMBtu. The smaller systems were assumed to have lower load factors and higher fuel costs. The net power cost is the fully amortized cost of providing power from the CHP system after the avoided boiler fuel is subtracted from annual operating costs. **Figure ES1** shows the range of net power costs for the chosen systems and application parameters. These net power costs are below the prevailing average power costs for most customers of similar size in the state. Current electric and gas prices in New York State were evaluated in detail to determine the actual impacts that the current tariff structure, including standby charges, will have on project economics. In addition, future price tracks were determined based on the New York State 1998 Energy Plan (High Case) for electricity supply with a

continuation of current delivery tariff structure. Standby tariffs proved to be so critical to the economic competitiveness of CHP that specific scenarios were developed to reflect moderation of the current charges. For the base case (business-as-usual) it was assumed that the standby charges would remain at current levels (upstate standby charges for the base case were modified – essentially set at two-thirds of Niagara Mohawk's Rule 12 charge -- to approximate the recently adopted SC-7 Standby Service Rates approved by the New York Public Service Commission). For the accelerated case, it was assumed that standby charges would be further reduced to one third to one-half of the base case values, to a level consistent with states such as Illinois and Texas. The impact of completely eliminating standby charges was also calculated though only as a benchmark; this outcome was not considered in the market analysis. The results of the payback analysis are summarized in **Table ES3.** In the market analysis, a payback of 2 years or less was assumed to be acceptable to all customers. A payback of 8 years or more was assumed to rule out any market penetration. A linear relationship was assumed between these two values.

Figure ES1. Net Power Costs from CHP as a Function of Size

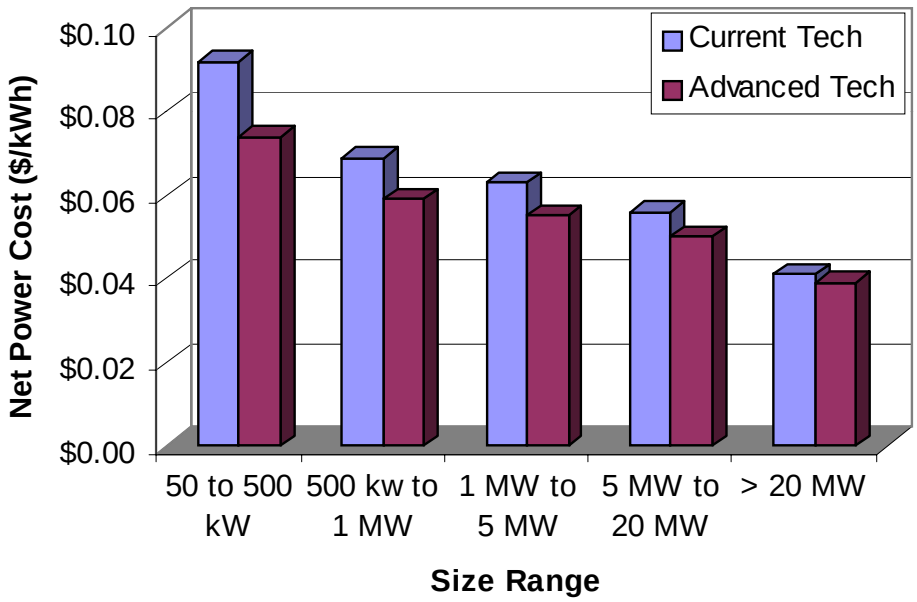


Table ES3. Summary of Paybacks for All Cases (Years)

CHP Paybacks (years) Scenario	100 kW Engine	800 kW Engine	5 MW Turbine	10 MW Turbine	50 MW Turbine
Current Technology, Upstate					
Full Standby* and CTC	7.7	4.5	6.9	5.0	2.8
No Standby or CTC	2.9	1.9	3.1	2.5	1.7
Reduced Standby and CTC	4.2	2.7	4.3	3.3	2.1
Current Technology, Downstate					
Full Standby and CTC	10.6	3.4	3.0	2.5	1.3
No Standby or CTC	3.5	1.7	1.6	1.5	0.9
Reduced Standby and CTC	4.5	2.1	1.9	1.7	1.0
Advanced Technology, Upstate					
Full Standby* and CTC	4.6	2.7	4.3	3.4	2.4
No Standby or CTC	1.7	1.2	2.2	1.8	1.4
Reduced Standby and CTC	2.5	1.6	2.9	2.4	1.8
Advanced Technology, Downstate					
Full Standby and CTC	5.7	2.3	2.0	2.1	1.2
No Standby or CTC	2.2	1.2	1.1	1.2	0.8
Reduced Standby and CTC	2.8	1.4	1.3	1.4	0.9

*Full standby for upstate is based on 2/3 of Niagara Mohawk's Rule 12 tariff structure. Reduced standby rates are 1/3 of full standby in downstate and ½ of full standby in upstate to reflect levels consistent with states such as Illinois and Texas

The following conclusions can be drawn concerning these results:

- Standby charges have a major impact on CHP market competitiveness. With the modification of the current upstate standby charges, CHP competitiveness is marginally improved. With more significant reductions to standby charges, the competitiveness of CHP increases significantly.

- Advanced technology improves competitiveness in all sizes. This improvement is greatest in the smaller customer size categories.

- Without standby charges, CHP would be economic in all size ranges for both the upstate and downstate markets. While this may not represent a realistic case, reducing the current standby charge impact by two-thirds would open up the economic markets for CHP in all customer size ranges considered.

- Paybacks generally improve as the CHP system size increases. This improvement reflects the increase in efficiency and reduction in cost for larger CHP systems. An exception to this trend is seen in the comparison of the 800 kW and 5 MW systems. A large reciprocating engine was chosen as the representative technology for the 800 kW system. For the 5 MW system, an industrial gas turbine was selected. In this size range, large engines compete somewhat better than small turbines.

MARKET PENETRATION SCENARIOS

Penetration of the economic market will be based on the degree of economic advantage for CHP compared to separately purchased fuel and power, the prevailing size of the CHP market, the speed with which the current market can *ramp-up* in the development of new projects, and the sites remaining with economic potential. These factors were combined into a simple market-estimating model that defines projected year-by-year market penetration. The analysis was undertaken for upstate and downstate regions in five size ranges for CHP equipment that reflect the differences in equipment performance and application needs. Two scenarios were considered:

- *Base Case* – business as usual based on current CHP technology and current standby rates (standby rates in the upstate region were estimated to be two-thirds of Niagara Mohawk's Rule 12 level -- to approximate the recently adopted SC-7 Standby Service Rates approved by the New York Public Service Commission).

- *Accelerated Case* – based on gradual evolution from current to advanced technology, immediate reduction of standby charges to one-half of the base case level (for both upstate and downstate markets), immediate implementation of CHP Initiatives that offer tax incentives equivalent to 10% of initial cost, and increase in customer awareness and adoption rates.

The results of these cases are summarized in **Table ES4.** In the *Base Case*, an additional 764 MW of CHP is projected to be installed by the year 2012. Nearly 70% of this capacity will be in the downstate region. The greater penetration of CHP in the downstate region is due to a somewhat higher technical potential for new CHP (54% to 46%), higher power costs, and somewhat lower standby charges. Even with a moderation of the current upstate standby rates (two-thirds of Rule 12) assumed in the *Base Case*, market penetration lags in all sizes except the greater than 20 MW size range. The upstate region has a greater potential for large industrial systems.

In the *Accelerated Case* scenario, CHP is economic in all size ranges in both the upstate and downstate regions. Cumulative market penetration reaches nearly 2,200 MW statewide. The regional split is more

balanced than in the *Base Case*, but still about 60% of the market penetration is projected for the downstate region.

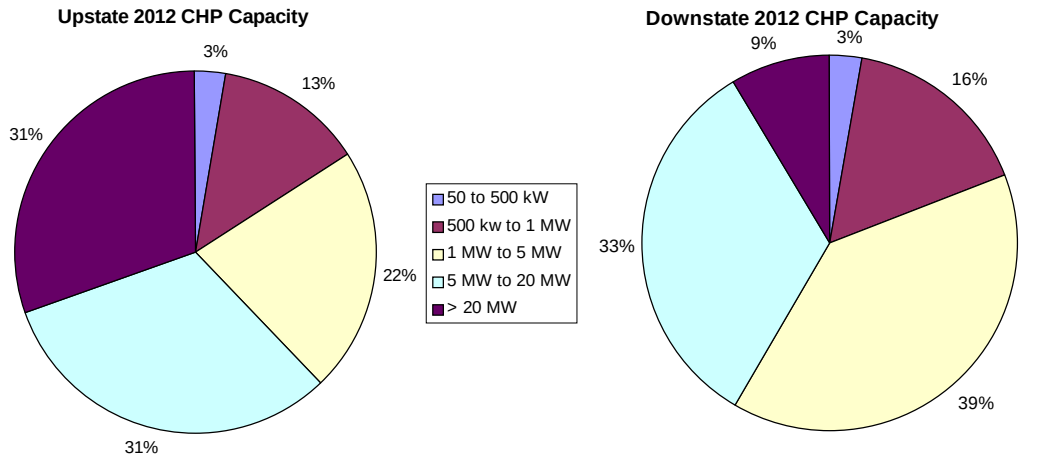
Figure ES2 shows the cumulative market penetration for the year 2012 by size range for the *Accelerated Case* in the upstate and downstate regions. The smallest size category, 50-500kW, accounts for only about 3% of the total added installed CHP in both regions. The 500kW to 1 MW size accounts for 13 and 16% of the total added capacity in the upstate and downstate regions respectively. In the larger size systems, the two regions diverge significantly in the composition of market share. In the downstate region, the largest market penetration is achieved by 1-5 MW systems accounting for 39% of total added CHP market penetration. In the upstate region the largest market penetration is achieved in the largest sized systems, over 20 MW, with a penetration share of 31% (compared to 9% of the downstate total in the big systems).

Table ES4. CHP Market Penetration by Size and Region for 2007 and 2012 (MW)

Market Segment and Region	Base Case			Accelerated Case		
	Upstate	Downstate	Total	Upstate	Downstate	Total
2007						
50 to 500 kW	0.0	0.0	0.0	5.6	8.6	14.2
500 kW to 1 MW	3.1	20.8	23.9	24.9	47.4	72.4
1 MW to 5 MW	0.0	54.9	54.9	48.3	123.0	171.3
5 MW to 20 MW	19.3	40.2	59.5	63.9	104.2	168.1
> 20 MW	88.4	52.8	141.2	151.3	64.9	216.2
2007Total	110.8	168.7	279.4	294.0	348.1	642.1
2012						
50 to 500 kW	0.0	0.0	0.0	24.0	37.4	61.4
500 kW to 1 MW	7.5	84.1	91.6	113.8	217.3	331.1
1 MW to 5 MW	0.0	204.1	204.1	184.0	515.2	699.1
5 MW to 20 MW	60.8	147.2	208.0	267.2	436.3	703.4
> 20 MW	169.8	90.0	259.8	260.5	113.5	374.0
2012 Total	238.2	525.4	763.6	849.4	1,319.7	2,169.1

The economics and market penetration analysis included in this report are not meant to be predictions of eventual market development, but as an indication of how certain market scenarios affect CHP economics and potential market penetration using a simplified market model. The objective is to determine how robust the economics might be under various scenarios, what critical factors impact economics and deployment of CHP, and which of these factors impact target markets and applications of interest to policymakers and planners.

Figure ES2. Comparison of 2012 CHP Market Share for the Accelerated Case: Upstate and Downstate Regions



Upstate Capacity 2012 – 850 MW **Downstate Capacity 2012 – 1320 MW**

BENEFITS OF CHP

CHP contributes economic savings, energy savings, reduction in criteria pollutants, and a reduction in emissions that contribute to global warming. A summary of these benefits for the base and accelerated market penetration cases is shown in **Table ES5**.

Table ES5. CHP Benefits in New York

CHP Benefits	Base Case	Accelerated Case
User Savings		
2012 Annual ($million)	$109	$487
Cumulative Savings ($million)	$536	$1,825
Net Present Value ($million)	$253	$808
Energy Savings		
2012 Annual (trillion Btu)	25	74
2002-2012 Savings (trillion Btu)	118	316
Emissions Savings Annual (2012)		
NOx (tons/year)	3,210	10,282
SO2 (tons/year)	9,778	27,766
CO2 (1000 tons/year)	1,259	3,854

The economic savings realized by the customer drives market penetration of CHP. The net savings reflect the cost of purchased electricity and fuel saved less the operating and capital charges on the CHP system. In the *Accelerated Case*, the user economic benefits reach nearly $500 million/year by the end of the forecast period. In the *Base Case*, the user benefit, based on a much lower market penetration, is $109 million/year. The total stream of user benefits is equal to the savings attributable to the cumulative CHP market penetration in each year. In the *Accelerated Case*, the total stream of user benefits equals $1.8 billion with a net present value (using a 10% discount rate) of $800 million.

When comparing fossil-fueled scenarios, CHP systems use less fuel than central station power plants and separate boilers because the exhaust heat is utilized productively in meeting *on-site* thermal needs rather than being wasted as it is in central power stations. The total energy savings from CHP over the forecast period in the *Accelerated Case* equal about 316 trillion Btu. The rate of savings equals 74 trillion Btu/year by the end of the forecast period.

The CHP generation is projected to emit less NOx than the avoided utility generation emissions[2] in all sizes except the 0.5-1.0 MW size range which, for purposes of the market forecast, was based on lean burn engine technology with no exhaust clean-up. However, CHP market penetration provides NOx reduction in all sizes when avoided boiler emissions are accounted for. The total NOx emissions reduction for the *Accelerated Case* is 10,282 tons/year by 2012. The *Accelerated Case* contributes 3.2 times the NOx reduction as the *Base Case*.

CHP market penetration has the potential for large reduction of SO2 emissions. The gas-fired CHP technology emits almost no SO2 whereas the average fossil-based emissions for central station generation by 2012 are expected to remain very significant. Avoided boiler emissions are also very small due to the assumption that this amount is all gas-fired. The total avoided SO2 emissions in the *Accelerated Case* amount to nearly 28,000 tons/year by 2012. In the *Base Case*, the total avoided emissions are 9,800 tons/year by 2012. The *Accelerated Case* increases SO2 savings by a factor of 2.8 compared to the *Base Case*.

CHP market penetration also reduces CO2 emissions. CO2 emissions contribute to global warming. CO2 emissions depend on the overall energy efficiency of the process and on the type of fuel being combusted. Natural gas contributes less CO2 per unit of energy than does oil or coal. Therefore, CHP provides benefits in two ways, by increasing the efficiency of energy use and by substituting natural gas for oil and coal. CO2 emissions reduction for the A*ccelerated Case* reaches 3.9 million tons/year by 2012. The *Base Case* provides a 1.3 million-tons/year reduction.

[2] Calculations assumed that future CHP penetration would back-out the average emissions from the average fossil mix component of future generation.

MARKET HURDLES

There are numerous hurdles that face developers and consumers trying to implement CHP. These hurdles encompass a variety of concerns that typically face new entrants offering competing products and services in markets with well-established incumbents.

Implementation of CHP creates a complicated interaction between the user and the local power distribution utility. The CHP system must meet interconnection regulations and requirements that are, in some cases, not well defined and costly to meet. The economic operation of the CHP system generally requires cooperation of the distribution utility to provide power when the CHP system is down unexpectedly (back-up power), for uses above the capacity of the CHP system (supplementary power), and for scheduled maintenance (maintenance power.) The tariffs for these services are higher in New York than in other large states where CHP has made an impact – such as California, Texas, and Illinois.

Securing the necessary permits for a CHP system can be an expensive and time-consuming process. The process of acquiring environmental permits is hampered by rules that focus on the site emissions without consideration for the level of economic output or the reduction in emissions elsewhere in the power system. Local building codes often don't adequately address the needs of CHP systems, creating delays, expense, and uncertainty for project developers.

Financing capital-intensive CHP processes is also a hurdle. There are perceived risks that limit the availability of capital for these projects and also make the financing cost more expensive. In addition, many not-for-profit and institutional and government sector customers that show high economic potential for CHP have very involved processes for raising funds for capital projects. Federal tax policy also impacts CHP projects. Longer depreciation periods for on-site power generation equipment reduce the project economic attractiveness.

ROLE OF PUBLIC POLICY

Widespread adoption of CHP and clean distributed generation technologies requires the development of new market rules and procedures for the generation, transmission and distribution of electric power. The development of broader markets may be facilitated, or conversely hampered, by local, regional and federal laws and guidance regarding the siting, permitting and codes applicable to CHP and clean Distributed Generation (DG). Federal, state, and local public policy changes are needed to reduce the hurdles that are restricting the economic adoption of CHP.

Significant progress can be made by a thorough examination of the current regulatory structures including:

- Standardizing requirements and minimizing costs of interconnection with the electricity distribution system,
- Revising methods for assessing tariffs for distributed generators to better account for actual costs and offsetting system benefits,
- Streamlining the air permitting process for demonstrably clean CHP, and
- Ascertaining and eliminating unreasonable obstacles in local codes, siting and permitting issues as they relate to CHP

In each instance the focus must be on bringing a greater degree of uniformity, transparency, and simplicity to these processes, while at the same time protecting the public interest in air quality, safe and secure operation of the electric network, and genuine local safety and land use issues. New York State is currently engaged in examining policies that impact the siting of CHP and clean DG technologies. New York was the first state to establish a standardized interconnection process and establish Standardized Interconnection Requirements (SIR). Texas and California soon followed. In early 2002, New York was in the process of proffering some changes to the SIR based on a review of the effectiveness of the initial requirements. Like the state of Texas, and more recently California, New York has initiated a process that will lead to a new rulemaking on air emissions procedures for small electric generators. And as noted earlier, on October 26, 2001, the Public Service Commission set forth principles on the rates terms and conditions for the provision of electric standby service. As of this writing, settlement negotiations are underway.

There are specific areas where policy decisions can promote CHP market penetration. The dialogue regarding the appropriate regulatory treatment of CHP/Clean DG has only recently been initiated. These issue areas are a select subset that are offered as potentially productive topics for ongoing inquiry and study by regulators and policymakers:

Interconnection Policy

- Clear procedures with adequate utility resources devoted, regulatory sanctions for consistently poor performance
- Advanced disclosure and itemized billing for interconnection services and fees for studies
- Development of performance-based incentives for utilities that show good performance in this area

Air Permit Policies

- Treat older vintage generating resources on a comparable basis with new smaller generating units
- Development of a simplified procedure for CHP systems smaller than 5 MW
- Development of an output-based permitting system that rewards rather than penalizes efficiency

Tariff Policies

- Modification of excessive or unreasonable standby charges according to the regulatory process already underway
- Re-evaluation of competitive transition charges aimed at CHP customers
- Tariff structures that identify and provide incentives for systems that provide localized grid support
- Transparent pricing such as web-based tariff calculators.

CHP systems can provide an economic benefit to the user and an environmental benefit to New Yorkers in general. One goal of this study is to initiate a dialogue in pursuit of policies that will help foster an environment that allows CHP to compete fairly in the future power market in a fashion that is not subsidized by other power customers or detracts from the regulated power distribution industry's responsibility to provide economic service to all customers. Achieving this goal will support a healthier power industry, higher economic productivity, and fewer adverse environmental impacts.

Recognizing the important efficiency and environmental benefits of CHP, NYSERDA has initiated a development and demonstration program to encourage the deployment of efficient combined heat and power systems in the state. This program provides co funding for small CHP installations and is intended to demonstrate the viability of this concept in various applications and market segments. These demonstrations will help reduce the hurdles to the development of small CHP. Table ES6 presents the anticipated results from NYSERDA's initial demonstration funding in 2001 and 2002.

Table ES6. NYSERDA's CHP Demonstration Program by Size (KW)

Expected Installations	2002	2003	Total
Less than 500 kW	3,048	4,701	7,749
500 kW to 1 MW	4,020	4,561	8,581
1 MW to 5 MW	23,988	20,760	44,748
5 MW to 20 MW	0	6,700	6,700
> 20 MW	0	0	0
Total	33,058	38,725	67,778

1. INTRODUCTION

Businesses and industry in New York State that utilize both electricity and fuel for thermal processes can dramatically increase the efficiency of their energy use and reduce environmental impacts by employing on-site power generation with heat recovery to replace the need for purchased boiler fuel. This approach, called *combined heat and power* (CHP – also known as cogeneration), is already an important generating resource in New York with approximately 5,000 MW of capacity installed at 210 sites.

The New York State Energy Research and Development Authority (NYSERDA) with cooperative support from the U.S. Department of Energy (through Oak Ridge National Laboratory) initiated a multiphase study to better understand the potential for increased use of CHP in New York and the resultant benefits, to identify critical hurdles to development of this potential, and to develop a CHP implementation strategy for the state. The Energy Nexus Group of Onsite Energy Corporation (Energy Nexus) led the overall project team. Pace Energy Project contributed to the effort with a focus on utility issues and state-specific business and regulatory hurdles.

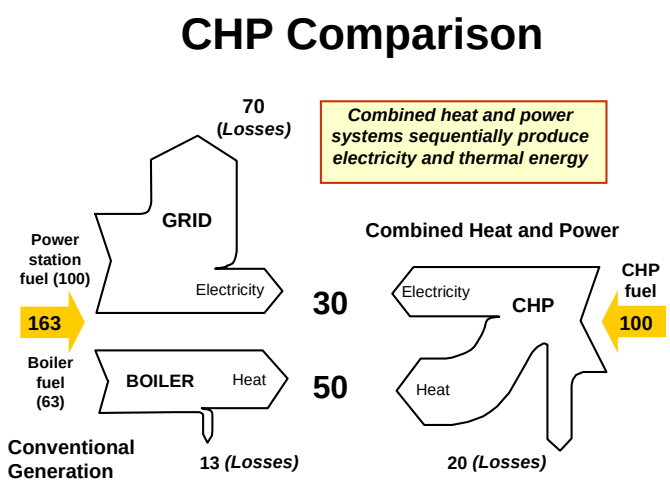
This final report details the results and conclusions from this study. The report is organized into the following sections:

1. Introduction – description of the project objectives and organization
2. CHP Technologies – a summary of CHP equipment and applications
3. Existing CHP in New York State – characterization of the 5,000 MW of existing CHP capacity in the state
4. Technical Potential – estimation of the total number of commercial and industrial sites and the associated electrical capacity that could support CHP
5. Economic Analysis – analysis of the long-term competitiveness of CHP by size and region within the state
6. Market Penetration – Identification of the economic potential within the total CHP technical potential and scenarios for market penetration
7. Benefits of CHP – analysis of the environmental benefits of replacing fossil-fueled central station power generation with CHP
8. Market Hurdles – detailed discussion of the regulatory and market factors that impact the economic penetration of CHP in New York.

2. CHP TECHNOLOGIES

There are numerous technologies that can be used for combined heat and power. In most cases, small power generation consists of a heat engine, or prime mover that creates shaft power that, in turn, drives an electric generator. In a CHP application, the heat from the prime mover is recovered to provide steam or hot water to meet on-site needs. In some cases, the heat can be used directly in place of process heat. **Figure 2.1** shows the clear efficiency advantage of CHP compared with purchased electricity and fuel-fired boilers. By combining the electrical and thermal energy generation in one process, the example CHP system shown has an overall efficiency of 80% compared with 30-33% for simple-cycle electric generation. Considering both thermal and electrical processes together, CHP requires 40% less primary energy than separately generated power and heat.

Figure 2.1. CHP versus Separate Power Generation and Heat Production



CHP systems are complex integrated systems that consist of a number of individual components from fuel treatment, combustion, mechanical energy, electric energy, electricity conditioning, heat recovery, and heat rejection systems. However, they are typically identified by the prime mover that drives the overall system. Many of the prime movers for distributed generation are commonly in use today, some are just entering the market, and others will be available within a few years. These prime movers are capable of burning a variety of fuels, but in the United States, and especially in New York State, the economics, availability, and environmental cleanliness of using natural gas make it by far the most preferred fuel for CHP technologies.

Selecting a CHP technology for a specific application depends on many factors, including the amount of power needed, the duty cycle, space constraints, thermal needs, emission regulations, fuel availability, utility prices and interconnection issues. **Table 2-1** summarizes the characteristics of each CHP

technology. The table shows that CHP covers a wide capacity range from 50 kW reciprocating engines to 50 MW gas turbines. Estimated costs per installed kW range from $500-$1400/kW.

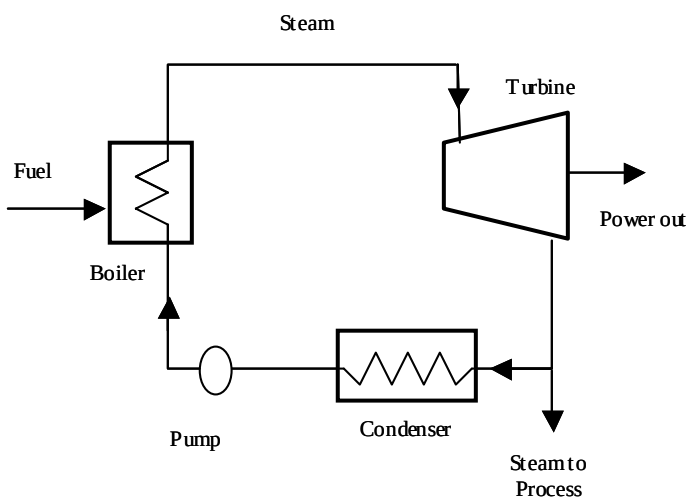
Table 2-1. Comparison of CHP Technologies

	IC Engine	Steam Turbine	Gas Turbine	Micro-turbine	Fuel Cells
Technology Status	Commercial	Commercial	Commercial	Early entry	Early entry/ development
Electric Efficiency (LHV)	25-45%	5 – 15%	25-40% (simple) 40-60% (combined)	20-30%	40-70%
Size (MW)	0.05-5	0.01-100	0.5 -50	0.025-0.25	0.2-2
Footprint (ft^2/kW)	0.22-0.31	<0.1	0.02-0.61	0.15-1.5	0.6-4
CHP installed cost ($/kW)	800-1500	800-1000	700-900	500-2500	>3000
O&M Cost ($/kWh)	0.007-0.015	0.004	0.002-0.008	0.005-0.015	0.003-0.015
Availability	92-97%	Near 100%	90-98%	90-98%	>95%
Hours between overhauls	24,000-60,000	>50,000	30,000-50,000	5,000-40,000	10,000-40,000
Start-up Time	10 sec	1 hr-1 day	10 min –1 hr	60 sec	3 hrs-8 hrs
Fuel pressure (psi)	1-45	n/a	120-500 (may require compressor)	40-100 (may require compressor)	0.5-45
Fuels	natural gas, biogas, propane, liquid fuels	All	natural gas, biogas, propane, distillate oil	natural gas, biogas, propane, distillate oil	hydrogen, natural gas, propane
Noise	moderate to high (requires building enclosure)	moderate to high (requires building enclosure)	moderate (enclosure supplied with unit)	moderate (enclosure supplied with unit)	low (no enclosure required)
NO_x Emissions (lb/MWh)	0.4-10	Function of boiler emissions	0.3-2	0.4-2	<0.05
Uses for Heat Recovery	hot water, LP steam, district heating	LP-HP steam, district heating	direct heat, hot water, LP-HP steam, district heating	direct heat, hot water, LP steam	hot water, LP-HP steam
Thermal Output (Btu/kWh)	1,000-5,000	n/a	3,400-12,000	4,000-15,000	500-3,700
Useable Temp for CHP (F)	200-500	n/a	500-1,100	400-650	140-700

2.1 STEAM TURBINES

Steam turbines convert steam energy into shaft power and are one of the most versatile and oldest prime mover technologies used to drive a generator or mechanical machinery. The capacity of steam turbines can range from fractional horsepower to several hundred MW for large utility power plants. A steam turbine is captive to a separate heat source and does not directly convert a fuel source to electric energy. Steam turbines require a source of high-pressure steam that is produced in a boiler or heat recovery steam generator (HRSG). Boiler fuels can include fossil fuels such as coal, oil and natural gas or renewable fuels like wood or municipal waste. Most of the electricity in the United States is generated by conventional steam turbine power plants. Steam turbine CHP systems are primarily used in industrial processes where solid or waste fuels are readily available for boiler use. In CHP applications (**Figure 2.2**), steam is extracted from the steam turbine and used directly in a process or for district heating or it can be converted to other forms of thermal energy including hot water or chilled water.

Figure 2.2. Steam Turbine CHP



2.2 RECIPROCATING ENGINES

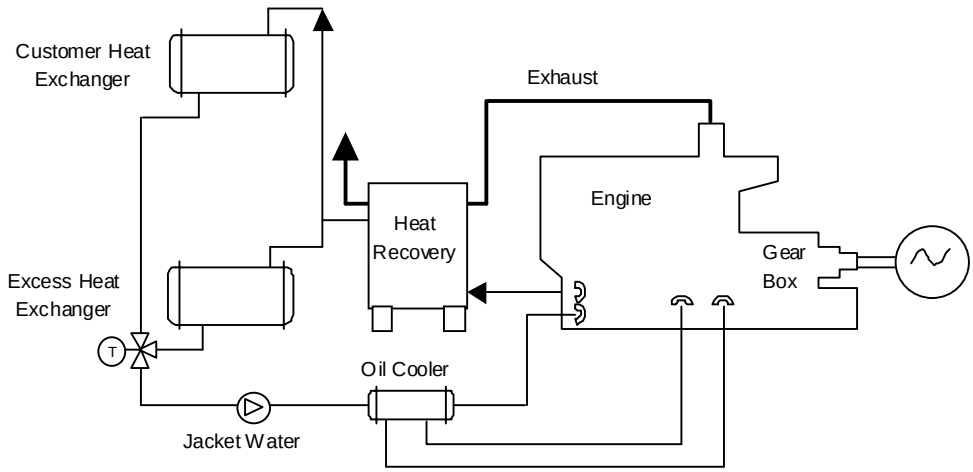
Reciprocating internal combustion (IC) engines (**Figure 2.3**) represent a widespread and well-known technology for power generation, transportation, mining, construction, and agriculture. Reciprocating engines are used for all types of power generation from small portable *gen-sets* to large industrial engines that power generators of several megawatts.

Figure 2.3. Reciprocating Engine Driven Generator

Spark ignition (SI) engines for power generation use natural gas as the preferred fuel – though can be set up to run on propane or gasoline. Diesel cycle, compression ignition (CI) engines operate on diesel fuel or heavy oil or can be set up in a dual-fuel configuration that can burn primarily natural gas with a small amount of diesel pilot fuel or be switched to 100% diesel. Current generation IC engines offer low first cost, easy start-up, proven reliability when properly maintained, and good load-following characteristics. Drawbacks of IC engines include relatively high noise levels, relatively high air emissions and the need for regular maintenance. Emissions of IC engines have been reduced significantly in the last several years by exhaust catalysts and through better design and control of the combustion process. IC engines are well suited for packaged combined heat and power (CHP) in commercial and light industrial applications of less than 5 MW. Smaller systems IC engine systems produce hot water. Larger systems can be designed to produce low-pressure steam.

The most common method of recovering engine heat is the closed-loop cooling system as shown in **Figure 2.4**. These systems are designed to cool the engine by forced circulation of a coolant through engine passages and an external heat exchanger. An ancillary heat exchanger transfers engine heat to a cooling tower or radiator when there is excess heat generated. Closed-loop water cooling systems can operate at coolant temperatures between 190°-250°F. Low-pressure steam (15 psig) can be produced either by exhaust heat recovery alone or in conjunction with *ebullient cooling systems*. These systems cool the engine by natural circulation of a boiling coolant through the engine.

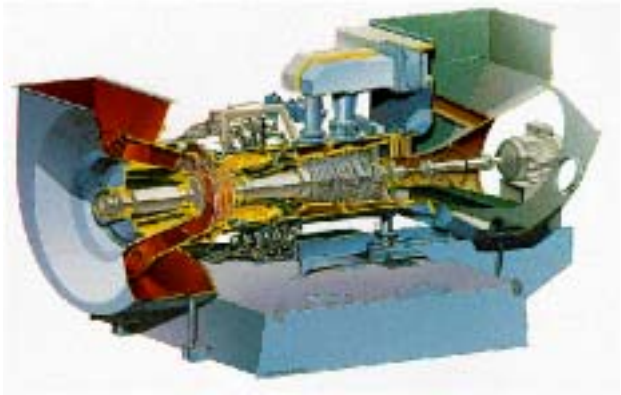
Figure 2.4. Closed-Loop Heat Recovery System



2.3 INDUSTRIAL GAS TURBINES

Industrial gas turbines (**Figure 2.5**) are an established technology in sizes from several hundred kilowatts up to about 50 MW. Utility-sized combustion turbines fall in the 100-300 MW size range. Gas turbines produce high quality heat that can be used to generate steam for on-site use or for additional power generation (combined cycle). Gas turbines can be set up to burn natural gas, a variety of petroleum fuels or can have a dual-fuel configuration. Gas turbine emissions can be controlled to very low levels using dry combustion techniques, water or steam injection, or exhaust treatment such as selective catalytic reduction (SCR). Maintenance costs per unit of power output are among the lowest of CHP technology options. Low maintenance and high quality heat make gas turbines an excellent choice for industrial or commercial CHP applications larger than 5 MW. Technical and economic improvements in small turbine technology are pushing the economic range into smaller sizes as well.

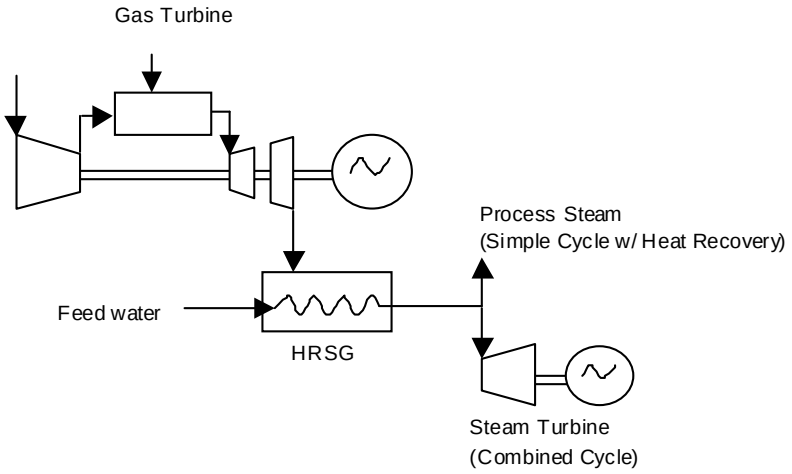
Figure 2.5. Cutaway View of Typical Industrial Gas Turbine for Power Generation



An important advantage of CHP using gas turbines is the high quality heat available in the exhaust gas. The high temperature exhaust gas is suitable for generating high-pressure steam making it a preferred CHP technology for many industrial processes. In the *simple cycle* gas turbine, hot exhaust gas can be used directly in a process or by adding a heat recovery steam generator (HRSG) that uses the exhaust heat to generate steam or hot water. Since gas turbine exhaust is oxygen rich, it can support additional combustion through supplementary firing. A duct burner can be fitted within the HRSG to increase the steam production at efficiencies of 90% and greater.

For larger gas turbine installations, it is sometimes economic to utilize the recovered steam to produce additional electricity in a steam turbine. Electric generation efficiencies of up to 60% are possible in these *combined cycle* power plants. The heat recovery options available from a steam turbine used in the combined cycle can be implemented to further improve the overall CHP efficiency (as discussed previously.) **Figure 2.6** shows a schematic of power and heat generation from a combustion turbine. Both simple and combined cycle alternatives are indicated in the figure.

Figure 2.6. Heat Recovery Options for a Combustion Turbine



2.4 MICROTURBINES

Microturbines (**Figure 2.7**) are very small combustion turbines with outputs of 30 kW to 300 kW. Microturbine technology has evolved from the technology used in automotive and truck turbochargers and auxiliary power units for airplanes and tanks. Several companies have developed commercial microturbine products and are in the early stages of market entry. A number of other competitors are developing systems and planning to enter the market within the next few years. In the typical configuration, the turbine shaft spinning at up to 100,000 rpm drives a high-speed generator. This high frequency output is converted to the 60 Hz power used in the U.S. by sophisticated *power electronics* controls. Electrical efficiencies of 25-

30% are achieved by employing a recuperator that transfers heat energy from the exhaust stream back into the combustion air stream. Microturbines are compact and lightweight with few moving parts. Many designs are air-cooled and some even use air bearings, thereby eliminating the cooling water and lube oil systems.

Low emissions combustion systems are being demonstrated that provide emissions performance approaching that of larger gas turbines. Microturbines' potential for low emissions, reduced maintenance and simplicity promises to make on-site generation much more competitive in the 30 to 300 kW size range characterized by commercial buildings or light industrial applications. Microturbines for CHP duty are typically designed to recover hot water or low-pressure steam.

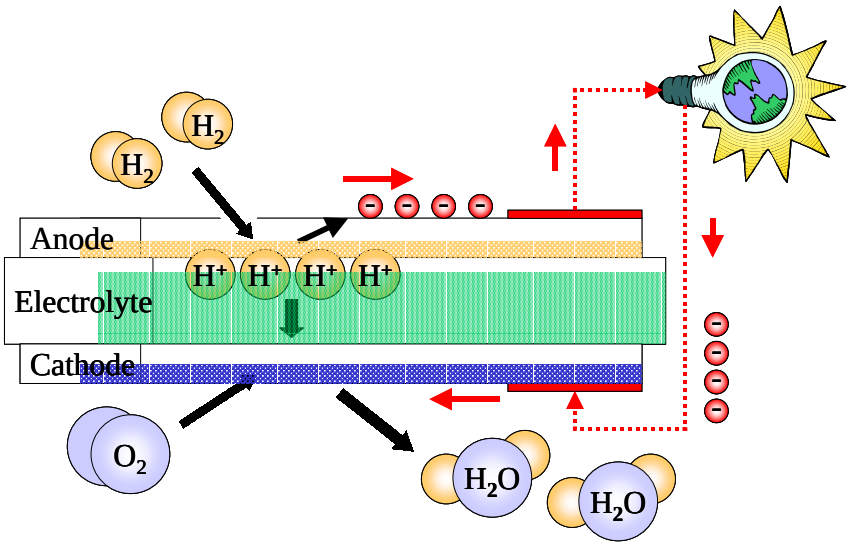
Figure 2.7. Microturbine Generator

2.5 FUEL CELLS

Fuel cells **(Figure 2.8**) produce power electrochemically, more like a battery than like a conventional generating system. Unlike a storage battery, however, which produces power from stored chemicals, fuel cells produce power when hydrogen fuel is delivered to the cathode of the cell and oxygen in air is delivered to the anode. The resultant chemical reactions at each pole create a stream of electrons (or direct current) across the oppositely charged poles of the cell. The hydrogen fuel can come from a variety of sources, but the most economic is steam reforming of natural gas – a chemical process that strips the hydrogen from both the fuel and the steam. There are several different liquid and solid media that can be used to create the fuel cell's electrochemical reactions – phosphoric acid (PAFC), molten carbonate

(MCFC), solid oxide (SOFC), and proton exchange membrane (PEM). Each of these media comprises a distinct fuel cell technology with its own performance characteristics and development schedule. PAFCs are in early commercial market development now with 200 kW units delivered to over 120 customers worldwide. The SOFC and MCFC technologies are now in field test or demonstration. PEM units are in early development and testing. Fuel cells promise higher efficiency than generation technologies based on heat engine prime movers. In addition fuel cells are inherently quiet and extremely clean running. Like microturbines, fuel cells require power electronics to convert the direct current to 60-Hz alternating current. Many fuel cell technologies are modular and capable of application in small commercial and even residential markets; other technology utilizes high temperatures in larger sized systems that would be well suited to industrial CHP applications. Because of current high costs, fuel cell application has been limited to niche markets such as very high cost areas or those requiring near zero emissions.

Figure 2.8. Fuel Cell Electrochemical Process



3. EXISTING CHP IN NEW YORK STATE

An analysis of the most recent update to the Hagler Bailly *Independent Power Data Base* (HBI) was conducted to develop a profile of existing cogeneration activity in New York. Energy Nexus has not found any single database that contains a complete listing of existing CHP and independent power facilities (i.e., coverage of small systems in the HBI database is incomplete). However, Energy Nexus considers the HBI data as the best available data and has worked with it extensively over the past several years to understand its content and to enhance its coverage and value. The profile was developed to understand the technologies and applications that comprise existing CHP capacity and to provide insight into projections of future market development. The HBI database includes information for each CHP site including technology, fuel use, electrical capacity (MW), ownership and sell-back of power to the grid. The HBI data for New York was updated with additional site-specific information from the U.S. Department of Energy's Energy Information Administration's *1999 Inventory of Non-Utility Electric Power Plants* and from data on non-utility generators published by the New York Power Authority. These updates ensured more complete coverage for CHP facilities greater than 1 MW.

Based on this data, there were an estimated 210 active CHP projects in the state of New York in the year 2000 with a total electric capacity of 5,070 MW. As a result of a state-wide standard offer instituted in the late 1980s and early 1990s that guaranteed 6 cents/kWh for power sold back to the grid from Qualified Facilities under the Public Utilities and Regulatory Policies Act, much of this installed capacity is concentrated in a few large, third party-owned, merchant plants - 12 sites ranging in capacity from 100 to 1,034 MW provide 60% of the total CHP capacity. Natural gas is the principal fuel, and gas turbines are the most important prime mover. While large capacity, industrial-based, merchant CHP systems dominate the installed capacity figures, the commercial and institutional sector actually has a greater number of active projects than the industrial sector.

3.1 APPLICATIONS

The industrial sector accounts for 78% of the existing CHP capacity in the State. **Figure 3.1** shows the capacity breakdown by application type. Over half (54%) of the capacity is concentrated in the metals, paper, and chemicals industries. The remaining capacity is divided equally between other industrial processes and the commercial/institutional sector.

Figure 3.1. CHP Capacity in New York by Application Type

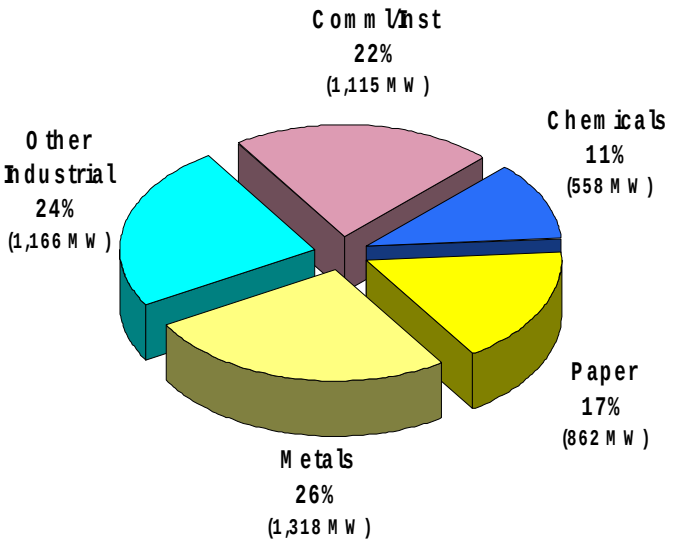
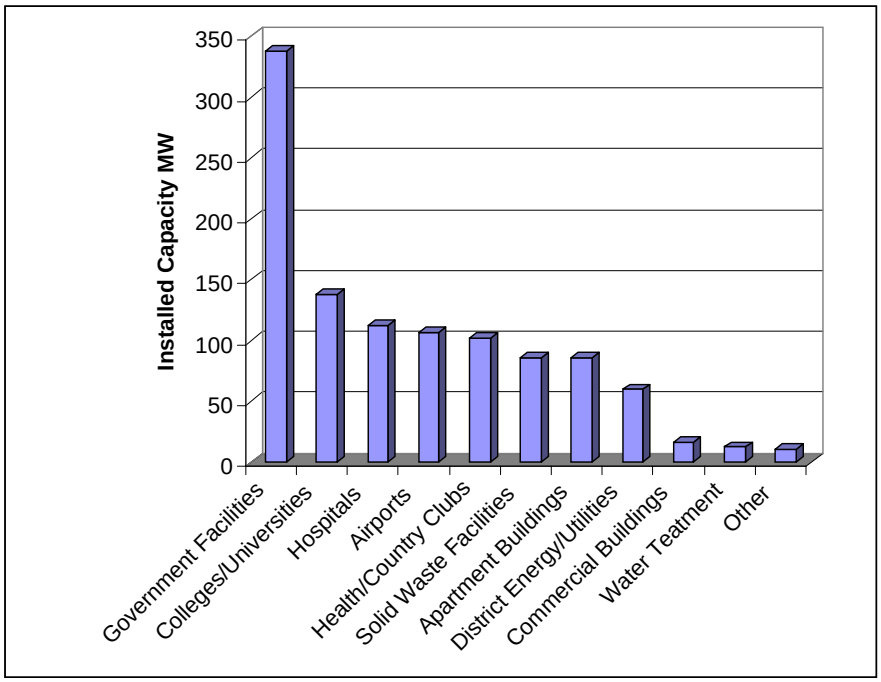


Figure 3.2 shows the most important commercial and industrial applications in terms of installed capacity. As shown in the figure, important uses are government buildings, colleges and universities, airports, health clubs, and waste treatment facilities. Some applications that fall into the other category like nursing homes,

Figure 3.2. Breakdown of CHP Capacity in the Commercial/Industrial Sector



schools, and apartment buildings are important in that they represent a significant number of applications of small CHP. These projects show the potential for small CHP in the commercial sector.

3.2 TECHNOLOGIES

Figure 3.3 shows the breakdown of CHP capacity by prime mover. Combined cycle plants dominate the existing CHP capacity in New York State, representing 78% of capacity. Combined cycle plants are appropriate for the large merchant plants that make up a large share of the state's capacity. These plants maximize power production with remaining steam sold to industrial *steam hosts*. Boiler/steam turbine systems represent 14%, simple cycle gas turbines 5%, and reciprocating engines only 3% of total installed capacity. Measured in terms of the number of active sites, reciprocating engines represent the most common technology.

Figure 3.3. Existing CHP Capacity by Prime Mover

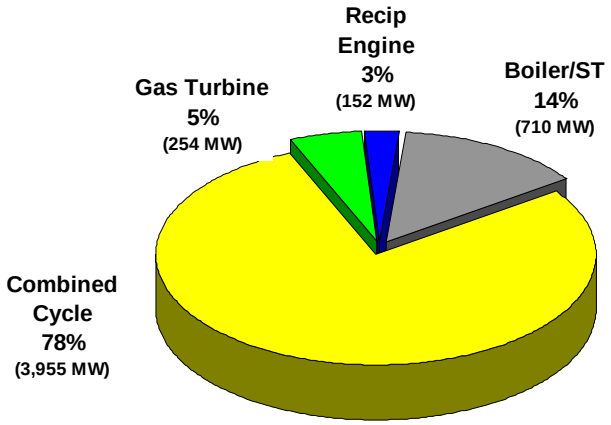
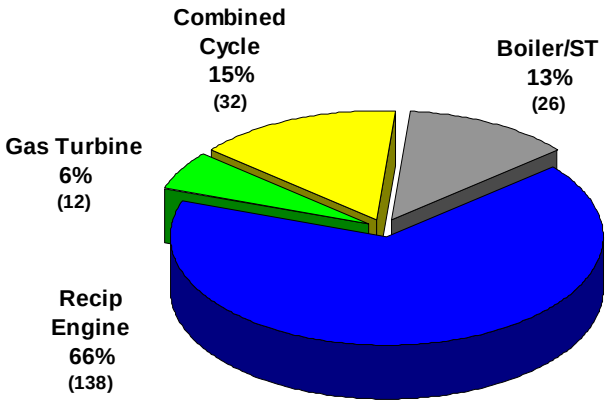


Figure 3.4 shows the share of prime movers in active CHP projects by number of sites. On this basis, reciprocating engines represent 66% of the active projects.

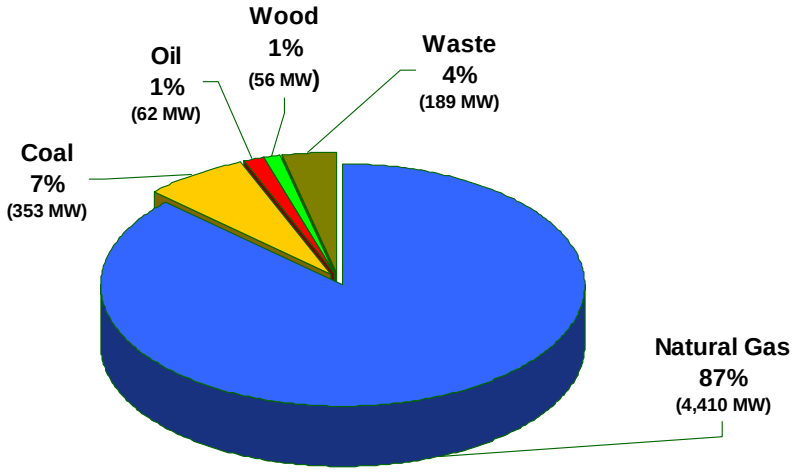
Figure 3.4 Number of Active CHP Sites by Prime Mover



3.3 FUEL CHOICE

Natural Gas is the preferred fuel for existing CHP. As shown in **Figure 3.5**, natural gas fuels 88% of the total capacity in the state. Coal, waste, and wood fuels are used primarily in boiler/steam turbine systems. These fuels contribute 11% to the total CHP capacity but represent over 85% of the steam turbine CHP systems. A majority of the oil fueled systems, making up only 1% of the total, are also fired in boilers for steam turbine generation.

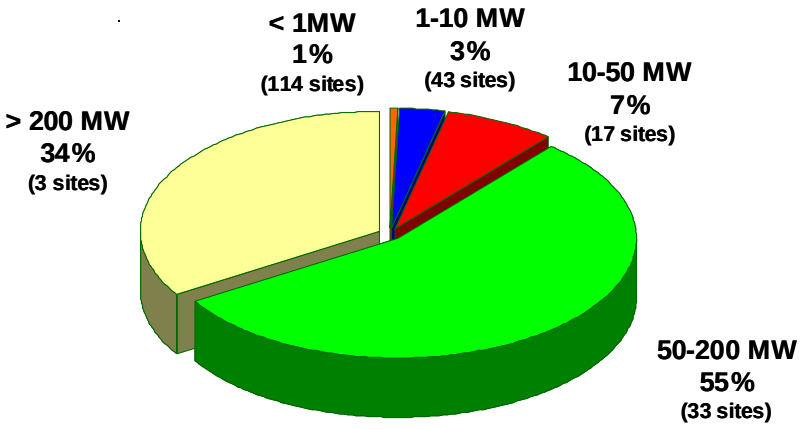
Figure 3.5. Existing CHP Capacity by Fuel Type



3.4 CHP SYSTEM SIZE

The size breakdown of the existing CHP systems is shown in **Figure 3.6**. The size range is a function of the application and is an indication of the level of CHP adoption in the state by size of customer. The figure shows that 36 sites account for 89% of existing CHP Capacity. The remaining 11% of capacity in size ranges below 50MW is the size range that is generally described as Distributed Generation (DG). Though small in total capacity compared to the larger independent power producers, these DG sites make up 83% of the total number of active CHP sites in the state.

Figure 3.6 Distribution of Existing CHP Capacity by Size Range



4. TECHNICAL POTENTIAL

This section summarizes the analysis of CHP technical potential in the manufacturing and commercial/institutional sectors of New York. This analysis is based on existing manufacturing and commercial/institutional facilities and estimates of their current power and thermal energy consumption. The estimated potential is a snapshot of the technical potential for CHP at these facilities at the end of 2000 and does not include an analysis of sector growth over time. The technical market potential is an estimation of market size constrained only by technological limits—the ability of CHP technologies to fit existing customer energy needs. The technical potential includes sites that have the energy consumption characteristics that could apply CHP. The technical market potential does not consider screening for other factors such as ability to retrofit, owner interest in applying CHP, capital availability, natural gas availability, and variation of energy consumption within customer application/size class. All of these factors affect the feasibility, cost and ultimate acceptance of CHP at a site and are critical in the actual economic implementation of CHP. The analysis also considers only traditional hot water-steam/electric power CHP. No estimate was made for mechanical drive applications or for uses of thermal energy other than hot water or steam.

4.1 METHODOLOGY

The following approach was used to estimate the market potential for CHP in the commercial/institutional and industrial sectors:

- *Identify applications where CHP provides a reasonable fit to the electric and thermal needs of the user*. Target applications were identified based on reviewing the electric and thermal energy consumption data for various building types and industrial facilities. Data sources include the DOE EIA *1995 Commercial Buildings Energy Consumption Survey (CBECS)*, the DOE *Manufacturing Energy Consumption Survey (MECS), 1994* and various market summaries developed by GRI and the American Gas Association. Existing CHP installations in the commercial/institutional and industrial sectors were also reviewed to understand the required profile for CHP applications and to identify target applications.

- *Quantify the number and size distribution of target applications*. Once applications that could technically support CHP were identified, the iMarket, Inc. *MarketPlace Database* was utilized to identify potential CHP sites by SIC code or application. The *MarketPlace Database* is based on the Dun and Bradstreet financial listings and includes information on economic activity (8 digit SIC), location (metropolitan area, county, electric utility service area, state) and size (employees) for commercial, institutional and industrial facilities. In addition, for select SICs limited energy consumption information (electric and gas consumption, electric and gas expenditures) is provided

based on data from Wharton Econometric Forecasting (WEFA). The *MarketPlace Database* was used to identify the number of facilities in target CHP applications and to group them into size categories based on average electric demand in kWs.

- *Estimate CHP potential in terms of MW capacity.* Total CHP potential was then derived for each target application based on the number of target facilities in each size category. It was assumed that the CHP system would be sized to meet the average site electric demand for the target applications unless thermal loads limited electric capacity.

4.1.1 Target CHP Applications

The simplest integration of CHP into the commercial and industrial sectors is in applications that meet the following criteria:

- relatively coincident electric and thermal loads
- thermal energy loads in the form of steam or hot water
- electric demand to thermal demand (steam and hot water) ratios in the 0.5 to 2.5 range (this matches available technologies as identified in Section 2), and
- moderate to high operating hours (>4000 hours per year)

Commercial CHP A review of energy consumption intensity data for commercial/institutional building types as presented in the 1995 CBECS is shown in **Table 4.1**. Electric intensities are taken directly from the CBECS data for each building type. Space heating and water heating data in CBECS reflect fuel energy inputs for each category. These fuel inputs were modified to reflect building thermal demands using a conversion efficiency of 85%. The building types are compared in terms of *energy intensity* and *electric/thermal energy ratio (E/T)*. Energy intensity, measured in kWh/square foot, is an indication of the importance of energy use in the application.

Applications with high-energy intensity are more likely to have large electric loads and to be interested in finding ways to reduce energy costs. Electric/thermal energy ratio is the ratio of electric power used to thermal energy used, measured in like units. As described in Section 2, the outputs from available CHP technologies have electric to thermal ratios in the range of 0.5 to 2.5. Thermal energy output is usually in the form of steam or hot water.

Table 4.1. Energy Intensities for Commercial/Institutional Buildings

Sector	Electric Use (Tbtu)	Electric Intensity (kWh/sg ft)	Space Heating (1000 Btu/sq ft)	Water Heating (1000 Btu/sq ft)	E/T Ratio (Total)	E/T Ratio (Water Htg)
Education	221	8.4	32.8	17.4	0.67	1.94
Health Care	211	26.5	55.2	63	0.9	1.69
Lodging	187	15.2	22.7	51.4	0.82	1.19
Food Service	166	36	30.9	27.5	2.47	5.25
Food Sales	119	54.1	27.5	9.1	5.93	23.86
Offcie	676	18.9	24.3	8.7	2.3	8.72
Mercantile/Service	508	11.8	30.6	5.1	1.33	9.29
Public Assembly	170	12.7	53.6	17.5	0.72	2.91
Public Order	49	11.3	27.8	23.4	0.89	1.94
Religious Worship	33	3.5	23.7	3.2	0.52	4.39
Warehouse/Storage	176	6.4	15.7	2	1.45	12.85
Other	75	22	59.6	15.3	1.18	5.77
Apartment Buidlings		5875 kWh/unit	N/A	25 MMBtu/unit	N/A	0.8

Thermal loads most amenable to CHP systems in commercial/institutional buildings are space heating and hot water requirements. The simplest thermal load to supply is hot water. Retrofits to the existing hot water supply are relatively straightforward, and the hot water load tends to be less seasonally dependent than space heating, and therefore, more coincident to the electric load in the building. Meeting space heating needs with CHP can be more complicated. Space heating is seasonal by nature, and is supplied by various methods in the commercial/institutional sector, centralized hot water or steam being only one. For these reasons, primary targets for CHP in the commercial/institutional sectors are those building types with electric to hot water demand ratios consistent with the range of the CHP system: education, health care, lodging, and certain public order and public assembly applications. Office buildings, and certain warehousing and mercantile/service applications can be target applications for CHP if space heating needs can be incorporated.

Table 4.2 presents the specific building types most amenable to engine-driven CHP based on an analysis of existing CHP in the commercial/institutional sectors and a review of available building energy characteristics.

Table 4.2. CHP Target Applications - Commercial, Existing Technology

Application	CHP System Size	Thermal Demand
Hotels/Motels	100 kW- 1+ MW	Domestic hot water, space heating, pools
Nursing Homes	100 – 500 kW	Domestic hot water, space heating, laundry
Hospitals	100 kW – 5+ MW	Domestic hot water, space heating, laundry
Schools	50 – 500 kW	Domestic hot water, space heating, pools
Colleges/Universities	300 kW – 30 MW	Centralized space heating, domestic hot water
Commercial Laundries	100 – 800 kW	Hot water
Car Washes	100 – 500 kW	Hot water
Health Clubs/Spas	50 – 500 kW	Domestic hot water, space heating, pools
Country/Golf Clubs	100 kW – 1 MW	Domestic hot water, space heating, pools
Museums	100 kW – 1+ MW	Space heating, domestic hot water
Correctional Facilities	300 kW – 5 MW	Space heating, domestic hot water
Water Treatment/Sanitary	100 kW – 1 MW	Process heating
Large Office Buildings*	100 kW – 1+ MW	Space heating, domestic hot water
Apartment Buildings	50 kW – 1+ MW	Domestic hot water, space heating

* > 100, 000 square feet

Technology development efforts targeted at heat activated cooling/refrigeration and thermally regenerated desiccants could expand the application of engine-driven CHP by increasing the thermal energy loads in certain building types. Use of CHP thermal output for absorption cooling and/or desiccant dehumidification could increase the size and improve the economics of CHP systems in existing CHP markets such as schools, lodging, nursing homes and hospitals. Use of these advanced technologies in applications such as restaurants, supermarkets and refrigerated warehouses provides a base thermal load that opens these applications to CHP. **Table 4.3** includes potential CHP target applications that are often currently marginal because of inadequate thermal loads but that would be future target applications based on the use of these advanced technologies.

Table 4.3. CHP Target Applications - Commercial, Advanced Technology

Application	CHP System Size	Thermal Demand
Extended Service Restaurants	50 – 300 kW	Domestic hot water, absorption cooling, desiccants
Supermarkets/Grocery	100 – 500 kW	Desiccants, domestic hot water, space heating
Refrigerated Warehouses	300 kW – 5 MW	Desiccants, domestic hot water
Medium Office Buildings*	100 – 500 kW	Absorption cooling, space heating, desiccants

* 50,000 – 100,000 square feet

Industrial CHP **Table 4.4** lists the primary industrial applications for CHP based on an analysis of existing CHP and a review of industrial energy characteristics such as E/T ratios and thermal energy needs (i.e., hot water, low - high pressure steam).

Table 4.4. Target Industrial CHP Applications

SIC	Application	E/T Ratio	Thermal Demand
20	Food Processing	0.4-1.0	Hot water, low pressure steam
22	Textiles	0.5-1.5	Hot water, low pressure steam
24	Lumber/Wood	2.0-5.0	Low pressure steam, direct heat
25	Furniture	1.5-3.0	Low pressure steam, direct heat
26	Paper Products	0.8-2.0	Medium - high pressure steam
28	Chemicals	0.4-1.0	Low - high pressure steam
30	Rubber/Plastic Products	1.0-3.0	Low pressure steam, direct heat
33	Primary Metals	0.5-4.0	Medium-high pressure steam
34	Fabricated Metals	0.75-3.0	Low pressure steam, direct heat
35	Machinery	2.0-4.0	Hot water, low pressure steam
37	Transportation Equipment	1.2-2.2	Hot water, low pressure steam
38	Instruments	1.0-2.5	Hot water, low pressure steam
39	Misc Manufacturing	2.0-4.0	Hot water, low pressure steam

As described earlier, the iMarket, Inc. *MarketPlace Database* was utilized to identify potential CHP sites for the target applications included in **Tables 4.2, 4.3** and **4.4**. The *MarketPlace Database* is based on the Dun and Bradstreet financial listings and includes information on economic activity (8 digit SIC), location (metropolitan area, county, electric utility service area, state) and size (employees) for commercial, institutional and industrial facilities. In addition, for select SICs limited energy consumption information (electric and gas consumption, electric and gas expenditures) is provided based on data from Wharton Econometric Forecasting (WEFA). The *MarketPlace Database* was used to identify the number of existing facilities in target CHP applications and to group them into size categories based on average electric demand in kWs. Office buildings and Apartment buildings are exceptions to this approach. The *MarketPlace Database* includes information on individual tenants within an office building, but not on the building as a whole. The number of office building sites amenable to CHP was derived from CBECS data on office buildings with peak electric demand of 250 kW or greater (about 73,000 buildings nationwide). The MarketPlace Database does not contain any information on apartments. The number of apartment buildings amenable to CHP was derived from the EIA *Residential Energy Consumption Survey*. The survey estimates that there are approximately 11,800 apartment buildings nationwide with peak electric demand of 330 kW or greater. Assuming a load factor of 20%, this roughly correlates to average electric loads of 70 to 100 kW and greater.

The technical potential for CHP in terms of MW capacity was estimated assuming that the CHP systems would be sized to meet the average electric demand for most applications. For the majority of the target markets there is a reasonable match between electric to thermal ratios of the application and the power to heat output of existing CHP technologies. Sizing to meet average electric demand supplies thermal needs for these applications and maximizes the energy efficiency of CHP deployment. It should be noted that the existing CHP capacity described in Section 3 includes a number of large installations that are sized to sell significant amounts of excess power to the grid. The estimate of technical potential in this study assumes all power will be used on-site. A mean system size was calculated for each size category assuming a log normal distribution (150 kW for 100 to 500 kW; 750 kW for 500 to 1000 kW; 2.5 MW for 1 to 5 MW; and 12.5 MW for 5 to 20 MW, and 75 MW for > 20<W) and applied to the number of establishments contained in each category**.** The exceptions to this methodology are office buildings, restaurants, refrigerated warehouses, schools, museums and supermarkets in the commercial sector and lumber, furniture, metals, machinery, transportation equipment and instruments in the industrial sector. Thermal loads in these applications are generally inadequate to support CHP systems sized to the average electric demand based on current CHP technologies. MW capacities for these applications were reduced using factors that better reflect the electric to thermal ratio of these applications based on CBECS and MECS averages.

4.2 SUMMARY OF TECHNICAL POTENTIAL

Using the methodology described in the previous section, the total CHP technical potential was defined for New York State. **Table 4.5** summarizes these results. There are nearly 8,500 MW of remaining CHP technical potential in New York at 26,000 sites. Detailed tables of remaining CHP technical potential by application, size, and region are contained in **Appendix A**.

Sites with existing CHP were subtracted from the total number of sites in estimating the remaining technical potential. While there are 5,000 MW of existing CHP, only about 1,500 MW is used to directly offset on-site needs. This existing on-site capacity is concentrated mostly in the industrial sector and mostly in the upstate market**.**

Table 4.5. Summary of Remaining Industrial and Commercial Technical Potential for CHP

Size Range	Industrial		Commercial		Total	
	Sites	MW	Sites	MW	Sites	MW
State Total						
50 to 500 kW	3,894	300	16,048	1,240	19,942	1,540
500 kW to 1 MW	428	195	3,867	1,584	4,295	1,778
1 MW to 5 MW	434	685	1,280	2,256	1,714	2,940
5 MW to 20 MW	63	488	149	1,240	212	1,728
> 20 MW	9	280	7	210	16	490
Total	4,828	1,948	21,351	6,529	26,179	8,477
Downstate*						
50 to 500 kW	2,160	185	9,919	723	12,079	909
500 kW to 1 MW	143	73	2,520	977	2,663	1,050
1 MW to 5 MW	111	211	804	1,335	915	1,546
5 MW to 20 MW	10	88	108	848	118	935
> 20 MW	0	0	5	150	5	150
Total	2,424	556	13,356	4,033	15,780	4,589
Upstate						
50 to 500 kW	1,734	115	6,129	517	7,863	632
500 kW to 1 MW	285	122	1,347	606	1,632	728
1 MW to 5 MW	323	474	476	920	799	1,394
5 MW to 20 MW	53	401	41	393	94	793
> 20 MW	9	280	2	60	11	340
Total	2,404	1,392	7,995	2,496	10,399	3,887

* Downstate market is made up of LIPA, Consolidated Edison and Orange and Rockland service areas. Upstate is made up of the remainder of the state.

The total remaining potential is split fairly evenly between the upstate and downstate markets – 54% downstate and 46% upstate. Upstate has a greater industrial sector potential and downstate has greater commercial sector potential. While existing CHP in New York has been characterized by a preponderance of very large plants, there are only 16 sites remaining in the state that could support a plant size greater than 20 MW for internal power consumption. Close to three-fourths of remaining capacity potential is below 5 MW in size. About 80% of the potential sites and over 75% of the remaining technical potential is in the commercial sector.

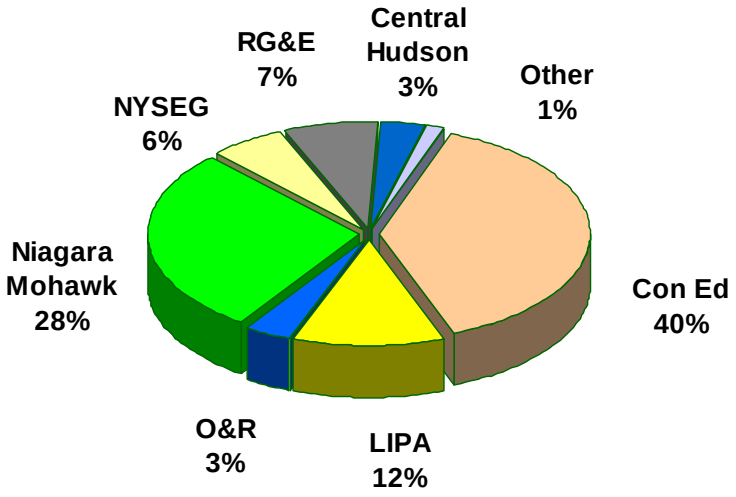
Table 4.6 and **Figure 4.1** summarize the remaining technical potential for CHP by major electric utility in New York State. As the data show, the vast majority of the remaining potential is contained in three utility service areas; Consolidated Edison, Niagara Mohawk and Long Island Power Authority represent almost 80% of the approximately 8,500 MW of remaining CHP capacity. Consolidated Edison represents about 45% of the potential commercial/institutional capacity. Niagara Mohawk represents about 52% of the remaining capacity in the industrial sector.

Table 4.6. Summary of Remaining Industrial and Commercial Technical Potential for CHP by Utility

Utility	Industrial		Commercial		Total	
	Sites	MW	Sites	MW	Sites	MW
Consolidated Edison	1,409	334	9,192	2,942	10,601	3,276
Long Island Power Authority	843	161	3,316	834	4,159	995
Orange & Rockland	162	61	722	229	884	290
Downstate Total	2,424	556	13,356	4,033	15,780	4,589
Central Hudson	98	19	622	260	720	279
New York State Elect & Gas	269	100	1,223	381	1,492	481
Niagara Mohawk Power Co.	1,609	1,007	4,743	1,404	6,352	2,411
Rochester Gas & Electric	445	261	1,180	365	1,625	626
Upstate Total	2,404	1,392	7,995	2,496	10,399	3,888
State Total	4,828	1,948	21,351	6,529	26,179	8,477

Columns in the table may not add to totals due to rounding and a small number of sites in both downstate and upstate that are not included in the seven specified utility regions

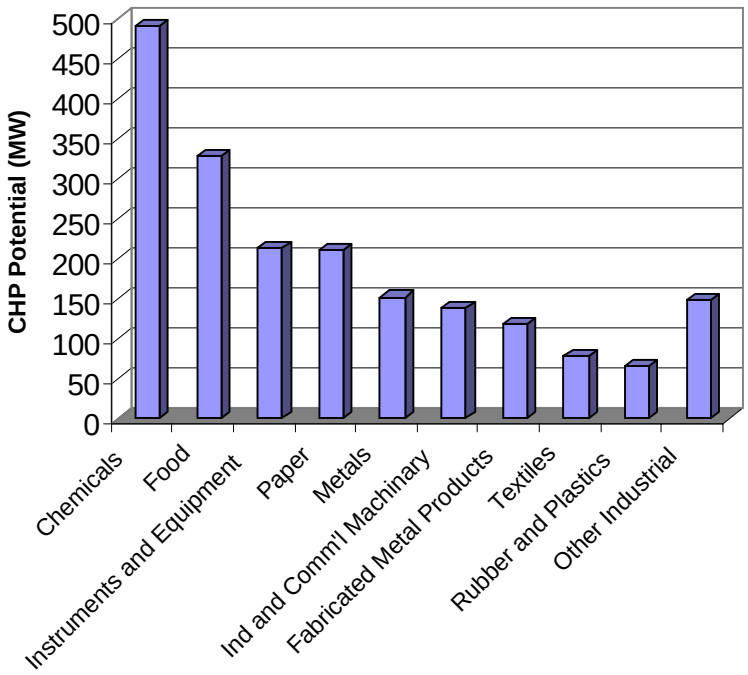
Figure 4.1. Remaining Technical Potential for CHP by Electric Utility



4.2.1 Industrial Market Summary

There are 1,948 MW of remaining CHP potential in 4,828 industrial sites in the state. **Figure 4.2** shows the MW potential by major industry group in order of highest to lowest potential. Sixty four percent of the industrial potential is in four industry groups: chemicals, food, paper and instruments. Primary metals, machinery and fabricated metals products are also important industry segments comprising about 20% of the total potential.

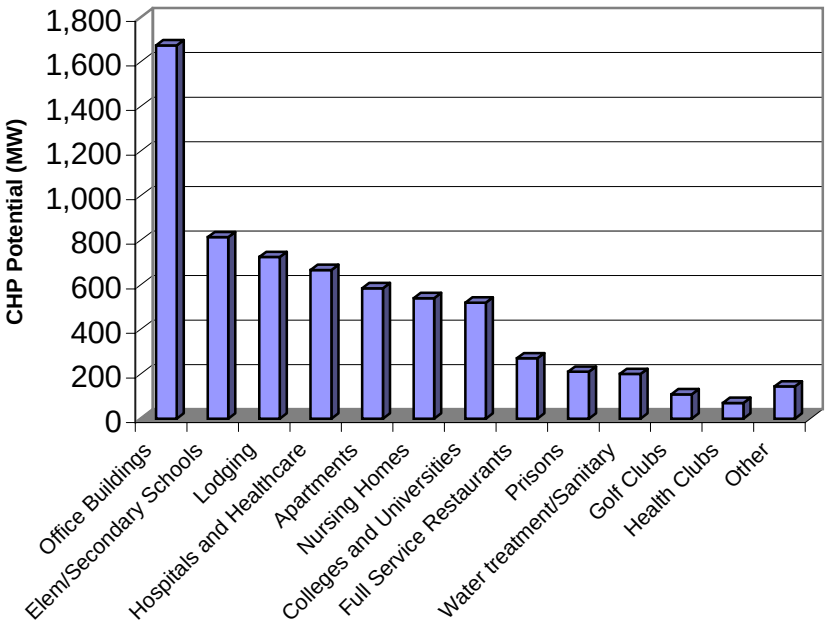
Figure 4.2. Industrial CHP Remaining Technical Potential (MW)



4.2.2 Commercial Market Summary

The remaining technical CHP potential in the commercial sector is equal to 6,529 MW in over 21,000 sites. Based on this analysis, there are nearly four times as many potential sites with over three times the electrical capacity compared to the industrial sector**.** **Figure 4.3** shows the commercial applications in order of their technical potential. Almost half of the total potential identified by the data screen are in three sectors: office buildings, elementary and secondary education, and hotels/motels. Another 40% of the technical potential is in five sectors: hospitals, apartments, nursing homes, colleges and restaurants. Together these eight commercial sectors account for 90% of the remaining potential in the commercial/institutional market.

Figure 4.3. Remaining Commercial Sector CHP Technical Potential



4.2.3 Conclusions

Conclusions from preliminary review of the analysis results include:

- **The bulk of remaining CHP technical potential exists at commercial/institutional facilities** – Unlike existing CHP installations in which 78% of the capacity is in industrial applications, almost 70% of the remaining technical potential (6,500 MW) is in commercial and institutional facilities.

- **The majority of the remaining technical potential is in the smaller size range** – 74% of the technical potential is below 5 MW in size. 39% is below 1 MW in size. For commercial/institutional applications, 43% of the remaining capacity is below 1 MW in size. 25% is below 1 MW in size for the remaining industrial sector potential.

- **The majority of remaining CHP potential is in three utility service areas** – 78% of the CHP technical potential in terms of capacity is included in Consolidated Edison (38%), Niagara Mohawk (28%) and Long Island Power Authority (12%) service areas.

Analysis of the results shows that existing market penetration of CHP is small except for large industrial applications. Penetration of CHP into the commercial/institutional and light industrial markets has been

minimal to-date. This is likely due to a combination of factors: Deficiencies in small CHP technologies and systems, lack of an adequate sales and service infrastructure for small systems, low familiarity of users and building owners of CHP systems and benefits, and a number of critical market and regulatory hurdles as outlined in Section 8.

It should also be noted that the technical market for CHP could be further expanded in the commercial/institutional sectors with advanced technologies that utilize thermal energy for non-traditional applications. CHP potential is limited in commercial/institutional applications due to the lack of adequate thermal energy needs in many building types. Advanced technologies such as heat-activated cooling and thermally regenerated desiccants can expand the economic applications of CHP by providing a base thermal load in building types that do not currently have adequate thermal needs. Cost effective CHP systems in smaller sizes (below 100 kW) would also expand the potential market and increase application of CHP.

5. ECONOMIC ANALYSIS

This section describes the results of a detailed economic analysis of CHP in New York.

5.1 ECONOMIC PERFORMANCE MODEL

Energy Nexus developed an economic performance model to determine the economic attractiveness to end-users of installing and operating an on-site CHP system. The model assumes that the decision is based on the payback achieved from *on-site* use of generated power and thermal energy. The analysis considers the following variables:

- **CHP Technology Cost and Performance –** The cost and performance of CHP technologies was evaluated for the five size ranges considered in the evaluation of technical potential covering sizes from 50 kW to over 20 MW. Both current and advanced technologies were evaluated to determine the impact of technology advances over the next 10 years.
- **Utility and Fuel Costs –** The analysis includes both a detailed look at current rate structures and an estimate of the future fuel and power rates in New York. The impact of utility standby charges is evaluated.
- **Applications Analysis –** Electric and thermal loads were developed for prototype applications in each of the five size categories. These loads were used to define economic competitiveness of CHP by size range and by upstate and downstate regions of New York based on the forecast of energy prices.

5.2 CHP TECHNOLOGY COST AND PERFORMANCE

Table 5.1 shows the technology cost and performance assumptions for currently available CHP technology that would be applicable to each of the five size categories covered in the assessment of technical market potential. **Table 5.2** shows the corresponding values for advanced technology. CHP cost and performance specifications were taken from detailed assessments of CHP technology conducted by Onsite Energy for the Energy Information Administration.[3],[4] The fuel price estimates are based on the analysis of New York prices that will be described in more detail in the next section. The data shown in the table include the following parameters:

- System type and size
- Electrical generation efficiency (also expressed in different units as heat rate)
- Recoverable heat from the prime mover that can be used *on-site*

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[3] *Commercial CHP Market Assessment*, Onsite Energy Corporation for the Energy Information Administration, January 2000.
[4] *Industrial CHP Market Assessment*, Onsite Energy Corporation for the Energy Information Administration, January 2000.

- Fully operational capital and maintenance costs
- Natural gas fuel cost
- Financial parameters: economic life, interest rate, fixed charge rate
- Application factors: annual operating load factor and share of available heat that is actually utilized by the process instead of being wasted.
- Net power costs after credit for avoided fuel use for thermal applications is applied

The technology selection and assumptions are based on the following systems:

- The 100 kW base system is based on product specifications for the Caterpillar G3306 gas engine generator set in a naturally aspirated high-compression ratio configuration. The advanced 100 kW system is based on a microturbine system meeting long-term development goals.
- The 800 kW gas engine system is based on the Caterpillar G3516 engine system. The advanced performance was based on target specifications for a high performance system being developed by the Gas Technology Institute and Caterpillar.
- The base case 5 MW system is based on the Solar Taurus 60; the advanced case 5 MW system is based on the 4.2 MW Solar Mercury 50, a recuperated turbine system that was the successful product of the DOE Advanced Turbine System program
- The 10 MW system is based on the Solar Mars 100; the advanced 10 MW system is based on the Mitsui SB60 (17.7 MW) combined cycle turbine system.
- The base case 50 MW system is based on the GE LM6000; the advanced 50 MW system is based on qualitative assessments of potential improvements from the use of ceramic components and advanced combustors. The advanced 50 MW system has a higher electrical efficiency, but lower heat recovery resulting in a slightly higher net power cost, but slightly lower payback periods in the economic analysis undertaken for this study.

Net Power costs shown in **Figures 5.1 and 5.2** are calculated based on the fuel, O&M, and amortized capital costs minus the avoided boiler fuel costs that are replaced by the available thermal energy. This net annual dollar figure is divided by total electrical output of the CHP system. Net power costs from current CHP technology are progressively lower as the size of the CHP system increases. A 100 kW small commercial sized system produces power at a net cost (after thermal credits are taken) of 9.2 cents/kWh (based on $6/mmBtu gas costs). A very large industrial sized unit of 50,000 kW can produce power for a net cost of 3.9 cents/kWh (based on $5/mmBtu gas costs). Advanced technology produces lower net power costs for CHP systems in all sizes except for the largest size category. In this size, the increase electrical efficiency is offset by the lower thermal energy available.

In the market penetration analysis described later in *Section 6*, the accelerated case assumes a gradual evolution from current to advanced technology. The accelerated case also assumes regulatory and tax initiatives that would result in the equivalent of a 10% reduction in first cost. The costs shown in this section show the differences between current and advanced technology but do not include the impact of any tax credits or accelerated depreciation that might be part of a CHP regulatory initiative.

Table 5.1. Cost and Performance for Currently Available CHP Technologies by Size Range

System Parameters	Gas Engine	Gas Engine	Gas Turbine	Gas Turbine	Gas Turbine
Size kW	100	800	5,000	10,000	50,000
Applicable Size Range (kW)	50-500	500-1,000	1,000-5,000	5,000-20,000	>20,000
Efficiency (HHV)	28.1%	30.9%	27.6%	29.1%	37.0%
Heat Rate (Btu/kWh HHV)	12,126	11,050	12,366	11,750	9,220
Recov. Heat (Btu/kWh)	5683	4323	5622	5282	3779
Basic Turnkey Cost ($/kW)	$1,390	$975	$1,075	$965	$700
O&M Cost $/kWh	$0.017	$0.011	$0.006	$0.006	$0.004
Natural Gas Cost $/MMBtu	$6.00	$5.50	$5.50	$5.50	$5.00
Project Economic Life (Years)	10	15	15	15	20
Annual Load Factor*	80%	80%	80%	80%	90%
Percentage of Available Heat Used*	70%	70%	80%	90%	90%
Interest Rate	10%	10%	10%	10%	10%
Fixed Charge Rate	16.27%	13.15%	13.15%	13.15%	11.75%
Power Cost $/KWh					
CHP System	$0.092	$0.069	$0.063	$0.056	$0.039

*These application factors reflect reasonable conditions of operation determined by the application. They do not represent limits of the technology, but represent typical sizing targets for CHP applications. CHP units would be sized to maximize running hours, meeting the sites baseload thermal needs and as much of the baseload power need as possible. Operation to produce baseload power during shoulder seasons and off-hours results in reduced usage of available heat in smaller systems.

Figure 5.1. Current Technology Comparative CHP Power Costs

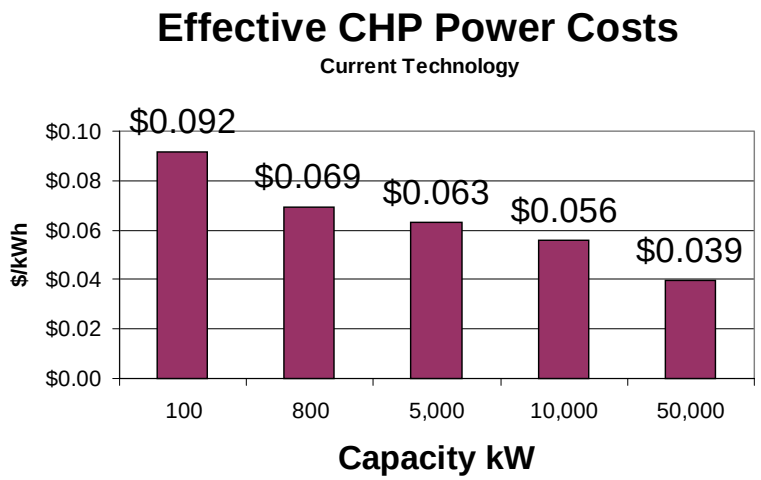
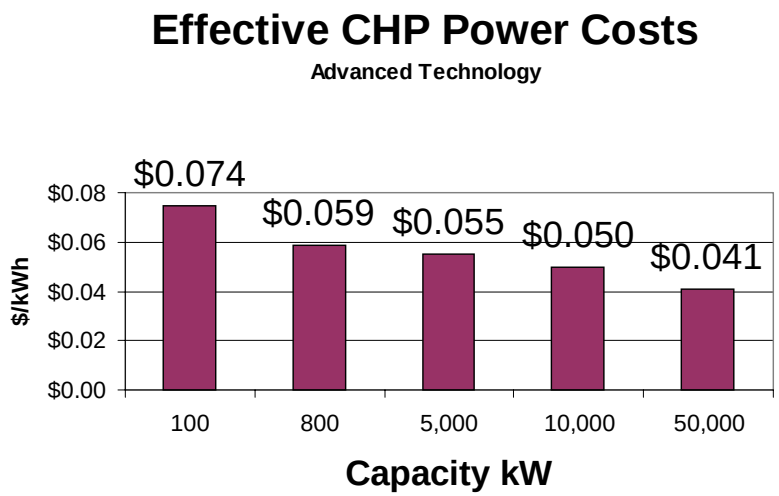


Table 5.2. Cost and Performance for Advanced CHP Technologies by Size Range

System Parameters	Microturbine	Gas Engine	Gas Turbine	Gas Turbine	Gas Turbine
Size kW	100	800	5,000	10,000	50,000
Applicable Size Range (kW)	50-500	500-1,000	1,000-5,000	5,000-20,000	>20,000
Efficiency (HHV)	36.0%	36.4%	35.5%	37.7%	40.0%
Heat Rate (Btu/kWh HHV)	9,477	9,382	9,605	9,054	8,530
Recov. Heat (Btu/kWh)	2748	3096	3746	3259	2730
Basic Turnkey Cost ($/kW)	$915	$690	$950	$830	$625
O&M Cost $/kWh	$0.011	$0.009	$0.005	$0.005	$0.004
Natural Gas Cost $/MMBtu	$6.00	$5.50	$5.50	$5.50	$5.00
Project Economic Life (Years)	10	15	15	15	20
Annual Load Factor	80%	80%	80%	80%	90%
Percentage of Available Heat Used	70%	70%	80%	90%	90%
Interest Rate	10%	10%	10%	10%	10%
Fixed Charge Rate	16.27%	13.15%	13.15%	13.15%	11.75%
Power Cost $/KWh					
CHP System	$0.074	$0.059	$0.055	$0.050	$0.041

Figure 5.2. Advanced Technology Comparative CHP Power Costs



5.3 ENERGY COSTS TO CUSTOMERS

For this analysis, we conducted a multilevel analysis of energy costs to customers. The analysis in this section consists of the following:

- Comparison of utility power costs in New York
- Detailed analysis of a specific utility's rate structures including standby and supplementary service
- Customer natural gas prices
- Long term price trends.

5.3.1 Comparison of Utility Power Costs in New York

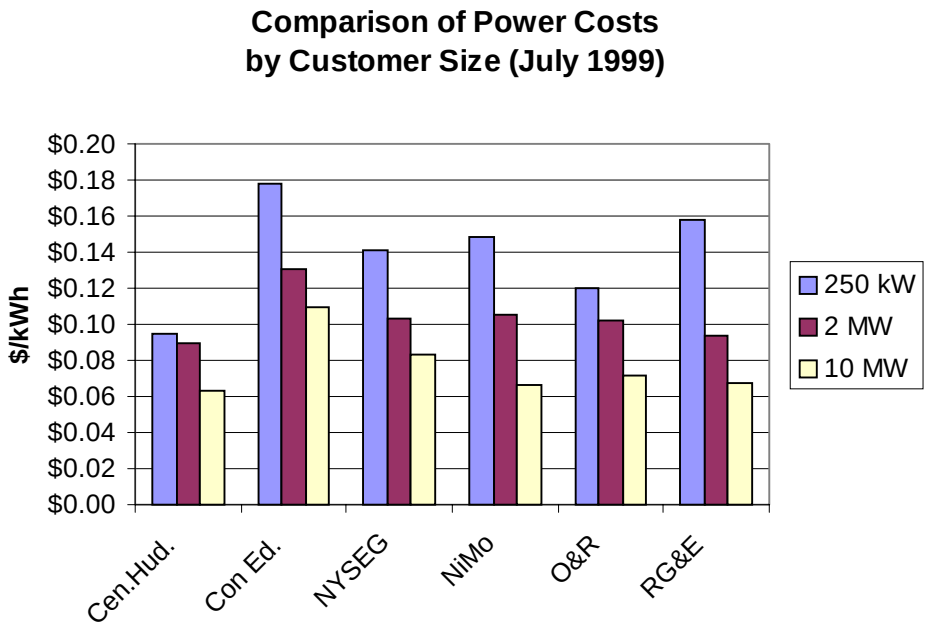
Electric utility rates in New York are uniformly higher than much of the rest of the country. However, there is quite a bit of variation among the utility companies within New York State in terms of the cost of power to customers. The New York Public Service Commission compared rates for six major electricity providers in the state for hypothetical customers with varying levels of demand from 250 kW to 10,000 kW.[5]

Figure 5.3 compares each of the six utilities and the three commercial and industrial sized customers. Central Hudson has the lowest power costs across the board. Consolidated Edison has the highest power costs. Rochester Gas & Electric has the largest spread in costs, with considerable cost reductions as customer size increases. In general, Consolidated Edison and, by inference, the Long Island Power

[5] New York Public Service Commission, Internet Website

Authority, have power costs that are significantly different than power costs upstate. Orange and Rockland has high supply costs but low delivery charges making it overall a lower cost provider. However, because of geographical proximity and similar transmission and distribution constraints, O&R was included in the downstate group for analysis of future CHP potential. All other utilities are included in the upstate group. There is considerable variation in this group as well. However, all show an ability to provide much lower power costs to large customers than can be provided by Con Ed or LIPA.

Figure 5.3. New York PSC Analysis of Power Costs



Figures 5.4, 5.5, and 5.6 show a comparison of power costs for 250 kW, 2,000 kW, and 10,000 kW customers respectively. The rates are separated into supply charges that are now determined by the NY-ISO and delivery charges that remain based on the individual utility company tariffs. For the 250kW customer shown in **Figure 5.4**, average power costs range from a low of 9.5 cents/kWh for Central Hudson and a high of 17.8 cents/kWh for Consolidated Edison. The horizontal line in the figure reflects the net power cost from a currently available 100 kW CHP system – a rate of 9.2 cents/kWh. Prices decline for the 2,000 and 10,000 kW customers across the board. For the 10,000 kW customer, average electricity costs vary from 6.3 to 11.0 cents/kWh. For each size customer, however, the comparative net power costs from CHP is lower than the average power costs for each of the six utilities analyzed as shown by the horizontal line on each figure – 6.9 cents/kWh for an 800 kW CHP system and 5.6 cents/kWh for a 10,000 kW system. While this comparison shows very favorably for CHP market potential, *the actual rates in effect today in upstate New York with standby and transition charges would allow a new CHP customer to save*

only the supply portion of the rate, not the delivery costs. As shown in this series of figures, few of the CHP systems would compare favorably if only the supply portion of the bill could be avoided. This effect will be described in more detail in the next section, which covers a detailed analysis of Niagara Mohawk power rates for customers with on-site generation. The impacts of standby charges are less severe in Consolidated Edison territory (which was used to represent the downstate market) but still significant compared to rates across much of the rest of the country.

Figure 5.4 NY-PSC Comparison of Electric Costs for a 250 kW Customer with 30% Load Factor

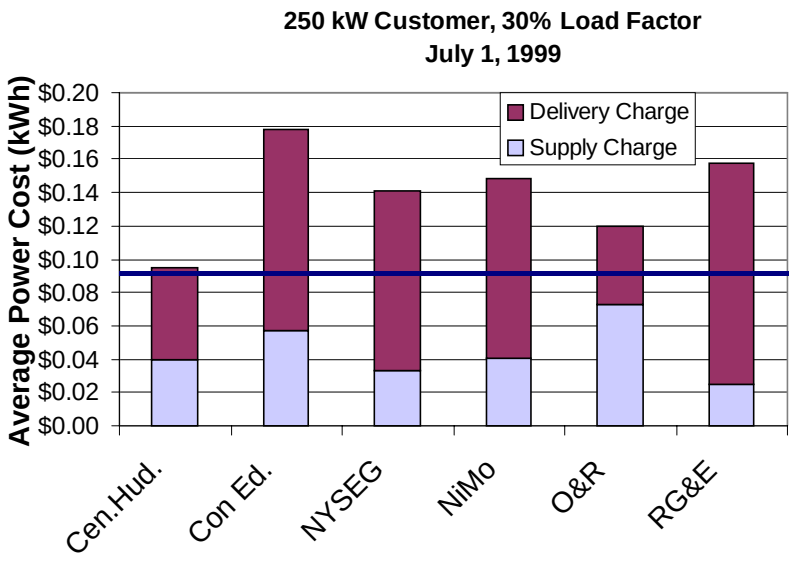


Figure 5.5 NY-PSC Comparison of Electric Costs for a 2,000 kW Customer with 50% Load Factor

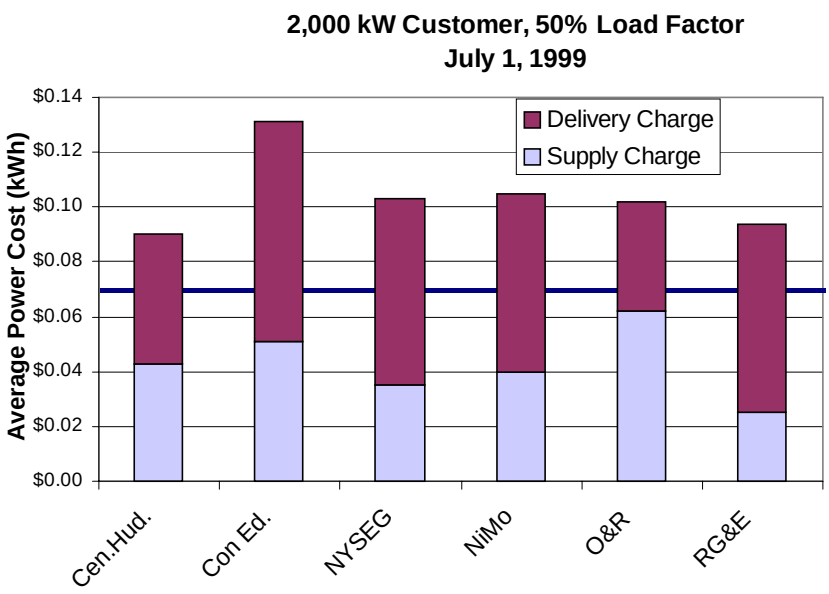
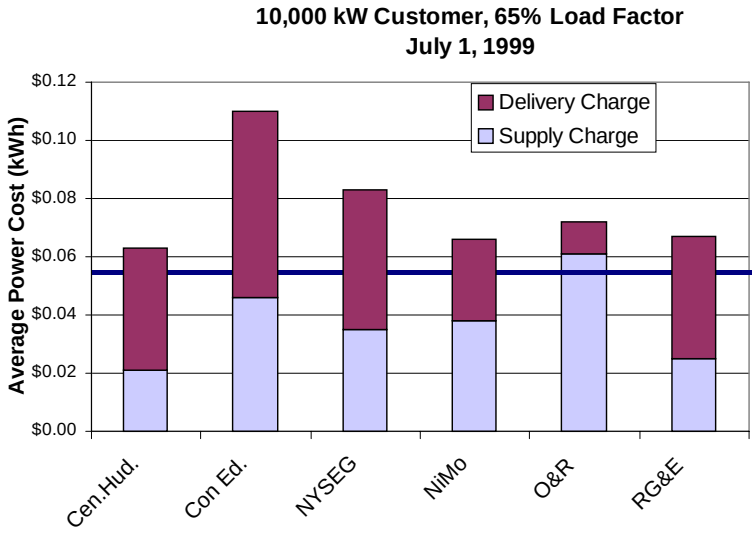


Figure 5.6 NY-PSC Comparison of Electric Costs for a 10,000 kW Customer with 65% Load Factor



5.4 DETAILED ANALYSIS OF UTILITY TARIFFS

High average power costs like those described in the previous section indicate that energy end-users have a strong economic interest in seeking alternatives to purchased power such as that provided by CHP. The actual economic performance of CHP, however, depends on the rate structures and rules under which power is sold. These rate structures can and do affect the ability of CHP to avoid costs and provide an economic benefit.

Niagara Mohawk (NiMo), the largest electric utility in the upstate region of New York was selected as the basis for analysis of customer rates and specific charges related to customers with CHP or other on-site generating systems in the upstate market. Consolidated Edison Company (ConEd) was used as the basis for estimating economic competitiveness in the downstate market.

Under the newly restructured power markets in the state, utilities bill customers separately for delivery charges and supply charges. The delivery charges cover the utility costs for their local transmission, distribution, and customer service operations. Supply charges represent the costs for electricity generation and transmission; in the current market, the New York Independent System Operator (NY-ISO) sets these costs on a regional basis. These supply costs are passed through to the customer. The transition to restructuring also contains rules for the utility to collect competitive transition charges and public interest funds as part of their delivery charges.

5.4.1 Upstate Market – Niagara Mohawk

For each of the five size categories in the CHP market assessment, the appropriate NiMo electric rate was selected. These rates are summarized below:

- 100-500 kW -- SC3 -- Large General Service
- 500-1,000 kW -- SC3 -- Large General Service
- 1-5 MW -- SC3a -- Large General Service Time of Use, Secondary
- 5-20 MW -- SC3a -- Large General Service TOU, Primary
- Greater than 20 MW -- SC3a -- Large General Service, Transmission voltage
- Standby Rates -- Rule 12 (modified to reflect the partial settlement proposal submitted in response to the Public Utility Commissions Standby Service Tariff Inquiry)

Niagara Mohawk, Large General Service Rate

Table 5.3 shows the *Large General Service Rate* for Niagara Mohawk. This is the rate that would apply to customers with power demands from 100 kW to 2 MW. The tariff is basically a 3-part rate with customer, demand, and energy charges. Energy charges are broken into supply and delivery components. The delivery charge is based on an *hours-of-use* calculation. *Hours-of-use* are defined as the ratio of energy consumption divided by maximum demand. To put it simply, customers with a load factor exceeding about 60% would have a portion of their consumption billed at the lower block-rate. Electricity supply charges change month by month based on the hourly costs for each supply sector by the NY-ISO. (The analysis of these charges is described in a later section.) Charges vary as a function of service voltage. The table shows costs for a typical customer receiving service at secondary voltage, i.e., below 2.2 kV. A portion of the demand and delivery charges is defined as a competitive transition charge.

Based on our analysis of prototype customers, for the CHP economic analysis, a customer with a 400 kW peak demand and an annual 40% load factor would pay an average of 13.7 cents/kWh on this rate.

Niagara Mohawk, Large General Service, Time-of-Use Rate

Customers with demands greater than 2 MW have a time of use rate. **Table 5.4** shows this rate. These customers have defined peak periods (8am to 10pm weekdays) and electricity supply charges that vary by hour. For this analysis, a prototype customer with a peak demand of 12 MW and an annual load factor of 65% would pay an average of 9.4 cents/kWh for electricity.

Table 5.3 Niagara Mohawk, Large General Service Rate

Niagara Mohawk SC-3 = Large General Service (Customers >100 kW)*		Load Zones A& B	Load Zones C, D & E	Load Zone F*
		<2.2 KV	<2.2 KV	<2.2 KV
Customer Charge		$260.15	$260.15	$260.15
Demand Charge				
	Minimum kW (first 40 kW)	$598.80	$598.80	$598.80
	Per kW Charge (over 40 kW)	$14.97	$14.97	$14.97
Delivery Charge (per kWh)				
	First 450 hrs. of Max kW Usage	$0.03201	$0.03141	$0.02615
	Over 450 hrs. of Max kW Usage	$0.01454	$0.01394	$0.00868
RKVA Charge		$0.85	$0.85	$0.85
Delivery Charge Adjustment +		Charge varies by month and load zone.		
Customer Service Credit (per kWh)**		$0.00300	$0.00300	$0.00300
System Benefits Charge (per kWh)		$0.00167	$0.00167	$0.00167
Electricity Supply Charge +		Charge varies by month and load zone.		

* A business whose monthly measured demand exceeds 100 kW in each of the previous 12 consecutive months would take service under Service Classification No. 3. Once served under this service classification, a company remains on this service class until the monthly measured demand has been less than 100 kW for 12 consecutive months following the initial term of service.
** Only applies if the customer takes electricity supply service from an eligible ESCo. Availability of this credit is limited and available on a first-come, first-serve basis. Your ESCo will advise you if funds for this credit are still available or view the Estimated Current Customer Service Backout Credit status.
+ The supply charge and delivery charge adjustments are based on the NY-ISO supply price. These prices vary based on market conditions.

Until recently, standby charges for NiMo have been determined by a specific tariff -- *Rule 12*. Rule 12 required a generating customer to have a billing meter (the same as all customers), an on-site generation meter (OSG) that measured the output of the customers generating equipment, and a credit meter that measured any sales from the customer to the utility. Under Rule 12, the customer paid customer, demand and energy rates as defined in their applicable rate classification. Electricity supply charges were based on the actual consumption of the customer as measured by the billing meter. However, for all delivery and CTC related costs, the customer paid based on the sum of their billing meter and OSG meter (less any sales back to the utility.) Under Rule 12, the customer was unable to avoid any delivery related or CTC charges as a result of self-generation. This rate has historically reduced the economic competitiveness of CHP and other forms of on-site generation in Niagara Mohawk's territory. On October 26, 2001, the State of New York Public Service Commission approved *Guidelines for the Design of Standby Service Rates* and ordered

the investor-owned utilities to file updated tariffs within six months from that time (the deadline has since been extended). Niagara Mohawk was the first to file, and the New York Public Service Commission approved the proposed SC-7 Standby Service Rates in June of 2002. The SC-7 standby rates are approximately two-thirds of the previous Rule 12 rates. This approximation was used in the analysis as the current standby rate for upstate New York, and as the consensus future outlook for CHP under business-as-usual assumptions.

Table 5.4 NiMo Large General Service, Time of Use (SC3A*)

Service Voltage	**Secondary Up to 2.2 kV**	**Primary 2.2-15 kV**	**Sub-transmission 22-50 kV**	**Transmission Over 60 kV**
Customer Charges				
·Distribution Delivery	$902.00	$902.00	$1,400.00	$1,673.15
Competitive Transition Charge	$0.00	$0.00	$0.00	$1,498.85
Demand Charges				
Distribution Delivery (per kW)**	$6.09	$8.09	$2.59	$2.08
Competitive Charge (per kW)**	$4.31	$0.77	$3.60	$3.40
RkVA Charges	$1.02	$1.02	$1.02	$1.02
Energy Charges	Based on NY-ISO hourly electricity supply charge			
CTC Charges Load Zones C, D, & E*				
1st 250 Hours of Use				
On-Peak kWh	$0.0275	$0.0292	$0.0273	$0.0261
Off-Peak kWh	$0.0232	$0.0253	$0.0230	$0.0213
Next 150 Hours of Use				
On-Peak kWh	$0.0154	$0.0173	$0.0166	$0.0168
Off-Peak kWh	$0.0113	$0.0134	$0.0130	$0.0135
Over 400 Hours of Use				
On-Peak kWh	$0.0051	$0.0052	$0.0049	$0.0048
Off-Peak kWh	$0.0038	$0.0036	$0.0034	$0.0033

* For customers served under SC-3A after September 1, 1998—When the monthly demand has exceeded 2,000 kW in any six consecutive months of the previous twelve months, or whenever in the Company's opinion the applicant's demand will exceed 2,000 kW in any six consecutive months. A customer once served under this service classification shall remain on this service classification until the monthly measured demand has been 1,800 kW or less for six consecutive months following the initial term of service, whereupon service may be taken from another appropriate service classification.
** Demand charges are based on the highest 15-minute reading on the demand meter but not less than the contracted demand amount.

Energy Supply Prices

Under the state restructuring plan (since 1998), large general customers are charged for their energy supply based on the NY-ISO day ahead hourly prices. These prices reflect the costs of energy supply only. Delivery charges, customer charges, competitive transition charges, system benefits, and taxes are all charged separately according to the tariffs shown above. **Figure 5.7** shows the average hour-by-hour energy supply prices for Niagara Mohawk customers on secondary voltage. The chart shows that weekday prices increase to around $60.00/MWh between the hours of 8am and 10pm. Not shown on the figure, but hourly prices increased about 50% during 2000, so the overall average is a combination of before and after the natural gas price spike. For purposes of the economic analysis of CHP, average on-peak and off-peak prices were calculated. These averages are $59.45/MWh and $36.37/MWh for on-peak and off-peak respectively.

For the CHP economic analysis, these hourly rates were collapsed into an on-peak and off-peak rate. These rates, based on the curves shown in Figure 5.7, are as follows:

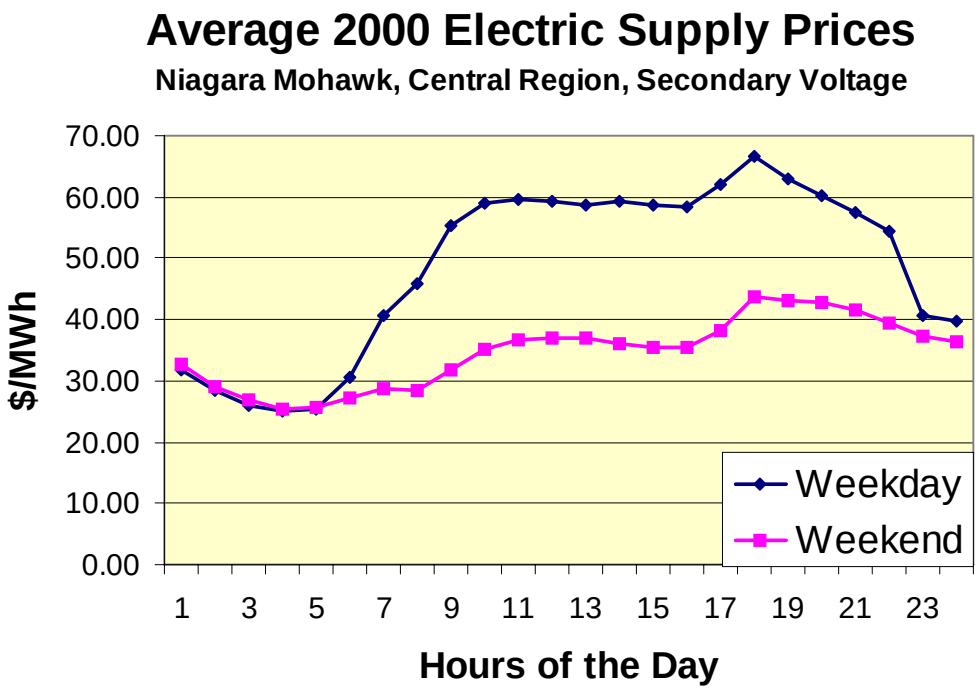
- On-peak rate – 5.945 cents/kWh
- Off-peak rate – 3.637 cents/kWh.

5.4.2 Downstate Market – Consolidated Edison

For each of the five size categories in the CHP market assessment, the appropriate ConEd electric rate was selected. These rates are summarized below:

- Customers with demand between 10kW and 1,500 kW – SC9, Rate I – General, Large
- All customers with demand greater than 1,500kW – SC9, Rate II – General, Large, Time-of-use
- Supplementary Rate – SC10 – Supplementary Service
- Standby Rates – SC3 – Back-up Service.

Figure 5.7. Average Hourly Electricity Supply Prices



ConEd – SC9,Rate I – General Large

Customers with demand between 10kW and 1,500 kW receive service under SC9, Rate I. The customer pays a demand charge with discrete components for market supply and adjustment, transmission, and distribution. Energy charges vary from about 8.5 cents/kWh for most of the year, rising to 12 cents/kWh in the four peak summer months (June-September). Customers also pay a system benefits charge of 1.8 mills/kWh. ConEd updates these rates every six months. The demand and energy charges are shown in **Table 5.5**.

Table 5.5. ConEd – SC9 – General Large Tariff

Month	Demand $/kW	Energy ¢/kWh
Nov-00	$20.69	8.54 ¢
Dec-00	$19.28	8.39 ¢
Jan-01	$17.92	8.81 ¢
Feb-01	$18.70	8.15 ¢
Mar-01	$20.31	8.26 ¢
Apr-01	$19.28	7.83 ¢
May-01	$15.96	8.59 ¢
Jun-01	$18.96	10.19 ¢
Jul-01	$17.56	12.03 ¢
Aug-01	$17.62	12.06 ¢
Sep-01	$19.49	9.17 ¢
Oct-01	$16.13	8.30 ¢

The average cost of power for a customer with a peak demand of 400 kW and an annual load factor of 39% under these rates is 16.1 cents/kWh.

ConEd – SC9,Rate II – General Large, Time-of-Use

Customers with peak demand greater than 1,500 kW are required to go on the time-of-use portion of the SC9 rate. The demand and energy costs are shown in **Table 5.6**. The demand charges shown are the sum of three components as follows:

- Market Supply and Adjustment applied to peak demand weekdays, 8am to 6pm (June 2001 value = $7.23/kW.)
- Transmission applied to peak demand weekdays, 8am to 6pm (June 2001 value = $5.28/kW.)
- Primary Distribution applied to peak demand weekdays, 8am to 10pm (June 2001 value = $9.92/kW.)
- Secondary Distribution (for those customers on the secondary system) applied to peak demand at anytime (June 2001 value = $9.79/kWh.)

Energy charges are split into peak and off-peak periods as shown in Table 5.5. The energy peak period is 8am to 10pm, Monday through Friday. Off-peak energy rates are charged at all other times.

Table 5.6. ConEd – SC9,II – General Large Tariff, Time-of-Use

Month	Demand $/kW	Peak Energy ¢/kWh	Off-Peak Energy ¢/kWh
Nov-00	$20.87	8.93 ¢	5.54 ¢
Dec-00	$20.25	9.64 ¢	5.08 ¢
Jan-01	$19.12	11.13 ¢	4.88 ¢
Feb-01	$19.60	9.23 ¢	5.09 ¢
Mar-01	$20.51	8.47 ¢	5.48 ¢
Apr-01	$20.18	7.79 ¢	5.51 ¢
May-01	$17.41	8.61 ¢	7.01 ¢
Jun-01	$32.22	11.04 ¢	7.18 ¢
Jul-01	$31.41	15.16 ¢	6.71 ¢
Aug-01	$31.42	15.18 ¢	6.73 ¢
Sep-01	$32.54	8.91 ¢	7.35 ¢
Oct-01	$17.51	7.85 ¢	7.07 ¢

For this analysis, a prototype customer with a peak demand of 12 MW and an annual load factor of 57% would pay an average of 14.24 cents/kWh for electricity.

ConEd – Supplementary (SC10) and Standby (SC3)

ConEd requires standby service for customers with on-site generation for periods in which the customer's generator is down for scheduled or unscheduled outages. Where the customer's generator does not supply his complete demand, the customer is required to contract for supplementary service. Standby and Supplementary service are very similar in terms of their demand charge structure. However, Standby service has high energy charges for summer period on-peak consumption compared to Supplementary service. In the economic calculations for this analysis, it was assumed that the CHP customer would purchase his power under the Supplementary Rate (SC10.)

The supplementary rate has a more complicated set of demand and energy charges. **Table 5.7** shows the demand and energy charges for the SC10, Rate I customer. There is a three-part demand charge as follows:

- Contract Demand – the customer pays each month for the total amount of his contracted demand – this demand charge equals $5.90/kW.
- As Used, Market Supply – the customer pays for demand used. There is a 6-month ratchet for the "summer capability period" and one for the "winter capability period." Given the reality of CHP

operation, the ratchet would be triggered in each of those periods meaning that the customer would pay for his highest demand in each of the two capability periods. Market Supply demand charges vary by month from $4.74 to $11.07/kW.

- As Used, T&D – the customer pays for the highest demand used in the 4-month summer period (June-September) based on a ratchet. This demand equals $20.25/KW for each of the 4 summer months. It is very unlikely that a CHP system would not go down at all during this entire period, and any outage would trigger 4-months worth of demand charges.

The energy charges vary by peak and off-peak periods even for customers that otherwise would be on SC9, Rate I. The rates are very similar for SC10, Rate II except that the energy charges during the period that is defined as the peak period under Rate I are split into a 6-hour peak and an 8-hour shoulder period. The rates for these periods are nearly identical to each other, so, for this analysis, we averaged them and used the 14-hour peak period the same as for SC10, Rate I.

Table 5.7. ConEd, Supplementary Rate SC10, Rate I

Month	Demand Charges			Energy Charges	
	Contract	As Used		On Peak	Off Peak
		T&D	Market Supply		
	$/kW	$/kW	$/kW	¢/kWh	¢/kWh
Nov-00	$6.34		$11.01	8.91 ¢	5.31 ¢
Dec-00	$6.34		$9.20	9.53 ¢	4.86 ¢
Jan-01	$5.90		$8.36	10.98 ¢	4.67 ¢
Feb-01	$5.90		$9.27	9.13 ¢	4.88 ¢
Mar-01	$5.90		$11.07	8.45 ¢	5.29 ¢
Apr-01	$5.90		$10.21	7.69 ¢	5.25 ¢
May-01	$5.90		$5.89	8.39 ¢	6.79 ¢
Jun-01	$5.90	$20.25	$6.46	10.84 ¢	6.95 ¢
Jul-01	$5.90	$20.25	$4.74	14.93 ¢	6.52 ¢
Aug-01	$5.90	$20.25	$4.79	14.95 ¢	6.53 ¢
Sep-01	$5.90	$20.25	$7.19	8.71 ¢	7.10 ¢
Oct-01	$5.90		$6.09	7.64 ¢	6.85 ¢

The impact of the ratcheted demand charges in the SC10 tariff make the cost of utility standby to the customer cost over $200/kW per year. This cost is 3 to 4 times the cost of standby to CHP customers in other states such as Illinois, Texas, and California. According to market developers, CHP projects are going ahead with a variety of alternative measures designed to avoid these high charges, from running

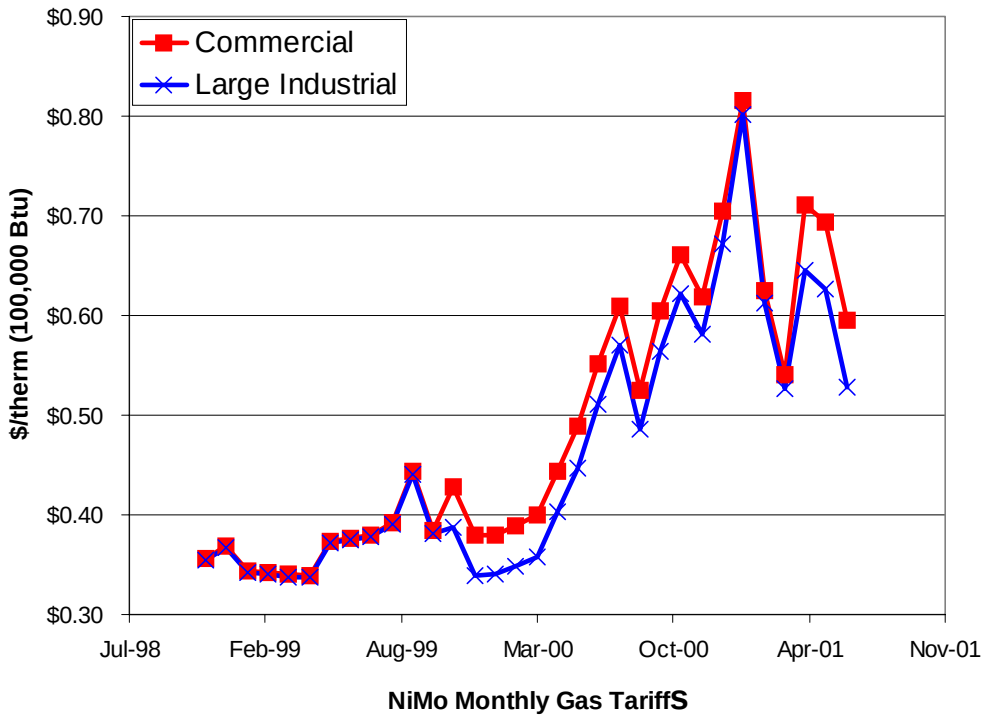
completely grid isolated to disaggregating loads onto different accounts and using standby generators to provide backup to the generator, rather than the utility grid.

The impact of Standby charges in ConEd territory represents a deterrent to market development in that the only realistic savings possible are the energy charges that vary from 8-12 cents/kWh in Rate I and 5-15 cents/kWh for Rate II.

5.5 NATURAL GAS PRICES

Figure 5.8 shows the actual delivered prices for NiMo customers. The chart reflects the run-up in prices that began in 2000 and peaked in the winter of 2000-2001. The price level as of the middle of 2001 is about $6.00/MMBtu for commercial customers and $5.30/MMBtu for large industrial customers.

Figure 5.8 NiMo Monthly Gas Tariffs for Commercial and Large Industrial Customers

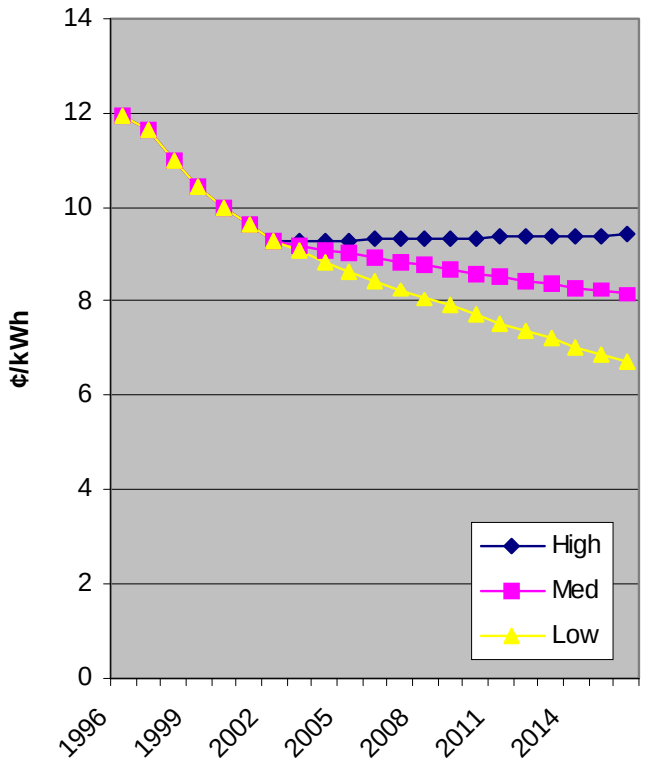


5.6 ENERGY PRICE FORECASTS

To provide a basis for the economic analysis of likely future penetration of CHP in New York, we estimated future natural gas and electricity prices based on published forecasts of EIA and NYSERDA. The last complete energy forecast completed by NYSERDA was the 1998 New York State Energy Plan. This plan preceded the recently experienced disturbances in the natural gas markets and contains what

might be termed, in light of recent market events, considerable optimism regarding the course of electricity restructuring in the state. **Figure 5.9** summarizes the three price scenarios from the 1998 Plan. The low case is based on a very rapid rate of technological improvement. The high case assumes that combined cycle power plants, at current costs and efficiencies and with fuel price escalation, will set the marginal cost of power for the market. **Figure 5.9** compares these electric price scenarios. The costs shown include generation plus average customer transmission and distribution.

Figure 5.9 Comparison of Electricity Price Forecasts (1998 New York State Energy Plan)



For this analysis, the NYSERDA project team recommended using the high price track as the basis for this competitive assessment. Therefore, we estimated what the cost of power from a combined cycle power plant, with updated natural gas prices. This price was assumed to set the NY-ISO electricity supply costs. The combined cycle plant was assumed to have a cost of $690/kW and an electrical generating efficiency of 46%. For on-peak periods, 115% of fully burdened costs were used to reflect line losses and congestion. For off-peak periods, only the running costs of the system were used. **Figure 5.10** shows these costs based on a natural gas price of $4.65/MMBtu. For the economic analysis, the year-by-year forecast gas prices were used to determine the marginal electricity supply cost.

Figure 5.10 Estimate of Long Term Electricity Supply Costs based on Combined Cycle Plant as the Marginal Source of Supply

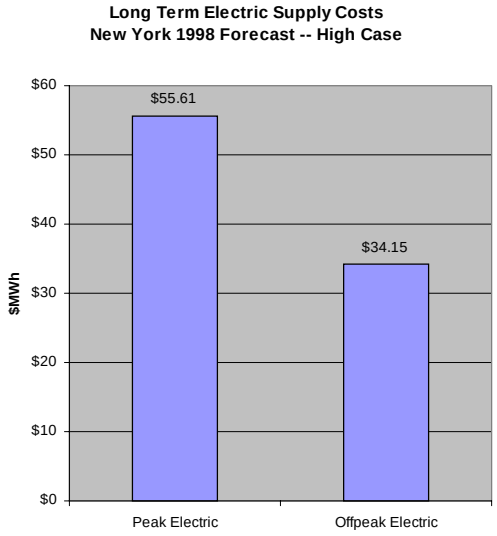
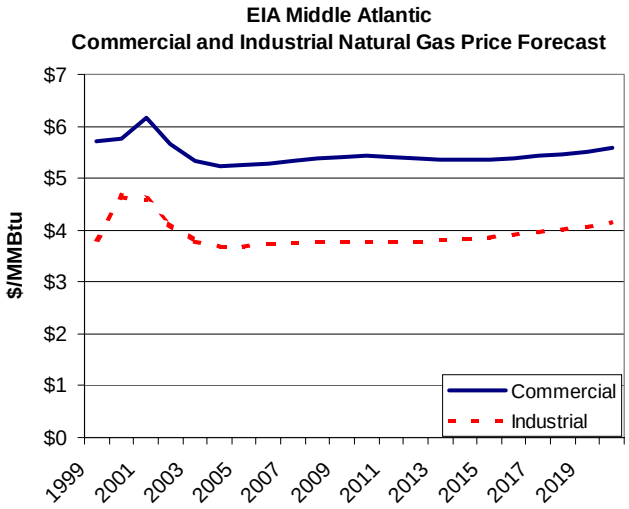


Figure 5.11 Long Range EIA Forecast of Natural Gas Prices for the Middle Atlantic Region



Based on recommendations from the NYSERDA project tem, future natural gas prices were tied to the EIA middle Atlantic forecast from the 2000 Annual Energy Outlook. **Figure 5.11** shows this price forecast. The forecast shows a near-term reduction in recent high prices with a gradual increase over time. Commercial rates are forecast between $5.25 and $5.50/MMBtu and industrial prices range between $3.70 and $4.20/MMBtu.

5.7 CHP SYSTEM PAYBACKS BY REGION, SIZE, AND TECHNOLOGY

The economic competitiveness of CHP was analyzed as a function of size, region, technology characteristics, and future rate scenarios. The analysis was structured as follows:

- Prototype customers were defined for each of the five size categories used in the description of technical market potential (Section 4.2).
- Both currently available and advanced technology was considered as described in Section 5.2.
- The rate variations for upstate and downstate customers were evaluated based on the rate comparisons (Section 5.3) and the detailed rate analysis (Section 5.4)
- The effect of standby and CTC charges was considered with three cases: 1) full standby (in the upstate case this is based on the PSC approved SC-7 Standby Service Rate from Niagara Mohawk and is approximated by using 2/3 of the Rule 12 rates, 2) full avoidance of standby and CTC charges, and 3) a case that reduces standby charges to one half of the full standby values (consistent with practices in states such as Illinois and Texas).

These factors combine to create 60 individual economic cases. For each of these cases, the payback for installing CHP was defined. This section describes the results of that analysis.

For each of the five size bins, a prototype customer load was created to allow analysis of the interaction of CHP production on rates and standby charges. The characteristics of these customers are shown in **Table 5.8**. The customer prototypes are designed to reflect higher load factors as the customer size gets larger. The average power cost for these customers has been calculated for upstate and downstate customers based on the analysis of Niagara Mohawk and Consolidated Edison rates. These average rates are higher in the downstate region with the differential increasing as the customer size increases.

Table 5.8 Prototype Customer Characteristics

CHP Size Range MW	Load Factor %	Upstate Average Cost Cents/kWh	Downstate Average Cost Cents/kWh
0.1-0.5	40%	13.70	16.10
0.5-1	40%	13.59	17.53
1-5	65%	9.39	14.24
5-20	65%	9.39	14.24
>20	80%	8.36	13.10

Table 5.9 shows the results of the analysis for currently available technology and current (at the time of the analysis) upstate rates, including the expired Rule 12 standby tariff. These rates do not allow the customer to avoid any delivery charges as a result of self-generation. Therefore, the benefits are considerably reduced, and CHP is economic only in the largest size category where adequate savings exist in competing with the electricity supply component of rates alone.

Table 5.9. CHP Paybacks by Size for Upstate Region Assuming Rule 12 Standby Charges are Applied

CHP Size	100 kW	800 kW	5 MW	10 MW	50 MW
Technology	Engine	Engine	Turbine	Turbine	Turbine
CHP O&M Cost	$11,662	$60,587	$208,000	$393,778	$1,655,640
CHP Fuel	$50,988	$340,729	$2,383,164	$4,528,920	$18,172,620
Thermal Savings	$29,870	$166,626	$1,083,472	$2,290,381	$8,379,460
Utility Bill	$154,289	$1,283,015	$4,602,586	$9,205,172	$24,116,403
Total Costs w CHP	$187,069	$1,517,705	$6,110,278	$11,837,489	$35,565,203
Base Utility Bill	$190,216	$1,570,433	$6,414,134	$12,828,268	$43,944,874
Annual Savings	$3,147	$52,728	$303,855	$990,779	$8,379,672
First Cost	$139,000	$780,000	$5,375,000	$9,650,000	$35,000,000
Payback Years	44.2	14.8	17.7	9.7	4.2

Table 5.10 shows upstate, base technology case results for the case in which the PSC approved SC-7 rate is approximated. This change is represented by standby charges that are approximately two-thirds of the rates as prescribed in Rule 12. This change creates economic opportunities in all sizes, though paybacks remain marginal in all but the largest size systems.

Table 5.10 CHP Paybacks by Size for Upstate Region Assuming SC-7 Approved Rates (approximated as 2/3rd Rule 12 Charges) are Applied

CHP Size	100 kW	800 kW	5 MW	10 MW	50 MW
Technology	Engine	Engine	Turbine	Turbine	Turbine
CHP O&M Cost	$11,662	$60,587	$208,000	$393,778	$1,655,640
CHP Fuel	$50,988	$340,729	$2,383,164	$4,528,920	$18,172,620
Thermal Savings	$29,870	$166,626	$1,083,472	$2,290,381	$8,379,460
Utility Bill	$139,390	$1,163,821	$4,129,043	$8,258,086	$20,017,105
Total Costs w CHP	$172,170	$1,398,511	$5,636,736	$10,890,403	$31,465,905
Base Utility Bill	$190,216	$1,570,433	$6,414,134	$12,828,268	$43,944,874
Annual Savings	$18,046	$171,922	$777,398	$1,937,864	$12,478,969
First Cost	$139,000	$780,000	$5,375,000	$9,650,000	$35,000,000
Payback Years	7.70	4.54	6.91	4.98	2.80

Table 5.11 summarizes all of the payback results for each of the 60 cases analyzed.

Table 5.11 Summary of Paybacks for All Cases (Years)

CHP Paybacks (years) Scenario	100 kW Engine	800 kW Engine	5 MW Turbine	10 MW Turbine	50 MW Turbine
Current Technology, Upstate					
Full Standby* and CTC	7.7	4.5	6.9	5.0	2.8
No Standby or CTC	2.9	1.9	3.1	2.5	1.7
Reduced Standby and CTC	4.2	2.7	4.3	3.3	2.1
Current Technology, Downstate					
Full Standby and CTC	10.6	3.4	3.0	2.5	1.3
No Standby or CTC	3.5	1.7	1.6	1.5	0.9
Reduced Standby and CTC	4.5	2.1	1.9	1.7	1.0
Advanced Technology, Upstate					
Full Standby* and CTC	4.6	2.7	4.3	3.4	2.4
No Standby or CTC	1.7	1.2	2.2	1.8	1.4
Reduced Standby and CTC	2.5	1.6	2.9	2.4	1.8
Advanced Technology, Downstate					
Full Standby and CTC	5.7	2.3	2.0	2.1	1.2
No Standby or CTC	2.2	1.2	1.1	1.2	0.8
Reduced Standby and CTC	2.8	1.4	1.3	1.4	0.9

* Full standby for upstate is based on the SC-7 rates approved by the New York State Public Service Commission. This rate is approximately 2/3 of Niagara Mohawk's previous Rule 12 tariff structure. Reduced standby rates are 1/3 of full standby in downstate and ½ of full standby (2/3 Rule 12) in upstate to reflect levels consistent with states such as Illinois and Texas

The following conclusions can be drawn concerning the analysis:

- Standby charges have a major impact on CHP market competitiveness. With the modification of the current upstate standby charges, CHP competitiveness is marginally improved. With more significant reductions to standby charges, the competitiveness of CHP increases significantly.

- Advanced technology improves competitiveness in all sizes. This improvement is greatest in the smaller customer size categories.

- Without standby charges, CHP would be economic in all size ranges for both the upstate and downstate markets. While this may not represent a realistic case, reducing the current standby charge impact by two-thirds would open up the economic markets for CHP to all customer size ranges considered.

- Paybacks generally improve as the CHP system size increases. This improvement reflects the increase in efficiency and reduction in cost for larger CHP systems. An exception to this trend is seen in the comparison of the 800 kW and 5 MW systems. For the 800 kW system a large reciprocating engine was chosen as the representative technology. For the 5 MW system, an industrial gas turbine was selected. In this size range, large engines compete somewhat better than small turbines.

These results are based on the current prices analyzed. The methodology and results are extended to the price forecasts described in Section 5.6 in order to develop estimates for future competitiveness. These results are described in the next section.

6. MARKET PENETRATION

This section combines the results of the technical market potential and the economic analysis to develop an estimate of market penetration.

6.1 APPROACH

Scenario Definition

We defined two market penetration scenarios to represent a *Base Case* to represent business-as-usual at the low end and an *Accelerated Case* to represent a business and regulatory environment more supportive of CHP. The business-as-usual scenario is based on current technology and the current framework of CHP standby charges. The accelerated case scenario is based on the following assumptions:

- A gradual improvement in CHP technology cost and performance between now and 2012.
- An immediate moderation of standby charges so that they are only one-third to one-half of their current level. This level reflects the average of standby costs in other strong CHP markets (Illinois, Texas, California.)
- An immediate implementation of incentive programs contained in the federal CHP Initiative that would reduce capital costs by 10% either through tax credits or accelerated depreciation.
- A higher market response rate reflecting more developers in the market and a greater level of customer awareness that would combine to produce higher adoption rates.

For each scenario the market penetration was disaggregated into upstate and downstate regions. As previously defined, the downstate region includes Consolidated Edison, Long Island Power Authority, and Orange & Rockland. All other utility territories were aggregated into the upstate region.

The analysis is driven by the following variables:

- Two technology cost and performance levels (current and advanced)
- Five application/technology size ranges
- Two regions (upstate and downstate)
- Three electric pricing cases (full standby, one third standby, and zero standby)
- Ten-year time frame (2002 to 2012).

Market Penetration Model

CHP market penetration depends on the current levels of market penetration, the economic value to the customer, a maximum achievable growth rate, and the size of the remaining potential market. The current levels of market penetration represent a starting point. The current depressed level of CHP development

reflects the lack of economic value – after siting and certification issues, interconnection, and standby charges are considered. As economic value increases, the market penetration rates will also increase. However, if there are limited numbers of experienced market development, construction, and financing entities operating today, this rate of increase will be constrained to some maximum rate at which these development groups can expand their efforts to meet the new market conditions. As market development proceeds, there will be an ever-declining pool of potential customers, those in the technical market potential, which are available for development. We, therefore, developed a market penetration model that had the following features:

- Initial market rates are based on an assessment of current market levels.

- Maximum growth rates are defined that reflect how fast the market can ramp up if the economic value to the customer is at an optimum level.

- Maximum growth rate is modified by an economic acceptance factor that equals 100% for project paybacks of 2 years or less and declines to zero for paybacks of 8 years or more.

- As the ratio of remaining market potential to initial market potential declines, the maximum rate of growth declines.

- It is not possible to penetrate 100% of the technical market potential due to site restrictions, customer risk preferences, customer diversity in economic value received, site restrictions, or other factors that would inhibit the customer from implementing CHP. These restrictions become more important with the smaller the size of the customer.

- It is possible to define alternative market penetration rates based on changes in economic value to the customer as might be produced by advanced technology and changes in standby rates.

The cumulative market penetration formulas are shown below.[6] The model allows for rapid early growth rates from historical levels that ultimately are moderated by market saturation as the technical potential is approached. The result in a robust economic market is a typical S shaped market penetration curve.

[6] Adapted from earlier work, *Market Assessment of Combined Heat and Power in the State of California*, for the California Energy Commission, Onsite Energy Corporation, 1999.

The model structure is defined below:

$AM_0 = TMP_0 \times MMP$

$MP_1 = AM_0 \times IMS \times EAF$

$MP_n = AM_n \times (1+MaxGR \times EAF) \times sqrt.(AM_{n-1}/AM_0)$

AM_0 = initial addressable market

$AM_n = AM_{n-1} \times 1.01 - MP_{n-1}$ (note[7])

TMP_0 = initial technical market potential (MW)

MMP = maximum market penetration (%)

EAF = economic acceptance factor from 100% to 0% as paybacks vary from 2 years or less to 8 years or more

MP_1 = market penetration in year 1

MP_n = cumulative market penetration in year n

IMS = initial market share

MaxGR = maximum growth rate

The technical potential includes every site in the database that has the energy consumption characteristics that could apply CHP. The technical market potential does not include screening for other factors such as ability to retrofit, owner interest in applying CHP, capital availability, gas availability, and variation of energy consumption within customer application/size class. All of these factors are important in the actual economic implementation of CHP. Therefore the technical market potential was discounted by an assumption of maximum market penetration (MMP). Maximum market penetration is assumed to be a lower percentage of technical market potential in the smaller size categories. For example, in the base case it was assumed that in the 50-500kW size range only 20% of the sites in the technical potential could implement CHP. The MMP assumptions increase in the larger size ranges as shown in **Table 6-1.** In the accelerated case, it was assumed that MMP factors would increase due to greater customer awareness, streamlined permitting and installation and more aggressive marketing. The initial market share (IMS) represents the initial market penetration of the addressable market (AM). This factor was selected to represent observable penetration rates by size class during active historical periods. The maximum growth rate (MGR) is the maximum rate at which the early market can increase. Given the current low state of market activity, these maximum growth rates are quite high, higher for the smaller sizes than for larger system development. The assumed model values for these parameters are shown in **Table 6.1**.

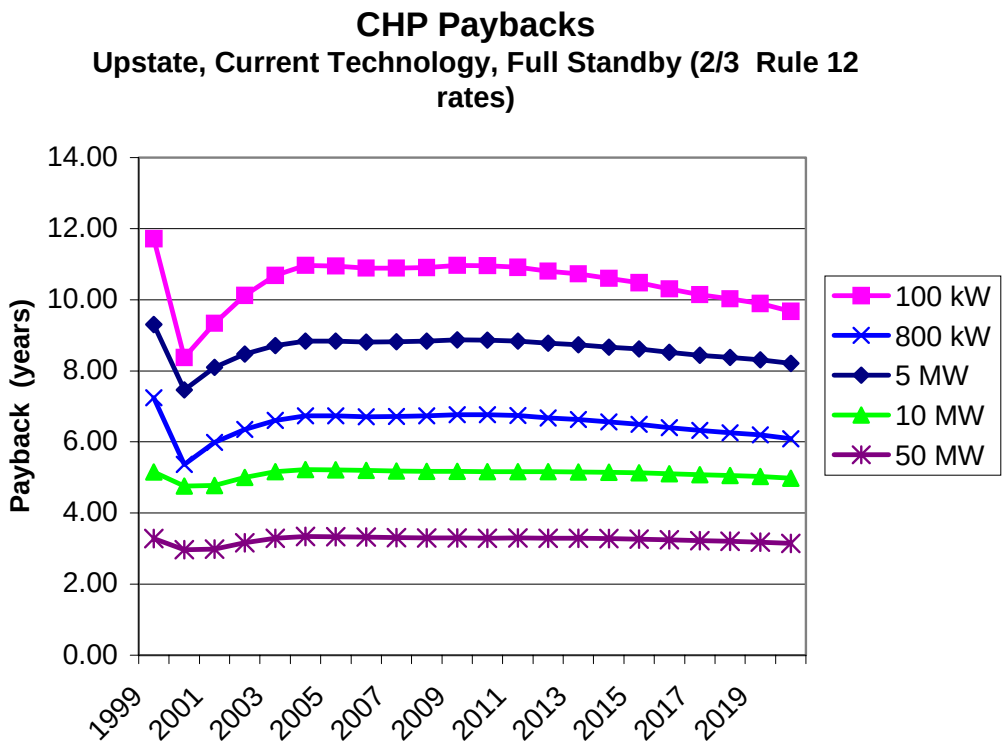
[7] The addressable market, based on the technical market potential is assumed to grow at 1% annually. Gross State Product by sector forecasts provided by NYSERDA were analyzed using a weighted average growth rate for the sectors identified in the technical market potential. The average growth in GSP for these sectors was 1.25% per year. It was assumed that the growth in electric and thermal consumption would be lower due to increases in energy productivity and more growth in service and high value sectors rather than energy intensive sectors of the New York economy.

Table 6.1. Market Model Assumptions by Market Category

Market Size Category	Initial Market Share (IMS)	Maximum Growth Rate (MGR)	Maximum Market Penetration Base (MMP)	Maximum Market Penetration Accelerated (MMP)
50 to 500 kW	0.5%	40%	20%	25%
500 kW to 1 MW	0.8%	40%	25%	35%
1 MW to 5 MW	1.0%	40%	40%	50%
5 MW to 20 MW	1.0%	40%	50%	70%
> 20 MW	5.0%	30%	70%	90%

The market penetration rates are driven by the economic value of the CHP projects for each year of the market forecast. An example is shown in **Figure 6.1** for the upstate *Base Case* with the assumption that full standby charges as included in the settlement proposal are based on the recently approved Niagara Mohawk SC-7 Standby Service Rate approximated as two-thirds of the original Rule 12 rates. A payback of 2 years or less corresponds to an economic acceptance factor of 100%. A payback of 8 years or more results in zero market penetration (EAF = 0). In between these two values the EAF percentage is interpolated.

Figure 6.1. Paybacks by System Size for Upstate Region, Current Technology, and Full Standby (Two-Thirds Rule 12) Case



6.2 MARKET RESULTS

Based on the approach described in the previous section, the market penetration rates for each size range and region were aggregated according to two scenarios as follows:

- *Base Case* – business as usual based on current CHP technology and current standby rates (standby rates in the upstate region were based on the PSC approved SC-7 rate estimated to be two-thirds of Niagara Mohawk's Rule 12 level).

- *Accelerated Case* – based on 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.

The results of these cases are summarized in **Table 6.2** and shown graphically in **Figure 6.2**. In the *Base Case*, an additional 764 MW of CHP is projected to be installed by the year 2012. Nearly 70% of this capacity will be in the downstate region. The greater penetration of CHP in the downstate region is due to

a somewhat higher technical potential (54% to 46%), higher power costs, and somewhat lower standby charges. Even with a moderation of the upstate standby rates (two-thirds of Rule 12) assumed in the *Base Case*, market penetration lags in all sizes except the greater than 20 MW size range. The upstate region has a greater potential for large industrial systems.

In the *Accelerated Case* scenario, CHP is economic in all size ranges in both the upstate and downstate regions. Cumulative market penetration reaches nearly 2,200 MW statewide. The regional split is more balanced than in the *Base Case*, but still about 60% of the market penetration is projected for the downstate region.

Figure 6.3 shows the increase in installed CHP (cumulative market penetration) for the upstate and downstate regions and the *Base Case* and *Accelerated Case*. As in the *Base Case*, the upstate region accounts for more of the larger size projects, whereas the downstate region has a higher penetration of smaller projects. The improvement in market climate assumed for the *Accelerated Case* results in an additional 1,400 MW of CHP market penetration over the forecast period. While it is difficult to determine exactly the impact of the various assumptions that make up the *Accelerated Case* due to interaction among them, we have estimated that the reduction in standby charges between the two cases is responsible for about 35% of the increase in market penetration.

Table 6.2. Summary of CHP Market Penetration by Size and Region for 2007 and 2012 (MW installed)

Market Segment and Region	Base Case			Accelerated Case		
	Upstate	Downstate	Total	Upstate	Downstate	Total
2007						
50 to 500 kW	0.0	0.0	0.0	5.6	8.6	14.2
500 kW to 1 MW	3.1	20.8	23.9	24.9	47.4	72.4
1 MW to 5 MW	0.0	54.9	54.9	48.3	123.0	171.3
5 MW to 20 MW	19.3	40.2	59.5	63.9	104.2	168.1
> 20 MW	88.4	52.8	141.2	151.3	64.9	216.2
2007 Total	110.8	168.7	279.4	294.0	348.1	642.1
2012						
50 to 500 kW	0.0	0.0	0.0	24.0	37.4	61.4
500 kW to 1 MW	7.5	84.1	91.6	113.8	217.3	331.1
1 MW to 5 MW	0.0	204.1	204.1	184.0	515.2	699.1
5 MW to 20 MW	60.8	147.2	208.0	267.2	436.3	703.4
> 20 MW	169.8	90.0	259.8	260.5	113.5	374.0
2012 Total	238.2	525.4	763.6	849.4	1,319.7	2,169.1

Figure 6.4 shows the cumulative market penetration for the year 2012 by size range for the A*ccelerated Case* in the upstate and downstate regions. The smallest size category, 50-500kW, accounts for only about 3% of the total added installed CHP in both regions. The 500kW to 1 MW size accounts for 13 and 16% of the total added capacity in the upstate and downstate regions respectively. In the larger size systems, the two regions diverge significantly in the composition of market share. In the downstate region, the largest market penetration is achieved by 1-5 MW systems accounting for 39% of total added CHP market penetration. In the upstate region the largest market penetration is achieved in the largest sized systems, over 20 MW, with a penetration share of 31% (compared to 9% of the downstate total in the big systems.)

Figure 6.2. Comparison of Cumulative Market Penetration for Base Case (Business-as-Usual) and Accelerated Cases for 2007 and 2012

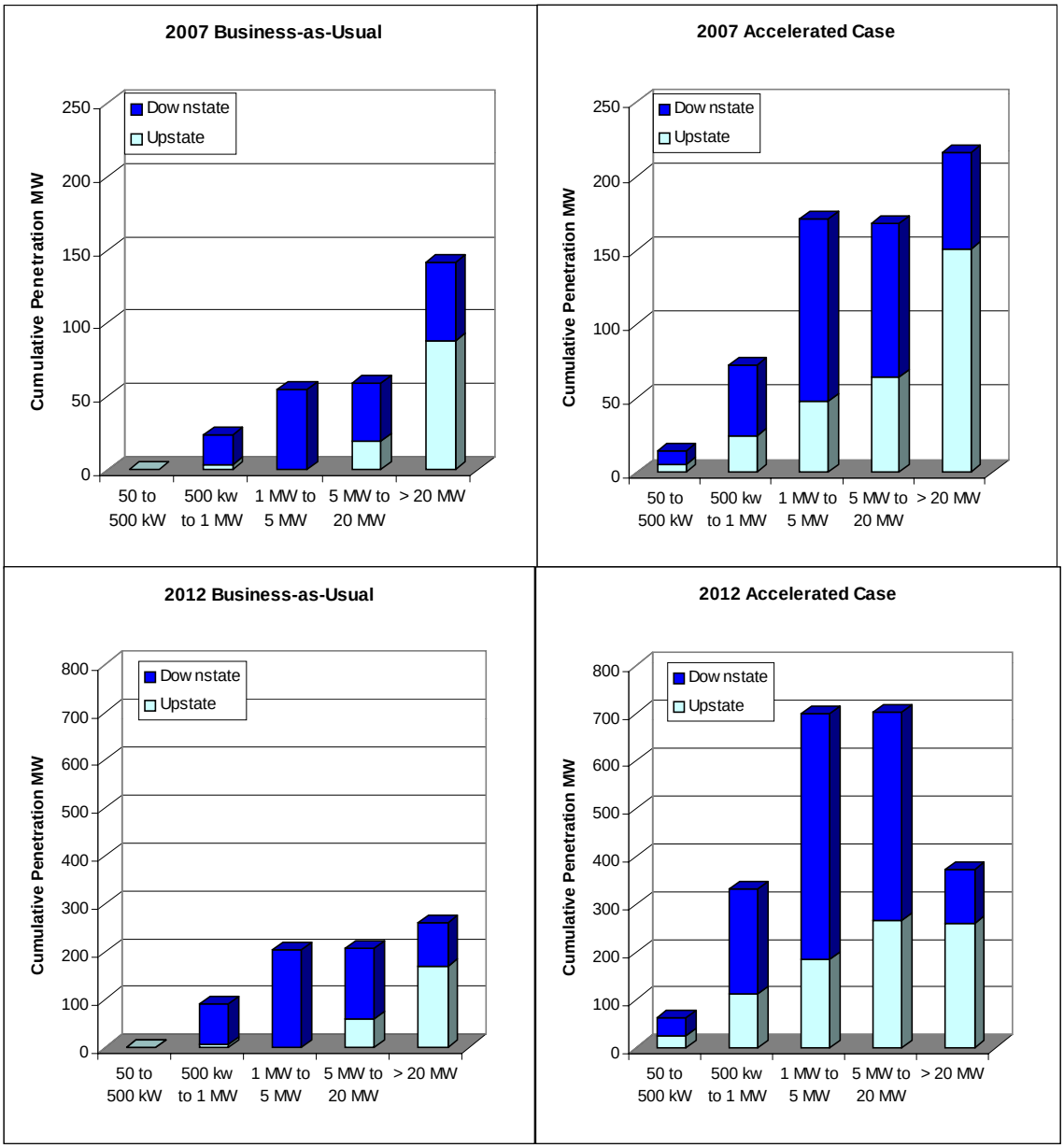


Figure 6-3. Year-by-Year Cumulative Market Penetration of CHP by Region and Scenario

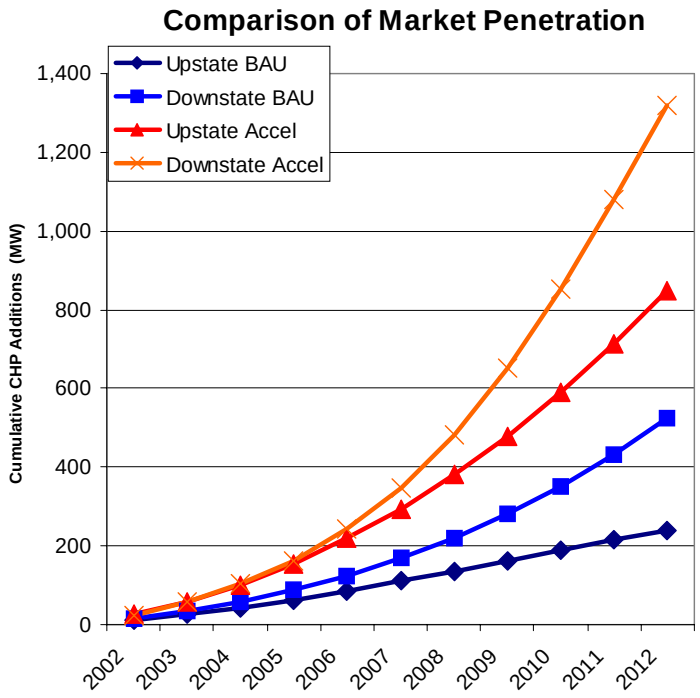
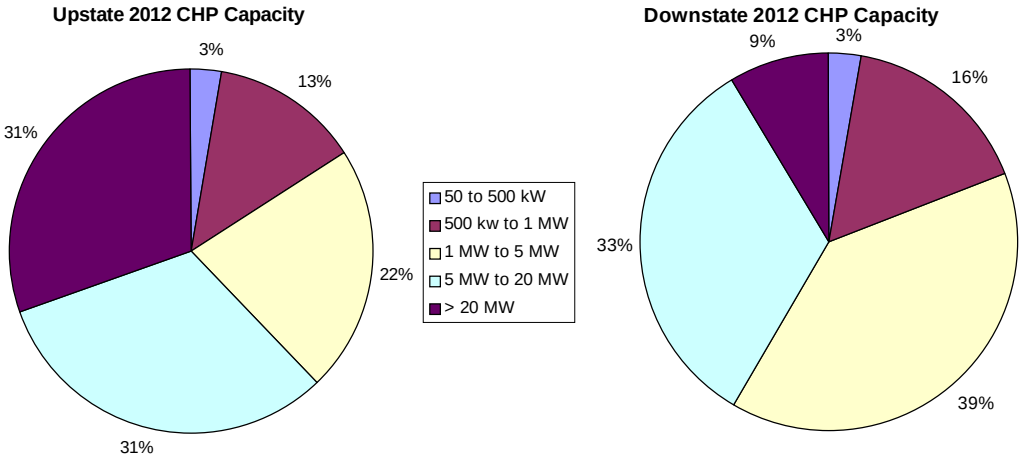


Figure 6-4. Comparison of 2012 CHP Market Share for the Accelerated Case: Upstate and Downstate Regions



Upstate Capacity 2012 – 850 MW **Downstate Capacity 2012 – 1320 MW**

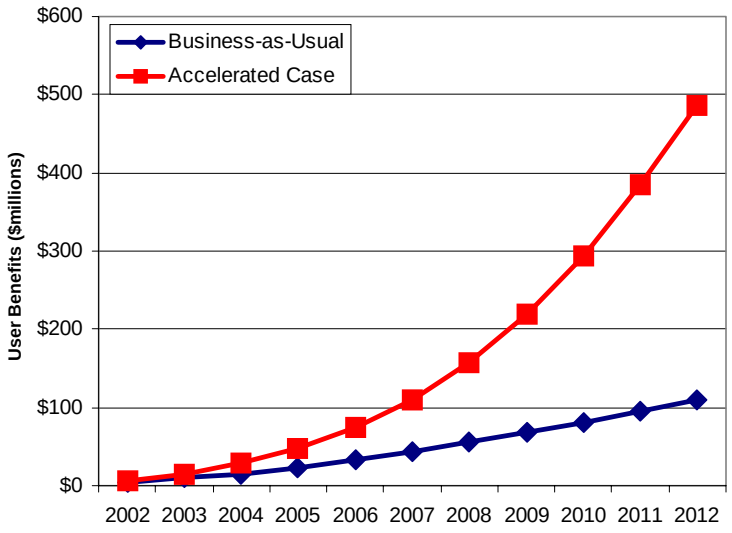
7. BENEFITS OF CHP

This section quantifies the economic, energy, and environmental benefits associated with the market penetration of CHP in New York. These energy savings and user benefits are based on the market model and data inputs described in the previous sections. The environmental benefits are based on a comparison of the environmental performance of the CHP technology used in the economic analysis (described in Section 5.2) with the projected emissions rates for the New York Power Industry based on internal projections provided by NYSERDA.

7.1 USER SAVINGS

The economic savings realized by the customer driven market penetration of CHP. The estimate of annual user savings is shown in **Figure 7.1**. The figure shows the annual stream of user benefits from CHP systems for both the *Base Case (business-as-usual)* and the *Accelerated Case* scenarios. These values incorporate both the operating cost and the amortized capital cost impact to the user. In the *Accelerated Case*, the user benefits reach nearly $500 million/year by the end of the forecast period. In the business-as-usual case, the user benefit, based on a much lower market penetration, is $109 million. The total stream of user benefits is equal to the area under each curve. In the *Accelerated Case*, the total stream of user benefits equals $1.8 billion with a net present value (using a 10% discount rate) of $800 million.

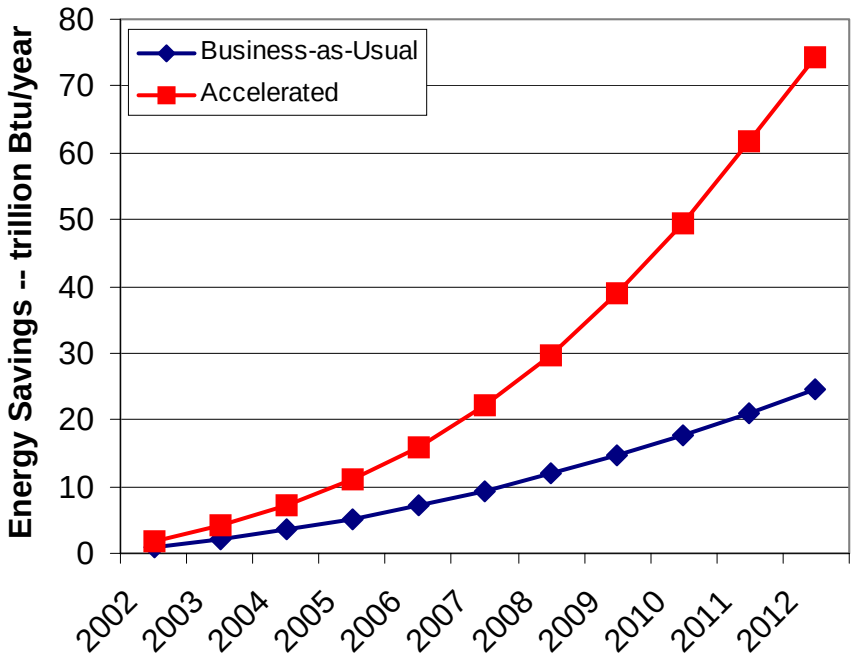
Figure 7.1 Comparison of Annual User Benefits for Base and Accelerated Case Scenarios



7.2 ENERGY SAVINGS

Figure 7.2 shows the annual stream of energy savings due to CHP in the two market scenarios. When comparing fossil-fueled scenarios, CHP systems use less energy than central station power plants and separate boilers because the exhaust heat is utilized productively in meeting *on-site* thermal needs rather than being wasted as it is in central power stations. The total energy savings from CHP over the forecast period in the *Accelerated Case* equal about 316 trillion Btu. The rate of savings equals 74 trillion Btu/year by the end of the forecast period.

Figure 7.2 Comparison of Annual Energy Savings for Base and Accelerated Case Scenarios



Apart from the user savings already quantified, energy savings represent a social benefit in lowering the pressure on fuel and electricity supply and infrastructure, thereby providing lower prices for all consumers. In addition, lowered energy use helps to reduce CO2 emissions that contribute to global warming. These impacts are difficult to quantify, but represent at least part of the motivation behind social goals to increase the efficiency of energy utilization.

7.3 ENVIRONMENTAL BENEFITS

Analytical Approach

We calculated environmental benefits in the form of reduced NOx, SO2, and CO2 emissions. To make these calculations we defined the direct emissions from the CHP systems, the avoided utility generation emissions, and the avoided user boiler emissions. Each of these estimations involves a considerable degree of uncertainty. We made assumptions in each of these areas as follows:

- **CHP System Emissions –** Since the market penetration model is based on the assumption that future CHP market penetration will be primarily gas fired, the CO2 and SO2 emissions values are simply a function of the fuel consumed. There is no technology specific component. However, for NOx emissions it is necessary to assume a specific control technology for each system. These assumptions are defined in **Table 7.1**. For the business-as-usual case, the costs for the prototype CHP systems used in the economic analysis were based on levels of NOx emissions control that have been certified in New York in the 1990s. For the *Accelerated Case*, emissions improvements are shown, but it is assumed that selective catalytic reduction (SCR) is used only on the largest systems.

- **Utility Generation Emissions –** While there is more than adequate data on the level of emissions from existing and new generation equipment, the real uncertainty lies with the assumption regarding what central station generation will actually be avoided. There are some analysts who have looked at DG as an alternative to new central station equipment. For the most part, this new equipment will be a gas-fired combined cycle power plant with extremely high efficiency and extremely low emissions. However, in a competitive market, multiple decision makers are making their production decisions simultaneously. CHP projects are being developed at the same time as new merchant plants are being developed. The market then reacts and equilibrates all of these new and existing supply sources to the available demand. Based on market forces, the new CHP systems and merchant plants will operate more at the expense of older plants that are less efficient, less reliable, and less environmentally friendly. As new plants come on line, either merchant plants or CHP, these older plants will be downgraded to intermediate or peaking duty or in some cases retired altogether. We assume that this competition will be among fossil-based generation sources only, as the hydroelectric and nuclear capacities are assumed to be operated on a *must-run* strategy. We have therefore assumed that future CHP penetration will back-out the average emissions from the average fossil mix component of future generation. These emissions rates are shown in **Figure 7.1** and **Table 7.2.** We should point out that current regulation places utilities in New York under *emissions cap* rules. CHP production that is not under the cap would allow central station generators to lower generation but not lower emissions under the cap system. Therefore, we characterize the analysis here as potential emissions reductions due to CHP, realizing that these reductions may not fully

materialize because of the nature of the current regulatory approach to emissions control for the power sector.

- **Customer Boiler Emissions** – Like the other two areas, there is a wide range of fuels and emission control technologies involved in customer steam and hot water generation. Newer technologies are much cleaner than existing technologies. Gas-fired technologies are very much cleaner than oil or coal-fired boilers. For this analysis, the assumption is that the avoided boiler emissions are based on the current average gas-fired boiler as defined by the EPA – with emissions of 0.1476 lbs./MMBtu. This seems to be a reasonable assumption since the largest source of market potential as defined in *Section 4* comes from the existing customer base.

Table 7.1. CHP System NOx Emission Assumptions

Size Range MW	Representative Technology	Electric Effic. %	Emissions		
			Value	Units	lbs/MWh
Business-as-Usual Case					
0.1-0.5	Recip. Engine	28.1%	0.15	g-bhp-hr	0.443
0.5-1	Recip. Engine	30.9%	0.7	g-bhp-hr	2.070
1-5	Gas Turbine	27.6%	25	ppmv 15% O2	1.139
5-20	Gas Turbine	29.0%	25	ppmv 15% O2	1.082
>20	Gas Turbine	37.0%	9	ppmv 15% O2	0.306
Accelerated Case					
0.1-0.5	Microturbine	36.0%	9	ppmv 15% O2	0.314
0.5-1	Recip. Engine	36.4%	0.5	g-bhp-hr	1.478
1-5	Gas Turbine	35.5%	15	ppmv 15% O2	0.531
5-20	Gas Turbine	37.7%	15	ppmv 15% O2	0.500
>20	Gas Turbine	40.0%	3	ppmv 15% O2	0.094

Figure 7.3 Future New York Central Station Emissions – Existing plus New Generation (Fossil Only)

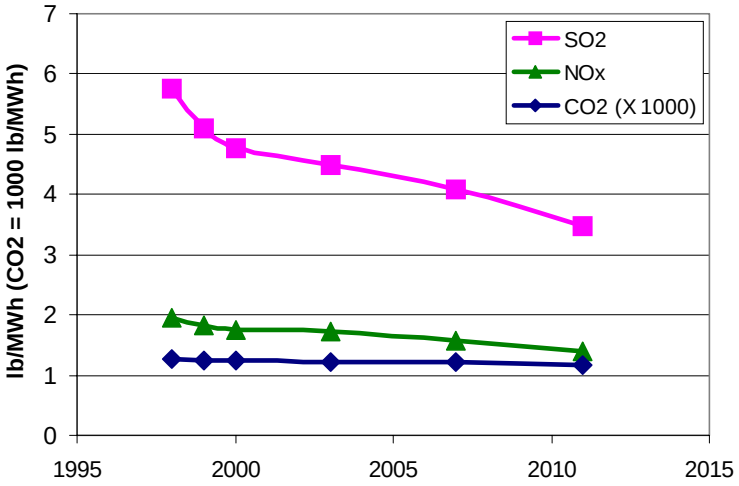


Table 7.2. New York State Generation and Emissions Forecast

	Units	1998	1999	2000	2003	2007	2011
Generation Forecast							
Total	GWh	149,791	151,935	154,023	159,643	167,153	174,732
Nuclear	GWh	34,243	32,102	32,310	32,206	31,860	24,415
Hydro	GWh	26,971	24,374	24,374	24,635	24,635	24,635
Net Fossil	GWh	88,577	95,459	97,339	102,802	110,658	125,682
Existing System							
SO2	1000tpy	254.75	242.86	231.86	230.89	225.31	218.84
NOx	1000tpy	86.75	87.43	85.44	88.17	85.98	84.39
CO2	Million tpy	56.68	58.73	59.90	60.96	58.78	57.13
Existing System plus New Energy Sources if Supplied by Natural Gas							
SO2	1000tpy	254.75	242.86	231.86	230.90	225.35	218.93
NOx	1000tpy	86.75	87.43	85.44	88.51	87.37	87.08
CO2	Million tpy	56.68	58.73	59.90	62.90	66.91	72.85
Existing System plus New Energy Sources if Supplied by Natural Gas (Total)							
SO2	lb/MWh	3.401	3.197	3.011	2.893	2.696	2.506
NOx	lb/MWh	1.158	1.151	1.109	1.109	1.045	0.997
CO2	1,000 lb/MWh	0.757	0.773	0.778	0.788	0.801	0.834
Existing System plus New Energy Sources if Supplied by Natural Gas (Fossil Based)							
SO2	lb/MWh	5.752	5.088	4.764	4.492	4.073	3.484
NOx	lb/MWh	1.959	1.832	1.756	1.722	1.579	1.386
CO2	1,000 lb/MWh	1.280	1.230	1.231	1.224	1.209	1.159

Source: NYSERDA 1998 Energy Plan

NOx Emissions

The total avoided NOx emissions for the *Base* and *Accelerated Cases* are shown in **Table 7.3**. The CHP capacity shown represents cumulative market penetration by 2012, the end of the forecast period. The CHP generation emits less NOx than the avoided utility generation emissions in all sizes except the 0.5-1.0 MW size range which is based on lean burn engine technology with no exhaust clean-up. CHP systems also save the NOx emissions from on-site, fuel-fired boilers; these savings are an important component of the environmental benefit. CHP market penetration provides NOx reduction in all sizes when boiler emissions reductions are included. The total NOx emissions reduction for the accelerated case is 10,270 tons/year by 2012. The *Accelerated Case* contributes 3.2 times the NOx reduction as the *Base Case*.

Table 7.3 Avoided NOx Emissions for Cumulative Market Penetration through 2012

Size Range MW	CHP Capacity MW	CHP Output GWh	CHP tons/year	Utility tons/year	Boiler Emissions tons/year	Avoided NOx tons/year
Base Case						
0.1-0.5	0	0	0	0	0	0
0.5-1	92	642	664	467	204	6
1-5	204	1,431	815	1,041	590	816
5-20	208	1,458	789	1,061	565	836
>20	260	1,821	278	1,325	505	1,551
Total	764	5,351	2,546	3,893	1,863	3,210
Accelerated Case						
0.1-0.5	61	430	68	313	87	332
0.5-1	331	2,320	1,715	1,688	527	500
1-5	699	4,899	1,300	3,564	1,346	3,610
5-20	703	4,930	1,233	3,586	1,178	3,532
>20	374	2,621	124	1,907	525	2,308
Total	2,169	15,201	4,440	11,059	3,663	10,282

Assumptions:

CHP emissions from Table 7.1

CHP load factor = 80% (7008 equivalent full load hours/year)

Avoided utility emissions are for year 2011 from Table 7.2

Line losses of 5% are added to avoided utility generation

Avoided boiler emissions = .147 lb/MMBtu

Avoided boiler efficiency = 80%

SO_2 Emissions

CHP market penetration has the potential for large reduction of SO2 emissions. The gas-fired CHP technology emits almost no SO2 (0.00059 lbs/MMBtu) whereas the average fossil-based emissions for central station generation by 2011 are expected to remain very significant. Avoided boiler emissions are also very small due to the assumption that this amount is all gas-fired. **Table 7.3** shows the SO2 reduction potential for the *Base* and *Accelerated cases*. The total avoided SO2 emissions in the accelerated case amount to nearly 28,000 tons/year by 2012. In the *Base Case*, the total avoided emissions are close to 10,000 tons/year by 2012. The *Accelerated Case* increases SO2 savings by a factor of 2.8 compared to the *Base Case*.

Table 7.4 Avoided SO2 Emissions for Cumulative Market Penetration through 2012

Size Range MW	CHP Capacity MW	CHP Output GWh	CHP tons/year	Utility tons/year	Boiler Emissions tons/year	Avoided SO2 tons/year
Base Case						
0.1-0.5	0	0	0	0	0	0
0.5-1	92	642	2	1,174	1	1,173
1-5	204	1,431	5	2,616	2	2,614
5-20	208	1,458	5	2,666	2	2,664
>20	260	1,821	5	3,331	2	3,328
Total	764	5,351	17	9,787	7	9,778
Accelerated Case						
0.1-0.5	61	430	1	787	0	786
0.5-1	331	2,320	8	4,244	2	4,239
1-5	699	4,899	18	8,961	5	8,949
5-20	703	4,930	17	9,016	5	9,004
>20	374	2,621	7	4,794	2	4,789
Total	2,169	15,201	51	27,802	15	27,766

CO_2 Emissions

CHP market penetration also reduces CO2 emissions. CO2 emissions contribute to global warming. CO2 emissions depend on the overall energy efficiency of the process and on the type of fuel being combusted. Natural gas contributes less CO2 per unit of energy than does oil or coal. Therefore, CHP provides benefits in two ways, by increasing the efficiency of energy use and by substituting natural gas for oil and coal. **Table 7.4** shows that the CO2 emissions reduction for the *Accelerated Case* reaches 3.9 million tons/year by 2012. The business-as-usual case provides a 1.3 million-tons/year reduction.

Table 7.5 Avoided CO2 Emissions for Cumulative Market Penetration through 2012

Size Range MW	CHP Capacity MW	CHP Output GWh	CHP 1000 tpy	Utility 1000 tpy	Boiler Emissions 1000 tpy	Avoided CO2 1000 tpy
Base Case						
0.1-0.5	0	0	0	0	0	0
0.5-1	92	642	426	391	167	132
1-5	204	1,431	1,061	871	483	292
5-20	208	1,458	1,028	887	462	322
>20	260	1,821	1,007	1,108	413	514
Total	764	5,351	3,522	3,257	1,524	1,259
Accelerated Case						
0.1-0.5	61	430	245	262	71	88
0.5-1	331	2,320	1,306	1,412	431	537
1-5	699	4,899	2,824	2,982	1,101	1,259
5-20	703	4,930	2,678	3,000	964	1,287
>20	374	2,621	1,341	1,595	429	683
Total	2,169	15,201	8,394	9,252	2,996	3,854

8. MARKET ISSUES AND HURDLES

While CHP represents a significant energy resource for New York, on-site generation, particularly small on-site generation, has historically faced severe market and regulatory hurdles. These may include utility practices and electricity rate designs that discourage on-site generation, lengthy and costly environmental permitting and siting processes, uneven tax treatment of on-site generation assets, and high customer hurdle rates for energy related investments. These obstacles can stand in the way of CHP and clean distributed generation competing effectively in markets for electric power services. These issues are discussed in this section as follows:

Utility Interconnection Regulations and Requirements –The optimal economic use of CHP for most customers requires integration with the utility grid for back-up, supplemental power needs, and, in selected cases, for marketing or wheeling generated power. Therefore, the key to the ultimate market success of small on-site generation is the ability to safely, reliably and economically interconnects with the existing utility grid system. However, grid interconnection requirements for self-generators, as they exist today, at times pose a hurdle to more widespread economic deployment of CHP. These requirements add cost, complexity, and uncertainty to the process of developing CHP projects. New York State has been a leader in efforts to attempt to streamline this process.

Air Permitting Issues – New CHP projects in New York must negotiate a course through a system of environmental regulations. Like interconnection, air permitting issues may add cost, complexity, and uncertainty to the CHP development process. In addition, the potential benefits of higher efficiency and lower overall emissions that CHP offers may be blocked by sub-optimal regulations that control emissions based on fuel input rather than useful work and that focus on incremental emissions at a site rather than on net incremental emissions overall. New York is among a handful of States that is in the process of examining a new approach to regulating smaller-sized electric generating equipment.

Local Siting Issues – CHP systems must meet applicable building codes and standards. These codes often do not adequately address CHP systems and emerging technologies. Enforcement of codes and standards is hampered by a lack of familiarity and understanding with on-site generation systems.

Tariff Issues – Electric utility customers that self generate must contract with their utility service provider for standby, maintenance and supplementary power. They also should have the opportunity to sell or wheel power that is not needed on-site. Utility charges for this service should reflect the true costs of serving generating customers so that onsite generators are not paying more than their fair share. Utilities that consider on-site generation a market threat are often able to discourage on-site generation by either erecting economic hurdles through high standby charges or expensive interconnect requirements, or by offering

economic incentives to forego installation through deferral rates. Unless carefully guarded against, utilities may assess these charges in a discriminatory manner imposing an effective barrier against CHP projects.

Economic and Financing Issues – CHP projects require an up-front investment to generate a future stream of savings for the user. CHP investment, like any type of investment, carries risks that future savings will not materialize. There is a risk that unforeseen changes in future fuel and electric prices will not provide the required financial margin or that the CHP technology itself will not perform as well as projected or cost more to maintain and operate. Related to project risk, but also separate, is the availability of financing to implement CHP projects. Commercial, industrial, and institutional entities that operate facilities that could utilize CHP may either lack capital for investment or be unwilling to commit capital for energy projects that meet reasonable targets for return on investment.

Regulatory and Policy Initiatives -- Some of these issues can be resolved by legislative and regulatory initiatives. Indeed, there has been positive movement in New York in several critical areas. New York State has been a national leader in the development and implementation of standardized interconnection requirements. With respect to standby tariffs, in October 2001, the Public Service Commission adopted generic principles to guide the establishment of rates, terms and conditions for electric standby service. The Department of Environmental Conservation has announced the initiation of a rulemaking process permitting small electric generating units. This process is scheduled to result in a draft rule issued in late 2002 or early 2003.

There is a critical role for regulators and policymakers. As defined in this study, the greatest opportunity for future CHP in New York State resides in the commercial sector and in the smaller generation size classes. Widespread adoption of CHP and clean distributed generation technologies will require a new regulatory paradigm. This is particularly the case for the smaller unit sizes and for those sectors with less formalized internalized structures for energy management.

This section provides a thorough examination of the current economic and environmental regulatory structures. Reducing the market hurdles in these areas will require a regulatory and economic environment that introduces a greater degree of uniformity, transparency, and simplicity to the processes, and at the same time protects the public interest in air quality, safety and security of network operation.

8.1 INTERCONNECTION ISSUES

An on-site generation system can be designed to serve the customer's electric power needs without connecting to the local utility distribution system. However, it is usually more cost-effective to size the on-site system to meet a portion of the user's power needs and to have the user physically connect with the

local utility system for supplemental power needs beyond their self generation capacity and/or for standby and back-up service during outages or planned maintenance. As such, interconnection to the utility grid is vital to the success of most CHP projects. Without the ability to rely on grid power in the event of a planned or unplanned outage of the primary on-site unit, the customer would otherwise have to purchase redundant generation to ensure that load continues to be served. Depending upon the circumstances, this can significantly change the economics of the project.

Additionally, the customer-generator may be interested in exporting power that is not needed to serve customer load to the grid. Absent interconnection, customers would be precluded from participation in the New York State's net metering program for small-scale photovoltaics, and more generally in the programs recently instituted by the ISO[8] to foster price responsive load reduction activities.

Non-standardized, out-dated, and in some cases, overly stringent interconnect requirements have long been a nation-wide hurdle to greater deployment of small on-site generation technologies. Interconnect requirements vary by state and/or utility and are often not based on state of the art technology or data. Compliance often requires custom engineering and lengthy negotiations that add cost and time to system installation. These requirements can be especially burdensome to smaller systems (i.e., under 500 kW). Non-standardized requirements also make it difficult for equipment manufacturers to design and produce modular packages. Whether the technology is a micro-turbine, fuel cell, or engine-generator set, the lack of interconnection standards hampers the efforts of distributed generation manufacturers to realize economies of scale. Thus, the lack of uniformity from state to state, as well as from utility to utility within a given state, discourages the economic business case for on-site generation.

Interconnection has been a major friction point between customer-generators and utilities in New York. The development of standardized and streamlined interconnection procedures by the New York Public Service Commission has made the process of obtaining utility approval to interconnect on-site generation systems somewhat more transparent, but to-date does not appear to have significantly reduced the number or intensity of disputes between the system owner and the utility. Discussions with developers and utilities reveal that this remains a contentious area, in part, because these respective stakeholders come at the issue from very different perspectives.

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[8] The programs can be classed as follows:

Emergency demand reduction programs to avoid voltage reductions and blackouts. Under such programs, the generator is fired up only when necessary to avert an imminent outage.
Economic incentive programs offer to pay consumers to reduce their usage at certain times.
Demand curve bid programs that will allow consumers, or their aggregators to bid in the day-ahead market, allowing consumers to specify how much they will take at successively higher prices. The difference between load and metered demand can be made up through on-site generation.

The customer is primarily interested in assurances that they will be allowed to connect to the grid: 1) within a reasonable time frame, 2) at a reasonable cost, and 3) with its legal and technical rights and responsibilities fairly allocated and readily understood. Utility protection personnel have very different interests. Their primary concerns are in maintaining the reliability and integrity of the grid, protecting utility personnel and equipment, and safeguarding the public. The proliferation of customer-sited CHP is seen as further complicating the utility's ability to fulfill this primary mission.

The State has the responsibility to insure that a proper balance is struck between legitimate utility concerns for safety and system integrity and the customer need for timely, low-cost and uncomplicated interconnection process. The issues of concern for CHP include:

Complexity of the interconnection process
Time duration of the process (project delays)
Cost for required interconnection equipment
Cost for equipment that may be unique to a specific interconnection
Billing for utility services
Fees for studies.

These issues are developed more fully below.

8.1.1 Development of Standard Interconnect Requirements (SIRs)

The Solar Choice Act of 1997 set in motion the first comprehensive review of interconnection policies in New York since the advent of the Public Utility Regulatory Practices Act (PURPA) in the late 1970's. The Solar Choice Act of 1997 required, among other things, net metering for residential photovoltaic (PV) systems up to 10 kW. To facilitate net metering, the cost of dedicated interconnection equipment was capped by the legislation at $350. Moreover, the Commission was required to review its interconnection policies and procedures.

The development of standardized interconnection for small-scale PV highlighted the need to rationalize the interconnection of other emerging distributed generation technologies to the utility grid. In 1998, the Department of Public Service (DPS) initiated a collaborative investigation into standardizing and streamlining existing interconnection requirements for small, distributed generation units.[9] This collaborative was viewed as a nationally significant development, as evidenced by the active participation of utilities, equipment manufacturers and their trade associations, facility owners, project developers, environmental and consumer groups, and marketers.

[9] Opinion 99-13, Opinion and Order Adopting Standard Interconnection Requirements for Distributed Generation Units, issued and effective December 31, 1999, p. 1.

The collaborative proceeded along two separate tracks – technical and non technical. Additionally, as a threshold matter, the collaborative decided that the most progress could be gained by focusing first on systems up to 300 kVA operating in parallel with radial distribution systems. Some questioned the feasibility of standardizing interconnection requirements for larger and more complex systems. Moreover, interconnection to network systems raised additional complexities that some felt could best be addressed after experience was gained with interconnections to radial systems.

There were two significant outcomes of the interconnection collaborative:

1. Development of Standardized Interconnection Requirements (SIRs) – SIRs defined the design and operating requirements and standards for power quality. In addition, the SIRs instituted *type testing* of protection switchgear. Type testing is one of the more innovative features of the New York SIRs: Once a package meets the type-test criteria described in the SIRs, the design is accepted by New York State utilities. This obviates the need for the utility to separately test individual units to ensure that they conform to the protection settings spelled out in the SIRs.

2. Application Process – The DPS established a multi-step application review process. The goal of this process is to complete the utility review of an applicant's proposed design package within 38 days for systems using type-tested equipment (15 kVA and under) and up to 68 days for larger, non-type tested systems. However, the necessity for a coordinated electric interconnection system review, scheduling of utility installation of system modifications and metering requirements, as well as verification testing will continue to delay commencement of parallel operation.

3. Standardized Contract – Another significant step in the progress towards rationalizing New York's interconnection process is the development of standardized contracts. These legal documents spell out the respective rights and obligations of the utility and the customer-generator with respect to interconnection.[10] The Commission's goal in providing for standardized contracts "is to minimize disputes between applicants and the utilities and to streamline the process for obtaining approval for interconnection of distributed generation units."[11] The contract clarifies the cost obligations and contract term and provides a mechanism for resolution of disputes.

[10] These contracts do not deal with the sale of electricity from the customer-generator to the utility; the latter are covered by separate purchase agreements.
[11] Opinion 99-13, at 19.

8.1.2 Limitations of the New York SIRs: Remaining Hurdles

Despite the considerable progress made to date on interconnection issues, there is general acknowledgement that the SIRs do not address all situations. First, the SIRs are limited by their own terms. As noted, the SIRs do not cover systems above 300 kVA. Secondly, the SIRs are limited by their own terms to the interconnection of on-site generation units to radial distribution systems. This has great practical significance because it means that interconnections in the vast Con Edison service territory, as well as in other parts of the state, are not covered or aided by the SIRs. Thirdly, it is unclear how the SIRs will affect existing systems. The Commission has made clear that the SIRs should not force retrofits of units meeting standards applicable when the unit was deployed, unless the safety and reliability of the system would be threatened. Nonetheless, Niagara Mohawk has recently required one upstate hydropower facility, which had been selling to the utility without contract, to submit to an Interconnection Study, and to upgrade equipment to meet the company's current standards.[12]

Additionally, it is clear that while the SIRs specify to some degree the performance standards applicable to interconnection equipment, utility protection engineers retain considerable discretion in determining how the SIRs will be implemented. This is best illustrated by the broad discretion conferred to utilities to impose additional interconnection requirements on a case-by-case basis. The Commission determined that "absent the utilities ability to protect its system on a case-by-case basis the safety of the utility system may be compromised…Therefore, the Commission will allow the utilities to exercise reasonable engineering judgment in all instances in finalizing the overall design package, but admonish that every utility should, in every instance, make every effort to treat similar situations uniformly."

Apart from the rather narrowly circumscribed situations in which the SIRs are applicable, other limitations have become manifest as the SIRs are applied in specific situations across the state.

1. Staff reports that for small systems applications are taking slightly longer to process than envisioned in guidelines, but not outside what it would consider to be "the zone of reasonableness". Staff further believes that much of the delay can be attributed to incomplete applications being submitted and/or lack of familiarity on the part of the installer with SIRs.[13]

2. Another lingering area of contention, notwithstanding the SIRs, relates to the costs of connecting the customer-generator to the grid. Project developers and their customers are understandably sensitive to the extent to which additional costs may be imposed by the utility in connecting to the grid. Because

[12] See Chittenden Falls v. Niagara Mohawk, Docket No. 01-E-0769. Modifications proposed by DPS Staff would require utility review "of modifications affecting the interface at the point of common coupling". Staff Proposed Revisions to NY SIR, February 2002.
[13] Interview with Charlie Puglisi, Pat Maher, dated July, 2001.

these costs cannot be confirmed at the outset of a project, unanticipated interconnection costs can undermine the viability of DG projects regarded by the customer and the developer as economic.

8.1.3 Developers' Perspective

Project developers were contacted for their perspective on the success of the SIRs in minimizing interconnection costs. Interconnection costs fall broadly into two categories: *transaction costs* and *capital costs.* Transaction costs are those costs incurred by the customer-generator in supplying the utility the requisite information regarding the safety features of the system and the anticipated impacts of the DG unit on the utility's system. The SIRs specify certain costs associated with processing the customer generators' application. For example, a $350 (non-refundable) fee[14] to cover the utility's costs of processing the customer-generator's request must accompany the application. Other costs, however, are left to the utility's discretion. For example, the utility may order and conduct a detailed Coordinated Electric System Interconnection review for larger systems, or interconnection in more complex situations (e.g., interconnection to three-phase branches of a radial distribution circuit). A review of the customer-generators' interconnection design package will also be conducted, as will on-site verification.

Developers raise three major issues with respect to study costs. First, in specific instances developers have disputed the engineering basis for the required design/interconnection reviews. Secondly, developers regard the fees being charged by the utilities for these services as somewhat arbitrary and not cost-based. Thirdly, developers complain that the SIRs confer on the distribution utility a virtual monopoly on the provision of these engineering services; they believe that the services can be performed quickly, competently and more cost-effectively by outside consultants and would like the flexibility to contract with engineers of their own choosing.

Similarly, disputes over the need for, and costs of protection equipment continue to surface even under the SIRs. Under the SIRs, utilities retain the prerogative to direct modifications to the customer-generator's design package, and to condition interconnection upon the customer-generator's consent to pay for any system modifications and/or metering requirements deemed necessary. Developers believe that utilities' have been arbitrary and overly stringent in the exercise of this discretion, increasing project costs across the value chain.

Developers also see the process as unnecessarily lengthy. Some see delays as the inevitable result of the imposition of a new process, and believe that the process will become more transparent and efficient over time. Others are decidedly less charitable, attributing delays to several factors, including:

[14] This fee is waived for systems under 15kVA.

- a belief that interconnection is not a priority for distribution utilities. Utilities see interconnection as a regulatory obligation disconnected from their core responsibilities to provide safe, reliable and affordable electricity.
- lack of customer focus – One developer offered that the utility he dealt with manifested a "we'll get to it when we get to it" attitude that is reflective of a regulated monopoly.
- lack of a clearly defined process for application review and designated point of contact– A prospective customer generator asserts that the completed application languished for several months without any action by the responsible utility personnel.
- redundant reviews – One developer complained of a lack of coordination between the district manager and the headquarters office as to who bore responsibility for reviewing the application.
- revolving utility personnel – This developer cited utility downsizing and internal restructuring as contributing to delays in processing his interconnection application.
- financial disincentives to utility for prompt interconnection – This developer argued that interconnection will be slow so long as on-site generation represents lost sales and lost revenues to the utility.

8.2. AIR PERMIT ISSUES

Combined Cooling Heat and Power (CHP) systems are often highly efficient, provide reliable and clean power to the site and may offer significant local transmission and distribution system benefits. CHP is in many instances cleaner than separately produced heat and power – heat produced on-site and power purchased from the grid – and, as shown in Section 7 of this report, has the potential to reduce overall emissions of both criteria pollutants (NO_x, SO_2) and greenhouse gases.

The use of on-site generation by customers to supply some or all of their electricity will displace the need for power purchases, thereby offsetting emissions at the central station plant. CHP also displaces emissions from the existing boiler/burner at the site. However, existing environmental regulations do not adequately account for the efficiency and emissions benefits of CHP. These regulations are based on limiting the emission of criteria pollutants per unit of fuel input or their concentration in exhaust streams from specific sources. This approach does not credit CHP generation with the emissions reductions associated with reduced consumption of electricity from the grid and may not fully capture the displaced emissions from existing on-site sources.

In addition, regulatory emphasis has focused on new sources, which theoretically can more easily meet stringent regulations. In fact, older facilities receive favorable treatment under air pollution regulations, being "grand fathered" under the Clean Air Act. Grand fathered facilities can have emissions of criteria

pollutants an order of magnitude greater than the new generation source. This approach penalizes installation of new power generation facilities, including efficient on-site generation systems such as CHP.

Siting of clean CHP at a facility may involve significant hurdles in obtaining necessary state environmental permits for construction and operation. The air quality permitting process can be lengthy, complex and costly. In non-attainment areas, which encompass much of the 10 county greater New York area, major new sources are required to meet New Source Review (NSR) standards. New sources must meet stringent standards for criteria pollutants, are required to install the Best Available Control Technologies (BACT), and must offset emissions through purchase of emissions reductions or curtailment elsewhere. These requirements can be costly and the time required to complete the process is often lengthy. "Permitting is long, slow, detailed and different in each state, which tends to drive away investors."[15]

There are a few key factors that determine the time, complexity and cost of permitting. These factors are the total emissions from a source (or it's potential to emit) and the location of the source (non-attainment, severe non-attainment areas). In turn, the total emissions from a source are a function of the generator size, fuel use, and criteria pollutant emissions. The major source thresholds for pollutants in the Downstate and Upstate regions of New York are listed in the **Table 8.1**.

Table 8.1 Major Facility Thresholds in New York

MAJOR FACILITY THRESHOLDS		
POLLUTANT	Downstate[A] Tons / year	Upstate[B] Tons / year
Volatile Organic Compounds	25	50
Hazardous Air Pollutants (any single one)	10	10
Hazardous Air Pollutants (total of all)	25	25
Nitrogen Oxide (NO_X)	25	100
Particulate Matter <= 10 microns (PM-10)	100[C]	100

[A]Downstate = New York City, Nassau, Suffolk, Westchester, Rockland Counties, and Lower Orange County: towns of Blooming Grove, Chester, Highlands, Monroe, Tuxedo, Warwick and Woodbury

[B]Upstate = all other counties, and the remainder of Orange County

[C]PM-10 Threshold in the County of New York is 70 tons per year

[15] *CLEAN AIR TECHNOLOGIES 2000: A Report of the Conference. May 26-27, 1999. Pittsburgh, PA.* Marian Chertow, School of Forestry and Environmental Studies, Yale University

8.2.1 Air Permitting Process Overview

Facilities that emit air pollutants are required to obtain a Title V Permit, a state facility permit or air facilities registration, unless specifically exempted. The air permitting requirements are defined in Part 201 of Title 6 of the New York Code of Rules and Regulations (NYCRR). *Exempt and Trivial Activities* are enumerated and described in Part 201-3. Exempted activities include diesel or natural gas powered internal combustion engines which have a maximum mechanical power rating of less than 250 brake horsepower operating within severe non-attainment areas, or, mechanical power rating of less than 400 brake horsepower when operating outside of a severe non-attainment area.

The details of the air permitting process that a CHP/DG facility will encounter is governed by the equipment size, and consequently, whether or not the total projected emissions will exceed threshold levels set for the local area. Most environmental permits under the jurisdiction of the Department of Environmental Control (DEC), including the air and water pollution control permits, are administered under the guidelines of the Uniform Procedures Act as defined in Article 70 of the New York State Environmental Conservation Law. The UPA specifies the *steps* and establishes the *time frames* for :

Determining the adequacy of permit applications
Establishing criteria and process for soliciting public involvement
Resolving issues
Final decisions on permit applications
Appeals of Department decisions.

Title V Permits

Title V permits are required for any source for which the *potential to emit* (PTE) exceeds the major source threshold for any regulated contaminant. The PTE is the maximum capacity to emit air pollutants if the source were operated 8,760 hours per year. As an example, a generation source that has a NO_X emission rate of .15 lbs/MMBTU, a heat rate of 10,000 BTU's/kWh and is 1MW in size has a PTE of 6.57 tons per year.[16]

For severe non-attainment areas the major stationary source threshold level for both VOC and NO_X emissions is 25 tons per year (TPY). New York City for example is a severe non-attainment area. In the Upstate area the major source threshold is 50 tons per year of VOC's or 100 tons per year of NO_X emissions.

[16] This source emits 1.5 lbs of NOX per MWH (.15 lbs/MMBTU * 10 MMBTU's/MWH). It generates 8760 MWH's if running all hours of the year (8760 hours * 1MW). The total emissions are 8760 MWH's * 1.5 lbs/MWH = 13,140 lbs or 6.57 tons per year PTE

About 900 manufacturing sites and large combustion facilities are subject to the Title V permit program. A number of facilities that had previously been classified as majors have subsequently been determined to be able to cap out of Title V by accepting conditions in a federally enforceable permit. A State Fiscal Year 2000 report from the Division of Air Resources indicated that the number of facilities classified as major in the Aerometric Information Retrieval System (AIRS) had dropped to 590. [17].

Control technologies for Title V permits would generally fall into the categories specified under the Prevention of Significant Deterioration, which requires Best Achievable Control Technology (BACT), **or** the stricter standards that apply to Non-Attainment New Source Review, which require the source to go beyond BACT and emit the Lowest Achievable Emissions Rate (LAER).

One of the critical distinctions in the air permit process is that of Major Source versus Minor source. An issue for siting CHP at an existing site is whether or not that *incremental addition* of an on-site generator moves the facility from the category of Minor to Major source. If that is the case, there is a considerable increase in the oversight, complexity and perhaps costs of compliance. If the facility is not given some credit for displaced emissions, then there is a significant disincentive to investing in combined heat and power.

The Title V application process is lengthy and complex. It requires applicants to identify and address each applicable state and federal requirement. All permits require posting of public notice prior to being approved by the DEC. The upfront costs involved in obtaining a permit include: engineering; consulting; legal fees; drawings and so on. This is in addition to direct charges levied by DEC. Once the Title V Permit is issued, the source will receive a bill each year from DEC based on its actual emissions of regulated pollutants.[18] Developers and engineering firms specializing in CHP assert that oftentimes obtaining the permit is not the problem; it is the **time** it takes to obtain the permit that is really the issue of concern to them.

State Facilities Permits

State Facilities permits are required for those major sources that do not have emissions levels requiring a Title V permit, but are unable to meet the requirements in 6 NYCRR Part 201 Sub-Part 201-4, for Minor Facility Permits. These sources are governed by the requirements within Part 201 Sub-Part 201-5. They have a potential to emit that would cross the threshold for major sources, but they are unable to meet the 50% threshold that is permitted by the Minor Facility "Cap-By-Rule" option. Facilities that produce levels of emissions that do not meet Major source thresholds, nevertheless are still required to file air permits.

[17] Division of Air Resources. Compliance and Enforcement: Summary. SFY 1999-2000. May 2000 page 6
[18] Source: **Title V Permit**. Small Business Assistance Program. NYS Environmental Facilities Corp. http://www.nysefc.org/bigdoc/3Aaiii.htm

These are Minor source facilities that have a potential to emit that exceeds one-half of the major source thresholds. In order to attain a permit to construct and permit to operate, the facility must identify facility emissions sources and control technologies tom be employed at the site.

Synthetic Minor Permit. The first method is to obtain a "synthetic minor" permit with special conditions specific to a source. New York State has 8,500 synthetic minor sources. "Synthetic minor" means that although the facility's potential to emit makes it a major source, its operating conditions or other limitations cause its actual emissions to be less than the major thresholds. Obtaining a State Facility Permit as a synthetic minor source involves providing a written request to DEC, accompanied by a State Facility Permit application for the affected emission units or facility. The requesting facility actually receives a State Facility Permit with conditions that require it to limit its emissions to less than the major thresholds. [19] New Source Performance Standards (NSPS) are required for equipment installed after December 14, 1982. For equipment installed before this time, RACT is required.

It routinely takes up to 120 days to issue a State Facilities Permit[20], as opposed to Minor Facilities Registrations, discussed below, which must be issued within 30 days.

Minor Facilities Registration

Facilities that have emissions of criteria air pollutants that are 50% or less than the major source threshold levels are eligible for Registration permit. In the severe non-attainment areas Downstate, the operative threshold is 12.5 TPY or less of NO_X or VOC's. In Upstate the operative threshold is 25 tons per year (VOC's) and 50 tons per year (NO_X)

An Air Facilities registration is accomplished on a short form, one page in length. The registration is *typically* one-time, though renewal may be required. Additional documentation is sometimes required for the registration; an inspection report may accompany the filing. It is a requirement that specifications accompany the filing. There is a record keeping requirement. The DEC rules state that the Department must receive application for registration at least 30 days prior to the time that the activity is to commence. The Department will then notify the owner/operator of the acceptability of the application within 30 days from receipt. The Governor's Office of Regulatory Reform (GORR) reports that the average duration for obtaining the permit is reported to be 5 days for the initial permit and 5 days for a renewal. The permit cost is $160. Additional documentation may be required of the operator.

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[19] How Can I Limit My Facility's Potential To Emit? NYS Environmental Facilities Corp. http://www.nysefc.org/bigdoc/3AcLimitPotentialToEmit.htm

[20] Small Business Assistance Program Newsletter. Fall/Winter 1999. Page 3. http://www.nysefc.org/tas/SBAP/Newsletters/fall1999.pdf

For projects that are subject to New Source Performance Standards (NSPS) the use of Registration permits is not allowed. Permit conditions must be part of State permits to identify compliance with NSPS. Registration Permits do not allow for the incorporation of permit conditions. Therefore the *minimum* level of permit for NSPS sources is a State Facilities Permit.[21]

The advantage of the State Facilities Permit over Registration is that it provides greater operational flexibility. Registration, or capping by rule, significantly limits the allowable emissions at the facility to a maximum of one-half of the major threshold amounts. The State Facilities Permit provides the facility the opportunity to emit up to the major threshold amounts. However, the permit application process is far more complex than the registration process. Also, the permit once completed is subject to more rigorous DEC scrutiny and it may be subjected to a public comment process.[22]

Registration reduces the cost, complexity and time necessary to obtain an air permit. If the facility is certain not to exceed the maximum threshold amounts, for example, 12.5 tons of NOX per year in the New York City area, then the Registration offers several advantages. The form is simple. The timeframe for obtaining the Registration is short. The costs are significantly less than for a State Facilities permit. The Registration may cost $500 to $600 to obtain, whereas the SFP might cost $5,000 to $6,000.

Exempt and Trivial Activities

In 1996 when the DEC revised Part 201, its permitting rule, the number of exempt activity categories increased significantly from 37 to more than 100. Exempt and trivial activities are identified in Subpart 201-3. A facility is exempt if all of the sources of emissions fall within the exempt and trivial definitions.

Subpart 201-3.2.(3) states that stationary or portable internal combustion engines powered by natural gas or diesel fuel are exempt from the regulations in this Part if they have a maximum mechanical rating of less than 225 brake horsepower if located within a severe ozone non-attainment area, or, less than 400 brake horsepower if located outside of any severe ozone non-attainment area. Exempt activities do not require a SFP or Facility Registration but are not exempt from other air pollution control regulations. Exempt activities must be listed on Title V permits

[21] See "Review of Regulatory Requirements for Operation Of Emergency Generators". Prepared for NYS-Energy Research & Development Authority, Prepared By Novus Engineering. July 2001 page 5
[22] How Do I Decide Which Method I Should Use? NYS Environmental Facilities Corp. : Small Business Assistance Program. http://www.nysefc.org/bigdoc/3AcMethodUse.htm

Reasonably Available Control Technology (RACT) for Oxides of Nitrogen (NOX) are Identified in Sub-Part 227-2. Control requirements for internal combustions engines are as follows:

> *(f) Internal combustion engines: Effective May 31, 1995, any owner or operator of a stationary internal combustion engine of 225 horsepower or larger in the severe non-attainment area, and 400 horsepower in the rest of the State, which provides primary power or is used for peak shaving generation, must comply with the following emission limit:*
> *(1) For rich burn engines, 2.0 grams per brake horsepower-hour.*
> *(2) For lean burn engines:*
> > *(i) 3.0 grams per brake horsepower-hour for gas only fired units; or*
> > *(ii) 9.0 grams per brake horsepower-hour for units firing other fuels.*

It is important to note that the limits specified above for Registration and State Facilities permits, that is, less than 50% of the major source threshold and less than 100% of the major source threshold respectively, would include in the calculation any exempt sources. That is, the thresholds are set on the basis of all emissions from all sources including exempt and trivial sources.

8.2.2 Significant Hurdles in Air Permitting

Delay

One of the greatest concerns expressed with the air permit process is the potential that exists for delay. There is an important balance that must be struck between the issuing agency's legitimate concerns to protect air quality and the concern of the CHP project developer to have the permits obtained in a timely manner. From the perspective of the CHP developer, time delays increase costs, lower project returns and in some instances can threaten the viability of the project. Determinations of BACT and obtaining offsets, if required, can be a time consuming process. Project review may be held up by lack of resources at the regulatory agency, or perhaps due to incomplete filings made by the developer.

Complexity and Ambiguity

The owner/decision-maker at a site evaluating a CHP capital investment is not likely to be well versed in environmental permitting procedures. This is more so the case as we move into industry sectors where CHP has traditionally played a minor role. For smaller sized facilities outside of the energy intensive manufacturing sectors, internal experience may be lacking. Therefore, for many of the potential projects at or below 5 MW, and certainly the vast majority below 1 MW, it is imperative that the process be as simple and as transparent as it feasibly can be made

Developers also suggest that at times there is too much ambiguity in the permit process. Some have asserted that a filing could be viewed in one way by one region of the state (or by a reviewer in a region)

and in a different manner by a different reviewer. This leads to uncertainties about ultimate costs and delays projects while the developer and regulator go through what may be unnecessary iterations in permit writing.

Source versus Performance Regulation

The regulatory method for assessing emissions is based on pollutant per unit of fuel input, rather than on pollutant per unit of useful energy output. This approach penalizes highly efficient technologies such as CHP. Whereas a CHP system may be able to extract 80 to 85 units of useful energy from 100 units of fuel input, a typical configuration of separately provided heat and power is likely to extract just 45 to 48 units of useful energy from each 100 units of fuel input[23]. The pollutant per unit of fuel input in the two cases may be exactly the same. The 75% efficiency advantage of the CHP configuration yields a much lower amount of pollutant emitted in order to achieve the same level of energy output.

Because the conversion efficiency is being ignored, setting emissions standards on the basis of fuel input creates a penalty for systems that are very efficient in converting input fuels into useful energy. CHP systems will generally increase emissions at a site if electricity generation takes place where it did not previously. The CHP system is providing useful heat and power displacing emissions from electricity production that would have occurred elsewhere and from the on-site fuel-fired boilers. The rationale for the output-based system is portrayed in the following **Figure 8.1**.

Figure 8.1 Output-Based Emissions Standards

Redefining the Emissions Paradigm:

Output-based regulations promote efficiency

Input-based:

$$\text{Rate} = \frac{\text{Emissions}}{\text{Fuel input}}$$

Allows more emissions the more fuel used

Output-based:

$$\text{Rate} = \frac{\text{Emissions}}{\text{Useful output}}$$

Allows <u>reduced controls,</u> the more efficient the system

[23] Assuming that separately produced heat comes from a boiler operating at 85% efficiency and grid electricity is produced at an average efficiency of 35% with T&D losses averaging 9% the system efficiency of separate heat and power is approximately 48.8%

8.3. LOCAL CODES, SITING, AND PERMIT ISSUES

At the local level there are a host of codes, siting and permitting issues involved in an on-site power/CHP installation. This includes building codes, electrical codes, fire codes, planning and zoning concerns, noise and aesthetic considerations. One major impediment to the development of broader markets for CHP and other clean Distributed Generation (DG) technologies is that for the most part they are simply not referenced in the codes. The outcome of this omission might be that the project does not get permitted, or, that the project undergoes a very time consuming and costly review. This point is made in a recent paper from Pacific Northwest National Laboratory examining current codes and standards and the issues posed for distributed energy resources:

> *In such cases when a technology is not specifically referenced in the applicable code documents, code officials may disallow the installation and operation of that unit. Building officials may require specific tests to demonstrate "alternative compliance"; performing the necessary site-specific studies--possibly requiring modifications to the installation--can increase the installed cost of a unit beyond any reasonable expectation for return on investment. Further, with 44,000 state and local code jurisdictions in the United States, the absence of any reference in the national code bodies may kill altogether the early prospects for the mass deployment of a new energy technology such as microturbines.*[24]

This issue has been corroborated in early discussions with codes officials in New York State. In the absence of reference by code and without the benefit of widely accepted standards, new CHP technologies will move into the marketplace at a very slow pace. The costs involved in terms of lost time and additional compliance will add to the economic burden of projects and delay or derail their implementation.

In New York State there is somewhat of a dual-system of codes development and enforcement. For all of New York State, outside of New York City, there is a fairly centralized system of codes promulgated at the State level. New York City has it's own set of codes and code enforcement entities.

A wide variety of codes are applicable in the five boroughs of New York City, generally administered and enforced through the City Department of Buildings (DOB). There are different rules for emergency, standby, optional standby, and backup generation equipment in buildings regulated by the DOB, though the rules are less restrictive for optional standby or backup generation, where various fire protection emergency requirements are not applicable. The key code requirements that seem to apply for generation systems intended for semi-continuous operation include venting and stack height requirements, gas pressure issues, and noise level concerns.

[24] Pacific Northwest National Lab. By Anne Marie Borbely-Bartis, et.al

Any project that exceeds 1000 kVA in size must go to the Bureau of Electrical Control (BEC) Advisory Board for review. If the unit is less than 1,000 kVA but greater than 480 volts it does not go through a full Advisory Board submission but does have to file with the BEC. Also, any products or materials used in buildings in the City (including any combustion or generation equipment) must go through the City DOB's "Materials & Equipment Acceptance (MEA)" process, which approves any new technologies. The Advisory Board Process has the potential to present a bottleneck in the approval process. However, it was noted that on "straight examinations" a project typically proceeds rather quickly through the process. The Advisory Board meets every three weeks so that there is not an inordinate delay due to scheduling.

A second major issue area is education and training for local officials. Early research has found that there is a general lack of education and familiarity among code officials with respect to CHP and clean distributed generation technologies. In workshops on codes issues sponsored by the Urban Consortium's Energy Task Force of Public Technologies Inc. the need for education and training materials was consistently a topic of key concern. Representatives from the electrical codes community, building codes, fire marshals, city planning and zoning interests and so on highlighted this as a priority.

8.4. TARIFF ISSUES

Tariff structures can create significant hurdles to the development of more robust markets for CHP applications in New York State. The tariffs that are in place include standby / backup and maintenance charges for services available when the facility requires power due to unplanned or planned outages of the CHP system. In addition, fees may be imposed when the CHP host site removes all or a portion of their energy and power demand from the local distribution company's system.

The provision of *fair*[25] Standby service charges is essential for the development of markets for CHP. If Standby charges are priced at too high a level, then the potential CHP investment may be abandoned, or may choose to meet all of its needs through self-generation. In the latter case, this requires the facility to significantly over-invest in capital on its premises, in order to attain the required level of reliability. This redundant investment significantly lengthens payback periods, raising the cost of doing business in New York State.

From the utilities vantage point, if the standby service is priced at a level that does not capture the costs of serving these facilities, then other users of the system will have to bear the cost. In general, standby tariffs should be structured in accordance with well-established ratemaking principles that include efficiency, fairness, and public policy considerations. The Public Service Commission has recently promulgated a set

[25] Fair standby charges are made at a rate and under terms that are just and reasonable, when taking account of the actual incremental cost to the distribution utility of providing the service.

of principles for the design of electric standby service charges. The application of these general principles to the specific circumstances of each of the distribution utilities is a process that is now underway.

8.4.1 Tariffs for Standby, Maintenance, and Supplemental Service

The distribution utility assesses charges for backup, maintenance and supplemental services[26], for customers who ordinarily would self-generate all or a significant fraction of their electric power requirements:

Backup service is required when the facility's onsite generation is temporarily out of service due to some ***unplanned*** system failure.

- ***Maintenance*** service is required when the facility's generation is out of service for ***planned maintenance*** reasons. By definition, maintenance service is scheduled ahead of time generally during periods when the utility system has adequate supply and delivery resources.
- ***Supplemental*** service is the regular provision of distribution services to a facility for normal power requirements not met by the onsite generation system, so that the two taken together meet the entire requirements of the facility. For example, a facility that sizes its onsite generation to satisfy 75% of its daily peak power needs will then require the additional 25% as supplemental service on a regular basis through the peak hours and season.

Developers have asserted that the backup, standby and maintenance tariffs levied in the past by the utilities in New York often made otherwise cost-effective projects uneconomic. Some developers stated that onerous standby and backup tariffs created a situation where the host location would have required a redundant system, adding 50% or more to the cost of the project and ruining project economics. The ideal project is usually one where the generation is sized to meet the thermal needs of the facility. The added constraint of self-supplying all electric requirements is likely to create a situation where there is no use for a significant portion of the available heat and therefore some becomes wasted. This severely curtails the energy efficiency of the projects, as well as greatly increasing project investment costs.

The utilities argue that the level of tariff and the imposition of exit fees are necessary charges permitting a fair return. A standby charge is required to capture the costs imposed in serving the customer who places occasional, not constant, demands on the distribution system. This charge should reflect not only the variable cost of serving the partial requirements customer, but also a portion of the fixed costs of the system that must be in place in order to meet this demand, something akin to an insurance premium.

[26] These services are often not independently priced. They are differentiated here to clarify the distinctions.

In a region where the standby tariffs are less (more) onerous the numbers of projects that will pass an economic analysis hurdle will be greater (lesser). These regional differences may well be due to unique system cost differences. To the extent that they are not cost-based, they present opportunities for modifying tariff structures in a way that may provide gains for the local distribution utility as well as for the CHP site.

There is a strong incentive to run on-site generation at peak, as this is precisely the time when the value of the power is greatest. On a probabilistic basis, there is some likelihood that particular on-site generation units will be down at the system peak. Likewise, on a probabilistic basis, there is little likelihood that most or all on-site generation units will be down at the time of the system peak

Standby tariffs should account for the random nature of the load that CHP outages place on the system and the diversity of occurrence of that load. CHP developers argue that the standby tariffs as structured are not fair because they fail to fully recognize the diversity of on-site generation and to credit them with system benefits that may accrue from onsite power.

8.4.2 Special Charges for Stranded Costs

In some of the distribution utility service territories a competitive transition charge ("CTC") has been levied on facilities removing its prior demand from the distribution system. The fee is levied on both power supplied to the customer over the distribution system, as well as power used on-site by the customer that does not pass through the distribution system. The rationale for charging the customer on the basis of power used, rather than on the basis of power delivered, is that the customer should be held responsible for system costs incurred historically on their behalf by the company. The only recourse that the facility has to avoid paying this fee is to remove itself entirely from the grid, a drastic response that few businesses are willing to undertake.

The effect on the market that high CTC's can have is highlighted by analysis that has been done of Niagara Mohawk's now expired Rule 12 impact on New York State farms[27]. The AA Dairy in Candor, NY is a Governor's Award winning facility operating a 130 kW anaerobic digester system in NYSEG's service territory. *If* the digester system were subject to Rule 12 charges, the Dairy's net 1999 electricity costs of $9,000 would increase to $24,000[28]. This cost increase of $15,000 would have a significant impact on the payback and economics of the digester installation.

[27] NIMO's Rule 12 has expired and was replaced in June 2002 by the SC-7 Standby Service Rates approved by the New York State Public Service Commission.
[28] Potential Electricity Generation From On-Farm Anaerobic Digestion: Discouraging Impacts Of Rule 12, And A Possible Remedy. NYS-ERDA memo, Tom Fiesinger. June 12, 2001

Because of the 130 kW cap on system size before triggering Rule 12 implementation, another effect is to cause the downsizing of projects that were economic, absent the charge. Dairy Development International (DDI) in Cortland County (Niagara Mohawk's service territory). DDI was planning to install two 75-kW microturbines, but the costs of Rule 12 for that large of an operation would be prohibitive and lead to downsizing the generation capacity to 75 kW or possibly 105 kW.[29]

It is important to note that with the new Commission Guidelines on the provision of electric standby ervice, Rule 12 no longer exists. Nonetheless, as discussed below, utilities will continue to recover stranded costs from standby service customers. A major issue in utility specific standy rate filings will be whether the standby service customers are bearing more then their fair share of costs to compensate utilities for historical investments.

8.4.3 Pricing Signals for Grid Support

CHP developers assert that economic efficiency is lacking when considered from a dynamic (over-time) perspective. Well-sited CHP can provide a set of system benefits including the deferral of capital projects designed to reinforce the current system, deferring the expansion of the network to serve new demand and reducing replacement costs for distribution capital that fails as a result of the intensity of use.

However, the utility's local distribution costs are not visible, either through the pricing structure or public disclosure. In the absence of utility provided information the potential CHP project is unaware of the value of site-specific locations. Although CHP/clean DG (when well sited) is a substitute for distribution capital expense, the utility has no incentive to meet distribution service needs by employing CHP. Capital expenditures by the utility are rewarded with a guaranteed rate of return. The utility has a strong incentive to (over) build its own capital asset base, and a disincentive to employ CHP, even where it is a more economical choice.

Transparent Prices

The tariffs may be complex, ambiguously worded and confusing. For prices to play their role of informing decision-makers about the cost implications of investment decisions, the prices (tariffs) must be made as simple and transparent as feasible. A facility should not require a rate consultant to deconstruct the tariffs for them or hire an attorney to ascertain the implications of ambiguous requirements. Tariffs should be designed so the CHP developer is able to narrow the range of uncertainty surrounding the cost of utility provided power standby power.

[29] ibid page 1

Ongoing Standby Service Rate Inquiry

In November 1999, the New York State Public Service Commission issued a notice soliciting comments in Case 99-E-1470 Petition to Initiate an Inquiry into the Reasonableness of the Rates, Terms and Conditions of the Provision of Electric Standby Service Filed by Independent Power Producers of New York, Inc. This proceeding is designed to establish a set of generic principles guiding the future development of rates, terms and conditions for electric standby service in New York.

Parties including utility and non-utility interests were given an opportunity to comment on an initial staff straw proposal setting forth such guidelines. Perhaps the most contentious issue centered on the extent to which the costs the utility incurs in standing ready to serve on-site generators in the event of a planned or unplanned outage should be recovered through fixed (and therefore unavoidable) charges, or alternatively, through usage-sensitive (and therefore avoidable) charges. Utilities have advocated for a two-part tariff that recovers the cost of dedicated (i.e., exclusively for use by the customer-generator) facilities through a ratcheted contract demand charge, and recovers the costs of shared (i.e., joint and common) facilities through a monthly "as used demand charge".

The utility position is grounded on the propositions that fixed costs are tied to the potential - not actual - usage level of connected customers, and that fixed costs should be recovered through fixed charges. By contrast, non-utility parties generally support usage-based charges. They contend that usage-based charges advance economic efficiency and fairness by requiring the customer generator to pay for only as much standby services as they use, and by providing economic incentives to the customer-generator to avoid "leaning on the system" during high-volume peak usage periods.

Non -utility parties argued that standby rates should reflect the fact that reliance by on-site generation owners on standby service is highly diverse, random and unlikely to coincide with system peak. Their argument states that ignoring the diversity of the standby customer would likely result in significant overcharges . Furthermore, the onsite power generator may provide a significant system benefit that other loads on the distribution system do not offer. Failing to recognize this benefit may result in situations where the investments are never made and consequently the benefits not realized.

In October 2001 the Public Service Commission fashioned a new set of principles to guide the design of future Standby, Backup and Supplemental Service tariffs. The distribution utilities filed updated tariffs in response. Niagara Mohawk was the first to file, and the New York Public Service Commission approved the proposed SC-7 Standby Service Rates in June of 2002. The SC-7 standby rates are approximately two-thirds of the previous Rule 12 rates.

8.5. ECONOMIC AND FINANCING CONSIDERATIONS

8.5.1 Economic Issues

CHP facilities, particularly small CHP systems, are not likely to compete with separately provided cooling, heating and power, unless there is an adequate demand for the available heat from onsite generation. This demand needs to be relatively continuous throughout the day, and seasons of the year. An industrial plant with a sizeable and constant thermal load or a commercial facility that has long operating hours and sufficiently sized summer and winter demands for available heat are strong candidates

The economics of a project decline rapidly with the proportion of available heat that goes unused and therefore becomes wasted. As that fraction unused increases, project economics fall. Likewise, the system needs to be sized in a manner that permits the generators to run at or near rated capacity. This is especially true for certain technologies such as microturbines. Although reciprocating engines maintain efficiency at part loads, with microturbines, as the proportion of time that the generators are run at part load increases, system efficiencies fall markedly.

If the system is sized to meet thermal loads, then surplus electric generation available for export to the grid will likely be available only in low loading hours when the grid prices are low. However, in capacity constrained areas there ought to be opportunities for payments to on-site generators that reduce loads that would otherwise be served from the grid.

8.5.2 Financing Issues

Obtaining the capital to install a CHP system can be problematic. The sources of funds available will differ in part depending on the size of the business as well as the business type (industrial/commercial, non-profit, government/institutional). A private sector project will have to secure a loan from commercial lenders. Projects in the institutional and not-for-profit sectors, such as colleges and universities, not-for-profit hospitals and health care facilities, may have access to tax exempt public financing sources.

Industrial/Commercial Sector

CHP projects undertaken in the manufacturing and commercial sectors will be financed by internal funds, commercial debt or certain types of third party arrangements such as vendor financing, energy service companies or some form of leasing. Projects underwritten by commercial loans face a distinct set of hurdles. There are numerous aspects of the project that will increase the risk that the private lender perceives such as CHP fuel price volatility and technology risk. The commercial lender that the facility is

used to dealing with may not have experience with CHP. The borrower may have to bring the project to several lenders before securing a loan. The lender may not be comfortable with the CHP facility's ability to successfully incorporate the new project into its ongoing operations. These issues are likely to be more of a problem for smaller business establishments operating without a deep or sophisticated energy management staff.

A product supplier, or a third party diminishes many of these issues if an Energy Service Company (ESCO) finances the project, with experience in energy management. The financing arrangements will be dictated by the level of risks to be assumed by the project site versus the ESCO. The greatest total benefits may be obtained by internal financing. On the other hand, the largest degree of risk is retained by the organization when using this approach. A partnership arrangement with ESCO's, or Equipment Vendors are likely to move some of the operating risk outside of the organization to the project partner. However, shifting this risk is obtained at some cost to the CHP host.

The CHP host company's balance sheet plays a significant role in the financing decision. If the company is already highly leveraged, they may wish to consider an "off-balance sheet" financing scheme. If the project is kept off the balance sheet of the facility this frees debt constraints for other projects that might be seen as being more central to the facility's core business plan.

A central issue in the financial analysis is the return on investment forecast from the CHP project. The investment return may be measured by a fairly simple analytic tool such as the investment payback period, or may be subject to a more rigorous probabilistic net present value analysis under a set of scenarios regarding future economic operating environment and fuel and power prices. If the CHP investment generates a return to capital less than that which the organization typically expects, it is unlikely that the project will go forward. In the private sector, the benchmarks expected for payback period or return on capital are much more demanding than that in the not-for-profit, institutional and government sector. Some of the components comprising the rate of project return are policy variables under the control of Federal and State activities.

The Federal government is considering shortening the depreciation period for CHP. Presently, CHP operates under a fifteen to twenty year depreciation schedule. A change to an accelerated depreciation occurring over 5 to 7 years would significantly improve the economics of CHP projects. New York State follows the federal depreciation schedules. Therefore, changes at the federal level would likely be passed through to the State. Historically there has been precedent for a decoupling of the state from the federal schedules. This policy if enacted would advantage a CHP facility in New York by reducing its state tax burden. However, past experience with decoupling state from federal depreciation treatment proved very

cumbersome and complex, thus decoupling has not been recommended in our conversations with state tax experts.

Unlike alterations to the state depreciation schedule, investment tax credits (ITC) or production tax credits (PTC) are efficient mechanisms for the State to promote the development of more robust markets for combined heat and power and clean distributed generation technologies in New York. An investment tax credit would give the CHP project a financial advantage over other capital investments by lowering the capital cost through a dimunition of the firm's tax obligations. A refundable credit would give the firm immediate access to the credit, whether or not there was a tax obligation in the current year. An ITC may be configured with generous carry-back and carry forward provisions and even with a tax-benefit lease provision that would permit the firm to sell the tax benefits to a third party without having to transfer other ownership rights. These terms allow the firm great flexibility in timing the use of the credit and far greater liquidity by permitting the transfer to other parties for whom the value of the credit exceeds the firm's internal valuation.

Institutional and Not-for-Profit Markets

The institutional and not-for-profit sectors represent the greatest source of remaining CHP potential in New York State. Hospitals, nursing homes, schools, colleges and universities are all among the top 10 remaining sectors in terms of untapped CHP potential. The financing concerns in the not-for-profit and institutional sector will differ markedly from those affecting private sector industrial and large commercial establishments.

There may be more attractive financing opportunities in the institutional and not-for-profit sectors as compared with private sector projects. Often in these sectors projects can be financed with tax-exempt instruments. The lower interest rates make the economics of the projects more favorable. At the same time, the decision calculus of the institutional and not-for-profit sector is less driven by the need for a fast payback or a high return on invested capital.

In the institutional and non-profit sectors there is the opportunity to access tax exempt markets for financing. Two important sources for tax exempt financing are the Dormitory Authority of the State of New York (DASNY) and Civic Facility Revenue Bonds.

The Dormitory Authority is among the leading public building construction agencies in the nation, with a $3 billion pipeline of construction projects for the State's independent colleges and universities; the State and City universities; health-care providers, including the New York City Health & Hospitals Corporation; courtrooms and related facilities; and other public-purpose projects. The Authority also sells tax-exempt

bonds more often than any other issuer in the nation, negotiating with top Wall Street investment firms to obtain low interest rates for its customers to finance capital projects.[30]

The Tax Exempt Leasing Program (TELP) initiated by the Dormitory Authority provides New York colleges, universities, hospitals, and nursing homes with a cost-effective source of tax-exempt funds for capital equipment projects. The TELP program fills a need for project financing in smaller sized lots. The lease is structured as a three-party transaction. The lessee makes payments to the Dormitory Authority and the Dormitory Authority in turn makes payments to the lessor. Because DASNY is involved in the transaction, the lessor does not make federal, state or local tax payments on the interest portion of the lease. These organizations can sometimes obtain the tax-exempt financing on their own but for many reasons, including not having the requisite resources, the legal staff, the time, they often find it advantageous to proceed with DASNY.

The Tax Exempt Leasing Program (TELP) has been used to finance a CHP facility at Lake Shore Health Care Center in Chautauqua County. The hospital install a new energy-efficient cogeneration plant that now saves the hospital more than $160,000 in annual energy costs a savings of more than 38%[31].

Lake Shore is using the Dormitory Authority's Tax Exempt Leasing Program (TELP) to lease natural gas-fired cogeneration equipment to reduce its electricity and thermal energy costs by more than one-third. The company installing the equipment Gerster Trane, located in Buffalo has guaranteed the Center its energy savings. These savings will be used to pay the $800,000 costs of the five-year lease. In the case of the Lake Shore project, use of this instrument resulted in an interest rate that was 350 basis points lower than that which would have been available from a taxable lease. This particular deal provided Lake Shore with a savings of more than $80,000 over the seven-year term.

In 1999 the Governor signed S.6111/A.7968-C which reauthorized the law that allows industrial development agencies (IDA's) to issue *civic facility revenue bonds* through July 2002. It is expected that this sunset date will be extended sometime in early 2002 for another two years. These tax-exempt bonds are available to any project undertaken by a facility that qualifies for 501(c)(3) not for-profit status. The new law increases the maximum project size to $20 Million for a single project. Furthermore, there is no dollar limit for non-dormitory projects undertaken by educational institutions

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[30] "Governor Announces 3 New Schools to Be Built on Former DASNY Property" DASNY news release. April 3, 2001. Source: http://www.dasny.org/dasny/news/2001/govann.shtml

[31] **Rural Hospital Cuts Energy Costs With DASNY Program**. Source: http://www.dasny.org/dasny/news/1999/rural.shtml Date April 19,1999

Of course the primary advantage of Civic Facility Revenue Bonds over a conventional bank loan is that the interest income received by the bondholders is exempt from federal and state taxation. The financing costs for the borrower is markedly lower, in some instances as much as 200 basis points lower than conventional loan rates. In addition, with the issuance of these bonds, the not-for-profit is exempt from mortgage recording taxes, which can be as high as ¾ of a percent of the project cost -- a substantial savings in itself.

Although significant savings are available through lower interest rates and waiver of the mortgage recording tax, there are other costs associated with IDA financing that are not encountered in a conventional commercial loan. These can include fees charged by the IDA, Agency Counsel, Bond Counsel, Underwriter, Bond Insurer (or a bank providing a Letter of Credit- essentially a guarantee), and so on. As a result, depending on the fees charged by these various groups, oftentimes projects of less than $1 million are not worth doing with bonds.

APPENDIX A: TECHNICAL CHP POTENTIAL

Table A-1 Industrial Sector State Totals (Net Remaining CHP Potential)

SIC	Industry	50 to 500 kW		500 kW to 1 MW		1 MW to 5 MW		5 MW to 20 MW		> 20 MW		Total	
		Sites	MW	Sites	MW	Sites	MW	Sites	MW	Sites	MW	Sites	MW
20	Food	421	63	52	39	66	165	5	63	0	0	544	330
22	Textiles	287	32	18	10	19	36	0	0	0	0	324	78
24	Lumber	234	7	13	2	6	3	0	0	0	0	253	12
25	Furniture	125	6	5	1	4	3	1	4	0	0	135	14
26	Paper	216	32	49	37	37	93	4	50	0	0	306	212
28	Chemicals	302	45	54	41	73	183	18	225	0	0	447	493
29	Petroleum Refining	66	10	15	11	4	10	1	13	0	0	86	44
30	Rubber	327	15	57	13	50	38	0	0	0	0	434	65
33	Primary Metals	111	4	24	5	29	18	16	50	3	75	183	152
34	Fabricated Metal Products	559	25	38	9	48	36	5	19	1	30	651	118
35	Machinery	592	22	43	8	29	18	5	16	3	75	672	139
37	Transportation Equipment	111	8	12	5	25	31	3	19	0	0	151	63
38	Instruments	259	19	35	13	39	49	5	31	2	100	340	213
39	Miscellaneous	284	11	13	2	5	3	0	0	0	0	302	16
	Total	3,894	300	428	195	434	685	63	488	9	280	4,828	1,948

Table A-2 Industrial Sector Downstate Totals (Net Remaining CHP Potential)

SIC	Industry	50 to 500 kW		500 kW to 1 MW		1 MW to 5 MW		5 MW to 20 MW		> 20 MW		Total	
		Sites	MW	Sites	MW	Sites	MW	Sites	MW	Sites	MW	Sites	MW
20	Food	220	33	16	12	13	33	0	0	0	0	249	78
22	Textiles	275	31	7	4	9	17	0	0	0	0	291	52
24	Lumber	75	2	1	0	2	1	0	0	0	0	78	3
25	Furniture	75	3	0	0	0	0	0	0	0	0	75	3
26	Paper	155	23	19	14	12	30	0	0	0	0	186	68
28	Chemicals	230	35	31	23	39	98	5	63	0	0	305	218
29	Petroleum Refining	36	5	4	3	0	0	1	13	0	0	41	21
30	Rubber	177	8	16	4	7	5	0	0	0	0	200	17
33	Primary Metals	70	3	7	1	6	4	2	6	0	0	85	14
34	Fabricated Metal Products	257	12	10	2	4	3	0	0	0	0	271	17
35	Machinery	166	6	8	2	5	3	2	6	0	0	181	17
37	Transportation Equipment	79	6	6	2	6	8	0	0	0	0	91	16
38	Instruments	140	11	10	4	8	10	0	0	0	0	158	24
39	Miscellaneous	205	8	8	2	0	0	0	0	0	0	213	9
	Total	2,160	185	143	73	111	211	10	88	0	0	2,424	556

Table A-3 Industrial Sector Upstate Totals (Net Remaining CHP Potential)

SIC	Industry	50 to 500 kW		500 kW to 1 MW		1 MW to 5 MW		5 MW to 20 MW		> 20 MW		Total	
		Sites	MW	Sites	MW	Sites	MW	Sites	MW	Sites	MW	Sites	MW
20	Food	201	30	36	27	53	133	5	63	0	0	295	252
22	Textiles	12	1	11	6	10	19	0	0	0	0	33	26
24	Lumber	159	5	12	2	4	2	0	0	0	0	175	9
25	Furniture	50	2	5	1	4	3	1	4	0	0	60	10
26	Paper	61	9	30	23	25	63	4	50	0	0	120	144
28	Chemicals	72	11	23	17	34	85	13	163	0	0	142	276
29	Petroleum Refining	30	5	11	8	4	10	0	0	0	0	45	23
30	Rubber	150	7	41	9	43	32	0	0	0	0	234	48
33	Primary Metals	41	2	17	3	23	14	14	44	3	75	98	138
34	Fabricated Metal Products	302	14	28	6	44	33	5	19	1	30	380	102
35	Machinery	426	16	35	7	24	15	3	9	3	75	491	122
37	Transportation Equipment	32	2	6	2	19	24	3	19	0	0	60	47
38	Instruments	119	9	25	9	31	39	5	31	2	100	182	188
39	Miscellaneous	79	3	5	1	5	3	0	0	0	0	89	7
	Total	1,734	115	285	122	323	474	53	401	9	280	2,404	1,392

Table A-4 Commercial Sector State Totals (Net Remaining CHP Potential)

SIC	Industry	50 to 500 kW		500 kW to 1 MW		1 MW to 5 MW		5 MW to 20 MW		> 20 MW		Total	
		Sites	MW	Sites	MW	Sites	MW	Sites	MW	Sites	MW	Sites	MW
4222	Refrigerated Warehouse	53	4	17	6	2	3	0	0	0	0	72	13
494/495	Water treatment/Sanitary	124	19	99	74	28	70	3	38	0	0	254	200
54	Food Sales	1161	35	60	9	10	5	0	0	0	0	1,231	49
581	Full Service Restaurants	2664	160	246	74	32	32	1	5	0	0	2,943	271
7011	Hotels/Motels	972	146	155	116	120	300	13	163	0	0	1,260	725
721	Laundries	102	15	27	20	0	0	0	0	0	0	129	36
7542	Carwashes	106	16	0	0	0	0	0	0	0	0	106	16
7991	Health Clubs	342	51	25	19	0	0	0	0	0	0	367	70
7992/7	Golf Clubs	524	79	40	30	0	0	0	0	0	0	564	109
805	Nursing Homes	227	34	317	238	108	270	0	0	0	0	652	542
806	Hospitals and Health Care	79	12	50	38	212	530	7	88	0	0	348	667
822	Colleges and Universities	259	39	65	49	48	120	25	313	0	0	397	520
821/4/9	Elementary and Secondary Schools	3466	208	1220	366	180	180	12	60	0	0	4,878	814
8412	Museums	147	13	23	10	4	6	0	0	0	0	174	30
9223	Prisons	22	3	23	17	61	153	3	38	0	0	109	211
	Apartments	650	98	150	113	75	188	15	188	0	0	890	585
	Office Buildings	5150	309	1350	405	400	400	70	350	7	210	6,977	1,674
	Total	16,048	1,240	3,867	1,584	1,280	2,256	149	1,240	7	210	21,351	6,529

Table A-5 Commercial Sector Downstate Totals (Net Remaining CHP Potential)

SIC	Industry	50 to 500 kW		500 kW to 1 MW		1 MW to 5 MW		5 MW to 20 MW		> 20 MW		Total	
		Sites	MW	Sites	MW	Sites	MW	Sites	MW	Sites	MW	Sites	MW
4222	Refrigerated Warehouse	14	1	8	3	1	1	0	0	0	0	23	5
494/495	Water treatment/Sanitary	54	8	41	31	10	25	2	25	0	0	107	89
54	Food Sales	655	20	4	1	1	1	0	0	0	0	660	21
581	Full Service Restaurants	1,320	79	137	41	22	22	1	5	0	0	1,480	147
7011	Hotels/Motels	353	53	75	56	70	175	9	113	0	0	507	397
721	Laundries	59	9	13	10	0	0	0	0	0	0	72	19
7542	Carwashes	59	9	0	0	0	0	0	0	0	0	59	9
7991	Health Clubs	227	34	19	14	0	0	0	0	0	0	246	48
7992/7	Golf Clubs	145	22	18	14	0	0	0	0	0	0	163	35
805	Nursing Homes	98	15	161	121	56	140	0	0	0	0	315	275
806	Hospitals and Health Care	43	6	23	17	123	308	4	50	0	0	193	381
822	Colleges and Universities	119	18	29	22	24	60	15	188	0	0	187	287
821/4/9	Elementary and Secondary Schools	1,973	118	744	223	98	98	6	30	0	0	2,821	470
8412	Museums	78	7	15	7	4	6	0	0	0	0	97	20
9223	Prisons	7	1	8	6	20	50	1	13	0	0	36	70
	Apartments	450	68	100	75	50	125	10	125	0	0	610	393
	Office Buildings	4,265	256	1,125	338	325	325	60	300	5	150	5,780	1,368
	Total	9,919	723	2,520	977	804	1,335	108	848	5	150	13,356	4,033

Table A-6 Commercial Sector Upstate Totals (Net Remaining CHP Potential)

SIC	Industry	50 to 500 kW		500 kW to 1 MW		1 MW to 5 MW		5 MW to 20 MW		> 20 MW		Total	
		Sites	MW	Sites	MW	Sites	MW	Sites	MW	Sites	MW	Sites	MW
4222	Refrigerated Warehouse	39	3	9	3	1	1	0	0	0	0	49	8
494/495	Water treatment/Sanitary	70	11	58	44	18	45	1	13	0	0	147	112
54	Food Sales	506	15	56	8	9	5	0	0	0	0	571	28
581	Full Service Restaurants	1,344	81	109	33	10	10	0	0	0	0	1,463	123
7011	Hotels/Motels	619	93	80	60	50	125	4	50	0	0	753	328
721	Laundries	43	6	14	11	0	0	0	0	0	0	57	17
7542	Carwashes	47	7	0	0	0	0	0	0	0	0	47	7
7991	Health Clubs	115	17	6	5	0	0	0	0	0	0	121	22
7992/7	Golf Clubs	379	57	22	17	0	0	0	0	0	0	401	73
805	Nursing Homes	129	19	156	117	52	130	0	0	0	0	337	266
806	Hospitals and Health Care	36	5	27	20	89	223	3	38	0	0	155	286
822	Colleges and Universities	140	21	36	27	24	60	10	125	0	0	210	233
821/4/9	Elementary and Secondary Schools	1,493	90	476	143	82	82	6	30	0	0	2,057	344
8412	Museums	69	6	8	4	0	0	0	0	0	0	77	10
9223	Prisons	15	2	15	11	41	103	2	25	0	0	73	141
	Apartments	200	30	50	38	25	63	5	63	0	0	280	193
	Office Buildings	885	53	225	68	75	75	10	50	2	60	1,197	306
	Total	6,129	517	1,347	606	476	920	41	393	2	60	7,995	2,496

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

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

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

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

Table A-9 LIPA - Industrial Sector (Net Remaining CHP Potential)

SIC	Industry	50 to 500 kW		500 kW to 1 MW		1 MW to 5 MW		5 MW to 20 MW		> 20 MW		Total	
		Sites	MW	Sites	MW	Sites	MW	Sites	MW	Sites	MW	Sites	MW
20	Food	55	8.3	4	3.0	1	2.5	0	0.0	0	0.0	60	13.8
22	Textiles	23	2.6	0	0.0	1	1.9	0	0.0	0	0.0	24	4.5
24	Lumber	15	0.5	0	0.0	2	1.0	0	0.0	0	0.0	17	1.5
25	Furniture	23	1.0	0	0.0	0	0.0	0	0.0	0	0.0	23	1.0
26	Paper	56	8.4	1	0.8	4	10.0	0	0.0	0	0.0	61	19.2
28	Chemicals	103	15.5	14	10.5	9	22.5	1	12.5	0	0.0	127	61.0
29	Petroleum Refining	17	2.6	0	0.0	0	0.0	0	0.0	0	0.0	17	2.6
30	Rubber	76	3.4	6	1.4	4	3.0	0	0.0	0	0.0	86	7.8
33	Primary Metals	27	1.0	2	0.4	0	0.0	0	0.0	0	0.0	29	1.4
34	Fabricated Metal Products	104	4.7	3	0.7	1	0.8	0	0.0	0	0.0	108	6.1
35	Machinery	85	3.2	3	0.6	3	1.9	2	6.3	0	0.0	93	11.9
37	Transportation Equipment	53	4.0	4	1.5	4	5.0	0	0.0	0	0.0	61	10.5
38	Instruments	80	6.0	6	2.3	8	10.0	0	0.0	0	0.0	94	18.3
39	Miscellaneous	40	1.5	3	0.6	0	0.0	0	0.0	0	0.0	43	2.1
	Total	757	62.5	46	21.5	37	58.5	3	18.8	0	0.0	843	161.3

Table A-10 LIPA- Commercial Totals (Net Remaining CHP Potential)

SIC	Industry	50 to 500 kW		500 kW to 1 MW		1 MW to 5 MW		5 MW to 20 MW		> 20 MW		Total	
		Sites	MW	Sites	MW	Sites	MW	Sites	MW	Sites	MW	Sites	MW
4222	Refrigerated Warehouse	3	0.2	4	1.5	0	0.0	0	0.0	0	0.0	7	1.7
494/495	Water treatment/Sanitary	8	1.2	22	16.5	7	17.5	1	12.5	0	0.0	38	47.7
54	Food Sales	193	5.8	0	0.0	0	0.0	0	0.0	0	0.0	193	5.8
581	Full Service Restaurants	294	17.6	26	7.8	2	2.0	0	0.0	0	0.0	322	27.4
7011	Hotels/Motels	101	15.2	9	6.8	4	10.0	0	0.0	0	0.0	114	31.9
721	Laundries	16	2.4	3	2.3	0	0.0	0	0.0	0	0.0	19	4.7
7542	Carwashes	15	2.3	0	0.0	0	0.0	0	0.0	0	0.0	15	2.3
7991	Health Clubs	62	9.3	2	1.5	0	0.0	0	0.0	0	0.0	64	10.8
7992/7	Golf Clubs	83	12.5	6	4.5	0	0.0	0	0.0	0	0.0	89	17.0
805	Nursing Homes	23	3.5	42	31.5	7	17.5	0	0.0	0	0.0	72	52.5
806	Hospitals and Health Care	8	1.2	2	1.5	21	52.5	1	12.5	0	0.0	32	67.7
822	Colleges and Universities	18	2.7	3	2.3	2	5.0	3	37.5	0	0.0	26	47.5
821/4/9	Elementary and Secondary Schools	498	29.9	226	67.8	24	24.0	2	10.0	0	0.0	750	131.7
8412	Museums	18	1.6	0	0.0	0	0.0	0	0.0	0	0.0	18	1.6
9223	Prisons	2	0.3	3	2.3	2	5.0	0	0.0	0	0.0	7	7.6
	Apartments	46	6.9	10	7.5	5	12.5	1	12.5	0	0.0	62	39.4
	Office Buildings	1,098	65.9	290	87.0	84	84.0	15	75.0	1	30.0	1,488	341.9
	Total	2,486	178.3	648	240.6	158	230.0	23	160.0	1	30.0	3,316	838.9

Table A-11 Orange & Rockland - Industrial Sector (Net Remaining CHP Potential)

SIC	Industry	50 to 500 kW		500 kW to 1 MW		1 MW to 5 MW		5 MW to 20 MW		> 20 MW		Total	
		Sites	MW	Sites	MW	Sites	MW	Sites	MW	Sites	MW	Sites	MW
20	Food	11	1.7	1	0.8	0	0.0	0	0.0	0	0.0	12	2.4
22	Textiles	4	0.5	0	0.0	1	1.9	0	0.0	0	0.0	5	2.3
24	Lumber	8	0.2	0	0.0	0	0.0	0	0.0	0	0.0	8	0.2
25	Furniture	4	0.2	0	0.0	0	0.0	0	0.0	0	0.0	4	0.2
26	Paper	10	1.5	3	2.3	2	5.0	0	0.0	0	0.0	15	8.8
28	Chemicals	25	3.8	3	2.3	12	30.0	0	0.0	0	0.0	40	36.0
29	Petroleum Refining	1	0.2	1	0.8	0	0.0	0	0.0	0	0.0	2	0.9
30	Rubber	14	0.6	3	0.7	2	1.5	0	0.0	0	0.0	19	2.8
33	Primary Metals	2	0.1	3	0.6	2	1.3	0	0.0	0	0.0	7	1.9
34	Fabricated Metal Products	16	0.7	3	0.7	3	2.3	0	0.0	0	0.0	22	3.6
35	Machinery	9	0.3	0	0.0	0	0.0	0	0.0	0	0.0	9	0.3
37	Transportation Equipment	1	0.1	0	0.0	0	0.0	0	0.0	0	0.0	1	0.1
38	Instruments	8	0.6	1	0.4	0	0.0	0	0.0	0	0.0	9	1.0
39	Miscellaneous	9	0.3	0	0.0	0	0.0	0	0.0	0	0.0	9	0.3
	Total	122	10.7	18	8.3	22	41.9	0	0.0	0	0.0	162	60.9

Table A-12 Orange & Rockland - Commercial Totals (Net Remaining CHP Potential)

SIC	Industry	50 to 500 kW		500 kW to 1 MW		1 MW to 5 MW		5 MW to 20 MW		> 20 MW		Total	
		Sites	MW	Sites	MW	Sites	MW	Sites	MW	Sites	MW	Sites	MW
4222	Refrigerated Warehouse	3	0.2	1	0.4	1	1.3	0	0.0	0	0.0	5	1.9
494/495	Water treatment/Sanitary	11	1.7	2	1.5	2	5.0	0	0.0	0	0.0	15	8.2
54	Food Sales	51	1.5	1	0.2	0	0.0	0	0.0	0	0.0	52	1.7
581	Full Service Restaurants	86	5.2	12	3.6	2	2.0	0	0.0	0	0.0	100	10.8
7011	Hotels/Motels	33	5.0	4	3.0	4	10.0	0	0.0	0	0.0	41	18.0
721	Laundries	8	1.2	0	0.0	0	0.0	0	0.0	0	0.0	8	1.2
7542	Carwashes	8	1.2	0	0.0	0	0.0	0	0.0	0	0.0	8	1.2
7991	Health Clubs	15	2.3	2	1.5	0	0.0	0	0.0	0	0.0	17	3.8
7992/7	Golf Clubs	14	2.1	2	1.5	0	0.0	0	0.0	0	0.0	16	3.6
805	Nursing Homes	8	1.2	14	10.5	4	10.0	0	0.0	0	0.0	26	21.7
806	Hospitals and Health Care	1	0.2	1	0.8	13	32.5	0	0.0	0	0.0	15	33.4
822	Colleges and Universities	5	0.8	1	0.8	2	5.0	0	0.0	0	0.0	8	6.5
821/4/9	Elementary and Secondary Schools	130	7.8	36	10.8	7	7.0	0	0.0	0	0.0	173	25.6
8412	Museums	7	0.6	0	0.0	0	0.0	0	0.0	0	0.0	7	0.6
9223	Prisons	2	0.3	2	1.5	3	7.5	0	0.0	0	0.0	7	9.3
	Apartments	15	2.3	3	2.3	2	5.0	0	0.0	0	0.0	20	9.5
	Office Buildings	150	9.0	40	12.0	11	11.0	2	10.0	1	30.0	204	72.0
	Total	547	42.3	121	50.2	51	96.3	2	10.0	1	30.0	722	228.8

Table A-13 Central Hudson - Industrial Sector (Net Remaining CHP Potential)

SIC	Industry	50 to 500 kW		500 kW to 1 MW		1 MW to 5 MW		5 MW to 20 MW		> 20 MW		Total	
		Sites	MW	Sites	MW	Sites	MW	Sites	MW	Sites	MW	Sites	MW
20	Food	17	2.6	1	0.8	0	0.0	0	0.0	0	0.0	18	3.3
22	Textiles	2	0.2	0	0.0	0	0.0	0	0.0	0	0.0	2	0.2
24	Lumber	11	0.3	1	0.2	0	0.0	0	0.0	0	0.0	12	0.5
25	Furniture	4	0.2	0	0.0	0	0.0	0	0.0	0	0.0	4	0.2
26	Paper	1	0.2	0	0.0	0	0.0	0	0.0	0	0.0	1	0.2
28	Chemicals	3	0.5	1	0.8	0	0.0	0	0.0	0	0.0	4	1.2
29	Petroleum Refining	5	0.8	0	0.0	1	2.5	0	0.0	0	0.0	6	3.3
30	Rubber	4	0.2	3	0.7	2	1.5	0	0.0	0	0.0	9	2.4
33	Primary Metals	1	0.0	0	0.0	1	0.6	1	3.1	0	0.0	3	3.8
34	Fabricated Metal Products	10	0.5	1	0.2	1	0.8	0	0.0	0	0.0	12	1.4
35	Machinery	14	0.5	2	0.4	0	0.0	0	0.0	0	0.0	16	0.9
37	Transportation Equipment	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0
38	Instruments	4	0.3	3	1.1	0	0.0	0	0.0	0	0.0	7	1.4
39	Miscellaneous	4	0.2	0	0.0	0	0.0	0	0.0	0	0.0	4	0.2
	Total	80	6.3	12	4.1	5	5.4	1	3.1	0	0.0	98	18.8

Table A-14 Central Hudson - Commercial Totals (Net Remaining CHP Potential)

SIC	Industry	50 to 500 kW		500 kW to 1 MW		1 MW to 5 MW		5 MW to 20 MW		> 20 MW		Total	
		Sites	MW	Sites	MW	Sites	MW	Sites	MW	Sites	MW	Sites	MW
4222	Refrigerated Warehouse	7	0.5	0	0.0	0	0.0	0	0.0	0	0.0	7	0.5
494/495	Water treatment/Sanitary	9	1.4	4	3.0	2	5.0	0	0.0	0	0.0	15	9.4
54	Food Sales	54	1.6	3	0.5	0	0.0	0	0.0	0	0.0	57	2.1
581	Full Service Restaurants	79	4.7	12	3.6	0	0.0	0	0.0	0	0.0	91	8.3
7011	Hotels/Motels	78	11.7	13	9.8	10	25.0	3	37.5	0	0.0	104	84.0
721	Laundries	5	0.8	0	0.0	0	0.0	0	0.0	0	0.0	5	0.8
7542	Carwashes	5	0.8	0	0.0	0	0.0	0	0.0	0	0.0	5	0.8
7991	Health Clubs	12	1.8	0	0.0	0	0.0	0	0.0	0	0.0	12	1.8
7992/7	Golf Clubs	21	3.2	1	0.8	0	0.0	0	0.0	0	0.0	22	3.9
805	Nursing Homes	5	0.8	9	6.8	6	15.0	0	0.0	0	0.0	20	22.5
806	Hospitals and Health Care	2	0.3	2	1.5	4	10.0	0	0.0	0	0.0	8	11.8
822	Colleges and Universities	5	0.8	2	1.5	4	10.0	1	12.5	0	0.0	12	24.8
821/4/9	Elementary and Secondary Schools	93	5.6	20	6.0	9	9.0	1	5.0	0	0.0	123	25.6
8412	Museums	3	0.3	0	0.0	0	0.0	0	0.0	0	0.0	3	0.3
9223	Prisons	2	0.3	2	1.5	4	10.0	0	0.0	0	0.0	8	11.8
	Apartments	32	4.8	8	6.0	6	15.0	1	12.5	0	0.0	47	38.3
	Office Buildings	62	3.7	16	4.8	5	5.0	0	0.0	0	0.0	83	13.5
	Total	474	42.9	92	45.6	50	104.0	6	67.5	0	0.0	622	260.0

Table A-15 NYSEG - Industrial Sector (Net Remaining CHP Potential)

SIC	Industry	50 to 500 kW		500 kW to 1 MW		1 MW to 5 MW		5 MW to 20 MW		> 20 MW		Total	
		Sites	MW	Sites	MW	Sites	MW	Sites	MW	Sites	MW	Sites	MW
20	Food	38	5.7	5	3.8	4	10.0	0	0.0	0	0.0	47	19.5
22	Textiles	2	0.2	2	1.1	0	0.0	0	0.0	0	0.0	4	1.4
24	Lumber	29	0.9	1	0.2	0	0.0	0	0.0	0	0.0	30	1.0
25	Furniture	7	0.3	0	0.0	1	0.8	0	0.0	0	0.0	8	1.1
26	Paper	4	0.6	3	2.3	0	0.0	0	0.0	0	0.0	7	2.9
28	Chemicals	7	1.1	3	2.3	4	10.0	0	0.0	0	0.0	14	13.3
29	Petroleum Refining	9	1.4	0	0.0	0	0.0	0	0.0	0	0.0	9	1.4
30	Rubber	19	0.9	2	0.5	6	4.5	0	0.0	0	0.0	27	5.8
33	Primary Metals	5	0.2	3	0.6	0	0.0	1	3.1	0	0.0	9	3.9
34	Fabricated Metal Products	28	1.3	2	0.5	2	1.5	0	0.0	0	0.0	32	3.2
35	Machinery	43	1.6	5	0.9	4	2.5	1	3.1	1	25.0	54	33.2
37	Transportation Equipment	4	0.3	2	0.8	3	3.8	1	6.3	0	0.0	10	11.1
38	Instruments	4	0.3	1	0.4	1	1.3	0	0.0	0	0.0	6	1.9
39	Miscellaneous	12	0.5	0	0.0	0	0.0	0	0.0	0	0.0	12	0.5
	Total	211	15.1	29	13.1	25	34.3	3	12.5	1	25.0	269	99.9

Table A-16 NYSEG - Commercial Totals (Net Remaining CHP Potential)

SIC	Industry	50 to 500 kW		500 kW to 1 MW		1 MW to 5 MW		5 MW to 20 MW		> 20 MW		Total	
		Sites	MW	Sites	MW	Sites	MW	Sites	MW	Sites	MW	Sites	MW
4222	Refrigerated Warehouse	2	0.2	0	0.0	0	0.0	0	0.0	0	0.0	2	0.2
494/495	Water treatment/Sanitary	8	1.2	5	3.8	1	2.5	0	0.0	0	0.0	14	7.5
54	Food Sales	99	3.0	3	0.5	0	0.0	0	0.0	0	0.0	102	3.4
581	Full Service Restaurants	156	9.4	9	2.7	3	3.0	0	0.0	0	0.0	168	15.1
7011	Hotels/Motels	128	19.2	16	12.0	6	15.0	1	12.5	0	0.0	151	58.7
721	Laundries	3	0.5	0	0.0	0	0.0	0	0.0	0	0.0	3	0.5
7542	Carwashes	5	0.8	0	0.0	0	0.0	0	0.0	0	0.0	5	0.8
7991	Health Clubs	14	2.1	2	1.5	0	0.0	0	0.0	0	0.0	16	3.6
7992/7	Golf Clubs	56	8.4	2	1.5	0	0.0	0	0.0	0	0.0	58	9.9
805	Nursing Homes	21	3.2	24	18.0	8	20.0	0	0.0	0	0.0	53	41.2
806	Hospitals and Health Care	7	1.1	3	2.3	22	55.0	0	0.0	0	0.0	32	58.3
822	Colleges and Universities	34	5.1	6	4.5	4	10.0	3	37.5	0	0.0	47	57.1
821/4/9	Elementary and Secondary Schools	275	16.5	98	29.4	19	19.0	1	5.0	0	0.0	393	69.9
8412	Museums	17	1.5	1	0.5	0	0.0	0	0.0	0	0.0	18	2.0
9223	Prisons	2	0.3	1	0.8	5	12.5	0	0.0	0	0.0	8	13.6
	Apartments	22	3.3	5	3.8	3	7.5	0	0.0	0	0.0	30	14.6
	Office Buildings	91	5.5	23	6.9	8	8.0	1	5.0	0	0.0	123	25.4
	Total	940	81.0	198	87.9	79	152.5	6	60.0	0	0.0	1,223	381.4

Table A-17 Niagara Mohawk - Industrial Sector (Net Remaining CHP Potential)

SIC	Industry	50 to 500 kW		500 kW to 1 MW		1 MW to 5 MW		5 MW to 20 MW		> 20 MW		Total	
		Sites	MW	Sites	MW	Sites	MW	Sites	MW	Sites	MW	Sites	MW
20	Food	125	18.8	29	21.8	39	97.5	4	50.0	0	0.0	197	188.0
22	Textiles	11	1.2	9	5.1	9	16.9	0	0.0	0	0.0	29	23.2
24	Lumber	111	3.3	10	1.5	5	2.5	0	0.0	0	0.0	126	7.3
25	Furniture	33	1.5	4	0.9	4	3.0	1	3.8	0	0.0	42	9.1
26	Paper	37	5.6	19	14.3	24	60.0	4	50.0	0	0.0	84	129.8
28	Chemicals	53	8.0	15	11.3	28	70.0	11	137.5	0	0.0	107	226.7
29	Petroleum Refining	18	2.7	9	6.8	3	7.5	0	0.0	0	0.0	30	17.0
30	Rubber	91	4.1	27	6.1	27	20.3	0	0.0	0	0.0	145	30.4
33	Primary Metals	31	1.2	13	2.4	22	13.8	12	37.5	3	75.0	81	129.9
34	Fabricated Metal Products	199	9.0	15	3.4	34	25.5	5	18.8	1	30.0	254	86.6
35	Machinery	269	10.1	22	4.1	14	8.8	2	6.3	2	50.0	309	79.2
37	Transportation Equipment	24	1.8	2	0.8	13	16.3	1	6.3	0	0.0	40	25.1
38	Instruments	65	4.9	14	5.3	16	20.0	3	18.8	0	0.0	98	48.9
39	Miscellaneous	57	2.1	5	0.9	5	3.1	0	0.0	0	0.0	67	6.2
	Total	1124	74.1	193	84.4	243	365.0	43	328.8	6	155.0	1609	1007.3

Table A-18 Niagara Mohawk - Commercial Totals (Net Remaining CHP Potential)

SIC	Industry	50 to 500 kW		500 kW to 1 MW		1 MW to 5 MW		5 MW to 20 MW		> 20 MW		Total	
		Sites	MW	Sites	MW	Sites	MW	Sites	MW	Sites	MW	Sites	MW
4222	Refrigerated Warehouse	18	1.4	4	1.5	1	1.3	0	0.0	0	0.0	23	4.1
494/495	Water treatment/Sanitary	32	4.8	26	19.5	12	30.0	1	12.5	0	0.0	71	66.8
54	Food Sales	318	9.5	30	4.5	5	2.5	0	0.0	0	0.0	353	16.5
581	Full Service Restaurants	856	51.4	67	20.1	5	5.0	0	0.0	0	0.0	928	76.5
7011	Hotels/Motels	358	53.7	49	36.8	23	57.5	1	12.5	0	0.0	431	160.5
721	Laundries	33	5.0	12	9.0	0	0.0	0	0.0	0	0.0	45	14.0
7542	Carwashes	30	4.5	0	0.0	0	0.0	0	0.0	0	0.0	30	4.5
7991	Health Clubs	67	10.1	3	2.3	0	0.0	0	0.0	0	0.0	70	12.3
7992/7	Golf Clubs	172	25.8	13	9.8	0	0.0	0	0.0	0	0.0	185	35.6
805	Nursing Homes	82	12.3	104	78.0	26	65.0	0	0.0	0	0.0	212	155.3
806	Hospitals and Health Care	22	3.3	19	14.3	49	122.5	3	37.5	0	0.0	93	177.6
822	Colleges and Universities	59	8.9	17	12.8	9	22.5	6	75.0	0	0.0	91	119.1
821/4/9	Elementary and Secondary Schools	940	56.4	290	87.0	38	38.0	3	15.0	0	0.0	1,271	196.4
8412	Museums	36	3.2	3	1.4	0	0.0	0	0.0	0	0.0	39	4.6
9223	Prisons	8	1.2	7	5.3	21	52.5	0	0.0	0	0.0	36	59.0
	Apartments	101	15.2	25	18.8	12	30.0	2	25.0	0	0.0	140	88.9
	Office Buildings	535	32.1	136	40.8	45	45.0	7	35.0	2	60.0	725	212.9
	Total	3,667	298.6	805	361.5	246	471.8	23	212.5	2	60.0	4,743	1404.3

Table A-19 Rochester Gas & Electric - Industrial Sector (Net Remaining CHP Potential)

SIC	Industry	50 to 500 kW		500 kW to 1 MW		1 MW to 5 MW		5 MW to 20 MW		> 20 MW		Total	
		Sites	MW	Sites	MW	Sites	MW	Sites	MW	Sites	MW	Sites	MW
20	Food	22	3.3	3	2.3	10	25.0	1	12.5	0	0.0	36	43.1
22	Textiles	0	0.0	0	0.0	1	1.9	0	0.0	0	0.0	1	1.9
24	Lumber	8	0.2	0	0.0	0	0.0	0	0.0	0	0.0	8	0.2
25	Furniture	6	0.3	0	0.0	0	0.0	0	0.0	0	0.0	6	0.3
26	Paper	19	2.9	8	6.0	1	2.5	0	0.0	0	0.0	28	11.4
28	Chemicals	10	1.5	4	3.0	2	5.0	1	12.5	0	0.0	17	22.0
29	Petroleum Refining	6	0.9	2	1.5	0	0.0	0	0.0	0	0.0	8	2.4
30	Rubber	36	1.6	9	2.0	8	6.0	1	3.8	0	0.0	54	13.4
33	Primary Metals	5	0.2	1	0.2	0	0.0	0	0.0	0	0.0	6	0.4
34	Fabricated Metal Products	65	2.9	10	2.3	7	5.3	0	0.0	0	0.0	82	10.4
35	Machinery	100	3.8	6	1.1	6	3.8	0	0.0	0	0.0	112	8.6
37	Transportation Equipment	4	0.3	2	0.8	3	3.8	1	6.3	0	0.0	10	11.1
38	Instruments	46	3.5	7	2.6	14	17.5	2	12.5	2	100.0	71	136.1
39	Miscellaneous	6	0.2	0	0.0	0	0.0	0	0.0	0	0.0	6	0.2
	Total	333	21.5	52	21.7	52	70.6	6	47.5	2	100.0	445	261.4

Table A-20 Rochester Gas & Electric - Commercial Totals (Net Remaining CHP Potential)

SIC	Industry	50 to 500 kW		500 kW to 1 MW		1 MW to 5 MW		5 MW to 20 MW		> 20 MW		Total	
		Sites	MW	Sites	MW	Sites	MW	Sites	MW	Sites	MW	Sites	MW
4222	Refrigerated Warehouse	8	0.6	5	1.9	0	0.0	0	0.0	0	0.0	13	2.5
494/495	Water treatment/Sanitary	6	0.9	5	3.8	3	7.5	0	0.0	0	0.0	14	12.2
54	Food Sales	56	1.7	20	3.0	4	2.0	0	0.0	0	0.0	80	6.7
581	Full Service Restaurants	203	12.2	21	6.3	2	2.0	0	0.0	0	0.0	226	20.5
7011	Hotels/Motels	55	8.3	2	1.5	11	27.5	0	0.0	0	0.0	68	37.3
721	Laundries	2	0.3	2	1.5	0	0.0	0	0.0	0	0.0	4	1.8
7542	Carwashes	7	1.1	0	0.0	0	0.0	0	0.0	0	0.0	7	1.1
7991	Health Clubs	23	3.5	1	0.8	0	0.0	0	0.0	0	0.0	24	4.2
7992/7	Golf Clubs	31	4.7	6	4.5	0	0.0	0	0.0	0	0.0	37	9.2
805	Nursing Homes	22	3.3	16	12.0	12	30.0	0	0.0	0	0.0	50	45.3
806	Hospitals and Health Care	5	0.8	2	1.5	13	32.5	0	0.0	0	0.0	20	34.8
822	Colleges and Universities	19	2.9	4	3.0	3	7.5	0	0.0	0	0.0	26	13.4
821/4/9	Elementary and Secondary Schools	185	11.1	56	16.8	17	17.0	1	5.0	0	0.0	259	49.9
8412	Museums	6	0.5	4	1.8	0	0.0	0	0.0	0	0.0	10	2.3
9223	Prisons	2	0.3	3	2.3	10	25.0	0	0.0	0	0.0	15	27.6
	Apartments	44	6.6	11	8.3	6	15.0	1	12.5	0	0.0	62	42.4
	Office Buildings	196	11.8	50	15.0	17	17.0	2	10.0	0	0.0	265	53.8
	Total	870	70.3	208	83.8	98	183.0	4	27.5	0	0.0	1,180	364.5

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