Connecticut Siting Council Review of the Ten-Year Forecast of Connecticut Electric Loads and Resources

Draft Report

May 26, 2006

INTRODUCTION

Pursuant to Connecticut General Statutes (CGS) § 16-50r[1], the Connecticut Siting Council (Council) annually reviews the forecasts of electric loads and resources in the State of Connecticut.

By March 1, each year, all Connecticut electric transmission/distribution companies and electric generators with an output of greater than one megawatt are required to provide detailed figures to the Council, either estimated or actual, on energy use and peak loads for the five preceding years and peak loads, resources, and margins for the ten upcoming years. Any current plans to build new generating plants or transmission/distribution lines, put new ones into service, upgrade existing ones (including plant to bury lines, as mandated by law), must also be stated. In addition, the Council examines the forecast from the Independent System Operator for New England (ISO-NE).

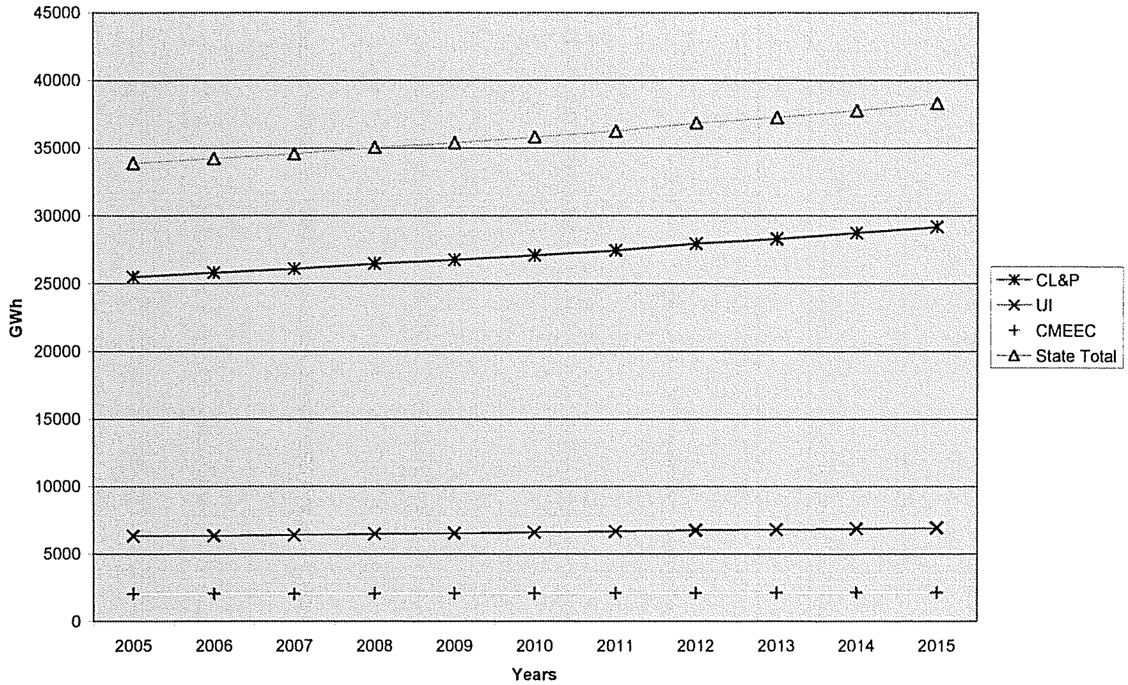
After gathering this information, the Council invites discussion at a public hearing, and, utilizing all those inputs, issues a final report.

ELECTRIC ENERGY CONSUMPTION AND LOAD FORECAST

ENERGY CONSUMPTION GROWTH

The state's electric transmission/distribution utilities, The Connecticut Light and Power Company (CL&P), The United Illuminating Company (UI), and the Connecticut Municipal Electric Energy Cooperative (CMEEC) predict the total annual electric energy requirements for the state throughout the forecast period to grow from 34,237 GWh[2] in 2006 to 38,313 GWh during 2015. This results in a statewide average annual compound growth rate of 1.26 percent. CL&P projects an average annual compound growth rate of 1.37 percent throughout the forecast period. CMEEC projects a 0.58 percent average annual compound growth rate, and UI projects a 1.00 percent average annual compound growth rate. The forecast of the state's electrical energy requirements is depicted in Figure 1.

Figure 1: Connecticut Electric Utilities' Projected Energy Requirements



Forecasting is used to decrease the risk of a mismatch between supply and demand. The demand for electricity can be affected by weather, economic conditions, customers' usage patterns, and improvements in efficiency, including conservation. The supply of electricity can be affected by private entities' interest in constructing new generation, the operating condition of older generating plants, shutdown of generating plants for scheduled maintenance or repairs, and limitations in the transmission system.

There are inherent risks in both under and over-forecasting electric demand. Under-forecasting demand for electricity could result in insufficient generation, transmission, and distribution facilities, which could result in blackouts, brownouts, and other service problems. Alternatively, over-forecasting could result in excessive generation, over-designed transmission, and the like, which could lead to economic penalties. Nonetheless, future electric supply and demand is difficult to predict.

Historically, Connecticut's increasing electricity consumption over the long term is largely attributable to the number of new and larger homes, an active economy, the growing use of electric appliances or office machines, computers, and especially air conditioning.

GROWTH IN PEAK LOADS

Connecticut is a summer peak load[3] state. That is, the state's highest electrical load for the year typically occurs on a summer day. This is largely attributable to air conditioning. Air conditioning is often one of the largest electric loads in homes and buildings.

Furthermore, in CL&P's 2006 Forecast Report, CL&P notes an interesting phenomenon. Although customers are conserving electricity most of the year in reaction to higher energy prices, resulting in lower energy growth, they appear to be less concerned about high prices during the summer heat waves when they increase their use of air conditioning, resulting in higher growth in peak demand.

Specifically, Figure 2 depicts the actual and projected peak electric loads for Connecticut from year 2001 through 2015[4]. In 2005, the peak electric load for the state was approximately 7,135 MW[5], which is a 4.1 percent increase from the previous high in 2002 of 6,851 MW and a 12 percent increase from the year 2004 peak load of 6,364 MW. ("Non-coincident" means that the peaks for the three utilities may not necessarily occur on the same day of the year, but nevertheless are combined in Figure 2 and the results would not be materially different.)

Connecticut's electric utilities estimate that the total peak load, under normal weather conditions, will be 6,855 MW in 2006. Looking ahead, this number is expected to grow to 7,654 MW in 2015. This results in an average annual compound growth rate of 1.2 percent for the state. This data takes into account conservation and load management programs by the utilities and is depicted on Figure 2 as "CT Utilities' Peak w/conservation."

The majority of Connecticut's peak load is due to CL&P customers, since CL&P has the largest service area of the three utilities. The CL&P peak load data in Figure 2 are based on a 50/50 scenario, which means that the peak load has a 50% chance of being exceeded in a given year.

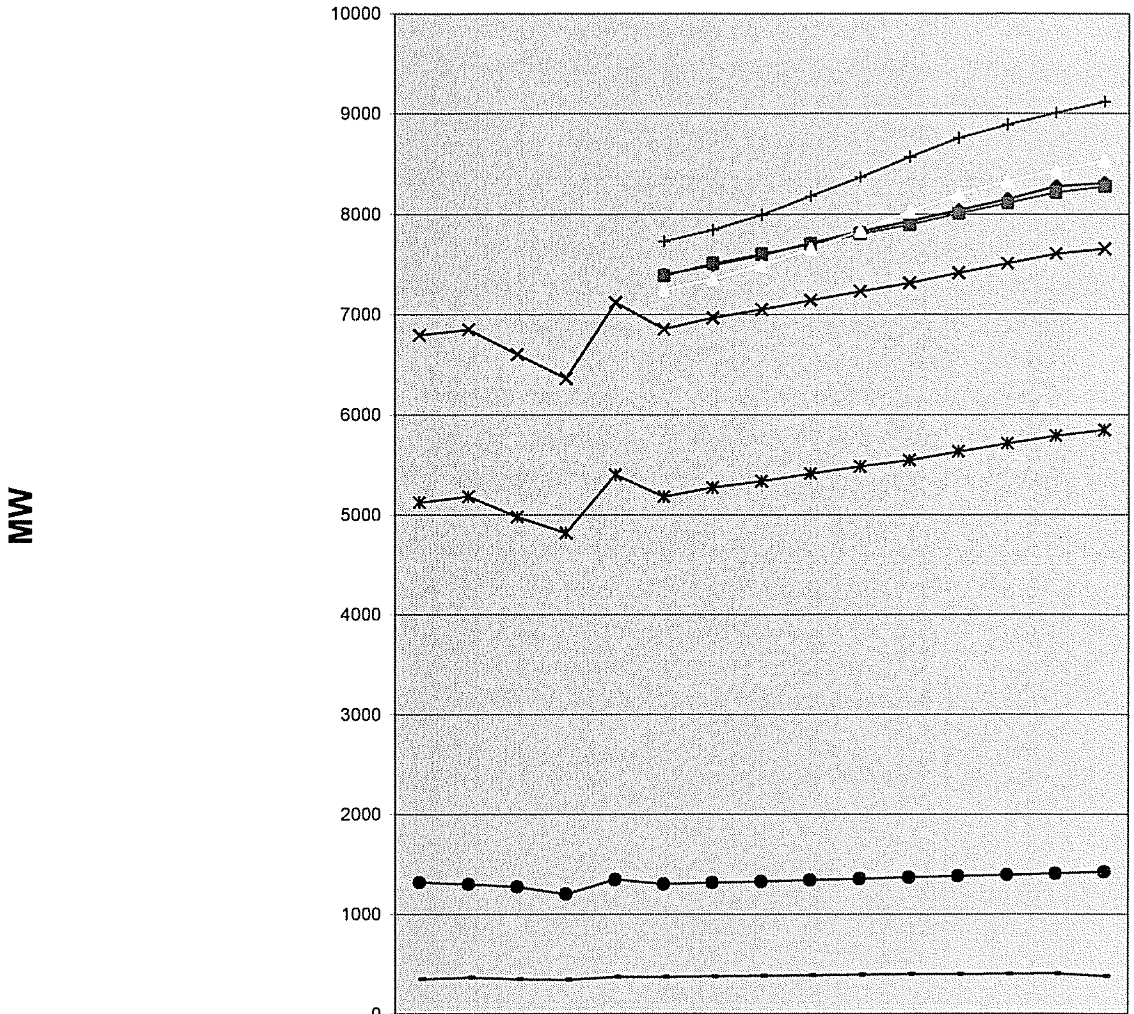
The Connecticut utilities' projected (future) data (except for the extreme weather scenario) are weather-normalized. This means that the data are based on average historical weather conditions over an approximately 30-year time period. For example, CL&P's forecast model assumes a mean daily temperature of 83 degrees Fahrenheit (F) for a summer peak day based on average peak temperatures from 1972-2001. For the extreme weather scenario, CL&P's projected loads are based on a mean daily temperature of 88 degrees F on a peak day. CL&P's extreme weather forecast is approximately a 98/2 scenario, i.e. the forecast peak would have approximately a two percent chance of being exceeded. However, this assumes the same economic and other non-weather assumptions as the 50/50 scenario.

In addition to the Connecticut utilities' electric load forecasts, the Council also reviews and considers the forecast produced by ISO New England (ISO-NE). ISO-NE is the organization that oversees New England's bulk power and transmission, administers the region's wholesale electric market, and manages regional planning processes for electric transmission. It receives forecasts from the Connecticut utilities, but prepares its own forecasts for Connecticut, the other New England States, and the region as a whole.

Also using a 50/50 analysis, ISO-NE predicts that the total Connecticut peak load will grow from a projected 7,250 MW in 2006 to 8,535 MW in 2015. This results in an average annual compound growth rate of 1.8 percent for the state. In the 90/10 scenario (meaning the peak load has only a 10 percent chance of being exceeded), ISO-NE predicts that the summer peak load will grow from 7,730 MW in 2006 to 9,120 MW in 2015. Thus, the ISO-NE 90/10 forecast results in an average annual compound growth rate of 1.9 percent for the state.

As depicted in Figure 2, the ISO-NE 90/10 forecast (the top curve) essentially represents the worst-case scenario of all the Connecticut electric forecasts. This forecast is used for facility planning purposes so as to ensure that the electric system is designed to handle unusually high peak loads. (The ISO-NE forecast data is obtained from ISO-NE's 2006 Regional System Plan Forecast.) For example, on July 27, 2005, Connecticut set a peak load record of 7,135 MW: this greatly exceeded the utilities' 2005 normal weather forecast of 6,757 MW and ISO-NE's 50/50 forecast peak of 7,055 MW at that time. However, this peak did not exceed ISO-NE' 90/10 forecast peak of 7,510 MW. Accordingly, in Table 2 of this report (see page 9), the Council has included the ISO-NE 90/10 peak load forecast to provide the most conservative comparison of resources versus load.

Figure 2: State and Utility Peak Load in MW



	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
ISO-NE 90/10 CT Forecast Peak						7730	7845	7995	8180	8370	8570	8760	8890	9010	9120
CT Utilities' Peak w/o conservation						7398	7494	7595	7710	7830	7929	8039	8151	8274	8312
CT Utilities Peak Extreme Weather						7386	7509	7603	7703	7804	7896	8007	8112	8217	8276
ISO-NE 50/50 CT Forecast Peak						7250	7350	7490	7655	7835	8025	8200	8325	8435	8535
CT Utilities' Peak w/conservation	6795	6851	6604	6364	7120	6855	6968	7051	7142	7232	7314	7416	7510	7605	7654
CL&P Peak	5126	5183	4980	4818	5402	5181	5274	5338	5412	5483	5546	5632	5711	5789	5849
UI Peak	1318	1300	1274	1201	1346	1302	1315	1328	1341	1354	1368	1382	1395	1409	1424
CMEEC Peak	351	368	350	345	372	372	379	385	389	395	400	402	404	407	381

Megawatts

CONNECTICUT ENERGY EFFICIENCY FUND

In 1998, the Connecticut Legislature created the Energy Conservation and Management Board (ECMB) to guide the state's electric distribution companies in the development and implementation of an annual plan—which is submitted for approval by the Department of Public Utility Control (DPUC)—for cost-effective energy conservation programs pursuant to CGS § 16-245m. This legislation also created the Connecticut Conservation and Load Management Fund, now named the Connecticut Energy Efficiency Fund (CEEF). The CEEF supports energy efficiency and increased productivity; it also helps to reduce the peak electric demand in the state, especially in southwest Connecticut. (Until recently, the CEEF Fund has applied to publicly-traded electric distribution companies only. However, with the passage of Public Act 05-01, C&LM has been recently expanded to include municipal electric utilities.)

In 2005, CL&P and UI customers contributed a total of approximately $65 million to the CEEF Fund via a surcharge on their electric bills. The energy savings resulting from CEEF programs in 2006 was 318 GWh, a 9.3 percent increase from the year 2005 savings of 291 GWh. According to the ECMB's annual report to the legislature dated March 1, 2006, the 2005 CEEF programs are projected to have a lifetime savings of 4,400 GWh. This savings is equivalent to providing electricity to 572,000 homes for one year or saving approximately $550 million in electric costs.

The CEEF also reduces air pollution by reducing demand for electric generation. The ECMB estimates that carbon dioxide emissions were reduced by 198,586 tons in 2005 due to CEEF measures. Carbon dioxide is believed to be a "greenhouse gas" associated with global warming and is emitted by all fossil fuel burning power plants. In addition, the CEEF reduced emissions of pollutants such as sulfur oxides and nitrogen oxides in 2005 by 334 tons and 123 tons, respectively. Table 1 depicts the actual annual and lifetime projected reduction in air pollution due to the CEEF.

Table 1: Air Pollution Reductions Due to CEEF Programs (in tons)

	2005 Annual Actual Savings	2005 Lifetime Actual Savings	2006 Annual Projected Savings	2006 Lifetime Projected Savings
Sulfur Oxides	334	4,616	262	3,590
Nitrogen Oxides	123	1,702	97	1,324
Carbon Dioxide	198,586	2,748,461	155,865	2,137,815

Source: ECMB Report dated March 1, 2006

In addition, the CEEF is projected to reduce the peak summer demand by approximately 534 MW in 2006 and 548 MW in 2015 in CL&P's service area. This is equivalent to the output of a moderately-sized power plant.

Similarly, UI's CEEF contributions are projected to reduce the peak summer demand by approximately 9 MW in 2006 and as much as 123 MW by 2015. This results in a statewide total projected peak load reduction of approximately 543 MW in 2006 and 671 MW in 2015. (This forecast assumes that the CEEF program would continue throughout the ten-year forecast period.)

Figure 2 depicts the Connecticut utilities' peak load with these conservation measures considered and also depicts what the projected peak loads would be without CEEF measures. Without CEEF measures, even under normal weather conditions, Connecticut's peak load would be significantly higher, roughly matching the utilities' extreme weather load projections.

The Council believes that energy efficiency and programs like CEEF are an extremely important part of Connecticut's electric energy strategy. Increase efficiency allows the state's needs to be met, in part, without the additional pollution caused by new generating facilities. Reductions in peak load due to increased efficiency can also increase the life of existing utility infrastructure such as transmission lines, substations, distribution feeders, etc. However, the Council cautions that energy efficiency measures alone cannot meet all of state's growing electrical demand. The supply side of the equation will be examined next.

RESOURCE FORECAST

SUPPLY RESOURCES

The Council anticipates that the state's supply resources will be adequate to meet demand under normal weather conditions (using either the utilities' normal weather forecast or ISO-NE's 50/50 forecast) assuming the availability of all units and no loss of existing generation due to retirement. However, taking in account the most conservative forecast (ISO-NE's 90/10 estimate), Connecticut faces a significant generation capacity shortage throughout the forecast period. (See Table 2, page 9.)

In addition, some subregions such as southwest Connecticut and, to a lesser extent, eastern Connecticut are threatened with supply deficiencies and operating problems due to insufficient transmission and inadequate resources within the region. To address these transmission deficiencies, two large transmission projects, Docket No. 217 Bethel – Norwalk 345-kV line and Docket 272 Middletown – Norwalk 345-kV line, as well as a 345-kV/115-kV substation project (Docket 302) in the Killingly/Putnam area, have been approved by the Council and are now under construction.

If a major failure in serving base load were to happen—for instance, if Millstone nuclear units were to go offline—Connecticut's electric generating and transmission/distribution companies would institute the following plan:

- operate all available generating units to their reasonable limits;
- maximize the import of electricity from adjacent states;

- explore possible interruption of service with certain industrial and commercial customers;
- maximize the use of customer-owned generators; and
- implement public awareness efforts for conservation and load shifting, including voluntary reductions and/or shifting consumption to off-peak hours.

Although such response mechanisms have been helpful in the past, it is also vitally important for resources to be strategically located on the grid to ensure supply, both technically and economically. Some generating plants that were called upon to generate at their maximum capacity in the past may not be able to do so in the future because of age, transmission constraints, fuel restrictions (such as natural gas availability during periods of extreme demand), or environmental concerns (such as air emission regulations).

Connecticut's newest generating plant is Milford Power, which was activated in 2004. It is fueled with natural gas, and has a summer power output[6] of approximately 492 MW. In 2001, a natural gas-fired generating plant in Wallingford was activated. This plant has a summer power output of approximately 215 MW. In 2002, the Lake Road Power Station in Killingly was activated. The Lake Road facility is natural gas-fired, and it has a summer power output of approximately 698 MW. Three additional generation facilities: NRG in Meriden (544 MW); Towantic Energy in Oxford (512 MW); and Kleen Energy in Middletown (520 MW) have been approved, but have not materialized due to financial commitments. Their in-service dates are not known and thus have been estimated on Table 2 (page 9), assuming a three-year lead time.

Connecticut Resource Balance

Table 2: CT Resource Balance (based on ISO-NE's 2006 90/10 Forecast and Table 4.8 of ISO-NE's 2005 RSP) (units are in megawatts)										
Capacity Situation	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
ISO-NE 90/10 Load	7730	7845	7995	8180	8370	8570	8760	8890	9010	9120
Reserves (largest unit)	1200	1200	1200	1200	1200	1200	1200	1200	1200	1200
Total Capacity Req'd	8930	9045	9195	9380	9570	9770	9960	10090	10210	10320
Existing Capacity*	6764	6764	6764	6764	6764	6764	6764	6764	6764	6764
Assumed Unavailable Capacity	483	483	483	483	483	483	483	483	483	483
Total Net Capacity	6281	6281	6281	6281	6281	6281	6281	6281	6281	6281
Import Limit	2500	2500	2500	2500	2500	2500	2500	2500	2500	2500
Total Available Resources	8781	8781	8781	8781	8781	8781	8781	8781	8781	8781
Available Surplus/Deficiency	-149	-264	-414	-599	-789	-989	-1179	-1309	-1429	-1539
Southern NE Reinforcement Proj.	0	0	0	0	0	0	1000	1000	1000	1000
SWCT RFP Awards	250	256	256	0	0	0	0	0	0	0
Available Surplus/Deficiency (assumes no changes in generation cap.)	101	-8	-158	-599	-789	-989	-179	-309	-429	-539
Source: ISO-NE 2005 Regional System lan and 2006 ISO-NE RSP Forecast Data										
Connecticut Siting Council Assumptions:										
Hypothetical Retirement of Oil Fired Generation 40 years old or older	-912	-942	-958	-1044	-1191	-1598	-1614	-2014	-2014	-2462
Approved Generation not completed										
Meriden				544	544	544	544	544	544	544
Middletown				520	520	520	520	520	520	520
Oxford				512	512	512	512	512	512	512
Net Surplus/Deficiency	-811	-950	-1116	-67	-404	-1011	-217	-747	-867	-1425

Nuclear Powered Generation

Nuclear plants use nuclear fission (a reaction in which uranium atoms split apart) to produce heat, which in turn generates steam: steam pressure operates the turbines that spin the generators. Since no step in the process involves combustion (burning), nuclear plants essentially produce electricity with "zero-air emissions." Pollutants commonly emitted from fossil-fueled plants are avoided, such as carbon dioxide, sulfur dioxide, nitrogen oxides, mercury, and carbon monoxide. Another advantage to nuclear power is that it runs on domestic fuel, reducing dependence on foreign oil. However, issues remain with regard to security, the short and long-term storage of nuclear waste, and cost.

Connecticut currently has two operational nuclear electric generating units (Millstone Unit 2 and Unit 3) contributing a total of 2,037 MW of summer capacity, approximately 30.1 percent of the state's generating capacity. (The Millstone facility is the largest generating facility in Connecticut, by power output.) Previously, nuclear power supplied approximately 45 percent of Connecticut's electricity. However, this capacity has been reduced by the retirement of the Connecticut Yankee plant in Haddam Neck (December 1996) and Millstone Unit 1 (July 1998).

Following these retirements, Dominion Nuclear Connecticut Inc. (Dominion), Millstone's owner, recently increased the power outputs of Units 2 and 3 via an upgrade to the low pressure turbine rotors, so that the nominal design electric rating for Unit 2 went from 870 MW to 883.5 MW, and Unit 3 went from 1153.6 MW to 1156.5 MW. Thus, the total power output for these units increased by 16.4 MW without any rise in fuel consumption.

Dominion submitted its license renewal applications to the United States Nuclear Regulatory Commission (NRC) on January 22, 2004. On November 28, 2005, the NRC announced that it had renewed the operating licenses of Unit 2 and Unit 3 for an additional 20 years. With this renewal, the operating license for Unit 2 is extended to July 31, 2035 and the operating license for Unit 3 is extended to November 25, 2045.

Coal Powered Generation

Connecticut currently has two coal-fired electric generating facilities contributing 553 MW, or approximately 8.2 percent of the state's current capacity. The AES Thames facility, located in Montville, currently burns domestic coal and generates approximately 181 MW. The AES Thames facility is technically a cogeneration facility because, besides generating electricity for the grid, it also provides process steam to the Jefferson Smurfit-Stone Container Corporation.

On August 29, 2005, an underground 115 kilovolt transmission line connecting the AES Thames facility failed. The repair was completed on October 7, 2005. A subsequent line study showed the thermal sand around the underground cable needed replacement to allow full load operation during the summer months. AES Thames is currently replacing the backfill material around the cable with flowable fill to allow the line continue full load operation when the summer season begins on June 1.

The other coal-fired generating facility in Connecticut is the Bridgeport Harbor #3 facility located in Bridgeport. This facility burns imported coal and has a power output of approximately 372 MW.

In general, using coal as fuel has the advantages of an abundant domestic supply (US reserves are projected to last more than 250 years), and an existing rail infrastructure to transport the coal. However, despite these advantages, imported coal is sometimes consumed by power plants when it is more economical to do so.

In conventional coal-fired plants, coal is pulverized into a dust and burned to generate heat and thus, steam to operate the turbines. However, burning coal to make electricity causes air pollution by emitting pollutants including sulfur dioxide, carbon monoxide, and mercury. In addition, carbon dioxide emissions have been alleged to contribute to global warming.

One alternative to conventional coal-fired generation is "clean coal technology." This is a complex process in which gaseous fuel (such as carbon monoxide) is extracted from coal and then burned in a gas turbine engine. The result is higher efficiency and significant lower air pollution than conventional coal-fired power plants.

In particular, NRG Energy Inc. (NRG) is interested in developing clean coal generation at one of its four major sites in Connecticut. NRG is currently evaluating a 630 MW Integrated Gasification Combined Cycle (IGCC) plant. NRG expects to complete the current analysis phase later this summer and will announce at that time whether to proceed with the pursuing financing for the project.

Petroleum Powered Generation

Connecticut currently has 25 oil-fired electric generating facilities contributing 2,473 MW, or 36.6 percent of the state's current capacity. This takes into account the deactivation of Devon 8 (107 MW) and Devon 7 (105 MW) in Milford, on June 7, 2004, and October 1, 2004, respectively.

Both Devon 7 and 8 are now considered deactivated reserve. However, NRG is evaluating their return to service. NRG's efforts to date have included budgeting and scheduling return to service requirements including staffing the facility as well as commissioning a transmission study which ISO-NE known as the Devon Export Expansion Project. Initial indications are that recent changes to the transmission system will allow deliverability of all generation currently connected to Devon substation.

However, because the industry generally rates the service life of oil-fired units to be 40 years, some older oil-fired units may face retirement during the forecast period. This could further reduce the already tight generation capacity in Connecticut unless the loss is replaced by a sufficient number of new generating units. Figures 4a and 4b depict the existing and projected generation fuel mix for Connecticut, assuming the effects of possible retirement of oil-fired generating units at least 40 years of age or older. (The 2015 fuel mix includes, as an assumption, all three natural gas-fired units that currently have not been constructed and/or completed. See page 20.) In addition, Table 2 (see page 9) includes the hypothetical loss of Connecticut's resource capacity due to the retirement of oil-fired units 40 years of age or older. The Council does note, however, that in 2005, NRG, the largest owner of oil-fired generation in Connecticut, testified that it currently had no plans to retire any of its oil-fired units during the forecast period.

New oil-fired generation is not expected in the near future, due to market volatility and mounting oil prices. In particular, the price of crude oil has recently exceeded $70 per barrel this year. With approximately 60% of the nation's oil being imported, petroleum supply and prices are highly vulnerable to disruptions and instabilities in supplier countries.

Moreover, oil-fired generation presents environmental problems, particularly related to the sulfur content of the oil, and may face tighter air-emissions standards in the near-term, such as regulation of carbon dioxide emissions. Some of the oil-fired generating facilities in Connecticut are dual-fueled, meaning that they can switch to natural gas if necessary. Currently, four active plants in Connecticut (Middletown #2 and #3; Montville #5; and New Haven Harbor #1) totaling approximately 882 MW have the ability to change from oil to gas. The Council believes that dual-fuel capability is an important part of diversifying the fuel mix for electric generation and avoiding overdependence on a given fuel.

Figure 4a: 2006 Fuel Mix

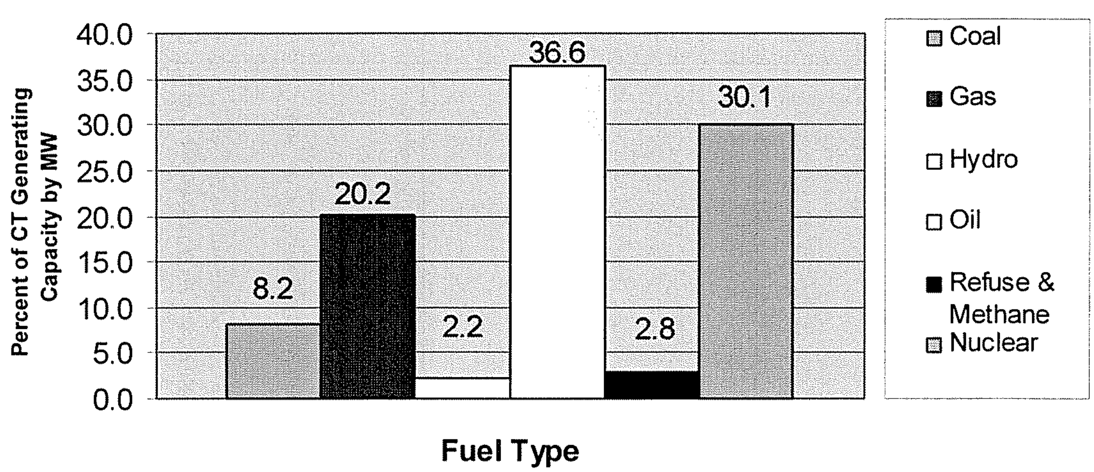
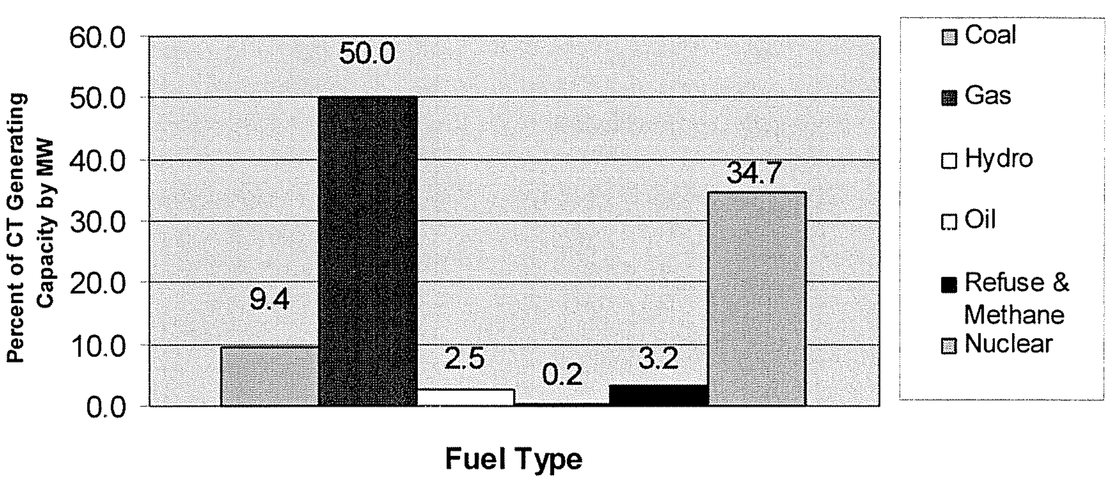


Figure 4b: 2015 Projected Fuel Mix



* Lake Road generating plant is not included in the fuel mix. See page 23 for an explanation.

Natural Gas Powered Generation

Connecticut currently has 14 natural gas-fired generating units (not including Lake Road) contributing a total of 1,363 MW, or 20.2 percent of the state's generating capacity. This includes recent additions such as the Milford Power facility, with a total summer seasonal claimed capability (SCC) rating of 492 MW.

Natural gas-fired electric generating facilities are preferred over those burning coal or oil primarily because of higher efficiency, lower initial cost per kW, and lower air pollution. Natural gas generating facilities also have the advantage of being linked directly to their fuel source via a pipeline.

Some natural gas generating plants, such as Bridgeport Energy, Milford Power and Lake Road, are combined-cycle. Added to the primary cycle, in which gas turbines turn the generators to make electricity, is a second cycle, in which waste heat from the first process is used to generate steam: steam pressure then drives another turbine that generates even more electricity. Thus, a combined-cycle plant is highly efficient. However, the tradeoffs are higher initial costs and increased space requirements for the extra generating unit.

In the event of severely cold weather, unusually high demand for natural gas to heat buildings can coincide with high demand for natural gas to generate electricity. At such times, some generating plants may experience either a forced outage due to pipeline capacity limitations, or an "economic curtailment", a situation in which it is not economical to generate electricity, given the higher natural gas fuel costs at that time. During economic curtailments, some units have the ability to switch to oil. Connecticut currently has 8 natural gas-fired generating plants (not including Lake Road), totaling approximately 701 MW, that can switch to oil.

In the regional planning document (the 2005 ISO-NE Regional System Plan, or 2005 RSP), ISO-NE has recognized the problems with natural gas generation during unusually cold weather, and has taken steps to address it. Specifically, the 2005 RSP notes that ISO-NE has developed a new operating procedure called Cold Weather Event Operations (CWEO). CWEO forecasts, notifies, and temporarily modifies the wholesale electric market trading deadlines to minimize the risk of fuel-supply interruptions. (This is accomplished through an early procurement of the natural gas commodity and timely securing of transport.)

According to RSP 2005, ISO-NE also has created a Natural Gas Pipeline Contracts Database. This database identifies the contracts gas-fired generators have for firm gas-transportation from prominent natural gas trading hubs outside the region. This information clarifies which units should have fuel availability during periods of peak-gas demand, based on their contractual capability.

Lastly, ISO-NE has worked with state air regulators to clarify existing air permits on two gas-fired facilities, with additional rules pending. These revised air permits will allow these facilities to burn limited amounts of fuel oil under specific ISO-NE declared emergencies. Other improvements include weekly communications during the winter-peak period between ISO-NE and the regional natural gas sector and continued employee training on gas/electricity operations and interdependencies.

Hydroelectric Power Generation

Connecticut's hydroelectric generation consists of 28 facilities contributing approximately 149 MW, or 2.2 percent of the state's current generating capacity. Hydroelectric generating facilities use a domestic, largely renewable energy source, emit zero air pollutants, and have a long operating life. Also, some hydro units, such as Stevenson, Rocky River and Tunnel Jet have black start capability[7]. However, hydroelectric units divert river flows from worthwhile public uses, such as recreation and irrigation; and can disrupt fish and wildlife. The main obstacle to the development of additional hydroelectric generation in Connecticut, however, is a lack of suitable sites.

Northeast Generation Company (NGC) received its license renewal order from the Federal Energy Regulatory Commission (FERC) on June 23, 2004, which extended the licensing of the Falls Village, Bulls Bridge, Shepaug, Stevenson, and Rocky River hydroelectric facilities to June 23, 2044. (These five facilities have a combined SCC rating of approximately 117 MW

The Scotland hydroelectric facility's license expires on October 5, 2012. (This is the earliest expiration date of the NGC hydroelectric facilities.) No re-licensing activities are underway for Scotland. The Scotland facility has a summer rating of 1.69 MW and is located in the Town of Windham.

Solid Waste Power Generation

Connecticut currently has approximately 184 MW of solid waste-fueled generation, approximately 2.7% of the state's generation capacity. The Exeter generating plant in Sterling burns used tires, and has a summer rating of approximately 24 MW. The remaining 160 MW of solid waste-fueled generation includes: Bridgeport Resco; Bristol Resource Recovery Facility (RRF); Lisbon RRF; Preston RRF; Wallingford RRF; and the Connecticut Resource Recovery Agency South Meadows #5 and #6 facilities. Solid waste has the advantage of being a renewable, locally supplied fuel and it contributes to Connecticut's fuel diversity. It is not affected by market price volatility, nor supply disruptions—significant advantages over fossil fuels. In addition, the combustion of solid waste produces relatively low levels of greenhouse gas, and reduces the amount of space needed for landfills.

Recently passed federal energy legislation includes certain incentives to support the development and expansion of waste-to-energy facilities. Specifically, Title XIII of the

Energy Tax Incentives Act of 2005 extends desirable tax-credit provisions until December 31, 2007. Also, an ongoing state policy initiative being administered by the Connecticut Clean Energy Fund and the DPUC—"Project 100"—already has sparked interest among developers of innovative biomass facilities fueled at least in part by waste wood from construction.

Miscellaneous Small Generation

Approximately 133 MW of electricity is generated by 61 independent entities in Connecticut such as schools, businesses, homes, etc. This portion of generation is not credited to the state's capability to meet demand because ISO-NE does not control its dispatch. However, these privately-owned units do serve to reduce the net load on the grid, particularly during periods of peak demand. They range from 5 kW to 32.5 MW in size and are fueled primarily by natural gas, with several others using oil, solid waste, hydro, solar, wind, landfill gas (essentially methane), and propane. The newest significant addition to this category is the 24.9 MW cogeneration facility at the University of Connecticut. This unit was put into service in August 2005. The installation of additional privately-owned generation in Connecticut is expected, but only by entities that view self-generation as a benefit.

OTHER GENERATION TECHNOLOGIES

Fuel Cells

A fuel cell consumes hydrogen and oxygen and produces electricity, with water as a waste product. Fuel cells also can be designed to run on natural gas. They have the advantages of negligible air emissions, low noise, and reliable operation. Their waste heat can be used for other purposes to further increase overall efficiency. For example, they can pre-heat domestic hot water, provide hydronic (hot water) heating or operate an absorption air conditioning system.

Fuel cells generate direct current (DC) electricity. However, inverters can be added that convert DC current to alternating current (AC), the main type of current that flows through the transmission and distribution system.

Pursuant to CGS §16-50k(a), the Council has the legislative charge to review all fuel cell proposals. As such, the Council has reviewed and approved several fuel cell installations for various uses throughout Connecticut. For example, on April 19, 2005 the Council approved Petition No. 707 for a five kilowatt (kW) fuel cell to be used as a backup generator for a cellular telecommunications facility. Also, on May 11, 2005, the Council approved Petition No. 711 for a 250-kW fuel cell to supply power to meet some of an industrial building's base electric load.

Fuel cells cost more per kilowatt than other generation technologies, so they are usually limited in size. Nevertheless, fuel cells are well suited for backup generation, supplemental base-load generation for buildings, and distributed generation. The Council strongly encourages the use of fuel cell technology, particularly from in-state companies.

OTHER RESOURCES THAT SUPPORT CONNECTICUT'S DEMAND

Import Capability

As noted in Table 2 (page 9), Connecticut has the ability to import a total of approximately 2,500 MW of electricity from outside the state without compromising grid voltage and system operating stability. In ISO-NE's 2005 RSP, Connecticut's import capacity was reported to be 2,300 MW. However, preliminary studies for the 2006 RSP indicate that the import limit will be raised to 2,500 MW. As such, the updated import limit is reflected in Table 2.

Having this import capability is especially important during periods of peak demand or when a large base-load generating facility, such as Millstone is unavailable. However, the Council cautions that this current amount of import capacity may not necessarily be available in its entirety for the entire forecast period, due to electric system limitations in bordering states.

MARKET RULES AFFECTING SUPPLY

INSTALLED CAPACITY MARKET

Under restructuring, independent electric generators bid their supply of electricity into the grid via the regional wholesale electricity market, which is governed and operated by ISO-NE. However, transmission constraints (see later sections) can result in generating capacity not being able to operate in a given region, or not being able to deliver electricity to a given region. According to ISO-NE's 2004 Regional Transmission Expansion Plan, the current Installed Capacity market (ICAP) does not recognize the differences in the value of capacity based on location. For example, a resource located in a congested area or one with high load growth would receive the same capacity compensation as a resource located in a non-congested zone or one with sufficient capacity. Also, prices in the single ICAP market have a tendency to become unstable around the point at which generation capacity is just sufficient to meet resource planning minimums. The uncertainty and instability in capacity-market prices have discouraged investment in new and existing electric generating capacity.

To address the issues relative to the single ICAP market, FERC was considering the implementation of a Locational Installed Capacity (LICAP) market. LICAP would differentiate the value of resources based on their location. The intent of LICAP was to improve price stability and encourage investments in new and existing electric generating capacity in congested areas. However, pursuant to a settlement agreement among regional stakeholders, a redesigned wholesale electric capacity market has been proposed in lieu of LICAP.

According to an ISO-NE press release dated March 6, 2006, the settlement agreement was filed on March 6, 2006 with FERC and would establish a Forward Capacity Market (FCM) under which ISO-NE would project the needs of the power system three years in advance and then hold an annual auction to purchase power resources to satisfy the region's future needs. These resources include new and existing power plants, alternative energy sources, and demand-response assets.

ISO-NE estimates that the first forward capacity auction could be held as early as December 2007, with the resources being paid roughly 2.5 years later, in 2010. If resources phased in from the auction are not available during power system emergencies, they will fail to earn their full payments.

Because FCM prices will be subject to market forces, the agreement does not include cost estimates for the auction. In addition, ISO-NE notes that the agreement must be approved by FERC before it can be implemented. The parties have requested that FERC issue its final ruling by June 30, 2006.

LEGISLATION AFFECTING ELECTRIC SUPPLY

Electric Restructuring

In 1998, Public Act 98-28, "An Act Concerning Electric Restructuring" (Act) instituted historic changes to the electric system in Connecticut. Its primary provision permitted customers of Connecticut's two private investor-owned electric utilities, CL&P and UI, to choose their retail electric suppliers as of January 1, 2000. The law also allowed a municipal electric utility to engage in competitive generation supply if it reciprocally opened its service territory to other competitive retail suppliers. State-licensed independent retail generation suppliers were allowed to compete for customers. The overall intent was that competition would lower prices for electricity, foster technological innovation, and boost supply options, while at the same time improving environmental quality.

Pursuant to the Act, the DPUC established and completed procedures for "unbundling" generation from the transmission and distribution components of electric utility service. In the process, the DPUC developed individual non-bypassable line item charges that fund energy conservation programs, investments in renewable energy technologies, and the system benefit charge, which support consumer education and public policy, and provides assistance to utility workers and municipalities impacted by restructuring.

While the market-based provisions of the Act have already been executed, including the divestiture of generating plants and consumer choice of a generation supplier, continued monitoring of the electric supply markets is necessary to ensure the development of an open competitive market.

The vast majority of Connecticut customers are still being served through the two utilities' generation service arrangement, formerly called the "Standard Offer", currently called the "Transitional Standard Offer." Relatively few customers have chosen an alternative electric supplier. Market conditions and minimal consumer awareness or interest may be the reasons. The standard offer rate, which the Act capped at ten percent below 1996 base rates, expired on December 31, 2003. Before this transpired, however, the legislature passed Public Act 03-135, which established the new "Transitional Standard Offer", effectively capping rates at their 1996 base rate level for three more years, through December 31, 2006, buffering consumers against potential price volatility.

The current statute requires the DPUC to set the price for standard service by October 1, 2006 and periodically thereafter, but not more than once per calendar quarter. The electric distribution companies must procure power for this service under a DPUC-approved plan designed to reduce price volatility.

Renewable Portfolio Standards

As well as capping rates for electricity, Public Act 03-135 revised the 1998 restructuring law on the Connecticut Renewable Portfolio Standards (RPS) and required retail electric suppliers to ensure that a certain minimum percentage of their electricity comes from renewable energy sources. Legislation has divided renewable fuels into two classes, depending roughly how much pollution they cause, and their sustainability. The formula that dictates their use is complicated (see Figure 5), but the bottom line is that RPS should encourage a greater supply of electricity from more diverse sources, both goals that the Council supports.

Figure 5 depicts the required percentages for Class I[8] and Class II[9] renewable energy sources through 2010.

Figure 5	**Renewable Portfolio Standards**	
Effective Date	***Minimum Class I Percentage***	***Addt'l Percentage of Class I or II***
1/1/2004	1 percent	3 percent
1/1/2005	1.5 percent	3 percent
1/1/2006	2 percent	3 percent
1/1/2007	3.5 percent	3 percent
1/1/2008	5 percent	3 percent
1/1/2009	6 percent	3 percent
1/1/2010	7 percent	3 percent
Source: PA 03-135		

An Act Concerning Energy Independence

On July 21, 2005, Public Act 05-1 (PA 05-1), "An Act Concerning Energy Independence" was approved. Its purpose is to boost electric supply through a combination of innovative means, with the incentive being relief from congestion charges, that is, charges imposed by FERC on Connecticut rate-payers in locations where demand is especially high and supply is especially low. Three of PA 05-1's provisions most relevant for the Council's forecast review are discussed below.

PA 05-1 requires the DPUC to solicit proposals for reducing congestion costs during 2006-2010. Proposals can be submitted for customer-side distributed resources[10], grid-side distributed resources[11], new generation facilities, including expanded or repowered generation, and contracts for no more than 15 years for the purchase of electric capacity rights. DPUC is instructed to prefer proposals that cause the greatest aggregate reduction in federally mandated congestion charges[12]; make efficient use of existing sites and supply infrastructure; and serve the long-term interests of ratepayers.

PA 05-1 permits the Council to approve by declaratory ruling:

- the construction of a facility solely for the purpose of generating electricity, other than an electric generating facility that uses nuclear materials or coal as a fuel, at a site where an electric generating facility operated prior to July 1, 2004;
- the construction or location of any fuel cell—unless the Council finds a substantial environmental effect—or of any customer-side distributed resources project or facility or grid-side distributed resources project or facility with a capacity of not more than 65 megawatts, so long as such the project meets the air quality standards of the Department of Environmental Protection;
- the siting of temporary generation solicited by DPUC pursuant to section 16-19ss of this act.

PA 05-1 also creates a new Municipal Energy Conservation and Load Management Fund. This would be funded by an assessment of certain number of mills[13] per kilowatt-hour of metered firm electric retail sales within the municipal electric utility service area.

Finally, PA 05-1 requires electric distribution companies and electric suppliers, on or after January 1, 2007, to demonstrate that no less than one percent of the total output of the suppliers or the standard service of an electric distribution company is obtained from Class III resources[14], a newly-defined group of resources focusing on combined heat and power systems[15] and C&LM. On January 1, 2008, this percentage increases to 2 percent. For January 1 of years 2009 and 2010, the percentages are 3 and 4 percent, respectively.

COUNCIL APPROVED GENERATION

New Natural Gas-fired Generation

Under Connecticut's restructured electric system, the Council has approved seven natural gas-fired electric generating facilities. These are listed below with their respective nominal power outputs[16] and operating status:

- 520 MW Bridgeport Energy LLC project in Bridgeport became operational in August of 1998.
- 544 MW Milford Power Company, LLC f/k/a/ PDC-El Paso, LLC project in Milford became fully operational in May 2004.
- 544 MW NRG Northeast Generating LLC project in Meriden was approved by the Council on April 27, 1999 and has until December 31, 2011 to complete construction.
- 792 MW Lake Road Generating Company, L.P. project in Killingly became fully operational May 2002.
- 512 MW Towantic Energy LLC project in Oxford was approved by the Council on June 23, 1999. Construction has not yet begun, and its Certificate of Environmental Compatibility and Public Need (Certificate) expires on June 26, 2006.
- 250 MW Wallingford PPL project in Wallingford became operational July 2001.
- 520 MW Kleen Energy Systems, LLC project in Middletown was approved by the Council on March 25, 2003. Construction has not yet begun, and its Certificate expires on November 21, 2006.

The total nominal capacity of these plants is 3,682 MW. However, currently, only 2,106 MW or 57 percent of the approved capacity is now operating. Most of the delays are project-specific, but all the projects are experiencing financial vulnerability due to uncertain market conditions.

In 2003, as the process of electric restructuring continued, the legislature reconstituted the Connecticut Energy Advisory Board (CEAB), and charged it to perform a variety of functions related to energy infrastructure planning statewide[17].

TRANSMISSION SYSTEM

Transmission is the "backbone" of the electric system, the part that carries large amounts of electricity long distances efficiently by using high voltage. In Connecticut, electric lines with a voltage of 69 kilovolts (kV) or more are considered transmission lines. Distribution lines are generally below 69-kV. They are the lines that come down our streets to connect[18] with even lower-voltage lines feeding each residence or business.

The state's electric transmission system contains approximately: 398 circuit miles of 345-kV transmission; 1,300 circuit miles of 115-kV transmission; 5.8 miles of 138-kV transmission; and 97 circuit miles of 69-kV transmission. (These figures refer to AC transmission. The Cross Sound Cable is not counted because it is DC [see below].) Connecticut's electric transmission system is depicted in the map in Appendix B. Appendix C shows planned new transmission, reconductoring, or upgrading of existing lines to meet load growth and/or system operability needs.

The majority of Connecticut's electric transmission, as noted above, is 115-kV. CL&P's remaining AC transmission is rated between 69-kV and 138-kV. The 138-kV transmission line connects Norwalk, Connecticut to Long Island via an underwater cable. In addition, CL&P has 13 ties (connections) with CMEEC, twenty with UI, and nine interstate connections. Of these interstate connections, one tie is with National Grid in Rhode Island; one tie is with Central Hudson in New York state; and five ties are with the Western Massachusetts Electric Company (WMECO) in Massachusetts.

The CL&P 345-kV transmission system transmits power from large central generating stations such as Millstone, Lake Road, and Middletown #4 via four 345-kV transmission ties with neighboring utilities. This includes one tie with UI, as well as three ties that cross the state line to connect with: National Grid in Rhode Island, WMECO in Massachusetts, and Consolidated Edison in New York State.

The three interstate 345-kV ties are approximately 35 to 40 years old and were designed when loads were considerably smaller than today. Given the present size of the loads and the future projected loads, it is likely that these ties will have to be supplemented in the not too distant future. The Council notes, for instance, that a new future 345-kV transmission line is being considered by CL&P and ISO-NE to connect Card Substation in Lebanon to the Lake Road Substation in Killingly, continuing from there to Rhode Island.

Another important interstate tie is the Cross Sound Cable. Connecticut's only significant DC transmission line, it goes underwater from New Haven, Connecticut to Brookhaven, New York. It has a 330 MW capacity.

Having been under dispute for environmental reasons before and during its construction, the Cross Sound Cable was deactivated almost as soon as it was built, but it was reactivated during the August 2003 blackout on an emergency basis, and currently operates pursuant to a settlement agreement among the Long Island Power Authority (LIPA), the Connecticut Department of Environmental Protection, DPUC, CL&P, and the Cross Sound Cable Company, LLC.

ELECTRIC TRANSMISSION IN SOUTHWEST CONNECTICUT

The most critical and constrained transmission area in the state, as well as New England, is a 54 town region referred to as Southwest Connecticut (SWCT), including all of UI's service territory. This area is essentially west of Interstate 91 and south of Interstate 84. It accounts for approximately one-half the state's peak load, and is one of the fastest growing and economically vital areas of the state. The 115-kV lines that serve SWCT have reached the limit of their ability to support the area's current and projected loads reliably and economically.

Within SWCT, a critical sub-area is called the Norwalk-Stamford Sub-Area. Historically, Norwalk and Stamford have relied on local generation. Since generation has become less predictable, given electric restructuring, and given the age of generating plants around Norwalk and Stamford, the Norwalk-Stamford Sub-Area has had to look at transmission, rather than generation, to meet its needs.

After studying the problems in SWCT and the Norwalk-Stamford Sub-Area, ISO-NE, CL&P, and UI devised a plan to supplement the existing 115-kV transmission lines with a new 345-kV "loop" though SWCT that would integrate the area better with the 345-kV system in the rest of the state and New England, and provide electricity more efficiently.

The first phase of this proposed upgrade (known as "Phase One"), involves the construction of a 345-kV transmission line from Plumtree Substation in Bethel to the Norwalk Substation in Norwalk. The Phase One proposal was the subject of Council Docket No. 217, approved by the Council on July 14, 2003. Construction is currently underway and is expected to be complete by year-end 2006.

The second phase of the upgrade (known as "Phase Two") was the subject of Council Docket No. 272. This proposal includes the construction of a 345-kV transmission line from Middletown to Norwalk Substation. This project was approved by the Council on April 7, 2005: currently, Development and Management Plans are being discussed with the affected municipalities and submitted for Council review and approval. Construction is anticipated to begin in the first quarter of 2006 and finish by year-end 2009.

ISO-NE Gap RFP

To help address the needs of SWCT in the interim, ISO-NE has issued RFP awards for several temporary emergency generators, and has instituted new demand response programs to reduce load. ISO-NE planners estimate that, per their 90/10 forecast, these emergency actions prevented a 130-MW shortfall in SWCT for 2004, and will mitigate further gaps gradually worsening to 270 MW by 2007. As depicted in Table 2 (see page 9), the ISO-NE RFP award measures are assumed to remain in place through approximately 2008, according to ISO-NE 2005 RSP.

Pursuant to these RFP awards, the Council has reviewed and approved several emergency generators for SWCT. For example, on May 19, 2004, the Council ruled favorably on the proposed installation of four 2 MW diesel generators in Wallingford under Petition No. 672. Also, the Council also ruled favorably on the proposed installation of three 2 MW diesel generators in East Norwalk under Petition No. 676. Figure 6 depicts ISO-NE's Quick Start Capacity schedule for SWCT pursuant to its RFP awards.

Figure 6	**ISO-NE**	**Quick-Start**	**Capacity**	**for SWCT**
Technology	**2004 Summer MW**	**2005 Summer MW**	**2006 Summer MW**	**2007 Summer MW**
On-Peak Conservation	1	4	5	5
Emergency Generation	94	153	154	154
Load Reduction	21	53	74	74
Combined Energy and Load Reduction	3	12	22	27
Total	**119**	**222**	**255**	**260**

System Contingencies and Reserve Requirements

Electric utilities must be able to handle capacity loss in the event of the loss of a transmission line or a generator. The loss must be replaced by another line or other generation in relatively short period of time to ensure reliability of the system. (Generation that can be activated in 30 minutes or less is called quick-start generation.) The single largest contingency currently in Connecticut is the Millstone 3 generating facility, with a summer output of 1,155 MW. Therefore, rounding to the nearest 100 MW, ISO-NE uses 1,200 MW as a reserve requirement in the 2005 RSP. In addition, Table 2 (see page 9) uses 1,200 MW as a reserve requirement.

This concept of planning for contingencies also affects SWCT. Both the Phase One and Phase Two projects increase the import capacity into SWCT. By the time the Phase Two line is placed into service, in late 2009, it will become the largest contingency in SWCT. Thus, significant quick-start generation resources will be needed in SWCT.

In the 2005 RSP, ISO-NE recommended the addition of 350 MW of quick-start capability in SWCT. ISO-NE is currently preparing the 2006 RSP which is expected later this year, taking into account increased transfer limits into SWCT. It is not yet clear what ISO-NE's recommendation for quick-start capability in SWCT will be in the 2006 RSP. However, the Connecticut Energy Advisory Board, in its report titled *Connecticut's Long Term Electric Capacity Requirements*, dated April 7, 2006, notes that ISO-NE's recommendation for additional quick-start capacity in SWCT could be as much as 750 MW by 2010.

ELECTRIC TRANSMISSION IN NORTHEAST CONNECTICUT

Lake Road Generating Facility

Currently, the Lake Road generating facility (approximately 693 MW summer rating) in Killingly is not counted towards Connecticut's generation capacity. The reason is that only one 345-kV line connects the plant with the nearest substation—Card Street Substation in Lebanon: if this line were to go down, the plant would be disconnected from Connecticut's 345-kV transmission system.

However, CL&P is actively seeking solutions which if implemented would allow ISO-NE to classify Lake Road as Connecticut generation. With the settlement of the LICAP proceedings, CL&P anticipates that ISO-NE will identify detailed capacity market rules to allow it to approve a solution in late 2006. In the mean time, CL&P has been pursuing three separate courses of action: special protection system modifications; Lake Road interconnection modifications; and the Southern New England Transmission Reinforcement Analysis.

CL&P is working with the Lake Road Generating Company and ISO-NE to study whether the special protection system (SPS) at the Lake Road Substation that was installed to protect the generator shafts from high mechanical torques can be removed. Currently, the Lake Road Generating units are tripped off-line by SPS whenever there is an outage of an interconnected 345-kV line, however brief. The Lake Road Generating Company has hired their generator manufacturer to assess the risk of equipment damage during 345-kV line trip and re-close operations. (The study is expected to be available in the Fall of 2006.) CL&P also is working with Lake Road Generating Station to further analyze the impact of 345-kV transmission line trips and re-close operations and their effects on the generator shafts. If it is determined that SPS can be removed, it may be possible to allow some of the Lake Road units to be considered as Connecticut generation resources.

The Lake Road Generating Company, ISO-NE, and CL&P are also studying possible modifications to the generator's interconnection to allow some or all of the Lake Road units to be considered Connecticut resources. Currently, all three units are interconnected to the 345-kV transmission grid at Lake Road Substation, located adjacent to the units. Each generating unit has a transformer that steps the voltage up from 21-kV to 345-kV. If the removal of SPS is not possible, CL&P plants to study two options to interconnect the units to the 115-kV transmission system via two underground 115-kV cables from Lake Road Substation to the new Killingly Substation. (See Section titled "Substations and Switchyards.")

The first option is to replace the existing Lake Road 21/345 kV generator step-up transformers with new 21/115 kV step-up transformers for two of the three generating units, with each step-up transformer connecting to one of the 115-kV cables to the Killingly Substation.

The second option is to install a new 345/115 kV autotransformer at the Lake Road Substations, connect it to the two 115-kV cables to Killingly Substation, and reconfigure the 345-kV facilities so the 21/345 step-up transformers for two of the three generating units connect only to this new autotransformer.

Lastly, CL&P is working with National Grid and ISO-NE on a comprehensive review of southern New England reliability problems. This study is called the Southern New England Transmission Reinforcement (SNETR) analysis and has identified several interdependent system reliability problems that Connecticut shares with Massachusetts and Rhode Island. To address these problems, one option that is being considered is the possible construction of a second 345-kV transmission line from CL&P's Card Street Substation in Lebanon to the Lake Road Substation in Killingly and then onto a National Grid Substation in northwest Rhode Island via the new Killingly Substation. If this line were to be constructed, it may enable the Lake Road generating units to be counted as Connecticut generation capacity. CL&P expects to learn by year-end 2006 whether this new 345-kV line is included in the preferred SNETR master plan.

SUBSTATIONS AND SWITCHYARDS

On May 11, 2005, the Council approved the Northeast Connecticut Reliability Project as Docket No. 302. This project includes the construction of a new 345-kV/115-kV substation (known as Killingly Substation) on CL&P property straddling the Killingly/Putnam town line. The new substation will connect to an existing overhead 345-kV transmission line, then use that source to feed into two existing overhead 115-kV transmission lines. This project is expected to alleviate transmission capacity constraints and improve electric system reliability in this region of the state. The substation is expected to be in service by late 2006.

In addition, as depicted in Figure 7, as many as six new substations are planned for the next four years to address other high load areas within the state. Some of the substations are associated with the 345-kV transmission projects in SWCT. Other additional substations are being considered, with the estimated in-service dates to be determined.

Figure 7: Planned Substation Projects	**Est. In-Service Date**	**Company**
Install a new 345-kV Kleen Switching Station in Middletown	TBD	CL&P
Install the new 345-kV Norwalk Substation in Norwalk	2006	CL&P
Install a new 345-kV/115-kV Killingly Substation in Killingly	2006	CL&P
Modify the existing 115-kV Tracy Substation in Putnam	2006	CL&P
Expand the existing 345-kV Card Substation in Lebanon	2006	CL&P
Expand the existing 115-kV Triangle Substation in Danbury	2007	CL&P
Expand the existing 115-kV Middle River Substation in Danbury	2007	CL&P
Install a new 115-kV Wilton Substation in Wilton	2007	CL&P
Install the new 115-kV Trumbull Substation in Trumbull	2007	UI
Install 115-kV transmission portion of Metro North Union Avenue Substation in New Haven	2007 or later	UI
Modify the existing 115-kV Norwalk Substation in Norwalk	2008	CL&P
Expand the existing 115-kV Glenbrook Substation in Stamford	2008	CL&P
Expand the existing 138-kV/115-kV Norwalk Harbor Substation in Norwalk	2008	CL&P
Install a new 345-kV Barbour Hill Substation in South Windsor	2008	CL&P
Expand the existing 115-kV Bunker Hill Substation in Waterbury	2008	CL&P
Expand the existing 115-kV Devon Substation in Milford	2009	CL&P
Install the new 345-kV Beseck Switching Station in Wallingford	2009	CL&P
Install the new 345-kV East Devon Substation in Milford	2009	CL&P
Expand the existing 345-kV Scovill Rock Switching Station in Middletown	2009	CL&P
Expand the existing 345-kV Norwalk Substation in Norwalk	2009	CL&P
Expand the existing 345-kV Card Substation in Lebanon	2009	CL&P
Naugatuck Valley 115-kV Voltage Improvement Project	2010 or later	UI
Install a new 115-kV substation in western Fairfield	2014 or later	UI
Install a new 115-kV substation in North Branford	2014 or later	UI
Expand the existing 345-kV Haddam Substation in Haddam	TBD	CL&P
Expand the existing 115-kV Glenbrook Substation in Stamford	TBD	CL&P
Expand the existing 115-kV Norwalk Harbor Station in Norwalk	TBD	CL&P
Install the new 115-kV Stepstone Substation in Middletown	TBD	CL&P
Install the new 115-kV Cohanzie Substation in Waterford	TBD	CL&P

Instal the new 115-kV Oxford Substation in Oxford	TBD	CL&P
Install the new 115-kV Windsor Substation in Windsor	TBD	CL&P
Install the new 115-kV Goshen Substation in Goshen	TBD	CL&P

Because of the development of new transmission as well as new substation/switching facilities may be considered undesirable by local communities, utilities must carefully assess supply locations, load center demands, and the need for new or upgraded facilities far in advance of actual construction. These issues must be considered along with environmental concerns including electric and magnetic fields, aesthetics and the availability of suitable sites.

RESOURCE PLANNING

The Council fully endorses and participates in initiatives to maintain electric reliability, including programs such as C&LM, resource modeling, and transmission planning. The need to coordinate these efforts has substantially increased as growing demand has stressed existing resources; at the same time, because of electric restructuring, the overall task of matching supply to demand has become more complex. Rate pressures, congestion management, targeted demand side programs, regional transfers, and scarce locations for siting facilities are only a few of the issues that are making the Council's decisions difficult and critical.

As depicted in Appendix B, the Council continues to assess the existing electric system to maintain and improve reliability. Further, the Council notes the CEAB's legislated mandate for stimulating alternatives to proposed electric facilities that come before the Council. Such alternatives may include new transmission technologies, generation using renewable fuels, distributed generation, wholesale and retail market strategies, CEEF, and combinations thereof. The Council encourages innovation. In order for regulators to work well, they must look at multiple scenarios, and consider diverse solutions. The future never sits still.

CONCLUSION

This Council's forecast review has considered Connecticut's electric energy future for the next ten years and concludes that supplies are expected to meet demand under normal weather conditions assuming no losses of generation due to retirement. However, under the more stringent ISO-NE "90/10" forecast, Connecticut faces a significant shortage of supply, even including the three approved generating facilities not yet constructed and/or completed. Much needs to be done to assure the electric system's long-term reliability.

Issues that warrant attention in the future include:

- maintain sufficient emergency generation and demand response in SWCT until long term transmission upgrades are completed;
- facilitate the addition of new generation in Connecticut, and address delays in construction of approved generation;

- continue to explore options to allow all or some of Lake Road Generating Station's capacity to be considered Connecticut capacity;

- be proactive regarding the deactivation/retirement of older generating facilities in the context of electric system needs;

- encourage conservation and demand response;

- avoid excessive reliance on any one fossil fuel for generation; and

- encourage innovations.

End Notes

1. CGS §16-50r states, "(a) Every person engaged in electric transmission services, as defined in section 16-1, electric generation services, as defined in said section, or electric distribution services, as defined in said section generating electric power in the state utilizing a generating facility with a capacity greater than one megawatt, shall, annually, on or before March first, file a report on a forecast of loads and resources which may consist of an update of the previous year's report with the council for its review. The report shall cover the ten-year forecast period beginning with the year of the report. Upon request, the report shall be made available to the public. The report shall include, as applicable: (1) A tabulation of estimated peak loads, resources and margins for each year; (2) data on energy use and peak loads for the five preceding calendar years; (3) a list of existing generating facilities in service; (4) a list of scheduled generating facilities for which property has been acquired, for which certificates have been issued and for which certificate applications have been filed; (5) a list of planned generating units at plant locations for which property has been acquired, or at plant locations not yet acquired, that will be needed to provide estimated additional electrical requirements, and the location of such facilities; (6) a list of planned transmission lines on which proposed route reviews are being undertaken or for which certificate applications have already been filed; (7) a description of the steps taken to upgrade existing facilities and to eliminate overhead transmission and distribution lines in accordance with the regulations and standards described in section 16-50t; and (8) for each private power producer having a facility generating more than one megawatt and from whom the person furnishing the report has purchased electricity during the preceding calendar year, a statement including the name, location, size and type of generating facility, the fuel consumed by the facility and the by-product of the consumption. Confidential, proprietary or trade secret information provided under this section may be submitted under a duly granted protective order. The council may adopt regulations, in accordance with the provisions of chapter 54, that specify the expected filing requirements for persons that transmit electric power in the state, electric distribution companies, and persons that generate electric power in the state utilizing a generating facility with a capacity of greater than one megawatt. Until such regulations are adopted, persons that transmit electric power in the state shall file reports pursuant to this section that include the information requested in subdivisions (6) and (7) of this subsection; electric distribution companies in the state shall file reports pursuant to this section that include the information requested in subdivisions (1), (2), (7) and (8) of this subsection; persons that generate electric power in the state utilizing a generating facility with a capacity greater than one megawatt shall file reports pursuant to this section that include the information requested in subdivisions (3), (4), (5) and (8) of this subsection. The council shall hold a public hearing on such filed forecast reports annually. The council shall conduct a review in an executive session of any confidential, proprietary or trade secret information submitted under a protective order during such a hearing. At least one session of such hearing shall be held after six-thirty p.m. Upon reviewing such forecast reports, the council may issue its own report assessing the overall status of loads and resources in the state. If the council issues such a report, it shall be made available to the public and shall be furnished to each member of the joint standing committee of the General Assembly having cognizance of matters relating to energy and technology, any other member of the General Assembly making a written request to the council for the report and such other state and municipal bodies as the council may designate."

2. Household electric energy consumption is generally stated in kilowatt-hours, which is the equivalent of operating a one-thousand watt load (ten light bulbs of 100 watts each, for example) for one hour. On a statewide scale, a larger unit called a gigawatt-hour is used. One gigawatt-hour (GWh) is the equivalent of operating a one billion watt load for an hour.

3. Electric load can be thought of as the rate at which electricity is consumed. In utility forecasting and planning, electric loads are generally rated in megawatts. One megawatt (MW) represents an electric load of one million watts. This is the equivalent of operating 10,000 light bulbs of 100 watts each simultaneously.

4. The ten-year forecast period is from 2006 through 2015. However, Figure 2 includes past peak loads from the year 2001 to give the reader a longer term picture of the past electric loads.

5. Electric loads vary with time depending on demand. Utility forecasting considers the peak load, which is the highest load experienced during the year. The Connecticut Valley Electric Exchange (CONVEX) reported a record peak of 7,135 MW in 2005. The sum of three Connecticut utilities' peaks is 7,120 MW in Figure 2. However, the percent difference is small and on the order of 0.2 percent.

6. The electric power outputs for generating plants have both a summer and winter rating, referred to as seasonal claimed capability (SCC). SCC ratings are the maximum dependable load-carrying ability, expressed in megawatts, of a generating unit or units, excluding the capacity required for the power station's own use. SCC ratings are computed per ISO-NE's rule "M-20" for installed capacity and correspond to the power generating capacities at 20 degrees F and 90 degrees F ambient temperatures for the winter and summer ratings, respectively. The SCC for a given generating facility that may be claimed by the New England Power Pool must be verified by conducting a claimed capacity audit. Generally, fossil-fueled plants have a higher SCC rating in the winter than the summer.

7. Black start capability (BSC) is the ability of a generating station to start and commence generation without any outside source of electricity. (For example, a power plant with BSC may have its own on-site diesel generators that can start under battery power and then produce electricity in order to start the main generating units.) ISO-NE audits BSC and determines which plants would require BSC. Certain hydroelectric plants inherently have this capability due to the natural water flow and their design. Currently, existing generating plants that have black start capability include: Stevenson Hydro plant; Rocky River Hydro plant; Tunnel Jet Turbine; South Meadows Jet Turbine; Middletown #10; Montville #10 and #11; Franklin Drive #10; Torrington Terminal #10; Branford #10; and PPL Wallingford. In the event of a major blackout, units without black start capability that have been shut down are dependent on outside grid power to restart.

8. Class I renewable energy sources are defined as follows: "(A) energy derived from solar power, wind power, a fuel cell, methane gas from landfills, ocean thermal power, wave or tidal power, low emission advanced renewable energy conversion technologies, a run-of-the-river hydropower facility provided such facility has a generating capacity of not more than five megawatts, does not cause an appreciable change in the river flow, and began operation after the effective date of this section, or a biomass facility, including, but not limited to, a biomass gasification plant that utilizes land clearing debris, tree stumps or other biomass that regenerates or the use of which will not result in a depletion of resources, provided such biomass is cultivated and harvested in a sustainable manner and the average emission rate for such facility is equal to or less than .075 pounds of nitrogen oxides per million BTU of heat input for the previous calendar quarter except that energy derived from a biomass facility with a capacity of less than five hundred kilowatts that began construction before July 1, 2003, may be considered a Class I renewable energy source, provided such biomass is cultivated and harvested in a sustainable manner, or (B) any electrical generation, including distributed generation, generated from a Class I renewable energy source."

9. Class II renewable energy sources are defined under PA 03-135 as "energy derived from a trash-to-energy facility, a biomass facility that began operation before July 1, 1998, provided the average emission rate for such facility is equal to or less than 0.2 pounds of nitrogen oxides per million BTU of heat input for the previous calendar quarter, or a run-of-the-river hydropower facility provided such facility has a generating capacity of not more than five megawatts, does not cause an appreciable change in the riverflow, and began operation prior to the effective date of this section."

10. Customer-side distributed resources are defined under PA 05-1 as "the generation of electricity from a unit with a rating of not more than sixty-five megawatts on the premises of a retail end user within the transmission and distribution system including, but not limited to, fuel cells,

photovoltaic systems or small wind turbines, or a reduction in demand for electricity on the premises of a retain end user in the distribution system through methods of conservation and load management, including, but not limited to, peak reduction systems and demand response systems."

11. Grid-side distributed resources are defined under PA 05-1 as "the generation of electricity from a unit with a rating of not more than sixty-five megawatts that is connected to the transmission or distribution system, which units may include, but are not limited to, units used primarily to generate electricity to meet peak demand."

12. Federally mandated congestion charges are defined under PA 05-1 as "any cost approved by the Federal Energy Regulatory Commission as part of New England Standard Market Design including, but not limited to, locational marginal pricing, locational installed capacity payments, any cost approved by the Department of Public Utility Control to reduce federally mandated congestion charges in accordance with this section, sections 16-99ss, 16-32f, 16-50i, 16-50k, 16-50x, 16-244c, 16-244e, 16-245m, and 16-245n, as amended by this act, and sections 8 to 17, inclusive, and 20 and 21 of this act and reliability must run contracts."

13. The rate schedule is 1.0 mills on and after January 1, 2006; 1.3 mills on and after January 1, 2007; 1.6 mills on and after January 1, 2008; 1.9 mills on and after January 1, 2009; 2.2 mills on and after January 1, 2010; and 2.5 mills on and after January 1, 2011.

14. Class III renewable energy sources are defined under PA 05-1 as "the electricity output from combined heat and power systems with an operating efficiency level of no less than fifty percent that are part of customer-side distributed resources developed at commercial and industrial facilities in this state on or after January 1, 2006, or the electricity savings created at commercial and industrial facilities in this state from conservation and load management programs begun on or after January 1, 2006."

15. Combined heat and power systems are defined under PA 05-1 as "a system that produces, from a single source, both electric power and thermal energy used in any process that results in an aggregate reduction in energy use."

16. The nominal power outputs are those reported in their respective applications to the Council. The actual power outputs of active plants vary seasonally. See Appendix A.

17. CGS § 16a-3(b) states that "The Board shall, (1) prepare an annual report pursuant to section 17 of this act; (2) represent the state in regional energy system planning processes conducted by the regional independent system operator, as defined in section 16-1; (3) encourage representatives from the municipalities that are affected by a proposed project of regional significance to participate in regional energy system planning processes conducted by the regional independent system operator; (4) issue a request-for-proposal in accordance with subsections (b) and (c) of section 19 of this act; (5) evaluate the proposals received pursuant to the request-for-proposal in accordance with subsection (f) of section 19 of this act; (6) participate in a forecast proceeding conducted pursuant to subsection (a) of section 16-50r; and participate in a life-cycle proceeding conducted pursuant to subsection (b) of section 16-50r."

18. The distribution lines connect to the wires supplying a home or business via a transformer. The transformer drops the voltage from the distribution level to that required by the end user.

19. The Kleen Energy Switching Station associated with the proposed Kleen Energy Plant has been delayed because construction of the plant has not commenced at this time.

Appendix A
Existing Electric Generation Facilities
as of September, 2005

Facility	Owner	Town	Fuel	Summer Rating	Winter Rating	In-Service Date
AES Thames	AES Thames, Inc.	Montville	Coal/Oil	181.00	182.15	12/1/1989
Aetna Capitol District	Capitol District Energy Ctr.	Hartford	Gas/Oil	51.69	57.77	11/1/1988
Bantam #1	NGC	Litchfield	Hydro	0.07	0.32	1/1/1905
Branford #10	NRG	Branford	Oil	15.84	20.95	1/1/1969
Bridgeport Energy	Bridgeport Energy LLC	Bridgeport	Gas	446.47	525.71	8/1/1998
Bridgeport Harbor #2	PSEG Power, LLC	Bridgeport	Oil	130.50	147.51	8/1/1961
Bridgeport Harbor #3	PSEG Power, LLC	Bridgeport	Coal/Oil	372.21	370.37	8/1/1968
Bridgeport Harbor #4	PSEG Power, LLC	Bridgeport	Oil	9.92	14.72	10/1/1967
Bridgeport Resco	CRRA	Bridgeport	Refuse	58.52	58.74	4/1/1988
Bristol RRF	Ogden Martin Systems-CT	Bristol	Refuse/Oil	13.20	12.74	5/1/1988
Bulls Bridge #1- #6	NGC	New Milford	Hydro	8.40	8.40	1/1/1903
Dexter	Alstom	Windsor Locks	Gas/Oil	38.00	39.00	5/1/1990
Colebrook	MDC	Colebrook	Hydro	1.37	1.37	3/1/1988
Cos Cob #10	NRG	Greenwich	Oil	17.88	22.78	9/1/1969
Cos Cob #11	NRG	Greenwich	Oil	18.24	23.23	1/1/1969
Cos Cob #12	NRG	Greenwich	Oil	18.44	23.34	1/1/1969
Dayville Pond	Summit Hydro Power	Killingly	Hydro	0.06	0.06	3/1/1995
Derby Dam	McCallum Enterprises	Shelton	Hydro	7.05	7.05	3/1/1989
Devon #7	NRG	Milford	Oil/Gas	0.00	0.00	1/1/1956
Devon #11	NRG	Milford	Gas/Oil	29.58	39.10	10/1/1996
Devon #12	NRG	Milford	Gas/Oil	29.24	38.45	10/1/1996
Devon #13	NRG	Milford	Gas/Oil	30.76	39.76	10/1/1996
Devon #14	NRG	Milford	Gas/Oil	29.75	40.33	10/1/1996
Exeter	Oxford Energy, Inc.	Sterling	Tires/Oil	24.17	25.66	12/1/1991
Falls Village #1- #3	NGC	Canaan	Hydro	9.76	11.00	1/1/1914
Franklin Drive #10	NRG	Torrington	Oil	15.42	20.53	11/1/1968
Glen Falls	Summit Hydro Power	Plainfield	Hydro	0.10	0.10	3/1/1998
Goodwin Dam	MDC	Hartland	Hydro	2.06	2.06	2/1/1986
Hartford Landfill	CRRA	Hartford	Methane	2.37	2.37	8/1/1998
Kinneytown A	Kinneytown Hydro Co.	Ansonia	Hydro	0.25	0.25	3/1/1988
Kinneytown B	Kinneytown Hydro Co.	Seymour	Hydro	0.65	0.65	11/1/1986
Lake Road #1	Lake Road Generating Co., L.P.	Killingly	Gas/Oil	232.75	268.37	7/1/2001
Lake Road #2	Lake Road Generating Co., L.P.	Killingly	Gas/Oil	232.80	268.43	11/1/2001

Appendix A
Existing Electric Generation Facilities
as of September, 2005

Facility	Owner	Town	Fuel	Summer Rating	Winter Rating	In-Service Date
Lake Road #3	Lake Road Generating Co., L.P.	Killingly	Gas/Oil	232.57	268.20	5/1/2002
Lisbon RRF	Riley Energy Systems	Lisbon	Refuse	12.96	13.04	1/1/1996
Mechanicsville	Saywatt Hydro Associates	Thompson	Hydro	0.10	0.10	9/1/1995
Middletown #2	NRG	Middletown	Oil/Gas	117.00	120.00	1/1/1958
Middletown #3	NRG	Middletown	Oil/Gas	236.00	245.00	1/1/1964
Middletown #4	NRG	Middletown	Oil	400.00	402.00	6/1/1973
Middletown #10	NRG	Middletown	Oil	17.12	22.02	1/1/1966
Milford Power #1	Milford Power Company, LLC	Milford	Gas/Oil	239.00	267.24	2/12/2004
Milford Power #2	Milford Power Company, LLC	Milford	Gas/Oil	253.09	287.63	6/1/2004
Millstone #2	Dominion Nuclear CT, Inc.	Waterford	Nuclear	882.14	881.96	12/1/1975
Millstone #3	Dominion Nuclear CT, Inc.	Waterford	Nuclear	1155.00	1155.48	4/1/1986
Montville #5	NRG	Montville	Oil/Gas	81.00	81.59	1/1/1954
Montville #6	NRG	Montville	Oil	407.40	409.91	7/1/1971
Montville #10 & #11	NRG	Montville	Oil	5.30	5.35	1/1/1967
New Haven Harbor #1	PSEG Power, LLC	New Haven	Oil/Gas	447.89	454.64	8/1/1975
New Milford Landfill	Vermont Electric Power Co.	New Milford	Methane/Oil	2.01	2.01	8/1/1991
Norwalk Harbor #1	NRG	Norwalk	Oil	162.00	164.00	1/1/1960
Norwalk Harbor #2	NRG	Norwalk	Oil	168.00	172.00	1/1/1963
Norwalk Harbor #10 (3)	NRG	Norwalk	Oil	11.93	17.13	10/1/1996
Norwich 2nd St./Greenville Dam	CMEEC	Norwich	Hydro	0.95	0.95	10/1/1998
Norwich 10th St.	CMEEC	Norwich	Hydro	0.98	1.21	1/1/1966
Norwich Jet	CMEEC	Norwich	Oil	15.26	18.80	9/1/1972
Pinchbeck	William Pinchbeck, Inc.	Guilford	Wood	0.01	0.01	7/1/1987
PPL Wallingford Unit #1	PPL EnergyPlus, LLC	Wallingford	Gas	43.50	48.95	8/1/2001
PPL Wallingford Unit #2	PPL EnergyPlus, LLC	Wallingford	Gas	41.37	52.37	8/1/2001
PPL Wallingford Unit #3	PPL EnergyPlus, LLC	Wallingford	Gas	43.53	48.43	8/1/2001
PPL Wallingford Unit #4	PPL EnergyPlus, LLC	Wallingford	Gas	44.51	49.79	8/1/2001
PPL Wallingford Unit #5	PPL EnergyPlus, LLC	Wallingford	Gas	42.57	53.57	8/1/2001
Preston RRF	SCRRF	Preston	Refuse/Oil	16.01	16.85	1/1/1992
Putnam	Putnam Hydropower, Inc.	Putnam	Hydro	0.58	0.58	10/1/1987
Quinebaug	Quinebaug Associates LLC	Killingly	Hydro	0.98	2.81	9/1/1990
Rainbow Dam	Farmington River Power Co.	Windsor	Hydro	8.20	8.20	1/1/1980
Robertsville #1- #2	NGC	Colebrook	Hydro	0.32	0.62	1/1/1924

Appendix A
Existing Electric Generation Facilities
as of September, 2005

Facility	Owner	Town	Fuel	Summer Rating	Winter Rating	In-Service Date
Rocky Glen/Sandy Hook Hydro	Rocky Glen Hydro LP	Newtown	Hydro	0.04	0.04	4/1/1989
Rocky River	NGC	New Milford	Hydro-pump strg.	29.35	29.00	1/1/1928
Scotland #1	NGC	Windham	Hydro	1.69	2.20	1/1/1937
Shepaug #1	NGC	Southbury	Hydro	41.51	42.56	1/1/1955
South Meadow #5	CRRA	Hartford	Refuse	25.60	29.23	11/1/1987
South Meadow #6	CRRA	Hartford	Refuse	27.11	30.45	11/1/1987
South Meadow #11	NGC	Hartford	Oil	35.78	46.92	8/1/1970
South Meadow #12	NGC	Hartford	Oil	37.70	47.87	8/1/1970
South Meadow #13	NGC	Hartford	Oil	38.32	47.92	8/1/1970
South Meadow #14	NGC	Hartford	Oil	35.01	46.61	8/1/1970
Stevenson #1- #4	NGC	Monroe	Hydro	28.31	28.90	1/1/1919
Taftville #1- #5	NGC	Norwich	Hydro	2.03	2.03	1/1/1906
Torrington Terminal #10	NRG	Torrington	Oil	15.64	20.75	8/1/1967
Toutant	Toutant Hydro Power, Inc.	Putnam	Hydro	0.16	0.16	2/1/1994
Tunnel #1- #2	NGC	Preston	Hydro	1.53	2.10	1/1/1919
Tunnel #10	NGC	Preston	Oil	15.89	20.76	1/1/1969
Wallingford RRF	CRRA	Wallingford	Refuse/Oil	6.35	6.90	3/1/1989
Willimantic #1	Willimantic Power Corp.	Willimantic	Hydro	0.42	0.42	6/1/1990
Willimantic #2	Willimantic Power Corp.	Willimantic	Hydro	0.39	0.39	6/1/1990
Wyre Wynd	Summit Hydro Power	Griswold	Hydro	1.80	1.80	4/1/1997
	Seasonal Claimed Capability of coal fired plants			553.21	552.52	
	Seasonal Claimed Capability of natural gas fired plants			1363.06	1588.10	
	Seasonal Claimed Capability of oil fired plants			2473.48	2616.34	
	Seasonal Claimed Capability of hydroelectric plants			149.11	155.33	
	Seasonal Claimed Capability of methane fired plants			4.38	4.38	
	Seasonal Claimed Capability of nuclear plants			2037.14	2037.44	
	Seasonal Claimed Capability of refuse fueled plants (inc. tires)			183.92	193.61	
	Seasonal Claimed Capability of wood fired plants			0.01	0.01	
	Total Seasonal Claimed Capability available for dispatch to the grid.			6764.31	7147.72	
	(Lake Road is excluded from the total.)					

Appendix A
Existing Electric Generation Facilities
as of September, 2005

Facility (self generation)	Owner	Town	Fuel	Summer Rating	Winter Rating	In-Service Date
Connecticut Valley Hospital	State of Connecticut	Middletown	Oil	2.05	2.05	5/9/1999
Fairfield Hills Hospital	Fairfield Hills Hospital	Newtown	Oil	3.95	3.95	5/9/1999
Federal Paper Board	Federal Paper Board	Sprague	Oil	9.00	9.00	5/9/1999
Fishers Island Elec. Co.	Fishers Island Elec. Co.	Groton	Oil	1.10	1.10	1/1/1965
Groton Sub Base	U.S. Navy	Groton	Oil/Gas	18.50	18.50	1/1/1966
Loctite	Loctite	Rocky Hill	Gas	1.18	1.18	4/1/1994
Norwalk Hospital	Norwalk Hospital	Norwalk	Gas	2.36	2.36	1/1/1992
Norwich State Hospital	Norwich State Hospital	Norwich	Oil	2.00	2.00	5/9/1999
Pfizer #1	Pfizer	Groton	Oil	32.50	32.50	1/1/1948
Pratt & Whitney	UTC	E. Hartford	Gas	23.80	23.80	4/1/1992
Pratt & Whitney	UTC	Middletown	Oil	1.00	1.00	5/9/1999
Smurfit-Stone Container Co.	Smurfit-Stone Container Co.	Montville	Refuse	2.00	2.00	9/1/1989
Southbury Training School	State of Connecticut	Southbury	Oil	1.50	1.50	5/9/1999
University of Conn. COGEN	State of Connecticut	Mansfield	Gas/Oil	24.90	24.90	8/1/2005
	Total Natural Gas Fired Generation less than 1 MW each			4.41	4.41	
	Total Propane Fired Generation less than 1 MW each			0.03	0.03	
	Total Hydroelectric Generation less than 1 MW each			2.22	2.22	
	Total Methane Fueled Generation less than 1 MW each			0.13	0.13	
	Total Solar (photovoltaic) Generation less than 1 MW each			0.15	0.15	
	Total Wind Powered Generation less than 1 MW each			0.05	0.05	
	Generation retained by facility			132.83	132.83	
	Total MWs of generation in Connecticut.			6897.14	7280.55	

Appendix B
Planned Transmission Lines in Connecticut

Planned Transmission Lines in Connecticut	Length (miles)	Voltage (kV)	Estimated In Service Date
Plumtree S/S, Bethel - Norwalk S/S, Norwalk (new line) (overhead) (Docket No. 217)	8.6	345	2006
Plumtree S/S, Bethel - Norwalk S/S, Norwalk (new line) (underground) (Docket No. 217)	11.8	345	2006
Killingly S/S, Killingly (new substation) - Tracy S/S, Putnam (new line) (overhead) (Docket No. 302)	0.1	115	2006
Killingly S/S, Killingly (new substation) - Tracy S/S, Putnam (new line) (overhead) (Docket No. 302)	0.1	115	2006
Plumtree S/S, Bethel - Triangle S/S, Danbury (rebuild line) (overhead)	1.8	115	2007
Plumtree S/S, Bethel - Triangle S/S, Danbury (rebuild line) (overhead)	1.8	115	2007
Norwalk Harbor Station, Norwalk - Northport Station, Northport, NY (replace line) (underwater)	5.8	138	2008
Norwalk S/S, Norwalk - Glenbrook S/S, Stamford (new line) (underground) (circuit #1)	8.8	115	2008
Norwalk S/S, Norwalk - Glenbrook S/S, Stamford (new line) (underground) (circuit #2)	8.8	115	2008
East Devon S/S, Milford (new substation) - Singer S/S, Bridgeport (new substation) (new line) (underground) (Docket No. 272)	2.4	345	2009
East Devon S/S, Milford (new substation) - Singer S/S, Bridgeport (new substation) (new line) (underground) (Docket No. 272)	2.4	345	2009
Singer S/S, Bridgeport (new substation) - Norwalk S/S, Norwalk (new line) (underground) (Docket No. 272)	15.4	345	2009
Singer S/S, Bridgeport (new substation) - Norwalk S/S, Norwalk (new line) (underground) (Docket No. 272)	15.4	345	2009
Devon S/S, Milford - Wallingford Station, Wallingford (rebuild a portion of #1640 line) (overhead) (Docket No. 272)	23.6	115	2009
Devon S/S, Milford - Wallingford Station, Wallingford (new portion of #1640 line) (underground) (Docket No. 272)	0.5	115	2009
Devon S/S, Milford - June Street S/S, Woodbridge (rebuild a portion of #1685 line) (overhead) (Docket No. 272)	13.4	115	2009
North Haven S/S, North Haven - Branford S/S, Branford (rebuild a portion of #1655 line) (overhead) (Docket No. 272)	1.2	115	2009
East Devon S/S, Milford - Devon S/S, Milford (new line) (underground) (Docket No. 272)	1.3	115	2009
East Devon S/S, Milford - Devon S/S, Milford (new line) (underground) (Docket No. 272)	1.3	115	2009
East Meriden S/S, Meriden - North Wallingford S/S, Wallingford (rebuild a portion of #1466 line) (overhead) (Docket No. 272)	2.0	115	2009
June Street S/S, Woodbridge - Southington S/S, Southington (rebuild a portion of #1610 line) (overhead) (Docket No. 272)	10.5	115	2009
Devon S/S, Milford - Devon Switching Station, Milford (rebuild line) (overhead) (Docket No. 272)	0.1	115	2009
Devon S/S, Milford - Devon Switching Station, Milford (rebuild line) (overhead) (Docket No. 272)	0.1	115	2009
Devon S/S, Milford - Derby Jc., Shelton - Beacon Falls S/S, Beacon Falls (overhead)(reconductor a portion of #1570 line)	3.8	115	2009
Bunker Hill S/S, Waterbury - Baldwin Jct., Waterbury - Beacon Falls S/S, Beacon Falls (overhead) (reconductor a portion of #1575 line)	3.8	115	2009
Devon S/S, Milford - Lucchini Jct., Meriden - Southington S/S, Southington (new line) (overhead) (Docket No. 272)	22.5	115	2009
Scovill Rock S/S, Middletown - Chestnut Jct., Middletown (new line) (overhead) (Docket No. 272)	2.6	345	2009
Oxbow Jct., Haddam - Beseck S/S, Wallingford (new switchyard) (new line) (overhead) (Docket No. 272)	8.0	345	2009
Black Pond Jct., Middlefield - Beseck S/S, Wallingford (new switchyard) (overhead) (Docket No. 272)	2.8	245	2009
Black Pond Jct., Middlefield - Beseck S/S, Wallingford (new switchyard) (overhead) (Docket No. 272)	2.8	245	2009
Beseck S/S, Wallingford (new switchyard) - East Devon S/S, Milford (new substation) (new line) (overhead) (Docket No. 272)	33.4	345	2009
Haddam S/S - East Meriden S/S, Meriden (rebuild a portion of # 1975 line) (overhead) (Docket No. 272)	8.4	345	2009
Manchester S/S, Manchester - Hopewell S/S, Glastonbury (reconductor line) (overhead)	7.0	115	2006

Appendix B
Planned Transmission Lines in Connecticut

Other Proposed Transmission Lines in Connecticut	Length (miles)	Voltage (kV)	Estimated In Service Date
Lake Road S/S, Killingly - Killingly S/S, Killingly (new line)	1.0	115	TBD
Lake Road S/S, Killingly - Killingly S/S, Killingly (new line)	1.0	115	TBD
Tunnel S/S, Preston - Ledyard Jct., Ledyard (rebuild line and upgrade to 115-kV)	8.5	69	TBD
Ledyard Jct., Ledyard - Gales Ferry S/S, Ledyard (upgrade line to 115-kV)	1.6	69	TBD
Gales Ferry S/S, Ledyard - Montville Station, Montville (upgrade line to 115-kV)	2.4	69	TBD
Ledyard Jct., Ledyard - Buddington S/S, Groton (upgrade line to 115-kV)	4.7	69	TBD
Card S/S, Lebanon - Wawecus Jct., Bozrah (rebuild line)	12.7	115	TBD
Norwalk Harbor Station, Norwalk - Glenbrook S/S, Stamford (new line)	9.2	115	TBD
South End S/S, Stamford - Tomac S/S, Greenwich (reconductor a portion of the #1750 line)	0.4	115	TBD
East Meriden S/S, Meriden - North Wallingford S/S, Wallingford (reconductor the westerly portion of the #1466 line)	0.5	115	TBD
Schwab Jct., Wallingford - Colony S/S, Wallingford (new line)	1.5	115	TBD
Manchester S/S, Manchester - Barbour Hill S/S, South Windsor (rebuild line)	7.5	115	TBD
Oxbow Jct., Haddam - Beseck Jct., Wallingford (unbundle and rebuild line)	14.7	115	TBD
Colony S/S, Wallingford - North Wallingford S/S, Wallingford (unbundle line)	2.4	115	TBD
Frost Bridge S/S, Watertown - Bunker Hill S/S, Waterbury (new line)	3.9	115	TBD
Frost Bridge S/S, Watertown - Walnut Jct., Thomaston (new line)	6.4	115	TBD
Frost Bridge S/S, Watertown - Campville S/S, Harwinton (rebuild line)	10.3	115	TBD