Report to the Connecticut Siting Council on Loads and Transmission Resources

April 10, 2008

The United Illuminating Company
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Section I. Load Forecast Update

As in previous years, The United Illuminating Company's ("UI" or "Company") sales forecast has been developed for budgeting and financial planning purposes. This year, the Company has further enhanced its long-range peak forecasting model. Similar to last year, this year's long-range peak forecasting model utilizes econometric models that incorporate economic indicators along with specifically identified customer load growth. The economic parameters utilized in this year's model are expected to be a better predictor of future long-range system peak loads. The parameters used in the individual econometric models vary depending upon the customer class of interest. Over the past ten years, UI has experienced slightly less weather adjusted sales growth as compared to system peak growth. An accurate long-range peak load forecast is required to properly plan for infrastructure modifications and additions to ensure that required capacity and transmission/distribution infrastructure is in place to safely and reliably meet customer demand.

This year, the Company has included in this submittal its "normal weather" system peak load forecast and one sensitivity ("extreme weather") forecast which, when taken together, represent a range of possible futures. The actual sales and system peak load experienced by UI will be heavily impacted by summer weather conditions. In 2006, UI experienced an all-time high peak load, but a decrease in annual sales relative to 2005. The 2006 actual system peak exceeded the forecast 2010 "extreme weather" peak as stated in the Company's 2006 Connecticut Siting Council ("CSC") filing by 0.9%.

Peak and sales data for 2006 illustrate that the system load factor is not a constant. The past several years have reflected above average weather during the critical summer period (2001, 2002, and 2006), average weather (2003, 2005 and 2007), and a below average weather year (2004). However, the 2006 UI system peak demonstrates that the potential for an extremely high system peak load exists within the Company's service territory.

Another variable that can impact the system peak is the level of economic development activity that occurs. Proper planning dictates that a range of possible future peak load scenarios be developed in order to capture the range of potential peak loads that may be experienced and provide sufficient input into the infrastructure planning process. It is for this reason that the Company has developed a peak load forecast that assumes average/normal weather combined with probabilistically weighted economic development activity along with a load forecast that assumes extreme weather and aggressive economic development activity.

Normal Weather

The forecast shown in Exhibit 1 includes system energy requirements, sales and system peak based on "average" or "normal" weather along with the forecast system peak under "extreme" weather conditions. The base for the "normal" forecast is historical weather-corrected sales. The Company reviewed its historical load growth, on a weather-adjusted basis. The predominant factors driving the forecast are background (base) economic growth projections along with the currently estimated impacts of customer installed distributed generation (DG), the Company's conservation and load management

(C&LM) activities, known consumption changes in the future for our large actively-managed commercial and industrial customers and incremental sales efforts.

In an effort to better plan the transmission and distribution infrastructure, the Company embarked on an effort in late 2006 to develop an econometric based ten-year system peak load forecast. This peak forecast would be the basis for the UI ten-year transmission plan. The econometric based load forecast was derived by aggregating historic monthly energy sales by customer class. Energy sales by major customer class were first weather normalized using multiple regression models and then weather corrected to a 30 year monthly “temperature normal.” Economic and demographic variables from independent sources were incorporated in the Residential and Commercial-Industrial models based upon their logical and statistical relevance. The variables include publicly available data such as: number of Connecticut households, Connecticut real household income, Connecticut real Gross State Product, New England real electric price, and the Ten-Year Treasury Bill yield rate. The resultant sales forecasts were then increased to reflect a loss factor – which includes Company usage and electric energy losses - to develop the system energy requirements forecast.

The system “normal weather” peak load forecast was then calculated based on the Company’s econometric based system energy requirements (that is, sales plus Company use plus losses, in GWh) and the weather normalized system load factor based on “50-50” or normal weather over the past ten years. The system “normal” peak load forecast can be found in Exhibit 1.

Extreme Weather Forecast

As the past six summers have shown, the potential for a peak load far above a "normal" or "average" weather forecast is a realistic possibility. In an effort to bound the potential future load, the Company has developed a sensitivity peak load forecast. The "extreme weather" peak forecast was adjusted for aggressive economic development activity and extreme "90-10" weather. The economic development activity includes expansion of existing UI customers, redevelopment of existing areas and new "green field" construction. The "extreme weather" peak load forecast is shown in Exhibit 1 in conjunction with the "normal weather" forecast.

The ability to predict when extreme weather will occur or the exact amount of economic activity that will be realized is difficult. Therefore, prudent infrastructure planning requires that the possibility of the effects of abnormally hot weather within the forecast time period be recognized, as well as an appropriate assumption of future economic development activity. Plans must be formulated to meet this possible demand. The bounds of the Company's forecasts are intended to provide a plausible range of futures. No single forecast will be accurate throughout the forecast period. Rather, extreme weather will occur one year, maybe not the next and then perhaps occur the third or fourth year. When extreme weather occurs, regardless of the timing, the system infrastructure must be in place to serve the high load safely and reliably. In fact, on a sales basis, the years 2001 through 2003 were above "average," that is, actual sales were above the weather corrected (degree days) sales, while 2004 was near "average" with the actual sales being almost identical to the weather corrected sales level. In 2005, the Company experienced a high summer peak load and annual sales that were above those of an “average” weather year. In 2006, UI experienced a high summer peak load coupled with annual sales that were below those of an “average” weather year. However, in 2007, the Company experienced sales below “average” weather corrected sales.

Distributed Generation

The Connecticut General Assembly passed a landmark legislative initiative in 2005: Public Act 05-01, June Special Session, *An Act Concerning Energy Independence* (“PA 05-01”). Although the legislation is now nearly three years old, the full potential of the Distributed Generation (DG) sections are only now beginning to come to pass. The implementation of the Act, carried out by the Department of Public Utility Control (“DPUC”), provides significant monetary grants to offset the capital cost of installing DG. Despite these large capital grants, the decision of whether or not such an installation is economically attractive is unique to each customer. As such, the remaining number of installations that may occur under the Act is difficult to predict.

The first monetary grant under the Act to a DG unit in the UI service territory was made late last year. Other customers have applied for capital grants and have been approved by the DPUC. The in-service dates for these additional units is under the control of the owners, but all of these units are scheduled to be operational over the next few years. These units have all been included as offsets to additional generation in the analysis that supports both the current sales and system peak load forecast.

Conservation & Load Management

The electric distribution companies in Connecticut have delivered nationally recognized conservation and load management programs for the benefit of consumers statewide. In 2007, the American Council for an Energy-Efficient Economy ("ACEEE"), a national organization that promotes energy efficiency ranked Connecticut number one in a tie with California and Vermont for excellence in its energy efficiency programs. ACEEE also gave several of the individual programs the companies in Connecticut offer an exemplary ranking.

The programs benefit from the input of the Energy Conservation Management Board (ECMB) and are approved by the DPUC through an annual review process. This collaborative effort has led to the development of the excellent program offerings. This collaboration has also led to impressive energy savings for Connecticut. As a result of the efforts of UI, the ECMB and the DPUC, the cumulative savings for the period 2000—2007 for UI's service territory is 1.3 billion kWh, or 1.3 million MWh.

The legislation that restructured the electric industry in Connecticut created the ECMB and also specified the collection rate to fund the conservation and load management programs at 3 mils per kWh. Legislative action in 2003 had diverted some of the funding and reduced the amount available to run programs to approximately 2 mils/kWh. Funds were earmarked in last year's State budget to restore the collection rate to the original 3 mils/kWh and the resulting increase in savings projections is included in this year's forecast.

There will be a new market for generation capacity in New England beginning in 2010. The Forward Capacity Market, developed by ISO New England ("ISO-NE"), is intended to produce a mechanism to assure adequate generating capacity in New England. One of the unique features of this new market is that demand side resources can be treated as fully qualified capacity and receive the same payments as a supply side resource (generating unit). The Demand Side Management (DSM) resources included in the ten-year forecast will be entered into this new market, will receive capacity payments and be treated as a resource.

There was a piece of ground breaking legislation passed into law this past summer. The legislation, Public Act 07-242, *An Act Concerning Energy Efficiency*, includes numerous significant changes to the energy industry. Many of these sections deal with demand side management technologies. Although many of the features of the Bill are still being implemented by the DPUC, there exists the potential to increase the level of DSM implemented in Connecticut.

One of the features of the legislation that has the greatest potential to change the energy landscape is the Integrated Resource Plan (IRP) that is required to be completed by the electric distribution companies ("EDC") and submitted to first the Connecticut Energy Advisory Board ("CEAB") and then the DPUC. This IRP is required to consider all cost-effective energy efficiency and has the potential to deliver significantly more DSM savings. The first annual plan is currently being reviewed by the CEAB. The plan includes unprecedented levels of DSM savings that have not yet been approved and funding to implement has not yet been received. Although the formal review process has not yet been completed, UI has included the impacts of the aggressive levels of DSM savings into the load forecast analysis.

Section II. Transmission Planning

The combination of increased energy consumption and the development of the competitive wholesale generation marketplace has impacted transmission system utilization. The UI projects included in this filing are a result of the impact of these factors on the existing infrastructure. These projects will enable the Company to fulfill its obligation to provide reliable service to its customers and to meet the design standards mandated by independent national and regional authorities responsible for the reliability of the transmission system: the North American Electric Reliability Council (NERC), the Northeast Power Coordinating Council (NPCC), ISO-NE, and the New England Power Pool (NEPOOL).

The on-going restructuring efforts in the electric industry at the state and federal levels have brought about numerous significant changes. The move towards open access to competing generation resources has resulted in changes in generating patterns due to competitive pricing and the siting and operation of merchant generating facilities. This has now become an additional impetus for transmission infrastructure upgrades. Prior to restructuring, changes to the transmission system had been undertaken predominantly to (1) accommodate area load growth, and (2) maintain system reliability and voltage, and/or upgrade aging facilities. Generation-related transmission upgrades had been limited to the addition or retirement of planned, specific generating units. Now, transmission upgrades also assist in the development of the competitive wholesale generation marketplace and also help reduce the economic penalties paid by

Connecticut's electricity ratepayers as a result of limitations on the ability to import lower cost generation.

Recent regulatory developments regarding renewable electric generation and emissions may provide impetus for additional transmission projects in the future. Connecticut, like other New England states, has established a substantial renewable portfolio standard (RPS) that ramps up over time (from approximately 6.5% of energy in 2007 to 23% of energy in 2020 for Class I and II renewables). Connecticut's and New England's requirements for renewable generation are projected by ISO-NE as follows: 2,095 GWh in 2007 and 8,618 GWh in 2020 for Connecticut; and 3,731 GWh in 2007 and 20,576 GWh in 2020 for all of New England.[1]

For Connecticut and likely other southern New England states it appears it will be difficult to satisfy the RPS exclusively with domestic (in-state) assets. To the extent the RPS cannot be satisfied locally or through alternative compliance payments, additional transmission projects may be necessary to tap remote renewable-rich regions and facilitate import of remote renewable generation. In addition to potential renewable resources in northern New England, substantial potential exists in the Canadian provinces. In a recent preliminary assessment, ISO-NE indicated that the eastern Canadian provinces have potential in excess of 13,000 MW of renewable resource capacity.[2]

[1] ISO-NE Planning Advisory Committee Meeting, March 19, 2008 – Northeast International Committee on Energy (NICE) Update Presentation.
[2] ibid

On April 1, 2008, multiple parties (including UI) submitted requests to ISO-NE for "economic studies" pursuant to new Attachment K of the region-wide transmission tariff. Attachment K was developed in 2007 in response to the Federal Energy Regulatory Commission (FERC) Order 890. It provides a means to assess improvements that may (a) reduce total production costs, (b) reduce congestion, or (c) integrate new resources/loads. It is likely that several of the April 1 study requests relate to the tapping of remote renewable resources and satisfaction of states' RPS. ISO-NE's initial hierarchy for studies will be delivered to stakeholders on or before April 30, 2008. A minimum of three concepts are to be assessed commencing later this year.

UI's planned transmission system modifications are listed in Exhibit 2 and are outlined below.

The Middletown to Norwalk Project, which received a certificate of environmental compatibility and public need from the CSC, on April 7, 2005, involves expanding the 345-kV transmission system from Middletown to Norwalk and rebuilding and modifying portions of the 115-kV system. This expands the 345-kV backbone from Beseck Junction (Wallingford) to East Devon (Milford); East Devon to Singer (a new substation to be built in Bridgeport); and Singer to Norwalk. The project also includes a new 345-kV switching station at Beseck Junction and new 345/115-kV substations in Milford (East Devon Substation) and Bridgeport (Singer Substation). Modifications to CL&P's Scovill Rock 345-kV Switching Station and Norwalk 345-kV Substation, and to UI's Pequonnock 115-kV Substation will be required. The proposed new 345-kV Singer Substation will be located in the vicinity of UI's existing 115-kV Pequonnock Substation

(Bridgeport). Singer Substation is now under construction as a sixteen-breaker gas insulated substation (GIS) in a breaker-and-one-half configuration. This transmission arrangement will allow for 345-kV line terminations from the 345-kV East Devon and Norwalk substations.

Additionally, two 600 MVA 345/115-kV autotransformer banks will be installed at Singer Substation. These autotransformers will interconnect the 115-kV Pequonnock Substation and the Bridgeport Energy generation facility to the 345-kV system. The design will ensure that a single malfunctioning 345-kV circuit breaker will not interrupt both transmission paths from East Devon and Norwalk, or both 345/115-kV autotransformers simultaneously.

The Middletown to Norwalk Project, which is on schedule to be completed in 2009, will complete a 345-kV transmission loop into Southwest Connecticut, thereby improving customer reliability and reducing transmission congestion costs. It will also provide an infrastructure capable of allowing greater access to more of New England’s competitively priced generation. When compared to the scenario where the transmission system is not expanded, this expansion project should result in lower energy costs to all of Connecticut’s consumers as well as the continued reliable operation of the electric system.

UI has other transmission infrastructure upgrades planned or under internal review.

The Trumbull area has experienced significant load growth. In 2007, the Council granted a certificate of environmental compatibility and public need for the new Trumbull Substation, a new 115/13.8-kV substation that is needed to address reliability and capacity issues. The Trumbull Substation project is currently under construction and is on schedule to be in service by June 2008.

The Naugatuck Valley area (Ansonia, Derby and Shelton) of UI's service territory is presently supplied by three 115/13.8-kV distribution substations: Ansonia, Indian Well and Trap Falls. These substations are connected to the 115-kV transmission system via CL&P's and UI's 1545, 1560, 1570 and 1594 overhead lines. Presently, these circuits no longer provide an adequate 115-kV voltage supply to the area. A voltage collapse condition for UI customers supplied by either Ansonia, Indian Well or Trap Falls substations could result due to a single contingency loss of both the 1545 and 1570 lines. The 1545 and 1570 lines are constructed on common 115-kV structures and share a common 115-kV circuit breaker at Devon 115-kV Switching Station. A single failure associated with any structure shared by these circuits, referred to as a Double Circuit Tower (DCT) contingency, or with the 115-kV circuit breaker at Devon, referred to as a stuck breaker contingency, would result in loss of both the 1545 and 1570 lines. If this 1545-1570 DCT or Devon stuck circuit breaker contingency occurs during summer peak load conditions, there is a potential for UI customers in the Naugatuck Valley area to experience a severe low voltage condition.

In addition, UI's 115-kV transmission corridor connecting Derby Junction, Indian Well Substation and Ansonia Substation, as well as portions of the CL&P 115-kV transmission corridor between Stevenson – Trap Falls, are designed with double overhead 115-kV transmission circuits (1560/1570 lines and 1560/1594 lines) constructed on single structures. A Double Circuit Tower (DCT) contingency anywhere along the 10.3 mile corridor where the 1560 and 1570 lines share towers will cause a significant loss of load, projected to be above 115 MW (summer peak) in 2010, for customers served from Ansonia and Indian Well Substations.

UI is concerned with this outage exposure as nearly 30,000 customers (9% of UI's customer base) are at risk with the 1560/1570 Line DCT contingency, which could result from many causes, such as lightning strikes, tower failure due to severe weather such as ice and wind, or other equipment related events. The loss of both substations (Indian Well and Ansonia) due to one of these events will lead to a prolonged outage for these 30,000 customers, the majority of which will not be able to have power restored until the cause of the transmission outage is corrected for at least one of these 115-kV transmission circuits, which could take up to 24 hours or more, depending upon the severity of the problem. Also, a DCT contingency along the 2.6 mile corridor where the 1560 and 1594 lines share towers will also cause the loss of all customer load served by Ansonia Substation, projected to be above 45 MW (summer peak) in 2010. Therefore, there is a total of 12.9 miles of 115 kV DCT loss of load exposure for all 12,000 Ansonia Substation customers.

The Shelton area is also experiencing significant load growth. The Shelton Substation Project, a new 115/13.8-kV substation, is needed to address distribution reliability and capacity issues. UI is evaluating the synergies between this Shelton

Substation Project and the Naugatuck Valley 115-kV Reliability Improvement Project discussed earlier. UI anticipates making a filing with the CSC for these projects later in 2008, which are projected to be in service in 2010 and 2012, respectively.

Load growth has also warranted further study of new 115/13.8-kV substations in New Haven, Fairfield, Orange, Hamden and North Branford. Anticipated completion for these substations would be 2010 or later as described below:

- New Haven I – Projected in service for 2010.
- Fairfield – Projected in service for 2012.
- Orange – Projected in service for 2013.
- Hamden – Projected in service for 2014.
- North Branford – Projected in service for 2014.
- New Haven II – Projected in service for 2015.

Also, the need for a new 115/13.8-kV substation is being evaluated to serve the potential load growth in the Steel Point area of Bridgeport. A new proposed development called “Bridgeport Landing” entails construction of a new mixed-use community complete with a waterfront pedestrian esplanade and a marina on a 52 acre site, with a projected peak demand of about 30 MW. A better understanding for the substation’s need is expected to be determined by the end of 2008.

To address 115-kV short circuit interrupting capability issues in the greater Bridgeport-Milford area, UI is recommending a Pequonnock 115-kV Fault Duty Mitigation Project, expected to be in service by 2012. In 2008, UI, CL&P and ISO-NE are expected to complete the necessary studies to document the needs and provide a solution for the Pequonnock 115 kV Fault Duty Mitigation Project. UI anticipates making a filing with the CSC for this project in 2009.

To address reliability compliance issues in the greater New Haven area, UI is recommending a Grand Avenue 115 kV Rebuild Project, expected to be in service by 2012. By mid-2008, UI expects to complete the necessary studies to document the needs and develop a solution for the Grand Avenue 115 kV Rebuild Project. UI anticipates making a filing with the CSC for this project by 2009.

On September 1, 2005, the FERC issued a notice of proposed rulemaking for the establishment of an Electric Reliability Organization (ERO). This was in response to the newly enacted Energy Policy Act of 2005, which in part directed FERC to establish an ERO, and develop mandatory electric reliability standards and enforcement procedures for reliability violations. NERC has since been selected as the ERO and is in the process of setting mandatory standards and penalties for non-compliance. UI must now respond to NERC’s expanding role and new requirements for maintaining system reliability.

UI is unaware of any instances where a UI transmission line exceeded its long-time or short-time emergency rating during abnormal system conditions. UI and CL&P in conjunction with CONVEX (the Connecticut Valley Electric Exchange), ISO-NE, and NEPOOL periodically review the performance of the transmission system as part of a coordinated effort to provide adequate and reliable transmission capacity at a reasonable cost.

Please note that Exhibit 2 to this Report includes only those planned transmission projects that UI is responsible to undertake. It does not include any plans or proposed actions by third parties that would comprise or require transmission system modifications in UI's service territory. It would be the responsibility of such third parties to provide the CSC with a report of their plans as appropriate. Any such proposed modifications would require notification and coordination with UI so that UI can assess the impacts on its transmission system and ensure the system's continued reliability.

Section III EXHIBITS

EXHIBIT 1 System Energy Requirements, Annual Sales, and Peak Load Table

The United Illuminating Company

System Energy Requirements, Annual Sales, and Peak Load

	Year Actual	Total Sys. Req'ts (GWH)	Annual Change (Pct.)	System Peak (MW)	Annual Change	Load Factor (Pct.)	Extreme Weather Scenario System Peak (MW)	Annual Change	Load Factor (Pct.)	Actual Sales (GWH)	Annual Change (Pct.)	Weather Adjusted Sales (GWH)	Annual Change (Pct.)
History	1997	5,631	-0.2%	1,173	12.3%	55%				5,376	0.7%	5,421	1.2%
	1998	5,728	1.7%	1,143	-2.6%	57%				5,452	1.4%	5,485	1.2%
	1999	5,943	3.8%	1,273	11.4%	53%				5,652	3.7%	5,625	2.6%
	2000	5,977	0.6%	1,153	-9.4%	59%				5,654	0.0%	5,708	1.5%
	2001	6,010	0.6%	1,318	14.3%	52%				5,724	1.2%	5,689	-0.3%
	2002	6,051	0.7%	1,300	-1.4%	53%				5,781	1.0%	5,684	-0.1%
	2003	6,071	0.3%	1,274	-2.0%	54%				5,772	-0.2%	5,734	0.9%
	2004	6,205	2.2%	1,201	-5.8%	59%				5,952	3.1%	5,952	3.8%
	2005	6,360	2.5%	1,346	12.1%	54%				6,106	2.6%	5,995	0.7%
	2006	6,149	-3.3%	1,456	8.2%	48%				5,919	-3.1%	5,979	-0.3%
	2007	6,119	-0.5%	1,298	-10.9%	54%				5,917	0.0%	5,929	-0.8%
	1997 - 2007 growth		8.7%		10.6%						10.1%		9.4%
				Normal Weather Scenario			**Extreme Weather Scenario**						
				System Peak (MW)	Annual Change	Load Factor (Pct.)	System Peak (MW)	Annual Change	Load Factor (Pct.)				
Forecast	2008	6,192	1.2%	1,333	2.7%	53%	1,460	12.5%	48%			5,892	-0.6%
	2009	6,092	-1.6%	1,359	2.0%	51%	1,493	2.3%	47%			5,796	-1.6%
	2010	5,921	-2.8%	1,399	2.9%	48%	1,539	3.1%	44%			5,634	-2.8%
	2011	5,872	-0.8%	1,435	2.6%	47%	1,586	3.1%	42%			5,587	-0.8%
	2012	5,825	-0.8%	1,468	2.3%	45%	1,634	3.0%	41%			5,542	-0.8%
	2013	5,750	-1.3%	1,500	2.2%	44%	1,670	2.2%	39%			5,471	-1.3%
	2014	5,699	-0.9%	1,532	2.1%	42%	1,707	2.2%	38%			5,422	-0.9%
	2015	5,653	-0.8%	1,563	2.0%	41%	1,742	2.1%	37%			5,379	-0.8%
	2016	5,631	-0.4%	1,589	1.7%	40%	1,771	1.7%	36%			5,358	-0.4%
	2017	5,582	-0.9%	1,611	1.4%	40%	1,796	1.4%	35%			5,311	-0.9%
	2007 - 2017 growth		-8.8%		24.1%								-10.4%

1. System Requirements are sales plus losses and company use.
2. Load Factor = System Requirements (MWHr) / (8760 Hours X System Peak (MW)).

EXHIBIT 2   Transmission System Planned Modifications

Report to the Connecticut Siting Council

List of Planned Transmission Facilities on which Proposed Route Reviews are Being Undertaken, for which Certificate Applications are Being Contemplated, may be subject to Declaratory Ruling, or have Already Been Filed

I. Route Reviews Being Undertaken

	Project	kV	Date of Completion
1.	Naugatuck Valley 115-kV Reliability Improvement Project	115	2012

II. Certification Applications or Petitions Contemplated

	Substation Projects	kV	Date of Completion
1.	Installation of new substation in Shelton	115	2010
2.	Installation of new substation in New Haven I	115	2010
3.	Naugatuck Valley Reliability Improvement Project	115	2012
4.	Pequonnock Fault Duty Mitigation Project	115	2012
5.	Installation of new substation in Fairfield	115	2012
6.	Installation of new substation in Orange	115	2013
7.	Installation of new substation in Hamden	115	2014
8.	Installation of new substation in North Branford	115	2014
9.	Installation of new substation in New Haven II	115	2015

	Transmission Line Project	Length (miles)	kV	Date of Completion
1.	See Middletown / Norwalk Project below	5.7	345	2009

III. Facilities which are or may be subjects of Requests for Declaratory Ruling by Council.

		kV	Date of Completion
1.	Grand Avenue Rebuild Project	115	2012

IV. Facilities Associated with the Middletown/Norwalk Project.

	Substation Projects	kV	Date of Completion
1.	Installation of new Singer Substation, Bridgeport (See Note 1)	345	2009
2.	Pequonnock Substation, Bridgeport – Circuit Breaker and Bus Addition (see Note 1)	115	2009

	Transmission Line Projects	Length (miles)	kV	Date of Completion
1.	Installation of underground lines from Singer Substation, Bridgeport to splicing chamber just west of Housatonic River, Stratford (see Note 1)	5.7	345	2009

Notes:

1) This project is a part of the Middletown/Norwalk Project, which also includes other 345-kV additions as well as upgrades to existing 115-kV facilities.