An Assessment and Report

of

Distributed Generation Opportunities in Southwest Connecticut

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At Eastern Connecticut State University

Institute for Sustainable Energy
At Eastern Connecticut State University

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EXECUTIVE SUMMARY

E.1 INTRODUCTION AND SUMMARY

Governor John Rowland's Executive Order No. 26, issued April 12, 2002, and Public Act 02-95 (PA 02-95), signed into law on June 3, 2002, raise critical questions about current energy planning and management, including the necessity and benefits of transmission projects, technology alternatives to transmission expansion, and the individual and cumulative effects of proposed crossings within Long Island Sound. PA 02-95 established a Working Group and a Task Force to examine these matters and to assist with the preparation of a comprehensive assessment and report.

This report, "An Assessment of Distributed Generation Opportunities in Southwest Connecticut," is intended to support the these efforts and provide information about distributed generation (DG) technologies, and the resulting role they can be expected to play in shaping the energy infrastructure of Southwest Connecticut (SW CT). A companion report entitled "An Assessment of Conservation and Load Management Opportunities in Southwest Connecticut," explores conservation and load management opportunities – another key component of addressing energy issues in SW CT.

In summary, this assessment found that the technical potential for DG use among commercial/ institutional and industrial customers in SW CT is over 650 MW. To determine how much of the technical potential was economically feasible, market penetration analysis, using payback period as a key variable, was performed. Based on current DG technologies and costs, Base Case market penetration is projected to be 20.7 MW of new DG by 2013. An Accelerated Case (business and regulatory climate more supportive of DG) using advanced DG (products/ improvements expected to be commercial in the near to mid-term) projects that up to 186.6 MW could be achieved by 2013.

E.2 DG BACKGROUND

DG systems are integrated systems comprised of multiple individual components that perform a variety of functions. For combined heat and power (CHP) technologies, these functions typically include fuel treatment, combustion, mechanical energy, electric energy, electricity conditioning, heat recovery, and heat rejection. CHP technologies are typically identified by the prime mover that drives the overall system. For certain renewable technologies, such as wind and solar, the systems are somewhat less complex, as heat recovery and heat rejection are generally non-issues.

Conventional electricity generation processes are capable of converting only about a third of the potential energy in fuel into usable energy. In applications that utilize separate heat and power systems, total system efficiency typically approaches only 45%. However, the use of CHP in commercial and industrial applications can provide a tremendous opportunity, as system efficiencies approaching 85% can be attained. The prospects for economical onsite generation improve dramatically when waste heat from electricity generation can be used to offset costs associated with space heating, water heating, and air conditioning needs.

Power generation systems that use renewable resources — the sun, wind, organic matter, and geothermal energy — have some advantages over traditional fossil-fuel-powered generation systems. For example, most renewable power technologies do not produce greenhouse gases and emit far less pollution than does burning oil, coal, or natural gas to generate electricity. With the exception of biomass technologies, renewable energy utilizes free fuel sources. The use of indigenous renewable energy sources also provides a secure and stable source of energy.

In addition to benefits associated with the use of renewable energy, the use of DG technology, whether renewable or not, can provide a number of other important benefits. In SW CT, a region that currently consumes more electricity than it produces, the ability to import power is constrained by the existing transmission system. The congestion of the transmission system threatens electric reliability in this part of the state. The development of new DG capacity throughout the region is one potential strategy for alleviating transmission-related constraints in the region. Other DG benefits include potential savings to electricity customers, peak load reduction, environmental benefits (especially with fuel cells and renewables), energy security, and economic development.

Despite the potential benefits of more widespread DG development, DG has been slow to gain a firm foothold in most commercial and industrial energy markets. Often cited barriers include, but are not limited to cost, siting, permitting, and interconnection issues, standby charges, and emissions concerns associated with some DG technologies and fuel options.

The barriers to DG development give rise to a wide array of potential incentives and support mechanisms to promote the development of additional DG capacity. A number of existing and potential initiatives that could provide support for DG development include:

- Capital cost buy-down and low cost financing
- Tax Incentives
- Standardized Interconnection Procedures
- Tariff Revisions (e.g. reduced standby charges)
- Avoided Transmission & Distribution Investment Credit
- Load Response Programs
- Net Metering
- Renewable Portfolio Standard
- Emissions Policy Incentives

The market penetration analysis performed in this study sheds light on the impacts of and need for incentives to promote DG in SW CT.

E.3 MARKET PENETRATION ANALYSIS AND RESULTS

A number of assumptions are implicit in the development of DG market penetration forecasts for SW CT. Key general assumptions and limitations of this research are highlighted below.

- DG technologies are assumed to operate as CHP units. In most cases, the economics of non-renewable DG will not lead to project development unless process heat can be captured and re-used. Recoverable heat is valued at the cost of natural gas delivered to the end-user.
- Only the lowest cost permittable technologies capable of operating at base load are considered in the market penetration estimates (e.g., no diesel generators). Renewable energy market potential is discussed but not quantified in the DG market penetration analysis due to its unique characteristics and economic considerations.
- Market penetration of DG technologies into the residential electricity market is not included in the analysis. Even when net metering is considered, the penetration of DG technologies into the residential marketplace is expected to be insignificant in terms of total MW.
- Estimates of technical potential for DG for commercial/institutional and industrial customers in SW CT are not derived from customer specific data. Rather, these estimates are based largely on interpolation of national and statewide data. This is a limitation of the study. For instance, a finding of the study is that a large portion of the market potential for DG in SW CT resides with large customers with peak demands of 5 MW or more. However, without customer specific data, it is difficult to discern the extent to which these loads actually exist.

Development of market penetration scenarios for SW CT involved the following key steps:

- Estimate technical CHP potential for each energy sector for SW CT.
- Sub-divide CHP potential into five categories based on application size: (100 to 500 kW; 500 to 1000 kW; 1 to 5 MW; 5 to 20 MW; and >20 MW).
- Develop levelized cost estimates and associated payback periods for "current" DG technology and "advanced" DG technology for each application size based on lowest cost base load technology.
- Run market penetration scenarios based on paybacks for each technology according to a Base Case and Accelerated Case.

Technical market potential provides an estimate of market size constrained only by technological limits— e.g., the ability of CHP technologies to meet existing customer needs. In this analysis, the technical potential for DG among commercial/ institutional and industrial customers is estimated to be over 650 MW in SW CT.[1]

Market potential is estimated based on economic analysis to determine the economic attractiveness to end-users of installing and operating an on-site DG system. The analysis assumes that the decision is based on payback achieved from on-site use of generated power (and thermal energy for CHP applications) and other potential savings/revenue, such as demand response credit.

The following tables show performance characteristics and associated payback period in years for current CHP and advanced CHP technologies.

Table ES- 1
CHP Payback by Size for Current Technologies

CHP Size	100 kW	800 kW	5 MW	10 MW	50 MW
Technology	Engine	Engine	Turbine	Turbine	Turbine
CHP O & M Cost	$ 11,914	$ 61,670	$ 210,240	$ 420,480	$ 1,576,800
CHP Fuel Cost	$ 54,375	$ 395,581	$ 2,767,992	$ 5,250,625	$ 23,228,693
Thermal Savings	$ 31,811	$ 193,589	$ 1,573,497	$ 2,956,673	$ 10,576,741
Annual Utility Bill with CHP	$ 8,557	$ 49,975	$ 318,017	$ 636,033	$ 3,914,052
Total Costs with CHP	$ 43,034	$ 313,638	$ 1,722,753	$ 3,350,465	$ 18,142,805
Base Utility Bill w/out CHP	$ 32,663	$ 245,482	$ 2,167,850	$ 4,335,701	$ 24,878,400
Annual Savings	$ (10,372)	$ (68,155)	$ 445,098	$ 985,236	$ 6,735,595
First Cost	$ 139,000	$ 780,000	$ 5,375,000	$ 9,650,000	$ 35,000,000
Payback Years	**N/A**	**N/A**	**12.1**	**9.8**	**5.2**

[1] It is important to reiterate that the technical potential for SW CT was not based on specific SW CT customer electricity data. Therefore, actual technical potential within each customer category may vary. However, assuming that the total technical potential for all customer categories 1 MW and larger would remain approximately the same, it is reasonable to assume (based on similar payback periods and penetration rates) that the market penetration projections would also remain approximately the same.

Table ES- 2
CHP Payback by Size for Advanced Technologies

CHP Size	100 kW	800 kW	5 MW	10 MW	50 MW
Technology	Microturbine	Gas Engine	Gas Turbine	Gas Turbine	Gas Turbine
CHP O & M Cost	$ 7,709	$ 50,458	$ 175,200	$ 350,400	$ 1,576,800
CHP Fuel Cost	$ 42,443	$ 335,809	$ 2,152,017	$ 4,052,870	$ 21,486,541
Thermal Savings	$ 15,382	$ 138,642	$ 1,048,438	$ 1,824,271	$ 7,640,779
Annual Utility Bill with CHP	$ 8,557	$ 49,975	$ 318,017	$ 636,033	$ 3,914,052
Total Costs with CHP	$ 43,326	$ 297,599	$ 1,596,795	$ 3,215,032	$ 19,336,615
Base Utility Bill w/out CHP	$ 32,663	$ 245,482	$ 2,167,850	$ 4,335,701	$ 24,878,400
Annual Savings	$ (10,664)	$ (52,117)	$ 571,055	$ 1,120,668	$ 5,541,785
First Cost	$ 91,500	$ 552,000	$ 4,750,000	$ 8,300,000	$ 31,250,000
Payback Years	**N/A**	**N/A**	**8.3**	**7.4**	**5.6**

Market penetration scenarios for SW CT were defined to represent a **Base Case**, or "business-as-usual" scenario, and an **Accelerated Case** to represent a business and regulatory environment more supportive of CHP. The Base Case scenario is based on current technology and current CL&P standby charges. The Accelerated Case is based on: gradual reduction in CHP technology cost between now and 2012; moderation of standby charges below their current level; implementation of an incentive program that reduces present value of capital costs (e.g., buy downs, tax credits, or accelerated depreciation); customer receipt of a demand response capacity payment during the summer months; and a higher market response rate to reflect more developers in the marketplace and greater levels of customer awareness. The following table shows initial payback period for current and advanced technologies under the Base Case and the Accelerated Case.

Table ES- 3
Initial Payback Period in Years for Current and Advanced Technologies

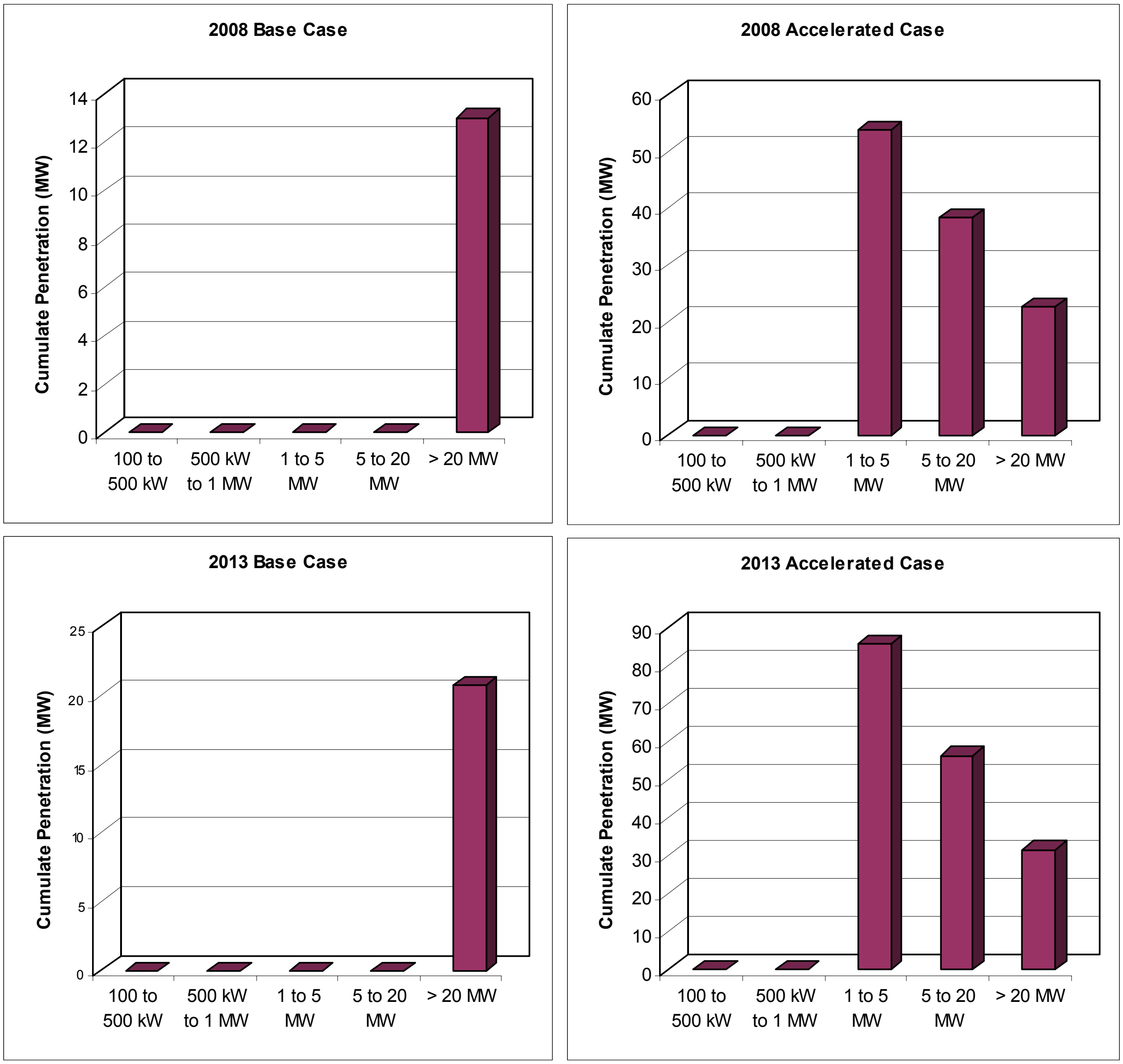
Market Segment	Current Technology		Advanced Technology	
	Base Case	**Accelerated Case**	**Base Case**	**Accelerated Case**
100 to 500 kW	N/A	1168.5	N/A	N/A
500 kW to 1 MW	N/A	109.1	N/A	22.1
1 to 5 MW	12.1	5.3	8.3	4.1
5 to 20 MW	9.8	4.5	7.4	3.6
> 20 MW	5.2	2.7	5.6	2.7

Based on the assumptions of the model, a payback period of less than eight years is a prerequisite for market penetration. Using the payback periods shown above, market penetration estimates can be derived based on the Accelerated and Base Case scenarios. The results are as follows:

In the Base Case scenario, using current technology, 20.7 MW of new CHP capacity are estimated to be installed in SW CT through 2013. All of this capacity would be developed in the largest customer category. With advanced technologies, this number would increase to 31.2 MW.

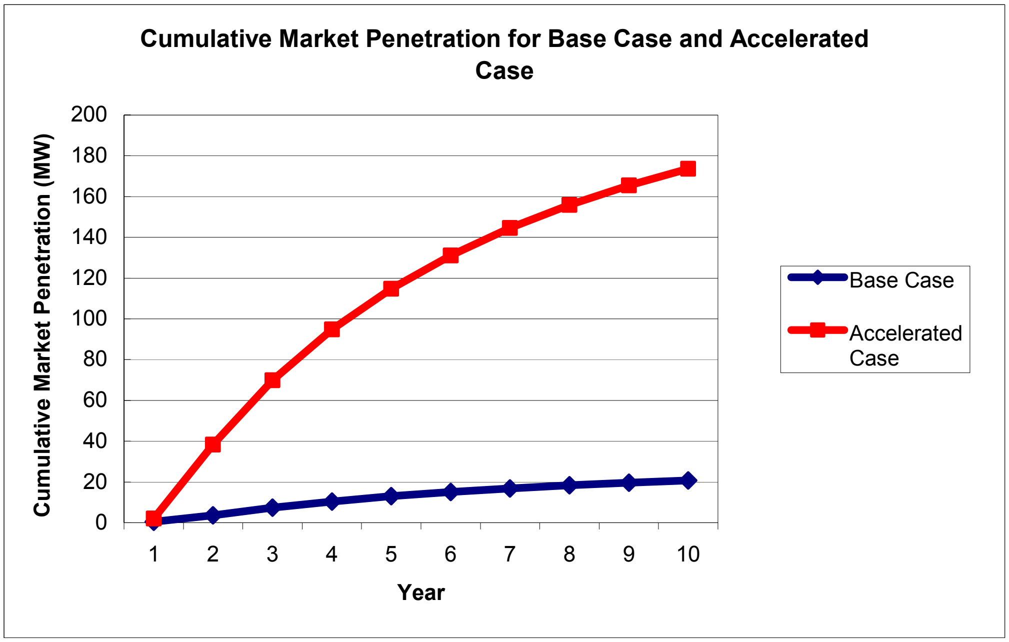
In the Accelerated Case scenario, using current technology, 173.6 MW of new CHP capacity are estimated to be installed in SW CT through 2013. This capacity would be spread among the top three customer size categories. With advanced technologies, a total capacity of 186.6 MW is expected, also spread among the top three customer size categories. These results are shown in the four quadrants below.

Figure ES- 1
SW CT Cumulative Market Penetration for Base Case and Accelerated Case for Current Technologies in 2008 and 2013



The figure below depicts total cumulative CHP market penetration on a year by year basis for current technologies under the Base Case and Accelerated Case in SW CT. As can be expected, the Accelerated Case results in a more rapid and higher degree of CHP market penetration than in the Base Case.

Figure ES- 2
CHP Cumulative Market Penetration for SW CT for Base and Accelerated Cases



Overall, the analysis shows that while DG technologies have the potential to be an important component of any potential solution to the electricity problems presently faced by Southwest CT, the use of DG technologies will not eliminate the need to consider other strategies, such as conservation and load management (C& LM), increasing transmission capacity, and increasing centralized base load electricity supply.

Despite significant technical potential for DG in SW CT, Base Case analysis of market potential for DG using existing simple payback period as a key criterion reveals limited market penetration for both current and advanced technologies over the next ten years. The Accelerated Case shows that market penetration of up to 186 MW of installed DG could be achieved by 2013. These findings substantiate the need for further research and potentially, the formation of policy measures to address market barriers and create support mechanisms for DG.

Areas of additional research that would help to clarify and quantify the benefits and impacts of DG in SW CT, and ultimately form a quantitative case for or against the various options to support DG, are listed below.

- Perform Comprehensive Customer-Based Analysis and Site Audits
- Research Potential DG Customer Financial Decision Making
- Quantify the Technical and Economic Impact of DG on the T&D System
- Determine Impact of DG on Natural Gas Delivery System
- Environmental Impact Assessment
- Economic Development Research

Consistent with the above areas of research, and the associated objective of pursuing a suite of associated policy initiatives for supporting DG, potential growth opportunities for DG in SW CT could be realized by considering the following recommendations.

- Develop and Institutionalize Funding Mechanisms
- Further Explore Tax Benefits to Support DG
- Continue to Support Standardized Interconnection
- Develop Supportive Municipal Ordinances
- Research Tariff Revisions
- Explore T&D Avoided Investment Credit/ Incentives
- Continue to Support Load Response
- Refine Net Metering
- Promote Inclusive Renewable Portfolio Standard
- Foster Emissions Policy that is Supportive of Low Emissions DG
- Promote Public Education and Awareness

1 INTRODUCTION

Governor John Rowland's Executive Order No. 26, issued April 12, 2002, and Public Act 02-95 (PA 02-95), signed into law on June 3, 2002, raise critical questions about current energy planning and management, including the necessity and benefits of transmission projects, technology alternatives to transmission expansion, and the individual and cumulative effects of proposed crossings within Long Island Sound. PA 02-95 established a Working Group and a Task Force to examine these matters and to assist with the preparation of a comprehensive assessment and report.

This report, "An Assessment of Distributed Generation Opportunities in Southwest Connecticut," is produced to support the efforts of the Working Group of Southwest Connecticut and Task Force on Long Island Sound in regards to Public Act No. 02-95. This study seeks to provide background and forward looking information about the current and potential status of distributed generation (DG) technologies, and the resulting role they can be expected to play in shaping the energy infrastructure of Southwest Connecticut (SW CT) over the next ten years and beyond.

This research is one of three related reports. A companion report entitled "An Assessment of Conservation and Load Management Opportunities in Southwest Connecticut" explores conservation and load management opportunities – another key component of addressing energy issues in SW CT.

The final companion report, "An Assessment of Energy Opportunities for the City of Norwalk," will provide specific insights and recommendations for Norwalk. This report will be available in early 2003. It should be noted that the assessment of Norwalk is not specifically part of the Working Group and Task Force's efforts, but is part of XENERGY's total scope of work with the Institute of Sustainable Energy at Eastern Connecticut University.

After providing background information about the most viable DG technologies, including relevant technological, economic, and policy issues, information will be provided about the current utilization of each technology in SW CT. Drawing from existing research, the technical potential (absent of many market considerations) of each technology will be discussed. Next, utilizing a combination of new analysis and secondary sources, market potential (based in large part on project economics) for each technology will be estimated for SW CT. The results of this analysis will be used to highlight opportunities for DG development in SW CT, and shed light on potential policy improvements that could further support their growth. Note, this analysis focuses on DG technologies capable of operating as base load generation units.

2 DG OVERVIEW

2.1 DISTRIBUTED GENERATION BACKGROUND

2.1.1 Distributed Generation Technology Overview

DG systems are integrated systems comprised of multiple individual components designed to perform a variety of functions. For CHP technologies, these functions typically include fuel treatment, combustion, mechanical energy, electric energy, electricity conditioning, heat recovery, and heat rejection. CHP technologies are typically identified by the prime mover that drives the overall system. For solar and wind renewable technologies, the systems are somewhat less complex, as heat recovery and heat rejection are generally non-issues.[1] Renewable technologies are typically named by the resource they seek to capture for purposes of electricity generation. The following CHP technologies and renewable resources were considered in this research (see Table 2-1):

Table 2-1
CHP and Renewable Technologies

Combined Heat and Power	Renewable
Reciprocating Engine	Biomass
Gas Turbine	Landfill Gas
Steam Turbine	Wind
Microturbine	Solar Photovoltaic
Fuel Cell	

A description of each technology above is provided in subsequent sections. Note that cost information for each technology is provided in the section on Market Potential (see Page 4-15).

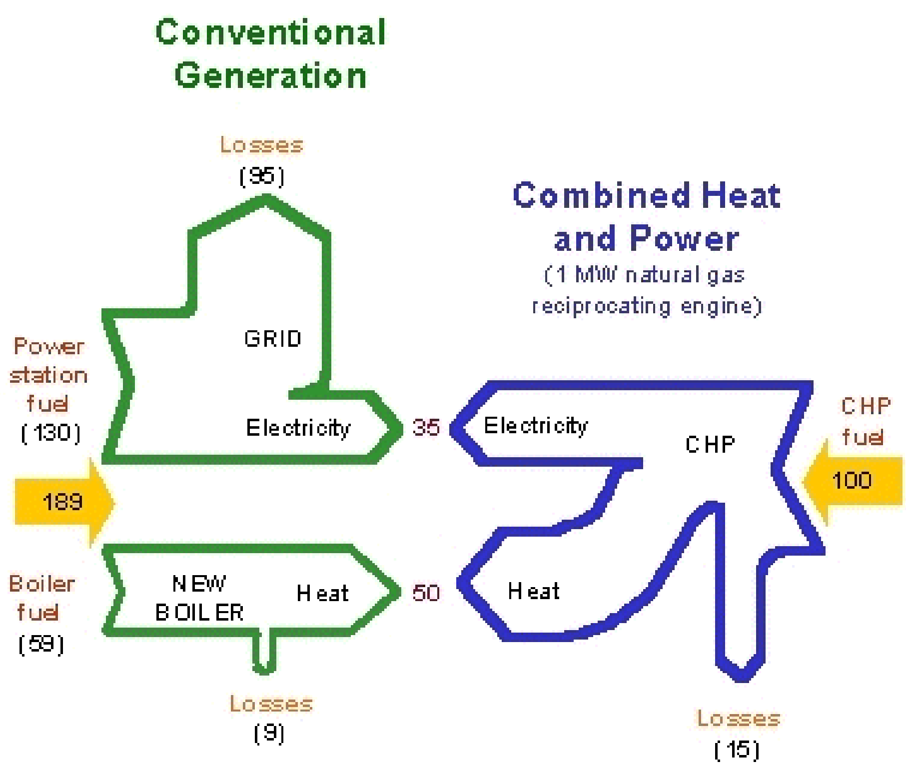
2.1.2 Combined Heat and Power DG Systems

Conventional electricity generation processes, which are capable of converting only about a third of the potential energy in fuel into usable energy, are inherently inefficient. In applications that utilize separate heat and power systems, total system efficiency typically approaches only 45%. However, the use of CHP in commercial and industrial applications can provide a tremendous opportunity, as system efficiencies approaching 85% can be attained. The following figure

[1] Fuel cells, which qualify as a Class I Renewable under Connecticut definitions, are an exception. Many biomass applications can also operate as CHP systems.

compares the typical fuel input needed to produce 35 units of electricity and 50 units of heat using separate heat and power versus combined heat and power (see Figure 2-1).[2] As illustrated, the use of CHP requires less fuel to produce the same electricity and heat value as a separate generator and boiler.

Figure 2-1
Fuel Input Required for Conventional vs. CHP System



Recent advancements have resulted in the development of new technologies and systems for CHP applications. For instance, improvements in electricity generation technologies – namely advanced combustion turbines and engines – have led to the development of new configurations that reduce system size but increase output efficiency. The prospects for economical onsite generation improve dramatically when waste heat from electricity generation can be used to offset costs associated with space heating, water heating, and air conditioning needs.

[2] DOE, Office of Renewable Energy and Energy Efficiency, Combined Heat and Power Web Site: http://www.eren.doe.gov/der/combined_heat_power.html.

Common CHP technologies are described below.[3,4]

Reciprocating Engine

Reciprocating engines, also called internal combustion engines, are a widespread and well-known technology. Electric efficiencies of 25 to 50 % make them an economic CHP technology for a variety of applications. Depending on the ignition source, reciprocating engines are categorized in one of two ways: 1) spark ignited engines are typically fueled by gasoline or natural gas; and 2) compression-ignited engines are typically fueled by diesel fuel, heavy oil, or a combination of oil and gas. Reciprocating engines range in size from a few kW to several MW. Advantages of reciprocating engines include low capital costs, easy start-up, proven reliability, good load-following characteristics, and good heat recovery. Applications in power generation include prime power generation, peak-shaving, back-up power, premium power, remote power, and standby power.

Combustion Gas Turbine

Combustion turbines (CTs) use the expansion of hot combustion gases to drive a rotating power turbine. CTs have been developed using technology from jet airplane engines. Technological advancements have helped them evolve into compact and efficient prime movers for power generation. CTs are most commonly fueled by natural gas, although they are capable of utilizing a broad range of gaseous and liquid fuels. Although CTs represented just 20% of the power generation market 20 years ago, they now claim approximately 40% of new capacity additions. CTs are economic for CHP in sizes ranging from five to several hundred MW. Heat dissipation associated with gas turbine use is a concern for applications in which the surplus heat cannot be utilized. Additionally, interconnected applications must be synchronous to the system.

Steam Turbine

Steam turbines are the most versatile and oldest prime mover technology used for electricity generation. They are widely used in the U.S. and Europe for CHP applications. Steam turbines require a source of high-pressure steam that is produced in a boiler or heat recovery steam generator to drive a turbine. Boiler fuels include fossil and renewable fuels, such as coal, oil, natural gas, wood, and municipal waste. Steam turbine applications are very compatible with existing sources of waste high-pressure steam. Unlike combustion gas turbines, they can also directly utilize solid fuels such as coal and biomass in boilers to create steam. However, for DG

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[3] DOE, Office of Renewable Energy and Energy Efficiency, Distributed Energy Resources Web Site: http://www.eren.doe.gov/der.

[4] "Market Assessment of Combined Heat and Power in the State of California." Prepared for California Energy Commission by ONSITE SYCOM Energy Corporation. December 22, 1999.

applications (smaller scale applications) standalone steam turbine systems can be more capital intensive and less efficient than other combustion-based DG technologies.

Microturbine

As their name implies, microturbines are very small combustion turbines that range in size from 20 to 250 kW. Microturbine technology evolved from automotive and truck turbochargers, auxiliary power units for airplanes, and small jet engines. Microturbines typically operate at high speed (70,000 to 100,000 rpm) and drive a high-speed generator directly. The high frequency power must be rectified and inverted to 60 Hz using complex power electronics. Although they have yet to reach commercial maturity, microturbines are expected to offer numerous potential advantages compared to other technologies for small-scale power generation. Advantages include: few moving parts; compact size; light weight; relatively high efficiency; and low emissions. Waste heat recovery can be used with the microturbine systems to achieve efficiencies greater than 80%.

Fuel Cell

Fuel cells refer to a class of technologies that convert fuel to electricity via an electrochemical process. Unlike a battery, the chemical input is not stored in the system, but is fed continuously into the fuel cell. The chemical input to the fuel cell takes place in the form of hydrogen and oxygen. Any of various fuels, including natural gas, methanol, ethanol, and gasoline, can be reformed to provide the hydrogen necessary for the fuel cell.

Fuel cells are named according to the electrolyte they utilize. The following table shows the four major types of fuel cells currently under development, and their various operational characteristics (see Table 2-2).

Table 2-2
Operating Characteristics of Primary Fuel Cell Technologies

Fuel Cell Technology	Electrolyte	Anode	Cathode	Operating Temperature (°F)	Electrical Efficiency (%)	Overall Efficiency (%)
Molten Carbonate (MCFC)	Molten Li/Na/K carbonate	Nickel	Nickel Oxide	1200	45 – 55	67 - 86
Phosphoric Acid (PAFC)	Phosphoric Acid	Platinum	Platinum	392	35 - 39	65 - 81
Proton Exchange Membrane (PEMFC)	Ion-exchange membrane, hydrated organic polymer	Platinum	Platinum	176	31 – 36	47 – 70
Solid Oxide (SOFC)	Ytirra-doped zirconia	Nickel	Sr-doped manganite	1830	45 – 50	73 - 87

Of the four types of fuel cells identified above, only the PAFC is readily available commercially, with others expected to become available over the next several years.

Fuel cells are a frequently mentioned DG technology, and have the potential to provide a wide variety of benefits in CHP applications, including: high efficiency; high reliability; low noise; ease of siting/permitting; ease of operations; size flexibility; fuel flexibility; and low emissions. The use of fuel cells is presently limited by high capital costs and a lack of commercial availability. Additionally, fuel cell stacks require replacement approximately every three to five years, which creates an added cost for fuel cell electricity applications.

CHP Technology Summary

The following table compares the operational characteristics of the CHP technologies discussed above (see Table 2-3).[5]

[5] Adapted from "The Market and Technical Potential for Combined Heat and Power in the Commercial/Institutional Sector."

Table 2-3
Operational Characteristics of CHP Technologies

	Diesel Engine	Natural Gas Engine	Steam Turbine	Combustion Gas Turbine	Micro-Turbine	Fuel Cell
Electric Efficiency (LHV)	30-50%	25-45%	15-35%	25-40% (simple) 40-60% (combined)	20-30%	40-70%
Size (MW)	0.05-5	0.05-5	Any	0.5-200	0.025-0.25	0.2-2
Footprint (sqft/kW)	0.22	0.22-0.31	<0.1	0.02-0.61	0.15-1.5	0.6-4
CHP Installed Cost ($/kW)	800-1500	800-1500	800-1000	700-900	500-1300	>3000
O&M Cost ($/kWh)	0.005-0.008	0.007-0.015	0.004	0.002-0.008	0.002-0.01	0.003-0.015
Availability	90-95%	92-97%	Near 100%	90-98%	90-98%	>95%
Hours between Overhauls	25,000-30,000	24,000-60,000	>50,000	30,000-50,000	5,000-40,000	10,000-40,000
Start-up Time	10 sec	10 sec	1hr - 1day	10min - 1hr	60 sec	3hrs - 2days
Fuels	Diesel and residual oil	Natural gas, biogas, propane	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 to high (requires building enclosure)	Moderate (enclosure supplied with unit)	Moderate (enclosure supplied with unit)	Low (no enclosure required)
NO_x Emissions (lb/MWh)	3.0-33	2.2-28	1.8	0.3-4	0.4-2.2	<0.02
Uses for Heat Recovery	Hot water, LP steam, district heating	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
CHP Output (Btu/kWh)	3,400	1,000-5,000	n/a	3,400-12,000	4,000-15,000	500-3,700
Useable Temp for CHP (F)	180-900	300-500	n/a	500-1,100	400-650	140-700

2.1.3 Renewable Energy DG Systems

Power generation systems that use renewable resources — the sun, wind, organic matter, and geothermal energy — have some advantages over traditional fossil-fuel-powered generation systems. For example, most renewable power technologies do not produce greenhouse gases and emit far less pollution than does burning oil, coal, or natural gas to generate electricity. With the exception of biomass technologies, renewable energy utilizes free fuel sources. The use of indigenous renewable energy sources also provides a secure and stable source of energy. Additional performance and levelized cost ($/kWh) information for renewable energy technologies can be found in a later section in Table 4-8.

Biomass Power

Biomass electricity conversion technologies convert renewable biomass fuels into electricity (and heat) using a variety of different technologies, including: modern boilers, gasifiers, turbines, generators, and other methods. Electricity from biomass also can be produced from a variety of fuels, including residues from the wood and paper products industries, residues from food production and processing, trees and grasses grown specifically to be used as energy crops, and gaseous fuels produced from solid biomass, animal wastes, or landfills. Current U.S. biomass power plants have a combined capacity of 7000 MW, and use approximately 60 million tons of biomass fuels (primarily wood and agricultural wastes) to generate 37 million kWh of electricity annually.[6]

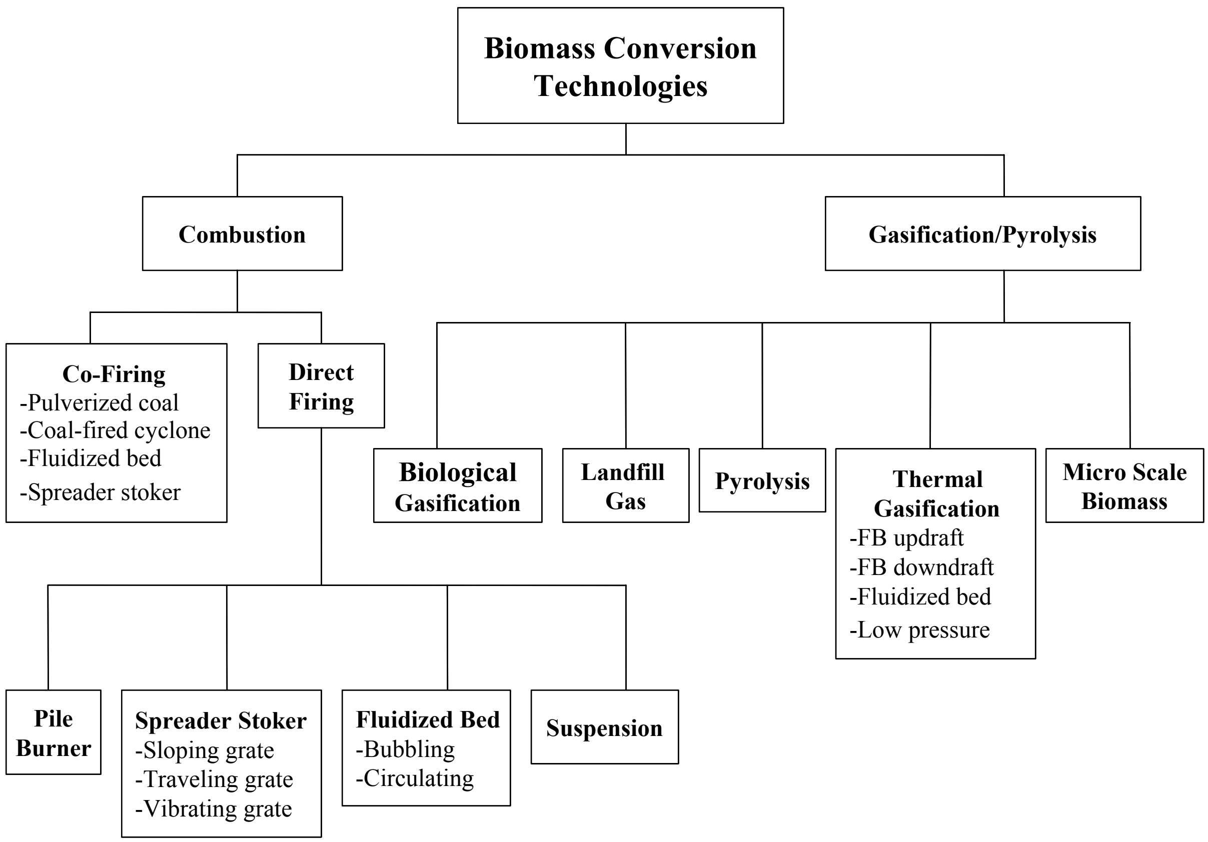
Biomass power conversion technologies for electricity production can be broadly categorized into direct combustion technologies, gasification technologies, and pyrolysis. Direct combustion technologies, probably the most widely known option for simultaneous power generation and heat production from biomass, involve the oxidation of biomass with excess air in a process that yields hot flue gases that are used to produce steam in boilers. The steam is used to produce electricity in a Rankine cycle. Typically, electricity only is produced in a “condensing” steam cycle, while electricity and steam are co-generated in an “extracting” steam cycle.

Pyrolysis refers to the basic thermochemical process for converting solid biomass into a more useful liquid fuel. During pyrolysis, biomass is heated in the absence of oxygen, or partially combusted in the presence of a limited oxygen supply, to produce a hydrocarbon rich gas mixture, an oil-like liquid, and char. The pyrolitic or "bio-oil" can be easily transported and refined into various products. Thermal gasification is itself a form of pyrolysis, although the presence of more air and higher temperatures during the gasification process serves to optimize gas production. Generally speaking, if the primary product of pyrolysis is gas, the process is considered to be gasification; if the primary products are condensable vapors, the process is

[6] DOE, Office of Renewable Energy and Energy Efficiency, Biomass Power Web Site: http://www.eren.doe.gov/der/biomass.html.

considered to be pyrolysis. The diagram below depicts the relationship among various biomass technologies (see Figure 2-2).[7]

Figure 2-2
Relationship Among Biomass Power Conversion Technologies



The electricity conversion technologies in the preceding graphic can be characterized into two broad categories, based upon their stage of development. Existing technologies, which consist of most direct combustion applications, are typically well-established, but tend to be expensive relative to most fossil fuel options, have generally low efficiencies, and have greater air emissions than most other renewable energy options.

New biomass technologies include biomass gasification and pyrolysis. These technologies promise some advantages over traditional biomass technologies, including higher efficiencies, improved environmental performance, and potentially more favorable project economics. They are, however, still costly in their developmental stages and not yet commercially competitive.

[7] "Securing a Place for Biomass in the Northeast United States: A Review of Renewable Energy and Related Policies." Available from the Northeast Regional Biomass Program (www.nrbp.org).

Landfill gas, technically a form of biomass, is a methane-rich biogas produced by the decay of wastes containing biomass. If it is to be used for purposes of electricity generation, landfill gas must be cleaned to remove harmful and corrosive chemicals. Landfill gas can be used for electricity generation in conjunction with combustion turbines, reciprocating engines, microturbines, and fuel cells.

The key barriers facing biomass today include: project financing; the ability to secure long-term contracts; permitting and siting (issues similar to those of siting a natural gas combined cycle power plant); guaranteeing feedstock availability and contracting; and transmission pricing and interconnection issues.

In spite of these barriers, the outlook for biomass energy remains favorable in several regions of the U.S. due to the technology's economic competitiveness and reliability. In addition, abundant feedstocks, growing electricity demand, and effective renewable energy policies in several state markets further improve the outlook for biomass. A final key advantage of biomass relative to other renewables is its ability to operate as baseload, and not on an intermittent basis.

Solar Photovoltaic

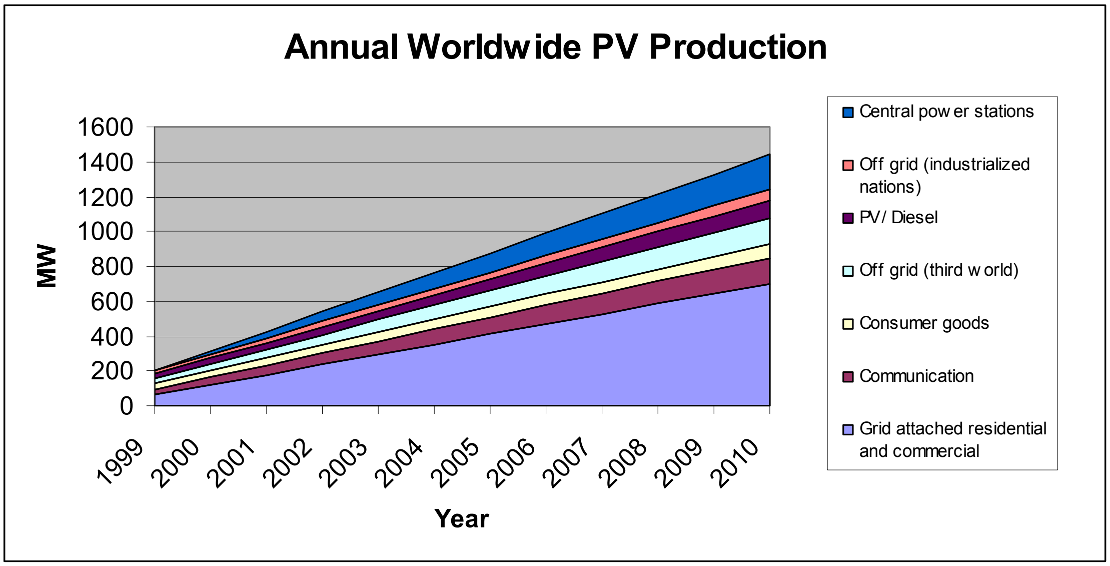
Solar photovoltaic (PV) systems, which convert sunlight directly into electricity, offer many advantages as generation systems, both as a supply side option and as a demand-side management option. Solar PV is the most modular and operationally simple of the clean, distributed power technologies. Its benefits include the ability to provide peak period power, distribution benefits (reduced strain on distribution infrastructure), environmental benefits, reduced fuel price risk, and local economic development. PV technology has several niche and broader applications, including:

- Grid attached residential and commercial
- Communication (e.g., to power a remote switch tower)
- Consumer goods (power for cell phones, watches, etc.)
- Off grid (developing world)
- Off grid/remote (industrialized nations)
- Central power stations (typically 100 kW or larger)

According to some forecasts, worldwide PV electricity production could increase seven fold by 2010 due to increasing cost reductions and aggressive policy measures (assumes 25% annual growth).[8] The following figures project annual worldwide PV production through 2010 by application (see Figure 2-3).

[8] "PV 2001: The Market, Players, and Forecast." Sarasin Basic Report. November 2001.

Figure 2-3
Annual Worldwide PV Production



Grid attached residential and commercial applications currently dominate the PV market with 31% market share. This market is projected to grow to over 50% of the PV market by 2010. While the PV market is in a relatively immature stage at present, central power applications are expected to be second in market share with 14% by 2010.[9]

The most significant challenges facing the widespread use of solar PV electricity generation include: very high cost of the technology; regulatory barriers that complicate the interconnection and sale of excess electricity to the grid; and the intermittent nature of the solar resource.

Wind Power

A wind energy system transforms the kinetic energy of the wind into mechanical or electrical energy that can be harnessed for practical use. Mechanical energy is most commonly used for pumping water in rural or remote locations. Wind turbines generate electricity for homes and businesses and for sale to utilities.

The most economical application of electric wind turbines is in groups of large machines (700 kW and up), called "wind power plants" or "wind farms." Wind plants can range in size from a few megawatts to hundreds of megawatts in capacity. Wind power plants are "modular," which means they consist of small individual modules (the turbines) and can easily be made larger or

[9] "PV 2001: The Market, Players, and Forecast." Sarasin Basic Report. November 2001.

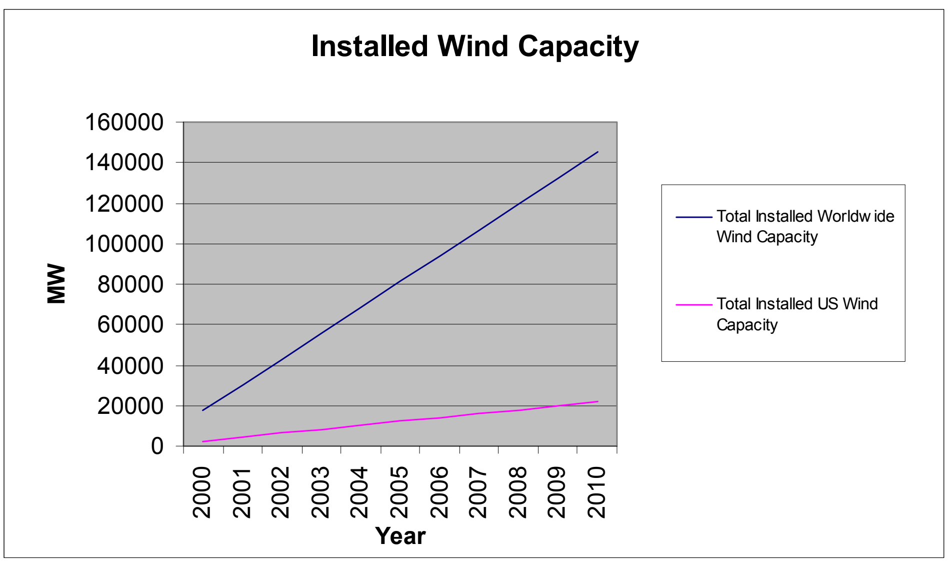
smaller as needed. Turbines can be added as electricity demand grows. Today, construction of a 50 MW wind farm can be completed in 18 months.

Offshore wind is another emerging opportunity, with thousands of MW of offshore wind in active development in Europe. Turbines located offshore take advantage of strong and steady winds, typically yielding up to 40% more energy than similar turbines located on land. This results in greater electricity production and helps stabilize the price of electricity for consumers. Offshore wind speeds vary less than wind speeds over the land. When winds are relatively constant, less stress is put on the mechanical parts of the turbines and their operating life is extended. This lowers the cost of producing electricity.

U.S. wind power capacity totaled about 2,500 MW and generated about 5.5 billion kWh of electricity in 2000 (enough to power about 1,750,000 homes). According to the U.S. Department of Energy, the nation has enough wind resources to generate more than 10.7 trillion kWh each year – three times the total electricity annually consumed in the U.S.

Due to technology-driven cost reductions and environmental benefits, the U.S. wind energy industry is poised for rapid growth. U.S. wind capacity is expected to increase by up to 4,500 MW over the next several years, and, assuming the continuation of policy supports, U.S. wind capacity could exceed 20,000 MW by 2010. Offshore wind power will be a key component of this growth. Projections of U.S. and worldwide installed wind capacity are depicted in the following figure (see Figure 2-4).[10]

Figure 2-4
U.S. and Worldwide Installed Wind Capacity



[10] "2000 Global Wind Markets Report." American Wind Energy Association.

According to figures provided by the Battelle Pacific Northwest Laboratory, at the theoretical economically viable upper bound, U.S. land based wind energy alone could supply about 20% of the nation's electricity.[11] California is the state in which the most wind power development has occurred. Other states with sizable wind capacity include Colorado, Idaho, Minnesota, Oregon, Texas, Wisconsin, and Wyoming. Smaller projects are being developed in the Northeast and other parts of the country. It is worth noting that there are fairly good wind resources in and near Cape Cod, New York, and Maine.

Advantages of wind energy include its affordability, reliability, low maintenance requirements, and adaptability. Wind energy also provides more jobs per dollar invested than any other energy technology.[12] Wind turbines also provide economic development in rural areas, and can add value to land without interfering with other uses such as cattle grazing or farming.

Wind energy development does face several obstacles. A primary challenge associated with the use of wind energy is its intermittent nature. Wind turbines also must be sited in elevated areas or in open spaces where there is little hindrance of air movement. Likewise, to be economically viable, consistent, reasonably strong wind levels are a necessity. Zoning and other land use regulations can also be problematic for individuals wanting to install turbines in some locations.

2.2 DG BENEFITS

In addition to benefits associated with the use of renewable energy discussed in the previous section, the use of DG technology, whether renewable or not, can provide a number of other important benefits. In SW CT, a region that currently consumes more electricity than it produces, the ability to import power is constrained by the existing transmission system. The congestion of the transmission system threatens electric reliability in this part of the state. The development of new DG capacity throughout the region is one potential strategy for alleviating transmission-related constraints in the region. This and other potential benefits of DG are aptly described in the Connecticut Energy Advisory Board's 2000 Energy Policy Report:[13]

> While both location- and technology-specific, the potential benefits of distributed generation and other forms of distributed energy are considerable. Distributed generation has the potential to provide site-specific reliability and transmission and distribution ("T&D") benefits including: increased reliability, shorter and less extensive outages, lower reserve margin requirements, improved power quality, reduced lines losses, reactive power control, mitigation of transmission and distribution congestion, and increased system capacity with reduced T&D investment. Distributed generation also provides economic benefits because DG technologies are

[11] "An Assessment of the Available Windy Land Area and Wind Energy Potential in the Contiguous United States." Battelle Pacific Northwest Laboratory. 1991.

[12] DOE, Office of Renewable Energy and Energy Efficiency, Wind Power Web Site: http://www.eren.doe.gov/der/wind_power.html.

[13] "Possibilities for the New Century: The Energy Policy Report of the Connecticut Energy Advisory Board." February 1, 2000.

> modular and provide location flexibility and redundancy as well as short lead times. Economic benefits can also be gained by using DG technologies in peak shaving, combined heat and power (cogeneration), and standby power applications. In addition, many DG technologies provide environmental benefits including reduced land impacts, low or no environmental emissions, and lower environmental compliance costs. And with little or no fuel costs, renewable energy technologies used in distributed applications mitigate the risk of uncertain future fuel costs…..

2.3 DG BARRIERS

Despite the potential benefits of more widespread DG development, DG has been slow to gain a firm foothold in most commercial and industrial energy markets. Even in regions like SW CT, where DG could provide potential relief to significant electricity T&D constraints, DG has not been widely adopted by end-users. A discussion of barriers to increased development of DG is provided in the Connecticut Energy Advisory Board's 2000 Energy Policy Report:[14]

> …electricity restructuring, zoning and permitting processes, and regulatory and business practices developed under the framework of an industry based on a central station generation and ownership of generation facilities have created potential barriers to the development of distributed generation in competitive electric markets. These barriers include lack of standardized interconnection requirements, high standby charges for backup power, charges for utility stranded cost recovery, and low utility buy-back rates. In order to capture the benefits that distributed generation can bring to competitive electric markets, these barriers must be addressed. The Board recommends that it be the policy of the state to remove any barriers that would impede the development of distributed energy generation, storage and management facilities that are consistent with state policy goals.

Other frequently mentioned relevant barriers to DG development include the following:

- Relatively immature technology, lack of commercial availability, and associated high capital costs make DG uneconomical for many applications.
- The technical ability of the T&D grid to support DG. The SW CT distribution and transmission system may have a finite ability to support DG interconnection due to engineering limitations.
- Certain DG technologies (e.g. non-renewables) may be difficult to site due to emission concerns.
- Noise restrictions, local zoning restrictions, and other permitting issues can make it difficult to site certain DG technologies.
- Uncertainties about natural gas infrastructure and supply, as well as unproven reliability and O&M costs, create added risks for DG developers.

[14] "Possibilities for the New Century: The Energy Policy Report of the Connecticut Energy Advisory Board."

- Technical requirements associated with interconnection, such as integrated controls, protective relaying, and the ability of the existing electricity distribution infrastructure to support DG, create challenges for DG developers.
- An inability on the part of regional transmission organizations to verify environmental and other attributes from small generators prevents DG operators from capturing a full benefits stream.
- Potential external costs associated with DG development, such as gas infrastructure modifications, upgrades to the electrical system, siting and permitting, and real estate, are likely to affect DG development.
- Wind and solar are intermittent energy sources, e.g. not generating electricity when there are no wind or solar resources.

2.4 DG EMISSIONS

As indicated in the above excerpt from the Connecticut Energy Advisory Board's 2000 Energy Policy Report, the use of DG is often looked upon to provide environmental benefits in the form of reduced NO_x, SO_2, and CO_2 emissions. At present, however, DG resources in the Northeast U.S. are dominated by diesel generators, which operate as peaking and back-up power units and typically produce relatively high levels of air emissions. As a result of emissions concerns, DG technologies, especially current applications, may generally be regarded as deleterious to local and regional air emissions. The environmental impact and regulation of DG emissions is an area of continuing study. [15]

By way of example, the tables below compare the emissions rates of typical back-up, typical and advanced base load, and associated regional average air emissions (Table 2-4 & Table 2-5).

[15] For example, the Regulatory Assistance Project is currently studying the regulation of air emissions from DG sources. For more information, see the DR Emissions Working Group web site: http://www.rapmaine.org/workgroup.html#Background_documents. NESCAUM is also in the process of assessing the environmental impacts of DG.

Table 2-4
Emissions Rates for Typical Back-Up DG Technologies[16]

	Uncontrolled Gas-Fired Lean Burn IC Engine (lbs/MWh)	Uncontrolled Diesel Engine (lbs/MWh)	SCR Controlled Diesel Engine (lbs/MWh)	N.E Marginal Emission Rates[17] (lbs/MWh)
NO_x	2.2	21.8	4.7	1.9
SO_2	0.006	0.454	0.454	6.2
PM-10	0.03	0.78	0.78	n/a
CO_2	1,108	1,432	1,432	1,488.1
CO	5.0	6.2	6.2	n/a

Table 2-5
Emissions Rates for Baseload DG Technologies

	Solid Oxide Fuel Cell (lbs/MWh)	Phosphoric Acid Fuel Cell (lbs/MWh)	Micro Turbine (lbs/MWh)	Small Gas Turbine (lbs/MWh)	Large Gas Combined Cycle (lbs/MWh)	N.E Marginal Emission Rates (lbs/MWh)
NO_x	0.01	0.03	0.44	1.15	0.06	1.9
SO_2	0.005	0.006	0.008	0.008	0.004	6.2
PM-10	n/a	n/a	0.09	0.08	0.04	n/a
CO_2	950	1,078	1,596	1,494	776	1,488.1
CO	n/a	n/a	0.42	1.10	0.05	n/a

In densely populated areas, or in areas with existing air quality concerns, even new DG resources operating on natural gas may give rise to emissions concerns. This study does not attempt to model DG emissions according to various market penetration scenarios. However, if one assumes that future CHP market penetration will be primarily gas-fired, new CHP can generally be expected to displace electricity generation from older central generation facilities that are less efficient, less reliable, and less environmentally friendly. The footnoted resources in this section provide a good starting point for finding recent analysis of potential DG emissions and impacts in the Northeast.

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16 Regulatory Assistance Project. Expected Emissions Output of Various Distributed Generation Technologies. 2002. http://www.rapmaine.org/DGEmissionsMay2001.PDF

17 ISO-NE. Marginal Emissions Rate Analysis. 2000. http://www.iso-ne.com/Planning_Reports/Emissions/

3 DG INCENTIVES AND SUPPORT MECHANISMS

The previously mentioned barriers to DG development give rise to a wide array of potential incentives and support mechanisms to promote the development of additional DG capacity. A number of existing and potential initiatives designed to provide support for DG development are discussed below. The potential impacts of such initiatives on DG market development in SW CT are further borne out in the DG market penetration analysis described in Section 4-5. Recommendations for further implementation are discussed in Section 5.

3.1 FUNDING MECHANISMS

Funding mechanisms provide a relatively simple way to promote the development of additional generating capacity in SW CT. One option is low interest loans for DG development. For example, the state could opt to make new DG eligible for **low cost financing** from the state's economic development agencies (the Department of Economic and Community Development, the Connecticut Development Authority, or Connecticut Innovations, Inc.) if the new capacity was located in SW CT and met certain other pre-determined criteria.

Another possibility is a **capital cost buy-down** program. Under this type of program, the state could promote the development of preferred DG technologies/applications by offering grants to "buy-down" their capital costs.

For instance, in 2003, the Connecticut Clean Energy Fund will award $1 million to companies that present proposals for installing photovoltaic systems to power commercial, industrial and institutional buildings. Incentives may take the form of grant, loan, equity investment, or other actions and equal up to the equivalent of $6000/kW.

California provides another example. To encourage the development of renewable DG technologies in California, the California Energy Commission currently offers cash rebates of up to $4500/kW for the installation of generating systems that utilize photovoltaics, fuel cells, small wind turbines, or solar thermal electricity systems.[1] A similar incentive in CT could promote preferred DG technologies.

[1] For additional information see the California Consumer Energy Center Web Site: http://www.consumerenergycenter.org/buydown/program.html.

3.2 TAX INCENTIVES

Tax incentives offered by the State present another opportunity for encouraging DG development. A number of states including CT currently offer various tax benefits to encourage renewable energy development. For instance, CT allows municipalities the option of offering property tax exemptions for certain renewable energy systems.[2] Such systems include solar space and water heating, photovoltaics, wind systems, fuel cells, and micro-hydro. Adoption of this exemption varies from one municipality to another. In some cases, the exemption applies to the total value of the qualifying renewable energy system and can be applied to residential, commercial, and industrial property.

As a way to promote DG, the state could provide tax benefits to new generating capacity installed in SW CT. For example, it could exempt DG sold for installation in the region from applicable sales taxes. Likewise, it could extend the property tax exemption above to include CHP systems that meet certain low emissions or efficiency criteria. Other potential tax benefits include tax credits, accelerated depreciation, and income tax deductions.

3.3 STANDARDIZED INTERCONNECTION

To enable the development of robust markets for distributed resources, DG developers argue that there is a need for uniform technical interconnection standards on a national and statewide basis, as well as for simplified contractual and other interconnection requirements at the state and local levels. Accordingly, simplified interconnection requirements would help minimize engineering and system design costs, streamline the installation and operation of distributed systems, and increase safety by promoting the use of simpler, more reliable protective relaying systems.

To this end, work toward **standardized interconnection** procedures for DG has occurred along several fronts. At present, the Institute of Electrical and Electronics Engineers (IEEE) Standards Coordinating Committee 21 is continuing development of the IEEE P1547 Draft Standard for Distributed Resources Interconnected with Electric Power Systems. Draft 10 of the proposed standard overwhelmingly passed the committee in Fall 2002. This standard, when approved and adopted, is expected to be a key milestone in the quest for a standardized and appropriate interconnection standard for the U.S. power industry.[3]

Similarly, on July 31, 2002 the National Association of Regulatory Utility Commissioners (NARUC) approved and adopted a "Model Distributed Generation and Interconnection

[2] For additional information, see Connecticut General Statutes Ch. 203, Sec. 12-81

[3] For additional information, see the IEEE P1547 Working Group Web Site: http://grouper.ieee.org/groups/scc21/1547/1547_index.html.

Procedures and Agreement," which is intended to provide a model for states seeking to develop standardized interconnection procedures.[4]

In CT, the DPUC has initiated a process to look at DG interconnection. Under Docket No. 02-08-20, the DPUC sought comments with regard to the Federal Energy Regulatory Commission's (FERC) Standardization of Small Generator Interconnection Agreements and Procedures Advanced Notice of Proposed Rulemaking. In its response to FERC, the CT DPUC opposed efforts by FERC to establish jurisdiction over small generator interconnections to distribution lines, "which would unnecessarily add another layer of regulation on distribution companies and could frustrate state laws in areas of environmental protection and building codes." The CT DPUC also asserted that FERC's position would create overly complex interconnection standards and agreements, which themselves will raise barriers to entry to interconnection of small generation resources."[5] The CT DPUC instead came out in support of the NARUC model, citing it as "less burdensome and easier to understand."

Connecticut Light and Power's (CL&P) current protocol for handling new interconnection is as follows:

- Applications to be interconnected to DG facilities can be approximately 10-15% of the distribution feeder's capacity; or approximately 1 to 1.5 MW.
- DG facilities between 1.5 and 5 MW must be connected at the distribution bus of the nearest distribution substation and an interconnection study must be performed by the distribution company in each case to assess the impact on the substation's operation.
- Anything over 10 MVA must be interconnected to the transmission system (115-kV).[7]

3.4 Local Ordinances

Several communities across the nation have developed or explored local ordinances that are supportive of DG. These measures include DG planning, adoption of green building[8] codes, municipal commitments to DG, and streamlined local permitting.

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[4] To access the final report, see http://www.naruc.org/Programs/dgia/dgiaip.pdf.

[5] Rulemaking Comments of Connecticut Department of Public Utility Control on Standardization of Small Generator Interconnection Agreements & Procedures under RM02-12 ET.

[6] Denotation is changed to MVA (MegaVolt-Amperes) in order to account for the reactive power compensation.

[7] According to CL&P, the transmission system is already at the limits of its design criteria.

[8] For more information on green buildings see: http://www.usgbc.org/LEED/LEED_main.asp

3.5 TARIFF REVISIONS

Excessive standby charges, back-up rates, and insurance requirements have been used in the past by utilities in various states to prevent new generators from interconnecting and competing in an equitable cost environment.[9] Proponents of DG argue that these pricing issues need to be addressed if electricity markets are to become fully accessible. One solution is to require incumbent utilities to sell back-up/ standby power at firm, interruptible rates that are reasonable and non-discriminatory and account for actual incremental power cost. A more aggressive solution would allow an exemption from back-up and standby power charges for preferable or low emissions DG applications. It is important to note that adjustments to standby and related charges would have implications for other customers or CL&P's regulated return. CL&P rates for standby and back-up service are outlined in Rate 984–Supplemental Power Service and Rate 985–Back-up and Maintenance Power Service.

3.6 T&D AVOIDED INVESTMENT CREDIT

Another potential option for reducing costs is to have utilities provide DG projects that are strategically located with financial credits for helping to offset transmission and distribution costs, or alternatively to allow for utilities to recover savings incurred via investment in DG projects. Research indicates that DG can help offset T&D costs based on location and other variables. Development of this concept will require significant technical and economic research, as well as a potentially lengthy regulatory process.[10]

3.7 LOAD RESPONSE

Load response programs seek to reduce electricity use from the grid during periods of peak power demand. A key objective of load response is to increase reliability and moderate the energy-clearing price during system-wide peak demand times. Load response can take the form of reduced electrical load or generation in the form of qualifying emergency generators on the customer side of the meter.

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[9] Standby power refers to power that is used to supplement a customer's generation capacity in cases where the customer's own generation capacity is less than the maximum load. Back-up power is intended to provide the customer with a back-up supply of power when a customer's generating facilities are not in operation or are operating at less than full capability.

[10] The Regulatory Assistance Project has prepared several reports on the value of DG as a T&D cost offset. See http://www.rapmaine.org/distribution.html.

ISO New England (ISO-NE) has established a region-wide load response program to promote electric reliability during capacity deficient periods. Under the ISO program, participating customers are called upon to reduce load when a peak load event occurs; they are compensated for the value of their forgone load. Customers may qualify as Class 1 (reliability) or Class 2 (voluntary) participants. Class 1 customers are required to reduce load during a peak load event or lose the monthly capacity payments they receive in return for participation. Class 2 customers may voluntarily reduce load during a peak load event. For a detailed description of the ISO-NE load response program, see Attachment A.

In the summer of 2002, as an additional component of its load response program, ISO-NE issued a separate RFP for 80 MW of load reduction in SW CT. Program participants agreed to commit to mandatory energy reductions (or equivalent electricity provision) on 30-minute notice from ISO-NE. Based on the costs of this program, in DPUC Docket No. 02-01-22, Review of the Connecticut Light and Power Company's and the United Illuminating Company's Budgets and Modifications for Conservation and Load Management Activities for Year 2002, the DPUC approved use of $186/kW as the capacity value for computing cost effectiveness of load response programs focusing on peak use reductions in summer 2002.

Although the future of this program is uncertain -- the ISO-NE program is scheduled to run from May 1, 2002 through May 31, 2003 and may be affected by the implementation of the FERC Standard Market Design (SMD) rule-making – it provides an example of the types of additional support mechanisms that may be available for DG in SW CT. Moreover, the capacity value of $186/kW provides a data point for market analysis of DG support mechanisms.

3.8 NET METERING

Net metering is a policy vehicle intended to support the development of small onsite renewable generation by allowing end users to sell excess generation back to the utility. In CT, as outlined in CT's restructuring law Public Act 98-28 (RB 5005), the state's investor-owned utilities must offer net metering to all residential customers generating electricity with solar, wind, hydro, fuel cell, or sustainable biomass systems, effective January 1, 2000. Net metering provisions were included in utility tariffs approved by the CT DPUC. The tariffs call for utilities to offer net metering for qualifying facilities with a generating capacity up to 50 kW (100 kW for renewable energy resources). Net metering was required as early as 1990 under rate tariffs filed with the DPUC (CPUCA No. 159).

Net excess generation is purchased at the spot market energy rate, which is essentially avoided cost. Electric suppliers must make required interconnections, install the necessary metering equipment, and provide a credit for any electricity generated by a residential customer. Net metered customers are charged, however, for the competitive transition assessment and the system benefits charge based on the amount of energy consumed by the customer from the facilities of the electric distribution company without netting any electricity produced by the customer.

3.9 Renewable Portfolio Standard

Renewable portfolio standards (RPS) require a state's electricity suppliers to maintain a minimum percentage of renewable energy within their resource portfolio. If successful, an RPS in Connecticut would create an additional revenue stream for renewable energy projects, many of which would be DG. The structure of the RPS in CT is established in the state's restructuring legislation and subsequent rules.[11] It creates a two-tiered structure for qualifying renewable resources, with Class I resources favored and growing over time. Class II resources are also supported by increasing percentages. By 2009 a total of 13% of CT's electricity supply is to be drawn from either Class I or II resources. The required percentages are outlined in the table below (see Table 3-1).

Table 3-1
Connecticut RPS Requirements by Class

Year	Class I	Class I and II
Before 7/1/01	0.5%	5.5%
7/1/01	0.75%	5.5%
7/1/02	1%	5.5%
7/1/03	1.5%	5.5%
7/1/04	2%	6%
7/1/05	2.5%	6%
7/1/06	3%	6%
7/1/07	4%	6%
7/1/08	5%	6%
7/1/09	6%	7%

Class I technologies include solar, wind, fuel cell technologies, and biomass meeting specific criteria: methane gas from landfills and biomass facilities, including, but not limited to biomass gasification plants that utilize land clearing debris, tree stumps, or other biomass that regenerates or the use of which will not result in a depletion of resources. Class II renewable energy sources include hydropower facilities of any size, trash-to-energy facilities, and biomass facilities that do not meet the criteria for a Class I source.

Significantly, providers of the default Standard Offer (SO) service are exempt from meeting the requirements of the RPS. Yet, as of 2002, the vast majority of CT electricity customers are taking service from the default SO. The SO service is due to be eliminated in 2004 unless extended by legislative action. In addition, it is unclear whether the RPS would include electricity that is generated behind the meter and not sold into the grid.

[11] Connecticut General Statutes Section 16-245a. Portfolio standards for electric suppliers, Public Act 99—225 and Public Act 01-204.

As currently structured, the CT RPS is unlikely to stimulate significant growth in DG markets. However, there is considerable debate in CT about the possibility of closing the loophole that allows SO providers to avoid RPS requirements and the inclusion of behind the meter electricity. The outcome of this debate is likely to influence the potential development of DG in SW CT.

3.10 EMISSIONS POLICIES

As discussed above, emissions policies may serve as a barrier for certain DG technologies. However, for cleaner DG technologies, such as PV, wind, and fuel cells, emissions policies may provide an additional source of revenue. In addition, to the extent that future emissions policies can be designed to recognize the efficiency of CHP applications and their lower emissions on a total energy basis, this may help to promote the use of DG or at least reduce the market barrier presented by emissions regulations.

Relevant emissions policies in CT include the NO_x budget program that allocates NO_x allowances to large sources of electricity generation starting in Summer 2003. As of now, CT does not provide offsets or allowance credits to renewables or energy efficient technologies. However, NO_x allowances may be transferable to sources in other states or purchased from out of state sources. Additionally, the Massachusetts and New Hampshire NO_x budget programs will provide renewable energy and energy efficiency with set-asides.

In addition, CT may develop a Generation Performance Standard (GPS) that requires suppliers to meet emission rate requirements per unit of electricity sold. The DEP issued Draft R.C.S.A. Section 22a-174-34 (“Section 34”) that established a GPS policy for retail suppliers of electricity that would require each supplier’s annual average emission rate of NO_x, CO_2, and SO_2 must meet emission performance standards. Still in the development stage, the GPS may not include behind the meter generation.

4 DG MARKET PENETRATION ANALYSIS FOR SOUTHWEST CONNECTICUT

4.1 ASSUMPTIONS

A number of assumptions are implicit in the development of DG market penetration forecasts for SW CT. General assumptions and limitations of this study are highlighted below. Specific assumptions are discussed in each section as appropriate.

- For purposes of this analysis, the term DG is used broadly to include onsite renewable and non-renewable energy generation in five different capacity ranges: 100 to 500 kW; 500 kW to 1 MW; 1 to 5 MW; 5 to 20 MW; and >20 MW. Depending on application size and other factors, DG described in this report may be connected to either the distribution system or the transmission system.[1]
- The lowest cost permittable base load technology was used to determine market penetration for each size category. Diesel generators, which are likely to operate as peaking units only, are not considered permittable as base load and are therefore not reflected in our market forecast. Renewable energy market potential is discussed but not quantified in the DG market penetration analysis due to its unique characteristics and economic considerations.
- Base load DG technologies are assumed to operate as CHP units. In most cases, the economics of non-renewable DG will not lead to project development unless process heat can be captured and re-used. Recoverable heat is valued at the cost of natural gas delivered to the end-user.
- Estimates of technical potential for DG for commercial/institutional and industrial customers in SW CT are not derived from customer specific data. Rather, these estimates are based largely on interpolation of national and statewide data. This is a limitation of the study. For instance, a finding of the study is that a large portion of the market potential for DG in SW CT resides with large customers with peak demands of 5 MW or more. However, without customer specific data, it is difficult to discern the extent to which these loads actually exist.
- Fuel cells currently qualify as a Class I Renewable Energy Source in CT, and are treated as such in this analysis. However, for purposes of discussion in this report, fuel cells are considered under the category of CHP technologies.
- Market penetration of DG technologies into the residential electricity market is not included in the analysis. Even when net metering is considered, the penetration of DG technologies into the residential marketplace is expected to be insignificant in terms of

[1] Generally units over 5 MW are not connected in parallel to the distribution system.

total MW. High capital costs and immaturity of applicable technology are contributing factors.

4.2 METHODOLOGY

Market penetration scenarios of DG in SW CT were developed using a methodology developed and published in a 2002 study by NYSERDA, *Combined Heat and Power Market Potential for New York State.*[2] Technology and market data relevant to CT were adapted from two corollary studies completed for the U.S. Energy Information Administration.[3,4]

Development of market penetration scenarios for SW CT involved the following key steps:

- Estimate technical CHP potential for each energy sector for SW CT.
- Sub-divide CHP potential into five categories based on application size: (100 to 500 kW; 500 to 1000 kW; 1 to 5 MW; 5 to 20 MW; and >20 MW).
- Develop levelized cost ($/kWh) estimates and associated payback periods for "current" DG technology and "advanced" DG technology for each application size based on capital costs, fuel costs, electricity costs, interest rate, etc. Levelized cost estimates were also developed for renewable technologies.
- Run market penetration scenarios based on paybacks for each technology according to a Base Case and Accelerated Case.

Each step of the methodology is described in greater detail in the sections below.

4.3 CURRENT STATUS OF DISTRIBUTED GENERATION IN SW CONNECTICUT

This section provides information about existing DG facilities in SW CT. Data were taken from the Connecticut Siting Council's list of existing generation facilities in CT, which was last updated in July 31, 2002.

Based on Siting Council data, the following table provides a breakdown of total electricity generating capacity for CT and SW CT that generates electricity primarily for sale to the grid (see Table 4-1). The table also shows existing renewable energy capacity in SW CT. For a

[2] "Combined Heat and Power Market Potential for New York State." October 2002. Prepared for NYSERDA by Energy Nexus Group Onsite Energy Corporation and Pace Energy Project.

[3] "The Market and Technical Potential for Combined Heat and Power in the Industrial Sector." January 2000. Prepared for U.S. Energy Information Administration by ONSITE SYCOM Energy Corporation.

[4] "The Market and Technical Potential for Combined Heat and Power in the Commercial/ Institutional Sector." January 2000. Prepared for U.S. Energy Information Administration by ONSITE SYCOM Energy Corporation.

complete list of generation facilities (that sell electricity to the grid) in SW CT, see Attachment B.

Table 4-1
CT and SW CT Generation Capacity (For Sale to Grid) (MW)

Jurisdiction	MW
CT Total Capacity	7361.3
SW CT Total Capacity	2561.2
SW CT Total Renewable Capacity	155.5

As indicated above, renewable energy capacity in SW CT is 154.7 MW. This figure represents includes approximately 3 MW of landfill gas, 66 MW of waste refuse, and 87 MW of hydropower.[5]

The following table provides total onsite, or behind the meter, electricity generation in CT and SW CT (see Table 4-2). Onsite generation capacity for renewable DG in SW CT is also shown. This figure, 0.4 MW, is representative of two small solar facilities, a small wind facility, and a small hydro facility. For a complete list of onsite generation facilities in SW CT, see Attachment C.

Table 4-2
CT and SW CT Onsite Generation Capacity (MW)

Jurisdiction	MW
CT Total Onsite Capacity	127.1
SW CT Total Onsite Capacity	36.9
SW CT Total Onsite Renewable Capacity	0.4

4.4 Technical Potential of Distributed Generation in SW Connecticut

As a first step in developing market penetration scenarios for DG in SW CT, it was necessary to develop estimates of the total technical potential for DG in SW CT. Technical market potential implies no consideration of economics, and represents the upper bound of potential penetration within a given market size category. Technical market potential is an estimate of market size constrained only by technological limit — e.g., the ability of CHP technologies to meet existing customer needs. The technical potential includes sites that have energy consumption

[5] For a breakdown of the various renewable energy projects see Attachment B.

characteristics that could apply to CHP. For commercial and industrial sites, this means 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 ratios in the 0.5 to 2.5 range; and
- Moderate to high operating hours (>4000 hours per year).

The estimates of technical market potential provided here do not consider such factors as ability to retrofit, owner interest in applying CHP, capital availability, natural gas availability, and variation of energy consumption within customer application/size class. The technical market potential also does not consider the capability of distribution systems in SW CT to support DG. All of these factors affect the feasibility, cost, and ultimate acceptance of CHP at specific sites, and are critical to the economic implementation of CHP. Notably, the analysis also considers only traditional hot water-steam electric power CHP, and makes no estimate for mechanical drive applications or for uses of thermal energy other than steam or hot water.[6]

Using the above conditions, estimates of technical potential for DG for SW CT were derived for the industrial and commercial/ institutional energy sectors. Specific estimates and the data used to arrive at them are described below.[7]

4.4.1 Technical Potential – Industrial Sector

The following table shows estimated industrial CHP technical potential by application size for CT and SW CT (see Table 4-3). The data provide the basis for developing DG market penetration scenarios for SW CT.

Table 4-3
Industrial CHP Technical Potential by Application Size for CT and SW CT

Jurisdiction	100- 500 kW	500-1000 kW	1-5 MW	5-20 MW	>20 MW	Total
CT Industrial CHP Potential (MW)	116.6	75.8	266.2	189.6	108.8	757.0
SW CT Industrial CHP Potential (MW)	45.5	29.6	103.8	74.0	42.4	295.2
SW CT Industrial CHP Potential Minus Existing (MW)	44.7	29.1	102.1	72.7	41.7	290.2

[6] For more detailed information about how technical market potential is estimated, see “Combined Heat and Power Market Potential for New York State.”

[7] It is important to reiterate that the technical potential for SW CT was not based on specific SW CT customer electricity data. Therefore, actual technical potential within each customer category may vary. However, assuming that the total technical potential for all customer categories 1 MW and larger would remain approximately the same, it is reasonable to assume (based on similar payback periods and penetration rates) that the market penetration projections would also remain approximately the same.

Estimates of industrial technical potential were developed based on the following approach. First, in the previously cited Onsite study, the total U.S. industrial CHP technical potential was found to be 132,583 MW. This figure reflects integrated output from three separate databases of U.S. industrial facilities and the conditions described above.[8] Next, based on data provided by the U.S. Energy Information Administration, CT industrial customers were found to represent about 0.57% of total U.S. industrial usage. Accordingly, CT CHP total potential is estimated to represent approximately 757.0 MW, or 0.57% of total U.S. industrial CHP technical potential. In order to estimate SW CT industrial CHP potential, this figure was multiplied by the percentage of total CT electricity usage represented by SW CT (39%) to arrive at 295.2 MW for SW CT. Data for producing these estimates were derived from forecasts of 2002 electricity usage from the CT Siting Council and ISO-NE. Figures for existing, or baseline CHP,[9] were then netted out to arrive at SW CT industrial technical market potential.

As a next step, to allow for estimates of market penetration, CHP technical potential for SW CT was subdivided into five categories representing the aforementioned application sizes (100 to 500 kW; 500 to 1000 kW; 1 to 5 MW; 5 to 20 MW; and >20 MW). Capacity within each category in SW CT was estimated by applying the ratios in each category from published estimates for New York State. For the industrial sector, the analysis therefore assumes that the breakdown of total industrial CHP potential by application size in New York State is similar to that of SW CT. Other assumptions pertinent to the analysis include: estimates of technical potential for CHP assume that CHP systems are sized to meet the average electric demand for most applications; and estimates of technical potential assume all power will be used on-site.

4.4.2 Technical Potential - Commercial/ Institutional Sector

The following table shows commercial/ institutional CHP technical potential by application size for CT and SW CT (see Table 4-4).

Table 4-4
Commercial/ Institutional CHP Technical Potential
by Application Size for CT and SW CT

Jurisdiction	100-500 kW	500-1000 kW	1-5 MW	>5 MW	Total
CT C/I CHP Potential (MW)	276.6	311.7	326.0	66.9	981.2
SW CT C/I CHP Potential (MW)	106.8	120.3	125.8	25.8	378.7

Estimates of commercial/ institutional technical potential by application size for CT were developed and published in an appendix in the aforementioned Onsite report on CHP technical

[8] For more information, see p. 32, Industrial CHP Assessment, Onsite Sycom Energy Corporation.

[9] 5 MW of the 36.9 MW of existing onsite generating capacity in SW CT was estimated to be Industrial CHP. See Attachment C for a list of onsite generation projects.

and market potential in the commercial/ institutional sector. The above numbers reflect these published estimates. Note, unlike industrial CHP potential above, this number is already net of existing CHP. Therefore, to develop analogous estimates of commercial/ institutional CHP technical for SW CT, we simply multiplied statewide figures by the percentage of total CT electricity usage represented by SW CT (39%).

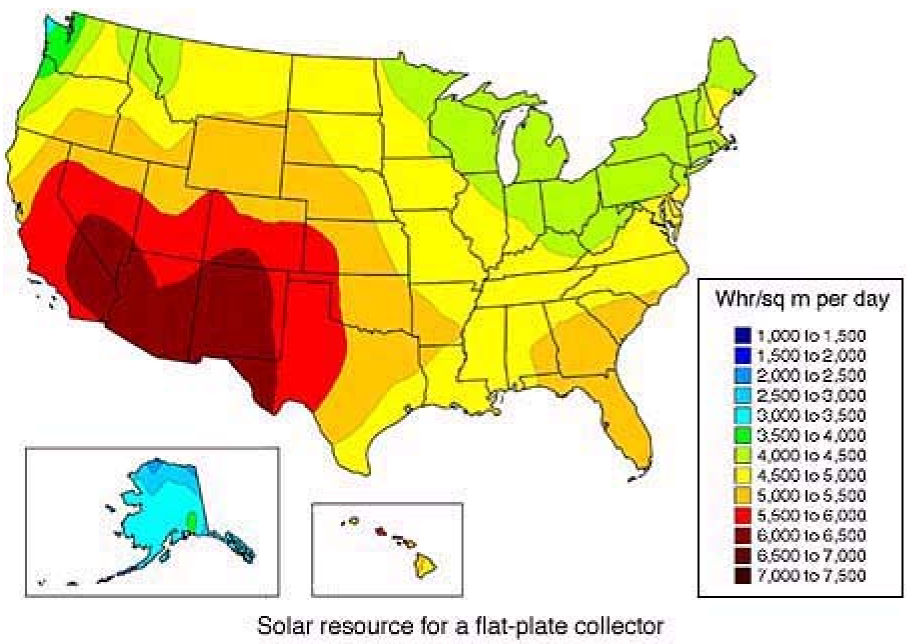
4.4.3 Technical Potential - Renewable

Renewable energy technical potential is limited by natural resource availability in addition to technical considerations. The technical potential of the following renewable resources in SW CT is discussed below: solar, wind, and biomass.

4.4.4 Technical Potential - Solar Photovoltaic (PV)

Solar energy resource availability for electricity PV conversion varies by location and time of year. Solar resource maps for CT show that mid-range solar resources are available throughout the state. As shown in the map of CT below, CT solar resource availability falls between 4000 and 4500 Wh/m^2/day (see Figure 4-1).

Figure 4-1
Solar Resource Map of the U.S. for a Flat Plate Collector[10]



[10] U.S. Department of Energy, Energy Efficiency and Renewable Energy Network web site: http://www.eren.doe.gov/state_energy/tech_solar.cfm?state=CT.

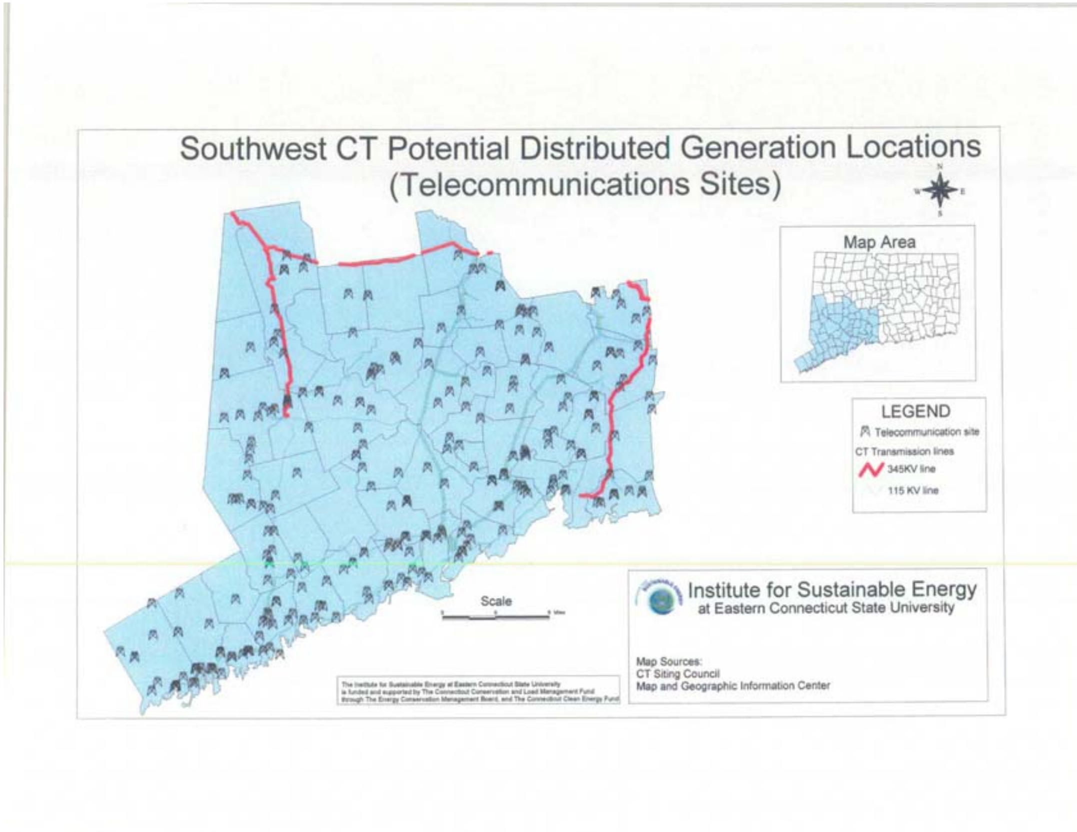
This is the same as saying in an optimal location for solar electricity (i.e., one free of obstruction from vegetation, buildings, or other obstacles), a flat-panel solar PV array the size of a football field would produce approximately 863,000 kWh per year. Solar concentrator technology, which tracks the movement of the sun to maximize the amount of insolation captured, cannot be cost-effectively used in CT, or in most northern states of the U.S. For comparison, in a location with high solar insolation levels, say Arizona, the same size PV array would produce approximately 1,216,000 kWh per year. With solar concentrator technology, which is economically viable in Arizona, an array the size of 150 acres would produce 63,364,000 kWh per year.[11]

Further perspective is provided by the National Renewable Energy Laboratory's PVWATTS model, which calculates average monthly and annual energy production for a PV system of given size, type, and location in the U.S. According to the model, a 100 kW (DC) fixed flat panel system located at an unobstructed location in Bridgeport can be expected to produce 128,225 kWh annually.[12] In addition, PV can be easily sited in many locations (e.g. business, institutional, and residential rooftops), and typically generates electricity coincident with peak usage periods.

As one example, as shown in the map below (Figure 4-2), there may be significant opportunity to use PV (or other DG technologies) at telecommunications sites in SW CT.

[11] U.S. Department of Energy, Energy Efficiency and Renewable Energy Network web site: http://www.eren.doe.gov/state_energy/tech_solar.cfm.
[12] PVWATTS web site: http://rredc.nrel.gov/solar/codes_algs/PVWATTS/.

Figure 4-2
SW CT Potential DG Sites (Telecommunications Sites)[13]



Although adequate solar resources and potential applications exist in SW CT, such estimates need to be considered in an economic context. Given the very high capital costs of PV solar electricity relative to other renewable and non-renewable types of electricity generation, combined with other market and regulatory issues (e.g., nascent markets for RPS credits and green power) the near- to mid-term development of solar electricity in SW CT can be expected to be quite limited. Even when developed in large arrays to maximize economies of scale (e.g., >500 kW capacity), the costs of producing solar electricity are at least four to five times greater than for alternatives.

Aggressive government grants and incentives for solar installations, combined with decreasing capital costs, green power price premiums, and policies to spur market development of renewables (e.g., renewable portfolio standards) will all contribute to make solar electricity increasingly attractive in SW CT in coming years. However, in spite of these incentives, moderate solar resources and high costs are likely to prevent solar resources from making a significant contribution to regional electricity generation capacity in the near and mid-term.

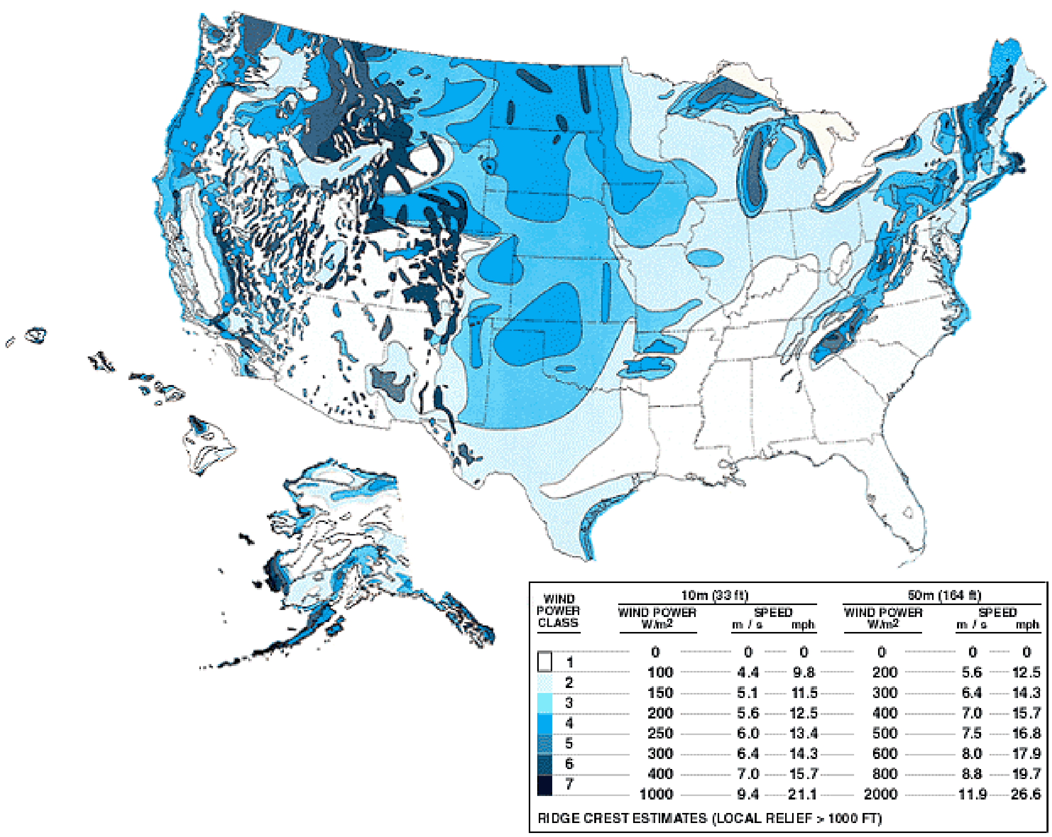
[13] Institute for Sustainable Energy at Eastern Connecticut State University

Technical Potential – Wind

Wind resources can be captured by large wind turbines for utility scale applications, and by small wind turbines for onsite generation. To gauge the viability of using wind resources in a particular region, wind is classified according to wind power classes, which are based on typical wind speeds. These classes range from Class 1 (lowest) to Class 7 (highest). In general, large utility scale wind turbines can generate power with wind power of Class 3 or higher, and small turbines can be used at any wind speed. However, wind resources are considered <u>economically</u> feasible for land-based wind development only if they are Class 5 or higher.

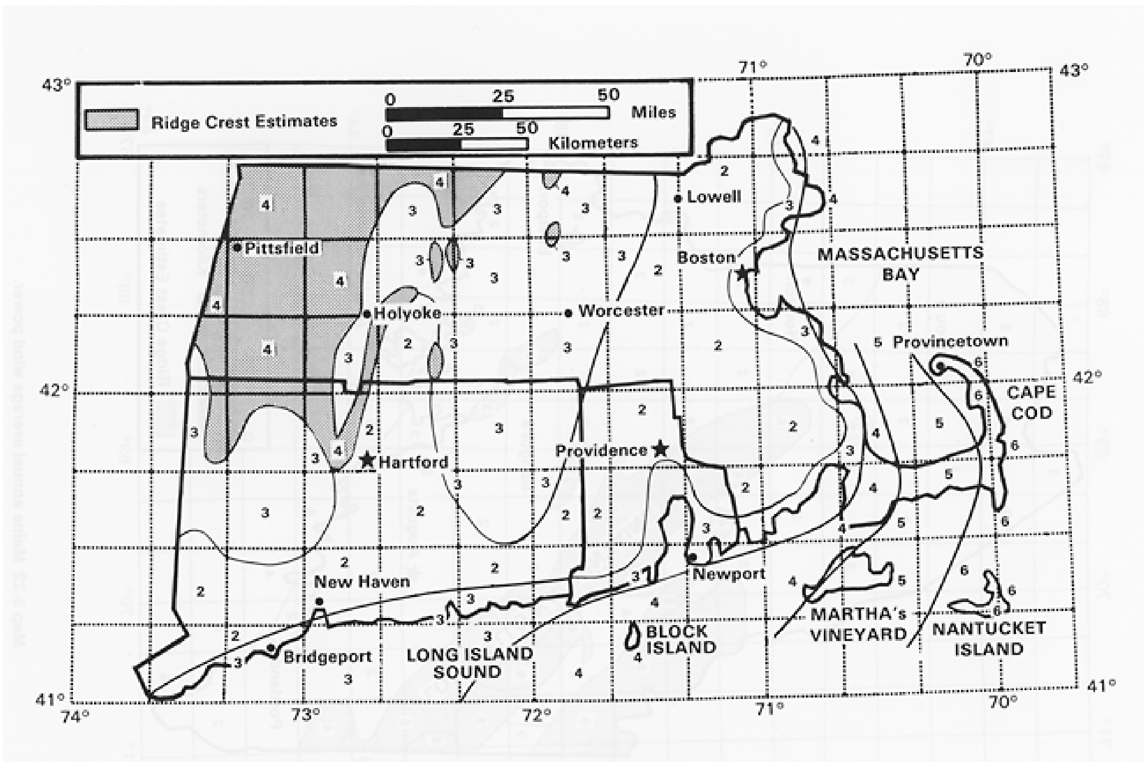
The following map shows wind power resources throughout the United States (see Figure 4-3).

Figure 4-3
Wind Resource Map of the U.S.



In New England, wind resources considered economically feasible for development are generally found along higher north-south mountain ridges in Vermont, New Hampshire, and Maine and in some offshore areas. The following wind resources map for CT, Massachusetts, and Rhode Island (see Figure 4-4) shows that CT is wholly lacking in wind resources of Class 5 and above.

Figure 4-4
Estimated Wind Resources for Connecticut, Massachusetts, and Rhode Island[14]



Based on <u>usable</u> wind resources of Class 3 or higher, the <u>technical</u> potential of wind energy for CT can be determined. According to DOE estimates, after 50% of forestland, 30% of farmland, and 10% of rangeland is netted out, about 6% of CT is predicted to have usable winds for electricity generation. If all of this potential were developed using utility-scale wind turbines, approximately 6 million MWh of electricity would be produced annually. Notably, only a thin band along the coastline of wind resources of Class 3 or higher is located in SW CT, meaning only a fraction of this technical potential resides in SW CT.

Given the deficiency of economically developable wind resources throughout CT, it is unreasonable to expect the development of any significant wind capacity in the state in the near to mid-term. With regard to the New England region as a whole, other geographic areas offer considerably more promise. As outlined in an assessment of wind energy in the Northeast

[14] Wind Energy Resource Atlas of the United States: http://rredc.nrel.gov/wind/pubs/atlas/maps.html.

completed for the Connecticut Clean Energy Fund, the following bullets describe probable wind power development scenarios for New England and CT:[15]

- **Relatively small (20 MW or less) wind farms in central and northern New England and upstate New York** – a likely scenario, but due to siting and transmission constraints, will likely add only moderate amounts of electricity to the region.
- **Larger (50 MW and greater) offshore wind farms off the coasts of Cape Cod and possibly Southern Rhode Island and eastern Massachusetts** – untried in the U.S. and subject to significant siting and permitting obstacles, but has the potential to add hundreds of MW of wind energy to the region.
- **Distributed wind energy resources (250 kW or less) on a behind the meter basis in CT and elsewhere** – a likely scenario, but will add relatively small amounts of wind energy to the region.

Technical Potential – Biomass

Recent studies indicate that CT has good biomass resource potential. Despite this fact, the recent history of biomass in CT indicates minimal biomass energy production. With the exception of one small 150 kW unit, there is no biomass electricity currently generated in the state. Notably, the state has a history of relatively intense public opposition to those biomass plants that have been proposed. This history is important to recognize when considering present and future potential for siting biomass in CT.[16]

In general terms, CT and the states of the Northeast can be considered well-endowed with biomass resources. These biomass resources fall into the following categories: agricultural residues; forest residues; primary and secondary mill residues; paper sludge; urban wood wastes; urban tree residues; waste paper; potential dedicated energy crops; and landfill gas. When the advantages of biomass are considered – storability, availability, and dispatchability – the impact of the state's biomass resources could far surpass that of other renewable resources in the near-term. However, due to insufficient information about these resources, it is difficult to precisely define the nature of the available biomass in CT, the specific locations where it is available, and associated delivered costs to the end-users. Consequently, making an accurate estimate of the state's total biomass power potential is challenging. According to a report written for the Connecticut Clean Energy Fund, 100 to 300 MW of electric generation potential from biomass power resides in CT, depending upon resource availability and technologies utilized.[17]

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[15] "Wind Energy in the Northeastern U.S.: Leverage Points for Growth." Prepared for the Connecticut Clean Energy Fund by Energy & Environmental Ventures, LLC.

[16] "Biomass Strategies for Connecticut." Prepared for the Connecticut Clean Energy Fund by Environmental Energy Solutions. July 27, 2000.

[17] "Biomass Strategies for Connecticut."

The U.S. Department of Energy offers another estimate of CT biomass potential on its Energy Efficiency and Renewable Energy Network web site. According to its fact sheets, an estimated 1.3 billion kWh of electricity could be generated using renewable biomass fuels in CT. This biomass resource potential is found in five general categories of biomass: urban residues; mill residues; forest residues; agricultural residues; and energy crops. The fact sheet further notes that of these potential biomass supplies, most forest residues, agricultural residues, and energy crops would be considered uneconomic to use at the present time due to collection, processing, and conversion technology costs.[18]

Another estimate of biomass potential is found in a recent report prepared for the Northeast Regional Biomass Program.[19] Utilizing data from a 1999 national feedstock assessment by the Oak Ridge National Laboratory, combined with data from a 1998 feedstock assessment by the National Renewable Energy Laboratory, the report tabulated total electricity potential for each Northeast state. Assuming that generators are willing to pay for biomass feedstock at a delivered price of up to $3.50/MMBtu, annual biomass electricity potential was estimated to be 1.83 million MWh. Annual electricity generation potential by specific biomass resource is indicated in the table below (see Table 4-5). Assuming a capacity factor of 75%, these resources would support approximately 275 MW of biomass.

Table 4-5
Connecticut Annual Biomass Electricity Production Potential (MWh) < $3.50/MMBtu[20]

Agric. Residue	Forest Residue	Primary Mill Waste	Secondary Mill Waste	Paper Sludge	Urban Wood Waste	Tree Residue	Waste Paper	Dedicated Crops (potential)	Landfill Gas	Total
-	200,601	89,440	14,251	-	404,508	727,314	118,434	196,223	79,092	1,829,863

While no central data source exists concerning what portion of these resources can be found in SW CT, the following figure (Figure 4-5) shows the locations of compost and biomass sources across SW CT.

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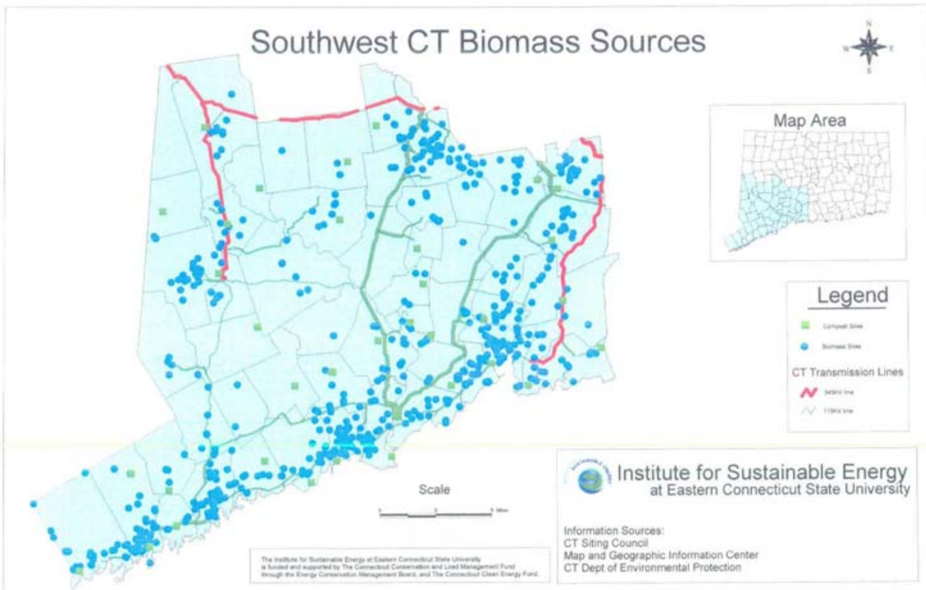
[18] U.S. Department of Energy, Energy Efficiency and Renewable Energy Network web site: http://www.eren.doe.gov/state_energy/tech_biomass.cfm?state=CT.

[19] "Securing a Place for Biomass in the Northeast United States: A Review of Renewable Energy and Related Policies." Prepared by XENERGY Inc. for the Northeast Regional Biomass Program. Available from the NRBP.

[20] The heat rates used for conversion of MMBtu to MWh are: 1) 17,500 Btu/kWh for solid biomass; and 2) 12,000 Btu/kWh for landfill gas.

Figure 4-5
Southwest CT Biomass Sources[21]



Landfill gas merits additional discussion. According to the most recent data provided by the EPA Landfill Methane Outreach Program, CT has at least two operational landfill gas electricity generation projects: a 2.9 MW reciprocating engine at the Hartford Landfill, and a 3.3 MW gas turbine at the New Milford Landfill. In addition, at least 5 other sites have been tagged as potential projects, either for electricity production or direct use of landfill methane gas.[22] SW CT has nine candidate landfills for landfill gas development, of which at least 2 (New Milford and Shelton) have been developed. Another biomass energy concept in the early stages of commercialization is the use of digester gas that can be collected from sewage treatment facilities, another potentially abundant resource in SW CT. Two other projects, in Groton and

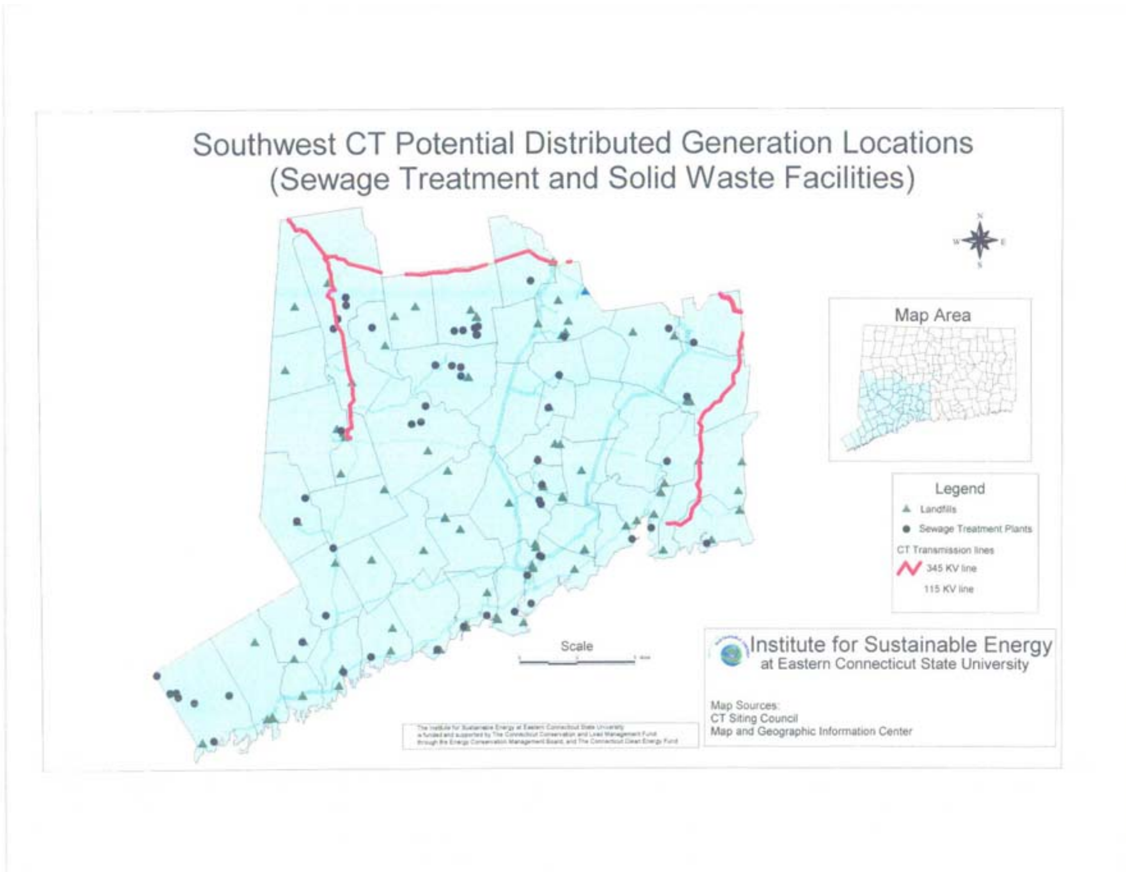
[21] Institute for Sustainable Energy at Eastern Connecticut State University

[22] Landfill Methane Outreach Program, Current Projects and Candidate Landfills: http://www.epa.gov/lmop/projects/projects.htm.

Shelton, representing 2 MW of electricity generation capacity, have been shutdown in recent years.[23]

The following figure (see Figure 4-6) shows all of the landfills (candidate and other) and sewage treatment facilities in SW CT.

Figure 4-6
SW CT Potential DG Locations (Sewage Treatment and Solid Waste Facilities)



Given currently available biomass data, it is impossible to precisely quantify biomass resources in SW CT. Because of its seemingly widespread availability, as well as its advantages related to base load operations, waste reduction, and emissions reductions, biomass energy merits further exploration. A key initial first step will be a detailed biomass resource inventory of the state and SW CT.

[23] The Shelton project was shutdown because the methane quality from the landfill was not substantial enough to make the project feasible. They are currently flaring off the gas. The Groton project was a demonstration case that just ran its course and was closed.

4.5 MARKET POTENTIAL OF DG IN SW CONNECTICUT

This section presents information about the market potential under various scenarios for DG in SW CT. Market potential is estimated based on economic analysis that determines the economic attractiveness to end-users of installing and operating an on-site DG system. The analysis assumes that the decision is based on payback achieved from on-site use of generated power (and thermal energy for CHP applications) and other potential savings/revenue.

4.5.1 Levelized Cost Estimates of Selected Technologies

The following tables provide estimates of levelized cost for current CHP (see Table 4-6), advanced CHP (see Levelized Cost and Performance of Advanced CHP Technologies by Size Range), and renewable technologies (see Table 4-8).[24] "Current" technologies refer to those DG technologies that are widely available on a commercial basis and their associated performance characteristics. "Advanced" technologies refer to DG technologies that are expected to be widely available on a commercial basis in the near to mid-term (in the case of microturbines), or current technologies that could potentially achieve performance and cost improvements in the near to mid-term. Estimates of levelized cost of electricity were developed according to the performance data indicated in the tables. Natural gas price is based on U.S. DOE EIA forecasted price of delivered natural gas in CT to commercial customers in 2003.

[24] Data for levelized cost calculations for CHP technologies are adapted from data provided in "Combined Heat and Power Market Potential for New York State." Data for levelized cost calculations for renewable technologies are developed from a variety of XENERGY in-house resources and expertise.

Table 4-6
Levelized Cost and Performance of Current CHP Technologies by Size Range

System Parameters	Gas Engine	Gas Engine	Gas Turbine	Gas Turbine	Gas Turbine
Applicable Size Range (kW)	50-500	500-1,000	1,000-5,000	5,000-20,000	>20,000
Size (kW)	100	800	5,000	10,000	50,000
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
Recoverable Heat (Btu/kWh)	5,683	4,323	5,622	5,282	3,779
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
O&M Cost $/kW/yr	$119.136	$77.088	$42.048	$42.048	$31.536
Natural Gas Cost $/MMBtu	$6.39	$6.39	$6.39	$6.39	$6.39
Project Economic Life (Years)	10	15	15	15	20
Annual Load Factor	80%	80%	80%	80%	90%
% of Recoverable Heat Used	70%	70%	80%	90%	90%
Fixed Charge Rate	16.27%	13.15%	13.15%	13.15%	11.75%
Interest Rate	10%	10%	10%	10%	10%
Levelized Cost of CHP ($/kWh)	**$ 0.1014**	**$ 0.0805**	**$ 0.0764**	**$ 0.0687**	**$ 0.0516**

Table 4-7
Levelized Cost and Performance of Advanced CHP Technologies by Size Range

System Parameters	Microturbine	Gas Engine	Gas Turbine	Gas Turbine	Gas Turbine
Applicable Size Range (kW)	50-500	500-1,000	1,000-5,000	5,000-20,000	>20,000
Size kW	100	800	5,000	10,000	50,000
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
Recoverable Heat (Btu/kWh)	2,748	3,096	3,746	3,259	2,730
Basic Turnkey Cost ($/kW)	$915	$690	$950	$830	$625
O&M Cost $/kWh	$0.011	$0.009	$0.005	$0.005	$0.004
O&M Cost $/kW/yr	$77.088	$63.072	$35.040	$35.040	$31.536
Natural Gas Cost $/MMBtu	$6.39	$6.39	$6.39	$6.39	$6.39
Project Economic Life (Years)	10	15	15	15	20
Annual Load Factor	80%	80%	80%	80%	90%
% Recoverable Heat Used	70%	70%	80%	90%	90%
Fixed Charge Rate	16.27%	13.15%	13.15%	13.15%	11.75%
Interest Rate	10%	10%	10%	10%	10%
Levelized Cost of CHP ($/kWh)	**$ 0.0805**	**$ 0.0680**	**$ 0.0651**	**$ 0.0597**	**$ 0.0521**

Table 4-8
Levelized Cost and Performance Renewable Technologies by Size Range

Levelized Cost and Performance for Renewable Technologies								
System Parameters	Solar PV (Small to Med.)	Solar PV (Large)	Wind (Small to Med.)	Wind (Large)	Biomass (LFG)	Biomass (FBC)	MCFC	PAFC
Applicable Size Range (kW)	50-500	>500	100-500	>500	< 1000	> 5000	>2000	200 - 2000
Size kW	100	800	100	800	1000	10000	2000	800
Efficiency (HHV)	N/A	N/A	N/A	N/A	33%	25%	49%	36%
Heat Rate (Btu/kWh HHV)	N/A	N/A	N/A	N/A	10400	13650	7000	9400
Recov. Heat (Btu/kWh)	N/A	N/A	N/A	N/A	0	7500	1800	3500
Basic Turnkey Cost ($/kW)	$ 8,000	$ 6,000	$ 2,000	$ 1,000	$ 1,100	$ 2,000	$ 4,500	$ 3,500
O&M Cost $/kW/yr	$ 10.00	$ 5.00	$ 30.00	$ 20.00	$115.00	$ 50.00	$150.00	$150.00
Natural Gas Cost $/MMBtu*	N/A	N/A	N/A	N/A	$ 2.50	$ 3.50	$ 6.39	$ 6.39
Project Economic Life (Years)	20	20	20	20	15	15	20	20
Annual Load Factor	17%	17%	30%	30%	80%	75%	90%	95%
Percentage of Recoverable Heat Used	N/A	N/A	N/A	N/A	N/A	70%	70%	70%
Fixed Charge Rate	11.75%	11.75%	11.75%	11.75%	13.15%	13.15%	11.75%	11.75%
Interest Rate	10%	10%	10%	10%	10%	10%	10%	10%
Levelized Cost of Electricity/ CHP ($/kWh)	**$0.6379**	**$0.4768**	**$0.1008**	**$0.0523**	**$0.0631**	**$0.0770**	**$0.1308**	**$0.1177**

With regard to renewables, levelized cost estimates for solar PV are based on solar resources available in SW CT. Levelized cost estimates for wind are based on of Class 5 wind resources being available. Regarding landfill gas, a fuel cost of $2.50/MMBtu assumes the gas flare and collection system is not already in place prior to project development. Regarding biomass fluidized bed combustion (FBC), natural gas cost refers to the cost of delivered feedstock. O&M cost estimates for molten carbonate and phosphoric acid fuel cells include embedded cost of stack replacement every five years.

For illustrative purposes the following table compares the levelized cost ($/kWh) of electricity purchased from the utility with the levelized cost of owning and operating DG and paying the utility the standby rate. As indicated, the higher cost of operating a 100 kW advanced DG unit results in a levelized cost that is higher than the utility rate, whereas the purchase and operation of a larger advanced DG unit (10 MW) would make it a favorable option on a levelized cost basis.

Table 4-9
Levelized Cost: Utility vs. Onsite Generation

Levelized Cost: Utility vs. Onsite Generation			
Customer Size Range (MW)		0.1 - 0.5	5.0 - 20.0
Application Size (kW)		100	10000
Load Factor (%)		40%	65%
Typical Annual Usage (kWh)		350,400	56,940,000
Levelized Cost of Electricity (From Utility) -$/kWh	Total	$ 0.0932	$ 0.0761
Levelized Cost of Electricity (Advanced Onsite Generation) - $/kWh	Onsite	$ 0.0805	$ 0.0597
	Back-up Charges	$ 0.02442	$ 0.01117
	Total	$ 0.10492	$ 0.07087
Levelized Savings		$ (0.01172)	$ 0.00523

It is important to note that this levelized cost information is provided as a reference and not used in the calculation of market penetration. As discussed below, simple payback, a technique commonly used by businesses and institutions to evaluate capital expenditure options, is used as the basis for the market penetration analysis.

4.5.2 Payback of Selected Technologies

The following tables provide an estimate of payback period in years for current CHP (see Table 4-10), advanced CHP (see Table 4-11), and renewable technologies (see Table 4-12). Estimates of payback presented below are representative of the Base Case scenario (see Scenario Definitions, page 4–20). Payback periods for each technology were projected on a moving forward basis for each year forecasted in the market penetration analysis. Payback periods form the basis of developing market penetration scenarios, described below.

Thermal savings are calculated based on recoverable heat valued at the delivered price of natural gas. Utility bills are based on appropriate CL&P tariffs. Customers that use onsite generation, even to meet 100% of their needs, will still need to pay CL&P standby charges. For an example of CL&P rates, methodology for calculating utility bills, and associated assumptions, see Attachment D. Payback periods of "N/A" indicate that the technology is uneconomic under a scenario (e.g., annual costs with the CHP application exceed annual costs without the CHP application, and therefore the first costs can never be recovered). With regard to renewables, for small wind and solar applications (100 kW), the CT net metering law is deemed to be applicable, so back-up charges are eliminated, although the system benefits charge and competitive transition charge are still applied.

Table 4-10
CHP Payback by Size for Current Technologies

CHP Size	100 kW	800 kW	5 MW	10 MW	50 MW
Technology	Engine	Engine	Turbine	Turbine	Turbine
CHP O & M Cost	$ 11,914	$ 61,670	$ 210,240	$ 420,480	$ 1,576,800
CHP Fuel Cost	$ 54,375	$ 395,581	$ 2,767,992	$ 5,250,625	$ 23,228,693
Thermal Savings	$ 31,811	$ 193,589	$ 1,573,497	$ 2,956,673	$ 10,576,741
Annual Utility Bill with CHP	$ 8,557	$ 49,975	$ 318,017	$ 636,033	$ 3,914,052
Total Costs with CHP	$ 43,034	$ 313,638	$ 1,722,753	$ 3,350,465	$ 18,142,805
Base Utility Bill w/out CHP	$ 32,663	$ 245,482	$ 2,167,850	$ 4,335,701	$ 24,878,400
Annual Savings	$ (10,372)	$ (68,155)	$ 445,098	$ 985,236	$ 6,735,595
First Cost	$ 139,000	$ 780,000	$ 5,375,000	$ 9,650,000	$ 35,000,000
Payback Years	**N/A**	**N/A**	**12.1**	**9.8**	**5.2**

Table 4-11
CHP Payback by Size for Advanced Technologies

CHP Size	100 kW	800 kW	5 MW	10 MW	50 MW
Technology	Microturbine	Gas Engine	Gas Turbine	Gas Turbine	Gas Turbine
CHP O & M Cost	$ 7,709	$ 50,458	$ 175,200	$ 350,400	$ 1,576,800
CHP Fuel Cost	$ 42,443	$ 335,809	$ 2,152,017	$ 4,052,870	$ 21,486,541
Thermal Savings	$ 15,382	$ 138,642	$ 1,048,438	$ 1,824,271	$ 7,640,779
Annual Utility Bill with CHP	$ 8,557	$ 49,975	$ 318,017	$ 636,033	$ 3,914,052
Total Costs with CHP	$ 43,326	$ 297,599	$ 1,596,795	$ 3,215,032	$ 19,336,615
Base Utility Bill w/out CHP	$ 32,663	$ 245,482	$ 2,167,850	$ 4,335,701	$ 24,878,400
Annual Savings	$ (10,664)	$ (52,117)	$ 571,055	$ 1,120,668	$ 5,541,785
First Cost	$ 91,500	$ 552,000	$ 4,750,000	$ 8,300,000	$ 31,250,000
Payback Years	**N/A**	**N/A**	**8.3**	**7.4**	**5.6**

Table 4-12
Payback by Size for Renewable Technologies

Technology	Solar PV	Solar PV	Wind	Wind	Biomass LFG	Biomass FBC	MCFC	PAFC
Size	100 kW	800 kW	100 kW	800 kW	100 kW	10 MW	2 MW	200 kW
CHP O & M Cost	$ 1,000	$ 4,000	$ 3,000	$ 16,000	$ 115,000	$ 500,000	$ 300,000	$ 30,000
CHP Fuel Cost	$ -	$ -	$ -	$ -	$ 182,208	$ 3,138,358	$ 705,303	$ 99,974
Thermal Savings	$ -	$ -	$ -	$ -	$ -	$ 2,301,340	$ 201,515	$ 39,183
Annual Utility Bill with CHP/RE	$ 4,351	$ 49,975	$ 4,351	$ 49,975	$ 4,351	$ 636,033	$ 127,206	$ 17,115
Total Costs with CHP/RE	$ 5,351	$ 53,975	$ 7,351	$ 65,975	$ 301,559	$ 1,973,051	$ 930,994	$ 107,905
Base Utility Bill w/out CHP/RE	$ 32,663	$ 245,482	$ 32,663	$ 245,482	$ 32,663	$ 4,335,701	$ 867,140	$ 65,325
Annual Savings	$ 27,312	$ 191,507	$ 25,312	$ 179,507	$ (268,896)	$ 2,362,649	$ (63,853)	$ (42,580)
First Cost	$ 800,000	$ 4,800,000	$ 200,000	$ 800,000	$ 1,100,000	$ 20,000,000	$ 9,000,000	$ 700,000
Payback Years	**29.3**	**25.1**	**7.9**	**4.5**	**N/A**	**8.5**	**N/A**	**N/A**

4.5.3 Market Penetration of Selected Technologies

Scenario Definitions

Market penetration scenarios for SW CT were defined to represent a **Base Case**, or a "business-as-usual" scenario, and an **Accelerated Case**, or a business and regulatory environment more supportive of CHP. The Base Case scenario is based on current technology and current CL&P standby charges. The Accelerated Case is based on: gradual reduction in CHP technology cost between now and 2012; moderation of standby charges below their current level; implementation of an incentive program that reduces present value of capital costs (e.g., buy downs, tax credits, or accelerated depreciation); payment of a demand response capacity payment during the summer months; and a higher market response rate to reflect more developers in the marketplace and greater levels of customer awareness. The two scenarios are summarized in the table below (see Table 4-13).

Table 4-13
Base and Accelerated Case Scenarios for Market Penetration

Base Case	Accelerated Case
Cost of Technology Remains Constant	Cost of Technology Decreases by 2%/ Year
Current CL&P Rates for Standby Charges	50% Reduction in CL&P Standby Charges
No Capital Cost Incentive Program	10% Capital Cost Reduction
No Demand Response Capacity Payment	Summertime DR Capacity Payment of $186/kW
Standard Market Response	Accelerated Market Response

Using the above two cases, the analysis is driven by the following variables:

- Two technology cost and performance levels (current and advanced);
- Five application/ technology size ranges; and
- Ten-year time frame.

Note, market penetration for renewable technologies is discussed, but not quantified according to the above methodology.

Market Penetration Model

The market penetration model used in this study was developed based on the CHP market penetration model utilized in the aforementioned study of CHP market potential in New York State.[25]

CHP market penetration is dependent upon a multitude of factors, including current levels of market penetration, the economic value of CHP to the customer, a maximum achievable growth rate, and the size of the remaining potential market. Current market penetration levels represent a starting point. The depressed current levels of CHP development in SW CT reflect a lack of economic value for CHP to the potential customer. Therefore, as economic value increases, market penetration rates can also be expected to increase. However, because there are a limited number of experienced market development, construction, and financing entities currently operating, the rate of increase will be constrained to some maximum rate at which such development groups can expand their efforts to meet new market conditions. Similarly, as market development proceeds, there will be an ever-declining pool of potential customers that is available for development. Accounting for these hypotheses, the market penetration model incorporates the following features:

- Initial market rates are based on an assessment of current market levels.
- Maximum growth rates are defined to reflect the speed at which the market can ramp up if the economic value to the customer achieves an optimum level.

[25] "Combined Heat and Power Market Potential for New York State."

- Maximum growth rate is tempered by an economic acceptance factor (EAF) that equals 100 % for project paybacks of 2 years or less and declines linearly to zero for paybacks of 8 years or more.
- As the ratio of remaining market potential to initial market potential declines, so too does the maximum rate of growth.
- It is impossible to achieve 100% penetration of the technical market potential due to a variety of factors, including: site restrictions; customer risk preferences; customer diversity in economic value received; and any of a number of other factors that might inhibit the customer from implementing CHP. Such restrictions become more limiting as customer size decreases.
- Alternative market penetration rates may be defined on changes in economic value to the customers, e.g., through technology cost improvements, incentives, and changes in standby rates.

The model allows for rapid early growth rates from historical levels, which then decrease as a result of market saturation as technical potential is approached. Cumulative market penetration formulas are shown below:[26]

$$AM0 = TMP \text{ x } MMP$$
$$MP1 = AM_0 \text{ x } IMS \text{ x } EAF$$
$$MPn = AM_n \text{ x } (MaxGR \text{ x } EAF) \text{ x } \text{sqrt.}(AM_{n-1}/AM_0)$$

Where,

AM_0 = initial addressable market
$AM_n = AM_{n-1}$ x (1+AMG) – MP_{n-1}
TMP_0 = initial technical market potential (in MW)
MMP = maximum market penetration (%)
EAF = economic acceptance factor; increases linearly from 0 to 100% 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
AMG = addressable market growth[27]

[26] The formulas are developed from CHP market penetration equations utilized in the aforementioned study of CHP market potential in New York State that was completed for NYSERDA in October 2002. The model allows for rapid early growth rates from historical levels that are moderated by market saturation as technical potential is approached. The outcome in a robust economic market is a typical "S-shaped" market penetration curve.

[27] Based on the technical market potential, the addressable CHP market is assumed to grow at 1% annually. This is a considered to be a conservative estimate, as over the past 5 years, real GDP in Connecticut has expanded at an average annual rate of 4%.

As noted previously, the technical market potential (TMP) does not account for external factors that might limit CHP penetration, such as ability to retrofit, owner interest in CHP, capital availability, and natural gas availability. Certainly these factors are important in the actual economic implementation of CHP. TMP is therefore discounted by an assumption of maximum market penetration (MMP). Assumptions of MMP increase in the larger technology size ranges. The accelerated case is based on the assumption that MMP increases due to factors such as greater customer awareness, streamlined permitting and installation, and more aggressive marketing. The initial market share (IMS) represents initial market penetration of the addressable market (AM). The maximum growth rate (MaxGR) is the maximum rate at which the early market can increase. Given low current levels of market activity, MaxGR is relatively high, and is higher for the smaller sizes than for larger system development. The assumed model values for the above parameters are shown in the table below (see Table 4-14).

Table 4-14
Market Penetration Model Assumptions by Market Category

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

Market penetration rates are ultimately driven by the economic value of CHP projects to the customer for each year of the market forecast.

Market Penetration Results

Using the approach described above, CHP market penetration was estimated for each market size category. Anticipated customer paybacks serve as the basis for developing the various estimates of market penetration. Initial (year one) customer paybacks for CHP in each customer size category are shown below for the Base and Accelerated cases (see Table 4-15). Recall that the CHP technologies described in Table 4-6 and Table 4-7 serve as the basis for these payback estimates.

Table 4-15
Initial Payback Period in Years for Current and Advanced Technologies

Market Segment	Current Technology		Advanced Technology	
	Base Case	Accelerated Case	Base Case	Accelerated Case
100 to 500 kW	N/A	1168.5	N/A	N/A
500 kW to 1 MW	N/A	109.1	N/A	22.1
1 to 5 MW	12.1	5.3	8.3	4.1
5 to 20 MW	9.8	4.5	7.4	3.6
> 20 MW	5.2	2.7	5.6	2.7

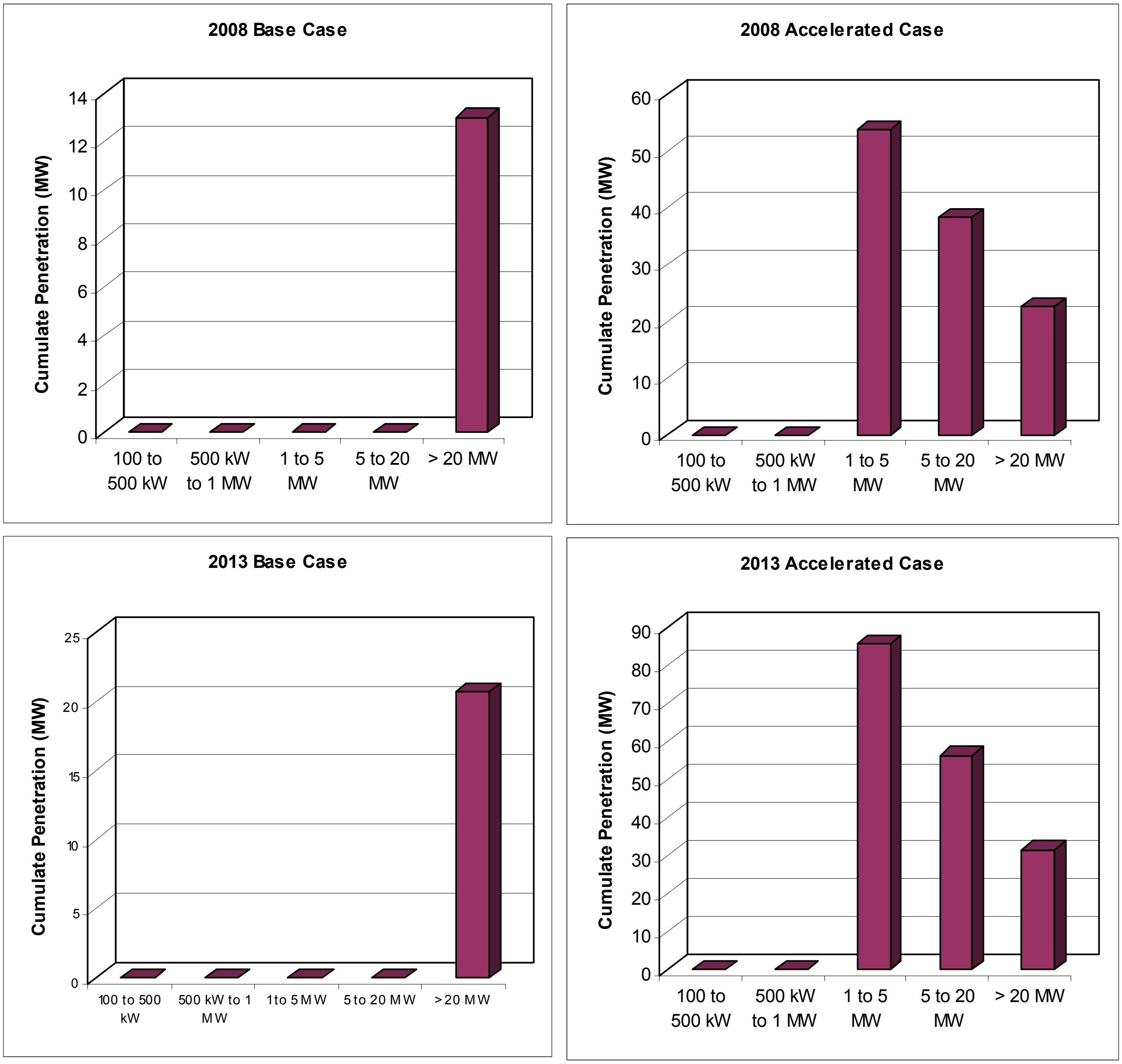
In the Base Case with current technologies, only the largest customer category has an initial customer payback period of less than eight years. Based on the assumptions of the model, a payback period of less than eight years is a prerequisite for market penetration. Under the Accelerated Case with current technology, only technologies in the two customer classes below 1 MW have a payback of eight years or greater. Under none of the cases is a payback of less than eight years expected for customers in the two customer classes below 1 MW. Using the payback periods shown above, market penetration estimates can be derived based on the Accelerated and Base Case scenarios. The results are summarized in Table 4-16 and shown graphically in Figure 4-7.

Table 4-16
Cumulative Market Penetration (MW) for Base and Accelerated Cases in 2008 and 2013[28]

Market Segment	Current Technology		Advanced Technology	
2008	**Base Case**	**Accelerated Case**	**Base Case**	**Accelerated Case**
100 to 500 kW	0	0	0	0
500 kW to 1 MW	0	0	0	0
1 to 5 MW	0	53.8	0	67.2
5 to 20 MW	0	38.3	5.8	43.7
> 20 MW	13.0	22.67	11.3	22.7
2008 Total	**13.0**	**114.8**	**17.1**	**133.6**
2013				
100 to 500 kW	0	0	0	0
500 kW to 1 MW	0	0	0	0
1 to 5 MW	0	85.8	0	95.3
5 to 20 MW	0	56.3	12.2	59.7
> 20 MW	20.7	31.5	19.0	31.6
2013 Total	**20.7**	**173.6**	**31.2**	**186.6**

[28] Notably, the model does allow for incremental market penetration based on the payback period and other factors independent of the representative technology size for that category. This is a reasonable assumption, given that larger customers have greater flexibility and can therefore more efficiently utilize smaller technologies thereby justifying a shorter payback period.

Figure 4-7
Cumulative Market Penetration for Base Case and Accelerated Case for Current Technologies in 2008 and 2013

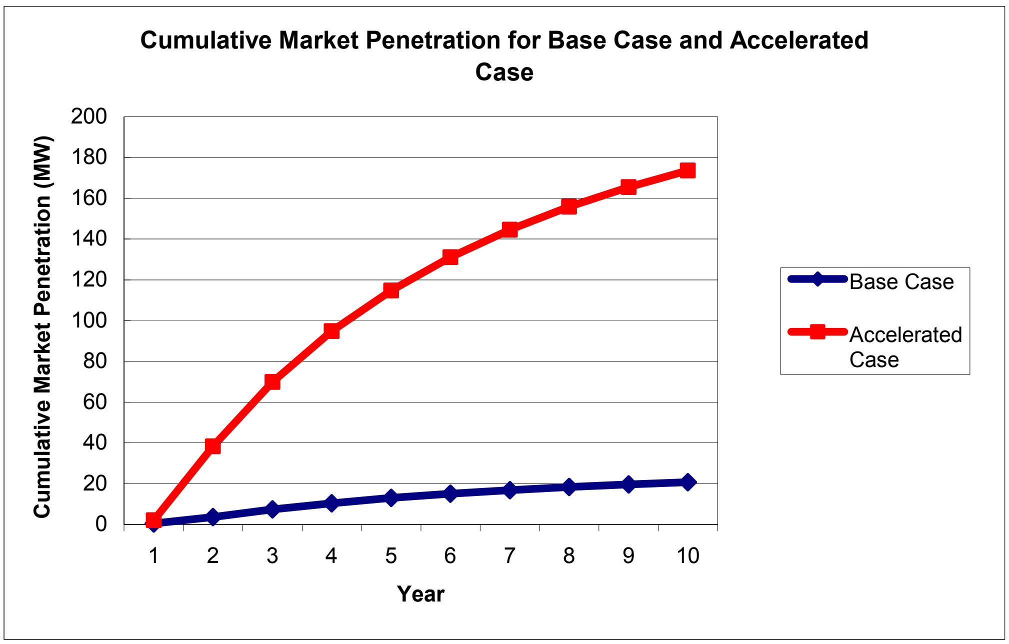


In the Base Case scenario, using current technology, 20.7 MW of new CHP capacity are estimated to be installed in SW CT through 2013. All of this capacity would be developed in the largest customer category. With advanced technologies, this number would increase to 31.2 MW.

In the Accelerated Case scenario, using current technology, 173.6 MW of new CHP capacity are estimated to be installed in SW CT through 2013. This capacity would be spread among the top three customer size categories. With advanced technologies, a total capacity of 186.6 MW is expected, also spread among the top three customer size categories.

Figure 4-8 depicts total cumulative CHP market penetration on a year by year basis for current technologies under the Base Case and Accelerated Case in SW CT. As can be expected, the Accelerated Case results in a more rapid and larger degree of CHP penetration than the Base Case.

Figure 4-8
CHP Cumulative Market Penetration
for SW CT for Base and Accelerated Cases



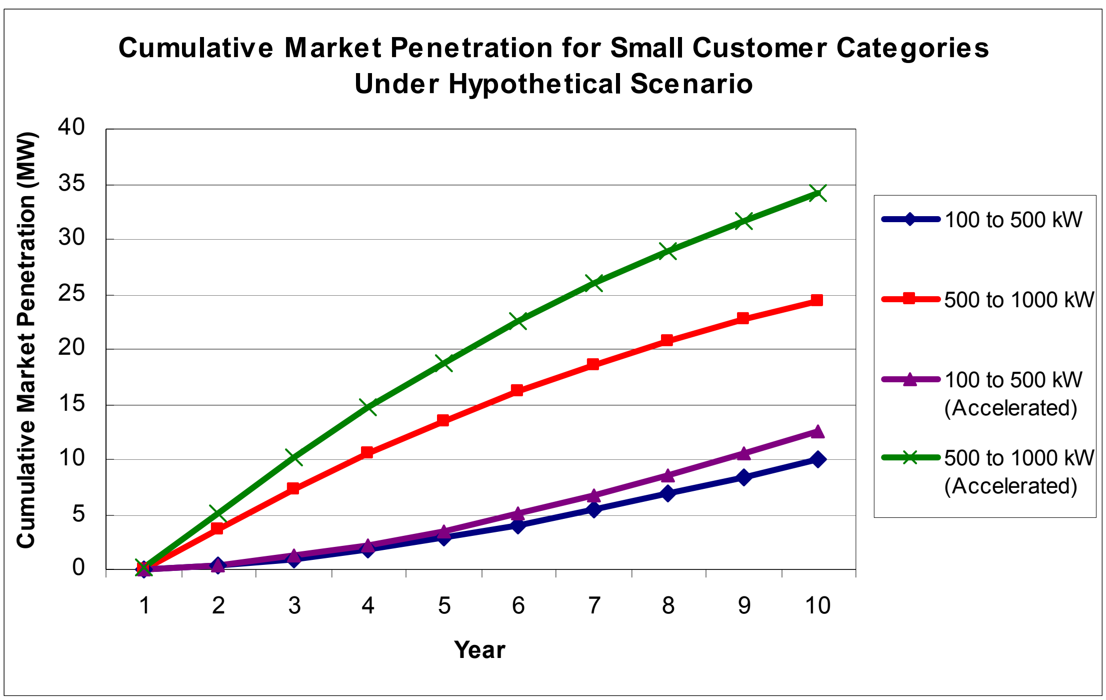
Hypothetical Small Customer Penetration

With regard to the two smallest customer size categories of CHP, the results indicate that no market penetration will occur in either the Base Case or the Accelerated Case. This result is due to the somewhat lower efficiencies, higher O&M costs, and higher capital costs of the representative technologies for these customer size categories. Utility back-up charges also contribute to make these technologies uneconomic in both scenarios. To provide greater insight into what it would take to achieve immediate market penetration in the two lowest customer size categories, a number of scenarios were executed. This analysis found the following minimum scenario was required to achieve market penetration in Years One and Two for current technologies:

- Cost of technology decreases by 2% annually
- Elimination of CL&P standby charges
- 75% capital cost buy-down (approximately $1040/kW for 100 kW gas engine and $730 for 800 kW gas engine)
- Summertime DR capacity payment of $186/kW (based on DPUC approved use of $186/kW as the capacity value for computing cost effectiveness of load response programs focusing on peak use reductions in summer 2002)

Under the above scenario, cumulative CHP market penetration of approximately 10 MW is expected through 2013 for customers in the 100 to 500 kW range. For customers in the 500 to 1000 kW range, cumulative CHP market penetration is expected to achieve 24.4 MW of capacity. Under an assumption of accelerated maximum market penetration (as described in Table 4-14), penetration rates under the scenario outlined above are expected to achieve 12.5 MW and 34.2 MW respectively for the 100 to 500 kW and 500 to 1000 kW customer size categories. Cumulative CHP market penetration on a year by year basis for these size categories under the hypothetical scenario above is shown below (see Figure 4-9).

Figure 4-9
Hypothetical Case: Total CHP Cumulative Market Penetration for SW CT for 100 to 500 kW and 500 to 1000 kW under Baseline and Accelerated Market Penetration



Although levelized cost estimates (Table 4-8) and customer payback periods (Table 4-12) were derived for renewable energy, due to reasons outlined in the discussion of technical potential of renewable energy in SW CT, renewable energy market penetration was not projected. With regard to solar PV, very high capital costs relative to alternatives currently constrain solar PV technology. Without aggressive capital cost reduction policies, combined with a robust competitive and regulatory market that provides added-value revenues for solar power in the form of green power premiums, RPS credits, and emissions credits, solar PV is not expected to make a significant contribution to new DG capacity in SW CT.

Wind energy is frequently cited as an attractive potential renewable energy source on the basis of its cost competitiveness relative to conventional electricity generation in large scale applications. However, due to a lack of economic wind resources in SW CT, little or no wind development is expected in SW CT without significant technology improvements.

Based on levelized cost estimates and associated payback periods, biomass energy in certain applications may be economic in SW CT. For example, both landfill gas and direct combustion (with fluidized bed technology) biomass facilities are expected to have estimated levelized cost of electricity in the \$.05 to \$.08/kWh range and a potentially acceptable payback period, depending on assumptions (e.g., feedstock availability, delivered feedstock cost, etc.). However, uncertainties associated with landfill gas availability, in the case of the former, and feedstock availability, in the case of the latter, prevent meaningful quantification of market potential in this analysis. Importantly, uncertainties and past challenges associated with siting biomass facilities in CT suggest biomass is unlikely to have an immediate impact in SW CT. Additionally, with regard to landfill gas, it is worth noting that among landfill gas-to-energy technology options, development of landfill gas using direct use strategies, rather than electricity generation strategies, is expected to increase dramatically in the future.[29] Developmental biomass technologies such as gasification and pyrolysis offer potential to provide efficient and lower emission electricity production from biomass in the future, however, these technologies are not presently available on a commercial basis.

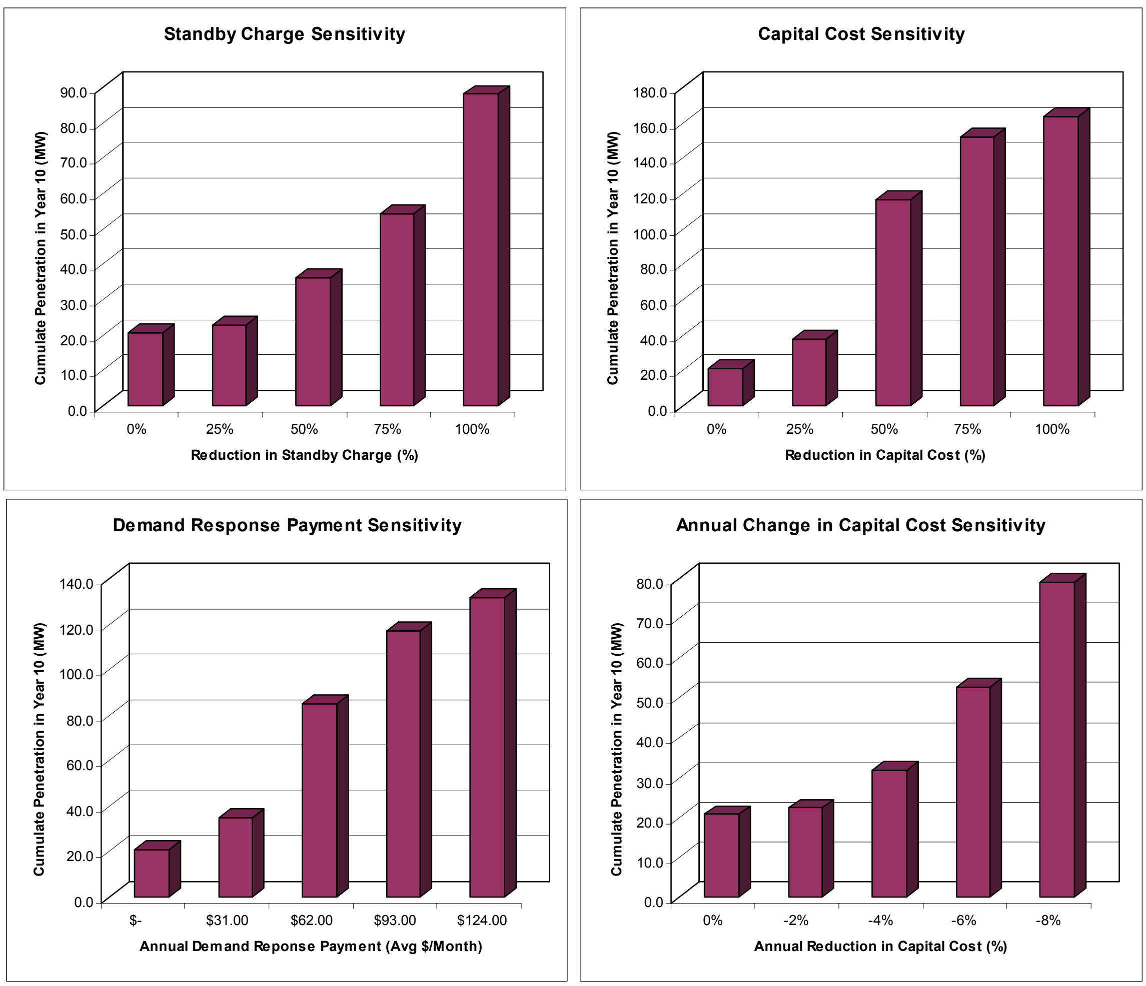
With regard to fuel cells, high costs relative to commercially available CHP alternatives, a lack of commercial maturity, and low present production capabilities suggest that fuel cells are not likely to significantly contribute to the CHP market in SW CT in the near future. However, as is the case with other renewables, aggressive capital cost reduction policies in the near term, combined with robust competitive and regulatory markets that provide revenue streams in the form of green power premiums, RPS credits, and emissions credits, will help to stimulate growth of fuel cell applications in the mid to long-term.

[29] "Landfill Gas-to-Energy Economics." Presentation by Tom Kerr, Climate Protection Division, US EPA, Landfill Methane Outreach Program.

Sensitivity Analysis

Sensitivity analyses were performed to evaluate the independent impact of variables on cumulative market penetration in SW CT in Year 10. Under the Base Case scenarios, sensitivities were performed on changes in standby charges, capital cost, demand response payment, and annual change in capital cost (i.e., capital cost reductions due to technology improvements). The results of sensitivity analysis are shown in the figure below.

Figure 4-10
Sensitivity Analysis of Key Variables



For each graph, the bar on the far left shows cumulative market penetration in Year 10 under the Base Case value for the variable under consideration. As that variable is increased (or decreased), the positive impact on cumulative market penetration in Year 10 can be observed.

With regard to standby charges, the figure indicates Year 10 cumulative market penetration of approximately 20 MW under the Base Case. A 50% reduction in standby charges increases market penetration in Year 10 to approximately 36 MW – an 80% increase. Removing standby charges completely results in 88 MW of CHP in Year 10 – more than a 400% increase over the Base Case.

The figure for capital cost sensitivity indicates the potential impact of capital cost reduction incentives on CHP in Year 10. Under the Base Case, cumulative market penetration of approximately 20 MW is observed. As expected, increasing capital cost reduction results in a higher degree of market penetration. The figure also indicates a pronounced market response to capital cost reductions in the range of 25 to 50%, with a significant but smaller response on a percentage basis for capital cost reductions in the range of 75 to 100%. This latter effect is the result of market saturation.

A demand response payment of $62/kW/month corresponds to the annual summertime demand response payment of $186/kW discussed above. The demand response figure suggests that these payments have a significant positive impact on CHP market penetration.

The figure on the bottom right shows the effect of annual changes in the price of CHP technology on market penetration. Again, a strong positive trend is observed.

5 Summary and Conclusions

A diverse array of commercially proven and emerging DG technologies could be utilized to help meet the energy needs of SW CT. Policy and market forces are driving the technological advancements that have improved and will continue to increase the efficiency and economic viability of DG. However, the analysis shows that while DG technologies have the technical potential to be an important component of any potential solution to the electricity problems presently faced by SW CT, the use of DG technologies will not eliminate the need to consider other strategies, such as conservation and load management (C& LM), increasing transmission capacity, and increasing centralized base load electricity supply. This conclusion is consistent with findings reported in Part I of the Working Group and Task Force's Comprehensive Assessment and Report.[1]

As reported in the analysis, DG has the potential to provide a key component of the energy solution in SW CT. The advantages of DG, including avoided T&D congestion and investment, efficient and potentially clean power production, and compatibility with load response, respond directly to many of SW CT's energy needs. Furthermore, the analysis reveals significant technical potential for DG in SW CT. When technical potential is limited by a few criteria, such as the need for coincident thermal and electric loads and moderate to higher operating hours per year, the technical potential for DG among commercial/ institutional and industrial customers is over 650 MW in SW CT.

Despite significant technical potential for DG in SW CT, Base Case analysis of market potential for DG using existing simple payback period as a key criterion reveals limited market penetration for both current and advanced technologies over the next ten years. This finding is entirely consistent with the limited penetration that DG has historically achieved to date in CT. An Accelerated Case, which assumes optimistic but possible capital cost reductions, incentives, and increased revenue (e.g., through demand response capacity credit), would encourage greater overall DG penetration and the use of DG by a broader range of customer sizes. The Accelerated Case shows that market penetration of up to 186 MW of installed DG could be achieved by 2013. One related finding is the lack of DG penetration among customers smaller than 1 MW. This is primarily due to higher capital, O&M, and fuel costs associated with these smaller applications, barriers that could potentially be addressed with public policy measures.

Differences between penetration achieved in the Base Case and Accelerated Case substantiate the need for further research and potentially, the formation of policy measures to address market barriers and create support mechanisms for DG. First, in recognition of the limitations of this analysis, areas of additional research that would help to clarify and quantify the benefits and

[1] Comprehensive Assessment and Report, Part I of the Working Group of Southwest Connecticut and the Task Force on Long Island Sound. Prepared by Levitan & Associates for the Institute for Sustainable Energy at Eastern Connecticut State University. January 1, 2003.

impacts of DG in SW CT, and ultimately form a quantitative case for or against the various options to support DG, are highlighted below. Secondly, consistent with the objective of further quantifying the benefits and impacts of DG in SW CT, and pursuing a suite of associated policy initiatives for supporting DG, a number of potential recommendations are outlined.

It is important to note that these recommendations are intended to complement and build upon the recommendations included in previous studies, such as the Center for Energy and Climate Solutions Study,[2] that identified a number of measures to address market barriers for clean energy.

Areas of additional research include the following:

- **Perform More Comprehensive Customer-Based Analysis and Site Audits** – The market penetration analysis is only intended to provide a generic analysis of the potential for DG in SW CT and is not based on specific SW CT customer class electricity data. Based on these initial findings, the next step should be to perform a more comprehensive customer-based analysis (of both existing and potential new customers) to better determine the technical and financial feasibility of DG (from a customer perspective) in SW CT. The research could also include customer cost savings analysis. The companion report "Volume III: An Assessment of Energy Opportunities for the City of Norwalk", will provide specific insights and recommendations for Norwalk and could serve as a basis for ongoing customer-based analysis.
- **Research Potential DG Customer Financial Decision Making Process** – It is important to highlight that payback period is just one way that businesses and institutions evaluate capital projects. Payback is typically used to evaluate capital investment options assuming similar costs of capital and limited sources of capital. Some businesses use more complex capital budgeting models and may be willing to look beyond the simple payback offered by DG if encouraged to do so by unique financing mechanisms and other incentives for DG, e.g. low interest loans, tax benefits, etc. A better understanding of the financial decision making process of potential DG users will help inform the development of meaningful policy incentives. This research could coincide with the comprehensive customer-based analysis discussed above. In addition, this work would dovetail with the "corporate strategies" to recognize the value of clean power that was recommended by the Center for Energy & Climate Solutions Study.
- **Quantify the Technical and Economic Impact of DG on the T&D System –** The technical potential of DG in this analysis did not specifically quantify technical issues associated with the interface of DG and the T&D system, such as the benefits or detriments of DG to the reliability of the T&D system. To better understand the benefits that DG may be able to provide for the T&D system, as well as any limitations or burdens

[2] Center for Energy & Climate Solutions. A Profile of the Electric System, Air Quality Issues, and the Economic Situation in Southwestern Connecticut. June 2002.
http://www.sso.org/otc/Publications/2002/SWCT%20Profile%20Final_0206.pdf

that DG may impose upon the system, it will be essential to study this issue. In addition, such a study should be specific to SW CT and serve to identify locations where DG can help avoid T&D investment.

This information will be vital to effectively siting and locating DG, as well as to potentially justifying regulations to support T&D avoided investment credits for DG projects, or alternatively, for supporting investment decisions for utility developed and owned DG projects. This work could complement the "clean energy siting map/ tool" recommended by the Center for Energy & Climate Solutions Study. Also, other research has already been performed in this area. For example, the Electric Power Research Institute (EPRI) has developed the Area Investment Strategy Model that can help utilities to compare DG versus T&D expansion options.[3] In addition, the previously mentioned Regulatory Assistance Project work outlines a research methodology for determining the impact of DG on the T&D system.

- **Determine Impact of DG on Natural Gas Delivery System** --- Another issue of concern is the extent to which significant DG penetration will impact the natural gas delivery system. While little public information exists on the impacts of DG on the local gas utility retail system, Levitan & Associates completed a study on the adequacy of New England's wholesale pipeline infrastructure to support natural gas-fired generation. Indicative of potential supply and system issues, the study found that up to 3,960 MW of capacity could be at risk for fuel supply during peak winter natural gas periods.[4] Accordingly, additional study is needed concerning the impact of DG market penetration on the wholesale and retail natural gas distribution systems.
- **Environmental Impact Assessment** --- While emerging technologies promise to provide cleaner DG in the long-term, in the near-term there may be potential emissions concerns associated with certain DG technologies and applications. Additional environmental impact research to determine the impact or benefit of various DG market penetration scenarios would help to highlight or address related concerns. Along these lines, the Northeast States for Coordinated Air Use Management (NESCAUM), with funding provided by the U.S. Environmental Protection Agency, intends to issue a final report in 2003 providing: 1) an inventory assessment to estimate DG units in the Northeast U.S., their emissions characteristics, and the extent to which these units have been permitted by state air agencies; and 2) an assessment of available control technologies using case studies of real-world applications.
- **Economic Development Research** –The economy of CT could potentially benefit from a growing local and world DG market, as well as from accelerated cost competitiveness of stationary fuel cells. This economic development potential merits further quantification.

[3] For more information visit: http://www.epri.com/corporate/products_services/project_opps/DR/1007018.pdf.

[4] Levitan & Associates, Inc. Public Domain Version of the Executive Summary. "Steady-State and Transient Analysis of New England's Interstate Pipeline Delivery Capability, 2001-2005." Prepared for ISO-NE. February 2002.

The recommended research above will help to highlight the advantages/ disadvantages of DG in SW CT, and in so doing will shed light on the potential to create meaningful support mechanisms for DG. However, even in the absence of this additional information, the inherent benefits of DG present a strong case for policy support measures. The market penetration analysis performed in this study demonstrates a need for these supports if meaningful DG market penetration is to be achieved. Expanding upon the discussion of the status of DG incentives and support mechanisms in Section 3, and drawing from the results of the market penetration analysis, recommendations for a variety of specific and general support mechanisms for DG are suggested below.

- **Develop and Institutionalize Funding Mechanisms** – Overall, a clear, targeted, and long-term buy-down and low interest loan strategy will be essential to the development of DG in SW CT. The CCEF is an obvious entity for the development and administration of these programs. However, recognizing that most economic DG technology would not qualify for funding from the CCEF, financial support from other economic development agencies in CT could also be explored.
- **Further Explore Tax Benefits –** There are several tax benefits that CT may wish to evaluate based on their potential to support DG growth. These include, but are not limited to, sales tax exemptions, accelerated depreciation schedules, and other tax deductions.
- **Continue to Support Standardized Interconnection –** CT should continue to pursue the development of simplified and standardized interconnection standards.
- **Develop Supportive Local Ordinances** – SW CT communities should examine and seek to change any local ordinances that might provide a barrier to the siting and permitting of clean DG. In addition, local communities should explore opportunities to proactively support DG and other energy conservation measures, such as DG plans and commitments, development of green building codes, etc.
- **Research Tariff Revisions –** CT could evaluate the need for standby charges and explore various policy options for reducing or eliminating these charges. As discussed below, one option is to modify the net metering charge to allow for larger generators (>100 kW) to qualify and to provide net metering with an exemption from stranded cost charges. Another is to offset standby charges by quantifying T&D avoided investment potential (see below).
- **Explore T&D Avoided Investment Credit** – Though complex, this concept could provide an important source of funding for DG projects. If T&D impact research suggests that constrained areas in SW CT could be relieved by siting DG in congested areas, DG would be shown to have added value to the T&D provider. DG work currently being performed by the Regulatory Assistance Project includes a guide for developing a Pilot Program for providing customers and vendors with a credit. Similarly, CT may wish to consider measures for encouraging utilities to invest and own DG as an alternative to T&D investments.

- **Load Response** - The DG penetration modeled in this analysis was of a base-load nature. However, these base load DG applications will still contribute to load response when customers can reduce load requirements and sell additional DG generation and related ancillary services into the grid. CT should continue to pursue efforts to improve the load response programs offered by ISO-NE (and CL&P and UI) and provide incentives for participation by base load DG units.
- **Refine Net Metering –** As mentioned earlier, net metering could be modified to be more inclusive of larger DG projects and to waive the need to pay stranded cost charges. For example, in order to help address energy problems, California net metering law includes generators up to 1 MW through the end of 2002.
- **Advocate for an Inclusive Renewable Portfolio Standard** – As the RPS legislation is revisited in the next legislative session, CT could ensure: 1) that the RPS applies to both suppliers and the standard offer; and 2) that it is inclusive of all DG by allowing behind the meter generation to create RPS credits. It is important to note that the NEPOOL Generation Information System (GIS) will provide the infrastructure required to allow for the inclusion of generation from behind the meter projects.
- **Develop Supportive Emissions Policy –** As these policy initiatives continue to evolve, CT could work to ensure that they are inclusive of DG and thus encourage the use of low-emission DG technologies. Similarly, CT could develop policy mechanisms that offer avoided emissions credits to DG owners that use combined heat and power.
- **Promote Public Education and Awareness –** In addition, initiatives to develop DG potential in SW CT should be complemented by campaigns to increase awareness about the need and benefits of DG and educate consumers and others about the process for developing and implementing DG projects.

A

ISO NEW ENGLAND LOAD RESPONSE PROGRAM

ISO New England Load Response Programs	
Program Sponsor	ISO New England
Program Name	Demand Response Program
Program Summary	The Demand Response Program (also known as Class 1) requires participants (load serving entities or aggregators must represent end-users) to commit to mandatory energy reductions on 30-minute notice from ISO-NE. Reductions must be a minimum of 100 kW and can be up to 5 MW. Customers in the Demand Response Program receive payment for just committing to the program through an Installed Capability (ICAP) credit and operating reserve payments. They are also paid for energy reductions during each curtailment event. The Class 1 program also included the issuance of an RFP to loads in Southwest Connecticut (a congestion area).
Program Objective	The purpose of the ISO-NE programs are to reduce energy and improve system reliability during peak periods by providing participant with two different options to reduce load in response to market signals.
Program Period	The program is scheduled to run from May 1, 2002 and will continue through May 31, 2003, noting that implementation of the FERC SMD may impact the end date or the nature of the program.
Participant Eligibility (Load/ Resource)	Any NEPOOL participant can subscribe either itself and/or an end-user to provide load reduction of not less than 100 kW (aggregation of load by the participant is allowed) and not more than 5 MW. Larger load reductions may be allowed at the discretion & approval by ISO-NE. Participants can sign up any eligible load located within the ISO-NE control area.
Pricing Basis (Fixed/ Market/ Mixed)	Market-based - Participants are paid to be available (under contract with ISO-NE) to reduce demand based on the Thirty-Minute Operating Reserve (TMOR) clearing price, and an Installed Capability (ICAP) credit that can be used to meet ICAP requirements or sold. For each event, participants are paid for load reductions based on the higher of the Energy Clearing Price (ECP) adjusted by a Congestion Cost Multiplier (CCM) or \$100/MWh, noting that the upward of the CCM is capped at the ECP plus \$100/MWh). The CCM is based on historic regional congestion costs for the previous 18 months. CCM's were developed for Boston, Southwest Connecticut, and a portion of Vermont (the CCM value ranges from 1.8 to 2.0). TMOR payments are based on the TMOR market price (though participants do not bid into this market). ICAP needs to be sold through a bilateral transaction or used to meet market requirements by the participant load serving entity. It is important to note that most Class 1 participants were selected through an RFP process that offered winning respondents a guaranteed short-term ICAP contract.
Price Signals	The Class 1 participants selected through the RFP process receive a fixed capacity payment. Other Class 1 participants are exposed to bilateral market prices for ICAP.

ISO New England Load Response Programs	
	All Class 1 participants are exposed to the market for TMOR. For load curtailment events, all Class 1 participants receive a minimum of $100/MWh of load curtailed. There have been no events during Summer 2002. But, in general, the forecasted ECP and TMOR may not reflect the actual price due to weather and system changes. The Class 1 participants that were selected through the RFP were paid $15 million for 85 MW for four months, or about $45,000/MW/month. In addition, the TMOR payment added another $160,000 for the 85 MW during one month.
Baseline Criteria	The baseline is the average hourly load, rounded to the nearest kWh, for each of the 24 hours in a day. The baseline is based on the 10 previous eligible weekdays (weekdays that are non-holidays and non-interruption days). The baseline is adjusted (down or up) to reflect actual usage for the two hours preceding the interruption. For example, if a participant's baseline load is 330 kWh for 10 AM, the time at which an interruption is due to start, but the participant's actual usage from 8 AM to 10 AM is 20 kWh below the baseline, the baseline will be adjusted down to reflect the actual load. Load curtailments that occur during the 10 day period are not included in the establishment of the baseline. For on-site generation, the generator output as metered will be used to establish the baseline.
Curtailment Trigger	Load response events are triggered when system conditions indicate that 10-minute operating reserve is deficient with calculated Voltage Reduction amounts considered as 10-minute reserve or, when a contingency loss occurs and the ISO-NE Operations Shift Supervisor has determined that required 10-minute reserve will not be restored in 30 minutes. This did not occur during the Summer of 2002.
Curtailment Event Notification/ Response Period	Participants and end-users must be willing and capable of interrupting load within 30 minutes of receiving the instruction from ISO-NE through the RETX System. Interruptions would occur, Monday-Friday, on non-holidays between 7:00 AM – 6:00 PM. Interruptions will normally not exceed two hours, but an interruption may be longer.
Compliance Verification	Performance is measured as the difference between the baseline (adjusted) and the actual metered usage (or output) by hour during the event.
Penalties for Non-Compliance	A participant that does not reduce demand during a load response event will lose its TMOR payment and capacity rating. In addition, on a moving forward basis, the participant will no longer receive TMOR payments or a capacity rating until the participant can demonstrate full compliance (e.g. at the next event). A participant that is able to partly reduce demand during a load response event, but is unable to reduce the full amount of its agreed-upon exception with the ISO-NE, will be paid a reduced TMOR amount and will receive a reduced capacity rating, until it can demonstrate otherwise.
Settlement	Payments are made to participants on a monthly basis about 45 days after each event. Payments are based on energy reduction, TMOR, and ICAP (ICAP payment are only given to the 85 MW selected through the RFP). Other Class 1 participants must secure ICAP value on their own.
Communication	Participants communicate with the ISO-NE with web-based software supplied by

ISO New England Load Response Programs	
System	RETX. Most large customers, 300 kW and larger, in New England have interval meters (in some states, it is all customers 100 kW and larger). For Class 1 participation, these need to be integrated with the web-based communications software in real-time. The website in conjunction with email and phone notification is used to notify participants about events.
Metering Requirements	Interval metering that can be read in real-time is required.
Program Marketing Procedures/ Channels	Participants are typically not end-users, but energy suppliers. Therefore, energy suppliers are used to help market and aggregate end-users for the program. ISO-NE also holds general forums for potential participants and training for participants and end-users. The most effective tool for marketing the Summer 2002 program was the issuance of an RFP for Class 1 participants that are located in Southwest Connecticut.
Program Performance (number of participants, etc.)	The long-term goal is to have 600 MW of participation, and 200 MW in 2002 was significantly higher than 30 MW (7 MW in Class 1 and 22 MW in Class 2) in 2001. Class 1 participants represent 107 MW of load. 85 MW are in Southwest Connecticut, most of which were selected through the RFP. There is about a 50/50 spilt between load reduction and onsite generation capability. In addition, because of the CCM almost all participant represented load is located in congestion areas. There were no Class 1 events during the Summer of 2002.
Customer Satisfaction	In general, customers are pleased with their capacity and TMOR payments. This is especially true for the Southwest Connecticut RFP participants that received about $45,000/MW/month. Other key changes that increased participation where: 1) the addition of the CCM, and 2) reduction of the Class 1 commitments (from until 11 pm to until 6 pm).
Program Operating Costs	100% of hardware and software costs for the first 1000 Class 1 participants are being paid for by ISO-NE (if the customer is 300 kW or larger). The costs are between $1000 and $1800 per site along with an $100 per month license fee. ISO-NE invests the equivalent of about 3 FTE in the program. Costs incurred by ISO-NE are socialized among the market's load serving entities.
Outlook	ISO-NE is in the process of refining its demand response programs in order to prepare for compliance with FERC standard market design (SMD). Future programs will provide customers with the ability to bid a price at which they would curtail load as opposed to response to prices. This will allow for greater integration of the demand response program into the wholesale market design.
Contact Information	Robert Burke 413 535-4356 / rburke@iso-ne.com

ISO New England Load Response Programs	
Program Sponsor	ISO New England
Program Name	Price Response Program
Program Summary	The Price Response Program (also known as Class 2) allows end-users to voluntarily reduce energy consumption during certain periods as determined by ISO-NE. Participants of the Price Response Program only receive payments for the actual energy they curtail. The voluntary energy reduction must be between 100 kW and ~5 MW unless otherwise approved by the ISO-NE.
Program Objective	The purpose of the ISO-NE programs are to reduce energy and improve system reliability during peak periods by providing participant with two different options to reduce load in response to market signals.
Program Period	The program is scheduled to run from May 1, 2002 and will continue through May 31, 2003, noting that implementation of the FERC SMD may impact the end date or the nature of the program.
Participant Eligibility (Load/ Resource)	Any NEPOOL participant can subscribe either itself and/or an end-user to provide load reduction of not less than 100 kW (aggregation of load by the participant is allowed) and not more than 5 MW. Larger load reductions may be allowed at the discretion & approval by ISO-NE. Participants can sign up any eligible load located within the ISO-NE control area.
Pricing Basis (Fixed/ Market/ Mixed)	Participants are paid the hourly ECP adjusted by the CCM for the duration of the interruption (The upward impact of the CCM is capped at the ECP plus $100/MW). The CCM is based on historic regional congestion costs for 18 months. CCM's were developed for Boston, Southwest Connecticut, and a portion of Vermont (the CCM value ranged from 1.8 to 2.0).
Price Signals	In general, the forecasted ECP may not reflect the actual ECP due to weather and system changes.
Baseline Criteria	The baseline is the average hourly load, rounded to the nearest kWh, for each of the 24 hours in a day. The baseline is based on the 10 previous eligible weekdays (weekdays that are non-holidays and non-interruption days). The baseline is adjusted (down or up) to reflect actual usage for the two hours preceding the interruption. For example, if a participant's baseline load is 330 kWh for 10 AM, the time at which an interruption is due to start, but the participant's actual usage from 8 AM to 10 AM is 20 kWh below the baseline, the baseline will be adjusted down to reflect the actual load. Load curtailments that occur during the 10 day period are not included in the establishment of the baseline. For on-site generation, the generator output as metered will be used to establish the baseline.
Curtailment Trigger	Load curtailment requests are sent to participants when the forecasted ECP is $100/MWh or greater.
Curtailment Event Notification/ Response Period	Participants and end-users are provided with the day ahead ECP forecasts as early as 6 PM the previous day. Updates of the forecasted ECP are provided on an ongoing basis. Once notified, the window of availability for Class 2 Load Response can be as early as 7 AM and remain open until 11 PM (i.e., between the hour ending 0800 through the hour ending 2300). Requested load reduction events can occur, Monday-Friday, on non-

ISO New England Load Response Programs	
	holidays between 7:00 AM – 6:00 PM. Interruptions will normally not exceed two hours, but an interruption may be longer.
Compliance Verification	Performance is measured as the difference between the baseline (adjusted) and the actual metered usage (or output) by hour during the event.
Penalties for Non-Compliance	Participants that fail to respond when ISO-NE announces a curtailment event are not subject to any penalties.
Settlement	Payments are made to participants on a monthly basis about 45 days after each event. Payments are based on energy reduction only.
Communication System	Participants can communicate with the ISO-NE via the web-based software supplied by RETX or via a low-tech email/ web site communication option. For Class 2 participants, metering information for each event must be provided to ISO-NE within 36 hours.
Metering Requirements	Interval, but not real-time metering is required.
Program Marketing Procedures/ Channels	Participants are typically not end-users, but energy suppliers. Therefore, energy suppliers are used to help market and aggregate end-users for the program. ISO-NE also holds general forums for potential participants and training for participants and end-users. The most effective tool for marketing the Summer 2002 program was the issuance of an RFP for Class 1 participants that are located in Southwest Connecticut – it also got potential participants interested in the Class 2 program.
Program Performance (number of participants, etc.)	The long-term goal is to have 600 MW of participation, and 200 MW in 2002 was significantly higher than 30 MW (7 MW in Class 1 and 22 MW in Class 2) in 2001. Participants represent about 95 MW of load. There is about a 50/50 spilt between load reduction and onsite generation capability. There were about 10 Class 2 events during Summer 2002. Payments are still being calculated but averaged over $200/MWh in 2001. In addition, because of the CCM almost all participants represented load is located in congestion areas.
Customer Satisfaction	In general, customers are pleased with prompt payment and the addition of the CCM.
Program Operating Costs	50% of hardware costs for the first 1000 Class 1 participants are being paid for by ISO-NE (if customers are 100 kW or larger), and charged back to participants based on participation in load response. The costs are between $1000 and $1800 per site along with a $100 per month license fee. The participant is charged the remaining 50%. ISO-NE invests the equivalent of about 3 FTE in the program. Costs incurred by ISO-NE are socialized among the markets load serving entities.
Outlook	ISO-NE is in the process of refining its demand response programs in order to prepare for compliance with FERC standard market design (SMD). Future programs will provide customers with the ability to bid a price at which they would curtail load as opposed to response to prices. This will allow for greater integration of the demand response program into the wholesale market design.
Contact Information	Robert Burke 413 535-4356 / rburke@iso-ne.com

B

Listing of Generation Facilities (For Sale to Grid) in Southwest Connecticut

Southwest Connecticut Generation (For Sale to Grid)					
RENEW	Facility	Town	Fuel	Summer Rating (MW)	Winter Rating (MW)
X	Bridgeport RRF	Bridgeport	Refuse	59.50	59.65
X	Bulls Bridge #1- #6	New Milford	Hydro	8.40	8.40
X	Derby Dam	Shelton	Hydro	7.05	7.05
X	Kinneytown A	Ansonia	Hydro	0.25	0.25
X	Kinneytown B	Seymour	Hydro	0.65	0.65
X	McCallum Enterprises	Derby	Hydro	0.28	0.28
X	New Milford Landfill	New Milford	Methane/Oil	3.01	3.01
X	Rocky Glen	Newtown	Hydro	0.04	0.04
X	Shelton Landfill	Shelton	Methane	0.00	0.62
X	Shepaug #1	Southbury	Hydro	41.71	43.40
X	Stevenson #1- #4	Monroe	Hydro	28.31	28.90
X	Wallingford RRF	Wallingford	Refuse/Oil	6.35	6.90
	Branford #10	Branford	Oil	14.90	18.80
	Bridgeport Energy	Bridgeport	Gas	447.88	527.12
	Bridgeport Harbor #2	Bridgeport	Oil	50.98	166.15
	Bridgeport Harbor #3	Bridgeport	Coal	370.39	400.00
	Bridgeport Harbor #4	Bridgeport	Oil	12.38	16.88
	Cos Cob #10	Greenwich	Oil	15.52	20.97
	Cos Cob #11	Greenwich	Oil	15.52	20.87
	Cos Cob #12	Greenwich	Oil	16.12	22.57
	Devon #10	Milford	Oil	17.20	19.20
	Devon #11	Milford	Gas/Oil	30.85	40.37
	Devon #12	Milford	Gas/Oil	30.86	40.07
	Devon #13	Milford	Gas/Oil	31.00	40.00
	Devon #14	Milford	Gas/Oil	30.80	41.37
	Devon #7	Milford	Oil/Gas	107.00	109.00
	Devon #8	Milford	Oil/Gas	106.84	109.00
	New Haven Harbor #1	New Haven	Oil/Gas	449.56	466.00
	Norwalk Harbor #1	Norwalk	Oil	162.00	164.00

	Norwalk Harbor #2	Norwalk	Oil	168.00	172.00
	Norwalk Harbor 10	Norwalk	Oil	11.53	16.73
	Rocky River	New Milford	Pump storage	29.35	30.40
	Wallingford	Wallingford	Gas	250.00	250.00

C

LISTING OF ONSITE GENERATION FACILITIES IN SOUTHWEST CONNECTICUT

Southwest Connecticut Onsite Generation (Behind the Meter)					
RENEW	**Facility**	**Town**	**Fuel**	**Summer Rating (MW)**	**Winter Rating (MW)**
X	Fairfield University	Fairfield	Solar	0.01	0.01
X	Gianninoto Wind Turbine	Redding	Wind	0.02	0.02
X	John Roundtree	Norwalk	Solar	0.02	0.02
X	S CT Reg. Water Auth.	North Branford	Hydro	0.30	0.30
	Agnes Morely Apts	Greenwich	Gas	0.03	0.03
	Fairfield YMCA	Fairfield	Gas	0.03	0.03
	Notre Dame Convalescent	Norwalk	Propane	0.03	0.03
	Sycamore Place	Bridgeport	Gas	0.04	0.037
	Maefair Health Care	Trumbull	Gas	0.04	0.04
	Nova Metal Finishing	Waterbury	Gas	0.04	0.04
	Atrium Plaza	New Haven	Gas	0.06	0.06
	Bridgeport J City Ctr	Bridgeport	Gas	0.06	0.06
	Bridgeport YMCA	Bridgeport	Gas	0.06	0.06
	Davenport Residence	Hamden	Gas	0.06	0.06
	Dunbar Residence	Hamden	Gas	0.06	0.06
	Greenwich YMCA	Greenwich	Gas	0.06	0.06
	Laurelwood	Bridgeport	Gas	0.06	0.06
	Longobardi	North Haven	Gas	0.06	0.06
	New Haven JCC	Woodbridge	Gas	0.06	0.06
	Washington Heights	Bridgeport	Gas	0.06	0.06
	Westport YMCA	Westport	Gas	0.06	0.06
	First Baptist Housing	Bridgeport	Gas	0.08	0.08
	Candid Associates 1&2	North Haven	Gas	0.12	0.12
	Sheraton	Waterbury	Gas	0.15	0.15
	CT Job Corp	Hamden	Gas	0.15	0.15
	Apple Hill	Hamden	Gas	0.15	0.15
	Candid Associates 3	North Haven	Gas	0.18	0.18
	Norconn	Meriden	Gas	0.20	0.20
	Inter Church	Bridgeport	Gas	0.24	0.24
	Southern CT Gas Co.	Milford	Gas	0.27	0.27
	Pitney Bowes	Stamford	Gas	0.75	0.75
	Southbury Training School	Southbury	Oil/Gas	1.50	1.50

	Norwalk Hospital	Norwalk	Gas	2.36	2.36
	Simkins	New Haven	Gas/Oil	2.50	2.50
	Fairfield Hills Hospital	Newtown	Oil	3.95	3.95
	Yale Univ diesels	New Haven	Diesel	4.50	4.50
	Yale Univ Unit 1	New Haven	Gas/Oil	6.20	6.20
	Yale Univ Unit 2	New Haven	Gas/Oil	6.20	6.20
	Yale Univ Unit 3	New Haven	Gas/Oil	6.20	6.20

D

Explanation of Utility Rates Utilized in Technology Payback Analysis

Electricity rates were used in the calculation of payback periods for each customer size category. Connecticut Light & Power tariffs were consulted to enable two different calculations: 1) base utility bill without CHP; and 2) annual utility bill with CHP. The latter calculation refers to additional costs in the form of back-up charges that DG hosts are required to pay under current rate structures. Discussed here are the sources of rate information and assumptions used to calculate electricity rates and back-up charges for each of the five categories of customers.

Sources of Rate Data

The following CL&P tariffs were utilized for calculating the base utility bill without CHP:

- **Rate 35 Intermediate General Electric Service** - General Service for Customers with Annual Maximum Demands less than 350 kW.

- **Rate 55 Intermediate Time-Of-Day Electric Service Manufacturers** - Mandatory for Customers with Annual Maximum Demands greater than or equal to 350 kW but less than 1000 kW, unless the Customer opts for an Interruptible Rate. Sales Tax Exempt Industrial Customers only.

- **Rate 56 Intermediate Time-Of-Day Electric Service Non-Manufacturers** - Mandatory for Customers with Annual Maximum Demands greater than or equal to 350 kW but less than 1000 kW, unless the Customer opts for an Interruptible Rate. Non-Sales Tax Exempt C&I Customers and large governmental, educational, and religious institutions.

- **Rate 57 Large Time-Of-Day Electric Service Manufacturers** - Mandatory for Customers with Annual Maximum Demands greater than or equal to 1000 kW, unless the Customer opts for an Interruptible Rate. Sales Tax Exempt Industrial Customers only.

- **Rate 58 Large Time-Of-Day Electric Service Non-Manufacturers** - Mandatory for Customers with Annual Maximum Demands greater than or equal to 1000 kW, unless the Customer opts for an Interruptible Rate. Non-Sales Tax Exempt C&I Customers and large governmental, educational, and religious institutions.

In addition to the above tariffs, many customers that use onsite generation instead of grid power must pay a back-up charge to CL&P. Some smaller projects are exempt from back-up charges.

Levelized back-up charges ($/kWh) and exemptions (base utility bill with CHP) were derived from the following rates and riders:

- **Rate 984 Supplemental Power Service** - Customers that self-generate but need additional energy regularly to operate.

- **Rate 985 Back-Up and Maintenance Power Service** - Customers that self-generate with a need for service during periods when the Customer's generation is unavailable.

- **Rider N Self-Generator Net Energy Billing Service** - Customers with small generating capacity - up to 50 kW (if nonrenewable fuel) or up to 100 kW (if renewable fuel) - can net their generation from their usage. Available to any Qualifying Facility whose installed generating capacity is less than 50 kilowatts, or if fueled by a renewable resource, is less than 100 kilowatts. Customers electing service under this rider shall be metered by a single meter which may be allowed to run backwards. For load research purposes and in the event meters cannot register reverse flow, the customer shall provide a suitable meter socket to permit the Company, at its option and expense, to measure kilowatt-hours sold to the Company. In the event of dual metering, kilowatt-hours sold to the Company shall be deducted from purchases prior to billing.

Methodology and Findings

The methodology used to estimate electricity rates and findings for each of the five categories is summarized below:

- **100 kW – 500 kW** – The cost of electricity was estimated using Rate 35 for customers with a demand of less than 350 kW. The estimated levelized cost is $.00932 per kWh.

- **500 kW – 1 MW** – The cost of electricity was estimated using the average of Rate 55 and Rate 56, the rate classes for medium manufacturers and non-manufacturers. The estimated levelized cost is $.00876 per kWh.

- **1 MW – 5 MW** – The cost of electricity was estimated using the average of Rate 57 and Rate 58, the rate classes for large manufacturers and non-manufacturers. The estimated levelized cost is $.00761 per kWh.

- **5 MW – 20 MW** – Same as the previous category, the cost of electricity was estimated using the average of Rate 57 and Rate 58, the rate classes for large manufacturers and non-manufacturers. The estimated levelized cost is $.00761per kWh.

- **> 20 MW** -- The cost of electricity was also estimated using the average of Rate 57 and Rate 58, the rate classes for large manufacturers and non-manufacturers. However, the levelized cost was found to be lower due to an improved load profile that was assumed in the model. The estimated levelized cost is $.00710 per kWh.

Back-up charges were estimated using Rate 985 Back-Up and Maintenance Power Service. Back up charges for the two small renewable cases (100 kW and less) were estimated using Rider N Self-Generator Net Energy Billing Service.

Rider N customers are exempt from most back-up charges, but are required to pay a monthly service fee if generation exceeds consumption on a given month. As Rider N was applied to small renewable generation of an intermittent nature, it was assumed that generation would not exceed consumption in any given month. Net metered customers are charged, however, for the competitive transition assessment and the systems benefits charge based on the amount of energy consumed by the customer from the facilities of the electric distribution company without netting any electricity produced by the customer.

In general, Rate 985 requires customers with onsite generation to continue to pay the monthly service charge and distribution and transmission demand charges for the amount of the contracted back-up demand, even if no back-up electricity is required. Usage charges, similar to those on the relevant rate would apply if a customer uses contracted back-up power. Based on this assumption, back-up charges for each KWh of onsite generation were estimated as follows:

- **100 kW – 500 kW** – The estimated levelized cost is $.02442 per kWh.
- **500 kW – 1 MW** – The estimated levelized cost is $.01783 per kWh.
- **1 MW – 5 MW** – The estimated levelized cost is $.01117 per kWh.
- **5 MW – 20 MW** – The estimated levelized cost is $.$.01117 per kWh.
- ➢ **20 MW** -- The estimated levelized cost is $.$.01117 per kWh.

In order to perform monthly bill analysis, it was also necessary to develop prototypical customer load factors for each category of customer. Applicable tariffs and load factors for each of the five customer categories are shown in the table below (see Table D-1).

Table D-1
Prototypical Customer Characteristics for Rate Analysis

Customer Size Range (MW)	Application Size (MW)	Applicable Tariffs	Load Factor (%)
0.1 - 0.5	100	Rate 35	40%
0.5 - 1.0	800	Rate 55/ Rate 56	40%
1.0 - 5.0	5000	Rate 57/ Rate 58	65%
5.0 - 20.0	10000	Rate 57/ Rate 58	65%
> 20.0	50000	Rate 57/ Rate 58	80%

The model used to develop base and back-up utility bills for general service customers under Rate 35 is shown below (see Figure 1).

Figure 1
Example Rate Determination Model for CL&P Rate 35

Rate 35 Intermediate General Electric Service -General Service for Customers with Annual Maximum Demands less than 350 kW.

Monthly Bill Analysis

Peak Demand	100	kW	
Load Factor	40%		
Peak Coincidence	75%	66% = Level Load	
Total Usage	29,200	kWh	
Peak Usage	21,900	kWh	
Off-Peak Usage	7,300	kWh	
Levelized Cost	$ 0.093	Per kWh	
Service Charge	$ 241.11	Fixed	$ 241.11
Distribution	$ 3.72	Per kW	$ 372
	$ 0.00533	Per First 400 kWh Per kW	$ 156
Transmission	$ 1.18	Per kW	$ 118
SBC	$ 0.00092	Per kWh	$ 27
CTC	$ 2.82	Per kW	$ 282
	$ 0.00184	Per First 400 kWh Per kW	$ 54
Conservation	$ 0.003	Per kWh	$ 88
Renewable	$ 0.00075	Per kWh	$ 22
Generation	$ 0.04668	Per First 400 kWh Per kW	$ 1,363
	$ 0.04369	Other kWh	$ -
Total Monthly Bill			**$ 2,722**

Monthly Bill Analysis - Onsite Generation with Best Case Back-Up Power Contract

Service Charge	$ 241.11	Fixed	$ 241.11
Distribution	$ 3.72	Per kW	$ 372
Transmission	$ 1.00	Per kW	$ 100
Back-up Monthly Bill			**$ 713**
Back-up Levelized Cost			**$ 0.0244**